Rhode Island Power Sector Transformation

Distribution System Planning Principles and Recommendations

October 13, 1017

Draft for Stakeholder Comment

1. Introduction

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

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

Traditional utility infrastructure – substations, feeders, transformers, etc. – form the conventional set of solutions in the utility toolbox to address system requirements. In today's changing technology landscape, however, a diverse set of resources and strategies[1] – such as energy efficiency, renewable energy, energy storage, and dynamic electric rates – offer the potential to substitute for conventional infrastructure solutions. In many instances, these solutions may be financed, implemented, or owned by customers or third parties, as opposed to the utility. Although many of these solutions are not new, their pace of deployment is accelerating as falling technology costs drive maturing markets and broader consumer adoption.

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

In other words, not only are customers and third parties[2] impacting the system in new – and potentially significant – ways, but they are also now able to become part of the solution set to address grid needs through their own investment choices. DSP, a process which identifies and characterizes areas of need on the grid, must adapt to changing technologies, markets and policy and become a valuable tool for guiding not only utility investment, but also customer and marketplace activity, which can provide value to the grid and the system.

To provide critical guidance to clean energy deployment and customer investment decisions, DSP can leverage a new and growing availability of data. The ongoing modernization of the electric grid includes deployment of devices that yield significant amounts of data about the time, location, and magnitude of electricity consumption and flow. Data pertaining to the electric grid may include customer-specific data emanating from a customer meter or system data emanating from devices

[1] E.g., "Distributed energy resources" (DER), but also technologies and strategies including dynamic rate designs and grid-side optimization technologies.
[2] E.g., DER providers.

located on the grid to monitor the reliability and operation of the electric distribution system. Looking ahead, the abundance of customer and system data – with the proper security and privacy protections in place – offers an opportunity to guide investment decision-making by customers and third parties in addition to utilities.

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

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

2. Regulatory Context

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

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

The Company undertakes these DSP activities in order to develop investment plans for maintaining safe and reliable service in Rhode Island. Today the Company's DSP process supplies information to two distinct planning and investment processes: (1) The Infrastructure, Safety, and Reliability Plan (ISR), and (2) The System Reliability Procurement Plan (SRP).[3] The costs of infrastructure projects are recovered in the ISR; the costs of implementing "non-wires alternative" (NWA) solutions are recovered in the SRP.[4] The ISR and SRP are considered in separate dockets, filed annually with the

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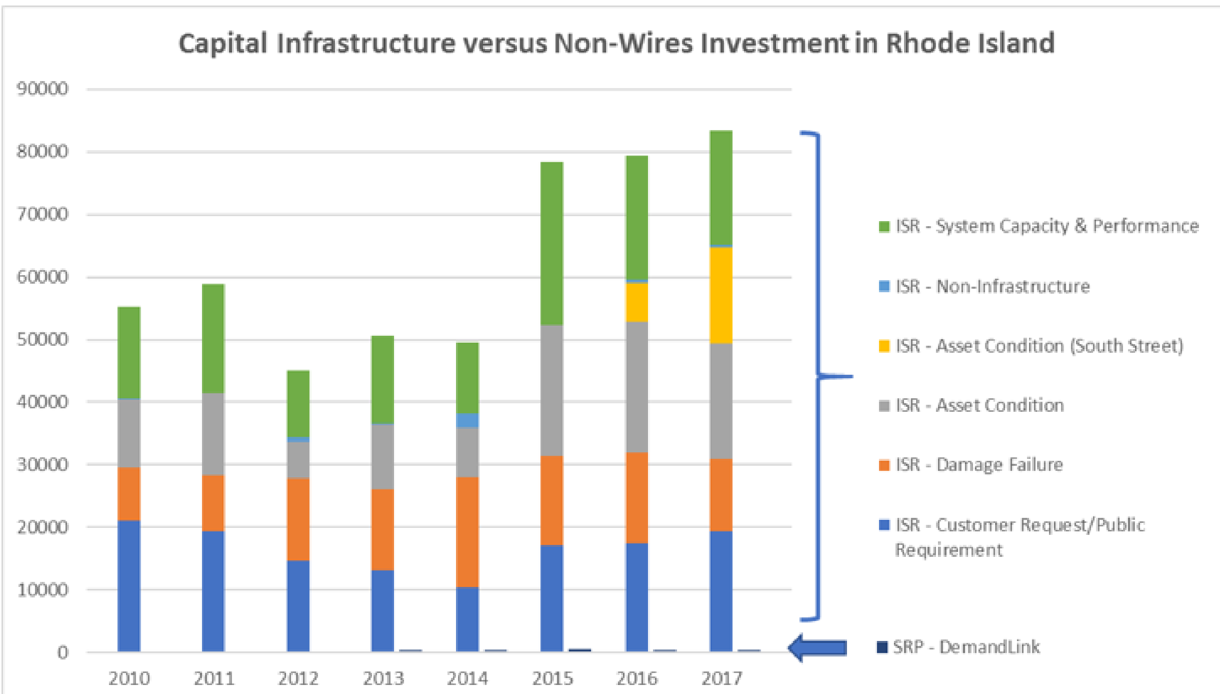
[3] ISR: http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-1/39-1-27.7.1.HTM; SRP: http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-1/39-1-27.7.HTM

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

state's Public Utilities Commission (PUC), however, each has its own with distinct planning cycles.[5] This dichotomy can result in siloed processes among stakeholders and within the utility and is an obstacle to holistic assessment of how the Company should best implement DSP.

Although the Company screens all capital projects for NWA eligibility according to a set of suitability criteria outlined in the SRP Standards,[6] few NWA opportunities have been identified, and investment in traditional utility infrastructure solutions has dwarfed investment in NWA solutions in recent years (Figure 1).

Figure 1. Infrastructure versus Non-Wires Investment in Rhode Island (2010 to 2018)



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

A variety of reasons have been cited to explain the limited opportunities for NWA to date. The Company has indicated that the vast majority of capital projects are driven by an asset condition[7] need (for which NWA are ineligible) due to the aging nature of Rhode Island's distribution infrastructure. Additionally, due to the success of the state's nation-leading energy efficiency programs, electricity consumption has flattened, presenting limited opportunities for deferral of load growth-related investments. As illustrated in Figure 1, however, significant capital investment

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

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

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

persists to address system capacity issues (i.e., circuit peaks driven by load growth). According to the Company, many of these projects address an asset condition issue in tandem with a load issue, which can be viewed as representing bargain value for ratepayers.

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

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

Principles for DSP Reforms:

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

3. **Stakeholder Comment**

- Rhode Island System Data Portal
  - National Grid plans to include reports/information; heat map; and hosting capacity map initially and expand offerings over time. Other commenters want more data and functionality as soon as possible.
  - Several stakeholders suggested a Data Portal working group, potentially through existing working groups.
  - NECEC and AEE have very detailed recommendations for specific data, information and tools they want to see on the Portal for customer data, system data, and grid modernization data. Sunrun's data recommendations were also quite specific.
- Third-Party Data Access
  - Data Types (and formats, frequency, needs, etc.) (customer & system)
    - Several commenters asserted that data needs to be accessible, machine-readable, and in a common format, and that it isn't now.
    - NECEC and AEE recommend a data exchange standard like Green Button.
    - National Grid emphasized the need for identifying use cases for datasets in conjunction with stakeholders.
  - Aggregation Standards
    - National Grid described 15/15 as conservative and temporary until there is a statewide standard.
    - NECEC and AEE think 15/15 is overly restrictive.
    - REIMA said the 15 minimum seems low to get any kind of statistical benefit.
    - Sunrun said New York utilities proposed a 4/50 privacy standard for aggregated whole building data and that this should be a maximum standard.
  - Value-Added Data
    - Commenters differed on whether the utility should be allowed to charge market rates for "value-added" data. The Heartwood Group, Inc., Handy Law, LLC., and Sunrun contended that any data or information collected by the distribution utility should be considered and treated as public information and made accessible without charge. The Acadia Center and NECEC stated that decisions on what constitutes value-added data and associated fees should be made through a docketed proceeding with stakeholder input.
- Forecasts
  - Commenters agreed that annual forecasts and forecast methodologies should be furnished by the Company and presented in the RI System Data Portal.
  - Multiple commenters emphasized the importance of opportunities for meaningful input into the forecast during the course of the development process, with drafts made available with sufficient time to provide input. Because the forecast is developed over multiple months, such feedback will need to be considered by the Company during the development process before the forecast product is finalized.
- Hosting Capacity Analysis
  - National Grid noted that this will only be useful for small projects and will not be sufficient for fast-track approval or detailed interconnection analysis.

    - NECEC and AEE have very specific comments on what analysis is needed in what situations, which may be more than National Grid is planning to provide.
- Heat Maps
    - National Grid intends to present a roadmap for the evolution of the heat map in the pending SRP Plan.
    - Several commenters recommend frequent updating (National Grid – once a year; NECEC and AEE – twice a year; RIEMA – weekly; Sunrun – monthly); and eventual automation.
- Alignment of DSP/Capital/NWA Planning
    - National Grid says it is already working on this with stakeholders.
    - Seth Handy said that stakeholders need to have full access to information and be given the capacity to participate in all system planning processes, but that challenges to this abound.
- DSP Process Recommendations (stakeholder engagement, DSP filings, etc.)
    - Seth Handy said the utility should not oversee or administer any of these functions unless and until incentives are properly reframed per the UBM process.
    - As noted above, several stakeholders suggested a Data Portal working group, potentially through existing working groups.
    - Acadia said the utility plans should include inflection points when decisions can be revisited and adjusted, and stakeholder input continually incorporated.
    - As noted above, several commenters want more stakeholder engagement in forecasting.

4. <u>Recommendations</u>

To achieve the long-term DSP vision, the DPUC and OER propose four reforms to distribution system planning in Rhode Island:

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

<u>Coordinated DSP Filings</u>
To date, the Company has performed distribution system planning entirely in house. Stakeholders and regulators have gained occasional glimpses into DSP activities through PUC docket proceedings such as the Infrastructure, Safety and Reliability dockets and the System Reliability Procurement dockets. The need for more open engagement with DSP, however, will only increase in importance as DER growth in Rhode Island accelerates. Existing filings such as SRP and ISR offer useful platforms for building more transparency into key DSP-related activities such as forecasting, customer and third-party data access, and DER sourcing and compensation. These dockets can serve as coordinated vehicles to house ongoing DSP policy deliberation and stakeholder engagement.

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

***Recommendation**:* The Company should begin filing the ISR and SRP as two linked, synchronized, and cross-referenced DSP filings each year. Linking these two filings and including key DSP-related content will: (1) provide increased transparency and a codified mechanism for stakeholder and regulatory input into the improvement of DSP analytics and tools over time and (2) enable the PUC and stakeholders to consider investments proposed in the ISR and SRP in a comprehensive and holistic manner. ISR/SRP filings should include the following elements:[8]

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

Forecast Improvements

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

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

New approaches to enhance forecasting in a high-DER future could include scenario analysis and probabilistic planning. Scenario forecasts consider a range of possible futures where varying levels of DER are adopted on the system. Probabilistic planning, as opposed to the current deterministic

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

approach, would account for uncertainties introduced by factors including increasing DER penetration and weather variability.

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

- Description of current process for developing forecasts. The Company should describe the following information:
  - What information/metrics do forecasts contain?
  - How are these forecasts used in distribution system planning and how do they affect capital and NWA planning?
  - What are the limitations of current forecasting techniques and, in particular, what impact will increased DER penetration have on the forecasting process?
  - What improvements are needed to forecasting to achieve the objectives of Power Sector Transformation and why? How will new DER-related factors be reflected in forecasting?
- Description of process for reassessing forecasting as technologies and data-gathering capabilities improve. The Company should describe the following information:
  - What information/metrics should forecasts contain going forward as technologies and capabilities improve?
  - How will the utility ensure accuracy of forecasts as DER penetration levels increase?
  - What role should scenario analysis and probabilistic planning play in forecasting and distribution system planning (i.e., how would scenarios inform planning)?

Customer and Third-Party Data Access

Access to data – system data and customer data – could help customers and third parties contribute towards meeting grid needs and maximizing the net benefits of their investments in clean energy technologies.[9] For example, clean energy companies might be able to use information on the location and characteristics of grid needs to target offerings to customers located in beneficial areas. The ability to retrieve customer data – with the proper privacy and security protections in place – could allow clean energy companies to tailor offerings to customers or for customers themselves to take action on their energy use.

The Company should develop data sharing procedures to make key system and customer data available to customers and third parties. Third parties may include, but are not limited to: DER providers and other private energy technology companies; regulators and policymakers; researchers and academics; and local governments. Each of these users may have unique needs,

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

interests, and requirements for datasets, as well as specific use cases for certain datasets they would like to obtain. Enhancing data access should enable customers to more effectively implement solutions to their own energy needs, as well as guide informed investment by DER providers and thereby help the market provide optimal value to customers and the system. The DPUC and OER have identified low-cost, low-risk improvements to data sharing – with privacy and security protections – that can be implemented in the near term. These initial steps should provide learnings that will inform a thoughtful approach to long-term data access strategy.

Recommendation*:* The Company should include and seek approval of a plan for establishing and improving customer and third-party data access in the upcoming rate case. Updated data access plans should be included in future annual SRP/ISR filings.[10] Inclusion of data access plans within the SRP/ISR filings will provide regulators and stakeholders with the opportunity to provide ongoing review and feedback. These plans should include the following elements:

System Data

- Description of data types to be provided
    - Existing Datasets: The Company should provide an up-to-date, comprehensive inventory of datasets (system data) that it already collects and provides through existing filings, web pages, or other means. The Company should indicate the location, format, and frequency of update of these datasets, as well as any fee structure currently in place for third-party access.
    - Near-Term Datasets: The Company should develop specific, near-term, new datasets of importance to DSP objectives – hosting capacity maps and heat maps:[11]
        - A hosting capacity map identifies any substations on the utility's distribution system that cannot host additional DER (DG and EV), due to system constraints. The map, or set of maps, should provide information for a time span into the future consistent with the Company's planning horizon.
        - A heat map (i.e., distribution constraint map) identifies the extent to which each substation on the utility's system is constrained. The map, or set of maps, should provide information for a time span into the future consistent with the Company's planning horizon.
    - Future Datasets: Using the lists of system data provided in the Northeast Clean Energy Council (NECEC) stakeholder comments[12] and the New York Supplemental

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

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

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

Distributed System Implementation Plan (DSIP)[13] as starting points, the Company should engage DER providers to propose a schedule for provision of new datasets over time. The Company should work with DER providers and regulators to define use cases[14] for future datasets and receive input on data formats and prioritization. The schedule should be informed by the Company's ability to collect and generate new datasets when enabled by implementation of advanced grid connectivity and functionality.

- Description of how data will be made available to users
    - Data Portal: A new Rhode Island DSP Data Portal[15] should serve as a clearinghouse for users to access key distribution system and planning data in a central and publicly-accessible online location. Peak/load forecasts, capital plans, distribution system planning process descriptions, heat maps, hosting capacity maps, and other key data should be made available through the Portal. Where possible and appropriate, data should be made available in machine-readable format. Annual reporting on Portal performance should occur through the SRP/ISR and include tracking of key user experience metrics, evaluation of qualitative and/or quantitative costs and benefits, stakeholder feedback, and any proposed improvements.
        - All existing datasets should be provided on the Portal by a date determined by regulators in consultation with the Company and stakeholders.
        - All near-term datasets should be provided on the Portal by a date determined by regulators in consultation with the Company and stakeholders.
    - Data Requests: Initially, decisions on the inclusion of new datasets in the Portal should be considered on an annual basis through SRP/ISR filings. After evaluating initial experience and success of the Portal, the Commission should consider the merits of the Company building capabilities to field on-demand data requests submitted by third parties through a standardized application, built-in form on the DSP Data Portal, or another appropriate formalized process.[16]
- Description of conditions when the utility should be able to charge for data
    - Value-Added Data: The Company should be able to charge market rates to third parties in exchange for developing and providing "value-added" data. The Company should work in consultation with stakeholders to make a proposal to regulators on guidelines for what datasets should be subject to charge and what fee structures

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

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

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

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

might look like. As a general rule, there should be no charge for third parties to access data produced as a matter of normal course of business at the utility. However, if there is additional processing required to create the data, consideration of a cost-based charge may be warranted. Once guidelines for value-added data are determined, summaries of types of value-added datasets and associated fee structures should be published on the Portal.

- Description of data security measures
    - Data Security: The Company should highlight any security concerns and propose adequate security protections for data sharing.

Customer Data

- Description of customer rights to data
    - Individual Customers: All customers should have the right to access their own usage and billing data for free in an easily-organized and standard format (e.g., consumption data for each rate element used for billing on the monthly statement, consumption during peak-time events [once enabling metering is in place]).
    - Third Party Authorization: Customers should be able to authorize third party access to their data.
- Description of data types to be provided
    - Existing Datasets: The Company should provide an up-to-date, comprehensive inventory of datasets (customer-specific data as well as aggregated customer data) that the Company already collects and provides through existing filings, customer accounts, billing, subscription services, or other means.[17] The Company should indicate the location, format, and frequency of update of these datasets, as well as any fee structure currently in place for access.
    - Aggregated Customer Data: The Company should make available a basic set of uniform aggregated customer datasets at no charge: monthly kW and/or installed capacity (ICAP), customer counts, and kWh data aggregated by zip code and/or tax district, and segmented by rate class. For rate classes with time-of-use periods, kW and kWh data should be aggregated by time-of-use periods and in total.
        - All aggregated customer datasets should be provided by a date determined by regulators in consultation with the Company and stakeholders.
    - Future Datasets: The Company should engage DER providers to identify any additional customer-oriented datasets of value and propose a schedule for provision of new datasets over time. The Company should work with DER providers and regulators to define use cases[18] for future datasets and receive input on data formats and prioritization. The schedule should be informed by the Company's ability to collect and generate new datasets when enabled by implementation of advanced grid connectivity and functionality.
- Description of how data will be made available to users

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

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

    - Methods and Tools: The Company should indicate methods and/or tools currently in place to support the exchange of customer-specific and aggregated customer data. The Company should propose tools that will be developed to make these data more easily accessible and/or retrievable on a more real-time basis.[19] Minimum requirements for data sharing methods include:
        - Capability to transfer granular usage data in machine readable format.
        - Implementation plan for "Green Button Connect My Data," an existing trademark-protected industry standard protocol for customers to obtain and share their granular usage data with authorized third parties.
        - Ability to supply usage data in "real-time" or "near real-time" once AMI infrastructure is in place.
- Description of conditions when the utility should be able to charge for data
    - Value-Added Data: The Company should be able to charge market rates to third parties in exchange for developing and providing "value-added" data. The Company should work in consultation with stakeholders to define guidelines for what datasets should be subject to charge and what fee structures might look like. As a general rule, there should be no charge for third parties to access data produced as a matter of normal course of business at the utility. However, if there is additional processing required to create the data, consideration of a cost-based charge is warranted. Once guidelines for value-added data are determined, summaries of types of value-added datasets and associated fee structures should be published.
- Description of data privacy measures
    - Privacy / Aggregation Standard: Aggregated data is data that have been summed or combined across a group of multiple accounts in order to preserve individual customer privacy. In order to appropriately protect customer privacy, the Company should propose an aggregation or privacy standard to be used for supplying whole-building aggregated energy data to building owners or their authorized third-parties. The Company should adopt as a starting point the 4/50 privacy standard for aggregated data adopted in New York, which would require data to be drawn from a minimum of four accounts and limits the load of any single account to less than 50% of the total load for the dataset. The Company should indicate, however, whether there are any unique features to Rhode Island's grid or customer profile that would merit a more flexible standard or require a more stringent one.

DER Sourcing and Compensation

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

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

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

To date, Rhode Island has incentivized the system-wide development of DER with only limited experience to date on incentivizing DER in beneficial locations or at beneficial times (e.g., the Tiverton/Little Compton System Reliability Procurement Pilot). In the future, a variety of programmatic and market mechanisms could be used to direct DER development to optimal locations and encourage performance at times of grid need. Broadly referred to as "locational incentives" or "value of DER," specific methods of sourcing and compensating DER are: pricing, programs, and procurements. According to ICF International,[20] these may be defined as:

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

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

- Identify locationally-varying value components of interest
    - For each kWh generated (or other unit of performance), a DER produces a set of value components. Value of DER inquiries typically investigate and develop methodologies to quantify these different value components, or "value stack," of DER. Some of these values, such as avoided capacity or environmental attributes, do not vary locationally (within the distribution system). Others, such as distribution system avoided costs, do vary locationally.
    - The Docket 4600 Benefit/Cost Framework provides a comprehensive list of the value components of distribution system and/or DER investments. It can be used as a basis for considering the value of DER question.
- Describe how beneficial locations are identified
    - Once the locationally-varying value components of interest are identified, beneficial locations on the distribution system must be identified. Beneficial locations would be areas where services of interest – such as peak load reduction or voltage regulation – are needed, and DER that could provide these services would provide value. By providing peak load reduction, for instance, DER could avoid distribution capacity costs.
    - Two candidate paths for identifying beneficial locations in Rhode Island should be evaluated:

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

        - Annual screen: An annual “Excel-based” screen of National Grid’s feeders. This screen can sort feeders according to basic parameters such as % loading, asset condition, and expected load growth.
        - Heat map: A “modeling-based” heat map, which provides more detail on sectional analysis and voltage issues.
- Determine approach to sourcing and compensating DER at these locations
    - Determine the expected performance of the DER during the time period of need
        - An intermittent DER resource – such as a solar PV installation – will only contribute a portion of its MW capacity at the time of local peak. Until advanced metering functionality is available, a methodology to determine what portion of the capacity can be “counted on” is needed. The methodology could differ according to technology type and/or other characteristics (e.g., intermittent versus non-intermittent).
    - Determine the value of the benefit provided by the DER
        - Once the expected performance of the DER is determined, a $ benefit per unit of value component must be determined. Various methodologies could be considered, such as an avoided marginal cost of distribution system investment (system-wide, or local if available), an average feeder $ cost per mile multiplied by actual length of feeder, or other options. Calculating the $ benefit provided by a DER installation in a beneficial location could have several applications, including but not limited to: informing the structure, level, and design of an incentive to the DER provider or aiding in cost/benefit analysis of NWA proposals.
    - Determine the level and structure of incentive for DER
        - The compensation framework for a DER developed in a beneficial location must be determined. This includes:
            - How the level of incentive is calculated (e.g., Equivalent to calculated benefit, or is some portion of the benefit reserved for ratepayers? Based off of incremental costs or lost revenues to configure the DER to serve the local need [e.g., orienting a PV system west and sacrificing overall production, or incorporating tracking technology at incremental cost?]); and
            - How the incentive is structured (e.g., Is a flat incentive offered [e.g., similar to a one-time grant award]? Or, is a tariff-based incentive offered [similar to net metering, for instance]? Or, are incentives not predetermined, but simply determined on a competitive basis via RFP’s issued for DER in beneficial locations?).
    - Determine how the DER are sourced
        - A process needs to be agreed upon whereby the utility communicates the identified beneficial locations to the marketplace at some regular interval, or on a continuous basis. Then DER providers need to be able to take advantage of locational incentives available for those specific locations. Incentives would be issued to DER providers via one of the options identified above (e.g. flat payment, tariff-based incentives, or competitively-bid awards).
    - Determine how value of DER interacts with existing programs and tariffs

- Net-metering and Renewable Energy Growth tariffs do not vary by time or location in Rhode Island. Could these mechanisms be adapted to incorporate locational incentive features? Or could new locational incentives be coordinated with these mechanisms? Some statutory change may be necessary due to the value of net metering compensation being defined in statute, for instance.