595 Market Street
29th Floor
San Francisco, CA 94105

June 19, 2017

Rhode Island Office of Energy Resources
Division of Public Utilities and Carriers
89 Jefferson Boulevard
Warwick, RI 02888

RE: Comments from Sunrun Inc. in Response to Power Sector Transformation Initiative Notice of Inquiry into Distribution System Planning

To the Rhode Island Division of Public Utilities and Carriers & Office of Energy Resources:

Sunrun, Inc. ("Sunrun") respectfully submits the following preliminary comments in response to the Rhode Island Division of Public Utilities and Carriers ("Division") and Office of Energy Resources ("Office") Notice of Inquiry into Distribution System Planning and Request for Stakeholder Comment ("Notice") issued on June 2, 2017.

Sunrun is a leader in residential solar, storage, and energy management. We pioneered the "solar-as-a-service" model 10 years ago and today are the largest dedicated residential solar company in the United States. Sunrun commends Governor Raimondo's call for this Power Sector Transformation Initiative ("Initiative") to develop a new energy compact for Rhode Island.[1] As Governor Raimondo describes, a more nimble electric grid is needed to strategically integrate clean energy resources and enable customers to take advantage of new clean energy technologies. The Division and Office's Notice states that the Initiative seeks to shape the ongoing transformation of the electric grid to achieve three policy objectives:

1. Control the long-term costs of the electric system;
2. Give customers more energy choices; and
3. Build a flexible grid to integrate more clean energy generation

The purpose of this inquiry into distribution system planning (DSP) is to (a) identify the necessary elements of DSP, (b) determine how DSP should offer transparency and data to relevant utility, market, and policy actors, and (c) determine appropriate DSP processes.

The answers to these questions are necessarily informed by Rhode Island's energy policy, grid modernization, and other public policy goals. It is also essential that the inquiry into DSP be informed by guiding principles for achieving Rhode Island's goals of a cleaner, more reliable and resilient electric grid through increased deployment of distributed energy resources ("DER")

[1] Correspondence from Governor Gina Raimondo to the PUC, DPUC, and OER. March 2, 2017. Available at: http://www.ripuc.org/utilityinfo/electric/GridMod_ltr.pdf

and other clean energy technologies. Sunrun has participated in similar important inquiries across the country from Hawaii to New York and offers the following principles as additional guideposts for consideration throughout this inquiry. DSP should be conducted such that it:

1. Provides transparent and meaningful opportunities for stakeholder engagement in system planning, investment, and operational decisions.
2. Promotes economically efficient distribution system investments.
3. Enhances system operational reliability, resilience, and flexibility.
4. Enables customers and other non-utility market participants to seamlessly integrate DERs and other clean energy technologies, manage power consumption, contribute to system reliability, provide grid services, and reduce the carbon intensity of the electric system.
5. Facilitates competition between customers and non-utility market participants through non-discriminatory access to opportunities to provide strategic solutions to system requirements that can substitute for conventional infrastructure solutions.

Sunrun appreciates the opportunity to submit these comments and looks forward to the opportunity to continue to engage throughout this proceeding.

I. What should be the key elements of DSP?

The Division identified the following potential elements of DSP for a twenty-first century utility:

- **Forecasting** of energy demands on the system to determine future peak requirements.
- **Power flow analysis** to test whether the existing system can accommodate forecasted demands and maintain voltages within established standards.
- **Conditions assessments** to determine the health of system components and develop replacement strategies before failure.
- **Solution identification** to select options to address identified needs.
- **Hosting capacity analysis** to determine the maximum amount of DERs that a substation feeder can support without additional upgrades.

The Notice poses the following questions regarding DSP elements:

1) How important are each of the DSP elements described here to the future electric utility? Are there additional elements not described here that should be included as a strategic focus of the electric utility? What does success look like for each element?
2) Utility investment in grid modernization capabilities will provide increasing visibility into the system, allowing a more sophisticated and granular approach to DSP. What should the future state of planning look like as visibility improves? What should the transition look like between current DSP and the future state of DSP?

Sunrun believes that each of the elements identified in the notice are important to the DSP, with the following qualifications:

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- DSP **forecasting** must include forecasting of both capacity and energy needs. Additionally, forecasting should incorporate an assessment of the current state of DER deployment and projections of DER deployment by performing an analysis that assesses current system capability together with planned investments.
- While **power flow analysis** is an important element of the DSP, a power flow analysis must recognize DERs on a circuit. The DSP should include an analysis that quantifies the capability of the system to integrate DERs within thermal ratings, protection system limits, and power quality and safety standards of existing equipment.
- **Solution identification** should be conducted with the policy objective to maximize DERs as alternatives to traditional distribution equipment.

While each of the elements identified is important to DSP, of equal importance is that the assumptions used within the various analyses are visible to stakeholders, and that the DSP process is transparent and allows for stakeholder analysis and feedback. Further, the DSP process should be designed to consistently incorporate feedback and evolve to drive customer-facing programs that address the needs identified within the DSP elements. The DSP should incorporate a plan to optimize distribution system needs and the needs of the ISO with specific consideration as to how to leverage customer DERs. As retail customers adopt technologies with capabilities that can be aggregated for participation within ISO New England, the DSP must understand the potential market interaction effects on the distribution system. An evaluation of approaches to address greater DER participation methods should be evaluated from a technical and policy perspective to ensure resiliency and maximum ratepayer benefits.

Successful implementation of the DSP elements will create an integrated distribution planning process that will continuously work to forecast growth and changes in demand and usage while monitoring equipment conditions, in order to identify distribution needs with enough time to allow procure lower cost, innovative solutions through an open sourcing process. DERs have a unique opportunity to be developed in locations where they may be needed most. For example, if a utility is capacity constrained, or constrained in a particular location on its grid, DER may be the least cost option to help defer additional capacity or expensive utility upgrades. An integrated DSP process will allow ratepayers and utilities to benefit from the full suite of values that DERs can provide, and enable the development of customer programs that drive investments that decrease distribution and ISO costs for ratepayers, while maintaining safe and reliable electricity service.

For example, an integrated distribution planning process that identifies potential areas of load growth or capacity concerns will allow the Commission to proactively explore non-wires alternatives (NWAs), to encourage DER investment, or to change consumption in specific locations by providing targeted rate design programs or incentives for customers.

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Through the DSP process, the utility should provide DER providers and other market participants access to opportunities to provide grid solutions, including NWAs to traditional utility infrastructure, such as distributed generation, energy efficiency, energy storage, and demand response. Rhode Island's grid modernization and other energy policy goals are directly tied to transforming the electric utility's traditional strategic and investment planning approach to one that accommodates the changing electric sector and grid modernization efforts. This requires the utility to better incorporate the role of the modern customer in its operations and planning processes. The DSP design and decision-making process must be flexible and transparent to accommodate new technologies and solutions, as well as evolving goals and priorities.

The utility must conduct the DSP process in a proactive manner and include distribution circuit studies to determine hosting capacity in advance, rather than the utility reacting to interconnection applications as they arrive. If anticipated growth in DERs exceeds a circuit's hosting capacity, the DSP process should provide the information to identify how additional DERs, NWAs, or other infrastructure necessary can accommodate that growth. This planning can reduce the inefficiencies that often arise when individual DG customers pay for system upgrades that can impede customer choice and DG growth, as discussed above. Aligning DSP with grid modernization efforts allows solutions such as advanced meter functionality and communications systems to inform the types of NWAs and other DER solutions that can be incorporated into the DSP and enhance customer energy choices.

It is also important to note that efforts to implement a DSP process will also likely raise the question of the value of DERs, and specifically the locational valuation of DERs, as recommended in the Stakeholder Report[2] and the subsequent April 21 memo from Commission Staff,[3] to be addressed in Docket 4600. DERs can provide grid supportive services and reduce system costs and these values should be reflected in DSP decision-making. Proper valuation of DERs on the grid will be necessary to inform cost-benefit analyses conducted in DSPs, thus the timing of these proceedings is important to consider. Similar to NWAs, locational value of DERs should be additive to general, mass market value propositions, which may include temporal value. Tariffs and programs for DERs must take into account the value these technologies provide to the utility, and must evolve to accommodate technology advancements.

As data is becoming increasingly available, analytics and forecasting are becoming more sophisticated. The DSP process should be iterative, transparent, and open to stakeholders to ensure there are opportunities for utilities and stakeholders to continually assess the DSP to make improvements to both the process, and to data availability and transparency. Additionally, as the DSP evolves, it will need to be more focused on solution based planning vision to enable regulatory program development along with near-term solicitations to ensure required

[2] Docket 4600: Stakeholder Working Group Process. Report to the Rhode Island Public Utilities Commission. April 5, 2017. Available at: http://www.ripuc.org/eventsactions/docket/4600-WGReport_4-5-17.pdf
[3] PUC Staff Memorandum Re: Docket 4600 Report – Summary and Staff Recommendations. April 21, 2017. Available at: http://www.ripuc.org/eventsactions/docket/4600-PUC-Staff-OM-Memo(5-4-17).pdf

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infrastructure upgrades are addressed in a manner consistent with the Governor's vision.[4] DER programs may need to be developed in the short term in order to incentivize customers' energy investments that align to the greatest extent possible with the broad power system needs. This will foster a DER evolution, which will advance based on lessons learned and progress made on the DSP elements.

II. How should DSP offer transparency where appropriate to relevant utility, market, and policy actors?

A lack of visibility into distribution system conditions, bulk electric system conditions, or actual performance of DERs will limit DER deployment of operations**.** Central to the goals of giving customers more choices is customer and third-party access to data – including both customer and distribution grid data. Policies and practices must be designed to balance market innovation and participation, customer protections, safety, and grid reliability. Customer access to near or real-time data about their electricity use is essential to enabling customers to make informed energy choices, and DER provider or third-party access to customer and grid data allows DER providers to assist customers in making informed decisions and target strategic areas for development.

The Notice poses the following questions about transparency:

1. Who are the users of system and customer data? What data do users need to guide investment decisions, support business models, or guide policy/program activities? What are the specific use cases for each dataset? What is the desired format of each dataset? What is the frequency with which datasets should be updated?

2. What are the key data access safety and security considerations? How should customer privacy be protected? How will the utility's requirement to protect the grid and maintain sensitive information be balanced with the need for more visibility?

Distribution planning requires various amounts and types of data to be transferred between the Utilities and third parties. Data sharing involves a mechanism for communicating the data among the Utilities, customers, and DER owners/operators.

Sunrun identifies the following data that should be available to users as part of DSP. This data should be made available in a consistent format that is easily accessible, downloadable data file. Additionally, where possible, the data should be provided in maps available online.

- Generation production characteristics, including for intermittent resources

[4] Correspondence from Governor Gina Raimondo to the PUC, DPUC, and OER. March 2, 2017. Available at: http://www.ripuc.org/utilityinfo/electric/GridMod_ltr.pdf

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- Existing distribution characteristics at substation and feeder-level — coincident & non coincident peaks/ capacity levels/ outage data/ projected investment need
- Circuit Data
- Circuit-Level loading data
- Customer type breakdown
- Circuit Node Loading
- Existing DER Capacity, including storage penetration, electric vehicle and charging station populations, and DG population characteristics, incorporated into hosting analysis
- Energy efficiency and demand response related data
- Equipment thermal ratings
- Planned capacity projects
- DER load growth forecasts vs. integrated capacity
- Planned voltage/power quality projects
- Observed violations statistics
- Customer complaints, in order to assess investment plan needs
- Planned reliability/resiliency/security projects
- Reliability statistics
- Existing supply redundancy level

Making the data identified above available to stakeholders, regulators, and DER providers will allow the data users to assess the utility's investment plans and identify areas to target DERs, including to identify areas where DERs can be deployed to offset major investments. Additionally, this data can allow users to assess when DER and load growth will exceed capacity, and compare that timing against planned projects and investments. The data will also allow users to evaluating thermal loading limits, estimate load curves, and understand loading along different circuits.

III. What should the DSP process look like?

The Notice poses the following questions for DSP process.

1. What DSP information – such as information associated with the DSP elements identified earlier in this document – should be made available to users, including the market, regulators, and policymakers?

2. How often should this information be made available and in what format? Should this information be compiled in a new DSP docket proceeding (or filing within an existing docket)? How should any new DSP filings be coordinated with ISR and SRP? How should they be coordinated with any other applicable filings?

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3. Utility DSP must take into account both current and long term system impacts. Solutions require multiple years for design and implementation. How will the utility and stakeholders coordinate efforts to develop solutions, particularly those that are implemented by customers and not controlled by the utility, such that there is certainty of implementation before system operational issues arise? How will a "safety net" be implemented to ensure that the utility can implement solutions (traditional or NWA) if third party commitments fail, particularly when there are long lead times for implementation?

As described throughout these comments, the assumptions used within the various analyses of DSP Elements must be transparent to stakeholders, and the DSP must be a process that enables third-party analysis and stakeholder feedback.

With regard to customer solutions not controlled by the utility, the DSP should inform a regulatory process to develop DER programs that incentivize customer's energy investments, which align to the greatest extent possible with the broad power system needs. These new DER programs may have defined schedules that are set at the time of installation and would ensure alignment with DSP's needs without the need for remote utility or third party controls. For all identified capital investment needs that are not met through DER programs, the DSP should include open NWA RFP opportunities to allow for innovative solutions and access to opportunities by third parties. Standard contracts for fulfilling the distribution system needs should include provisions that require service by the identified date of need; third party providers of NWAs have an inherent incentive to provide services as promised and meet contract needs. NWA contracts could include regular reporting of project progress in order to prove additional certainty, and to provide an early warning system if circumstances are possibly preventing the project from meeting deadlines.