June 19, 2017

Macky McCleary
Administrator
Division of Public Utilities and Carriers
89 Jefferson Boulevard
Warwick, RI 02888

Carol J. Grant
Commissioner
Office of Energy Resources
One Capitol Hill
Providence, RI 02908

Re: Notice of Inquiry into Distribution System Planning and Request for Stakeholder Comment

Dear Administrator McCleary and Commissioner Grant:

Enclosed, please find comments from the Northeast Clean Energy Council (NECEC) and Advanced Energy Economy Institute (AEE Institute) in response to your agencies' June 2nd Notice of Inquiry into Distribution System Planning and Request for Stakeholder Comment.

Our organizations are available as a resource to you as efforts within the Power Sector Transformation Initiative continue to develop and progress. Please let us know if we can be of any assistance.

Sincerely,

Peter Rothstein, *President*
NECEC

Janet Gail Besser

Janet Gail Besser, *Executive Vice President*
NECEC

Lisa Frantzis, *Senior Vice President*
Advanced Energy Economy

Cc: Hannah Polikov, AEE
Ryan Katofsky, AEE
Jamie Dickerson, NECEC

Notice of Inquiry into Distribution System Planning and Request for Stakeholder Comment

Introduction

The Northeast Clean Energy Council (NECEC) and Advanced Energy Economy Institute (AEE Institute) commend the Rhode Island Division of Public Utilities and Carriers (DPUC), the Office of Energy Resources (OER), and the Public Utilities Commission (PUC or Commission) for their ongoing work within the Power Sector Transformation Initiative. We greatly appreciate the opportunity to respond to this *Notice of Inquiry into Distribution System Planning and Request for Stakeholder Comment, issued June 2, 2017.* Much like the Utility Business Model inquiry, your agencies' distribution system planning (DSP) investigation is timely and opportune, as technological advancements and policy urgency are pushing commissions around the country to view DSP as a pivotal mechanism for attaining the grid of the future. With more granular data, deeper and more instantaneous grid-visibility, more involved customers and third-parties, *and* a changing utility business model, planning for the distribution system must change. NECEC and AEE Institute appreciate the opportunity to participate in and support this effort.

NECEC is a clean energy business, policy and innovation organization. Our mission is to create a world-class clean energy hub in the Northeast delivering global impact with economic, energy and environmental solutions. NECEC is the only organization in the Northeast that covers all of the clean energy market segments, representing the business perspectives of investors and clean energy companies across every stage of development. Our members span the broad spectrum of the clean energy industry, including energy efficiency, demand response, wind, solar, combined heat and power, energy storage, fuel cells, and advanced and "smart" technologies. Many of our members are doing business and investing in Rhode Island, and many more are interested in doing so in the future.

AEE Institute is a charitable and educational organization whose mission is to raise awareness of the public benefits and opportunities of advanced energy. AEE Institute is affiliated with Advanced Energy Economy (AEE), a national business association representing leaders in the advanced energy industry. AEE supports a broad portfolio of technologies, products and services that enhances U.S. competiveness and economic growth through an efficient, high-performing energy system that is clean, secure and affordable.

NECEC and AEE Institute submit these comments on distribution system planning in response to the June 2 Notice. In these comments, NECEC and AEE Institute will be referenced collectively as "the advanced energy community," "we," and "our."

NECEC and AEE Institute have substantial experience participating in grid modernization proceedings across the country. As organizations with stakeholders that provide a range of technologies and services, we balance a wide variety of interests and address issues with a technology-neutral perspective. Every state has different goals, legal requirements, and market conditions, and so therefore takes a different approach to grid modernization and potential distribution system planning reforms. In these comments, we have based our responses to the questions posed in the June 2 Notice on NECEC's extensive experience in regulatory, policymaking, and legislative processes in Rhode Island, as well as the experience of both of our organizations in other states, while keeping in mind the unique characteristics of Rhode Island.

What should be the key elements of DSP?

Distribution system planning is integrally linked to the utility business model. As NECEC emphasized in its 2014 Grid Modernization white paper,

> "Utilities should develop and implement forward-looking business plans, including distribution system investment plans, *to make the transition from a commodity electricity delivery business model to a business model in which the utility serves as a distributed platform system operator* that integrates distributed energy resources, enables bidirectional markets for electricity services and is a hub for grid data and information services, while continuing to provide the safe, reliable and affordable service customers expect."[1] (emphasis added)

[1] *Leading the Next Era of Electricity Innovation: The Grid Modernization Challenge and Opportunity in the Northeast*, August 2014, p.2.

And as we stated in our May 19 comments on the Electric Utility Business Model,

> "Our vision of a future electric utility is as an integrator and market enabler, where the utility operates the grid as both a physical platform and market platform. The utility would own and invest in the platform infrastructure and operate this platform to integrate and coordinate assets and services owned and provided by third parties and customers. The utility's primary focus should be around managing the increasingly complex grid and not just in operating the connected grid edge technologies." (p.3)

Distribution system planning will need to change to address and accommodate changing technologies and the changing economics of technologies on both the grid- and customer-side of the meter, as well as increasing customer adoption of distributed energy resources (DER), like energy efficiency, demand response, distributed generation and storage. These technologies affect both customers' energy usage and their use of the distribution system. Fortunately, Rhode Island has begun to anticipate these changes and established several planning and regulatory mechanisms, on which it can build – the Energy Efficiency and Resource Management Council (EERMC), the System Reliability Procurement (SRP), Systems Integration Rhode Island (SIRI) and the Infrastructure, Safety, and Reliability (ISR) cost recovery mechanism – to provide a regulatory framework for future distribution system planning. NECEC and AEE Institute elaborate further in response to the agencies questions below.

How important are each of the DSP elements described here to the future electric utility?

The agencies identify several potential elements that DSP for a twenty-first century may include, noting that "[t]he electric utility performs many, but not all, of these elements of DSP today." They are:

- Forecasting,
- Power flow analysis,
- Condition assessments,
- Solution identification, and
- Hosting capacity analysis.

Distribution system planning should chart a path to a twenty-first century distribution grid and electricity system and as such, should include all of the elements listed. Utilities should recognize that customers are increasingly choosing different ways to meet their energy service needs, with and without public policy support and encouragement.

Forecasting will need to take these customer choices into account, as will power flow analyses. Distribution utilities will need to enhance their visibility into the system as well as their monitoring and communications capabilities to understand and anticipate customer actions, particularly decisions to deploy distributed generation, and their impact on the system in terms of both benefits and costs. These capabilities will also be needed to improve condition assessments so that utilities can operate the system more efficiently and plan for upgrades that will increasingly enhance its capability. While distribution planning changes in these areas may generally be enhancements of current utility practices, they will require changes in planning practices and greater grid- and customer-facing functionality to enable them.

Solution identification will involve more changes to current utility DSP. While National Grid may consider and seek to implement non-wires alternatives (NWA) to distribution investments as a component of its distribution system planning, problem definition and solicitation of solutions from third parties and customers are not fully integrated into the planning process. Distribution utilities should take the approach of defining system problems and soliciting solutions. Access to both customer and system data, noted in our comments on the Electric Utility Business Model and discussed further below, will be essential to enable third parties and customers to devise solutions to meet distribution system needs and to stimulate innovation in technologies that can help utilities to meet these needs. Hosting capacity analyses will produce some of the information and data that must be made available to customers and third parties so that they can not only devise solutions to problems but also avoid creating them – i.e., by optimizing deployment of DER.

Are there additional elements not described here that should be included as a strategic focus of the electric utility?

As we noted in our Electric Utility Business Model comments, "[u]tilities are increasingly being tasked - sometimes directly, sometimes indirectly - with helping states meet their environmental targets such as GHG emission reductions." As such, the utility should take policies and goals into account in their planning and forecasting processes. One of the ways to accomplish this is to consider benefits across a wide range of performance priorities,[2] using a "Business Case Approach" to analyze the benefits and costs (and cost-effectiveness) of investments and operations. A Business Case Approach will also facilitate consideration and comparison of third party and customer options, in addition to distribution utility options. Priorities and objectives should be defined up front by policymakers, distribution utilities and stakeholders, including third party providers of energy services, customers and environmental advocates, so that they can guide distribution planning efforts. Outcomes to measure accomplishment of these objectives should also be determined so that performance against objectives can be measured. This may be particularly useful where the objectives and outcomes go beyond traditional utility distribution system planning. For example, metrics for GHG emission reductions, DER integration, enhanced optionality and risk management should be considered.

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?

Please see discussion on transparency and data below.

What should the transition look like between current DSP and the future state of DSP?

Rhode Island should use its existing planning and regulatory processes (EERMC, SRP, SIRI and ISR) in making the transition between current DSP and future DSP. Establishing an up front process to achieve *consensus on objectives* to be achieved and agreement on the *role of the distribution utility* among policymakers, the distribution utility and stakeholders is critical. *Stakeholder input* to DSP is an essential element as customers' choices to meet their energy service needs will affect their use of and impact on the distribution grid, even as they present new opportunities for value to the distribution utility and other customers. Existing processes should be expanded and/or supplemented to ensure that DSP integrates and takes advantage of the full range of capabilities that DER offers for system planning and grid operations. Distribution utilities should explore and test innovation in their planning processes and the regulatory framework should provide the opportunity to do so by approving budgets for research,

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[2] *Leading the Next Era of Electricity Innovation,* p. 12.

development and deployment of new technologies and approaches to the elements discussed above.[3]

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

The Notice of Inquiry, states, "Access to data – system data and customer data – could help customers become resources toward meeting grid needs and maximizing the net benefits of customer investments in clean energy technologies." In fact, access to data is essential to power sector transformation, affecting the electric utility business model, distribution system planning, grid connectivity and beneficial electrification. In a world of "big data," transparency and access to information are needed to enable a smooth transition. New tools and capabilities to manage the data will be required and utilities will need to look beyond current practices to engage and take advantage of third party and customer capabilities. As mentioned above and in our Electric Utility Business Model comments,

> "Utilities will have a role to play in enabling access to data available now and the massive amounts of granular data that will become available through enhanced connectivity services. It will be the utilities' role to ensure timely and convenient access to both customer and system data to stimulate innovation and enable third parties and customers to devise solutions to meet the needs of the future electricity system. This role may include establishing data access standards, customer authorization procedures and/or potential data exchanges. We support using the US Department of Energy's Green Button program in furtherance of this objective."

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?

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?

[3] Id., pp.18-19.

The agencies ask a number of important questions about how and to whom access to data can and should be provided, with appropriate privacy and security protections. Distribution utilities, customers and third-party providers of energy services will all be users of system and customer data. In order to be useful, the data may need to be provided to each of these entities in a different format. Customers may need data in a summary form for it to be useful to them in making decisions about how to manage their energy use, including whether to adopt DER. Customers will also need access to data in a timely manner, for example, so that they can act in advance to reduce peak load before they impose costs on the system and incur higher charges as a result. Customers may also choose to delegate their energy management to third parties, who will then be the entities that need access to timely data in a form that they can use. Third parties can also be sources of granular data on customer energy usage through devices such as in-home thermostats and energy management systems that collect information about household and business electricity use. How to make this information available to distribution utilities to assist in DSP also needs to be explored.

NECEC and AEE Institute recommend that the agencies consider establishing a process focused on data access and ensure that distribution utilities, third parties, customers and other stakeholders are adequately represented and able to participate effectively in it. The questions asked here could be a starting point for the group's consideration

What should the DSP process look like?

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?

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?

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?

NECEC and AEE Institute recommend that Rhode Island use its existing processes, including the ISR, SRP and SIRI and consider how they might be adapted to provide an overarching regulatory framework for Power Sector Transformation or how an overarching framework might be developed to encompass them. Rhode Island is fortunate in that it has begun to look at some of the elements related to DSP in these processes; the challenge before it now is how to integrate them.

The agencies state, "Utility DSP must take into account both current and long-term system impacts." The challenge is that system needs will change over time and in unexpected ways. As we noted in our comments on the Electric Utility Business Model, this argues for greater focus on optionality and risk management.[4]

- The complexity of the electricity system and the pace of technology change will continue to increase, making keeping a long-term focus in distribution system planning more important than ever. Optionality – making investments that allow for flexibility as circumstances change and that do not lock in certain investment or technology paths for the future – is increasingly important in this environment. These "investments" may include taking advantage of NWA, traditional infrastructure or new technology solutions.
- Procuring services rather than owning assets themselves may be another way to preserve flexibility and balance short- and long-term system needs. For example, procuring software as a service (SAAS) that is developed and hosted by a vendor in the cloud allows the technology to be more easily and more cost-effectively updated. This service model could be adapted for other solutions as well. A "procurement of services" approach has implications for the utility business model, which will need to be addressed. For example, the New York Public Service Commission included language in its Track 2 Reforming the Energy Vision Order that clearly states its support for utilities to earn a rate of return on SAAS investments.

[4] NECEC/AEEI Comments on the Electric Utility Business Model, May 19, 2017, pp. 9-10.

- New approaches to DSP will also have implications for other aspects of the utility business model and regulation, such as accounting treatment of shorter-lived investments due to rapidly changing technologies such as communications hardware and software.

Conclusion

Rhode Island is in a unique position to transform the electric grid by controlling the long-term costs of the electric system, giving customers more energy choices, and by building a smarter and more flexible grid to reduce costs, improve reliability and resiliency, integrate more advanced energy generation, and reduce environmental impacts. In order to do so, distribution system planning must change to be consistent with and enable evolving electric utility business models. To guide this change, regulatory frameworks and processes must also change to ensure that this alignment occurs and utility planning, actions and investment meet future distribution system needs, achieve public interest objectives and continue to deliver safe, affordable and reliable service to customers.[5]

NECEC and AEE Institute greatly appreciate the opportunity to provide these comments to the agencies and we look forward to our continued involvement in this process.

[5] NECEC expands on changes needed in distribution system planning in its paper, *Leading the Next Era of Electricity Innovation: The Grid Modernization Challenge and Opportunity in the Northeast*, particularly at pages 10-12. Please see http://www.necec.org/files/necec/Policy%20Documents/Grid%20Mod%20Report%20NECEC%20Aug.%202014.pdf.