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National Association of Regulatory Utility Commissioners

State Commission Staff "Surge" Call: New Approaches to Distribution System Planning

On April 9, 2018, NARUC's Center for Partnerships & Innovation and the Staff Subcommittee on Energy Resources and the Environment convened a state commission staff "surge" call, on which staff discussed different state approaches to emerging issues in electricity regulation. This call covered distribution system planning (DSP), an increasingly important topic for many states as penetration of distributed energy resources (DERs) grows. Lisa Schwartz, Energy Efficiency Team Leader in the Electricity Markets and Policy Group at Lawrence Berkeley National Lab, moderated the discussion.

Lisa began with an overview of the benefits and challenges of DSP. Improved DSP practices can help utilities and commissions get to least-cost solutions for meeting the needs of the evolving distribution system. With the Edison Electric Institute (EEI) estimate of over $32 billion spent on improving the distribution system in 2016, it is imperative for regulators to have key information on distribution investments.

On the call, staff from Hawaii, Washington, Indiana, Ohio, and Rhode Island shared what their commissions are doing. This call follows a DSP discussion on a surge call in September 2017 featuring Minnesota, Michigan, and California. NARUC will continue to follow the evolution of this issue and may convene a follow-up surge call with other states later in 2018.

Summary

This call represents a brief snapshot of how five states are approaching DSP. Across these five states, there are some clear similarities in goals of DSP: multiple staff cited pursuing least-cost solutions, achieving renewable portfolio goals, and providing the most current information as DSP objectives. Commission staff agree on the importance of stakeholder engagement, improving transparency, and educating commissioners, commission staff, utilities, and others involved in the process.

Commissions diverge in the paths to these objectives, though. States face different levels of DER penetration and consequently feel differing levels of urgency in addressing DSP requirements. Timelines and requirements for integration with existing planning processes vary. Commissions differ in the level of oversight and direct involvement they will have.

Notes from each state's participants are below.

Hawaii

The 50th state is in the early days of a formal distribution planning process. The island has conducted a traditional integrated resource planning (IRP) process for many years. In 2014, a significant influx of DERs – particularly customer-sited rooftop solar – entering the system led to disruptions throughout the distribution system of the state's largest investor-owned utility, Hawaiian Electric Company (HECO). Following these disruptions, the commission noted substantial limitations with HECO's IRP methodology and approach and ordered the submission of a Power Supply Improvement Plan (PSIP) integrating DER and demand response (DR) forecasting. Concurrently, HECO had an advanced metering infrastructure investment project before the commission.

Seeing the need to connect the dots between smart grid investments and DER penetration, the commission ordered HECO to articulate an overall grid modernization strategy. Staff noted that considering investments at the distribution system without also looking at transmission and resource needs may result in a less optimized portfolio. HECO responded with a Grid Modernization Strategy that, in part, proposed an integrated grid planning process in which distribution, resource, and transmission planning would be conducted simultaneously and holistically to enable HECO and the commission to evaluate grid needs on a technology-neutral basis. HECO is also proposing to issue RFPs early in the planning process to incorporate up-to-date market pricing into planning. While this market-based process introduces more complexity, staff believe looking at all investments simultaneously will lead to an optimized portfolio and the best outcome for ratepayers.

Hawaii staff shared some initial lessons learned.

- Stakeholder engagement is critical to the long-term success of the planning process.
- Any tools or models used by utilities need to be transparent and available to regulators and stakeholders.
- Staff cautioned states looking to get into the process that adequate DSP takes substantial investments of time and effort to educate utilities, regulators, and stakeholders.
- The commission has played an important role in prioritizing the discussion and avoiding rabbit holes that can derail the effort.

Looking ahead, staff anticipate iterative cycles for the commission to learn and improve.

Washington

Moving to the mainland, a Washington commission staffer shared the state's progress on distribution system planning (DSP). Beginning with a workshop on electric and natural gas distribution planning in March 2017, the commission has been accepting comments from stakeholders and working on a public draft of what a DSP process would look like. Washington's IRP rules have included a distribution planning element for more than a decade. However, information submitted to the commission has been somewhat erratic due to a lack of specific language from the commission on what it wants to see.

With the development of a contentious transmission investment, the commission began to discuss what information belongs in an IRP and what belongs in other filings. The overall objective of embarking on DSP is to ensure that investments in the distribution system are least-cost and least-risk, a challenge given that technological advances and changing customer needs are reshaping the entire system.

The commission envisions DSP feeding into IRP along with conservation potential estimates, which are already required under current IRP rules. The justification for this model is for utilities to look for ways the distribution system can reduce resource needs, and to reflect reduced needs in the IRP. The commission is proposing a two-year IRP cycle and is floating ideas to clarify public involvement, including the potential to form a technical advisory group to provide focused comments from critical stakeholders. The commission is not yet sure how to procure the most up-to-date information on resource options, and staff may look closely at Hawaii's market-based approach. All of these questions will be open for public comment, and the commission is eager to hear feedback.

Indiana

Indiana lacks formal DSP rules, relying on a state law requiring electric and natural gas utilities to submit seven-year investment plans for upgrades to modernize the transmission and distribution (T&D) systems. The law defines eligible projects as new investments undertaken for safety, reliability, system modernization, or economic development that are both: (1) not already included in the rate base and (2) designated in the utility's commission-approved seven-year investment plan. The law also requires utilities to submit a rate case to the commission at some point within the seven years.

The seven-year plans use a risk model to analyze the consequences and likelihood of equipment failure at various facilities. Utilities must use a risk-based approach looking at the health, age, and criticality of each facility to develop a prioritized list of projects based on replacement costs and other resource constraints.

Utilities must include the best cost for eligible improvements for each individual project in their seven-year plans. This can be difficult, as seven years is a relatively long planning horizon with some uncertainty in estimating project costs. Utilities must demonstrate that projects will provide for the public convenience and necessity, and they must also show that the estimated costs of a project are justified by the estimated benefits provided.

Approved projects recover their costs in two ways: a tracker allows the utility to recover 80 percent of capital expenditures and costs (including depreciation, operations and maintenance, and taxes) as the projects are finished and go into commercial operation. The remaining 20 percent of costs are deferred until the next rate case, putting a burden on utilities to smooth costs as state law prohibits rate hikes of more than 2 percent per year.

Three of the state's five electric IOUs have received commission approval of their seven-year plans, primarily through settlements. One has yet to submit a plan and one has yet to be approved. The commission is in the process of finalizing an update to IRP rules but the affected utilities have agreed to implement the draft rules prior to the rules being finalized. These proposed rules require stakeholder advisory processes and an annual IRP Contemporary Issues workshop. The commission is hosting a workshop on April 24, 2018, which will include presentations on distribution system IRP and hosting capacity projections.

Ohio

As a restructured state with energy efficiency and renewable energy benchmarks but a relatively low penetration of DERs, Ohio is in the perfect position to develop a proactive planning strategy before DERs put stress on the distribution system. Currently, the commission requires utilities to file long-term forecast reports, which provide a summary of energy and peak load demands. The forecasts for electric transmission owners also include data on the use of existing transmission lines and facilities, along with plans for future transmission lines and proposed substations. The report also includes historical receipts of the energy purchased through each utility's competitive bidding process used to provide generation service for Standard Service offer customers. Currently, these reports are primarily used in the commission's estimate of statewide and regional energy needs. However, they provide some "FYI" type information for the distribution system planning process, though they don't currently allow for formal commission or stakeholder engagement on DSP and potentially overlook least-cost solutions.

The commission's Power Forward grid modernization proceeding is currently conducting information-gathering workshops, including a recent workshop on DSP. Stakeholders were asked about the proper role of a distribution utility and what services, functions, and capabilities utilities need to develop to support a modernized distribution system. Stakeholders discussed the potential for DERs to reduce losses and delay large infrastructure investments. Pacific Northwest National Lab brought up the importance of increased transparency in the DSP process. In general, the commission is looking at getting more involved in the planning process, enhancing engagement, and improving transparency. The commissioners plan to release a vision policy document later in 2018 to articulate these priorities and other outcomes of the workshops.

Rhode Island

Rhode Island has aggressive goals for renewable penetration, greenhouse gas reduction, and least-cost procurement. As the design of programs to achieve renewable goals has clashed with least-cost procurement, the commission felt the need to examine how it can use regulatory tools to better align the two and oversee a distribution system that meets state utility, energy, and environmental policy goals with the greatest benefit to customers. Distribution system planning is an important key to this alignment.

For example, as part of the state's renewable generation policy, a feed-in tariff provides cost-of-service payments for program participants. The tariff incorporates cost estimates for building and interconnecting different customer classes, and introduces price competition for participants above 250 kWh. The program has a statutory target of 400 MW over ten years. National Grid, serving virtually all of Rhode Island's electricity customers, receives 1.75 percent of the feed-in tariff regardless of performance. The more expensive the feed-in tariff program is, the more National Grid earns, creating an inconsistency between renewable goals and least-cost procurement.

In an annual infrastructure tracker docket, the PUC began questioning how National Grid's planning accounts for state policy by asking two overarching questions: (1) does distribution system planning include expectations for system load if energy and environmental goals are achieved, and (2) is the utility designing the system to incorporate more DERs? On the former question, energy efficiency was included in utility forecasts, but DERs were difficult to forecast and largely left out, as were statutory program targets. On the latter, the "brute force" case-by-case interconnecting National Grid had been conducting was inconsistent with least-cost procurement, particularly in the long term.

The commission's first finding and order on this matter was to direct National Grid to consider DERs as part of its long-range planning studies. National Grid proposed a distribution system "heat map" to visualize system load and generation constraints to identify locations where incentives could drive additional customer investment rather than costlier system upgrades. This finding, in part, led the commission to have a broader discussion with stakeholders about the value and functions of the system and what options and limitations National Grid faces.

The commission opened a stakeholder docket and accepted stakeholders' unanimous recommendations for a widely applicable benefit-cost framework, rate design principles, and goals for the electric system. Note that:

- Staff found that a strawman proposal was important to get stakeholders to begin building consensus, after starting from a concept-based proposal that left stakeholders struggling to keep up with staff's vision early in the docket.

- Another factor in improving engagement was to keep the dockets uncontested, making it easier for advocates to participate by reducing the need for lawyers.

A current rate case includes a grid modernization proposal articulating some of these options and how they fit into public policy goals as well as incentives for National Grid's performance. The case is scheduled to be decided in August 2018.

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