UM 2005 - Distribution System Planning
Stakeholder Questions for August 25, 2020 Special Public Meeting discussion

NW Energy Coalition
August 21, 2020

1. What kind of actionable baseline data and system assessment information should be included in the first utility DSP plans in order to help parties reach a shared understanding of the current state of the distribution systems?

Technical system data

- By feeder (and lateral if available), also aggregated to zonal and utility level as appropriate:
  - Number of meters by customer class; maximum load capacity, average load, maximum load by year and by season/month; topology (radial, network, loop, …); number of annual line faults and other exceedances, SAIFI and other standard metrics as appropriate; current interconnections and estimated average/peak load for DER (solar, battery, EV); number of public EV charging points; total EV charging capacity
- By substation:
  - Basic configuration (e.g. breaker-and-a-half), number of transformers, high side/low side voltage, presence/absence of SCADA, AMI, capability for VVO/CVR
- Systemwide:
  - Data quality assessment for each data source: vintage, variance, outliers, missing values

Sociodemographic data

Identify proportion of utility, zones and feeders as ***highly impacted*** (who has already been cumulatively impacted by things like fossil fuel and other infrastructure, lack of access to clean energy, etc.) and ***vulnerable*** (more at risk for future harms, based on their characteristics or location, and predicted location of energy impacts). We recommend that utilities work in tandem with the Oregon Health Authority, Census and other sources to create data sets and overlay maps highlighting highly impacted and vulnerable communities in the context of climate change. An initial stage could start by providing disconnection, outage, and DER data, overlaid with sociodemographic data.

It is important to present data, maps and results to impacted communities in a way that does not require technical expertise and assists those communities in understanding and responding to the findings. Clean Energy for Resilient Communities has summarized successful efforts by Exelon affiliates Pepco and Baltimore Gas & Electric to provide such data addressing resilience and clean energy divide issues for their low and moderate income communities.
https://www.abell.org/sites/default/files/reports/envcleanenergy214.pdf

2. When considering the first utility DSP plans, is a "bottom-up" DER/EV forecasting methodology worth the likely additional cost when compared to a "top-down" forecasting methodology? Why or why not?

It may be appropriate to take both paths to determine what relative value each can offer, and perhaps to develop a blended approach. We understand that a 3-year forecast may be feasible, but the duration should be the subject of further discussion. Summary forecast data should be provided by feeder and indicate the date of the most recent feeder study and the study cycle in years (e.g., yearly, every 5 years, etc.).

3. When considering the first plans utilities file, what are likely to be the best uses for HCAs, and in what ways would your organization use them? For example, to screen projects (as a partial substitute for interconnection studies)? To help utility customers understand the general state of their feeder? For researching the overall opportunity for DERs in a given area? What form of data presentation would your use benefit from (e.g. raw, tabular data or visualized on a map)?

We suggest a two stage approach. For the first DSP fling, basic distribution system data and topology should be provided and at least a rough cut on hosting capacity. This should be accompanied by a data quality assessment (also referred to in #1 above) to identify data vintage, gaps and outliers that should be addressed.

The second DSP filing would refine the inputs and the modeling and add additional detail to the HCA.

For each HCA analysis, data should be provided in tabular and map (spatially explicit GIS) formats, and if possible should be available to stakeholders via a public applications program interface (API).

4. How could a Community Engagement Plan and process lead to improved distribution project outcomes for residents, business owners, and stakeholders in impacted areas?

A Community Engagement Plan should build support and relationships between utilities, staff and communities, which would lead to better outcomes going forward.

"The plan would provide a forum for information sharing and education, leading to a common understanding of issues and a common vocabulary." –*The Rising Value of Stakeholder Engagement in Today's High-Stakes Power Landscape*, DeMartini et al., p. 2

When should community engagement around a project begin? What is a practical "project threshold" to determine which projects warrant this?

An effort should be made to identify metrics of need/vulnerability/impact that determine which projects more readily need targeted community engagement. For instance, utilities could identify the sites of fewest historical grid upgrades and/or least forecasted DER growth, and where those identified sites intersect with highest energy burden, largest percentage of non-white population, or most frequent outages.

The Oregon Health Authority, under EO 20-04, is required to publish yearly reports (the first one will come out end of October) on what exactly climate change impacts are to certain communities. The PUC could collaborate to use that data.

What metrics, evaluation and reporting should be required? How might the PUC support utilities to develop and showcase projects co-created with community partners?

The co-creative process should begin by identifying community need, rather than grid need, then pairing community need with grid capacity. Together, the community and the utility should identify possible burdens and mitigation strategies for those burdens. Then stakeholders can co-create a plan.

Utilities should fund technical expertise in equity just as for any other contract technical expert. While "stakeholder engagement" is broad and likely unfunded, engagement of target communities to achieve equitable outcomes is now required by the Governor's executive order and as such should be treated as needed technical expertise.

Regarding reporting and evaluation, too often community members are asked for their expertise, but their input is considered outside the scope of utility work, so it is dropped. Therefore, the utility should provide a summary of comments from target community stakeholders received while drafting/pursuing a project, along with the utility's responses, including whether issues raised in comments were addressed and incorporated, and documenting the reasons for rejecting input if applicable.

For community engagement on specific projects (for example, a substation upgrade), the process should start as early as possible and be continuous in interacting and collecting community interest and concerns.

5. In what ways do stakeholders foresee DSP affecting utilities' current business model? Do these represent incentives to pursue DSP, or barriers? Are there any changes that need to be made to Oregon's approach to regulation in order to succeed at advancing DERs cost-effectively? Which barriers and uncertainties to long-term DSP are most significant from your perspective?

DSP should help explicitly assure the equalization of service quality and utility investment.

A key outcome of DSP is to facilitate and help accelerate the uptake of customer driven investment (DG, EV, etc.).

DSP should also surface and address issues of differential investment incentive (utility rate base vs. customer/provider investment) to find the best overall mix of investment and avoid gold-plating, underinvestment or imbalanced investment.

DSP should address underlying issues of distribution system data quality and provide clear rules and practice for data protection and access to facilitate more effective use and enhancement of the distribution system and customer side resources, and customer value overall.

6. What are your reactions to the overarching goals below? How are your needs reflected or missing? Do you recommend changes?

1. Promote the reliability, safety, security, quality, and efficiency of the distribution system for all customers.

How can utilities recognize or even value community development and wealth-building benefits of DERs? Can more be done than say "we can't do that because we only evaluate what's good for the grid as a whole, not for individual communities"? If not, how will we go about prioritizing equitable investments?

• Reinforce our existing mission, targeted for the distribution system but also updated for security, whether physical or cyber.

The goal should be restated as providing both system protection and customer protection (including safety, privacy and autonomy).

• Facilitate investment to reduce costs over time and promote system efficiencies.

The goal should add customer value and choice especially for an expanded range of customer side resources.

• Enable the best and highest possible uses of the distribution system, to benefit customers and utilities.

The "highest and best use" language is too vague and has specific meaning in other contexts (land use, for example). Also, whose "uses" are being referred to? The goal should be refined to clarify that utilities and customers have somewhat different interests but a common purpose of accessing and enhancing the full value of the distribution system.

2. Be customer-focused and promote inclusion of underserved communities.

• Empower all customers with authentic choices, including access to diverse providers.

The term "underserved" captures only grid need, and can under-reflect historical and institutional impacts. In the Washington CETA rulemaking, utilities are mandated to examine "vulnerable" and "highly impacted" community need, recognizing that equalizing current grid conditions does not adequately address historical burdens, which then exacerbates new burdens.

For example, according to Energy Trust of Oregon data, Tribal Nations, even when controlling for income, have had less access to ETO programs. Raising service levels to a proportional rate to other customers would not not fully capture the historical harms (i.e., displacement).

Within its broad mandates, the PUC should seek to name and mitigate historical harm.

• Create inclusive, nondiscriminatory, equitable access to opportunities across customer types, with particular attention to those that reduce energy burden.

• Engage customers in an approachable, fully-accessible manner.

It is also important to provide customers with an indication that their concerns are heard and being acted on.

• Provide access to detailed, real-time information on electricity use and costs to help customers manage use and costs and understand how to save.

Real-time access is complex and costly and not necessary for all data categories, but should be used for highest-value data that has immediate use value.

• Create procedural inclusion for new stakeholders traditionally not represented.

It is important to have substantive not only procedural inclusion. That is, participation in program or project planning must be accompanied by participation in implementing activities.

• Promote collaboration between utilities and community based organizations to broaden perspectives and representation in planning process and outcomes.

3. Ensure optimized operation of the distribution system.

• Minimize total distribution system costs for the benefits of all customers.

• Consider advanced technologies and opportunities with future promise of lowering system costs.

There should be active testing of advanced technologies, and not only consideration. This continues the long-running practice under the utility Smart Grid Plans.

• Promote fair competition in resource options including third-party delivery of programs and services with the best options for customers.

Include safeguards with third-party service and program delivery for customer protection, and provide a fair competitive environment where utilities and third parties are competing to provide services.

• Provide justification for the customer benefits resulting from system investments.

We are unclear what "provide justification" refers to, but this should go beyond the normal cost recovery process under the respective tariffs.

4. Accelerate integration of DERs and other clean energy technologies.

• Fair cost allocation and fair compensation for services and benefits provided to and by customers, and other non-utility service providers.

• Present transparent data about system operations and characteristics, including greenhouse gas implications.
• Enable and streamline utility co-investment in the grid for decarbonization.

5. Strive for regulatory efficiency through aligned, streamlined processes

• Focused, strategic reporting that enables efficient regulatory response.
• Consistency and synchronization across related utility planning efforts.

DSP should also seek to support resilience strategies.

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Fred Heutte
Senior Policy Associate
NW Energy Coalition
fred@nwenergy.org

/s/

Heather Moline
Energy and Environmental Justice Policy Associate
NW Energy Coalition
heather@nwenergy.org