August 21, 2020

Distribution Planning Staff
Oregon Public Utility Commission

RE: Response to Stakeholder Questions for August 25, 2020 Special Public Meeting discussion

Dear Mr. Sayen,

Thank you again for your comprehensive, open minded and foreward thinking approach to this docket of such tremendous importance.

As a cross cultural organization representing front line, isolated, load pocket communities, Oregon Coastal Energy Alliance Network (OCEAN) is keenly interested in the process and outcome of this docket and has attached our response to the questions asked of stakeholders in preparation for our next Special Public Meeting on this topic.

Respectfully,

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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?

The first utility DSP should be focusd on making data that is already readily available to the utility accessible to stakeholders. This would (and should) include the following:

1) **Substation Information:**
    a. **Name or identification number**
    b. **Voltages**
    c. **Substation transformers nameplate rating**
    d. **Existing Generation (weekly refresh rate)**
    e. **Queued Generation (weekly refresh rate)**
    f. **Total Generation (weekly refresh rate)**
    g. **8760 Load profile by substation and transformer**
    h. **Percentage of residential, commercial, industrial customers**
    i. **Currently scheduled upgrades**
    j. **Has protection and/or regulation been upgraded for**
    k. **reverse flow (yes/no)**
    l. **Number of substation transformers and whether a bus**
    m. **tie**
    n. **exists**
    o. **Notes (include any other relevant information to help guide**
    p. **interconnection applicants, including electrical restrictions,**
    q. **known constraints, etc.)**

2) **Feeder Information:**
    a. **Name or identification number**
    b. **Which substation the feeder connects to**
    c. **Feeder voltage**
    d. **Number of phases**
    e. **Which substation transformer the feeder connects to**
    f. **Feeder type: radial, network, spot, mesh etc.**
    g. **Feeder length**
    h. **Feeder conductor size and impedance**
    i. **Service Transformer rating**
    j. **Service Transformer daytime minimum load**
    k. **Existing Generation (weekly refresh rate)**
    l. **Queued Generation (weekly refresh rate)**
    m. **Total Generation (weekly refresh rate)**
    n. **8760 Load profile**
    o. **Percentage of residential, commercial, industrial customers**
    p. **Currently scheduled upgrades**
    q. **Notes (other relevant information to help guide interconnection**
    r. **applicants)**

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?

Provided that a “bottom – up” methodology is required by a specified timeline or other threshold for progresss towards, the first utility DSP can be published as a tradition “top-down” analysis provided that third party

verification of this initial plan is included along with third party recommendations for successful transition to a "Bottom-Up" approach for subsequent planning processes.

How might the PUC support utilities to develop and showcase projects co-created with community partners?

The PUC can support utilities in co-creation and development of projects with community partners by providing a pilot offering of third party facilitation of co-development (between utility and locational community partners) of needs analysis and solicitations. The outcomes of said projects will inform process and provide utilities with "bragging rights" for doing the right thing.

5. In what ways do stakeholders foresee DSP affecting utilities' current business model?

DSP should result in more contracting with third-parties for the provision of distribution services allowing utilities to focus on operations, maintenance and planning efficiencies and optimization. Third party services supplied by parties focused on energy security, best available technology integration and specific lanes of technological expertise (in areas such as battery storage systems and customer response through load shifting or curtailment of activities) would reduce stresses on utility staffing, expedite solution integration and ultimately result in savings to both rate payers and utilities.

Contracting for these services may reduce the need for capital investment by the utility and reduce earning opportunities on those assets. However, a well designed DSP process will reduce project design timelines, utility staff strain and rate payer burden while increasing system reliability (ie, reduce utility risk, response to interruption expense and loss of sales revenue) and rate payer satisfaction.

Do these represent incentives to pursue DSP, or barriers?

As our communities, and those responsible for maintaining infrastructure to support those communities, continuously respond to the ever increasing frequency of catastrophic events we must consider means of providing for the safe and reliable service of those communities while maintaining the IOU return on investment.

The utilities will serve their investors by proactively incorporating the realities of meeting their mandates of safe, reliable electricity to ratepayers in these increasingly dynamic times through open minded consideration of the long term fiscal benefits of a full suite of non- wires solutions.

Are there any changes that need to be made to Oregon's approach to regulation in order to succeed at advancing DERs cost-effectively?

Compulsion of IOU's to incorporate third party validation of DSP plans, needs assessments, solicitations and interconnection studies would all accelerate, economize and advance cost effective DER adoption.

Compulsion of IOU's to provide a consistent framework of data availability that can be readily accessed by and incorporated into tabular and GIS/ mapping formats by tribal nations, Oregon DOE, Emergency Responders, Resiliency Mitigation Planners, Department of Defense, energy developers and other stakeholders would expedite the identification of mutually beneficial DER opportunities that could levereage multiple stakeholder benefit (including IOUs) with multiple stakeholder funding streams.

Which barriers and uncertainties to long-term DSP are most significant from your perspective?

Access to and transparency of utility data (including feeder level reliability data), potentially self-serving or otherwise perspective limited IOU development of solicitations and an unbiased procurement process are all significant barriers.

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.

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

Safety and reliability have been elements of the PUC mission since 1911, however IOUs have previously been provided the allowances of meeting those metrics through an IOU lense. If, in deed, the above elements of the modern, post SB 987, mission are actualized not only from the perspective of the utilities but also from the perspective of the feeder line level of the communities served, then OCEAN embraces this goal. We do not support the aggregation of reliability statistics nor the exclusion of public health and safety by virtue of loss of electricity in these goals as has been the case previously.

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

Costs should be reduced for both the IOUs and rate payers.

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

Agreed

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

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

Warmly welcomed.

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

Warmly welcomed.

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

This engagement should occur at the stage when the utilities are figuring out how to engage by collaborating with those focused on this rapidly emerging and highly localized sector of specialization for "field fit best practices" with binding outcomes.

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

On a full utility scale, this is a reasonable goal to be incorporated as upgrades and technology advance to cost effectively allow it. In the mean-time, all utility investments should incorporate this goal and be designed for the ready acceptance and relay of additional data and levels of resolution as utility, rate payer and third party investments in grid assets progress.

• *Create procedural inclusion for new stakeholders traditionally not represented.*

This is of utmost importance if we are to realize meaningful customer representation.

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

Warmly welcomed.

3. Ensure optimized operation of the distribution system.

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

Agreed. Given the institutional practice and training of utilities to serve utility safety and bottom line, this will best be met by incorporating the costs of contracting third parities in the development of solution set soliciations.

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

Please see response above.

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

Please see response above.

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

Agreed

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.

All are warmly welcomed.

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.

The incorporation of mutually informative DSP, Transmission System Planning and Resource Adequacy processes must be a component of this success.