NW Energy Coalition
for a clean and affordable energy future

Investigation into Distribution System Planning
UM 2005
Stakeholder Survey

Comments of NW Energy Coalition
August 30, 2019

The NW Energy Coalition provides these comments based on the survey format and questions provided by Oregon PUC staff. We recognize that the scope and details of this process are evolving, so these are initial views.

Distribution planning has existed since utilities began providing network service. Until now, it has basically been an engineering exercise to assure that equipment and operations in the local grid can support current and anticipated peak load conditions, generally on a feeder by feeder basis, as well as at the substation and aggregate system level. Distribution planning is often siloed in a utility, with few connections to integrated resource planning.

Distribution system planning (DSP) is not intended to displace this core function, but rather to build on it and provide a new set of planning tools, methods and broader stakeholder participation, for two reasons.

First, rapid innovation of technology, policy and markets is bringing customers into a more active role in making choices and managing their own electric use, as well as providing services back to the grid. This requires a more comprehensive assessment of system capability and operations, connecting various planning processes and enouraging broader participation by customers and other stakeholders.

Second, more diverse and often interconnected third party providers and value networks are augmenting the distribution network and customer equipment behind the meter. This requires changes to planning tools, data resources and interface definitions. It also has implications for the interconnected nature of the distribution system and supply and demand-side resources.

Therefore, NWEC believes that DSP is about identifying and promoting investment by *utilities and customers* to expand the carrying capacity and optimize the operation of the distribution system. A key difference

from traditional distribution planning is that connected customer-side resources can provide system value for all customers as well as other benefits including improved operating conditions for the utility.

DSP will also surface a range of new issues and challenges. A key challenge is addressing the differential incentive created by cost-based ratemaking for "wires" investments in the distribution system (which generally are included in rate base) and "non-wires" investments, generally on the customer side. Resolution of this tension is properly a ratemaking issue outside the scope of this docket, but it must be recognized so that DSP fairly treats all measures that can enhance distribution carrying capacity, improve operations and ultimately enhance customer value.

1) Commission principles for distribution system planning: a) What principles should the Commission adopt? Please explain and define.

A. Maximize value to customers: cost, reliability, safety, choice, protection.
B. Be inclusive: All customers should have opportunities to participate in distribution system enhancements through tariffs and programs that compensate them fairly for the value they provide, with particular consideration given to low-income customers and other traditionally underserved or hard-to-reach customers.
C. Provide for equity, access and the needs of underserved communities. Because DSP is locationally explicit, investment must be fairly allocated to assure all customers have access over time. A clear example is the buildout of electric vehicle charging infrastructure and distribution system support. Feeders where customers are already adopting EVs may well require distribution system upgrades, which in turn incent more customers to adopt EVs. Yet all customers pay for system upgrades; therefore, while prioritization may be needed to assure system reliability, investment must also be directed across the system to provide fair access. Additionally, costs or impacts from distribution system planning should be equitable across customers and burdens should not fall disproportionally on any group(s) of customers.
D. Support state climate and energy goals.
E. Support community resilience strategies, especially weather, climate and seismic risk.
F. Be transparent in DSP process, metrics and methods.
G. Consistency in DSP analysis, while recognizing differences across the distribution system, for example at the feeder level.
H. Incorporate an open approach to data sharing, except where precluded for specific reasons of security, privacy and demonstrated business confidentiality. Data access and constraints must have clear definitions, appropriate safeguards for customer privacy/autonomy/choice and business confidentiality.

I. Consider all resources and options, both wires and non-wires. Be technology agnostic, while recognizing trends in technology innovation and diffusion. For example, power electronics in inverters (rooftop solar, battery storage, etc.) can provide a range of grid services traditionally provided by distribution system equipment.
J. Promote competition of measures and suppliers while recognizing the core responsibilities of the utility to provide safe and reliable service.
K. Use a scenario approach to assess feasible futures, especially those driven by state climate/clean energy goals (e.g., transportation electrification).
L. Ensure close coordination with utility integrated resource planning and transmission planning.
M. Enhance visibility/situational awareness of the distribution system, demand patterns and flexible demand management for overall utility operations.
N. Provide necessary data for rate design, cost allocation and recovery, and for appropriate compensation to customers for providing value to the system.
O. Support physical and cyber security.

b) What level of specificity is most helpful to include in principles?

NWEC believes that systemwide technical assessment is a must, along with granularity at least to the feeder level where feasible. We recognize this will be an evolving process. A "bottom up" approach with a few selected areas that are projected to the system as a whole will be insufficient for selecting the best distribution system enhancements.

2) Maximizing customer value: a) How you would define "maximize customer value" in the context of distribution system planning?
b) What considerations (from Staff whitepaper or other thoughts) are most important to focus upon when maximizing customer value in planning for the distribution system?

As mentioned above, NWEC focuses on three areas: direct value to customers (cost, reliability, safety, choice, protection), as well as inclusion and equity. DSP evaluation of customer value must also take a long-term view rather than focusing primarily on short-term economics.

While the traditional notion of customer value, for example, in ratemaking and integrated resource planning, comes down to a cost basis or formulation like "least cost/least risk," the importance of the distribution system in providing reliability is highly significant but difficult to quantify. Traditional service performance (SAIDI, SAIFI) and power quality measures are a good starting point but additional metrics may be appropriate. Additionally, impacts from distribution system decisions should be equitable across customers and burdens should not fall disproportionally on any group(s) of customers.

3) Evaluation of utility distribution system plans: a) Which criteria or metrics should the Commission use in evaluating the proposed distribution plans (Plans)?

NWEC believes that more concrete answers will emerge in the forthcoming process including input from the Commission and staff, utilities and stakeholders. In addition, the evolving process and practice will also require flexibility in Commission review, but we believe it is appropriate to set clear expectations concerning data availabilty and granularity, coverage (at a system and feeder level), cost estimation, technology agnostic assessment, reliability metrics and exchange of data and other inputs/outputs with IRP and transmission planning,

b) How will your organization evaluate and/or otherwise use the proposed Plans?

NWEC anticipates using the DSP process and the plans to deepen our understanding of the features and operations of the distribution system and to refine our thinking and advocacy, on behalf of our 100 organizational members as well as individual members, for programs and measures that open up customer access, choice, fair compensation for providing grid services, and rate recovery. We are focused on the uptake of clean energy measures, assuring access and equitable treatment for all customers, and achieving our state clean energy and climate goals.

c) How should distribution system plans be integrated with other planning activities, such as resource planning, interconnection, transmission, or others?

NWEC recognizes that DSP, IRP and transmission planning are separate realms requiring different assessment frameworks and modeling capabilities. However, they cannot function as completely separate silos any longer, resulting in capital misallocation and lost opportunities that undermine the achievement of a clean resource mix and optimizing system operations.

DSP will draw more directly on IRP data and metrics, for example, looking at a range of future demand scenarios based on differing conditions in our economy, technology and market development, and the positive direction set by Oregon's climate and clean energy policies.

DSP will also provide valuable and granular data to IRP on changes in demand patterns, and uptake of customer-side and distribution resources supporting clean energy and reliability.

Effective DSP will help shape distribution system operations in a way that improves transmission system operations and the generation resource mix, leading to improved reliability and decreased cost on the bulk power system.

Overall, we would prefer to label this next phase as "coordination" rather than "integration," which could occur at a later stage. In the oncoming period, we urge the Commission, utilities and stakeholders to consider ways to sequence and align each of the major planning cycles: DSP,

IRP and transmission planning. A two-year (but flexible) cycle has worked well for IRP but may or may not be the right duration for the others; however, all three should be better synchronized going forward.

To make this more concrete, we have already proposed that DSP, IRP and transmission planning share one or more scenarios in the next round with a common theme and metrics such as accelerated EV adoption. This would provide insight on key issues and identify how external technology, policy and market developments could affect distribution, power and transmission and prepare utilities and customers to respond accordingly.

d) What are reasonable options for stakeholder participation in the planning process: direct engagement in the development of plans, the review of draft and final plans, other?

The DSP process in other states including California, New York, Minnesota, Hawaii and Rhode Island has resulted in a wide range of scope, practices and assessment processes arising from this single basic concept. Oregon has the opportunity to pick up lessons already learned while refining an approach best suited to our state, our utilities and our customers.

DSP differs somewhat from IRP, which is primarily an economic planning exercise. In DSP, engineering-based methods, for example hosting capacity analysis (HCA) and locational net benefit analysis (LNBA), will be driven by utility modeling but must also include input from technically competent stakeholders.

However, DSP is not only HCA and LNBA, it is also an assessment of the capabilities, role and costs of distribution and behind-the-meter equipment, customer behavior and preferences, data sharing and protection policies, and so on. There will be a greater variety of roles for stakeholders in the DSP process, and that should be ccommodated from the start.

We anticipate that as in other states, subgroups focusing on various subareas of DSP will be formed, contrasting with the IRP process which is typically a single-room approach.

As a result, frequent summary of subgroup work for the overall stakeholder process will be important, as well as the well-tested process for drafts, review and comment in preparing final DSP plans.

e) How often should a utility distribution plan be submitted for Commission review?

NWEC initially believes a two year update cycle is appropriate, but is open to other options. Perhaps more important is assuring that actionable information also flows to and from DSP, IRP and transmission planning in a way appropriate to all three processes.

4) Planning Scenarios: a) How should the selection of scenarios used in distribution planning be determined?
b) What criteria should be used by utilities to identify relevant planning scenarios?

Scenario selection should be determined through the stakeholder process, but we suggest close attention to current trends and possible futures for system demand, technology uptake, customer participation and state policy as key determinants of scenario development.

5) Access to grid and planning data by customers and third parties: a) Discuss categories of data needed by third parties to:
i. Participate in developing system plans.
ii. Critically review proposed plans.
iii. Prepare commercial projects in response to plans.

We do not have specific listings at this time. However, data is a crucial aspect of DSP assessment, so we will be active in reviewing and commenting on data inclusion in the DSP process.

b) Identify any categories of data that may be unsuitable for access, e.g. for reasons of security, trade secret, customer privacy, or burdensomeness.

As noted above, NWEC strongly supports a policy of open access except where precluded for specific reasons of customer privacy, cyber and physical security, and business sensitivity. In all cases, the choice between access and restriction is a tradeoff. Business sensitivity is a particularly difficult category because utilities possess a vast amount of relevant data, providers also have data relevant to DSP that may be business-sensitive, and customer data, including as generated from operation of the distribution system, has aspects of privacy, anonymity and agency that will be very important to prioritize.

c) How should and in what format should the results of a hosting capacity analysis or native loading analysis be made available by utilities? Please indicate which formats are currently available and which are not currently available.

NWEC will participate to the extent feasible in this part of the DSP process, recognizing that significant technical expertise is required.

d) How should the commission evaluate utility investments that enable more transparent interconnection data to be made available? What are the costs and benefits that the Commission should consider?

This is a very important topic requiring a more concrete discussion than is possible at the front end of this docket. In general, data restrictions can become serious obstacles to both DSP and implementation of distribution system enhancements, which is why we strongly support an "open except where reasonably precluded" policy approach.

In addition, moving from the earlier era of simple telemetry systems (first generation SCADA) to more interactive communications and control at present, to dynamic grid management that will eventually involve millions of interactive devices beyond the meter, poses very substantial challenges in achieving multiple system goals while coping with massively expanding dataflow. In that context, it is essential to focus on fitness-to-purpose and data quality.

6) Are there other issues or topics not covered here that are relevant to discuss in distribution system planning? If so, what are they and why are they relevant?

As with other areas of utility investment, DSP procurement decisions are subject to capital bias – the utility earns a return on capital investments for infrastructure, while it does not earn a return on many non-wire alternatives or investments made primarily by customers. Additionally, the shorter timeline for payback of some technology investments may also reduce utilty earnings. The PUC should consider establishing performance metrics, based on DSP principles, for the most effective DSP investments in order to overcome these earnings challenges in utility decisionmaking.

Thank you for your consideration of NWEC's comments.

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