

## Staff Proposed Distribution System Planning (DSP) Guideline Revisions

### Executive Summary

Staff's Proposal includes this document with a request for public comment by May 31, 2024, an accompanying summary of proposed revisions, and Guidelines in both redline and clean formats. Oregon DSP Guidelines were adopted by the PUC in December 2020. As the energy landscape grows more complex and conversations about rate pressure and utility cost containment evolve, Staff seeks to focus the next round of plans on vetting core investment planning information to directly inform the rate recovery process. Additionally, Staff seeks to continue to harmonize and prioritize investments between DSP, transmission systems investments, and other key planning activities before the PUC.

In the next round of plans, Staff will focus on performing a thorough review of the Companies' proposed grid investments and operational plans to 1) allow participants to influence decisions prior to their implementation; and 2) lay the groundwork for rate recovery and any associated performance metrics. Staff's primary objective is understanding of the major drivers, level of spend, prioritization strategy, and benefits of the Company's five-year Near-term Action Plan. This will require the utilities to provide detailed and comprehensive information about planned operational budgets (including operational changes) and system investments, along with a clear rationale for prioritizing these expenses to maintain, improve, or avoid investments in the grid.

In addition, Staff seeks to better understand the following high priority questions:

- How is the Company prioritizing and containing spend while making decisions across multiple objectives, such as load growth, aging infrastructure, policy obligation, and heightened demands?
- How are the decisions that the Company is making related to distribution assets interacting with non-distribution asset strategies? Essentially, what alternatives to distribution investment could be considered and if certain distribution investments are made, what impacts do they have on other network assets?
- How is load growth, particularly from large commercial and industrial customers, impacting the Company's grid needs, costs, and strategies? What would the plans look like if those large loads were not being considered? What barriers to modern technology exist and how can the planning and commissioning process mitigate those barriers?
- How is the plan informed by and/or informing the PUC's work to incorporate resilience considerations into investment planning? How are Wildfire Mitigation Plans informing/informed by the Company's DSP?

For large distribution projects Staff will continue to prioritize the DSP as the primary venue for utility accountability for community input and equity assessments.

Utility demand response (DR)/flexible load plans are interrelated and require coordination with DSP, but Staff expects to continue to review them as separate plans.

## Review of Proposed Guideline Revisions

DSP Guidelines were established through [Order No. 20-485](#). Utilities filed inaugural plans in two parts, with each filing accepted by the Commission, most recently in March 2023. The inaugural DSPs were accepted by the Commission, generally well-received by Stakeholders, and successful in many respects. However, Staff also critiqued inaugural DSPs, noting shortcomings such as incomplete discussion of grid needs, partial presentation of investment decision making and prioritization, and ill-defined proposed investment and expenditure levels. Staff proposes Guideline revisions that focus DSP on grid needs, expenditure decision making and prioritization, and proposed investments and expenditures.

Staff proposes substantive revisions to eight sections of the Guidelines, removing four sections and revising one. Staff summarizes proposed Guideline revisions, and maps current and proposed Guideline numbers in Table 1.

**Table 1. Detailed Summary of Proposed Revisions**

Current Guideline Section	Summary of Proposed Revisions	Proposed Guideline Section
1. Process and Timing	<b>Substantive revisions</b> modifying timing and cadence.	No change
2. Commission Action	<b>Modest revisions</b> cleaning up language.	No change
3. Scope	<b>Removed</b> as future plans will be one filing.	N/A
4.1 Baseline Data and System Assessment	<b>Substantive revisions</b> removing requirements on net metering/small generator map and data, electric vehicle and DR data. Adds new requirement for summary progress report, and to address data from Annual Reliability Reports. Requires preparation of electronic data and submittal to Commission for public review.	4. Current System Data and Assessment
4.2 Hosting Capacity Analysis	<b>Removed.</b> Staff will propose updated direction to maintain system maps, with specific refresh cadence and latency expectations. Staff does not propose a hosting capacity threshold as a grid need in DSP at this time.	N/A
4.3 Community Engagement Plan	<b>Substantive revisions</b> to Guidelines integrating engagement into ongoing community/stakeholder processes such as Clean Energy Planning and local-area planning, and noting opportunity for community and in-person meetings. Refocuses the Community Engagement Plan. Removes engagement requirements in developing non-wires solutions pilot concept proposals.	3. Community Engagement
4.4 Long-term Distribution System Plan	<b>Substantive revisions</b> to timeframe and requiring the roadmap consist of planned investments/expenditures/activities, discuss prioritization, and include connections to: 1) grid needs, 2) conditions identified in the System Assessment, and 3) other planning processes. Places Long-Term Plan after Near-Term Plan.	9. Long-term Plan
4.5 Plan for Part 2 Development	<b>Removed</b> as future plans will be one filing.	N/A

Current Guideline Section	Summary of Proposed Revisions	Proposed Guideline Section
5.1 Forecasting of Load Growth, DER Adoption, and EV Adoption	<b>Substantive revisions</b> increasing granularity, specifying that DSP forecasts include data, inputs, and assumptions from the most recent IRP/CEP including discussion of how IRP/CEP forecasting is decomposed to, and reconciled with, areas of the distribution system.	No change
5.2 Grid Needs Identification	<b>Substantive revisions</b> to discuss and identify anticipated grid needs of a variety of types, and provide summary table of each identified need by asset class, with timing.	6. Grid Needs
5.3 Solution Identification	<b>Substantive revisions</b> to assess each identified grid need for non-wires solution and document traditional and non-wires solutions in the Long-term and Near-term Plans. Relocates the requirement for community engagement for larger projects. Removes requirement to develop non-wires solutions pilot concept proposals.	Now Section 7
5.4 Near-term Action Plan	<b>Substantive revisions</b> for a 5-year plan of the utility’s proposed solutions to address grid needs. For activities estimated to cost more than \$2M requires discussion of prioritization, and includes connections to: 1) grid needs, 2) conditions identified in the System Assessment, and 3) coordination with other planning processes. Requires projected cost and timeline by asset class.	8. Near-term Action Plan
6. Overview of the Distribution System Planning Process	<b>Removed.</b>	N/A

## Request for Public Comment

Staff requests public comment on the accompanying proposed Guideline revisions. Stakeholders should submit comments to [nick.sayen@puc.oregon.gov](mailto:nick.sayen@puc.oregon.gov) by May 31, 2024.

Staff welcomes general feedback; however, comments on specific revisions are especially helpful. If commenting on specific revisions, please reference current Guidelines. For example, *the removal of requirement 4.1 g)...* or *the addition to requirement 5.1 b) i)...* Staff appreciates feedback identifying areas where proposed revisions are not sufficiently clear.

Staff will consider these comments and present a final version of updated DSP Guidelines to the Commission at a Public Meeting, estimated in July.

## Staff Contacts

If you would like to join the service list for Docket No. UM 2005, email your request to [puc.hearings@puc.oregon.gov](mailto:puc.hearings@puc.oregon.gov). If you have questions about providing public comment, or other distribution system planning in general, please contact Nick Sayen at [nick.sayen@puc.oregon.gov](mailto:nick.sayen@puc.oregon.gov) or 503-510-4355.

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

---

In this document, Staff first summarizes proposed Guideline revisions and deletions. Proposed Guideline revisions follow in redline and then clean format.

## Proposed Substantive Revisions

### *Guideline 1 Process and Timing*

Under the current Guidelines DSPs are filed on a floating, approximately 24-month cadence. PGE's next DSP is due February 28, 2025. Pacific Power's and Idaho Power's next DSPs are due March 21, 2025. Staff invites utilities to suggest their preferred next filing dates, no later than March 31, 2026. Staff proposes that the specific filing date and cadence of subsequent Plans be set in the next Guideline revision process (anticipated to be late 2026 or early 2027) or by Commission order. Staff proposes to move workshop requirements to the Community Engagement section.

### *Guideline 4.1 Baseline Data and System Assessment*

Staff proposes removing a requirement for a map identifying locations of net metering and small generator facilities as Staff understands such a map is now redundant with current system maps developed in response to Guideline 4.2. Staff also proposes removing requirements for 1) service territory electric vehicle (EV) data which is available from more robust sources; 2) high-level summary demand response (DR) data, which is available through utility annual reporting; and 3) a redundant requirement for Net Metering and Small Generator data. Staff proposes an additional requirement to make clear that any proposed investments based in whole, or part, on reliability improvements must demonstrate those improvements by cross-referencing underlying data and information contained in the Company's most recently filed Annual Reliability Report. Staff proposes a summary progress report on activities included in the most recently filed DSP. Staff proposes that data assembled for this requirement be prepared in electronic format and submitted to the Commission for public review.

### *Guideline 4.3 Community Engagement Plan*

Staff proposes that DSP engagement be integrated with ongoing community and stakeholder processes, and leverage best practices and lessons learned from engagement efforts from prior Plans and other planning processes. Staff proposes removing Guidelines for engagement related to developing non-wires solutions pilot concept proposals as these proposals are removed, as discussed in the Guideline 5.3 Solution Identification section. Staff proposes that utility Community Engagement Plans focus on possible non-wires solutions projects, and larger projects, and that these plans consider engaging local governments and Tribal nations.

### *Guideline 4.4 Long-term Distribution System Plan*

Staff proposes that a utility's long-term vision for the distribution system address the next 10 years. Staff proposes that a utility's roadmap consist of a list of planned investments, expenditures, and activities to advance the long-term vision. The roadmap should discuss criteria and methods of prioritization. The roadmap list should aid Staff and stakeholders in linking the Long-term Plan to investments submitted in future general rate cases.

### *Guideline 5.1 Forecasting of Load Growth, DER Adoption, and EV Adoption*

Staff proposes that forecasting granularity increase from the substation level to the feeder level. Two utilities exceeded the original substation requirement and forecast to this higher level of granularity in inaugural plans. Staff also proposes language to consistently define requirements for load forecasting, and DER adoption and electric vehicle (EV) adoption forecasting; and that

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

---

DSP forecasts include data, inputs, and assumptions from the most recent Integrated Resource Plan (IRP)/Clean Energy Plan (CEP). Staff proposes a Guideline for utilities to document whether or not they complete forecasting for the entire distribution system.

## *Guideline 5.2 Grid Needs Identification*

Staff proposes requirements to discuss and identify anticipated grid needs of a variety of types, and a summary table of each identified grid need by asset class, along with timing, that links DSP to investments to what is submitted in future general rate cases.

## *Guideline 5.3 Solution Identification*

Staff proposes that utilities assess each identified grid need for non-wires solutions, and that all identified traditional and non-wires solutions are documented in the Long-term and Near-term Plans as appropriate. The solutions identified should correspond to investments seen in future general rate cases. Staff proposes the requirement for community engagement for larger projects move to the community engagement section, and removing the requirement for developing additional non-wires solutions pilot concept proposals. Non-wires solutions pilot concept proposals were intended as a limited-time activity to educate and inform Staff and stakeholders. However, Staff supports utilities continuing any current non-wires solutions pilot concept proposals to completion.

## *Guideline 5.4. Near-term Action Plan*

Staff places this section before the Long-term Plan and proposes a prioritized five-year plan listing the utility's proposed solutions to address identified grid needs. Staff proposes that the Action Plan lists activities estimated to cost more than \$2 million, and discusses criteria and methods of prioritization. Staff proposes the Action Plan include the projected cost and timeline by asset class. The activities list and projected spending should aid Staff and stakeholders in linking the Near-term Action Plan to investments submitted in future general rate cases.

## **Proposed Modest Revisions**

### *Guideline 2 Commission Action*

Staff proposes DSPs continue to be considered for acceptance by the Commission. Staff continues to believe it is premature for DSPs to be considered for acknowledgement as guidance around cost-effectiveness is still to be developed.

## **Proposed Deletions**

### *Guideline 3 Scope*

Staff proposes removal of this Guideline as future plans will be prepared and submitted as one filing.

### *Guideline 4.2 Hosting Capacity Analysis (HCA)*

Staff proposes removal of this Guideline as HCA options analysis was intended as a one-time activity to educate and inform Staff and stakeholders. Utilities should maintain and update current system maps developed in response to this Guideline. However, *evolution* of current utility system maps is being considered in Staff's investigation into interconnection processes and policies in Docket No. UM 2111, specifically updated screening practices, export controls, and the IEEE 1547 standard update.<sup>1</sup> Staff will propose updated direction to maintain system

---

<sup>1</sup> See Docket No. AR 659, Order No. 24-068: [apps.puc.state.or.us/orders/2024ords/24-068.pdf](https://apps.puc.state.or.us/orders/2024ords/24-068.pdf).

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

---

maps, with refresh cadence and latency expectations, in coordination with Docket No. UM 2111. That investigation will be moving forward with an intent to work with stakeholders to set the scope for, and confirm the most important issues to consider, in Phase 2. In light of this ongoing work, Staff does not propose a hosting capacity threshold as a grid need in DSP at this time.

## *Guideline 4.5 Plan for Part 2 Development*

Staff proposes removal of this Guideline as future plans will be prepared and submitted as one filing.

## *Guideline 6 Overview of the Distribution System Planning Process*

Staff proposes removal of this Guideline.

Guidelines adopted in 2020 included contextual discussion and illustrative figures. These elements were helpful in establishing intent, and possible future evolution, of the new Guidelines. Staff proposes removing these elements at this time as the context for DSP is further established and evolution of the grid is advancing at different rates across the state. Staff maintains that distribution system planning is, and will continue to be, evolving and dynamic with advanced stages in the future.

**Staff Proposed Distribution System Planning (DSP) Guideline Revisions**

**April 2024**

---

Redline version

**Distribution System Planning Guidelines**

**Table of Contents**

1. Process and Timing	2
2. Commission Action	2
3. Community Engagement	3
4. Current System Data and Assessment	6
5. Forecasting of Load Growth, DER Adoption, and EV Adoption	14
6. Grid Needs	16
7. Solution Identification	18
8. Near-term Action Plan	20
9. Long-term Plan	22

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

---

## 1. Process and Timing

The following development and review process will guide the ~~initial~~-utility filing of a Distribution System Plan (Plan) for a utility's service territory in Oregon.

a) Each electric utility<sup>2</sup> must file ~~its next Plan on or before the following dates, the first portion of its Plan (Part 1) on October 15, 2021~~ or an alternative date designated by Commission order.

Idaho Power: Month Day, Year

Portland General Electric: Month Day, Year

Pacific Power: Month Day, Year

~~b) Each utility must file the second portion of its Plan (Part 2), on August 15, 2022 or an alternative date designated by Commission order.~~

~~c) Subsequent Plans will be filed in their entirety, combining Parts 1 and 2.~~

~~bd) The date and cadence of filing Each utility must file a subsequent Plans will be set in the next Guideline revision process, or by Commission order within two years of the Commission order for Part 2.~~

~~For both Part 1 and Part 2 of the utility Plan:~~

~~e) During Plan development, prior to filing, each utility must hold at least two workshops with stakeholders to ensure a range of community perspectives are heard and considered. Each utility must hold additional community meetings during development of pilot projects.~~

~~cf) Each utility will present the results of each the filing to the Commission at a separate public meeting.~~

~~dg) Upon each filing, the Commission will set a procedural schedule under which interested parties will have the opportunity to provide comment and make recommendations on the filing.~~

~~eh) The Commission will generally consider comments and recommendations on a utility's filing at a public meeting three to five months after it is filed. The Commission will consider whether to accept the filing as meeting the objectives of these Guidelines. The Commission may provide guidance on the development and content of future Plans.~~

~~fi) The Commission may provide the utility an opportunity to revise the filing before making its decision.~~

The design and implementation of this proposed process will serve the long-term regulatory efficiency goals through aligned, streamlined processes, inclusion, and transparency.

## 2. Commission Action

~~A utility must file its Plan as provided in Guideline 1.~~ The Commission will consider whether to accept the filed Plan ~~(or Plan Part)~~ as meeting the objectives of these Guidelines. As used in this Guideline, "acceptance" means the Commission finds the Plan meets the criteria and requirements of these Guidelines. Acceptance does not constitute a determination on the prudence of any individual actions discussed in the Plan. A decision to not accept a Plan means that the Plan does not meet the criteria or requirements of the Guidelines.

---

<sup>2</sup> "Electric utility" or "utility" for purposes of these guidelines means an electric company that is engaged in the business of distributing electricity to retail electricity consumers in this state and that owns and operates a distribution system connecting the transmission grid to the retail electricity consumer.



# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

## 34.3 Community Engagement Plan

A utility should involve the public in the preparation and implementation of each utility Distribution System Plan. Involvement includes opportunities to contribute information and ideas, as well as to receive information, similar to the public input process in an IRP. Interested parties must have an opportunity to make relevant inquiries of the utility formulating the Plan. These updated guidelines for community engagement are intended to foster a developing process that has continued to develop since DSP Guidelines were adopted in 2020, and that supports a human-centered approach to DSP.

Community-based organizations (CBOs) may play an integral role in DSP-related community engagement. CBOs can offer insight to inform the utility's bottom-up forecasting of technology deployment, especially in vulnerable communities. CBOs can provide input to the utility on the methodology to identify and prioritize distribution system investments and project development. CBOs can also identify or support implementation of customer-sited non-wires solutions.

Local governments and Tribal nations may also play an important role in DSP-related community engagement, and can provide input to the utility on policies intersecting with distribution system planning.

~~In the *Connectivity Means Community* presentation, presenters noted five approaches to engagement: inform, consult, involve, collaborate, and defer to.<sup>3-4</sup> Each of these approaches should be incorporated into a robust community engagement plan and ongoing process. Further, best practices for community engagement highlighted during the May 20, 2020 workshop include:~~

- ~~● Be easy;~~
- ~~● Be trusted;~~
- ~~● Be adaptable;~~
- ~~● Be flexible;~~
- ~~● Be positive;~~
- ~~● Be equitable; and~~
- ~~● Be a great ally.<sup>5</sup>~~

~~Grounded in these insights and conclusions, Figure 3 introduces the initial requirements and expected evolution for community engagement.~~

### Figure 3

<sup>3</sup>~~Connectivity Means Community—Distributed System Planning for Humans, Oriana Magnera and Charity Fain, Verde and Community Energy Project, May, 20, 2020,~~

~~<https://www.oregon.gov/puc/utilities/Documents/DSP-Magnera-Fain-Presentation.pdf>.~~

<sup>4</sup>~~The Spectrum of Community Engagement to Ownership, Rosa Gonzalez, Facilitating Power, <https://movementstrategy.org/b/wp-content/uploads/2019/09/Spectrum-2-1-1.pdf>.~~

<sup>5</sup>~~Connectivity Means Community—Distributed System Planning for Humans, Oriana Magnera and Charity Fain, Verde and Community Energy Project, May, 20, 2020,~~

~~<https://www.oregon.gov/puc/utilities/Documents/DSP-Magnera-Fain-Presentation.pdf>.~~

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

<b>Community Engagement</b>		
Stage 3	Utilities collaborate with CBOs and environmental justice communities so that community needs inform DSP project identification and implementation. "Community needs" could address energy burden, customer choice and resiliency.	
Stage 2	Reflecting UM 2005 outreach requirements, utility holds ongoing community stakeholder meetings during grid needs assessment, solution identification, and action planning.	
	Utilities and OPUC agree on community goals, project tracking and coordination activities.	
	Conduct baseline study to increase detailed knowledge of service territory communities. Engage CBO experts to inform co-created community pilot(s).	
	Consult with communities to understand identified needs and opportunities, then seek to co-develop solution options, documenting longer-term needs.	
Stage 1	Hold four public pre-filing workshops with stakeholders on Plan development.	
	Utilities create a collaborative environment among all interested partners and stakeholders. Utilities document community feedback and utility's responses.	
	OPUC prepares accessible educational materials on DSP with consultation from CBOs and utilities.	
	Prepare a draft community engagement plan as part of Plan.	
	Utilities conduct focused community engagement for planned distribution projects.	
	OPUC to host quarterly public workshop and technical forums after Plan filings.	
	2021-2022	2023 and beyond

## Initial Requirements

Community engagement should occur during the Distribution System Plan development and throughout Plan implementation with detailed documentation included in the Plan. Specific requirements for utilities include; unless noted as OPUC activities, are:

### a) During Plan Development

ai) During Plan development Aa utility should host at least four~~two~~ stakeholder workshops prior to filing ~~each Part of the utility's Plan,~~<sup>6</sup> for a minimum total of four workshops. These workshops should be held during Plan development, at a stage in which stakeholder engagement can influence the filed Plan. The workshops may include in-person meetings located in a community, and may include presentation of the Plan outline, data and assumptions under consideration or challenges encountered, and the utility's approach to community engagement. ~~the Community Engagement Plan, described in (b).~~ During stakeholder workshops,

<sup>6</sup> An electric utility that makes sales of electricity to retail electricity consumers in an amount that equals less than three percent of all electricity sold to retail electricity consumers may host at least two stakeholder workshops.

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

a utility must invite community members to share their perspectives, relevant needs, challenges, and opportunities or novel solutions for the grid.

b) To engage stakeholders and community on distribution system planning, a utility should leverage best practices, and lessons learned from engagement efforts from prior Plans, and other planning processes. A utility should also leverage ongoing community and stakeholder engagement processes, and integrate distribution system planning engagement to the full extent it is beneficial to do so. Ongoing processes may include but are not limited to Clean Energy Planning, regional or local-area planning exercises.

c) During preparation and implementation of a DSP, a utility should document community and stakeholder comments and feedback and utility response, including comments and feedback that were heard but not implemented. This documentation should be included in the utility's Plan when filed.

dii) A utility should ~~develop~~ maintain a Community Engagement Plan, as developed in the Company's prior DSP. The Community Engagement Plan should describe actions the utility will implement in order to engage community members and CBOs if it needs to develop and implement non-wire solutions to address grid needs, or if it needs to engage communities around implementing larger projects. Larger projects may exclude, for example, regular maintenance projects, or inspection projects during development of the pilot concept proposals required in Solutions Identification requirements (Part 2, Section 5.3. (d)). The Community Engagement Plan should include the activities described below ~~(1-4)~~. A utility should implement these activities as part of the development of pilot proposals prior to filing Part 2 of its DSP Plan:

(1i) Proactively engage stakeholders regarding ~~proposed pilots~~ possible non-wire solutions or larger projects in impacted communities. Engagement of the local community may include in-person meetings located in the community; presentation of the project scope, timeline, rationale; discussion of proposed utility projects and the value and risks associated with options; and solicitation of public comment, particularly to understand community needs and opportunities.

(2) ~~Document stakeholder comments and utility response, including comments that were heard but not implemented.~~

(3ii) Collaboratively develop and share datasets and metrics to guide community-centered planning of the possible non-wire solutions or larger projects.

(4) ~~Refer to Section 5.3. (d, i-vi) for the community-centered questions that should be addressed through the process above, and during development of pilot proposals described in Part 2, Solutions Identification.~~

iii) The Plan should consider engagement of local governments and Tribal nations for input on possible non-wire solutions, larger projects, as well as input on other policies intersecting distribution system planning. These may include opportunities or interest in micro-grids and other resiliency planning, or local environmental and climate plans such as fleet-electrification and building-electrification efforts.

iiie) Utilities should aim to create a collaborative environment among all interested CBO partners and stakeholders. ~~To support collaboration between all interested parties, Staff plans to host public workshops and a technical working forum. These are in addition to the utility workshops required during Plan and pilot development.~~

iv) ~~With consultation from utilities and stakeholders, OPUC will prepare accessible, non-technical educational materials on DSP to support public engagement.~~

## Expected Evolution

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

~~The investigation identified numerous opportunities for community engagement in Oregon. In addition to the content presented in the workshop series, stakeholder comments in the investigation frequently spoke to community engagement needs. In comments filed in preparation for the August 25, 2020 Special Public meeting, the Oregon Citizens' Utility Board (CUB), Energy Trust of Oregon, Northwest Energy Coalition (NVEC), and Oregon Solar Energy Industries Association (OSEIA) each commented on the need for solutions to be co-developed with CBOs and stakeholders. Some spoke of the need to acknowledge, value, and compensate CBOs as technical experts in the planning process.<sup>7,8,9,10</sup>~~

~~Based on these insights gained through the investigation, for stages 2 and 3 of Plans, a utility should meet the benchmarks identified in Figure 3.~~

~~Commission acknowledgement of a Plan may be premature given that the DSP process is in its initial stage of development. At later stages, the Commission may revisit this topic and address whether subsequent Plans may be considered for Commission acknowledgement.~~

## ~~3. Scope~~

~~An electric utility will file the initial utility Distribution System Plan in two sections:~~

### ~~Part 1 (October 2021)~~

- ~~● Baseline Data and System Assessment~~
- ~~● Hosting Capacity Analysis~~
- ~~● Community Engagement Plan~~
- ~~● Long-term Plan~~
- ~~● Plan for Development of Part 2~~

### ~~Part 2 (August 2022)~~

- ~~● Forecasting of Load Growth, DER Adoption, and EV Adoption~~
- ~~● Grid Needs Identification~~
- ~~● Solution Identification~~
- ~~● Near-term Action Plan~~

## ~~4. Part 1~~

### ~~4.1 Baseline Current System Data and System Assessment~~

~~To foster transparency and enable effective decision-making, Distribution System Plans should provide a fundamental understanding of the current physical status of the utility distribution systems and equipment, recent progress of investment in those systems, and the level of~~

~~<sup>7</sup> Energy Trust of Oregon UM 2005 Responses to Stakeholder Questions for August 25 Special Public Meeting, August 21, 2020, <https://edocs.puc.state.or.us/efdocs/HAC/um2005hac75744.pdf>.~~

~~<sup>8</sup> Responses of the Oregon Citizens' Utility Board for Aug. 25, 2020 Special Public Meeting, August 20, 2020, <https://edocs.puc.state.or.us/efdocs/HAC/um2005hac17184.pdf>.~~

~~<sup>9</sup> Oregon Solar Energy Industries Association Response to Stakeholder Questions for August 25, 2020 Special Public Meeting discussion, August 21, 2020, <https://edocs.puc.state.or.us/efdocs/HAC/um2005hac17748.pdf>~~

~~<sup>10</sup> Northwest Energy Coalition Stakeholder Questions for August 25, 2020 Special Public Meeting discussion, August 21, 2020, <https://edocs.puc.state.or.us/efdocs/HAC/um2005hac163634.pdf>.~~

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

distributed energy resources (DERs) currently integrated into those systems,<sup>11</sup> and management and monitoring practices of those systems. ~~Figure 1 introduces the initial requirements and expected evolution for baseline data and system assessments.~~

**Figure 1**

<del>Baseline Data and System Assessment</del>	
Stage 3	<del>Refine asset financial planning processes and strengthen relationships with DER planning and integration processes.</del>
	<del>Use software systems to proactively monitor and support operation of the distribution system and DERs.</del>
Stage 2	<del>Share asset financial planning processes and show relationships with DER forecasting and planning processes.</del>
	<del>Leverage remote sensing technologies to provide detailed insight on physical infrastructure to support efficient operation of the distribution system.</del>
Stage 1	<del>Identify existing grid equipment inventory and financial data, as well as DER-related data with locational granularity.</del>
	<del>2021-2022</del>
	<del>2023 and beyond</del>

### **Initial Requirements**

~~In initial Distribution System Plans, a utility is required to identify the existing grid equipment inventory, management and monitoring practices, financial data, and DER data. This requirement consolidates reporting requirements currently effective under the Smart Grid Reports, Transportation Electrification Plans, and others. This data may come from the utility or from other sources, and should be the most recent data available. The utility should provide, at minimum:~~

- a) A description of any currently used ~~internal baseline and~~ system assessment practices (such as system reliability baseline assessments, system asset health baseline assessments, etc.) that are utilized in identifying grid needs and evaluating possible solutions, which may includes:
  - i) Method and tools used to develop the ~~baseline and~~ assessment
  - ii) Forecasting time horizon(s)
  - iii) Key performance metrics
- b) A summary description and table of the utility's distribution system assets including:
  - i) Asset classes
  - ii) Number of assets in each class

<sup>11</sup> For the purposes of these guidelines "distributed energy resource" includes distributed generation resources, distributed energy storage, demand response, energy efficiency, and electric vehicles that are connected to the electric distribution power grid.

U.S. Department of Energy, Modern Distribution Grid Volume I: Customer and State Policy Driven Functionality, page 7, [https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid\\_Volume-I\\_v1\\_1.pdf](https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-I_v1_1.pdf).

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

---

- iii) Average age of assets in each class
  - iv) Age range of assets in each class
  - v) ~~Industry-l~~life expectancy of assets in each class
  - vi) Percentage of assets in each class at or beyond the end of expected life
- c) A discussion of distribution system monitoring and control capabilities including:
- i) Number of feeders
  - ii) Number of substations
  - iii) Monitoring and control technologies (such as SCADA, AMI, etc.) currently installed, and the percentage of substations, feeders, and other applicable equipment with each technology
  - iv) A description of the monitoring and control capabilities (for example, percentage of system with each technology, resulting capacity, such as remote fault detection or power quality monitoring, and what time interval measurements are available)
- d) A discussion of any advanced control and communication systems (for example: distribution management systems, distributed energy resources management systems, demand response management systems, outage management systems, field area networks, etc.). The discussion should include:
- i) a description of system visibility and capabilities;
  - ii) the percentage of system reached with each capability, the percentage of customers reached with each capability, ~~and~~
  - iii) any utility programs utilizing each capability;
- e) Historical distribution system spending for the past five years, in each category:
- i) Age-related replacements and asset renewal
  - ii) System expansion or upgrades for capacity
  - iii) System expansion or upgrades for reliability and power quality
  - iv) New customer projects
  - v) Grid modernization projects
  - vi) Metering
  - vii) Preventative maintenance
- f) Net Metering and Small Generator information:<sup>12</sup>
- i) Total existing net metering facilities and small generator facilities interconnected to the distribution grid (or to the transmission system, as appropriate for small generator facilities) at time of filing, by feeder.
    - (1) The total number of net metering facilities by resource type
    - (2) The total estimated rated generating capacity of net metering facilities by resource type
    - (3) The total number of small generator facilities by resource type
    - (4) The total nameplate capacity of small generator facilities by resource type
  - ii) The total number and nameplate capacity of queued net metering facilities and small generator facilities at time of filing, by feeder, broken down by resource type

---

<sup>12</sup> A utility that is exempt from the Annual Net Metering Report requirement pursuant to OAR 860-039-0070 is not required to report net metering data required in section f).

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

~~iii) A map, in electronic format, identifying locations of net metering facilities and small generator facilities interconnected to the distribution grid (or to the transmission system, as appropriate for small generator facilities) at time of filing.~~

~~g) Total number of electric vehicles (Evs) of various sizes served by the utility's system at time of filing~~

~~h) Number of Evs added to the utility's system in each of the last five years~~

~~i) Total number of charging stations on the utility's system, broken down by type, ownership, and feeder~~

~~j) Total number of charging stations added to the utility's system in each of the last five years, broken down by type~~

~~i) Data on the availability and usage patterns of charging stations~~

~~k) Summary data of other transportation electrification infrastructure, if applicable~~

~~l) A high-level summary of demand response (DR) pilot and/or program performance metrics for the past five years including:<sup>13</sup>~~

~~i) Number of customers participating by residential and business customer class, and combined total~~

~~ii) By winter and summer demand response season:~~

~~(1) Maximum available capacity of DR by residential and business customer class, and combined total~~

~~(2) Season system peak~~

~~(3) Available capacity of DR, expressed as a percentage of the season system peak~~

~~m) Plans should include the utility's most recently filed Annual Net Metering Report and the most recently filed Annual Small Generator Report, each as an appendix to the Plan.~~

~~gn) Plans should include the utility's most recently filed Annual Reliability Report as an appendix to the Plan.~~

~~i) Any descriptions of reliability challenges and opportunities in the Distribution System Plan should cross-reference underlying data and information contained in the Annual Reliability Report.~~

~~ii) Any proposed investments based in whole, or in part, on reliability improvements must demonstrate those improvements by cross-referencing underlying data and information contained in the Annual Reliability Report~~

~~h) Summary progress report on activities included in the most recently filed DSP to clearly communicate advancement or completion of:~~

~~i) Investments, expenditures, and activities from the Long-term Plan~~

~~ii) Investments, expenditures, and activities from the Near-term Action Plan~~

~~i) Data assembled for this requirement should be prepared in electronic format, and submitted to the Commission for public review~~

## **Expected Evolution**

~~This investigation identified numerous opportunities for gaining greater insight into the utility distribution systems and the DERs contributing to and relying on those systems. Staff's 2019~~

<sup>13</sup> For example see Table 26 on page 101 of Appendix 1 of 2019 PGE Smart Grid Report, <https://edocs.puc.state.or.us/efdocs/HAQ/um1657haq15635.pdf>.

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

Whitepaper on Distribution System Planning laid out the vision for a transition to a modern grid, including a desire for automated system operations and real-time system visibility.<sup>14</sup> Additionally, at the February 26, 2020 workshop, utilities provided an overview of their existing DSP processes, including monitoring and automation practices.<sup>15, 16, 17</sup> Presentations highlighted that each utility has different capabilities and system needs, which guide their planning and related outcomes.

Based on the insights gained through the investigation, for stages 2 and 3 of utility Plans, a utility should meet the benchmarks identified in Figure 1.

## 4.2 Hosting Capacity Analysis

Hosting Capacity Analysis (HCA) provides information about the ability of a distribution system to support new DER integration without system faults. To date, analyses of a system's hosting capacity has become an important piece of DSP in Minnesota, New York, Hawaii, Nevada and California.<sup>18</sup> The following requirements are intended to initiate hosting capacity analysis in Oregon with the ultimate aim of informing grid investment decisions made by the utilities, while also informing siting decisions made by DER developers. Figure 2 introduces the initial requirements and expected evolution for hosting capacity analysis.

Figure 2

Hosting Capacity Analysis	
Stage 3	Comprehensive hosting capacity considering both distribution and transmission.
	Increased level of detail regarding distribution constraints, asset performance, and DER performance metrics. Address emerging technology development.
	Maps indicate node/section-level hosting capacity.
	Update and publish hosting capacity maps and datasets sufficiently accurate and frequent to streamline interconnection.
	Conduct system-wide hosting capacity evaluations to inform Grid Needs Identification.

<sup>14</sup> Staff Whitepaper: A Proposal for Electric Distribution System Planning, March 2019, <https://edocs.puc.state.or.us/efdocs/HAU/um2005hau15477.pdf>.

<sup>15</sup> Distribution System Highlights, Portland General Electric, February 26, 2020, <https://edocs.puc.state.or.us/efdocs/HAH/um2005hah16124.pdf>.

<sup>16</sup> Idaho Power: Current Distribution System and Small Scale Generation, Idaho Power, February 26, 2020, <https://edocs.puc.state.or.us/efdocs/HAH/um2005hah14343.pdf>.

<sup>17</sup> Current Distribution System: Questionnaire Section C, Pacific Power, February 26, 2020, <https://edocs.puc.state.or.us/efdocs/HAH/um2005hah9537.pdf>.

<sup>18</sup> Distribution Planning Regulatory Practices in Other States, Lisa Schwartz, Berkeley Lab, May 21, 2020, [https://www.oregon.gov/puc/utilities/Documents/DSP\\_Schwartz\\_Presentation.pdf](https://www.oregon.gov/puc/utilities/Documents/DSP_Schwartz_Presentation.pdf).





# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

~~b) Each utility should analyze three options to meet future HCA needs consistent with Figure 2. This analysis should be included in Part 1 of the Plan. At minimum, a utility shall develop cost and timeline estimates for each of the following three options. A utility should identify any data security, cost, result validation, or implementation concerns and/or barriers for each of the three options. Each utility should recommend a preferred timeline and development path for achieving the vision set forth in Figure 2, accounting for the relative strengths of Options 1, 2 and 3 below. The Commission will consider these cost and timeline estimates, concerns, and recommendations in adopting a path forward for HCA in Oregon.~~

~~i) Option 1: The primary use of HCA is to inform Grid Needs Identification (see Section 5.2) and includes the following parameters:~~

- ~~● Methodology: stochastic modeling / EPRI DRIVE modeling~~
- ~~● Geographic granularity: circuit~~
- ~~● Temporal granularity: annual minimum daily load~~
- ~~● Data presentation: web-based map for the public and available tabular data~~
- ~~● Annual refresh~~
- ~~● Planned/queued generation details such as number and size of projects, description and costs of upgrades assigned to planned generation~~

~~ii) Option 2: The two main uses are to inform Grid Needs Identification and to share regularly updated results publicly to inform stakeholders of potential interconnection challenges.<sup>22</sup> Option 2 includes the following parameters:~~

- ~~● Methodology: same as Option 1~~
- ~~● Geographic granularity: feeder~~
- ~~● Temporal granularity: monthly minimum daily load~~
- ~~● Data presentation: same as Option 1~~
- ~~● Monthly refresh~~
- ~~● Planned/queued generation details: same as Option 1~~

~~iii) Option 3: The two main uses are to inform Grid Needs Identification and to replace portions of the interconnection studies.<sup>23</sup> Option 3 includes the following parameters:~~

- ~~● Methodology: iterative modeling~~
- ~~● Geographic granularity: line segment~~
- ~~● Temporal granularity: hourly assessment~~
- ~~● Data presentation: same as Option 1~~
- ~~● Monthly refresh~~
- ~~● Planned/queued generation details: same as Option 1~~

~~Beyond these requirements, any utility may seek to accelerate its testing and deployment of new hosting capacity analysis through a pilot or demonstration. A utility that proposes to do so should detail the pilot objectives, plan, budget, and evaluation method in the Plan.~~

## ~~Expected Evolution~~

~~This investigation identified numerous opportunities for hosting capacity analysis in Oregon. Given that hosting capacity and the related analysis have multiple definitions and best practices are continuously evolving, it is important for stakeholders to identify and prioritize use cases for the analysis. Multiple jurisdictions incorporate hosting capacity analysis into distribution system planning because the analysis and outputs can support DER adoption and flag potential~~

~~<sup>22</sup> Xcel Minnesota performs HCA implementation that illustrates some of these parameters.~~

~~<sup>23</sup> California utilities perform HCA implementation that illustrate some of these parameters.~~

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

---

~~interconnection issues.<sup>24</sup> Over time, hosting capacity analysis may reduce the need for interconnection studies.<sup>25, 26</sup>~~

~~Based on these insights gained through the investigation, for stages 2 and 3 of utility Plans, a utility should meet the benchmarks identified in Figure 2.~~

## ~~4.5 Plan for Part 2 Development~~

~~As Part of its Part 1 filing each utility should prepare for the upcoming transition period and include a high level summary to discuss:~~

- ~~a) How legacy distribution planning practices will be transitioned to the requirements of Part 2~~
- ~~b) Whether all legacy distribution planning practices will be transitioned in time for filing Part 2, and if not, the expected timeframe for that eventual transition~~
- ~~c) Efforts to synchronize IRP activities with requirements of Part 2~~

---

<sup>24</sup> ~~Hosting Capacity – Lessons Learned, Steve Steffel, Pepco Holdings, May 6, 2020, <https://www.oregon.gov/puc/utilities/Documents/DSP-Hosting-Capacity-SSteffel.pdf>.~~

<sup>25</sup> ~~OPUC Hosting Capacity Overview, Aram Shumavon, Kevala Analytics, May 6, 2020, <https://www.oregon.gov/puc/utilities/Documents/DSP-Shumavon-Presentation.pdf>.~~

<sup>26</sup> ~~UM2005 Distribution System Planning, Webinar #9, OPUC Policies and Practices, June 10, 2020, <https://www.oregon.gov/puc/utilities/Documents/DSP-Webinar9-PUC-Presentation.pdf>.~~

5. Part 2

5.4 Forecasting of Load Growth, DER Adoption, and EV Adoption

Accurately forecasting load growth, a critically important exercise utilities have done for decades, enables the distribution system to reliably meet future energy, demand and ancillary grid service needs. As DER and EV adoption grows, forecasting must advance to better account for their impact on load, as well as the ability of these resources to productively modify load. The following updated requirements aim to improve the accuracy and granularity of forecasting, by requiring DER and EV growth forecast at the substation level. This in turn should be intended to improve the accuracy and granularity of existing and anticipated constraints on the distribution system revealed in the engineering analysis to identify Grid Needs Identification. Figure 4 introduces the initial requirements and expected evolution for the forecasting of load growth, DER adoption and EV adoption.

Figure 4

Forecasting of Load Growth, DER Adoption, and EV Adoption		
Stage 3		Refine hybrid forecast approach to allow more granular locational and temporal forecasts, aiming for consistent outputs across utilities.
Stage 2		Identify potential locational system benefit from strategic placement of DERs on the distribution grid.
		Examine data to better understand opportunities for customer participation by energy-burdened households.
		Leverage both top-down forecasts and bottom-up customer models to build forecasts (approaches may be specified).
Stage 1		Allocate system-wide DER forecasts from utility IRP filings to greater locational granularity.
		Document forecasting process and indicate existing and anticipated constraints on the distribution system.
	2021-2022	2023 and beyond

**Initial Requirements**

These Guidelines require a utility to document in the Distribution System its Plan current utility load forecasting processes for distribution service, and Plans should build on that foundation with forecasting processes for DER adoption and EV adoption as follows:

- a) Forecast of load growth by feeder Discussion of current utility processes for distribution system load growth forecasting including discussion of:
  - i) Forecasting method and tools used to develop the forecast
  - ii) Forecasting time horizon(s)
  - iii) Data sources used to inform the forecast

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

- iv) The load forecast should include data, inputs, and assumptions from the Company's most recent IRP/CEP, which should be clearly listed in the DSP. Examples include but are not limited to:
  - (1) System modeled scenarios decomposed to the distribution system
  - (2) Discussion of how IRP/CEP forecasting is decomposed to, and reconciled with, geographic areas of the distribution system, and identification of those specific geographic areas. Examples of such areas may include transitional planning areas.
- iv) Locational granularity of the load forecast
- b) Forecast of DER adoption and EV adoption by feeder/substation including discussion of:
  - i) Forecasting method and tools used to develop the forecast
  - ii) Forecasting time horizon(s)
  - iii) Data sources used to inform the forecast
  - iv) The forecast should include high/medium/low scenarios for both DER adoption and EV adoption
  - ii) A utility should fully describe its methodologies for developing the DER forecast, EV forecast, high/medium/low scenarios, and geographical allocation in its plan (for example methods and tools, time horizons, data sources).
  - v) The DER adoption and EV adoption forecasts should include data, inputs, and assumptions from the Company's most recent IRP/CEP, which should be clearly listed in the DSP. Examples include but are not limited to:
    - (1) Community based renewable energy (CBRE) forecast, potential study, RFP, needs assessment, etc.
    - (2) Small scale renewable (SSR) forecast, potential study, RFP, needs assessment, etc.
  - viii) For the initial Plan, the methodology for geographical allocation (to the substation) is at the utility's discretion. The Commission may provide direction for subsequent Plans.
  - iv) A utility may consider leveraging information such as: historical utility program trends, historical customer adoption trends, data from Energy Trust of Oregon, data from Transportation Electrification Plans and pilots, or studies on DER technical and economic potential used in other dockets. Utilities should use the most recent data available.
- c) Results of forecasting load growth, DER adoption, and EV adoption
  - i) Document existing and anticipated constraints on the distribution system
- c) If a utility does not complete forecasting for its entire distribution system and instead completes forecasting for a portion of its distribution system, it must state so clearly and:
  - i) explain the reasons for completing the exercise for a portion of the system
  - ii) describe for how much of the system the exercise was completed, in terms of customers, load, substation count, and feeder count
  - iii) discuss whether and how the utility plans to complete the exercise in future DSPs

## **Expected Evolution**

This investigation identified numerous opportunities for improved creation and use of more granular forecasting of load growth, and DER and EV adoption. The presentation *Forecasting load on distribution systems with distributed energy resources* from the National Renewable Energy Laboratory (NREL) identified several approaches and tools for top-down and bottom-up DER forecasts, including the use of historical trends, program-based approaches, and customer

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

~~adoption models.<sup>27</sup> In comments filed in response to Staff's questions for the August 25, 2020 Special Public Meeting, numerous parties suggested that the OPUC apply multiple approaches to calibrate and refine forecasts over time.~~

~~Based on these insights gained through the investigation, for stages 2 and 3 of Plans, utilities should meet the benchmarks identified in Figure 4.~~

## 65.2 Grid Needs Identification

Grid needs identification compares the current capabilities of a distribution system and the demands on that system to infer its future needs.

At its core, a grid needs identification answers the question of what technical requirements must be addressed to ensure a safe, reliable and resilient system that provides adequate power quality to the customers it serves. Adding to this core, ~~a holistic approach to~~ grid needs identification ~~anticipates should include constraints related to forecast DER adoption of customer and front-of-the-meter DER. by customers, as well as~~ Additionally, the social and economic needs of the communities that depend on distribution systems, and the contributions they can make to strengthen it should be addressed. Grid needs identification should be comprehensive and inclusive, identifying the biggest drivers and trends behind needed investments and operational budgets.

~~Figure 5 introduces the initial requirements and expected evolution for grid needs identification.~~

---

<sup>27</sup>~~See [https://www.oregon.gov/puc/utilities/Documents/DSP\\_Sigrin\\_Presentation.pdf](https://www.oregon.gov/puc/utilities/Documents/DSP_Sigrin_Presentation.pdf) for more detail.~~



# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

~~grid needs reported in a DSP to investments submitted in future general rate cases. constraints publicly, including criteria used for prioritization.~~

~~d) Provide a timeline by which the grid need(s) must be resolved to avoid potential adverse impacts.~~

~~In fulfilling these requirements, each Plan should cross-reference Plan sections of Baseline Data and System Assessments; Community Engagement; and Forecasting of Load Growth, DER Adoption, and EV Adoption.~~

## **Expected Evolution**

~~This investigation identified numerous opportunities for grid needs identification in Oregon. In the *Connectivity Means Community* presentation, presenters highlighted the need for community engagement and responsiveness to community needs in relation to grid needs identification.<sup>28</sup> A human-focused approach to identifying grid needs, implemented in partnership with communities and CBOs, can create value-adding investments for communities, and align the energy system with community priorities.~~

~~Based on these insights gained through the investigation, for stages 2 and 3 of utility Plans, a utility should meet the benchmarks identified in Figure 5.~~

## **7.5.3 Solution Identification**

Solution identification proposes the equipment, technology or program(s) the utility will advance to meet identified grid needs. Previously, a Distribution System Plan would rely on traditional hardware solutions (such as substation upgrades, reconductoring, and additional transformer deployment). These Guidelines advance more holistic distribution system planning, calling for consideration of a wider range of potential solutions (for example increased system monitoring automation, expanded switching capability, distributed energy resources). The solutions identified should correspond to future general rate cases.

The utility should assess grid needs to determine cost effective solutions as follows:

~~Experts contributing to the OPUC's workshops on Non-Wire Solutions and Distributed Energy Resource Valuation suggested that Solution Identification include a comprehensive exposition of the options available to serve grid needs. This section of the Plan should weigh the pros and cons of each option across standardized criteria, with inclusive approaches to weighing the cost and benefits of each path forward.~~

~~Figure 6 introduces the initial requirements and expected evolution for solution identification.~~

---

<sup>28</sup>~~*Connectivity Means Community – Distributed System Planning for Humans*, Oriana Magnera and Charity Fain, Verde and Community Energy Project, May, 20, 2020, <https://www.oregon.gov/puc/utilities/Documents/DSP-Magnera-Fain-Presentation.pdf>.~~



# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

**Figure 6**

<b>Solution Identification</b>		
Stage-3	Co-develop solutions with communities and community-based organizations.	
	Streamline and refine non-wires solutions and aggregations of non-wires solutions to defer distribution system upgrades.	
Stage-2	In assessing options for distribution system pilots and projects, engage community organizing experts to gain input from potentially impacted communities.	
	Prior to filing, publicly present data used to identify distribution system investments, and understand data most useful to stakeholders.	
	Co-develop solutions with communities and community-based organizations.	
	Utilize non-wires solutions to defer distribution system upgrades. This includes harnessing DERs for voltage support and frequency event support.	
Stage-1	Stakeholders provide feedback on what data would be useful to them. OPUC determines if additional datasets are necessary and may direct utilities to submit them in the next Distribution System Plan filing.	
	Provide summary and description of data used in distribution system investment decisions such as: feeder level details (including customer types on feeder, loading information), DER forecasts and adoption.	
	Document the process to identify a range of possible solutions to address grid needs. For larger projects, engage with communities early in solution identification. Facilitate discussion of proposed investments that allow for mutual understanding of the value and risks associated with resource investment options.	
	2021-2022	2023 and beyond

### Initial Requirements

The utility should assess proposed solutions to address grid needs. Specific requirements include:

a) Document the process to identify the range of possible solutions to address priority grid needs and discuss how this process was applied to identify the proposed solutions in the Long-term and Near-term Plans

b) First, the utility process should assess each identified grid need to identify opportunities for no or low-incremental cost grid solutions such as rebalancing distribution loading through switching and phase balancing, or other actions

c) Second, if a specific grid need cannot be addressed by b) the utility should identify both a traditional solution and screen the grid need for suitability of a non-wires solution, if the cost for the traditional solution is \$1 million or more

i) Determine the suitability of a non-wires solution based on the following screening criteria:

(1) Grid need is not a redundant supply to a radial load;

(2) Grid need is not a maintenance, asset condition, or safety need;

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

- (3) Grid need is not a stability or short circuit problems; or
- (4) Grid need must be addressed within two years

ii) If a grid need is suitable for a non-wires solution and comparatively cost-effective to the traditional solution, then the utility should identify the proposed non-wires solution(s) program, pricing, and/or procurement.

d) All identified utility traditional and non-wires solutions should be documented in the Long-term and Near-term Plans as appropriate.

## 58.4 Overarching Requirement—Near-term Action Plan

In this section of the Plan, a utility should present the utility's proposed solutions to address near-term grid needs, ~~as well as other investments in the distribution system~~. Specific requirements include:

a) Action Plan: Provide a 52-4 year plan ~~consisting~~ of the utility's proposed solutions to address identified grid needs. The Action Plan should include: ~~and other investments in the distribution system~~

i) Prioritized list of investments, expenditures, and activities

ii) A discussion of each planned investment/expenditures/activity estimated to cost more than \$2 million. Each discussion should include:

(1) Project narrative including foundational assumptions and key barriers or constraints (including financial, technical, organizational) and mitigation plans

(2) Timeframe

(3) Investment/expenditure amount

(4) Description of the criteria and methods the utility used to prioritize the investment/expenditure/activity, including explicit consideration of how the investment/expenditure/activity advances State policies and goals and PUC objectives, including but not limited to:<sup>29</sup>

(a) Reliability

(b) Safety and security

(c) Customer benefits and promoting inclusion of underserved populations

(d) Optimized operation of the system

(e) Efficient integration of DERs

When possible, the description should include quantification of the improvement in the goal.<sup>30</sup> Should a planned investment/expenditure/activity advance a goal not included in (a)-(e), a utility should explain the rationale for the

<sup>29</sup> These high-level goals were developed collaboratively with parties through the course of the Docket No. UM 2005 investigation.

<sup>30</sup> Examples may include but are not limited to:

Reliability – reduction in outages or duration

Safety and security – reduction in equipment failures, or vulnerabilities

Customer benefits, and promote inclusion of underserved populations – improvement in customer service, increased program participation in underserved populations

Optimized operation of the system – reduction in operating costs

Efficient integration of DERs – increased adoption of demand-side and renewable resources

## Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

investment/expenditure/activity, and when possible, include quantitative outcomes.

(5) Explanation of how the investment/expenditure/activity is coordinated with the utility's other planning processes (such as the most recent IRP/CEP, Wildfire Mitigation Plan, Transportation Electrification (TE) Plan, and DR/Flexible Load Plan).

(6) Any proposed investments/expenditures which address a grid need previously identified as a non-wires solution opportunity by the non-wires solutions screen should be identified and include a summary of the range of possible alternatives analyzed, the analysis results, and discussion of why the non-wires solution was not selected.

(7) Discussion of whether the proposed investment/expenditure/activity interacts with non-distribution asset strategies, whether alternatives to distribution investment were considered, and if made, what impact does the proposed investment/expenditure/activity have on other network assets.

~~b) Projected spending: Disclose Provide the projected system spending cost and timeline by asset class to implement the a Action pPlan, timeline for improvement, and anticipated requests for a Provide a description of anticipated requests for cost recovery mechanism~~

~~c) The Action Plan prioritized list (Guideline 8 a) i)) and discussions (Guideline 8 a) ii)), as well as the projected spending (Guideline 8 b)) should aid Staff and stakeholders in linking the Near-term Action Plan to investments submitted in future general rate cases. Further, when pursuing recovery in a general rate case, utilities should prepare to provide materials assembled for the DSP filing as well as additional materials such as documentation of proposed and various alternative solutions considered, and a detailed accounting of the relative costs and benefits of the chosen and alternative solutions, such as engineering reports, feeder level details (such as customer types on the feeder; loading information), DER forecasts and EV adoption rates.~~

~~e) Relation to other investments: As applicable, the Action Plan should identify areas of relation and interaction with other investments such as transmission projects and demand response programs~~

~~d) Document current innovations and pilots being conducted to improve, modernize, and/or enhance the grid beyond its current capabilities~~

~~b) For each identified Grid Need provide a summary and description of data used for distribution system investment decisions including: discussion of the proposed and various alternative solutions considered, a detailed accounting of the relative costs and benefits of the chosen and alternative solutions, feeder level details (such as customer types on the feeder; loading information), DER forecasts and EV adoption rates.~~

~~c) For larger projects (this may exclude, for example, regular maintenance projects, or inspection projects), engage with impacted communities early in solution identification. Facilitate discussion of proposed investments that allow for mutual understanding of the value and risks associated with resource investment options.~~

~~d) Evaluate at least two<sup>34</sup> pilot concept proposals in which non-wire solutions would be used in the place of traditional utility infrastructure investment. The purpose of these pilots is to gain experience and insight into the evaluation of non-wire solutions to address priority issues such~~

---

<sup>34</sup>~~An electric utility that makes sales of electricity to retail electricity consumers in an amount that equals less than three percent of all electricity sold to retail electricity consumers may evaluate one pilot concept proposal.~~

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

as the need for new capacity to serve local load growth, power quality improvements in underserved communities. These pilots will prepare utilities to achieve the goals listed in Stages 2 and 3 of Figure 6.

In its pilot concept proposals, a utility should discuss the grid need(s) addressed, various alternative solutions considered, and provide detailed accounting of the relative costs and benefits of the chosen and alternative solutions. The pilot concept proposals should be reasonable and meet the Guidelines, even if the individual proposal may not be cost-effective. In addition, evaluation of pilot concept proposals should utilize the community engagement process developed in Section 4.3. (a) (ii) and address:

- i) Community interest in clean energy planning and projects
- ii) Community energy needs and desires
- iii) Community barriers to clean energy needs, desires, and opportunities
- iv) Energy burden within the community
- v) Community demographics
- vi) Any carbon reductions resulting from implementing a non-wires solution rather than providing electricity from the grid's incumbent generation mix

The pilot concept proposal should include a process in which the utility works with stakeholders to set equity goals, as may be appropriate for the pilot.

## Expected Evolution

This investigation identified numerous opportunities for solutions identification in Oregon. The need to co-develop distribution system solutions with communities and CBOs remains a priority throughout the DSP evolution. Beyond community engagement, the regulatory framework, utility processes and structures, and procurement practices also need to evolve to enable implementation of non-wires solutions.<sup>32</sup> As non-wires solutions are constructed and their performance in serving grid needs and deferring grid upgrades is better understood, valuation methods may be needed to compare non-wires solutions to traditional utility hardware (for example substation upgrades, additional transformer deployment).<sup>33</sup>

Based on these insights gained through the investigation, for stages 2 and 3 of utility Plans, a utility should meet the benchmarks identified in Figure 6.

## 49.4 Overarching Requirement — Long-term Distribution System Plan

This section of the Distribution System Plan will consist of the utility's long-term distribution system investment plan, and inform broader goals related to maximizing reliability, customer benefits, and efficient operation of the distribution system. A utility This section of the plan should include:

<sup>32</sup> *Non-wires Solutions: Context, Rationale, and Opportunity*, Jason Prince, Rocky Mountain Institute, May 13, 2020, <https://www.oregon.gov/puc/utilities/Documents/DSP-Prince-Presentation.pdf>.

<sup>33</sup> Refer to *Valuation of Distributed Energy Resources* presentation from Debra Lew for details on approaches to valuing non-wires solutions and distributed energy resources, <https://www.oregon.gov/puc/utilities/Documents/DSP-LewPresentation.pdf>.

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

a) The utility's vision for the distribution system ~~over for~~ the next 5-10 years, aligned with State policies and goals and PUC objectives, including but not limited to:<sup>34</sup>

- i) Reliability
- ii) Safety and security
- iii) Customer benefits and promoting inclusion of underserved populations
- iv) Optimized operation of the system
- v) Efficient integration of DERs

~~, including any strategies, goals or objectives, and their alignment with State law and OPUC policies. These goals may include increased reliability, effective integration of DERs, broader greenhouse gas emissions reduction, or others.~~ b) Roadmap of the utility's planned investments, ~~tools expenditures,~~ and activities to advance the long-term DSP distribution system vision, using for a 5-10-year planning horizon. The roadmap should include:

- i) Prioritized list of long-term investments, expenditures, and activities
- ii) A discussion of each planned investment/expenditures/activity including:
  - (1) Project narrative including foundational assumptions and key barriers or constraints (including financial, technical, organizational) and mitigation plans
  - (2) Estimated timeframe
  - (3) Estimated investment/expenditure
  - (4) Description of the criteria and methods the utility used to prioritize the investment/expenditure/activity, including explicit consideration of how the investment/expenditure/activity advances policies/goals/objectives identified in a) i)-v). When possible, the explanation should include quantification of the improvement in the goal.<sup>35</sup> Should a planned investment/expenditure/activity advance a goal not included in a) i)-v), a utility should explain the rationale for the investment/expenditure/activity, and when possible, include quantitative outcomes.
  - (5) Any connections to, and impacts on, Near-term Action Plan projects
  - (6) Explanation of how the investment/expenditure/activity fits with the utility's other planning processes (such as the most recent IRP/CEP, Wildfire Mitigation Plan, Transportation Electrification (TE) Plan, and DR/Flexible Load Plan) including how the investment/expenditure/activity is coordinated with each planning process with respect to related inputs and outputs such as data sets and prices, and assumptions such as macro-economic policies and growth rates.
- iii) The Long-term Plan Roadmap prioritized list (Guideline 9 b) i)) and discussions (Guideline 9 b) ii)) should aid Staff and stakeholders in linking the Long-term Plan to investments submitted in future general rate cases.

~~i) Assessment of investment options to enhance the grid across the following range of areas, including relative costs and benefits:~~

<sup>34</sup> These high-level goals were developed collaboratively with parties through the course of the Docket No. UM 2005 investigation.

<sup>35</sup> Examples may include but are not limited to:

Reliability – reduction in outages or duration

Safety and security – reduction in equipment failures, or vulnerabilities

Customer benefits, and promote inclusion of underserved populations – improvement in customer service, increased program participation in underserved populations

Optimized operation of the system – reduction in operating costs

Efficient integration of DERs – increased adoption of demand-side and renewable resources

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

- ~~(1) Substation and distribution network and operations enhancements
  - ~~(a) Plans for conservation voltage reduction~~~~
- ~~(2) Distributed resource and renewable resource enhancements
  - ~~(a) Penetration and activation/utilization of smart inverters~~~~
- ~~(3) Transportation Electrification enhancements~~
- ~~(4) Customer information and demand-side management enhancements
  - ~~(a) Plans to continue to expand customer benefits resulting from investments in advanced metering infrastructure~~~~
- ~~(5) General business enhancements
  - ~~(a) Communications and supporting systems~~
  - ~~(b) Interoperability of systems and equipment~~
  - ~~(c) Work management systems~~
  - ~~(d) Other enhancements~~~~
- ~~(6) As applicable, any transmission network and operations enhancements~~
- ~~ii) Explanation of how the investments reduce customer costs, improve customer service, improve reliability, facilitate adoption of demand-side and renewable resources, and convey other system benefits~~
- ~~iii) Long-term assumptions, and impacts of Action Plan investments, etc.~~
- ~~iv) Forecasting future technical and market potential of DERs~~
- ~~v) Plans to further build community needs assessment and co-created community solutions into DSP roadmap~~
- ~~vi) Transitional planning and operational activities underway in the organization to build capabilities in DSP-related functions~~
- ~~vii) Key barriers or constraints the utility faces to advancing investment (whether financial, technical, organizational) and mitigation plans~~
- ~~c) Smart Grid investment<sup>36</sup> opportunities
  - ~~i) List and describe smart grid opportunities that the utility is considering for investment over the next 5-10 years and any constraints that affect the utility's investment considerations~~
  - ~~ii) Describe evaluations and assessments of any smart grid technologies, applications, pilots, or programs that the company is monitoring or plans to undertake~~~~
- ~~d) Key opportunities and possible benefits for distribution system investment~~
- ~~e) Research and development the utility is undertaking or monitoring~~
- ~~f) Future policy and planning intersections:
  - ~~i) Discussion of how planned investments fit with the utility's IRP~~
  - ~~ii) Discussion of how planned investments fit with the utility's annual construction budget for major distribution and transmission investments~~
  - ~~iii) Discussion of how distribution system planning may be coordinated in the future with other major policy and planning efforts discussed in these Guidelines. At a minimum, address the IRP and transmission planning, including: how the Distribution System Plan~~~~

---

<sup>36</sup> Smart grid investments were defined in Order No. 11-172 and that definition is retained here. Smart grid investments are utility investments in technology with two-way communication capability that will (1) improve the control and operation of the utility's transmission or distribution system, and (2) provide consumers information about their electricity use and its cost and enable them to respond to price signals from the utility either by using programmable appliances or by manually managing their energy use. Smart grid technologies include sensors and remote control switches at the distribution system level, synchro phasors and flexible AC transmission system devices at the transmission level, and information displays and appliance control circuits at the consumer level.

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

---

~~filing is coordinated with each policy or planning effort, related inputs and outputs such as data sets or prices, and assumptions such as macro-economic policies or growth rates~~

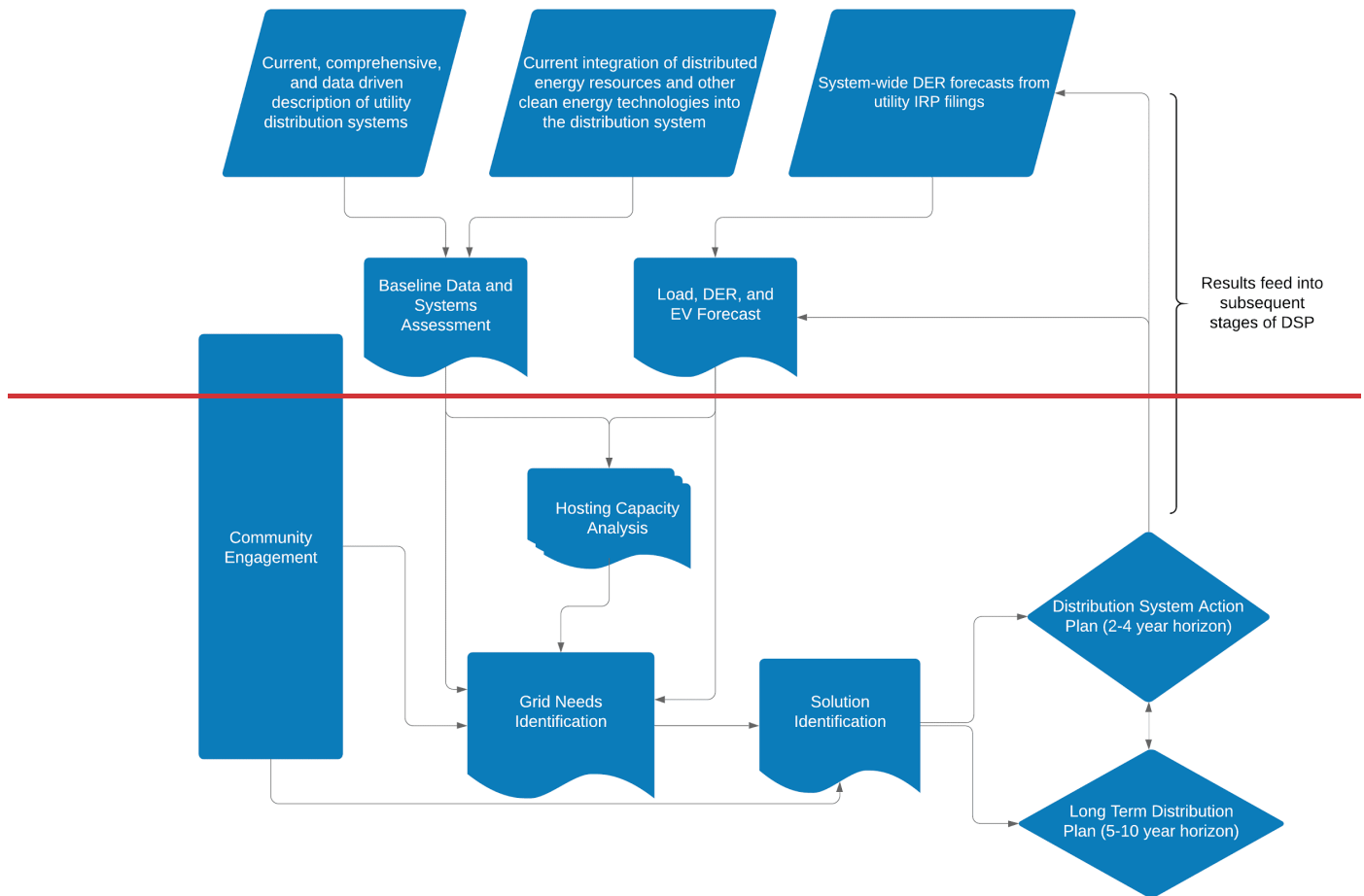
~~g) Plans to monitor and adapt the long-term Distribution System Plan~~

## ~~6. Overview of the Distribution System Planning Process~~

~~The elements of Distribution System Planning described in these Guidelines must be integrated and used iteratively to form a holistic planning process to meet Oregon's needs. These Guidelines specify the initial requirements for utility Distribution System Plan filings, and identify baseline expectations for how these requirements may evolve over time. Figure 7 depicts this process in a conceptual manner. Figure 7 does not address the respective timing of these elements as outlined in the Guidelines.~~

Figure 7

Oregon Public Utilities Commission Distribution System Planning Process Diagram



Key conceptual relationships depicted in Figure 7 include:

- ~~Baseline Data and System Assessments are informed by current information and data on the current state of utility distribution systems and the DERs already contributing to and depending on those systems. The initial Plan requirements are primarily a consolidation of this information and data from other existing reports.~~
- ~~Load, DER and EV Adoption Forecasts are informed by system-wide forecasts utilized currently in each utility's Integrated Resource Planning. The allocation of those forecasts to the substation level represents an incremental advance beyond current practices introduced by these Guidelines.~~
- ~~In the future, Hosting Capacity Analysis will compare the capabilities of the system and the demands on the system, as recognized by forecasts of load growth, and DER and EV adoption. As depicted in this figure, the hosting capacity analysis will inform distribution planning as an input into the Grid Needs Identification.~~



## Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

---

- ~~Grid Needs Identification will compare the capabilities of, and demands on, the system, and will utilize the improved forecasting of load growth, and DER and EV adoption noted above.~~
- ~~The Plan's Solution Identification should show how the utility intends to meet the needs identified in the preceding step. The requirement of non-wire solutions pilot concept proposals is an incremental advance beyond current practices introduced by these Guidelines.~~
- ~~The integration of community engagement is also an incremental advance beyond current practices introduced by these Guidelines. Each Plan should seek and account for community input in identifying Solutions.~~
- ~~Each Plan's Near-term Action Plan will be derived from its Solution Identification, providing specific steps the utility will take to secure identified solutions within the next 2-4 years, as well as proposed deadlines, milestones and projected costs.~~
- ~~Each Plan's Long-term Plan affords the utility an opportunity to explain how its Action Plan represents a step toward its envisioned long-term modernization of the distribution system.~~
- ~~Finally, recognizing the iterative nature of planning, each Plan's Action Plan and Long-term Plan will provide a basis for subsequent phases of DSP.~~

~~Together, a utility's successful integration of these elements should amount to a transparent, robust and holistic distribution planning system.~~

**Staff Proposed Distribution System Planning (DSP) Guideline Revisions**

**April 2024**

---

Clean version

**Distribution System Planning Guidelines**

**Table of Contents**

1. Process and Timing	2
2. Commission Action	2
3. Community Engagement	2
4. Current System Data and Assessment	4
5. Forecasting of Load Growth, DER Adoption, and EV Adoption	6
6. Grid Needs	7
7. Solution Identification	7
8. Near-term Action Plan	8
9. Long-term Plan	9

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

---

## 1. Process and Timing

The following development and review process will guide the utility filing of a Distribution System Plan (Plan) for a utility's service territory in Oregon.

- a) Each electric utility<sup>1</sup> must file its next Plan on or before the following dates, or an alternative date designated by Commission order.
  - Idaho Power: Month Day, Year
  - Portland General Electric: Month Day, Year
  - Pacific Power: Month Day, Year
- b) The date and cadence of filing subsequent Plans will be set in the next Guideline revision process, or by Commission order.
- c) Each utility will present the results of the filing to the Commission at a public meeting.
- d) Upon filing, the Commission will set a procedural schedule under which interested parties will have the opportunity to provide comment and make recommendations on the filing.
- e) The Commission will generally consider comments and recommendations on a utility's filing at a public meeting three to five months after it is filed. The Commission will consider whether to accept the filing as meeting the objectives of these Guidelines. The Commission may provide guidance on the development and content of future Plans.
- f) The Commission may provide the utility an opportunity to revise the filing before making its decision.

The design and implementation of this proposed process will serve the long-term regulatory efficiency goals through aligned, streamlined processes, inclusion, and transparency.

## 2. Commission Action

The Commission will consider whether to accept the filed Plan as meeting the objectives of these Guidelines. As used in this Guideline, "acceptance" means the Commission finds the Plan meets the criteria and requirements of these Guidelines. Acceptance does not constitute a determination on the prudence of any individual actions discussed in the Plan. A decision to not accept a Plan means that the Plan does not meet the criteria or requirements of the Guidelines.

## 3. Community Engagement

A utility should involve the public in the preparation and implementation of each utility Distribution System Plan. Involvement includes opportunities to contribute information and ideas, as well as to receive information, similar to the public input process in an IRP. Interested parties must have an opportunity to make relevant inquiries of the utility formulating the Plan. These updated guidelines for community engagement are intended to foster a process that has continued to develop since DSP Guidelines were adopted in 2020, and that supports a human-centered approach to DSP.

Community-based organizations (CBOs) may play an integral role in DSP-related community engagement. CBOs can offer insight to inform the utility's bottom-up forecasting of technology deployment, especially in vulnerable communities. CBOs can provide input to the utility on the

---

<sup>1</sup> "Electric utility" or "utility" for purposes of these guidelines means an electric company that is engaged in the business of distributing electricity to retail electricity consumers in this state and that owns and operates a distribution system connecting the transmission grid to the retail electricity consumer.

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

---

methodology to identify and prioritize distribution system investments and project development. CBOs can also identify or support implementation of customer-sited non-wires solutions.

Local governments and Tribal nations may also play an important role in DSP-related community engagement, and can provide input to the utility on policies intersecting with distribution system planning.

Specific requirements for utilities include:

a) During Plan development a utility should host at least four stakeholder workshops prior to filing the utility's Plan.<sup>2</sup> These workshops should be held during Plan development, at a stage in which stakeholder engagement can influence the filed Plan. The workshops may include in-person meetings located in a community, and may include presentation of the Plan outline, data and assumptions under consideration or challenges encountered, and the utility's approach to community engagement. During stakeholder workshops, a utility must invite community members to share their perspectives, relevant needs, challenges, and opportunities or novel solutions for the grid.

b) To engage stakeholders and community on distribution system planning, a utility should leverage best practices, and lessons learned from engagement efforts from prior Plans, and other planning processes. A utility should also leverage ongoing community and stakeholder engagement processes, and integrate distribution system planning engagement to the full extent it is beneficial to do so. Ongoing processes may include but are not limited to Clean Energy Planning, regional or local-area planning exercises.

c) During preparation and implementation of a DSP, a utility should document community and stakeholder comments and feedback and utility response, including comments and feedback that were heard but not implemented. This documentation should be included in the utility's Plan when filed.

d) A utility should maintain a Community Engagement Plan, as developed in the Company's prior DSP. The Community Engagement Plan should describe actions the utility will implement in order to engage community members and CBOs if it needs to develop and implement non-wire solutions to address grid needs, or if it needs to engage communities around implementing larger projects. Larger projects may exclude, for example, regular maintenance projects, or inspection projects. The Community Engagement Plan should include the activities described below.

i) Proactively engage stakeholders regarding possible non-wire solutions or larger projects in impacted communities. Engagement of the local community may include in-person meetings located in the community; presentation of the project scope, timeline, rationale; discussion of proposed utility projects and the value and risks associated with options; and solicitation of public comment, particularly to understand community needs and opportunities.

ii) Collaboratively develop and share datasets and metrics to guide community-centered planning of the possible non-wire solutions or larger projects.

iii) The Plan should consider engagement of local governments and Tribal nations for input on possible non-wire solutions, larger projects, as well as input on other policies intersecting distribution system planning. These may include opportunities or interest in

---

<sup>2</sup> An electric utility that makes sales of electricity to retail electricity consumers in an amount that equals less than three percent of all electricity sold to retail electricity consumers may host at least two stakeholder workshops.

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

---

micro-grids and other resiliency planning, or local environmental and climate plans such as fleet-electrification and building-electrification efforts.

e) Utilities should aim to create a collaborative environment among all interested CBO partners and stakeholders.

## 4. Current System Data and Assessment

To foster transparency and enable effective decision-making, Distribution System Plans should provide a fundamental understanding of the current physical status of the utility distribution systems and equipment, progress of investment in those systems, the level of distributed energy resources (DERs) currently integrated into those systems,<sup>3</sup> and management and monitoring practices of those systems.

The utility should provide, at minimum:

a) A description of any currently used system assessment practices (such as system reliability assessments, system asset health assessments, etc.) that are utilized in identifying grid needs and evaluating possible solutions, which may include:

- i) Method and tools used to develop the assessment
- ii) Forecasting time horizon(s)
- iii) Key performance metrics

b) A summary description and table of the utility's distribution system assets including:

- i) Asset classes
- ii) Number of assets in each class
- iii) Average age of assets in each class
- iv) Age range of assets in each class
- v) Life expectancy of assets in each class
- vi) Percentage of assets in each class at or beyond the end of expected life

c) A discussion of distribution system monitoring and control capabilities including:

- i) Number of feeders
- ii) Number of substations
- iii) Monitoring and control technologies (such as SCADA, AMI, etc.) currently installed, and the percentage of substations, feeders, and other applicable equipment with each technology
- iv) A description of the monitoring and control capabilities (for example, percentage of system with each technology, resulting capacity, such as remote fault detection or power quality monitoring, and what time interval measurements are available)

d) A discussion of any advanced control and communication systems (for example: distribution management systems, distributed energy resources management systems, demand response

---

<sup>3</sup> For the purposes of these guidelines "distributed energy resource" includes distributed generation resources, distributed energy storage, demand response, energy efficiency, and electric vehicles that are connected to the electric distribution power grid.

U.S. Department of Energy, Modern Distribution Grid Volume I: Customer and State Policy Driven Functionality, page 7, [https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid\\_Volume-I\\_v1\\_1.pdf](https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-I_v1_1.pdf).

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

---

management systems, outage management systems, field area networks, etc.). The discussion should include:

- i) a description of system visibility and capabilities
  - ii) the percentage of system reached with each capability, the percentage of customers reached with each capability
  - iii) any utility programs utilizing each capability
- e) Historical distribution system spending for the past five years, in each category:
- i) Age-related replacements and asset renewal
  - ii) System expansion or upgrades for capacity
  - iii) System expansion or upgrades for reliability and power quality
  - iv) New customer projects
  - v) Grid modernization projects
  - vi) Metering
  - vii) Preventative maintenance
- f) Net Metering and Small Generator information:<sup>4</sup>
- i) Total existing net metering facilities and small generator facilities interconnected to the distribution grid (or to the transmission system, as appropriate for small generator facilities) at time of filing, by feeder.
    - (1) The total number of net metering facilities by resource type
    - (2) The total estimated rated generating capacity of net metering facilities by resource type
    - (3) The total number of small generator facilities by resource type
    - (4) The total nameplate capacity of small generator facilities by resource type
  - ii) The total number and nameplate capacity of queued net metering facilities and small generator facilities at time of filing, by feeder, broken down by resource type
- g) Plans should include the utility's most recently filed Annual Reliability Report as an appendix to the Plan.
- i) Any descriptions of reliability challenges and opportunities in the Distribution System Plan should cross-reference underlying data and information contained in the Annual Reliability Report
  - ii) Any proposed investments based in whole, or in part, on reliability improvements must demonstrate those improvements by cross-referencing underlying data and information contained in the Annual Reliability Report
- h) Summary progress report on activities included in the most recently filed DSP to clearly communicate advancement or completion of:
- i) Investments, expenditures, and activities from the Long-term Plan
  - ii) Investments, expenditures, and activities from the Near-term Action Plan
- i) Data assembled for this requirement should be prepared in electronic format, and submitted to the Commission for public review

---

<sup>4</sup> A utility that is exempt from the Annual Net Metering Report requirement pursuant to OAR 860-039-0070 is not required to report net metering data required in section f).

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

---

## 5. Forecasting of Load Growth, DER Adoption, and EV Adoption

Accurately forecasting load growth, a critically important exercise utilities have done for decades, enables the distribution system to reliably meet future energy, demand and ancillary grid service needs. As DER and EV adoption grows, forecasting must advance to better account for their impact on load, as well as the ability of these resources to productively modify load. The updated requirements aim to improve the accuracy and granularity of forecasting. This in turn is intended to improve the accuracy and granularity of existing and anticipated constraints on the distribution system revealed in the engineering analysis to identify Grid Needs.

The Guidelines require a utility to document in its Plan current utility load forecasting processes for distribution service, and forecasting processes for DER adoption and EV adoption as follows:

- a) Forecast of load growth by feeder including discussion of:
  - i) Forecasting method and tools used to develop the forecast
  - ii) Forecasting time horizon(s)
  - iii) Data sources used to inform the forecast
  - iv) The load forecast should include data, inputs, and assumptions from the Company's most recent IRP/CEP, which should be clearly listed in the DSP. Examples include but are not limited to:
    - (1) System modeled scenarios decomposed to the distribution system
    - (2) Discussion of how IRP/CEP forecasting is decomposed to, and reconciled with, geographic areas of the distribution system, and identification of those specific geographic areas. Examples of such areas may include transitional planning areas.
- b) Forecast of DER adoption and EV adoption by feeder including discussion of:
  - i) Forecasting method and tools used to develop the forecast
  - ii) Forecasting time horizon(s)
  - iii) Data sources used to inform the forecast
  - iv) The forecast should include high/medium/low scenarios for both DER adoption and EV adoption
  - v) The DER adoption and EV adoption forecasts should include data, inputs, and assumptions from the Company's most recent IRP/CEP, which should be clearly listed in the DSP. Examples include but are not limited to:
    - (1) Community based renewable energy (CBRE) forecast, potential study, RFP, needs assessment, etc.
    - (2) Small scale renewable (SSR) forecast, potential study, RFP, needs assessment, etc.
  - vi) The methodology for geographical allocation is at the utility's discretion. The Commission may provide direction for subsequent Plans.
- c) If a utility does not complete forecasting for its entire distribution system and instead completes forecasting for a portion of its distribution system, it must state so clearly and:
  - i) explain the reasons for completing the exercise for a portion of the system
  - ii) describe for how much of the system the exercise was completed, in terms of customers, load, substation count, and feeder count
  - iii) discuss whether and how the utility plans to complete the exercise in future DSPs

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

---

## 6. Grid Needs

Grid needs identification compares the current capabilities of a distribution system and the demands on that system to infer its future needs. At its core, a grid needs identification answers the question of what technical requirements must be addressed to ensure a safe, reliable and resilient system that provides adequate power quality to the customers it serves. Adding to this core, grid needs identification should include constraints related to forecast of customer and front-of-the-meter DER. Additionally, the social and economic needs of the communities that depend on distribution systems, and the contributions they can make to strengthen it should be addressed. Grid needs identification should be comprehensive and inclusive, identifying the biggest drivers and trends behind needed investments and operational budgets.

A utility's Distribution System Plan should:

- a) Document processes used to assess grid adequacy and identify grid needs
- b) Discuss criteria, methods, and tools used to identify needs by asset class
- c) Discuss and identify anticipated grid needs, including the following:
  - i) Renewal needs based on asset condition
  - ii) Grid needs to address forecasted load growth, DER adoption, EV adoption
  - iii) Grid needs to address customer needs such as new service, additional service, or service quality
  - iv) Grid needs to address other relevant utility plans including
    - (1) IRP/CEP
    - (2) Wildfire Mitigation Plan, including but not limited to identified Increased risk, either in geographically targeted areas, or at a system-level
    - (3) Transportation Electrification Plan
    - (4) Geographically targeted efforts of any demand side programs/DER programs
    - (5) Annual reliability reporting, and any related performance issues
  - v) Timing of grid needs
- d) Provide a summary table of each identified grid need by asset class and specifying the timing of need. The summary table should aid Staff and stakeholders in finding a thru-line from grid needs reported in a DSP to investments seen in future general rate cases.

## 7. Solution Identification

Solution identification proposes the equipment, technology or program(s) the utility will advance to meet identified grid needs. Previously, a Distribution System Plan would rely on traditional hardware solutions (such as substation upgrades, reconductoring, and additional transformer deployment). These Guidelines advance more holistic distribution system planning, calling for consideration of a wider range of potential solutions (for example increased system monitoring automation, expanded switching capability, distributed energy resources). The solutions identified should correspond to future general rate cases.

The utility should assess grid needs to determine cost effective solutions as follows:

- a) Document the process to identify the range of possible solutions to address grid needs and discuss how this process was applied to identify the proposed solutions in the Long-term and Near-term Plans
- b) First, the utility process should assess each identified grid need to identify opportunities for no or low-incremental cost grid solutions such as rebalancing distribution loading through switching and phase balancing, or other actions



# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

---

c) Second, if a specific grid need cannot be addressed by b) the utility should identify both a traditional solution and screen the grid need for suitability of a non-wires solution, if the cost for the traditional solution is \$1 million or more

i) Determine the suitability of a non-wires solution based on the following screening criteria:

- (1) Grid need is not a redundant supply to a radial load;
- (2) Grid need is not a maintenance, asset condition, or safety need;
- (3) Grid need is not a stability or short circuit problems; or
- (4) Grid need must be addressed within two years

ii) If a grid need is suitable for a non-wires solution and comparatively cost-effective to the traditional solution, then the utility should identify the proposed non-wires solution(s) program, pricing, and/or procurement.

d) All identified utility traditional and non-wires solutions should be documented in the Long-term and Near-term Plans as appropriate.

## 8. Near-term Action Plan

In this section of the Plan, a utility should present the utility's proposed solutions to address near-term grid needs. Specific requirements include:

a) Action Plan: Provide a 5 year plan of the utility's proposed solutions to address identified grid needs. The Action Plan should include:

i) Prioritized list of investments, expenditures, and activities

ii) A discussion of each planned investment/expenditures/activity estimated to cost more than \$2 million. Each discussion should include:

- (1) Project narrative including foundational assumptions and key barriers or constraints (including financial, technical, organizational) and mitigation plans
- (2) Timeframe
- (3) Investment/expenditure amount
- (4) Description of the criteria and methods the utility used to prioritize the investment/expenditure/activity, including explicit consideration of how the investment/expenditure/activity advances State policies and goals and PUC objectives, including but not limited to:<sup>5</sup>
  - (a) Reliability
  - (b) Safety and security
  - (c) Customer benefits and promoting inclusion of underserved populations
  - (d) Optimized operation of the system
  - (e) Efficient integration of DERs

When possible, the description should include quantification of the improvement in the goal.<sup>6</sup> Should a planned investment/expenditure/activity advance a goal

---

<sup>5</sup> These high-level goals were developed collaboratively with parties through the course of the Docket No. UM 2005 investigation.

<sup>6</sup> Examples may include but are not limited to:

Reliability – reduction in outages or duration

Safety and security – reduction in equipment failures, or vulnerabilities

Customer benefits, and promote inclusion of underserved populations – improvement in customer service, increased program participation in underserved populations

# Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

---

not included in (a)-(e), a utility should explain the rationale for the investment/expenditure/activity, and when possible, include quantitative outcomes.

(5) Explanation of how the investment/expenditure/activity is coordinated with the utility's other planning processes (such as the most recent IRP/CEP, Wildfire Mitigation Plan, Transportation Electrification (TE) Plan, and DR/Flexible Load Plan).

(6) Any proposed investments/expenditures which address a grid need previously identified as a non-wires solution opportunity by the non-wires solutions screen should be identified and include a summary of the range of possible alternatives analyzed, the analysis results, and discussion of why the non-wires solution was not selected.

(7) Discussion of whether the proposed investment/expenditure/activity interacts with non-distribution asset strategies, whether alternatives to distribution investment were considered, and if made, what impact does the proposed investment/expenditure/activity have on other network assets.

b) Projected spending: Provide the projected cost and timeline by asset class to implement the Action Plan. Provide a description of anticipated requests for cost recovery.

c) The Action Plan prioritized list (Guideline 8 a) i)) and discussions (Guideline 8 a) ii)), as well as the projected spending (Guideline 8 b)) should aid Staff and stakeholders in finding a thru-line from the Near-term Action Plan to investments seen in future general rate cases. Further, when pursuing recovery in a general rate case, utilities should prepare to provide materials assembled for the DSP filing as well as additional materials such as documentation of proposed and various alternative solutions considered, and a detailed accounting of the relative costs and benefits of the chosen and alternative solutions, such as engineering reports, feeder level details (such as customer types on the feeder; loading information), DER forecasts and EV adoption rates.

## 9. Long-term Plan

This section of the Distribution System Plan consists of the utility's long-term investment plan. This section of the plan should include:

a) The utility's vision for the distribution system for the next 10 years, aligned with State policies and goals and PUC objectives, including but not limited to:<sup>7</sup>

- i) Reliability
- ii) Safety and security
- iii) Customer benefits and promoting inclusion of underserved populations
- iv) Optimized operation of the system
- v) Efficient integration of DERs

b) Roadmap of the utility's planned investments, expenditures, and activities to advance the distribution system vision, for a 10-year planning horizon. The roadmap should include:

- i) Prioritized list of long-term investments, expenditures, and activities
- ii) A discussion of each planned investment/expenditures/activity including:

---

Optimized operation of the system – reduction in operating costs

Efficient integration of DERs – increased adoption of demand-side and renewable resources

<sup>7</sup> These high-level goals were developed collaboratively with parties through the course of the Docket No. UM 2005 investigation.

## Staff Proposed Distribution System Planning (DSP) Guideline Revisions

April 2024

---

- (1) Project narrative including foundational assumptions and key barriers or constraints (including financial, technical, organizational) and mitigation plans
  - (2) Estimated timeframe
  - (3) Estimated investment/expenditure
  - (4) Description of the criteria and methods the utility used to prioritize the investment/expenditure/activity, including explicit consideration of how the investment/expenditure/activity advances policies/goals/objectives identified in a) i)-v). When possible, the explanation should include quantification of the improvement in the goal.<sup>8</sup> Should a planned investment/expenditure/activity advance a goal not included in a) i)-v), a utility should explain the rationale for the investment/expenditure/activity, and when possible, include quantitative outcomes.
  - (5) Any connections to, and impacts on, Near-term Action Plan projects
  - (6) Explanation of how the investment/expenditure/activity fits with the utility's other planning processes (such as the most recent IRP/CEP, Wildfire Mitigation Plan, Transportation Electrification (TE) Plan, and DR/Flexible Load Plan) including how the investment/expenditure/activity is coordinated with each planning process with respect to related inputs and outputs such as data sets and prices, and assumptions such as macro-economic policies and growth rates.
- iii) The Long-term Plan Roadmap prioritized list (Guideline 9 b) i)) and discussions (Guideline 9 b) ii)) should aid Staff and stakeholders in finding a thru-line from the Long-term Plan to investments seen in future general rate cases.

---

<sup>8</sup> Examples may include but are not limited to:

Reliability – reduction in outages or duration

Safety and security – reduction in equipment failures, or vulnerabilities

Customer benefits, and promote inclusion of underserved populations – improvement in customer service, increased program participation in underserved populations

Optimized operation of the system – reduction in operating costs

Efficient integration of DERs – increased adoption of demand-side and renewable resources