Staff Proposed Distribution System Planning (DSP) Guideline Revisions

September 2024

Redline version

New changes are shown with yellow highlight. For guiding context for these revisions, please see Staff's September 17, 2024, Update and Response to Stakeholder Feedback, posted to Docket No. UM 2005 separately.

Distribution System Planning Guidelines

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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[1] 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: March 6, 2026~~Month Day, Year~~
Portland General Electric: April 1, 2025~~Month Day, Year~~
Pacific Power: March 31, 2026~~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.~~
b~~d~~) 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.~~
c~~f~~) Each utility will present the results of ~~each~~ the filing to the Commission at a ~~separate~~ public meeting.
d~~g~~) 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.
e~~h~~) 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~~i~~) 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.

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[1] "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.

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.[2, 3] 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.[4]~~

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

~~**Figure 3**~~

~~[2] *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.~~

~~[3] *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.~~

~~[4] *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.~~

~~**Community Engagement**~~		
~~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~~

a~~i~~) During Plan development ~~A~~a utility should host at least four~~two~~ stakeholder workshops prior to filing ~~each Part of~~ the utility's Plan.[5]~~, 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

[5] 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.

engagement.~~the Community Engagement Plan, described in (b).~~ 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, while maintaining accessible engagement forums, 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, and 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~~ii~~) 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 that may have a reasonable expectation of impacting surrounding communities. 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:~~

~~(1~~i) 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.~~

~~(3~~ii) Collaboratively develop and share information, for example 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 C~~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. Examples of such policies~~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.

~~Iii~~e) Utilities should aim to create a collaborative and accessible 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~~

~~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 (NWEC), 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.~~[6, 7, 8, 9]

~~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~~

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[6] ~~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.~~

[7] ~~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.~~

[8] ~~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~~

[9] ~~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.~~

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 distributed energy resources (DERs) currently integrated into those systems, ~~.~~[10] 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~~

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

~~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)~~

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[10] 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.

~~iii) Key performance metrics~~

a~~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) ~~Industry l~~Life expectancy of assets in each class
vi) Percentage of assets in each class at or beyond the end of expected life

b~~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)

c~~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 i~~I~~nclude:

i) ~~a~~A description of system visibility and capabilities~~,~~
ii) ~~the~~ The percentage of system reached with each capability, the percentage of customers reached with each capability~~, and~~
iii) ~~any~~ Any utility programs utilizing each capability~~.~~

d~~e~~) Historical distribution system spending for the past five years, in categories that reflect Company project management and financial management practices, and have been shared with Staff prior to filing.~~ 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~~

e~~f~~) Net Metering and Small Generator information:[11]

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.

[11] 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).

(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.

~~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:~~[12]

~~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.~~

fg~~n~~) 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, or other properly cited, publicly available data source.~~.~~

~~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~~

g) Plans should include high-level summary data on electric vehicles (EV) and EV charging, or link to such data if it is provided through other utility planning practices or publicly available sources. If not provided through other utility planning practices or publicly available sources, the data should include:

~~[12] 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.~~

i) Total number of EVs of various sizes served by the utility's system at time of filing
ii) Number of EVs added to the utility's system in each of the last five years
iii) Total number of charging stations on the utility's system, broken down by type, ownership, and feeder
iv) Total number of charging stations added to the utility's system in each of the last five years, broken down by type
v) Data on the availability and usage patterns of charging stations
vi) Summary data of other transportation electrification infrastructure, if applicable

h) Plans should include high-level summary data on demand response/flexible load pilot and/or program performance metrics for the past five years, or link to such data if it is provided through other utility planning practices. If not provided through other utility planning practices, the data should include:

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

i~~h~~) Summary-level progress report on activities included in the last~~-most recently~~ filed DSP to clearly communicate substantive developments (for example project advancement, ~~or~~ completion, or delay) of:

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

j~~i~~) Data and information assembled for the Current System Data and Assessment~~this~~ requirement should be ~~prepared in electronic format, and~~ submitted to the Commission in electronic format and without protective order~~ 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 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.[13] Additionally, at the February 26, 2020 workshop, utilities provided an overview of their existing DSP processes, including monitoring and automation practices.[14, 15, 16] Presentations highlighted~~

~~[13] Staff Whitepaper: A Proposal for Electric Distribution System Planning, March 2019, https://edocs.puc.state.or.us/efdocs/HAU/um2005hau15477.pdf.~~
~~[14] *Distribution System Highlights*, Portland General Electric, February 26, 2020, https://edocs.puc.state.or.us/efdocs/HAH/um2005hah16124.pdf.~~
~~[15] *Idaho Power: Current Distribution System and Small Scale Generation*, Idaho Power, February 26, 2020, https://edocs.puc.state.or.us/efdocs/HAH/um2005hah14343.pdf.~~
~~[16] *Current Distribution System: Questionnaire Section C*, Pacific Power, February 26, 2020, https://edocs.puc.state.or.us/efdocs/HAH/um2005hah9537.pdf.~~

~~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.[17] 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.~~
~~Stage 2~~	~~If determined through Docket UM 2111, conduct hosting capacity analysis inform stakeholders of potential interconnection challenges, or replace portions of interconnection studies; publish hosting capacity maps with greater detail over time. Update areas with greater/faster DER adoption more frequently.~~
	~~Include distribution-level impacts to the substation and transmission system.~~
	~~Conduct hosting capacity evaluations to inform Grid Needs Identification.~~
~~Stage 1~~	~~Conduct a system evaluation to identify areas of limited DER growth.~~
	~~Provide a plan to conduct hosting capacity evaluations in the near-term which may inform Grid Needs Identification, inform stakeholders of potential interconnection challenges, or~~

~~[17] *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.~~

~~**Hosting Capacity Analysis**~~		
	~~replace portions of interconnection studies. Plan may address options that may provide more approachable and instructive data for communities.~~	
	~~2021-2022~~	~~2023 and beyond~~

~~**Initial Requirements**~~

~~Under these Guidelines, for initial Distribution System Plans, each utility should conduct system evaluations to identify generation constrained areas where it is difficult to interconnect DERs without system upgrades. Each utility should present the results through an unredacted map that the utility should make available on its website on a continuing basis. In addition, a utility should include an Options Analysis for investing in more sophisticated HCA capabilities in the near-term. Specific requirements include:~~

~~a) Upon Commission adoption of these Guidelines each utility should begin conducting a system evaluation to identify areas where it is difficult to interconnect DERs without system upgrades. Each utility should present the results through an unredacted map that is continuously available on the utility's website.~~[18]

- ~~i) A utility should adopt the methodology underlying PGE's Net Metering Map, as presented in UM 2099, for calculating and identifying areas where it is difficult to interconnect DERs without system upgrades.~~[19]
  - ~~(1) If this methodology is not feasible, a utility should present an alternative methodology with documentation of why it is necessary, and an explanation of any ways in which it may be different from the methodology utilized by PGE.~~
- ~~ii) The resulting system-evaluation map should:~~
  - ~~(1) At minimum, meet the level of functionality of PGE's Net Metering Map.~~[20]
  - ~~(2) Label feeders serving Public Safety Power Shutoff areas.~~

~~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~~

[18] ~~This requirement is not grounded in the Commission's net-metering administrative rules. Any utility exemptions from net-metering administrative rules do not correspond to an exemption from to this requirement.~~

[19] ~~See *PGE Reply Comments*, Docket UM 2099, (September 22, 2020) pages 6 and page 8: https://edocs.puc.state.or.us/efdocs/HAC/um2099hac154013.pdf.~~

[20] ~~https://www.portlandgeneral.com/business/power-choices-pricing/renewable-power/install-solar-wind-more/net-metering/net-metering-map~~

- ~~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.[21] 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.[22] 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 interconnection issues.[23] Over time, hosting capacity analysis may reduce the need for interconnection studies.[24, 25]~~

~~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.~~

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[21] ~~Xcel Minnesota performs HCA implementation that illustrates some of these parameters.~~
[22] ~~California utilities perform HCA implementation that illustrate some of these parameters.~~
[23] ~~*Hosting Capacity - Lessons Learned*, Steve Steffel, Pepco Holdings, May 6, 2020, https://www.oregon.gov/puc/utilities/Documents/DSP-Hosting-Capacity-SSteffel.pdf.~~
[24] ~~*OPUC Hosting Capacity Overview*, Aram Shumavon, Kevala Analytics, May 6, 2020, https://www.oregon.gov/puc/utilities/Documents/DSP-Shumavon-Presentation.pdf.~~
[25] ~~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.~~

~~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~~

~~5. Part 2~~

5.~~1~~ 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~~ 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 ~~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~~

The~~se~~ 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 ~~of~~ for DER adoption and EV adoption as follows:

a) Forecast of load growth to a granularity of, at a minimum, the substation level, ~~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 (sources and vintage should be clearly identified in DSP filings)

iv) The load forecast should include data, inputs, and assumptions from the Company's most recent IRP/CEP, or from the most current and accurate sources at the time. Sources should be consistent with those used in other Company planning practices at the time.~~, 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 to a granularity of, at a minimum, the substation level,~~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 (sources and vintage should be clearly identified in DSP filings)

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 or from the most current and accurate sources at the time. Sources should be consistent with those used in other Company planning practices at the time.~~, 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~~iii~~) ~~For the initial Plan, t~~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) E~~e~~xplain the reasons for completing the exercise for a portion of the system

ii) ~~d~~Describe for how much of the system the exercise was completed, in terms of customers, load, substation count, and feeder count

iii) ~~d~~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 adoption models.[26] 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.~~

6~~5~~.~~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 utility-owned or third-party~~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 considered~~addressed~~. Grid needs identification should be comprehensive and inclusive, identifying the biggest drivers and trends behind needed investments and operational budgets. A utility's DSP investments are expected to be generally responsive to identified grid needs. Where investments do not align with identified grid needs, a utility should be prepared to explain the change in needs and circumstances requiring substantial divergence from the DSP as part of the cost recovery process.

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

~~[26] See https://www.oregon.gov/puc/utilities/Documents/DSP-Sigrin-Presentation.pdf for more detail.~~

~~Figure 5~~

~~**Grid Needs Identification**~~	
~~Stage 3~~	~~Identify grid needs and present a summary of prioritized grid constraints, utilizing prioritization criteria such as community priorities, equity analysis, constraints on DER adoption, and evolving public policy goals.~~
	~~Provide new datasets and analysis responsive to OPUC, community inputs and policy evolution.~~
~~Stage 2~~	~~Develop robust “future state” data needs, including inputs in the following categories:~~
	~~Perform equity analysis overlaying customer geographic and socio-economic data relative to system reliability and customer options. Make findings publicly available.~~
	~~Needs identification includes results of community needs assessments, DER forecasting, and equity analysis.~~
	~~Identify grid modernization needs and present a summary of prioritized grid constraints and opportunities publicly.~~
~~Stage 1~~	~~Present summary of prioritized grid constraints publicly, including criteria used for prioritization.~~
	~~Document process and criteria used to identify grid adequacy and needs. Discuss criteria used to assess reliability and risk, and methods and modeling tools used to identify needs.~~
~~2021-2022~~	~~2023 and beyond~~

~~Initial Requirements~~

A utility’s~~, in its~~ Distribution System Plan~~,~~ should:

a) Describe any currently used system assessment ~~Document the~~ processes and practices (such as system reliability assessments, system asset health assessments, etc.) that are utilized in ~~used to~~ assessing grid adequacy and identifying grid needs and evaluating possible solutions, which may include:~~.~~

i)~~b) Discuss C~~criteria, methods, and tools used to develop the assessment~~identify needs by asset class~~

ii) Forecasting time horizon(s)

iii) Key performance metrics

b)~~c)~~ Discuss and identify anticipated grid needs, to the extent such identification does not violate customer privacy or NERC/CIP protections, including the following:~~criteria used to assess reliability and risk, and methods and modeling tools used to identify needs.~~

i) Replacement~~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 identified through~~to address~~ other ~~relevant~~ utility planning processes including, as relevant:

(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

c)~~c)~~ ~~d)~~ Provide~~Present~~ a summary table of ~~prioritized~~ each identified grid need, ~~by asset class~~ and specify~~ing~~ the timing of each need. ~~The summary table should aid Staff and stakeholders in linking 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.[27] 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). A utility's DSP investments are expected to be generally consistent with identified solutions. Where investments do not align with the solutions identified, a utility should be prepared to explain the information and circumstances that informed the selection of an investment inconsistent with identified solutions as part of the cost recovery process.~~The solutions identified should correspond to future general rate cases.~~

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

~~[27] *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.~~

~~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.~~

~~**Figure 6**~~

~~**Solution Identification**~~	
~~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) Identify at a project- or program-level processes or approaches to employing~~First, the utility process should assess each identified grid need to identify opportunities for~~ no or low-incremental cost options to resolve a grid need without capital projects (examples may include ~~grid solutions such as~~ rebalancing distribution loading through switching and phase balancing, or other actions).

c) Assess each identified grid need for possible traditional solutions, alternative solutions, and for low-cost solutions.

i) Document possible solutions in Near-term Action Plan investment/expenditure summaries.

~~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) Evaluate at least two non-wires solutions pilot concept proposals. In these proposals non-wire solutions would be used in the place of traditional utility investment/expenditure. The purpose of these pilots is to gain experience and insight into the evaluation of non-wire solutions to address priority issues such as the need for new capacity to serve local load growth, or power quality improvements in underserved communities.

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, pilot concept proposals should utilize the utility's Community Engagement Plan 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.
~~d) All identified utility traditional and non-wires solutions should be documented in the Long-term and Near-term Plans as appropriate.~~

~~5~~8.4 ~~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~~. The Near-term Action Plan should include a prioritized list of investments/expenditures, investment/expenditure summaries, and projected spending. These elements should guide DSP implementation and provide a preview of investments/expenditures for which cost recovery may be sought in future general rate cases. Where a utility's implementation of the Near-term Action Plan does not align with the Near-term Action Plan contained in the DSP, a utility should be prepared to explain its rationale for deviation in the cost recovery process.

Specific requirements include:

a) Prioritized list ~~Action Plan: Provide a 52-4 year plan consisting~~ of the utility's proposed solutions (investments/expenditures) over the next five years to address identified grid needs.
b) A summary ~~. 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/expenditure~~s/activity~~ estimated to cost more than $2 million. Each summary should be no more than one page in length and ~~discussion~~ should include:

i)~~(1)~~ Project narrative including the asset classes and unit counts of proposed solution, and as available, foundational assumptions and key barriers or constraints (for example ~~including~~ financial, technical, organizational) and mitigation plans
ii)~~(2)~~ Estimated t~~T~~imeframe
iii) Estimated project cost~~(3) Investment~~/expenditure amount
iv)~~(4)~~ Description of the criteria and methods the utility used to prioritize the investment/expenditure~~/activity,~~ in Guideline 8a, including ~~explicit~~ consideration of if, and how the investment/expenditure~~/activity~~ advances State policies and goals and PUC objectives, including but not limited to:[28]

- ~~(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~~.~~[29] and should demonstrate improvement by using cited, publicly available data, for example a utility's Annual Reliability Report. Should a planned investment/expenditure~~/activity~~ advance a goal not included ~~in (a)-(e)~~above, a utility should explain the rationale for the investment/expenditure~~/activity~~, and when possible, include quantitative outcomes.
v) Description of alternative solutions considered (for example, traditional utility solutions, low-cost solutions, and if applicable any non-wires solutions the utility may have considered) including the proposed asset classes and unit counts, and estimated project cost/expenditure amount for each alternative.
vi)~~(5)~~ Description~~Explanation~~ of if, and 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~~

[28] These high-level goals were developed collaboratively with parties through the course of the Docket No. UM 2005 investigation.
[29] 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

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

c~~b~~) Projected spending: ~~Disclose~~ Provide a table of the projected annual ~~system spending~~cost and timeline ~~by asset class~~ to implement the ~~a~~Action ~~p~~Plan. ~~, 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.~~

~~c) 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[30] 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 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~~

~~[30] 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.~~

~~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.[31] 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).[32]~~

~~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~~ consists 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~~The Long-term Plan should include a 10-year vision, a list of investments/expenditures the utility expects to make in years 6 through 10 (an extension of the Near-term Action Plan), and investment/expenditure summaries. These elements should present investments/expenditures a utility anticipates pursuing, recognizing that grid needs, circumstances, and State polices may change over the planning horizon. These elements should provide Staff and stakeholders with a preview of investments/expenditures that may be seen in future distribution system plans, and possibly in future general rate cases. Staff anticipates that a utility's actions should remain consistent with its 10-year vision for the distribution system. However, refinement of the list of expected investments/expenditures will likely be necessary. A utility should be prepared to explain evolution of its Long-term Plan in each distribution system plan.

~~[31] *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.~~

~~[32] 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.~~

Specific requirements~~This section of the plan should~~ include:

a) The utility's vision for the distribution system ~~over~~ for the next ~~5-~~10 years, and a discussion of if, and how, it aligns~~aligned~~ with State policies and goals and PUC objectives, including but not limited to:[33]

- ~~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~~ Prioritized list of ~~the utility's planned~~ investments~~,/ tools~~ expenditures~~, and activities~~ the utility expects to make in years 6 through 10 in order to advance the ~~long-term DSP~~ 10-year~~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~~.
c)
~~ii)~~ A summary~~discussion~~ of each planned investment/expenditure~~s/activity~~ which should be no more than one page in length, and includ~~eing~~ the following, as available:

i)~~(1)~~ Project narrative including, as available, foundational assumptions and key barriers or constraints (for example~~including~~ financial, technical, organizational) and mitigation plans.
ii)~~(2)~~ Estimated timeframe
iii)~~(3)~~ Estimated project cost~~investment~~/expenditure amount
iv)~~(4)~~ Description of the criteria and methods the utility used to prioritize the investment/expenditure~~/activity,~~ in Guideline 9b, including ~~explicit~~ consideration of if, and how the investment/expenditure~~/activity~~ advances policies/goals/objectives identified in Guideline 9a, and consideration of ~~a) i)-v). When possible, the explanation should include quantification of the improvement in the goal.[34] 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) A~~any connections to, and impacts on, Near-term Action Plan projects.
v)~~(6)~~ Description~~Explanation~~ of if, and 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~~

[33] These high-level goals were developed collaboratively with parties through the course of the Docket No. UM 2005 investigation.
~~[34] 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~~

~~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:~~
~~(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[35] 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~~

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[35] ~~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.~~

~~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 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~~

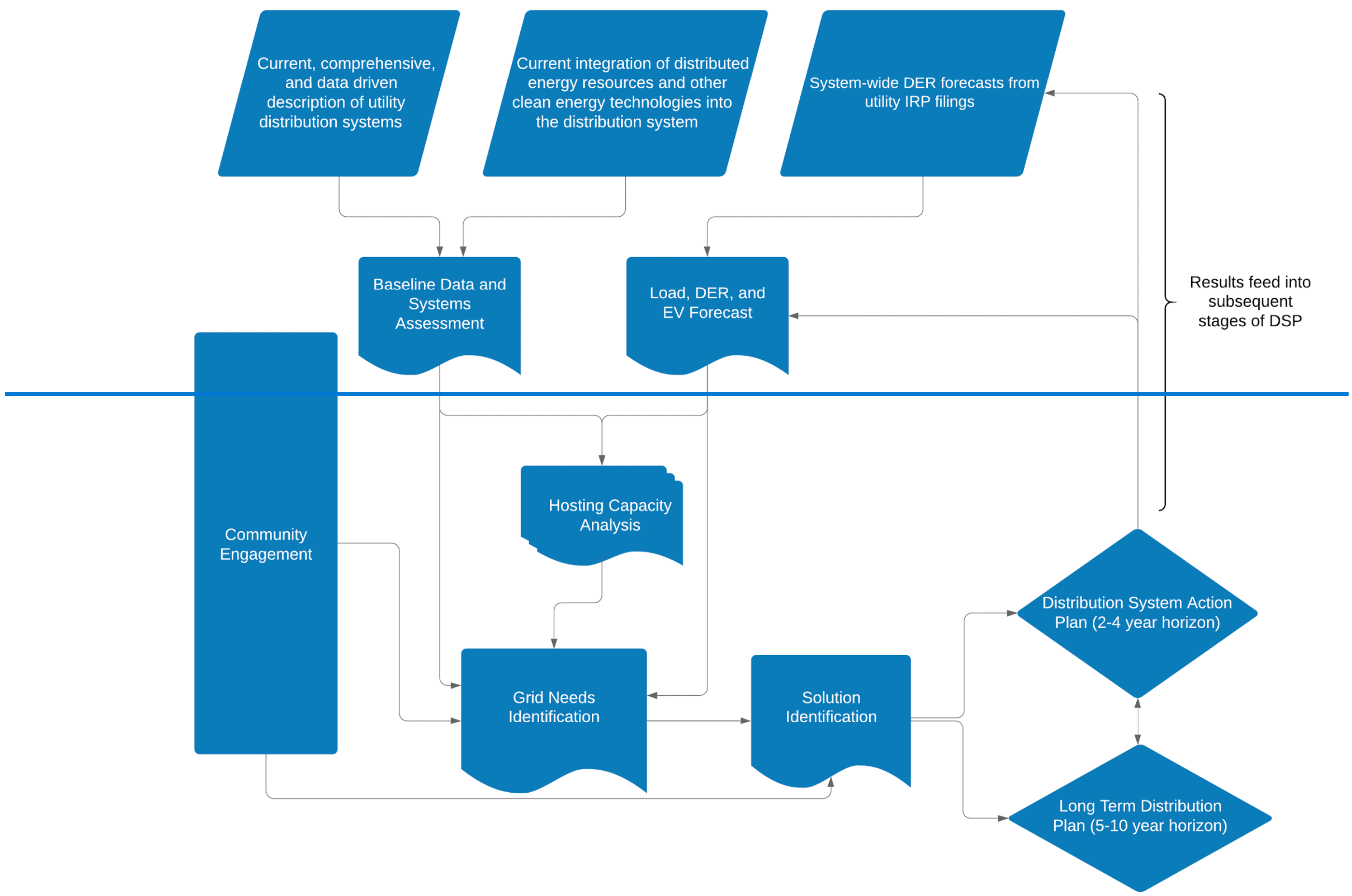
~~g) Plans to monitor and adapt the long-term Distribution System Plan~~

~~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.~~

- ~~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

September 2024

Clean version

New changes are shown with yellow highlight. For guiding context for these revisions, please see Staff's September 17, 2024, Update and Response to Stakeholder Feedback, posted to Docket No. UM 2005 separately.

Distribution System Planning Guidelines

Table of Contents

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[1] must file its next Plan on or before the following dates, or an alternative date designated by Commission order.
Idaho Power: March 6, 2026
Portland General Electric: April 1, 2025
Pacific Power: March 31, 2026
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

[1] "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.

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.[2] 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, while maintaining accessible engagement forums, 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, and 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 that may have a reasonable expectation of impacting surrounding communities. 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 information, for example datasets and metrics to guide community-centered planning of the possible non-wire solutions or larger projects.

[2] 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.

iii) Consider engagement of local governments and Tribal nations for input on possible non-wire solutions, larger projects, as well as on other policies intersecting distribution system planning. Examples of such policies may include 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 and accessible 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,[3] and management and monitoring practices of those systems.

The utility should provide, at minimum:

a) 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

b) 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)

c) 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

[3] 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.

ii) The percentage of system reached with each capability, the percentage of customers reached with each capability

iii) Any utility programs utilizing each capability

d) Historical distribution system spending for the past five years, in categories that reflect Company project management and financial management practices, and have been shared with Staff prior to filing.

e) Net Metering and Small Generator information:[4]

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.

f) Plans should include the utility's most recently filed Annual Reliability Report as an appendix to the Plan. 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, or other properly cited, publicly available data source.

g) Plans should include high-level summary data on electric vehicles (EV) and EV charging, or link to such data if it is provided through other utility planning practices or publicly available sources. If not provided through other utility planning practices or publicly available sources, the data should include:

i) Total number of EVs of various sizes served by the utility's system at time of filing

ii) Number of EVs added to the utility's system in each of the last five years

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

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

v) Data on the availability and usage patterns of charging stations

vi) Summary data of other transportation electrification infrastructure, if applicable

h) Plans should include high-level summary data on demand response/flexible load pilot and/or program performance metrics for the past five years, or link to such data if it is provided through other utility planning practices. If not provided through other utility planning practices, the data should include:

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

ii) By winter and summer demand response season:

[4] 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).

(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

i) Summary-level progress report on activities included in the last-filed DSP to clearly communicate substantive developments (for example project advancement, completion, or delay) of:

i) Investments/expenditures from the Long-term Plan

ii) Investments/expenditures from the Near-term Action Plan

j) Data and information assembled for the Current System Data and Assessment requirement should be submitted to the Commission in electronic format and without protective order.

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 to a granularity of, at a minimum, the substation level, 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 (sources and vintage should be clearly identified in DSP filings)

iv) The load forecast should include data, inputs, and assumptions from the Company's most recent IRP/CEP, or from the most current and accurate sources at the time. Sources should be consistent with those used in other Company planning practices at the time. 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 to a granularity of, at a minimum, the substation level, 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 (sources and vintage should be clearly identified in DSP filings)

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 or from the most current and accurate sources at the time. Sources should be consistent with those used in other Company planning practices at the time. 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

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 utility-owned or third-party 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 considered. Grid needs identification should be comprehensive and inclusive, identifying the biggest drivers and trends behind needed investments and operational budgets. A utility's DSP investments are expected to be generally responsive to identified grid needs. Where investments do not align with identified grid needs, a utility should be prepared to explain the change in needs and circumstances requiring substantial divergence from the DSP as part of the cost recovery process.

A utility's Distribution System Plan should:

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

i) Criteria, methods, and tools used to develop the assessment

ii) Forecasting time horizon(s)

iii) Key performance metrics

b) Discuss and identify anticipated grid needs, to the extent such identification does not violate customer privacy or NERC/CIP protections, including the following:

i) Replacement 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 identified through other utility planning processes including, as relevant:
(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

c) Provide a summary table of each identified grid need, and specify the timing of each need.

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). A utility's DSP investments are expected to be generally consistent with identified solutions. Where investments do not align with the solutions identified, a utility should be prepared to explain the information and circumstances that informed the selection of an investment inconsistent with identified solutions as part of the cost recovery process.

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

a) Document the process to identify the range of possible solutions to address grid needs.
b) Identify at a project- or program-level processes or approaches to employing no or low-incremental cost options to resolve a grid need without capital projects (examples may include rebalancing distribution loading through switching and phase balancing, or other actions).
c) Assess each identified grid need for possible traditional solutions, alternative solutions, and for low-cost solutions.

i) Document possible solutions in Near-term Action Plan investment/expenditure summaries.

d) Evaluate at least two non-wires solutions pilot concept proposals. In these proposals non-wire solutions would be used in the place of traditional utility investment/expenditure. The purpose of these pilots is to gain experience and insight into the evaluation of non-wire solutions to address priority issues such as the need for new capacity to serve local load growth, or power quality improvements in underserved communities.

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, pilot concept proposals should utilize the utility's Community Engagement Plan 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.

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. The Near-term Action Plan should include a prioritized list of investments/expenditures, investment/expenditure summaries, and projected spending. These elements should guide DSP implementation and provide a preview of investments/expenditures for which cost recovery may be sought in future general rate cases. Where a utility's implementation of the Near-term Action Plan does not align with the Near-term Action Plan contained in the DSP, a utility should be prepared to explain its rationale for deviation in the cost recovery process.

Specific requirements include:

a) Prioritized list of the utility's proposed solutions (investments/expenditures) over the next five years to address identified grid needs.
b) A summary of each planned investment/expenditure estimated to cost more than $2 million. Each summary should be no more than one page in length and should include:

i) Project narrative including the asset classes and unit counts of proposed solution, and as available, foundational assumptions and key barriers or constraints (for example financial, technical, organizational) and mitigation plans
ii) Estimated timeframe
iii) Estimated project cost/expenditure amount
iv) Description of the criteria and methods the utility used to prioritize the investment/expenditure in Guideline 8a, including consideration of if, and how the investment/expenditure advances State policies and goals and PUC objectives, including but not limited to:[5]

- Reliability
- Safety and security
- Customer benefits and promoting inclusion of underserved populations
- Optimized operation of the system
- Efficient integration of DERs

When possible, the description should include quantification of the improvement in the goal[6] and should demonstrate improvement by using cited, publicly available data, for

[5] These high-level goals were developed collaboratively with parties through the course of the Docket No. UM 2005 investigation.
[6] 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

example a utility's Annual Reliability Report. Should a planned investment/expenditure advance a goal not included above, a utility should explain the rationale for the investment/expenditure, and when possible, include quantitative outcomes.
v) Description of alternative solutions considered (for example, traditional utility solutions, low-cost solutions, and if applicable any non-wires solutions the utility may have considered) including the proposed asset classes and unit counts, and estimated project cost/expenditure amount for each alternative.
vi) Description of if, and how the investment/expenditure 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).
vii) Description of if, and how the proposed investment/expenditure interacts with non-distribution asset strategies (for example, transmission strategies), whether alternatives to distribution investment were considered, and if made, what impact does the proposed investment/expenditure have on other network assets.

c) Projected spending: Provide a table of the projected annual cost and timeline to implement the Action Plan. Provide a description of anticipated requests for cost recovery.

9. Long-term Plan

This section of the Plan consists of the utility's long-term investment plan. The Long-term Plan should include a 10-year vision, a list of investments/expenditures the utility expects to make in years 6 through 10 (an extension of the Near-term Action Plan), and investment/expenditure summaries. These elements should present investments/expenditures a utility anticipates pursuing, recognizing that grid needs, circumstances, and State polices may change over the planning horizon. These elements should provide Staff and stakeholders with a preview of investments/expenditures that may be seen in future distribution system plans, and possibly in future general rate cases. Staff anticipates that a utility's actions should remain consistent with its 10-year vision for the distribution system. However, refinement of the list of expected investments/expenditures will likely be necessary. A utility should be prepared to explain evolution of its Long-term Plan in each distribution system plan.

Specific requirements include:

a) The utility's vision for the distribution system for the next 10 years, and a discussion of if, and how, it aligns with State policies and goals and PUC objectives, including but not limited to:[7]

- Reliability
- Safety and security
- Customer benefits and promoting inclusion of underserved populations
- Optimized operation of the system
- Efficient integration of DERs

b) Prioritized list of investments/expenditures the utility expects to make in years 6 through 10 in order to advance the 10-year vision.

c) A summary of each planned investment/expenditure which should be no more than one page in length, and include the following, as available:

Optimized operation of the system – reduction in operating costs
Efficient integration of DERs – increased adoption of demand-side and renewable resources
[7] These high-level goals were developed collaboratively with parties through the course of the Docket No. UM 2005 investigation.

i) Project narrative including, as available, foundational assumptions and key barriers or constraints (for example financial, technical, organizational) and mitigation plans.
ii) Estimated timeframe
iii) Estimated project cost/expenditure amount
iv) Description of the criteria and methods the utility used to prioritize the investment/expenditure in Guideline 9b, including consideration of if, and how the investment/expenditure advances policies/goals/objectives identified in Guideline 9a, and consideration of any connections to, and impacts on, Near-term Action Plan projects.
v) Description of if, and how the investment/expenditure fits with the utility's other planning processes (such as the most recent IRP/CEP, Wildfire Mitigation Plan, TE Plan, and DR/Flexible Load Plan).