

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UM 2005

In the Matter of

PUBLIC UTILITY COMMISSION OF
OREGON,

Consideration for Adoption Staff Proposed
Guidelines for Distribution System Planning.

ORDER

DISPOSITION: STAFF'S RECOMMENDATION ADOPTED WITH MODIFICATION

This order memorializes our decision, made and effective at our December 15, 2020 Regular Public Meeting, to adopt Staff's recommendation in this matter, with a modification, as proposed by Staff during the public meeting. The modification proposed by Staff deletes the parenthetical phrase included with the definition of distributed resources in the approved guidelines. The Staff Report with the recommendation is attached as Appendix A.

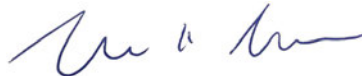
Made, entered, and effective Dec 23 2020.



Megan W. Decker
Chair



Letha Tawney
Commissioner



Mark R. Thompson
Commissioner



A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Circuit Court for Marion County in compliance with ORS 183.484.

ITEM NO. RA4

**PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: December 15, 2020**

REGULAR X CONSENT EFFECTIVE DATE 12/16/2020

DATE: December 7, 2020

TO: Public Utility Commission

FROM: Nick Sayen

THROUGH: Bryan Conway, JP Batmale, and Sarah Hall **SIGNED**

SUBJECT: OREGON PUBLIC UTILITY COMMISSION STAFF:
(Docket No. UM 2005)
Consideration for adoption Staff proposed guidelines for distribution system planning.

STAFF RECOMMENDATION:

The Public Utility Commission of Oregon (Commission or PUC) should approve the Distribution System Planning (DSP) Guidelines for use by investor-owned electric utilities. The Commission should also suspend the next Smart Grid Report filing cycle, and require elements currently required in the Transportation Electrification Plan to be further developed in the Distribution System Plan.

DISCUSSION:

Issues

1. Whether the Commission should approve the Distribution System Planning Guidelines for use by investor-owned electric utilities.
2. Whether the Commission should suspend the next Smart Grid Report filing cycle under Order No. 17-290.
3. Whether the Commission should require elements of the Transportation Electrification Plan to be developed in the Distribution System Plan under the DSP Guidelines, per OAR 860-087-0020(4).

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Applicable Law

This docket was opened as an investigation under ORS 756.515(1) in Commission Order No. 19-104. As further provided in ORS 756.515(4), after making an investigation, the Commission may make such findings and orders as the commission deems justified or required by the results of its investigation.

ORS 756.040 describes the general powers of the Commission to supervise and regulate every public utility, and to do all things necessary and convenient in the exercise of that authority.

Under ORS 756.105(1), “Every public utility or telecommunications utility shall furnish to the Public Utility Commission all information required by the commission to carry into effect the provisions of ORS chapters 756, 757, 758 and 759.”

The Commission may direct an electric company under OAR 860-087-0020(4) to incorporate the Transportation Electrification Plan required by the rule into other electric company planning documents.

A Smart Grid Report is required to be filed biennially per Order No. 17-290 in Docket No. UM 1460.

Analysis

Background

The Commission issued Order No. 19-104 March 22, 2019, opening the UM 2005 investigation to “develop a transparent, robust, holistic regulatory planning process for electric utility distribution system operations and investments.”¹ Staff’s whitepaper on distribution system planning (2019) identified two proactive drivers for the UM 2005 investigation. The first is the procedural driver of insight. Staff and stakeholders asserted the near-term need for increased visibility and holistic engagement in utilities’ distribution-level investments. The second is the operational driver of optimization. This is a longer-term need that seeks to ensure the operation of the changing distribution system by maximizing operational efficiency and customer value.²

Staff managed a stakeholder process to inform the development of DSP guidelines (Guidelines) for initial distribution system plans (Plans) to be filed by electric utilities in

¹ See UM 2005, Order No. 19-104, March 22, 2019 at <https://apps.puc.state.or.us/orders/2019ords/19-104.pdf>.

² Staff Whitepaper: A Proposal for Electric Distribution System Planning, March 2019, <https://edocs.puc.state.or.us/efdocs/HAU/um2005hau15477.pdf>.

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Oregon. Robust stakeholder participation across 14 workshops and webinars explored distribution system planning approaches, best practices from subject matter experts across the country, and related PUC policies. Additionally, the Commission held a Special Public Meeting and public comment period on Staff's draft Guidelines. The active participation of utilities and stakeholders in this investigation, from more than 40 parties, has provided new insight on a range of topics. These include the capabilities, needs and future of Oregon's distribution systems, distributed energy resources, and the customers and communities they serve.³

Informing Staff's proposal for DSP Guidelines are Senate Bill (SB) 978 (2017) and Governor Brown's Executive Order No. 20-04.4 SB 978 tasked utilities and the PUC with exploring new expectations for the electric grid, highlighting the clear importance of clean energy, inclusivity, and customer options in addition to the core mission of the PUC. The report encourages increased transparency in distribution system planning.⁵ EO 20-04 sets new science-based greenhouse gas (GHG) emissions goals for Oregon and directs state agencies to identify and prioritize actions to meet those goals.⁶ Staff's proposed DSP Guidelines support the EO's GHG emissions goals by enabling efficient grid integration of distributed energy resources (DERs) and other clean energy technologies. The proposed DSP process seeks to supports these aims and advance various State and PUC policy goals.

Proposed DSP Guidelines

Staff's proposed DSP Guidelines are attached to this memo as Attachment 1. Major features of the Guidelines include:

Procedural Elements:

- Utilities will develop and file their initial Plans in two parts, the first part in Fall 2021 and the second part in Summer 2022.
- During Plan development, prior to filing each part, utilities must hold at least two workshops with stakeholders to ensure a range of community perspectives are heard and considered.

³ Records from the workshops are available online through the UM 2005 investigation docket <https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=21850>. Records from the webinar series are located in the Webinar Archive on the PUC Distribution System Planning Webpage, as well as in the UM 2005 docket, <https://www.oregon.gov/puc/utilities/Pages/Distribution-System-Planning.aspx>.

⁴ See Executive Order No. 20-04 (EO 20-04, March 10, 2020), at https://www.oregon.gov/gov/Documents/executive_orders/eo_20-04.pdf.

⁵ Ibid, at page 21.

⁶ See Executive Order No. 20-04 (EO 20-04, 2020), Section 2, page 5 at https://www.oregon.gov/gov/Documents/executive_orders/eo_20-04.pdf.

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Substantive Elements:

- Baseline Data and System Assessment – Utilities will provide a fundamental understanding of the current physical status of the utility distribution systems, recent investment in those systems, and the level of DERs currently integrated into those systems.
- Hosting Capacity Analysis (HCA) – Utilities will conduct system evaluations to identify generation constrained areas where it is difficult to interconnect DERs without system upgrades, and present the results through a map on their websites. Utilities will prepare an analysis of options for investing in more sophisticated HCA capabilities in the near-term. The Commission can consider the results of these analyses in adopting a path forward for HCA in Oregon.
- Community Engagement Plan – Utilities will develop a plan describing how they will engage community representatives in development of the pilot concept proposals required in Solution Identification, below.
- Long-term Distribution System Plan – Utilities will present their long-term (5-10 year) distribution system investment plans, and address broader goals related to maximizing reliability, customer benefits, and efficient operation of the distribution system.
- Forecasting of Load Growth, DER Adoption, and EV Adoption – Utilities will build on their legacy load growth forecasting processes by forecasting DER and EV growth at the substation level.
- Grid Needs Identification – Utilities will present their methodology of comparing the current capabilities of a distribution system to the forecast demands on that system to meet future needs. This will include any resulting faults or constraints.
- Solution Identification – In addition to proposing the equipment, technology or programs needed to meet identified grid needs, utilities will develop two or more pilot concept proposals in which non-wire solutions will be used in place of traditional utility infrastructure investments. Utilities will develop pilot proposals collaboratively with community stakeholders in order to address community needs.
- Near-Term Action Plan – Utilities will present proposed solutions to address grid needs, and other investments in the distribution system, in the form of a 2-4 year Action Plan.

The Guidelines provide for threshold exemptions. Requirement 4.1, Baseline Data and System Assessment, includes section f, which addresses reporting on net metering and small generator information. 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. This exemption applies to Idaho Power.

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Requirement 5.3, Solutions Identification, includes section d, which requires the utility to evaluate at least two pilot concept proposals in which non-wire solutions will be used in the place of traditional utility infrastructure investment. 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. This exception applies to Idaho Power.

Changes to Upcoming Current Planning or Reporting Requirements

Staff and stakeholders believe the proposed DSP process should guide distribution planning going forward. To achieve focused and strategic reporting on distribution planning, current related regulatory processes and reports will change. The changes below are anticipated, and specific requirements are included in the Guidelines.

- Smart Grid Report (SGR) – Staff recommends temporarily suspending the next Smart Grid Report filing cycle requirement as established in Docket No. UM 1460, Order No. 17-290 (currently PGE – June 1, 2021, Pacific Power – August 1, 2021, Idaho Power – October 1, 2021). As the DSP process becomes established, Staff anticipates requesting that Order Nos. 12-158 and 17-290, issued in Docket No. UM 1460, be revised or these orders may be superseded by new requirements adopted in this docket.

Staff recommends continuing several forward-looking aspects of the SGR and integrating these into the DSP Guidelines section of Long-term Distribution System Plan. These are specified in the Guidelines.

- Transportation Electrification (TE) Plan – Staff recommends this biennial plan continue to be separately produced, though information reported in the TE Plan may be sourced from the Distribution System Plan. Under OAR 860-087-0020(4), the Commission may direct an electric company to incorporate the Transportation Electrification Plan into other electric company planning documents. Staff recommends the Distribution System Plan be used to develop several elements currently required in the TE Plan. These are specified in the Guidelines. Once developed and provided in the Distribution System Plan, a utility can include that data in its TE Plan. As the DSP process becomes established Staff will consider recommending changes to the requirements of OAR 860-087-0020.

Stakeholder Comments on DSP Guidelines

Stakeholders shared comments on the draft Guidelines at an October 2020 workshop and through written comments. Comments from stakeholders were generally supportive of the draft Guidelines, though most parties identified specific requests for changes.

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Below Staff describes key topics of shared concern and consensus, Staff's response in the Guidelines, and outstanding elements that were not addressed at this time. These include the role of third-parties in non-wires solutions, rural pilots, inclusion of socio-economic data, and increased clarity of vision and principles. Staff developed a summary of the requested changes to the draft Guidelines that stakeholders submitted. The summary includes Staff response, is attached to this memo as Attachment 2.

More Time to Leverage IRP and Implement Community Engagement

- PGE, PacifiCorp, and Idaho Power commented on the need to synchronize the DSP and IRP processes. Utilities requested DSP follow IRP filings to allow for IRP outputs to inform DSP. Additionally utilities cited the desire to leverage the public stakeholder processes required in the IRP process for DSP development.
- PacifiCorp suggested more time for a transition between legacy planning processes and the implementation of new processes required by the Guidelines.
- PGE and the Joint Parties (NW Energy Coalition, Community Energy Project, Oregon Solar Energy Industries Association, Vote Solar, Renewable Northwest, Oregon Coast Energy Alliance Network, Oregon Citizens' Utility Board, Spark Northwest, Multnomah County Office of Sustainability, and Wallowa Resources) noted that, in order to maintain synchronization with the IRP, the next DSP filing date should be two years after the Commission order on the preceding Plan rather than two years after Plan filing. Idaho Power requested a four-year filing cadence.
- PGE requested additional time for planning and implementing community workshops in the Community Engagement Plan, and requested more time for developing non-wires solutions pilots. Idaho Power requested additional time to leverage a separate, existing stakeholder process for the DSP Community Engagement requirement.
- The Joint Parties, Community Energy Project, and Wallowa Resources noted that utilities should be required to conduct community engagement early in the planning process in order for parties to influence investment decisions.
- The Energy Trust of Oregon commented that revising the efficiency forecasting process, or including renewable resource forecasting in the DSP process, may require increased staffing resources.

Staff responded to these concerns by splitting the Guideline requirements into two parts, with Part 2 to be filed ten months after Part 1. The revised filing schedule is shown in Figure 1. This staged approach allows additional time for the synchronization of IRP and DSP processes as, per discussions with PGE and PacifiCorp, it will allow for the analysis necessary to generate IRP outputs needed to inform DSP. It allows additional time for integration of Energy Trust related processes. This approach requires the timely development of plans for community engagement in Part 1, while allowing

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additional time for the implementation of those plans in Part 2. It supports the opportunity for utilities to engage community-based organizations early in the pilot development process before decisions are made.

Staff also revised the Guidelines to state the second Plan filing will occur two years after the date of Commission action. Staff will consider Idaho Power's request for a four-year cadence when the DSP Guidelines are reviewed after the initial round of Plan filings.

Figure 1

<p>Part 1 (October 2021)</p> <ul style="list-style-type: none">● Baseline Data and System Assessment● Hosting Capacity Analysis● Community Engagement Plan● Long-Term Plan● Plan for Development of Part 2 <p>Part 2 (August 2022)</p> <ul style="list-style-type: none">● Forecasting of Load Growth, DER Adoption, and EV Adoption● Grid Needs Identification● Solution Identification● Near-Term Action Plan
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More Aggressive Outcomes in Ten Years

- The Joint Parties and Renewable Northwest expressed concern that the ten-year window for future stages of DSP (as noted in the draft Guideline figures) is far too long a timeframe. They expressed concern that progress in reducing greenhouse gas (GHG) emissions must be made sooner.
- Renewable Northwest commented on the need for climate costs/benefits in addition to monetary costs, and requested GHG emissions data.

Staff understood the concern about the ten-year window and removed references to specific years for future stages of DSP. Further, the Guidelines now have language noting future stages may be accelerated. Staff included a requirement to the Solution Identification pilot concept proposals to address any potential GHG reductions resulting from implementing a non-wires solution rather than providing electricity from the grid's incumbent generation mix.

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Community Engagement Requirements and Funding

- The Joint Parties, Community Energy Project, Wallowa Resources and PGE noted that two stakeholder meetings was inadequate and more should be held.
- The Joint Parties and Community Energy Project suggested that community-based organizations (CBOs) should be financially compensated for their time and expertise in advising utilities on distribution system planning.

Staff responded by increasing the number of stakeholder meetings from a minimum of two, to a minimum of four. The Guidelines also require utilities to conduct separate stakeholder meetings during development of pilot projects.

Staff does not directly address stakeholder compensation in the revised Guidelines. However, Staff recognizes that participation in the DSP process places an additional burden on the time and resources of involved citizens and organizations. Staff will explore opportunities to facilitate community-based organization participation, and aims to provide educational materials and public workshops. Staff supports resourcing of community-based organizations to inform decision-making.

Cost Recovery and Regulatory Development

Utilities provided numerous comments on various aspects of cost recovery. PacifiCorp requested additional guidance from the Commission on cost recovery related to staffing or investments required to comply with the new DSP processes. PGE suggested one or more stakeholder workshops on cost recovery to allow utilities to incorporate feedback into their DSPs. PacifiCorp recommended identifying targets and metrics for requirements that cannot be measured by established engineering or reliability criteria and least cost economic analysis.

Staff recognizes some additional expenses may be incurred as a result of Plan development and compliance. If the result of these activities is a significant increase in expense, cost-recovery mechanisms are available to utilities and can be addressed outside of this proceeding. Pilots specified within these Guidelines may allow utilities cost recovery mechanisms.

PUC recognizes the need for ongoing conversations about how DSP activities align or interact with the utilities' existing business models and regulatory approaches. To address the changes that utilities may make in implementing the DSP process, the PUC may explore new regulatory mechanisms that may better align with utilities' efforts to plan and invest in DSP over the long-term. Staff believes that these discussions may be premature at this stage. After utilities submit initial Plans, Staff will engage with utilities and stakeholders to explore how new regulatory mechanisms may support DSP in the future.

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Data that is Useful and Publicly Accessible

An issue of importance to Joint Parties, Renewable Northwest and other attendees at public workshops was accessible data. Parties want data outputs from the DSP to be useful and actionable, publicly accessible, and written in formats that are understandable by non-technical audiences.

Staff recognizes this need and responded in several ways in the Guidelines. Staff clarified the intended end use of data requirements. Staff specified in the Baseline requirement that Net Metering and Small Generator information be provided at the feeder level, as well as in an electronic map. Other responses by Staff include future provision of public workshops and development of educational materials written for non-technical audiences to assist in community education.

Clarification or Further Specification

Stakeholders commented on the need to address topics including cybersecurity, community outreach, regulatory development, and data transparency. To explore these topics during development of Plans, Staff will keep UM 2005 open and active. Docket activities may include workshops and a technical working group. The technical working group may assist utilities in vetting new materials needing stakeholder feedback, such as new data presentations.

PGE, PacifiCorp, Idaho Power, and Joint Parties requested clarification on the distinction between acceptance and acknowledgement of a Plan. PacifiCorp and Idaho Power recommended clarifying the meaning of locational aspect, while Renewable Northwest recommended Staff establish locational granularity guidance for second DSP filings. The Joint Parties, PGE, and Idaho Power noted the need for greater clarity in the hosting capacity analysis requirement.

Staff responded by providing further information to improve clarity on the requested points above. Staff also simplified the requirement for hosting capacity analysis through use of an options analysis.

Other Outstanding Elements

Renewable Northwest and Joint Parties commented on the role of third-parties in developing non-wires solutions. Third-party participation in non-wires solutions is based on an analytical foundation (such as time-specific, locational system benefits) that Oregon utilities are just beginning to assemble.

Wallowa Resources expressed the importance of addressing the needs of rural ratepayers, and requested that Guidelines require each utility to implement one non-wires pilot in a rural community. Staff supports utilities in making such project decisions.

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The Joint Parties and Renewable Northwest commented on the importance of integrating demographic and socio-economic data to inform equitable investment decisions. This is a Stage 2 requirement that will build on the system baseline data in the initial Plans. Staff anticipates discussing how to most effectively integrate this data when Guidelines are revised.

PacifiCorp suggested clarifying the vision for DSP and regulatory principles. Renewable Northwest suggested better distinguishing goals and utilizing a grid architecture model. Staff appreciates these comments and will consider revisions to the Guidelines following the initial round of Plan filings.

Plan Submission and Commission Action

The utilities will develop and file their initial Plans in two parts. The first part will be submitted in the Fall of 2021. The second part will be submitted in the Summer of 2022. Each utility is encouraged but not required to submit updates to Part 1 when filing Part 2, should there be any meaningful changes.

The Plans will be presented at a Public Meeting between three to five months following each filing, after a period of stakeholder and Staff review. The Commission may accept the Plans and may provide additional guidance for future Plan filings. As used in the Guidelines, “acceptance” means the Commission finds that the Plan meets the criteria and requirements of these Guidelines and does not constitute a determination on the prudence of any individual actions discussed in the Plan. Non-acceptance means that the Plan does not meet the criteria or requirements of the Guidelines.

Following the issuance of the final Commission orders, Staff will review the DSP Guidelines. Staff will also launch a stakeholder process identifying improvements to the Guidelines for future Plan filings.

Staff anticipates that the subsequent “rounds” of DSP will follow a two-year cycle. The second round should commence after Commission acceptance of both parts of the initial Plan. The second Plan will likely be submitted in an integrated fashion, rather than in two parts.

Vision for Distribution Planning Evolution

The initial Plan filings will be the first stage in an evolving multi-stage process. Staff anticipates that the forming, filing, and acceptance of the initial Plans will educate all parties and identify areas for continuous improvement. Table 1 illustrates Staff’s expected evolution from the initial Guidelines to more advanced stages.

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To ensure progress toward long-term goals and reflect guiding principles, each element of the Guidelines includes “Initial Requirements” and a description of “Expected Evolution.” Staff proposes the “Initial Requirements” for the first utility Plans, while “Expected Evolution” includes potential benchmarks for future stages. This structure provides utilities a firm foundation of guidance for the first Plans, while introducing a flexible vision for the future that may be adapted based on new information. Achievement of Stages 2 and 3 may be accelerated depending on circumstances and readiness of utilities and participants.

Table 1

Stage 3		Achieving the long-term vision for distribution system planning capabilities and outcomes
Stage 2		Advancing requirements incrementally to better match growing utility capabilities and evolving grid, customer and community needs
Stage 1	Beginning with Initial Requirements of Utility DSP Filings, providing a foundation for future stages	
	2021-2022	2023 and beyond

Conclusion

The proposed DSP Guidelines are the result of an extensive investigation, in which a number of stakeholders were engaged and provided valuable information and input. The resulting draft Guidelines will enable the Commission to better understand the current state of distribution systems and any needed improvements. Second, the Commission will gain insight into utility planning processes used to propose investments to address improvements. Finally, the Commission will be able to evaluate whether utilities’ investments maximize operational efficiency and customer value. Staff recommends the Commission approve the DSP Guidelines as set forth in Attachment 1. Staff also recommends the Commission take action to allow for integration of some elements of “smart grid” reporting and transportation electrification planning in the DSP process.

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PROPOSED COMMISSION MOTION:

Approve the Distribution System Planning Guidelines, Attachment 1, for use by the investor-owned electric utilities. Suspend the next Smart Grid Report filing cycle. Require elements of the Transportation Electrification Plan to be developed in the Distribution System Plan.

UM 2005

Distribution System Planning Guideline

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**OPUC UM 2005 Distribution System Planning (DSP) 20-485
DSP Plan Guidelines****December 2020**

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 utility¹ must file the first portion of its Plan (Part 1) on October 15, 2021 or an alternative date designated by Commission order.
- 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.
- d) Each utility must file a subsequent Plan 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.
- f) Each utility will present the results of each filing to the Commission at a separate public meeting.
- 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.
- 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.
- 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.

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.

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.

3. Scope

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

Part 1 (October 2021)

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

Part 2 (August 2022)

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

4. Part 1

4.1. Baseline 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, recent investment in those systems, and the level of distributed energy resources (DERs) currently integrated into those systems.² Figure 1 introduces the initial requirements and expected evolution for baseline data and system assessments.

² For the purposes of these guidelines “distributed energy resource” includes distributed generation resources (either net metering or Qualifying Facilities), 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.

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.		
	<table border="1"> <tr> <td>2021-2022</td> <td>2023 and beyond</td> </tr> </table>	2021-2022	2023 and beyond
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, system asset health baseline, etc.) that includes:
 - i) Method and tools used to develop the baseline and assessment
 - ii) Forecasting time horizon(s)
 - iii) Key performance metrics
- b) A summary 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 life expectancy of assets in each class
- c) A discussion of distribution system monitoring and control capabilities including:
 - i) Number of feeders
 - ii) Number of substations
 - iii) Monitoring and control technologies (such as SCADA, AMI, etc.) currently installed, and the percentage of substations, feeders, and other applicable equipment with each technology
 - iv) A description of the monitoring and control capabilities (for example, percentage of system with each technology, resulting capacity, such as remote fault detection or power quality monitoring, and what time interval measurements are available)

-
- d) A discussion of any advanced control and communication systems (for example: distribution management systems, distributed energy resources management systems, demand response management systems, outage management systems, field area networks, etc.). Include a description of system visibility and capabilities, the percentage of system reached with each capability, the percentage of customers reached with each capability, and any utility programs utilizing each capability.
- e) Historical distribution system spending for the past five years, in each category:
- i) Age-related replacements and asset renewal
 - ii) System expansion or upgrades for capacity
 - iii) System expansion or upgrades for reliability and power quality
 - iv) New customer projects
 - v) Grid modernization projects
 - vi) Metering
 - vii) Preventative maintenance
- f) Net Metering and Small Generator information:³
- 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
 - 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:⁴

³ 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).

⁴ 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) 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.
- n) 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.

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.⁵ Additionally, at the February 26, 2020 workshop, utilities provided an overview of their existing DSP processes, including monitoring and automation practices.^{6, 7, 8} Presentations highlighted that each utility has different capabilities and system needs, which guide their planning and related outcomes.

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

4.2. Hosting Capacity Analysis

Hosting Capacity Analysis (HCA) provides information about the ability of a distribution system to support new DER integration without system faults. To date, analyses of a system's hosting capacity has become an important piece of DSP in Minnesota, New York, Hawaii, Nevada and California.⁹ 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.

⁵ Staff Whitepaper: A Proposal for Electric Distribution System Planning, March 2019, <https://edocs.puc.state.or.us/efdocs/HAU/um2005hau15477.pdf>.

⁶ *Distribution System Highlights*, Portland General Electric, February 26, 2020, <https://edocs.puc.state.or.us/efdocs/HAH/um2005hah16124.pdf>.

⁷ *Idaho Power: Current Distribution System and Small Scale Generation*, Idaho Power, February 26, 2020, <https://edocs.puc.state.or.us/efdocs/HAH/um2005hah14343.pdf>.

⁸ *Current Distribution System: Questionnaire Section C*, Pacific Power, February 26, 2020, <https://edocs.puc.state.or.us/efdocs/HAH/um2005hah9537.pdf>.

⁹ *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>.

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 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.¹⁰

¹⁰ 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.

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- 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.¹¹
- (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.¹²
- (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
 - 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.¹³ 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.¹⁴ 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

¹¹ 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>.

¹² <https://www.portlandgeneral.com/business/power-choices-pricing/renewable-power/install-solar-wind-more/net-metering/net-metering-map>

¹³ Xcel Minnesota performs HCA implementation that illustrates some of these parameters.

¹⁴ California utilities perform HCA implementation that illustrate some of these parameters.

- 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.¹⁵ Over time, hosting capacity analysis may reduce the need for interconnection studies.^{16, 17}

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

4.3. 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 guidelines for community engagement are intended to foster a developing process 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.

In the *Connectivity Means Community* presentation, presenters noted five approaches to engagement: inform, consult, involve, collaborate, and defer to.^{18, 19} 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:

¹⁵ *Hosting Capacity - Lessons Learned*, Steve Steffel, Pepco Holdings, May 6, 2020, <https://www.oregon.gov/puc/utilities/Documents/DSP-Hosting-Capacity-SSteffel.pdf>.

¹⁶ *OPUC Hosting Capacity Overview*, Aram Shumavon, Kevala Analytics, May 6, 2020, <https://www.oregon.gov/puc/utilities/Documents/DSP-Shumavon-Presentation.pdf>.

¹⁷ 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>.

¹⁸ *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>.

¹⁹ *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>.

- Be easy;
- Be trusted;
- Be adaptable;
- Be flexible;
- Be positive;
- Be equitable; and
- Be a great ally.²⁰

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

Figure 3

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

²⁰ *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>.

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, unless noted as OPUC activities, are:

- a) During Plan Development
 - i) A utility should host at least two stakeholder workshops prior to filing each Part of the utility's Plan, for a minimum total of four workshops. These workshops should be held at a stage in which stakeholder engagement can influence the filed Plan. The workshops may include presentation of the Plan outline, data and assumptions under consideration or challenges encountered, and the utility's approach to the Community Engagement Plan, described in (b). During stakeholder workshops, a utility must invite community members to share their relevant needs, challenges and opportunities.
 - ii) A utility should develop a Community Engagement Plan. The Community Engagement Plan should describe actions the utility will implement in order to engage community members and CBOs 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) Proactively engage stakeholders regarding proposed pilots in impacted communities. Engagement of the local community may include in-person meetings located in the community; presentation of the project scope, timeline, rationale; 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) Collaboratively develop and share datasets and metrics to guide community-centered planning.
 - (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) Utilities should aim to create a collaborative environment among all interested CBO partners and stakeholders. To support collaboration between all interested parties, Staff plans to host public workshops and a technical working forum. These are in addition to the utility workshops required during Plan and pilot development.
 - iv) With consultation from utilities and stakeholders, OPUC will prepare accessible, non-technical educational materials on DSP to support public engagement.

Expected Evolution

The investigation identified numerous opportunities for community engagement in Oregon. In addition to the content presented in the workshop series, stakeholder comments in the investigation frequently spoke to community engagement needs. In comments filed in preparation for the August 25, 2020 Special Public meeting, the Oregon Citizens' Utility Board (CUB), Energy Trust of Oregon, Northwest Energy Coalition (NVEC), and Oregon Solar Energy Industries Association (OSEIA) each commented on the need for solutions to be co-developed

with CBOs and stakeholders. Some spoke of the need to acknowledge, value, and compensate CBOs as technical experts in the planning process.^{21, 22, 23, 24}

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.

4.4. Overarching Requirement - Long-term Distribution System Plan

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

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

²¹ 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>.

²² 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>.

²³ 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>

²⁴ 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>.

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- 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 investment²⁵ opportunities
 - i) List and describe smart-grid opportunities that the utility is considering for investment over the next 5-10 years and any constraints that affect the utility's investment considerations
 - ii) Describe evaluations and assessments of any smart-grid technologies, applications, pilots, or programs that the company is monitoring or plans to undertake
 - d) Key opportunities and possible benefits for distribution system investment
 - e) Research and development the utility is undertaking or monitoring
 - f) Future policy and planning intersections:
 - i) Discussion of how planned investments fit with the utility's IRP
 - ii) Discussion of how planned investments fit with the utility's annual construction budget for major distribution and transmission investments
 - iii) Discussion of how distribution system planning may be coordinated in the future with other major policy and planning efforts discussed in these Guidelines. At a minimum, address the IRP and transmission planning, including: how the Distribution System Plan 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

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

²⁵ 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.

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 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 improve the accuracy and granularity of existing and anticipated constraints on the distribution system revealed in Grid Needs Identification. Figure 4 introduces the initial requirements and expected evolution for the forecasting of load growth, DER adoption and EV adoption.

Figure 4

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

Initial Requirements

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

- a) Discussion of current utility processes for distribution system load growth forecasting including:
 - i) Forecasting method and tools used to develop the forecast
 - ii) Forecasting time horizon(s)
 - iii) Data sources used to inform the forecast
 - iv) Locational granularity of the load forecast
- b) Forecast of DER adoption and EV adoption by substation
 - i) The forecast should include high/medium/low scenarios for both DER adoption and EV adoption

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- 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).
 - iii) For the initial Plan, the methodology for geographical allocation (to the substation) is at the utility's discretion. The Commission may provide direction for subsequent Plans.
 - iv) A utility may consider leveraging information such as: historical utility program trends, historical customer adoption trends, data from Energy Trust of Oregon, data from Transportation Electrification Plans and pilots, or studies on DER technical and economic potential used in other dockets. Utilities should use the most recent data available.
- c) Results of forecasting load growth, DER adoption, and EV adoption
- i) Document existing and anticipated constraints on the distribution system

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.

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 DER adoption by customers, as well as the social and economic needs of the communities that depend on distribution systems and the contributions they can make to strengthen it.

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	<p>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.</p> <p>Provide new datasets and analysis responsive to OPUC, community inputs and policy evolution.</p>		
Stage 2	<p>Develop robust “future state” data needs, including inputs in the following categories:</p> <p>Perform equity analysis overlaying customer geographic and socio-economic data relative to system reliability and customer options. Make findings publicly available.</p> <p>Needs identification includes results of community needs assessments, DER forecasting, and equity analysis.</p> <p>Identify grid modernization needs and present a summary of prioritized grid constraints and opportunities publicly.</p>		
Stage 1	<p>Present summary of prioritized grid constraints publicly, including criteria used for prioritization.</p> <p>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.</p>		
	<table border="1" style="width: 100%; border-collapse: collapse;"> <tr> <td style="width: 25%; text-align: center;">2021-2022</td> <td style="text-align: center;">2023 and beyond</td> </tr> </table>	2021-2022	2023 and beyond
2021-2022	2023 and beyond		

Initial Requirements

A utility, in its Distribution System Plan, should:

- a) Document the process used to assess grid adequacy and identify needs.
- b) Discuss criteria used to assess reliability and risk, and methods and modeling tools used to identify needs.
- c) Present a summary of prioritized grid 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.

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).

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.

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>.

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.
- 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 two²⁸ 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 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.²⁹ 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).³⁰

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.

5.4. Overarching Requirement - Near-term Action Plan

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

²⁸ 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.

²⁹ *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>.

³⁰ 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>.

**OPUC UM 2005 Distribution System Planning (DSP) 20-485
DSP Plan Guidelines****December 2020**

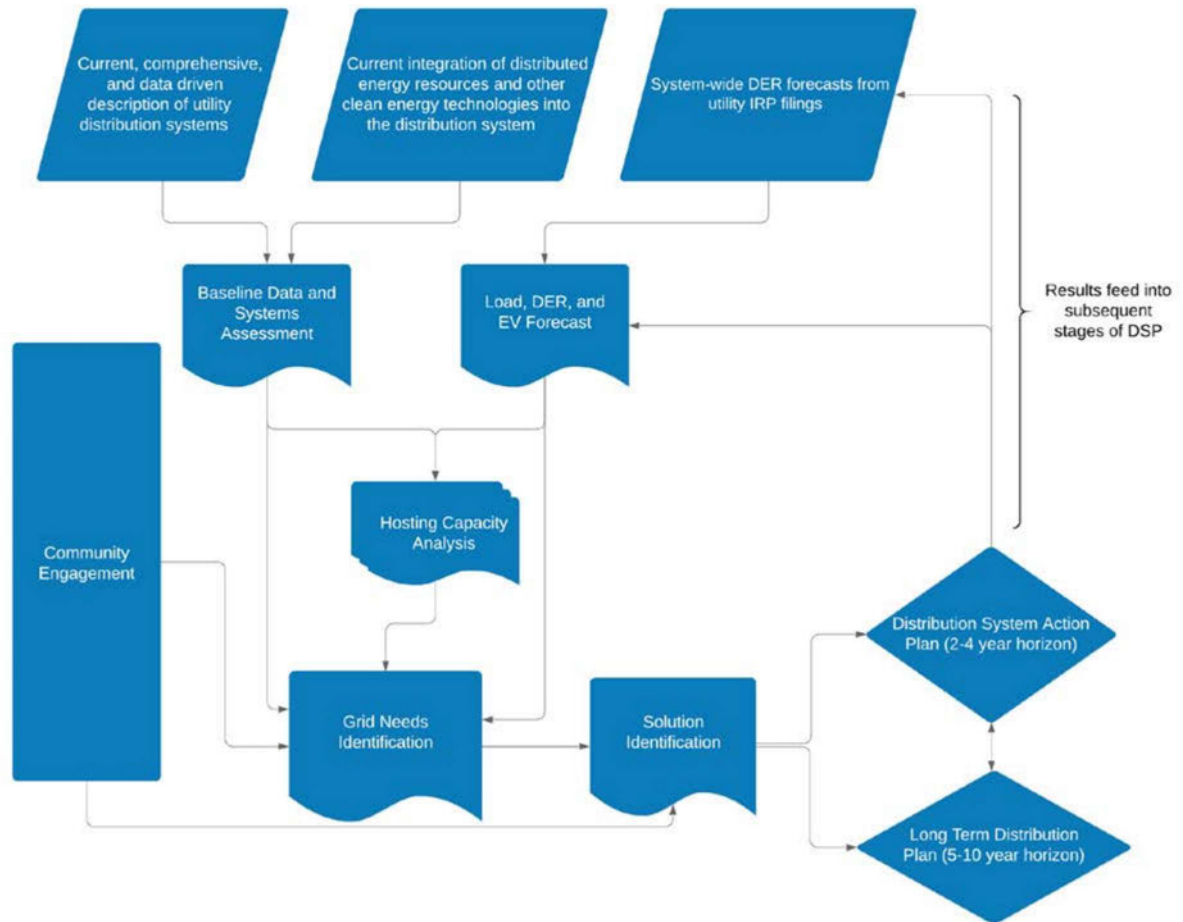
- a) Action Plan: Provide a 2-4 year plan consisting of the utility's proposed solutions to address grid needs and other investments in the distribution system
- b) Projected spending: Disclose projected system spending to implement the action plan, timeline for improvement, and anticipated requests for a cost recovery mechanism
- 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

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.

			Section	PGE	PAC	Idaho Power	Energy Trust	Joint Parties	Renewable NW	Community Energy Project	Wallowa Resources	Anterix	Temix, Inc.		
			Overarching or General Comments	X	X			X	X		X				
			Timing and Commission Action	X	X	X		X	X						
			Process Alignment	X	X	X		X							
			Baseline Data and System Assessment	X	X	X	X	X	X		X				
			Load, DER and EV Forecasting	X	X	X	X		X		X				
			Hosting Capacity Analysis	X		X	X	X							
			Community Engagement Plan	X	X	X		X		X	X				
			Grid Needs Identification	X	X		X	X	X			X			
			Solution Identification	X	X	X	X	X		X	X	X	X		
			Near-term and Long-term Action Plans	X			X		X						
			Evolution of DSP	X	X	X		X	X				X		
ID	Topic	Comment Summary												Response	Recommendation
1	Commission Action	Not require "acceptance" or "acknowledgment" of the initial DSP; rather begin Commission action with the second DSP Plan		X										Modify draft Guidelines	Clarify intent of acceptance for first plan
2	Timing	Submit biennially based on date of Commission action on Plan, not on date submitted		X										Modify draft Guidelines	Change to two years based on Commission action on Plan
3	Timing	Align the timing of a DSP with IRP filings / should be driven by current IRP schedule		X	X	X								Modify draft Guidelines	Stagger the filing into Part One and Part Two. This allows utilities to perform detailed forecasting and granular planning after IRPs.
4	Baseline - clarity	Specify a date range for all datasets (e.g., items k, m, and o of Staff's recommendations) to ensure consistency between datasets.		X										Modify draft Guidelines	Baseline data guidelines now consistently reference past five years when inquiring about historical data.
5	Baseline - spending	Limit reporting on spending to defined DSP investments for item j., remove preventative maintenance and vegetation management		X										Modify draft Guidelines	Remove vegetation management category; maintain preventative maintenance category
6	Baseline - clarity	Clarify item f., a summary of the measurements on the distribution system OR the actual measurements themselves		X										Modify draft Guidelines	Clarify Guideline as requested within Baseline section
7	Baseline	Remove requirement item n. (map), instead provide information at an aggregated level, such as feeder-level or circuit-level.		X										No action	Maintaining requirement as drafted to bolster transparent understanding of system, and to balance stakeholder interests
8	Cyber security, data security	Undertake a process to work with utilities and experts on cybersecurity considerations for DERs; should inform long-term evolution of DSP in regard to data transparency and security		X										Implementation guidance	Staff will consider stakeholder workshops in Q1-Q2 2021, to include cybersecurity as topic
9	Forecasting - DER	Clarify if utilities not only have discretion around the granularity of locational aspect of DER adoption but also on the vintage of data		X										Modify draft Guidelines	Replace "locational aspect" references with "substation" references. Regarding vintage of data, revise Guideline to encourage utilities to use the highest quality data available

			Section	PGE	PAC	Idaho Power	Energy Trust	Joint Parties	Renewable NW	Community Energy Project	Wallowa Resources	Anterix	Temix, Inc.		
			Overarching or General Comments	X	X			X	X		X				
			Timing and Commission Action	X	X	X		X	X						
			Process Alignment	X	X	X		X							
			Baseline Data and System Assessment	X	X	X	X	X	X		X				
			Load, DER and EV Forecasting	X	X	X	X		X		X				
			Hosting Capacity Analysis	X		X	X	X							
			Community Engagement Plan	X	X	X		X		X	X				
			Grid Needs Identification	X	X		X	X	X			X			
			Solution Identification	X	X	X	X	X		X	X	X	X		
			Near-term and Long-term Action Plans	X			X		X						
			Evolution of DSP	X	X	X		X	X				X		
ID	Topic	Comment Summary												Response	Recommendation
10	Forecasting - DER	Clarify whether Staff's definition of DERs includes Qualifying Facilities (QF)		X										Modify draft Guidelines	Confirm that Staff definition of DERs includes Qualifying Facilities
11	Hosting capacity analysis	Consolidate proposed HCA roadmaps into a singular roadmap		X										Modify draft Guidelines	Revise requirement to replace the "dual roadmap" approach with "option analysis" of three streamlined and more clearly articulated options
12	Hosting capacity analysis	Remove the requirement d. types of analyses and parameters for HCA		X										Modify draft Guidelines	Revise requirement to replace the "dual roadmap" approach with "option analysis" of three streamlined and more clearly articulated options
13	Community engagement plan - timing	Request additional time to scope and implement community workshops; suggest more than 2 workshops		X										Modify draft Guidelines	1) Divide Plan filing into 2 parts, allowing more time to scope and implement community workshops; 2) Double number of workshops, for minimum of 4 total (2 per part)
14	Community engagement plan	Request additional time to develop 2 pilot non-wires pilot proposals with community; intend spectrum of engagement based on project status (existing vs new)		X										Modify draft Guidelines	Divide Plan filing into 2 parts, allowing more time to develop 2 pilot proposals for non-wires solutions with community.
15	Cost recovery	Clarify expectations for stakeholder participation, specifically, what types of engagement would allow stakeholders (such as CBOs) to recover costs associated with participation		X										Implementation guidance	Staff will consider offering workshops in 2021. These may address community engagement metrics and expectations
16	Grid needs identification	Clarification on pilots, specifically, types of projects, costs, scope, and timing.		X										Modify draft Guidelines	Remove pilot from Grid Needs Identification section. Clarify expectations for pilots within Solution Identification section
17	Grid needs identification	Clarification on level of engagement sufficient to develop shared understanding of community needs in relation to Grid Needs Identification. Recommend starting with NWA screening criteria that would narrow the list of distribution projects		X										Modify draft Guidelines	Remove pilot from Grid Needs Identification section. Clarify expectations for pilots within Solution Identification section

			Section	PGE	PAC	Idaho Power	Energy Trust	Joint Parties	Renewable NW	Community Energy Project	Wallowa Resources	Anterix	Temix, Inc.		
			Overarching or General Comments	X	X			X	X		X				
			Timing and Commission Action	X	X	X		X	X						
			Process Alignment	X	X	X		X							
			Baseline Data and System Assessment	X	X	X	X	X	X		X				
			Load, DER and EV Forecasting	X	X	X	X		X		X				
			Hosting Capacity Analysis	X		X	X	X							
			Community Engagement Plan	X	X	X		X		X	X				
			Grid Needs Identification	X	X		X	X	X			X			
			Solution Identification	X	X	X	X	X		X	X	X	X	X	
			Near-term and Long-term Action Plans	X			X		X						
			Evolution of DSP	X	X	X		X	X					X	
ID	Topic	Comment Summary												Response	Recommendation
18	Grid needs identification	Allow initial DSP to report on the status of community engagement and assessment, and not have an expectation that work necessarily be completed		X										Modify draft Guidelines	Clarify expectations for Community Engagement across planning and implementation phases, and existing and new projects
19	Solution identification	Provide clarification regarding allowance for non-cost-effective pilots		X										Modify draft Guidelines	Clarify expectation that pilots do not have to be cost-effective
20	Solution identification	Consider and clarify how DERS are evaluated within Solution Identification; evaluate DERS providing grid flexibility for capabilities differently?		X										Future Guideline consideration	Staff will review this issue after first Plan filings with consideration of related dockets (for example energy efficiency avoided costs) and benefit-cost quantification
21	Solution identification	Tailor community engagement. e.g. regulatory and safety related DSP activities are less productive areas of engagement than load growth, DER adoption and non-wires alternatives which are immediate concern for collaboration.		X										Already captured/No action required	Staff agrees and support utilities to select most appropriate activity and project types for community engagement
22	Long-term plan	Consider how a potential long-term plan may inform the IRP and vice versa.		X										Already captured/No action required	Guidelines confirm need to coordinate related planning efforts
23	Least-cost/risk planning	Consider how "acknowledgment" of a DSP may influence portfolio selections in IRP; if a DSP considers different cost/benefits than an IRP, how will that inform the development of an IRP preferred portfolio that aims to achieve the least-cost, least risk portfolio.		X										Future Guideline consideration	Staff will review issue after first Plan filings for "acceptance." This issue will need examination if Commission considers "acknowledgement" of future plans.
24	Cost recovery - evolution	Suggests formal process, at minimum one stakeholder workshop on cost recovery to allow utilities to incorporate feedback into their DSPs.		X										Implementation guidance	Staff will consider offering workshops in 2021 that may address regulatory reform. A variety of cost recovery mechanisms exist outside the UM 2005 docket.
25	Evolution - Cyber security, data security	Customer data remain confidential between the customer and the utility, as governed by existing law and privacy policies		X										Already captured/No action required	Guidelines confirm need to legally protect customer privacy

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			Overarching or General Comments	X	X			X	X		X				
			Timing and Commission Action	X	X	X		X	X						
			Process Alignment	X	X	X		X							
			Baseline Data and System Assessment	X	X	X	X	X	X		X				
			Load, DER and EV Forecasting	X	X	X	X		X		X				
			Hosting Capacity Analysis	X		X	X	X							
			Community Engagement Plan	X	X	X		X		X	X				
			Grid Needs Identification	X	X		X	X	X			X			
			Solution Identification	X	X	X	X	X		X	X	X	X		
			Near-term and Long-term Action Plans	X			X		X						
			Evolution of DSP	X	X	X		X	X				X		
ID	Topic	Comment Summary												Response	Recommendation
26	Evolution - regulatory development	Staff begin developing a series of topic-focused workshops needed to address specific topics of transformational regulatory development		X										Implementation guidance	Staff will consider offering workshops in 2021 that may address regulatory reform. Staff believes this topic will be more applicable after learnings from the first Plan filings.
27	Goals / Principles	Additional goal of maintaining affordability			X									Modify draft Guidelines	Affordability added to summary-level Goal
28	Cost recovery	Requests additional clarification on “aim to provide utilities with guidance on reasonable levels of spending for upfront costs to identify and plan for risks.”			X									Modify draft Guidelines	Remove language due to lack of clarity. Clarify further within Cost Recovery section.
29	Cost recovery	Requests clarification on the meaning of “uncertainty” in the context of the second bullet regarding cost recovery; also, which process, also associated pilots			X									Modify draft Guidelines	Remove language due to lack of clarity. Clarify further within Cost Recovery section.
30	Evolution - vision	The Commission should articulate a plan that will identify long-term policy issues, confirm how the Commission will balance competing goals, and explain how the new objective function for DSP addresses short comings in the current objective function.			X									Future Guideline consideration	Staff appreciates suggestion and will review for implementation in subsequent Guidelines and development of DSP vision
31	Timing	Reduce the five-month review period to three.			X									Modify draft Guidelines	Adjust range to between three and five months
32	Commission action	Requests clarification regarding the distinction between acceptance and acknowledgement; define and explain DSP acceptance more clearly		X	X	X		X						Modify draft Guidelines	Clarify intent of acceptance for first plan
33	Cost recovery	Recommends identifying targets and metrics for requirements that cannot be measured by established engineering/reliability criteria and least cost economic analysis.			X									Implementation guidance	Staff will consider offering workshops in 2021. These may address community engagement metrics and expectations

			Section	PGE	PAC	Idaho Power	Energy Trust	Joint Parties	Renewable NW	Community Energy Project	Wallowa Resources	Anterix	Temix, Inc.		
			Overarching or General Comments	X	X			X	X		X				
			Timing and Commission Action	X	X	X		X	X						
			Process Alignment	X	X	X		X							
			Baseline Data and System Assessment	X	X	X	X	X	X		X				
			Load, DER and EV Forecasting	X	X	X	X		X		X				
			Hosting Capacity Analysis	X		X	X	X							
			Community Engagement Plan	X	X	X		X		X	X				
			Grid Needs Identification	X	X		X	X	X			X			
			Solution Identification	X	X	X	X	X		X	X	X	X		
			Near-term and Long-term Action Plans	X			X		X						
			Evolution of DSP	X	X	X		X	X				X		
ID	Topic	Comment Summary												Response	Recommendation
34	Scope	Suggest transition period allowing current processes to run in parallel concurrent to implementing activities to comply with DSP Guidelines.			X									Modify draft Guidelines	Recognize need for transition period and adjust timing to support utility planning transition.
35	Timing - data	Requests clarification regarding the timing of combined reporting... should regulatory reporting be based on the data used in the development of the DSP, or updated information prior to the filing?			X									Modify draft Guidelines	Revise Guideline to encourage utilities to use the highest quality data available. Revise Guideline to acknowledge legacy planning processes and need to transition
36	Baseline - locational granularity	Clarification regarding the "locational granularity" required, keeping in mind data privacy issues, substation, feeder, or region level			X									Modify draft Guidelines	Revise baseline requirement to specify feeder-level locational granularity
37	Baseline - data	Guidelines should provide a description of why any specific information is necessary and how it will be used.			X									Already captured/No action required	Baseline requirement states rationale and goal driving this requirement.
38	Baseline - data	Recommends a goal-based approach that starts with clearly articulated goals, and then breaks out the data needed to measure/assess the characteristics of each goal.			X									Future Guideline consideration	Staff appreciates suggestion and will review for inclusion in subsequent Guidelines
39	Baseline - data	Recommends Staff and the utilities create a small technical workgroup to define the format for data collection and presentation that standardizes the data fields for consistency in review and assembly of the plan			X									Implementation guidance	Staff will consider convening technical working group in 2021
40	Forecasting - locational granularity	Recommends that the Commission clarify what is meant by locational aspect in (b)(iii). / Requests clarity about "locational granularity of the load forecast" and definition of forecasting DER and EV adoption "with a locational aspect"			X	X								Modify draft Guidelines	Replace "locational aspect" references with "substation" references.
41	Cost recovery	Guidelines that require utility to change operations or increase staffing or investment in order to comply, should be clearly identified to allow for cost recovery.			X									Future Guideline consideration	Staff recognizes some additional costs may be incurred to comply.

		Section	PGE	PAC	Idaho Power	Energy Trust	Joint Parties	Renewable NW	Community Energy Project	Wallowa Resources	Anterix	Temix, Inc.		
		Overarching or General Comments	X	X			X	X		X				
		Timing and Commission Action	X	X	X		X	X						
		Process Alignment	X	X	X		X							
		Baseline Data and System Assessment	X	X	X	X	X	X		X				
		Load, DER and EV Forecasting	X	X	X	X		X		X				
		Hosting Capacity Analysis	X		X	X	X							
		Community Engagement Plan	X	X	X		X		X	X				
		Grid Needs Identification	X	X		X	X	X			X			
		Solution Identification	X	X	X	X	X		X	X	X	X		
		Near-term and Long-term Action Plans	X			X		X						
		Evolution of DSP	X	X	X		X	X				X		
ID	Topic	Comment Summary											Response	Recommendation
42	Community engagement plan	Requests that the Commission commit to act as a technical liaison to provide resources for community members.		X									Implementation guidance	Staff will serve as technical liaison on DSP plan development
43	Community engagement plan	Requests clarification regarding the metric of utility responsiveness to Community Energy plan interests; recommends that components (reliability, community benefits, costs, and rate impacts) be discussed together, with defined expectations and metrics for review, so that it is clear how those expectations outweigh traditional least cost and least risk decision-making.		X									Implementation guidance	Staff will consider offering workshops in 2021. These may address community engagement metrics and expectations
44	Community engagement plan	The directive that utilities conduct focused community engagement goes beyond DSP process, and appears to create a new regulatory requirement that has no defined applicability or threshold criteria for what projects would qualify.		X									Implementation guidance	Staff will consider offering workshops in 2021. These may address community engagement metrics and expectations
45	Community engagement plan	Reevaluate offering of quarterly OPUC-hosted public workshop and technical forum, after DSP filings		X									Modify draft Guidelines	Revise timing of workshop offerings to occur during Plan development period
46	Grid needs identification	Section 3.2 (e) appears to combine creating a competitive resource procurement process with community energy planning activities; recommends adding a step or process to set equity goals which the utility can design to meet in the least cost and risk manner, to optimize the technical planning and economics.		X									Modify draft Guidelines	Remove pilot from Grid Needs Identification section. Clarify expectations for pilots within Solution Identification. Staff supports utility process to set equity goals to meet in the least cost and risk manner,
47	Solution identification - data	Clarification regarding what needs to be included in the "detailed datasets" to be made publicly available, along with the purpose for their usage.		X									Modify draft Guidelines	Remove requirement 3.6.d for detailed datasets

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			Overarching or General Comments	X	X			X	X		X				
			Timing and Commission Action	X	X	X		X	X						
			Process Alignment	X	X	X		X							
			Baseline Data and System Assessment	X	X	X	X	X	X		X				
			Load, DER and EV Forecasting	X	X	X	X		X		X				
			Hosting Capacity Analysis	X		X	X	X							
			Community Engagement Plan	X	X	X		X		X	X				
			Grid Needs Identification	X	X		X	X	X			X			
			Solution Identification	X	X	X	X	X		X	X	X	X		
			Near-term and Long-term Action Plans	X			X		X						
			Evolution of DSP	X	X	X		X	X				X		
ID	Topic	Comment Summary												Response	Recommendation
48	Solution identification - pilots	Clarify requirement (e) at least two proposals for pilots in which non-wire solutions as this goes beyond the Commission's authority and it is entirely unclear what is to be tested under the pilot programs.			X									No action	Redefine pilots as "concept evaluations" within Solution Identification section. Add clarification about expectations for cost-effectiveness
49	Timing - final guidelines	Believe Staff should postpone its submission of revised guidelines to allow for further discussion and clarity around the many details and requirements				X								No action	Staff will consider offering technical workgroup and workshops in 2021 to support Plan development
50	Timing - first plan	October 2022 is a reasonable timeframe for submitting its first plan				X								Modify draft Guidelines	Stagger filing dates into 2 parts to provide more time to complete filing
51	Timing - cadence	Requests that its plan be updated on a four-year filing cycle so that stakeholder information and system data are meaningful				X								Future Guideline consideration	Staff appreciates suggestion and will work with company after first Plan filing to assess future frequency of filing.
52	Process alignment - IRP	Requests that guidelines allow flexibility to incorporate DSP efforts into long-term resource planning				X								Modify draft Guidelines	Modify to allow more time to synchronize through staggered filing
53	Process alignment - exemption	Clarify exemption from Annual Net Metering Report				X								Modify draft Guidelines	Add footnote to Guideline noting Idaho Power exemption from the Annual Net Metering Report and exemption from requirement
54	Cost recovery	Requests additional guidance from the Commission on cost recovery related to all aspects of DSP				X								Implementation guidance	Staff will consider workshops in 2021 with potential to discuss regulatory reform. Staff believes more detailed discussion should follow after first Plan filing
55	Scope	Unclear if elements of DSP are expected to be gathered for only the Company's Oregon service area.				X								Modify draft Guidelines	Confirm scope is Oregon service area
56	Scope - forecasting	IPC does not expect to see enough adoption to justify forecasting of these technologies with any "granularity," should be forecasted system-wide				X								Future Guideline consideration	Maintain granularity as stated and consider in future Guideline revision, based on results of first Plan filing

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			Overarching or General Comments	X	X			X	X		X				
			Timing and Commission Action	X	X	X		X	X						
			Process Alignment	X	X	X		X							
			Baseline Data and System Assessment	X	X	X	X	X	X		X				
			Load, DER and EV Forecasting	X	X	X	X		X		X				
			Hosting Capacity Analysis	X		X	X	X							
			Community Engagement Plan	X	X	X		X		X	X				
			Grid Needs Identification	X	X		X	X	X			X			
			Solution Identification	X	X	X	X	X		X	X	X	X		
			Near-term and Long-term Action Plans	X			X		X						
			Evolution of DSP	X	X	X		X	X				X		
ID	Topic	Comment Summary												Response	Recommendation
57	Hosting capacity analysis	Request for specific timing on the requirement to update areas with greater/faster DER adoption more frequently (Figure 3)				X								Modify draft Guidelines	Staff plans subsequent Guideline revision process which may address the timing of future stages (as shown in Guideline Figures) and pace of progress
58	Hosting capacity analysis	Requests more complete explanation of the requirement to include distribution-level impacts to the substation and transmission system (Figure 3)				X								Modify draft Guidelines	Revise requirement to include "options analysis" and clarify that decisions about future HCA will be made utilizing information from options analysis
59	Hosting capacity analysis	Clarification about whether Idaho Power is expected to produce a Net Metering Map				X								Modify draft Guidelines	Add footnote to Guideline clarifying this requirement is not grounded in net-metering rules. As a result exemptions from net-metering administrative rules do not correspond to an exemption from this requirement.
60	Hosting capacity analysis	Meaning of planning-use case (Figure 3 and elsewhere)				X								Modify draft Guidelines	Revise and clarify language, and structure of Guideline
61	Community engagement plan	Would like the flexibility to conduct two stakeholder workshops in conjunction with the WTVEP Advisory Council process				X								Implementation guidance	Staff supports the suggestion and sees potential to do this for Part 2 of filing
62	Solution identification - pilots	The number of pilots is arbitrary. The needs of the distribution system and the ability to serve customers reliably and affordably should determine the appropriate solution, not the other way around				X								Modify draft Guidelines	Add threshold exemption for Idaho Power that requires a minimum of one (1) non-wire pilot
63	Solution identification	Would like the flexibility to define "larger projects" between itself and stakeholders.				X								Already captured/No action required	Staff supports suggestion
64	Evolution - long term	Would like Staff to consider adding language about sending energy prices tagged with GHG emission rates from the point of generation to the end nodal connection point; known as a PRICE/GHG server											X	Future Guideline consideration	Staff appreciates suggestion and will review for inclusion in subsequent Guidelines

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			Overarching or General Comments	X	X			X	X		X				
			Timing and Commission Action	X	X	X		X	X						
			Process Alignment	X	X	X		X							
			Baseline Data and System Assessment	X	X	X	X	X	X		X				
			Load, DER and EV Forecasting	X	X	X	X		X		X				
			Hosting Capacity Analysis	X		X	X	X							
			Community Engagement Plan	X	X	X		X		X	X				
			Grid Needs Identification	X	X		X	X	X			X			
			Solution Identification	X	X	X	X	X		X	X	X	X		
			Near-term and Long-term Action Plans	X			X		X						
			Evolution of DSP	X	X	X		X	X				X		
ID	Topic	Comment Summary												Response	Recommendation
65	Community engagement plan	Suggest more than two stakeholder meetings. This is inadequate.						X		X	X			Modify draft Guidelines	Require two workshops prior to filing Part One and two workshops prior to filing Part Two. Require separate stakeholder meetings during development of pilot proposals.
66	Community engagement plan - timing	Ask for more clarity to ensure that CEPs outline how utilities will engage before decisions are made. Should be collaborating with CBOs earlier in the process						X		X	X			Future Guideline consideration	Staff appreciates suggestion and will review benefit-cost quantification for inclusion in subsequent Guidelines
67	Goals / Principles	Additional goal of non-electric service-related social, economic, and environmental benefits in DSP									X			Future Guideline consideration	Staff appreciates suggestion and will review for inclusion in benefit-cost quantification in subsequent Guidelines
68	Cost recovery	There should be guidance on reasonable levels of spending for communities to participate in the DSP process and funding to support those efforts									X			Future Guideline consideration	Staff supports needed resourcing of community-based organizations to inform decision-making.
69	Baseline - data / hosting-capacity analysis	Utilities should immediately publish maps of substations, feeders, and existing DERs allowing CBOs and developers to prioritize projects using existing data (UM 2000)									X			Already captured / Future Guideline consideration	Staff appreciates suggestion; the current map requirement includes locations of existing net metering and small generation facilities. Remaining elements will be reviewed for inclusion in subsequent Guideline revision
70	Forecasting	Community Energy Plans should be considered when available, esp. when ratified by localities.									X			Future Guideline consideration	Staff appreciates suggestion and will work with stakeholders to review for subsequent Guidelines
71	Community engagement plan	Regional representatives of the utilities engage with communities directly and at the County scale in partnership with CBOs.									X			Future Guideline consideration	Staff appreciates suggestion and will work with stakeholders to review for subsequent Guideline revision
72	Solution identification - pilots	One of the pilots should be in a USDA rural area									X			Future Guideline consideration	Staff appreciates suggestion and will work with stakeholders to review for subsequent Guideline revision

			Section	PGE	PAC	Idaho Power	Energy Trust	Joint Parties	Renewable NW	Community Energy Project	Wallowa Resources	Anterix	Temix, Inc.		
			Overarching or General Comments	X	X			X	X		X				
			Timing and Commission Action	X	X	X		X	X						
			Process Alignment	X	X	X		X							
			Baseline Data and System Assessment	X	X	X	X	X	X		X				
			Load, DER and EV Forecasting	X	X	X	X		X		X				
			Hosting Capacity Analysis	X		X	X	X							
			Community Engagement Plan	X	X	X		X		X	X				
			Grid Needs Identification	X	X		X	X	X			X			
			Solution Identification	X	X	X	X	X		X	X	X	X		
			Near-term and Long-term Action Plans	X			X		X						
			Evolution of DSP	X	X	X		X	X				X		
ID	Topic	Comment Summary												Response	Recommendation
73	Forecasting	Energy Trust provides efficiency forecasts to utilities in conjunction with IRP; permutations of this process for DSP, and incorporation of renewable resources, may require significant Energy Trust resources					X							Modify draft Guidelines	Split the filing into Part One and Part Two to allow additional time for coordination between Energy Trust and utilities
74	Solution identification	Permutations of existing forecasting for DSP may require significant resources from Energy Trust					X							Modify draft Guidelines	Split the filing into Part One and Part Two to allow additional time for coordination between Energy Trust and utilities
75	Near-term Action Plan	Assembling components of Near-term Action Plans could require significant Energy Trust resources					X							Modify draft Guidelines	Split the filing into Part One and Part Two to allow additional time for coordination between Energy Trust and utilities
76	Goals / Principles	Carefully consider the balance between the capabilities, cost, reliability and resilience of the distribution system.						X						Already captured/Future Guideline consideration	Guidelines aim to maximize operational efficiency and customer value. Staff will continue to review in future Guidelines
77	Goals / Principles	Align DSP with state and local energy, climate, resilience and equity goals						X						Future Guideline consideration	Staff appreciates suggestion and will review for implementation in subsequent Guidelines
78	Process - planning interaction	Recommend including at least summaries of smart grid opportunities and constraints relevant for the distribution system under item C.3 of Order 12-158						X						Modify draft Guidelines	Include smart grid opportunities in Long-term Distribution Plan requirement.
79	Cyber security, data security	Recommend the Commission sponsor workshops to discuss issues in detail and provide input to the initial Plans						X						Implementation guidance	Staff will consider stakeholder workshops in Q1-Q2 2021 to offer guidance and convene stakeholders
80	Timing	Concerns about the extended duration envisioned in the Guidelines; suggest removing references to specific years, could also direct Guidelines be reopened for refinement following acceptance of first DSPs						X	X					Modify draft Guidelines	Remove references to specific years in discussion of future stages. Add language noting varying paces of progress, and that faster progress is supported. Add language clarifying Guidelines will be reopened for revision after first DSP filings

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			Overarching or General Comments	X	X			X	X		X				
			Timing and Commission Action	X	X	X		X	X						
			Process Alignment	X	X	X		X							
			Baseline Data and System Assessment	X	X	X	X	X	X		X				
			Load, DER and EV Forecasting	X	X	X	X		X		X				
			Hosting Capacity Analysis	X		X	X	X							
			Community Engagement Plan	X	X	X		X		X	X				
			Grid Needs Identification	X	X		X	X	X			X			
			Solution Identification	X	X	X	X	X		X	X	X	X		
			Near-term and Long-term Action Plans	X			X		X						
			Evolution of DSP	X	X	X		X	X				X		
ID	Topic	Comment Summary												Response	Recommendation
81	Community engagement plan	Difference between "baseline study" Fig. 4 and "equity analysis" Fig. 5?						X						Already captured/No action required	Baseline study is intended as broader assessment of community needs, challenges and opportunities for investment. Both are proposed Stage 2 deliverables. Staff will work with stakeholders to refine after first Plans.
82	Baseline - data	We advocate for utilities to publish comprehensive, granular data that connects grid need with ratepayer demographics, as soon as possible in the process / We recommend baseline system data to be correlated with customer demographics and socio-economic status						X	X					Already captured / Future Guideline consideration	Phase 2 includes correlation of demographic analysis with system reliability and services. Staff will consider further comments in subsequent Guidelines
83	Hosting capacity analysis	We suggest clarifying the distinction between a planning use-case and an interconnection use-case.						X						Modify draft Guidelines	Revise and clarify language, and structure of Guideline
84	Community engagement plan	In addition to workshops require multimodal engagement and feedback mechanisms, such as surveys; contract with trusted messengers to create education and outreach materials; incorporate affinity groups into larger public gatherings; secure community leader participation before scheduling workshops						X						Future Guideline consideration	Staff appreciates suggestion and will review for inclusion as specific community engagement requirements in subsequent Guideline revision
85	Community engagement plan	We urge creativity in compensation so as to fulfill needs that may not be explicitly connected to utility-envisioned projects						X						Future Guideline consideration	Staff supports resourcing of community-based organizations to inform decision-making. Staff will explore opportunities to facilitate community-based organization participation.
86	Solution identification	It would be helpful to get a clearer sense of activities or projects envisioned in Solution ID and how to include elements such as community engagement and data availability						X						Modify draft Guidelines	Add language to clarify desired documentation of utility analytical work and decision-making in evaluating solutions
87	Goals / Principles	Recommend distinguishing between procedural goals (what the DSP process would ideally achieve) and operational goals (for the resulting distribution system)							X					Future Guideline consideration	Staff appreciates suggestion and will review for possible use in subsequent Guidelines

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			Overarching or General Comments	X	X			X	X		X				
			Timing and Commission Action	X	X	X		X	X						
			Process Alignment	X	X	X		X							
			Baseline Data and System Assessment	X	X	X	X	X	X		X				
			Load, DER and EV Forecasting	X	X	X	X		X		X				
			Hosting Capacity Analysis	X		X	X	X							
			Community Engagement Plan	X	X	X		X		X	X				
			Grid Needs Identification	X	X		X	X	X			X			
			Solution Identification	X	X	X	X	X		X	X	X	X		
			Near-term and Long-term Action Plans	X			X		X						
			Evolution of DSP	X	X	X		X	X				X		
ID	Topic	Comment Summary												Response	Recommendation
88	Evolution	We recommend that beyond adoption of the Guidelines, or as future DSP processes, additional development of robust regulatory framework necessary to create the macro grid architecture							X					Future Guideline consideration	Staff appreciates suggestion and will review for possible use in subsequent Guidelines
89	Baseline - data	We reiterate the need to have insight into climate costs/benefits in addition to monetary costs by including GHG emissions in the data relating to existing distribution system infrastructure (including DERs).							X					Modify draft Guidelines	To Solution Identification pilot concept proposals, include requirement to estimate possible GHG reductions resulting from non-wires solutions.
90	Baseline - data	Locational granularity regarding the age of various assets could be helpful for stakeholders to engage with possible needs and solutions							X					Future Guideline consideration	Staff appreciates suggestion and will review for possible use in subsequent Guidelines
91	Baseline - data	Understanding where distribution system investments have occurred can help understanding needs and solutions, also equity considerations							X					Future Guideline consideration	Staff appreciates suggestion and will review for possible use in subsequent Guidelines
92	Baseline - data	We recommend the Guidelines include DER information at the feeder level (not substation)							X					Modify draft Guidelines	Revise Guideline to request data on net metering and small generators at the feeder level
93	Forecasting - locational gran.	We recommend that Staff establish locational granularity guidelines for all except the first DSP filings.							X					Modify draft Guidelines	Replace references to "locational aspect" and utility discretion, with "substation level."
94	Grid needs identification	We would like to see an accelerated adoption of non-wires solutions to defer distribution system upgrades (avoid gold-plating)							X					Future Guideline consideration	Staff appreciates suggestion and will review for possible use in subsequent Guidelines
95	Long-term plan	We recommend utilities frame how each solution is identified and incorporated into an action plan that helps the system evolve towards the operational outcome.							X					Future Guideline consideration	Staff appreciates suggestion and will review for possible use in subsequent Guidelines
96	Evolution - vision	We recommend use of the grid evolution framework for long-term action plans							X					Future Guideline consideration	Staff appreciates suggestion and will review framework for possible use in subsequent Guidelines