Distribution System Planning Guidelines

Introduction

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1. Purpose

This Introduction provides context for the accompanying draft Distribution System Planning (DSP) Guidelines for Oregon's investor-owned electric utilities, under Oregon Public Utility Commission Docket UM 2005. OPUC Order 19-104, issued March 22, 2019, opened an investigation to "develop a transparent, robust, holistic regulatory planning process for electric utility distribution system operations and investments."[1] The draft Guidelines (Appendix 1) outline requirements for the initial utility DSP Plan (Plan) to be submitted to the Commission in 2021.

Staff believes a new regulatory structure for DSP will enable utilities to better identify system needs and evaluate the evolving range of opportunities that can meet those needs. Staff wants to advance least-cost investments to modernize the grid as a foundation for optimization of the distribution system, in order to foster higher levels of customer access and interaction, and integration of variable resources. Staff seeks to maximize customer value by ensuring that the utilities' approach to managing and operating the distribution system is evolving in a least-cost, least-risk manner.

Staff envisions DSP as a critical step in advancing the state's expectations for a modern grid. Staff foresees an eventual transition to a more responsive platform capable of minimizing the frequency and impact of outages, supporting decarbonization, optimizing system performance, and enabling customers to deploy distributed energy resources in a manner that minimizes their costs while maximizing system benefits.

Since 2013, Oregon's investor-owned electric utilities have filed biennial Smart-Grid Reports, which provide important insight into innovative grid modernization projects. The DSP Guidelines will further expand and evolve this reporting framework.

Informing Staff's proposal for DSP Guidelines are SB 978 (2017) and Governor Brown's Executive Order No. 20-04 (EO 20-04) of March 10, 2020. SB 978 tasked utilities and the OPUC 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 OPUC. The OPUC's legislative report in 2018 cites distribution system resources and management technologies as one of four key themes most significant for Oregon's electric sector, requiring regulatory attention.[2] Importantly the agency outlines new efforts to create an environment of procedural inclusion for underserved communities including low-income, environmental justice and community-based organizations.[3]

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. The EO directs the Commission to use any and all authority at its discretion to help reduce the emission of greenhouse gases to at least 45 percent below 1990 levels by 2035 and 80 percent below 1990 levels by 2050. Section 5(A) first finds that: "It is in the interest of utility customers and the public generally for the utility sector to take actions that result in the rapid reduction of GHG emissions,

[1] See https://apps.puc.state.or.us/orders/2019ords/19-104.pdf.
[2] See *SB 978: Actively Adapting to the Changing Electricity Sector* September 2018, pages 9-11, available at: https://www.oregon.gov/puc/utilities/Documents/SB978LegislativeReport-2018.pdf.
[3] Id, at page 19.

at reasonable costs, to levels consistent with the GHG emission goals set forth in [this EO], including transitioning to clean energy resources and expanding low carbon transportation choices for Oregonians."

2. Drivers

Staff's whitepaper on distribution system planning (2019) identified two proactive drivers for the UM 2005 investigation that carry forward:

- Insight (procedural driver): The near-term need to establish visibility and holistic engagement in utilities' distribution-level investments.
- Optimization (operational driver): The longer-term need to ensure the operation of the changing distribution system maximizes operational efficiency and customer value.[4]

Historically, utility investments in the distribution system were understood to be sufficient for operations and maintenance, or to serve increased or new load. That investment was typically in equipment to support one-directional flow of power and communication, and serve predictable load patterns. This traditional type of investment was generally regarded as necessary and prudent.

However, changes in state and federal public policy, evolving technology, and rapidly decreasing costs of distributed energy resources (DERs)[5] have led to the utilization of advanced metering infrastructure (AMI), increasing adoption of solar PV and battery storage, and increasing adoption of electric vehicles and installation of charging stations. These changes have led to new and increased *demands* on the distribution system in order to "keep the lights on," and new *opportunities* for the distribution system to deliver new value to customers and utilities through enabling higher levels of intermittent DERs, providing carbon-free energy for transportation, serving to decarbonize the utility sector and reduce GHG emissions as directed by EO 20-04, and other grid services.

As a result, the distribution system should evolve to leverage the two-way flow of power and communication, greatly increased levels of intermittent power generation, and the potential for highly flexible load patterns. The types and amount of investment in the distribution system are expected to change as well. In other states, investment in the distribution system has already been significantly transformed. As a critical step in advancing the state's expectations for a modern grid, a new DSP planning framework in Oregon will help ensure investments are planned and customer value maximized. In contrast to unplanned, erratic development of the system with uneven benefits, a robust DSP process will advance a modern and reliable system,

[4] Staff Whitepaper: A Proposal for Electric Distribution System Planning, March 2019, https://edocs.puc.state.or.us/efdocs/HAU/um2005hau15477.pdf.
[5] For the purposes of these guidelines "distributed energy resource" includes distributed generation resources, distributed energy storage, demand response, energy efficiency, and electric vehicles that are connected to the electric distribution power grid.
U.S. Department of Energy, Modern Distribution Grid Volume I: Customer and State Policy Driven Functionality, page 7, https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-I_v1_1.pdf.

positioned to form a foundation for higher levels of customer access and interaction, and higher levels of generation and load variability.

3. Goals and Principles

Long-Term Goals

In developing this proposal, Staff has been guided by the following overarching goals for Oregon's long-term DSP process. These overarching goals were developed collaboratively with parties through the course of the investigation.[6]

- Promote the reliability, safety, security, and quality of the distribution system for all customers;
- Be customer-focused and promote inclusion of underserved populations, including frontline, environmental justice communities;
- Ensure optimized operation of the distribution system;
- Enable efficient integration of DERs and other clean energy technologies; and
- Strive for regulatory efficiency through aligned, streamlined processes.

Guiding Principles

Staff also utilized the following guiding principles to inform development of the initial DSP Guidelines.

Principle	Does the requirement or activity…
Flexibility	Allow for plans to evolve as the state of the distribution system changes? Allow for variance among utilities? Accommodate changes over time in variables such as technology and costs?
Practicality	Deliver information that is usable by utilities and stakeholders? Appropriately weigh complexity and cost? Streamline regulatory efforts?
Efficiency	Achieve efficient integration of distributed energy resources (DERs) and accelerate decarbonization? Lead to more efficient operation of the distribution system?
Transparency	Yield results that improve insight? Deliver information needed to holistically understand long-term distribution system plans?
Inclusion	Meaningfully include a broader range of participants? Remove barriers to public participation to ensure all voices are heard in the decision-making process?

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

[6] See https://edocs.puc.state.or.us/efdocs/HAH/um2005hah145318.pdf.

proposes the "Initial Requirements" for the first utility Plans, while "Expected Evolution" includes potential benchmarks for future phases. (See section 8 for a further discussion.) 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 put forward by the utilities and stakeholders.

Guidelines will be revised after the first utility Plan filings and the resultant Commission orders, reflecting stakeholder input and learnings. Staff anticipates lessons from the filing process and Plan review will inform an assessment of the Guidelines.

4. Planning Interactions and Streamlining

To achieve focused and strategic reporting for DSP, current related regulatory requirements will change. The changes below are anticipated; specific requirements are included in the Plan Guidelines.

a. Smart Grid Report (SGR). This biennial report is the current regulatory requirement with the largest focus on the distribution system. Conceived nearly 10 years ago, the SGR has played a critical role, but it is not a planning document. In order to allow for utilities to shift focus from the SGR to DSP, Staff recommends temporarily suspending the next Smart Grid Report filing cycle requirement as established in Docket 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 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 sections of Long-term Distribution System Plan, and Planning Interactions and Streamlining. These include (from Order No. 12-158): C.1. (any distribution system plan strategies, goals or objectives, and their alignment with State and Commission policies) and C.2.b. (a description of upcoming investment options across a range of categories).

b. Transportation Electrification (TE) Plan. This biennial plan presents the utility's long-term strategy to accelerate transportation electrification in its Oregon service territory. The TE Plan serves numerous important purposes, and Staff recommends it continue to be separately produced, though information reported in the TE Plan may be sourced from the Distribution System Plan.

   Because transportation electrification has the potential for such a large impact on the distribution system, Staff recommends the Distribution System Plan be used to develop several elements that will also be included in the TE Plan, Specifically, Staff recommends developing and including the following information currently required in TE Plans in the Distribution System Plan: OAR 860-087-0020(3)(a)(C) (existing data on the availability and usage of charging stations), (D) (number of EVs in the service territory and projected number of EVs in the coming years), (E) (other related infrastructure, if applicable), and (G) (Distribution system impacts and opportunities for efficient grid management). Once 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.

Staff recommends utilities include the elements referenced above within the DSP Guidelines sections of Baseline and System Assessment, and Load, Distributed Energy Resources and EV Forecast.

c. Annual Net Metering Reports. This report conveys important information in understanding the distribution system and DERs. In order to integrate this information into the Distribution System Plan, while requiring it be reported only once, Staff recommends a waiver temporarily suspending the next annual Net Metering Report filing cycle requirement as established in OAR 860-039-0070(2) (currently April 1, 2021). As the DSP process becomes established Staff will consider recommending changes to the requirements of OAR 860-039-0070.

   Staff recommends continuing reporting net metering data and integrating this information into the DSP Guidelines section Baseline and System Assessment. These reference: OAR 860-039-0070(2)(a) (total number of net metering facilities by type), (b) (total estimated rated generating capacity of net metering facilities by type), and (3) (upon request each utility must file maps, records and reports to identify, locate and summarize net metering facilities).

d. Annual Small Generator Reports. This report also conveys important information in understanding the distribution system and DERs. In order to integrate this information into the Distribution System Plan, while requiring it be reported only once, Staff recommends a waiver temporarily suspending the next annual report filing cycle requirement as established in OAR 860-082-0065(3) (currently May 30, 2021). As the DSP process becomes established Staff will consider recommending changes to the requirements of OAR 860-082-0065.

   Staff recommends continuing reporting small generator data and integrating this information in the DSP Guidelines section Baseline and System Assessment. These include: OAR 860-082-0065(3)(a) (number of complete small generator interconnection applications received), (b) (number of small generator facility interconnections completed), (c) (types of small generator facilities applying for interconnection and the capacity of the facilities), (e) (for each Tier 3 and Tier 4 small generator interconnection approval, the basic telemetry configuration, if applicable), (f) (for each Tier 4 small generator interconnection approval), (A) (interconnection facilities required to accommodate the interconnection of a small generator facility and the estimated costs of those facilities), and (B) (system upgrades required to accommodate the interconnection of a small generator facility and the estimated costs of those upgrades).

e. Annual Reliability Reports. This report conveys information vital to understanding the distribution system's performance in delivering reliable service to customers. However, this report serves other important purposes as well, and Staff recommends Annual Reliability Reports continue separate from a Distribution System Plan, with each Plan including the most recent reliability report.

f. Demand response (DR) reporting. Utilities currently report the performance of demand response programs on an annual basis. These reports cover important and detailed aspects of their operation and efficacy. Overall DR capability and results can affect the distribution system, and so Staff recommends summary-level demand response reporting be included in the Plan, while current and detailed DR reporting continue separate from a Distribution System Plan.

g. Integrated Resource Plan. Staff recognizes the significant time and effort required for the Integrated Resource Planning (IRP) process, and welcomes suggestions on how best to synchronize this effort with the Distribution System Planning process. In order to inform any future synchronization, in the DSP Guidelines section, Long-term Distribution System Plan, utilities should include a discussion of how the IRP and Plans are coordinated. This should include related inputs and outputs such as data sets or prices, and assumptions such as macro-economic policies or growth rates.

5. Data Privacy and Security

It is important that utility data be provided to the Commission and to stakeholders, as appropriate, at the necessary level of detail to ensure a sound review process. Staff recognizes that some information should not be widely distributed to the public in every instance, such as personally identifiable customer information or critical infrastructure information. Utilities should provide as detailed a Plan as possible.

6. Cost Recovery

Utility costs:

- The OPUC will aim to provide utilities with guidance on reasonable levels of spending for upfront costs to identify and plan for risks. This should include new resources needed to meet requirements for community engagement and planning not currently recovered through rates.
- This process requires incremental progress. Staff recognizes current utility performance and the uncertainty that utilities will take on throughout the process.
  Associated pilots may allow utilities cost recovery mechanisms.

Stakeholder costs:

- Participation in this process places an increased burden on involved organizations' time and resources. Staff will explore opportunities to support community-based organization participation.

7. Regulatory Development

OPUC recognizes the need for ongoing conversations about how DSP activities align or interact with the utilities' existing business models and regulatory approaches. Utilities and stakeholders should explore whether an alternative regulatory framework would assist in aligning incentives for utility long-term DSP investment and DER development, is in customers' interest, and aligns with the clean energy vision articulated by the State of Oregon. To address the changes that utilities may make in implementing the DSP process, the OPUC may explore new regulatory mechanisms that may better align with utilities' efforts to plan and invest in DSP over the long-term.

8. Vision for Distribution Planning Evolution

The initial DSP Plan filings required herein 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 Requirements put forward in Guidelines to more advanced stages.

Table 1

Distribution System Planning Evolution Framework			
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	2023-2027	2029 and beyond

Utilities will develop and file their initial Plans in Fall 2021, resulting in Commission orders that 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 expectations of the Guidelines.

Following the issuance of these initial Commission orders, Staff will work with parties to identify improvements to DSP Guidelines and processes for future filings.

8.1. Insights Provided by Parties and Subject Matter Experts

The vision for DSP in Oregon relies heavily on the input provided to Staff by diverse parties and subject matter experts throughout the 2020 workshop series. Robust stakeholder participation across 12 workshops and webinars explored distribution system planning approaches, best practices from across the country, and related OPUC policies. The active participation of utilities and stakeholders in this investigation, from more than 40 parties, has provided new insight into the capabilities, needs and future of Oregon's distribution systems, distributed energy resources, and the customers and communities they serve.[7] The impact of this input on the DSP Guidelines is substantial, initiating a new era of transparency, rigor and opportunity for DSP in Oregon.

[7] 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 OPUC Distribution System Planning Webpage, as well as in the UM 2005 docket, https://www.oregon.gov/puc/utilities/Pages/Distribution-System-Planning.aspx.

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1. Process and Timing

Staff proposes the following development and review process for the initial utility filing of a Distribution System Plan (Plan).

a) Utilities must file a Distribution System Plan every two years, on October 15, 2021 or an alternative date designated through Commission order.
b) During Plan development, prior to filing a Plan, utilities must hold at least two workshops with stakeholders to ensure a range of community perspectives are heard and considered.
c) Utilities will present the results of its filed Plan to the Commission at a public meeting.
d) Upon filing, the Commission will set a procedural schedule under which interested parties will have the opportunity to provide comment and make recommendations on a utility's Plan.
e) The Commission will generally consider comments and recommendations on a utility's Plan at a public meeting five months after it is filed. The Commission will consider whether to accept the Plan as meeting the objectives of these Guidelines, and issue an order accordingly. The Commission may provide guidance on the development and content of future Plans.
f) The Commission may provide the utility an opportunity to revise the Plan before issuing an order.

Staff's design and implementation of this proposed process will achieve Staff's long-term goals or guiding principles of regulatory efficiency through aligned, streamlined processes, and inclusion and transparency.

2. Commission Action

Initial utility Plan filings will be reviewed for Commission acceptance, rather than acknowledgement. Staff understands there is much to learn for all parties, and that Commission acknowledgement may be premature given the state of DSP process maturity.

At later stages, Staff proposes to revisit this topic and address whether subsequent Plans are filed for Commission acknowledgement.

3. Scope

Initial utility Distribution System Plans will address and provide the following:

- Baseline Data and System Assessment
- Load, Distributed Energy Resource (DER), and Electric Vehicle (EV) Adoption Forecasts
- Hosting Capacity Analysis
- Community Engagement Plan
- Grid Needs Identification
- Solution Identification
- Near-Term Action Plan and Long-Term Plan

3.1. Baseline Data and System Assessment

To foster understanding 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 distributed energy resources[1] (DERs) currently integrated into those systems. Figure 1 introduces the initial requirements and expected evolution for baseline data and system assessments.

Figure 1

Baseline Data and System Assessment			
Stage 3			Refine asset financial planning processes and strengthen relationships with DER planning and integration processes.
			Use software systems to proactively monitor and support operation of the distribution system and DERs.
Stage 2		Share asset financial planning processes and show relationships with DER forecasting and planning processes.	
		Leverage remote sensing technologies to provide detailed insight on physical infrastructure to support efficient operation of the distribution system.	
Stage 1	Identify the existing grid equipment inventory and financial data with locational granularity, and DER-related data.		
	2021	2023-2027	2029 and beyond

Initial Requirements

Stage 1 Distribution System Plans are required to identify the existing grid equipment inventory and financial data with locational granularity, and include related DER data (e.g., number of connected systems and generation capacity). This requirement consolidates reporting requirements currently effective under the Smart Grid Reports, Transportation Electrification Plans, Annual Net Metering Reports, Annual Small Generator Reports, and others. (See section 4, Planning Interactions and Streamlining, for further detail). The utility should provide, at minimum:

a) A description of any currently used, relevant, internal baseline and system assessment practices (such as system reliability baseline, system asset health baseline, system DER penetration 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) Number of feeders

[1] For the purposes of these guidelines "distributed energy resource" includes distributed generation resources, distributed energy storage, demand response, energy efficiency, and electric vehicles that are connected to the electric distribution power grid.
U.S. Department of Energy, Modern Distribution Grid Volume I: Customer and State Policy Driven Functionality, page 7, https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-I_v1_1.pdf.

c) Number of substations
d) Percentage of substations, feeders, and other applicable equipment with monitoring and control capabilities
e) Number of AMI meters by customer class, and a count of customers without AMI meters
f) A summary of the measurement of the performance of the distribution system (feeder-level and time interval), resulting from equipment with monitoring and control capabilities, and AMI meters, including information on percentage of system with each level of visibility (ex. max/min, daytime/nighttime, monthly/daily reads, automated/manual)
g) 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.
h) A summary of system visibility, and capabilities of these advanced control and communication systems, including information on the percentage of system reached with each capability, the percentage of customers reached with each capability, the programs utilizing each capability, etc.
i) A summary of the utility's distribution system assets including the following:
    i) Asset classes
    ii) Average age of assets in each class
    iii) Age range of assets in each class
    iv) Industry life expectancy of assets in each class
j) 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
    viii) Vegetation management
    ix) Other
k) Existing distributed generation resources and distributed energy storage systems interconnected to the distribution grid (or to the transmission system, as appropriate for small generator facilities) at time of filing, by substation
    i) The total number of net metering facilities by resource type
    ii) The total estimated rated generating capacity of net metering facilities by resource type
    iii) The total number of small generator facilities by resource type
    iv) The total nameplate capacity of small generator facilities by resource type
    v) The total number, and nameplate capacity, of other distributed generation resources and distributed energy storage systems not included as net metering or small generators, by resource type

l) Distributed generation resources and distributed energy storage systems interconnected to the distribution system (or to the transmission system, as appropriate for small generator facilities) for each of the five prior years, by substation
   i) The total number of net metering facilities by resource type
   ii) The total estimated rated generating capacity of net metering facilities by resource type
   iii) The total number of net metering facilities that had interconnection denied, by resource type
   iv) The total number of complete small generator interconnection applications received
   v) The total number of small generator facility interconnections completed
   vi) The types of small generator facilities applying for interconnection and the nameplate capacity of the facilities
   vii) For each Tier 3 and Tier 4 small generator interconnection approval, the basic telemetry configuration, if applicable
   viii) For each Tier 4 small generator interconnection approval:
      (1) The interconnection facilities required to accommodate the interconnection of a small generator facility and the estimated costs of those facilities
      (2) The system upgrades required to accommodate the interconnection of a small generator facility and the estimated costs of those upgrades
   ix) The number, and nameplate capacity, of other distributed generation resources and distributed energy storage systems not included as net metering or small generators, by resource type
   x) The total number, and estimated rated generating capacity, of net metering facilities, small generator facilities, and other distributed generation resources and distributed energy storage systems not included as net metering or small generators, by resource type by substation

m) The total number and nameplate capacity of queued net metering, small generator, or other distributed generation resources and distributed energy storage systems not included as net metering or small generators, at time of filing, broken down by resource type

n) A map, in electronic format, identifying locations of net metering, small generator, and any other distributed generation resources and distributed energy storage systems

o) Total number of electric vehicles (EVs) of various sizes served by the utility's system at time of filing

p) Number of EVs added to the utility's system in the prior year

q) Total number of charging stations on the utility's system, broken down by type, ownership, and substation location

r) Total number of charging stations added to the utility's system in the prior year, broken down by type
   i) Data on the availability and usage patterns of charging stations

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

t) A summary of demand response (DR) program performance metrics for the past five years including:
   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

Distribution System Plans should include the utility's Annual Reliability Report as an appendix to Plan filings. 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.[2] Additionally, at the February 26, 2020 workshop, utilities provided an overview of their existing DSP processes, including monitoring and automation practices.[3] [4] [5] Presentations highlighted that each utility has different capabilities and system needs, which guide their planning and related outcomes.

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

3.2. Load, Distributed Energy Resource, and EV Forecasting

Accurate load forecasting enables the distribution system to reliably meet energy, demand and ancillary grid service needs. As DER and EV adoption grows, load forecasting must better account for its impact on load, as well as the ability of these resources to productively modify load. Figure 2 introduces the initial requirements and expected evolution for load, DER and EV forecasting.

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

Figure 2

Load, DER, and EV Forecasting			
Stage 3			Refine hybrid 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	2023-2027	2029 and beyond

Initial Requirements

These Guidelines require that initial Distribution System Plans document existing utility load forecasting processes for distribution service. Plans should build on that foundation with forecasts of DER and EV adoption as follows:

a) Discussion of current distribution system load forecasting process 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 with a locational aspect.
   i) The forecast should include high/medium/low scenarios for both DER adoption and EV adoption.
   ii) A utility should fully describe its methodologies for developing the DER forecast, high/medium/low scenarios, and geographical allocation in its plan (e.g., methods and tools, time horizons, data sources).
   iii) For the initial Plan, the methodology to apply a locational aspect, and the granularity of the locational aspect for DER and EV forecasts, are at the utility's discretion. The Commission may provide direction for subsequent Plans.
   iv) Utilities 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.
c) Reported results of load, DER, and EV forecasting.
   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 load, DER and EV adoption forecasts. 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.[6] 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 2.

3.3. 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.[7] Figure 3 introduces the initial requirements and expected evolution for hosting capacity analysis.

[6] See https://www.oregon.gov/puc/utilities/Documents/DSP-Sigrin-Presentation.pdf for more detail.
[7] *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 3

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 as a planning use case to guide DSP investments.
Stage 2		If determined through Docket UM 2111, conduct hosting capacity analysis as an interconnection use case; 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 distribution system investment plans, and to enhance distribution system visibility when determining locations for future DER.	
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 considering both the planning use case for DSP investments, and interconnection use case. Plan may address alternate tool options that may provide more approachable and instructive data for communities.		
	2021	2023-2027	2029 and beyond

Initial Requirements

Under these Guidelines, for initial Distribution System Plans, utilities should conduct system evaluations to identify areas of limited DER growth, and refers to the methodology underlying PGE's Net Metering Map.[8] In addition, Plans should provide a plan, or roadmap, to conduct hosting capacity analysis in the near-term considering both planning, and interconnection use-cases. (Staff notes aspects of the analytical exercise may be shared between the two use-cases and suggests Plans note this when applicable.) Specific requirements include:

a) Utilities should conduct a system evaluation to identify areas of limited DER growth.
   i) Utilities should adopt the methodology underlying PGE's Net Metering Map as presented in UM 2099 for calculating and identifying areas of limited DER growth.[9]

[8] https://www.portlandgeneral.com/business/power-choices-pricing/renewable-power/install-solar-wind-more/net-metering/net-metering-map
[9] 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.

ii) If this methodology is unworkable, utilities should present an alternative methodology with documentation of why it is necessary, and any ways it may prove deficient to the proposed methodology. The result should, at minimum, meet the level of functionality of PGE's Net Metering Map.

b) Utilities should prepare a roadmap to implement HCAs for a planning use-case, as part of the utility's future distribution system planning process (e.g., HCA is conducted, load growth and DER are forecasted, system needs are identified). The utility may prepare an additional roadmap for an alternative analytical approach for comparison to HCA, if the utility believes the alternative approach may provide greater benefits than HCA, or the same benefits as HCA at lower costs. The roadmap(s) should include:
   i) Analysis of integrating hosting capacity as an input into the utility's distribution system planning practices, as well as project plans with: a summary of scope, a timeline with milestones, consideration of validation requirements, identification of any existing barriers to implementing hosting capacity analyses, forecast of the time and resources needed to overcome these barriers, estimated costs, as well as any additional relevant information to help inform the project.
   ii) Identified plans, costs, and barriers should be identified for the types of analyses and parameters listed below in section d).

c) Utilities should prepare a roadmap to implement HCAs for an interconnection use-case, in order to provide customers information about the conditions of the distribution system to assist DER site selection and project design. The utility may prepare an additional roadmap for an alternative analytical approach for comparison to HCA, if the utility believes the alternative approach may provide greater benefits than HCA, or the same benefits as HCA at lower costs. The roadmap should include:
   i) Analysis of utilizing hosting capacity as a tool to inform customers of distribution system conditions, as well as project plans with: a summary of scope, a timeline with milestones, consideration of validation requirements, identification of any existing barriers to implementing hosting capacity analyses, forecast of the time and resources needed to overcome these barriers, estimated costs, and additional relevant information to help inform the project.
   ii) Identified plans, costs and barriers should be identified for the types of analyses and parameters listed below in section d).

d) Types of analyses and parameters HCA roadmaps should consider:
   i) Modeling methodology
      (1) Stochastic modeling
      (2) Iterative modeling
      (3) EPRI Distribution Resource Integration and Value Estimation (DRIVE) modeling
      (4) Alternative methodologies considered that are not listed above
   ii) Geographic granularity
      (1) Circuit level
      (2) Main trunk
      (3) Line segment
   iii) Temporal granularity
      (1) Peak assessment
      (2) Hourly annual assessment
   iv) Data presentation
      (1) Tabular/spreadsheet presentation only
      (2) Tabular/spreadsheet presentation with output based on customer application (for example ComEd's Small Generator Pre-Application Form and Report)

(3) Map-based visual presentation
(4) Raw data via Open API
v) Refresh timing
(1) Refresh biennially
(2) Refresh annually
(3) Refresh every six months
(4) Refresh weekly
vi) Planned generation
(1) Number and size of projects
(2) Proposed frequency of refreshing planned generation information
(3) Description, and costs, of upgrades assigned to planned generation

Beyond these requirements of all Distribution System Plans, any utility may accelerate its testing and deployment of new hosting capacity analysis through a pilot or demonstration. A utility wishing to take advantage of this opportunity should detail the pilot objectives, plan, budget, and evaluation method in the Distribution System 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.[10] Over time, hosting capacity analysis may reduce the need for interconnection studies.[11, 12]

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 3.

3.4. 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) offer insight that can inform the utility's bottom-up forecasting of technology deployment, especially in vulnerable communities; provide input to the utility on the methodology used in the DSP process to identify and prioritize distribution system investments and project development; and identify or support implementation of customer-sited non-wires solutions.

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[10] *Hosting Capacity - Lessons Learned*, Steve Steffel, Pepco Holdings, May 6, 2020, https://www.oregon.gov/puc/utilities/Documents/DSP-Hosting-Capacity-SSteffel.pdf.
[11] *OPUC Hosting Capacity Overview*, Aram Shumavon, Kevala Analytics, May 6, 2020, https://www.oregon.gov/puc/utilities/Documents/DSP-Shumavon-Presentation.pdf.
[12] 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.

In the *Connectivity Means Community* presentation, presenters noted five approaches to engagement: inform, consult, involve, collaborate, and defer to.[13, 14] Each of these approaches should be incorporated into a robust community engagement plan and ongoing process. Further, best practices for community engagement highlighted during the May 20, 2020 workshop include:

- Be easy;
- Be trusted;
- Be adaptable;
- Be flexible;
- Be positive;
- Be equitable; and
- Be a great ally.[15]

Grounded in these insights and conclusions, Figure 4 introduces the initial requirements and expected evolution for community engagement.

[13] *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.
[14] *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.
[15] *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 4

Community Engagement			
Stage 3			Utilities collaborate with community-based organizations 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. Utilize paid 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 two 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	2023-2027	2029 and beyond

Initial Requirements

Community engagement should occur during Distribution System Plan development and throughout Plan implementation. Specific requirements for utilities include the following, unless noted as OPUC activities:

a) During Plan Development
   i) Hold at least two stakeholder workshops prior to filing the utility's Plan. These workshops should be at a stage in which stakeholder engagement can influence the final 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 (iii). Stakeholder workshops must invite community members to share their relevant needs, challenges and opportunities.

ii) Create a collaborative environment among all interested CBO partners and stakeholders. To support collaboration between all interested parties, Staff plans to host quarterly public workshops and technical working forums.
iii) With consultation from utilities and stakeholders, OPUC will prepare accessible, non-technical educational materials on DSP to support public engagement.
iv) Provide a draft Community Engagement Plan as part of the Distribution System Plan filed with the Commission. The Community Engagement Plan should detail plans to engage community members and CBOs during project development of pilots required in Grid Needs Assessment and Solutions Identification requirements.

b) During Project Development
   i) Proactively engage stakeholders regarding proposed projects in impacted communities. Engagement of the local community may include in-person meetings located in the community; presentation of the project scope, timeline, rationale; and solicitation of public comment, particularly to understand community needs and opportunities.
   ii) Document stakeholder comments and utility response, including comments that were heard but not implemented.
   iii) Collaboratively develop and share datasets and metrics to guide community-centered planning.

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 Citizens' Utility Board (CUB), Energy Trust of Oregon, Northwest Energy Coalition (NWEC), and Oregon Solar Energy Industries Association (OSEIA) each commented on the need for solutions to be co-developed with CBOs and stakeholders. Some spoke of the need to acknowledge, value, and compensate CBOs as technical experts in the planning process.[16, 17, 18, 19]

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

3.5. Grid Needs Identification

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

[16] 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.
[17] 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.
[18] 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
[19] 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.

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

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

Figure 5

Grid Needs Identification	
Stage 3	Identify grid needs and present a summary of prioritized grid constraints, utilizing prioritization criteria such as community priorities, equity analysis, constraints on DER adoption, and evolving public policy goals.
	Provide new datasets and analysis responsive to OPUC, community inputs and policy evolution.
Stage 2	Develop robust "future state" data needs, including inputs in the following categories:
	Perform equity analysis overlaying customer geographic and socio-economic data relative to system reliability and customer options. Make findings publicly available.
	Needs identification includes results of community needs assessments, DER forecasting, and equity analysis.
	Identify grid modernization needs and present a summary of prioritized grid constraints and opportunities publicly.
Stage 1	Pilot grid needs assessment with CBO expertise to increase learnings about community needs within service territory.
	Present summary of prioritized grid constraints publicly, including criteria used for prioritization.
	Document process and criteria used to identify grid adequacy and needs. Discuss criteria used to assess reliability and risk, and methods and modeling tools used to identify needs.
	2021 / 2023-2027 / 2029 and beyond

Initial Requirements

Utility Distribution System Plans 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.

e) Pilot a grid needs assessment process with CBO input and expertise to increase learnings about community needs within the service territory. Pilots should address:
   i) Status of community planning
   ii) Challenges facing the community
   iii) Energy burden within the community
   iv) Community energy needs and desires
   v) Community interest in clean energy planning and projects
   vi) Ongoing engagement with community members on a schedule determined by the community
   vii) Community demographics

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

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.[20] 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.

3.6. Solution Identification

Solution identification complements a Distribution System Plan grid needs identification by proposing the equipment, technology or program(s) the utility will advance to meet identified grid needs. Traditionally, a Distribution System Plan would rely on traditional hardware solutions (e.g., substation upgrades, reconductoring, additional transformer deployment). These Guidelines advance more holistic distribution system planning, calling for consideration of a wider range of potential solutions (e.g., increased system monitoring automation, expanded switching capability, distributed energy resources).

Experts contributing to the OPUC's workshops on Non-Wire Alternatives and Distributed Energy Resource Valuation suggest Solution Identification include a comprehensive exposition of the options available to serve grid needs, weighing of the pros and cons of each option across standardized criteria, and inclusive approaches to weighing the cost and benefits of each path forward.

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

[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.

Figure 6

<table>
<tr><th colspan="4">Solution Identification</th></tr>
<tr><td colspan="3" rowspan="2">Stage 3</td><td>Co-develop solutions with communities and community-based organizations.</td></tr>
<tr><td>Streamline and refine non-wires solutions and aggregations of non-wires solutions to defer distribution system upgrades.</td></tr>
<tr><td colspan="2" rowspan="4">Stage 2</td><td colspan="2">In assessing options for distribution system pilots, projects, engage community organizing experts to gain input from potentially impacted communities.</td></tr>
<tr><td colspan="2">Prior to filing, publicly present data used to identify distribution system investments, and understand data most useful to stakeholders.</td></tr>
<tr><td colspan="2">Co-develop solutions with communities and community-based organizations.</td></tr>
<tr><td colspan="2">Utilize non-wires solutions to defer distribution system upgrades. Includes harnessing DERs for voltage support and frequency event support.</td></tr>
<tr><td rowspan="3">Stage 1</td><td colspan="3">Make detailed datasets publicly available and host a listening session/workshop describing data used in investment decisions. 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.</td></tr>
<tr><td colspan="3">Provide summary and description of data used in distribution system investment decisions such as: feeder level details (e.g., customer types on feeder, loading information), DER forecasts and adoption.</td></tr>
<tr><td colspan="3">Document the process to the 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.</td></tr>
<tr><td></td><td>2021</td><td>2023-2027</td><td>2029 and beyond</td></tr>
</table>

Initial Requirements

This section should identify the utility's 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 larger 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.
c) Provide a summary and description of data used for distribution system investment decisions such as: a detailed accounting of the relative costs and benefits of the chosen and alternative solutions, feeder level details (e.g., customer types on the feeder; loading information), DER forecasts and adoption rates.
d) Make detailed datasets publicly available and host listening sessions and/or workshops to describe data used in investment decisions. Stakeholders will provide feedback on data that would be useful to them. OPUC will determine if publication of additional datasets is necessary and may direct utilities to submit them in the next Plan filing.

e) Submit to the Commission at least two proposals for pilots in which non-wire solutions are used in the place of traditional utility infrastructure investment. Provide detailed accounting of the relative costs and benefits of the chosen and alternative solutions, including estimated greenhouse gas emissions impacts. Pilots should prioritize community engagement to accelerate and expand the benefits of the pilot to communities in need.

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.[21] 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 (e.g., substation upgrades, additional transformer deployment).[22]

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.

3.7. Overarching Requirements and Explanation

3.7.1. Near-Term Action Plan

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

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 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.

3.7.2. Long-term Distribution System Plan

This section of the 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. It 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 and OPUC policies. These

[21] *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.
[22] 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.

goals may include increased reliability, effective integration of DERs, broader greenhouse gas emissions reduction, or others.

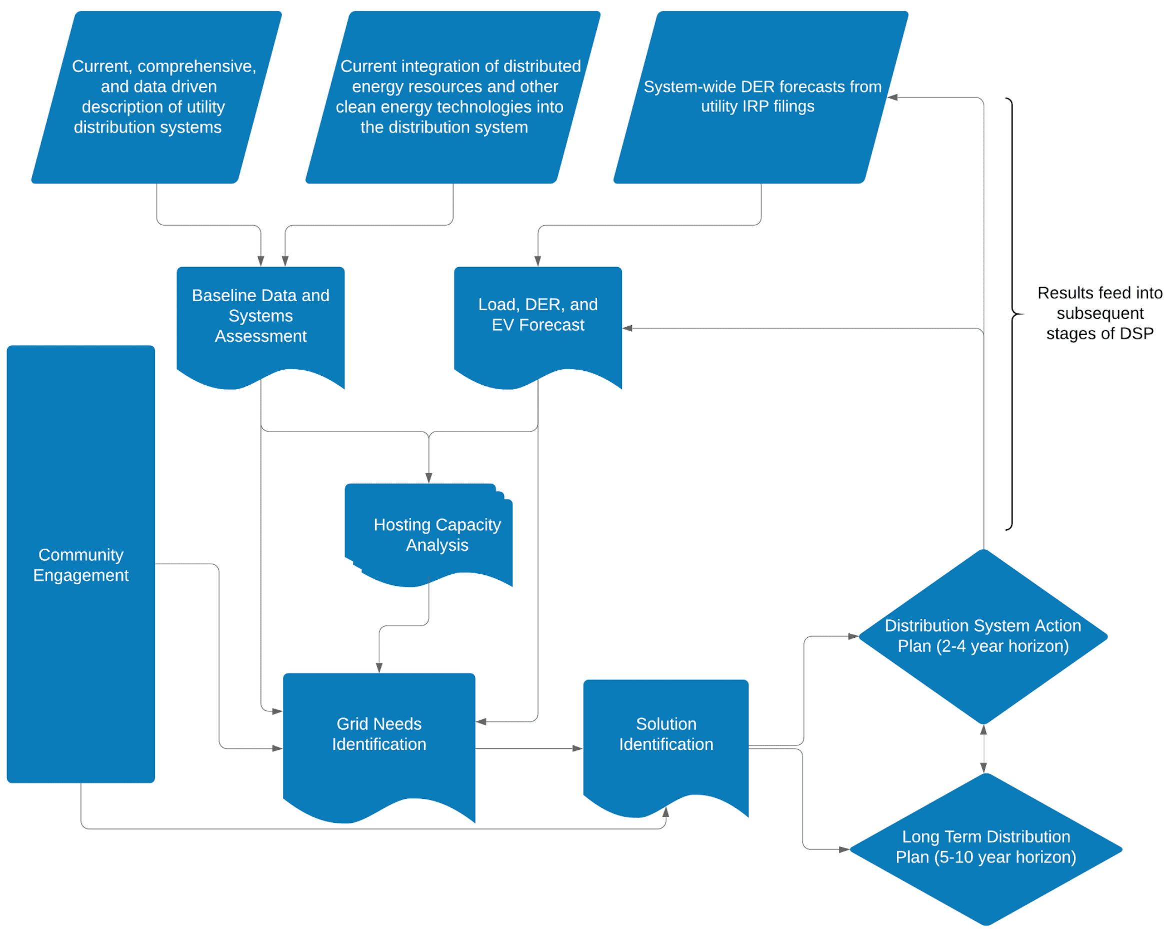
b) Roadmap of planned investments, tools and activities to advance the long-term DSP vision, using a 5-10-year planning horizon
   i) Assessment of investment options to enhance the grid across the following range of areas, including relative costs and benefits:
      (1) Substation and distribution 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) Any other business enhancements
         (e) Other enhancements
      (6) As applicable, any transmission network and operations enhancements
   ii) Explanation of how the investments reduce customer costs, improve customer service, improve reliability, facilitate adoption of demand-side and renewable resources, and convey other system benefits
   iii) Long-term assumptions, and impacts of Action Plan investments, etc.
   iv) Forecasting future technical and market potential of DERs
   v) Plans to further build community needs assessment and co-created community solutions into DSP roadmap
   vi) Transitional planning and operational activities underway in the organization to build capabilities in DSP-related functions
   vii) Key barriers or constraints the utility faces to advancing investment (whether financial, technical, organizational) and mitigation plans
c) Key opportunities and possible benefits for distribution system investment supported by company executives
d) Research and development the utility is undertaking or monitoring
e) 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 Guideline requirements. 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
f) Plans to monitor and adapt the long-term Distribution System Plan

4. 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. Therefore, in addition to specifying the initial requirements for utility Distribution System Plan filings, and expectations for how those requirements will evolve over time, these Guidelines suggest how those pieces fit together. Figure 7 depicts this process.

Figure 7

Oregon Public Utilities Commission Distribution System Planning Process Diagram



Key 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 current system-wide forecasts in each utility's Integrated Resource Planning. The allocation of those forecasts to distribution planning area represents an incremental step introduced by these Guidelines.
- Beginning in Stage 2, Hosting Capacity Analysis will compare the capabilities of the system as presented in the baseline data and system assessment and the demands on the system, as recognized by forecasts of load, 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.
- In its Grid Needs Identification, each Plan should draw on the Baseline Data and System Assessments, Forecasts of load, DER and EV Adoption, as well as insights gained through community engagement. By comparing the capabilities of, and demands on, the system, Plans should infer future needs of their respective grids. Two new requirements are introduced by these Guidelines:
    - Grid Needs will be assessed using locationally-specific forecasts of load, DER and EV adoption represents an incremental step introduced by these Guidelines;
    - Grid Needs will be determined with input from community engagement.
- Progressing forward, each Plan's Solution Identification should show how the utility intends to meet the needs identified in the preceding step. The requirement that non-wire solutions be considered among the options represents an incremental step introduced by these Guidelines.
- An additional incremental requirement introduced by these Guidelines is the integration of community engagement. Each Plan should seek and account for community input in identifying Grid Needs and 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.