ITEM NO. RA1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
SPECIAL PUBLIC MEETING DATE: February 28, 2023

REGULAR __X__ **CONSENT** ____ **EFFECTIVE DATE** ______N/A______

DATE: February 21, 2023

TO: Public Utility Commission

FROM: Nick Sayen

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

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket No. UM 2197)
Acceptance of Distribution System Plan – Part Two.

STAFF RECOMMENDATION:

Accept the Distribution System Plan – Part Two filing by Portland General Electric as meeting the criteria and requirements of the Distribution System Planning Guidelines established in Order No. 20-485 and suspend the 2023 Smart Grid Report filings.

DISCUSSION:

Issue

1. Whether the Public Utility Commission of Oregon (Commission) should accept Portland General Electric's (Company or PGE) Distribution System Plan – Part Two filing (Plan) filed August 15, 2022, in UM 2197 as meeting the criteria and requirements of the Distribution System Planning (DSP) Guidelines established in Order No. 20-485.

2. Whether the Commission should continue a suspension of the Smart Grid Report filing requirement under Order No. 17-290.

Applicable Rule or Law

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."

In Order No. 19-104, the Commission opened Docket No. UM 2005 to "develop a transparent, robust, holistic regulatory planning process for electric utility distribution system operations and investments."

Order No. 17-290 requires utilities to file a Smart Grid Report biennially.

In Order No. 20-485 the Commission suspended the Smart Grid Report filling cycle for 2021 in anticipation that Order Nos. 12-158 and 17-290 may be revised or superseded by new requirements adopted in UM 2005.

Order No. 20-485 established procedural and substantive DSP planning requirements, including Part One and Part Two DSP Plans as well as the process for Commission review of the Plans. The Part Two Guidelines require that utilities:

1. Document current load forecasting processes and build on that foundation with forecasts of distributed energy resource adoption and electric vehicle adoption by substation;
2. Document the process by which the Company compares the current capabilities of the system, and future demands on that system to infer future "grid needs;"
3. Document assessment of proposed solutions to address grid needs, and evaluate at least two pilot concept proposals utilizing non-wires solutions which are to be informed by a community needs assessment;[1]
4. Present a near-term action plan consisting of selected, proposed solutions to address grid needs.

[1] 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.

Analysis

Background

PGE's DSP Part Two filing presents an integrated plan uniting new practices and topics in distribution system planning. PGE's combined Part One and Part Two filings serve as a broad information platform that provides insights into planning and new capabilities enabling targeted investments, in particular to support underserved communities. The Company's efforts to engage the communities it serves has evolved during the process.

This memo provides brief policy context prior to Staff's review of PGE's Part Two Plan, and next steps in distribution system planning. The memo integrates stakeholder feedback and concludes with Staff's recommendation to accept PGE's Plan. Throughout, Staff identifies opportunities for continued learning or improvement. These observations are not intended as proposed conditions for Commission acceptance of the Plan. Rather, Staff intends to reference these insights while working in partnership with utilities and stakeholders moving forward in the evolution of DSP.

The Part Two filing represents the culmination of more than three years of work and conclusion of the opening chapter of distribution system planning at the Commission. Staff's investigation into distribution system planning (UM 2005) began in March 2019. The key drivers behind the docket were to increase insight into utility planning processes and distribution-level investments, and optimization to ensure system operational efficiency and customer value.[2] These drivers led to the adoption of DSP Guidelines in 2020.[3] The Guidelines set forth an initial path to evolve utilities' legacy practices for distribution system planning through a transparent stakeholder process aimed at advancing legacy practices in new ways.

The Guidelines directed the utilities to file their first DSP in two parts. PGE filed Part One in October 2021,[4] which included major components such as a baseline system assessment, community engagement requirements, and a long-term plan involving a 5-

---

[2] See Docket No. UM 2005, Staff Whitepaper: A Proposal for Electric Distribution System Planning, https://edocs.puc.state.or.us/efdocs/HAU/um2005hau15477.pdf.
[3] See Order No. 20-485 in Docket No. UM 2005, https://apps.puc.state.or.us/edockets/orders.asp?OrderNumber=20-485.
[4] See Distribution System Plan Part 1 in Docket No. UM 2197, https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAA&FileName=um2197haa85326.pdf.

to 10-year roadmap of planned investments. The Commission accepted PGE's Part One filing in March 2022.[5]

Policy Shift in Planning

Since the launch of the DSP process, Oregon has undergone a dramatic energy policy shift. In 2021 the Legislature passed into law HB 2021. The law established a clean energy framework for electric companies to decarbonize their retail electricity sales by 2040. The law requires utilities to file Clean Energy Plans (CEPs) along with Integrated Resource Plans (IRPs) to detail specific actions that make progress towards clean energy targets. The Commission set expectations that the first CEP will be fully integrated into the IRP and contemplated a strong, but evolving, connection to the DSP.[6] The Commission also set an expectation that the CEP include targets and strategies for acquiring community-based renewable energy projects, or CBREs, that are informed by a quantitative CBRE potential study and initial Community Benefits Indicator (CBI) metrics. The initial CBIs will be used to begin capturing resilience, health and community well-being, environmental impacts, energy equity, and economic impacts of the utility's overall decarbonization strategies and ongoing IRP updates. HB 2021 also requires utilities to develop Utility Community Benefits and Impacts Advisory Group (UCBIAG) to inform a broad range of utility activities, that will likely include CEPs and DSPs.

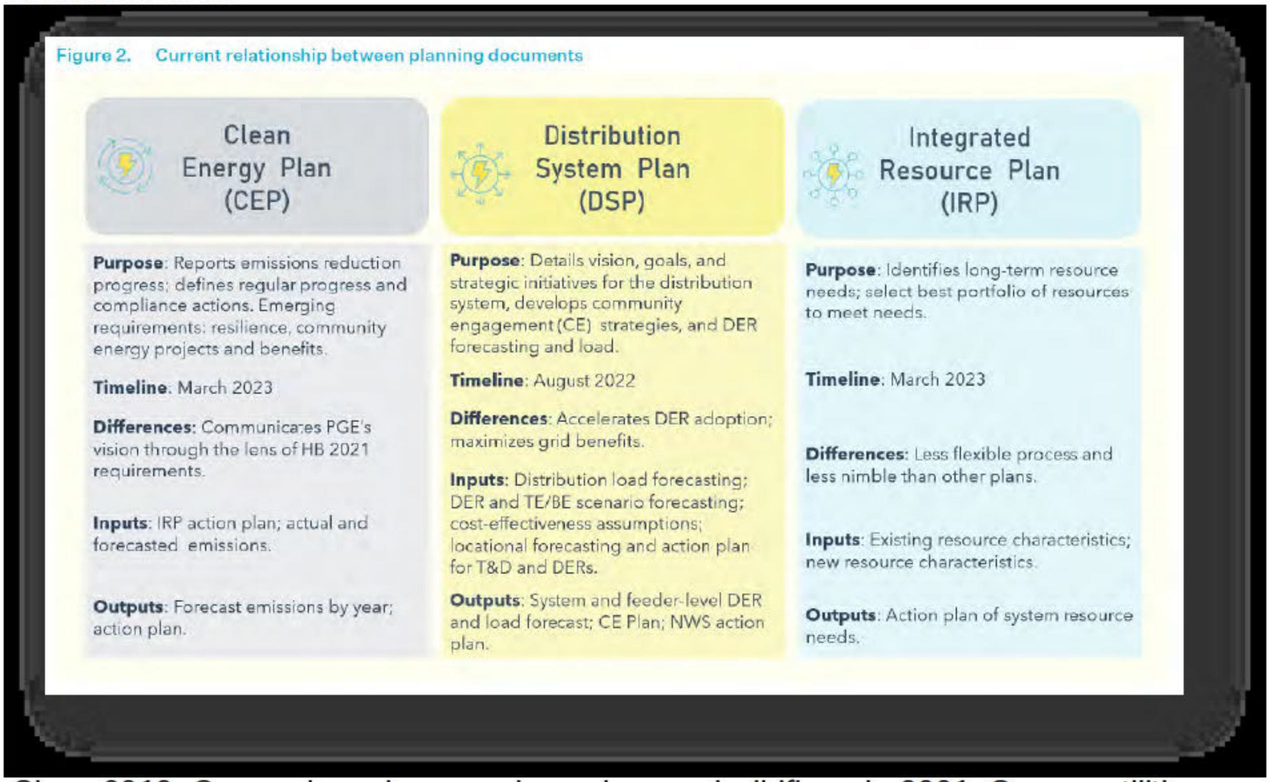
HB 2021 requires that the CEP include a risk-based examination of resiliency opportunities based on industry standards and Commission guidelines. The Grid Modernization Laboratory Consortium (GMLC) of the U.S. Department of Energy developed the report, *Considerations for Resilience Guidelines for Clean Energy Plans*, to support the Commission's understanding of industry practices and standards.[7] This process revealed that resiliency is a key CBI and a key focus for the development of CBRE acquisition strategies for the first CEP. Further, the GMLC report revealed that resource planning is only one component of resiliency planning and the majority of best practices and standards are even more applicable to other planning practices at the Commission, including DSP. At a technical conference on December 15, 2022, the

---

[5] The Guidelines call for the Commission to consider whether to accept the filed Plan (or Plan Part) as meeting the objectives of the Guidelines. As used, "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. See Order No. 22-083 in Docket No. UM 2197, https://apps.puc.state.or.us/edockets/orders.asp?OrderNumber=22-083.
[6] See Order No. 22-206 in Docket No. UM 2225, https://apps.puc.state.or.us/orders/2022ords/22-206.pdf.
[7] See Docket No. UM 2225, Staff's Resiliency Planning Standards and Practices, September 7, 2022, accessed at: https://edocs.puc.state.or.us/efdocs/HAH/um2225hah113046.pdf.

Commission, stakeholders, and Staff highlighted the importance of continuing to incorporate the resiliency planning practices discussed in the GMLC report into the broader planning framework over time.

PGE articulates its perspective on the relationship between the interrelated planning activities below.[8]



Since 2019, Oregon has also experienced several wildfires. In 2021, Oregon utilities filed their first Wildfire Mitigation Plans detailing investments related to vegetation management and risk.[9] DSP Guidelines predated HB 2021 and do not address CEP requirements or wildfire mitigation planning. However, the Guidelines do explicitly require that utilities develop DSPs and IRPs that inform one another. To this end, Staff envisions future IRP/CEPs being both informed by and informing DSPs and will work to make sure DSP Guideline revisions support this. In procedural equity and inclusion, utilities are now combining the community outreach and engagement efforts of DSP and IRP/CEP development. Staff understands utilities are currently proposing that

[8] PGE Distribution System Plan – Part 2, page 14.
[9] See Docket No. UM 2208, 2022 Wildfire Mitigation Plan, https://edocs.puc.state.or.us/efdocs/HAA/um2208haa115610.pdf.

engagement activities for topics such as diversity, energy equity, and social justice, shift to UCBIAGs, while engagement activities for projects with impacts to local communities, or for tailoring investments/actions specific to the communities will be addressed in future DSPs.

PGE Part Two Plan and Staff Review
PGE began preparing the Part Two Plan in early 2022 by hosting its DSP Partner Workshop and Community Workshop series. The workshops represented substantial effort in involving the public in preparing the Part Two Plan, contributing information and ideas, and making inquiries and receiving information from PGE. On September 15, 2022, the Commission held a Special Public Meeting for the utilities to present their DSP Part Two filings to stakeholders, Commissioners, and Staff.[10] Staff solicited stakeholder comment through the DSP dockets.[11] Oregon Solar + Storage Industries Association (OSSIA), Renewable Northwest (RNW), and NW Energy Coalition (NWEC) provided over 30 comments on PGE's Plan. Staff is grateful to these organizations for providing feedback and looks forward to additional discussions in the future. Broadly speaking, comments provided constructive feedback and common themes, which Staff discusses throughout the memo.

Below, Staff discusses five key areas that increase insight into DSP or enable optimization of the distribution system: load growth forecasts, including adoption of distributed energy resources (DER) and electric vehicles (EV); grid needs and solutions identification; non-wires solutions (NWS); and near-term action planning. This discussion generally corresponds to the structure of PGE's Part Two Plan. Community engagement and equity are addressed throughout the new DSP process and Staff discusses those topics initially below.

1. Community Engagement and Equity Considerations

In the context of DSP, community engagement and equity include a variety of activities, and are discussed in chapter two and throughout the Plan. Examples of these activities include public involvement in the preparation and implementation of the Plan and engaging community-based organizations (CBOs) to increase awareness of large upcoming projects, to inform utility forecasting, or to provide input on development and

---

[10] See Docket No. UM 2197, Meeting Agenda, https://edocs.puc.state.or.us/efdocs/HAH/um2197hah15475.pdf, Staff's Presentation, https://edocs.puc.state.or.us/efdocs/HAH/um2197hah134041.pdf, and PGE's Presentation, https://edocs.puc.state.or.us/efdocs/HAH/um2197hah133114.pdf.
[11] See Docket No. UM 2005, https://edocs.puc.state.or.us/efdocs/HAH/um2005hah135743.pdf.

deployment of NWS. These activities represent new steps in traditional distribution planning practices.

Community engagement is important because it provides stakeholders and community members increased insight into both the distribution system itself and the planning processes utilities use to make decisions. Stakeholders and community members can examine outcomes such as the location of substations, or outage performance of feeders.

The DSP Guidelines required utilities to develop community engagement plans in Part One filings with the understanding that utilities would implement those plans in both preparing NWS proposals for the Part Two filings, and when beginning to construct large projects proposed in the Part Two filings. PGE successfully developed such a plan in preparing the Company's Part One filing.

PGE achieved substantial progress advancing community engagement and equity considerations in developing and executing two workshop series, developing an Energy Equity Index, and integrating equity data in various system maps. The overall engagement efforts contributed substantially to increased insight and form a foundation for future DSP filings. Staff finds that the community engagement accomplishments and planned future work presented in PGE's Plan met the Guideline requirements.[12]

Workshop Series – To engage technical and non-technical audiences PGE conducted both a DSP Partner and a community-focused workshop series. PGE catalogued feedback in Appendix B and plans to use lessons learned from the Community Workshop series to develop engagement plans for customers who may be affected by large, disruptive projects, or who may be able to participate in a NWS. In support of this PGE will identify a means to fund participation of CBOs. PGE plans to pursue community engagement work more effectively and efficiently by integrating DSP activities into CEP-, IRP-, and UCBIAG-related work groups.[13] Staff supports PGE's approach.

Non-Wires Solution Pilots – The Guidelines call for utilities to perform a community needs assessment to inform development of two NWS pilot concept proposals.[14] PGE began this process with a list of known grid needs which were evaluated as potential candidates for NWS. This led to five candidates and the eventual selection of the

[12] See Guidelines 5.3c and 5.3d.
[13] PGE Distribution System Plan – Part 2, page 40.
[14] See Guideline 4.3a ii).

Eastport and Dayton grid needs as candidates for NWS pilot concept proposals. PGE developed NWS for the Eastport and Dayton substations, and then engaged the communities. With the NWS pilot proposals developed, PGE began community outreach efforts for the Eastport NWS. This included meeting with leaders of CBOs and local government representatives, schools and select customers, and the Community Workshop series. For the Dayton NWS the Company did not engage customers and community partners to the same extent as for Eastport. Staff understands from the Plan this was a compromise due to time constraints driven by the misalignment of the Company's capital planning cycle and the DSP cycle. Staff encourages the Company to complete community engagement, and needs assessment, for the two pilots as the activities to date represent only partial responsiveness to the Guideline requirement. Staff will follow up in the next phase of DSP to ensure completion of this work from Order No. 20-485.

Energy Equity Index Development – PGE's Plan also presents the Company's efforts to develop an Energy Equity Index for use in DSP. PGE reviewed a range of possible equity data sources found in Appendix D.[15] The Company then utilized the Community Workshops to co-develop key metrics that have the most meaning for the participants and the communities they represent. The aggregation of these key metrics resulted in the Beta Energy Equity Index, for eventual incorporation into the Company's investment decision-making process. Staff supports its development and encourages further coordination with related efforts such as the Oregon Environmental Justice Council, CEP, CBIs, and Energy Trust equity metrics developed under HB 3141.[16]

In addition, PGE added some of this data to the DSP baseline feeder viewer map[17] and the Distributed Generation evaluation map.[18] The Company also began to incorporate various equity indicators into its DER adoption forecast tool; progress is presented in Appendix N. Adding equity data to the online maps and the forecasting tool combines new information with the engineering data traditionally used in DSP. It allows for improved targeting of future investments that may benefit underserved communities at

---

[15] Data sources include: Greenlink's Equity Map (GEM) data, customer payment metrics, Acxiom third-party datasets, U.S. Census' American Community Survey (ACS) data and Public-Use Microdata Sample (PUMS) data, and U.S. DOE's Low-Income Energy Affordability Data (LEAD) tool.

[16] For example, the Oregon Environmental Justice Council is working to develop a publicly available environmental justice mapping tool. See: https://www.oregon.gov/gov/policies/Pages/environmental-justice-council.aspx.

[17] See: https://www.arcgis.com/apps/instant/interactivelegend/index.html?appid=15681172c3ce43a6b3a01fc4efc68151.

[18] See: https://www.arcgis.com/apps/webappviewer/index.html?id=959db1ae628845d09b348fbf340eff03.

risk of being left behind in the clean energy transition and is another step in fostering a human-centered approach to DSP. Staff appreciates PGE’s efforts to achieve substantial progress advancing community engagement, and considerations of equity, in distribution planning practices and supports consolidation of these efforts across utility planning activities.

Stakeholders were complimentary of PGE’s community engagement and encouraged the Company to stretch farther in certain efforts. OSSIA appreciated PGE’s extensive workshops. RNW highlighted that PGE took the time to compile, analyze, and distill into common themes what the company heard in workshops. NWEC encouraged an expansion of workshops for community members to engage stakeholders in project co-development.

Regarding equity, RNW noted the Company’s commitment to address both current and historical disparities, and recognition of the need to build internal competence and add resources. RNW complimented PGE's capability to overlay equity data with DER forecasts as a significant advancement that positions PGE to better tailor programs to advance environmental justice goals. NWEC commended PGE for incorporating an equity lens into its DSP decision-making process and suggested it be incorporated and standardized across all planning and acquisition processes. NWEC would like to see PGE work with stakeholders to incorporate a metric for investments to reflect whether projects should be built in historically underinvested or disproportionately impacted communities.

2. Forecasting of Load Growth, DER Adoption, and Electrical Vehicle (EV) Adoption

Utility forecasting is a key element of the DSP Guidelines. It can play a critical part in achieving optimization of distribution system operational efficiency and customer value, especially over the long-term. This is because historically load growth has been one of the key factors determining traditional utility investments in the distribution system. In addition, increased adoption of DERs has led to new and expanded utility investments, and in the future increased adoption may do so to an even greater extent. Further, growth in the adoption of EVs over the coming years will play a major part in load growth. Staff finds that the Company’s forecasts for load growth, DER adoption, and EV adoption by substation meet the Guideline requirements.[19] Staff notes opportunities for future forecasting improvements below.

[19] See Guidelines 5.1a, 5.1b. and 5.1c.

Load Growth

PGE addresses forecasting in chapter three of the Plan. Staff understands that PGE creates a “top-down” load forecast, which it calls its corporate load forecast, to forecast systemwide sales to each customer class. In the short term, years one to five, PGE’s corporate load forecast is conducted separately for more than 30 distinct customer sub-classes.[20] For the long term, beyond five years, the Company aggregates these customers up to five revenue classes: residential, commercial, industrial, industrial sub-transmission, and lighting. A regression is estimated for each of these to relate the customer classes’ loads to weather and other relevant load forecasting inputs.[21] Staff notes this general methodology is similar to that used by Pacific Power and finds that it meets the Guideline requirements.

PGE also creates a “bottom-up” load forecast. This process begins by forecasting the load additions used in the long-term corporate load forecast. The Company then uses data and trends on expected load characteristics for each of the classes to estimate the new demand created by prospective projects.[22] These are then added to potential spot load additions, and the expected new load is allocated to substation transformer-level loads from the previous year. Then substation level loads are scaled to match the systemwide corporate load forecast over a twenty-year horizon.[23] This appears to be similar to the method that PGE uses to allocate new DER and EV load.[24]

Staff finds that PGE’s method to forecast existing load growth and load additions at the substation level meets the Guideline requirements and appears to be an acceptable way to forecast load for the purposes of the DSP. However, Staff notes that the importance of accurate forecasting in DSP and the newness of this load allocation methodology present an opportunity and need for a *future review of predicted- versus actual-peak loads for substations and feeders.*

DER Adoption

PGE utilizes its AdopDER model to forecast DER adoption including EV charging infrastructure, solar installations, microgrids, and behind-the-meter (BTM) storage. Energy efficiency long-run forecasts are provided by Energy Trust of Oregon. The Plan

---

[20] PGE Distribution System Plan – Part 2, page 57.
[21] PGE Distribution System Plan – Part 2, page 56.
[22] PGE Distribution System Plan – Part 2, page 59.
[23] PGE Distribution System Plan – Part 2, page 62.
[24] PGE Distribution System Plan – Part 2, page 71.

includes a high/medium/low assessment for DER adoption presented in Tables 14-19.[25] The AdopDER uses a statistical model to predict the propensity for a particular site to adopt light-duty EVs and solar installations. It creates a “heuristic model” to predict the propensity for creation of BTM storage, EV charging stations, and microgrids at various sites.[26] Staff finds that AdopDER appears to adequately balance rigor with applicability for the purposes of the DSP process. However, AdopDER’s complexity, centrality to forecasting, and apparent substantial potential result in an opportunity and need for *ongoing transparency in its functioning and accuracy.*

PGE uses AdopDER to forecast DER at the feeder level by forecasting the propensities to adopt these technologies at various sites and aggregating them up to the feeder level. PGE then uses a “Proportional Allocation Method” to allocate the total amount of DER adoption, including energy efficiency, to each feeder.[27] These results are then fed into PGE’s bottom-up load forecast to produce a total feeder-level load forecast. Regarding energy efficiency, the Company held discussions with Energy Trust to understand what locational factors might be suitable to develop such an approach. PGE also reviewed other utilities’ methodologies for disaggregating efficiency forecasts to the distribution system level. Here, as in Load Growth, Staff notes that the importance of accurate forecasting in DSP and the newness of this approach result in an opportunity and need for *future evaluation of the performance of the Proportional Allocation Method.*

From a stakeholder perspective, OSSIA commented that PGE's DER forecasting did not include Energy Trust of Oregon's "Solar Within Reach" program (SWR) or Oregon's "Solar+Storage" rebate program, and this resulted in inaccuracies in their Part Two filing. OSSIA asked that in the future PGE adjust the Company’s forecast to incorporate policies focused on solar adoption for low- and moderate-income households and asked the Commission to assess how these omissions will affect PGE’s choices for areas for DER system upgrades.

Staff engaged PGE regarding OSSIA’s comment and the Company confirmed that the DER forecast did not explicitly account for these two programs. The Company noted that while SWR is not explicitly modeled as a distinct program in the forecast, SWR projects are reflected in the model.[28] PGE stated that it plans to incorporate SWR low-moderate income incentives into the next DER forecast by Q2 2023. This will feed into

---

[25] PGE Distribution System Plan – Part 2, Tables 14-19, page 73.
[26] Response to Information Request 13.
[27] PGE Distribution System Plan – Part 2, page 71, PGE notes the Proportional Allocation Method is one of the three main methods recommended by the 2018 Distribution Forecasting Working Group.
[28] The forecast incorporates historical, site-level solar adoption into the locational propensity model, including projects previously completed through SWR.

the grid needs analysis and capital project planning for the 2025 capital cycle. Staff believes the omission of the SWR program may have a minimal to limited impact on PGE's choices for one round of capital project planning, the 2024 cycle. PGE stated in email to Staff that the decision not to incorporate the Oregon Solar+Storage rebate was based on the program sunsetting on January 1, 2024, and low participation.[29] Staff believes the omission of the Oregon Solar+Storage rebate will have a minimal impact on PGE's choices.

EV Adoption

PGE's use of AdopDER to estimate EV adoption growth rates differs from Pacific Power and Idaho Power which have applied national growth rates from published studies. PGE's Plan includes a high/medium/low assessment for EV adoption; this is presented in Table 18.[30] The Company states that its high/medium/low scenarios for EV adoption are informed by The Brattle Group's econometric estimation. However, Staff could not find other information in the Plan outlining the assumptions used to inform the choice of the high/medium/low scenarios. Staff notes that both Idaho Power and Pacific Power had sections clearly discussing the assumptions behind the high/medium/low scenarios in their Part Two filings. In response to this shortfall by PGE, Staff issued several Information Requests. PGE provided confidential materials used to create the forecasts.[31]

Staff finds the assumptions provided by PGE to be reasonable and more informative than the Plan. However, the confidential nature of the Information Request responses reveals the opportunity and need for a *transparent and accessible discussion of assumptions underlying EV adoption high/medium/low scenarios* as was envisioned in DSP requirement 5.1bii*.* Opacity of EV adoption assumptions notwithstanding, the systemwide load impacts of each scenario outlined in Tables 14-19, and expanded upon in Appendix M, appear to be reasonably reflective of what impact that level of EV adoption would have on system load, and meets the requirements of the Guidelines.

PGE's estimation of EV charging infrastructure did not rely on the Oregon Department of Transportation's Transportation Electrification Infrastructure Needs Analysis (TEINA). Instead, AdopDER used a proprietary augmentation of the U.S. Department of Energy's

[29] PGE noted that less than 10 percent of the 352 projects completed to date have been for low-moderate income qualifying projects in ZIP codes within PGE's service area
[30] PGE Distribution System Plan – Part 2, Tables 14-19, page 73. See also Figures 1 and 2 in Appendix G of PGE's DSP Part One filing, https://edocs.puc.state.or.us/efdocs/HAA/um2197haa85326.pdf.
[31] Response to Information Request 9.

(DOE) EVI Pro Lite model and Oregon's private charging need. This may omit the charging need of out-of-state EVs passing through Oregon on Interstate 5, which is included in TEINA's corridor model. In PGE's upcoming Transportation Electrification Plan, Staff expects the Company to estimate public charging infrastructure need using TEINA per Division 87 rules, or explain how its forecasts from AdopDER compare with that of TEINA.

The expected impact of transportation electrification (TE) on distribution system investments is not readily discernable from PGE's Plan. The Plan includes key research implying PGE's modeling can account for the marginal distribution system cost per EV and how proposed investments in the near-term action plan are sensitive to different EV adoption scenarios. However, the text of PGE's Plan does not connect these dots.[32] Most materially, Staff presumes the proposed investments in the near-term action plan align with the base case of EV adoption and the base case of DER forecasts from the AdopDER model, but the Plan does not state this. As EV adoption is still low[33] and PGE's Plan is the first in a new process, this is acceptable at this time. However, the importance of understanding whether proposed investments in the action plan align with the EV adoption forecast, and how sensitive those investments are to different EV adoption scenarios underscores the need for *a clearer discussion of the expected impact of TE on distribution system investments in future filings.*

3. Grid Needs and Solutions Identification

Grid needs and solutions identification are important because these processes drive the investment of millions of dollars annually and so play a major part in achieving optimization. A clear articulation of a system need, and possible solutions to that need, are fundamental to providing increased insight. PGE's discussion of grid needs and solution identification presents this material in an accessible manner, improving understanding and insight of this critical work. Staff finds that the grid needs and solutions identification discussion presented in PGE's Plan meets the Guideline requirements.[34,35] Staff's review of PGE's solutions helped illuminate a need to clarify whether filings should include project specific information, and whether or how proposed

[32] For example, Table 69 in Appendix M displays low, high, and reference case EV adoption distribution by substation, providing an example of how PGE is distributing the EV adoption modally. However the Part Two filing does not map that distribution to variation in other action plans, if the alternative scenarios were to be realized.
[33] As of June 2022, PGE had 32,981 EVs registered in the Company's service territory, Response to Information Request 11, Attachment A.
[34] See Guidelines 5.2a, 5.2b, 5.2c, 5.2d.
[35] See Guidelines 5.3a, 5.3b, and 5.3c.

projects are evaluated to meet the Guideline requirements. Staff also identifies opportunities for future improvement discussed below.

Grid Needs

PGE discusses grid needs in chapter four. Staff understands that PGE begins grid needs analysis through both near-term studies (one- to five-year) for project development, and long-term studies (five- to ten-year) to inform strategic substation and distribution infrastructure decisions. This work is highly technical involving complex forecasting and engineering exercises. Information is loaded into CYME distribution analysis software which is used to determine where grid needs exist. PGE also conducts risk analysis for distribution asset failure. This analysis considers many factors in determining the consequence of failure of specific distribution assets.

Ultimately grid needs are then prioritized using the Distribution Planning Ranking Matrix which includes five levels.[36] Staff notes that Level 5 (Safety and customer commitment) and Level 4 (Other Impacts) far outweigh Level 2 (Load Growth) and Level 1 (System utilization and DG readiness) scoring. PGE also includes key information about the Company's distribution system, and planning practices. Staff notes the opportunity to *discuss potential costs and benefits of stress-testing the Ranking Matrix and its underlying assumptions, as well as planning practices, in future filings.*

The Plan includes three key tables identifying grid needs. PGE presents in Table 21 a list of 12 prioritized grid needs that are part of the 2023 capital planning cycle, which began in 2021.[37] Table 22 presents a list of five grid needs from prior planning cycles.[38] These five needs already have solutions proposed and projects defined, but have been delayed long enough that they must be reevaluated and re-prioritized in the 2024 capital cycle, which began spring 2022. Finally, Table 23 presents 24 grid needs which will be included in the prioritization process for the 2024 capital cycle.[39] Staff finds that the discussion in chapter four meets the Guideline requirements.

In Section 4.6 PGE shares its plan to survey its customer base to acquire resiliency value of service (VOS) measures along with updated reliability VOS measures. Staff concurs with the need for improving information of this type, particularly in light of the 2021 ice storm, and the need for future Public Safety Power Shutoffs. However, Staff

---

[36] PGE Distribution System Plan – Part 2, page 88.
[37] PGE Distribution System Plan – Part 2, page 89.
[38] PGE Distribution System Plan – Part 2, page 90.
[39] PGE Distribution System Plan – Part 2, page 90.

notes the need for updated values is not limited to PGE customers. The U.S. DOE and the Edison Electric Institute are partnering with U.S. utilities and Lawrence Berkeley National Laboratory to update and upgrade the Interruption Cost Estimate (ICE) Calculator.[40] Staff believes there is an opportunity to address the need for *updated reliability and resiliency values across the state through coordinated participation of Oregon electric utilities in the DOE update effort.* In so doing, Oregon utilities will acquire better reliability and resiliency values for less cost than if acting independently, delivering better value to customers and savings to ratepayers, while also providing data for the state, region, and country. Staff offers to facilitate a workshop for DOE and National Lab staff to present further on the ICE Calculator and benefits and costs of participating in the update effort.

Solutions Identification

PGE describes the processes for identifying solutions to grid needs in chapter five. Staff understands that the PGE solution identification process involves highly technical work across multiple teams, and the work leads to a study which ultimately presents a recommended solution, and the rationale and cost for that solution. Table 26 presents a list of prioritized planning projects which address the grid needs presented in Table 21.[41] This list of projects was analyzed for solutions as part of the 2023 capital cycle (which began in 2021) and is used to inform the portfolio planning stage. Unfortunately, Table 26 does not include reference to the planning portfolio categories discussed below.[42]

As the Plan describes, projects move to the portfolio planning stage and are separated into categories. The first category is non-discretionary as they are focused on serving new customer load growth; these are called Grow the Business projects. The second category is called Sustain the Business projects. Sustain the Business projects are further broken down into discretionary and non-discretionary categories. Once non-

[40] The ICE Calculator is an electric reliability planning tool developed by Lawrence Berkeley National Laboratory (LBNL) and Nexant, Inc. This tool is designed for electric reliability planners at utilities, government organizations, and other entities interested in estimating interruption costs and/or the benefits associated with reliability improvements. The ICE Calculator is funded by the Energy Resilience Division of the U.S. DOE's Office of Electricity under LBNL, About page at https://icecalculator.com/home. Staff understands that Puget Sound Energy, Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric have agreed to participate in the update effort.
[41] PGE Distribution System Plan – Part 2, page 97.
[42] Staff was also unable to locate this info. in Appendix J, which presents additional detail on these projects.

discretionary Sustain the Business projects are funded, discretionary projects must be prioritized, resulting in a Final Prioritization Score.

Staff notes that prioritization of projects in the Grow the Business category is not discussed in much depth. For example, it is unclear whether every Grow the Business project is fully funded in each capital cycle. The Plan notes that decisions about non-discretionary, Sustain the Business projects are made outside of the process described for discretionary projects, however, that process will be expanded to include nondiscretionary projects. The Plan does not state timing, rationale, or potential impacts of these choices. Staff suggests discussing this change before the next filing. Understanding the process by which solutions are developed and become projects, and those projects are prioritized is vitally important to gaining insight into DSP broadly, and utility decision making specifically. While PGE's Plan advances insight significantly for discretionary Sustain the Business projects, there remains a need for *additional discussion of, and improved insight into, other planning portfolio categories*.

PGE's Plan notes four future developments. First, PGE discusses developing proactive replacement programs for several asset classes, such as substation transformers.[43] For the second development, PGE's Plan states that beginning with the 2024 capital planning cycle, grid need solutions will consider both traditional wired solutions and non-wires solutions. In the third development, grid need studies will be conducted using greater load variance with values expected once every ten years (instead of once every three), or summer 2021 values, whichever is higher.[44] Staff supports both of these revised analytical approaches.

For the fourth development, PGE will begin to integrate resiliency metrics into the capital decision framework likely using a new category to evaluate projects. Staff supports this development but is concerned about reliance on several of the risk elements incorporated into the Company's Strategic Asset Management construct. These elements appear to be largely in response to an observed trend in deterioration in day-to-day reliability, and the recent impact of several events which severely taxed the Company and significantly impacted customers. Staff notes that changes to PGE's investment decision making, such as proactive replacement programs or development of new resiliency metrics, create a need for *future discussion and review of these changes*.

---

[43] The programs will utilize economic life cycle models that calculate the optimal time, based on cost and risk, to proactively replace an asset.
[44] Upgrades resulting from this analysis will be considered a sensitivity option to be evaluated for benefit/cost ratio.

Stakeholders generally supported PGE's efforts, with RNW noting that PGE's load forecasting, grid needs identification (including the prioritization process), and risk/reliability methodologies provide good to excellent insight into these processes. Staff appreciates PGE's work to present this highly complex and technical material as accessibly as possible. The Plan has greatly increased insight to this critically important work. Staff finds that the discussion in chapter five meets the Guideline requirements.

Review of Proposed Solutions

PGE's Plan does not include project-specific data used by the Company to develop the solutions for each identified grid need. A key aspect of the Guidelines was documenting how solutions were assessed to meet grid needs. This is fundamental to enabling optimization of distribution system operational efficiency and customer value. Guideline 5.3b also prescribes that a Plan provide a project specific set of data used to develop solutions for each identified grid need. Despite the Guideline's lack of clarity about how to evaluate whether proposed solutions solve a respective grid need, Commission guidance was clear on documenting the link between grid needs and proposed solutions.[45]

Staff submitted project specific Information Requests to PGE in pursuit of understanding how solutions proposed in the Plan addressed the grid needs they were intended to resolve. The Information Requests prompted a useful dialogue that revealed clarity lacking from the Part Two Plan in several respects. First, at a practical level, because DSP is a forward-looking exercise, a utility may be prepared to propose a project in a DSP filing, but may not have completed preparing all the engineering and analysis for the project. Further, the utilities expressed concerns surrounding confidentiality and duplicative effort in providing project specific information as part of a DSP proceeding, a general rate case, or both. Ultimately PGE provided project specific data on projects from Table 26 as confidential responses to Staff's Information Requests. Staff appreciates PGE's willingness to provide a set of useful information and engage in productive dialogue. For now, project specific data will be included in general rate cases for projects predicted by utilities to be in service prior to the effective date for rates resulting from the general rate case filing. The clarity of Guideline 5.3b, including whether filings should include project specific information, and when Staff or

[45] Guideline 5.3b reads as follows: 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.

stakeholders are to evaluate whether proposed projects meet the Guideline requirements, needs to be improved in the future.

4. Non-Wires Solutions

NWS are, in simple terms, the use of DERs to address grid needs. NWS are important because they present the possibility to both address a grid need, and to deliver additional benefits to customers. Examples of this include energy efficiency measures, an energy storage system providing a customer resiliency during an outage and grid benefits at other times, or a demand response plan providing a customer an incentive for reducing their consumption at a particular time. NWS are often pursued as a lower-cost alternative to traditional utility solutions, and so in this response may also play a part in optimization.

PGE developed two NWS pilot proposals from existing grid needs and recommends moving ahead with both. Although PGE did not conduct a community needs assessment to inform the development of these two NWS pilots, Staff is supportive of PGE's recommendation and finds that the NWS discussion overall meets the requirements of the Guidelines.[46] Staff notes PGE's recommendation presents an opportunity for future improvement discussed below.

PGE presents its work on NWS in chapter six. Staff understands that PGE reviewed five NWS candidates in pursuit of developing two concept proposals (as called for by the Guidelines). These five candidates consisted of existing grid needs which an initial review suggested may be suitable for NWS. The Company developed the two proposals, while broader DSP practices were actively evolving. Staff appreciates the Plan's discussion and visualization of the process flow in which NWS consideration and evaluation take place.[47] Staff also appreciates the consideration of how community needs and grid needs may intersect, and how possible solutions (from DER programs to traditional, wired utility investments) may align with those needs.[48] In screening for two proposals, PGE considered numerous factors including the type of grid need, the forecast certainty of the need, the lead time, and minimum project cost. This led to the selection of the Eastport and Dayton candidates.

- The Eastport candidate explored resolution of a thermal planning criteria violation, the grid need, for both the Eastport-Plaza feeder and the Eastport WR1

[46] See Guideline 5.3d.
[47] PGE Distribution System Plan – Part 2, Figure 40, page 109, as well as Appendix E.
[48] PGE Distribution System Plan – Part 2, Figure 41, page 110, as well as Appendix E.

transformer. The Company explored three solutions: a traditional wired solution to provide a benchmark for evaluating the NWS, and two NWS with differing deployment of DERs, including energy efficiency. One NWS consisted of a front-of-the-meter approach relying on utility-scale battery storage, with some customer DER adoption, which included energy efficiency, demand response, and solar+storage. The second NWS consisted of more aggressive customer DER adoption, which reduced the need for a utility scale battery.

- The Dayton candidate explored resolution of a thermal planning criteria violation of the Dayton-East feeder and the Dayton BR1 transformer. While the violation is similar to Eastport, the Dayton candidate is a feeder serving about a third as many customers and is located in a rural area. Like the Eastport candidate, PGE explored three solutions: a traditional wired solution, a NWS that consisted of just one front-of-the-meter utility-scale battery storage, and a second NWS that included customer DER adoption including energy efficiency, which reduced the need for a utility scale battery.

In innovative and important work for the future, the Company developed costs and benefits of the wired and these non-wired solutions and makes preliminary efforts to represent these values from a system perspective. For example, costs of DERs include estimates of those borne by participants, while benefits of DERs include those to the broader system, not just those related to addressing the local grid need. However, proxies are used throughout, and customer/community benefits of DERs are not quantified. PGE also states its methodology for developing a locational value. For the Eastport candidate, the value of deferring the wired investment by 10 years is calculated to be an annualized locational value of $283.39/Kw-year. For the Dayton candidate, the value is calculated to be $650.53/kW-yr. Both values are orders of magnitude greater than the current system-wide value of $24.39/kW-yr used for energy efficiency cost-effectiveness.

The Plan notes PGE's work to gather equity data for residential customers in the two areas. This includes: the percentage in multifamily housing, the percentage renting their homes, the percentage in manufactured homes, the amount of energy assistance received, the number with registered medical equipment, as well as U.S. DOE LEAD data[49] and U.S. Census data PGE compiled developing the Distributed Generation Evaluation Map. Staff notes these analyses – capturing costs and benefits, determining

[49] U.S. DOE's Low-Income Energy Affordability Data (LEAD) tool, see https://www.energy.gov/scep/slsc/low-income-energy-affordability-data-lead-tool.

locational value, and understanding affected customers – may be valuable and informative for community based renewable energy projects.

PGE recommends moving forward with the second proposed NWS – more aggressive customer DER adoption and smaller utility scale battery – at both Eastport and at Dayton. The Plan notes critical next steps: a more detailed round of DER planning; validation of that planning by PGE, Energy Trust of Oregon, and other DER-partner organizations; and finally, PGE distribution engineers validating final plans with a power flow analysis to confirm the solution addresses the grid needs and no new issues arise.

Staff finds that the NWS discussion meets the requirements of the Guidelines and is supportive of the PGE's recommendation. Staff notes the *need for additional structure around further implementation.* This includes working with Staff, Energy Trust, and other stakeholders to clarify the regulatory pathway for advancing these efforts, and to further review and hone the pilots. Staff suggests one such opportunity may be coordinated with the Company's 2024 capital planning cycle that will consider both traditional solutions and NWS, as described in Appendix E.

5. <u>Near-term Action Plan</u>

The near-term action plan is important because it presents the utility's proposed investments in the next two to four years, as well as projected spending to implement those investments. A transparent presentation of planned projects, and a clear forecast of spending associated with those projects is vitally important in the pursuit of achieving long-term optimization of distribution system operational efficiency and customer value. From this perspective, the action plan may be the most important individual component of the Part Two filings. Staff finds that the action plan presented in the Plan meets the Guideline requirements.[50] However Staff's review of PGE's action plan suggests the next action plan should provide a finer definition of its scope and financial impacts, including project-specific costs and descriptions. Additionally, there are opportunities for future improvement discussed below.

PGE presents the action plan in chapter seven. The Company invested an average of approximately $300 million annually on distribution system upgrades from 2016 to 2020.[51] Looking forward, the Plan proposes estimated annual investments of

---

[50] See Guidelines 5.4a, 5.4b, 5.4c, and 5.4d.
[51] See Table 3, page 31, in PGE's DSP Part One filing, https://edocs.puc.state.or.us/efdocs/HAA/um2197haa85326.pdf.

$325 million from 2023 to 2026, with a total estimated cost of $1.3 billion. As presented, the proposed total covers five grid modernization projects, 276 capital projects over the next four years, and 12 projects to address prioritized grid needs investments in 2023. Staff focuses on four important aspects of the action plan in the comments that follow.

Grid Modernization

PGE first notes five investments to modernize the grid with a high-level summarization presented in Table 46.[52] More details are included in Appendix K, which is expansive and builds off PGE's Part One filing.[53] While Table 46 provides high-level information, and Appendix K provides voluminous detail, the action plan doesn't indicate specific actions the Company plans to take implementing these investments, or a timeline for those actions.

Similarly, and as discussed further below, the action plan next references 12 investments to address prioritized grid needs, and then presents summary information on nearly 300 grid needs. However, the action plan does not include specific actions. It is unclear if the action plan is meant to include only the modernization projects, the modernization projects and the prioritized grid need projects, or the modernization projects, the prioritized grid needs, and all the grid needs. Staff notes this uncertainty reveals an opportunity for *improved clarity and specificity in future action-plans.*

Distribution System Projects

PGE next notes 12 investments to address prioritized grid needs, previously discussed in the context of Table 26. The action plan then presents Table 47, which provides an annual count of 276 total projects by transmission and distribution investment type from 2023 to 2026. Presumably the 12 prioritized grid needs are included in the total, however it is not clear where these fit into Table 47.

While more specific information on the 12 prioritized grid needs is provided in Appendix J, the Plan does not provide much information about the remaining

---

[52] These investments include customer DER portal, design of a Virtual Power Plant, enhancements to AdopDER and other next generation planning resources, ADMS and distribution automation, and finally, sensing, measurement, and automation, telecommunications, and cybersecurity.
[53] Appendix K discusses these five investments, the Company's Resilience Action Plan, resilience investments, operational resilience, a discussion of targeted interventions to reduce wildfire risk from the Company's Wildfire Mitigation Plan, and finally investments to remove barriers to DER adoption.

264 projects. The action plan Guidelines reference grid needs irrespective of cause of the need, priority, estimated cost, etc.[54] And so, the lack of information about this sizable number of projects is a missed opportunity to achieve improved insight. To be clear, Staff does not suggest PGE erred including or excluding projects in the action plan. The Guidelines do not provide direction on what projects are to be included in the action plan, and this lack of clarity about scope, including whether programmatic investments are to be included with discrete investments, needs to be improved in the future.

Table 48. High-level action plan estimate

Investment Summary (estimated $M, incurred)	2023	2024	2025	2026	Total
Traditional T&D Investments for Customers, Reliability, Safety and Compliance	**$285.0**	**$285.0**	**$285.0**	**$285.0**	**$1,140.0**
Prioritized Grid Needs (included in Traditional T&D Investments)	$55.3	$56.3	$87.1	$28.7	$227.4
Grid Modernization Investments	**$40.0**	**$40.0**	**$40.0**	**$40.0**	**$160.0**
Total T&D and Grid Mod Investment	**$325.0**	**$325.0**	**$325.0**	**$325.0**	**$1,300.0**

Projected Spending

PGE provides estimated costs for proposed investments, on an annual basis from 2023 to 2026, along with totals, in Table 48. Table 48, excerpted below, presents these estimated costs broken into two categories, with one subcategory. The first category is effectively a catch-all and has a total estimated cost of $1.1 billion.[55] Prioritized Grid Needs is a subcategory of the first and has a total estimated cost of $227 million. The second category is Grid Modernization Investments and has a total estimated cost of $160 million.

[54] See Guideline 5.4a): 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.
[55] The first category is labeled: Traditional T&D Investments for Customers, Reliability, Safety, and Compliance.

Staff notes the lack of financial granularity in PGE's action plan.[56] Presenting estimated costs at such a coarse level represents a missed opportunity to achieve significant insight into estimated future spending. The lack of granularity makes it difficult to draw connections with other sections of the Plan (for example planning portfolio categories in the Solution Identification discussion) or to draw comparisons to the baseline information provided in Part One. Staff also notes the lack of project specific financial information in PGE's action plan. This concern is intertwined with the discussion of omitted project specific data in the Proposed Solutions section of this memo.

Despite these missed opportunities, Staff finds that the action plan presented in the Plan meets the Guideline requirements.[57] Staff does not suggest PGE erred in its presentation of projected spending in the action plan. The Guidelines currently do not provide direction on what level of financial granularity is required in the action plan and should be improved in the future. Staff sees this as a missed opportunity and plans to address it in DSP guidance going forward so to impact the next plan.

Prior to filing Part Two, PGE identified possible issues with estimating future investments. These included potential constraints between estimated forecasts in the DSP and public disclosure of estimated capital expenditures, specifically the quarterly completion of the U.S. Securities and Exchange Commission Form 10-Q.[58] Another concern was about the negative impact providing estimated project costs may have on the results of competitive bidding outcomes. Staff submitted Information Requests in pursuit of improving insight, and the Company's responses prompted a useful discussion about Staff's concerns. Staff appreciates the dialogue with PGE on these topics, as well as the Company's responsiveness to the Information Requests. Staff notes the Plan has improved overall insight substantially, and that despite challenges identified by PGE, there are opportunities for *improving insight into projects and project costs in future action plans.*

[56] The first category lumps 264 projects into one $915 million category, and Staff was unable to locate any project specific information about investments in this category. While Appendix J provides more information about the 12 prioritized grid needs projects it does not include costs. Though Appendix K discusses grid modernization plans thoroughly, there is scant mention of costs.
[57] See Guidelines 5.4a, 5.4b, 5.4c, and 5.4d.
[58] Response to Information Request 16, Form 10-Q is a report of financial performance submitted quarterly by public companies to the U.S. Securities and Exchange Commission, see https://www.investor.gov/introduction-investing/investing-basics/glossary/form-10-q.

Company-Proposed Regulatory Changes

The Plan presents in section 7.4 proposed changes to the existing regulatory framework addressing cost issues, investments, and incentives. PGE discusses that updated cost recovery guidance is needed to support proactive investment to make the system DER ready. PGE notes investments to support TE charging present particularly complex dynamics. RNW commented the Commission should work to remove regulatory barriers and encourage proactive grid modernization, as investments that are not aligned with the current regulatory paradigm may be the most efficient means to accelerate decarbonization. Staff notes that changing cost recovery principles for proactive grid investments is a topic that will require deliberate discussion and consideration by Staff, stakeholders, and the Commission.

PGE calls for updated cost sharing methods for interconnection. Staff notes that future phases of the Investigation into Interconnection Reform[59] will address cost issues and will be the appropriate venue to consider this issue. PGE presents principles to shift utility business incentives toward DER development, utilization, and optimization, including a proposed pilot incentive mechanism for NWS proposals. PGE does not ask for Commission action, instead seeking to work with the Commission on this topic in the Company's next general rate case. Staff thanks PGE for raising this topic and agrees that the general rate case is the appropriate place to consider such a proposal until, at such time, the Commission decides upon a more appropriate venue.

The Plan presents ongoing work to improve accounting of costs and benefits of DERs, aiming for a consistent cost-effectiveness model for use across planning activities. RNW emphasized that work on new cost-effective methodology for DERs and for value streams from NWS needs to be done transparently and in collaboration with Staff and stakeholders. RNW encouraged Staff to consider PGE's new methodology by utilizing the work and expertise of third parties.[60] OSSIA would also like to see stakeholder involvement in any change to PGE's cost-effectiveness evaluation. Staff appreciates this discussion and PGE's work, and notes that the NWS pilots may contribute rich data, development lessons, and other learnings to development of the DER valuation. Staff agrees on the need for a stakeholder process to consider DER valuation.

---

[59] See Docket No. UM 2111, https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=22475.

[60] RNW suggests considering using the principles of the National Energy Screening Project's National Standard Practice Manual for Benefit-Cost Analysis for DERs, as well as Rocky Mountain Institute's NWS Implementation Playbook.

Finally, PGE presents possible changes to the DSP Guidelines. RNW noted that revising the Guidelines should establish clear lines of sight between DSP requirements and state policy; it should be clear how each requirement supports this overarching policy and long-term DSP goals. Staff appreciates this discussion and PGE compiling these issues, and looks forward to working with the Company and stakeholders to evolve the DSP Guidelines.

Recommended Next Steps in Distribution System Planning
Staff recognizes there is much to be learned in exploring many conceptual areas moving forward. As DSP has evolved, and with the passage of HB 2021 it appears DSP will fill a key gap in an integrated planning framework. In the past, the majority of distribution system planning was conducted when certain thresholds were exceeded, such as loading limits or ages and types of equipment. This resulted in those network elements being examined for options to eliminate the exceedance, but on a very limited set of conditions, such as heavy or light loading cases, or when a certain element might be out of service. This practice was often called “deterministic planning.” In the future, more scenarios are anticipated, and Staff expects the impacts of policy, technology, and customer decisions to be profound. Staff sees DSP as the forum in which to vet these additional scenarios with network models, aligning assumptions made in other planning processes so that resource decisions, electrification expectations, and weather possibilities are all recognized when investment decisions are being made.

As clean energy planning requirements and greater incorporation of behind-the-meter uses are incorporated into DSPs, increased clarity on scenarios, resilience and risks will be helpful to new planning processes in IRP/CEPs and even to wildfire mitigation plans. Identification of risks, historic and expected performance, along with the various credible scenarios should be considered as part of the analytical framework as they are instrumental in estimating the expected benefits for a given investment. Staff believes future DSP filings can build on the good work by PGE to provide even better levels of information and insights that will empower those communities choosing in the near future to pursue community-based energy solutions or greater levels of resiliency in the face of climate change.

To this end, Staff has noted throughout this memo opportunities for continued learning or needs for improvements of future filings, which are compiled in Appendix A. Many of these opportunities do not require Guidelines revisions for implementation.

Staff recommends several next steps in DSP. First, after the Commission acts on Part Two filings, Staff plans to turn to the process of revising and improving the Guidelines in collaboration with stakeholders and utilities. Parties have begun to flag topics for inclusion in the process. Staff proposes launching the effort in Q2 2023 as utilities are required to file their second distribution system plans in the first quarter of 2025.[61] Staff will propose changes both to update Guidelines and address gaps resulting from policy and legislation to better match the Guidelines with growing utility capabilities and the evolution of the grid, customers and communities, and their needs.

More broadly Staff believes the primary focus of DSP moving forward should be utility investment planning, with an aim to improving transparency and consistency in evaluation of investments. Staff is exploring support from third party experts such as U.S DOE National Laboratories to assist in developing understanding and approaches to investment evaluation. Staff notes the following important related activities:

- Improving grid transparency for different uses, such as connecting solar generation or adding EV charging, provides greater insight into the distribution system and how it serves different communities. Staff should engage utilities and stakeholders to consider approaches to, and standards for, improving transparency-related investments – for example through hosting capacity analysis.
- A cost-benefit analysis framework that can be applied to multiple DERs across planning practices will allow for more informed and optimized utility investment decision making. Staff should consider the optimal way to develop such a framework including locational value, equity, risk, and resiliency.
- Community engagement for utility investments and actions impacting local communities should continue to be addressed in future DSPs. As the UCBIAGs progress, their discussions will inform DSP analysis moving forward.

Staff recommends the Commission accept PGE's plan. Staff's review makes no judgement on reasonableness. Commission acceptance of the Plan does not constitute a determination on the prudence of any individual actions discussed in the Plan. Staff understands that those individual actions, including project specific data, will be reviewed in a general rate case for projects predicted by utilities to be in service prior to the effective date. PGE will need to prove each project was prudent.

---

[61] See Guideline 1d): Each utility must file a subsequent Plan within two years of the Commission order for Part 2.

Conclusion

PGE's Plan represents a step forward in DSP. It improves insight into utility planning practices and forecasted outcomes. While there are still areas for improvement, especially around project selection transparency, the Plan also represents progress in engaging communities, considering equity in DSP and exploring NWS. PGE's plan provides value, most significantly in supporting decarbonization, and other critical policy goals. Staff finds that PGE's Plan meets the criteria and requirements of the Guidelines.

Staff also recommends renewed suspension for the 2023 Smart Grid Report filing cycle, as established in Docket No. UM 1460, Order No. 17-290 (currently PGE, June 1, 2023, Pacific Power, August 1, 2023, Idaho Power, October 1, 2023). 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 Smart Grid Report and integrating these into the next evolution of the DSP Guidelines.

PROPOSED COMMISSION MOTION:

Accept the Distribution System Plan – Part Two filing by Portland General Electric as meeting the requirements of the Distribution System Planning Guidelines established in Order No. 20-485 and suspend the 2023 Smart Grid Report filings.

Appendix A

The following table summarizes opportunities for continued learning and improvement in PGE's DSP as noted in Staff's Memo.

Forecasting
(Load Growth)
Staff notes that the importance of accurate forecasting in DSP and the newness of the load allocation methodology present an opportunity and need for a *future review of predicted- versus actual-peak loads for substations and feeders.*

(DER adoption)
AdopDER's complexity, centrality to forecasting, and apparent substantial potential result in an opportunity and need for *ongoing transparency in its functioning and accuracy.*

(EV adoption)
In EV adoption, as is the case in Load Growth, Staff notes that the importance of accurate forecasting in DSP and the newness of this approach result in an opportunity and need for *future evaluation of the performance of the Proportional Allocation Method.*

The confidential nature of Information Request responses reveals the opportunity and need for a *transparent and accessible discussion of assumptions underlying EV adoption high/medium/low scenarios* as was envisioned in DSP requirement 5.1bii.

Grid Needs
(Forecasting – EV adoption)
The importance of understanding whether proposed investments in the action plan align with the EV adoption forecast, and how sensitive those investments are to different EV adoption scenarios underscores the need for *a clearer discussion of the expected impact of TE on distribution system investments in future filings.*

(Grid needs)
Staff notes the opportunity to *discuss potential costs and benefits of stress-testing the Ranking Matrix and its underlying assumptions, as well as planning practices, in future filings.*

(Grid needs)
Staff believes there is an opportunity to address the need for *updated reliability and resiliency values across the state through coordinated participation of Oregon electric utilities in the DOE update effort.*

Improved Insight for Investment planning
(Solutions identification)
While PGE's Plan advances insight significantly for discretionary Sustain the Business projects, there remains a need for *additional discussion of, and improved insight into, other planning portfolio categories*.

(Solutions identification)
Staff notes that changes to PGE's investment decision making, such as proactive replacement programs or development of new resiliency metrics, create a need for *future discussion and review of these changes*.

(Near-term Action Plan)
Staff notes uncertainty about projects included in the Action Plan reveals an opportunity for *improved clarity and specificity in future action-plans.*

(Near-term Action Plan)
Staff notes the Plan has improved overall insight substantially, and that despite challenges identified by PGE, there are opportunities for *improving insight into projects and project costs in future action plans.*