BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

Docket No. UM 2198

In the Matter of PacifiCorp, dba Pacific Power Distribution System Planning Report.	Comments of NW Energy Coalition

NWEC appreciates the opportunity to provide comments on the first phase of the Distribution System Plan (DSP) submitted by PacifiCorp.

At the outset, we express our appreciation for the extensive work by PacifiCorp in preparing this first submission, as well as the work of all utilities, stakeholders and Commission Staff in the preparatory phase of Docket No. UM 2005.

We provide these initial comments knowing that additional insight will be gained from the forthcoming discussion of this and the other DSP Phase 1 filings by PGE and Idaho Power.

At the outset, we address the four core principles identified in the DSP filing (p. 3):

- *Transparent and comprehensive data sets for customers, communities, regulators and stakeholders to evaluate and set priorities recognizing goals of the state in advancing a clean, equitable energy future.*
- *Robust engagement with communities, stakeholders and regulators to ensure access to new datasets and technologies are properly advanced through investments by PacifiCorp and partners.*
- *Technology adoption at a pace customers can afford and the company can perform.*
- *Increasing resilience in the face of climate change and customer expectations.*

In NWEC's view, these principles are part, but only a part, of a solid foundation for DSP and the ongoing activities it will enable going forward. The principles do not directly address the importance of co-development with customers and communities of the policies, data sources and programmatic efforts.

The purpose is not only to support the utility's interest in more effective operation of the local system but also to provide for more choices and protection to customers in a manner that is grounded in equity and responsive to community development concerns.

The distribution system can help provide economic opportunity and electric service resilience in a manner that is grounded in equity. Furthermore, the key challenge ahead is turning starting principles into action. All of this will be considerably advanced by an initial commitment to full community engagement and accountability.

Our discussion below starts with community engagement and then turns to system description and hosting capacity analysis issues.

Community Engagement

NWEC appreciates the effort PacifiCorp has put into its community engagement plan thus far. However, we would like to see more actual engagement from PacifiCorp with its communities. Understanding that DSP is a highly technical and complex process, we believe that it is a crucial step in transforming our energy system and calls for direct participation and shaping by communities that this same system serves.

The DSP states (p. 73):

> *PacifiCorp is working to establish a DSP public participation process that is open, transparent, equitable and accessible. To meet those goals, the company has begun the process of seeking input by working to ensure that communication with stakeholders is proactive and easy to understand. The company will also prioritize outreach to communities and customers who have been identified as traditionally underserved and underrepresented . . .*

NWEC believes that this overall approach is appropriate; however, it should be executed in more effective ways as described below.

The DSP continues (p. 73):

> *PacifiCorp will engage with frontline communities, tribes, equity and environmental justice organizations, community-based organizations and others in Oregon to co-create the membership of the CIG and for input into the development of the DSP community engagement plan.*

The DSP also specifies (p. 79):

> *A core group of CIG members will be formalized that will include representatives from the following backgrounds and perspectives:*
>
> - *Environmental justice*
> - *Public health*
> - *Tribal*
> - *Asian Pacific Islander community*
> - *Hispanic community*
> - *Veterans*
> - *Low-income population*
> - *Agricultural workers*
> - *Local social service leader*
> - *Local business owner*

NWEC commends PacifiCorp's effort to put together a Community Input Group (CIG). We also appreciate PacifiCorp's plans to include various community leaders in the makeup of the CIG. PacifiCorp mentions that the CIG will ensure that its communities' health, safety, and interests are considered in the DSP process.

Without more information, however, it is difficult to discern precisely how the CIG will engage in this work and to what extent community members may interact with the CIG. PacifiCorp should provide this information and offer more context as to the purpose and plans for its CIG and how the broader communities within its territory may participate in this process and the continued work of the CIG.

PacifiCorp also mentions that its Regional Business Managers (RBM) are working with "stakeholders" and "expert advisors" to identify CIG "members" and "participants." It is unclear who all these players are. Where possible, PacifiCorp should identify which key stakeholders and expert advisors it is working with and explain the roles the CIG members and participants will hold. More clarity in this area will allow for rightful participation from community members in the DSP process; PacifiCorp will undoubtedly benefit from this participation as well.

Outreach Methodologies

The DSP provides (p. 75):

> *Direct outreach methods to the DSP stakeholders occurs via email and through a dedicated DSP webpage that provides meeting materials, stakeholder feedback forms, and participation information for each meeting.*

In addition to email and its dedicated DSP website, PacifiCorp lists a couple of other tools that it plans to use to disseminate information to its communities regarding DSP processes. These tools include: project facts sheets and flyers, CIG pre-meeting materials, CIG meeting summaries, utility bill inserts and messages, interactive voice response, social media, paid media, and partners channels.

Although NWEC believes that these tools can have practical value, one significant missing component of PacifiCorp's outreach plan is direct communication with its community members. PacifiCorp should endeavor to have more in-person and online meetings – depending on customer needs – to discuss DSP processes. These meetings are essential as they allow space for questions and immediate clarification on community members' concerns.

Community Input

The DSP states (p. 76):

> *PacifiCorp is in the early stages of developing a customer survey administered by a hired third party agency. The survey will be targeted at the company's Oregon customer base*

> *to gather input on DSP. The overall objective of this research is to measure the public's awareness of distribution system planning.*

In addition to its customer survey, PacifiCorp plans to collect input from its communities through email and public meetings and workshops. NWEC believes that these are good tools; however, they may be insufficient to collect information from its communities adequately.

To sufficiently collect input from its communities, PacifiCorp should ensure that it actively engages with its community members in ways that allow for accurate assessment of its communities' needs and wants. This engagement may include having in-person meetings and separate one-on-one meetings with community groups. Considering the complexities of DSP,

It would also be beneficial for PacifiCorp to offer its communities and other interested stakeholders a direct line of communication (by phone, text, email, and in-person) that is dedicated to answering questions and concerns regarding DSP. To maintain consistency in communication and increase transparency, it would be best to establish this via a single designated DSP staff. This framework will help remove existing barriers to understanding and participating in DSP processes.

As PacifiCorp begins its community engagement phase, it should always ensure that the information it provides and asks from its communities is straightforward, easy to understand, and accessible. This information-sharing structure will result in actual and effective participation from its community members.

In sum, NWEC appreciates PacifiCorp's initial plans to engage with its communities; however, more intentional and targeted community engagement work is necessary to bring about meaningful collaboration between PacifiCorp and its community members.

System Description

The DSP Phase 1 submission contains many elements that, for the first time, provide a comprehensive view of the PacifiCorp distribution system. We will not discuss every element in detail here and instead focus on notable aspects and pose further questions for refinement.

NWEC appreciates the clear and wide-ranging overview of the legacy distribution system and the assessment and planning methods and models used to manage the system.

The submission states that load growth assessment is conducted for five years going forward based on a linear extrapolation (p. 11). Later it states, "However, demand side changes and net metering impacts are incorporated as a form of load attrition by evaluating recent peak trend events, such that if demand response or customer generation resulted in a slower growth trend for an area, that trajectory would result in a lower future demand curve."

It would be helpful to understand how and where these adjustments are made – at the area, substation or feeder level. New demand drivers include the recent uptake of efficient LED lighting, the addition of new air conditioning and HVAC equipment in the wake of increasing summer heat waves, and increased uptake of rooftop solar and electric vehicle charging equipment. All of these may affect not only overall demand but the daily and seasonal shape affecting distribution system usage and constraints.

The submission states (p. 17) that vegetation management is completed on a four-year cycle except in Portland, where it is a two-year cycle. It would be helpful to understand the reason for this difference.

As indicated in Table 9 (shown below), Oregon distribution system expenditures have more than tripled recently, from $86.4 million in 2016 to $273.6 million in 2020. As highlighted, some categories have rapidly ramped up, while others, particularly grid modernization, have peaked and then fallen. Does PacifiCorp anticipate that the overall higher levels will continue going forward?

Table 9: Oregon Distribution Expenditures 2016-2020

Distribution Expenditures					
	2016	**2017**	**2018**	**2019**	**2020**
Age-related replacements and asset renewal[24]	$39,122,734	$47,876,750	$52,563,797	$64,365,314	$184,802,037
System expansion or upgrades for capacity	$15,384,819	$19,310,164	$13,534,878	$17,178,752	$13,806,592
System expansion or upgrades for reliability and power quality	$1,762,629	$3,005,717	$3,887,425	$5,226,282	$8,718,064
New customer projects	$22,957,880	$28,596,079	$52,196,585	$51,478,406	$59,743,493
Grid modernization projects	$6,014,745	$28,147,971	$62,737,874	$37,497,389	$4,929,728
Metering	$1,368,192	$1,325,336	$614,372	$551,449	$1,514,376
Preventive maintenance[25]	$0	$688	$21,304	$8,476	$42,685
Grand Total	**$86,464,085**	**$128,262,705**	**$185,556,235**	**$176,306,068**	**$273,556,974**

On a more specific point, we note that Table 8 (p. 54) provides a helpful summary of Oregon distribution system assets. For the 253 transformers in the Oregon system, the current average life is 46.9 years and the expected average lifetime is 53 years. Is PacifiCorp taking special steps to accelerate replacement, and if so what financial impact will that have?

Also, the 2021 Integrated Resource Plan (Table D.4) indicates a major increase in demand response acquisition of over 681,000 MWh in 2021-25. NWEC is very pleased to see this substantial commitment to new DR. Does PacifiCorp have any estimate of how much distribution system investment will be needed to support the new DR resources?

Table 17 summarizes Energy Trust of Oregon incentives by county. We note a wide disparity in the average incentives per customer. The top six counties are as follows:

County	Customers	Average ETO Incentive
Jackson	92,829	$16.13
Multnomah	85,671	$46.30
Deschutes	66,636	$18.74
Linn	51,741	$13.01
Douglas	44.075	$13.10
Josephine	43,025	$18.37

Our question is about the underlying reasons for the significant difference in average incentives. The more detailed data in Table 18 indicates much of the difference may be due to the greater aggregate size of commercial and industrial load in Multnomah County, but it also indicates the incentives per residential customer are still considerably higher than the other counties. We are concerned whether this pattern will persist for other distribution system equipment and incentive investments. In some cases, particularly for system hardening for wildfire, seismic and other resilience purposes, higher spending in outlying areas may well be in order.

Concerning future capacity analysis, the DSP notes (p. 67), "In the future, PacifiCorp anticipates the need for more granular capacity analysis processes which are supported by advanced tools capable of forecasting using appropriate econometric and weather-normalized modeling. These modeling improvements will incorporate customer-driven and customer-provided data. PacifiCorp envisions this approach to be 'crowd-sourced' options identification." It would be helpful to have more clarity about what "crowd-sourced" means in this context.

Referring to Figure 35, DOE's DSP Community-Accessible Program Options as a Function of Development Cycle, the DSP states (p. 69), "During the transitional time, the company proposes using study areas identified for 2022 as target areas for conducting community-involved pilot options locations. Those areas are shown below in Table 20 and Figure 36. This list was selected based on the need for planning study to be performed, the existence of circuit-level SCADA and the availability of DG capacity and opportunity for its deployment (based on the DG readiness rating)." We seek clarification about why the target areas apparently do not include any pilot locations in the Columbia Gorge, Portland, mid-Willamette Valley and central/south Oregon coast areas.

Finally, NWEC would like to suggest an additional topic for clarification. It is often said that the distribution system must evolve to accommodate "two-way flow," but it is not entirely clear what that actually requires. It is not simply the addition of system protection at the substation and elsewhere to mitigate the risk of backfeed, it also involves the modification of other elements including sensing, measurement and control and telecommunications. A clearer statement of PacifiCorp's view of what is needed to enable the two-way grid would be very helpful.

Resilience

The fourth core principle stated in the DSP is "Increasing resilience in the face of climate change and customer expectations." Yet the Phase 1 submission contains no effective discussion of the context or a strategy or roadmap to address these concerns and, importantly, to fully engage the most affected communities.

One question that often arises is whether undergrounding vulnerable parts of the distribution system can help improve resilience. But the DSP only briefly mentions the amount of underground assets and the inspection cycle. In addition to clarifying how many distribution line miles are currently underground and where, it would be helpful to have PacifiCorp's view of the conditions for which undergrounding of distribution wires and equipment can be beneficial, especially for wildfire and seismic risk mitigation.

It would also be useful to include within the DSP a regular process for including the lessons of event analysis such as the recent cycle of wildfire, ice storm and heat dome extreme weather events.

Hosting Capacity Analysis

NWEC appreciates the detailed discussion of the first phase of hosting capacity analysis. A key point is that HCA is very dependent on data availability and quality.

The DSP notes (p. 20), and also illustrates in Fig. 12 (p. 30), that SCADA is in place for 41% of circuits and half the customer base in Oregon. The discussion goes on (p. 37), "Currently load data is collected via SCADA or manually at the circuit breaker and substation transformer level and is not collected at any other device on the distribution system. This limits the scenarios that can be modeled and creates uncertainty as to how much load is on a line section or service transformer at any given time." Further (p. 38), "Currently in substations without SCADA the daytime minimum load has been determined based on historical load data from other circuits of similar topology, area, and customer makeup."

We have two initial concerns. First, the focus on daytime minimum load (DML) has a number of apparent shortcomings. Data quality is a concern, both in terms of consistency and gaps, regardless of what metric is used.

Second, the effects of distribution automation, SCADA and the presence of FLISR capabilities may affect the interpretation of the DML metric. We are not arguing against DML but rather in favor of further refinement and potentially developing a multi-factor index. It is also important, given the mixed availability of SCADA and other data sources in the Oregon distribution system, that data limitations not constrain the availability of distribution system enhancements and program offerings, whether through HCA assessment or other factors.

We also suggest designing reference use cases such as rooftop solar, community solar, a couple different forms of EV charging (for example, for light duty and heavy duty vehicles), and different types of battery storage, in order to provide a common framework for assessment of HCA outputs, particularly the use of the GIS mapping now in development. These use cases should be developed in conjunction with service providers and community based organizations, which will have somewhat overlapping and somewhat different needs for the same HCA data. It may also be beneficial to test specific new facilities envisioned by community based organizations with the evolving HCA framework.

Finally, NWEC appreciates the detailed discussion of the three options for further HCA development. In general, we believe that Option 2 provides the best balance of cost, effort and capability going forward, but this is also a topic deserving of additional technical workshop review.

Customers and Data

NWEC frequently stated our concern about data access, quality and security during the development phase of UM 2005. But the DSP submission does not discuss the many implications of this new complex data fabric, including both benefits and risks.

For example, the section on "Confidentiality and sensitive data protection" (p. 82) refers to protection of sensitive or CEII data for the bulk power system, as well as customer identification for substations serving a single industrial customer or the military. And Table 24, summarizing the three HCA options, notes for Option 2, "To maintain project confidentiality many feeder segments will require redaction and result in limited value to broad use by community stakeholders."

Those are valid concerns but do not fully represent the range of data issues at stake in distribution system planning and operation. Since distribution system data is ultimately about customer use and contribution to the power system, this raises substantial questions of customer protection, agency and access.

Traditionally and rightly, utilities have been obligated to tightly protect customer data. In the not distant past that primarily referred to monthly meter readings and billing data, all under direct utility control. The arrival of advanced metering infrastructure and the development of new customer energy services, automation, and convergence with telecommunications and information technology, has dramatically expanded the potential and the risks of data relating to the distribution system.

Data is no longer developed only within the utility's equipment up to the customer meter but also by a variety of other functions and services with many different sources and repositories on the customer side, including distributed generation, demand response and storage. These sources may be distinct from traditional meter and distribution system data, but increasingly are essential to operating the distribution system and may be used in multiple ways by utilities, service providers and customers alike.

Likewise, the same data sources and processes that provide much better identification of system faults, improved customer account management and new distribution system services also expose numerous risks for customers, suppliers and utilities.

All this raises some fundamental issues: who owns, has access to and has responsibility for distribution system and related customer data? What risks must be identified and addressed, including the risks created by combining otherwise disparate data sources as well as the often hidden consequences of variations in data quality?

We appreciate that these issues have gotten early attention in the UM 2005 technical workshops sponsored by Staff, but it is time for these data concerns to be addressed in the utility DSP filings.

This concludes NWEC's comments. We look forward to further discussion and development of the PacifiCorp Distribution System Plan.

Respectfully submitted,

/s/

Fred Heutte
Senior Policy Associate
NW Energy Coalition

Marli Klass
Energy and Environmental Justice Policy Associate
NW Energy Coalition

Jeff Bissonnette
Senior Advisor
NW Energy Coalition