Oregon Distribution System Plan – Part 2

PACIFICORP.

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Acronyms

Acronym	Term
AC	Air Conditioning
AEG	Applied Energy Group
AMI	Advanced Metering Infrastructure
AMPS	Asset Management and Planning System
AMR	Automated Meter Reading
ANSI	American National Standards Institute
CAES	Compressed Air Energy Storage
CAIDI	Customer Average Interruption Duration Index
CAISO	California Independent System Operator
CBIAG	Community Benefits and Impacts Advisory Group
CBO	Community-Based Organization
CEP	Clean Energy Plan
CES	Centralized Energy Storage
CIG	Community Input Group
CPA	Conservation Potential Assessment
CYME	Load flow modeling tool used by Field Engineers and Area Planners
DA	Distribution Automation
DER	Distributed Energy Resource
DG	Distributed Generation
DMS	Distribution Management System
DOE	Department of Energy
DRIP	Distribution Reliability Improvement Program
DSM	Demand-Side Management
DSP	Distribution System Planning
DR	Demand Response
EE	Energy Efficiency
EIM	Energy Imbalance Market
EPA	U.S. Environmental Protection Agency
ETO	Energy Trust of Oregon
ETR	Estimated Time of Restoration
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
FCA	Farmers Conservation Alliance
FE	Field Engineer
FERC	Federal Energy Regulatory Commission
FHCA	Fire High Consequence Area
FIOLI	Fuse It or Lose It

Acronym	Term
FLISR	Fault Location, Isolation and Service Restoration
FR	Fault Recording
GIS	Geographical Information System
GNA	Grid Needs Assessment
HB	House Bill
HCA	Hosting Capacity Analysis
IEEE	Institute of Electrical and Electronics Engineers
IMC	Incremental Measure Cost
IOC	Integrated Operations Center
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
ISO	Independent System Operator
IT	Information Technology
kW	Kilowatt
kWh	Kilowatt-hour
LEAD	Low Income Affordability Data Tool by DOE at https://www.energy.gov/eere/slsc/maps/lead-tool
M&V	Measurement and Verification
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Corporation
NIST	National Institute of Standards and Technology
NREL	National Renewable Energy Laboratory
NWS	Non-Wires Solution
O&M	Operations and Maintenance
OMS	Outage Management System
OPUC	Public Utility Commission of Oregon
OSSIA	Oregon Solar and Storage Industry Association
PG	Private Generation
P&N	Purpose and Necessity
PCT	Participant Cost Test
PHES	Pumped Hydroelectric Energy Storage
PMU	Phasor Measurement Unit
PV	Photovoltaic
RAS	Remedial Action Scheme
RBM	Regional Business Manager
RE	Range Extender
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SER	Sequence of Events Recording

Acronym	Term
SCADA	Supervisory Control and Data Acquisition
SOC2	Service Organization Controls
T&D	Transmission and Distribution
TE	Transportation Electrification
TLM	Targeted Load Management
TOU	Time-of-Use
TRC	Total Resource Costs
UCT	Utility Cost Test
VAR	Volt-Ampere-Reactive
WECC	Western Electricity Coordinating Council

Executive Summary

PacifiCorp shares a vision with its customers and communities in which clean energy across the West powers jobs and innovation. This bold vision has guided the Company's work for years. Most recently it took shape in our 2017, 2019 and 2021 Integrated Resource Plans, which outlined an ambitious path to substantially increase PacifiCorp's renewable energy capacity, evolving its existing portfolio and connecting supply with demand through an expanded, modernized transmission system. The vision is now extending into distribution system planning (DSP) as PacifiCorp supports Oregon's UM 2005 efforts to "develop a transparent, robust, holistic regulatory planning process." The Company also recognizes the need to maintain safe, resilient and affordable power and to support Oregon's diverse customer base as it shifts toward this clean energy future.

In Oregon, PacifiCorp has shared this commitment in a variety of ways over recent decades with its significant investments in renewable generation, the installation of smart meters that allow customers to pinpoint their power consumption, support of private generation, and innovative pilot activities to support new energy options, resources and programs

Over the past year, in response to state of Oregon measures related to DSP, PacifiCorp has expanded its efforts to broaden the perspective of DSP to become more engaged with its customer base and more transparent. Between May 2021 and July 2022, the Company held 10 stakeholder workshops to share and discuss upcoming infrastructure design plans, and to listen to its customers. In October of 2021, the Company provided the Oregon Public Utility Commission (OPUC) with DSP Part 1. This DSP Part 2 builds on the work from DSP Part 1 to further evaluate how to evolve planning processes and needs and outlines a roadmap to considering alternate solutions in a way continues incorporating valuable conversations with customers and stakeholders.

The Company and its customers are living through a period of accelerated change. By actively working with stakeholders and leveraging decades of institutional knowledge, PacifiCorp is leaning into that change in multiple ways. The future of this state and of this region involves renewable energy and storage, transportation electrification and a broad range of options for energy efficiency. From Coos Bay to Joseph and Portland to Klamath Falls, the Company is collaborating and learning, planning and acting. Traditionally, solutions to grid needs are thought to involve bigger conductors or added substations; the Company is learning how to identify and use localized data analysis to evaluate the costs and benefits of a wide range of non-wires solutions. In this DSP Part 2 report PacifiCorp provides specifics about its efforts to develop robust and transparent distribution network plans and processes that consider both wires and non-wires solutions to align with the regions shifting energy needs. The Company recognizes that increasingly innovative energy solutions designed in a measured, thoughtful manner will shape the path ahead.

The Company shares Oregon's vision of delivering affordable and reliable energy service while addressing greenhouse gas emissions. PacifiCorp *will* bring the best of the West to our customers' doors. With vision, with measured effort, with careful design, the energy grid *will* connect local communities to the low-cost and reliable energy they need. DSP Part 2 continues the Company's effort to evolve its methods toward that future and the building blocks, including the logical progression to support this vision.

Chapter 1: Introduction

1.1 Chapter 1: Readers Guide

This chapter outlines PacifiCorp's distribution system planning (DSP) vision and strategy, provides the regulatory framework as outlined by the Oregon Public Utility Commission (OPUC) and explains how the remainder of the filing is structured to support understanding of the Company's DSP plans.

First, this chapter introduces readers to PacifiCorp's vision and strategy for Oregon DSP against the broader context of PacifiCorp as a multi-jurisdictional utility and as a member of Berkshire Hathaway Energy. Next this chapter summarizes the regulatory guidelines for DSP Part 1 and Part 2.

The final sections of this chapter summarize the items covered in the DSP Part 1 materials, highlight objectives and goals for this Part 2 filing, and outline the contents of subsequent chapters to provide readers an understanding of the structure and contents of the document.

COVERED IN THIS CHAPTER

Present PacifiCorp's DSP vision and strategy

Detail the DSP regulatory structure (Part 1 + Part 2) and cover high-level guidelines

Summarize the materials included in DSP Part 1

Describe high-level goals and objectives for this Part 2 filing

1.2 Introduction to DSP Part 2

As the Company stated in its DSP Report Part 1, PacifiCorp supports Oregon's vision of a clean energy future that is safe and resilient, empowers customers and creates balanced outcomes for all participants. PacifiCorp has previously shared this commitment in a variety of ways. PacifiCorp reiterates this commitment to ensure understanding and broad awareness, particularly given the importance of the message and the new audience associated with DSP. The Company strives to bring the best of the West to its customers' doors by incorporating stakeholder concepts to reframe the Company's vision, while leveraging its experience with innovation. Critical to this future, is collaboration across a broader continuum of voices than has previously been integrated into Company plans. The DSP plan is intended to create a framework for understanding that future and the building blocks, including the logical progression and costs to support this vision.

PacifiCorp shares a bold vision with its customers for a future where energy is delivered affordably, reliably and without greenhouse gas emissions. A future where the Company's vast, modern energy grid connects local communities to the low-cost and reliable energy they need to innovate and achieve their goals. Like its customers, the Company believes that affordability and sustainability go hand in hand and form the foundation for a reliable, resilient energy future — where regional and state economies benefit from investments in energy resources and infrastructure that help them pioneer new growth opportunities. It is an ambitious vision, and one that is achievable. Together, we are creating the future by connecting the West's diverse resources to the vast reach of PacifiCorp's transmission system, and by investing in technology, partnerships and markets. PacifiCorp knows it is possible because it is already happening.

In 2019, the OPUC opened docket UM 2005 to investigate investor-owned utility's (IOU) DSP practices.[1] This investigation developed initial guidelines that accelerate Oregon's clean energy investments and transformed how IOUs plan for the distribution system. The DSP Guidelines were approved in OPUC Order No. 20-485 and set forth a "transparent, robust and holistic" DSP process.[2]

This document lays out how PacifiCorp will transform its system to enable this clean energy future for all customers. It further outlines critical elements that must be in place and tactically deployed to support this future state.

PacifiCorp Vision

When PacifiCorp joined Berkshire Hathaway Energy in 2006, the Company set out to deliver sustainable energy solutions while continuing to provide customers with the highest levels of service. The connection with Berkshire Hathaway Energy allowed the Company to reimagine how energy is produced, dispatched and delivered. In conjunction with re-envisioning production and distribution, PacifiCorp understood the significant value in discovering the needs and aspirations of its customers and communities. The Company also recognized the West's abundance of diverse natural resources could support delivering even greater value. Finally, PacifiCorp believed that the greatest gains could be realized by building upon the more than 100 years of innovation that helped create its 10-state energy grid.

By tackling every challenge and drawing on a track record of partnership and technology-driven innovation, PacifiCorp could transform its expansive grid into an industry-leading, interconnected energy system—a system uniquely equipped to access and deliver the best energy resources the West has to offer.

PacifiCorp got to work bringing this vision to life. As the largest regulated utility owner of wind power in the West, PacifiCorp is going further with strategic investments in renewable resources, energy storage and transmission for a reliable and resilient clean energy future.

PacifiCorp envisions an energy future where its distribution network delivers value to the communities it serves, through efficient energy delivery in a manner that benefits its diverse mix of customers. PacifiCorp serves a broad continuum of communities and advances this plan to meet

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[1] OPUC Distribution System Planning Initiative, https://www.oregon.gov/puc/utilities/Pages/Distribution-System-Planning.aspx

[2] *In the Matter of Public Utility Commission of Oregon, Consideration for Adoption Staff Proposed Guidelines for Distribution System Planning,* Docket No. UM 2005, Order No. 20-485 (Dec. 23, 2020) (available at https://apps.puc.state.or.us/orders/2020ords/20-485.pdf).

those communities where they are, whether that is in a highly dynamic energy trading environment or in a manner more aligned with the legacy system. To accomplish this, the legacy of one-way energy generation and delivery from the top down must evolve into a near-frictionless environment in which the use of decentralized resources is conducted equitably. The system must become highly intelligent (or have information and automation to support advanced operations) and be flexible as new needs, resources and scenarios evolve.

For more than a century, PacifiCorp has delivered safe, reliable and cost-efficient power to its customers. As customers' needs have evolved, so has the system; further, as technology afforded better costs and expansion of the network, those features have been and will continue to be delivered to customers and communities.

Strategy: Reinventing the Future Through Collaboration

For more than a decade, PacifiCorp has successfully reduced its carbon emissions and improved reliability while simultaneously delivering energy cost savings to its customers. The Company has achieved these results and created a more open and connected Western grid by collaborating with others outside of the organization and through the visionary efforts of Company generation, transmission, information technology and energy supply management teams.

In 2014, PacifiCorp pioneered the Western Energy Imbalance Market (EIM) in partnership with the California Independent System Operator (CAISO). This innovative market allows utilities across the West to access the lowest-cost energy available in near real-time, making it easy for zero-fuel-cost renewable energy to go where it is needed. If excess solar energy in California, excess wind from Wyoming or hydropower from Washington and Oregon is available, PacifiCorp will harness it and transport it instantly across the Company's 17,000-mile grid. Similarly, as the Company digitizes the distribution network, equivalent efficiencies will be harnessed within the local system. So, if a customer at one location is using less energy than their distributed generation resource, like a solar array, their neighbor can benefit from that resource by using the interconnected distribution system.

PacifiCorp recognizes that effectively conducted planning includes community involvement in prioritizing utility distribution investments; the Company considers this involvement to be foundational in implementing new technologies, whether on the customer or Company side of the meter. The DSP will create a pathway for advancing clean energy goals and will support equitable resource allocation across the diverse territory served by the Company.

DSP Core Principles

Transparent and comprehensive data sets for customers, communities, regulators and stakeholders to evaluate and set priorities while recognizing state goals for advancing a clean, equitable energy future

Robust engagement with communities, stakeholders and regulators to ensure access to information and data and to encourage adoption of new technologies through properly advanced investments by PacifiCorp and its 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

Regulatory Background

As informed by Oregon Senate Bill 978 (2017) and Governor Brown's Executive Order No. 20-04, these principles highlight the importance of exploring new expectations for the electric grid, the importance of clean energy, inclusivity and customer options. As a result of the Integrated Resource Plan (IRP) process, the OPUC sought to broaden planning to include more thoughtful consideration of electric utility grid modernization and to increase focus on DSP for the distribution system. On February 19, 2019, OPUC staff released a white paper, A Proposal for Electric Distribution Planning[3] that outlined a proposal to investigate distribution planning. On March 22, 2019, the OPUC opened an investigation, docket UM 2005, to "develop a transparent, robust, holistic regulatory planning process for electric utility distribution system operations and investments."[4] Staff developed guidelines through a series of stakeholder workshops and webinars that examined best practices and approaches to DSP; these guidelines were informed by an OPUC Special Public Meeting and public comment on the draft guidelines.

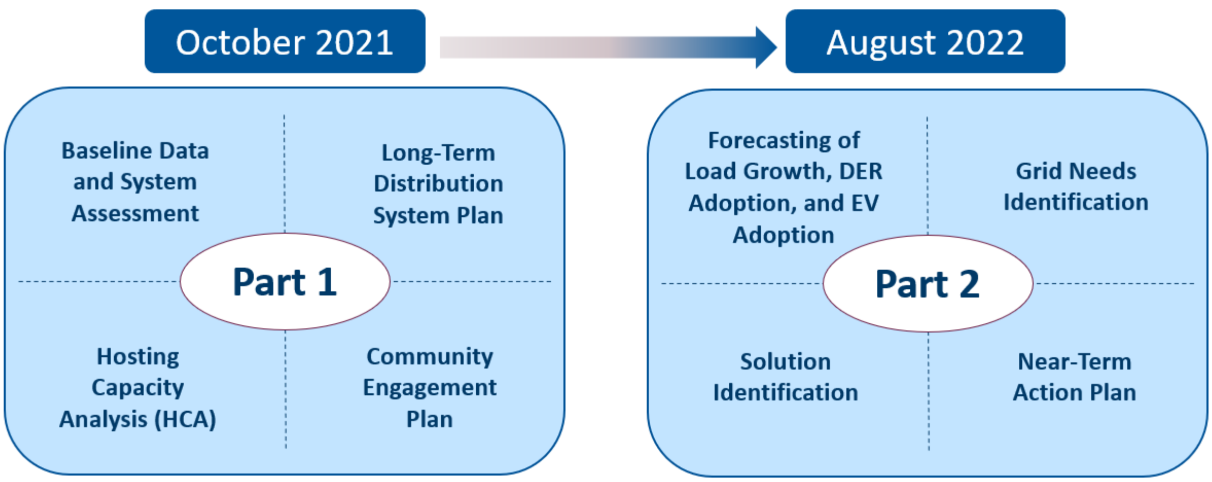


Figure 1: DSP Programs and Timeline

The DSP Guidelines for the utilities initial DSP plan are outlined below:

[3] Staff Whitepaper: A Proposal for Electric Distribution System Planning, March 2019. **https://edocs.puc.state.or.us/efdocs/HAU/um2005hau15477.pdf**

[4] *In the Matter of Public Utility Commission of Oregon, Investigation into Distribution System Planning, Docket UM 2005,* Order No. 19-104 (Mar. 22, 2019) (available at **https://apps.puc.state.or.us/orders/2019ords/19-104.pdf**).

DSP Report Guidelines – Part 1 (October 2021)

- **Baseline Data and System Assessment** — Utilities will provide a fundamental understanding of the current physical status of the utility distribution systems, recent investment in those systems, and the level of distributed energy resources (DER) currently integrated into those systems.
- **Hosting Capacity Analysis (HCA)** — Utilities will conduct system evaluations to identify generation constrained areas where it is difficult to interconnect DERs without system upgrades and present the results through a map on their websites. Utilities will prepare an analysis of options for investing in more sophisticated HCA capabilities in the near-term. The OPUC can consider the results of these analyses in adopting a path forward for HCA in Oregon.
- **Community Engagement Plan** — Utilities will develop a plan describing how they will engage community representatives in development of the pilot concept proposals required in Solution Identification, below.
- **Long-Term Distribution System Plan** — Utilities will present their long-term (5-10 year) distribution system investment plans, and address broader goals related to maximizing reliability, customer benefits and efficient operation of the distribution system.

DSP Report Guidelines – Part 2 (August 2022)

- **Forecasting of Load Growth, DER Adoption and Electric Vehicle (EV) Adoption** — Utilities will build on their legacy load growth forecasting processes by forecasting DER and EV growth at the substation level.
- **Grid Needs Identification** — Utilities will present their methodology of comparing the current capabilities of a distribution system to the forecast demands on that system to meet future needs. This will include any resulting faults or constraints.
- **Solution Identification** — In addition to proposing the equipment, technology or programs needed to meet identified grid needs, utilities will develop two or more pilot concept proposals in which non-wire solutions will be used in place of traditional utility infrastructure investments. Utilities will develop pilot proposals collaboratively with community stakeholders to address community needs.
- **Near-Term Action Plan** — Utilities will present proposed solutions to address grid needs, and other investments in the distribution system, in the form of a two- to four-year Action Plan.

PacifiCorp's DSP Part 1 was filed October 15, 2021,[5] and was accepted by the OPUC on March 11, 2022.[6] This document addresses the Part 2 requirements. The full list of DSP Part 2 requirements with cross references to the sections where these requirements are met has been included in **Appendix A**: Distribution System Plan Part 2 Guidelines References. Additionally, the beginning of each chapter begins with a Reader's Guide that further highlights the requirements covered.

State Policy Updates and Other Regulatory Proceedings

At the time of publication, there are several regulatory and state policies that relate to DSP, two regulatory proceedings that could impact future processes related DSP include:

Interconnection

In June 2020, OPUC opened an investigation, docket UM 2111, to address interconnection process and policies that were identified across multiple existing dockets.[7] Two topics that are included within the scope of DSP, specifically hosting capacity analysis (HCA) and community resiliency, are among the items addressed in greater detail in docket UM 2111.

As a result, those topics are not covered in the DSP Part 2 filing, pending further evaluation in UM 2111. PacifiCorp is actively involved in this proceeding as the issues are interrelated in UM 2111 and UM 2005.

Clean Energy Plan

In June 2021, Oregon passed House Bill (HB) 2021,[8] which directs utilities to decarbonize retail electricity sales and to reduce emissions levels below 2010-2012 baseline levels by 80% by 2030, 90% by 2035 and 100% by 2040. Utilities are required to develop a clean energy plan (CEP) for meeting those targets. In addition, utilities are required to convene a utilities Community Benefits and Impacts Advisory Group (CBIAG). Per HB 2021, the members of an electric company's CBIAG will be determined by the electric company with input from stakeholders who represent the customer interests or affected entities within the electric company's service territory. Members must include representatives of environmental justice communities and low-income ratepayers. In addition, the CBIAG will advise on matters including, but not limited to, the CEP, DSP, equitable contracting practices and best practices for reducing energy burden for customers in its service territory. The OPUC opened an investigation in February 2022, docket UM 2225,[9] and the Company has been actively participating in this proceeding. There are other proceedings that have an equity component. For discussion on how the Company is implementing equity policies see **Section 6.4**.

[5] PacifiCorp's Distribution System Planning Report – Part 1 was filed in docket, UM 2198.

[6] PacifiCorp's Distribution System Planning Report, Docket No. UM 2198, Order No. 22-083 (Mar. 11, 2022) (available at https://apps.puc.state.or.us/orders/2022ords/22-083.pdf).

[7] *In the Matter of Public Utility Commission of Oregon, Investigation Into Interconnection Process and Policies,* Docket No. UM 2111, Order No. 20-211 (July 6, 2020).

[8] House Bill 2021, available at: oregonlegislature.gov

[9] Staff HB 2021 Investigation Into Clean Energy Plans, Docket No. 2225.

With the CBIAG requirements introduced as part of UM 2225, the Company intends to stand up a single statewide advisory group — its CBIAG. As a result, the DSP Community Input Group (CIG) that was outlined in the Company's DSP Part 1 filing will not be formed. Please see **Chapter 7** of this document for further details of PacifiCorp's customer outreach and engagement status and plans moving forward.

PacifiCorp is closely coordinating efforts among the various OPUC dockets to ensure consistency of information and alignment of activities to avoid potential duplication of effort for customers, stakeholders, regulators and the Company.

1.3 Summary of DSP Part 1

PacifiCorp filed its report complying with the guidelines for DSP Part 1 on October 15, 2021. DSP Part 1 included a significant amount of foundational information about PacifiCorp's Oregon distribution system assets, the processes to plan and maintain the system, and the long-term plan for how DSP is expected to evolve over the coming decade.

The primary contents of the Part 1 report were:

- Baseline data (distribution system inventory)
    - Existing grid equipment inventory by asset class with average age, life expectancy, etc.
    - Historical spending for the past five years by category
- System assessment capabilities
    - Explanation of assessment practices
    - Discussion of distribution system monitoring and control
- Net metering, small generator and EV data for the distribution system at the feeder level
    - Inventory of net metering and small generator facilities (connected and in queue)
    - Background data about EVs on the distribution system including vehicles, charging stations and five-year historical changes
    - Rendered generator and EV facilities on a publicly available map
- Overview of demand response programs/pilots and data on participation and available capacity
- HCA – including:
    - System assessment to identify areas where it is difficult to interconnect DERs without system upgrades. Results provided publicly: https://experience.arcgis.com/experience/9de589f4f0604262a0867692e58a13a2.
    - Analysis of three options for the evolution of HCA – included preliminary cost estimates
- Overview of DSP process
- Introduction to distribution maintenance and inspection and reliability programs
- Outline of a community engagement plan for DSP
- Documentation of a long-term distribution system plan including:

    - Long-term investment plan (five – 10 years) including strategies, goals and objectives
    - Road map of planned investments with tools and activities to support the DSP vision
    - Investment opportunities including smart grid, R&D efforts and intersections with the IRP and transmission planning
- Plan for Part 2 requirements

With the breadth and depth of material provided in support of DSP Part 1, PacifiCorp does not intend to duplicate topics and context in Part 2, with one exception. In **Chapter 2**: Distribution System Planning of this document, PacifiCorp provides more detail on the current DSP process, which was also covered in Part 1. The current DSP process is foundational for explaining several specific requirements for Part 2 and is included for context and ease of reference.

In addition, PacifiCorp's DSP web page provides background information about PacifiCorp's DSP initiative including materials provided during stakeholder workshops, the DSP Map Viewer and the Part 1 filing: https://www.pacificorp.com/energy/oregon-distribution-system-planning.html

The Part 1 Report can be found here:
https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/dsp/2021_PacifiCorp_Oregon_Distribution_System_Plan_Report_Part1.pdf

1.4 Focus and Objectives for Part 2 Filing

The primary goals and objectives of this DSP Part 2 filing are:

A. Provide further details on the existing DSP process for background and context as the basis for the specific requirements outlined in the Guidelines in docket UM 2005

B. Explain how the specific docket UM 2005 requirements for Part 2 are addressed in this filing. Requirements will be covered in several chapters. The readers guide at the beginning of each chapter will provide guidance on the DSP requirements that are covered in the chapter and **Appendix A**: Distribution System Plan Part 2 Guidelines References provides a comprehensive map of the requirements to the section in the filing where each is addressed

C. Reflect on lessons learned from non-wires solution (NWS) pilot evaluations, community engagement and new DSP processes

D. Outline a near-term action plan to deliver DSP refinements with a focus on continuous improvement and evolution over time

1.5 Overview of Subsequent Chapters

Chapter 2 begins with a review of the distribution system and the characteristics of PacifiCorp Oregon service territory. It then provides a more detailed overview of the current DSP process to establish baseline context and a foundation for the next three chapters that will focus on responding to the specific requirements outlined in the Guidelines for Part 2. **Chapter 3**, **Chapter 4** and **Chapter 5** build from the foundational elements presented in **Section 2.3** and elements of this section can be used for reference. This chapter concludes by providing details on the DSP Stakeholder Survey that was completed by over 4,000 PacifiCorp customers and stakeholders in February and March of 2022.

Chapter 3 focuses on load forecasting in the DSP context and specifically addresses the requirements outlined in DSP Guidelines Section 5.1 for load growth, DER adoption and EV adoption. The contents in **Chapter 3** use the foundation for DSP load forecasting outlined in **Chapter 2** (**Section 2.3**) for complete study, forecast load). Using this as a foundation, **Chapter 3** will transition into the specific modeling as outlined in the DSP Guidelines and provide a high-level comparison of the forecast results for the Transitional Study areas.

Chapter 4 focuses on grid needs assessment as outlined in the DSP Guidelines Section 5.2. The chapter relies heavily on the contents in **Chapter 2** (**Section 2.3**, Assess Model Results, Identify Potential Grid Needs and Determine Potential Solutions, and address the specific guidelines outlined in DSP Guidelines Section 5.2.a though 5.2.d).

Chapter 5 uses the foundations of solution identification outlined in **Section 2.3** and extends it into the assessment of potential NWS in the Transitional Study areas with a specific focus on the grid needs/solutions identified for the overcapacity identified on a Klamath Falls distribution circuit. **Chapter 5** expands beyond traditional DSP to include assessment of nontraditional solutions and specific community outreach and engagement in the DSP Transitional Study approach.

Chapter 6 outlines PacifiCorp's Near-Term Action Plan. The initial section of the chapter outlines PacifiCorp's two to four year plan including proposed solutions to address grid needs and other investments in the distribution system. The plan includes timeline, costs, relationships to other investment and proposed recovery mechanisms if needed. The second section documents current innovations and pilots being conducted to improve, modernize and/or enhance the grid beyond its current capabilities.

Chapter 7 provides an update on customer outreach and engagement as outlined in DSP Part 1. The chapter reviews and highlights the company's plan for outreach and engagement from Part 1, including: Progress to date - including the impact of the Oregon Clean Energy Plan (CEP) on formation of the Community Input Group (CIG), summary of outreach and engagement activities during Part 2, and planned initial meetings/topics/enhancements, and framework for on-going engagement.

Chapter 8 provides items for consideration for future DSP planning and provides a conclusion to the Part 2 filing.

Chapter 2: Distribution System Planning

2.1 Chapter 2: Readers Guide

This chapter establishes several foundational elements as context for details elaborated in the following chapters in response to specific DSP Part 2 requirements.

Initially, the chapter provides context around the dispersed and varied nature of PacifiCorp's Oregon service territory and then recaps current DSP. These initial sections provide background and outline the DSP "As-Is" elements for several of the specific DSP Part 2 requirements.

The following section provides background and context on the Transitional Study areas used to explore new DSP processes and grid needs assessments.

Next, the Company provides insight from the DSP Stakeholder Survey that gathered input from over 4,000 PacifiCorp Oregon customers in February of this year. Several of the themes from the survey will be integrated into subsequent chapters.

The final section outlines how the specific requirements from docket UM 2005 Part 2 are addressed in subsequent chapters.

COVERED IN THIS CHAPTER

Refresh context on the disparate and varied nature of PacifiCorp's Oregon territory

Provide a comprehensive overview of the "As-Is" DSP process

Explain Transitional Study areas

Summarize findings from the DSP Stakeholder Survey conducted in February 2022

DSP Guidelines	Chapter Section
5.1.a	**Section 2.3.2.1**
5.1.c	**Section 2.3.2.2**
5.2.a	**Section 2.3.2.2**
5.2.b,c	**Section 2.3.3**
5.2.d.i	**Section 2.3.4**
5.3.a	**Section 2.3.2.3 - 4**
5.3.c	**Section 2.3.2**
5.2.d	**Section 2.5**

2.2 Distribution System

This section covers two primary topics: 1) a brief refresher on the electric utility system and the distribution system's role in delivering power to customers and 2) an overview of the PacifiCorp Oregon service territory to highlight elements that influence how the distribution system is planned and managed.

Referring to **Figure 2** electricity is generated at a facility (1) (such as a hydroelectric dam or combustion engine) after which its voltage is transformed (2) to match the voltage of the adjacent transmission assets (generally ranging from 69 kilovolts [kV] through 500 kV). The transmission system helps move that energy toward the "load" side of the system, or to the distribution system, via substations (3). Substations convert the "high side" or transmission voltages down to "low side" or distribution voltages, which range from 4 kV to 34.5 kV. The distribution system then, through the utility infrastructure of overhead and underground wires (4-8) connects with customers' meter (9), finally the electricity is delivered to the customer's appliance, via the house wiring.

The electric system can be thought of like a transportation network, where freeways (or transmission lines) can move large volumes of vehicles (or energy). Those vehicles move from the beginning of the route to their destination through any or all the different types of roads within the transportation network, such as highways, arterials or local surface streets. Since electricity follows the path of least resistance, how it gets from point A to point B is based upon what path is easiest for it to take — i.e., least resistance. This generally means the highest voltage, lowest impedance path.

Maintaining proper flow through these network elements historically relied upon deterministic guidelines that were the result of experiences with loading events, assessment of customers' energy usage, and system performance evaluation including a wide range of events. Real-time data, although limited, was readily available to make rapid adjustments to the system. These historically deterministic guidelines and practices kept the system functioning reliably through a range of load/weather/resource events.

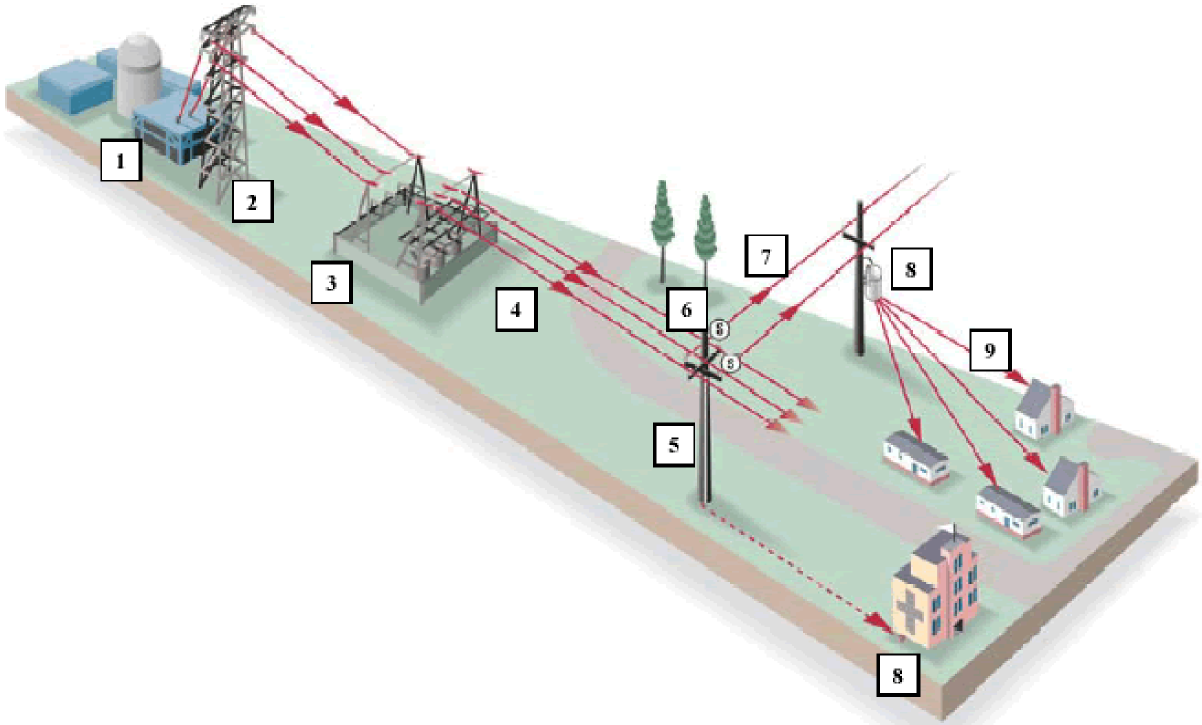
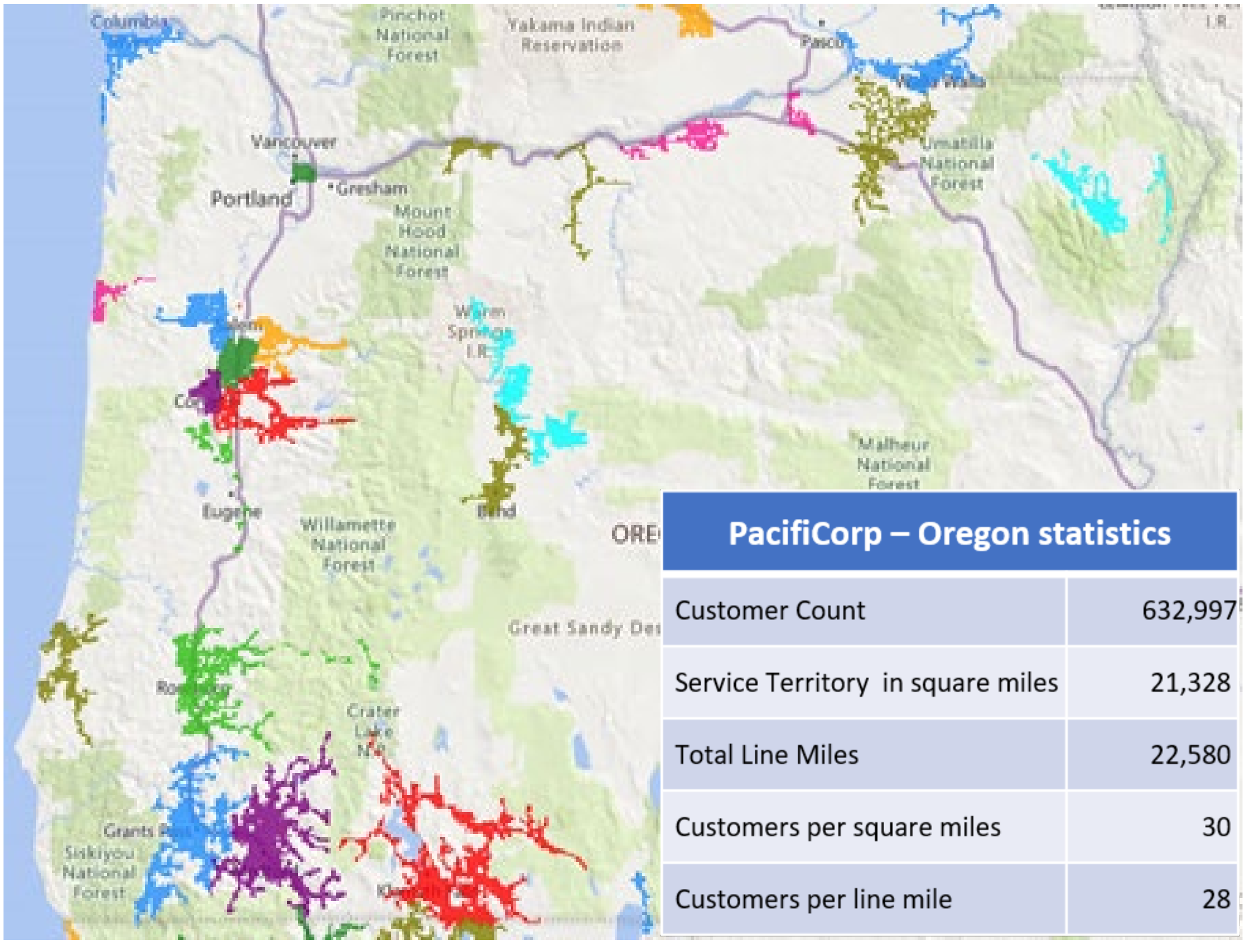


Figure 2: Legacy Electric System Diagram

Critical to this reliable, safe and economic operation are processes that must recognize a variety of changes needed within the system, such as when reliability declines and targeted improvements are needed, when equipment has aged and no longer performs acceptably, or when customers need additional supply for either new service or new uses.

The primary goals and objectives of PacifiCorp's DSP align with state commission policy of providing safe, reliable and affordable electric service to all customers in a least-cost, least-risk manner.

Pacific Power, which is part of PacifiCorp along with Rocky Mountain Power, has provided safe, reliable and affordable energy to customers in Oregon, Washington and California for over 100 years. In Oregon, PacifiCorp operates over 21,000 line miles of distribution on 370,000 distribution utility poles to provide electricity to over 600,000 customers throughout the state.



PacifiCorp – Oregon statistics	
Customer Count	632,997
Service Territory in square miles	21,328
Total Line Miles	22,580
Customers per square miles	30
Customers per line mile	28

Figure 3: PacifiCorp's Oregon Service Territory, June 2022

As described in PacifiCorp's DSP Part 1 Report, PacifiCorp's service area is unique and diverse: while the Company serves a portion of the Portland metropolitan area, most customers live in smaller communities and rural areas, making PacifiCorp the largest rural electricity provider in Oregon. For information on PacifiCorp's customer composition please refer to PacifiCorp's DSP Part 1 Report, Chapter 4, page 83). **Figure 3** has updated statistics as of June 2022.

This dispersed and varied service territory results in PacifiCorp having several distribution planning areas to cover its distribution system. PacifiCorp's distribution planning areas, summarized below in **Figure 4**, separates the distribution system into three regions (North, Central and South) with eight total districts (Portland, Walla Walla, Yakima, Bend, Albany, Roseburg, Klamath Falls, Medford) each with unique attributes. As a result, DSP has historically been a decentralized process customized for each district's unique configuration and needs that relies primarily on the familiarity and expertise of the field engineering personnel in each of the local district offices.

NORTH REGION			CENTRAL REGION			SOUTH REGION	
Portland	Walla Walla	Yakima	Bend	Albany	Roseburg	Klamath Falls	Medford
Operating Areas / Districts							
Clatsop (Astoria) Portland	Walla Walla Hermiston Umatilla Pendleton Enterprise Dalreed	Sunnyside Yakima	Madras Hood River Bend Redmond	Albany Corvallis Dallas Independence Cottage Grove Stayton Lebanon Lincoln City	Coos Bay Roseburg	Alturas Lakeview Tulelake Mt Shasta Klamath Falls Yreka	Crescent City Medford Grants Pass
Distribution System Profile							
95 Circuits 1,200 Line Miles 107,000 Customers	42 Circuits 2,500 Line Miles 54,000 Customers	106 Circuits 3,300 Line Miles 108,000 Customers	65 Circuits 2,800 Line Miles 77,000 customers	86 Circuits 3,700 Line Miles 137,000 Customers	66 Circuits 2,300 Line Miles 70,000 Customers	110 Circuits 5,000 Line Miles 75,000 Customers	138 Circuits 5,700 Line Miles 156,000 Customers
Unique Attributes							
Portland Underground Mesh Network Distributed Automation Pilot Project	Fire High Consequence Area	Fire High Consequence Area	High Growth Rate/New Connections	Distributed Automation Pilot Project Energy Storage Pilot	Fire High Consequence Area	California Code Requirements Fire High Consequence Area	Distribution Automation Pilot Project Fire High Consequence Area

Figure 4: PacifiCorp Planning Areas

In addition to the details in **Figure 4**, the variety of PacifiCorp's Oregon service territory is also highlighted by:

Dispersed and Varied Geography: PacifiCorp's Oregon service territory covers over 21,000 square miles from Washington to California, and from the coast to Idaho, broken into eight distinct planning districts.

Diverse Circuit Loading/Composition:

- Densest circuit in Portland with 638 meters per line mile
- Least dense in Hermiston with one meter per line mile
- Oregon average is 28 meters per line mile

Diverse Environmental Conditions: PacifiCorp's service territory spans distribution in eight of nine Oregon climate zones.

Various Interconnections: PacifiCorp's Oregon infrastructure interconnects with 16 other electrical power companies, including CAISO and the Bonneville Power Administration.

As a result, DSP has been a decentralized process that relies primarily on the familiarity and expertise of the field engineering personnel in each of the local area offices.

2.3 Distribution System Planning Overview

This section provides an overview of existing ("As-Is") DSP and provides context for the current process and considerations for load forecasting, grid needs assessment, solution identification and prioritization.

Local field engineering personnel carry out primary DSP activities. Given the geographic dispersion and rural nature of much of the Oregon service territory, the field engineers are the subject matter experts in the day-to-day operations of the local distribution systems and perform all distribution planning activities.

The current DSP process — from initiation to approval is depicted in **Figure 5** below.

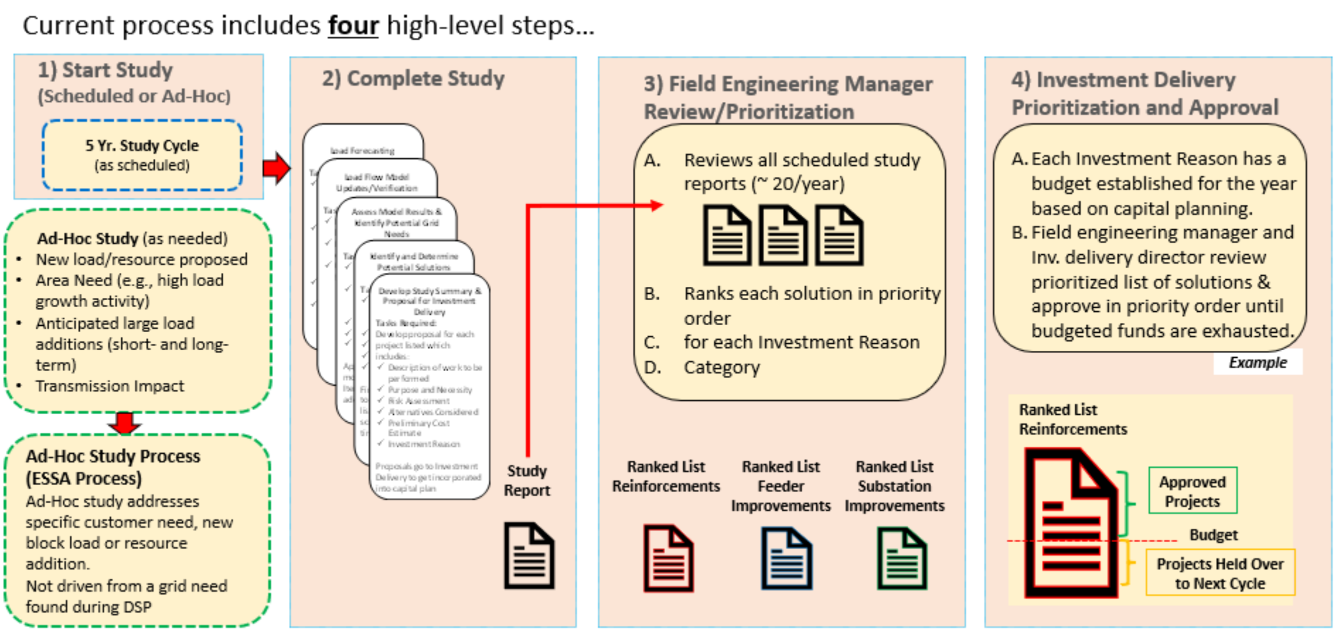


Figure 5: As-Is Distribution Planning Study Process

Step 1 – Start Study: Explains the different triggers that lead to a study

Step 2 – Complete Study: Explains field engineering steps to complete a distribution system study from initial forecasting through analysis, solution identification, study write-up and review/approval

Step 3 – Field Engineering Manager Review/Prioritization: Explains the process for reviewing each DSP study/report and prioritizing the proposed construction items/solutions that will proceed to budgeting and approval

Step 4 – Investment Delivery Prioritization and Approval: Explains the prioritization and budget approval process for DSP construction items/solutions from Step 3

These steps are described further in the following subsections.

2.3.1 Step 1 – Start Study

There are two types of studies for transmission and distribution (T&D) systems — scheduled and ad-hoc studies.

In scheduled studies, the primary objective is to determine the condition of the system at a future state based on assumptions, models and forecasts, typically five years for distribution and 10 years for transmission and address any grid needs associated with that future condition. Scheduled studies are cyclical in nature, and generally cover a large geographic area.

The primary objective for ad-hoc studies is to determine the condition of the system over a much shorter timeline (typically customer-driven) based on current conditions and to address any grid needs associated with providing service at a specific location on the distribution system. Ad-hoc planning is typically driven by a load, generation interconnection service or transmission service request and is generally focused to a specific location on the distribution system.

Table 1: Scheduled Study Versus Ad-Hoc Study[10]

Scheduled Distribution Planning Studies	Ad-Hoc Studies (Generation Interconnect or System Impact Study)
• All DSP studies are scheduled to be completed on a five-year cycle. • Study schedules are evaluated annually and may be shifted to occur sooner or later depending on multiple factors (high load growth activity, large load additions, etc.). • Currently there are 99 planning studies on five-year cycle in PacifiCorp's Oregon service territory. • Generally, two to three months are required to complete study analysis, review and prioritize results with a manager.	• Typically, ad-hoc studies are driven by load, generation interconnection service or transmission service requests. • These studies are generally focused on a specific location on the distribution system. • Shorter timeframes are typical to meet customer needs (~ three to four weeks for an initial study). • The customer shares in solution costs and influences what solutions to implement.

[10] This table does not include transmission planning studies.

Most UM 2005 analysis uses scheduled, cyclical distribution planning studies as the basis for documentation and assessment; their process is more stable and predictable than ad-hoc studies. Ad-hoc studies, by their nature, are limited in scope, provide little time for evaluation (especially for evaluation of nontraditional alternatives such as non-wires solutions), and are often driven by customer requirements (including types and costs of solutions). As a result, PacifiCorp expects to use scheduled distribution planning studies for evaluation and initial evolution of tools and processes. As the DSP evaluation tools and processes are tested and refined, they are expected to support ad-hoc studies when they are mature enough to meet the timelines and dynamic nature of such studies.

2.3.2 Step 2 – Complete Study

The next step in DSP is to complete the distribution planning study.

DSP studies are conducted by local field engineers who are familiar with the area, local distribution system and equipment. Field engineers support all day-to-day distribution system operations and function as SMEs for their areas. Because of this, they have latitude to use professional judgment in the execution of the distribution planning studies and in the prioritization of grid needs and recommended solutions.

Most distribution planning studies include a basic set of common elements. Field engineers add to these common elements as needed based on their knowledge of the system, recent events, new concerns highlighted by the study process, etc. When the study is complete, the engineer is confident that any likely risks have been addressed.

A high-level overview of the Complete Study step in the DSP process is broken down ino five subcomponents as depicted in **Figure 6** below.

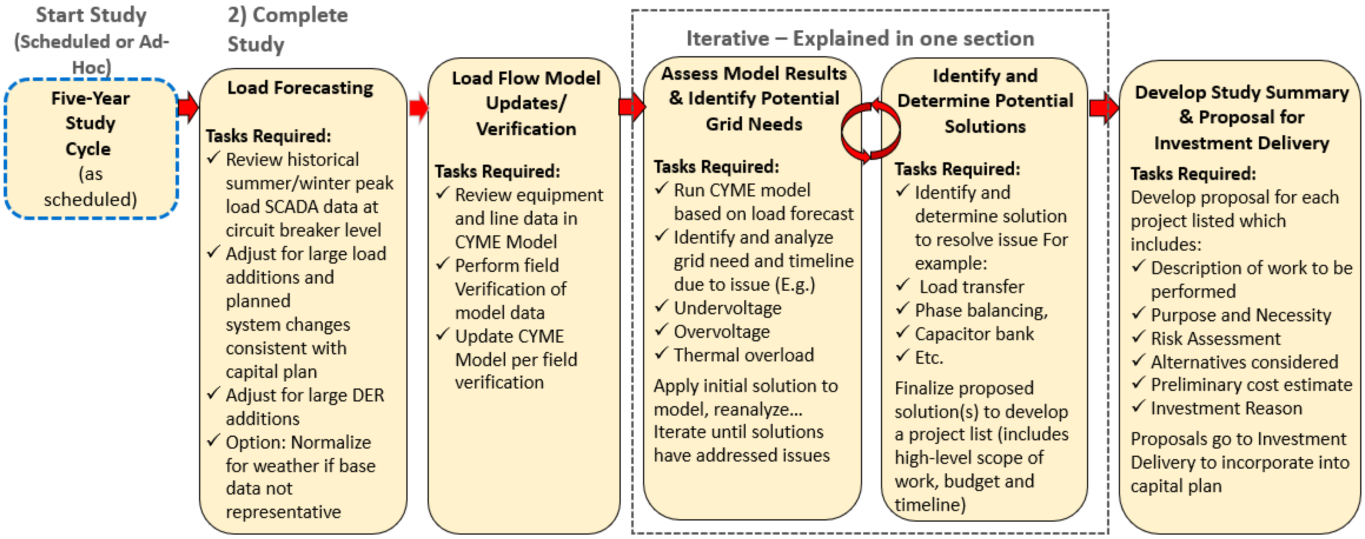


Figure 6: As-Is Distribution Planning Study Process Overview

These five subcomponents are further described in the following subsections.

2.3.2.1 Load Forecasting

The study process begins with forecasting the expected load (demand for electricity) to be delivered on the distribution system. For the area being studied (study area), the traditional load forecast relies on the field engineer to generate a forecast by using a minimum of five years of historical load data for the substations and feeders that are being evaluated.

Primarily, field engineers consider historic or existing trends as well as forecasted activity in an area to answer the following types of questions:

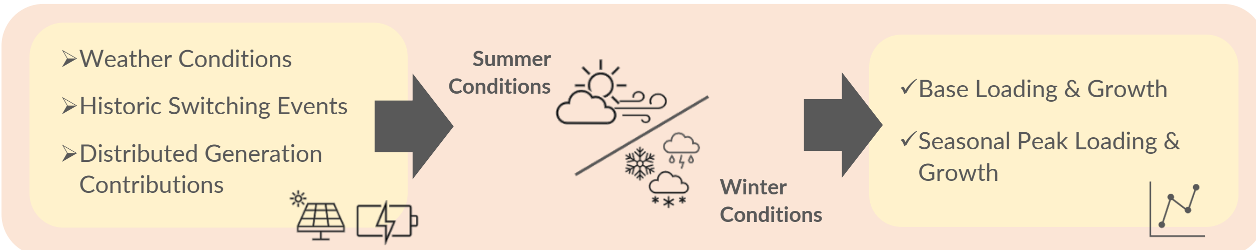
Historic or Existing Trend Questions

- What did the previous study identify?
- Were the previously proposed projects completed as planned?
- Did the previously forecasted growth materialize?
- Did other study assumptions hold?

Current or Forecasted Change Questions

- Has anything about the distribution system changed?
- Are there known operational or reliability issues?
- What has new connection activity looked like since the previous study?
- Are new industries or developments planned?

Field engineers also consider seasonal weather conditions, historical switching events and distributed generation contributions to determine starting load conditions for each substation transformer and circuit as well as the potential growth rates or variation in growth rates to use for each substation transformer and circuit for the summer and winter.



Next, the field engineer:

- Inputs demand and growth rates to into the load forecast
- Determines large load additions and generation interconnects, known circuit topography changes, etc., and their expected timing, and adds these factors into the load forecast
- Compares the distribution load forecast to the transmission load forecast

The field engineer determines a load growth rate based on a linear and exponential load forecasting using the worst-case historical summer and winter peaks over a minimum of five years and applies it to the starting load for summer and winter for each substation transformer and circuit five years into the future.

In the current method, the field engineer shares forecast information related to block load additions and generation interconnects in the planning area with transmission planning, but otherwise does not specifically consult IRP/jurisdictional/system load forecasts.

Key takeaways from current load forecasting:

- The field engineer develops a circuit-specific load forecast based on actual data (locally measured) with adjustments for known/expected load additions or generation interconnects, load transfers, etc.

- The local DSP forecast focuses and designs around worst-case summer and winter peak loading to set a planning baseline to ensure adequate capacity to deliver the required electricity through the distribution system when needed.
- The current forecast is a point-estimate and does not require development or understanding of shapes, time-of-day/year variations or customer demographics.
- The following elements are embedded in the forecast because they are embedded in the actuals used to generate the forecast:
    - Base level of demand-side management/energy efficiency and growth
    - Base level of net-meter generation/distributed energy resource (DER) and growth
    - Base level of EV charging and base level of growth

Note: More details about current and future load forecasting are provided in **Chapter 3** along with the specific forecasting requirements from the DSP Guidelines.

2.3.2.2 Load Flow Model Updates/Verification

Next the field engineer will review and refine the model in power flow modeling software (CYME). Before using the power flow modeling software, the field engineer first verifies the distribution system and key equipment to ensure the models reflect the current distribution system configuration (phasing and topography) and all wires and equipment match the size, type, location and configuration in the field. Then, the field engineer:

- Completes any necessary model corrections

  For example, a device may have an unknown rating in the geographical information system (GIS), and the study engineer will determine the rating and input that correction in the model. Typically, normal open points are confirmed, and large load data is verified.

- Confirms planning criteria and sets baseline parameters in the CYME model and confirms that equipment is accurately reflected in the model
- Conducts field verification as needed to ensure the model reflects conditions/equipment on the circuit
- Refers to specifications and criteria to establish thresholds and parameters in the model
- Inputs the load forecast into the CYME model and examines the results; may conduct a sensitivity assessment or explore different load scenarios to confirm that potential issues exist/do not exist
- Performs power flow analysis on the model in the base year (i.e., starting summer and winter load conditions)

When the model has been properly configured and confirmed, CYME is ready to begin the analysis and the field engineer moves to the next step in the process.

2.3.2.3 Assess Model Results, Identify Potential Grid Needs and Potential Solutions

The field engineer conducts these primary steps to identify grid needs on the study circuit:

- Using the load forecast and updated model in CYME, performs load flow analysis to identify the grid needs and determines the solutions required to address the issue
- Identifies and analyzes the grid need type, timeline and severity of the issue; examples of types of grid needs include:
    - Overcapacity/thermal overload – Exceeding equipment thermal rating
    - Undervoltage – Voltage that is below ANSI C84.1, range A limits
    - Overvoltage – Voltage that is over ANSI C84.1, range A limits
- Applies an initial solution to the grid need in the CYME model and reanalyzes
- Repeats until solutions have addressed all issues found
- For each future year in the planning horizon:
    - Evaluates the system for overloaded equipment
    - Evaluates the system for unacceptable voltage
    - Considers the effects of generation existing on the system

Since grid needs (and corresponding solutions) can vary widely in scope, severity and impact, the field engineer can exercise professional judgment to identify and prioritize the grid need. That said, PacifiCorp's Distribution System Planning Study Guide 1E.3.1 (DSP Guide), provides helpful guidance to prioritize needs.

The DSP Guide identifies potential operating issues/grid needs in the following priority order (**Figure 7**):

Priority Order	Type of Issue	Safety and Protection of Life and Property	Risk (Customer impact, type of issue, severity of issue)	Preservation of Company Facilities	Continuity of Service	Power Quality
1	Overloaded equipment and circuits	●	●	●	●	●
2	Voltage Problems	●	●	●	●	●
3	Protection Problems	●	●	●	●	●
4	Power Factor Problems	●	●	●	●	●
5	Critical Limiting Factors		●		●	●
6	Reliability Problems		●		●	
7	Regulatory Problems		●		●	
8	Power Quality Problems		●		●	
9	Other					●

Figure 7: Grid Need Prioritization Matrix

During the assessment of the grid needs and potential solutions, the field engineer considers the risks of *not* undertaking the project. Specifically, the field engineer examines the grid need and potential solution(s) in terms of:

- Safety and protection of life and property
- Risk (customer impact, type of issue, severity of issue)
- Preservation of Company facilities
- Continuity of service
- Power quality

In addition to examining the grid needs in terms of the priorities above, the DSP Guide suggests that field engineers address the following questions in considering risks associated with the proposed solution:

1. How many hours per year is the risk present?
2. How many customers would be affected?
3. How much load would be affected?
4. How much would emergency repairs cost?
5. How long would it take to perform emergency repairs, if possible?
6. What is the likelihood that a failure or service quality problem would occur?
7. How much revenue would be lost?

In developing solutions to address the grid need, field engineers use both experience and collaboration as well as guidance from the DSP Guide as needed.

The DSP Guide provides a table that identifies common grid needs and maps them to potential solutions. A snapshot of this guide has been included in **Figure 8.**

As an example, the DSP Guide may be used to consider the following issue: Substation Transformer is found to be overloaded:

Possible solutions (highlighted in **Figure 8**):

1A – Build new substation

2A – Replace or add substation transformer

2B – Add substation cooling equipment

2C – Parallel substation transformers

In this example, all solutions are focused on addressing the overload issue, which involves increasing equipment rating or offloading the equipment so it remains within its rating.

Figure 8, which is taken from Table 2 of the DSP Guide, outlines potential issues in a rough priority order on the left side of the figure, starting with the most significant issues at the top of the list in descending priority. Additionally, there is a preference to consider lower-cost solutions first to resolve potential grid needs to minimize rate impacts. If the need cannot be met with the lower-cost solution, then progressively more costly solutions may be considered. The solutions are discussed later in this section.

Issues \ Solutions	Build New Substation 1A	Replace or Add Substation Transformer 2A	Add Substation Cooling Equipment 2B	Parallel Substation Transformers 2C	Replace Overloaded Substation Equip. 3A	Increase Getaway Capacity 3B	Add Parallel Circuit Getaway 3C	New Feeder 4A	Transfer Load 4B	Reconductor 5A	Reconfigure System 5B	Add Underground Cable 5C	Remove an Environmental Hazard 5D	Replace Equipment 6A	Add Distribution Automation Equipment 6B	Replace Regulator 7A	Limit Regulator Operating Range 7B	Add Secondary Regulators 7C	Change Regulator Control Settings 7D	Add Line Regulator 7E	Relocate Line Regulator 7F	Install Line Capacitors 8A	Install Capacitor Switches and Controls 8B	Replace Step-Up or Step-Down Transformers 9A	Change Utilization Transformer Taps 9B	Voltage Conversion 9C	Add Protective Device 10A	Replace Protection Equipment 10B	Relocate Protection Equipment 10C	Demand Side Management 11A
Substation																														
Transformer	X	X	X	X				X	X						X											X				X
Regulator		X		X				X	X						X	X	X									X				X
Transformer Protection	X		X					X	X						X											X				X
Paralleled Transformers	X	X	X					X	X						X											X				X
Bus Capacity	X	X			X			X	X						X											X				X
Circuit																														
Getaway						X	X	X	X						X											X				X
Circuit Protective Device					X			X	X																	X				X
Switches					X				X																					
Guide Line Loading Limit						X	X	X	X						X											X				
Line and Equipment																														
Overhead Conductor						X	X	X	X	X					X											X				X
Underground Conductor								X	X	X		X			X											X				X
Line Switch									X					X												X				
Switch Cabinet or Device									X					X																
Regulator									X					X	X	X					X			X		X				
Protective Device																														
Recloser									X					X												X		X	X	
Fuse									X					X													X	X	X	
Series Transformer																														
Step Up or Down	X							X	X						X									X		X				X
Isolation Bank	X																							X		X				X
Grounding Bank Fault Capacity	X							X	X															X		X				
Service Quality Problems																														
Steady State Voltage Levels		X		X				X	X	X					X			X	X	X		X	X	X	X	X				
Regulator Range								X	X	X					X					X	X	X	X	X	X	X				
Regulator Settings															X	X			X											
Capacitor Controls															X	X			X		X		X	X		X				
Transient Voltage Levels																														
Motor Starts								X	X	X						X			X			X	X	X		X				
Capacitor Switching								X	X	X						X								X		X				
Harmonics								X	X	X		X				X								X		X				
Reliability Problems																														
Frequent Outages	X	X					X	X	X	X	X	X	X	X	X												X	X	X	
Excessive Risk or Exposure		X			X	X	X	X	X	X	X	X		X													X	X	X	
System and Economic Problems																														
VAR Delivery Limitations (Power Factor)									X						X							X	X							
Economic Performance (Efficiency)	X							X	X	X			X	X	X					X	X	X	X	X		X				
Capacity Utilization			X	X			X	X	X	X	X		X	X	X	X				X	X	X	X	X	X	X	X	X	X	

Figure 8: Issues/Solutions Matrix

Five-year distribution planning studies typically identify projects that address the need for capacity increases or system reinforcement. Though a variety of conditions are studied, capacity increase projects are generally proposed based on customer load increases, general load growth and equipment overload concerns. System reinforcement projects are generally proposed based on voltage or power quality concerns.

Projects are generally assigned a priority based first on compliance conformity and next on risk threshold (potential customer minutes lost, as an example). Projects with field-measured performance issues such as overloads, low voltage or poor power factor take precedence over projects with predicted (i.e., simulation-based) performance issues. Other factors such as budget, timeline and seasonal loading are also taken into consideration.

Where issues/grid needs are found to exist in the future system model, solutions are developed, compared and proposed in the completed study. All solution alternatives are developed to maintain safe, reliable delivery of energy under normal operating conditions. Each proposed solution is accompanied by a description of the work, its purpose and necessity (P&N), projected conditions/benefits, risk assessment and alternatives considered. Based on the solution type an "Investment Reason" is determined. For an ad-hoc study, the proposed solution becomes part of the discussion with the customer making the request. For a scheduled study, the proposed solution is used in budgeting to prioritize the proposed work. Development of solutions also entails determining cost causation — system-driven costs or costs driven by individual customers or specific state or local policies. The primary steps for solution identification are summarized below:

- Based on the results of the future conditions, determine reasonable solutions to any issues. Work with an area planner (transmission planning) for solutions that may involve substation modifications.
- For each possible solution, model the scenario (iteration between solution identification and grid needs). Using engineering judgment and accounting for construction costs and timeline, determine the preferred alternative.
- Determine the necessary timing for any solution project, and for any necessary field reads. For example, if the summer peak condition simulation shows problematic high reactive power flow, the engineer may arrange for volt-ampere reactive (VAR) recorders to be placed on the span in question during hot summer weather.
- Complete the documentation for each project, including its P&N, and the shortcomings of solution alternatives not selected.
- Compile report components in Asset Management and Planning System (AMPS) and route it for approval.

In addition to those basic elements, each field engineer may expand a given study based on their judgment. For example, if load flow results suggest a fuse size must be increased, this may prompt a miniature overcurrent coordination study that ordinarily would not be considered a required part of the planning study. If distributed generation (DG) is a significant contributor to the state of a circuit, the engineer may model several loads versus generation scenarios to verify there are no grid needs/issues under all conditions. Once the study is complete, the engineer should have confidence that any risks have been addressed.

In proposing mitigations, the situation is addressed in a triage manner in which the lowest-cost solution is the first proposal advanced. Thus, for conductor or equipment overloading beyond standard or emergency loading limits, measures taken could include transferring load, phase balancing, conductor replacement or additions, or at its most extreme, substation changes might be appropriate (in progression based on complexity and cost). For out-of-voltage performance,[11] some of mitigations are similar to overloads, such as transferring load, phase balancing, capacitor bank installation, voltage regulator installation and more substantial reconductoring efforts might be undertaken.

In current area planning, local generation is incorporated within studies on a case-specific basis. Large generators (typically greater than 1 megawatt [MW]), like large loads (typically greater than 1 MW) may be separately applied and evaluated against a wide range of scenarios under which the most extreme cases will be further analyzed for any needed network changes. Due to uncertainty around individual large generator performance, these resources are generally not used as an alternate to capacity within the network.

Once a primary solution is identified to address the grid need, the field engineer will:

- Identify and model the solution and any alternative solutions in CYME
- Confirm the recommended solution addresses the grid needs for the remainder of the study cycle

Alternatives are provided along with the recommended solution in the Study Summary Report for consideration.

The common solutions from **Figure 8** are further explained in the common solution titles and listed in **Figure 9** for ease of reference. Generally, the solutions are listed from most expensive to least expensive with a preference for the least expensive option.

[11] IEEE NESC ANSI Voltage Range A allows 5% variation from nominal voltage, i.e., 114-126 V for 120 V nominal and is an industry standard in the IEEE and NESC.

Title of Common Solutions from DSP Guide Book

- 1A Build New Substation
- 2A Replace or Add Substation Transformer
- 2B Add Substation Cooling Equipment
- 2C Parallel Substation Transformers
- 3A Replace Overhead Substation Equipment
- 3B Increase Getaway Capacity
- 4A New Feeder
- 4B Transfer Load
- 5A Reconductor
- 5B Reconfigure System
- 5C Add Underground Cable
- 5D Remove an Environmental Hazard
- 6A Replace Equipment
- 6B Add Distribution Automation Equipment
- 7A Replace Regulator
- 7B Limit Regulator Operating Range
- 7C Add Secondary Regulators
- 7D Change Regulator Control Settings
- 7E Add Line Regulator
- 7F Relocate Line Regulator
- 8A Install Line Capacitators
- 8B Install Capacitator Switches and Controls
- 9a Replace Step-up or Step-down Transformers
- 9B Change Utilization Transformers Taps
- 9C Voltage Conversion
- 10A Add Protective Device
- 10B Replace Protective Equipment
- 10C Relocate Protective Equipment
- 11A Demand Side Management

Figure 9: Common Potential Solutions

Several secondary objectives are also associated with the planning process. A current distribution planning study aids in system awareness for the field engineer and for engineering and operations management. This awareness supports operational and maintenance activities, as well as any efforts to adjust the timing or scope of proposed construction projects.

2.3.2.4 Develop Study Summary and Proposal for Approval

Each load/planning study concludes with a report. The common elements required for a completed distribution study are:

Planning study summary. This describes the substations and feeders included the author and completion date. It lists the proposed projects over the duration of the planning horizon. It also acts as the signature page for approval from requisite parties.

Study area description. This is an executive summary of the area studied. It typically provides an overview of the system, describes what makes the area unique, includes a summary of any equipment/system limitations, the dominant customer types and causes for growth, etc.

Study area summary. This is a summary of the analysis and findings for the study period to ensure the system meets future requirements. It may explicitly call out assumptions used, the need for follow-up, and any dependencies that may exist (e.g., other planning study results, changes to the area's economy or neighboring T&D systems, etc.).

Study area map. The map provides a geographical overview of the distribution system contained in the study area, which includes substation and feeder locations.

Load forecast summary. This provides a summary of the load forecasts for substation transformers and circuits in the study area, typically for both summer and winter. This tabular section of the study lists each substation transformer and circuit, load capacity, growth rate and planned additions to load and reactive power compensation, along with the expected percent loading at the end of the study period.

All proposed construction items. In studies where identified solutions require construction, each proposed construction item requires a description, construction year, estimated construction cost (block estimate), purpose and necessity, projected conditions/benefits, risk assessment, alternatives considered and a sketch/map.

After the individual study summary and proposal are completed, each is submitted to the field engineering manager for review and approval.

Field Engineering Manager Plan Review and Approval

All DSP study summary reports and construction items are reviewed and approved by the field engineering manager and the specific solutions are captured for prioritization. The solutions' P&N explains why the solution is required and maps to a higher-level category called an "Investment Reason." The Investment Reasons continue the prioritization process. See the explanation of "Investment Reasons" below.

Investment Reasons

Each solution is assigned to an Investment Reason that categorizes and defines the business reasons driving construction of a given capital project — not simply an explanation of the type of work to be performed. The Investment Reason ties directly to budgets that outline work activities.

Once each DSP study summary is completed, it will be prioritized by the field engineering manager.

The most common Investment Reasons for DSP study solutions are:

System Reinforcement – Feeder: Used for improvements and reinforcements needed to maintain acceptable feeder support for general load growth.

System Reinforcement – Substation: Used for improvements and reinforcements needed to maintain acceptable substation support for general load growth.

Feeder Improvements: Used for *functional* upgrades to a feeder (addition or enhanced functionality to existing operational function that was not directly related to a customer reliability improvement)

Substation Improvements: Used for *functional* upgrades to a substation, not directly related to a customer reliability improvement. *Depending on the voltage of the substation equipment, these solutions may be either a distribution investment or a transmission investment.*

Functional Upgrade – Reliability: Used for functional upgrades to a feeder, substation or transmission line for the purpose of improving circuit reliability that are directly associated with a customer reliability improvement. *(These items are identified and prioritized through centralized reliability analysis and specific improvement initiatives, not through regular DSP studies.)*

2.3.3 Step 3 – Field Engineering Manager Review and Prioritization

Once all distribution planning studies are completed for the year, the field engineering manager compiles a list of all identified solutions/construction items and prioritizes the list. This is the critical prioritization step as the field engineering manager (in consultation with the field engineers) force ranks the proposed solutions into priority order based on:

- Type of issue and severity
- Risk associated with issue
- Alternatives available
- Customer impact
- Projected conditions/benefits
- Timeline
- Cost
- Relationships to other solutions

Dialogue between field engineers and the manager throughout the prioritization process ensures that risks, potential impacts and other particulars are considered in the ranking of the proposed construction items. Once completed, the force-ranked list is provided to investment delivery.

At the conclusion of the field engineering manager prioritization, there is a priority ranked list of all solutions that are ready to move to implementation. The next step is to prioritize solutions against budget availability and seek approval for implementation.

2.3.4 Step 4 – Investment Delivery Prioritization and Approval

As previously described, each solution or project is assigned to an Investment Reason that categorizes and defines the business reasons driving construction of a given capital project. The Investment Reason ties directly to budgets that support work activities. Each of the Investment Reasons has a set budget for each year grounded in long-term planning and general rate case processes.

The budget levels reflect investment priorities for PacifiCorp overall and are generally set based on historic spending levels and approved general rate case funding. Specific budget levels are allocated to Pacific Power and, more specifically, the state of Oregon.

The construction items are force ranked against all other construction items in that category. Projects are approved starting from highest ranked to lower ranked and are phased consistent with approved budget amounts.

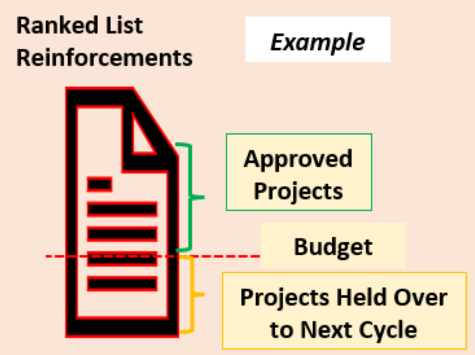
Any projects that cannot be completed in a given year are "carried over" and prioritized first during the following year to ensure they continue toward completion. New projects are considered for approval with remaining budget for that category.

While the amount of funding for each Investment Reason and the number of grid needs/solutions varies from year to year, generally 70% – 95% of identified solutions are moved forward consistent with this process.

4) Investment Delivery Prioritization and Approval:

A. Each Investment Reason has a budget established for the year based on capital planning.
B. Field engineering manager and Inv delivery director review prioritized list of solutions and approve in priority order until budgeted funds are exhausted.

Prioritization: Projects approved in priority order until budget fully allocated.
Projects entered for tracking during design and implementation.



In instances where time-sensitive or urgent needs arise outside of the budget cycle or are over the established budget, funding is considered on a case-by-case basis to ensure ongoing safe and reliable operations.

PacifiCorp reviewed the As-Is DSP process, including identification and prioritization of grid needs and solutions, during the Stakeholder Workshop #9, held on June 24, 2022. That review also included the lists of the prioritized and approved projects for the following Investment Reasons as of June 20, 2022:

- System reinforcement – feeder
- System reinforcement – substation
- Feeder improvements
- Substation improvements
- Functional upgrade – reliability (*not through regular DSP studies)*

2.3.4.1 Distribution Planning Study Tools

There are several toolsets used during the distribution planning study process. These toolsets provide the data that is input into the load forecasting and study model as well as perform the analysis and calculations to determine grid needs and solutions. **Figure 10** provides a summary of the toolsets used during each step of the distribution planning process:

Load Forecasting Tools

- **Supervisory Control and Data Acquisition (SCADA)/PI Historian:** Database for all SCADA load information.
- **Bluezone/RCMS:** Provides customer meter load information. Typically used for gathering spot load (generally 300 kVA or larger) information.
- **Microsoft Excel**: Uses SCADA load information and performs linear and exponential load forecasting analysis for peak loads to determine projected load each year, growth rates, and substation transformer and circuit capacity.

Study Analysis Tools

- **CYME:** Load flow analysis software used to determine grid needs and solutions.
- **ASPEN:** Distribution protection analysis software used for overcurrent protection studies.

Study Model Tools

- **FastMap:** Mapping tool using GIS data. Used during model updates/verification.
- **Greater:** Mapping tool using GIS data. Used during model updates/verification.
- **CYME:** Load flow analysis software where load flow model is stored.
- **CYME Gateway:** Provides the model and equipment database used in the load flow model.

Study Report Tools

- **AMPS:** Primary repository tool for grid needs, solutions, and studies

Figure 10: Distribution Planning Toolset Summary

2.3.4.2 Planning References From Part 1

There were multiple details provided in the DSP Part 1 filing that may be helpful for readers to access for topics related to DSP. **Table 2** provides potentially relevant topics with references to their location in the DSP Part 1 filing.

Table 2: Select References From DSP Part 1

Topic	Reference in PacifiCorp's DSP Report – Part 1
PacifiCorp's Maintenance Programs (Asset Inspection, Substation Inspection)	Page 14
Vegetation Management	Page 16
PacifiCorp's Targeted Reliability Improvement Programs	Page 20
Future Improvement Projects	Page 26
- Grid Modernization	Page 27
- AMI	Page 28
- CYME Load Modeling	Page 29
- Smart Devices	Page 30
- Distribution Automation	Page 32

2.4 Pilot / Transitional Study Areas Introduction / Rationale

As outlined in DSP Part 1, PacifiCorp targeted two regions to use as "Pilot" or "Transitional Study" areas where the Company would experiment with new DSP processes, explore potential NWS and solicit input on NWS pilot proposals. The focus areas for transitional study were Klamath Falls and Pendleton.

These areas were selected for transitional planning using the following criteria:

- DG capacity and readiness (SCADA availability, DG protection measures, daytime minimum load)
- Study cycle timing – both areas were on-cycle for DSP planning
- Historical DER project activity
- Area demographics and characteristics (suburban/rural)

PacifiCorp sought stakeholder input for NWS pilot proposals in these areas from March through May 2022. Feedback was sought via workshop, email, webpage content and community engagement. Additionally, PacifiCorp solicited input directly from DSP workshop participants in the form of feedback or suggestions. As a result, PacifiCorp received a total of three pilot proposals from two organizations, Farmers Conservation Alliance (FCA) and Oregon Solar and Storage Industry Association (OSSIA).

PacifiCorp used the new DSP processes for these Transitional Study areas, then used specific grid needs in the pilot areas to analyze potential NWS. By focusing on a specific area and grid need, the DSP team was able explore and understand the impacts of several new approaches within the existing DSP process framework. Specifically, PacifiCorp:

- Used and compared the new forecasting approaches against historical forecasts (e.g., the 2023 IRP load forecast, private generation (PG) and EV forecasts with specific allocation methodologies versus historic method based on local actuals) to understand similarities and differences
- Developed an understanding of forecasting and modeling needs and datasets that may be required to adequately analyze NWS
- Examined modeling toolsets with an eye toward future needs and new use cases

Based on the assessment of grid needs in the Transitional Study areas and stakeholder feedback, PacifiCorp moved forward a pilot to study potential solar + storage on one Klamath Falls circuit to understand how it addressed an identified overcapacity grid need. PacifiCorp incorporated two of the three proposed pilot studies: one from FCA (solar + storage) and smart inverter functionality (from OSSIA) into this solar + storage pilot evaluation.

This overcapacity grid need and pilot study of an NWS were reviewed at a local stakeholder input meeting in Klamath Falls. After providing background and education about DSP, the specific grid needs identified and the customer makeup on the circuit, stakeholders indicated they would like to explore targeted energy efficiency as the second NWS. PacifiCorp has evaluated targeted energy efficiency as one of the NWS, which is presented in **Chapter 5**.

2.5 DSP Stakeholder Survey and Results

As outlined in PacifiCorp's DSP Part 1, Chapter 3, Community Outreach and Engagement Plan, the Company completed a customer survey administered by MDC Research (a third-party market research agency) in the spring of 2022 (Full report is included in **Appendix B**). The survey was targeted at the Company's Oregon customer base to gather input on DSP.

The overall objectives of this research were to measure the public's awareness of DSP, prioritize the benefits associated with clean energy, understand concerns, and obtain high-level stakeholder feedback. Specific objectives included:

- Identify challenges facing the community and individuals
- Prioritize the benefits associated with clean energy
- Understand concerns associated with moving to clean energy
- Measure awareness of communications from PacifiCorp and understand recall of specific messages
- Identify communication channels

- Evaluate the clarity and efficacy of communications from PacifiCorp
- Measure satisfaction with PacifiCorp's outreach and engagement about plans for cleaner energy
- Understand stakeholders' perceptions about DSP, their informational needs and best practices for engagement
- Identify nontraditional stakeholder groups that should be part of the process, and understand how they can provide insight into energy equity goals

Broader objectives included:

- Provide high-level education/background on DSP
- Evaluate whether customers feel equipped to evaluate their energy usage options
- Understand whether customers feel connected to resources before, during and after making personal changes regarding energy use
- Categorize survey recipient regarding relationship with PacifiCorp (customer, jurisdiction, observer, developer, service provider)
- Seek to hear from a wide spectrum of customers, stakeholders and/or community voices
- Collect customer geographic, socioeconomic and demographic data for insights into energy equity, and energy burden with respect to system reliability and customer options

To achieve a broadly representative view of PacifiCorp's customer base in Oregon, this research was conducted using a mix of online and phone surveys and remote in-depth interviews with stakeholders.

Online surveys provide a cost-effective method of achieving a large sample size and are representative of customers who have provided their email address to PacifiCorp (e.g., those enrolled in paperless billing, etc.). This group tends to be more affluent, more likely to speak English and less likely to be a member of a frontline community.[12] Phone interviews were incorporated to provide an inclusive platform to gather feedback from those less likely to have an email address on file or respond to an online survey request.

[12] "Frontline communities are those that experience 'first and worst' the consequences of climate change. These are communities of color and low-income, whose neighborhoods often lack basic infrastructure to support them and who will be increasingly vulnerable as our climate deteriorates. These are Native communities, whose resources have been exploited, and laborers whose daily work or living environments are polluted or toxic." Source: Ecotrust

Target audience:

- PacifiCorp residential and business customers in Oregon
- PacifiCorp frontline customers
- Stakeholders

A total of 4,627 surveys, including 30 from frontline customers, were completed between February 1 and February 28, 2022. Online and phone surveys were available to customers in English and Spanish.

- Phone: 130 completed surveys
- Web: 4,497 completed surveys

Twenty-four in-depth interviews were conducted with a variety of stakeholders across the PacifiCorp territory.

- Eight energy consultants
- Six municipalities/government entities
- Four community-based organizations (CBO)
- Four economic development organizations
- Two tribal agencies

Interviews lasted 45-60 minutes.

- Participants were paid $100 as a thank you for their time and feedback
- All interviews were recorded
- Interviews were scheduled using a “warm handoff” from PacifiCorp

2.5.1 Key Findings

Clean Energy DSP Benefits and Concerns:

Top challenges facing the community are affordable housing and the high cost of living. Primary challenges faced by individuals are the high cost of living, climate change and health care.

Those in Portland are more likely to be concerned about homelessness, affordable housing, climate change, pollution, health care and education.

Those in Northeast Oregon and Willamette Valley South are more likely to mention access to jobs.

The most important benefits to a cleaner energy future are reducing the impact of climate change, preparation for natural disasters, decreased reliance on fossil fuels, spending less on energy bills and reducing the environmental impact of the electric system.

Those in Portland are more likely to consider the impacts of climate change and environmental issues as highly important.

Those in other regions are more likely to find personal and economic benefits more important.

Costs and potential bill increases are the primary concern with the transition to cleaner energy, with dependability of renewable sources and the potential impact of materials required for clean energy technology also concerning to more than half. Customers outside Portland and Hood River are more likely to express concerns about the transition to cleaner energy.

When looking at the specific values and benefits of cleaner energy, the environment and energy security are top priorities. When asking for the most desired benefits and concerns open-ended, lower cost was the most desired benefit and high cost was the most common concern.

Top Concerns

- Community: Affordable housing and high cost of living
- Individuals: High cost of living, climate change, health care
- Portland-Based Residents: Homelessness, affordable housing, climate change, pollution, health care and education
- NE Oregon and Willamette Valley: Access to jobs, health care

Clean Energy DSP Top Benefits

- Reducing the impacts of climate change
- Preparedness for natural disasters
- Decreased reliance on fossil fuel
- Lower energy bills
- Reducing the environmental impacts of the electric system
- Portland-Based Residents: Impacts of climate change and environmental issues
- Other Regions: Personal and economic benefits

Clean Energy DSP Top Concerns

- Costs and potential bill increases
- Dependability on renewable sources and impact of materials needed
- Customers outside of Portland and Hood River: More likely to express concern about the transition to cleaner energy

Communications:

Seven in 10 recall receiving communications from PacifiCorp in the past year, with two-thirds mentioning an email.

Bill messages and the PacifiCorp website are the next most common sources, each mentioned by one-third of customers.

Nearly all recall seeing messages in English, with 7% recall also seeing Spanish. All other languages combined are mentioned by less than 1% of customers.

The most commonly recalled messages are related to paperless billing, outage notifications or alerts and Blue Sky enrollment.

Messages through all channels from PacifiCorp are generally considered clear, although messages in Spanish are less clear than in English (apart from messages through local organizations or community centers).

Text messages, phone calls, the PacifiCorp website and local organizations or community centers are most useful; less than half find messages useful from direct mail, radio, friends/family/co-workers or newspapers.

Satisfaction with outreach and engagement from PacifiCorp is moderate regarding issues related to conserving energy, saving money, planning and renewable energy, with nearly half being "somewhat satisfied" with all attributes evaluated.

2.5.2 Recommendations

As a result of its public outreach, PacifiCorp was able to distill recommendations that will guide Company communications during the transition to a greener, more broadly integrative distribution system. Communications, in a range of formats, related to customer education on clean energy, its relevance and its impact on power bills will be critical, as will Company awareness of the divergent concerns of its broad customer base.

One recommendation: Educate customers about the plans to move toward a cleaner and more equitable energy grid. Explain the rationale, planning process and steps to be taken in clear and concise language.

A second recommendation: Focus clean energy education on the key desired benefits of the move toward a cleaner and more equitable energy grid — reducing the impact of climate change, preparing for natural disasters, decreasing reliance on fossil fuels, spending less on energy bills and reducing the environmental impact of the electric system.

It will be necessary to address the primary concern about DSP: the *cost of the transition and the potential impact on electric bills*. This aligns with one of the primary concerns both personally and for the community: high cost of living. While customers across the state, and particularly those in Portland, broadly recognize the environmental/climate change and resiliency benefits, it will be necessary to alleviate concerns about how addressing these issues will impact their monthly budget.

The focus on transitioning to an equitable energy grid will require explanation. Even among stakeholders, this concept is not universally understood, and it raises questions about what it means, how it could be done and how much it will cost.

PacifiCorp should use a mix of communication strategies. While email is the most common by far, it is important to reach customers through a variety of means to provide access to all. The Company should consider the PacifiCorp website, direct mailings and bill inserts (possibly directing customers to the website). While not widely used, local organizations and communities are perceived to provide very clear and useful information, and they could be strong allies in achieving the equity portion of the clean energy planning goal.

- Based on conversations with stakeholders, focusing communications on the impact of climate change, rather than climate change itself, is more likely to resonate with all customers across the state.

- Regardless of views, all communities are impacted by the risk of wildfires and/or drought, and efforts to mitigate those tangible concerns are more likely to be embraced.

PacifiCorp reviewed the DSP Stakeholder Survey with DSP stakeholders during DSP Workshop #8 on May 11, 2022 and has also published the Survey Summary on the DSP webpage.

PacifiCorp is committed to continuing an annual survey of Oregon customers and stakeholders to keep in step with the needs of the communities, customers and stakeholders across the state.

The primary themes in the customer survey related to DSP are:

- Cost of electricity remains a very important topic (both in terms of anticipated benefit and as the primary concern).
- The concept of energy equity is not well understood, even among energy savvy respondents. There must be a common definition to support dialogue and progress on development of energy equity metrics, potential equity identifiers and establishing areas of focus to support equitable development.
- PacifiCorp's far-flung Oregon territory contains a wide variety of attitudes and interests that span the entire spectrum of priorities around DSP. While cost was a common consideration across all areas, some geographies reflected very different attitudes about the journey toward a cleaner energy future. As such, it is important for the Company to engage locally to best gauge the specific needs of the communities as DSP activities move ahead.
- It is important to continue to engage with stakeholders to seek input as DSP evolves. PacifiCorp needs to do more going forward to proactively engage communities and stakeholders in the local communities via several communication platforms.

Chapter 3: Forecasting

3.1 Readers Guide

This chapter provides detail regarding the load forecasting methods used in the distribution system planning (DSP) context to meet requirements outlined in DSP Part 2. Specifically, the requirements outlined in **Section 5.1** for load growth, distributed energy resource (DER) adoption and electric vehicle (EV) adoption.

The first section in this chapter introduces DSP forecasting with a high-level overview of the steps involved in developing the DSP forecast and a summary of each section in this chapter.

Next the Company provides context for each of the elements that were incorporated into the load forecast — EV adoption, private generation (PG)[13] adoption, energy efficiency and demand response (DR) — and provides detail regarding how the state-level forecasts were provided down to the feeder/circuit level.

The final section offers a summary of the load forecasting results with DER and EV adoption incorporated for the two Transitional Study areas.

COVERED IN THIS CHAPTER

Refresh context on load forecasting and specific requirements outlined in DSP Guidelines Section 5.1

Provide an overview of the DSP load forecasting process

Offer context and explanation of each element incorporated into the DSP forecast (EV adoption, PG)

Provide detail pm how state level forecasts were provided down to feeder/circuit level

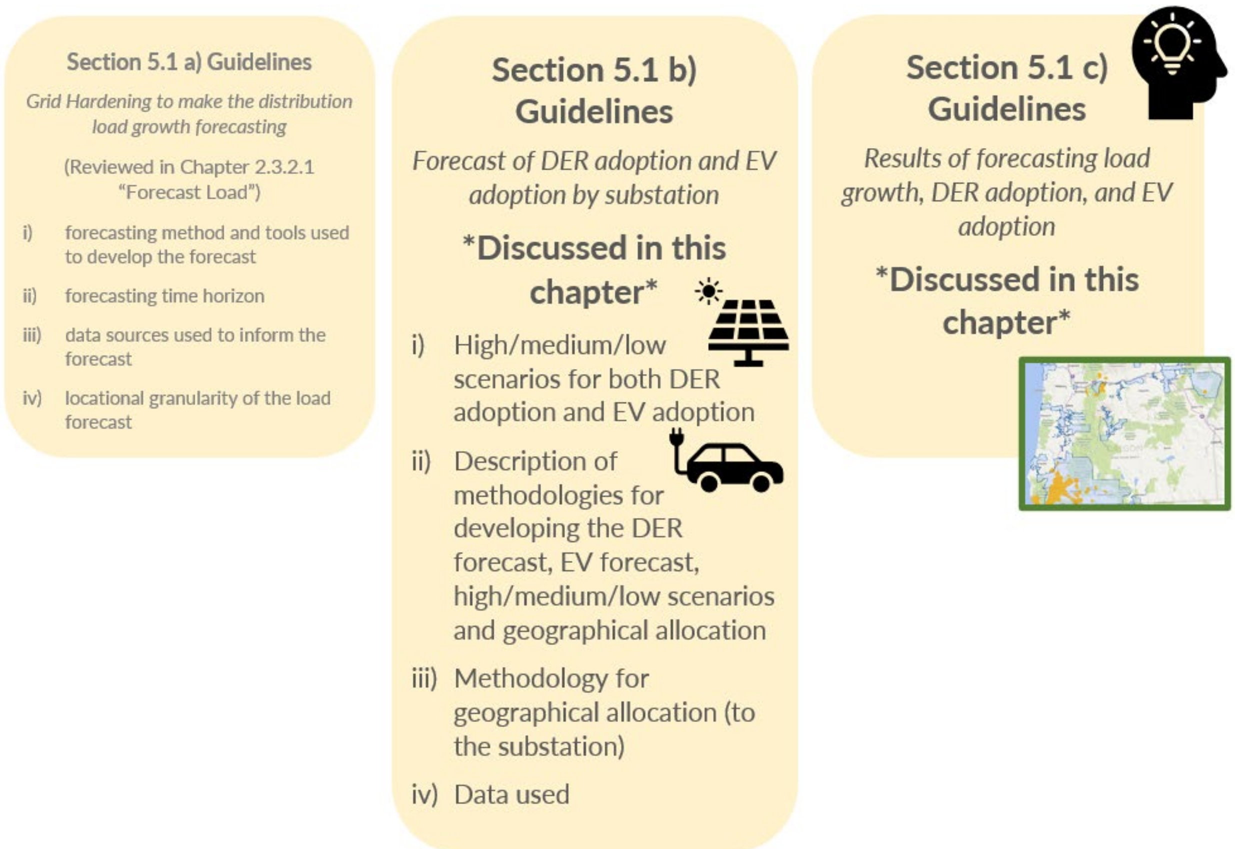
Summarize the results of forecasting load growth, EV and PG forecast in DSP Transitional Study areas

DSP Guidelines	Chapter Section
5.1.b.i	**Section 3.4 – 3.8**
5.1.b. ii	**Section 3.4 – 3.8**
5.1.b.iii	**Section 3.4 – 3.8**
5.1.b.iii	**Section 3.4 – 3.8**
5.1.b.iv	**Section 3.4 – 3.8**
5.1.c	**Section 3.8**

[13] Private generation (PG) refers to customer-owned, small-scale generation undertaken by both private and public customers.

3.2 Part 2 Forecasting Requirements

This chapter addresses the specific requirements as outlined in Section 5.1 b) and Section 5.1 c) of the DSP Guidelines:



3.3 DSP Forecasting Introduction

DSP forecasting uses the load forecasts generated by the field engineers as the foundation for the Transitional Study areas. As mentioned in **Chapter 2**, **Section 2.3.2.1** the field engineer load forecast is created by using historical peak load data for the substations and feeders being evaluated.

PacifiCorp engaged two vendors — DNV and Applied Energy Group (AEG) — to develop forecasts for PG (DNV) and EV (AEG) to meet the specific requirements outlined in the DSP Guidelines Section 5.1.b. Each vendor created forecasts that reflected high, medium and low adoption rates specific to PacifiCorp's Oregon service territory and provided forecasts down to the feeder/circuit level.

Twenty-four-hour load shapes were developed for the circuit using the field engineer load forecast and were subsequently used for load flow modeling and preliminary identification of grid needs, forming the basis for review of non-wires solutions (NWS). Final PG and EV forecast results were layered onto the 24-hour load shape to define the worst-case scenarios for DSP peak load and net minimum load forecasting.

Figure 11 summarizes the differences between the traditional (field engineer) load forecasting and DSP load forecasting.

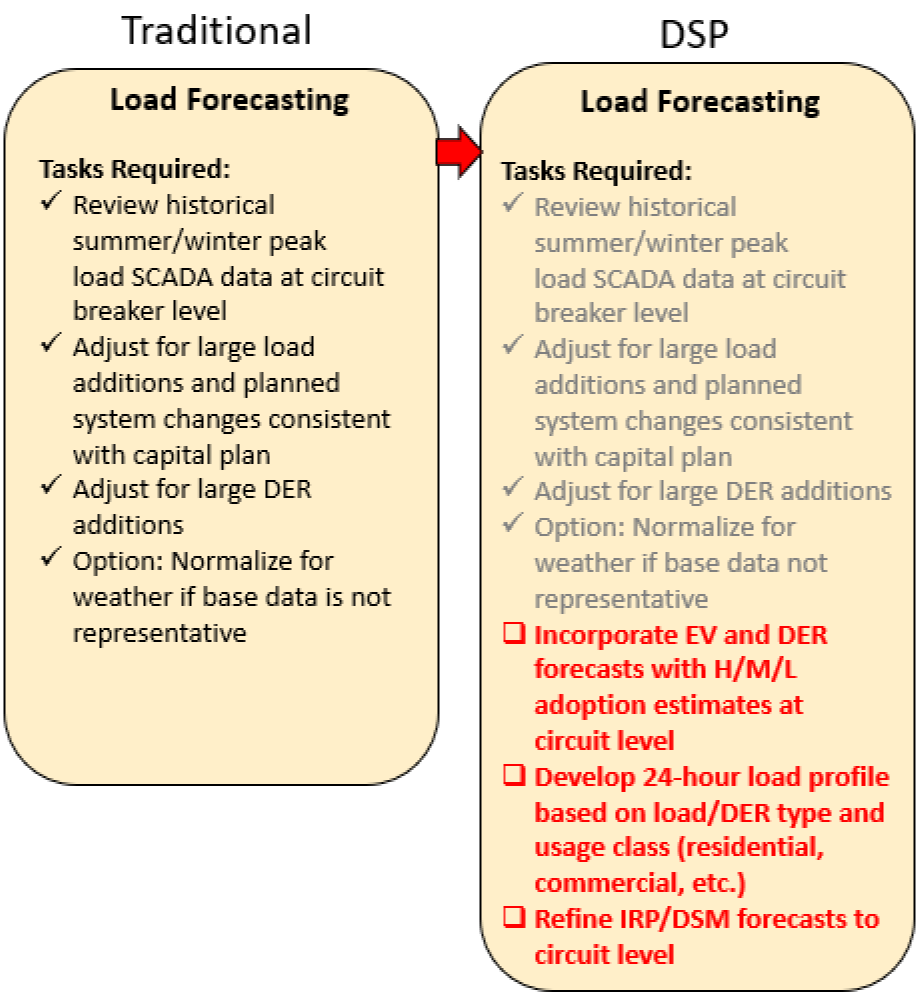


Figure 11: Traditional Versus DSP Forecast Overview

The remainder of this chapter provides further detail on EV and PG forecast development, additional information regarding other elements that were incorporated into the load forecast such as energy efficiency and demand response (DR), and a summary of the DSP load forecasting results applied to the two Transitional Study areas.

A brief overview of each section included in this chapter is provided below:

Section 3.4 — EV forecasting for PacifiCorp's Oregon service territory with results provided down to the feeder/circuit level. This section outlines how the EV forecast was generated; how the high, medium and low adoption scenarios were developed; and how the circuit level results were developed.

Section 3.5 — PG forecasting for PacifiCorp's Oregon service territory with results provided down to the feeder/circuit level. This section outlines how the PG forecast was generated; how the high, medium and low adoption scenarios were developed; and how the circuit level results were developed.

Section 3.6 — Energy efficiency forecast for PacifiCorp's Oregon service territory with results provided down to the feeder/circuit level. This section outlines how the energy efficiency forecast was generated and how the high, medium and low adoption scenarios were developed.

Section 3.7 — DR resource forecasting for PacifiCorp's Oregon service territory with results provided down to the feeder/circuit level. This section outlines how the DR forecast was generated; how the high, medium and low adoption scenarios were developed; and future considerations for DR forecasting in the context of DSP.

Section 3.8 — DSP load forecasting results for two Transitional Study areas. This section outlines the DSP Transitional Study areas and summarizes the results of implementing the DSP forecast on these areas.

Section 3.9 — Forecasting lessons learned. A summary of lessons learned while implementing new DSP forecasting methods.

3.4 Forecasting — Electric Vehicle

PacifiCorp expects EV adoption to be an area of growth for electric demand over the coming years. The Company expects future adoption to outpace recent historical adoption and therefore requires detailed analysis to ensure that future load growth expectations are accurately reflected in distribution planning.

PacifiCorp contracted with AEG to produce an EV registration forecast that complies with the Part 2 DSP requirements and provides insight into transportation electrification (TE) in PacifiCorp's Oregon service territory. Those requirements specify a disaggregated EV registration forecast at the substation level. Additional desired insights included visibility into feeder-level electrification trends and the distribution of EV registration by geography and population density.

In general, the EV registration forecast analysis included the following key aspects:

- The forecast was limited to light-duty vehicles (excluding fleets), based on the cumulative number of registrations, performed at the feeder level, and aggregated to the substation and state levels.
- The methodology included both top-down and bottom-up approaches. Both approaches were needed to account for as many factors as possible while maintaining the desired level of granularity.

    - **Top-Down Approach**: PacifiCorp developed a state-level forecast of EV registrations based on national trends that align with Bloomberg NEF's (BNEF) long-term EV outlook. The BNEF forecast provides the expected growth over the long run at the state level. During this forecast development, PacifiCorp also referenced the Wood-Mackenzie (WM) and Annual Energy Outlook (AEO) forecasts. However, this approach did not provide visibility into substation-level or feeder-level growth.
    - **Bottom-Up Approach**: AEG developed a regression-based[14] forecast at the most granular level. The forecast estimated EV registration growth over PacifiCorp feeders and substations in the Oregon service territory. Note: a regression-based forecast has limited drivers (inputs), including historical trends (time trend), economic (gas price and population count) and historical PG installations. This forecast did not account for other factors such as state EV adoption goals, technology improvements and proposed tax incentives. Ultimately, the bottom-up forecast produced reasonable estimates. However, constraints of this initial forecast, as described above, produced conservative growth rates, which generally align with the EV projection produced by the Annual Energy Outlook (AEO).

- The analysis included the development of four scenarios: low, medium, medium-high and high. Each scenario leveraged the characteristics of both approaches. The top-down approach provided more aggressive growth rates, and the bottom-up approach provided the distribution of EVs across the feeders and substations. PacifiCorp separately evaluated the EV forecast currently relied on in the 2023 IRP to help inform a scenario for the circuit level load forecast presented in **Section 3.8**. Although relatively similar in near-term magnitude, the high EV statewide forecast was higher than the 2023 IRP.

As part of the data development for the bottom-up approach, AEG updated the EV baseline data analysis completed under the previous DSP filing[15] to include registrations through December 2021. This update provided the historical adoption rates across PacifiCorp's Oregon territory

[14] Regression is a mathematical approach used to estimate statistical relationships between the dependent variable (in this case EV registrations at each feeder) and other independent variables such as economic trends, time, population growth, etc. These relationships can be used to generate a forecast of the dependent variable based on forecasted changes in the independent variables.

[15] https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/dsp/2021_PacifiCorp_Oregon_Distribution_System_Plan_Report_Part1.pdf

feeders. Feeders were then grouped by cumulative historical registrations into low, medium and high segments. Then, regression-based forecasts were developed separately for each segment to allow for different relationships between drivers and registrations. **Figure 12** presents the mapping of cumulative EV registrations in PacifiCorp's Oregon service territory by feeder, overlayed with substation designations identified by color. Low, medium and high registration segments are indicated by the size of the circles.

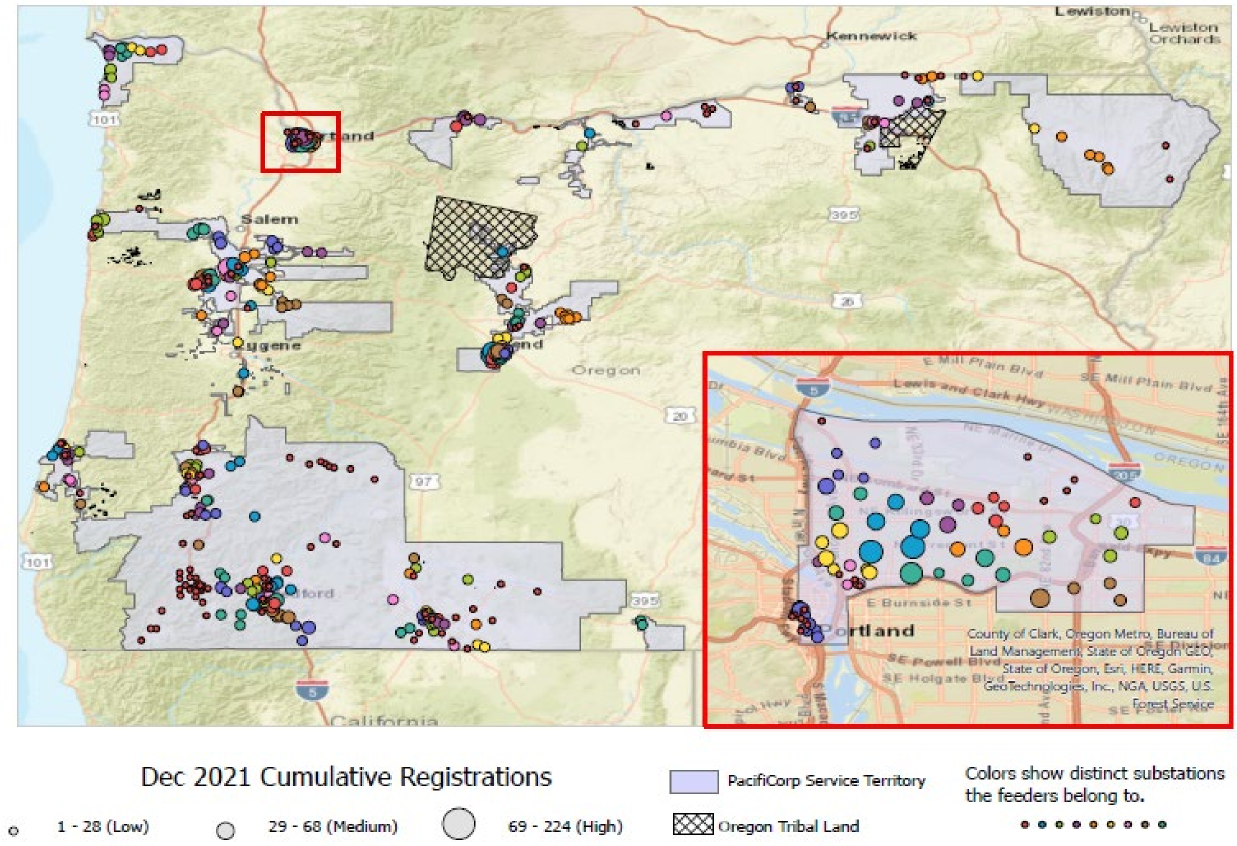


Figure 12: Mapping of Oregon EV Registrations

Table 3 and **Figure 13** summarize the preliminary results of the four scenarios developed under this analysis. Note that the AEO forecast is presented only for comparison with the two regression-based approaches. It does not include the feeder-level disaggregation and therefore is not considered one of the four scenarios.

Table 3: Estimated EV Cumulative Registrations by Year

Scenario	Cumulative Registrations 2021	2026	2031
Bloomberg (BNEF) (High)	9,117	45,446	152,012
Wood-Mackenzie (WM) (Medium-High)	9,117	25,904	67,938
Regression-based - Medium	9,117	29,132	55,811
Regression-based - Low	9,117	22,960	37,631
AEO	9,117	20,752	31,889

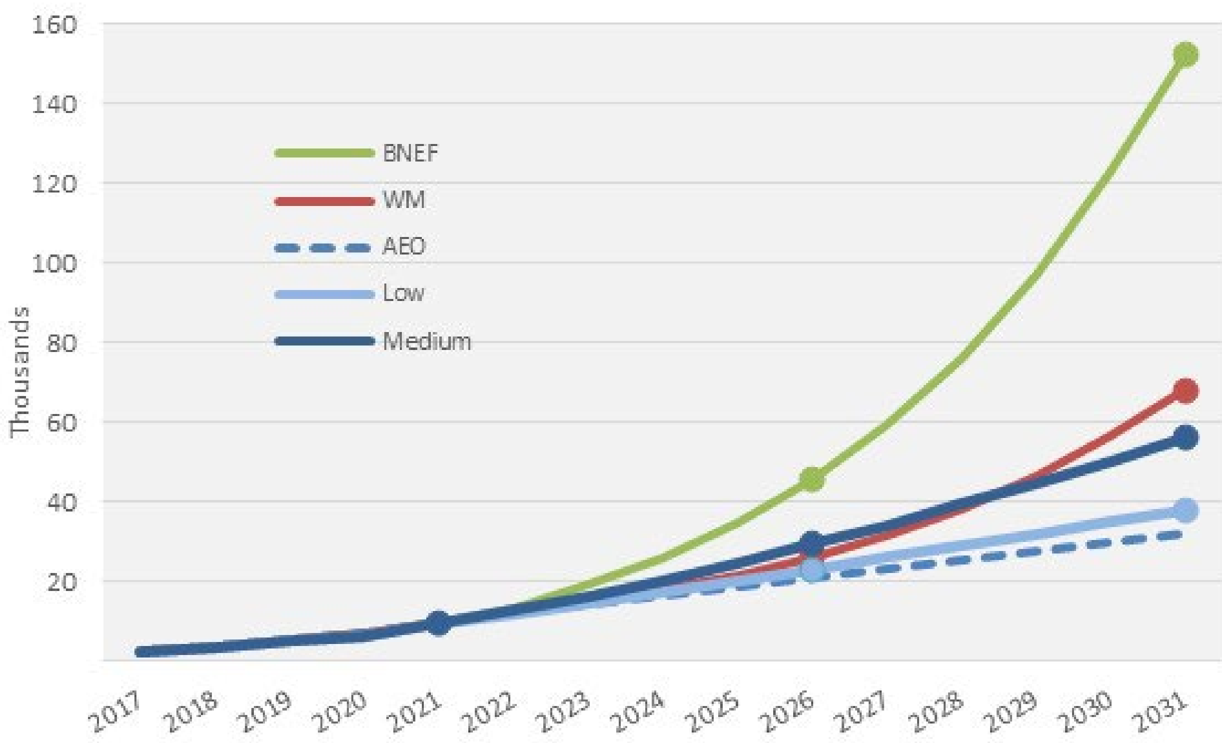


Figure 13: Preliminary 10-Year EV Forecast Results

*AEO forecast is presented for comparison only.

Key Findings

As part of DSP, PacifiCorp evaluates all previously discussed EV scenarios (see **Section 3.8** below). However, as a representative and baseline DSP EV forecast, PacifiCorp considers the top-down BNEF and WM EV forecasts to be most appropriate for planning, given the state's policy goals and future investment tailored toward accelerating EV adoption.

After assessing the results of each scenario, the modeling produced a number of key findings. At the five-year point (2026), all four scenarios reflect a very similar EV adoption forecast. Interestingly, the medium-high scenario (WM) is lower than the medium scenario in the near term, even though it ends up higher by the end of the forecast horizon. At the 10-year point (2031), three of the four scenarios still reflect similar forecasted adoption, with the medium-high (WM) scenario passing the medium scenario in 2029. Over time, the feeder distribution does not change dramatically. The analysis predicts that feeders will grow at a relatively steady rate commensurate with historical trends.

Consistent with EV baseline data analysis completed under the prior DSP filing, these revised EV forecast scenarios also include lower registration concentration on rural[16] area feeders, with nearly all high registration feeders occurring in urban areas. At the 10-year point (2031), under the high scenario (BNEF):

- The top five feeders (highest registrations) are in the Multnomah (three feeders), Linn (one feeder) and Hood River (one feeder) counties.
- 10% of EV registrations are located on 10 feeders or 2.5% of the total feeders analyzed.
- 20% of EV registrations are located on 22 feeders or 5.7% of the total feeders analyzed.

Regardless of the scenario used for disaggregation, dispersion of cumulative registrations stayed relatively consistent across forecast scenarios. While not the sole focus of this work, areas of low expected adoption can be used to inform future TE planning and well as DSP.

[16] Based on the U.S. Department of Agriculture (USDA) definitions on population density: https://www.ers.usda.gov/topics/rural-economy-population/rural-classifications

3.5 Forecasting — Private Generation

PacifiCorp expects private customer generation to continue to be an area of growth in the future. The DSP process allows the Company to perform detailed analysis to ensure that expected future load offset from private customer generation is accurately accounted for in distribution planning.

PacifiCorp worked with DNV to prepare the Long-Term Private Generation Resource Assessment for PacifiCorp's Oregon DER adoption forecast at the circuit level. PG projections from this study are used to support PacifiCorp's 2023 Oregon Distribution System Plan. This study evaluated the expected adoption of behind-the-meter DERs including photovoltaic solar (PV Only), photovoltaic solar coupled with battery storage (PV + Battery), wind, small hydro, reciprocating engines and microturbines for a 20-year forecast horizon (2023-2042). The adoption model developed is calibrated to the current[17] market penetration of these technologies, shown in **Figure 14**.

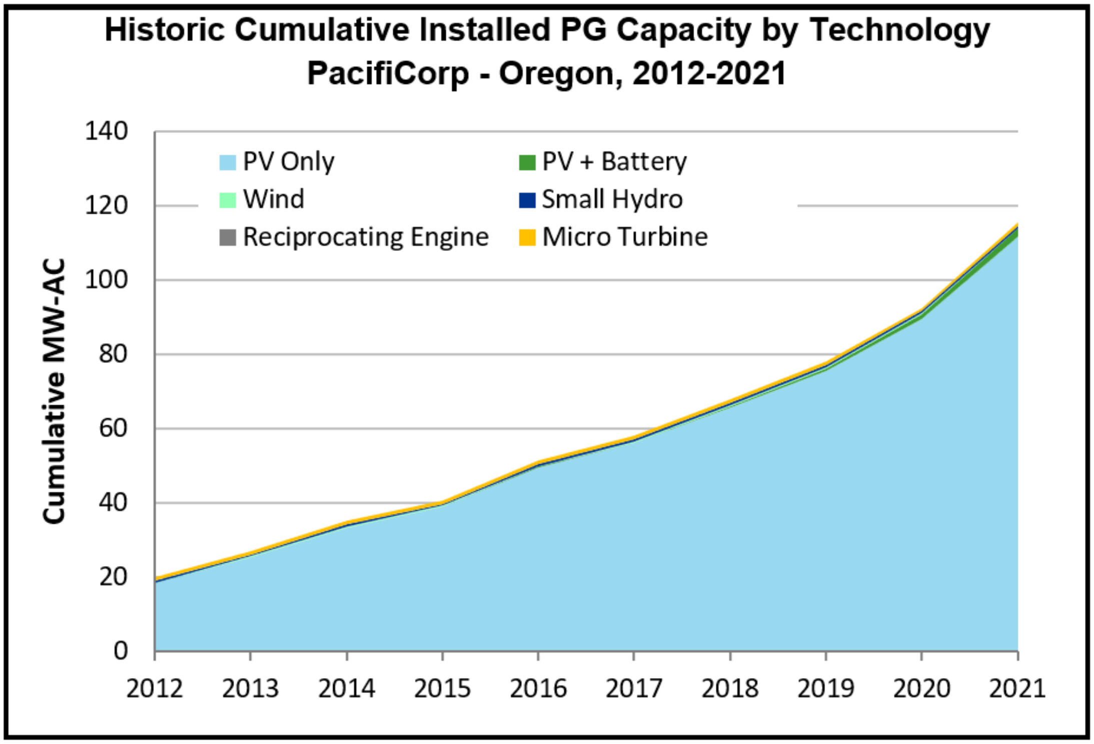


Figure 14: Historic Cumulative Installed PG Capacity

To date, approximately 96% of existing PG capacity installed in PacifiCorp's Oregon service territory is PV. To inform the adoption forecast, DNV conducted an in-depth review of the other technologies and did not find any literature to suggest that other technologies would take on a larger share of the PG market in Oregon during the future years of this study.

[17] PacifiCorp PG interconnection data as of February 2022.

For each technology and sector, DNV developed three scenarios: a base case, a high case and a low case. The base case is considered the most likely projection; it is based on current market trends and expected changes in costs and retail rates. The high and low cases test how changes in technology costs and retail rates impact customer adoption of these technologies. These scenarios use technology cost and performance assumptions specific to PacifiCorp's Oregon service territory in the base year of the study. The base case assumes the current federal income tax credit schedules and state incentives, retail electricity rate escalation from the AEO reference case, and a blended version of the National Renewable Energy Laboratory's (NREL) Annual Technology Baseline moderate and conservative technology cost forecasts. In the high case, retail rates increase more rapidly, and technology costs decline at a faster rate compared to the base case to incentivize greater adoption of PG. For the low case, retail rates increase at a slower rate than the base case and technology costs decrease at a slower rate.

Study Methodologies and Approaches

The forecasting methodologies and techniques applied by DNV and PacifiCorp in this analysis are commonly used in small-scale, behind-the-meter energy resource and energy efficiency forecasting. To forecast PG adoption at the circuit-level, DNV developed an adoption model to estimate total PG potential for PacifiCorp's Oregon service territory and then disaggregated these results to develop PG potential estimates for each circuit. The methods used to develop the statewide and circuit-level results are described in more detail below.

Statewide Forecast Approach

DNV and PacifiCorp developed a behind-the-meter net economic perspective that includes the acquisition and installation costs for each technology and incorporates the available incentives and economic benefits of ownership as offsets, which assumed that the current net metering policies for Oregon remained in place throughout the study horizon. The economic analysis calculated payback by year for each technology by sector. A corresponding technical feasibility analysis determined the maximum, feasible adoption for each technology by sector. The results of the technical and economic analyses were used to inform the Company's market adoption analysis. The methodology and major inputs to the analysis are shown in **Figure 15**. Changes to technology costs, retail rates and federal tax credits used in the high and low cases impact the economic portion of the analysis.

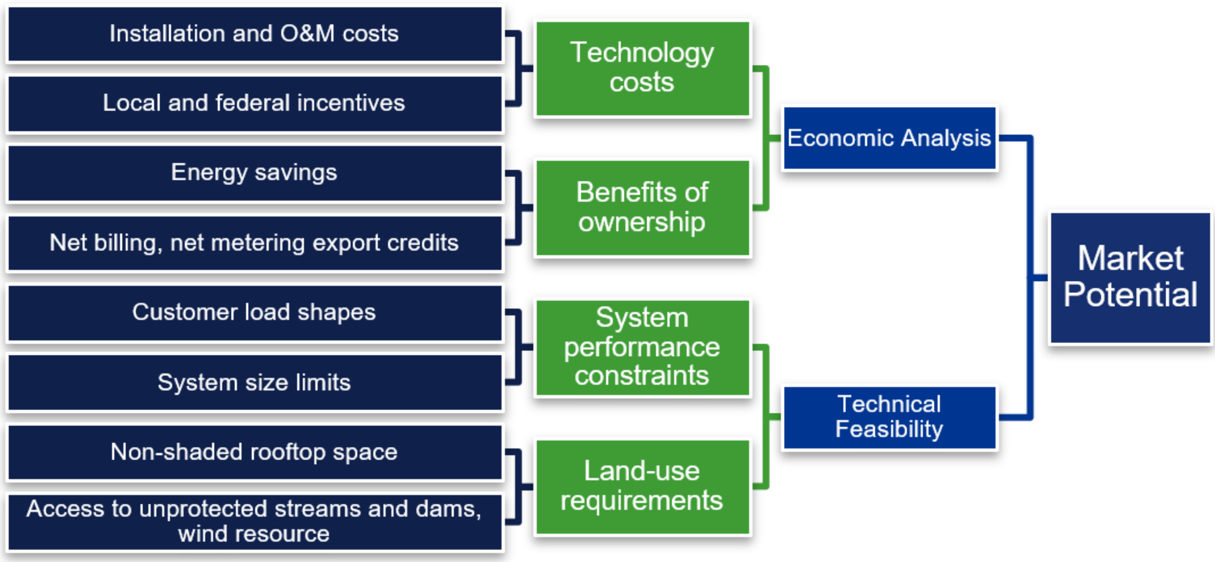


Figure 15: Methodology To Determine Market Potential of Private Generation Adoption

DNV used technology and sector-specific Bass diffusion curves to model market adoption and derive total market potential. Bass diffusion curves are widely used for forecasting technology adoption. Diffusion curves typically take the form of an S-curve with an initial period of slow early adoption, adoption increasing as the technology becomes more mainstream, and eventually tapering off among late adopters. The upper limit of the curve is set to maximum market potential, or the maximum share of the market that will adopt the technology regardless of the interventions applied to influence adoption. In this analysis, the long-term maximum level of market adoption was based on payback. As payback was calculated by year in the economic analysis to capture the changing effects of market interventions over time, the maximum level of market adoption in the diffusion curves vary by year in the study.

The model is characterized by three parameters: an innovation coefficient, an imitation coefficient and the ultimate market potential. The last of these PacifiCorp set equal to the payback-based maximum level of adoption. Together, these three parameters also determine the time to reach maximum adoption and the overall shape of the curve. The innovation and imitation parameters were calibrated for each technology and sector, based on current market penetration and when PacifiCorp started to see the technology being adopted in the Company's Oregon service territory.

Circuit-Level Forecasting Approach

PacifiCorp conducted a bottom-up approach to develop circuit-level adoption models for each sector and technology. The Company chose to disaggregate the statewide forecast (described in the previous section) for developing circuit-level forecasts. Starting with the statewide adoption models, for the circuit-level models the Company incorporated county-level PG installation data and resource availability,[18] census-tract-level demographic data and circuit-level reliability data. The Company applied the localized models to circuit-level customer counts to forecast circuit-level capacity by sector and technology. The results of this bottom-up capacity forecast by circuit were reconciled with the statewide capacity forecasts.

Private Generation Forecast Results

Figure 16 compares the latest Oregon PG capacity in cumulative MW-AC by 2033 projected for each scenario. The capacity presented is incremental to what is already installed in PacifiCorp's Oregon service territory in 2021.

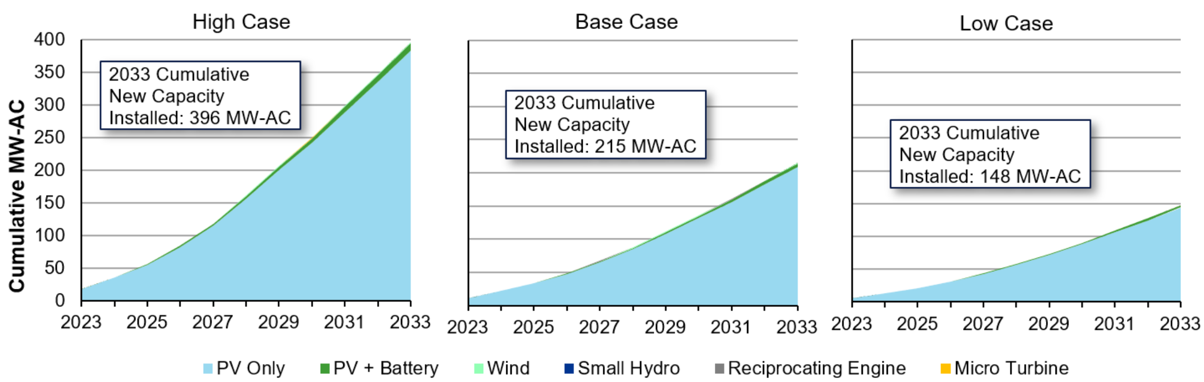


Figure 16: Private Generation Forecast by Technology, PacifiCorp Oregon, All Cases

Similar to the trends observed in currently installed capacity, solar PV accounts for approximately 96% of the new PG capacity forecast throughout the study period in all cases. By 2033, the cumulative new PV Only capacity in the base case is 209 MW and PV + Battery capacity is 5 MW. Compared to the base case, the low case forecasts 31% less PV Only capacity, and about 40% less PV + Battery capacity. The PV Only cumulative new capacity in the high case in 2033 is 83% greater than the base case. In the high case, 2033 PV + Battery cumulative new capacity is forecasted to be more than double the base case, at 11 MW.

[18] Conditions suitable for wind and hydro vary widely by region, and the economics of solar adoption is affected by local weather patterns.

Circuit-Level and Substation-Level Results Findings

Figure 17 illustrates the base case PG forecast over time by substation for the 504 circuits evaluated in Oregon and identifies the top five circuits by forecast PG capacity from 2023 to 2033. These five circuits account for 14% of cumulative new capacity through 2025 and 15% through 2033. The top 30 circuits account for 49% of new capacity in 2025 and 52% by 2033. Apart from the Medford substation, these substations are on the sunny east side of the Cascades, driving relatively higher solar adoption. The Medford substation lies in Jackson County, which has historically had higher-than-average adoption, suggesting a high level of awareness and an established network of solar contractors.

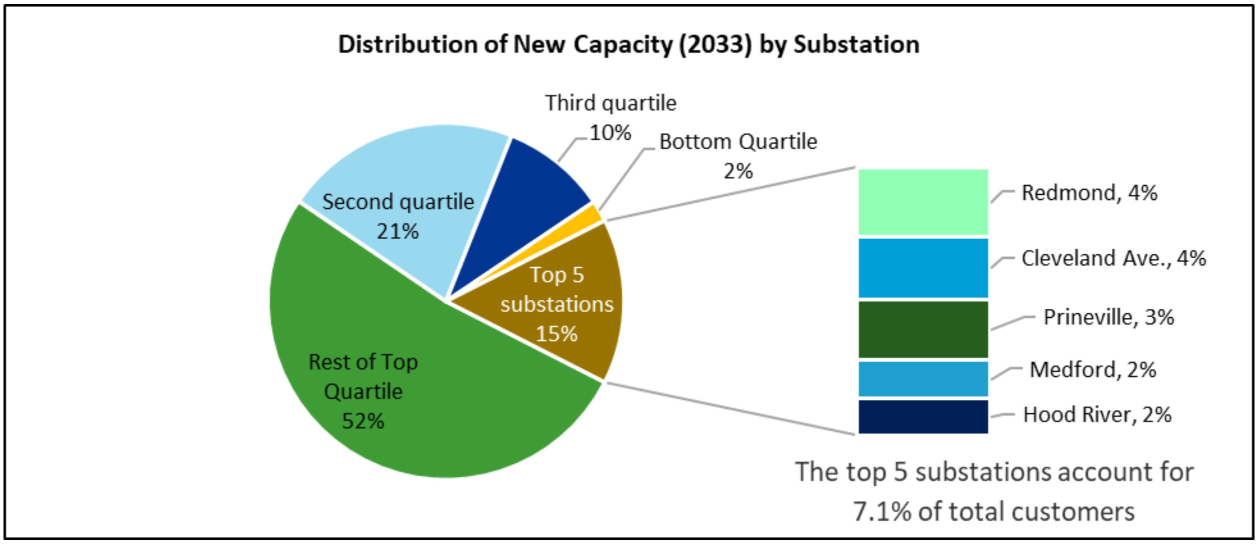


Figure 17: Private Generation Forecast Disaggregation by Substation, Oregon, Base Case

Figure 18 shows the breakdown of customers, by sector, at the top five substations. Because capacity sizes are larger for irrigation, commercial and industrial customers than for residential (four times larger for irrigation, nine times for commercial and 17 times for industrial), C&I customers contribute to capacity totals disproportionately to their share of the customer population. New construction has a two-fold impact on the capacity forecast: Directly, since there are customers on the substation who could adopt PG, and indirectly, since new construction has a higher propensity to adopt solar (with and without storage) than existing buildings.

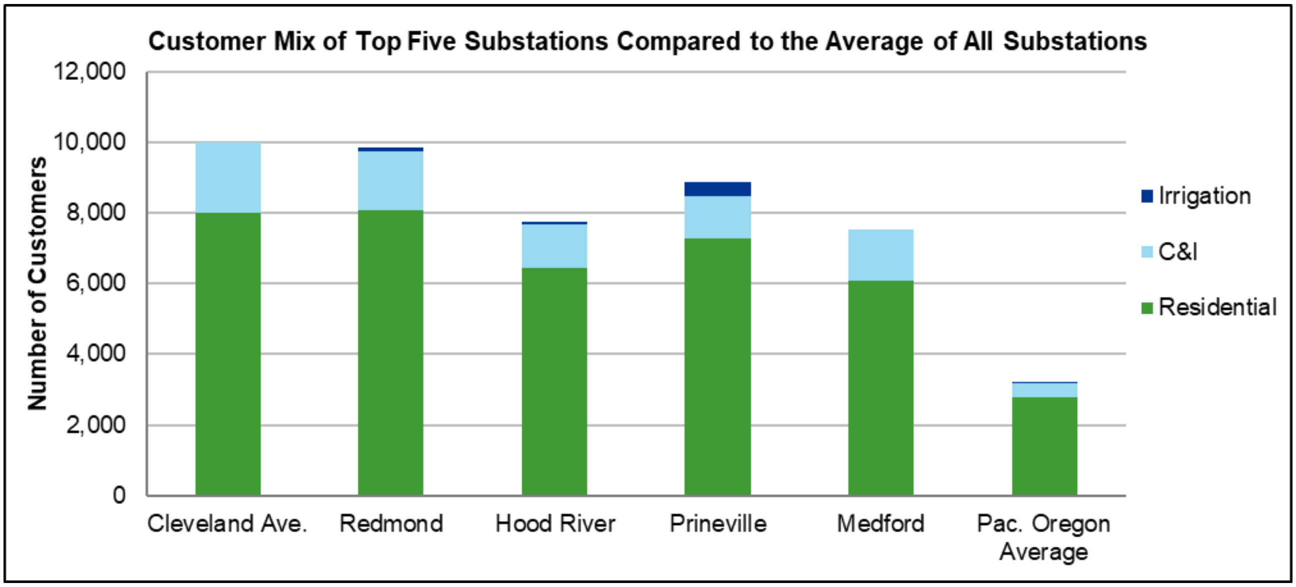
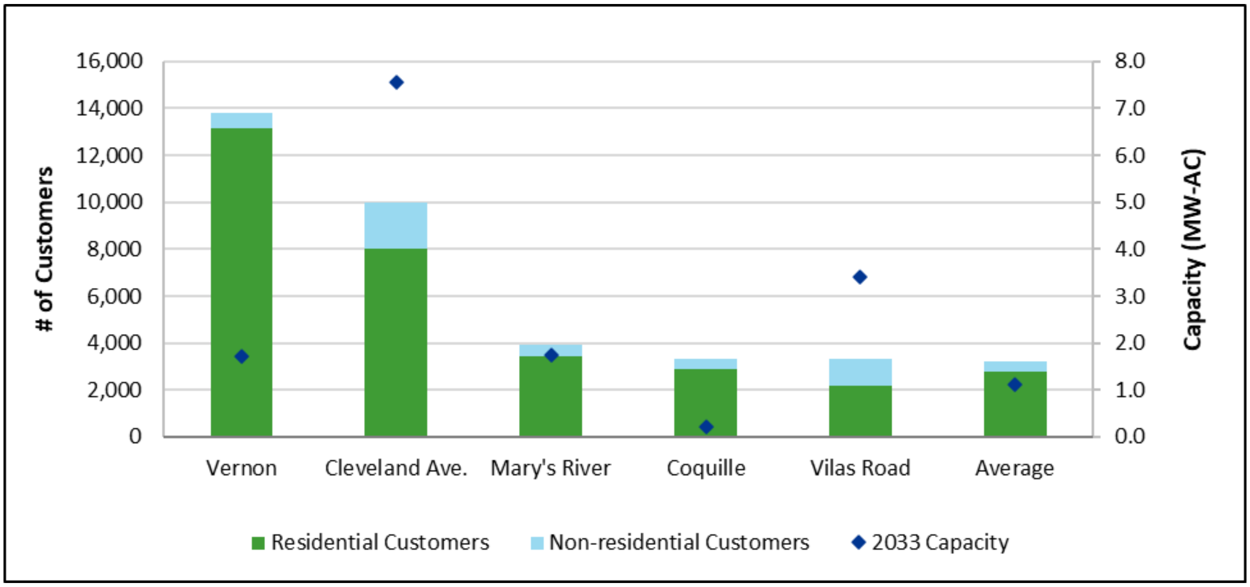


Figure 18: Customer Mix of Top Five Substations

With 193 substations across the state and so many factors influencing the disaggregated forecast, it is not feasible to conduct a deep dive of each substation's capacity forecast. Instead, we selected five substations to illustrate how different underlying factors affected their capacity allocations (see **Figure 19**). These substations were chosen to illustrate a range of characteristics influencing adoption, not because they are of special interest for planning.

Vernon and Cleveland Avenue are among PacifiCorp's top substations by number of customers but have very different climates and customer mixes. Cleveland Avenue lies on the east side of the Cascades and receives more sunshine, while Vernon is in the Portland operating area, which has more rain and more cloudy days, which adversely impacts solar generation and thus adoption. Nonresidential PV systems are larger than residential systems (modeled commercial systems are nine times larger; industrial systems are 17 times larger), so Cleveland Ave's higher share of nonresidential customers (20%) increases its capacity forecast compared to Vernon, with only 5% nonresidential customers. Cleveland Avenue also has double the rate of expected population growth that Vernon does over the next decade.

The remaining three substations shown each have a total customer count close to the statewide average, but very different capacity forecasts. Mary's River has high historic adoption and higher-than-average population growth, but less nonresidential and a lower home ownership rate than average resulted in a share of capacity almost proportional to the number of customers. Coquille has very low historic adoption, perhaps due to its less favorable climate for solar generation, and no expected population growth. Those factors, paired with lower-than-average income and low share of nonresidential customers led to a very low level of forecast PG capacity. The last substation we wish to highlight is Vilas Road in the Medford operating area. This substation has a very high share of nonresidential customers at 34%, and the higher capacity systems for these customers drives up the forecast. A favorable climate for solar with high historic adoption (residential and commercial) led to this substation being allocated a higher-than-proportional share of capacity.



Substation Attribute	Vernon	Cleveland Ave.	Mary's River	Coquille	Vilas Road	Average
Operating Area	Portland	Bend/ Redmond	Corvallis	Coos Bay/Coquille	Medford	--
Climate (for Solar)	Less favorable	More favorable	Less favorable	Less favorable	More favorable	--
Population Growth	1.0%	2.0%	1.3%	0.0%	1.7%	1.0%
%Non-res. Customers	5%	20%	12%	13%	34%	16%
Current Res. Solar Penetration	1.4%	3.0%	3.1%	0.9%	2.4%	1.8%
Home Ownership Rate	70%	55%	61%	77%	75%	65%
Avg. Household Income	$108,604	$136,460	$102,301	$74,543	$58,752	$87,499

Figure 19: Customer Attributes of Selected Substations Compared to Average PacifiCorp Oregon Substation

Figure 20 focuses on the Klamath Falls operating area to compare how the allocation of PV Only capacity compares to the distribution of customers by circuit. For each circuit in the Klamath Falls operating area, the chart shows the share of residential customers to the corresponding share of the 2033 residential PV Only capacity forecast. The figure demonstrates visually that more favorable factors for adoption, such as higher rates of home ownership, higher income, higher education, etc. result in a higher-than-proportional allocation of capacity.

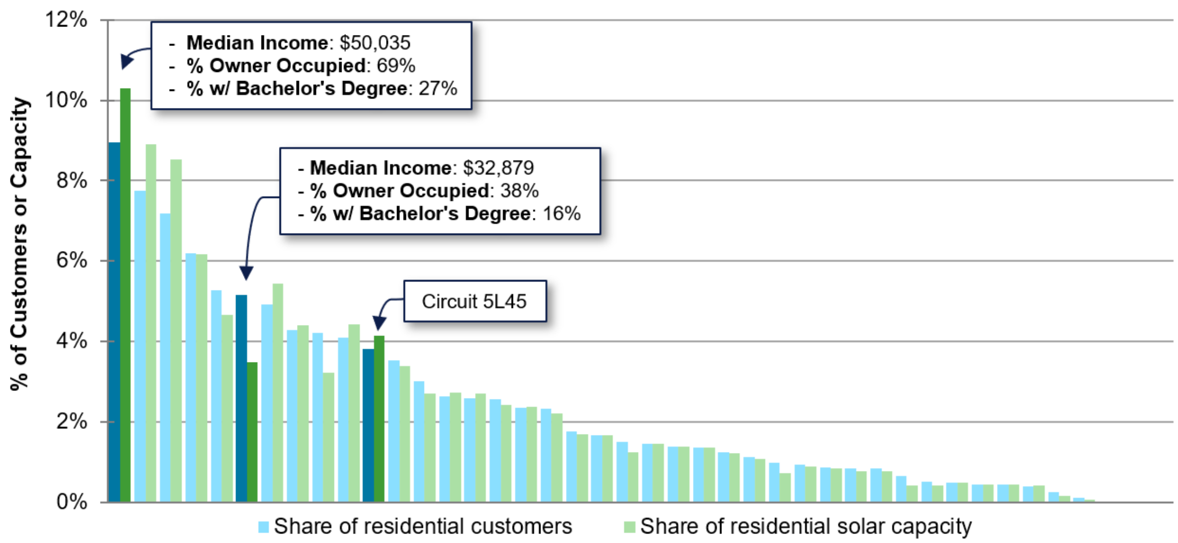


Figure 20: Share of Residential Customers vs. Share of Residential PV Only Capacity in 2033—Klamath Falls Operating Area

Key Findings

As part of the DSP, PacifiCorp evaluated each of the previously discussed PG scenarios. However, as the baseline DSP PG forecast, PacifiCorp considers the base case forecast to be most appropriate for planning, given current technology costs, incentive levels and net metering policies in place in Oregon. Of note, the baseline DSP PG forecast was used as the baseline PG forecast within the Company's 2023 IRP.

The Company's analysis incorporated the current rate structures and tariffs offered to customers in Oregon. Time-of-use rates, tiered tariffs and retail tariffs that include high demand charges increased the value of PV + Battery configurations compared to PV-Only configurations while other factors such as load profiles and DER compensation mechanisms minimized the impact of such tariffs on the customer economics of PV + Battery systems. The DER compensation mechanism in Oregon — traditional net metering — offers limited to no incentive for PV + Battery storage co-adoption.

PacifiCorp's sensitivity analysis found greater difference between the base case and the upper bound of PG adoption than the base case and lower bound of adoption. The low case assumed higher technology costs and lower retail electricity rates than the other cases, reducing the economic appeal of PG despite incentives being unchanged. For the high case, an assumed extension to the residential federal investment tax credit provided a significant boost to adoption alongside the lower technology costs and higher retail electricity rates used in that analysis. The resulting new capacity in the low case in 2033 is about 31% less than the base case, while the high case is 84% greater than the base.

Developing the circuit-level adoption models within the Oregon adoption model revealed additional areas of research related to PG and behind-the-meter battery storage adoption that would enhance future work. The following is a list of potential future enhancements to this study:

- A more nuanced approach to the new construction forecast would consider the creation of new circuits in high-growth areas. The current study allocates new construction only to existing circuits.
- The distribution analysis requires integrating data at different geographical resolutions (state, county, census tract and circuit). While PacifiCorp's data mapped circuits geographically, there were challenges in matching customer billing data to circuits. This study also used existing customer counts by sector by circuit, but corresponding energy use could not be calculated at the circuit-level. Similarly, existing PG could only be mapped at the county level since interconnection data had incomplete customer circuit information. Future studies will benefit from the circuit-level load forecasts PacifiCorp is developing for this DSP.
- Storage dispatch modeling would benefit from a finer disaggregation of large commercial and industrial load shapes. Technology that is not broadly cost-effective could still be beneficial for customers with certain load profiles that were not visible using class-level load shapes.
- Resilience appeared to be a significant driver of adoption. For PV + Battery storage, resilience could be a more significant driver of adoption than economics. A deeper understanding of what customer types value resilience and how that affects their willingness to pay would help refine the forecast.

3.6 Forecasting — Energy Efficiency Resources

In Oregon, PacifiCorp works closely with the Energy Trust of Oregon (ETO) to identify additional energy efficiency resource opportunities. Energy efficiency measures offered through ETO cover all customer classes and are designed to reduce energy consumption across numerous end-use loads. To better understand the potential impacts of energy efficiency at the circuit and substation level, PacifiCorp relied on the latest conservation potential assessment (CPA) prepared by ETO for its 2021 IRP. The CPA serves as the basis for demand-side management (DSM) resource potential and cost assumptions specific to PacifiCorp's Oregon service area. The CPA examines energy efficiency potential from two perspectives: technical potential and technically achievable potential, with the third perspective, cost-effective potential, output from the IRP modeling. The various inputs and energy efficiency outputs used for developing statewide energy estimates are illustrated in **Figure 21**.

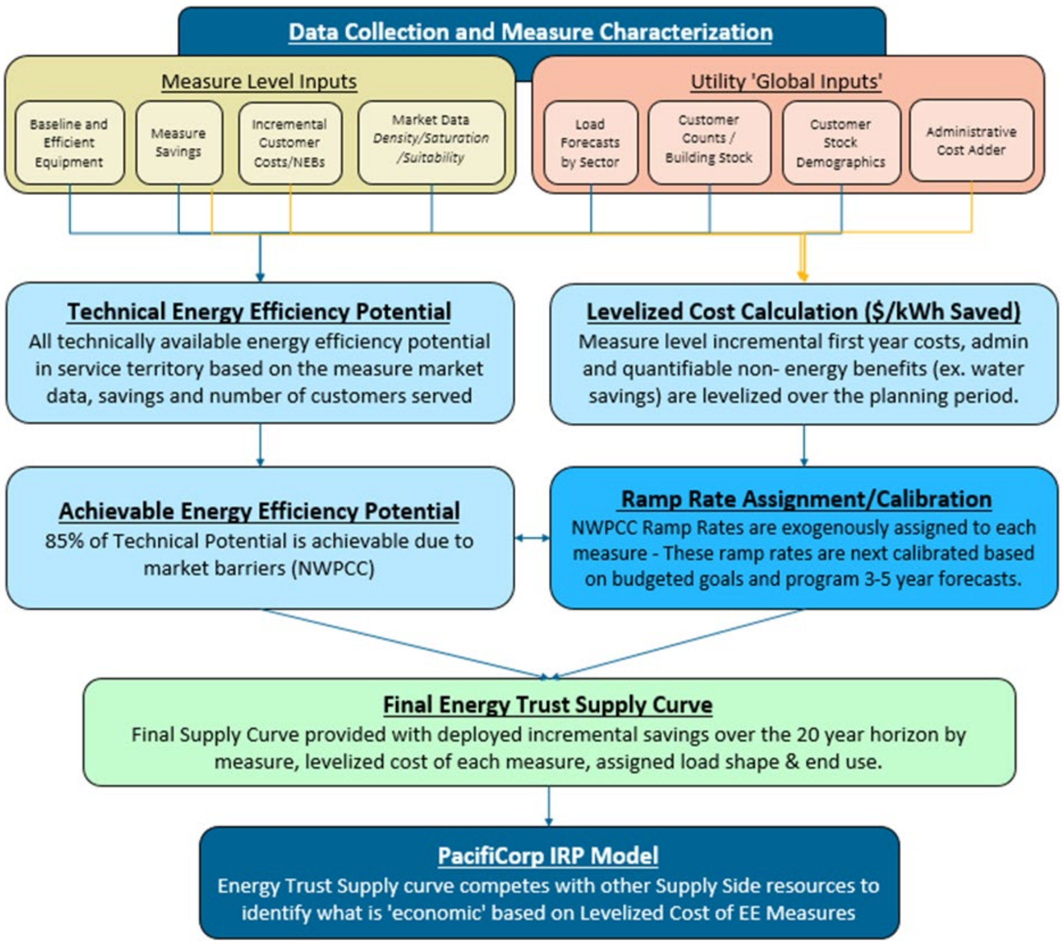


Figure 21: Energy Trust's 20-Year DSM Forecast Determination Flowchart

The first steps in forecast modeling are to identify and characterize a list of measures to include in the model. To support modeling, ETO compiles a list of commercially available and emerging technology measures for residential, commercial, industrial and agricultural applications installed in new or existing structures. Each measure includes numerous input assumptions (known as 'measure level inputs') that help inform key parameters such as the number of applicable units for treatment, per unit savings and per unit costs. Simultaneously, ETO collects data from PacifiCorp (known as 'global inputs') to run the model and scale the measure level savings to its Oregon service territory.

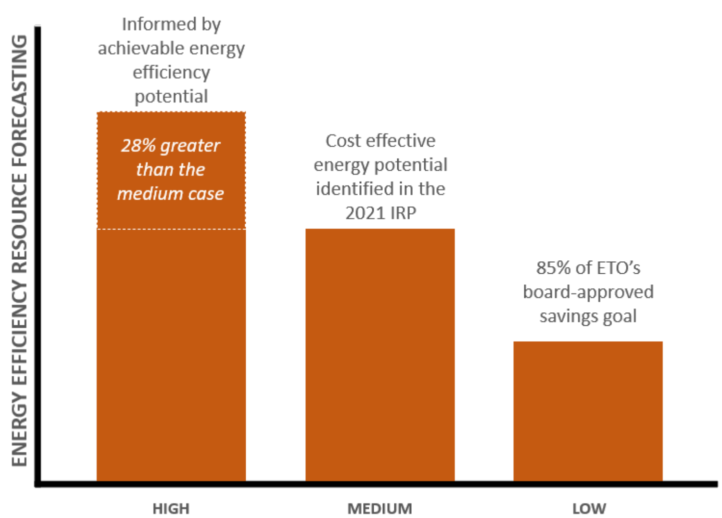
A key parameter for informing energy efficiency opportunities is the load forecast by sector and customer count. This parameter is essential to scale the measure level savings to a utility service area. For example, residential measures are scaled "per home," so the measure opportunities are calculated as the number of measures per home. The model then takes the number of Oregon homes that PacifiCorp serves and forecasts a number of homes to identify statewide measure level potential. This measure level potential is critical for disaggregating energy efficiency results to the feeder or substation level.

Energy efficiency potential across all sectors is segmented by customer type; this informs efficiency opportunities. Currently, 27 customer segment types are used to characterize efficiency potential in Oregon. To identify potential on a more granular level PacifiCorp took energy efficiency potential totals by measure and allocated those savings to each customer segment. PacifiCorp then took 2021 customer data and mapped annual usage (kWh) to CPA customers segments using Standard Industrial Classification (SIC) codes and dwelling codes. Mapping SIC and dwelling codes relies on the same methods used by ETO for the CPA, leading to consistency in load treatment as it relates to energy efficiency in both the IRP and DSP. Once customer usage was segmented, PacifiCorp could allocate measure savings to segments by feeder and substation for forecasting.

High, Medium and Low Case Development

As part of the DSP requirements, PacifiCorp developed a high, medium (base) and low case for energy efficiency impacts at the substation and feeder level.

High Case. The high case is informed by ETO's achievable energy efficiency potential. For the first year of the forecast, 2023, achievable potential is approximately 28% greater than the cost-effective potential identified in the medium case.



Medium Case. The medium case is informed by the cost-effective energy potential that was identified by the 2021 IRP model. While ETO budgeted savings may diverge from IRP modeling, it is generally accepted that cost-effective potential serves as the basis for initial savings expectations for future energy efficiency acquisition.

Low Case. The low case is informed by ETO'S performance metrics for savings and levelized costs. The single savings objective per utility is calculated each year as 85% of ETO's board-approved savings goal.[19]

3.7 Forecasting — Demand Response Resources

PacifiCorp's 2021 IRP identified an immediate need for DR beginning in 2023. Before the 2021 IRP Update, PacifiCorp issued a request for proposals (RFP) soliciting proposals from third-party implementation vendors for DR resources (2021 RFP). Although a variety of programs were eligible for consideration, PacifiCorp received successful bids from vendors focused on the following:

1. Nonresidential curtailment
2. Residential smart thermostats and water heaters
3. Irrigation load control
4. Customer sited (Wattsmart) batteries

As a result of the 2021 IRP and 2021 RFP, PacifiCorp now operates an Irrigation Load Control program that was approved by the OPUC on May 5, 2022. Looking ahead, PacifiCorp anticipates the program will be implemented at scale over the course of the next year and into 2023, which is Year 1 of the planning horizon. To inform prospective DR forecasts for distribution planning, PacifiCorp relied on the current DR expectations that have been, or are being, finalized in vendor contracts. Near-term, these contracts represent the most likely DR impacts to the distribution system (**Figure 22**).

[19] 2022 Performance Measure Recommendations for Energy Trust of Oregon. UM 1158 PM Order_encrypted_.pdf (state.or.us)

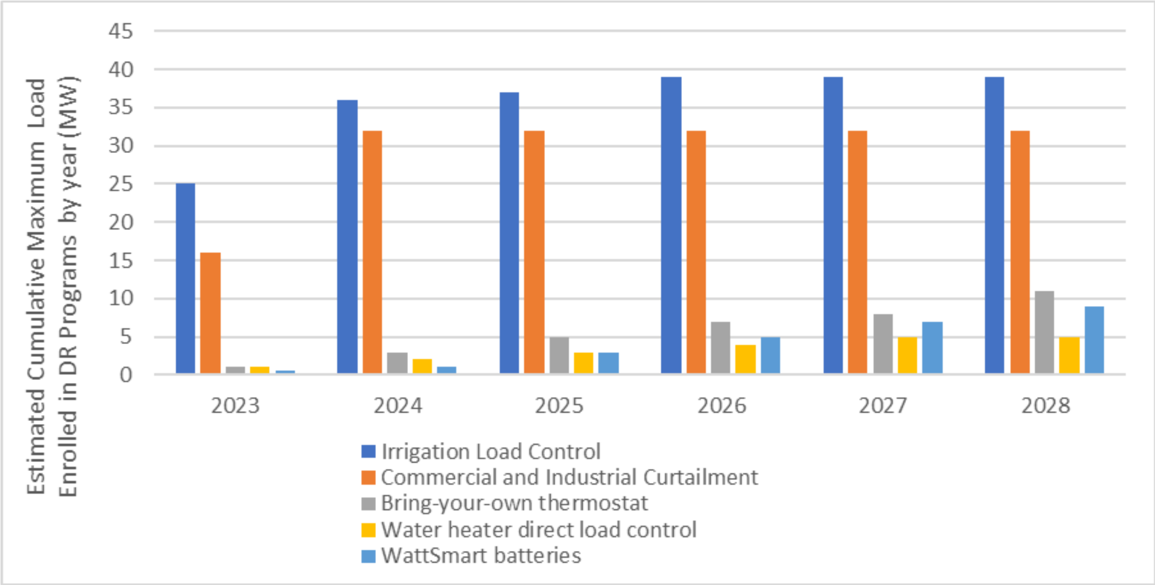


Figure 22: Prospective Demand Response Program Impacts

DR programs are primarily tailored to customer sectors: commercial and industrial, residential, irrigation and batteries. Therefore, it is logical to disaggregate DR program impacts at the circuit level by customer sector, except for batteries. Depending on the sector, differing disaggregation methods were used to associate program impacts with substation-level feeders. As programs mature, additional DR customer participation drivers may be identified and used to inform disaggregation techniques. In the interim, PacifiCorp will use the following high-level customer sector characterizations to inform disaggregation of program impacts.

Residential sector DR program impacts are primarily derived from the Water Heater Direct Load Control and Bring Your Own Thermostat programs. PacifiCorp used the proportion of residential sites on a particular substation or feeder to allocate residential DR impacts for the residential sector.

Commercial and industrial DR impacts are derived from the sector-specific curtailment program that targets multiple end-uses and customer types across Oregon. PacifiCorp used the loads from eligible commercial and industrial rate schedules to allocate program impacts based on the proportion of eligible customer loads on each substation or feeder.

Irrigation sector DR impacts are derived from the Irrigation Load Control program currently operating in Oregon. Irrigation loads are generally seasonal, with the greatest demand occurring in summer: June through August, with July and August generally being the highest months for demand. Therefore, historically, in Oregon, most irrigation curtailment events and impacts occur in August. To allocate Irrigation Load Control program impacts, PacifiCorp used the proportion of August demand (kW) from irrigation customers on a given feeder or substation to allocate program impacts to the irrigation sector.

The Wattsmart Battery impacts are derived from internal estimates of program adoption based on historical results with adjustments to account for Oregon markets. Unlike other DR impacts, the battery program would likely include customers from multiple sectors. PacifiCorp used the proportion of customer sited solar generation to allocate potential program impacts based on the proportion of generation on each substation or feeder. While solar is not a prerequisite for program eligibility, it is believed that customers with solar have a higher likelihood of participating in the Wattsmart Battery program.

High, Medium and Low Case Development

As part of the DSP requirements, PacifiCorp developed a high, medium (base) and low case for DR impacts at the substation and circuit level.

The high is informed by the expectation set in PacifiCorp DR tariff that any expenditures greater than 130% of projection would require OPUC and staff notice and authorization. Therefore, the Company set the high case to reflect the expectation that programs would operate within 130% of their expected performance in a given year. The medium case is informed by the 2021 DR RFP and current program contract expectations for DR. While performance expectations vary by program, planning generally assumes a minimum performance to 70% of committed resources each year. Therefore, 70% of expected volume is assumed to represent the low case for DR.

Conclusions and Future Work

As noted earlier, PacifiCorp is at the outset of developing and introducing a portfolio of DR programs in Oregon. There are several considerations to incorporate into future distribution planning efforts. First, the Company intends to refine disaggregation techniques to better match participation trends in programs. For example, the commercial and industrial program may realize that a specific customer segment is more likely to participate in a DR product offering; that higher likelihood of participation should be accounted for in future disaggregation. Second, once the program is implemented, DR impacts will likely show up in historical SCADA data used to project future loads. Future forecasting is done for localized areas; it will be important to adequately estimate future DR resources that are incremental relative to historical local resources. Finally, and perhaps most critically, DR is currently dispatched based on statewide system need. This does not mean that it cannot be dispatched to address localized grid needs, but it will take time for programs and processes to be established for localized DR dispatch. A key component of this involves integrating programs into a DER management system (DERMS) that can better facilitate localized dispatch. Looking ahead, PacifiCorp hopes to have most, if not all, DR programs integrated into a DERMS, which is expected to occur with other IT upgrades over the next few years and will not necessarily take place simultaneously for all programs.

3.8 DSP Load Forecasting Results for Two Transitional Study Areas

PacifiCorp selected two Transitional Study areas that were identified in DSP Part 1 to implement DSP forecasting to better understand the differences and potential impacts of incorporating EV and PG into the traditional load forecast. The two Transitional Study areas are Pendleton and Klamath Falls as indicated in **Figure 23**.

2022 Distribution System Planning Pilot Circuits								
Revised Load Bubble	BPA NITS		Central Oregon	West Main				
Revised Sub Load Bubble	Pendleton	Santiam	Bend	Clatsop Astoria		Southern Oregon/California		
DSP Planning Area	Pendleton	Stayton	Bend	Astoria	Klamath Urban	Merlin	Roseburg Urban	Upper Rogue
Circuits	5W202	4M120	5D10	5A204	5L112	5R232	4U10	4R13
	5W203	4M70	5D12	5A211	5L113	5R234	4U22	4R17
	5W401		5D155		5L45	5R248	4U30	4R9
	5W402		5D196		5L46	5R251	4U31	
	5W403		5D238		5L48		4U38	
	7W451		5D241		5L49		4U39	
	7W452		5D243		5L54		4U5	
	7W453		5D411				4U81	
	7W454		5D413				5U15	
			5D418				5U17	
							5U19	

Figure 23: DSP Transitional Study Areas as Presented in DSP Part 1

These areas were selected based on the following initial criteria:

- **DG (aka PG) capacity and readiness**: Circuits or areas with the capacity available to host DGs, SCADA availability, and specific protection measures (e.g., deadline check) installed for DG. Preference for areas with greater capacity available.
- **Study cycle timing**: Areas that had recently completed a study that could be used as a starting point for evaluation are preferred.
- **Historical DG/PG project activity**: The number of local net metering and community solar projects installed and in queue. Preference for higher level of activity.
- **Area demographics and characteristics**: The demographics and load characteristics of the areas would include anticipated load growth and geography representative of PacifiCorp's Oregon service territory.

Based on the initial criteria and areas identified, local circuits were reviewed to determine which best fit the criteria. The results from this review determined that Hornet Circuit 5L45 (also known as Crystal Springs) served from Hornet substation in Klamath Falls would be the best candidate to implement DSP forecasting at the circuit level. For Pendleton, the recent energization of the

McKay substation in January 2022 and rebalancing of several circuits meant that the initial study forecasts indicated adequate capacity with no grid needs. As such, the Company applied the PG and EV adoption scenarios to the base forecast at the area level (including multiple circuits) to highlight the impact on the overall forecast.

As previously described in **Section 2.3.2.1**, the foundation of the DSP forecast is the traditional load forecast performed by the field engineer. The traditional load forecast for Pendleton and Klamath Falls were completed in 2021, which allowed for the most recent load forecast information to be used for DSP implementation.

As shown in **Figure 11**: Traditional Versus DSP Forecast Overview, the DSP forecast includes the traditional load forecast with incorporation of EV and PG forecasts. The EV and PG forecasts were developed by third-party vendors AEG and DNV, respectively. Details regarding the methodologies and forecast derivations are included in **sections 3.4** and **3.5**. Prior to the current DSP effort, these forecasts were historically developed at the state/jurisdictional level to be used in the IRP load forecast. Since DSP requires a load forecast at the circuit breaker level, AEG and DNV performed studies to forecast EV and PG at the circuit breaker level, so they could be used in the DSP load forecast.

The results of adding the EV and PG forecasts to the traditional load forecast resulted in an average decrease of 0.06 MVA or 0.83 % per year for the Klamath Falls circuit. For the Pendleton area, the average decrease was 0.135 MVA or 0.5% per year for the peak load forecast. This would be indicative that the addition of PG was greater during the study period than EV and baseline growth.

In addition to the peak load forecasts, the DSP forecast also analyzed the circuits to identify when they are most vulnerable to reverse power flow. This forecast is referred to as the net minimum load forecast; it typically focuses on the spring/fall seasons when load is lowest and PG is highest. The net minimum load forecast is applicable to the circuit level and informs potential NWS applicability. Utilizing the net minimum load forecast, a generation study was completed to verify no grid needs resulted from this scenario for the Crystal Springs circuit in Klamath Falls.

The results of adding EV and PG forecasts to the net minimum load forecast resulted in an average decrease of 0.21 MVA per year or 8% per year for the Klamath Falls circuit. The DSP forecast confirmed the localized grid needs identified in Klamath Falls from the previous planning study. No grid needs were found in Pendleton even with the DSP-specific PG and EV inputs. Further detail regarding grid analysis and solution identification is provided in **Chapter 4** and **Chapter 5**.

The addition of the high, medium and low adoption scenarios for PG and EV in the DSP forecast resulted in nine different peak load forecasting trend lines and nine corresponding net minimum load forecasts — a total of 18 potential forecast trends. These trend lines are visualized in the following figures. For evaluating grid needs on distribution circuits, the worst-case scenario is used for both the peak load and net minimum load forecasts. For peak load forecast, the worst-case scenario, which is generally represented by the highest number, is used to determine if the circuit has adequate capacity under the worst-case load conditions. For the net minimum load forecast, the worst-case scenario, which is generally represented by a lower number, is used to identify when the circuit is most vulnerable to reverse power flow.

Peak Load Worst-Case Scenario

To determine the worst-case scenario for the peak load forecast the different EV and PG adoption rates were applied to the peak load forecast. The resulting peak load forecast scenarios are shown in **Figure 24**. The High EV (HEV)/Low PG (LPG) scenario resulted in the greatest load increase of 0.2 MVA, or 3% over five years. In this worst-case scenario, customers on a given circuit are transitioning to EVs at a high rate, increasing load, but adopting PG at a low rate that does not offset the EV load increase. This scenario was used for the peak load forecast in the grid needs analysis and is circled on **Figure 24**.

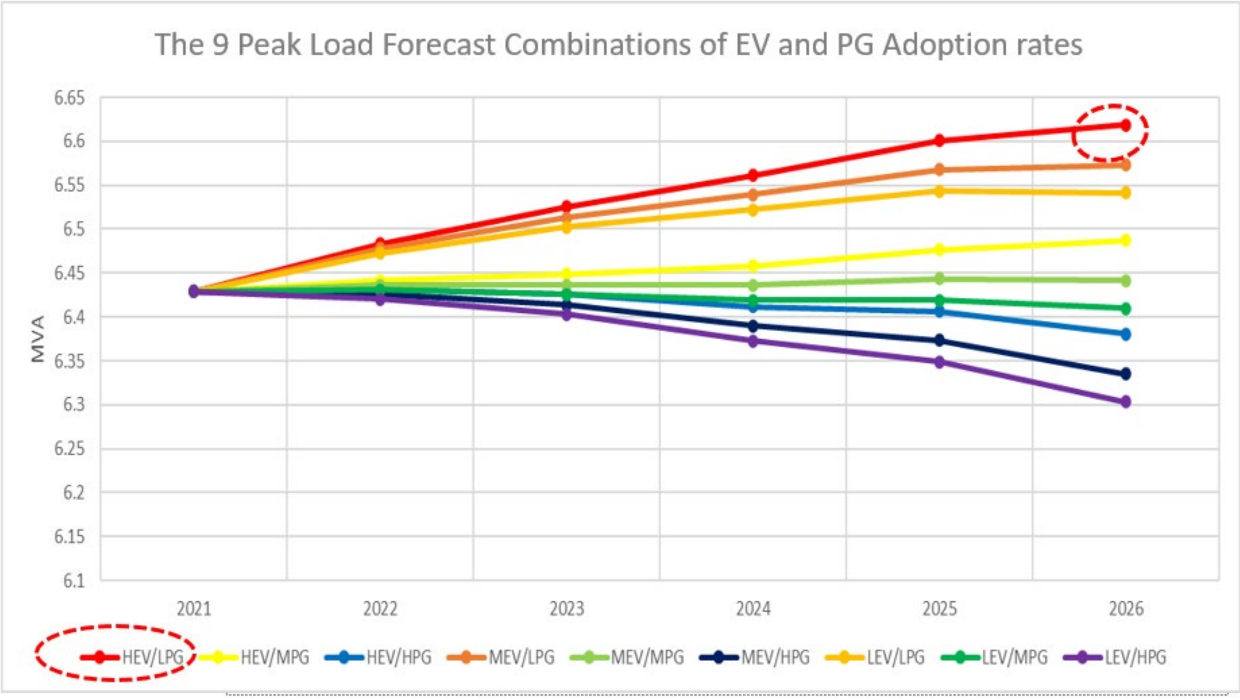


Figure 24: Klamath Peak Load Forecast Trends Under Different EV-PG Adoption Scenarios

Figure 25 provides the same comparison as discussed for the Klamath Falls area, but for the Pendleton area. **Figure 25** includes all nine distinct peak load forecast scenarios, however, due to overlap, all nine are not always visible. As before, the worst-case peak load forecast scenario is circled as shown below. Like the analysis in Klamath Falls, the HEV/LPG scenario is the worst-case load forecast scenario for the Pendleton area.

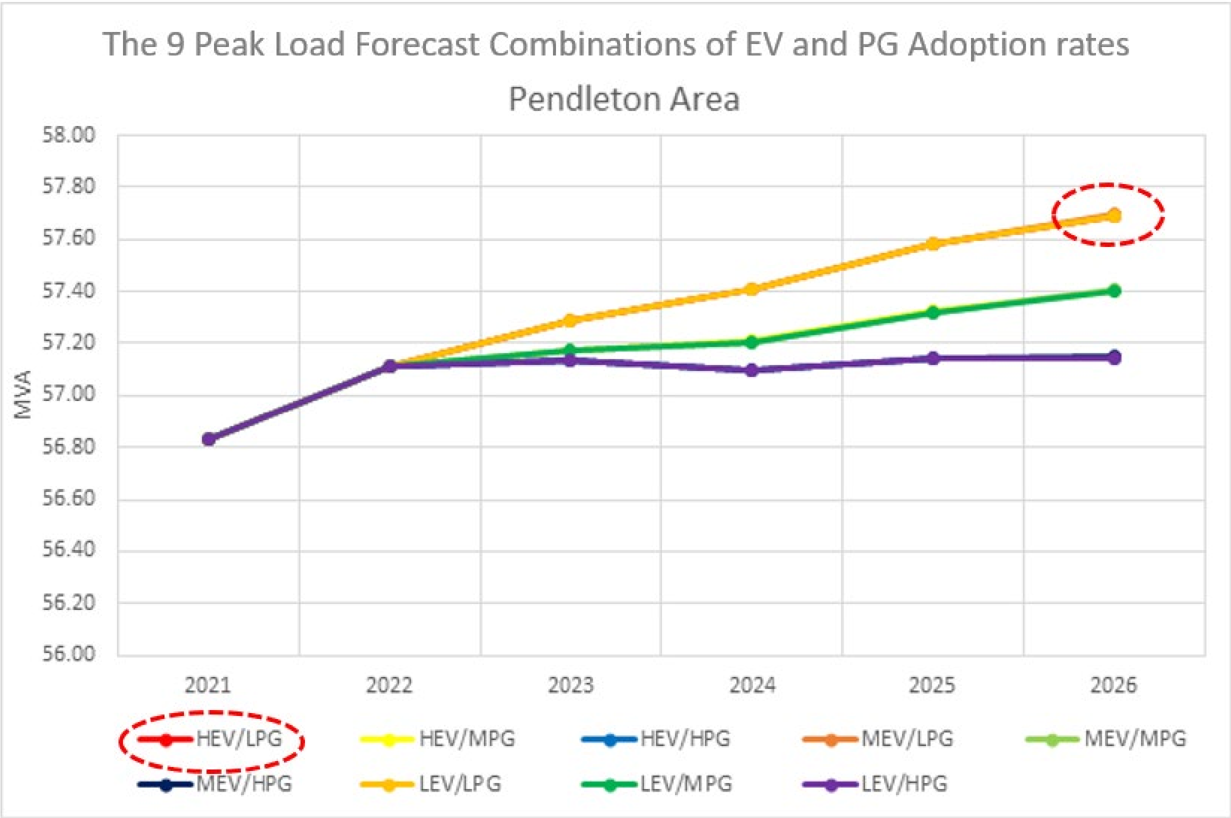


Figure 25: Pendleton Peak Load Forecast Trends Under Different EV-PG Adoption Scenarios

Net Minimum Load Forecast Worst-Case Scenario

To determine the worst-case net minimum load forecast scenario, the different EV and PG adoption rates were applied to the net minimum load forecast for the Crystal Springs circuit. The resulting net minimum load forecast are shown in **Figure 26**. The net minimum load forecast in **Figure 26**, highlight the worst-case scenario (Low EV [LEV]/High PG [HPG]). This net minimum load forecast scenario was used in the grid needs analysis and is circled on the figure.

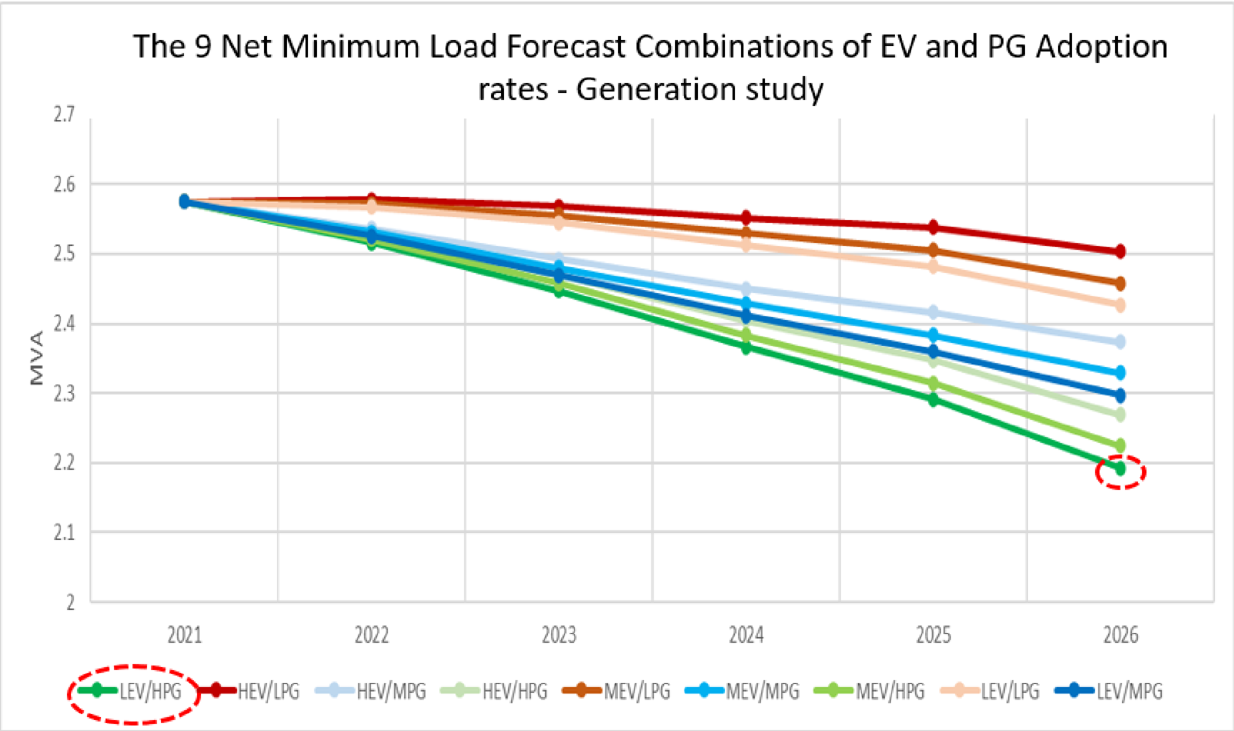


Figure 26: Klamath Net Minimum Load Forecast Trends Under Different EV-PG Adoption Scenarios

Resulting Combined DSP Forecast

After the worst-case scenarios were determined, the resulting forecasts were compared against the traditional load forecast to determine the difference in the DSP forecast.

For the Crystal Springs circuit in Klamath Falls, the comparison indicates that the peak load in the DSP forecast was 2% lower at the end of the five-year study period than the traditional load forecast as shown in **Figure 27**. This was due to the PG adoption rate having a greater effect on the load relative to the EV adoption rate in the HEV/LPG scenario. Additionally, the net minimum load forecast was plotted to illustrate the trend from the incorporation of LEV/HPG. The results found that the net minimum load forecast was 21% lower at the end of the five-year study period.

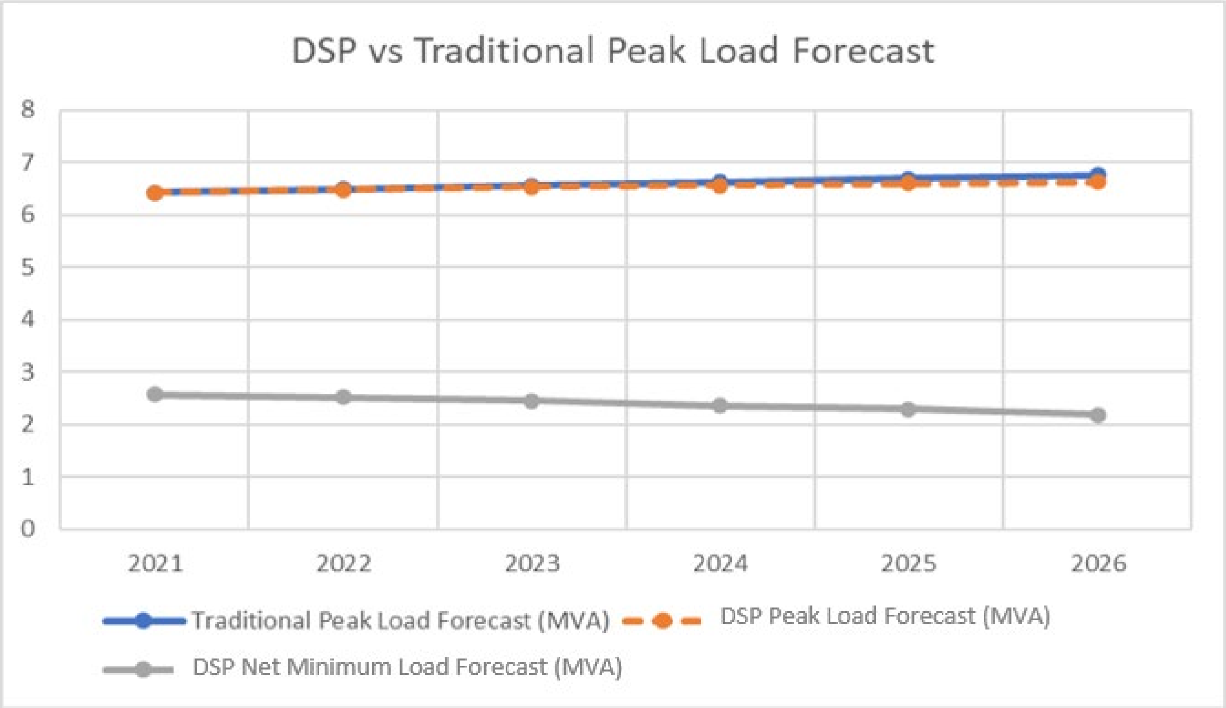


Figure 27: Klamath Traditional Load Forecast Versus DSP Load Forecast

For the Pendleton area forecasts, the comparison indicates that the peak load in the DSP forecast was nearly identical at end of the five-year study period to the traditional load forecast as shown in **Figure 28**. Additionally, the net minimum load forecast was plotted to illustrate a virtually unchanged forecast.

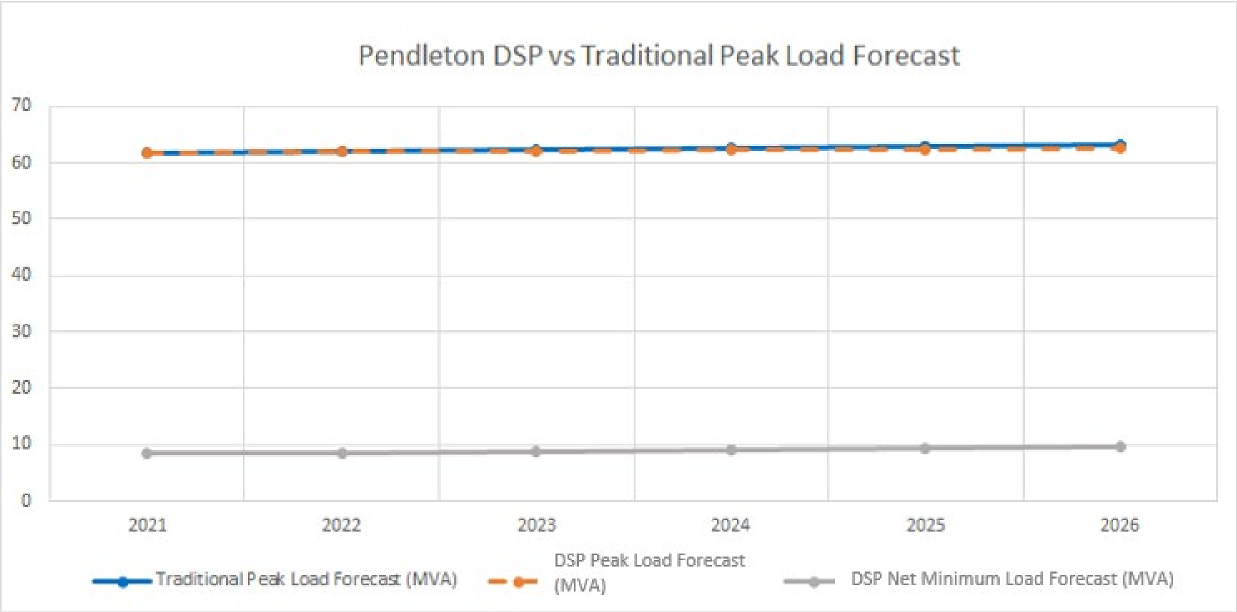


Figure 28: Pendleton Traditional Load Forecast Versus DSP Load Forecast

Overall, it was found that the DSP forecasts for Klamath Falls and Pendleton resulted in a lower peak load and a lower minimum load over the five-year study period. Due to the varied and disparate nature of PacifiCorp's service territory, the DSP forecast could be different in other areas due to the differing local EV and PG adoption rates.

Future Load Forecasting Process

The current DSP forecast process uses the traditional load forecast as a foundation for the DSP forecast and then incorporates circuit-level EV and PG outputs consistent with the IRP forecast. This approach is expected to continue to provide flexibility and account for differences in assumptions, methodology, granularity of data and requirements between the DSP and IRP load forecasts. The DSP base forecast uses SCADA load data at the circuit level, while the IRP focuses on statewide EV and PG adoption projections that are disaggregated to load bubbles.[20] The circuit-level granularity of the DSP forecast is necessary to determine the specific grid needs and potential wires/NWS for a particular area.

Although load forecasting methods are expected to remain relatively the same for DSP and IRP, interaction between the DSP and IRP will ensure coordination between the two planning

[20] Load bubbles are geographic areas that are developed based transmission constraints and area demand. IRP planning focuses on generation and transmission requirements, while DSP planning focuses on distribution within the load bubble.

processes. PacifiCorp will continue to evaluate opportunities to integrate the two forecasts as the DSP and IRP processes are further refined and evolve.

In the future, PacifiCorp plans to incorporate 24-hour load shapes for PG, EV and customer class into DSP forecasting and to further refine inputs and methodologies as new tools and data become available. **Figure 29** provides a summary of the differences PacifiCorp has identified between traditional load forecasting, current DSP forecasting and future DSP forecasting.

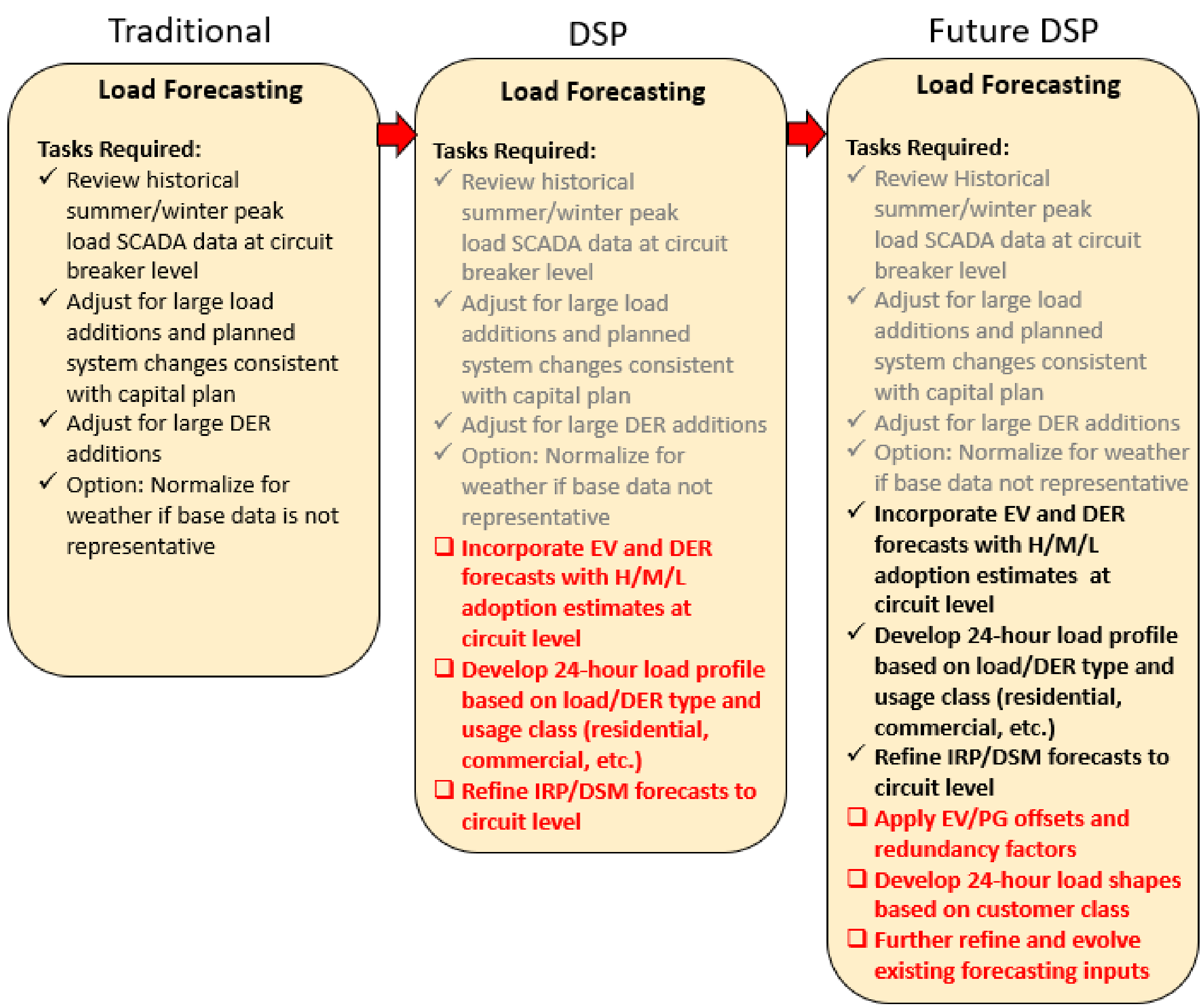


Figure 29: Traditional Versus Current DSP Versus Future DSP Forecast

Future Load Forecasting Tools

To evolve current DSP forecasting, improvements are required to existing toolsets to allow for additional inputs, data and analysis. These improvements include a more advanced load forecasting tool as outlined in **Figure 30**.

Current DSP forecasting requires SCADA load data from PI historian measured at the circuit breaker level and reviewing the load data each year to manually scrub the data, it is then input into a spreadsheet that is used to perform the load forecasting calculations. This is time-consuming and limits how frequently the load forecasts can be updated. In the future, by using a tool like an advanced load forecasting tool, the data from PI can be fed directly into the same tool that performs the load forecasting calculations, which allows SCADA load data to be streamlined and scrubbed automatically by utilizing advanced algorithms that are built into the tool. Additionally, this tool would have the ability to feed directly into CYME to allow a direct connection between the load forecasting and the grid needs analysis tool. This supports the ability to generate load forecasts and perform analysis more quickly so that information can be updated more frequently if desired. This is critical when the requirement to deliver capacity data becomes more frequent, such as monthly versus yearly forecasting.

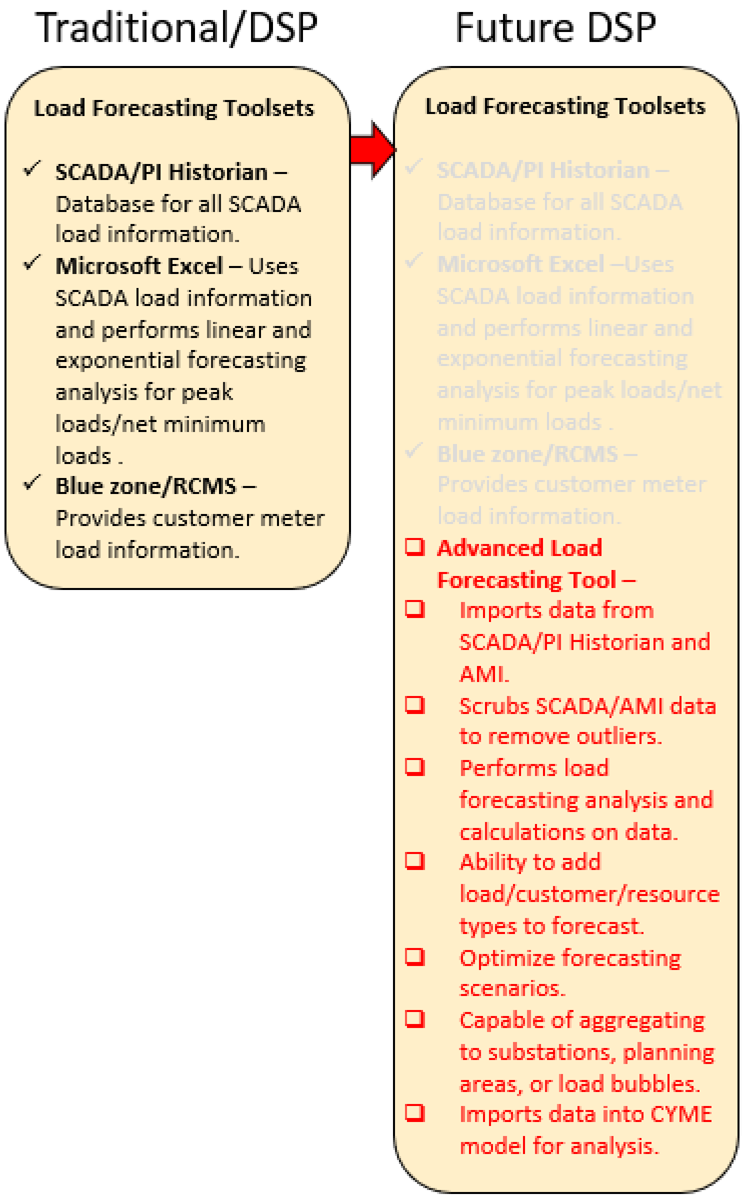


Figure 30: Current Versus Future DSP Forecast

3.9 Forecasting Lessons Learned

PacifiCorp gained insights into DSP forecasting while conducting activities for the Transition Study areas. These include:

- DSP forecasting is more complex than the traditional load forecasting and requires more granular data. Any forecast to support an NWS requires SCADA data.
- Net minimum load forecasting (finding the point where the circuit is most vulnerable to reverse power flow) is more complex than originally thought. This type of forecasting requires not just determining minimum load, but the time when low load and high PG generation are expected — producing minimum net load.
- Forecasting should continue to be refined to incorporate:
    - Refined load shapes for EV and PG and customer class inputs
    - Better reflection of potential seasonal PG resources
    - Enhancement of PG circuit level analysis (as noted by DNV)
    - H/M/L scenarios for distribution level energy efficiency and demand response
- Refining forecasts was a labor-intensive, manual exercise due to existing datasets and tools. PacifiCorp must find ways to automate much of the baseline effort. This may require the development of new datasets and the implementation of new tools.
- The approach used in DSP Part 2 focused on two specific Transitional Study areas. This provided the opportunity to explore new DSP processes on specific areas and grid needs. However, this focused approached limited the potential learning from broader trends and examination of the varied impacts in other areas. For example, PacifiCorp must still evaluate the broader circuit level forecast provided in the PG and EV studies, beyond the direct impact on Klamath Falls and Pendleton. As a result, PacifiCorp intends to more closely examine the PG and EV studies to look for trends and impacts across its Oregon service territory as highlighted in Item 1 of the Near-Term Action Plan (**Chapter 6**).
- On circuits with greater penetration of PG, it will become important to understand discreet impacts from installed resources to avoid skewing the SCADA-based forecasts.
- SCADA-based forecasting will become more challenging as DR become more prevalent on circuits.

Chapter 4: Grid Needs Analysis

4.1 Readers Guide

This chapter provides detail regarding the grid needs identification/assessment that was performed using the DSP forecast to meet requirements specifically outlined in the DSP Part 2. Initially, the chapter will review the specific requirements outlined in DSP Guidelines Section 5.2 for grid needs identification.

The following sections provide background about the type of grid needs that are commonly found in Oregon during the planning study cycle.

Additionally, the two Transitional Study areas (Klamath Falls and Pendleton) were evaluated using DSP forecasts to identify and perform grid needs assessment.

The final section of this chapter summarizes the results of the grid needs assessment using the DSP forecast and discusses the future state of grid needs analysis based on lessons learned.

COVERED IN THIS CHAPTER

Review specific requirements outlined in DSP Guidelines Section 5.2 for grid needs identification

Provide context on grid needs current process and overview of grid needs found during planning cycle

Summarize characteristics of the two Transitional Study areas that were evaluated using the DSP process

Summarize the results from the grid needs assessment for the two Transitional Study areas

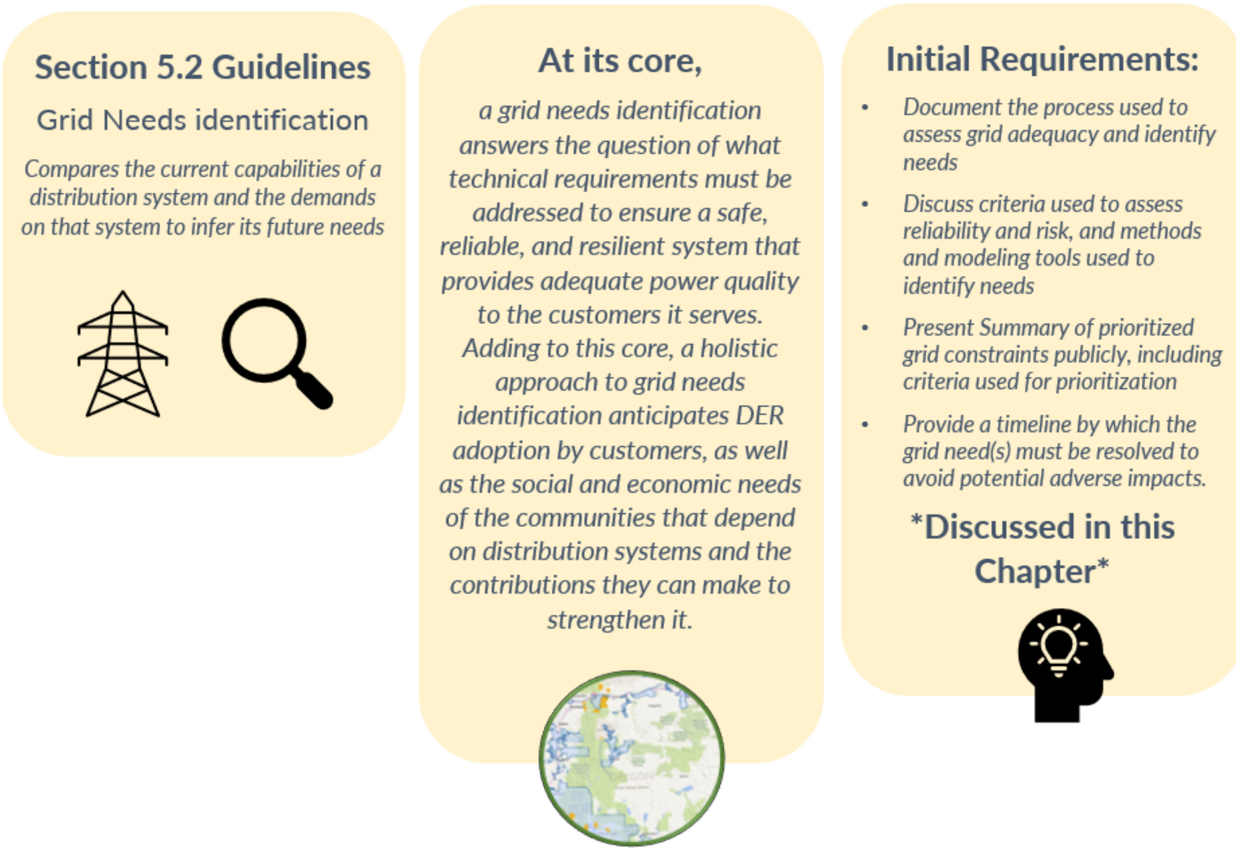
Discuss the future state of grid needs analysis based on lessons learned

DSP Guidelines	Chapter Section
5.2.a	**Section 4.3 – 4.4**
5.2.b	**Section 4.3 – 4.4**
5.2.c	**Section 4.3**
5.2.d	**Section 4.5 – 4.6**
5.3.d.v	**Section 4.5 – 4.6**

4.2 Part 2 Grid Needs Requirements

This chapter will address the specific requirements as outlined in Section 5.2 of the DSP Guidelines:

Guidelines Section 5.2:



4.3 Grid Needs Current Process

Chapter 2 discussed the existing DSP processes including details of how grid needs are currently identified, prioritized and examined. **Section 2.3.2.3** specifically addresses grid needs and the sections following (through **Section 2.4**) provide an overview of how grid needs and subsequent solutions are determined and prioritized.

Details to support requirements 5.2.a through 5.2.c were provided by PacifiCorp during DSP Workshop #9 on June 24, 2022, including materials and a discussion on the current DSP process and prioritization. As discussed, grid needs are initially prioritized within the distribution study by the field engineer and further grouped and prioritized based on solution type, constructability and

Investment Reason. DSP Guideline 5.2.c requires the Company to present a "summary of prioritized grid constraints." The prioritized lists of approved projects/construction items by Investment Reason were presented during Workshop #9 and included in this filing as **Appendix C**.

For DSP Part 2, the Company reviewed the latest DSP studies (~90) for all study areas in Oregon, excluding customer-driven or ad-hoc studies. PacifiCorp grouped the grid needs identified in these studies into the following categories: No Grid Needs, Overcapacity, Voltage, Protection and Power Quality. Finally, the DSP team captured rough cost estimates for wires solutions for analysis. A summary of the findings as well as cost breakdown for the identified grid needs is shown below and illustrated in **Figure 31**.

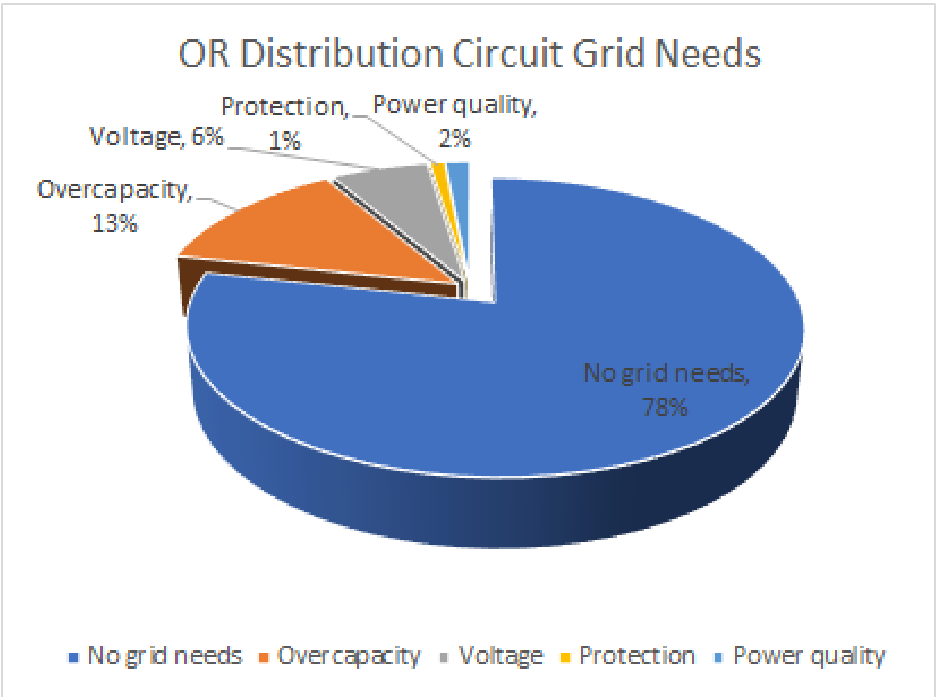


Figure 31: Oregon Distribution Grid Identified Grid Needs Breakdown

Findings:
- Grid needs found in 22% of circuits
- Overcapacity is the most common grid need (61% of found needs)
- 86% of found grid needs cost less than $200K
- Of those needs, not all will be suitable for NWS

Cost Breakdown of Identified Grid Needs:
117 total grid needs identified:
- 32% between $0 and $5K
- 54% between $5K and $200K
- 14% more than $200K

It is common for DSP studies to be completed and find no grid needs on a circuit. In the review of the DSP studies approximately 75% of circuits were satisfactory. Of circuits where a grid need was identified, the most common type of need was overcapacity; in the review, 61% of needs identified were found to be related to overcapacity.

As described in **Section 3.8**, Klamath Falls and Pendleton were used as Transitional Study areas for the grid needs assessment and NWS. The Company identified a circuit in Klamath Falls that presented a common grid need; this was used as the basis for evaluation.

4.4 Grid Needs Analysis Process for Initial DSP Filing

PacifiCorp followed the existing DSP process for identification and validation of grid needs as part of DSP Part 2 with the following additional steps as outlined in **Figure 32** and summarized below:

- Grid needs had already been identified in field engineering study for the Crystal Springs circuit (Klamath Falls). PacifiCorp confirmed load flow model configurations and independently validated grid needs in lieu of creating the study from scratch.
- PacifiCorp created a generation study for the circuit to evaluate the risk of reverse power flow.

The Company determined granular elements of the grid need to support NWS analysis, including magnitude, frequency, duration and time-of-day/time-of-year need. The Company analyzed customer composition on the circuit and specifically customer mix downstream of the grid need.

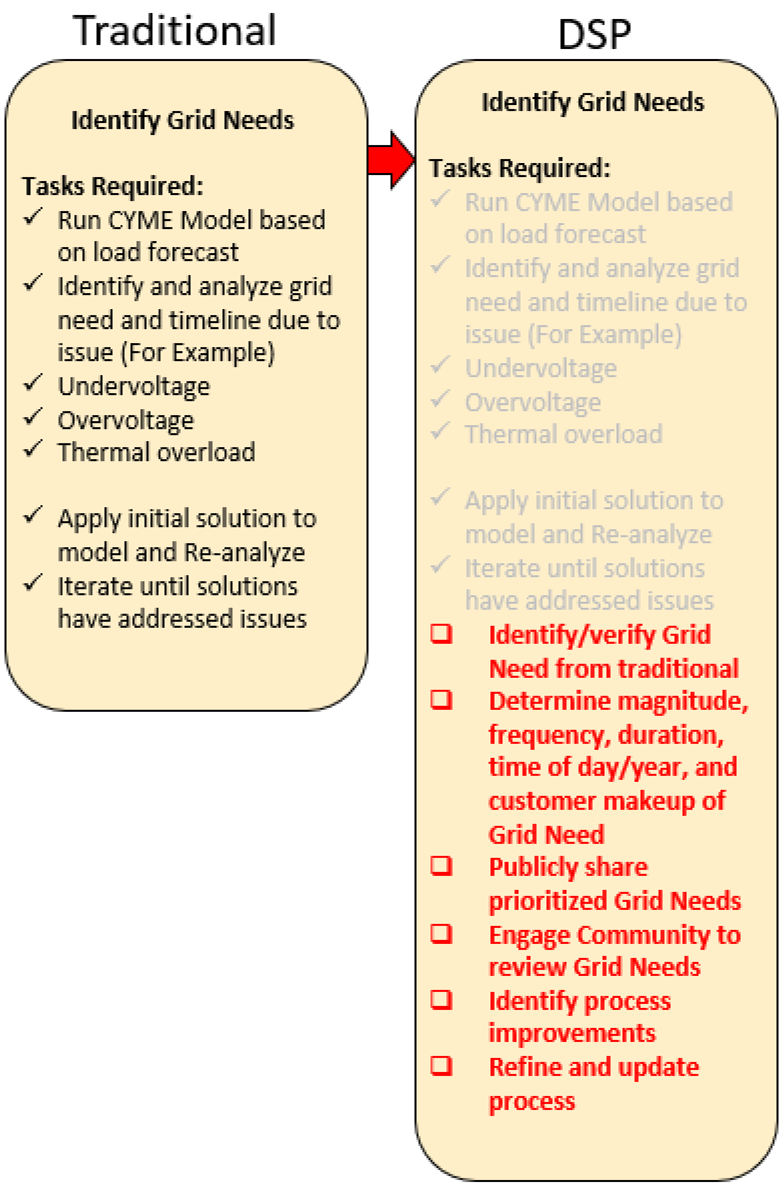


Figure 32: Traditional vs DSP Grid Needs Identification

4.5 Grid Needs Assessment — Pendleton

Pendleton is a city of approximately 17,000 people in northeast Oregon located 30 miles southeast of the Columbia River. Pendleton is part of PacifiCorp's Walla Walla operations area and makes up a significant portion of PacifiCorp's operations in northeastern Oregon. Pendleton has averaged 0.4% load growth over the previous decade and registered a peak 2021 load of approximately 59 MW.

Pendleton was chosen as one of the Transitional Study areas due to its position in the planning cycle and the availability of SCADA infrastructure. The planning cycle for Pendleton was set to align with the DSP timeline in a way that provides the most recent data to support planning evaluations and estimates. As a load center, the Pendleton baseline forecasts indicated stable load growth punctuated by several recent, larger commercial and industrial additions.

Supplemental forecasts considering the high, medium and low adoption rates for EV and PG showed minor differences from baseline load growth on the three- to five-year horizon, with most circuits showing reduced load growth due from PG — largely solar panels — offsetting EV adoption. Those summed differences accounted for approximately 1 MW difference (lower) in both high and low cases, as outlined in **Figure 33**.

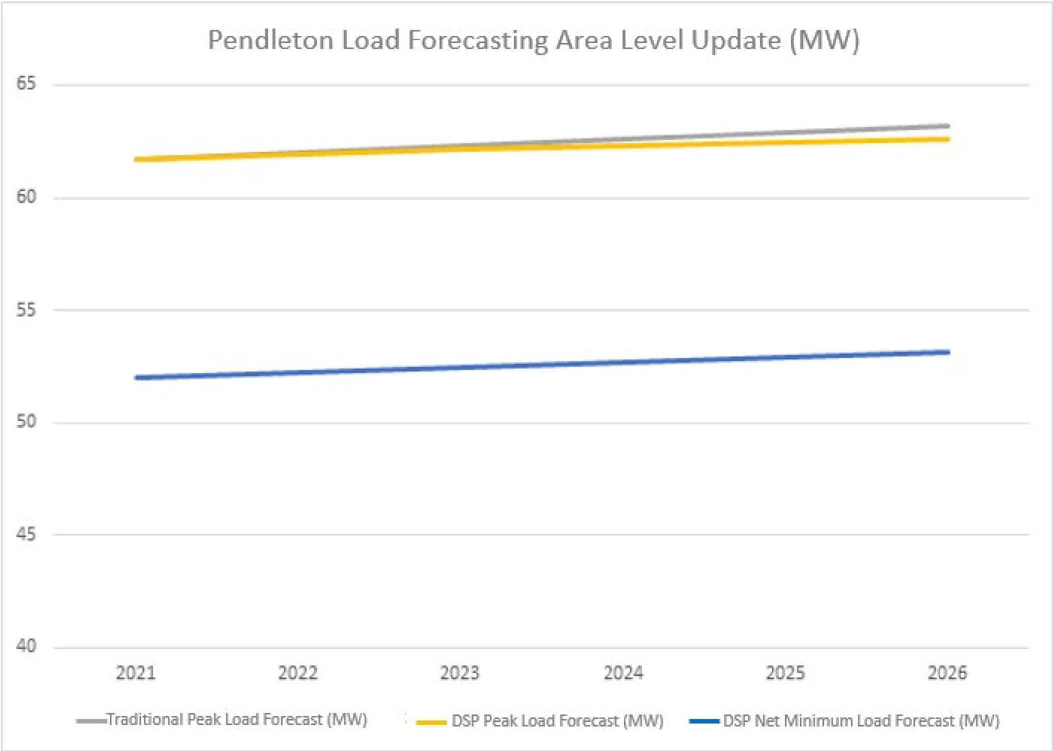


Figure 33: Pendleton Baseline Forecasts and Worst-Case EV-PG Forecast

In 2018, PacifiCorp received a request for a 3.3 MW commercial load addition on the far eastern side of the Pendleton city limits. An ad-hoc study was commissioned to evaluate the impact of the proposed load on the local distribution system. The study concluded that the increased load would necessitate the construction of a new substation, McKay substation, and provision of additional capacity to the existing circuits (see **Figure 34**).

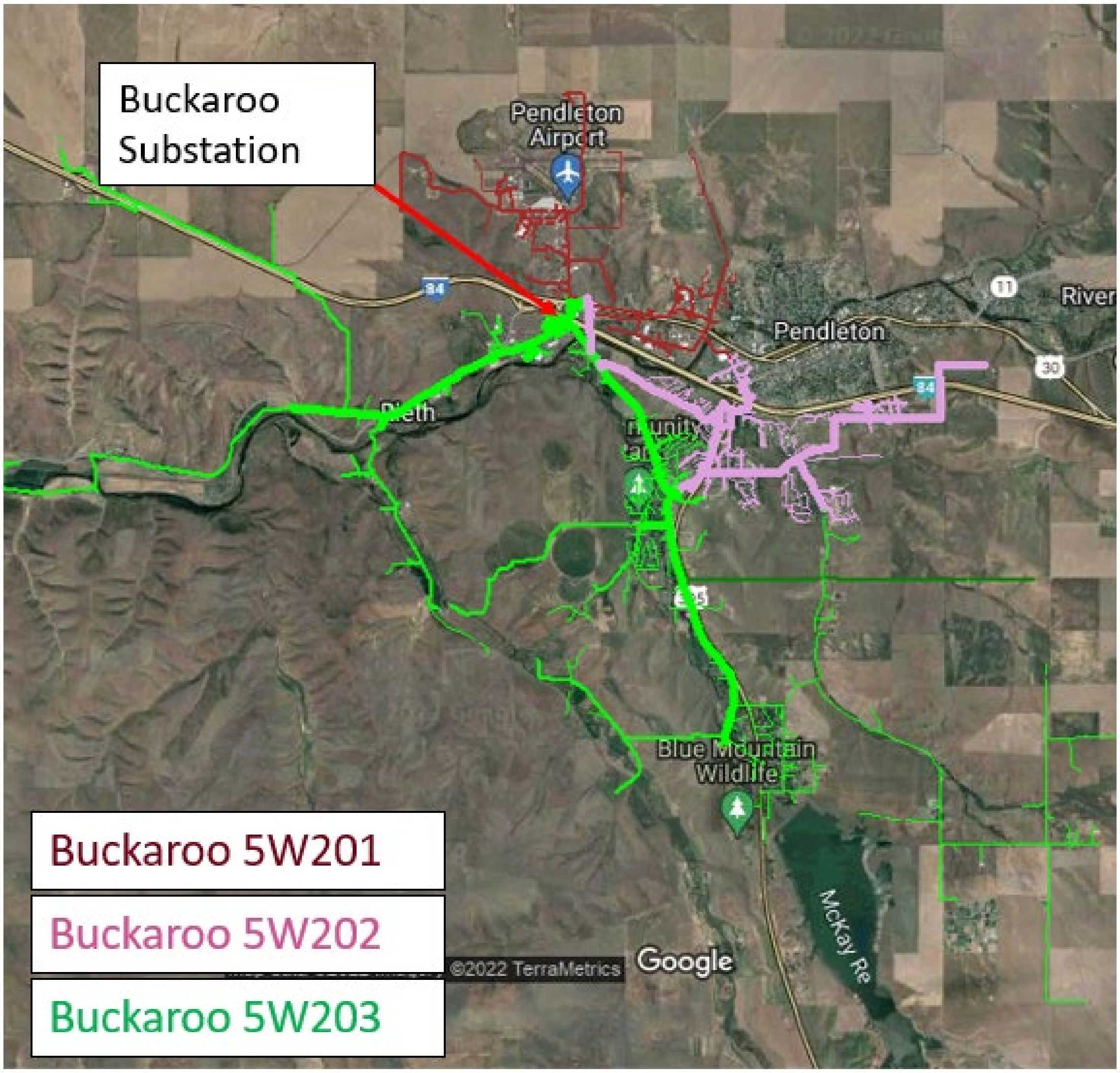


Figure 34: Pendleton Grid Topography Before Construction of the McKay Substation

The McKay substation was rapidly commissioned and finished construction in late 2021. The construction of the McKay substation gave the Pendleton field engineering team an opportunity to address multiple potential and existing grid issues, largely through rebalancing large segments of load between existing circuits and the new McKay circuits. By the time the McKay project was complete, large segments of existing circuits had been reallocated for more efficient operation, and sufficient capacity had been installed to account for future growth needs (see **Figure 35**).

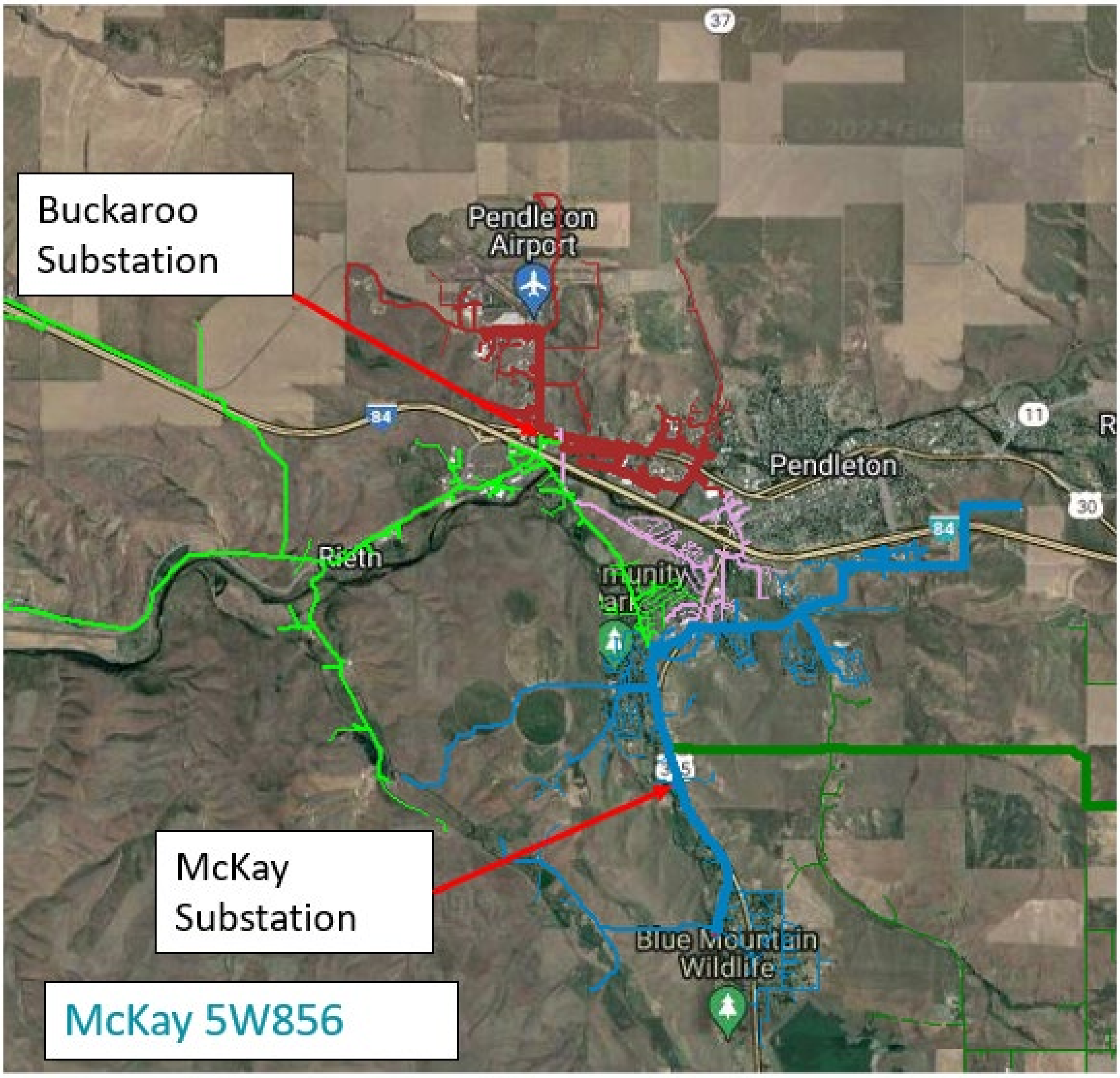


Figure 35: Pendleton Grid Topography After Construction of the McKay Substation

Construction of the McKay substation was a success for PacifiCorp and for Pendleton; it eliminated anticipated grid needs for the 2022 planning cycle. This extended into studies done for DSP, where projected additional loads from EV adoption did not cause significant grid impacts for the studied period.

4.6 Grid Need Assessment — Klamath Falls

Klamath Falls is a city of approximately 21,000 people in southwest Oregon. It is located 17 miles north of the California border at the heart of PacifiCorp's southern Oregon operations area, and at the apex of the BPA AC interconnection into Northern California. Klamath Falls is projected to have a 1.5% load growth in the next planning period, driven largely by several individual circuits with greater than 2.0% annual load growth. The local feeders in Klamath Falls can be winter peaking or summer peaking depending on customer makeup and activity; overall the area is summer peaking, with a peak 2021 load of 126.1 MVA.

As with Pendleton, Klamath Falls was chosen as a Transitional Study area due its position in the planning cycle and the availability of SCADA infrastructure.

Before starting the grid needs assessment, the Klamath Falls Crystal Springs circuit was reviewed to determine the circuit characteristics and demographics. The Crystal Springs circuit currently operates at 12.47 kV with a peak load occurring during summer afternoons/evenings and the daytime minimum load occurring during the spring. Additionally, the circuit has 1,499 customers comprised of 1,196 residential, 155 irrigation, 145 commercial and three industrial customers.

The first step of the grid need assessment was to confirm the grid need identified in the 2021 planning study with the traditional load forecast. This allowed verification of the baseline forecast to be used for the initial DSP forecast, verified/validated the load flow model being used, and confirmed the initial grid need. From this analysis PacifiCorp confirmed that the loading in a section of conductor was forecasted to potentially exceed its rating — resulting in an overcapacity (yellow line circled in red) and low voltage (red lines circled in orange) grid need as shown in **Figure 36**.

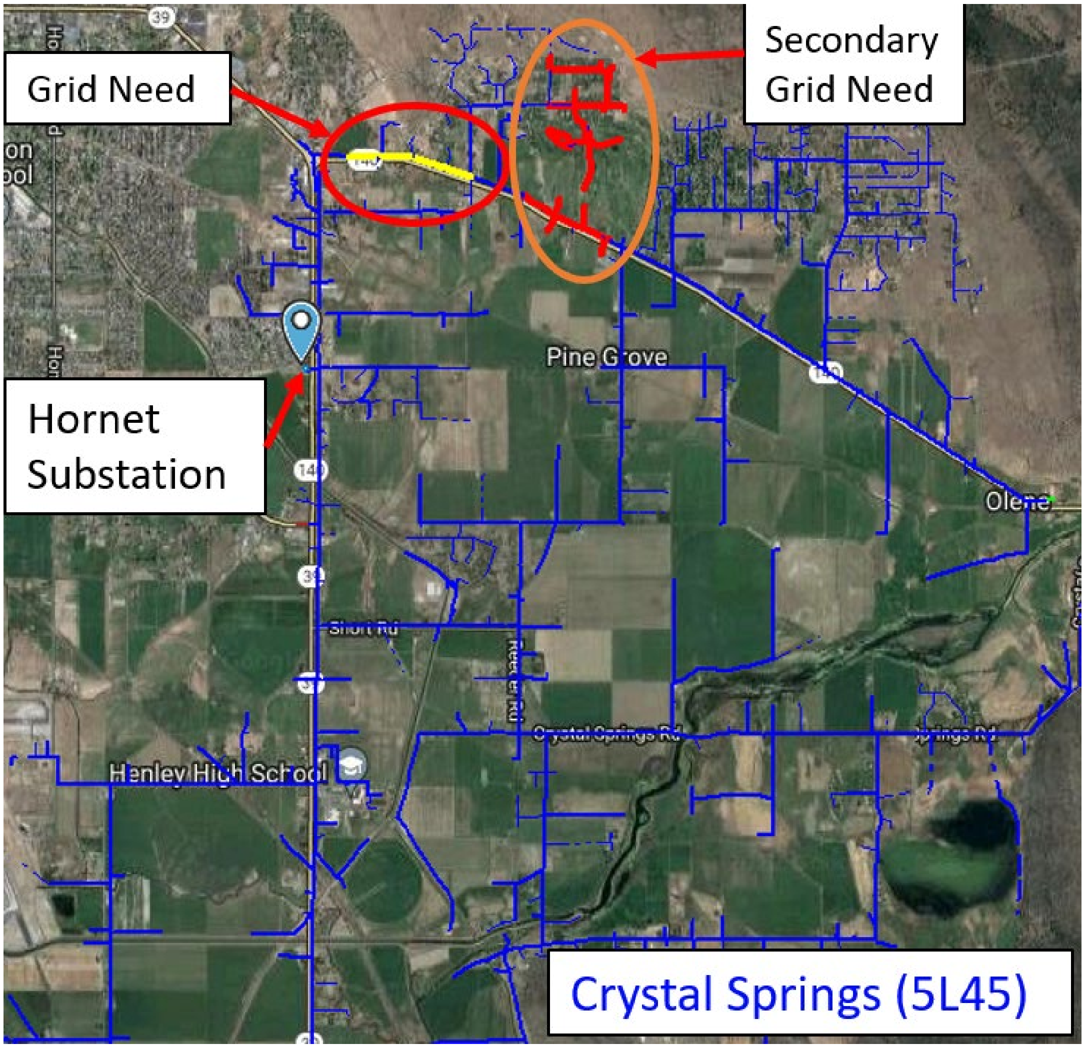


Figure 36: Overview of Grid Needs Identified on Crystal Springs in Klamath Falls

Once the grid need was confirmed, the DSP load forecast outlined in **Chapter 3** was used to determine how the severity of the overcapacity might change with incorporation of worst-case EV and PG adoption scenarios as outlined in **Chapter 3**. The results from this analysis confirmed the grid needs remained relatively the same over the study period.

The grid needs on the Klamath Falls circuit include overcapacity and low voltage. Overcapacity results in thermal overload of the conductor, over time this can lead to degradation of the physical characteristics of the conductor, ultimately leading to conductor failure. Low voltage, which does not directly affect system reliability, may result in power quality problems that can damage customer equipment. The severity of the grid needs found in the Crystal Springs circuit suggests a solution should be completed within two years. If the Crystal Springs circuit overcapacity issue is not addressed, it could result in an outage to approximately 45% of customers on that circuit.

Traditionally overcapacity and low voltage grid needs are modeled as a single point in time that would be addressed by a wires solution (phase balancing, reconductor, etc.). When considering NWS as part of this DSP process, a more granular understanding of the grid need is required — including annual frequency and duration. This is due to NWS design, scale, and technical feasibility being highly dependent on the size, duration, and frequency of the grid need. The identified grid need was plotted on the worst-case peak load day over a 24-hour period as shown in **Figure 37** to determine these requirements. It was found that the loading on the conductor exceeds the rating by as much as 750 kW and 3.9 MWh during peak events and is estimated to occur 20 to 50 hours a year between June and August from 2 p.m. to 10 p.m.

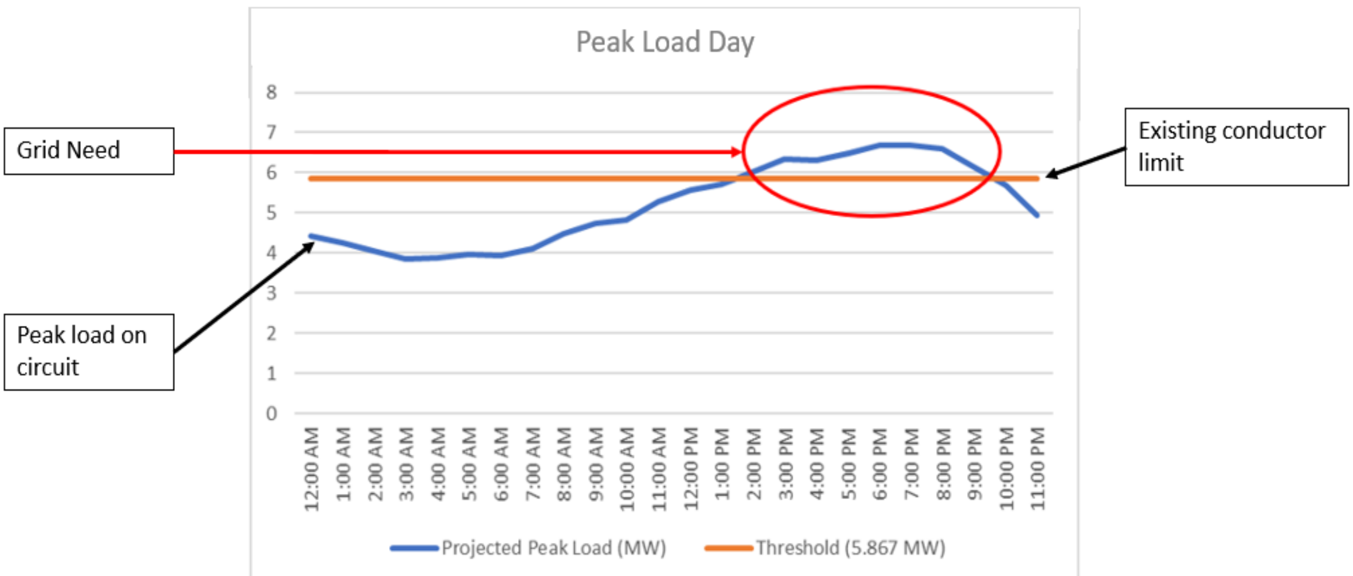


Figure 37: 24-Hour Load Profile for Crystal Springs

The potential solution options, traditional and NWS, for the grid need identified at the Crystal Springs circuit are discussed in **Chapter 5**, **Section 5.4** and **Section 5.5**.

4.7 Grid Needs Lessons Learned

While conducting DSP grid needs analysis activities over the past several months, PacifiCorp has distilled several lessons learned. These include:

- To properly frame the grid need for consideration of an NWS, engineers must understand the seasonality, frequency, duration and potential impact of the need in greater detail than for a traditional wired solution. For example, to consider an NWS, it is insufficient to identify just a peak need (a single data point in a forecast) and build capacity to meet that need. Framing and understanding the need for an NWS requires details around the specific times of day, days of year, number of times in a year and overall magnitude and duration of certain needs. All these details require data and time to understand.
- Engineers must account for queued generation projects (PGs in the interconnection process but not yet connected to the grid) when examining the grid need. Future generation additions can have a significant impact on the grid need and study.
- Engineers must also establish initial screening criteria to quickly triage potential grid needs that may require the more in-depth analysis to support an NWS evaluation.
- Finally, the Company must educate field engineers on new data requirements and frameworks that may be needed to support NWS analysis.

Chapter 5: Identification of Solutions

5.1 Readers Guide

This chapter details the expansion beyond the traditional DSP process to include assessment of non-wires solutions (NWS) for the Klamath Falls grid needs identified in **Chapter 4**: Grid Needs Analysis to meet the specific requirements of DSP Part 2.

Initially this chapter reviews the requirements that were outlined in DSP Guidelines 5.3 for solution identification.

The subsequent section provides context regarding the traditional solution that would be used to address the Klamath Falls grid need, then transitions to how the grid need would be addressed by alternative NWS. Details regarding the analysis, NWS alternatives considered and outreach efforts related to these alternatives are also provided in this section.

Next, the Company reviews and provides details regarding the NWS proposals it received from stakeholders, the proposal pros/cons, and the results of the related cost-benefit analysis.

COVERED IN THIS CHAPTER

Review specific requirements outlined in DSP Guidelines Section 5.3 for solutions identification

Provide context on traditional solution and overview of NWS identified to address grid need in Klamath Falls

Provide detail regarding analysis, NWS alternatives considered and outreach efforts

Review and provide details regarding two NWS proposals received from stakeholders

Summarize the results of solution identification and discuss lessons learned.

DSP Guidelines	Chapter Section
5.3.b	**Section 5.4 - 5.5**
5.3.d	**Section 5.5**

The final section summarizes the results of the solution identification of the grid need and discusses the future state of solution identification analysis based on lessons learned.

5.2 Part 2 Solution Identification Requirements

This chapter addresses the specific requirements as outlined in Section 5.3 of the DSP Guidelines:

Section 5.3 Guidelines

Solution identification

Compares the current capabilities of a distribution system and the demands on that system to infer its future needs.

Discussed in this Chapter

Previously,

a Distribution System Plan would rely on traditional hardware solutions (such as substation upgrades, reconductoring, and additional transformer deployment). These Guidelines advance more holistic distribution system planning, calling for consideration of a wider range of potential solutions (for example increased system monitoring automation, expanded switching capability, distributed energy resources).

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

Initial Requirements:

The utility should assess proposed solutions to address grid needs. Specific requirements include:

- *(a) Document the process to identify the range of possible solutions to address priority grid needs.*
- *(b) For each identified Grid Need provide a summary and description of data used for distribution system investment decisions including: discussion of the proposed and various alternative solutions considered, a detailed accounting of the relative costs and benefits of the chosen and alternative solutions, feeder level details (such as customer types on the feeder; loading information), DER forecasts and EV adoption rates.*

- *(c) For larger projects (this may exclude, for example, regular maintenance projects, or inspection projects), engage with impacted communities early in solution identification. Facilitate discussion of proposed investments that allow for mutual understanding of the value and risks associated with resource investment options.*
- *d) Evaluate at least two pilot concept proposals in which non-wire solutions would be used in the place of traditional utility infrastructure investment. The purpose of these pilots is to gain experience and insight into the evaluation of non-wire solutions to address priority issues such as the need for new capacity to serve local load growth, power quality improvements in underserved communities. These pilots will prepare utilities to achieve the goals listed in Stages 2 and 3 of Figure 6.*

d) (continued) In its pilot concept proposals, a utility should discuss the grid need(s) addressed, various alternative solutions considered, and provide detailed accounting of the relative costs and benefits of the chosen and alternative solutions. The pilot concept proposals should be reasonable and meet the Guidelines, even if the individual proposal may not be cost-effective. In addition, evaluation of pilot concept proposals should utilize the community engagement process developed in Section 4.3. (a) (ii) and address:

i. *Community interest in clean energy planning and projects*
ii. *Community energy needs and desires*
iii. *Community barriers to clean energy needs, desires, and opportunities*
iv. *Energy burden within the community*
v. *Community demographics*
vi. *Any carbon reductions resulting from implementing a non-wires solution rather than providing electricity from the grid's incumbent generation mix*

The pilot concept proposal should include a process in which the utility works with stakeholders to set equity goals, as may be appropriate for the pilot.

5.3 Solution Identification Current Process

Chapter 2 provides a thorough overview of the existing DSP processes including details of how solutions are currently identified and prioritized. **Section 2.3.2.3** specifically addresses grid needs and solution identification. The sections following (through **Section 2.4**) provide an overview of how grid needs and subsequent solutions are determined and prioritized.

Figure 38 summarizes the differences between the traditional (field engineer) solutions identification process and DSP solution identification process.

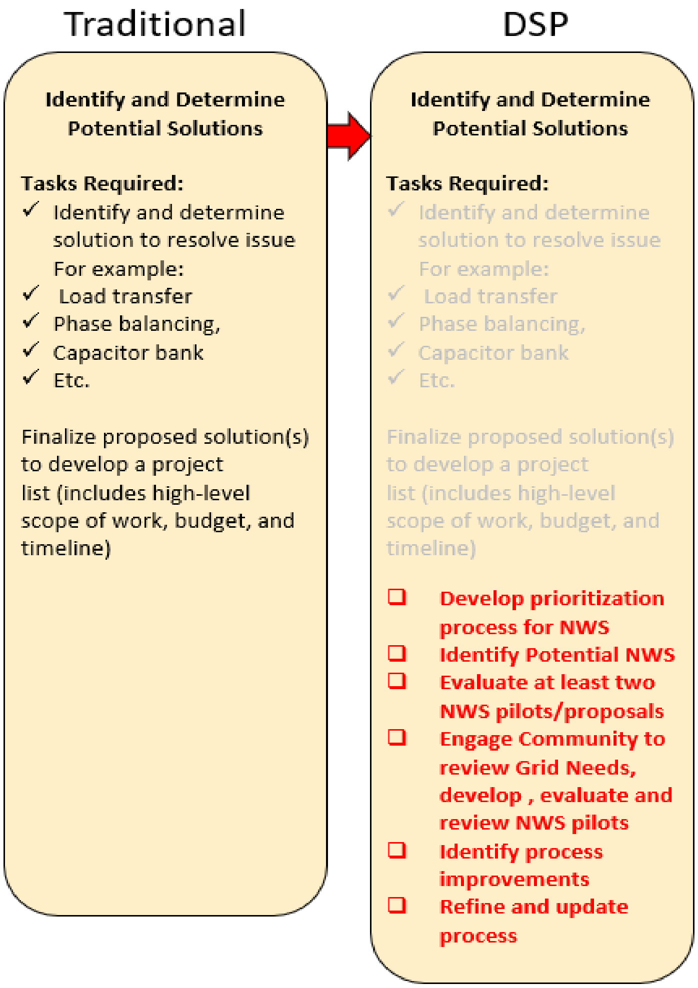


Figure 38: Traditional vs DSP Solution Identification Overview

As illustrated in **Figure 38**, DSP solution identification is the same as the traditional solution identification except it layers on additional items related to NWS and includes evaluation of two NWS pilots/proposals to meet the requirements in DSP Part 2. Details regarding DSP solution identification and how it was implemented are provided in the remaining sections of this chapter.

5.4 Grid Need – Klamath Falls: Traditional Solution

Summary of Traditional Solution

DSP solution identification for Klamath Falls started with identifying the traditional solutions (load transfer, phase balancing, capacitor bank, etc.). As previously described in **Chapter 4**, the identified grid need was an overcapacity issue on a section of conductor that was also causing a voltage issue on a portion of the Crystal Springs circuit, as shown in **Figure 39**.

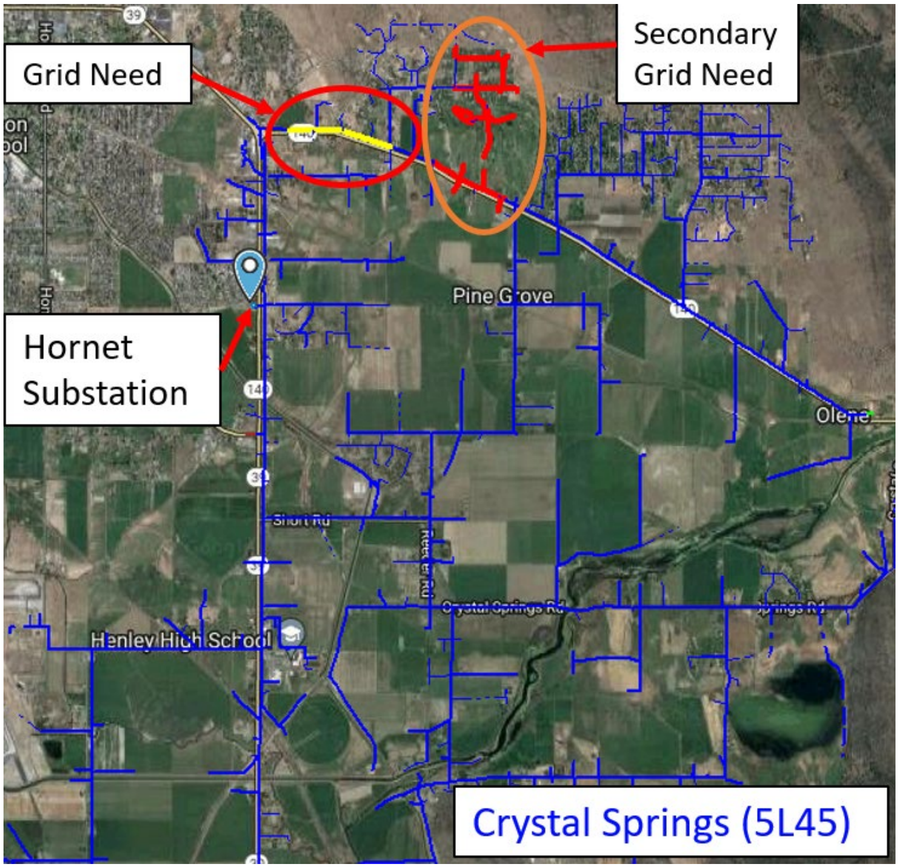


Figure 39: Overview of Grid Needs Identified on Crystal Springs in Klamath Falls

The traditional solution to address this grid need starts with consideration of the least-cost solution to resolve the issue and then reanalyzes to determine if the grid need would be resolved for the remainder of the study period.

Generally, an overcapacity issue in this scenario can only be resolved if the loading can be reduced on the conductor or if the conductor is replaced with larger conductor to increase capacity (reconductor). In **Figure 40**, an example illustrates the effect of a reconductor on an overcapacity grid need as found on the Crystal Springs circuit.

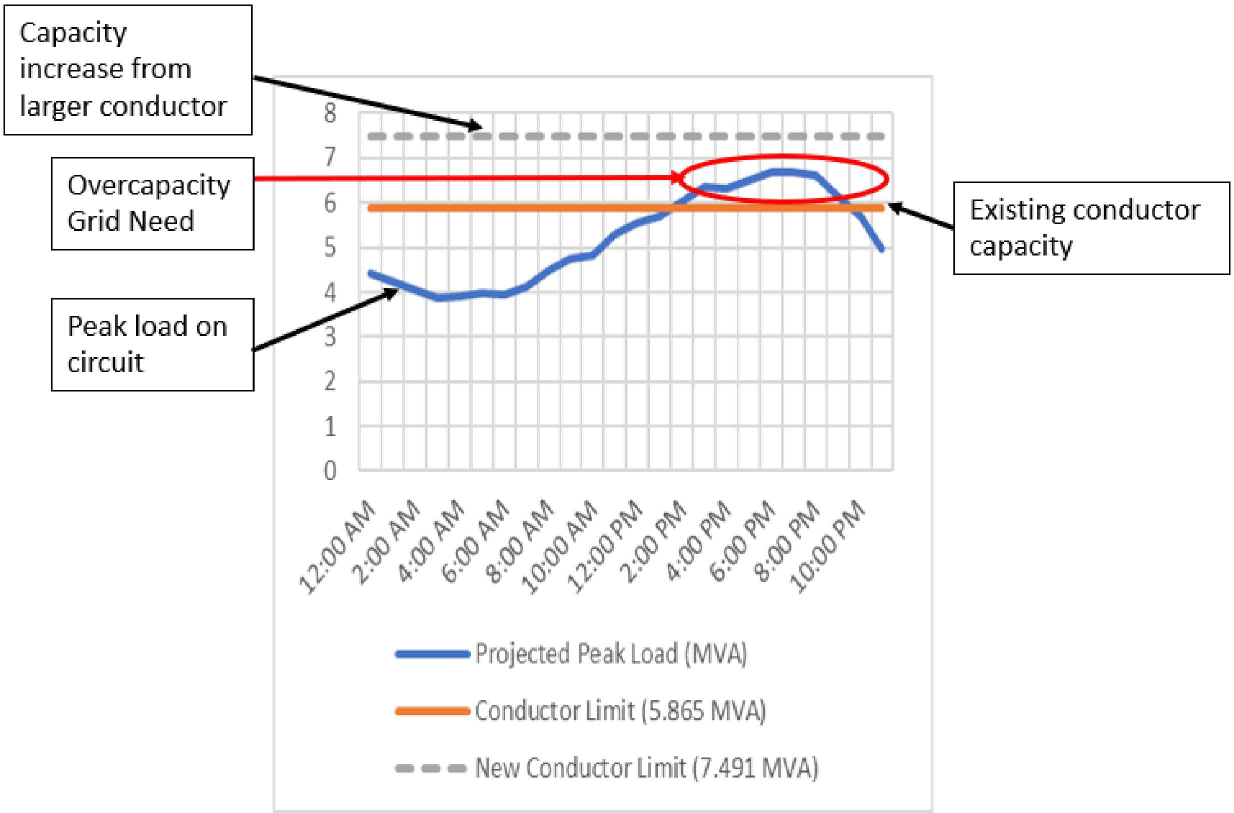


Figure 40: The Effect of a Reconductor on an Overcapacity Grid Need

Based on the severity of the overcapacity grid need, PacifiCorp found that the only traditional solution would be phase balancing and a reconductor of the existing conductor. **Figure 41** and **Figure 42** provide an overview of the solution that would need to be implemented.

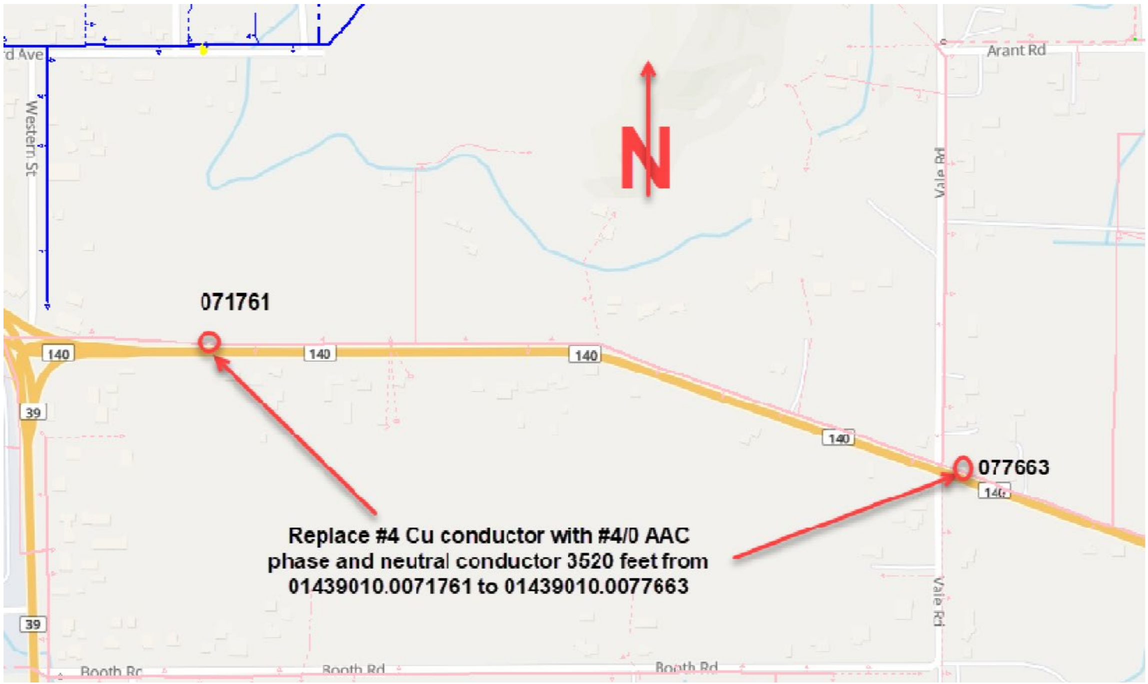


Figure 41: Crystal Springs Circuit — Overview of Traditional Solution

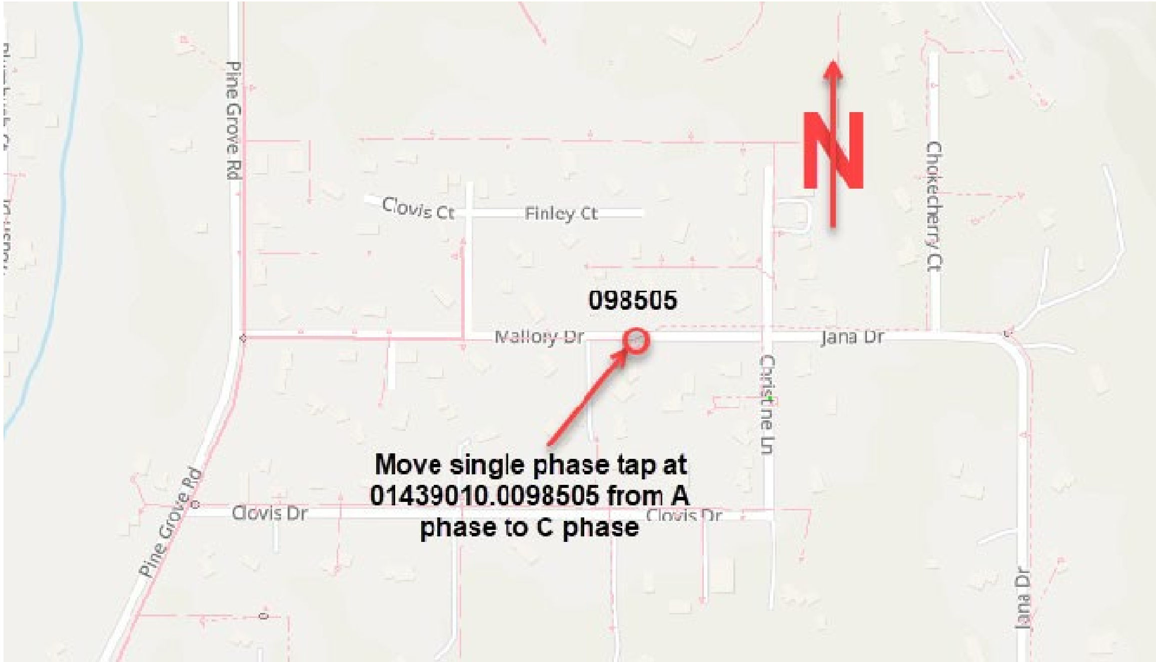


Figure 42: Crystal Spring Circuit — Overview of Traditional Solution (continued)

As shown in **Figure 41** and **Figure 42**, the traditional solution involves replacing 3,520 feet of existing conductor with larger conductor and phase balancing, which involves transferring load between phases. The preliminary cost estimate for the traditional solution identified is $220,740 or $41.26/foot for labor and $21.45/foot for material. These values are based on historical averages from actuals on similar projects that have been completed in the area. Once the project is approved, a detailed cost estimate will be developed.

5.5 Grid Need — Klamath Falls: Alternative/Non-Wires Solutions

To begin, the traditional solution identification process provides the foundation to examine potential NWS for the grid need identified in Klamath Falls. The evaluation process uses the following steps in the DSP solution identification process as shown in **Figure 43**.

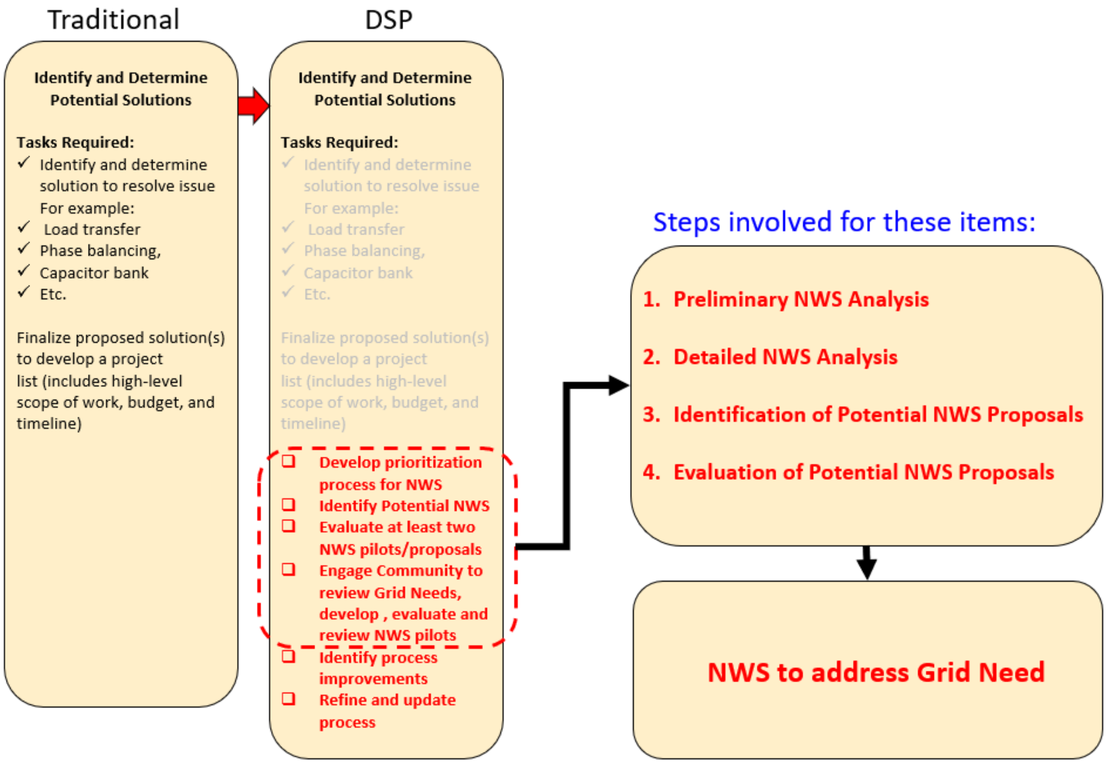


Figure 43: Traditional vs DSP Solution Identification Overview

A brief overview of each step is provided below:

1. **Preliminary NWS Analysis** – High-level review of recent planning studies, areas and data available to perform analysis to confirm grid need identified and NWS feasibility.
2. **Detailed NWS Analysis** – Detailed review and analysis of a specific area/circuit and grid need to determine potential NWS following the preliminary NWS analysis. This analysis includes increased granularity and an examination of potential NWS impacts on the grid need.
3. **Identification of Potential NWS Options** – Based on the detailed NWS analysis, development of a list of potential NWS options for addressing the grid need. The Company used this list as a reference for the two NWS pilot/proposals submitted by stakeholders.
4. **Evaluation of Potential NWS Proposals** – Once the two NWS pilot/proposals were received, they were evaluated. This evaluation included analysis that expanded beyond the detailed NWS analysis to include the grading of each NWS option based on categories outlined in **Section 5.5.4** as well as performing cost-benefit analysis and weighing the pros and cons of each NWS.

Additional details regarding the application of the steps outlined above are covered in the following sections of this chapter.

5.5.1 Preliminary NWS Analysis

The preliminary NWS analysis ensures that the circuit and the grid need identified are suitable for NWS before performing more detailed analysis that requires significant additional time.

With a focus on the Crystal Springs circuit in Klamath Falls, the preliminary NWS analysis is used to verify the following items:

- Traditional solution need, timeline and cost
- Circuit peak load season
- Ad-hoc additions status (large load or generation addition in progress?)
- Distributed generation (DG) capacity and readiness
- Area and circuit characteristics (customer makeup)

DG capacity and readiness (SCADA availability and protection measures) were already covered as part of the initial selection criteria used to select the circuit/area and is described in **Section 3.8**.

Once the DG capacity and readiness was verified, the traditional solution was reviewed to verify the grid need, the timeline required to resolve it and the total cost. Based on the grid need size (overcapacity of 750 kW) the Company determined that NWS would offer a feasible resolution. Additionally, in reviewing the timeline and total cost, it was determined the timeline was long enough and the cost was large enough to pursue NWS alternatives.

In addition to the examination of the grid need, further analysis was performed on the area and circuit characteristics, this included determining the generation type that would be most suited to the area and the customer makeup on the circuit.

Different areas based on their topography and weather may be more suitable for specific types of generation when compared to other areas based on energy output. Using EnviroAtlas (epa.gov) showed that the solar energy output was greater and more prevalent than wind and geothermal outputs. Additionally, since the Crystal Springs circuit is summer peaking, PacifiCorp concluded that the potential NWS should include a solar-based option.

Customer makeup was also verified on the area and circuit characteristics reviewed. Due to the location of the identified grid need, the Company found that the NWS participants would be limited to the 511 customers located downstream of the grid need. These customers were primarily residential, but commercial and irrigation customers were also present.

PacifiCorp also reviewed the status of ad-hoc additions in the area to ensure no large load or generation additions would cause significant changes to the circuit topography or require installing distribution system upgrades that would affect the grid need. The Company found one ad-hoc generation addition but based on its location the addition would not affect the identified grid need.

After verifying these items, PacifiCorp concluded that the Crystal Springs circuit and grid need were suitable for detailed analysis to determine the specifics available for potential NWS. The details regarding the process for detailed NWS analysis is provided in the next section.

5.5.2 Detailed NWS Analysis

The next step in the DSP solution identification process was the detailed NWS analysis. This step builds on the preliminary NWS analysis to further define and determine potential NWS that could resolve the grid need. This step of the analysis requires the following items:

- Increased grid need granularity
- 24-hour circuit peak and generation load shapes
- 24-hour customer type load shapes
- Modeling potential NWS to address grid need

Determining the potential NWS to resolve the grid need requires increased granularity; this granularity includes identifying the grid need's annual frequency and duration as well as specific customer makeup downstream of the need. As described in **Section 4.6**, the identified grid need was plotted on a 24-hour period as shown in **Figure 44** to determine these requirements. The Company found that the loading on the conductor exceeded the rating by as much as 750 kW and 3.8 MWh during peak events; exceeded load is estimated to occur 20 to 50 hours a year between June and August from 2 p.m. to 10 p.m.

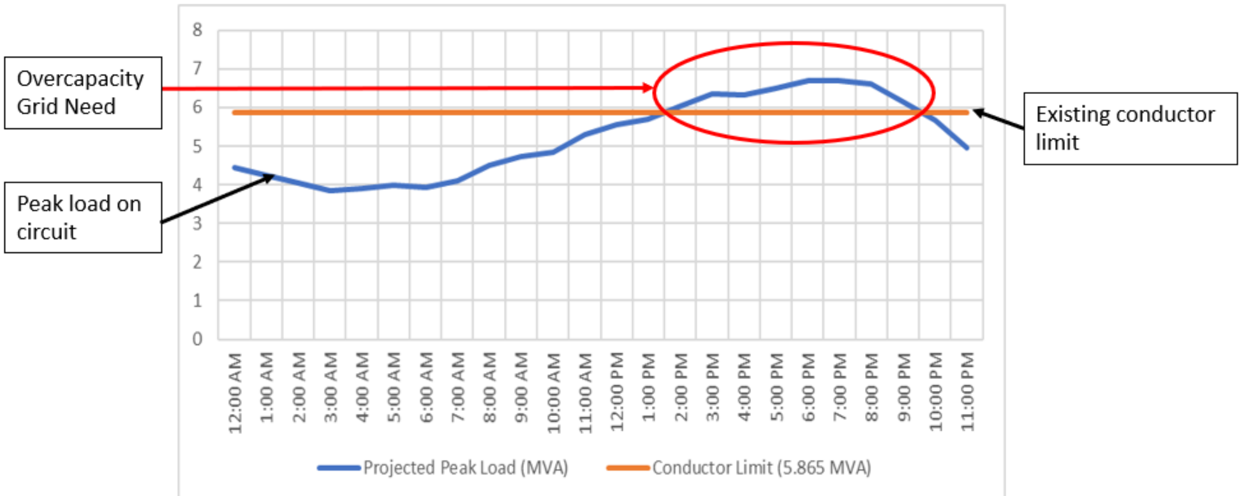


Figure 44: 24-Hour Load Profile for Crystal Springs

The specific customer makeup downstream of the issue was found to be 511 total customers (34% of the entire circuit) made up of 461 residential, 33 irrigation, 17 commercial and zero industrial. Additionally, these customers made up a total of 37% of the demand consumption (kWh) for the circuit with a breakdown of 24% residential, 13% irrigation and 1% commercial. Based on this PacifiCorp concluded that a potential NWS implemented on residential and irrigation customers on the circuit should be examined, since these customers made up a majority of the load on the circuit.

Once the Company established the NWS parameters for the grid need, it developed 24-hour load shapes for the circuit, customer types, and the ad-hoc generation addition to determine load quantity per customer type and when the peak load occurs for each type. This data informs the amount of load that could be reduced by adding generation to a specific customer type and the effect the NWS would have on reducing the peak load on the circuit. Reducing the peak load is required to resolve the grid need. The results of plotting the 24-hour load shape for each customer type is provided in **Figure 45**.

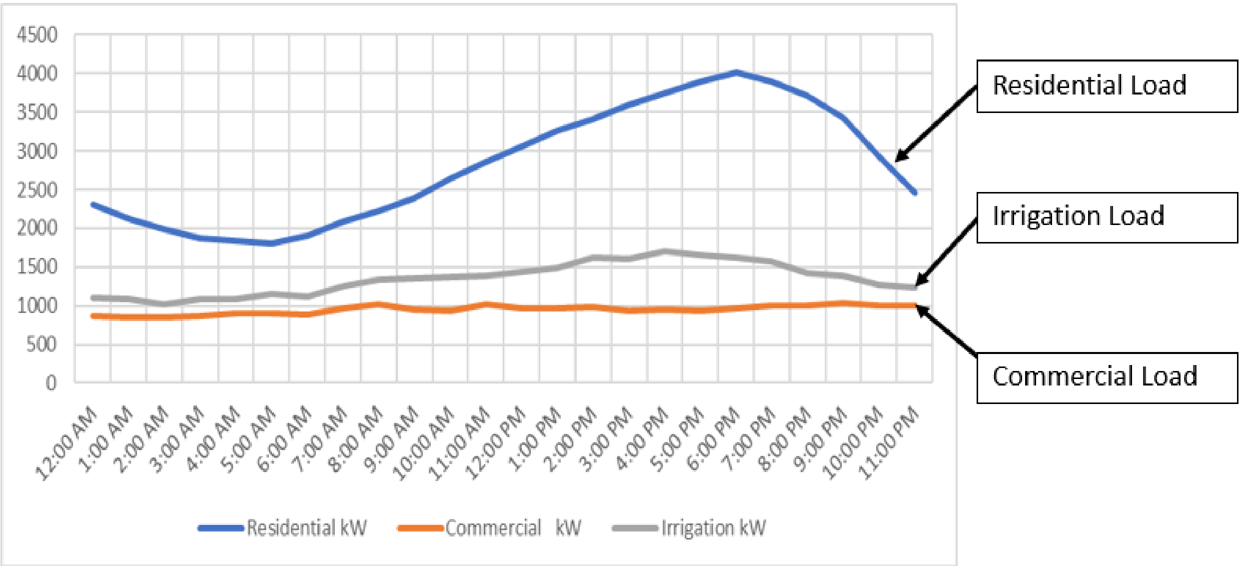


Figure 45: Peak 24-Hour Load by Customer Type for Crystal Springs

After the Company plotted 24-hour load shapes for each customer type, it modeled potential NWS to determine the NWS types that could resolve the grid need. The Company examined several options for the Crystal Springs circuit based on the type of grid need. All potential NWS would need to reduce the load below the existing conductor rating.

The first potential NWS modeled was load reduction or demand response (DR)/curtailment. DR involves customer participation in a load-reduction program active during the peak circuit loading time; the load reduction can prevent the circuit from exceeding the existing conductor rating. In this scenario, an 0.8 MVA reduction was modeled between 2 p.m. and 10 p.m. This resulted in the peak load of the circuit remaining below the existing conductor rating as shown in **Figure 46**.

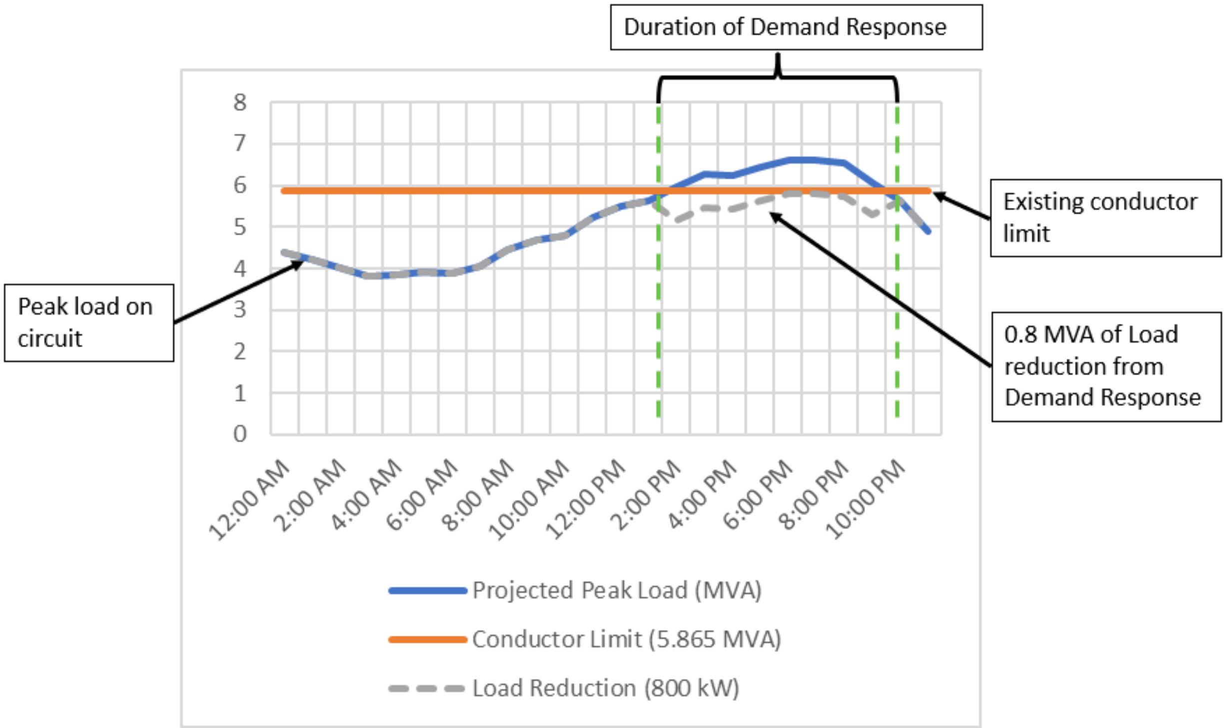


Figure 46: NWS — Demand Response Option for Crystal Springs

The second potential NWS modeled was solar only. As previously described in **Section 5.5.1**, the Company determined that solar had the highest energy output in the Klamath Falls area; it would be the most suitable PG to examine further. The addition of solar downstream of the grid need would result in decreased load. From modeling 2.4 MVA of solar downstream of the grid need, PacifiCorp found that the solar would only reduce a portion of the peak load on the circuit below the existing conductor rating. However, a portion of the circuit peak load would remain above the existing conductor rating from 5 p.m. to 10 p.m. as shown in **Figure 47**.

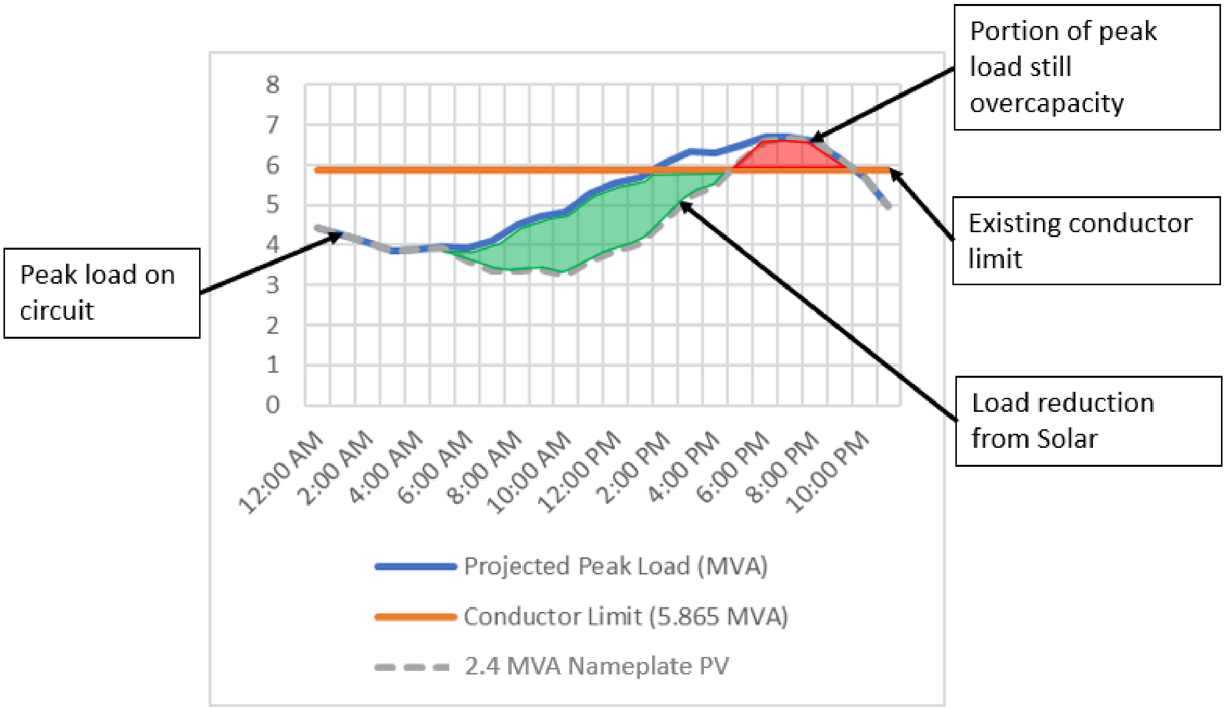


Figure 47: NWS – Solar-Only Option for the Crystal Springs Circuit

As a result of modeling solar only, the Company determined that a solar-only option was not a viable NWS since some of the circuit peak load remained above the existing conductor rating. However, based on the size and duration of the overage, PacifiCorp determined the overage could be addressed with the addition of battery storage, as illustrated in **Figure 48**. Combining solar with battery storage allows the solar to reduce the peak load during the day, while the use of battery storage reduces the remainder of the peak load below the existing conductor rating when solar is unavailable.

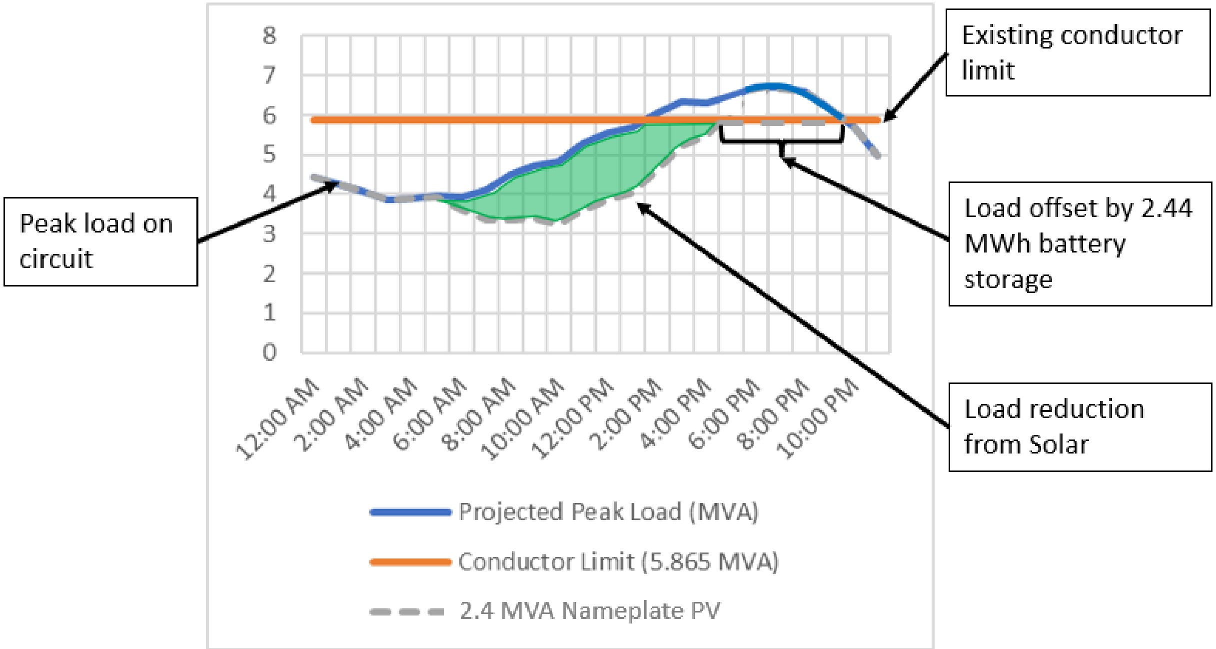


Figure 48: NWS — Solar + Storage Option for the Crystal Springs Circuit

When examining NWS that involve the addition of PG, the opposite scenario of peak load (net minimum load) must be studied to verify the maximum amount of PG that can be added without resulting in additional grid needs, and to ensure the PG addition does not result in exceeding limits that require additional protection measures on the upstream protective device. As described in **Section 3.8**, the net minimum load forecast was used in this scenario to determine the minimum net load that the PG would be applied to. PacifiCorp modeled the PG downstream of the grid need on the Crystal Springs circuit and found a total of 2.4 MVA could be installed without causing additional grid needs, as shown in **Figure 49.**

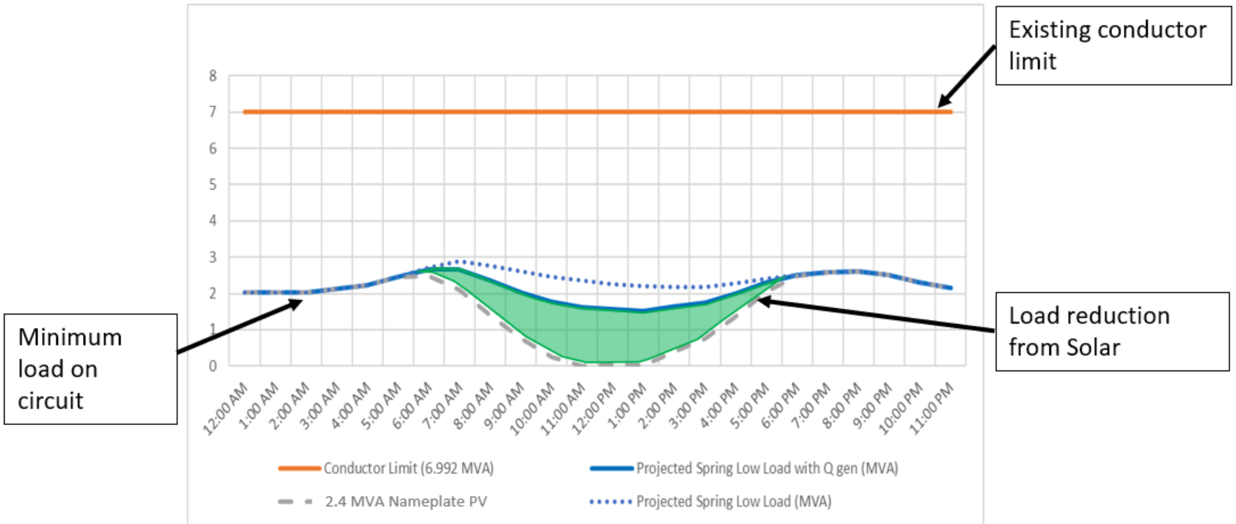


Figure 49: NWS — Solar + Storage Option for Crystal Springs, Minimum Load Scenario

Based on the detailed NWS analysis, a list of potential NWSs was developed. The Company then proceeded to a next NWS identification step and evaluation steps for the Crystal Springs circuit. These steps are described in detail in the next sections in this chapter.

5.5.3 Identification of NWS Options:

While not required by Stage 1 of DSP Part 2, in assessing options for NWS, PacifiCorp did specific outreach to the DSP stakeholder group to request proposals for alternative/NWSs for the Transitional Study areas starting in January 2022. The Company posted a form on its DSP webpage for interested parties to send proposals that could be used for consideration of the identified grid need. During the Company's workshops held in January and May, the DSP team continued to request input with a focus on Klamath Falls and Pendleton. This outreach resulted in the Company receiving three proposals from two different stakeholders: The proposals are summarized in **Table 4**.

Table 4: Non-Wires Solution Proposals From Stakeholders

Stakeholder	Proposal
Farmer's Conservation Alliance	**Solar and Battery Storage**
OSSIA	Pilot use of **Smart Inverters** Pilot "Solarize Campaign"

After receiving these proposals, and in consultation with the stakeholders, the DSP team determined that there were several types of NWS to consider for the Klamath Falls grid need. These were presented during Workshop #9. The Company outlined the potential alternate/NWS concepts based on the detailed NWS analysis to address the grid need identified in Klamath Falls. The NWS concepts are listed below:

Non-Wires Solutions Concepts PacifiCorp Considered for NWS Evaluation

- Solar: Uses a solar-only solution for customers downstream of the grid need. This NWS by itself did not resolve the grid need.
- Solar + Storage: Uses a combination of solar and battery storage at residential and commercial/irrigation customer sites downstream of the grid need. In this solution solar reduces the peak load during the day and battery storage is used when solar is unavailable to reduce the remainder of the peak load below the existing conductor rating.
- Load Control, Curtailment, DR: Uses a program that customers would sign up for to reduce the peak load during a specific time of year/day downstream of the grid need. This solution requires enough customers sign up for the program to reduce the peak load below the existing conductor rating.
- Targeted Energy Efficiency: Uses energy efficiency incentives and targeted marketing efforts to influence customers downstream of the grid need to adopt energy efficiency measures. This reduces the customer power usage and drops the feeder load below the conductor limit.
- Other distributed energy resources (DER) were considered, but were not further pursued:

- Micro-wind: Using customer-owned micro-wind turbines to generate power downstream of the grid need. Wind at this scale is not predictable enough to reliably address distribution grid needs.
- Micro-hydro: Using customer-owned micro-hydro turbines to generate power downstream of the grid need. Micro-hydro was considered within this evaluation, however hydro resources in the Crystal Springs area are classified as protected resources, or do not possess the required head to generate consistent power.
- Geothermal: Using geothermal plants to generate power downstream of the grid need. Klamath Falls is a well-known "hotbed" for geothermal resource, and geothermal was considered early in the evaluation process. Unfortunately, geothermal is not currently a scalable resource, and existing technologies were deemed too experimental for the purposes of this process.

For a high-level overview of how each of these options would affect the grid need refer to **Section 5.5.2.**

The Company combined the proposals from the Farmers Conservation Alliance (FCA) and Oregon Solar and Storage Industry Association (OSSIA) into a single NWS concept for the DSP Part 2 evaluation: Solar + Storage with a Smart Inverter. PacifiCorp considered this NWS concept to have several advantages:

- Engage with FCA, OSSIA and ETO who have expertise and insight to share on the NWS concept
- Develop a model, evaluate solar + storage and begin to identify distribution system impacts

In addition to DSP stakeholder outreach, the Company decided to do local-level engagement to seek input from the potentially impacted community, Klamath Falls. The DSP team sought engagement from local stakeholders in Klamath Falls to review specific options for NWS and to solicit input on several topics covered in the DSP Survey.

In coordination with PacifiCorp's Klamath Falls regional business manager, the DSP team invited local stakeholders and representatives from the following organizations to an in-person meeting in Klamath Falls in July 2022:

- Klamath/Lake Community Action Service – Community action organization providing support to families and veterans in need with energy, housing and health resources
- Klamath County Emergency Management Department
- Klamath County Chamber of Commerce
- Klamath County Public Works Department
- Klamath Falls Downtown Association
- Klamath Water Users Association
- Klamath Falls City Planning Department
- Klamath Community College
- Klamath residential customers

During the meeting, PacifiCorp provided background and context for DSP, provided further information about the identified grid need on the Crystal Springs circuit and then outlined the five alternative/NWSs. A summary from the discussion with Klamath Falls stakeholders is included as **Appendix D**.

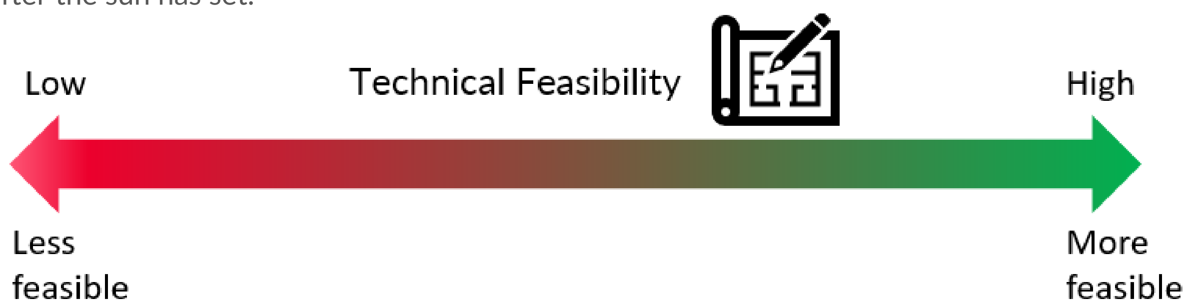
For some general context, the DSP team provided a comparison matrix to help facilitate discussion and get feedback on the second NWS.

5.5.4 Evaluation of NWS Proposals

After identifying the NWS options, the Company compared these options using a set of high-level categories. These categories were summarized in a comparison matrix, which was provided to the Klamath stakeholders to facilitate discussion and to solicit their input for the second NWS concept. The categories are preliminary, and the Company plans to revisit these to potentially include enhanced indicators in the future. The categories are described below, along with the comparison matrix for the traditional and NWS options.

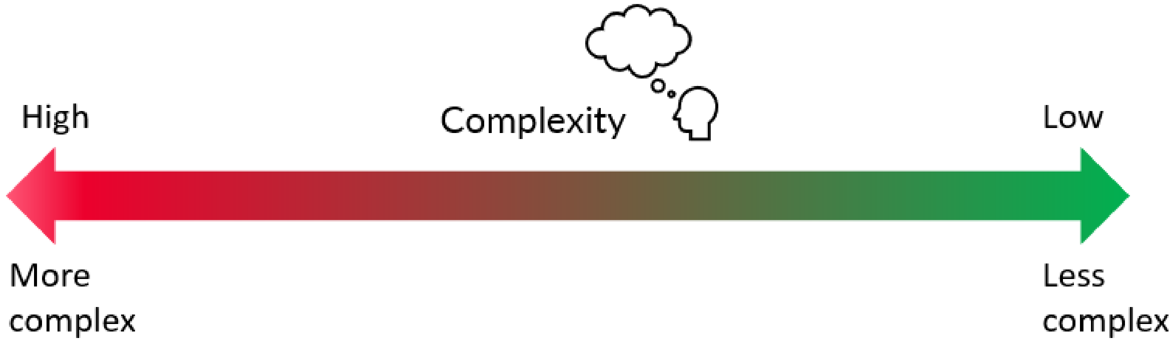
Description of Preliminary Evaluation Categories:

Technical Feasibility: (higher feasibility is preferred)
Can this solution meet (or meaningfully support meeting) the grid need identified? This includes some assessment of the maturity of the proposed solution and a preliminary understanding of the specific requirements of the need (e.g., time-of-day, time-of-year, infrastructure needs, etc.). For example, solar by itself does not meet grid needs that exist after the sun has set.

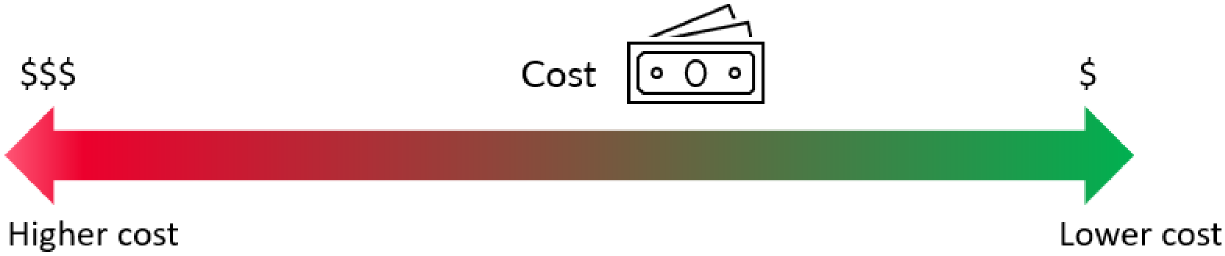


Estimated Timeline to Implement: (shorter time frames are preferred) How long, from now, would the solution realistically take to be in place to address the grid need? Overcapacity on the Crystal Springs circuit should be addressed within two years to avoid customer outages. An NWS taking more than two years would be rated less than one that could be completed within two years.

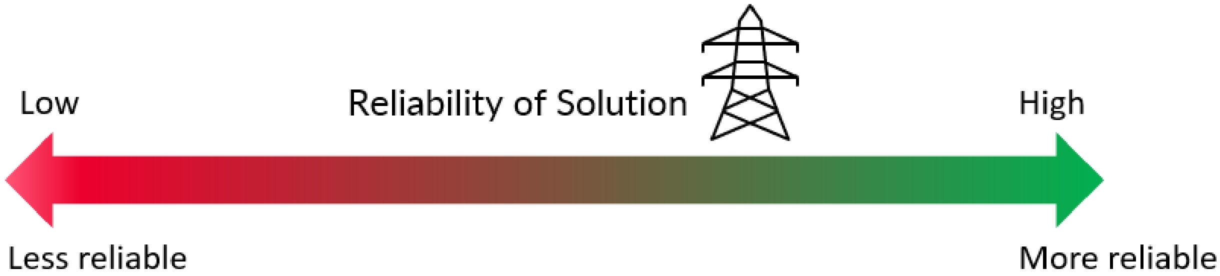
Complexity: (lower complexity is preferred) Generally, how many factors must be developed, coordinated, managed and executed to enable the solution to meet the identified grid need? Examples: A targeted energy efficiency NWS that required development of new programs, hiring of new contractor support, and a significant need for new marketing would indicate high complexity. A targeted energy efficiency NWS that used existing programs that were already fully supported might be a medium to low complexity. A traditional wires solution that does not require ongoing management would be a low complexity solution.



Cost: (lower cost is preferred) What is the total cost of solution required to meet the grid need?



Reliability of Solution: (high reliability is preferred) Generally as outlined, can the solution reliably meet the grid need identified? For example, a DR program NWS implemented to meet a peak time grid need where customers can opt out of events might be a medium for reliability.



Customer Benefits: (high Is preferred) What are the benefits that might come to end customers through implementation of the solution? For example, solutions like solar + storage are likely to have a high rating because they provide backup service to customers and reduce customer utility bills.

Community Benefits: (high is preferred) How does this solution benefit the community more broadly? Elements to consider in this area include emissions reductions from implementation of renewable DERs on a circuit, increases in community resilience from broader installation of storage, etc. For example, the solar + Storage would provide backup power during an outage.

Note: The Company intends to refine and expand the evaluation categories as it gains more experience with DSP level assessments and as conversations around energy equity metrics and further community benefit metrics continue. As highlighted from the input received from the DSP Community Survey and local stakeholder engagement, further definition is required around energy equity and potential equity metrics to determine appropriate criteria for more mature evaluations. The Company plans to actively engage in equity conversations with state and local stakeholders in the UM 2225 Clean Energy Plan (CEP) process and establishment of the CBIAG. In addition, PacifiCorp intends to continue to engage with local stakeholders in the DSP process to solicit input on how communities view and evaluate energy equity in the DSP context.

Table 5: Wires and NWS Comparison Matrix

NW Solution/ Category	Solar + Storage	Demand Response	Energy Efficiency	Solar	Wires Solution
Technical Feasibility	Med	Med	Low	Does Not Meet Need	High
Estimated Timeline to Implement	2-3 Years	1-2 Years	1-2 Years	2-3 Years	< 1 Year
Complexity	High	High	Med	Med	Low
Cost	$$$$	$$	$$	$$$	$$
Reliability of Solution	Med	Med	High	Low	High
Customer Benefits	High Backup power, on-site generation	Med Receive Customer Incentives	High Reduce kWh use	High On-site generation, reduce emissions	Med Does not require customer action, High Reliability
Community Benefits	High Reduce emissions	Med Reduce emissions	High Reduce emissions	High Reduce emissions	Med

Preliminary estimates based on early analysis. Subject to change based on completion of assessments

A comparison of some of the pros and cons for the traditional and NWS options are presented in **Table 6.**

Table 6: Traditional and NWS Options - Pros and Cons

Solution	Pros	Cons
Traditional Wires Solution	• Predictable and reliable – Will meet the grid need and provide capacity year-round • Moderate one-time investment and implementation provides long-term solution to grid need • Does not require a new program to ensure the solution is ready to meet the grid need	• Construction work may impact local customers • Does not specifically improve end usage patterns or encourage movement toward cleaner energy future
Customer Solar	• Renewable resource with no emissions; offsets generation that has some fossil fuel components resulting in reduced emissions • Reduction in overall energy costs for customers • Potentially enhances customer-level resilience • May be a benefit to customer's property value	• Solar alone cannot meet the specific grid need because the overcapacity condition continues past dusk in most instances • Substantial up-front cost • Output dependent on time of day and sunlight • Maintenance is dependent on system owner • Variable output creates uneven load curve, often requiring compensation from other generation • Solution is not accessible to a broad array of utility customers due to high cost and need for installation of specialized equipment (generally installed by property owners)
Customer Solar + Storage	• Renewable resource with no emissions; offsets generation that has some fossil fuel components resulting in reduced emissions • Reduction in utility energy costs for customers • Enhances customer-level resilience, especially with storage/battery backup • May be a benefit to customer's property value • Addition of storage with the ability to discharge the battery at specific times (smart inverter functionality), allows this NWS to meet the specific grid need identified • Addition of storage and smart inverters may allow this NWS to provide additional grid support in the future	• Substantial up-front cost • Solar output is dependent on time of day and sunlight – this is largely offset by storage • There is not an existing program to facilitate and enroll participants for such a solution • Maintenance is dependent on the system owner • The solution is not accessible to a broad array of utility customers due to high cost and need for installation of specialized equipment (generally installed by property owners)

Solution	Pros	Cons
Load Control, Curtailment, Demand Response	• Can be a very effective solution to specific peak-based grid needs • May be cost-effective solution for the utility • When properly designed and executed, can provide reliable load reductions to meet peak needs	• Requires a program to support formation, recruitment, administration and management of the aggregated participants to deliver required load reductions • May require communications to customer equipment and or meters • Can be disruptive to customers • Requires an aggregation of customers/loads that are available/agreeable to interruption
Targeted Energy Efficiency	• Does not require sophisticated technical controls or evaluation • Most measures that could be used are well understood and highly cost-effective • Provides reductions in emissions by reducing overall, year-round usage • Many measures are smaller in scope and investment to allow broader adoption and installation • There are existing programs to support most of the energy efficiency measures that would be implemented to meet the grid need • Several programs and community-based organizations (CBO) across the state support implementation of energy efficiency measures for low-income customers • Can provide benefits beyond peak reduction such as customer comfort or appliance effectiveness • Energy efficiency measures provide cumulative benefits over years – for example, once attic insulation is installed in a home, it continues to provide energy savings and improved comfort for many years to come	• While highly effective, it can take years to see significant results from targeted energy efficiency efforts • There is a practical limit to how much impact targeted energy efficiency can have in a year (average estimate is 1%-2% of retail sales in an area with active energy efficiency programs and incentives)

Based on feedback from Klamath Falls stakeholders, the Company selected two NWS concepts to evaluate for the identified grid need: 1) solar + storage and 2) targeted energy efficiency. The concepts, evaluation methods and costs and benefits will be described in the next sections.

Building on the detailed NWS analysis that determined the list of potential NWSs to address the grid need, the Company added the details included in the FCA/OSSIA proposal to further develop, refine and evaluate the Solar + Storage and Targeted Energy Efficiency solutions.

5.5.5 Solution Concept #1 – Solar + Storage – Klamath Grid Need

Solution Concept #1 Description:

As described in **Section 5.5.2**, this solution uses a combination of solar and battery storage at residential and commercial/irrigation customer sites downstream of the grid need. Specifically, this solution uses solar to reduce the peak load during the day and uses batteries when solar is not available to reduce the remainder of the peak load below the existing conductor rating. Due to the number of residential and commercial/irrigation customer sites available, the Company focused on a residential or commercial/irrigation solar + storage solution for the Crystal Springs circuit. PacifiCorp used existing programs such as the Wattsmart Battery program in Utah to develop the framework and requirements for implementation with these customer types.

Requirements and Assumptions:

As outlined in **Section 5.5.2**, the analysis for the peak load and minimum load scenarios, identified that 2.4 MW of solar with 2.44 MWh of battery storage capacity was needed to address the grid need as shown in **Figure 50.**

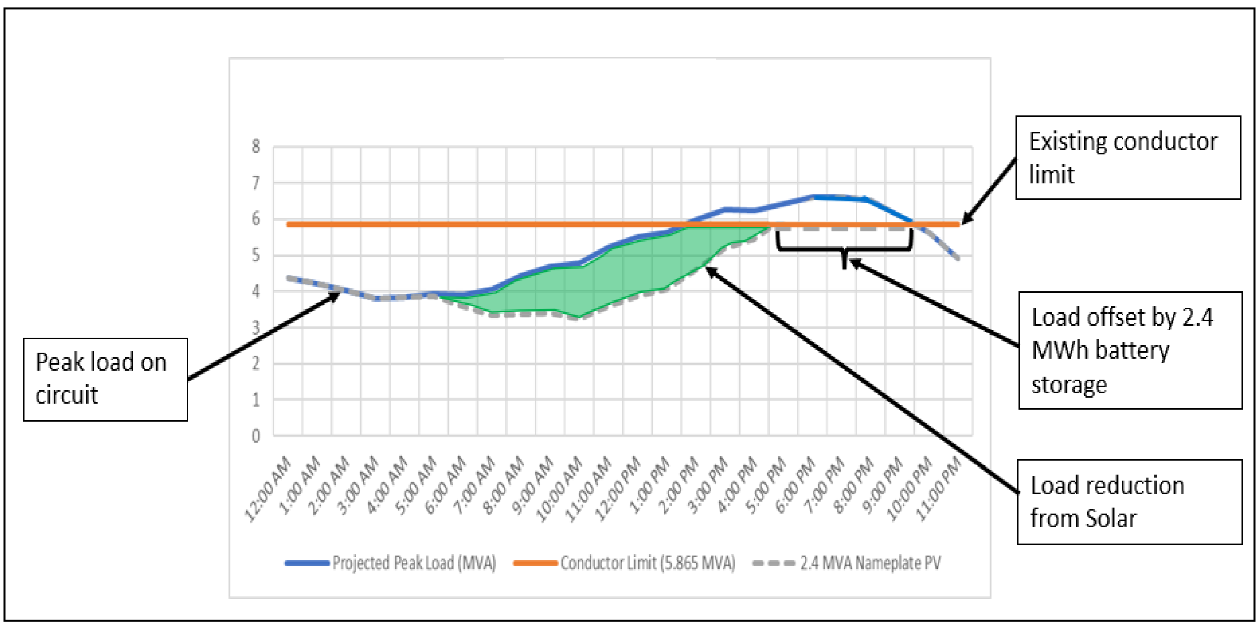


Figure 50: NWS — Solar + Storage Concept for Crystal Springs, Residential

With multiple potential sizes and configurations of solar + solutions, this study assumes a rooftop solar PV unit size of 10 kW and battery storage size of 10 kW and 10 kWh. A maximum battery depth of discharge of 80% was used to avoid damage to the customers batteries over time and to allow a backup reserve for outages. This means that a battery rated for 10 kWh will only be discharged by the utility up to 8 kWh. Given these parameters, the Company determined that 290 - 310 residential customers would need to participate to meet the grid need.

Estimated Costs and Utility Incentives:

Based on data from DNV and the National Renewable Energy Laboratory (NREL) the costs were estimated based on two installation scenarios: 1) installation of solar PV and battery storage and 2) adding battery storage to an existing solar PV. The estimated cost for scenario 1 solar + storage installation before any incentives or rebates is between $50,000 and $75,000 for the given unit sizes. In the second scenario the total costs were between $20,000 and $35,000 to add battery storage to existing solar PV.

The Company used information from the Wattsmart Battery program in Utah as the basis for program assumptions including potential program incentives. There were three layers of incentives that were considered: 1) ETO/utility incentives: (Lower-cost scenario) $400 per kW initial payment and $15 per kW each year after; (higher-cost scenario) an initial incentive of $600 per kW for early adopters and $15 per kW each year after, 2)a state tax rebate of $200 per kW installed capacity up to 40% of the net cost or $5k, whichever is less; and 3) a federal tax rebate of 22% of system cost for systems in service after December 31, 2022, and before January 1, 2024. After utility/ETO incentives and rebates it was estimated that the average customer installation cost would be between $45,000 to $70,000 for solar PV and battery storage and $14,000 to $26,000 for adding battery storage to an existing solar PV. The estimated costs per customer with and without incentives based on the installation scenario is provided in **Table 7.**

Table 7: Summary of Estimated Cost Per Customer for Solar + Storage Solution for the Crystal Springs Circuit

Installation Scenario	Estimated Cost Per Customer	Estimated Cost Per Customer With Utility/ETO Incentives
Adding Solar PV and Battery Storage	$50,000 to $75,000	$45,000 to $70,000
Existing Solar PV and Adding Battery Storage	$20,000 to $35,000	$14,000 to $26,000

Pros and Cons Summary:

The pros of this solution are the ability to resolve the grid need using renewable resources, reducing emissions as well as reducing the customers' utility bills. Additionally, this solution enhances customer resiliency, provides backup power in case of outages and may increase customer property value. The discharge-on-demand feature of the battery storage with the addition of smart inverter may also provide additional utility benefits in the future such as frequency response and other grid support functions.

The cons of this approach are the high up-front cost of the solution and the need for a relatively large proportion of customers to participate. This approach is dependent on the battery storage to offset the times of day when solar PV is not available and requires a certain level of maintenance from the customer. The utility does not currently have a program to support such a solar + storage offering and would need to extend the automated control system used in the Utah program for use in Oregon. Finally, the solution is not accessible to a broad range of customers due to high cost and need for installation of specialized equipment (generally installed by property owners).

Cost-Benefit Analysis:

PacifiCorp developed a preliminary cost-effectiveness framework to review the potential solar + storage solution. PacifiCorp worked with FCA, OSSIA and ETO, to assess cost inputs for evaluation. Benefit inputs were derived primarily from data used to inform the Wattsmart Battery program; the benefit framework used by PacifiCorp may change as a result of additional stakeholder review. As such, the Company has outlined the base assumptions and cost-effectiveness framework for the first time in this filing. PacifiCorp anticipates more detailed follow up with ETO, FCA and OSSIA will be needed to refine this analysis and ensure that assumptions and modeling are reviewed and well understood before executing next steps.

Solar + Storage Key Assumptions:

The Company explored two scenarios in the preliminary analysis:

1) A High or Optimistic case that uses assumptions that result in lower costs and higher benefits to explore the upper ranges of potential cost-effectiveness.
2) A Low/Conservative case that uses assumptions that result in higher costs and a more conservative viewpoint of benefits.

Key assumptions are highlighted in **Table 8** to explain the key differences between the scenarios.

Table 8: Comparison of Key Assumptions

Key Assumption Summary	Low/Conservative	High/Optimistic
Number of customers needed to meet the grid need	310	290
Customer cost for 10 kW solar + storage system - Installed	$75,000	$50,000
Utility incentives (modeled on Utah Wattsmart) $/kW – initial	$600	$400
Annual participation incentive (Utah Wattsmart) $/kW – Yr	$15	$15
Tax incentives – both scenarios – customer cost after incentives	22%	22%
Customer benefit ($/kWh)	$0.0933	$0.0933
Annual customer generation (kWh)	436,740	466,860
Annual utility program costs	$62,000	$31,000
Utility benefit values ($/kW for capacity – UT estimate + local deferral value	$174	$187
Utility value of avoided cost ($/kWh)	$0.0478	$0.0478

For simplicity and expedience, the Company used multiple assumptions from the Rocky Mountain Power Wattsmart Battery program in Utah for the following inputs: program incentives, high-level utility benefit values, program administration costs and customer costs. The Company recognizes that further cost and benefit refinements are necessary to better reflect the potential impact of such a solution in this environment.

To summarize, the Company calculation relied on three cost-effectiveness perspectives, the utility cost test (UCT), the participant cost test (PCT) and the total resource costs (TRC) test. A Benefit/Cost ratio greater than 1.0 indicates benefits are greater than costs and are generally considered cost-effective. These tests relied on the inputs shown in **Table 9**. These inputs might not cover all the potential benefit and costs streams that may be applicable under each test, however, they reflect how the inputs were used in each test. Additionally, a 10% benefit adder was applied to represent non-quantified benefits for values such as resiliency. This 10% benefit adder is consistent with the adder used by the Northwest Power Planning Council to recognize preference for energy efficiency resources.

Table 9: Cost and Benefit Inputs

Input	Utility (UCT)	Customer (PCT)	TRC
Incentives	-	+	
Program administration	-		-
O&M		+/-	+/-
Customer capital		-	
Tax credits		+	+
Bill savings		+	
Utility avoided costs	+		+
Non-energy impacts			+/-

Green color (+) = typically a benefit	*Yellow color (+/-) = either a benefit or a cost*	*Red color (-)= typically a cost*

The results from the preliminary cost-effective analysis are provided in **Table 10** and **Table 11**:

Table 10: Preliminary Cost-Effectiveness (CE) Results With Optimistic Inputs

Benefit Cost Assessment	CE – 5 Year	CE – 10 Year	CE – 20 Year
Utility (UCT)	1.38	2.07	2.70
Customer (PCT)	0.02	0.03	0.05
TRC	0.14	0.23	0.34

With 10% benefit adder	CE – 5 Year	CE – 10 Year	CE – 20 Year
Utility (UCT w/ adder)	1.52	2.27	2.97
Customer (PCT w/ adder)	0.02	0.03	0.05
TRC (w/ adder)	0.15	0.25	0.37

Table 11: Preliminary Results With Conservative Inputs

Benefit Cost Assessment	CE – 5 Year	CE – 10 Year	CE – 20 Year
Utility (UCT)	0.84	1.26	1.66
Customer (PCT)	0.01	0.02	0.03
TRC	0.08	0.13	0.20

With 10% benefit adder	CE – 5 Year	CE – 10 Year	CE – 20 Year
Utility (UCT w/ adder)	0.92	1.39	1.83
Customer (PCT w/ adder)	0.01	0.02	0.03
TRC (w/ adder)	0.09	0.15	0.22

The results show that a solar + storage solution based on the proposed program design would likely be cost-effective from the utility perspective (UCT values range from 0.84 to 2.27 depending on scenario and timeframe). From a customer and total cost perspective, such a program is not cost-effective, primarily because the technologies have such high up-front capital costs. None of the scenarios above produce a PCT or TRC above 0.4. While there may be additional customer or non-energy benefits associated with this solution, the high customer cost of the solution is the primary driver for the low benefit/cost ratios for PCT and TRC as the total customer costs are estimated to be between $15 million – $23 million.

Using the PacifiCorp 2021 IRP emissions forecast, this solar + storage solution producing 467 MWh of renewable energy per year would potentially offset a cumulative total of 1224 tons of carbon from 2023 to 2028.

Alternate Solution Considered (Commercial/Irrigation):

In PacifiCorp's discussion with stakeholders regarding the solar + storage proposal, there was a desire for the Company to investigate a commercial/irrigation solar + storage solution.

This analysis of this solution used the same data as the residential solar + storage solution, except the number of participants was limited to 30 customers or 90% of the total irrigation customers located downstream of the grid need. It was determined that 1.8 MVA of solar and 2.6 MWh of storage would be required to resolve the grid need as shown in **Figure 51**. This would involve installation of a 60 kW solar and 90 kWh battery storage for each customer.

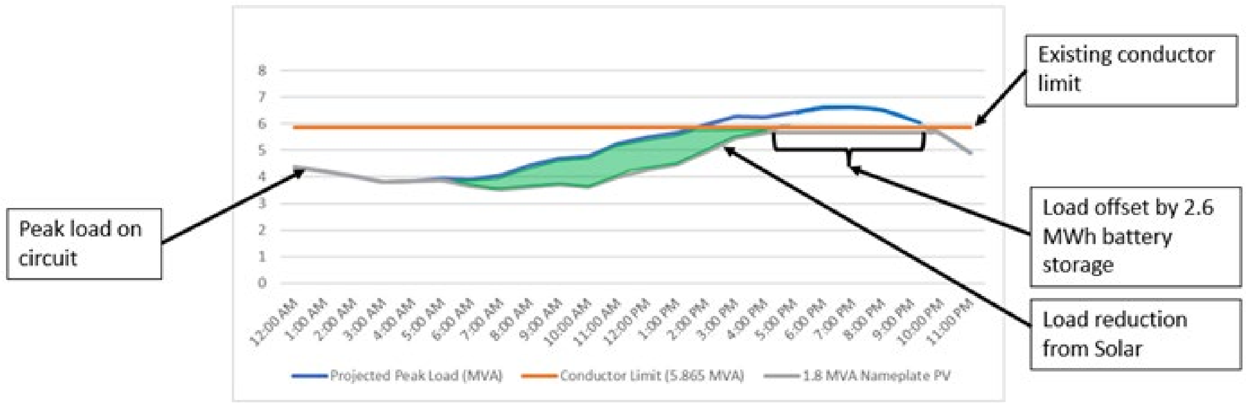


Figure 51: NWS — Solar + Storage Concept for Crystal Springs, Commercial/Irrigation

There are several unknowns such as unit sizing, costs and utility incentives that must be determined with this solution to make it viable. The Company is working with FCA to explore solution parameters so that these items can be potentially applied to irrigation customers and irrigation district patrons on this circuit. The Company also believes continuing to analyze this solution will help establish framework that could be used in other areas that have commercial/irrigation customers, rendering implementation more viable in the future.

5.5.6 Solution Concept #2 - Targeted Energy Efficiency – Klamath Grid Need

A targeted energy efficiency solution uses incentives via ETO and targeted marketing to influence customers to adopt energy efficiency measures. Energy efficiency measures offer opportunities for providing demand reduction during peak periods. The scale and scope of energy efficiency measures is vast and offers varying levels of demand reduction commensurate with the end-use load and energy savings. Using a portfolio of options for customers can help engage different customers with opportunities to adopt energy efficiency and manage overall risk toward project success.

Background on Previous Targeted Energy Efficiency Projects

PacifiCorp previously worked with ETO to pilot targeted load management (TLM) projects in specific locations in Oregon. These pilot projects tested non-wires concepts in the North Santiam (2017-2018) and Talent/Phoenix (2019-2020) areas in Oregon. Each of these pilots proved to be informative for future targeted energy efficiency planning and delivery efforts. Any future targeted energy efficiency concepts will build from the lessons learned in these previous pilots. A few key findings from the earlier pilots are provided below for consideration:

1. Achieving additional energy efficiency savings in the first year is challenging unless significant lead time is provided to program implementers to design an implementation strategy. Energy savings and cost targets specific to each program help set expectations for program implementers to gauge success.
2. The constraint on each feeder line may be different, so a menu of options is needed to streamline the process of implementing future TLM efforts.
3. Load reduction beyond baseline (business-as-usual) levels is most likely to occur with the larger base of residential customers who can choose from an extended menu of smaller investments. Load reduction beyond baseline for commercial and industrial customers requires targeted outreach with longer lead times, due to lengthy capital project budgeting and planning processes.

Solution Concept #2 Description:

As described in **Section 5.5.3**, the targeted energy efficiency solution uses energy efficiency incentives and targeted marketing efforts to influence customers downstream of the grid need to adopt energy efficiency measures. Adoption of energy efficiency measures results in increased annual energy efficiency savings, which can reduce the peak load below the existing conductor rating to address the grid need. Since energy efficiency savings that produce load reduction beyond baseline levels requires a large base of customers, the Company did not limit the energy efficiency solution to a specific customer type as it did in Solution Concept #1.

Requirements and Assumptions:

The targeted energy efficiency requirement solution leveraged the requirements as determined in the detailed NWS analysis. Based on the requirements of the grid need for the peak load and minimum load scenarios, it was found that a total of 4,525 MWh would need to be saved by energy efficiency to reduce the peak load by 750 kW to address the grid need as shown in **Figure 52**.

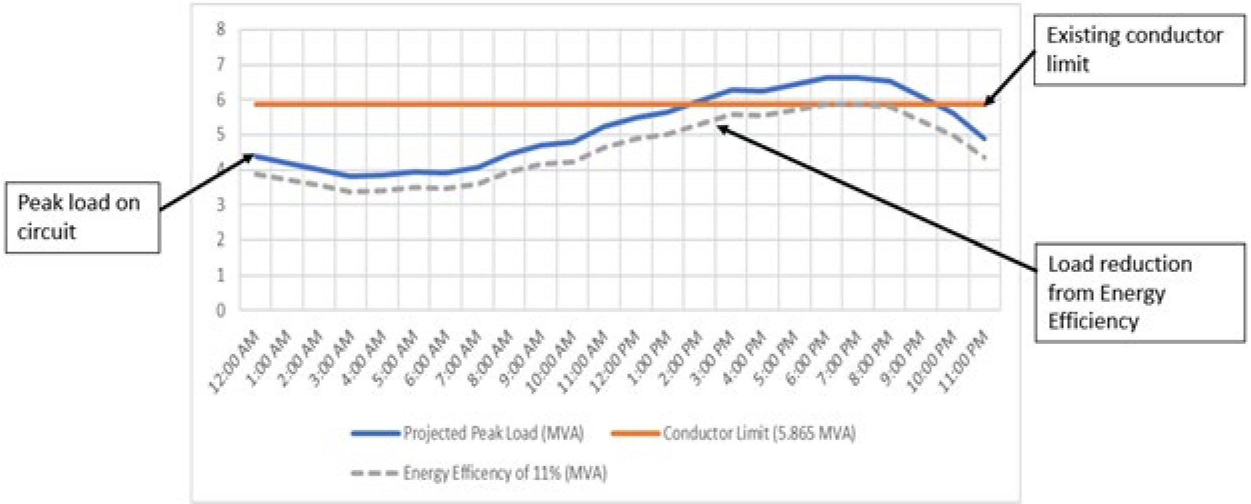


Figure 52: NWS — Targeted Energy Efficiency Concept for Crystal Springs

Energy efficiency impacts are often characterized on a first-year annual energy (kWh) basis. For purposes of assessing energy efficiency as an NWS, PacifiCorp needed to convert energy efficiency annual savings to annual demand reduction (kW) savings. To do this, the Company relied on end-use load shapes to determine the expected average kW impact across the hours where grid need has been identified, i.e., summer months from 3-9 p.m. Each energy efficiency measure has a corresponding load shape assigned to it that can convert annual energy savings to demand savings. Depending on when annual energy savings occur, energy efficiency measures provide varying levels of peak demand reduction. As a result, the assumed mix of installed energy efficiency measures is a key determinant in cost and impacts of an energy efficiency NWS.

To better understand the implications of varying energy efficiency measures on the Crystal Springs circuit, three scenarios were examined, each of which is described below.

Business-as-usual scenario: This scenario examines energy efficiency costs and impacts from a baseline perspective. This scenario assumes that no additional investment or energy efficiency activity occurs beyond ETO's current process. The business-as-usual scenario relies on the base case energy efficiency forecast described in **Section 3.6**. This scenario is important for two reasons: first it addresses whether incremental investment and energy efficiency adoption is necessary, second it provides the basis for calculating the incremental investment since some energy efficiency funding and activity is already occurring in the area.

Accelerated acquisition (typical measure mix): This scenario examines energy efficiency costs and impacts from the perspective of additional investment being used to increase savings with a similar measure mix to business-as-usual operations. This provides a higher-cost and lower-impact perspective to present the worst-case scenario. This is an unlikely scenario since the implementation strategy would target the highest demand reduction energy efficiency measures. However, this scenario is useful to contextualize results for the area.

Accelerated acquisition (targeted measure mix): This scenario examines energy efficiency costs and impacts from the perspective of additional investment being used to increase savings with a measure mix tailored toward the most impactful demand reduction measures. Since the grid need occurs primarily in the summer afternoon and evening hours, measures that target cooling loads are likely to provide the most demand reduction on per kWh basis. This scenario provides an initial assessment of what a highly effective targeted energy efficiency effort might look like under the assumption that one-third of energy savings come from cooling-related measures.

Estimated Costs and Energy Efficiency Impacts

Energy efficiency cost estimates are based primarily on the incremental customer cost of an energy efficiency measure. Incremental measure cost (IMC) is a key concept in the economics of energy efficiency and represents the difference in the cost of a baseline measure compared to the cost of a higher efficiency alternative. Administrative and incentive costs are characteristically a proportion of IMC therefore for planning purposes energy efficiency administrative and incentive costs are a proportion of energy efficiency IMC. To develop cost assumptions for each scenario, PacifiCorp relied on IMC, administrative, and incentive costs used to inform the 2021 conservation potential assessment (CPA) that was conducted by ETO. Administrative costs reflect all costs to administer energy efficiency including marketing, evaluation, and outreach expenditures.

For the accelerated scenarios, administrative costs and incentives are assumed to be 20% higher than typical incentive and administrative costs, because additional investment is needed to achieve the accelerated energy efficiency savings in the area. When evaluating the cost of energy efficiency with traditional utility resources, often the levelized cost of energy is used to create a balanced comparison of resources.

Energy efficiency savings are assumed to persist long enough to defer the grid need within 5 years. It is unclear if energy efficiency adoption would be able to meet a grid need sooner, but for the purposes of this analysis a five-year viewpoint was used. Based on the weighted average measure life[21] assumptions used in ETO's most recent budget, PacifiCorp expects that energy efficiency savings would accumulate and persist beyond five years, and therefore could be expected to be a viable solution to meet the grid need.

[21] Weighted average measure life, means, the average life of the implemented measures weighted by their first year annual savings.

Table 12 summarizes the costs and impacts of energy efficiency for each of the scenarios described above.

Table 12: Estimate Costs and Impacts by Scenario for Energy Efficiency

Scenario	Total Customer Incremental Costs	Total Program Costs (incentives and admin)[22]	UCT Levelized Cost $/kWh	Total MWh	Total kW
Business-as-usual	$490,160	$363,073	$0.037/kWh	1,195	203
Accelerated acquisition (typical measure mix)	$1,809,998	$1,608,850	$0.044/kWh	4,414	750
Accelerated acquisition (targeted measure mix)	$1,206,947	$1,072,817	$0.039/kWh	3,405	750

Cost-Benefit Analysis:

To evaluate each scenario a cost-benefit analysis was performed using the UCT and the TRC test. Each of these tests are required in Oregon to evaluate energy efficiency measures and programs[23] for cost-effectiveness. Each of these tests are described below in Equation 1 and Equation 2 and use inputs in a similar manner to the battery analysis cost-effectiveness tests presented in **Table 9**.

Equation 1: Total Resource Cost Test

$$TRC = \frac{NPV\left((Savings\ x\ Avoided\ Cost) + \ Non - energy\ impacts\right)}{\text{NPV (Incremental Measure Cost + Administrative Costs)}}$$

Equation 2: Utility Cost Test

$$UCT = \frac{NPV\left((Savings\ x\ Avoided\ Cost)\right)}{\text{NPV (Incentives Paid + Adminstrative Costs)}}$$

[22] While total costs represent the costs of all energy efficiency the accelerated scenarios would only incur costs above and beyond the business as usual case as those funds have already been allocated.

[23] Oregon Public Utilities Commission, Docket UM 551. Order UM 95-590 April 6. 1994 "Investigation Conservation" https://apps.puc.state.or.us/edockets/docket.asp?DocketID=4744

Avoided costs are the primary benefit for energy efficiency impacts. To estimate avoided costs impacts, PacifiCorp relied on the most recent approved avoided costs from docket UM 1893.[24] The avoided cost represented utility benefits that go beyond the NWS project, such as avoided energy and risk reduction values. Costs for each scenario were characterized using the values presented in

Table 12. Results for each cost-effectiveness test by scenario are presented in **Table 13.**

Table 13: Preliminary Cost-Effectiveness Results by Test and Scenario

Scenario	Utility Cost Test	Total Resource Cost Test
Business-as-usual	3.1	1.3
Accelerated acquisition (typical measure mix)	2.6	1.2
Accelerated acquisition (targeted measure mix)	3.0	1.4

All scenarios appear to be cost-effective from each perspective. However, the business-as-usual scenario resulted in less-than-sufficient demand reduction to meet the grid need. These results should be considered as a first draft and preliminary; total budgets for a potential pilot have not yet been determined and measure assumptions may have changed since the 2021 CPA. These results also do not examine the potential near-term rate impacts that may occur to fund the NWS. However, energy efficiency represents a relatively low risk and low life-cycle cost NWS worth future exploration.

Pros and Cons Summary:

The advantage of this solution is that it is relatively low risk. Even if it fails to meet the grid need it still provides substantial grid benefits that could warrant the investment. It also offers an opportunity to engage with all customers in the area and provide a solution that is proven to have high customer satisfaction. The impacts and delivery of energy efficiency are well established and have been vetted through evaluation, measurement and verification. Lastly, energy efficiency is truly a "clean" resource with minimal environmental impacts and zero greenhouse gas emissions. Utilizing the PacifiCorp 2021 IRP emissions forecast, the energy savings of approximately 681 MWh per year from targeted energy efficiency would potentially offset a cumulative total of 1785 tons of carbon from 2023 to 2028.

The disadvantage of this approach is that it is unknown whether the energy and demand reduction targets are feasible and attainable. PacifiCorp would need to work with ETO to improve cost

[24] Oregon Public Utilities Commission, Docket UM 1893. "STAFF INVESTIGATION OF METHODOLOGY AND PROCESS OF EE COST-EFFECTIVENESS" https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=20999

estimates and better understand whether these impacts are attainable in such a localized effort. Lessons learned from previous pilots have shown that longer lead times and enhanced up-front planning are critical to success. In this respect, energy efficiency is not a simple turnkey solution. Additionally, energy efficiency impacts are most demonstrable when they have accumulated over longer durations. Therefore, any energy efficiency solution may take longer to be noticeable in SCADA or other data.

5.6 Solution Identification and NWS Analysis Lessons Learned

While conducting DSP solution identification and NWS analysis over the past several months, the PacifiCorp DSP team has distilled several lessons learned. These include:

- There are multiple layers of analysis and evaluation required to confirm NWS viability including: customer makeup on a circuit, specific location of the grid need in relation to loads and DERs, existence of programs that support NWS, local zoning and code restrictions, local environmental conditions, etc. For example, in examining a potential solar + storage solution, Irrigation Districts are nonprofits and cannot take advantage of tax incentives for solar + storage. That customer-level difference can impact the attractiveness of solar and solar + storage as a potential NWS.
    - As a result, the Company is early in its journey to effectively identify the best opportunities for NWS to meet potential grid needs.
    - PacifiCorp will continue to explore and learn through expanded Transitional Study areas, regular outreach and engagement to facilitate learning, and the search for opportunities to combine NWS to meet needs.
- NWS analysis is significantly more involved and time-consuming than traditional wires solution analysis — as an estimate, it is three to four times as labor intensive. Development of screening criteria and a stage-gate process for NWS analysis will help ensure planning resources are used efficiently and effort is focused on the opportunities with the highest likelihood of success.
- NWS evaluation requires substantial support from subject matter experts in demand-side management (DSM) planning and analysis (including cost-effectiveness analysis). Additional resources will be required to allow the DSP team to support this increasing need.
- Many potential NWS require several years of lead time before they can deliver reliable results. The Company must explore methods to extend visibility to potential grid needs to allow time for consideration and implementation of potential NWS.

- There were multiple simplifications employed in the NWS assessments conducted during DSP Part 2. Brief explanations about the simplifications along with initial next steps are outlined below:
    - These initial NWS assessments were focused on a single type of solution at a time (e.g., examined how solar + storage on residential infrastructure could meet the entire grid need). This approach allowed the DSP team to explore the nuances of the assessment required for each type of NWS. However, the Company recognizes that not any one NWS is likely to fully solve a grid need and that more of a portfolio approach (examine multiple NWS in concert) will be required to find more effective solutions. Such analytical evolution is included in the Near-Term Action Plan outlined in **Chapter 6**.
    - Moving NWS from initial assessment into pilot design and potential implementation will require definition of not just technical elements of the potential solution, but thoughtful design and consideration of the program parameters, marketing, recruitment and administration of programs as well as a host of other details. During DSP Part 2, the Company was able to engage with ETO and other partners on a preliminary basis with a focus on the initial technical assessment of the NWS. There is continued work ahead including much more involved collaboration with ETO to properly frame and assess the initial NWS and extend into a potential pilot.

Chapter 6: Near-Term Action Plan

6.1 Readers Guide

This chapter provides details regarding PacifiCorp's Near-Term Action Plan, which provides an overview of the Company's planned activities over the next two to four years. The plan includes the proposed solutions to address grid needs and other investments in the distribution system to meet specific DSP Part 2 requirements.

Initially this chapter reviews the requirements outlined in DSP Guidelines 5.4 for the Near-Term Action Plan.

The next section of this chapter summarizes the plan, including the timeline, costs, relationships to other investments and proposed recovery mechanisms. Then, the Company provides detail on current innovations and pilots being conducted to improve, modernize and/or enhance the grid beyond its current capabilities.

The subsequent section summarizes projected spending for the next two to four years with regards to DSP activities and anticipated cost recovery.

The final section summarizes PacifiCorp's equity efforts thus far.

COVERED IN THIS CHAPTER

Review of the specific requirements outlined in DSP Guidelines Section 5.4 for Near-Term Action Plan.

Outline the Near-Term Action Plan in five sections:

1) Evolution of DSP processes, toolsets and capabilities
2) Projects to address grid needs and other distribution system investments
3) Other investments, current innovations and pilots
4) Projected spending for Near-Term Action Plan and proposed recovery mechanisms
5) Update regarding ongoing equity discussions

DSP Guidelines	Chapter Section
5.4.a	**Section 6.3.1- 2**
5.4.bi	**Section 6.3.4**
5.4.c	**Section 6.3.2**
5.4.d	**Section 6.3.3**

6.2 Near-Term Action Plan Requirements

Section 5.4 Guidelines

Near Term Action Plan

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

Specific requirements include:

a) *Action Plan: Provide a 2–4-year plan consisting of the utility's proposed solutions to address grid needs and other investments in the distribution system.*

b) *Projected spending: Disclose projected system spending to implement the action plan, timeline for improvement, and anticipated requests for a cost recovery mechanism.*

c) *Relation to other investments: As applicable, the Action Plan should identify areas of relation and interaction with other investments such as transmission projects and demand response programs*

d) *Document current innovations and pilots being conducted to improve, modernize, and/or enhance the grid beyond its current capabilities*

Discussed in this Chapter

6.3 Summary of the Near-Term Action Plan

PacifiCorp's Near-Term Action Plan focuses on several key investment areas to evolve DSP processes, toolsets and capabilities as well as specific planned and in-flight projects that address grid needs, support key monitoring and controlling capabilities and eventually support enhanced hosting-capacity analysis capabilities. The Near-Term Action Plan is presented in the following sections.

6.3.1 Evolution of DSP Processes, Toolsets and Capabilities

PacifiCorp intends to leverage the input and lessons learned through DSP Parts 1 and 2 as guidance to invest in the evolution of DSP processes, toolsets and capabilities. The primary elements of these investments are expected to be:

1. DSP analytical projects and pilot evaluations

2. DSP data evaluation and improvement
3. DSP toolset evaluation and implementation
4. DSP process improvements
    - DSP study-focused improvements
    - Coordination and collaboration improvements
5. DSP-specific outreach and engagement (local and statewide)
6. Utility staffing and development

These six key elements are described in the following subsections.

Item 1: DSP Analytical Projects and Pilot Evaluations Many activities included in this category are continuations and extensions of analyses initiated during DSP Parts 1 and 2 that require follow-up and additional focus. The anticipated activities are outlined below with brief explanations:	
Activity/Timeline	**Description**
1A. Continue evaluation of Part 2 NWS Q3/Q4 - 2022	PacifiCorp was able to develop a framework for evaluation of NWS for the Klamath Falls Crystal Springs circuit grid need, but several refinements and continued collaboration with the Farmers Conservation Alliance (FCA), Oregon Solar and Storage Industry Association (OSSIA) and Energy Trust of Oregon (ETO) are required to develop a more robust evaluation. The Company expects to continue and refine the technical and cost-benefit analyses and reach a conclusion about next steps related to a potential pilot. PacifiCorp expects to coordinate with ETO on DSP workstream support needs, data requirements and budget allocations as DSP evolves.
1B. Further Review & Synthesize Recently Completed Studies Q3/Q4 - 2022	In July 2022, the Company received the results from private generation (PG) studies completed by DNV, and electric vehicle (EV) forecasts, completed by Applied Energy Group (AEG), to comply with the Oregon DSP forecasting requirements. PacifiCorp incorporated the results from both studies into the Transitional Study areas (Pendleton and Klamath Falls) and reflected the results in the grid needs assessments; the Company plans to further review and synthesize the results from a statewide perspective. Similar steps will be taken to further synthesize the study results with updates to the most recent energy efficiency forecasts. The DSP team expects to review the two studies for trends and findings to target future evaluations and potential NWS pilot areas.
1C. Evolve NWS Analysis & Valuation 2023	Continue to develop capabilities and establish methods and models for NWS analysis including: layering multiple solutions (wires + non-wires) to meet grid needs, refinement of the cost-benefit analysis to reflect evolving perspectives and emerging approaches for community/equity priorities.

Item 2: DSP Data Evaluation and Improvement As highlighted in several of the lessons learned within this document, the evolution of DSP requires much greater granularity and accessibility of data to support analysis and evaluation. The activities in this category focus first on mapping current data structures, repositories and data flows that support key DSP processes and then identifying and executing improvements to the data structures, systems and data flows to better support DSP into Stage 2 and beyond. Activities are expected to provide inputs to the next category (toolset evaluation and implementation). The anticipated activities are outlined below with brief explanations:	
Activity/Timeline	**Description**
2A: Baseline data requirements and data flow analysis (Q4 2022 – Q2 2023):	Analyze and expand mapping current data structures and data flows, define high-level use cases, develop data requirements to support anticipated needs for analysis and reporting, define key requirements.
2B: Design and implement improvements to data structures, repositories & data flows Phase 1 (Q2 – Q4 2023), Phase 2 (Q2 – Q4 2024)	Based on the requirements established in 2A, implement improvements in a phased and coordinated approach. These efforts will be closely coordinated with toolset evaluation and implementation.

Item 3: DSP Toolset Evaluation and Implementation In concert with the DSP data evaluation and improvement effort, the Company intends to evaluate potential tools or toolsets to support DSP forecasting, analysis and reporting. If the evaluation identifies a suitable tool or toolset, then the effort would move forward to procurement and implementation. In DSP Part 1, PacifiCorp called for implementation of LoadSEER (a specific tool) along with upgrades to the CYME load flow tool to support future DSP analysis. After completing DSP Part 2, the Company still believes that investment in a tool will be critical for the advancement of DSP but plans to revisit the specific needs and further assess what tool best meets those needs now that DSP requirements are more fully understood. For planning purposes, the Company will retain the initial cost estimates associated with previous plans for LoadSEER implementation for the Near-Term Action Plan but may refine plans and forecasts following the assessment phase of this effort. The anticipated activities are outlined below with brief explanations:	
Activity/Timeline	**Description**
3A: Establish requirements for planning/analysis tool evaluation	In parallel with the data assessment in the previous item, define and document the requirements and anticipated use cases. Conduct initial review and evaluation of potential toolsets.

(Q3 2022 – Q1 2023):	
3B: Conduct evaluation and selection process (as needed) (Q1/2 2023)	Based on the requirements established in 3A, move forward to tool evaluation and then potentially to a tool selection process and potential procurement.
3C: Procure selected toolset (Q2/3 2023)	Dependent on the evaluation and successful selection process from 3B, move forward to tool procurement.
3D: Implement toolset and accompanying components Phase 1 (Q3 2023 – Q3 2024), Phase 2 as needed (Q1 2025 – Q2 2026)	Dependent on successful completion of the preceding steps, plan and execute a phased implementation of the selected tool. Timelines are indicative and subject to change.

Item 4: DSP Process Improvements
PacifiCorp expects the activities in these areas to be driven by a focus on continuous improvement throughout the Near-Term Action Plan; the Company anticipates needing a concerted effort to establish the initial set of improvements. The primary focus areas for DSP process improvements are outlined below:

Activity/Timeline	Description
4A: DSP study-focused improvements (ongoing)	These activities are focused on improvements for planning and execution of distribution studies to improve the processes and tools used by field engineers and DSP planning engineers. Specific improvements anticipated during the near-term include forecasting standardization and availability, standardization of criteria for generation studies, revision of the DSP Study Guide and implementation of regular collaboration among field engineers. The Company anticipates a regular schedule for ongoing improvements and information-sharing.
4B: Coordination and collaboration improvements (ongoing)	These activities are focused on collaboration of DSP activities with the broad variety of formal and informal initiatives underway that overlap with DSP's evolution and success. On the more formal end of the spectrum, there are several OPUC-driven initiatives that commonly require engagement and outreach to similar stakeholder groups for different dockets. For example, there are elements of energy equity

	included in this DSP docket as well as the CEP docket and Interconnection docket, each of which have different end objectives but prefer a single approach to stakeholders. On the less formal end of the spectrum, DSP Part 1 and 2 have focused primarily on distribution planning-specific activities, but DSP must be considered in the broader context of Company planning and strategy to bring the value anticipated from the formation of the OPUC DSP initiative. The Company recognizes the need to support internal and external collaboration to ensure that it is leveraging the resources across the various workstreams, teams and dockets.
4C: Identification and engagement in additional Transitional Study areas (Q4 2022 – Q1 2024)	Due to PacifiCorp's varied and dispersed Oregon territory and the need to continue to refine local-level DSP processes, the Company plans to extend the use of the Transitional Study areas. Based on feedback and lessons learned from DSP Part 2, PacifiCorp will target potential Transitional Study areas in the near term with more dynamic growth and PG/EV adoption (as identified in load, EV and PG studies), while still meeting the needs for available SCADA data and timing for cyclical study. Input from review of the EV and PG studies as outlined in Item 1B above will provide insights to guide selection of the next Transitional Study areas.

Item 5: DSP-Specific Outreach and Engagement (local and statewide) There are further details provided in **Chapter 7**: Community Outreach and Engagement Update for the planned DSP outreach and engagement activities. There are two primary focus areas for the DSP-specific outreach and engagement – local engagement and statewide engagement both outlined below.	
Activity/Timeline	**Description**
5A: DSP-specific local engagement (ongoing)	PacifiCorp intends to incorporate local engagement into ongoing DSP to ensure that local concerns, priorities and focus areas are highlighted early in the planning process to influence the forecasts and potential grid needs. As planning continues, PacifiCorp expects that further touch points will be established for review and discussion of findings and next steps. The initial year or two of DSP will function as trials for local engagement — fine-tuning participation for each of the areas, refining the approach and background materials, and coordinating more closely with regional business managers and local stakeholders.
5B: DSP-specific statewide engagement (ongoing)	PacifiCorp has engaged with a broad cross-section of stakeholders throughout the evolution of DSP Parts 1 and 2. While the proposed direction in DSP Part 1 was to form a statewide Community Input Group (CIG) to act as an advisory body for DSP and matters surrounding equity, the Oregon CEP has provided further requirements for such a statewide group. As a result, PacifiCorp will form a Community Benefits and Impacts Advisory Group (CBIAG) to

	focus primarily on equity matters. The DSP team anticipates using the CBIAG for guidance on equity matters and will continue to host public workshops in the same fashion as during development of DSP Parts 1 and 2. The Company expects the session topics to include evolution of DSP processes, updates on current analysis pilots and programs, and progress against this Near-Term Action Plan. The Company anticipates convening stakeholder workshops between two and four times per year depending on the pace of changes in the DSP and regulatory environments.

Item 6: Utility Staffing and Development To properly establish the foundation for DSP going forward, the Company must build its DSP team and capabilities around new requirements and skills. Within the timeline of the Near-Term Action Plan, PacifiCorp intends to build the DSP team in at least two phases with the following key attributes:	
Activity/Timeline	**Description**
6A: Staffing Phase 1 (Q3 2022 – Q3 2023):	Recruit and on-board new DSP team members in the following key areas: A. DSP manager - Lead for DSP efforts, liaison for internal/external collaboration, day-to-day management of DSP activities. B. Data governance and system analyst – Support for data evolution and development and maintenance of DSP/Planning toolsets C. DSP program manager – Develop and manage programs plans to support execution and tracking of all required DSP activities to drive progress and manage milestones such as but not limited to key Near-Term Action Plan deliverables, filings, development of analysis, implementation of new tools, stakeholder engagement sessions and workshops. D. DSP community engagement lead – Drive both statewide and local efforts, refine engagement approach to more closely connect with communities and stakeholders and support evolution of equity conversations.
6B: Staffing Phase 2 (TBD anticipated Q3 2024 – Q1 2025)	Extend and deepen the DSP Team. Anticipate adding DSP team members in the following areas: A. Additional engineers to support centralized analysis for ongoing study efforts B. Additional community engagement support – Plan and execute the expanding number of local, statewide and project-based engagement activities C. Additional resources to support project delivery and implementation based on solutions identified through DSP

6.3.2 Projects to Address Grid Needs and Other Investments in the Distribution System

There are several projects currently in execution to improve the Company's Oregon distribution system, and there are multiple projects in the planning stage. Some of these projects are specific to the DSP action plan, however the majority support other purposes. This section provides a brief overview of the specific DSP grid need projects as well as an overview of other distribution investments.

1. DSP-specific projects: SCADA build-out to Oregon substations and extensible base communications to Oregon substations.

   PacifiCorp's need to have SCADA monitoring and control capabilities at all Oregon substations functions as a critical enabler supporting the shift to a future distribution system. SCADA provides both the control and visibility to effectively operate circuits more efficiently; it provides the data that forms the foundation for any analysis of nontraditional grid solutions.

   These two combined projects are expected to extend SCADA capabilities to all Oregon substations that do not yet have SCADA. The total budget estimate for implementation over the next five years is approximately $12 million: $2.8 million for SCADA-specific installations/configuration and $9 million for required communications installation (to carry 24x7 SCADA data securely to and from the substations) at these remote sites. These investments are included in reliability/upgrade category in the overview of distribution investments **Figure 53**.

2. Placeholder for potential DSP pilot activity:

   During DSP Part 2, PacifiCorp initiated assessment of NWS to meet a specific grid need in Klamath Falls. As outlined in Item 1A of the Action Plan, the Company intends to continue the assessment of the potential NWS to refine the analysis framework and approach for analyzing a specific need. At this point, it is not clear if the identified Klamath Falls grid need will be a viable target for development of a full pilot program. The Company is committed to continuing to identify and work toward piloting NWS in areas where conditions are favorable for adoption. From a budget standpoint, PacifiCorp included $750,000 - $1.0 million for two pilot projects within the Near-Term Action Plan timeframe.

3. Overview of other distribution system investments by category:

   This section outlines the types of investment planned for PacifiCorp's Oregon distribution system over the coming four years. Due to the sensitive and confidential nature of many of these forward-looking estimates, details will not be provided on any of the specific years or categories. Potential investments included in the forward-looking estimates will follow standard practices for rate consideration as the investments move from initial assessment to planning and implementation.

Several large Company projects currently in progress are included in the investment categories, these include:

Willamette River Crossing: This project involves replacement and relocation of existing submarine cables under the Willamette River from the Albina substation, which serves the downtown Portland distribution network system. The existing cables must be removed to allow an EPA environmental remediation project to proceed in the Willamette River near downtown Portland. This project is included under the regulatory/compliance category of the Company's distribution investment categories.

SCADA Build-Out (Companywide): This build-out involves the replacement of existing circuit breaker relays and installation/replacement of communications to the substation to add SCADA data and control. In Oregon, this also includes the installation of equipment to improve DG readiness on circuits. This project is included under the upgrade/reliability category of the Company's distribution investment categories.

Mainline Sectionalizing (Companywide): This project involves distribution upgrades to reduce the total number of customers on a circuit; it improves reliability by installing automatic sectionalizing devices to reduce outage exposure to customers. This project is included under the upgrade/reliability category of the Company's distribution investment categories.

Oregon Wildfire Protection Plan: PacifiCorp's wildfire mitigation planning includes multiple projects to reduce wildfire risk in Oregon. Refer to the Company's 2022 Oregon Wildfire Protection Plan filed December 30, 2021, for a full list of these projects:

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/wildfire-mitigation/OR_2022_Wildfire_Protection_Plan.pdf. Projects included in this plan are under the regulatory/compliance category of the Company's distribution investment categories.

Oregon Energy Storage: This project involves the installation of 2 MW, 6 MWh of utility-scale battery project near Oregon Institute of Technology campus in Klamath Falls, OR to further study community resiliency and grid support applications. This project is included under regulatory/compliance category in the Company's distribution investment categories.

Russellville and Medford Fault Location, Isolation and Service Restoration (FLISR): These projects involve the installation of equipment at the substation and at reclosing devices on the circuit to provide distribution automation. These projects are included under the upgrade/reliability category of the Company's distribution investment categories.

Although these large projects are not a direct result of the DSP process, they will need to be considered when evaluating distribution circuits affected. As described earlier, SCADA load data is critical in determining more granular requirements of grid needs which is necessary for NWS analysis. DSP will be influencing investments in the SCADA build-out to install SCADA on circuits in Oregon that currently do not have it and to improve DG readiness so that this analysis can be performed. Additionally, as the DSP process evolves it is expected that more potential NWS could be implemented on the distribution system similar to the Oregon Energy Storage project or on a smaller scale. As a result of this, it is expected that DSP will influence investment categories in the upgrade/reliability, and system reinforcement categories which are described in detail later in this section.

PacifiCorp expects evolving DSP analysis to influence future investments in these categories. As the Company is just starting DSP, it expects the process improvement activities from Item 4B above to inform future collaboration, assessment, and prioritization of significant distribution system investments.

Figure 53 provides an overview of the categories for distribution level capital investments for PacifiCorp's Oregon service area.

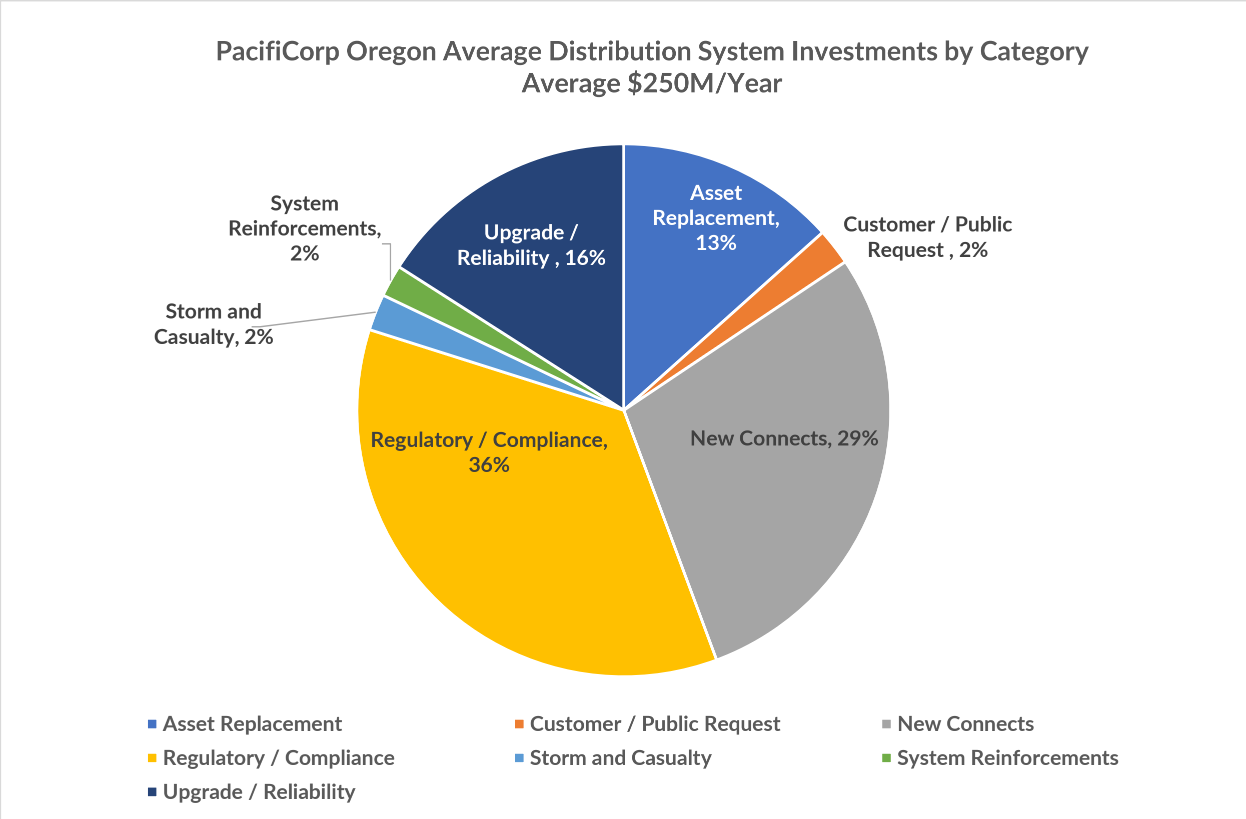


Figure 53: Distribution Investments by Category

Description of the categories below:

Asset Replacement: Replacement of distribution assets including conductors, transformers, meters, etc.

Customer/Public Request: This category is primarily for highway relocations, public accommodations (nongovernment change requests), and joint use.

New Connects: Budget to connect new customers across all customer classes.

Regulatory/Compliance: Investments to comply with regulatory and compliance requirements. The primary segments in this category are wildfire mitigation, undergrounding, code compliance and avian compliance.

Storm and Casualty: Budget estimate for storm damage and external events (e.g., car hits pole, vandalism, animal damage, etc.).

System Reinforcements: Improvements and reinforcements needed to maintain acceptable performance on feeders and substations (distribution portion of substation). *This is the primary category that DSP-identified solutions would directly influence.*

Upgrade/Reliability: Generally, these are larger projects that provide functional upgrades to both transmission and distribution circuits and substations. Reliability improvements identified through centralized analysis (e.g., FIOLI, Enhanced Fault Indication, Saving SAIDI, etc.) are also included in this category. The budget presented is only for distribution. *The budget for Oregon SCADA deployment is included in this category.*

As PacifiCorp gains experience with new DSP capabilities, it expects DSP to influence the selection and prioritization of investments in the distribution system over time.

6.3.3 Other Investments, Current Innovations and Pilots

PacifiCorp is constantly testing new procedures and technologies to better serve its customers and communities. Several of these procedures are already being used to support DSP goals, while other more investigative projects may support DSP in the future. Current innovations and pilots being conducted to improve, modernize and/or enhance the grid beyond its current capabilities are listed below:

- Irrigation Load Control: Agricultural irrigators are eligible for a peak energy reduction program in which they earn incentives by shutting off irrigation pumps during periods of peak demand. This program is being converted from a pilot to a systemwide offering and should be fully operational by 2023.
- Oregon Energy Storage Pilot: The Oregon Energy Storage pilot is a 2 MW, 6 MWh utility-scale battery project under construction near Oregon Institute of Technology campus in Klamath Falls, OR. Once online, the battery will give PacifiCorp the ability study various energy storage applications related to community resiliency and grid support.

- North Santiam Canyon Targeted Energy Efficiency: From July 2017 through December 2018, PacifiCorp worked with ETO to implement a series of targeted energy efficiency measures in the North Santiam Canyon area. The primary objective of this pilot was to develop and evaluate a replicable targeted energy efficiency program capable of rapidly reducing peak demand in targeted feeder circuits through increased marketing of existing ETO incentives. This program showed substantial reductions in peak load and is set for a wider rollout in 2024.
- Oregon Community Solar: The Oregon Community Solar program gives customers the option to receive utility bill credits in exchange for buying or leasing part of a community solar project. This benefits customers who may not have the resources or otherwise opportunity to invest in personal solar projects.
- PacifiCorp Blue Sky: Blue Sky is a Renewable Energy Credit program that allows customers to support renewable energy projects throughout the state of Oregon and the PacifiCorp service territory through a surcharge program. BlueSky Habitat provides the same benefits as the base Blue Sky program and supports restoration and preservation of native fish habitat in Oregon.
- Pumped Storage: PacifiCorp has submitted plans for 13 pumped storage sites throughout its service area, including two sites near Lakeview, Oregon. These pumped storage reservoirs will give PacifiCorp additional flexibility in managing variable energy sources and quickly reacting to emergency grid situations.
- Transportation Electrification:
  - EVs — PacifiCorp offers rebates for installation of Level 2 EV chargers at customer homes or places of business.
  - Electric highway corridors — PacifiCorp is committed to the expansion of the existing electric fast charger network in Oregon transportation corridors through Live Electric, a collaboration with the U.S. Department of Energy, and multiple other state and local organizations. PacifiCorp has also joined with a group of other West Coast utilities to build-out EV charging capacity through the I-5 corridor.
- Time-of-Use Pricing: PacifiCorp now offers time-of-use pricing, which sets lower rates for nonpeak electrical usage. Such pricing plans have the potential to "smooth out" load shapes, lowering peaks and potentially overall energy use

Grid Modernization Program: Grid modernization is the application of advanced technology, communications, and controls to the power system, from generation, through transmission, and distribution to the customer. There are a number of initiatives in flight to support grid modernization, including:

- AMI: — Advanced Metering Infrastructure: Smart meter deployment to over 600,000 PacifiCorp customers to support advanced outage notification and provide detailed data for customers to improve energy decisions. AMI is a foundation for data needed to evolve DSP.
- Smart Devices/SCADA Deployment: PacifiCorp is in the process of deploying a number of digital "smart" devices used for control of analysis of power system conditions. While

traditional SCADA systems make up the bulk of these deployments, PacifiCorp is constantly evaluating new technologies to enhance system capabilities.

- Distribution Automation (DA)/FLISR: DA or fault location, isolation and service restoration (FLISR) functionality advance the "self-healing" that can be delivered by using "smart" devices. DA functionality allows for "self-healing" or intelligently reconfigured network topology to limit the impact of fault events until repairs can be conducted.

PacifiCorp Targeted Reliability Programs: In addition to pilots and new programs and rate structures, PacifiCorp continues to evolve its targeted reliability improvement programs that were outlined in the DSP Part 1 Report (Chapter 1). Brief summaries of the reliability programs are provided below:

- FIOLI: Fuse it Or Lose It: PacifiCorp's fuse coordination program. FIOLI primarily ensures that fuses throughout the PacifiCorp system are appropriately sized to operate in conjunction with each other and with elements of the automated protection system. This allows for more selective isolation of portions of the grid when faced with an outage or interruption. FIOLI is slightly more expansive than its name would suggest and is engaged to deal with more general protection system upgrades such as conductor replacement, vehicle visibility, and animal guarding.
- Saving SAIDI: PacifiCorp's Circuit-hardening program. Saving SAIDI uses the System Average Interruption Duration Index (SAIDI) to identify system issues that are disproportionately responsible for disruptions to power delivery. Once identified, these conditions can be mitigated through replacement of responsible components, or redesign of faulty systems.
- DRIP – Distribution Reliability Improvement Program: DRIP duplicates many of the functions of FIOLI, only with a sharper, more comprehensive focus, allowing PacifiCorp to improve the function of its protection systems in specific subsets of its feeders.
- EFI – Enhanced Fault Indication: Enhanced Fault Indication is a subset of PacifiCorp's wildfire mitigation efforts. Improved detection and location of faults allows PacifiCorp to more swiftly address the underlying causes and apply solutions before dependent problems are created.

6.3.4 Projected Spending for the Near-Term Action Plan and Proposed Recovery Mechanisms

Table 14 below summarizes projected spending for DSP-related projects and activities as outlined in Items 1 through 6 in **Section 6.3.1**. Several cost items are placeholder estimates to recognize areas of significant investment that are uncertain at this time.

Table 14: Projected DSP Costs

DSP Near-Term Action Plan Estimated Costs	One-Time Costs (2022-2026)	Annual Costs (2022-2026)
SCADA Build-Out to Oregon Substations (2022-2026)	$2,754,000	
Extend Base Communications to Substations (2022-2026): Leases Fiber Multiple Address System (MAS)	 $250,000 $8,700,000 $775,000	
Placeholder – Investments to improve DSP data repositories and data flow (Q3 2022-Q3 2025) Consulting, design, and implementation support Hardware and software	 $200,000 - $300,000 $200,000 - $400,000	
Placeholder for DSP toolset acquisition and implementation (Items 3A-3D above) Toolset License (2023-2024) Toolset Implementation Phase 1 (2023-2024) Toolset Implementation Phase 2 (2025-2026, as needed) Integration with in-house tools/other IT projects (2023-2026)	 $2,500,000-$3,500,000 $750,000 - $1,500,000 $500,000 - $1,000,000 $400,000 - $500,000	
Potential NWS Pilot Activities Phase 1 (2023-2025) Phase 2 (2024-2026)	 $750,000 - $1,000,000 $750,000 - $1,000,000	
Extend Pilots for DS/FLISR (4 Years)		$1,500,000
DSP Communications Implementation: Annual Survey Ongoing Engagement Support (Events/Meetings, Facilities, Participant Comp) Develop Collateral and Communication Materials (Education, collateral, etc.)	 $150,000 - $200,000	 $100,000 - $150,000 $150,000 - $200,000
DSP Core Team – Anticipated Activities Support field engineering in transition to new DSP processes Maintain and improve data quality, availability, and modeling Identify and support opportunities for alternative solutions in DSP Perform integrative planning functions and studies Conduct local planning activities Conduct ongoing statewide stakeholder engagement Participate in parallel dockets and proceedings from DSP perspective Champion DSP-related investments through design and implementation Items 1 through 6 of the Action Plan		$2,000,000-$4,500,000
	Total Estimated One-Time Costs (2022-2026) **$18.7 M - $21.8 M**	**Estimated Annual Costs (2022-2026)** **$3.9 M - $6.5 M**
Total Estimated Cost for DSP Near-Term Action Plan (2022-2026) for One-Time and Annual Costs		**$36.7 M - $44.8 M**

Note: Estimated costs in **Table 14** do not include any expenditures to extend hosting capacity analysis (HCA) beyond Option 1 as outlined in DSP Part 1. If future requirements are identified for HCA, the budget will need to be updated to reflect costs associated with the HCA method proposed.

Figure 54 provides a timeline overview for how the improvements outlined above are anticipated to progress through the Near-Term Action Plan horizon.

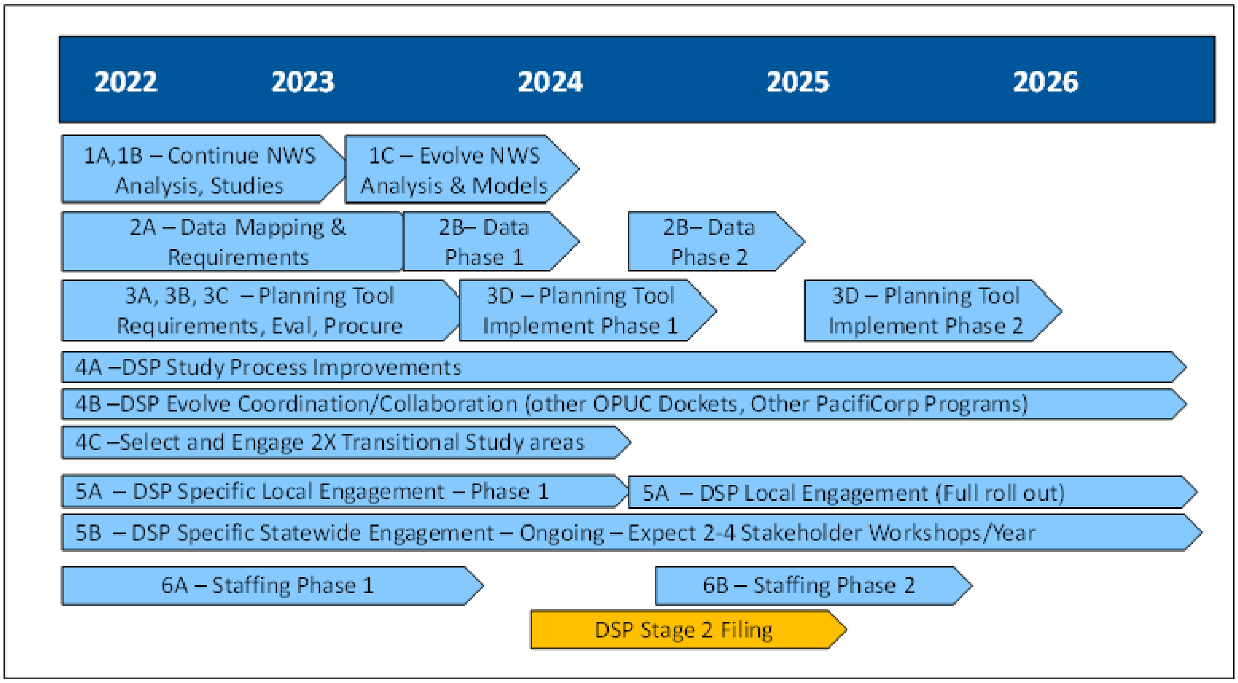


Figure 54: DSP Near-Term Action Plan Timeline

Cost Recovery:

For capital investment items and projects related to DSP (e.g., IT hardware and software, SCADA deployment, potential planning and forecasting toolsets), the Company intends to follow standard practices for review and inclusion in rates through traditional capital project ratemaking (using CWIP and adding to rates in future general rate case proceedings as projects are placed in service).

For incremental DSP O&M costs, the Company intends to continue utilization of a Deferral Account to capture incremental costs until such time as the deferred amounts are included in general rates via general rate case proceedings.

All costs associated with DSP are anticipated to be assigned to PacifiCorp's Oregon service territory.

6.4 Equity Update

PacifiCorp's efforts to achieve a fair, equitable power system in Oregon and the greater Northwest are guided by multiple, concurrent legislative directives (including DSP) shown in **Table 15**. These requirements are being unified into a single umbrella process overseen by the PacifiCorp Equity Advisory Group/Community Benefit Impact Advisory Group (EAG/CBIAG). The EAG/CBIAG was born of a requirement of Oregon's HB 2021, Clean Energy Targets Bill, but will be expanded to meet the needs of other equity efforts to maintain internal consistency. This group will be responsible for implementing an equity policy with effective internal coordination; consistent, comprehensive and granular datasets; and uniform methods to ensure that all areas served by PacifiCorp are treated fairly and appropriately.

Table 15: Equity Related Regulatory Proceedings

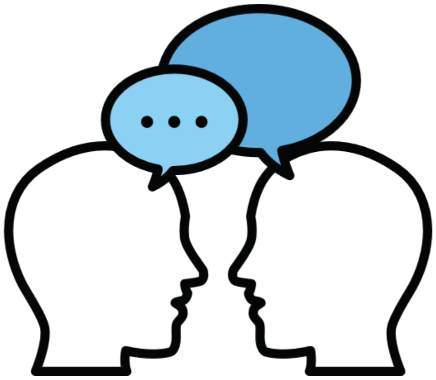
Bill / PUC Docket	Title	When Passed/ Approved	Stakeholder Input Requirements
HB 2021 / UM 2225	Clean Energy Targets Bill	2021	A Community Benefits Impact Advisory Group (CBIAG) will address equity, cost and environmental issues within the scope of utility operations with input from representatives of environmental justice communities, low-income ratepayers and representatives from other affected entities within an electric company's service territory.
UM 2005 / IRP Order Nos. 17-386 and 18-138	Distribution System Planning	2019	Utilities shall consider health, safety and interests of communities in DSP development in an equitable and inclusive manner.
HB2165 / UM 2165 & AR 654	Transportation Electrification Investment Framework	2021	Stakeholders to guide the transportation electrification budget requirements and process, accounting expectations, reporting requirements for expenditures and process for estimating 50% spend on underserved communities.
SB 1536	Emergency Cooling & Heating in Extreme Temperatures	2022	An advisory council — including nonprofit organizations, housing providers, heat pump technicians and other stakeholders as appropriate — will provide feedback on heat pump rebates and grants proposed (deployment program).
HB 4077	Environmental Justice (Task Force) Council	2022	Work groups comprised of regional stakeholders will inform on renewable energy projects and their feasibility.
HB 2475	Equity in Ratemaking	2021	Stakeholders including representatives of EJ communities, will provide feedback on proposed financial assistance programs.
HB 2842	Healthy Homes Program	2021	Stakeholders comprised of those that deploy and support programs to improve home-related health will identify barriers and consult on the Healthy Homes Program.
HB 3141/ UM 1158	Public Purpose Charge Modernization	2021	Stakeholders, including representatives of EJ communities, will provide feedback on action plans gathered through public process.
SB 978	Adapting to the Changing Electricity Sector	2017	A stakeholder group, including underrepresented populations, will be involved in decision-making processes for pilot program designs and evaluation plans through highly participatory stakeholder proceedings.

Before these efforts, PacifiCorp largely used census data for its equity measures, particularly energy burden measures from the Department of Energy's Low Income Affordability Data (LEAD) Tool. This data includes statistics such as proportion of population using rental housing and household income put toward energy use (e.g., energy burden). LEAD data is developed from U.S. Census surveys and as such is correlated to U.S. Census blocks. While this data has been adequate for PacifiCorp's effort to date, greater insight may be gained from more granular datasets. PacifiCorp is evaluating alternative datasets as part of its unified equity efforts.

Chapter 7: Community Outreach and Engagement Update

7.1 Chapter 7: Readers Guide:

This chapter provides updates on PacifiCorp's community and outreach strategy, including progress with PacifiCorp's Community Input Group/Oregon Equity Advisory Group and how the Company expects to engage with communities and stakeholders at the state and local levels as distribution system planning (DSP) evolves.



COVERED IN THIS CHAPTER

Update on Outreach and Engagement since Part 1 filing

Overview - Outreach tools and methods

Review of Engagement Activities and Language update

Brief overview of Stakeholder Survey

Update on evolution of Community Input Group

Overview of local community engagement

Overview of Future DSP specific engagement

Overview of IRP and Project based engagement

DSP Guidelines	Chapter Section
4.3.a.i	**Section 7.2.1**
4.3.a.ii	**Section 7.2 – 7.4**

7.2 Background — Community Engagement

Background on Engagement from Part 1

In Part 1 the guidelines included incorporating stakeholder feedback and identifying opportunities in current DSP to support increased transparency into utility investment, engineering and operational decisions. PacifiCorp outlined in its DSP Part 1 Report a community engagement vision and framework for how stakeholders, including Oregon customers and advisory groups, will contribute to the development of potential DSP pilot programs, and provided a road map for how

PacifiCorp will encourage participation and ensure that relevant information is accessible. Key components of the framework included:

- Outreach
- Language considerations
- A survey of customers across the state on clean energy and planning priorities
- Establishment of a Community Input Group (CIG)

The following sections provide an update to these key engagement strategy components based on the feedback from stakeholders, customers and lessons learned to date.

7.2.1 Outreach Update

PacifiCorp proposed several outreach methods to seek feedback and engage with community members. Several tools were implemented and used by the DSP team. Full descriptions of each tactic and target audiences are available in Chapter 3 of PacifiCorp's DSP Part 1 Report with a status update included in **Table 16**.

Table 16: Communication Tools and Tactics

Tool	Status Update
Public Meetings and Workshops	Complete – conducted five DSP Stakeholder Workshops since filing DSP Part 1 in October 2021. See below for summary of workshops
Local Engagement and Workshops	Conducted initial Local Stakeholder Engagement workshop in Klamath Falls to support NWS analysis and engagement.
Participation in other forums and dockets	DSP team participated in several UM 2225 Clean Energy Plan (CEP) workshops to ensure alignment for engagement Presented DSP background information in PacifiCorp IRP July workshop.
Project email (dsp@pacificorp.com) and web comment form	In use DSP@Pacificorp.com Announcements and DSP website updates are communicated to stakeholders via email.
Project Website: https://www.pacificorp.com/energy/oregon-distribution-system-planning.html	Website updated to include Spanish translation of DSP Part 1 document, feedback form and an NWS form.
Community surveys	Conducted statewide customer and stakeholder survey including more than 4,500 responses, phone surveys and targeted stakeholder interviews. – see **Section 2.5** DSP Stakeholder Survey and Results in **Chapter 2** and below for further details
Project fact sheet and flyers	In development
CIG pre-meeting materials	N/A – see **Section 7.2.4** below
Meeting summaries from CIG	N/A – see **Section 7.2.4** below
Utility bill inserts and messages	Proposed for future use
Social media, paid media	Proposed for future use
Partner channels	Proposed for future use

In addition to the proposal and implementation of these tactics, as set forth in **Table 17**, PacifiCorp conducted the following DSP-specific workshops as part of the DSP Part 2:

Table 17: DSP Part 2 Workshops

PacifiCorp Distribution System Plan Stakeholder Workshops				
October 25, 2021	January 13, 2022	May 11, 2022	June 24, 2022	July 21, 2022
• Overview of DSP Report • DSP Map Viewer • Data Discussion	• Community Engagement • Review plans for MDC Survey	• MDC Survey Results and Interviews • Updated CIG Development Strategy • Pilot Transitional Study areas and grid needs	• DSP Planning Process • Pilot Transitional Study areas and grid needs • Update on community engagement	• Load forecasting • Non-wires solutions • Update on community engagement

PacifiCorp Distribution System Plan - Other Engagement Activities		
July 7, 2022	July 11, 2022	July 14, 2022
Local Engagement – Klamath Falls: • Background on DSP • Community Perspectives and Feedback • Review non-wires solutions • Select second NWS for evaluation	Clean Energy Plan Workshop • Update customer engagement activities • Align engagement strategies between DSP/CEP	PacifiCorp IRP Workshop • Background about OR DSP • Overview of approach to DSP forecast and use of PG/EV studies •

Since completion of the DSP Part 1 filing, PacifiCorp's DSP team also provided information about DSP in workshops supporting other Oregon proceedings such as those referenced in **Section 1.2** – specifically:

- July 11, 2022: Clean Energy Plan workshop – provided customer engagement strategy and active local engagement
- July 14, 2022: Integrated Resource Planning workshop - provided an overview of the Oregon DSP process and background

PacifiCorp anticipates continued near-term overlap and information-sharing related to DSP among several proceedings including, Clean Energy Plan, IRP, transportation electrification (TE) and Interconnection Process and Policy. These proceedings were discussed further in **Section 1.2**.

7.2.2 Language

Accessibility is key to ensuring inclusive public participation. Consistent with the Company's outreach in Oregon, PacifiCorp has worked with a translation service to provide Spanish versions of the Executive Summary from the Company's DSP report, several feedback forms and one-to-one translation of the DSP webpage. PacifiCorp plans to continue translating DSP-related content to Spanish and will work to create an inclusive space and remove barriers.

7.2.3 Survey

As described in **Chapter 2** (**Section 2.5)**, PacifiCorp conducted a statewide survey targeting the Company's Oregon customer base to gather more input on DSP and the transition to a clean energy future. The Company surveyed over 4,600 Oregon customers to better understand the benefits associated with cleaner energy and prioritize customer concerns about energy transition, identify challenges facing communities and individuals, measure awareness of Company communications, and measure satisfaction with the Company's level of outreach and engagement among other topics. Survey participants included residential and business customers, frontline customers and other stakeholders. The study was conducted using online and phone surveys in English and Spanish. The survey was conducted between February 1 and February 28, 2022, with 130 completed phone surveys, 4,497 completed web surveys and 24 interviews conducted with stakeholder groups and CBOs.

A summary of the survey results is attached as **Appendix B.**

The survey was effective at gauging the baseline level of understanding of distribution planning and other processes, as well as the benefits and challenges for moving toward a clean energy future from the perspective of the Company's residential and business customers, frontline customers and service territory wide stakeholders. PacifiCorp anticipates conducting an Oregon-specific survey annually. The objective would be to understand and measure the impact of changes being made DSP and other energy planning efforts across the Company, to identify and improve communication and engagement strategies across the wide range of customers and stakeholders, and to track the benefits and challenges over time. The survey, while initially focused on DSP and the Company's goals toward a cleaner energy future, may be expanded to include other topics and may be modified by feedback provided by the equity advisory group or other stakeholders.

PacifiCorp plans to conduct an Oregon-specific survey annually to:

- UNDERSTAND and MEASURE the impact of changes being made to planning processes
- IDENTIFY and IMPROVE communication and engagement strategies
- TRACK the BENEFITS and CHALLENGES over time

7.2.4 Evolution of the Community Input Group (CIG)

To provide insight into PacifiCorp's preliminary vision on engaging stakeholders in DSP, PacifiCorp proposed the CIG concept in its DSP Part 1 Report. The Company outlined the development of the CIG, its composition and overall purpose, to provide meaningful engagement opportunities for the development of the DSP with stakeholders.

The formation of the CIG as envisioned by DSP was in its early stages when the OPUC launched the UM 2225 investigation into Clean Energy Plans on January 11, 2022, to level set on HB 2021 and coordinate engagement with other requests for customer and community input. Over the following months, PacifiCorp reviewed the timing and intent for community engagement in its energy planning processes. An initial engagement strategy was filed on April 21, 2022, that outlined PacifiCorp's plan to utilize elements of the IRP stakeholder engagement process along with a new Oregon-specific stakeholder group. Following several workshops in May, June and July, on August 4, 2022, PacifiCorp filed its updated CEP Community Engagement Strategy that outlines its plans to directly stand up a utility CBIAG as outlined in Section 6 of HB 2021 in lieu of the CIG. The vision, structure and composition of the CIG and CBIAG are consistent. PacifiCorp believes that it will be more efficient and less burdensome to form one equity advisory group rather than two separate advisory groups that have a similar mission. The Company also recognizes that participation in multiple advisory groups could be a resource burden on CBOs and nontraditional stakeholders and believes that a single group will mitigate that potential burden without impacting effectiveness.

The relationship between stakeholder engagement in each of the planning efforts is illustrated below.

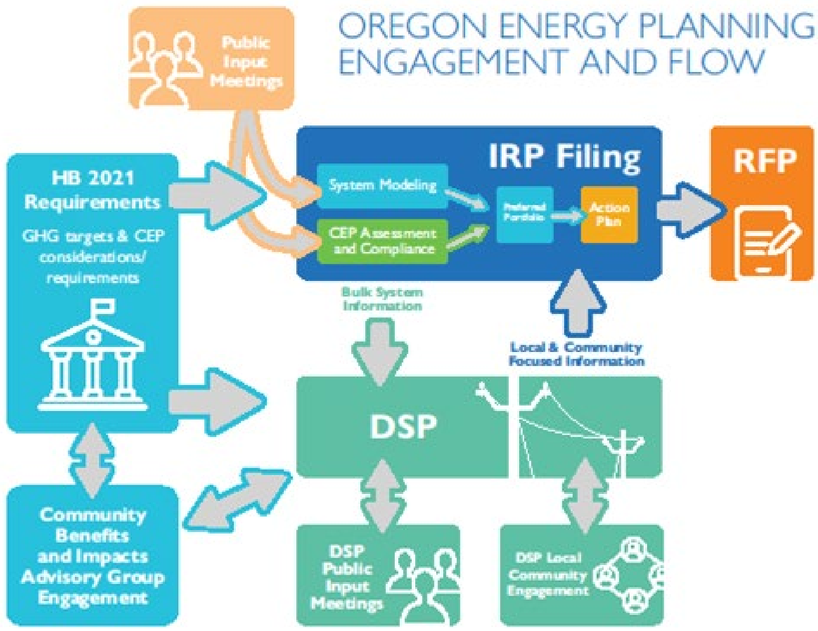


Figure 55: Stakeholder Engagement Relationship for DSP-IRP-CEP

PacifiCorp anticipates that DSP will engage with the CBIAG for input regarding equity matters (e.g., equity metrics for screening, suggested data sources, etc.).

PacifiCorp's DSP team will continue to host DSP-specific workshops (like those convened throughout development of DSP Parts 1 and 2) to address matters beyond the scope of the CBIAG as DSP moves beyond Part 2.

7.3 Local Community Engagement

As a result of the evolution of the CIG and its role in the CEP, as well as feedback from the statewide survey, PacifiCorp prototyped and hosted a local engagement workshop in one of the transitional planning areas, Klamath Falls. The objective of this workshop was to engage with local stakeholders to seek feedback on the NWS options and to seek additional input on several topics covered in the DSP Survey.

On July 7, 2022, PacifiCorp held an in-person meeting in Klamath Falls and invited a diverse group of community members that included representatives from:

- Klamath/Lake Community Action Service – Community Action Organization providing support to families and veterans in need with energy, housing and health resources
- Klamath County Chamber of Commerce
- Klamath Water Users Association
- Agricultural representatives
- Education
- Municipal planning/management/emergency management
- Residential customer from Chiloquin

The meeting included sharing an overview and providing background on PacifiCorp's DSP process, areas and regulatory guidelines. PacifiCorp also shared the grid needs identified in the Klamath Falls area, discussed potential traditional and NWS, solicited feedback on the pilot proposals to perform further evaluation, and received suggestions for improvements to distribution planning and customer/community engagement.

In the end, local stakeholders selected energy efficiency as the second NWS to evaluate alongside solar plus battery storage. In addition, they expressed interest in continued participation in local engagement meetings on DSP-related topics in the future. A summary from the discussion with Klamath Falls stakeholders is included as **Appendix D.**

7.4 Future DSP-Specific Engagement

PacifiCorp anticipates continued engagement with stakeholders on specific DSP-related topics through a series of workshops at the state and local level. The Company realizes that community engagement will evolve as the Company communicates with the stakeholders in its communities—learning more about specific community needs and wants across PacifiCorp's diverse and disparate service territory.

DSP-Specific Workshops

The Company has hosted DSP-specific workshops to provide opportunities for stakeholder engagement, solicit feedback and gain additional understanding of the Company's DSP process; this increases transparency on how the Company plans, invests and implements solutions to issues on its distribution system. In Part 1 and Part 2 the Company hosted DSP-specific workshops to incorporate stakeholder feedback into current planning to identify opportunities for increasing stakeholder engagement and to gather feedback on the Company's DSP process and NWS.

The Company foresees a continuation of DSP-specific workshops after the filing of the Company's DSP Part 2 report. PacifiCorp expects these workshops would be similar in format and participation to workshops that were provided as part of Part 1 and Part 2 and would include updates on topics and proposed activities presented in this report. Additionally, as PacifiCorp's distribution planning process evolves, it will use these workshops to solicit feedback from stakeholders to support its evolution.

DSP-Specific Local/Small Community Workshops

The level of engagement from the Klamath Falls local community workshop provided insight on the local interests and concerns that are invaluable to the distribution planning studies and process. The Company anticipates incorporating similar local/small community workshops in the DSP planning process. PacifiCorp may use its regional business managers, local planning engineers and DSP team to facilitate meetings with individuals, stakeholders and organizations at various points in the DSP process.

The potential DSP Local Stakeholder Engagement Model outlined in **Figure 56** depicts points in the DSP process where local engagement may be beneficial. This model outlines how local engagement might occur. The Company anticipates that outreach and engagement with the local community related to DSP and associated projects may vary depending on the type of project, community preferences and current activities and needs in the DSP process.

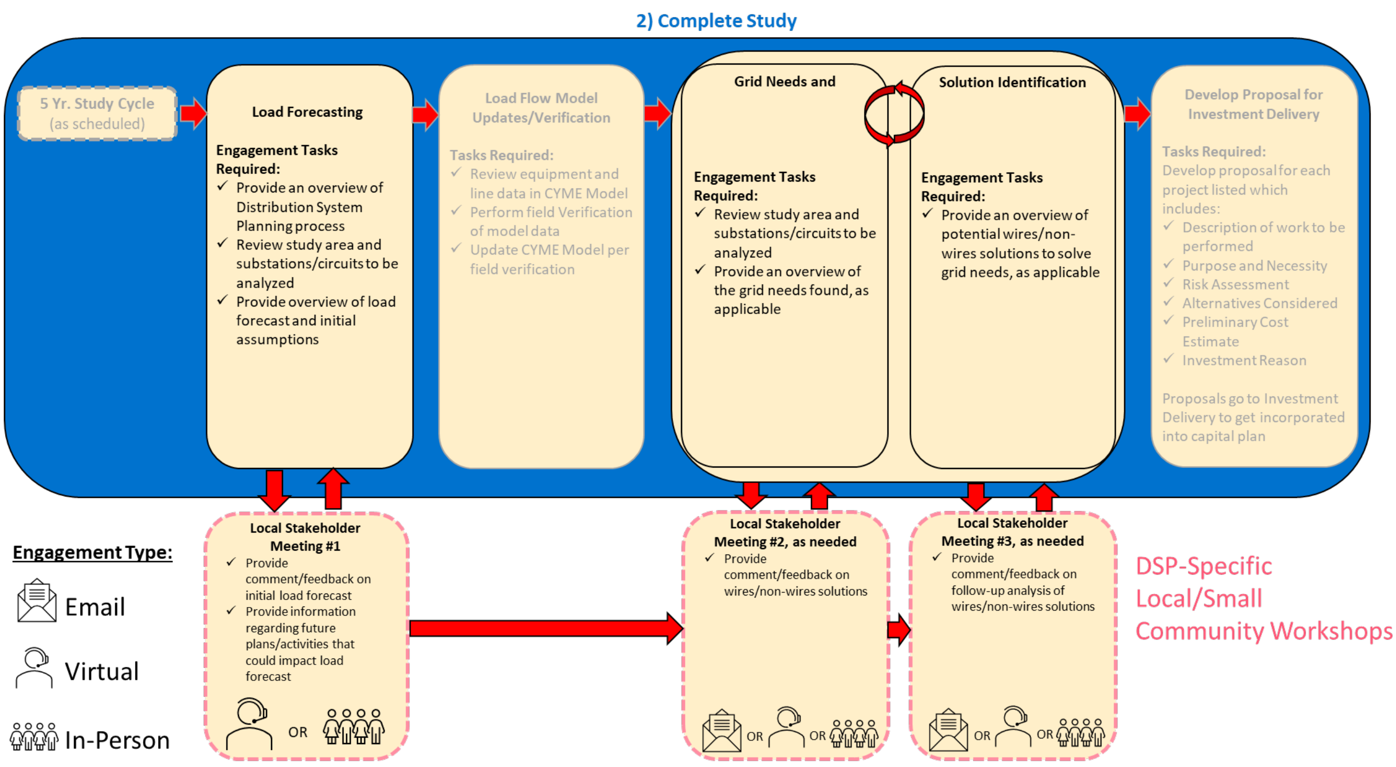


Figure 56: Potential DSP Local Stakeholder Engagement Model

The Company will continue to evaluate the local-level engagement and may adjust the level of engagement to each specific community's preferences, recognizing each community's unique characteristics.

7.5 IRP Workshops

The IRP process includes robust opportunities for stakeholder engagement and feedback through its public input meetings. If DSP-related topics or issues arise, the DSP team will participate in the IRP process, as appropriate. For example, an initial discussion of DSP was included in the IRP public input meeting held on July 14, 2022. As DSP develops, additional discussion will be brought into the IRP public input meeting series including addressing stakeholder feedback when appropriate. A DSP update is tentatively scheduled for the October 13-14 IRP public input meeting.

7.6 Project-Based Community Engagement

Background

PacifiCorp has a long history of engaging its customers and the public before and during large project construction. The amount frequency and type of community engagement and communications varies from project to project and community to community depending on needs and interests. Permit requirements are generally a key driver of communication scope and cadence. As a hypothetical, if the Company is reconstructing and rerouting several line miles of distribution infrastructure that traverses over tribal or federally protected land, the community engagement requirements will be largely dictated by the permitting process. However, the Company does leave space for independent internal assessment of communication needs absent of permit requirements.

Current Process

In addition to adhering to community engagement methods outlined by various permitting processes, PacifiCorp has adopted a broader community engagement internal review activity. This ensures appropriate levels of engagement and feedback loops are established before construction work begins, even if permits do not require public notice or stipulate community engagement. Adopting a "good neighbor first" approach, project managers engage regional business managers and corporate communications early in the planning process to develop appropriate community engagement strategies based on permit requirements and/or potential community impact. This process is iterative and nimble with the goal to incorporate community feedback before and during projects that impact the Company's neighbors.

Chapter 8: Considerations and Conclusion

8.1 Considerations

As outlined in DSP Part 1, the Company faces substantial challenges as it moves ahead with establishing the fully developed DSP process outlined in UM 2005. The challenges include the rapid pace; substantial human, technological and process changes; the need for parallel operations of “as is” and “to be;” and potential conflict or congruence with other important changes. In addition to these changes, DSP requires a manner of engagement with customers, communities and other stakeholders on technical matters that has not previously been undertaken by the Company. As such, foundational systems related to communicating and ensuring proper representation and inclusion of voices will represent a substantial cultural shift for PacifiCorp. Many of these process, technological and human changes will test Company employees,’ customers’ and communities’ ability to acclimate. Providing this space for acclimation is important. Thus, PacifiCorp’s expectations for involvement, for healthy discourse and collaborative solutions that please a wide variety of stakeholders must be managed.

While PacifiCorp is optimistic about the future and long-term potential benefits of DSP, the Company cautions that the envisioned DSP process is unlikely, in the interim, to be the most cost-efficient approach. In the near term, it is not obviously aligned to minimize cost while maximizing access based on simple customer class cost of service models. The evolution of DSP requires acquisition and study of new datasets that takes time and investment. Additionally, the way DSP contemplates engagement will require greater investment in technology, processes and employee and stakeholder resources. Furthermore, the evolution of DSP requires commitment to change management, where multiple process or approaches may need to be managed in the interim. In PacifiCorp’s relatively rural and sparse population, mitigating these cost impacts may be more challenging.

Despite these challenges, the Company is excited and committed to begin this journey.

8.1 Conclusion

As the Company has outlined in this DSP Part 2 report, much work lies ahead to continue evolution of DSP toward future stages, as framed in the DSP Guidelines. The Near-Term Action Plan recognizes the importance of continuous improvement, iterative development and continued stakeholder engagement as key components on the path to these broad, ambitious goals. In addition, successful evolution will require an unprecedented level of collaboration both externally — across multiple regulatory dockets and stakeholders’ competing priorities — and internally across multiple operating areas and planning functions. The Company believes that this DSP Part 2 report and Near-Term Action Plan represent a pragmatic and thoughtful approach to continuing this evolution.

Appendix A: Distribution System Plan Part 2 Guidelines References

5.1	Forecasting of Load Growth, DER Adoption, and EV Adoption	Reference
5.1.a.i-iv	Discussion of current utility processes for distribution system load growth forecasting including: i) Forecasting method and tools used to develop the forecast ii) Forecasting time horizon(s) iii) Data sources used to inform the forecast iv) Locational granularity of the load forecast	**Section 2.3.2**
5.1.b.i-iv	Forecast of DER adoption and EV adoption by substation: i) The forecast should include high/medium/low scenarios for both DER adoption and EV adoption ii) A utility should fully describe its methodologies for developing the DER forecast, EV forecast, high/medium/low scenarios, and geographical allocation in its plan (for example methods and tools, time horizons, data sources). iii) For the initial plan, the methodology for geographical allocation (to the substation) is at the utility's discretion. The Commission may provide direction for subsequent Plans. iv) A utility may consider leveraging information such as: historical utility program trends, historical customer adoption trends, data from Energy Trust of Oregon, data from transportation electrification (TE) plans and pilots, or studies on DER technical and economic potential used in other dockets. Utilities should use the most recent data available	**Section 3.4-3.8**
5.1.c	Results of forecasting load growth, DER adoption, and EV adoption: i) Document existing and anticipated constraints on the distribution system	**Section 3.8**

5.2	Grid Needs Identification	Reference
5.2.a	Document the process used to assess grid adequacy and identify needs.	**Sections 2.3.2 & 4.3-4.4**

5.2	Grid Needs Identification	Reference
5.2.b-c	b) Discuss criteria used to assess reliability and risk, and methods and modeling tools used to identify needs.	Sections 2.3.3 & 4.3-4.4
5.2.c	Present a summary of prioritized grid constraints publicly, including criteria used for prioritization.	Sections 2.3.4 & 4.3
5.2.d	Provide a timeline by which the grid need(s) must be resolved to avoid potential adverse impacts.	Sections 2.3.4 & 4.6

5.3	Solution Identification	Reference
5.3.a	Document the process to identify the range of possible solutions to address priority grid needs.	Sections 2.3.2 & 5.3
5.3.b	For each identified Grid Need provide a summary and description of data used for distribution system investment decisions including: discussion of the proposed and various alternative solutions considered, a detailed accounting of the relative costs and benefits of the chosen and alternative solutions, feeder-level details (such as customer types on the feeder; loading information), DER forecasts and EV adoption rates.	Sections 5.4-5.5
5.3.c	For larger projects (this may exclude, for example, regular maintenance projects, or inspection projects), engage with impacted communities early in solution identification. Facilitate discussion of proposed investments that allow for mutual understanding of the value and risks associated with resource investment options.	Sections 2.3.2 & 7.6
5.3.d	Evaluate at least two pilot concept proposals in which non-wire solutions would be used in the place of traditional utility infrastructure investment. The purpose of these pilots is to gain experience and insight into the evaluation of non-wire solutions to address priority issues such as the need for new capacity to serve local load growth, power quality improvements in underserved communities. These pilots will prepare utilities to achieve the goals listed in Stages 2 and 3 of **Figure 6**. In its pilot concept proposals, a utility should discuss the grid need(s) addressed, various alternative solutions considered, and provide detailed accounting of the relative costs and benefits of the chosen and alternative solutions. The pilot concept proposals should be reasonable and meet the guidelines, even if the individual proposal may not be cost-	Section 5.5

5.3	Solution Identification	Reference
	effective.	
5.3.d.i-iv	i) Community interest in clean energy planning and projects ii) Community energy needs and desires iii) Community barriers to clean energy needs, desires, and opportunities iv) Energy burden within the community	Section 2.5
5.3.d.v	Community demographics	Section 2.5 & 4.5-6
5.3.d.vi	Any carbon reductions resulting from implementing a non-wires solution rather than providing electricity from the grid's incumbent generation mix	Section 5.5

5.4	Overarching Requirement – Near-Term Plan	Reference
5.4.a	Action Plan: Provide a 2-4 year plan consisting of the utility's proposed solutions to address grid needs and other investments in the distribution system	Section 6.3.1
5.4.b	Projected spending: Disclose projected system spending to implement the action plan, timeline for improvement, and anticipated requests for a cost recovery mechanism	Section 6.3.4
5.4.c	Relation to other investments: As applicable, the Action Plan should identify areas of relation and interaction with other investments such as transmission projects and demand response programs	Section 6.3.2
5.4.d	Document current innovations and pilots being conducted to improve, modernize, and/or enhance the grid beyond its current capabilities	Section 6.3.3

Appendix B: PacifiCorp Clean Energy Research for Distribution System Planning

Oregon Clean Energy Research for Distribution System Planning

June 2022

Conducted by MDC Research

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Research Objectives

The overall objectives of this research were to prioritize the benefits associated with cleaner energy, understand the concerns, and obtain high-level stakeholder feedback. Specific objectives include:

- Identify challenges facing the community and individuals
- Prioritize the benefits associated with clean energy
- Understand concerns associated with moving to clean energy
- Measure awareness of communications from Pacific Power and understand recall of specific messages
- Identify communication channels
- Evaluate the clarity and efficacy of communications from Pacific Power
- Measure satisfaction with Pacific Power's outreach and engagement about plans for cleaner energy
- Understand stakeholders' perceptions about Distribution System Planning, their informational needs, and best practices for engagement
- Identify non-traditional stakeholder groups that should be part of the process, and understand how they can provide insight into energy equity goals

Methodology

To achieve a broadly representative view of Pacific Power's customer base in Oregon, this research was conducted using a mix of online and phone surveys and remote in-depth interviews with stakeholders.

Online surveys provide a cost-effective method of achieving a large sample size and are representative of customers who have provided their email address to Pacific Power (e.g., those enrolled in paperless billing, etc.). This group tends to be a little more affluent, more likely to speak English, and less likely to be a member of a frontline community. Phone interviews were incorporated to provide an inclusive platform to gather feedback from those less likely to have an email address on file or respond to an online survey request.

Target Audience:

- Pacific Power residential and business customers in Oregon
- Pacific Power frontline customers
- Stakeholders

A total of 4,627 surveys, including 30 from frontline customers, were completed between February 1 and February 28, 2022. Online and phone surveys were available to customers in English and Spanish.

- Phone: 130 completed surveys
- Web: 4,497 completed surveys

Twenty-four in-depth interviews were conducted with a variety of stakeholders across the Pacific Power territory.

- 8 Energy Consultants
- 6 Municipalities/Government Entities
- 4 Community-Based Organizations
- 4 Economic Development Organizations
- 2 Tribal Agencies

Interviews lasted 45-60 minutes and were conducted using Microsoft Teams.

- Participants were paid $100 as a "thank you" for their time and feedback
- All interviews were recorded
- Interviews were scheduled using a "warm handoff" from Pacific Power

Key Findings

Distribution System Planning and Clean Energy Benefits and Concerns

Top challenges facing the community are affordable housing and high cost of living. Primary challenges faced by individuals are high cost of living, climate change, and healthcare.

Those in Portland are more likely to be concerned about homelessness, affordable housing, climate change, pollution, healthcare, and education.

Those in Northeast Oregon and Willamette Valley South are more likely to mention access to jobs.

The most important benefits to a cleaner energy future are reducing the impact of climate change, preparation for natural disasters, decreased reliance on fossil fuels, spending less on energy bills, and reducing the environmental impact of the electric system.

Those in Portland are more likely to consider the impacts of climate change and environmental issues as highly important.

Those in other regions are more likely to find personal and economic benefits more important.

The costs and potential bill increases are the primary concern with the transition to cleaner energy, with dependability of renewable sources and the potential impact of materials required for clean energy technology also concerning to more than half. Customers outside Portland and Hood River are more likely to express concerns about the transition to cleaner energy.

When looking at the specific values and benefits of cleaner energy, the environment and energy security are top priorities. When asking for the most desired benefits and concerns open-ended, lower cost was the most desired benefit and high cost was the most common concern.

Communications

Seven in ten recall receiving communications from Pacific Power in the past year, with two thirds mentioning an email.

Bill messages and the Pacific Power website are the next most common sources, each mentioned by one third of customers.

Nearly all recall seeing messages in English, with 7% also seeing Spanish. All other languages combined are mentioned by less than 1% of customers.

The most commonly recalled messages are related to paperless billing, outage notifications or alerts, and Blue Sky enrollment.

Messages through all channels from Pacific Power are generally considered clear, although messages in Spanish are less clear than in English (apart from messages through local organizations or community centers).

Text messages, phone calls, the Pacific Power website, and local organizations or community centers are most useful; less than half find messages useful from direct mail, radio, friends/family/co-workers, or newspapers.

Satisfaction with outreach and engagement from Pacific Power is moderate regarding issues related to conserving energy, saving money, planning for the future, and renewable energy, with nearly half being "somewhat satisfied" with all attributes evaluated.

Recommendations

Educate customers about the plans to move toward a cleaner and more equitable energy grid. Explain the rationale, planning process, and steps to be taken in clear and concise language.

Focus on Distribution System Planning education on the key desired benefits of the move toward a cleaner and more equitable energy grid: reducing the impact of climate change, preparation for natural disasters, decreased reliance on fossil fuels, spending less on energy bills, and reducing the environmental impact of the electric system.

It will be necessary to address the primary concern about Distribution System Planning: the cost of the transition and the potential impact on electric bills. This aligns with one of the primary concerns both personally and for the community: high cost of living. While customers across the state, and particularly those in Portland, broadly recognize the environmental/climate change and resiliency benefits, it will be necessary to alleviate concerns about how it will impact their monthly budget.

The focus on transitioning to an "equitable" energy grid will require explanation. Even among stakeholders, this concept is not universally understood in the same manner, and it raises questions about what it means, how it could be done, and how much it will cost.

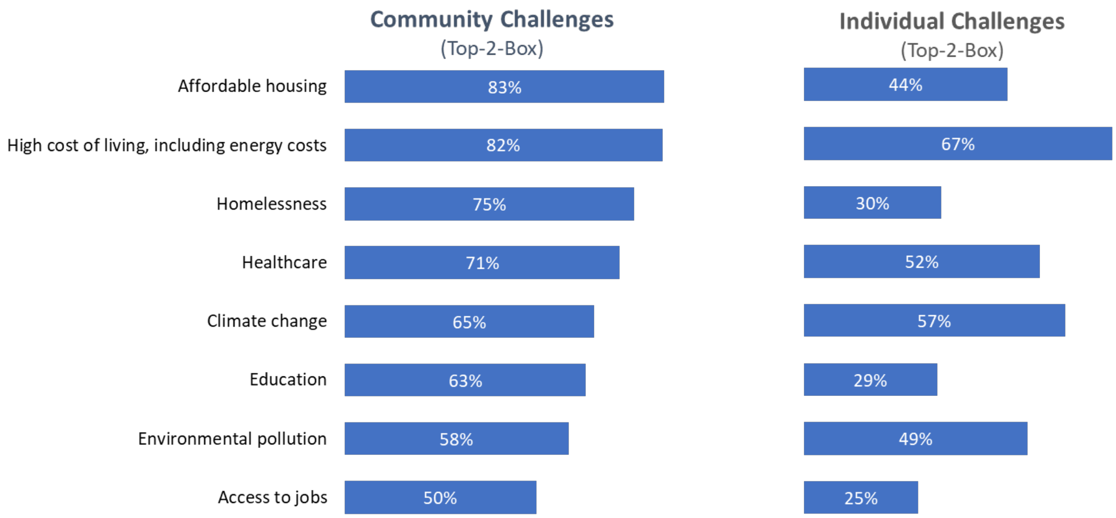
Utilize a mix of communication strategies. While email is the most common by far, it is important to reach customers through a variety of means to provide access to all. Consider the Pacific Power website, direct mailings, and bill inserts (possibly directing customers to the website). While not widely utilized, local organizations and communities are perceived to provide very clear and useful information, and they could be a strong ally in achieving the equity portion of the distribution system planning goal.

- Based on conversations with stakeholders, focusing communications on the impact of climate change, rather than climate change itself, is more likely to resonate with all customers across the state.
- Regardless of views, all communities are impacted by the risk of wildfires and/or drought, and efforts to mitigate those tangible concerns are more likely to be embraced.

Individual & Community Challenges

When asked about challenges faced by their respective communities, respondents most commonly mention affordable housing, high cost of living, and homelessness.

While the percentage rating each challenge as significant on a personal level than community level, the top personal challenges are high cost of living, climate change, and healthcare.



Affordable housing and high cost of living are consistent concerns across regions, but perceptions of other challenges currently facing the community vary across the state.

Those in Portland are more likely to cite homelessness, affordable housing, climate change, environmental pollution, healthcare, and education.

Customers in Northeast Oregon and Willamette Valley South are more likely to mention access to jobs.

% Mentioning as Significant Community Challenge	Total (n=4,627)	Central Oregon (n=672)	Hood River (n=59)	North Coast (n=164)	Northeast Oregon (n=146)	Portland (n=783)	Southern Oregon (n=1,227)	Willamette Valley N. (n=1,066)	Willamette Valley S. (n=480)
Affordable housing	83%	86%	92%	80%	82%	90%	79%	82%	76%
High cost of living, including energy costs	82%	84%	85%	77%	84%	84%	83%	81%	79%
Homelessness	75%	77%	59%	82%	46%	93%	73%	69%	72%
Healthcare	71%	67%	73%	70%	62%	77%	70%	72%	74%
Climate change	65%	69%	83%	65%	44%	86%	58%	62%	52%
Education	63%	57%	46%	54%	62%	67%	65%	62%	63%
Environmental pollution	58%	53%	56%	57%	42%	78%	55%	56%	49%
Access to jobs	50%	44%	42%	52%	59%	46%	51%	49%	58%

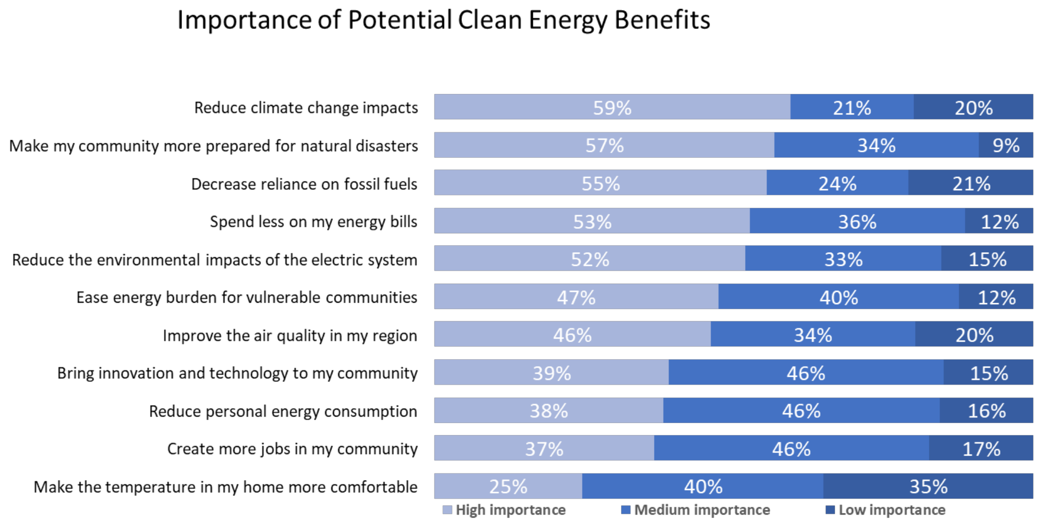
Higher than average across all regions

Lower than average across all regions

Importance of Potential Clean Energy Benefits

The most important benefits of transitioning to cleaner energy are reducing the impact of climate change, preparation for natural disasters, decreased reliance on fossil fuels, spending less on energy bills, and reducing the environmental impact of the electric system. Making the temperature inside the home more comfortable is least important.

Female respondents and renters are more likely than males and homeowners to find all potential benefits highly important.



The perceived importance of various benefits for transitioning to cleaner energy varies by region. Those in Portland are more likely to consider climate change and environmental impacts highly important, while those in other regions are more likely to find personal and economic benefits highly important.

% Considering Highly Important	Total (n=4,627)	Central Oregon (n=672)	Hood River (n=59)	North Coast (n=164)	Northeast Oregon (n=146)	Portland (n=783)	Southern Oregon (n=1,227)	Willamette Valley N. (n=1,066)	Willamette Valley S. (n=480)
Reduce climate change impacts	59%	64%	75%	58%	42%	80%	52%	59%	45%
Make my community more prepared for natural disasters	57%	50%	68%	62%	44%	60%	59%	57%	53%
Decrease reliance on fossil fuels	55%	60%	71%	55%	36%	79%	45%	56%	41%
Spend less on my energy bills	53%	51%	32%	45%	61%	38%	59%	53%	63%
Reduce the environmental impacts of the electric system	52%	55%	66%	43%	36%	69%	46%	52%	41%
Ease energy burden for vulnerable communities	47%	45%	42%	48%	45%	56%	44%	46%	47%
Improve the air quality in my region	46%	44%	44%	24%	31%	63%	52%	41%	31%
Bring innovation and technology to my community	39%	40%	31%	41%	38%	36%	40%	37%	44%
Reduce personal energy consumption	38%	40%	39%	32%	34%	40%	39%	38%	35%
Create more jobs in my community	37%	29%	32%	35%	53%	31%	39%	34%	51%
Make the temperature in my home more comfortable	25%	21%	15%	20%	32%	19%	28%	26%	28%

Higher than average across all regions
Lower than average across all regions

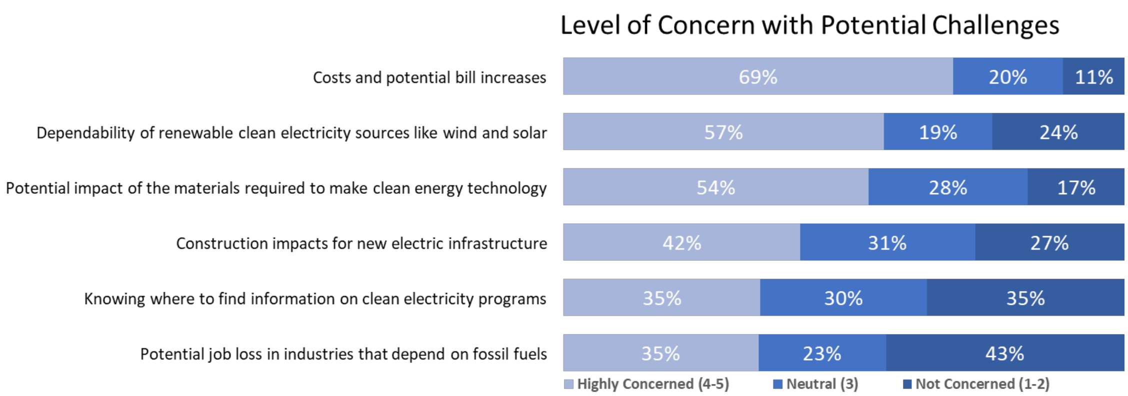
Potential Challenges with Transition to Cleaner Energy

The costs and potential bill increases are the biggest concerns customers have about the transition to cleaner energy, with two thirds highly concerned.

More than half are concerned with the dependability of renewable clean energy sources and the potential impact of materials required to make clean energy technology.

The following groups of customers have higher levels of concern with the potential challenges evaluated:

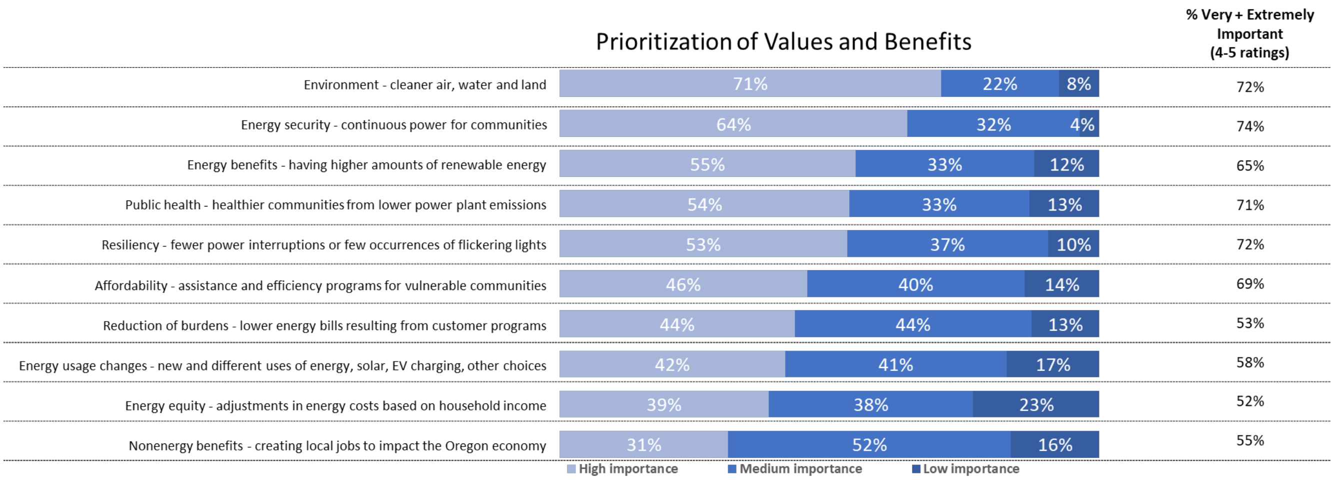
- Those with medical needs
- Those with English not as their primary language
- Female customers
- Customers age 45+
- Education level lower than Bachelor's Degree
- Non-white customers
- Customers outside of Portland and Hood River



Importance of Values and Benefits of Cleaner Energy Future

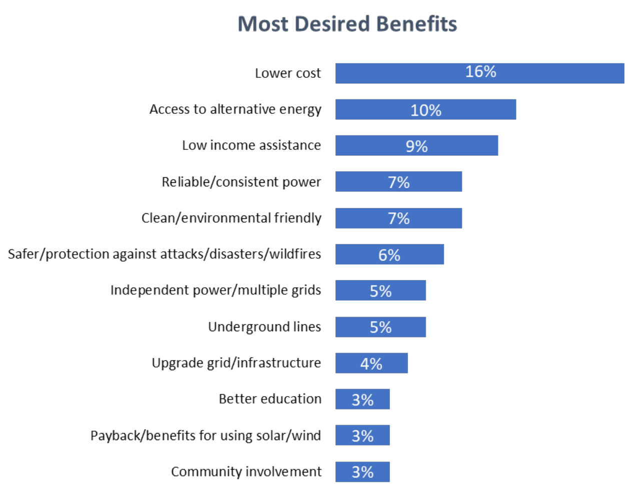
While all are considered important, the top priority values and benefits revolve around the environment (cleaner air, water and land) and energy security (ensuring continuous power to communities).

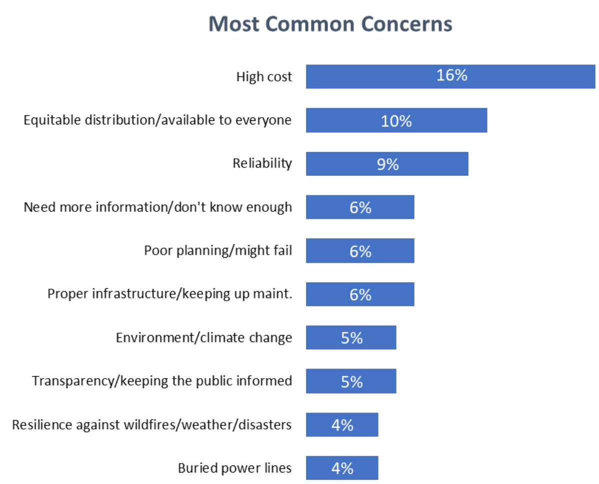
Female, younger respondents, renters, and those with lower incomes tend to place higher importance on most of the tested values and benefits.



Distribution System Planning Unaided Benefits and Concerns

The most desired benefit from distribution system planning is a reduction of cost, which also aligns with respondents' most common concern—high costs.

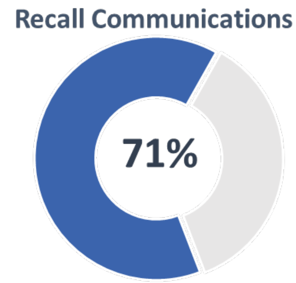




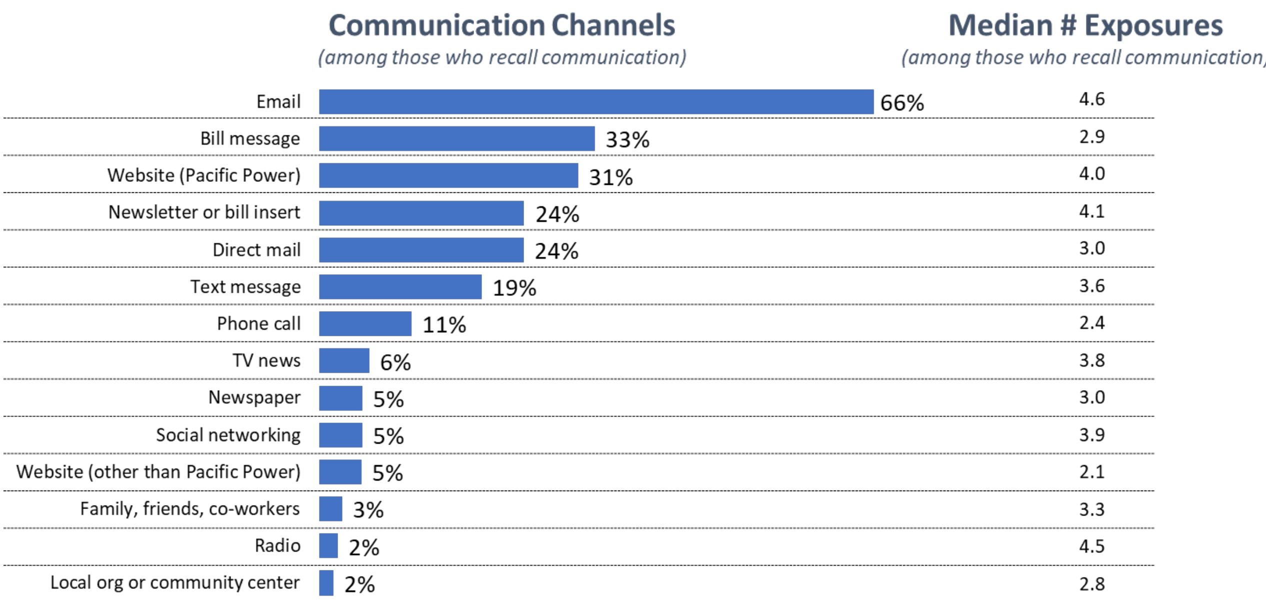
Pacific Power Communications

Seven in ten Pacific Power customers indicated that they have seen or heard a communication from their utility within the past year.

Of those recalling communications, nearly all report seeing messages in English and 7% reported seeing information in Spanish. Fewer than 1% mentioned seeing communications in any other language.

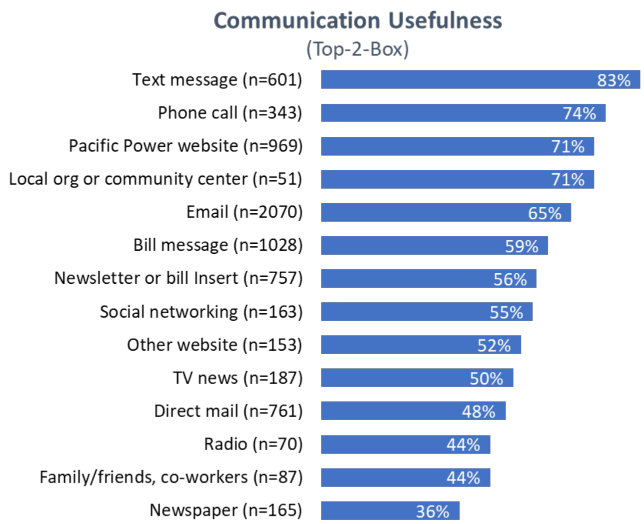


Email is the most common communication channel, mentioned by two thirds of customers. The median number of emails received is 4.6.

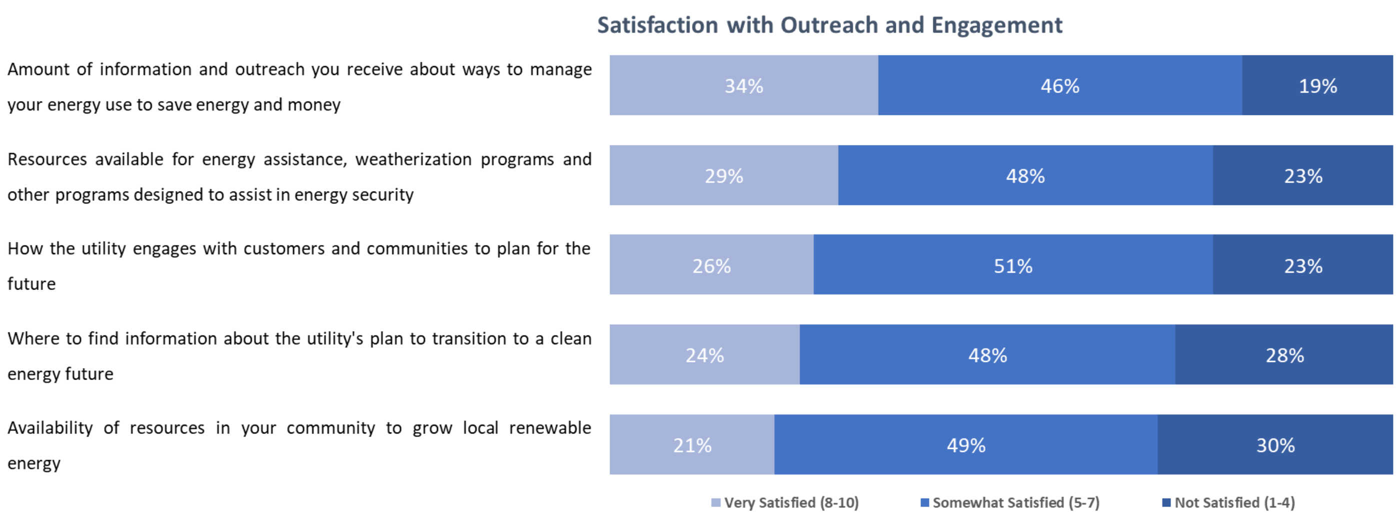


Text messages are considered most useful, followed by phone calls, the Pacific Power website, and local organizations or community centers.

Less than half find information via direct mail, radio, friends/family, co-workers, and the newspaper to be useful.



Customers are moderately satisfied with the types of outreach and engagement evaluated, with nearly half being “somewhat satisfied” (5-7 ratings).



Stakeholder Interviews

Challenges Facing Community

While each organization has their own perspective (e.g., economic development groups more concerned with economic issues, etc.), common themes emerge around climate change (or the effects of climate change, such as fires or drought), housing costs, workforce participation, and the need for adequate, reliable, and resilient energy resources.

Some based in Southern or Central Oregon mention the impacts of climate change, noting that using the term "climate change" could be considered political and counter productive. There is near universal agreement that wildfires and drought are becoming increasingly problematic throughout Oregon and the West.

Energy	**Social Justice**	**Economic**	**Environmental**
Infrastructure for small towns/rural communities Transitioning to clean energy (logistics, benefits, costs) Reliability of power grid Resilience of power grid in response to natural disasters (fire/earthquake) High or increasing energy costs	Lack of affordable housing Homelessness Wealth inequality Environmental justice Inequality of energy resources COVID and impact	Workforce availability Employment opportunities; workforce training Limited land or resources to support development Adequate electricity capacity to support development Development efforts to create/bring jobs	Climate change Wildfire risk and mitigation Drought and water resources Clean air and water

Awareness of Plans for Cleaner and more Equitable Grid

Awareness and understanding of efforts within Oregon to move to a cleaner and more equitable energy grid vary drastically across different groups of stakeholders.

- Those involved in the energy industry (consultants, advocacy organizations, etc.) are highly knowledgeable and tend to be plugged into Distribution System Planning discussions with regulators and utilities.
- Others are generally aware that the state is moving in that direction and may be aware of the long-term plans to phase carbon emissions but are not familiar with Distribution System Planning or any details about the planning.

Highly Aware	**Generally Aware**	**Not Aware**
Energy consultants, advocacy organizations or those involved in energy planning for municipalities Aware of legislation, with some specifically citing HB2021 Tend to be involved in discussions about Distribution System Planning and have a vested interest in having their voices heard during planning Looking for increased transparency and technical details about Distribution System Planning and resource planning	Municipalities, CBOs, economic development organizations Broadly know about plans to phase out carbon emissions over specific timeline (without detailed knowledge of the milestones) Generally support the concept, but may have questions/concerns about the implementation or how it will affect their responsibilities or community Want more information about the process at a simple level: what are the plans, how will we get there, what will be the impact	Municipalities, CBOs, economic development organizations Aware of general trend to reduce carbon emissions but not aware of any details Don’t know enough to have opinions about the concept, but most are onboard with reducing carbon emissions and reliance on fossil fuels Want very basic information about the objectives and how it will affect the community, including the associated costs and potential benefits other than decarbonization

Benefits of Cleaner and more Equitable Grid

While most agree that the primary benefits are reduced carbon emissions and mitigating the impact of climate change, resiliency and economic benefits are commonly cited.

- Resiliency benefits are primarily related to the ability to more quickly restore power after a natural disaster, but also backfill energy needs for underserved communities where the current energy supply does not meet the needs for current demand, additional development, or power quality standards.
- The primary economic benefits are having a competitive advantage over other places with less clean energy (attracting new businesses to the area) and providing opportunities for communities with energy constraints to add infrastructure and development.

Climate Benefits	Resiliency Benefits	Economic Benefits
Reduce carbon emissions Mitigate risk of wildfires and/or drought Doing our part to mitigate climate change	Potential for alternative sources (wind, solar, battery) to make the grid more resilient in the event of a natural disaster such as a wildfire or earthquake Opportunity for the grid to remain functional in the event of an outage outside the immediate area (e.g., not be affected if outage is "upstream") Distribution System Planning process has the opportunity to shore up energy delivery to places with limited resources (specifically mentioned at the coast and small towns where outages and power quality are current issues)	Ability to attract businesses due to offering 100% clean energy (competitive advantage over other places) Re-imagined grid could provide development opportunities to places with limited electrical infrastructure, bringing jobs and opportunities to coastal and rural areas in the state Construction/engineering jobs created during buildout of new grid Long-term jobs created to manage and maintain systems Despite initial investment, expectation that energy costs could be reduced over time

Meaning of "Equitable" Energy Grid

The concept of a more equitable energy grid is universally appealing, but there is not a consensus about what that means or how it can be done. The general consensus is that equitable in this context means access to energy, affordable energy, and the opportunity to support frontline communities that have historically been disadvantaged.

- Providing all communities with access to adequate energy resources is the most common interpretation, as those in coastal or rural areas feel they are at the "end of the line" and are the communities who experience issues with reliability or power quality, and without the ability to build energy projects or the capacity for increased development.
- Another common interpretation is that the planning processes need to ensure that energy remains affordable for all, although there is not consensus on how to achieve that goal. Tiered rates and long-term cost reductions associated with efficiency and renewables are the most commonly cited.

Access to Energy for All	Affordability	Supporting Frontline Communities
All communities have access to the electricity they need to manage their household, business, or economic development for the community This is generally considered to mean building out the infrastructure to coastal, tribal, and rural communities, so they have adequate capacity and power quality required Some interpreted this to mean that electrical grid planning should ensure all individuals living in more remote areas have access to electricity	Ensuring that energy costs are not a burden for those with the least ability to pay The planning process should ensure that energy efficiency measures are taken so that low-income households can benefit from advances in efficiency, and are not left paying more due to their lack of resources Some mention evaluating tiered rates in order to spread the cost of infrastructure more equitably A few perceive that Investor-Owned Utilities and shareholders should bear the cost for infrastructure rather than passing it on to ratepayers	Distribution System Planning is an opportunity to invest in historically disadvantaged communities, including tribal groups, and communities or neighborhoods that are predominantly low-income or people of color Additional energy infrastructure in these areas has the potential to boost economic development and employment prospects Investment also has the potential to bring the long-term cost savings associated with renewable energy to those who currently do not have resources to benefit from the technology

Concerns About Transition

The cost of transitioning to a cleaner and more equitable energy grid is the biggest concern. Other concerns are around transparency, incorporating community feedback, and the technical aspects of how to achieve cleaner energy while keeping it affordable for ratepayers.

- Those involved in economic development, public planning, and ratepayer advocacy are more likely to mention questions or concerns about the cost, and the impact on ratepayers.
- Stakeholders want to be sure Investor-Owned Utilities are fully transparent with the planning process, the costs that will be passed on to ratepayers, and ensuring electricity remains affordable. They want to ensure that Investor-Owned Utilities are truly listening to community voices and not just checking a regulatory box.

<table>
<tr>
<td>Costs
Initial investment required

Impact on ratepayers

Ensuring that the investment makes sense from a cost/benefit perspective, and not overbuilding

Potential negative impact on businesses and economic development</td>
<td>Transparency and Community Input
Perceived lack of transparency from Investor-Owned Utilities

Not truly listening to community voices

Distribution System Planning process has opportunity to shore up energy delivery to places with limited resources (specifically mentioned at the coast and small towns where outages and power quality are current issues)</td>
</tr>
<tr>
<td>Job Creation
Jobs may be temporary and consist of out-of-state workers

Access to housing if new jobs are created

Limited number of long-term jobs (similar to data centers)

Investment in workforce training required</td>
<td>Technical Details
Need more details on how it will be done, including transparency of planning process

Need details on how 100% carbon-free energy will be achieved, including renewable technologies, battery storage

Need details on how the grid will be integrated and resilient</td>
</tr>
</table>

Non-Traditional Groups to Engage

In order for Distribution System Planning to be equitable and incorporate a broad range of feedback, stakeholders recommend talking to a wide range of organizations representing a wide range of non-traditional groups.

- While stakeholders recognize the need to hear from a diverse group of organizations, there is not consensus about what each group will bring to the table. It is important to define the objectives beyond just "hearing their voices" and ensure that groups represented understand the value they bring.
- In addition to groups representing communities throughout Oregon, it is important to hear from non-traditional groups who can support the efforts to move toward a cleaner energy grid, including those providing technology to support the transition and those producing a wide range of renewable energy on a smaller than utility scale (e.g., community/localized wind farms, local or individual solar installations, small scale hydro (including farmers or water districts), biomass, hydrogen, etc.).

Groups to Represent		**Potential Partners to Engage**
Low-income	Elderly	Groups promoting energy efficiency/DSM
BIPOC	Homeless	Energy technology providers
Native American nations	Environmental groups	Small scale renewable energy producers (e.g., community/localized wind farms, local or individual solar installations, small scale hydro (including farmers or water districts), biomass, hydrogen, etc.)
Small businesses	Economic development groups	
Small/rural communities	Agriculture businesses	

How to Engage Stakeholders

While organizations highly engaged with Distribution System Planning have a vested interest in participating in the conversation, a common theme is to make it easy and worthwhile for Community Based Organizations and other non-traditional stakeholder organizations to be involved.

Non-traditional stakeholders often do not know what they can contribute, which creates a barrier to participation and hearing from a broad range of voices. Education and outreach are necessary to show why they should participate and the value they bring to the table.

Community Based Organizations and business organizations often do not have the resources or time to dedicate to traveling or attending meetings (in-person or virtual), if they do not see a clear benefit for participation, or some form of compensation to demonstrate value in their time and effort.

Communicate Value Prop	**Make Participation Easy**	**Listen to a Broad Audience**	**Offer Compensation**
Explain Distribution System Planning in simple and clear language; most non-traditional stakeholders are not familiar with these planning processes Help organizations understand why their feedback is important and what they can offer Show organizations the value their participation brings to their org and the broader community Personal outreach demonstrates more value than mass communications	Go to them by attending local meetings they are already planning to attend Continue to offer virtual meetings, but make sure the meetings are novice-friendly and welcoming One-on-one meetings (in-person, phone, online) would be more welcoming to people/organizations not comfortable participating in a broad meeting that they consider to be over their head or outside their charter	To promote equity, actively solicit feedback from a range of community-based groups, including those representing elderly, low-income, people of color, small businesses, and homeless populations Actively listen and internalize; not all feedback may be actionable, but maintain transparency and explain why decisions are made English is primary, but consider offering conversations in Spanish or other languages	Participation may be a significant time or financial burden for some people/ organizations Consider providing a stipend as a "thank you" for attendance Consider gas cards to pay for travel expenses

Appendix C: PacifiCorp Distribution System Planning Workshop #9, June 24, 2022

Distribution System Planning
Public Workshop #9
June 24, 2022



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Workshop #9 Information

Teams Meeting Information

- Microsoft Teams meeting
  Join on your computer or mobile app
  [Click here to join the meeting]

  Or call in (audio only)
  +1 563-275-5003,,418028485#   United States, Davenport
  Phone Conference ID: 418 028 485#

Please add the following to the Teams Chat when you log on to the meeting:
- Your Name
- Your Organization and Title/Role

- Please use **Microsoft Edge** or **Google Chrome** with Teams for best experience
- Please **place your phone on "Mute"** when not speaking
- If you call in using your phone in addition to joining via the online link, please make sure to **mute your computer audio**
- Please **do not use the "Hold"** function on your phone

- Please use the chat function in TEAMS to provide any questions or comments during this presentation. We will do our best to address those as they come up, if we are unable to get to them, we will follow-up directly or at an upcoming workshop.

Today's Agenda

1. Introductions and Review Agenda (10 minutes)
2. Review Pacific Power OR Service Territory (10 minutes)
3. Review Distribution Planning Process (60 minutes)
   - Study Cycle (5 Year Cycle)
   - Review Grid Needs Summary from latest cycle of DSP Studies
   - Review DSP Study Process – Highlighting Prioritization Steps
   - Review Current Year Distribution Investments (Results of last year's prioritization)

   Break (10 minutes)

4. Pilot/Transitional Study Areas and Grid Needs (45 minutes)
   - Introduction to Pilot Areas and focus areas
   - Grid Need - Klamath
   - Review potential solutions (Traditional and Non-wires)
   - Outline next steps
5. Update on Community Engagement (20 minutes)
   - CIG Update
   - Local Engagement
6. Review DSP Part 2 Schedule and Upcoming Topics (10 minutes)

2) Pacific Power Service Territory and DSP






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Pacific Power's Oregon Service Territory

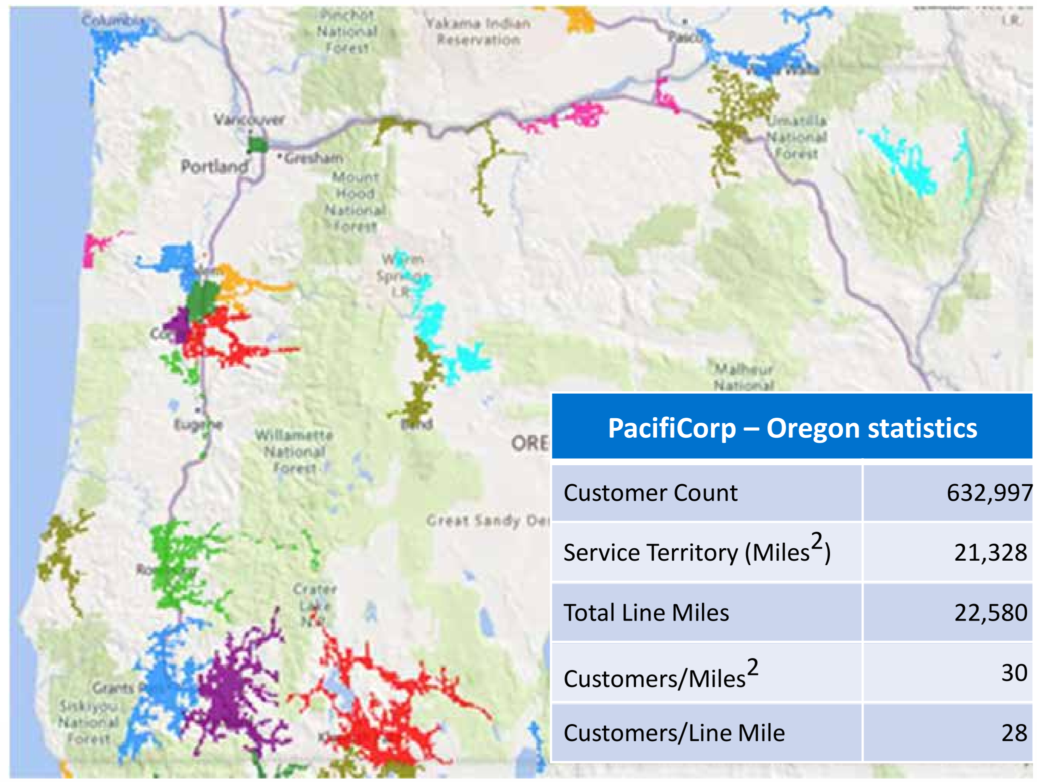
Overview of Pacific Power – Oregon

- 502 distribution circuits
- 191 distribution substations

Office	NORTH REGION			CENTRAL REGION			SOUTH REGION	
	Portland	Walla Walla	Yakima	Bend	Albany	Roseburg	Klamath Falls	Medford
Responsible Operating Areas	Clatsop (Astoria) Portland Hood River	Walla Walla Hermiston Pendleton Enterprise	Sunnyside Yakima	Madras Hood River Bend/Redmond Prineville	Albany Corvallis Dallas/Independe nce Cottage Grove Stayton Lebanon Lincoln City Junction City	Coos Bay Roseburg	Alturas Lakeview Mt Shasta Klamath Falls Yreka	Crescent City Medford Grants Pass
Distribution Profile	95 Circuits 1,200 Line Miles 107,000 Customers	42 Circuits 2,500 Line Miles 54,000 Customers	106 Circuits 3,300 Line Miles 108,000 Customers	65 Circuits 2,800 Line Miles 77,000 customers	86 Circuits 3,700 Line Miles 137,000 Customers	66 Circuits 2,300 Line Miles 70,000 Customers	110 Circuits 5,000 Line Miles 75,000 Customers	138 Circuits 5,700 Line Miles 156,000 Customers
District Specific Attributes	Portland UG Networks DA Pilot Project FHCA		FHCA	High Growth Rate/New Connections FHCA	DA Pilot Project	FHCA	Multiple Code Requirements FHCA & HFTD Footprint Energy Storage Pilot	Large FHCA Footprint DA Pliot Project

Pacific Power's Oregon Service Territory

- Dispersed and Varied Geography: Territory spans from Washington to California and the coast to Idaho, broken into eight distinct planning districts
- Diverse Circuit Loading/Composition:
  - Densest circuit in Portland with 638 customers per line mile
  - Least dense in Hermiston with one customer per line mile
  - Oregon average is 28 customers per line mile
- Diverse Environmental Conditions: Distribution in eight of nine Oregon climate zones
- Various Touchpoints: Interconnections with 16 other electrical power companies, including CAISO and Bonneville Power



PacifiCorp – Oregon statistics	
Customer Count	632,997
Service Territory (Miles^2)	21,328
Total Line Miles	22,580
Customers/Miles^2	30
Customers/Line Mile	28

3) Distribution System Planning Process (Highlight on Prioritization)



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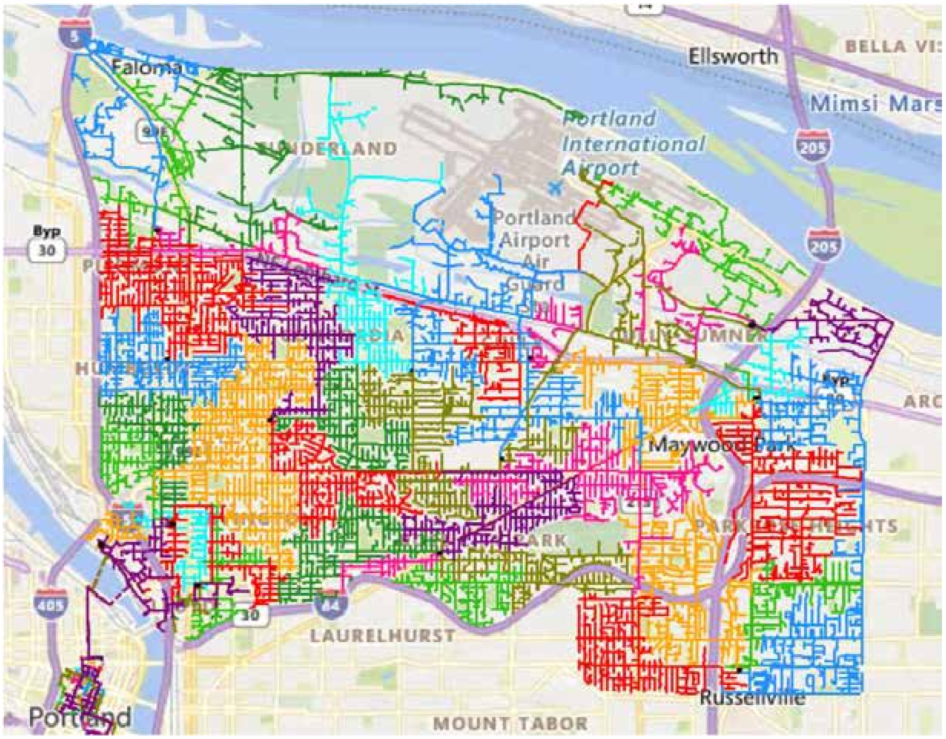
As-is DSP Studies – Cycle vs Ad-Hoc Studies

Distribution Planning Studies

- All distribution system planning studies are scheduled to be completed on a 5-year cycle.
- Study schedules are evaluated each year and studies may be shifted to occur sooner or later depending on a number of factors (high load growth activity, large load additions, etc.).
- Currently 99 planning studies on 5-year cycle in Pacific Power service territory.
- Generally, spend 2-3 months completing study analysis, review and prioritize results with Manager.

Ad-hoc Studies (Generation Interconnect or System Impact Study)

- Typically driven by load, generation interconnection service or transmission service requests
- Study is generally focused on a limited area, and the immediate effects of the request on reliability and load service
- Generally shorter timeframes to meet customer needs (~ 3-4 weeks for initial study).
- Customer shares in solution costs and influences what solutions to implement.



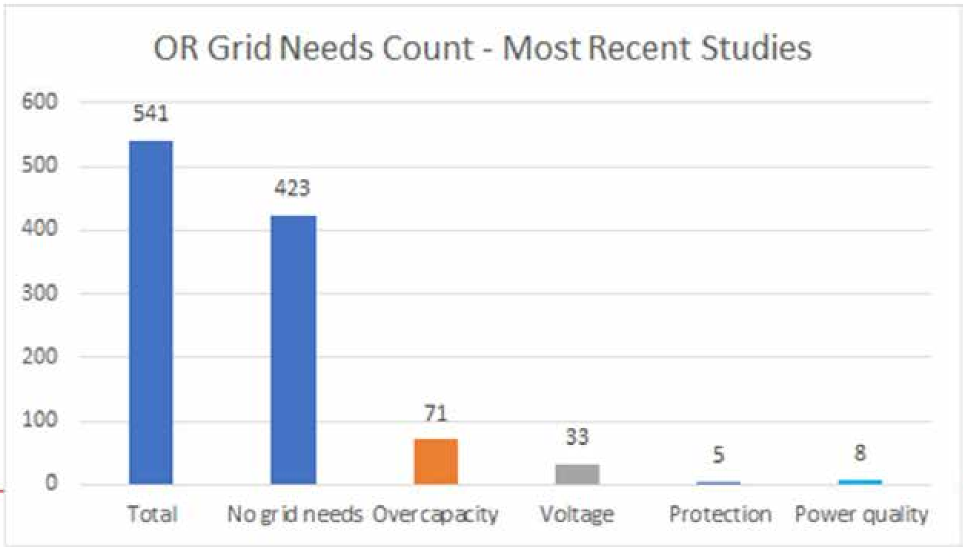
Distribution System Planning Grid Needs Context

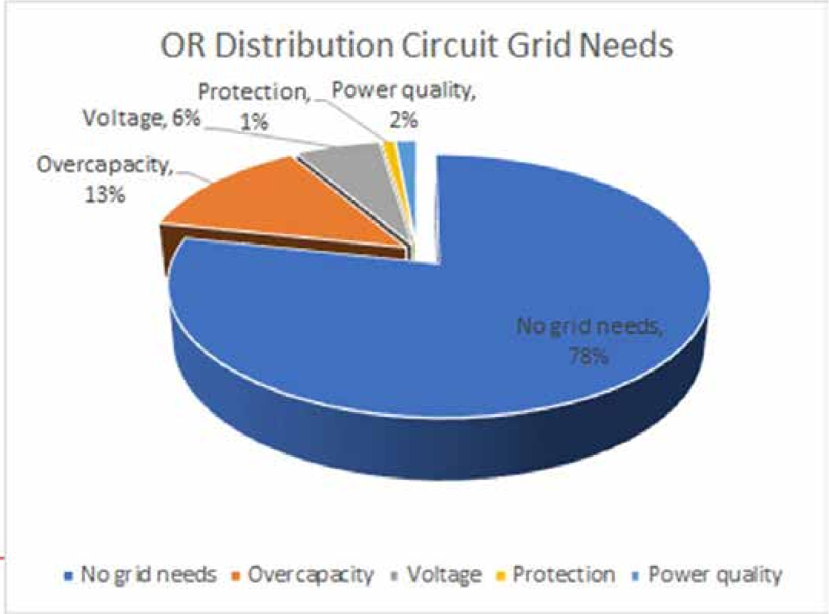
Reviewed the latest Distribution System Planning Studies for all study areas in Oregon (excludes customer-driven or ad-hoc studies):

- Categorized the grid needs that were identified in the studies (see results below)
- Captured rough cost estimates for wires solutions and added that breakdown – 117 total Grid Needs Identified:
  - 32% between $0 and $5K,
  - 54% between $5K and $200K,
  - 14% more than $200K

Findings:

- Grid needs found in 22% of circuits
- Overcapacity is the most common grid need (61% of found needs)
- 86% of found grid needs cost less than $200K
- Of those needs, not all will be suitable for NWS





As-Is Distribution System Planning Process
- Study Initiation Through Approval

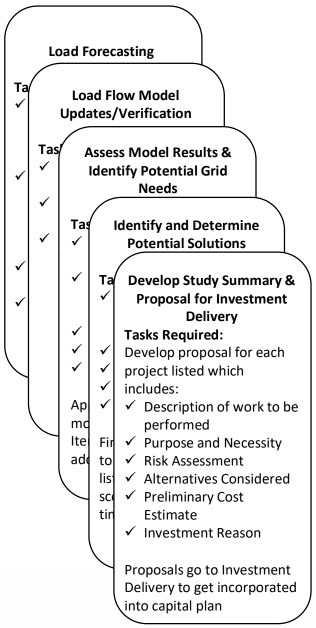
Current process includes **Four** high-level Steps…

1) Start Study
(Scheduled or Ad-hoc)

5 Yr. Study Cycle
(as scheduled)

Ad-Hoc Study
(Different Process)

2) Complete Study



3) Field Engineering Manager Review/Prioritization:

A. Reviews All Scheduled Study Reports (~ 20/year)

B. Ranks each Solution in priority order for each Investment Reason Category

4) Investment Delivery Prioritization and Approval:

A. Each Investment Reason has a budget established for the year based on capital planning.

B. Field Engineering Manager & Inv Delivery Director review prioritized list of solutions & approve in priority order until budgeted funds are exhausted.

As-Is Distribution System Planning Process
- Study Initiation Through Approval

The same **Four** steps with some detail…

1) Start Study (Scheduled or Ad-hoc)

5 Yr. Study Cycle
(as scheduled)

Ad-Hoc Study
(as needed)

- New Load/Resource Proposed
- Area Need (e.g., high load growth activity)
- Anticipated large load additions (short and long term)
- Transmission Impact

Ad-Hoc Study Process (ESSA Process)
Ad-Hoc study addresses specific customer need, new block load or resource addition.
Not driven from a grid need found during DSP

2) Complete Study

Load Forecasting

Load Flow Model Updates/Verification

Assess Model Results & Identify Potential Grid Needs

Identify and Determine Potential Solutions

Develop Study Summary & Proposal for Investment Delivery
Tasks Required:
Develop proposal for each project listed which includes:
- ✓ Description of work to be performed
- ✓ Purpose and Necessity
- ✓ Risk Assessment
- ✓ Alternatives Considered
- ✓ Preliminary Cost Estimate
- ✓ Investment Reason

Proposals go to Investment Delivery to get incorporated into capital plan

Study Report

3) Field Engineering Manager Review/Prioritization:

A. Reviews All Scheduled Study Reports (~ 20/year)

B. Ranks each Solution in priority order for each Investment Reason Category

Ranked List Reinforcements

Ranked List Feeder Improvements

Ranked List Substation Improvements

4) Investment Delivery Prioritization and Approval:

A. Each Investment Reason has a budget established for the year based on capital planning.

B. Field Engineering Manager & Inv Delivery Director review prioritized list of solutions & approve in priority order until budgeted funds are exhausted.

Ranked List Reinforcements

Example

Approved Projects

Budget

Projects Held Over to Next Cycle

As-Is Distribution System Planning Process
- Study Initiation Through Approval

The same **Four** steps indicating where Prioritization occurs…

1) Start Study (Scheduled or Ad-hoc)

5 Yr. Study Cycle (as scheduled)

Ad-Hoc Study (as needed)
- New Load/Resource Proposed
- Area Need (e.g., high load growth activity)
- Anticipated large load additions (short and long term)
- Transmission Impact

Ad-Hoc Study Process (ESSA Process)
Ad-Hoc study addresses specific customer need, new block load or resource addition.
Not driven from a grid need found during DSP

2) Complete Study

Load Forecasting

Load Flow Model Updates/Verification

Assess Model Results & Identify Potential Grid Needs

Identify and Determine Potential Solutions

Develop Study Summary & Proposal for Investment Delivery
Tasks Required:
Develop proposal for each project listed which includes:
- ✓ Description of work to be performed
- ✓ Purpose and Necessity
- ✓ Risk Assessment
- ✓ Alternatives Considered
- ✓ Preliminary Cost Estimate
- ✓ Investment Reason

Proposals go to Investme Delivery to get incorpora into capital plan

Study Report

Prioritization: Grid Needs + Solution
Each identified grid need will have a recommended solution, budget and supporting detail. The solution will go into a specific category for budget prioritization and approval.

3) Field Engineering Manager Review/Prioritization:

A. Reviews All Scheduled Study Reports (~ 20/year)

B. Ranks each Solution in priority order for each Investment Reason Category

Prioritization: Field Engineering Manager (One Person)
- Reviews all Study Reports & recommended solutions during study and prior to prioritization.
- Ranks each proposed solution from all of the studies in rank order (priority) based on:
  - Potential risk and impact
  - Timing (when solution needed/how long will it take to implement)
  - Any relationships to other solutions
  - Consultation with Field Engineer/Ops Managers

Ranked List Reinforcements

Ranked List Feeder Improvements

Ranked List Substation Improvements

4) Investment Delivery Prioritization and Approval:

A. Each Investment Reason has a budget established for the year based on capital planning.

B. Field Engineering Manager & Inv Delivery Director review prioritized list of solutions & approve in priority order until budgeted funds are exhausted.

Prioritization: Projects approved in priority order until budget fully allocated.
Projects entered for tracking during design and implementation.

Ranked List Reinforcements

Example

Approved Projects

Budget

Projects Held Over to Next Cycle

As-Is Distribution System Planning Study Schedule

1) Start Study (Scheduled or Ad-hoc)

5 Yr. Study Cycle (as scheduled)

Study Schedule

CY 2019 – 20 studies		CY 2020 – 20 studies		CY 2021 – 20 studies	
Office	**Study Name**	**Office**	**Study Name**	**Office**	**Study Name**
Albany	Harrisburg	Albany	Lebanon	Albany	Cottage Grove
Albany	Brownsville	Albany	Sweet Home	Albany	Oregon State University
Bend	Deschutes	Bend	Prineville	Albany	Stayton
Bend	Culver	Bend	Powell Butte	Bend	Bend
Klamath Falls	Alturas	Klamath Falls	Sacremento Canyon	Klamath Falls	Butte Valley
Klamath Falls	Agency Lake	Klamath Falls	Sprague River	Klamath Falls	Klamath Urban
Klamath Falls	Lower Klamath River	Klamath Falls	Yreka	Klamath Falls	Tulelake
Medford	Ashland & Talent	Medford	Glendale	Medford	Merlin
Medford	Gasquet-Patricks Creek	Medford	Grants Pass Urban	Medford	Upper Rogue
Medford	Klamath	Medford	Medford Urban North	Medford	Tolo-Gold Hill
Medford	Smith River	Medford	Ruch Area	Portland	Lincoln Network
Portland	Sherman County	Portland	Albina Network	Portland	Warrenton
Roseburg	North Umpqua	Portland	Lincoln Non-network	Portland	Astoria
Roseburg	North Spit	Portland	Hood River	Portland	Seaside
Roseburg	Coquille-Bandon	Roseburg	Myrtle Point	Roseburg	Roseburg Urban
Walla Walla	Touchet	Roseburg	Sutherlin-Oakland	Walla Walla	Pilot Rock
Walla Walla	Umapine	Walla Walla	Athena-Weston	Walla Walla	Pomeroy
Walla Walla	Hermiston-Umatilla	Walla Walla	Dodd Road	Walla Walla	Walla Walla
Yakima	Selah-Wenas	Walla Walla	Dayton-Waitsburg	Walla Walla	Pendleton
Yakima	Wapato-White Swan	Yakima	Yakima Urban	Yakima	Toppenish-Punkin Center

As-Is "Complete Study" Process

2) Complete Study

5 Yr. Study Cycle (as scheduled) →

Load Forecasting →

Tasks Required:
- ✓ Review Historical summer/winter peak load SCADA data at circuit breaker level
- ✓ Adjust for large load additions and planned system changes consistent with capital plan
- ✓ Adjust for large DER additions
- ✓ Option: Normalize for weather if base data not representative

Load Flow Model Updates/Verification →

Tasks Required:
- ✓ Review equipment and line data in CYME Model
- ✓ Perform field Verification of model data
- ✓ Update CYME Model per field verification

Identify Grid Needs ↔

Tasks Required:
- ✓ Run CYME Model based on load forecast
- ✓ Identify and analyze grid need and timeline due to issue (For Example)
- ✓ Undervoltage
- ✓ Overvoltage
- ✓ Thermal overload

Apply initial solution to model and Re-analyze Iterate until solutions have addressed issues

Identify and Determine Potential Solutions →

Tasks Required:
- ✓ Identify and determine solution to resolve issue For example:
- ✓ Load transfer
- ✓ Phase balancing,
- ✓ Capacitor bank
- ✓ Etc.

Finalize proposed solution(s) to develop a project list (includes high-level scope of work, budget, and timeline)

Develop Proposal for Investment Delivery

Tasks Required:
Develop proposal for each project listed which includes:
- ✓ Description of work to be performed
- ✓ Purpose and Necessity
- ✓ Risk Assessment
- ✓ Alternatives Considered
- ✓ Preliminary Cost Estimate
- ✓ Investment Reason

Proposals go to Investment Delivery to get incorporated into capital plan

Distribution System Studies are conducted by Field Engineers who are intimately familiar with the area and equipment.
Field Engineers support all day-to-day operations of the distribution systems and are the subject matter experts for their areas.
They are afforded latitude to utilize professional judgement in the execution of the studies and in the prioritization of grid needs and recommended solutions.

Guidance Provided by:
1E.3.1—Distribution System Planning Study Guide

Excerpt from Section 8.1 – Solution Optimization:
" To operate the distribution system in the most cost-effective manner possible, alternative solutions to problems must be considered and studied. Many problems may be solved by several different solutions or a combination of solutions. The easiest or most direct solution to a problem may not be the best or most economical one or yield the best utilization of the system.
Be creative; sometimes "off the wall" ideas lead to very cost-effective and innovative solutions. The solution chosen for the plan should factor in engineering, operating, and economic aspects."

As-Is Distribution System Planning Process - Field Engineer Study Process

Start Study
(Scheduled or Ad-hoc)

5 Yr. Study Cycle
(as scheduled)

2) Complete Study

Load Forecasting

Tasks Required:
- ✓ Review Historical summer/winter peak load SCADA data at circuit breaker level
- ✓ Adjust for large load additions and planned system changes consistent with capital plan
- ✓ Adjust for large DER additions
- ✓ Option: Normalize for weather if base data not representative

Load Flow Model Updates/Verification

Tasks Required:
- ✓ Review equipment and line data in CYME Model
- ✓ Perform field Verification of model data
- ✓ Update CYME Model per field verification

Assess Model Results & Identify Potential Grid Needs

Tasks Required:
- ✓ Run CYME Model based on load forecast
- ✓ Identify and analyze grid need and timeline due to issue (For Example)
- ✓ Undervoltage
- ✓ Overvoltage
- ✓ Thermal overload

Apply initial solution to model and Re-analyze Iterate until solutions have addressed issues

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- ✓ Alternatives Considered
- ✓ Preliminary Cost Estimate
- ✓ Investment Reason

Proposals go to Investment Delivery to get incorporated into capital plan

The Prioritization process for distribution investments for Field Engineers occurs in three stages in the As-Is DSP process.

Prioritization: Grid Needs
Field Engineer identifies and prioritizes grid needs for each circuit .

Prioritization: Solution Identification and Analysis
Field Engineer analyzes potential solutions, in consultation with Mgr/SMEs "DSM Guide"

Prioritization: Study Summary Report
Field Engineer document outlines recommended + alternative solutions – Assigns Investment Reason for Budget Prioritization

2) Complete Study

Assess Model Results & Identify Potential Grid Needs

Tasks Required:
- ✓ Run CYME Model based on load forecast
- ✓ Identify and analyze grid need and timeline due to issue (For Example)
- ✓ Undervoltage
- ✓ Overvoltage
- ✓ Thermal overload

Apply initial solution to model and Re-analyze
Iterate until solutions have addressed issues

Prioritization: Grid Needs
Field Engineer identifies and prioritizes grid needs for each circuit .

Stage 1

Prioritization: Grid Needs

Primary Steps: :

- Field Engineer identifies the grid need and determines the corrective action required to address the issue.
- Since grid needs (and corresponding solutions) can vary widely in scope, severity, and impact the Field Engineer is provided latitude to exercise professional judgement in the identification and prioritization of the grid need.

During assessment of the grid needs and potential solutions, the Field Engineer would consider the risks of not doing the project. Specifically, the Field Engineer would examine the grid need and potential solution(s) in terms of:

- Safety and protection of life and property
- Risk (Customer impact, type of issue, severity of issue)
- Preservation of company facilities
- Continuity of service
- Power Quality

The DSP Guide identifies potential operating issues/Grid Needs in the following rough **priority** order:

	Safety	Risk	Preservation	Continuity	Power Quality
1. Overloaded equipment and circuits	■	■	■	■	■
2. Voltage problems	■	■	■	■	■
3. Protection problems	■	■	■	■	■
4. Power factor problems	■	■	■	■	■
5. Critical limiting factors		■		■	■
6. Reliability problems		■		■	
7. Regulatory problems		■		■	
8. Power quality problems				■	
9. Other					■

2) Complete Study

Identify and Determine Potential Solutions

Tasks Required:

- ✓ Identify and determine solution to resolve issue For example:
- ✓ Load transfer
- ✓ Phase balancing,
- ✓ Capacitor bank
- ✓ Etc.

Finalize proposed solution(s) to develop a project list (includes high-level scope of work, budget, and timeline)

Prioritization: Solution Identification and Analysis
Field Engineer analyzes potential solutions, in consultation with Manager/SMEs "DSM Guide"

Stage 2

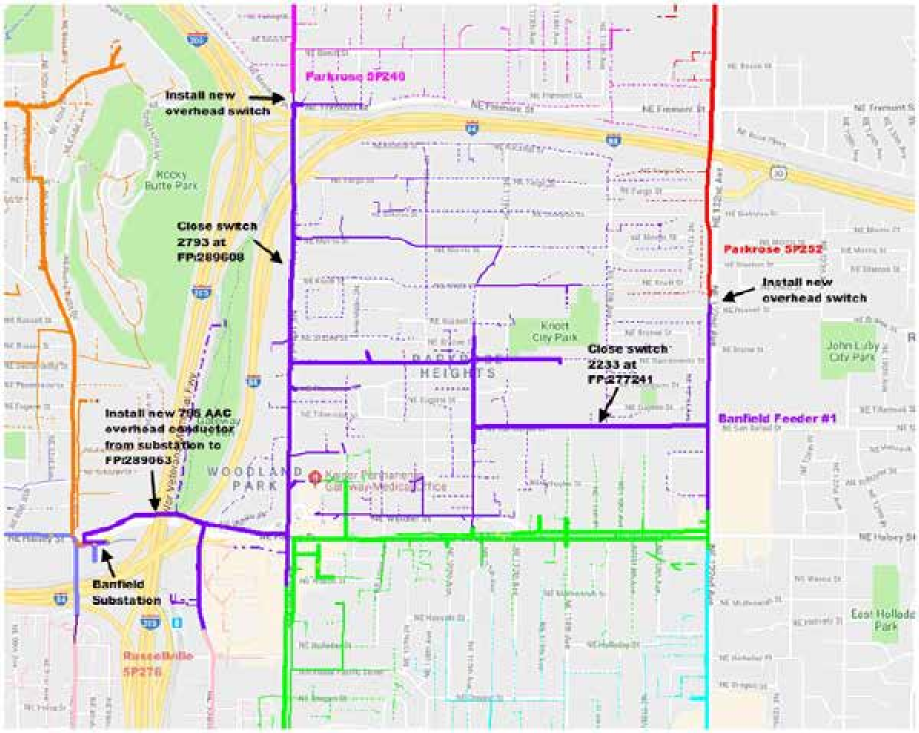
Prioritization: Solution Identification

During assessment, the Field Engineer would consider the risks of not doing the project – based on the following factors:

- Safety and protection of life and property
- Risk (Customer impact, type of issue, severity of issue)
- Preservation of company facilities
- Continuity of service
- Power Quality

The DSP Guide suggests that Engineers address the following questions in considering risks associated with the proposed solution:

1. How many hours per year is the risk present?
2. How many customers would be affected?
3. How much load would be affected?
4. How much revenue would be lost?
5. How much would emergency repairs cost?
6. How long would it take to perform emergency repairs, if at all possible?
7. What is the likelihood that a failure or service quality problem would occur?"



2) Complete Study

Identify and Determine Potential Solutions

Tasks Required:

- ✓ Identify and determine solution to resolve issue For example:
- ✓ Load transfer
- ✓ Phase balancing,
- ✓ Capacitor bank
- ✓ Etc.

Finalize proposed solution(s) to develop a project list (includes high-level scope of work, budget, and timeline)

Prioritization: Solution Identification and Analysis

Field Engineer analyzes potential solutions, in consultation with Manager/SMEs "DSM Guide"

Stage 2

Prioritization: Solution Identification (Cont.)

In developing solutions to address the grid need, Field Engineers utilize both experience and collaboration as well as guidance from the DSP Study Guide.

The DSP Guide provides a table that identifies common grid needs and maps them to potential solutions.

Example of using the Guide:

Issue: Substation Transformer is found to be overloaded

Possible Solutions:

1A – Build new substation

2A – Replace or add substation transformer

2B – Add substation cooling equipment

2C – Parallel substation transformers

1E.3.1—Distribution System Planning Study Guide

Table 2—Problem Solution References

Issues \ Solutions	1A Build New Substation	2A Replace or Add Substation Transformer	2B Add Substation Cooling Equipment	2C Parallel Substation Transformers	3A Replace Overloaded Substation Equip	3B Increase Getaway Capacity	3C Add Parallel Circuit Getaway	4A New Feeder	4B Transfer Load	5A Reconductor	5B Reconfigure System	5C Add Underground Cable	5D Remove an Environmental Hazard	6A Replace Equipment	6B Add Distribution Automation Equipment	7A Replace Regulator	7B Limit Regulator Operating Range	7C Add Secondary Regulators	7D Change Regulator Control Settings	7E Add Line Regulator	7F Relocate Line Regulator	8A Install Line Capacitors	8B Install Capacitor Switches and Controls	9A Replace Step-Up or Step-Down Transformers	9B Change Utilization Transformer Taps	9C Voltage Conversion	10A Add Protective Device	10B Replace Protection Equipment	10C Relocate Protection Equipment	11A Demand Side Management
Substation																														
Transformer	X	X	X	X				X	X						X											X				X
Regulator		X		X				X	X						X	X	X									X				X
Transformer Protection	X		X					X	X						X											X				X
Paralleled Transformers	X	X	X					X	X						X											X				X
Bus Capacity	X	X			X			X	X						X											X				X
Circuit																														
Getaway						X	X	X	X						X											X				X
Circuit Protective Device					X			X	X																	X				X
Switches					X				X																					
Guide Line Loading Limit						X	X	X	X						X											X				
Line and Equipment																														
Overhead Conductor						X	X	X	X	X					X											X				X
Underground Conductor								X	X	X		X			X											X				X
Line Switch									X					X												X				
Switch Cabinet or Device									X					X																
Regulator									X					X	X	X					X			X		X				
Protective Device																														
Recloser									X					X												X		X	X	
Fuse									X					X													X	X	X	
Series Transformer																														
Step Up or Down	X							X	X						X									X		X				X
Isolation Bank	X																							X		X				X
Grounding Bank Fault Capacity	X							X	X															X		X				
Service Quality Problems																														
Steady State Voltage Levels		X		X				X	X	X					X			X	X	X		X	X	X	X	X				
Regulator Range								X	X	X					X					X	X	X	X	X	X	X				
Regulator Settings															X	X			X											
Capacitor Controls															X	X			X		X		X	X		X				

2) Complete Study

Identify and Determine Potential Solutions

Tasks Required:
- ✓ Identify and determine solution to resolve issue For example:
- ✓ Load transfer
- ✓ Phase balancing,
- ✓ Capacitor bank
- ✓ Etc.

Finalize proposed solution(s) to develop a project list (includes high-level scope of work, budget, and timeline)

Prioritization: Solution Identification and Analysis
Field Engineer analyzes potential solutions, in consultation with Manager/SMEs "DSM Guide"

Stage 2

Prioritization: Solution Identification (Cont.)

Once primary solution is identified to address the grid need, the Field Engineer will:

- Identify and model the solution and any alternative solutions in CYME
- Confirm recommended solution addresses the technical needs for the remainder of the study cycle.

Alternatives are provided along with the recommended solution in the Study Summary Report for consideration.

The common solutions are further explained in text provide further guidance. The common solution titles are listed to the right for ease of reference.

Titles of Common Solutions from DSP Guide Book

- 1A Build New Substation
- 2A Replace or Add Substation Transformer
- 2B Add Substation Cooling Equipment
- 2C Parallel Substation Transformers
- 3A Replace Overhead Substation Equipment
- 3B Increase Getaway Capacity
- 3C Add Parallel Circuit Getaway
- 4A New Feeder
- 4B Transfer Load
- 5A Reconductor
- 5B Reconfigure System
- 5C Add Underground Cable
- 5D Remove an Environmental Hazard
- 6A Replace Equipment
- 6B Add Distribution Automation Equipment
- 7A Replace Regulator
- 7B Limit Regulator Operating Range
- 7C Add Secondary Regulators
- 7D Change Regulator Control Settings
- 7E Add Line Regulator
- 7F Relocate Line Regulator
- 8A Install Line Capacitors
- 8B Install Capacitor Switches and Controls
- 9A Replace Step-up or Step-down Transformers
- 9B Change Utilization Transformers Taps
- 9C Voltage Conversion
- 10A Add Protective Device
- 10B Replace Protective Equipment
- 10C Relocate Protective Equipment
- 11A Demand Side Management

2) Complete Study

Develop Study Summary & Proposal for Investment Delivery
Tasks Required:
Develop proposal for each project listed which includes:
- ✓ Description of work to be performed
- ✓ Purpose and Necessity
- ✓ Risk Assessment
- ✓ Alternatives Considered
- ✓ Preliminary Cost Estimate
- ✓ Investment Reason

Proposals go to Investment Delivery to get incorporated into capital plan

Prioritization: Study Summary Report
Document outlines recommended + alternative solutions – Assigns Investment Reason for Budget Prioritization

Stage 3

Prioritization: Study Summary Report

The Field Engineer creates the DSP Report and Construction Plan for Approval including:

- Report Preface
- Study Summary: grid needs, costs/benefits and risks for recommended and alternative solutions
- Load Forecast for each substation and circuit in the study
- Purpose and Necessity (Investment Reason) for each proposed solution (more on this below)
- Map(s) showing study area and proposed budget items
- Construction Plan and Approval

The recommended solution includes a level of ***prioritization*** *(that is - the recommended solution is prioritized above the alternative solutions), but there is not further prioritization among a variety of potential solutions until the reports are compiled and prioritized in the next step.*

Each solution assigned to an **"Investment Reason"** - categories that "define the business reasons driving construction of a given capital project… not simply an explanation of the type of work to be performed". The Investment Reason ties directly to budgets that outline work activities.

Prioritization – Field Engineering Manager

3) Field Engineering Manager Review/Prioritization:

A. Reviews All Scheduled Study Reports (~ 20/year)

B. Ranks each Solution in priority order for each Investment Reason Category

Prioritization: Field Engineering Manager (One Person)

- Reviews all Study Reports & recommended solutions during study and prior to prioritization.
- Ranks each proposed solution from all of the studies in rank order (priority) based on:
  - Potential risk and impact
  - Timing (when solution needed/how long will it take to implement)
  - Any relationships to other solutions
  - Consultation with Field Engineer/Ops Managers

Ranked List Reinforcements

Ranked List Feeder Improvements

Ranked List Substation Improvements

Field Engineering Manager Review and Approval: All DSP Reports and Construction Plans are reviewed and approved by the Field Engineering Manager (a single person) and the specific solutions are captured for prioritization.
The solutions' Purpose and Necessity/Investment Reason dictates the type of solution that is needed. The Investment Reasons are themselves a form of prioritization in the process.

Field Engineering Manager prioritization: compiles a list of all identified solutions and prioritizes the list by the Investment Reason. This is the critical prioritization step as the Manager (in consultation with the Field Engineers) force ranks the proposed solutions into priority order based on:

- Type of Issue and Severity
- Risk associated with issue
- Alternatives available
- Customer impact
- Projected Conditions/Benefits
- Timeline
- Cost
- Relationships to other solutions

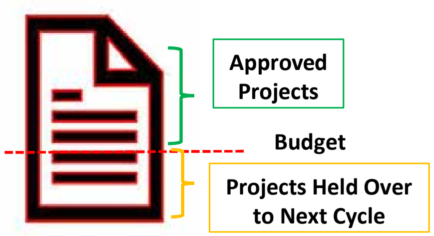
There is dialog throughout the prioritization process to ensure that risks, potential impacts and other particulars are considered in the ranking of the proposed construction items. Once completed, the force ranked list is provided to Investment Delivery.

4) Investment Delivery Prioritization and Approval:

A. Each Investment Reason has a budget established for the year based on capital planning.
B. Field Engineering Manager & Inv Delivery Director review prioritized list of solutions & approve in priority order until budgeted funds are exhausted.

Prioritization: Projects approved in priority order until budget fully allocated.
Projects entered for tracking during design and implementation.

Ranked List Reinforcements ***Example***



Prioritization – Investment Delivery

Investment Delivery Prioritization and Approval:

- Each of the Investment Reasons has a set budget for each year
- Budget level reflects investment priorities for PacifiCorp overall. Specific budget levels are allocated to Pacific Power.
- The construction/solution items are force ranked against all other construction items in that category. Projects are approved starting from highest ranked to lower ranked step by step until the annual budget has been exhausted.

"Carryover" projects from the previous year are approved first to ensure they continue toward completion. New projects then are considered for approval with remaining budget for that category.

Examples of the implementation projects currently in flight for calendar year 2022 are provided on the following slides:

- System Reinforcement – Feeder
- System Reinforcement - Substation
- Feeder Improvements
- Substation Improvements
- Functional Upgrade – Reliability (*not through regular DSP Studies)*

Distribution Investment Reasons

The most common Investment Reasons for DSP Study Solutions are:

Distribution System Reinforcements

System Reinforcement – Feeder: Used for improvements and reinforcements needed to maintain acceptable feeder support for general load growth.

Distribution Substation Reinforcements

System Reinforcement – Substation: Used for improvements and reinforcements needed to maintain acceptable substation support for general load growth.

Feeder Improvements

Feeder Improvements: Used for *functional* upgrades to a feeder (Addition or enhanced functionality to existing operational function that was not directly related to a customer reliability improvement)

Substation Improvements

Substation Improvements: *Functional* upgrades to a substation, not directly related to a customer reliability improvement. *Depending on the voltage of the substation equipment, these solutions may be either a Distribution investment or a Transmission investment.*

Reliability Improvements

Functional Upgrade – Reliability (*Not From DSP Studies*): Used for functional upgrades to a feeder, substation or transmission line for the purpose of improving circuit reliability that are directly associated with a customer reliability improvement.
(These items are identified and prioritized through centralized reliability analysis and specific improvement initiatives, not through regular DSP Studies)

Review 2022 Tracking Sheet
Distribution System Reinforcements

Cost Bracket Legend				
Small	Med 1	Med 2	L	XL
\$0 - \$50K	\$50K - \$300K	\$300K - \$1 M	\$1M - \$3M	\$3M +

State	Area	District	Project Type	Project	Planned y/n	Status	Aprvd	Cost Bracket
OR	Central	Albany	eng	STY-4M19-0801/300700-AMSVL-RECLOSER	y	Aprv	12/1/2021	Med 1
OR	Central	Albany	eng	LCS, 4M209 Inst Line Regs & Phase Swap	y	Pend		Med 1
OR	Central	Albany	eng	4M16 Vine St. 795 RVR CRX & 4/0 to 477ACC	y	Pend		Med 2
OR	Central	Albany	eng	CRF 4M206 Recondcutor Mainline	y	Pend		Med 1
OR	Central	Albany	eng	CRF 4M206 Configure Single Phase Loads	y	Pend		Med 1
OR	Central	Albany	eng	Murder Crk 4M243 2,100 reconductor to 4/0 (GoldFish)	y	Pend		Med 1
OR	Central	Albany	pq	IEW/Transformer upgrade:Raleigh Court	n	Aprv	1/25/2022	Small
OR	Central	Albany	pq	ALB:4M243:RECONDUCTOR GOLDFISH FARM RD	n	Aprv	3/2/2022	Med 1
OR	Central	Albany	pq	LYN-4M70-CASCADE VIEW-ML CTY-UPGRADE XFM	n	Aprv	5/21/2022	Small
OR	Central	Bend	eng	OVR5D106:PPL/PURCELL RD RECONDUCTOR	y	Aprv	2/16/2022	Med 1
OR	Central	Bend	eng	PNV 5D167 RECON & FUSING, PRINEVILLE	y	Aprv	12/20/2021	Med 1
OR	Central	Bend	eng	YEW:5D325:DN7:RECONDUCTOR	y	Teco	12/23/2021	Med 2
OR	Central	Bend	eng	CUV 5D5 Highland Ln Reg Bank Haystack FM	y	Aprv	4/5/2022	Med 1
OR	Central	Bend	eng	BND 5D10 Recon to 1,500 u.g.	y	Aprv	3/11/2022	Med 1
OR	Central	Bend	eng	SHP 5D241 Reconductor 4/0 to 1000 UG	y	Pend		Med 2
OR	Central	Bend	eng	OVR 5D120 Recon 4/0	y	Aprv	3/22/2022	Med 1
OR	Central	Bend	eng	CLV 5D94 Xfr load to 5D96	y	Aprv	2/16/2022	Med 1
OR	Central	Bend	eng	BND 5D10 RECONDCTOR TO 477 NW 12TH ST	y	Aprv	6/10/2022	Med 1
OR	Central	Bend	eng	OVR 5D106 Cfg reconductor with 795 AAC	y	Aprv	5/5/2022	Med 1
OR	Central	Bend	eng	BST 5D411 Upgrd to 3 phase	y	Aprv	4/5/2022	Med 1
OR	Central	Bend	eng	5D263 Swap Load to 5D265	y	Aprv	4/7/2022	Small
OR	Central	Bend	eng	CHH 5D142 Cfg Install Reg Bank	y	Pend		Med 1
OR	Central	Bend	eng	PBT.5D263 Recon with 1/0 Al	y	Pend		Med 1
OR	Central	Bend	eng	RDD 5D226 Inst Regs SW 67th St. Winter	y	Pend		Med 1
OR	Central	Bend	eng	PBT.5D263 Recon with 1/0 Al	y	Pend		Med 1
OR	SW	Grants Pass	pq	5R53:DN7:XFMR UPGRADE:228 S. REDWOOD HWY	n	Teco	12/16/2021	Small
OR	SW	Grants Pass	pq	IEW BETTERMENT 207 N FRONTAGE RD WC	n	Teco	3/28/2022	Small

Final List: Approved Distribution System Reinforcements

<u>System Reinforcement – Feeder:</u> Used for improvements and reinforcements needed to maintain acceptable feeder support for general load growth.

Cost Bracket Legend				
Small	Med 1	Med 2	L	XL
$0 - $50K	$50K - $300K	$300K - $1 M	$1M - $3M	$3M +

Review 2022 Tracking Sheet
Distribution System Reinforcements (Cont.)

State	Area	District	Project Type	Project	Planned y/n	Status	Aprvd	Cost Bracket
OR	SW	Klamath Falls	eng	CLA.8G65 Configure Fuse Coordination	y	Pend		Small
OR	SW	Klamath Falls	eng	Nutglade 8G95 Configure Fuse Coordination	y	Pend		Small
OR	SW	Klamath Falls	eng	5L112 Burnt Wire and Fuse Repl Summers Ln	y	Aprv	4/6/2022	Small
OR	NW	Hood River	eng	WASCO:4K1 GORDON HOLLOW VOLTAGE REG	Y	Aprv	6/4/2022	Med 1
OR	SW	Medford	eng	TOL-5R91-DN7-9370 JOHN DAY DR GOLD HILL	y	Teco	12/16/2021	Small
OR	SW	Medford	pq	TAL-5R240-DN7 960 ROSE ST, PHOENIX	n	Teco	4/26/2022	Small
OR	NW	Pendleton	eng	City of Pendleton Voltage Conversion 4KV to 12KV	y	Pend	5/11/2021	Small
OR	NW	Portland	eng	ALB:5P111:216V GRID SRV:1200 SW 12TH	y	Aprv	12/14/2021	Med 1
OR	NW	Portland	pq	HYW:5P205:UPGRADE O/L XFMR:3134 NE 68TH	y	Pend		Small
OR	NW	Portland	eng	ADW:5P604: (2) SWITCHED PAD-MT CAP BANKS	y	Pend		Med 1
OR	NW	Portland	pq	HYW:5P205:UPGRADE O/L XFMR:040 NE SKIDMO	n	Teco	12/22/2021	Small
OR	NW	Portland	pq	VRN:5P391:XFMR OVERLOAD:0101/243807	n	Teco	1/10/2022	Small
OR	NW	Portland	pq	CUL:5P292:UPGRADE O/L XFMR:3630 NE 90TH	n	Teco	2/4/2022	Small
OR	NW	Portland	pq	CUL:5P288:UPGRADE O/L XFMR:0102/203349	n	Teco	2/22/2022	Small
OR	NW	Portland	pq	RVL:5P278:INSL NEW XFMR:8304 NE DAVIS ST	n	Teco	2/23/2022	Small
OR	NW	Portland	pq	CUL:5P292:ROT POLE/OL ON CBL:3633 NE 90T	n	Teco	2/24/2022	Small
OR	NW	Portland	pq	MLY:5P266:XFMR OVERLOAD:01101001.0155701	n	Teco	2/28/2022	Small
OR	NW	Portland	pq	HDY:5P158:XFMR OVERLOAD:01101001.0261600	n	Teco	3/17/2022	Small
OR	NW	Portland	pq	KNO:5P233:XFMR OVERLOAD:01101001.0278409	n	Teco	3/18/2022	Small
OR	NW	Portland	pq	MLY:5P266:XFMR OVERLOAD:01101001.0102206	n	Aprv	3/18/2022	Small
OR	NW	Portland	pq	MLY:5P162:XFMR OVERLOAD:01101001.0143701	n	Aprv	4/25/2022	Small
OR	NW	Portland	pq	CUL:5P290:XFMR OVERLOAD:01101001.0259908	n	Aprv	4/26/2022	Small
OR	NW	Portland	pq	HYW:5P205:UPGRADE O/L XFMR:7114 NE SISKI	n	Aprv	5/18/2022	Small
OR	NW	Portland	pq	KDY:5P12:XFMR OVERLOADE:01101001.0138410	n	Aprv	6/8/2022	Small
OR	NW	Portland	pq	#N/A	n		6/8/2022	Small
OR	NW	Portland	pq	5P89 FP202643 ROTTEN POLE TOP	n	Teco	6/9/2022	Small
OR	Central	Roseburg	eng	4C36 Power Factor Correction	y	Pend		Small
OR	Central	Roseburg	eng	RID 5U2 New 3 Phase Line Regulators	y	Pend		Med 1
OR	Central	Roseburg	eng	LOC 4C49 Recon 1.6 mi of #6 Cu	y	Pend		Med 2
OR	Central	Roseburg	pq	DN7 OAK 5U12 1P XFMR UPGRADE 127 NE 1ST	n	Teco	5/19/2022	Small

Final List:
Approved
Distribution
System Reinforcements

<u>System Reinforcement – Feeder:</u> Used for improvements and reinforcements needed to maintain acceptable feeder support for general load growth.

Review 2022 Tracking Sheet
Distribution Substation Reinforcements

Cost Bracket Legend				
Small	Med 1	Med 2	L	XL
$0 - $50K	$50K - $300K	$300K - $1 M	$1M - $3M	$3M +

State	District	Project	In Servce Date	Status	Cost Bracket
OR	Albany	Prospect Hill-replc leakng roof	07/30/22	Teco	Small
OR	Albany	LYONS-R744-ADD ANML GRDS	07/10/22	Aprv	Small
OR	Albany	STAYTON-4M50IADD ANML GRDS	04/21/22	Teco	Small
OR	Albany	Junction City-4M102-add anml gurds	04/21/22	Aprv	Small
OR	Albany	Queen-4M258-add anml grding	07/30/22	Teco	Small
OR	Albany	Grant St-install fence and gate	04/21/22	Aprv	Small
OR	Albany	Sweet Home-CB4M94-add anml gurds	05/30/22	Aprv	Small
OR	Bend	Cleveland Install Bird Guarding	12/31/2022	Aprv	Med 1
OR	Bend	China Hat Install Bird Guarding	12/31/2022	Aprv	Small
OR	Bend	Prineville Add Bird Guard on 2kV Bus	12/31/2022	Aprv	Med 1
OR	Bend	Madras install bird guarding	12/31/2022	Aprv	Small
OR	Grants Pass	OIL WATER SEPARATOR GP SUB BANK3	10/05/22	Aprv	Small
OR	Grants Pass	OIL WATER SEPARATOR GP SUB BANK4	10/06/22	Aprv	Small
OR	Klamath Falls	Bly-Cantilever Bus Improvements	02/22/22	Teco	Small
OR	Medford	Whetstone-Install TRF & Cable Tray Water	12/31/22	Aprv	Med 1
OR	Medford	STEVENS RD- Bird Guarding	04/30/22	Aprv	Small
OR	Roseburg	Dixonville:Line 39 Rpl SW 2U21,2U23,2U2A	12/30/22	Aprv	Med 1
OR	Roseburg	Roberts Creek-BUS-Add bird guard	12/30/22	Teco	Small
OR	Walla Walla	Herm 5W602 Rpl Bird Guarding	12/30/22	Aprv	Small
OR	Walla Walla	Blalock Install bird guarding 5K40	12/31/22	Aprv	Small
OR	Walla Walla	Joseph Sub 5W21 Deadline Check Install	12/31/22	Aprv	Med 1
OR	Walla Walla	T32222 Rpl BirdG~Cap Arr~Nitro Reg~fan~D	12/31/22	Teco	Med 1
OR	Walla Walla	ProsPec Point T3195 RPL N2 reg, Oil Dryo	12/31/22	Aprv	Med 1

Final List:
Approved
Distribution Substation
Reinforcements

System Reinforcement – Substation:
Used for improvements and reinforcements needed to maintain acceptable substation support for general load growth.

Review 2022 Tracking Sheet - Feeder Improvements

Cost Bracket Legend				
Small	**Med 1**	**Med 2**	**L**	**XL**
$0 - $50K	**$50K - $300K**	**$300K - $1 M**	**$1M - $3M**	**$3M +**

State	District	Project Name	Status	In Servce Date	Approved Date	Cost Brack
or	Albany	OSU-7M60-MANHOLE/LADDER REPLACEMENTSX10	Pend	12/31/2022		**Small**
or	Albany	CircleBlvdSub Discharge Monitorig Sys	Aprv	12/31/2022	6/8/2021	**Med 2**
or	Albany	DVK:NEL:7A390:SUB RMVL:STEP DOWN XFMRS	Aprv	12/31/2022	3/30/2022	**Med 1**
or	Albany	STY-4M370-0901/287701-STYTN-RADIAL->LOOP	Aprv	12/31/2022	01/31/22	**Med 1**
or	Albany	VGN-4M86-2003/284004-4M90,4M28,4M75 SWTC	Aprv	12/31/2022	03/14/22	**Med 1**
or	Albany	Vine St 4M15 Mainline Sectionalizing Pln	Aprv	12/25/2022		**Med 1**
or	Bend	Cleveland 5D94 Mainline Sectionalzng Pln	Aprv	12/25/2022	04/21/22	**Med 2**
or	Lincoln Cit	Devils Lake 4A316 Instl Fiber Optic Cbl	Aprv	12/31/2022	7/26/2021	**L**
or	Medford	TAL-5R240-3 RECLOSER FLISR & DISTRO WORK	Pend	12/31/2022		**Small**
or	Medford	Medford Distrib Automation Proj-FLISR	Aprv	6/30/2022	12/16/2021	**L**
or	Medford	Griffin Crk 12.57KV Circ 5R204-Mainline	Aprv	2/28/2022	4/28/2022	**L**
or	Portland	Russellville Dist Automation Proj-FLISR	Aprv	3/31/2022	3/30/2021	**L**
or	Portland	Portland Willamette River Crossing Proj	Aprv	6/30/2025	03/28/19	**XL**
or	Portland	OR Multi Sub SCADA Installs & Upgrades	Aprv	12/31/2022		**Med 1**
or	Portland	PPL 500 BUILDING INSTALL HV INTERRUPTERS	Pend	12/31/2021		**Small**
or	Portland	PPL 700 BUILDING INSTALL HV INTERRUPTERS	Pend	12/31/2021		**Small**
or	Portland	Hollywood 5P208/5P204 Mainline Sect Plan	Aprv	12/25/2022		**Med 2**
or	Roseburg	Roseburg-Glide Tap Loop Feeder Improvmnt	Aprv	12/31/2022	08/18/21	**Med 2**
or	Roseburg	Recon Carnes 5U44 to Winston 5U49-4 Mile	Aprv	12/31/2023		**Med 1**

Final List
Approved
Feeder Improvements

Feeder Improvements:
Used for *functional* upgrades to a feeder (Addition or enhanced functionality to existing operational function that was not directly related to a customer reliability improvement)

Review 2022 Tracking Sheet: Substation Improvements

Cost Bracket Legend				
Small	Med 1	Med 2	L	XL
$0 - $50K	$50K - $300K	$300K - $1 M	$1M - $3M	$3M +

Project Name	2023 Plan ISD	FERC Code	State	Region	MVA Added	Cost Bucket
Aumsville New Substation and Transmission Loop D	6/15/2031	D	OR	PP	30	XL
Banfield New 115kV to 12.5kV Substation- D	6/15/2025	D	OR	PP	25	XL
Bend Area New Substation	6/15/2030	D	OR	PP		XL
Bend Sub Add Capacity and Transfer Load	6/15/2029	D	OR	PP		XL
Bend Substation 400 A Switches Replacement	5/15/2022	D	OR	PP	1.2	Med 1
Bond Street Add 2nd Transformer	5/15/2025	D	OR	PP	25	XL
China Hat Substation - Increase Capacity (25 MVA)	10/15/2029	D	OR	PP	25	L
Conser Road- Construct New 115kV to 20.8 kV substation D	10/15/2022	D	OR	PP	30	XL
Culver Sub Add Capacity	5/15/2024	D	OR	PP		XL
Dorris Sub- Capacity solution-Transformer (9.4 MVA)	5/15/2024	D	OR	PP	5	L
Empire and State Street Transformer Loading	5/15/2027	D	OR	PP	25	XL
Fraley Capacity Solution	6/15/2022	D	OR	PP	0.5	Med 2
Glendale Sub - Increase Capacity	5/15/2026	D	OR	PP	12.5	L
Henley Sub - Capacity Solution (New Sub - Net 19 MVA)	11/15/2032	D	OR	PP	25	XL
Hunters Circle Add Capacity	6/15/2029	D	OR	PP		XL
Independence Substation Capacity Relief	6/15/2022	D	OR	PP		Med 2
Jefferson Sub - Increase capacity 12.5 MVA	6/15/2022	D	OR	PP	7.5	L
Madras Sub Add Capacity	6/15/2029	D	OR	PP		L
Medford Sub Add Two 12.5kV Feeder Positions	11/15/2023	D	OR	PP		Med 2
Mill City Construct New Substation	11/15/2024	D	OR	PP	25	XL
Ochoco Substation Expansion D	5/15/2031	D	OR	PP		XL
Phoenix Area: New Substation	5/15/2029	D	OR	PP	25	XL
Prineville Sub Construct Three Breaker Ring Bus D	5/15/2031	D	OR	PP	25	XL
Prospect Point Transformer High-Side Fuse Replacement	5/15/2023	D	OR	PP		Med 2
Redmond Area New 115-12.47 kV Substation D	5/15/2026	D	OR	PP	25	XL
Rickreall- Construct New substation D	5/15/2024	D	OR	PP		XL
Rogue River Sub Capacity Relief	5/15/2024	D	OR	PP		Med 2
Shevlin Park Substation Increase Capacity	5/15/2022	D	OR	PP	25	XL
Wake Robin Ave- Construct New Substation D	5/15/2026	D	OR	PP	30	XL

Final List Approved Substation Improvements

Substation Improvements: Functional upgrades to a substation, not directly related to a customer reliability improvement.
Depending on the voltage of the substation equipment, these solutions may be either a Distribution investment or a Transmission investment.

Review 2022 Tracking Sheet: Reliability Improvements

Cost Bracket Legend				
Small	Med 1	Med 2	L	XL
$0 - $50K	$50K - $300K	$300K - $1 M	$1M - $3M	$3M +

Operating Area	Circuit ID	Description	Fund Y/N	Project Type	Cost Bracket
LINCOLN CITY	4A338	Install recloser and coordinate	Y	FIOLI	Med 1
LINCOLN CITY	4A312	Auto splice review, zone 2 FIOLI	Y	FIOLI	Small
LEBANON	4M63	Zone 2/3 FIOLI and install recloser	Y	FIOLI	Med 1
LEBANON	4M204	Install recloser and coordinate	Y	FIOLI	Med 1
STAYTON	4M19	Install recloser and coordinate	Y	FIOLI	Med 1
STAYTON	4M120	Visibility strips and pole protection		Circuit Hardening	
HOOD RIVER	5K44	Install reclosers as switches	Y	Saving SAIDI	Small
PORTLAND	5P274	Visibility strips and pole protection		Circuit Hardening	
PORTLAND	5P393	Zone 1 FIOLI	Y	FIOLI	Med 1
BEND/REDMOND	5D229	Zone 1 FIOLI	Y	FIOLI	Med 1
GRANTS PASS	5R133	Enhanced Fault Indication (EFI)	Y	EFI	Small
GRANTS PASS	5R106	Enhanced Fault Indication (EFI)	Y	EFI	Small
GRANTS PASS	5R52	Enhanced Fault Indication (EFI)	Y	EFI	Small
GRANTS PASS	5R65	Enhanced Fault Indication (EFI)	Y	EFI	Small

Final List:
Approved
Reliability Improvements

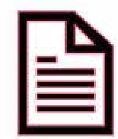
Functional Upgrade – Reliability
(*Not From DSP Studies*):
Used for functional upgrades to a feeder, substation or transmission line for the purpose of improving circuit reliability that are directly associated with a customer reliability improvement.
(These items are identified and prioritized through centralized reliability analysis and specific improvement initiatives, not through regular DSP Studies)

Review 2022 Tracking Sheet: Reliability Improvements
(Continued)

Cost Bracket Legend				
Small	Med 1	Med 2	L	XL
$0 - $50K	$50K - $300K	$300K - $1 M	$1M - $3M	$3M +

Operating Area	Circuit ID	Description	Fund Y/N	Project Type	Cost Bracket
KLAMATH FALLS	5L19	FIOLI and Enhanced Fault Indication (EFI)	Y	FIOLI	Med 1
COOS BAY/COQUILLE	4C41	Recloser Replacement	Y	FIOLI	Med 1
COOS BAY/COQUILLE	4C42	Recloser Replacement	Y	FIOLI	Med 1
MEDFORD	5R55	Full Circuit FIOLI	Y	FIOLI	Small
MEDFORD	5R68	Full Circuit FIOLI	Y	FIOLI	Small
ROSEBURG/MYRTLECREEK	4U5	FIOLI and Enhanced Fault Indication (EFI)	Y	EFI	Small
ROSEBURG/MYRTLECREEK	5U32	Small FIOLI and Reconfigure	Y	FIOLI	Small
PENDLETON	5W202	Full Circuit FIOLI/DSP Transition	Y	FIOLI	Med 1
PENDLETON	5W201	Full Circuit FIOLI/DSP Transition	Y	FIOLI	Med 1
PENDLETON	5W402	Full Circuit FIOLI/DSP Transition	Y	FIOLI	Med 1
PENDLETON	5W406	Pole Fire Mitigation	Y	PFM T1	Small
BEND/REDMOND	5D223	Full Circuit FIOLI	Y	FIOLI	Med 1
BEND/REDMOND	5D22	Full Circuit FIOLI	Y	FIOLI	Med 1
BEND/REDMOND	5D52	Reconductor:Reliability	Y	Circuit Hardening	Med 1
MEDFORD	5R103	Gang Switch	N		Small

Final List:
Approved
Reliability Improvements



Break – 10 Minutes



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4) Pilot/Transitional Study Areas and Grid Needs






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Preliminary Grid Needs – Pilot/Transitional Study Areas

Circuit/Area Characteristics:

- Suburban/rural feeders
  - low load density with high circuit miles
- Small conductor on the mainline, thus less load capacity and higher voltage drop
  - Does not necessarily = less DG readiness
- Historically higher DER adoption rates
  - Among Pacific Power service territory
- Ranked higher in DG capacity and readiness than other areas
  - Including necessary substation equipment

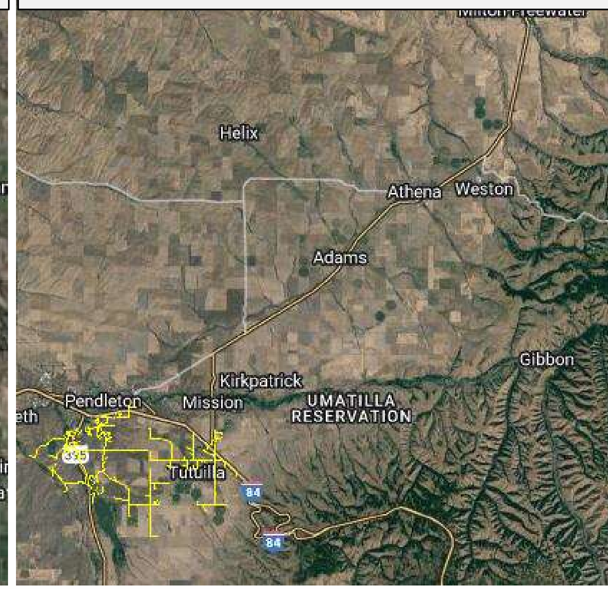
Preliminary findings/Grid Needs

Klamath Falls – Crystal Springs – 5L45

- Projected peak summer load drives overload on conductor
- Phase imbalance
- Low voltages on circuit

Pendleton – McKay – 5W856

- No grid needs due to recent investment upgrades
- Potential low voltages in outlying areas



Grid Needs – Pendleton

Circuit Details:
- Circuit 5W856 served from McKay substation
- Circuit operates at 12.47 kV
- Peak loading occurs during summer
- Daytime minimum loading occurs during the spring
- Overall Customer makeup:
    - 1,802 Total number of customers
        - 1,641 Residential
        - 28 Irrigation
        - 131 Commercial
        - 1 Industrial
        - 1 Hospital

No Grid Needs Found:
- Ad-hoc study performed during planning study cycle resolved any Grid Needs for area.

What Grid Needs could we have found if the Ad-hoc study did not occur?

Would it have been a good candidate for NWS?

Grid Needs – Pendleton

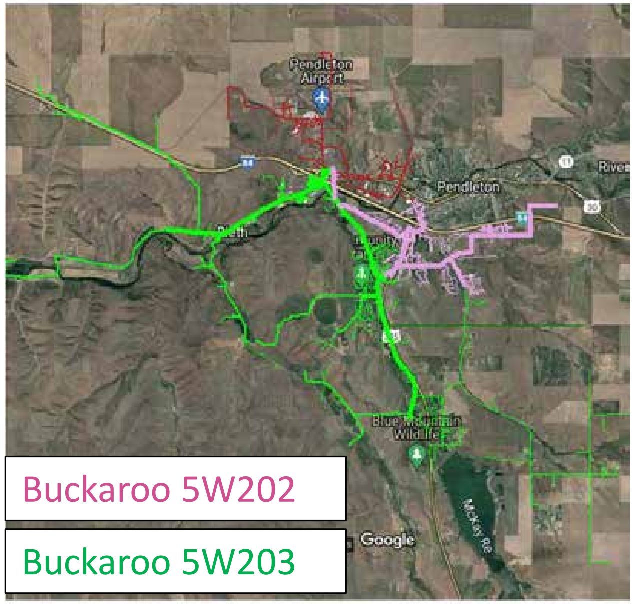
Model Scenario – Analyze the previous circuits as if the new substation and Ad-hoc study did not exist

McKay 5W856 is made up of sections of Buckaroo 5W202 and 5W203 served from Buckaroo Substation.

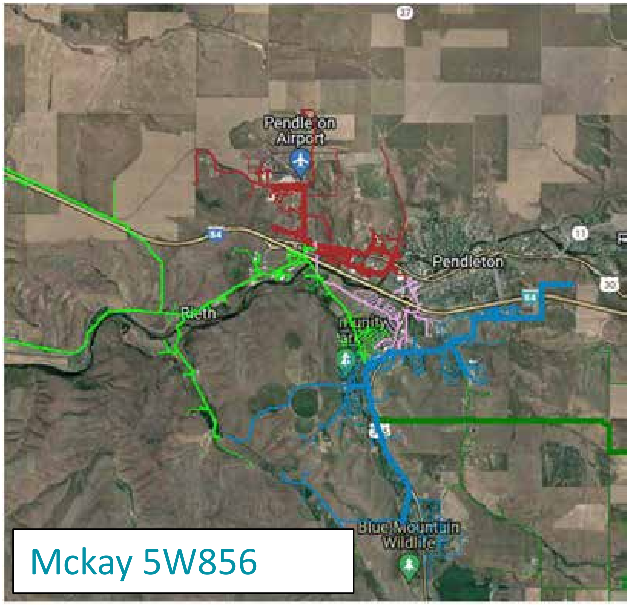
Scenario analyzes the two circuits without the new substation and applies the PV and EV forecast for Buckaroo 5W202 and 5W203

After removing the impact of the Ad-hoc study …
No Grid Needs Found

Before:



After:

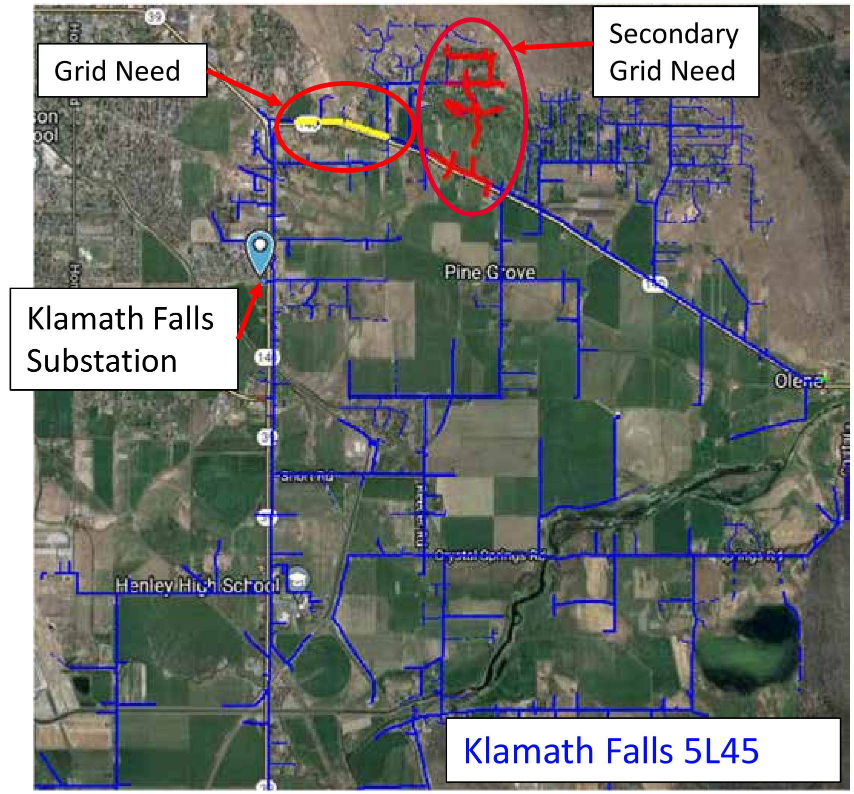


Grid Needs – Klamath Falls

Circuit Details:
- Circuit 5L45 served from Klamath Falls substation
- Circuit operates at 12.47 kV
- Peak loading occurs during summer
- Daytime minimum loading occurs during the spring

- Overall Customer makeup:
  - 1,499 Total number of customers
    - 1,196 Residential
    - 155 Irrigation
    - 145 Commercial
    - 3 Industrial

Grid Needs:
- Study identified an overcapacity issue causing conductor overload
- Also causes low voltage downstream

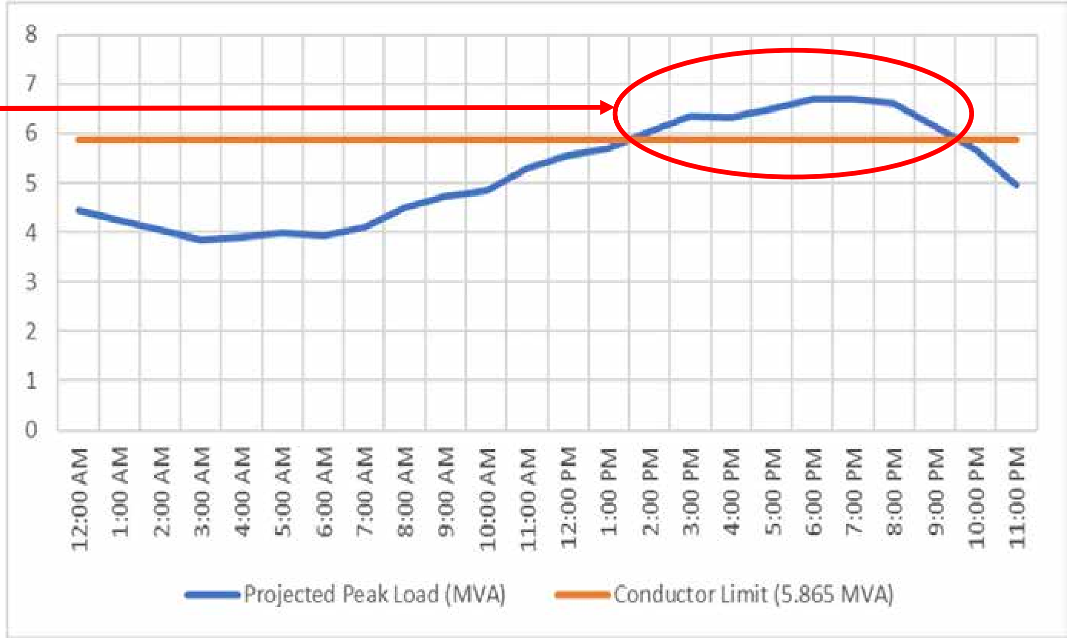


Grid Needs – Klamath Falls

Grid Need:

- Approximately 850 kW over existing conductor limit
- Occurs ~20 – 50 hours total per year in Summer ~ June through August

- Number of customers downstream of issue:
  - 511 Total customers (37% Summer kWh)
    - 461 Residential (24%)
    - 33 Irrigation (13%)
    - 17 Commercial (1%)
    - 0 Industrial (0%)

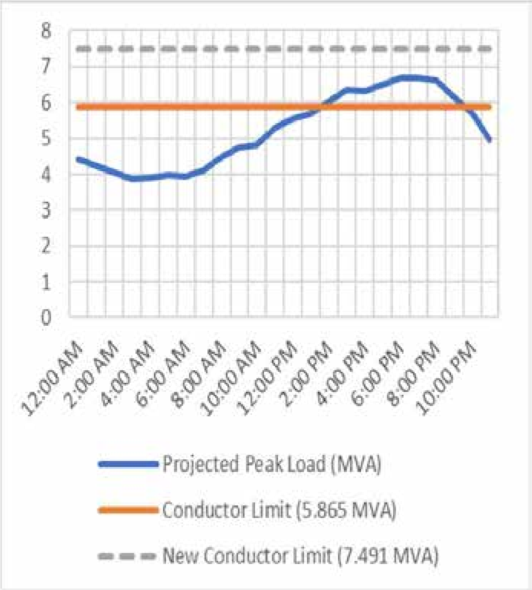


Based on the Grid Need and characteristics of circuit, there are several solutions available. All have different effects in terms of complexity, performance, and reliability.

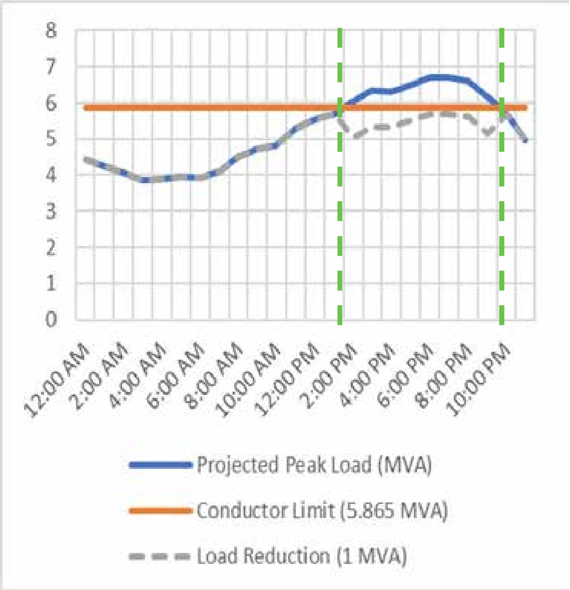
Grid Needs – Klamath Falls

List of hypothetical solutions:

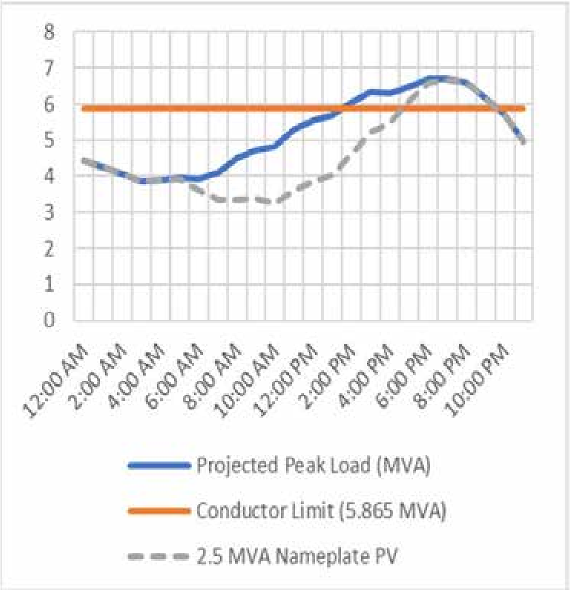
Traditional Wires Solution –
Reconductor overloaded conductor



Demand Side Management (DSM) Solution - Load reduction

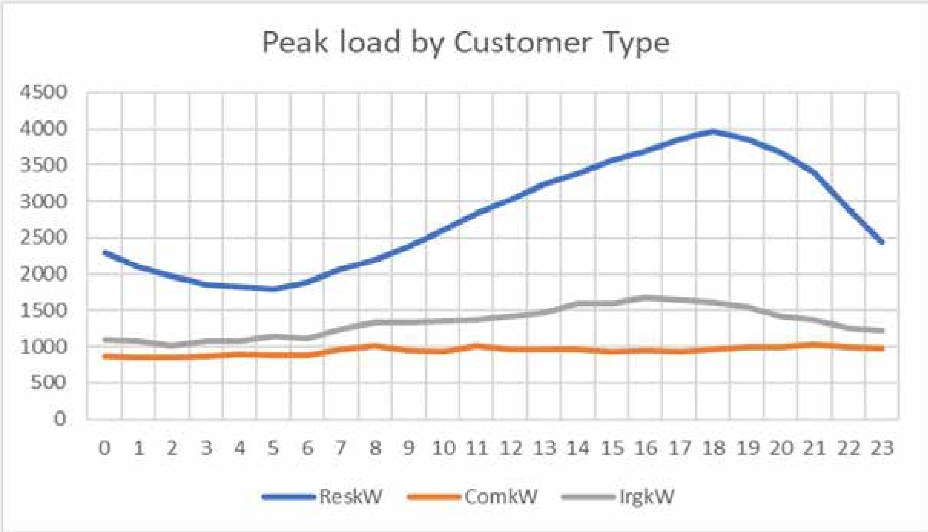


Non-Wires Solution -
Solar Only



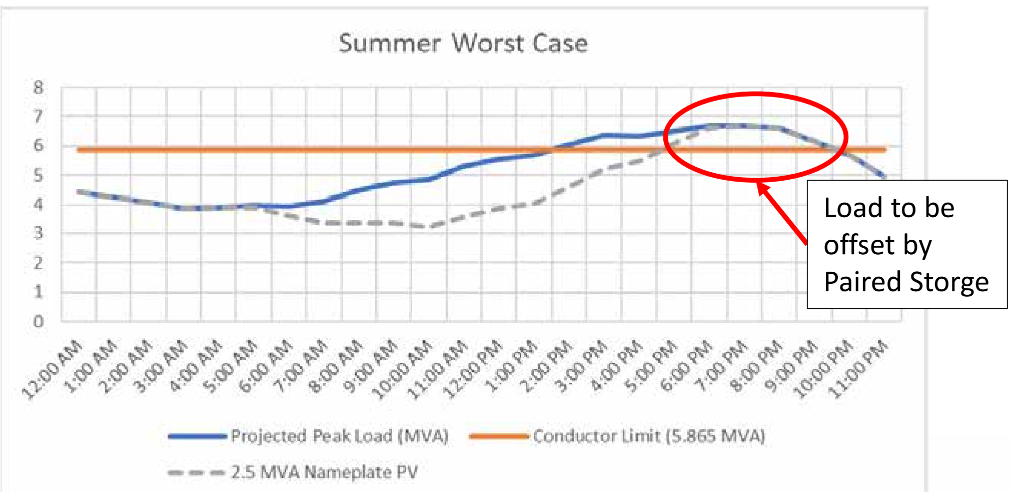
Hypothetical Load Reduction

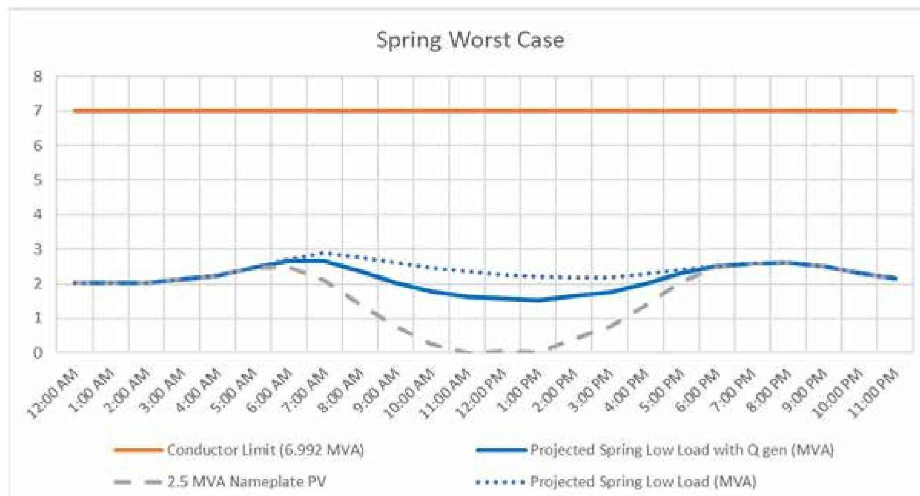
- Need critical mass of customers to participate in order to meet reduction target
- Peak Load day might require 9 or more hours of load reduction
- Needs to be adjusted for growth over time
- Amount & type of customers involved TBD



Hypothetical Solar + Storage

- Generation Study required in addition to Load Study
  - Different time of year and study assumptions
- Est 3.5 MWh needed for peak load (excluding buffer capacity), but mix of solar and PV TBD
- Needs to be adjusted for growth over time
- Advanced automated system required to control the smart inverters





Klamath Falls Grid Need and Potential Non-Wires Solutions

Klamath Falls – Crystal Springs – 5L45
- Projected peak summer load drives overload on conductor
- Phase imbalance
- Low voltages on circuit

Non-Wires Solutions PAC is Considering for evaluation
- Solar
- ***Solar + Battery Storage***
- Load Control, Curtailment, Demand Response
- Targeted DSM
- Other DER

Non-Wires Solutions Proposed by Stakeholders:

Farmer's Conservation Alliance:
- ***Solar + Battery Storage***

OSSIA:
- Pilot use of ***Smart Inverters***
- Pilot "Solarize Campaign"

Opportunity to Evaluate *Solar + Battery Storage, w/Smart Inverter*
- Work with local KFalls stakeholders + FCA + OSSIA
- Develop skillset to model and evaluate solar + storage and ID system impacts

2nd NWS – TBD Seek input from KFalls Stakeholders

Next Steps with Pilot Project

- Meeting with stakeholders in Klamath Falls 7/7
- Continue to engage FCA and OSSIA to refine pilot assessment
- Update models with more refined PV/EV adoption rate data from third party contractors
- Produce required equipment amounts and cost estimates

Initial Lessons Learned

DSP requires significantly more than historical approach…

- Much more Data Intensive
  - Requires new data sources and increased granularity for existing data
  - Analysis requires development of 24-hour representative curves instead of single peak point
  - Requires feeder SCADA telemetry instead of manually recorded data
  - Scaling up for DSP requires new toolsets/systems and analytical capabilities

- Broader and More Frequent Outreach
  - Significantly higher degree of community involvement
  - Discussions require deeper education to cover increasingly complex subjects
  - Expanding outreach processes to increase transparency

- Significant Changes to Internal Processes
  - Improve cross-functional/cross-department collaboration
  - Increased reporting requirements (not just DSP)
  - New groups, new responsibilities, and new procedures
  - New regulatory requirements

5) Update on Community Engagement at the State and Local Level



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Overlap of Regulatory Initiatives for Stakeholder Engagement

Several Community Engagement Regulatory Initiatives that Share Similar Goals

- Engaging potentially overlapping stakeholder groups
  - UM 2005 and Order No. 20-485 - Community Engagement Plan to prepare and implement a Distribution System Plan
  - HB 2021 – Community Benefits and Impacts Advisory Group (CBIAG)
  - UM 2225 – Community engagement strategy to support HB 2021

Section 6. Utility Community Benefits and Impacts Advisory Group

(1) An electric company that files a clean energy plan under section 4 of this 2021 Act shall convene a **Community Benefits and Impacts Advisory Group**.

The members of the electric company's Community Benefits and Impacts Advisory Group will be determined by the electric company with input from stakeholders that **represent the interests of customers or affected entities within the electric company's service territory**.

Members must include representatives of environmental justice communities and low-income ratepayers and may include representatives from other affected entities within the electric company's service territory.

Community Input Group Update

PacifiCorp is committed to the formation of the Community Input Group (considering renaming **Oregon Equity Advisory Group)**

- We see great benefit to forming a single equity advisory group in Oregon that focuses on Clean Energy planning including DSP.
- We are working with stakeholders to establish a path forward as we thoughtfully consider requirements of UM 2005 and UM 2225.
- This specific group will not be formed in time to provide input on DSP Part 2 but other engagement opportunities are available to get community and stakeholder feedback prior to filing.
- As we move forward, we plan to use the Oregon Equity Advisory Group as a sounding board for the evolution of PacifiCorp's DSP process.

Statewide Engagement Strategy

- Filed **initial** customer engagement proposal with Commission on April 21, 2022
- Provided mechanisms and processes for meaningful stakeholder engagement on utility initiatives including the Distribution System Plan and the Clean Energy Plan
- Proposed a hybrid stakeholder engagement model
    - Relies upon existing engagement processes within IRP
    - Develops new processes for engagement
- Currently identifying a broad potential participant list to reflect representatives of Environmental Justice communities within our service territory
- PacifiCorp will engage with frontline communities, tribes, equity and environmental justice organizations, community-based organizations and others in Oregon to gauge their interest in membership
- Updated Engagement Strategy to be submitted in July (anticipated after July workshop)
- The engagement strategy will continue to be refined over time

Local Engagement – Klamath Falls

- Received three proposals for Non-wires Pilot evaluation from Farmer's Conservation Alliance and OSSIA (covered previously).
  - Agreed to focus on Solar + Storage (with limited Smart Inverter functionality) as one of the NWS assessments.
  - Working with FCA and OSSIA to confirm assessment framework, assumptions and approach
- Also - engaging local stakeholders in Klamath Falls to participate in review of identified grid need and discuss potential solutions (including NWS)
  - Meeting with stakeholders in Klamath Falls 7/7 for background on DSP, Grid Needs and potential solutions
  - Anticipate second meeting in late July to review preliminary results from assessments and gather further input.

Planning to Attend:	Jeremy Morris – Klamath County Public Works Department – Director Roberto Gutierrez – Klamath Community College – President (Not available, may send delegate) Ellsworth Lang – Tentative (Participating as Pacific Power customer) Paul Simmons – Klamath Water Users Association – Executive Director Heather Harder – Klamath County Chamber of Commerce – Executive Director Randy Cox – Klamath County Economic Development Association – Executive Director Brandon Fouler – Klamath County Emergency Management Department – Director Joe Wall – Klamath Falls City Planner Darin Rutledge – Klamath Falls Downtown Association – Executive Director Christina Zamora – Klamath/Lake Community Action Service (TBD – confirming availability)

Questions?

6) Part 2 Schedule and Topics






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Part 2 - Schedule and Topics

- Schedule
  - OPUC DSP Workgroup Meetings – Expect one more meeting in late July
  - Pacific Power Final DSP Workshop – July 21
  - Distribution System Plan (Part 2) to be filed on August 15, 2022

- Pacific Power July Stakeholder Workshop – Proposed Topics
  - Review refined Load Forecast including adoption for DER and EV
  - Non-wires Solutions (NWS) – Review Initial Assessments
  - Review highlights for Short-Term Plan

Additional Information

- DSP Email / Distribution List Contact Information
  - DSP@pacificorp.com
- DSP Presentations
  - Pacific Power Oregon DSP Website (Now includes Spanish Language version)
- Additional Resources
  - Pacific Power's DSP Part 1 Report
  - DSP Pilot Project Suggestion Form
  - Pacific Power's 2019 Oregon Smart Grid Report
  - Pacific Power's Oregon Transportation Electrification Plan
  - PacifiCorp's Integrated Resource Plan

Thank You!






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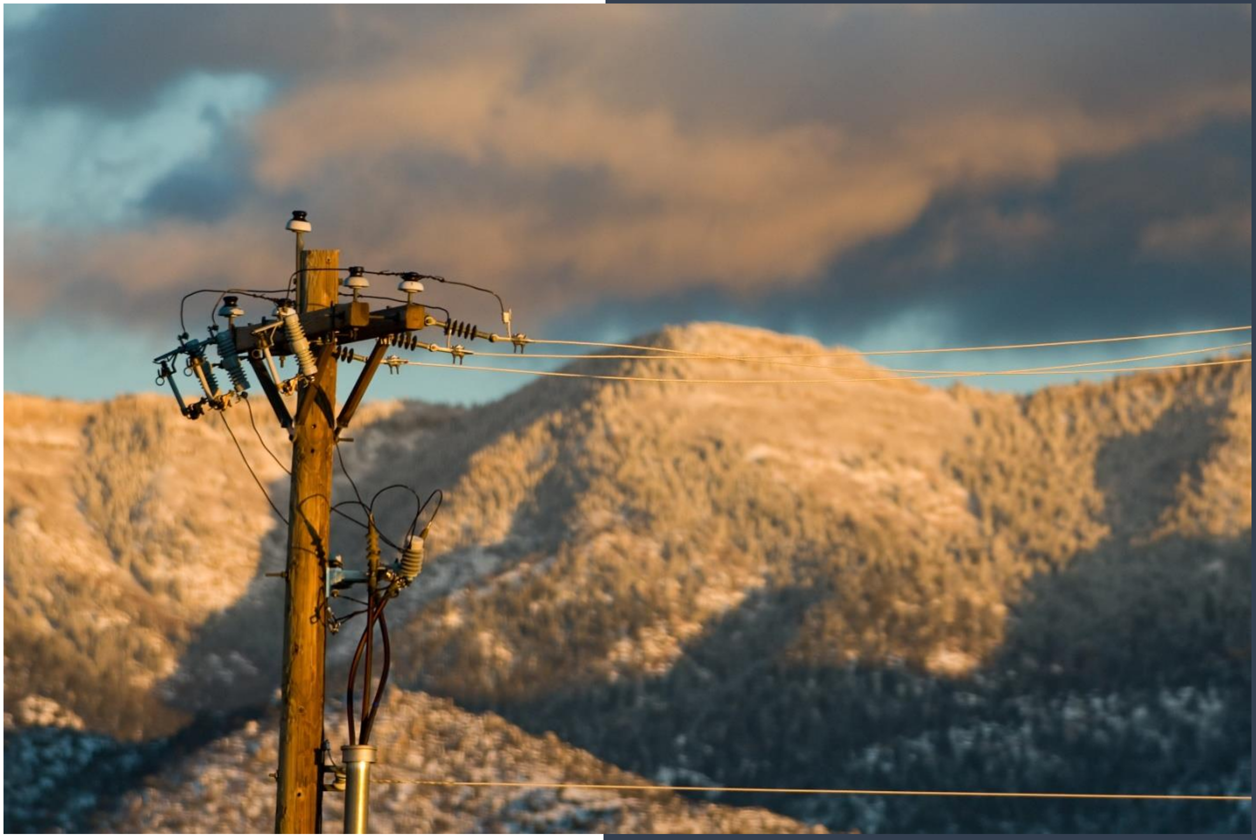
Appendix D: Klamath Workshop Summary, July 7, 2022

Klamath Falls Workshop Summary



July 7, 2022

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Klamath Stakeholder Group – Meeting Summary

On July 7, 2022, PacifiCorp held an in-person workshop in Klamath Falls, Oregon with local stakeholders from the Klamath Falls region. Representatives from the Company's Distribution System Planning (DSP) team, the Regional Business Manager (RBM), and local field engineers covered a variety of topics including an overview of PacifiCorp's distribution system planning (DSP) process and the Oregon Public Utilities Commission requirements on DSP, a discussion of the local grid need found in the area and proposed non-wire solutions (NWS) concepts. The meeting also provided an opportunity to obtain input on the proposed NWS preferences from the group, as well as collect feedback through open dialog and a survey on transitioning to a cleaner energy future. This document provides a summary of the meeting and survey objectives and results.

Overview of Grid Need and NWS Options - Klamath Falls

Prior to providing the survey, PacifiCorp provided a summary of the DSP process, an overview of the local grid need found in the area and provided a summary of the wires and non-wires solutions that were evaluated to address the grid need.

The two proposals submitted by stakeholders to be evaluated in Klamath Falls included solar + storage with smart inverter from Farmers Conservation Alliance (FCA) and Oregon Solar and Storage Industries Association (OSSIA) proposals (1st option) and PacifiCorp's demand response option (2nd option).

Since the 2nd option was PacifiCorp selected, the Company was seeking input from Klamath stakeholders on whether they would prefer to proceed forward with the proposed option or if a different option was preferred. To compare each of the options a set of high-level categories were developed by the Company. These categories were summarized in a comparison matrix as shown in Table 1, which was provided to the Klamath stakeholders to facilitate discussion and to solicit their input for the 2nd NWS option. Each NWS category was described to stakeholders as follows:

Technical Feasibility: (higher feasibility is preferred) Can this solution meet (or meaningfully support meeting) the grid need identified? This includes some assessment of the maturity of the proposed solution and a preliminary understanding of the specific requirements of the need (e.g., time of day, time of year, infrastructure needs, etc.). For example, solar by itself does not meet grid needs that exists after the sun has set.

Estimated Timeline to Implement: (shorter time frames are preferred) How long, from now, would the solution realistically take to be in place to address the grid need? Overcapacity on the Crystal Springs circuit should be addressed within two years to avoid customer outages. An NWS taking more than two years would be rated less than one that could be completed within two years.

Complexity: (lower complexity is preferred) Generally, how many factors must be developed, coordinated, managed and executed to enable the solution to meet the identified grid need? Examples: A targeted energy efficiency NWS that required development of new programs, hiring of new contractor support, and a significant need for new marketing would indicate high complexity. A targeted energy efficiency NWS that used existing programs that were already fully supported might be a medium to low complexity. A traditional wires solution that does not require ongoing management would be a low complexity solution.

Cost: (lower cost is preferred) What is the total cost of solution required to meet the grid need?

Reliability of Solution: (high reliability is preferred) Generally as outlined, can the solution reliably meet the grid need identified? For example, a DR program NWS implemented to meet a peak time grid need where customers can opt out of events might be a medium for reliability.

Customer Benefits: (high Is preferred) What are the benefits that might come to end customers through implementation of the solution? For example, solutions like solar + storage are likely to have a high rating because they provide backup service to customers and reduce customer utility bills.

Community Benefits: (high is preferred) How does this solution benefit the community more broadly? Elements to consider in this area include emissions reductions from implementation of renewable DERs on a circuit, increases in community resilience from broader installation of storage, etc. For example, the solar + storage would provide backup power during an outage.

Table 1: Wires and NWS Comparison Matrix

NW Solution/ Category	Solar + Storage	Demand Response	Energy Efficiency	Solar	Wires Solution
Technical Feasibility	Med	Med	Low	Does Not Meet Need	High
Estimated Timeline to Implement	2-3 Years	1-2 Years	1-2 Years	2-3 Years	< 1 Year
Complexity	High	High	Med	Med	Low
Cost	$$$$	$$	$$	$$$	$$
Reliability of Solution	Med	Med	High	Low	High
Customer Benefits	High Backup power, on-site generation	Med Receive Customer Incentives	High Reduce kWh use	High On-site generation, reduce emissions	Med Does not require customer action, High Reliability
Community Benefits	High Reduce emissions	Med Reduce emissions	High Reduce emissions	High Reduce emissions	Med

Preliminary estimates based on early analysis. Subject to change based on completion of assessments

Based on feedback from Klamath stakeholders, the second NWS concept preferred was energy efficiency. Main reasons for selection of an energy efficiency option were:

- Lower cost option and concerns for low-income people in the area
- Interest in using ETO more
- Ease of getting energy efficiency into homes

PacifiCorp agreed to proceed with evaluating energy efficiency as the second NWS concept. It is noted that many of the stakeholders expressed keeping the traditional wire option to solve the grid need.

After receiving feedback on the NWS, a survey was provided to Klamath Falls stakeholders to gain more insight into their community needs/concerns. The summary of the survey responses are provided in the following sections.

Transition to Cleaner Energy – Short Survey

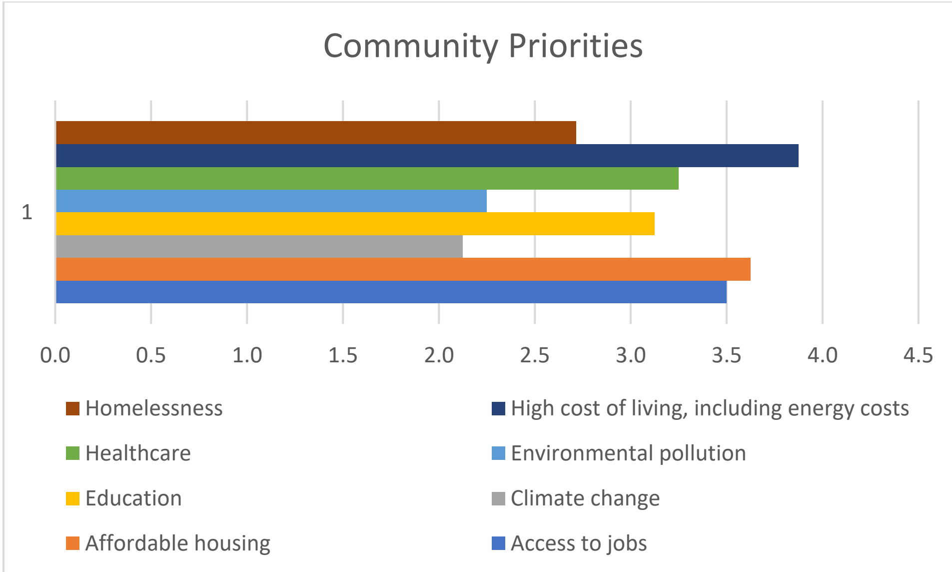
Participants were asked three questions about the transition to cleaner energy. The questions were the same as those asked in the overall survey completed by third party vendor MDC that PacifiCorp conducted in Spring 2022. The overall objectives of the survey were to obtain high-level stakeholder feedback on benefits associated with cleaner energy and understand the concerns of local stakeholder on non-wire solution options. The graphs provided in the next sections represent the average score from the participants.

Overall, the participants expressed that their highest concerns for the community in transitioning to a clean energy future were high cost of living (including energy costs), affordable housing and access to jobs. The potential benefits were viewed as creating more jobs, potentially spending less on energy and increasing innovation/technology to the area. Top concerns for transitioning to a cleaner energy were costs and reliance on variable clean energy sources.

Question #1: Community Priorities

We want to hear from you about how the transition to clean electricity and shaping a resilient and reliable system could also foster an equitable future in their individual communities.

Using a scale of 1-5, where 1 is "not significant" and 5 is "extremely significant," how would you rate the following challenges your community faces today?



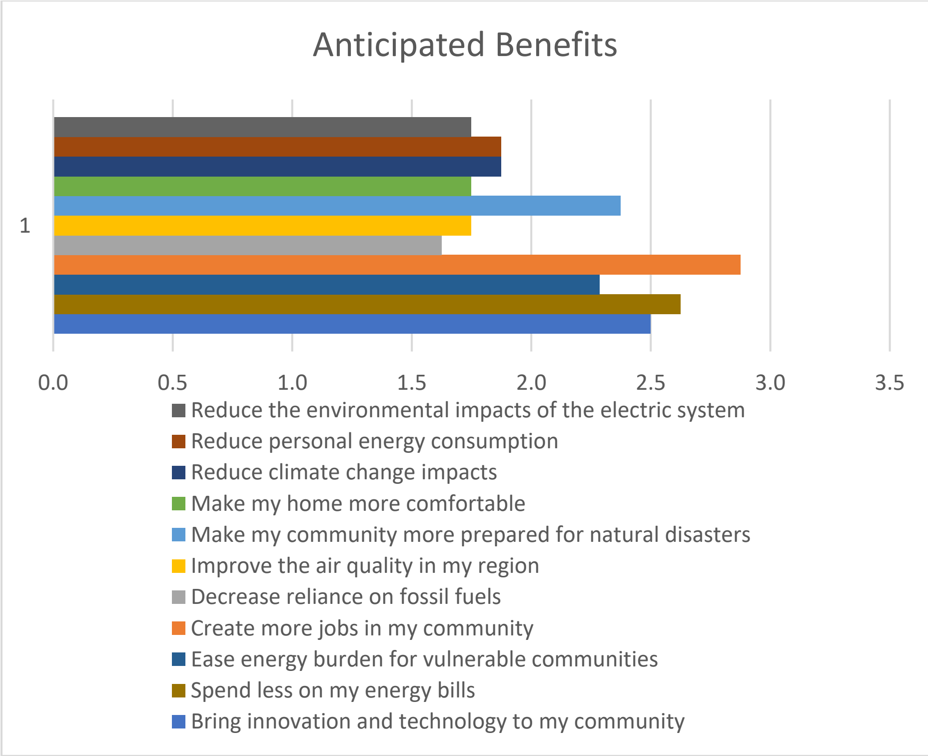
Scale: 1 not significant to 5 extremely significant

Open Comments on priorities and concerns for the community:

- Workforce, Attainable housing (80% - 120% MFI), Childcare, Water for agriculture.
- Community growth economically and infrastructure support.
- Fires/smoke statewide, Drought/Water local to Klamath area
- Housing in general
- Housing (not just low income, need workforce housing), Daycare desert - not enough daycare for working people, Climate change because it affects the policies that impact industries.
- Potential extreme and unpredictable variability in power demand (in a year-to-year sense).

Question #2: Anticipated Benefits

Thinking about transitioning to cleaner electricity, please look through the series of potential benefits for you and your community. For each, please indicate if it is of low importance, medium importance, or high importance.



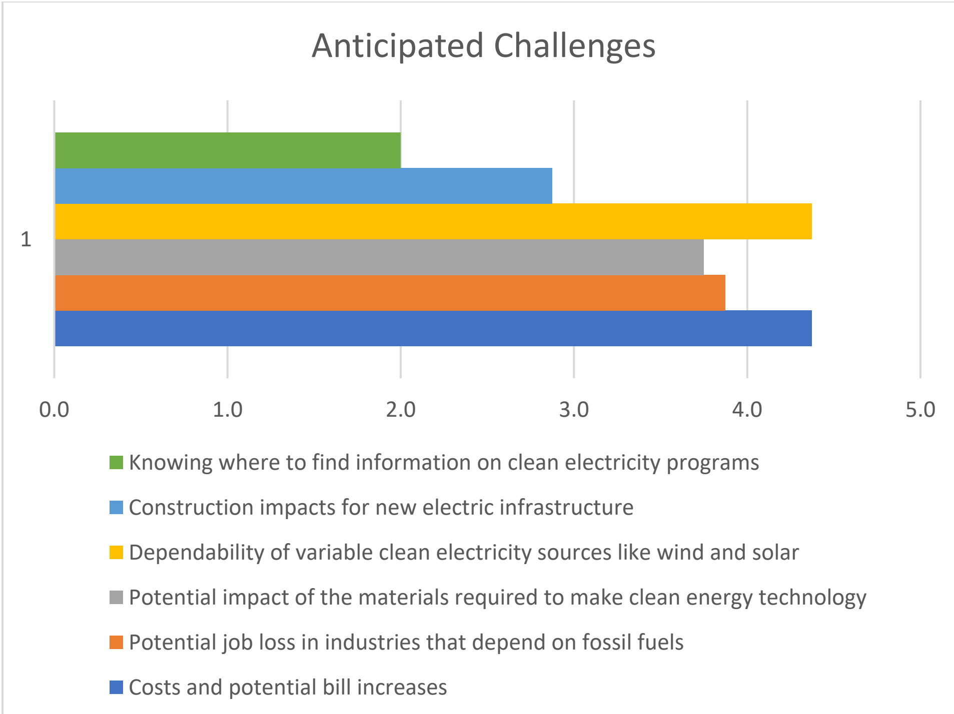
Scale: 1 Low Importance to 3 High Importance

Open Comments on anticipated benefits to customer or the community:

- Power available for companies requiring clean energy, long duration energy storage projects, clean tech jobs for OTI Grads, Energy hub in Klamath Falls for Oregon
- Positive impact to natural resource issues, increased agility for development (Time and $)
- Low-income community, so cost savings are always a benefit, being prepared for future with innovation and technologies is important
- Positive branding for the region

Question #3: Anticipated Challenges

Thinking about our transition to cleaner electricity, how would you rate your level of concern for the following potential challenges. Please use a scale of 1-5, where 1 is "not at all a concern" and 5 is a "significant concern."



Scale: 1 not at all a concern to 5 significant concern

Open comments on the potential challenges with transition to a cleaner energy for their community:

- Significant damage to wildlife from wind turbines, Dependence on other countries producing key elements of clean energy components, Cost of energy across community.
- In a time when energy consumption is going to increase (EVs etc.) the transition of generation seems problematic. Comparison on Green Energy to traditional does not add up - Solar and Wind cannot replace hydro, and nuclear options, especially if fossil fuel generation of removed.
- Will transition require batteries for storage overnight or during weather related emergencies?
- How it impacts large employers like agriculture, Kingsley, wood products, etc.

Workshop Feedback

The meeting concluded with a general discussion of the usefulness of this type of local workshop for distribution system planning. A questionnaire was provided to participants to gather feedback on the workshop and opportunities for future improvements to local-type meetings.

Question #1: Did this workshop provide helpful information to you in your role?

All participants found the workshop helpful to their role. Additional comments:

- I have some background in this, but thought the workshop was good.
- good basic information about how our power is distributed
- It is more complex that I could imagine

Question #2: Were the topics relevant to you and your role?

General consensus that the topics were relevant to their role in their community organization. Additional comments provided:

- Topics were relevant.
- Impacts our organization
- Good basic information about how our power is distributed.

Questions #3: Were you able to provide input on the perspectives for your community?

All agreed they were able to share perspectives and provide input for their community

Additional comments provided:

- May have more now that I'm more aware and have some time to think about it.
- It is more complex that I could imagine.
- Good basic information about how our power is distributed.

Question #4: Do you want us to hold a meeting to provide follow up on the Non-wires solutions?

All but one respondent expressed interest in a follow-up meeting. A single respondent was unsure and preferred to wait until after the filing was made with the PUC.

Question #5: Would you prefer to be informed before implementation?

All participants agreed. Additional comments:

- I believe in seeing all pieces of the process.
- Dialog is important

Questions #6: Who else should be involved?

Several felt that the stakeholder group that was invited to participate covered different perspectives and had good discussion. There were several other types of stakeholders that were identified such as industrial users, elected Official from county, and general community.

Question #7: Where in the process would you like to be involved in the future?

Comments varied in where people would like to be involved from anywhere or any point in the process to where meaningful before each decision point or when feedback is helpful.

Question #8: Other Comments or Input?

Participants express gratitude for being included in the workshop, and provided these other comments:

- Good overall discussion and informative.
- Find an emotional connection to create a campaign to change behavior.
- Good discussion overall