PNNL-39164

Power Lane County
Electric Grid Handbook

July 2026



LANE COUNTY OREGON

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PNNL-39164

Power Lane County Electric Grid Handbook

A comprehensive assessment of Lane County's electric system

July 2026

Edited and assembled by: Ali Trueworthy, Ian Hermanson, Brooke Marten, and Michael Barthelmes, Pacific Northwest National Laboratory

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Prepared for
The staff of Lane County, Oregon and the members of the public whom they serve. The information provided herein is accurate to the best information available at the time of writing. However, much of the data and practices that we discuss will change with time.

Pacific Northwest National Laboratory
Richland, Washington 99354

Executive Summary

In 2024, Lane County, Oregon, was selected to participate in the U.S. Department of Energy's (DOE's) Energy to Community (E2C) program. Through the program, national laboratory researchers from Lawrence Berkeley National Laboratory (LBNL), Pacific Northwest National Laboratory (PNNL), and the National Laboratory of the Rockies (NLR) provide three years of technical assistance to Lane County and their project partners: the Center for Rural Livelihoods, Springfield Utility Board, and Emerald People's Utility District. The project, named ***Power Lane County***, aims to improve the local electric system's affordability, reliability, and resilience in the face of natural hazards and potentially rising loads.

The ***Power Lane County Electric Grid Handbook*** establishes a foundational understanding of the electric system in Lane County to inform community engagement, education, and analysis in future project phases. This Handbook synthesizes public data and utility and stakeholder engagement, including utility interviews. It consists of three parts subdivided into nine total chapters and concludes with a review of identified Power Lane County project opportunities.

Part I: Foundations introduces the fundamental technologies, organizations, policies, history, and conditions that shape the modern U.S. electricity system. This information supports informed participation in energy decision-making. Part I has two chapters. ***Chapter 1: How Does the Lane County Electrical System Work?*** differentiates between energy and electricity before providing a foundation of how Lane County's electric system works, how it evolved, and who manages it today. Lane County's utilities participate in a complicated and dynamic system of electricity generation, transmission, and exchange involving entities like federal regulators, independent power producers, the Bonneville Power Administration (BPA), regional power markets, and end-users. Nine of the 10 electric service providers in Lane County are consumer-owned utilities that buy most of their electricity from BPA, the federal entity that markets and transmits power from the Pacific Northwest's system of federally owned hydropower dams. ***Chapter 2: What Policies Impact Lane County's Grid?*** reviews state and federal policies that impact grid management, development, energy efficiency and conservation efforts, and environment and resilience efforts related to energy.

Part II: Lane County Utilities reviews the external factors that impact Lane County's local electric utilities and the actions utilities can take to manage those impacts. Changes in the regional electricity system present challenges to Lane County utilities and can impact end-users. Utilities must navigate these challenges while fulfilling two key responsibilities: balancing electric load and generation, and balancing costs and revenues. ***Part II*** has four chapters. ***Chapter 3: Regional Dynamics Impacting Lane County Utilities*** examines the impacts of Western power market restructuring, resource adequacy, operational reliability, and rising costs on Lane County utilities. Despite these changes, utilities are expected to meet evolving customer and stakeholder expectations, including providing affordable service, serving changing electric loads, promoting efficient energy consumption, and providing reliable and resilient service. ***Chapter 4: Expectations of Lane County Utilities*** describes best practices for meeting those expectations, examining which of those practices are being implemented by utilities in Lane County, and where there are opportunities for improvement. Opportunities exist in the areas of rate design, demand management, and the valuation of resilience benefits. Lane County utilities are exposed to significant natural hazards that are increasing in both severity and frequency in the Pacific Northwest. ***Chapter 5: Utility Natural Hazard Mitigation and Preparedness*** summarizes Lane County's exposure to wildfire, earthquake, storm, and security hazards. This section includes best practices for utilities to mitigate risk from each of these

hazards. Opportunities for improvement emerge in the areas of risk modeling and management, wildfire mitigation, and wildfire hazard characterization. ***Chapter 6: Available Technologies for Grid Modernization*** presents a descriptive library of technologies available to utilities to improve distribution grid reliability and resilience. Technologies are divided into four groups: operations and hardening, visibility and monitoring, remote control and automation, and integrated management platforms.

Part III: Community Energy Baseline examines Lane County's electricity- and resilience-related community resources, vulnerabilities, and goals, and identifies local factors that impact energy decision-making for utilities, investors, and local governments. It has three chapters. ***Chapter 7: Local Electricity Generation Resource Availability*** maps the availability of solar, wind, and biomass electricity generation across Lane County. NLR's Annual Technology Baseline is used to estimate cost and performance for each energy technology in Lane County. As wind and solar technologies mature, they will become more economically competitive with current, low-cost Pacific Northwest power sources. Choosing where to invest in energy reliability and resilience projects and strategies is a challenge for Lane County planners, utilities, and partners. ***Chapter 8: Geospatial Data to Inform Project Prioritization*** maps socio-economic metrics and critical facility locations across Lane County to help decision makers identify where investment is most needed. Lane County cities and communities undertake energy and resilience planning to strategize community projects, policies, and coordinated actions. ***Chapter 9: Community Energy and Resilience Planning*** reviews available resilience and energy plans from Lane County municipalities to inform planning future coordination. By evaluating current practices against best practices, we identified key gaps and opportunities that could inform future projects that advance the Power Lane County goals.

The final chapter, ***Opportunities for Improving Lane County Electric System Affordability Reliability, and Resilience*** consolidates the various opportunities for improvement discussed throughout the Handbook. Opportunities are organized across five categories: utility studies and programs; collaborative evaluation, planning, and framework development; city efforts; public accessibility, education, and outreach; and countywide modeling.

The following ***Key Findings Summary*** synthesizes important electricity system takeaways from this document into a concise list.

Key Findings Summary

- Lane County is served by a high density of mostly small publicly owned utilities, which creates a patchwork of service areas, utility policies, local oversight and programs. This creates ***challenges for coordination and planning***.

- For Oregon publicly owned utilities that ***rely on low-cost BPA hydropower***, rising customer electricity rates have largely tracked inflation and are among the lowest in the nation. Customers of Oregon investor-owned utilities have seen larger rate increases. Pressure on rates is expected to rise.

- Policy makers are increasingly concerned about the electricity cost and reliability impacts of ***projected demand growth*** from data centers and electrification of homes and vehicles. Small public utilities tend to rely on BPA to predict future demand, however BPA's models are based on historic demand data, and do not always capture significant technology-driven changes. This leaves utilities and policy makers uncertain about future costs and risks. There is a ***need for more robust and data-driven methods of projecting future loads***.

- Extreme weather, increased wildfire risk, and other ***hazards stress the Pacific Northwest's aging electric infrastructure*** and require utility coordination and investment. These investments could increase customer rates but would promote resilience.

- Some areas of Lane County's electric grid are more reliable than others. Metropolitan Eugene/Springfield customers are served by multiple transmission lines and a redundant distribution network. Some rural areas, however, are served by a single transmission line and ***a more vulnerable distribution network***.

- High temperatures and low regional snowpack can decrease the water available for power generation in the PNW's hydropower- based electricity system.

- Lane County could look to local solar or wind energy generation to improve future resilience, however the limited renewable energy potential of those natural resources within the county means that the cost of electricity from them will be high compared to the current low cost of BPA hydropower. This makes it difficult for utilities to invest in local generation for resilience while keeping rates low.

- When new, large commercial or industrial users want to connect to the grid, sometimes both distribution utilities (Lane County's retail utilities that sell electricity to consumers like homes and businesses) and transmission utilities (BPA and Pacific Power, which both own transmission infrastructure in Lane County) need to conduct studies to make sure that the grid can serve those loads. If upgrades or new infrastructure are necessary, the utility determines whether the new large customer is financially responsible for the needed infrastructure. This can add a challenge to economic development, but it can also serve to ensure that existing customers do not bear the burdens of increased costs to serve new loads.

Key Findings Summary (continued)

- Powering some, but not all, loads in emergency or shortage situations can be difficult because utilities cannot control demand. The ability to isolate portions of the grid can improve resilience, for example, by providing continued service to critical facilities during shortages or by de-energizing a portion of the grid in a high wildfire risk area. Currently, there is room for improvement in knowledge of the electricity needs of critical facilities and the risks to the electric system, and the capacity of utilities to use this knowledge to isolate portions of the grid.

- Currently, none of the generation resources in Lane County have blackstart capabilities. This means that, in the event of a regional grid outage, none of the generation resources in Lane County would be able to generate usable electricity and deliver that electricity to end users. Because so much of Lane County's electricity comes from outside the county, in the event of a regional outage, the generation sources within Lane County could not come close to meeting the demand within the county.

- Demand response programs and distributed energy resources are ways that utilities can reduce peak loads. Reducing peak loads is important in circumstances when the costs of meeting peak loads are high or when individual grid components adjacent to peak loads are nearing their operational capacity limits. For Lane County utilities, the marginal cost of meeting peak demand is often manageable due to the terms of their contracts with BPA. Thus far the benefits of most types of demand response programs and distributed energy resources have not been seen by most of Lane County's utilities as outweighing the costs, however, interest may be emerging.

- Enhanced grid resilience can be supported by a portfolio of technology solutions that strengthen physical assets, improve operational flexibility, and build the capacity to anticipate and respond to disruptions. Utilities across Lane County are at varying stages of modernization, depending on their size, resources, and regional risks.

Acknowledgments

This research was supported by the Energy to Communities (E2C) program, which receives funding and support from the Integrated Energy Systems Office within the U.S. Department of Energy. The National Laboratory of the Rockies (NLR) manages the E2C program. Lane County, OR along with their partners, the Center for Rural Livelihoods, the Springfield Utilities Board, and Emerald People's Utility District were awarded three years of funding and support through the E2C program. This document is the result of the first year of efforts under the award.

While the primary authors are listed by chapter, we would also like to acknowledge the many reviewers and advisors to this work. Kristen Lee of Lane County, OR, leads the E2C project from Lane County. Rachel Dorfman of the Lane Council of Governments manages the project. Josh Fattal supports the Center for Rural Livelihoods' participation in the project. Kristen, Rachel, and Josh have read and provided feedback for this Handbook on multiple occasions. Steve Adams of Lane County, OR, also provided guidance.

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Candace Briggs created all the maps in this Handbook.

Michael Barthelmes copyedited and formatted.

Photos were provided by Kristen Lee and Rachel Dorfman.

Introduction and Purpose

Lane County, Oregon spans from Oregon's rugged coast to the foothills of the Cascade Mountains, with boundaries crossing the Oregon Coast Range and the Willamette Valley. Centered in Lane County is one of Oregon's most populous metropolitan areas, the Cities of Eugene and Springfield. The city is home to University of Oregon and sits at the confluence of the McKenzie and Willamette Rivers, which supply drinking water, recreation opportunities, and—as we will discuss—electricity from hydropower dams.

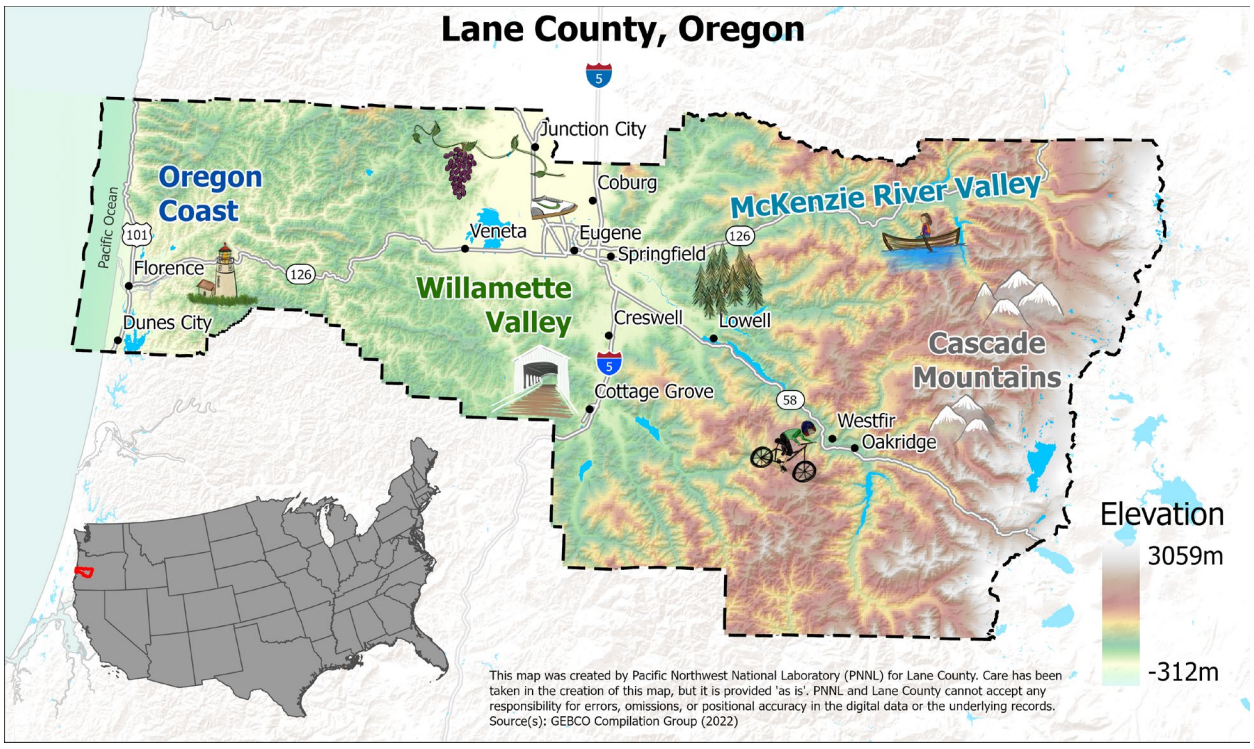


Figure 1: Map of Lane County, Oregon[1]

In 2024 Lane County was selected to participate in the U.S. Department of Energy's (DOE) Energy to Communities (E2C) program. The program supports Lane County and their project partners (the Center for Rural Livelihoods, Springfield Utility Board, and Emerald People's Utility District) with three years of technical assistance from DOE national laboratory researchers, namely, Lawrence Berkeley National Laboratory (LBNL), Pacific Northwest National Laboratory (PNNL), and the National Laboratory of the Rockies (NLR). Lane County is engaging all electric utilities that serve in Lane County (not just project partners), as well as other stakeholders. Lane County and their partners are focused on improving affordability, grid reliability in the face of potentially increasing electric loads, and grid resilience to support community resilience, especially during extreme weather events. These goals are further articulated in ***Table 1***.

[1] Data from GEBCO. *"General Bathymetric Chart of the Oceans,"* 2022. https://www.gebco.net/data-products/gridded-bathymetry-data/gebco-2022

Table 1: Lane County's Electricity System Goals

Power Lane County Goals	
Affordability	People in Lane County should be able to afford their electricity bills while Lane County utilities should be able to conduct business in such a way that ensures the financial stability and longevity of their operations.
Reliability	Lane County electric services should be consistently available, and customers should face minimal interruptions.
Resilience	Lane County electricity services should be able to withstand and quickly recover from disruptions such as those caused by storms, failures, or other hazards.

According to the Federal Energy Regulatory Commission (FERC), ***grid reliability*** is "the provision of adequate, secure, and stable flow of electricity as consumers may need it."[1] A reliable grid is one that always—or almost always—works. When an end user flips a switch, the lights come on.

Grid resilience is the ability of the electric grid to respond to and recover from a wide variety of hazards. Hazards might include natural hazards (see ***Sections 5.2–5.5***), security hazards (see ***Section 5.6***), or routine hazards such as workforce insufficiencies, changes in customer expectations or behavior, supply chain disruptions, and similar events.

Electric grid resilience can be thought of as a subset of energy resilience, as energy resilience covers the fuels systems as well. This Handbook discusses grid resilience and the ways that the electric system supports other types of community resilience. For instance, the cost of electricity can impact a community's economic resilience, or the efforts that a utility takes to prevent utility-caused wildfires (see ***Section 5.2***) can improve the natural hazard resilience of the community.

Over the course of the three-year E2C project, leaders in Lane County will work with researchers at national laboratories to explore opportunities for distributed energy resources, grid upgrades, grid management strategies, and natural hazard mitigation. The project aims to improve the reliability and affordability of energy, the resiliency of existing infrastructure, community resilience during electric outages, and the overall levels of community engagement and collaboration on energy issues across the county (***Figure 2***).

[1] Federal Energy Regulatory Commission. *"Reliability Explainer,"* Aug. 2023. https://www.ferc.gov/reliability-explainer



Figure 2: Aims of Power Lane County Project

The Power Lane County Project has three planned phases: a baselining phase to help leaders and researchers understand the needs and priorities of Lane County's electric system; an analysis phase to help inform current and future decision making; and an implementation planning phase to help Lane County move forward when the project concludes. This Handbook is the product of the first Phase of Power Lane County.

This Handbook establishes a foundational understanding of the energy landscape and electric grid in Lane County to inform community engagement, education, and analysis in future phases of Power Lane County. The information provided herein was gathered through publicly available data sources and utility and stakeholder engagement, including interviews with utility representatives detailed in Appendix A.

Following this brief ***Introduction and Purpose***, this document contains nine chapters, divided into three parts.

Part I: Foundations

- ***Chapter 1: How Does the Lane County Electrical System Work?*** introduces Lane County's electric energy system, how it evolved, and who keeps it working today.
- ***Chapter 2: What Policies Impact Lane County's Grid?*** reviews the policies that govern the grid, and the opportunities that Lane County and the local utilities have within the structures of state energy policy and strategy.

Part II: Lane County Utilities

- ***Chapter 3: Regional Dynamics Impacting Lane County Utilities*** discusses the ways that events on the regional grid impact Lane County's utilities.
- ***Chapter 4: Expectations of Lane County Utilities*** describes the main operational challenges facing Lane County electric utilities, the best practices for utilities dealing with those challenges, and Lane County utilities' adoption of best practices.
- ***Chapter 5: Utility Hazard Mitigation and Preparedness*** describes the main hazard-related challenges facing Lane County electric utilities, the best practices for utilities dealing with those challenges, and Lane County utilities' adoption of best practices.
- ***Chapter 6: Available Technologies for Lane County Utilities*** presents a suite of technologies available to utilities for improving reliability and resilience.

Part III: Community Energy Baseline

- ***Chapter 7: Local Energy Generation Resource Availability*** outlines available electricity generation within Lane County.
- ***Chapter 8: Geospatial Data to Inform Project Prioritization*** presents data on local vulnerabilities that could help decision makers prioritize reliability or resilience projects or programs.
- ***Chapter 9: Community Energy and Resilience Planning*** reviews available resilience and energy planning from cities and communities in Lane County.

The final section, ***Opportunities for Improving Lane County Electric System Affordability, Reliability, and Resilience*** summarizes feasible directions for action based on the information available in this assessment.

PART I
Foundations



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Part I: Glossary and Acronyms

Alternating Current (AC): Electric current that periodically reverses direction.

Balancing Authority: An entity responsible for integrating future resource plans, maintaining operational load-interchange-generation balance within a balancing area, and supporting interconnection frequency in real-time.

Behind-the-meter: Behind-the-meter, or direct-use, generation is located on the customer's side of the utility meter. Electricity produced by behind-the-meter systems is primarily used on-site, and excess generation may be exported to the grid for credit. Residential rooftop solar installations are behind-the-meter generation.

BPA: Bonneville Power Administration

Contract High Water Mark: The allotted amount of power that a consumer owned utility can purchase at Tier 1 rates.

Cost-Based Rates: Rates set such that the rate-setting organization can recover the costs incurred to provide the power.

COU: consumer-owned utilities

Current: Flow rate of electric charge, measured in ***Amps (A).***

Direct Current (DC): Electric current that flows continuously in a single direction.

Dispatchable Power: Electricity generation that can be turned on, ramped up, or reduced on demand to match real-time grid needs.

Distributed Energy Resources (DERs): DERs are modular and flexible energy generation, storage, or demand-side resources located near customers. DERs can be behind-the-meter, distribution-connected, or completely off-grid. Distributed energy generation is typically small-scale.

Distribution-connected: Distribution-connected generation interconnects to a utility's local distribution network and primarily serves local electricity demand. In some cases, distribution-connected resources may export excess electricity to the transmission system.

Distribution System: The network of power lines, transformers, and other equipment that delivers low-voltage electricity to end-users.

Distribution Utilities: Entities that own and operate the local, lower-voltage network, delivering electricity from substations to end-use customers.

DOE: U.S. Department of Energy

Energy: The capacity to do work. Energy can exist in a variety of forms such as thermal, electrical, chemical and nuclear energy.

Electricity: A form of energy involving charged particles.

Electrical Power: The rate at which electricity is transformed into other forms of energy, like light, heat, or motion. Measured in ***Watts (W)*** or ***Kilowatts (kW).***

Electrical Energy: The total amount of electric power used over time. Measured in ***Kilowatt Hours (kWh).***

EPUD: Emerald People's Utility District

EWEB: Eugene Water & Electric Board

FERC: Federal Energy Regulatory Commission

Frequency: Times per second an AC current changes direction, measured in ***Hertz (Hz).***

Generation: Producing electricity from energy sources like oil, natural gas, hydropower or wind.

GHG: greenhouse gases

IOU: investor-owned utility

kWh: kilowatt hours

Load: Anything that consumes electricity by converting it into a new form of energy. Synonymous with "electric load".

Local Generation: In this report, "local" refers to any generation resource that is geographically located within Lane County, regardless of size, ownership, or grid interconnection.

mWh: megawatt hours

NERC: North American Electric Reliability Corporation

NESC: National Electrical Safety Code

Net Metering: a metering and billing approach used by utilities to pay customers with small distributed generation resources for the excess power that they contribute to the grid.

NEVI: National Electric Vehicle Infrastructure

NRU: Northwest Requirements Utilities

NWPPA: Northwest Public Power Association

ODOE: Oregon Department of Energy

OPUDA: Oregon Public Utility Districts Association

ORECA: Oregon Rural Electric Cooperative Association

Photovoltaics (PV): Technologies that convert sunlight directly into electrical energy using semiconducting materials.

PMA: Power Marketing Administration

PNGC Power: Pacific Northwest Generating Cooperative

PNNL: Pacific Northwest National Laboratory.

PPC: Public Power Council

PUC: Oregon Public Utility Commission

PUD: Public Utility District

REA: Rural Electrification Act

RTO: Regional Transmission Operator

SEPA: Southeastern Power Administration

Small-scale Generation: Small-scale generation has less than 1 MW of capacity and is usually located at or near the point of consumption. Rooftop solar photovoltaic systems account for most small-scale generation in Lane County.

SUB: Springfield Utility Board

SWPA: Southwestern Power Administration

Transmission-connected Generation: Transmission-connected power plants connect directly to the high-voltage transmission network and supply the bulk power system. These facilities are typically located far from urban load centers.

Transmission System: The network of power lines, substations and other infrastructure that transfers high-voltage electricity long-distance from generation sources to distribution systems.

Transmission Utilities: Entities that own and operate the high-voltage grid, moving bulk electricity from generators to substations and other grids.

USACE: U.S. Army Corps of Engineers

Utility-scale generation: Utility-scale generation has a capacity of at least 1 MW and typically sells electricity to utilities through a power market.

Voltage: Force required to move an electric charge, measured in ***Volts (V)***.

WAPA: Western Area Power Administration

WECC: Western Electricity Coordinating Council

Part I: Foundations Preface

The energy system, illustrated in ***Figure 3***, supplies energy for human activities and encompasses all components related to production, conversion, delivery, and end-use of energy. ***Energy*** and ***electricity*** are not the same, but the electricity system is a subset of the larger energy system that includes things like natural gas infrastructure, transportation, and more.

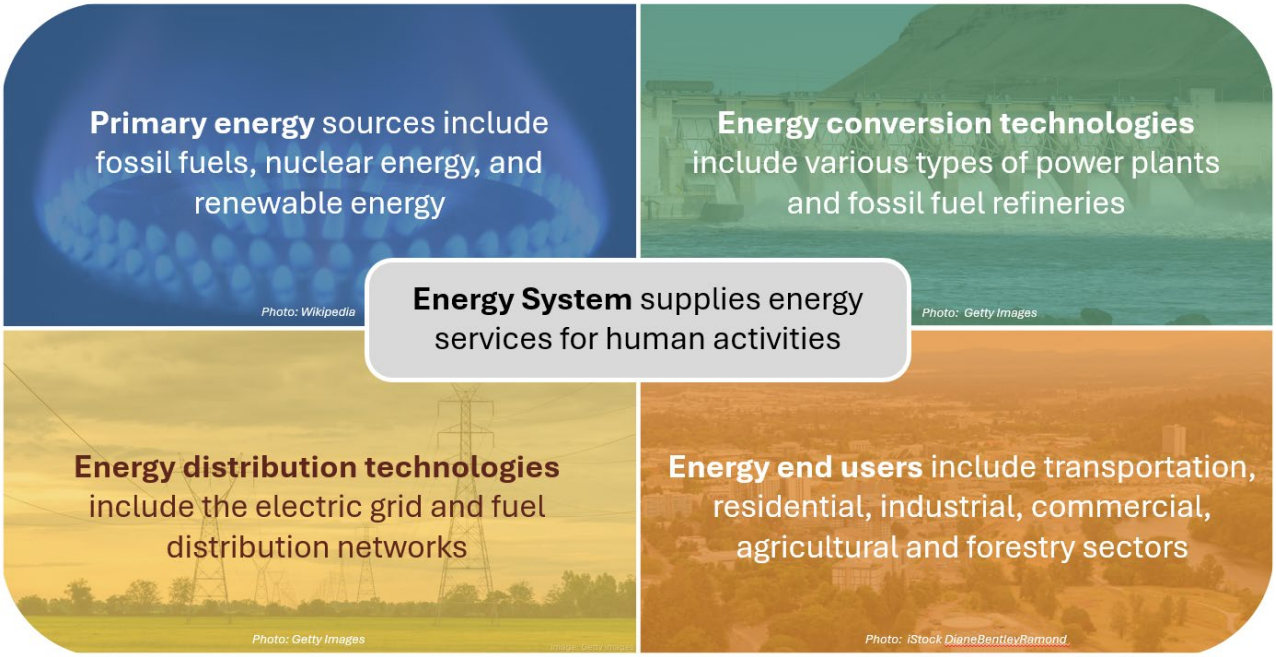


Figure 3: Elements of the energy system

Getting to know the technologies, organizations, policies, history, and existing conditions of the electricity system provides a foundation for future decision-making. The sections in this part of the assessment aim to help the reader build that foundation.

Chapter 1

How Does the Lane County Electrical System Work?

Ian Hermanson, Ali Trueworthy, and Candace Briggs

Many technologies, organizations, and policies help ensure that people in Lane County have access to electricity in their homes, businesses, and community spaces. This section provides a foundation for understanding the modern electric grid.

Energy is the ability to do work, and it can take many forms. Humans use technologies to convert naturally occurring energy sources into useful forms like light, heat, or motion. When a car engine combusts gasoline, hydrocarbons break in a burst of heat and pressure that is harnessed into mechanical motion. Water stored behind a dam builds immense pressure that drives turbines and generates electricity. Sunlight striking a solar panel excites electrons in semiconductor materials, producing a steady flow of electricity. Uranium atoms split inside a nuclear reactor, releasing heat that vaporizes water to spin massive turbines. When we charge our phones, have a package delivered by truck, or scrub dishes with hot water, we are consuming energy.

Electricity is a valuable form of energy that can be precisely controlled, efficiently carried over long distances, and easily converted to other energy forms. Power generation is the process of converting any primary energy source into electricity.

1.1 Energy and Electricity in Oregon

In the 2024 Biennial Report, the Oregon Department of Energy (ODOE) breaks Oregon's total 2022 energy consumption (energy consumed to meet demand in Oregon, sourced from in-state or out-of-state sources) into three categories: electricity, direct use fuels, and transportation fuels. ***Figure 4*** illustrates each category's share of total 2022 consumption, and ***Figure 5*** illustrates Oregon's 2023 state-level electricity resource mix.

On average, Oregonians use less electricity than the state generates, and the excess electricity is exported to other states.[1] Direct-use fuels include oil and natural gas used for building heating, cooking, and industrial processes. Transportation fuels include energy consumed to power vehicles, airplanes, ships, and trains. Oregon imports nearly all the consumed fuel types, including gasoline, diesel, propane, biofuels, and natural gas.[2]

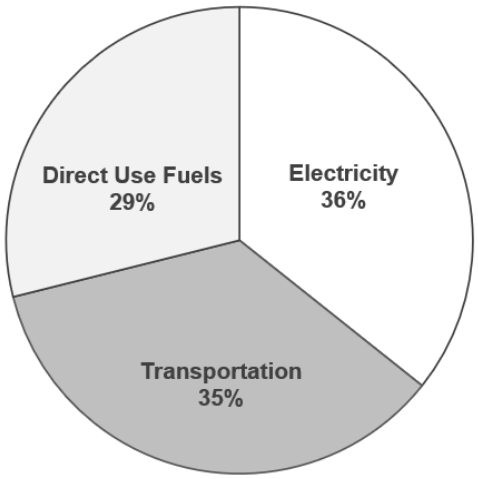


Figure 4: Oregon's 2023 Energy Consumption by Category[2]

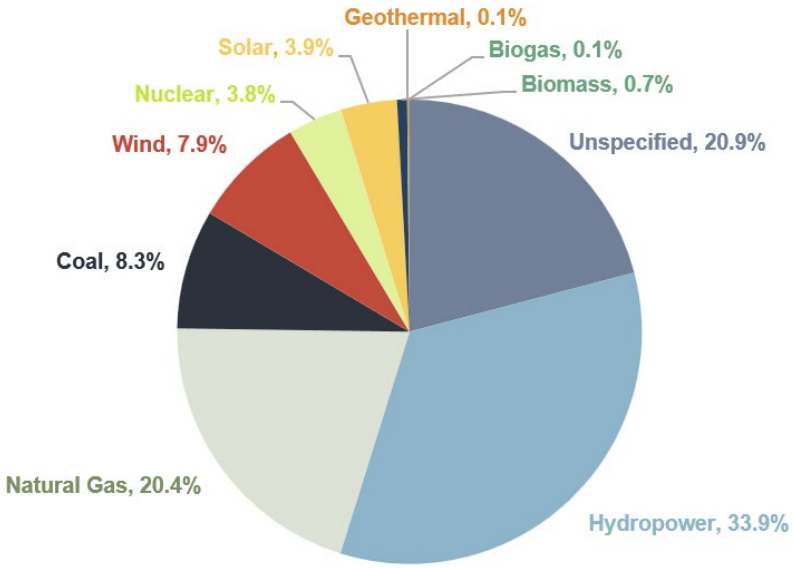


Figure 5: Oregon 2024 Electricity Use Resource Mix[3]

[1] Energy Information Administration. *"Oregon End-use energy consumption 2024, estimates,"* https://www.eia.gov/state/?sid=OR#tabs-4

[2] Figure adapted from Janine Benner *et al.*, *"2024 Biennial Energy Report,"* https://energyinfo.oregon.gov/ber

[3] Data from Oregon Department of Energy, *"Oregon Electricity Resource Mix,"* https://www.oregon.gov/energy/energy-oregon/Pages/Electricity-Mix-in-Oregon.aspx. The "Unspecified"

Oregon's population and economy have grown over the past twenty years while annual energy consumption has remained flat, as shown in ***Figure 6***. This trend is due in part to successful energy efficiency initiatives and has resulted in Oregon's relatively low per capita energy consumption. In 2022, Oregon ranked 10th among U.S. states for lowest per capita energy use overall[1] and 3rd for lowest per capita energy use in the residential sector.[2]

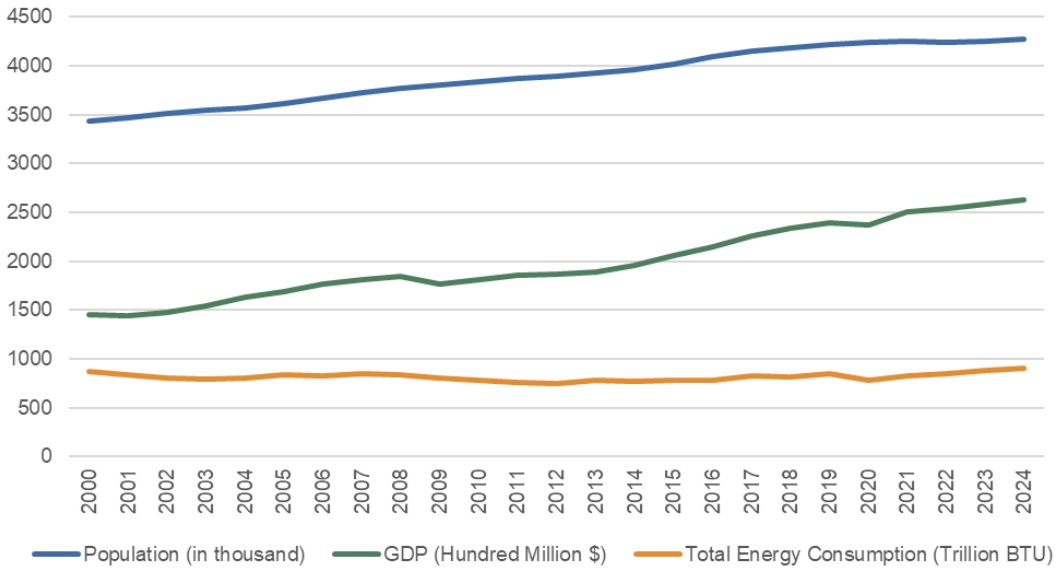


Figure 6: Population, GDP, and Total Energy Consumption in Oregon 2000–20242

1.2 Northwest Energy History

Before the advent of the electric grid and large-scale energy conversion, people living in the Pacific Northwest relied on local resources for energy. Waterways and wind propelled canoes that enabled regional transport. Woodfires provided indigenous peoples and early settlers with heat, light, and energy for cooking. In the pre-industrial Pacific Northwest, most usable energy came from food and burning wood and plant material. In many areas, seasonal salmon harvests and camas, an energy dense native-growing staple, were foundational caloric sources. Land-tending practices, including controlled burns, nourished the soil and supported camas and other harvests. As settlers and the U.S. government forcibly relocated Indigenous people to reservations, settler agriculture practices became the dominant mode of food production in the Pacific Northwest.

category includes real-time market purchases utilities make to meet demand and is used by ODOE due to the increasing complexity of accurately calculating a resource mix for market purchases.

[1] Janine Benner *et al.*, *"2024 Biennial Energy Report,"* Oregon Department of Energy, Nov. 2024. https://www.oregon.gov/energy/Data-and-Reports/Documents/2024-Biennial-Energy-Report.pdf

[2] Data from Energy Information Administration *"Analysis,"* June 2026. https://www.eia.gov/states/OR/analysis



Figure 7: Fishing with a Dip-net at Celilo Falls, 1942[1]

Throughout the 19th century, technological, social, and political forces dramatically changed human energy use. Irrigation technologies and fertilizers enabled a boom in farming throughout the Columbia River Basin, coal-powered trains brought more people and products to the west, and industries using mills and waterwheels were established along rivers. The first electric lights in Oregon came to Portland in 1880 on the *SS Columbia*. An onboard generator powered arc lights strung from the dock on the Willamette River to the Clarendon Hotel as thousands of people witnessed the spectacle. In 1889, a fourteen-mile high-voltage transmission line connected the Willamette Falls hydroelectric plant to Portland,[2] shown in ***Figure 8***. This was the first long-distance electricity transmission line in the United States.

[1] Image from Old Oregon Photos https://www.oldoregonphotos.com

[2] J. Hammarlund, *"Oregon's Role as an Energy Innovator," FORUM*. https://digitalcollections.willamette.edu/bitstreams/de2efbd2-14e5-49a6-8bb3-b3b409830210/download



Figure 8: Willamette Falls Powerhouse and Oregon's first High-Voltage Transmission Line[1]

Pacific Northwest electrical systems expanded dramatically in the early 20th century. At first, many private companies provided small-scale electricity services, and several industries owned their own generation. Private companies then began to consolidate, and industry began purchasing electricity from utilities. Nationally, electrification of rural areas lagged behind cities—by 1930, only about 10% of farms had electricity compared to nearly 90% of urban homes.[2] The 1936 Rural Electrification Act (REA) rapidly extended electric service to half of rural farms by 1942, as shown by ***Figure 9***.

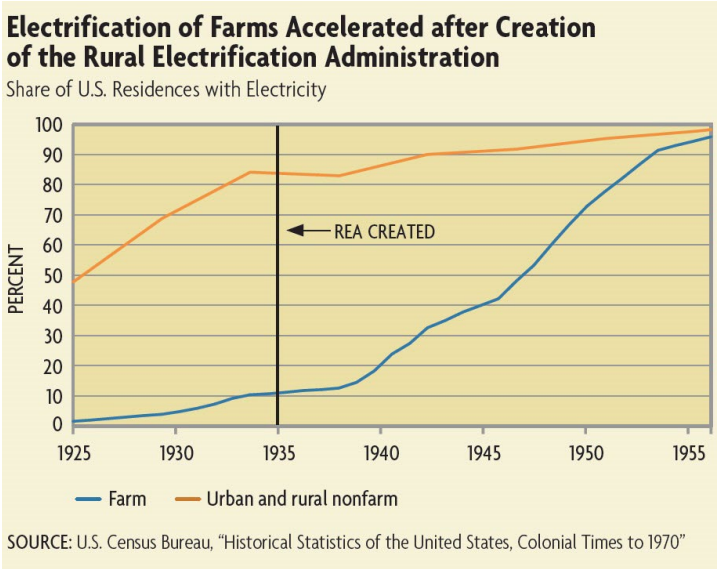


Figure 9: The Rural Electrification Administration's effect on Farm Electrification[2]

[1] Image from Old Oregon Photos https://www.oldoregonphotos.com/

[2] Information and Image from Federal Reserve Bank of Richmond, *"Electrifying Rural America,"* 2020. https://www.richmondfed.org/publications/research/econ_focus/2020/q1/economic_history

How did Lane County end up with so many electric service providers?

In the early 20th century, the growth of electric systems was rapid, chaotic, and uneven. Cities often had multiple service providers, while many rural areas did not have electricity. Many providers were private companies. Because providing electric services was a capital-intensive business with limited end user markets, the 1920s and '30s brought an era of consolidation as many companies that owned limited assets (e.g., a generation plant and power lines connecting a handful of customers) were bought out.

Lane County's consumer-owned utilities grew out of citizen discontent with private service providers and the lack of service in rural areas. Local community debates reflected a broader national discussion about whether electric service should be private or public. In 1908, citizens of Eugene voted to replace their private water company with the area's first municipal water utility following a typhoid epidemic. They created the Eugene Water Board, which would become the Eugene Water & Electric Board (EWEB). EWEB entered the electric service sector by constructing the Walterville Hydroelectric Plant in 1911 and purchasing assets from a competing private power company in 1916. In the early 1930s, Washington and Oregon passed state laws allowing rural areas to form public utility districts. Other consumer-owned utilities (COUs) in Lane County followed: Blachly-Lane in 1937, Lane Electric in 1939, Central Lincoln Public Utility District in 1943, Springfield Utility Board (SUB) in 1949, and Emerald People's Utility District (EPUD) in 1978.

Lane County citizens created COUs to serve their communities despite opposition from existing private service providers. Because COUs exist to serve community interests rather than to profit, these utilities had little incentive to expand. As a result, Lane County has many individual utilities that serve individual cities or specific rural areas.[1,2,3,4]

In 1929 the U.S. Army Core of Engineers (USACE) published what was known as the 308 Report.[5] The 308 Report recommended the construction of 10 hydroelectric dams on the Columbia River. Because such construction projects were too large for private utility companies, the federal government under President Franklin Roosevelt began construction of the Bonneville and Grand Coulee Dams in 1934. In 1937, Roosevelt established the Bonneville Power Administration (BPA) to market power and construct transmission lines for the new Bonneville and Grand Coulee Dams. There are now 274 hydroelectric dams in the Columbia River Basin, including 19 in British Columbia, Canada. Nearly 70% of the total generating capacity in the Columbia River basin is owned by the federal government. While BPA markets

[1] Eugene Water & Electric Board, *"EWEB History,"* www.eweb.org/your-public-utility/eweb-history
[2] Blachly Lane, *"About us,"* https://www.blachlylane.coop/about-us/
[3] Oregon Rural Electric Cooperative Association, *"A Lane of Their Own,"* https://www.oreca.org/a-lane-of-their-own/
[4] Springfield Utility Board, *"Lighting the Way: A History of Springfield Utility Board."* https://www.subutil.com/about-us/about-sub/
[5] U.S. Army Corps of Engineers Institute for Water Resources, *"308 Reports Series,"* https://www.iwr.usace.army.mil/Library/IWR-Library/308-Reports-Program-Series/

power from these dams, the dams themselves are owned and operated by USACE and the U.S. Bureau of Reclamation.[1] 19% of the basin's capacity is operated by municipally owned utilities, like Seattle City Light. The remaining 12% of the basin's capacity is owned by private companies like investor-owned utilities. ***Figure 10*** provides a map of major Columbia River Basin dams and operators.



Figure 10: Columbia River Basin Dams Map[2]

The government's expanding hydroelectric system provided abundant, reliable power that fueled post-war industrial growth. Between 1950 and 1970, the region's electric system expanded rapidly as a population boom, residential appliances, new industries, and rural electrification increased demand.[3] By the 1970s, hydroelectric capacity in the Columbia River Basin had reached its limit. Forecasts projected continued demand growth, which raised concerns about energy shortages. In 1968, BPA and Washington Public Power Supply System

[1] Northwest Power and Conservation Council, *"Dams: history and purpose,"* https://www.nwcouncil.org/reports/columbia-river-history/damshistory/

[2] Image from Bonneville Power Administration *"Columbia River Basin,"* https://www.bpa.gov/-/media/Aep/about/publications/maps/columbia-river-basin-map-major-federal-and-non-federal-dams.pdf

[3] J. Hammarlund, *"Oregon's Role as an Energy Innovator," FORUM*. https://digitalcollections.willamette.edu/bitstreams/de2efbd2-14e5-49a6-8bb3-b3b409830210/download

launched the Hydro-Thermal Power Program which aimed to build twenty nuclear plants and two coal power plants in Oregon and Washington to meet projected demand. However, project costs skyrocketed and the ***load*** growth forecasts that justified the massive project proved inaccurate. Only two nuclear power plants were built, and public perception of the electric industry soured as costs were passed on to customers.[1] With other options available, many customers left BPA. BPA is still paying off debt from this program.

Public interest in energy efficiency, distrust in BPA, concerns over declining salmon populations, and the need for a new long-term planning approach underpinned the 1980 Northwest Power Act, which created the Northwest Power and Conservation Council. With the passage of the Act, the Council was tasked to prioritize energy conservation and balance fish and wildlife protection with the region's need for affordable, reliable electricity. BPA funds were directed to mitigate hydropower impacts on fish and wildlife.[2]

Between the late 1990s and early 2000s, changing energy policies and a volatile regional electricity market caused BPA to swing from being overpriced and undersubscribed to underpriced and oversubscribed. At the time, BPA was obligated to meet the entire power demand of its customer base. If BPA could not fully meet customer demand, it was forced to buy relatively expensive power off the market to resell at a low rate. This was an untenable sales structure. In 2002, BPA customers approved a revised structure in which BPA would sell shares of the federal system output, known as "slices of the system." This shift would reduce the agency's market exposure by shifting financial risks and benefits to customers. In 2011, BPA introduced a tiered rate system that let customers decide whether the agency should purchase additional electricity from the market on their behalf when their loads exceeded the allotted amount[3] (see ***Sub-Section 1.5.1*** for a description of the tiered system).

Throughout the 2000s and 2010s Oregon passed legislation to reduce emissions from electricity and transportation. In 2007, Senate Bill 838 set a target for 25% renewable electricity by 2025, and in 2016 the Oregon Renewable Portfolio Standard increased that goal to 50% by 2030. The Oregon Department of Environmental Quality introduced incentives and targets for alternative transportation fuels, while additional programs promoted residential solar, energy efficiency, and electric vehicles. New wind and solar farms were gradually interconnected to the grid by BPA. In 2020, several large-scale wind and solar projects began development.[4]

A timeline of Oregon's Energy History is published by the Oregon Department of Energy.[4]

1.3 What is the Grid?

The electrical grid, depicted in ***Figure 11***, is a vast, interconnected network that delivers electricity to homes, businesses and other end users. The grid performs three main functions: generation, transmission, and distribution. Energy is converted from its primary source to electricity at a power ***generation*** facility. Generated electricity passes through generation

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[1] Northwest Power and Conservation Council *"Hydrothermal Power Program,"* https://www.nwcouncil.org/reports/columbia-river-history/hydrothermal/
[2] Northwest Power and Conservation Council *"Northwest Power Act,"* https://www.nwcouncil.org/reports/columbia-river-history/northwestpoweract/
[3] Northwest Power and Conservation Council *"Bonneville Power Administration: History,"* https://www.nwcouncil.org/reports/columbia-river-history/bpahistory/
[4] Oregon Department of Energy, *"Oregon's Energy History,"* 2020 Biennial Energy Report, 2020. https://www.oregon.gov/energy/Data-and-Reports/Documents/2020-Biennial-Energy-Report.pdf

substations that increase the ***voltage***. High-voltage electric current travels along ***transmission*** lines that can span thousands of miles. A local substation reduces voltage before ***distribution*** lines carry electricity to various end-users. Transformers further reduce voltage before electricity enters homes and businesses.[1,2]

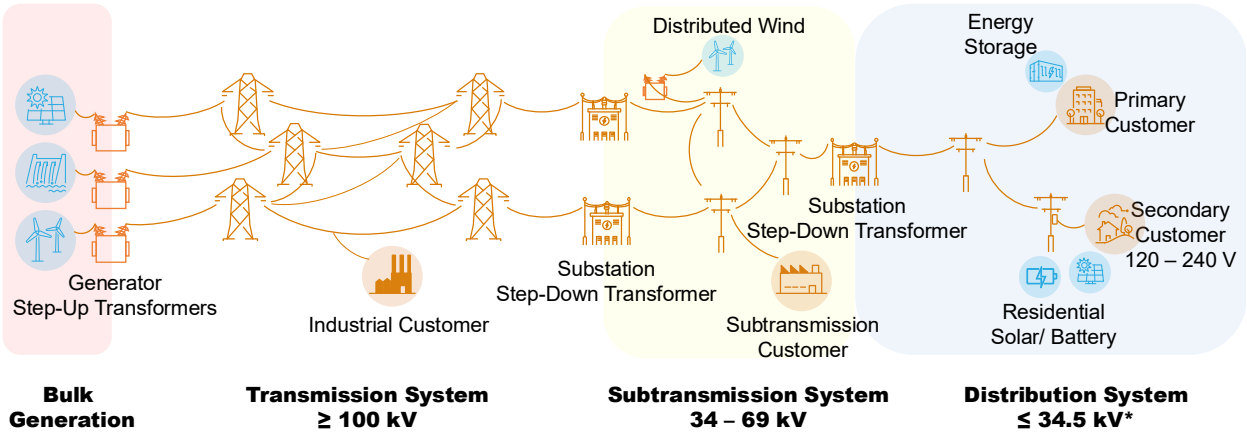


Figure 11: The Electric Grid

Electric grids span massive geographic areas called interconnections. The U.S. grid is divided into three geographic areas: west of the Rocky Mountain region, east of the Rocky Mountain region, and Texas, as shown in ***Figure 12***.[3] Interconnections evolved in the early 20th century as local utilities began connecting to neighboring ***transmission systems*** to meet growing electricity demand. Synchronizing power generation across an entire continent is a technical challenge, so the grid evolved into the separate Eastern Interconnection and Western Interconnections linked only by a few high-voltage DC ties. Within each interconnection, there are usually multiple routes for power to flow from generators to consumers. This redundancy promotes reliability by preventing individual component failures from causing outages or cascading failures.[4] Lane County is part of the Western Interconnection, which covers British Columbia and Alberta Canada, the United States west of the Rocky Mountain region to the Pacific, and Baja California, Mexico.

[1] The Seattle Times, *"Seattle utilities consider massive efforts that could help green our grid,"* Mar. 2023. https://www.seattletimes.com/pacific-nw-magazine/seattle-utilities-consider-massive-efforts-that-could-help-green-our-grid/

[2] National Laboratory of the Rockies, *"Explained: Fundamentals of Power Grid Reliability and Clean Electricity,"* Jan. 2024. https://www.nlr.gov/docs/fy24osti/85880.pdf

[3] U.S. Environmental Protection Agency, *"U.S. Grid Regions,"* Nov. 2025. https://www.epa.gov/green-power-markets/us-grid-regions

[4] U.S. Energy Information Administration, "*U.S. electric system is made up of interconnections and balancing authorities,"* July 2016. https://www.eia.gov/todayinenergy/detail.php?id=27152

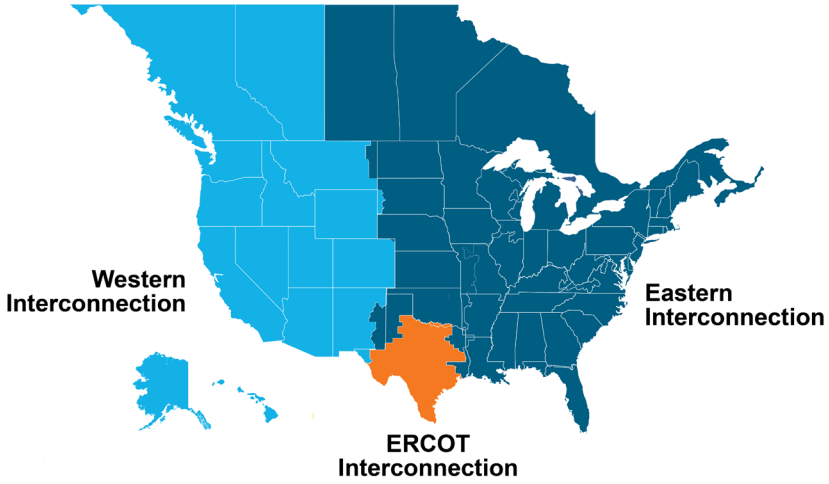


Figure 12: U.S. Interconnections

On the grid, electricity supply and demand must remain in balance. Excess supply or shortfalls risk triggering grid overloads, infrastructure and equipment failure (due to melting or breaking), and ***rolling blackouts***.[1] A reliable grid can withstand instantaneous changes in supply and demand to provide a stable and adequate flow of electricity to end users.[2] Grid reliability depends on long-term planning to balance generation and load (for more on this planning see ***Section 2.2***). Grid operators keep the grid balanced as electricity demands fluctuate by the minute, hour, day, season, and year. Operators can control the electric output of generation sources to adjust to demand changes.

Energy storage technologies support grid reliability by storing electricity when generation exceeds demand and releasing electricity back to the grid during higher-demand periods. Storage technologies include residential, commercial, and grid-scale batteries, pumped hydro storage, compressed air, and thermal systems.[3] Water stored in reservoirs behind hydroelectric dams is another form of energy storage. Utility-scale energy storage is growing in the United States.[4]

1.4 Who Manages the Grid?

The power grid, which is often described as the “world’s largest machine,” operates on scales too large for a single entity to manage. Electricity generation, transmission, distribution, sales, and regulation are managed by a network of interconnected organizations and structures. Those organizations vary in different regions of the United States. Generally, they include utilities, balancing authorities, power marketing administrators, and regulators.

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[1] The Seattle Times, ibid.
[2] Federal Energy Regulatory Commission, *“Reliability Explainer,”* Aug. 2023. https://www.ferc.gov/reliability-explainer
[3] New York State Energy Research and Development Authority, *“Types of Energy Storage,”* https://www.nyserda.ny.gov/All-Programs/Energy-Storage-Program/Energy-Storage-for-Your-Business/Types-of-Energy-Storage
[4] American Clean Power, *“REPORT: Energy Storage Market Continues Strong Growth in Q1 2025,”* https://cleanpower.org/news/u-s-energy-storage-monitor-q2-2025/

1.4.1 Utilities

Electric utilities manage the electric ***distribution system***, a network of low voltage power lines that delivers electricity to end-users such as homes and businesses.[1] Utilities can be investor-owned utilities (IOUs) or consumer-owned (COUs). IOUs are for-profit companies regulated as monopolies by state public utility commissions. COUs are public entities that fall into one of three categories: (1) Municipal COUs are governed by board members who are either elected by city residents or appointed by city officials, (2) Public Utility Districts (PUDs) are governed by commissioners elected by residents of the (usually rural) district, and (3) Cooperative COUs are governed by a board elected by co-op members.[2]

Figure 13 is a service area map of Lane County's ten electric utilities. Of the ten utilities, one is an IOU that serves a large area outside Lane County (Pacific Power) and the rest are COUs. Three COUs are public utilities that primarily serve areas outside Lane County, but have small service areas within the county (Consumers Power, Douglas Electric and Midstate Electric), two are municipal utilities (Springfield Utility Board and EWEB), two are people's utility districts (Emerald PUD and Central Lincoln PUD), and two are electric cooperatives (Lane Electric and Blachly-Lane). By number of customers, EWEB is the largest COU in Oregon Lane County utility types are listed in ***Table 2***. Lane County's utilities vary in both the size of the service area and the number of customers.

Table 2 shows these statistics for each utility. Throughout this report, we often provide information by utility, but do not always include information about Consumers Power, Douglas Electric, or Midstate Electric because their service territories in Lane County are so small. Of the remaining utilities, Pacific Power, a business unit of PacifiCorp, is the only one with most of their service area outside of Lane County.

[1] National Laboratory of the Rockies, *"Explained: Fundamentals of Power Grid Reliability and Clean Electricity,"* Jan. 2024. https://www.nlr.gov/docs/fy24osti/85880.pdf
[2] Oregon Citizens' Utility Board, *"Who Owns and Regulates Oregon's Energy Utilities?,"* May 2021. https://oregoncub.org/news/blog/who-owns-and-regulates-oregons-energy-utilities/2337

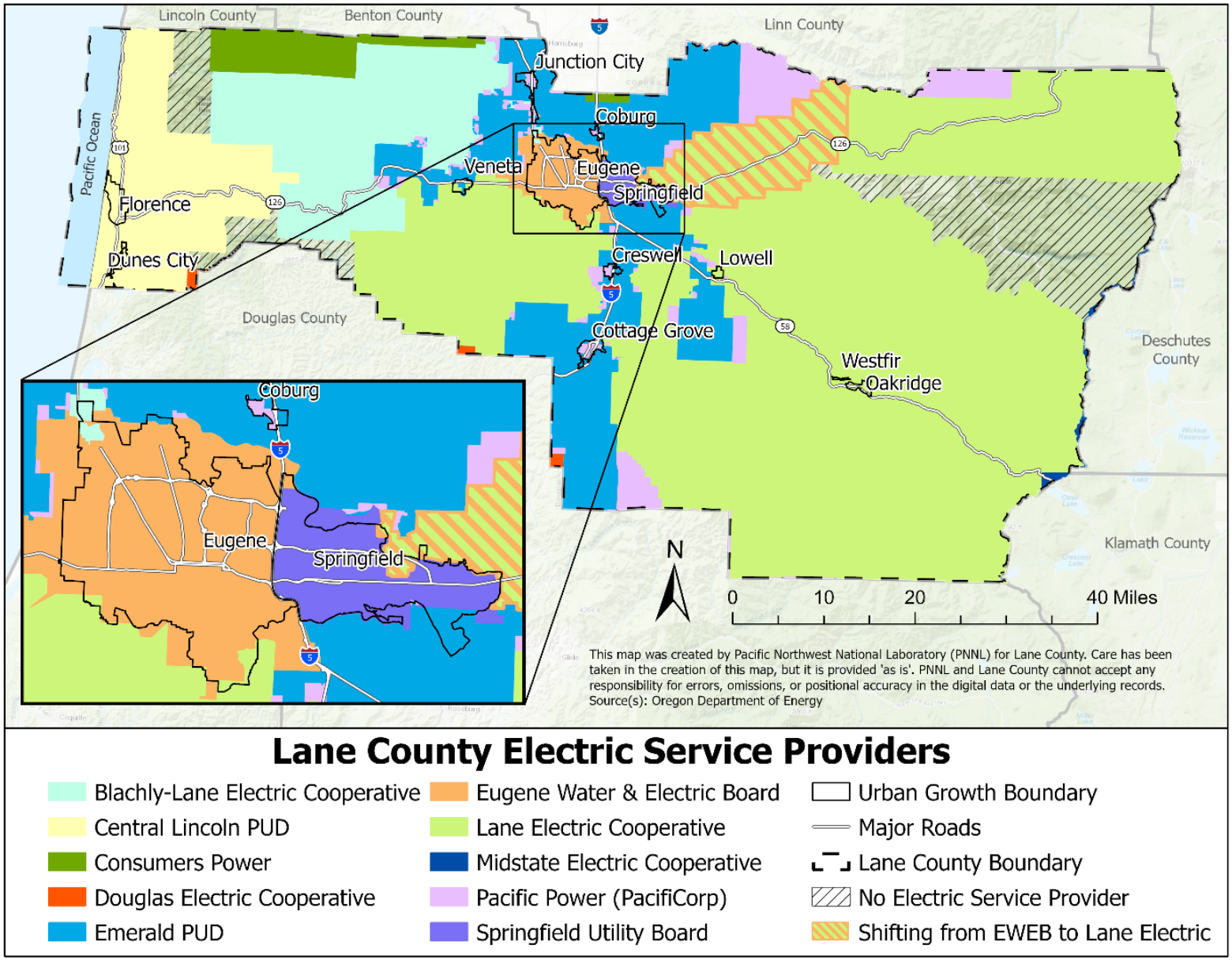


Figure 13: Lane County Electric Service Providers Map[1]

[1] Data (as of May 2026) from Oregon Department of Energy https://www.oregon.gov/energy/Pages/default.aspx

Table 2: Lane County Electric Utility Summary[1]

Utility	Type	Total Customers	Estimated Lane County Customers	Service Area
Eugene Water & Electric Board (EWEB)	Municipal	97,500	97,500	City of Eugene and adjacent areas west to Fern Ridge Lake (~236 mi^2)
Springfield Utility Board (SUB)	Municipal	33,400	33,400	City of Springfield (~25 mi^2)
Emerald People's Utility District (EPUD)	PUD	23,000	23,000	A patchwork of noncontiguous areas around Eugene and Cottage Grove, including Veneta (~572 mi^2)
Central Lincoln PUD	PUD	41,500	19,500	Oregon coast from Depoe Bay to Glasgow (~700 mi^2)
Lane Electric Co-op	Co-op	16,000	16,000	Rural areas south and southeast of Eugene to the Willamette pass, and east of Vida up the McKenzie Valley. Recently, the utility also began covering the region east of Springfield along HW 126 to Vida (~2,600 mi^2)
Pacific Power	IOU	630,000 in Oregon	4,100	Disjointed areas across Lane County, including portions of Junction City, Creswell, and Cottage Grove communities
Blachly-Lane Co-op	Co-op	3,800	3,800	Portion of highway 36 corridor and surrounding communities (~380 mi^2)

Pacific Northwest COUs are represented and supported by several key member organizations, including the ***Pacific Northwest Generating Cooperative*** (PNGC Power)[2], the ***Oregon Rural Electric Cooperative Association*** (ORECA)[3], and the ***Oregon Public Utility Districts Association*** (OPUDA)[4]. These groups provide policy coordination, advocacy, training, and shared services for public power and cooperative utilities across the region. COUs also collaborate through broader regional organizations such as the ***Northwest Public Power Association*** (NWPPA)[5], the ***Public Power Council*** (PPC)[6], and the ***Northwest Requirements Utilities*** (NRU)[7], which focus on regional policy, BPA issues, and utility coordination.

[1] Table estimates are approximate, rounded for clarity, and based on multiple sources: FindEnergy.Org, Oregon Public Utility Statistics. *"2024 Oregon Utility Statistics,"* 2024. https://www.oregon.gov/puc/forms/Forms%20and%20Reports/2024-Oregon-Utility-Statistics-Book.pdf, and utility websites

[2] Pacific Northwest Generating Cooperative. https://www.pngcpower.com/

[3] Oregon Rural Electric Cooperative Association. https://www.oreca.org/

[4] Oregon People's Utility District Association. https://www.opuda.org/

[5] Northwest Public Power Association. https://www.nwppa.org/

[6] Public Power Council. https://www.ppcpdx.org/

[7] Northwest Requirements Utilities. https://www.nru-nw.com/

1.4.2 Balancing Authorities

Balancing authorities stabilize and synchronize a defined region of the power grid, called the balancing authority area, with the rest of the interconnection. Each balancing authority ensures that energy supply and demand are finely balanced in their territory. To meet real-time and forecasted supply and demand change, balancing authorities exchange energy with neighboring balancing authorities and adjust the electric output from generation sources.[1] A variety of entities serve as balancing authorities. In the Western Interconnection, 38 different balancing authorities coordinate to maintain grid stability (***Figure 14***). Major balancing authorities include the California Independent System Operator (CAISO, noted as CISO on map), which manages most of California, the Bonneville Power Administration (or BPAT on the map, the "T" denotes transmission) which manages broad areas of the Pacific Northwest, and large IOUs such as Portland General Electric (PGE) and Pacific Power. Coordination across this complex balancing authority patchwork introduces planning and market coordination challenges but also offers opportunities to enhance reliability and reduce costs through regional resource sharing.

[1] U.S. Department of Energy, *"How it Works: The Role of a Balancing Authority,"* 2023. https://www.energy.gov/sites/default/files/2023-08/Balancing%20Authority%20Backgrounder_2022-Formatted_041723_508.pdf

WECC Balancing Authorities

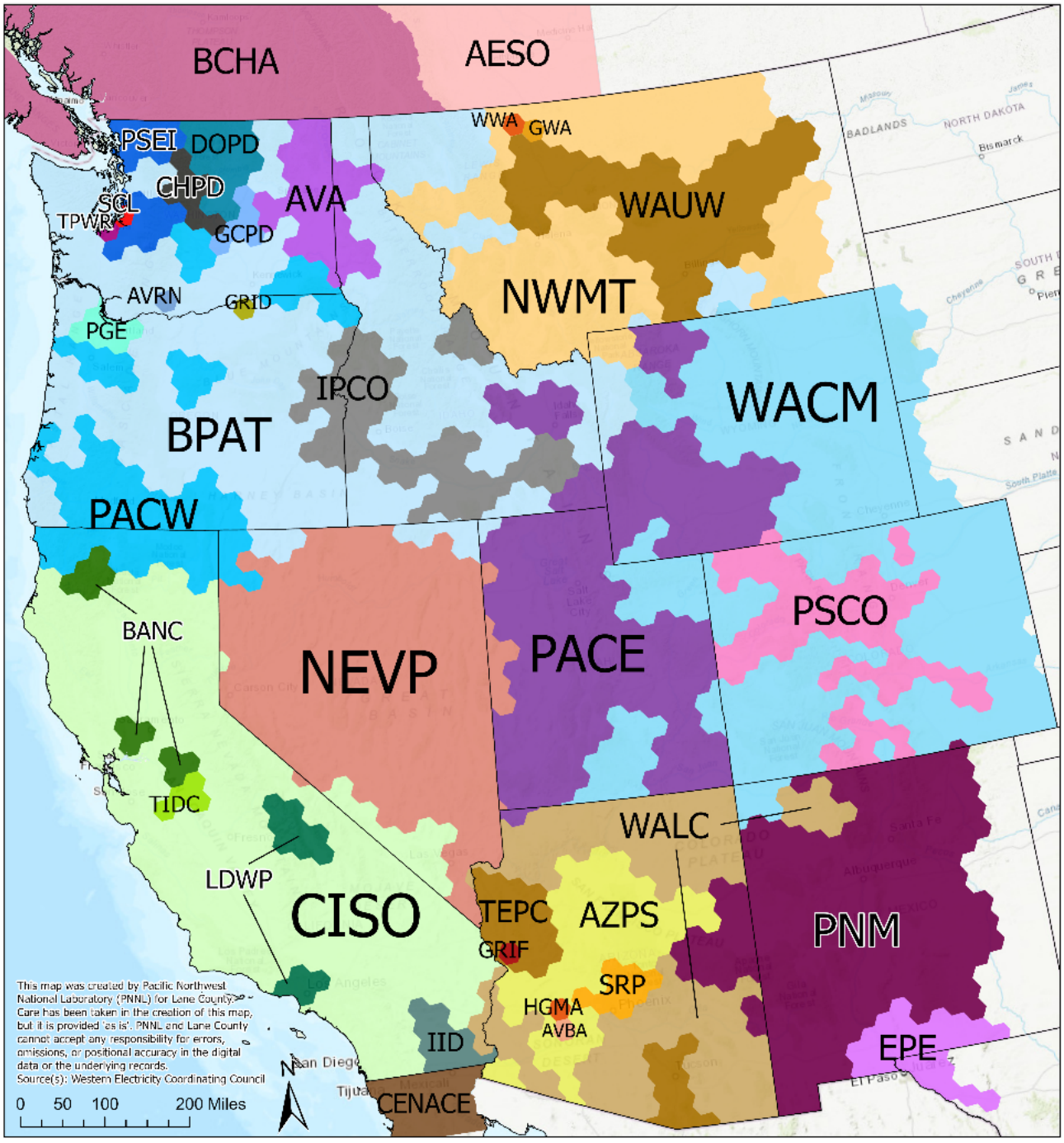


Figure 14: Major Balancing Authorities of the Western Interconnection[1]

[1] Data (as of March 2025) from https://www.arcgis.com/home/item.html?id=83f3a587c78a4d0cbbf10f6586b5e2b1

1.4.3 Power Marketing Administrators and the Bonneville Power Administration

A Power Marketing Administration (PMA) is a DOE agency that operates regional electric systems and sells the output of federally owned and operated hydroelectric dams.[1] PMAs generally operate in self-contained territories and commonly serve as the balancing authority for their respective regions. The United States has four PMAs: the BPA, Western Area Power Administration (WAPA), Southwestern Power Administration (SWPA), and Southeastern Power Administration (SEPA), shown in ***Figure 15***. The majority of PMA power is hydroelectric. By federal statute, PMAs prioritize selling power to publicly owned and cooperative utilities and set the lowest feasible electric rates. PMA power is relatively inexpensive because it originates from decades-old dams. Typically, PMAs do not own the generating plants, which are owned by USACE, U.S. Bureau of Reclamation, or International Boundary and Water Commission (an agency that operates hydroelectric dams along the U.S.-Mexico border.[2,3]

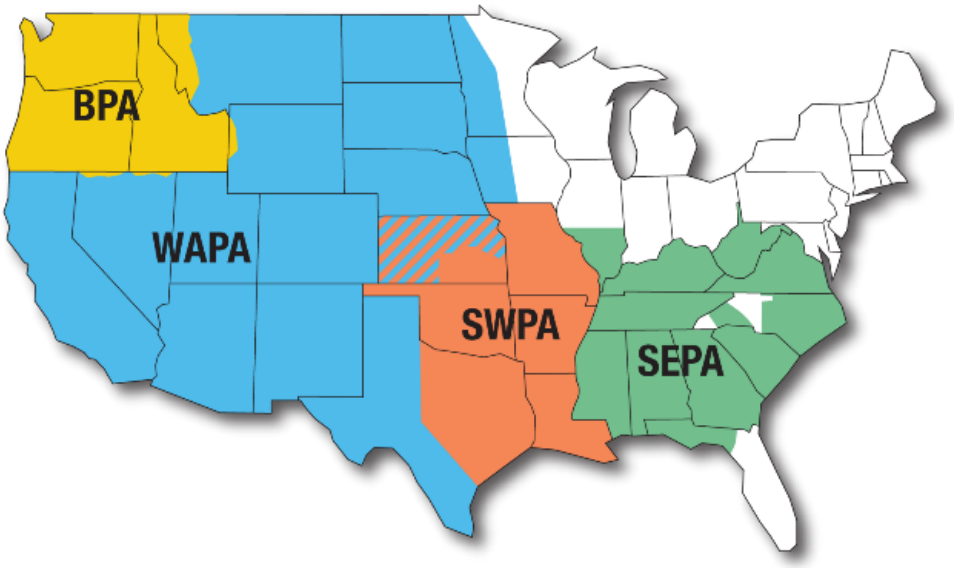


Figure 15: U.S. Power Marketing Administrators Map[4]

In the Northwest, BPA sells power from one nuclear power plant and 31 dams throughout the Columbia River Basin, serves as the balancing authority for most of the Pacific Northwest, including Lane County, and coordinates most of the Pacific Northwest's power supply. BPA manages around 15,000 miles of high-voltage transmission lines, representing 75% of the region's high-voltage transmission. WAPA manages 17,000 miles of high-voltage transmission across a much larger territory. While BPA operates slightly fewer miles of transmission than WAPA, its infrastructure is concentrated within a smaller geographic area. As a result, BPA has

[1] U.S. Department of Energy, *"Power Marketing Administrations,"* https://www.energy.gov/ea/power-marketing-administrations
[2] U.S. Energy Information Administration, *"Federal Power Marketing Administrations operate across much of the United States,"* June 2013. https://www.eia.gov/todayinenergy/detail.php?id=11651
[3] International Boundary and Water Commission, *"About Us,"* https://www.ibwc.gov/about-us/
[4] Image from Western Area Power Administration, *"Power Marketing Administrations Map,"* May, 2025. https://www.wapa.gov/about-wapa/regions/pma-map/

a distinctly outsized influence over the Pacific Northwest electrical system and broader economy relative to other PMAs.[1]

BPA is a self-financed agency that receives no federal appropriations or tax dollars, instead covering operating costs through power sales. To finance large projects, BPA borrows from the U.S. Treasury through bonds. As of 2018, BPA was $5.53 billion in debt to the U.S. treasury, nearing BPA's $7.70 billion borrowing cap.[1] Limited borrowing capacity constrains BPA's ability to tackle large infrastructure projects. Nevertheless, BPA currently has a portfolio of projects planned in their Grid Expansion and Reinforcement Portfolio.[2]

1.4.4 Regulation and Oversight

The ***Federal Energy Regulatory Commission*** (FERC) was created as an independent commission within DOE in 1977 when Congress passed the Department of Energy Organization Act (P.L 95-91). FERC was authorized to take over regulatory duties that were previously the domain of other agencies. FERC oversees the bulk power system, which includes interstate transmission of electricity, natural gas and oil, the wholesale electric market, and operation of federal hydroelectric projects. The ***North American Electric Reliability Corporation*** (NERC) is a non-profit, non-governmental organization certified by FERC in 2006 to maintain and improve the reliability of the bulk power system by issuing mandatory reliability standards and guidelines.[3] FERC and NERC delegated authority to six regional entities to coordinate and promote bulk electric system reliability across the United States. The ***Western Electricity Coordinating Council*** (WECC) is the regional entity responsible for system reliability across the Western Interconnection.[4]

The ***Oregon Public Utility Commission*** (PUC) is a state regulatory agency that regulates the rates, reliability and service quality of IOUs, natural gas utilities, and telephone service providers. PUC Commissioners are appointed by the Oregon governor for four-year terms.[5] Oregon PUC does not regulate COUs, except regarding safety. COU policy mandates are often less rigorous.[6] An important Oregon PUC role is enforcing the National Electrical Safety Code (NESC), which sets standards to protect utility workers and the public during the installation, operation and maintenance of transmission and distribution electrical systems and communication lines. The NESC is published by IEEE and updated every five years.[7]

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[1] Congressional Research Service. *"The Power Marketing Administrations: Background and Current Issues,"* Mar. 2019. https://www.congress.gov/crs-product/R45548

[2] Bonneville Power Administration, *"Grid Expansion & Reinforcement Portfolio Project Updates,"* Jan. 2026. https://www.bpa.gov/-/media/Aep/transmission/Grid-Expansion-and-Reinforcement-Portfolio-GERP/GERP-Project-Update.pdf

[3] Congressional Research Service. *"The Federal Energy Regulatory Commission (FERC): Authorities and Membership,"* Jan. 2026. https://www.congress.gov/crs-product/R48349

[4] Western Electricity Coordinating Council. https://www.wecc.org/about/about-wecc

[5] Oregon Public Utility Commission, *"PUC Roles and Responsibilities Background on the Form and Function of the Commission,"* Mar. 2022. https://www.oregon.gov/puc/about-us/Documents/PUC-Roles-and-Responsibilities.pdf

[6] Oregon Citizens' Utility Board. *"Who Owns and Regulates Oregon's Energy Utilities?"* May 2021. https://oregoncub.org/news/blog/who-owns-and-regulates-oregons-energy-utilities/2337

[7] Institute of Electrical and Electronics Engineers Standards Association. *"NESC Program,"* https://standards.ieee.org/products-programs/nesc/program/

The ***Oregon Consumer Utility Board*** was established in 1984 to advocate for consumer utility needs by conducting economic and legal analysis, engaging with community organizations and policy makers, and promoting equitable policies that prioritize communities.[1]

1.4.5 Regional Grid Operators and Power Markets

Regional Transmission Operators (RTOs) and Independent System Operators are organizations established by FERC to manage how power generators compete to generate and sell electricity. ***Figure 16*** provides a map of U.S. RTOs and ISOs. Many RTOs and ISOs also serve as balancing authorities, managing the transmission system and supporting grid reliability planning.

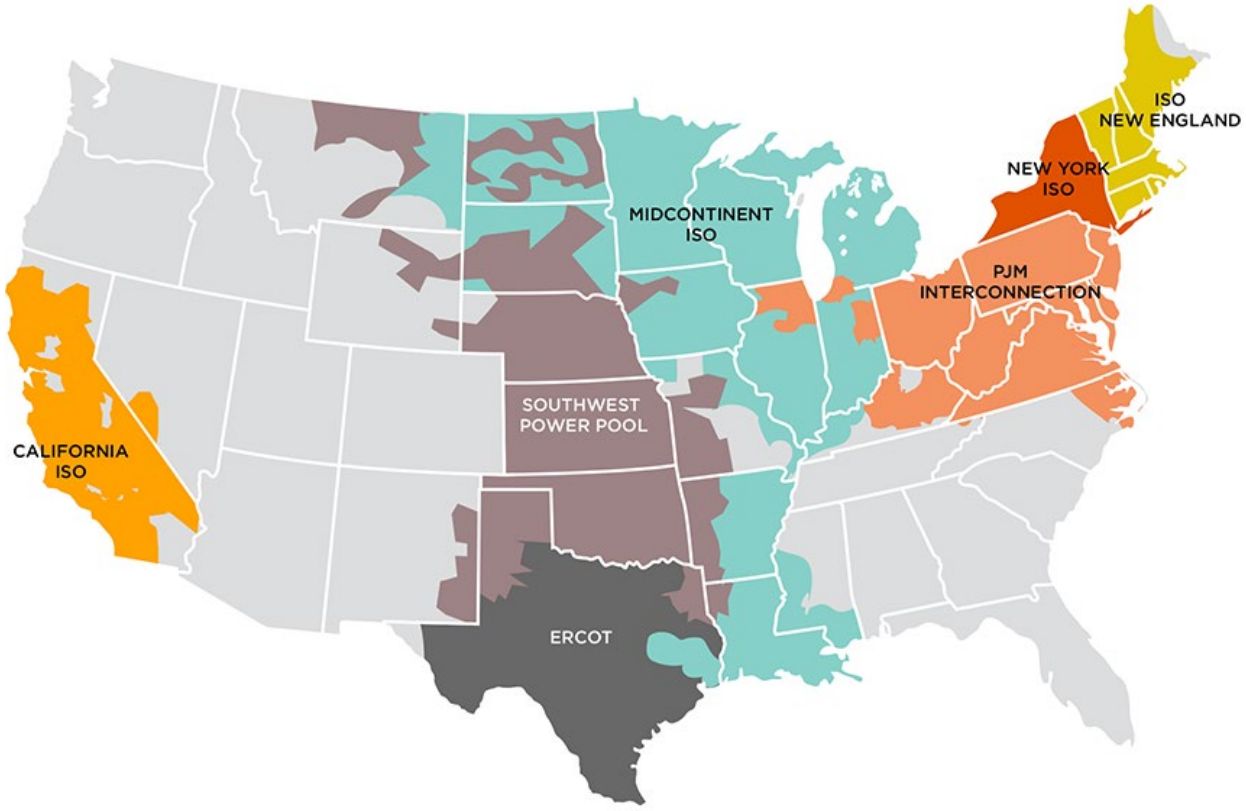


Figure 16: U.S. RTOs and ISOs Map[2]

While Oregon is not part of an ISO or RTO, some ISOs and RTOs that serve within the Western Interconnection offer power markets that Oregon utilities, balancing authorities, and independent power generators may choose to join (***Section 2.1***). Organized power markets provide a platform to exchange electricity across a broader regional network, which can lower electricity costs and provide access to diverse generation resources.[3] In Lane County, BPA and

[1] Oregon Citizens' Utility Board, *"About Us,"* https://oregoncub.org/who-we-are/

[2] Image from Federal Energy Regulatory Commission, *"Working for Reliable & Affordable Power for ALL,"* https://www.ferc.gov/introductory-guide-electricity-markets-regulated-federal-energy-regulatory-commission

[3] Oregon Department of Energy, *"Meeting the Demand of Oregon Energy Consumers,"* *https://energyinfo.oregon.gov/2024-electricity-markets*

EWEB are examples of entities that participate in power markets. BPA's and Pacific Power's current power market transition is detailed in ***Section 3.1***.

Power market participants—which include independent power producers, utilities, balancing authorities, and others—buy and sell electricity in day-ahead or real-time transactions. In day-ahead transactions, participants exchange electricity the day before service is needed based on demand and supply forecasts. Real-time markets allow participants to exchange electricity on the same day as service.[1] Day-ahead markets often include real-time components to respond to unexpected demand changes. Real-time and day-ahead transactions help utilities and balancing authorities plan and maintain system reliability.

1.5 How is Electricity Exchanged in Lane County

In the United States, electricity is exchanged through a dynamic system of interconnected transactions between independent power producers, power market administrators, power markets, utilities, and end-users. Because the structure and organization of these systems vary regionally, this section will focus specifically on Oregon and Lane County. ***Figure 17*** maps the main participants, interactions, and associated physical grid assets that comprise electricity exchange in the Pacific Northwest.

- ***Boxes*** represent entities participating in regional electricity exchange.
- ***Circles*** represent power generation facilities or other electricity sources. Although we use icons that represent different types of electricity generation (e.g., nuclear, wind), those are only examples. For instance, independent power producers sell electricity from many different resources, not just nuclear.
- ***Arrows*** represent electricity exchanges between entities. An exchange may involve physical transfer of electricity, a financial exchange for a quantity of electricity, or provision of an electrical service (e.g., utility service). Two arrows pointing in opposite directions indicate a bidirectional exchange. Each arrow is labeled with a letter that serves as a reference in this section.
- ***Colors*** are assigned to each entity and documented in the legend. These colors also indicate ownership or management of circled power sources and grid segments.

U.S. power sale can be divided into two main components: wholesale markets, which facilitate bulk power transactions between generators, BPA, and utilities; and retail markets, which govern how end-users purchase electricity from utilities

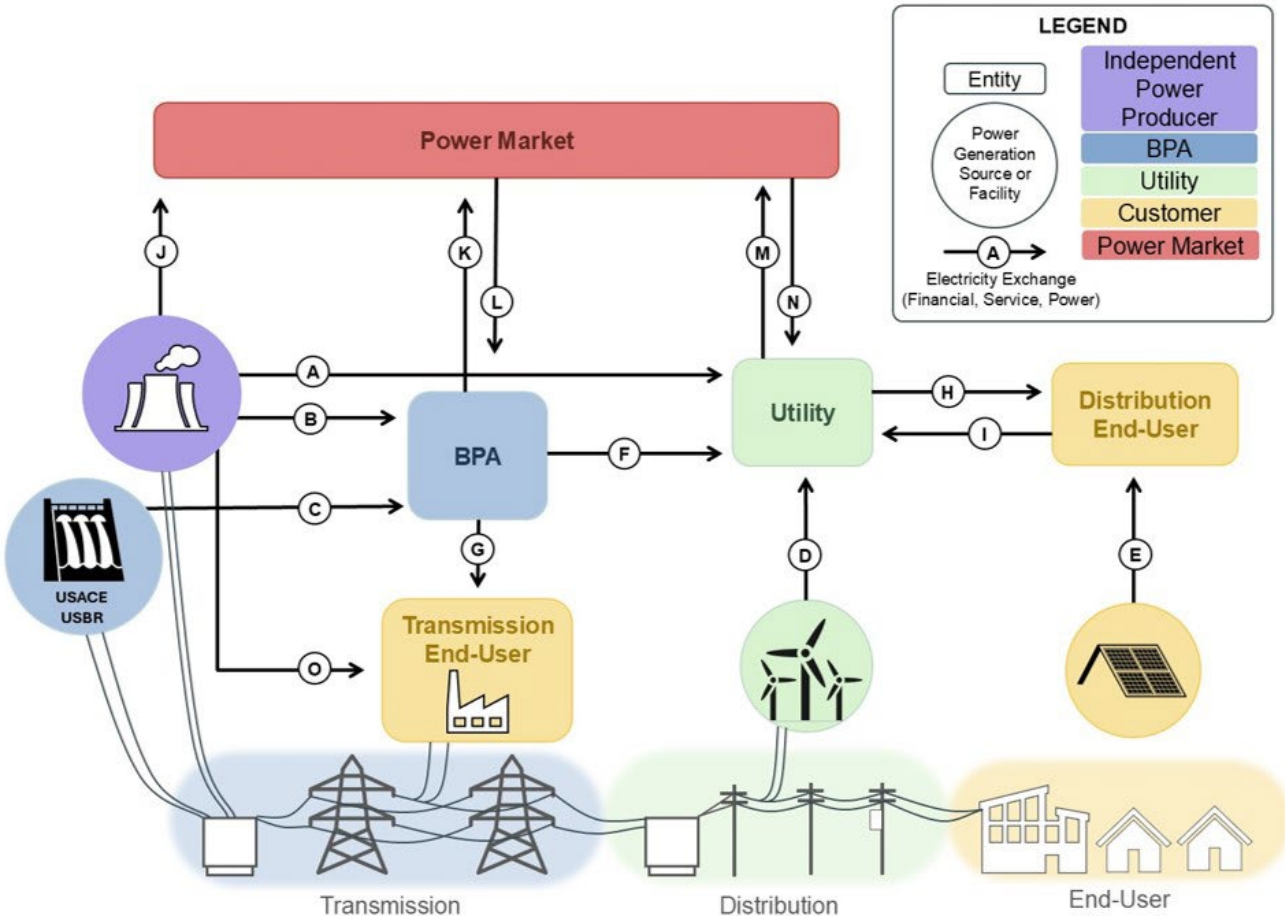
[1] Northwest Energy Coalition, *"Western Market Benefits to the Northwest,"* Apr. 2023. https://nwenergy.org/featured/western-market-benefits-to-the-northwest/

BPA

BPA sources electricity from federally managed hydroelectric dams operated by USACE and the U.S. Bureau of Reclamation **(C)**, contracts with independent power producers **(B)**, and purchases in regional power markets **(L).** BPA sells power to utilities **(F)** and large commercial or industrial customers **(G)** through long-term contracts and may also sell excess federal hydroelectric power regional power markets **(K)**

Power Markets

Organized power markets provide a platform for participating utilities and balancing authorities to purchase and exchange electricity across a broader regional network and access diverse generation resources. In Oregon, some independent power producers **(J)**, BPA **(L, K)**, and utilities **(M, N),** can choose to participate in an organized power market (cross ref). Organized power markets can promote transparent, standardized pricing, which reduces reliance on bilateral contracts—private, individually negotiated agreements between a buyer and seller—and improves cost efficiency.



Utilities

Each Lane County utility determines its own electricity resource portfolio. Utilities can purchase power through long-term contracts with BPA **(F)**, power purchase agreements with independent power producers **(A)**, or participation in regional power markets **(M, N)** (see Sub-Section 1.5.1). Utilities may also own generation facilities **(D)**, which can be connected to the distribution or transmission system. Utilities sell electricity to customers according to their rate schedules **(H).** Section 1.1 documents Lane County utility resource mixes.

Customers

Electricity end-users can be connected to the grid at the transmission or distribution level. ***Distribution-connected*** customers—including residential homes, commercial businesses, public buildings, community services, and other facilities **(H)**—purchase electricity from a local distribution utility. In Oregon, residential customers typically cannot choose which utility supplies their electricity. Customers may also own on-site generation (also called ***behind-the-meter*** generation), such as residential solar panels. (reference) **(E).** When on-site generation produces excess electricity, customers can send it to the distribution system and receive credit from their local utility **(I)**. Some end-users, like large commercial and industrial facilities, connect directly to the transmission system. Transmission-connected end-users sign contracts with BPA **(G)** or independent power producers **(O)**.

Figure 17: Northwest Electricity Exchange

1.5.1 Contracts Between BPA and Utilities

All of Lane County's electric utilities have contracts with BPA, with some buying almost all of their power from the organization. This section focuses on BPA contracts with COUs. COUs are BPA's "preferred customers"[1], meaning they get an allotted amount of the power generated by the federal system[2]. COUs purchase power at ***cost-based rates***, meaning that BPA sets rates such that they can recover the costs of generating and transporting power. The cost-based rates are relatively low and called "Tier 1" rates.

The allotment of power that a COU can buy at Tier 1 rates is referred to as the utility's ***Contract High Water Mark***. The Contract High Water Mark for the contract period from 2011 to 2028 was established through a process BPA called the ***Tiered Rate Methodology***. For contracts beginning in 2028, BPA will replace this Tiered Rate Methodology with the ***Public Rate Design Methodology***. There are some differences between the two methodologies, but generally the process remains the same. BPA guarantees that they will always be able to provide power up to the utility's Contract High Water Mark.

Utilities that require more electricity than the Contract High Water Mark Tier 1 electricity that they are allotted can elect to meet their additional need through BPA at the Tier 2 rate. Alternatively, a utility can purchase electricity from non-federal sources or a combination of Tier 2 and non-federal sources. The Tier 2 rates tend to be significantly higher than the Tier 1 rates, but may be slightly less than market rates.

To purchase power from non-federal sources, a utility needs to have the capacity to conduct market activities. In Lane County, EWEB is the only COU that buys power directly off the market, while some of the other utilities participate in the market through organizations (such as PNGC Power) that purchase on behalf of numerous COUs. Many COUs in Lane County meet their additional electricity need through BPA at the Tier 2 rate. ***Figure 18*** shows how a COU might determine whether they purchase Tier 2 power.

[1] See ***Section 1.5.1*** for an overview of the policies that established COUs as BPA's preferred customers
[2] Typically referred to as their "slice of the system"

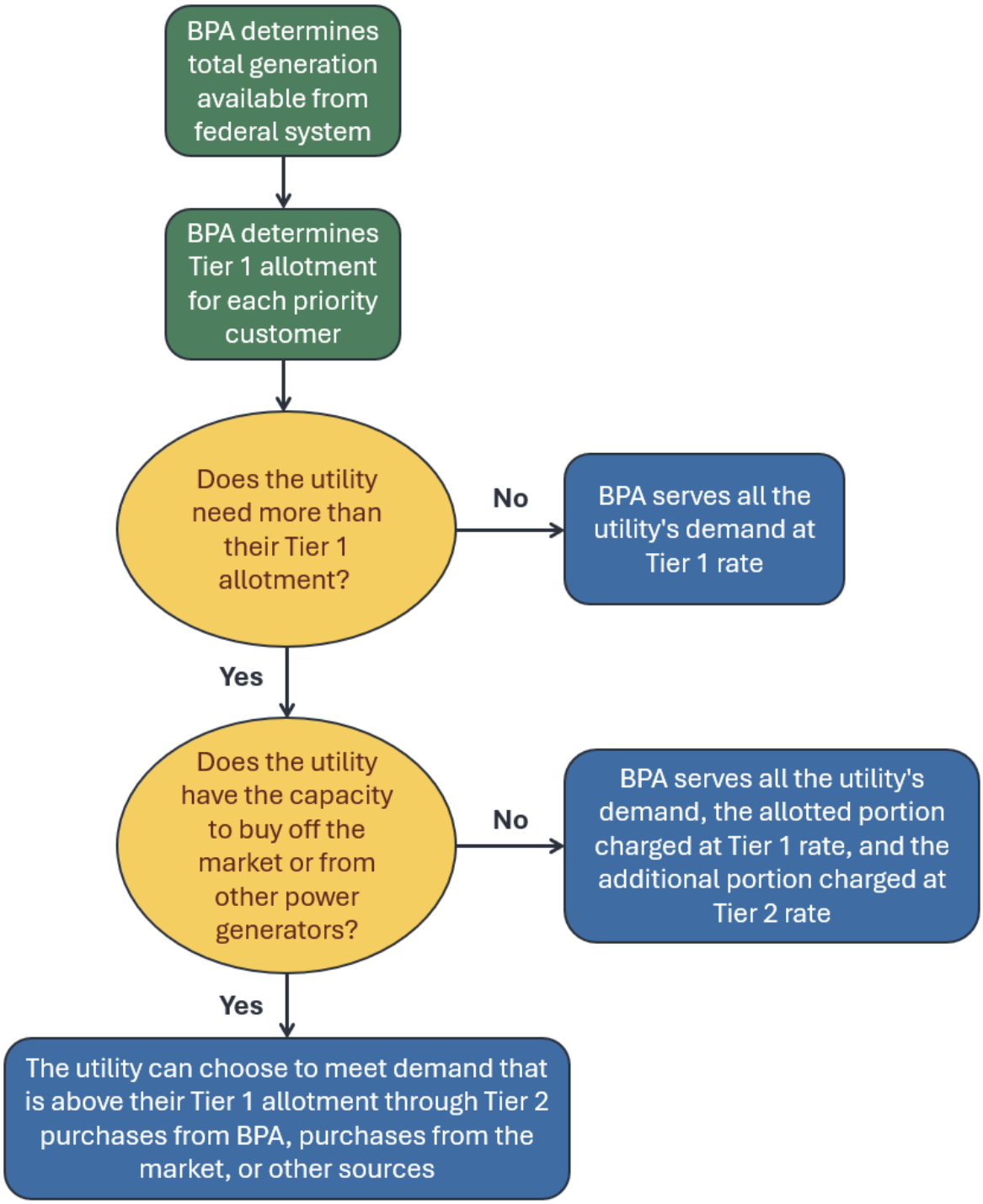


Figure 18: Flow Chart Showing Utility Decisions Regarding Power Purchase from BPA.

How do BPA Tier 1 and Tier 2 Rates compare to market rates?

BPA's published average rates (for fiscal years 2026–2028) for COUs who purchase only Tier 1 power is $37.77/MWh. For COUs purchasing both Tier 1 and Tier 2 power, the average rate is $40.16 per megawatt-hour (MWh).[1] ***Figure 19*** shows wholesale electricity prices by region in the United States. The additional green line is $40/MWh, exemplifying the relatively low cost of Tier 1 power.

BPA sets Tier 2 rates based on the actual or forecasted price paid by BPA to meet demand.

When BPA determines utilities' Contract High Water Marks, they do so based on conservative estimates of the power that will be available from the federal dam system (see ***Section 3.1*** for discussion of what factors impact the amount of available power). Because of their conservative estimate, there is often more power available than is contracted to utilities. BPA can then sell that power at Tier 2 rates.

When there is enough power in the federal system to meet demand, Tier 2 rates will often be less than the market rate for electricity. However, in cases where water levels behind the dams are low and/or demand is high, BPA Tier 2 rates will be closer to or above market prices because BPA will need to purchase power off the market to deliver to its customers.

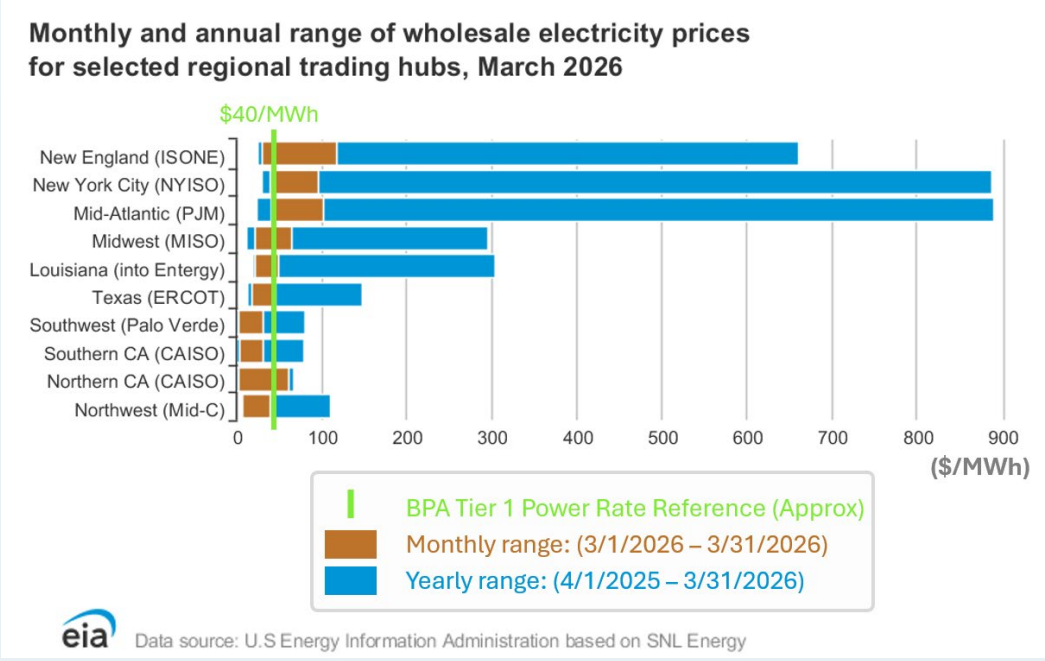


Figure 19: EIA U.S. Regional Wholesale Electricity Prices Comparison with BPA Tier 1 Rate[2]

[1] Bonneville Power Administration. https://www.bpa.gov/

[2] Image adjusted from U.S. Energy Information Administration, *"Regional Wholesale Markets: April 2026,"* June 2026. https://www.eia.gov/electricity/monthly/update/wholesale-markets.php

BPA's tiered approach to rate setting is meant to prevent BPA from independently shouldering unbound market costs, enable utility customers to choose how they want to meet their end user customers' load, and insulate customers from costs associated with the choices of other customers[1] (see ***Section 1.2*** for how and why this tier system was developed).

Utilities secure electricity supply through contracts with BPA that lock in the rate structure and power delivery agreements. The Tier 1 rate is set for a rate period of two years, meaning Tier 1 rates can change many times over the course of a contract period. Rates change according to the costs incurred by BPA to supply power and maintain the transmission system. The current contracts (known as ***Regional Dialogue*** contracts) span the period from 2011–2028; utilities are currently renegotiating contracts for 2028–2044 (called ***Provider of Choice*** contracts).

Distribution utilities pay both flat rate charges and use-based charges set by BPA. They may also pay charges for load shaping and/or risk adjustments, depending on the contract and power delivery product. Those charges vary between BPA's priority customers, which is why rates are given as averages. Full details on BPA charges can be found in the BPA rate schedule, currently available for the fiscal year 2026.[2]

Under extended contracts with BPA, utilities select BPA power delivery product options tailored to meet their needs.[3,4,5] There are two product types that a utility can choose for their BPA contract: ***Load Following*** and ***Planned Products***. The fundamental difference between Planned Products (which include Block and Slice/Block products) and the Load Following product is how (or to what extent) they deal with hourly changes in demand. For the Load Following product, BPA serves the utility's load on an hourly basis, regardless of the size of the load. For a Planned Product, BPA serves a pre-defined amount of the utility's load, and any peaks above that amount need to be served by additional resources dispatched or purchased by the utility.

Planned Products give utilities autonomy in how they serve their peak loads; however, they come with associated risks and requirements. For example, if a utility plans to serve their peak loads with their own generation, and something happens to limit the availability of that generation, they may be exposed to high market prices to meet peak loads or may be unable to meet those loads, leading to outages. A utility choosing a Planned Product must have control of dispatchable generation or the ability to purchase power in real-time markets so that they can meet peak demand.

Load Following products shift the responsibility of meeting peak demand to BPA, enabling the utility to allocate their effort to tasks other than dispatch or purchasing. That said, Load Following services come with additional charges from BPA. BPA demand charges apply to only their Load Following and Block with Shaping Capacity products. Other charges like the Load

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[1] Bonneville Power Administration, *"Provider of Choice Policy Record of Decision,"* Mar. 2024. https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/2024-rod/rod-20240321-bonneville-power-administration-provider-of-choice.pdf

[2] Bonneville Power Administration, *"2026 Power Rate Proposal,"* Oct. 2025. https://www.bpa.gov/energy-and-services/rate-and-tariff-proceedings/bp-26-rate-case

[3] Bonneville Power Administration, *"Fact Sheet Tiered Rate Methodology,"* Sep. 2020. https://www.bpa.gov/-/media/Aep/about/publications/fact-sheets/fs-202009-Tiered-Rate-Methodology.pdf

[4] Bonneville Power Administration, *"Fact Sheet Regional Dialogue Contracts,"* Aug. 2020. https://www.bpa.gov/-/media/Aep/power/provider-of-choice/fs-202008-regional-dialogue-contracts.pdf

[5] Bonneville Power Administration, *"Power Rates,"* https://www.bpa.gov/energy-and-services/rate-and-tariff-proceedings/power-rates

Shaping charge and the Risk Adjustment apply across products but will be applied more often for products that include more load shaping capabilities.

For the 2028–2044 contract period, BPA offers versions of their planned products with partial load shaping services. These products are called Block with Shaping Capacity and a Block with Shaping Capacity + Peak Load Variance. A summary of available products, their load shaping capabilities, and their resource flexibility is provided in ***Figure 20***.

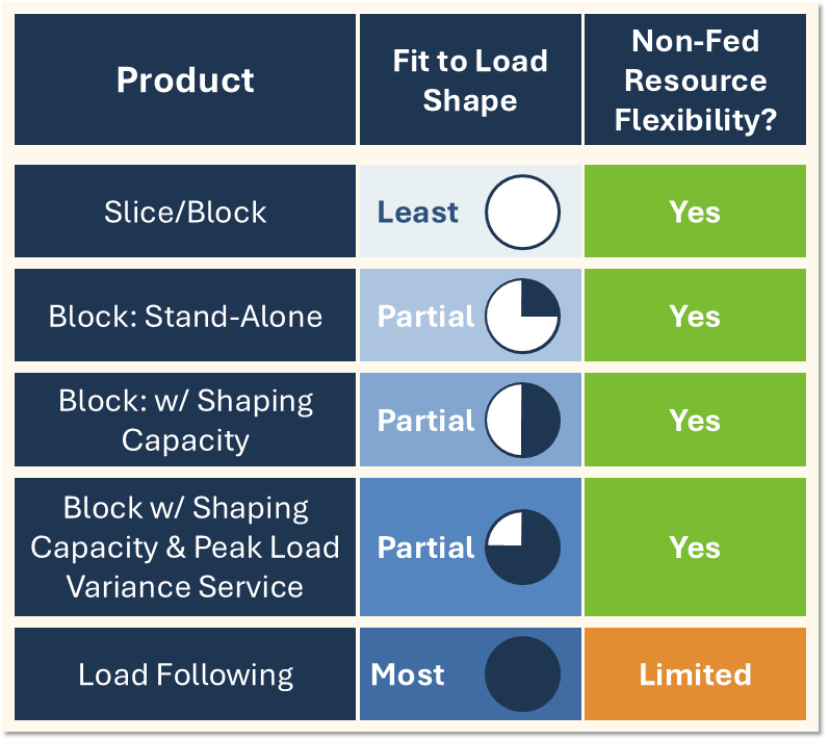


Figure 20: BPA Product Options

A utility's product choice can take many factors into consideration, including uncertainties (such as future load). ***Table 3*** shows some of the factors that would go into a utility's product choice. Operational and cost-related factors are relatively straightforward, but a utility's specific goals may also impact their product choice. For example, if a given utility expects many electric vehicles to come online in their service area, they may strategically choose a Load Following product that can handle large spikes in load. Alternatively, they might decide to dedicate more time and resources to establishing customer programs that reward customers for charging their electric vehicles during off-peak hours (an example of a demand response program, further discussed in ***Section 3.3***) and investing in their own generation, in which case, they might be inclined to choose a Block product.

Table 3: Considerations When Choosing a BPA Product

Consideration	Choice		Influencing Factors
	Yes	No	
Operational Capabilities: Does the utility have dispatchable generation resources or the ability to purchase non-federal power?	Utility might compare costs of different products	Utility will likely select a Load Following product	• Generation resources • Workforce capabilities
Cost: Which product is likely to result in the lowest cost to the utility?	The utility will likely choose the product they expect to result in lower costs. That said, predicting long-term costs might require cost modelling or various future scenarios, a task that not all utilities will be able to take on.		• Alignment of BPA allotments and utility-predicted load • Size of expected demand peaks • Typical variation in demand • Expectations for load or generation growth
Goals: Which product enables the utility to dedicate resources to meeting their board or community goals?	If there is not a product that is an obviously better financial choice, a utility might choose the product that better aligns with their or their community's goals.		• Conservation or energy efficiency related goals • Local generation goals • Customer programs goals

Table 4 shows the product choices of Lane County's utilities under the current ***Regional Dialogues*** contracts. In Lane County, all the utilities that do not own their own generation resources are Load Following customers. EWEB has published their tentative product choice for the new ***Provider of Choice*** contracts, which are still being negotiated.[1,2] EWEB selected for a Block with Shaping Capability + Peak Load Variance Service. ***Table 4*** also shows the utilities' demand relative to their Contract High Water Mark. Utilities below their Contract High Water Mark meet their customers' full demand with power purchased at Tier 1 rates.

[1] Eugene Water & Electric Board, *"2028 BPA Product of Choice Resolution for Recommendation and Next Steps,"* Memorandum. July 2025. https://www.eweb.org/documents/board-meetings/2025/07-08-25/m8_bpa_product_of_choice_final.pdf

[2] Eugene Water & Electric Board, *"Eugene Water and Electric Board Approves New Provider of Choice Contract With BPA,"* Jul 2025. https://www.newsdata.com/clearing_up/courts_and_commissions/eugene-water-and-electric-board-approves-new-provider-of-choice-contract-with-bpa/article_34ca04e7-7589-40dd-a3fd-48ec6f6721ed.html

Table 4: Lane County Utility BPA Product Choices

Utility	BPA Products Purchased Under Regional Dialogue Contracts (2011–2028)	Demand Relative to Contract High Water Mark
Eugene Water & Electric Board (EWEB)	Slice/Block, moving to Block with Shaping Capability + Peak Load Variance for 2028–2044[2]	Above
Springfield Utility Board (SUB)	Load Following	Below/Near
Emerald People's Utility District (EPUD)	Slice/ Block, moving to Load Following for 2028–2044	Above
Central Lincoln PUD	Load Following	Below
Lane Electric Co-op	Load Following through Pacific Northwest Generating Cooperative (PNGC Power)	Below/Near
Pacific Power (PacificCorp)	New Resource (NR) Block, Residential Exchange Program Settlement Implementation Agreement (REPSIA)[3]	Not a preferred customer
Blachly-Lane Co-op	Load Following through PNGC	Below

1.5.2 Sales from Distribution Utilities to Customers

Utilities use rate structures to differentiate costs between residential, commercial, and industrial customers. For example, an average U.S. residential home consumes 5.9 kWh per square foot annually,[4, 5]compared to 12.6 kWh for commercial buildings.[6] Data centers can use 10 to 50 times the energy per square foot of a typical commercial property.[7] By adjusting electricity prices and rate structures, utilities can respond to changes in wholesale power costs, operating expenses, and capital project costs. Any changes to consumer electricity rates must be approved by the utility's governing board (in the case of COUs) or the Oregon PUC (in the case

[1] Bonneville Power Administration, *"Regional Dialogue Long-Term (20 year) Contracts Customer Products List,"* Apr. 2024. https://www.bpa.gov/-/media/Aep/power/regional-dialogue/customerproductslist.pdf
[2] Eugene Water & Electric Board, *"Present State: Electric Utility Business Model,"* Oct. 2024. https://www.eweb.org/documents/board-meetings/2024/10-15-24/m2_electric_utility_business_model_2024-10-04.pdf
[3] Oregon Public Utility Commission, *"Order No. 08-480,"* Sep. 2008 https://apps.puc.state.or.us/orders/2008ords/08-480.pdf
[4] U.S. Energy Information Administration, *"Total square footage of U.S. homes, 2020,"* Mar. 2023. https://www.eia.gov/consumption/residential/data/2020/hc/pdf/HC%2010.1.pdf
[5] U.S. Energy Information Administration, *"How much electricity does and American home use?"* https://www.eia.gov/tools/faqs/faq.php?id=97&t=3
[6] U.S. Energy Information Administration, *"Table C22. Electricity consumption totals and conditional intensities by building activity subcategories, 2018,"* Dec. 2022. https://www.eia.gov/consumption/commercial/data/2018/ce/pdf/c22.pdf
[7] U.S. Department of Energy. *"Data Centers and Servers,"* https://www.energy.gov/cmei/buildings/data-centers-and-servers

of IOUs). When approving rate changes, boards/ commissions consider how the rate structure balances customer and utility needs.

Utilities combine several types of charges (also called “rate elements”) to determine the total charge on a customer’s electric bill. Utilities can choose rate elements to promote energy affordability, efficient electricity consumption, technology adoption, and commercial development. ***Table 5*** describes rate elements and the goals utilities can pursue through each type of charge. ***Chapter 4*** further discusses how different rate structures can be used to maintain affordable service (see ***Section 4.1***) and encourage efficiency (see ***Section 4.3***).

Table 5: Rate Structure Elements and Associated Utility Goals

	Fixed Charge ($/month)	Energy Charge ($/kWh)	Demand Charge ($/kW)
What	A fixed charge does not vary with a customer’s energy usage or demand. The most common fixed charge is a customer charge, which is typically a monthly fee per customer or per meter to receive service.	A volumetric energy charge directly links customer costs to energy consumption. Energy charges may remain constant (flat) or vary by time of day, month, or season. Block rates adjust the prices based on how much electricity a customer uses. An inclining or rising block rate increases prices as customer usage increases, while a declining or falling block rate decreases prices as customer usage increases.	A demand charge is based on a customer’s maximum electricity demand, measured in kilowatts. Customer demand is measured instantaneously or at a specific interval. Demand charges are more common for commercial and industrial customers.
Why	Fixed charges provide consistent revenue for utilities and a predictable bill for customers. Utilities might set this charge to align with the fixed costs of infrastructure upkeep. Another option is subscription pricing, in which a portion of a customer-specific bill is fixed. Varying a fixed charge based on customer-specific factors like income or the number of families at a residence can reduce the energy cost burden on vulnerable customers.	Declining block rates can encourage increased electricity use for larger industrial customers, promote electrification, and help utilities recover costs. Rising block and time-varying energy charges can encourage customers to adopt energy-efficient technologies and practices. These charges also encourage customers to shift when they use electricity, known as load flexibility. Load flexibility can lower system costs and improve grid reliability by reducing customer electricity use during peak demand periods. However, heavy reliance on energy charges can impact utility revenue stability if customers reduce usage.	Demand charges support cost-reflectivity and system reliability by aligning customer bills with their contribution to peak system demand and infrastructure costs. They can encourage customers to manage peak usage, helping reduce capacity investments and improve grid efficiency.

Residential rates cover single-family, multifamily, and manufactured homes, where electricity is used for heating, lighting, cooking, and appliances. Lane County utility residential rate structures are presented in ***Table 6***. Pacific Power is the only utility that differentiates between single and multi-family customers by offering a lower fixed charge for multi-family customers to promote affordability. All utilities apply an energy charge, but with varying complexity. EWEB, EPUD and Central Lincoln PUD include a flat energy charge—a single, fixed rate per kWh regardless of when or how much electricity is consumed. This provides customers with simple and predictable

billing but offers little financial incentive to reduce or shift consumption. SUB's seasonal rising block energy charge includes a higher winter kWh usage threshold, meaning that customers can consume more electricity before reaching the higher-priced block. Lane Electric's seasonal blocks have identical kWh usage thresholds but reduced prices in the winter to ease the cost of seasonal heating demands. Pacific Power is the only utility offering on-peak charge and off-peak credits to encourage demand flexibility and load shifting. No utilities use a residential demand charge.

Table 6: Lane County Residential Electricity Rate Schedules

Utility	Fixed Charge	Energy Charge	Demand Charge
Eugene Water & Electric Board (EWEB)[1]	Flat $/month	Flat $/kWh	N/A
Springfield Utility Board (SUB)[2]	Flat $/month	Seasonal (Oct–Apr, May–Sept) Rising Block $/kWh	N/A
Emerald People's Utility District (EPUD)[3]	Flat $/month	Flat $/kWh	N/A
Central Lincoln PUD[4]	Flat $/month	Flat $/kWh	N/A
Lane Electric Co-op[5]	Flat $/month	Seasonal (Nov–Apr, May–Oct) Rising Block $/kWh	N/A
Pacific Power[6]	Single and multi-family $/month	Flat $/kWh with On-Peak Adder and Off-Peak Credit	N/A
Blachly-Lane Co-op[7]	Flat $/month	Rising Block $/kWh	N/A

The commercial rate category includes government and office spaces, grocery stores, malls, and other businesses. ***Table 7*** summarizes commercial rates in Lane County. Commercial rate structures are more complex than residential rate structures, therefore ***Table 7*** includes some simplifications. Lane County utilities frequently use flat fixed charges, rising or falling block energy charges, and some form of a demand charge. Seasonal rates, fixed and energy charge blocks based on maximum demand, and on- and off-peak rates are less common.

[1] Eugene Water & Electric Board, *"Residential Rates & Fees,"* www.eweb.org/my-account/budget-and-rate-information/residential-pricing

[2] Springfield Utility District, *"Electric Rates,"* https://www.subutil.com/customer-service/rates-policies/electric-rates/

[3] Emerald People's Utility District, *"Rates,"* https://www.epud.org/my-account/rates/

[4] Central Lincoln People's Utility District, *"Rate Schedules,"* https://clpud.org/customer-information/rate-schedules-policies-guidelines-standards/rate-schedules/

[5] Lane Electric, *"Rates,"* https://www.laneelectric.com/your-account/rates/

[6] Pacific Power, *"Oregon rates and tariffs,"* https://www.pacificpower.net/about/rates-regulation/oregon-rates-tariffs.html

[7] Blachly-Lane Electric Cooperative, *"Electric Rates,"* https://www.blachlylane.coop/your-account/electric-rates/

Table 7: Commercial and Industrial Electric Rate Schedules

Utility	Categories	Sub-Categories	Fixed Charges	Energy Charges	Demand Charge
EWEB[1]	Small: up to 30 kW Medium: 31–500 kW Large: 501–10,000 kW	Medium and Large: Single- and Three-Phase Service Primary service over 300 kW.	Flat $/month: ↑ for 3-phase ↑ primary service ↑ w/ ↑ kW category size	Falling Block $/kWh for Small Flat $/kWh for Small, Medium, Large: primary service ↓ w/ ↑ kW category size	Rising Block $/kW for Small Flat $/kW for Medium & Large ↓ primary service ↑ w/ ↑ kW category size
SUB[2]	Small: up to 35 kW Medium: 35–3000 kW Large: >3000 kW	Single- and Two/Three-Phase Service	Flat $/month: ↑ for 3-phase Small > Medium = Large	Seasonal $/kWh: Small & Large: Flat Medium: Rising Block Small & Medium: Summer Rates ↓ Large: Summer Rates ↑	Medium: Seasonal Rising Block $/kW Large: Seasonal $/kW
EPUD[3]	Under 50 kW Over 50 kW	Single Phase Poly Phase	Flat $/month: ↑ Polyphase	Flat $/kWh: â kW category size	Over 50 kW Category: Flat $/kW
Central Lincoln PUD[4]	Small General Large General Commercial & Industrial Large Industrial	High Voltage	Flat $/month: ↑ w/ ↑ kW category size	Flat $/kWh for Small, Commercial, Industrial Small>Industrial>Commercial Large: kWh charge based on rising block kW demand	Commercial/Industrial: Flat $/kW Large: Falling Block $/KW
Lane Electric[5]	Single-phase Single-phase Commercial Three-phase	Categories based on service voltage and motor horsepower	Single-phase: Flat $/month Three-phase: Rising block $/month based on max kW demand.	Single-phase: Flat $/kWh Three-phase: Rising block $/kWh	Single Phase: Rising Block $/kW Three-phase: Rising block $/kW based on max kW demand.
Pacific Power Oregon[6]	Small, Medium, Large General Service Categories Time of Use (TOU), Partial Requirement Options Secondary, Primary, Transmission Options kW Size Categories	Flat $/month, Flat $/year, $/month based on max kW demand		$/kWh: Flat, Time of Use, Falling Block, Based on demand kW On- & Off-Peak & Seasonal TOU Rates	Flat $/kW Can be based on max facility kW On and Off-Peak $/KW Charges
Blachly-Lane[7]	Commercial w/ kW Commercial w/out kW Industrial 101–1000 kW Industrial 1000+ kW New Load > 1 Avg. MW	Commercial w/out kW Charge: Single and Poly Phase options	Flat $/month: ↑ Polyphase Industrial: ↑ w/ ↑ kW category size	Commercial w/ kW: Flat $/kWh Commercial w/out kW: Rising block $/kWh Industrial: Different $/kWh for kW category sizes	Commercial w/ kW: Flat $/kW Industrial: Flat $/kW ↑ w/ ↑ kW category size

Note that this table should not be used by customers trying to understand their rates. For that, please refer to each utility's individual rate schedule. Pacific Power's rates are too complicated to fit to table and are abbreviated. Most utilities have more categories for their rate schedules, but are simplified here to highlight the basic rate options that Lane County utilities offer.

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[1] Eugene Water & Electric Board, *"Non-Residential Pricing,"* www.eweb.org/my-account/budget-and-rate-information/commercial-pricing

[2] Springfield Utility Board. *"2025 SUB Electrical Rates,"* https://www.subutil.com/customer-service/rates-policies/electric-rates/

[3] Emerald People's Utility District, *"Rate Schedules 2025,"* https://www.epud.org/my-account/rates/

[4] Central Lincoln People's Utility District, *"Rate Schedules,"* https://clpud.org/customer-information/rate-schedules-policies-guidelines-standards/rate-schedules/

[5] Lane Electric, *"Rates,"* https://www.laneelectric.com/your-account/rates/

[6] Pacific Power, *"Oregon rates and tariffs,"* https://www.pacificpower.net/about/rates-regulation/oregon-rates-tariffs.html

[7] Blachly-Lane Electric Cooperative, *"Electric Rates,"* https://www.blachlylane.coop/your-account/electric-rates/

Together, ***Table 6*** and ***Table 7*** show that Lane County utilities deploy a variety of rate design elements. Pacific Power, Lane County's only IOU, offers the most complex rate structures, indicating a difference between large IOU and small COU approaches to rate design. Lane County COUs have an opportunity to adopt rate design strategies already used by other local utilities to address new community priorities, regional challenges, or energy and operating costs.

Average electricity rates in Lane County are lower than in Oregon statewide, which in turn is lower than the U.S. average. This is due to Oregon's access to low-cost federal hydropower, and Lane County's high concentration of consumer-owned utilities that predominantly purchase BPA power at Tier 1 rates. ***Figure 21*** shows average rates compiled from the Oregon Department of Energy 2024,[1] EIA Residential 2025,[2] FindEnergy.Com 2024,[3] and EnergySage.Com 2025.[4]

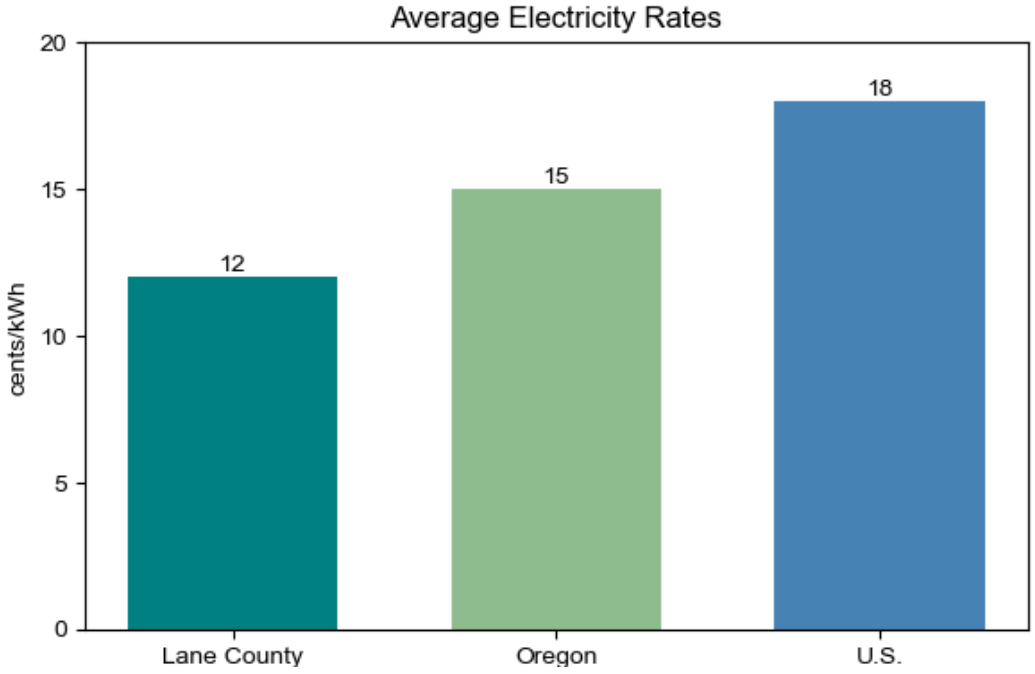


Figure 21: Average Electricity Rates in Lane County, Oregon, and the U.S.

1.6 What Electricity Generation Sources Supply Lane County

Each Lane County utility determines its own electricity resource portfolio. Most utilities in Lane County purchase nearly 100% of their electricity through long-term contracts with BPA, which is typical for small Pacific Northwest COUs. Utilities may also own local power generation facilities, sign contracts with independent generators, or participate in wholesale markets. Lane County utility resource mixes are documented in ***Table 8***.

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[1] Oregon Department of Energy, *"Lane County",* Oct. 2024. https://energyinfo.oregon.gov/energy-profiles-2024/lane

[2] U.S. Energy Information Administration, *"Electric Power Monthly,"* https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a

[3] Find Energy, *"Fine Energy & Power Outage Data,"* https://findenergy.com/

[4] Energy Sage, *"Cost of electricity in Lane County, OR: Real numbers from real people,"* June 2026. https://www.energysage.com/local-data/electricity-cost/or/lane-county/

Table 8: Lane County Electric Utility Resource Mix

Utility	Electrical Resource Mix
Eugene Water & Electric Board (EWEB)	80% BPA, 20% from three, local EWEB-owned hydroelectric plants, small amount of power from co-owned wind and biomass contracts.[1]
Springfield Utility Board (SUB)	100% BPA[2]
Emerald People's Utility District (EPUD)	97% BPA, ~3% from local Short Mountain landfill gas plant[3]
Central Lincoln PUD	100% BPA[4]
Lane Electric Co-op	Majority of power from BPA.[5] Exact stats are not publicly available.
Pacific Power	PacificCorp-owned generation plus contracts. ~%50 coal and natural gas[6]
Blachly-Lane Co-op	Majority of power from BPA. Co-owns Coffin Butte landfill gas plant.[7] Exact stats are not publicly available.

EWEB's 2024 electrical resource mix is shown in ***Figure 22***. EWEB's reported resource mix incorporates BPA's resource mix, so we separated BPA resource percentages. EWEB's energy portfolio is composed of roughly 80% BPA-sourced electricity.[8] The other 20% is supplied by local hydroelectric and biomass facilities or market purchases. EWEB is the only Lane County COU actively participating in wholesale markets.[9] Several of EWEB's hydroelectric projects are undergoing changes. EWEB is decommissioning the Leaburg Dam due to economic viability issues and operational risks and is currently evaluating the future of the Walterville Project.[10]

[1] Eugene Water & Electric Board, *"Our Power Supply,"* www.eweb.org/your-public-utility/power-supply
[2] Springfield Utility Board, *"2025-2026 Strategic Plan,"* Oct. 2024. https://www.subutil.com/wp-content/uploads/SUB-Strategic-Plan-2024-fin-lores.pdf
[3] Emerald People's Utility District, *"Power Generation,"* https://www.epud.org/about-us/your-utility/power-generation/
[4] Central Lincoln People's Utility District, *"The Benefits of Public Power,"* https://clpud.org/about-us/benefits-of-public-power/
[5] Lane Electric, *"Hydropower,"* https://laneelectric.com/programs-services/hydropower/
[6] PacificCorp, *"PacifiCorp Owned and Contracted Energy/Capacity Resource Mix,"* https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/about/Generation_Portfolio_Transformation.pdf
[7] Blachly-Lane Electric Cooperative, *"Green Power,"* https://www.blachlylane.coop/conservation/renewable-energy/green-power/
[8] Eugene Water & Electric Board, *"Where Your Power Comes From,"* 2024. https://www.eweb.org/your-public-utility/power-supply/where-your-power-comes-from
[9] Eugene Water & Electric Board, *"Power Supply & Transmission,"* www.eweb.org/environment-and-climate/climate-guidebook/power-supply-and-transmission
[10] Eugene Water & Electric Board, *"Decommissioning the Leaburg Hydroelectric Project,"* www.eweb.org/projects/mckenzie-river-hydro-projects/decommissioning-the-leaburg-hydroelectric-project

Pacific Power's Basic Service 2024 electrical resource mix is shown in ***Figure 23***. Pacific Power offers several clean energy service options, where customers pay a higher rate in exchange for electricity with a greater percentage of wind and solar generation resources.

Of the remaining Lane County COUs, only EPUD purchases power outside of BPA through the Short Mountain landfill gas power plant (***Figure 24***). The remaining utilities purchase 100% of their electricity from BPA (***Figure 25***).

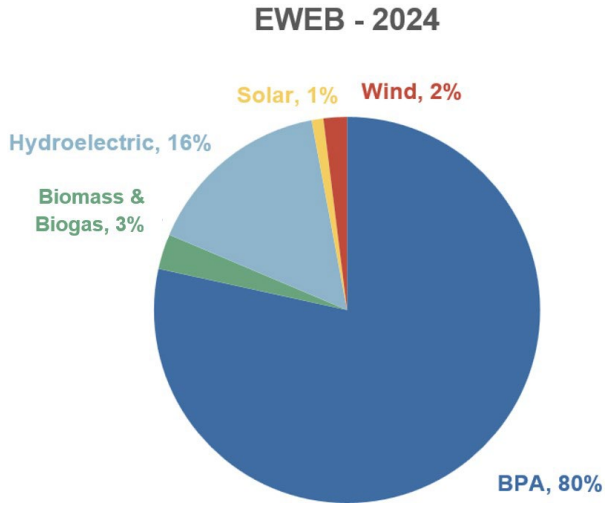


Figure 22: EWEB 2024 Electrical Resource Mix[1]

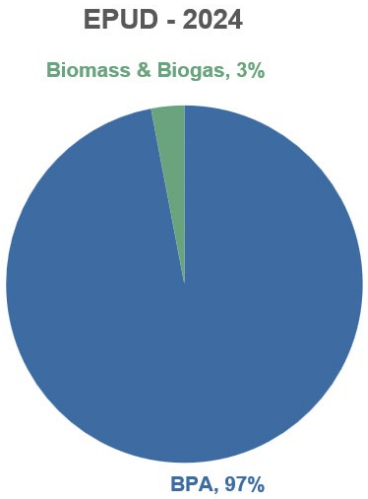


Figure 24: EPUD 2024 Electricity Resource Mix[3]

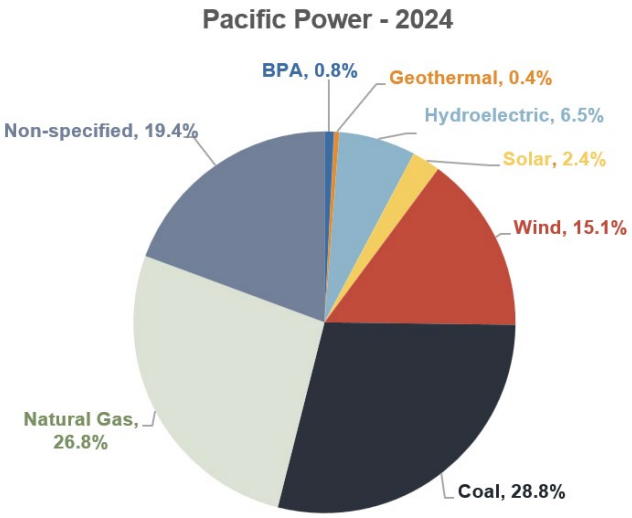


Figure 23: Pacific Power's 2024 Basic Service Electricity Resource Mix[2]

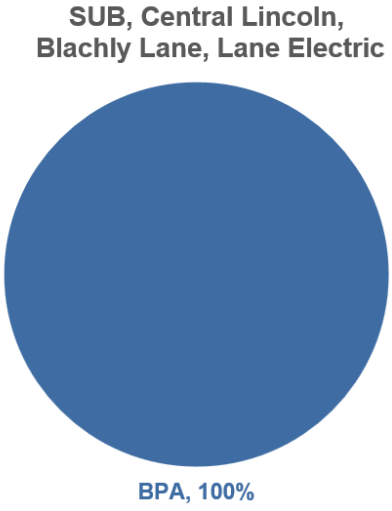


Figure 25: SUB, Central Lincoln, Blachly Lane, and Lane Electric Electricity Resource Mix[4]

[1] Eugene Water & Electric Board, *"Where Your Power Comes From,"* 2024. https://www.eweb.org/your-public-utility/power-supply/where-your-power-comes-from

[2] PacificCorp, ibid

[3] Emerald People's Utility District, *"Power Generation,"* https://www.epud.org/about-us/your-utility/power-generation/

[4] See *Table 8*

The categories used to define electrical generation resources delineate based on size, location, owner, or other factors. A single generation source can fit into multiple categories. For example, a rooftop solar ***photovoltaic (solar PV)*** installation is small-scale, behind-the-meter, and considered a ***distributed energy resource***. A large nuclear power plant is both utility-scale and transmission-connected. A local energy resource, like the Short Mountain Power Plant, is utility-scale and distribution-connected.

1.6.1 BPA Electricity Resource Mix

BPA electricity is generated from a mix of hydroelectric, nuclear, and renewable resources (***Figure 26***). The vast majority (74.4%) of BPA's 2024 generation is from federal hydroelectric power. Non-specified purchases include transactions within the Western Energy Imbalance Market and other systems without knowledge of specific energy sources.[1]

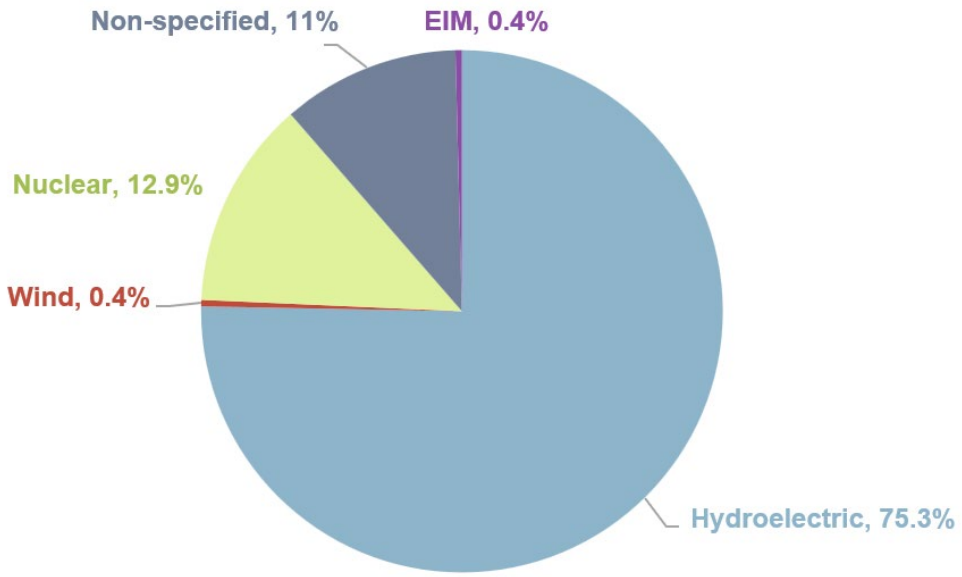


Figure 26: BPA 2024 Resource Mix[2]

1.6.2 Local Generation Facilities

Lane County's ***local generation*** facilities include grid-connected hydroelectric, biomass, and natural gas power plants, and distributed generation such as solar PV. ***Figure 27*** maps Lane County's grid-connected biomass and hydroelectric power plants, scaled by peak capacity in megawatts. ***Table 9*** lists grid-connected hydroelectric, biomass, and natural gas power plants operating within Lane County. Ownership and selling structures vary. Some local generation resources are owned and operated by a utility like EWEB or EPUD. These resources are connected to the utility distribution system and supply power exclusively to utility customers. Several local hydroelectric dams are federally owned and operated by BPA. University of Oregon's 10 MW combined heat and power plant is a distributed energy resource not connected

[1] Bonneville Power Administration, *"Power from the Willamette Basin dams,"* Aug. 2019. https://www.bpa.gov/-/media/Aep/about/publications/fact-sheets/fs-201908-Power-from-the-Willamette-Basin-dams.pdf

[2] Data from Bonneville Power Administration. *"2024 BPA fuel mix,"* https://www.bpa.gov/-/media/Aep/power/fuel-mix/2024-bpa-fuel-mix.pdf

to EWEB's grid. The UO campus can disconnect from EWEB's system and use the combined heat and power plant to operate as an isolated micro-grid. In early 2026, EWEB piloted a peak-shaving project with UO, which utilized this powerplant.[1]

Table 9: Lane County Generation Resources

Generation	Type	Peak Capacity	Owner	Year online	Selling Structure
Carmen-Smith	**Hydro**	114 MW	EWEB	1963	Owned and operated by EWEB for EWEB distribution system[2]
Cougar	**Hydro**	29 MW	USACE	1964	BPA markets power[3]
Hills Creek	**Hydro**	35 MW	USACE	1962	BPA markets power[3]
Lookout Point	**Hydro**	138 MW	USACE	1955	BPA markets power[3]
Dexter	**Hydro**	15 MW	USACE	1955	BPA markets power[3]
Short Mountain	**Biomass**	3.2 MW	EPUD	1992	Owned and operated by Waga Energy. Portion of power goes to EPUD distribution system[4]
International Paper (IP)	**Biomass** & supplemental **Natural Gas**	25.4 MW	EWEB owned; jointly operated with IP	1976	Costs and output shared 50/50 under agreement between EWEB and IP[5]
Sierra Pacific Industries	**Biomass**	19.8 MW	Seneca Sustainable Energy LLC	2011	PPA with EWEB[5]
UO Combined Heat and Power Station	**Natural Gas**	10.9 MW	University of Oregon	1948, modernized 2011	Powers UO Campus[6]

[1] Eugene Water & Electric Board, "EWEB and the UO extend energy generation study," https://www.eweb.org/your-public-utility/news/eweb-and-the-uo-extend-energy-generation-study
[2] Eugene Water & Electric Board, *"An In Depth Look at the Carmen Smith Hydroelectric Project,"* May 2017. www.eweb.org/your-public-utility/news/an-in-depth-look-at-carmen-smith-hydroelectric-project
[3] Bonneville Power Administration, Aug. 2019, ibid.
[4] Waga Energy, *"Waga Energy to Deliver Renewable Natural Gas in Eugene, Oregon"* Jan. 2026. https://waga-energy.com/en/waga-energy-to-deliver-renewable-natural-gas-in-eugene-oregon/
[5] Eugene Water & Electric Board, *"2023 Integrated Resource Plan,"* July 2023. https://www.eweb.org/documents/Projects/Energy%20Division/2022-IRP/2023-EWEB-IRP.pdf
[6] University of Oregon, *"Utilities & Energy,"* https://cpfm.uoregon.edu/utilities-energy/about

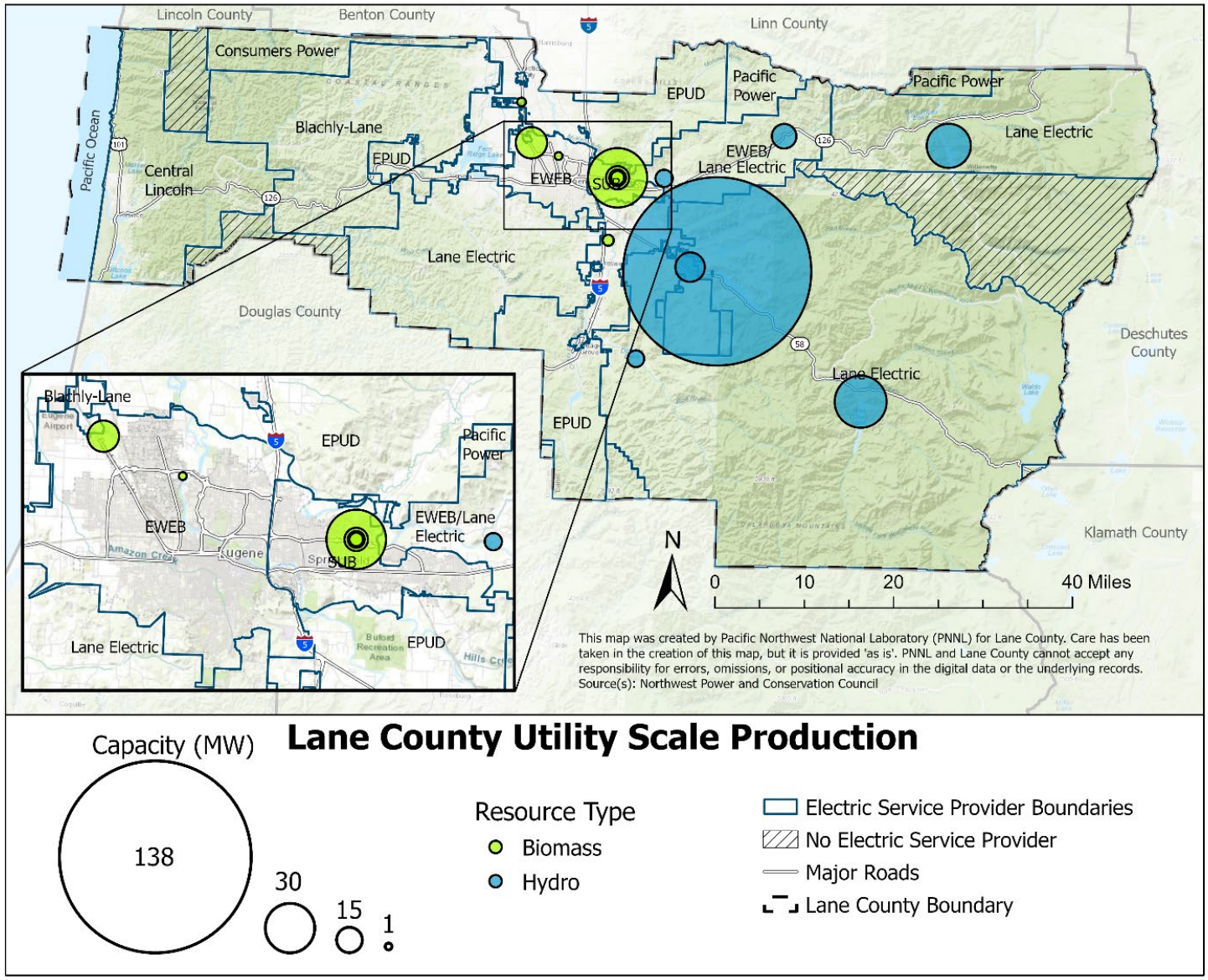


Figure 27: Grid-connected biomass (green) and hydro (blue) power production in Lane County scaled by MW capacity.[1]

[1] Data (as of April 2026) from Northwest Power and Conservation Council https://www.nwcouncil.org/energy/energy-topics/power-supply/map-of-power-generation-in-the-northwest/

Figure 28 maps behind-the-meter solar PV installations across Lane County, scaled by annual generation in MWh. Most solar PV production is concentrated in Eugene, with a single large commercial plant in the Wolf Creek area generating just over 1 gigawatt-hour (GWh) annually. This solar PV plant produces enough power to meet the average annual electricity consumption of 88 Lane County households.[1]

Construction of behind-the-meter solar PV installations in Lane County has accelerated in recent years with 55 new installations added in 2021 and 76 in 2022.[1] Lane County currently hosts 1,297 solar PV sites, of which 190 are commercial and 1,107 are residential. These installations are connected to the grid through "***net metering***" where power from the solar panels is used first to power the residence or business and then any excess flows to the grid; in cloudy periods or at night power is pulled from the grid for the residence or business. The electricity bill is based on the net difference between power used and power exported to the grid. If more power is produced than used, then the customer gets credit from the utility. Commercial solar facilities collectively produce 7,371.5 MWh per year, while residential systems contribute an additional 6,313.7 MWh.[2]

[1] Oregon Department of Energy, *"Lane County",* Oct. 2024. https://energyinfo.oregon.gov/energy-profiles-2024/lane

[2] Northwest Power and Conservation Council, ibid.

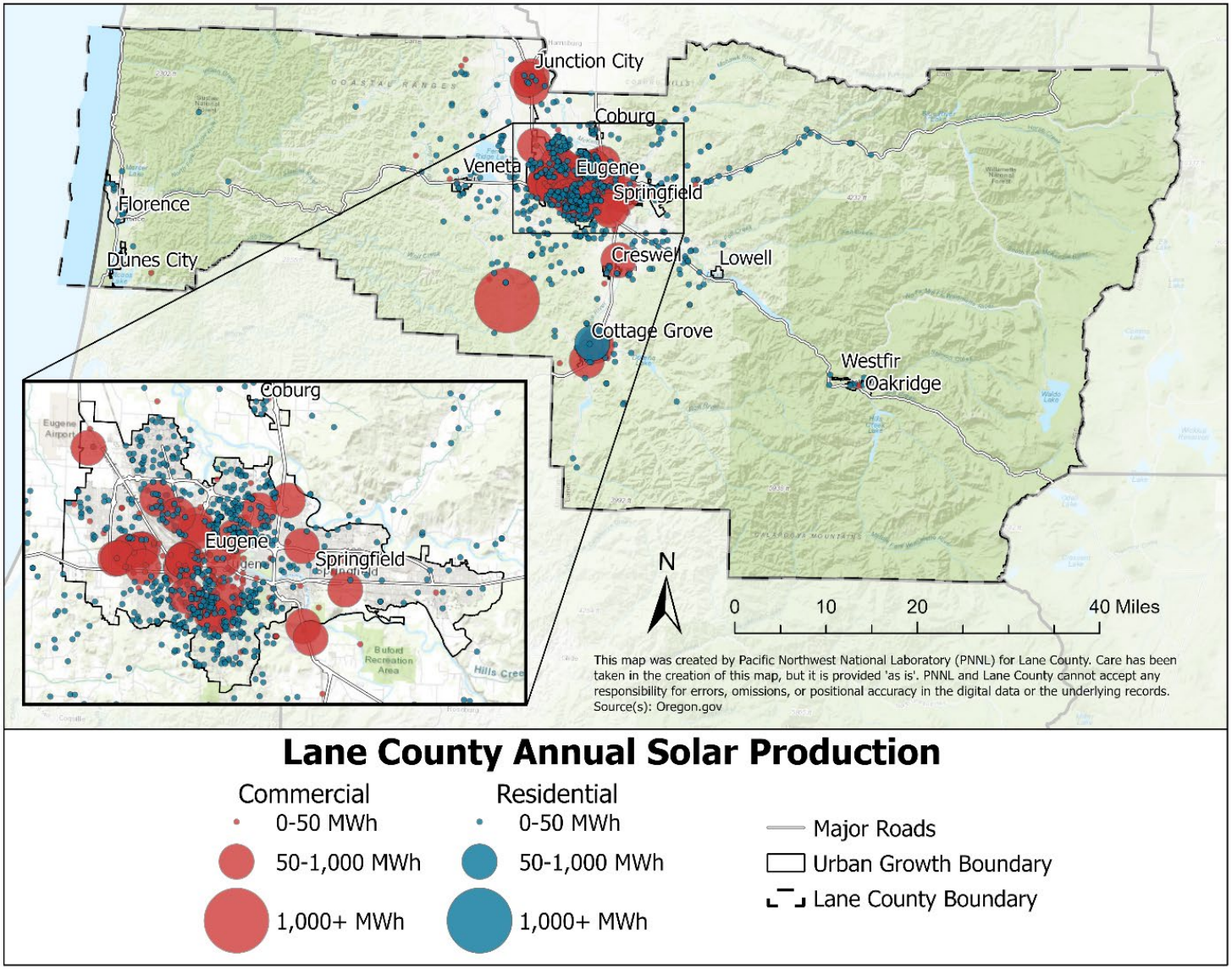


Figure 28: Solar PV Production in Lane County[1]

[1] Data (as of 2022) from Oregon Department of Energy, *"Oregon Solar Dashboard,"* https://www.oregon.gov/energy/energy-oregon/pages/oregon-solar-dashboard.aspx

None of the locally owned generation goes onto the bulk grid (though the USACE hydropower generation does). ***Section 3.4*** and ***Chapter 6*** discuss options for local generation on the distribution system, meaning electricity generated and used in Lane County.

Potential projects to develop utility scale projects that sell to the regional grid face several barriers. Any new power generating facility feeding onto the transmission system must obtain permission from the transmission line owner to connect to the grid. This process often requires lengthy studies to identify infrastructure upgrades and additions. As of 2025, around 200,000 MW of renewable energy projects were waiting for BPA approval, a process that can take many years. Public reporting on the interconnection queue for BPA has since driven state lawmakers in Oregon and Washington to take steps to speed up the build out of renewable energy generation.[1] For example, in 2025 Governor Tina Kotek released Executive Order 25-25 titled ***Accelerating Wind and Solar Energy Development in Advance of Elimination of Federal Clean Energy Tax Credits***.[2] The order establishes directives to expedite the permitting and development process for wind and solar energy projects to target as much new construction as possible before July 4, 2026 to leverage soon-to-be-terminated federal renewable energy tax credits.[3]

Interconnection requests for IOUs (in Lane County, Pacific Power) follow the policies put in place by Oregon Interconnection procedures AR 521 if they are less than 10 MW,[4] and information about interconnection of large projects can be found on BPA and Pacific Power websites.[5,6] If a generation project requires transmission upgrades, the project developer may be required by the transmission utility to pay for some or all upgrades. From what we know of transmission in Lane County, there are not currently major capacity constraints, but BPA is performing Interconnection Cluster Studies to build understanding of possible capacity constraints relative to interconnection requests in the queue.[7] The Interconnection Guidebook published by the Energy Trust of Oregon provides additional information.[8]

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[1] Oregon Public Broadcasting, *"Our reporting showed Washington ranks last in green energy growth. Now the state is working to speed it up,"* Jan. 2026. https://www.opb.org/article/2026/01/26/our-reporting-showed-washington-ranks-last-in-green-energy-growth/

[2] Office of the Governor State of Oregon, *"EXECUTIVE ORDER NO. 25-25,"* https://www.oregon.gov/gov/eo/eo-25-25.pdf

[3] State of Oregon Governor's Office, *"Governor Kotek Directs State Agencies to Accelerate Renewable Energy Siting,"* Oct. 2025. https://apps.oregon.gov/oregon-newsroom/OR/GOV/Posts/Post/governor-kotek-directs-state-agencies-to-accelerate-renewable-energy-siting

[4] Pacific Power, *"BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON AR 521,"* Nov. 2007. https://edocs.puc.state.or.us/efdocs/HAC/ar521hac83620.pdf

[5] Bonneville Power Administration, *"Large Generator Interconnection (LGI),"* https://www.bpa.gov/energy-and-services/transmission/interconnection/large-generator-interconnection

[6] Bonneville Power Administration, *"Interconnection,"* https://www.bpa.gov/energy-and-services/transmission/interconnection

[7] Bonneville Power Administration, *"Generator Interconnection Phase One Cluster Study Report,"* https://www.bpa.gov/energy-and-services/transmission/notices/20260130-generator-interconnection-phase-one-cluster-study-report

[8] Energy Trust of Oregon. *"Interconnection Guidebook For Developers of Small Scale Renewable Energy Generation Systems,"* 2016. https://www.energytrust.org/wp-content/uploads/2016/10/100908_Interconnection_Guidebook.pdf

Chapter 2

What Policies Impact Lane County's Grid?

Adrienne Rackley, Ali Trueworthy, Brooke Marten, and Ellie Estreich

Policies made by federal and state officials impact how Lane County utilities buy power; where and under what restrictions local governments, utilities, and developers can build new large loads or generation; how local governments and utilities pursue energy efficiency and conservation efforts; and where and how local governments, organizations, consumers, and utilities can find support efforts related to energy. This chapter provides an overview of policies in each of these categories.

2.1 Policies Governing BPA Ratemaking

All Lane County utilities purchase power from BPA. The collective impact of policies governing BPA ratemaking is that BPA sells, markets, and transmits electricity at the lowest feasible cost with preference to public utilities and toothwest Pacific Northwest customers.[1] BPA is mandated to set rates such that they can recover costs. They have no ongoing revenues from the federal government. They are not appropriated funding from Congress but can borrow money from the U.S. treasury. Current BPA rate structures for Lane County utilities are described in ***Chapter 4***. The historical statutes defining BPA's role in marketing federal hydroelectric power and the way that BPA sets its rates today are:

The Reclamation Act of 1902 required that the benefits of federal power be provided to the public at the lowest possible cost.[2]

The Bonneville Project Act of 1937 directed BPA to prioritize public bodies and consumer-owned utilities in power sales ("preference customers"), specifically those in the Pacific Northwest. The Act mandated BPA to set rates in order to recover the costs related to producing and transmitting energy from the Federal Columbia River Power System.[3]

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[1] Bonneville Power Administration, *"Bonneville Power Administration Rates Overview,"* Sep. 2024. https://olis.oregonlegislature.gov/liz/2023I1/Downloads/CommitteeMeetingDocument/285681

[2] J. Hammarlund, *"Oregon's Role as an Energy Innovator," FORUM*. https://digitalcollections.willamette.edu/bitstreams/de2efbd2-14e5-49a6-8bb3-b3b409830210/download

[3] Northwest Power and Conservation Council, *"Bonneville Power Administration: History,"* https://www.nwcouncil.org/reports/columbia-river-history/bpahistory/

The Flood Control Act of 1944 directed BPA to market power "in such a manner as to encourage the most widespread use thereof at the lowest possible rates to consumers consistent with sound business principles."[1] ***The PNW Consumer Power Preference Act of 1964*** limited BPA power sales outside of the Pacific Northwest to surplus energy, ensuring priority to regional customers.[2]

The Federal Columbia River Transmission System Act of 1974 gave BPA's administrator the authority to integrate and transmit power from sources beyond the federal dam system. This means that they can buy electricity on behalf of their customers. The Act also created the BPA Fund, which enabled BPA to manage funding and repayment obligations based on rates rather than on annual appropriations from congress.[3]

The Pacific Northwest Electric Power Planning and Conservation Act of 1980 (also known as the ***Northwest Power Act***) aimed to balance the need for affordable electricity with the obligation to protect fish and wildlife by establishing guidelines for cost allocation, encouraging transparent ratemaking processes, and allowing the BPA to prioritize energy conservation before pursuing new power sources.[4] The Northwest Power Act also created the ***Northwest Power and Conservation Council***, discussed in the next section.



Figure 29: Adult Chinook Salmon at the Bonneville Dam, 2003[5]

[1] United States Congress, "Flood Control Act of 1944," Dec. 1944. https://www.usbr.gov/power/legislation/fldcntra.pdf
[2] J. Hammarlund, "Oregon's Role as an Energy Innovator," *FORUM*. https://digitalcollections.willamette.edu/bitstreams/de2efbd2-14e5-49a6-8bb3-b3b409830210/download
[3] United States Congress, "Federal Columbia River Transmission System Act," Oct. 1974. https://www.usbr.gov/power/legislation/fedcolum.pdf
[4] Northwest Power and Conservation Council, *"Northwest Power Act,"* https://www.nwcouncil.org/reports/columbia-river-history/northwestpoweract/
[5] Image from Northwest Power and Conservation Council, *"Fish passage at dams,"* https://www.nwcouncil.org/reports/columbia-river-history/fishpassage/

2.2 Policies Impacting Large Load Development

Large new developments within COU service territories are constrained in how they can acquire and pay for electricity service. They do not always get access to federal hydropower resources at priority rates like many of the existing COU customers. This section reviews the policies governing these large developments (see ***Section 3.3.2*** for more). Overall, these policies strive to protect consumers from bearing the costs of large, energy-intensive developments.

BPA's New Large Single Load (1980) policy was established under the Northwest Power Act and describes how BPA defines, monitors, and sets rates for ***New Large Single Loads*** (NLSLs). The designation applies to any significant new load or expansion at a single facility in BPA service area that increases by 10 MW or more within any consecutive 12-month monitoring period. Once a facility is designated as an NLSL, the classification remains in effect regardless of future reductions in the load size.[1,2]

NLSLs are served at BPA's marginal resource cost-based rate, known as the New Resources Firm Power rate, rather than the lower Priority Firm Power rates that apply to preference customers. In 2026, the New Resource Firm Power rate is almost triple the Priority Firm Power rate.[3] The NLSL rate structure is designed to address the potential relocation of energy-intensive industries to the Pacific Northwest in pursuit of BPA's low-cost federal hydropower rates. The NLSL approach may also help ensure the costs of generating and delivering power are appropriately allocated when new, energy-intensive loads come online.[1,2]

BPA actively oversees its NLSL determination process. Utilities are required to notify BPA of any developing or planned NLSLs, as failure to report them may result in back billing to recover the difference in rates. BPA collaborates with utilities to establish service arrangements and monitor changes.[4,5] Facility types that frequently meet the 10 MW load threshold include data centers, heavy-duty fleet electric vehicle charging stations, and large industrial plants with substantial energy requirements.

The NLSL policy can both protect and constrain communities. The rate policy discourages energy-intensive industries from relocating to the region purely to take advantage of BPA's inexpensive federal power. While this may impede the development of industries or facilities with high energy demands, the policy also helps protect existing BPA customers from rate increases that could be triggered by new large loads. Additionally, it encourages investment in new, non-federal generation sources, greater energy efficiency, and demand-side management strategies.[6,7]

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[1] Bonneville Power Administration, *"Bonneville Power Administration New Large Single Load Policy," Apr. 2001.* https://www.bpa.gov/-/media/Aep/power/regional-dialogue/nlsl-policy-04-2001.pdf
[2] Bonneville Power Administration, *"Fact Sheet: New Large Single Load,"* Oct. 2020. https://www.bpa.gov/-/media/Aep/about/publications/fact-sheets/fs-202011-New-Large-Single-Load.pdf
[3] Bonneville Power Administration, *"Power Rates,"* https://www.bpa.gov/energy-and-services/rate-and-tariff-proceedings/power-rates
[4] Bonneville Power Administration, Apr. 2001. Ibid.
[5] Bonneville Power Administration, Oct. 2020. Ibid.
[6] GDS Associates, https://www.eesconsulting.com/bonneville-power-administration-bpa/large-industrial-load-analysis.html
[7] Tri-Cities Area Journal of Business, *"Clean energy policies hamper industrial development,"* Dec. 2022. https://www.tricitiesbusinessnews.com/articles/4193

POWER Act (HB3546, 2025), an Oregon state law, establishes new requirements for large energy-using facilities in the state, aiming to increase electricity service transparency, equitability, and accountability for facilities consuming 20 MW or more annually. The bill focuses on balancing the costs associated with powering these facilities while protecting other electricity consumers, promoting renewable energy integration, and ensuring compliance with Oregon's clean energy targets.[1]The Act directs the PUC to create policies holding large energy users accountable for their costs.[2]

While BPA's NLSL policy applies to public preference customers (i.e., a publicly owned utility or cooperative) and governs the rate at which BPA supplies federal power to new large loads, the POWER Act applies to investor-owned utilities and directs the Oregon PUC to ensure that the costs of serving large energy users are not shifted onto other ratepayers.[3]



Figure 30: Amazon Web Services Data Center, Boardman Oregon, 2024[4]

[1] Oregon Legislative Assembly, *"House Bill 3546,"* 2022. https://olis.oregonlegislature.gov/liz/2025R1/Downloads/MeasureDocument/HB3546/Enrolled

[2] Oregon Public Broadcasting, *"'POWER Act' bill would require Oregon's large energy users like data centers pay fair share of energy use,"* Mar. 2025. https://www.opb.org/article/2025/03/06/power-act-data-centers-electricity-use-oregon-lawmakers-energy-google-utilities/

[3] Governor's Office, *"Governor Kotek Signs Bills to Lower Energy Costs for Oregonians,"* Aug. 2025. https://apps.oregon.gov/oregon-newsroom/OR/GOV/Posts/Post/governor-kotek-signs-bills-to-lower-energy-costs-for-oregonians

[4] Image from OPB, *"Oregon Legislature passes 'POWER Act,' targeting industrial energy users like data centers,"* June 2025. https://www.opb.org/article/2025/06/05/oregon-data-centers-cryptocurrency-business-environment-power-electricity/

2.3 Policies Affecting Energy Efficiency and Conservation

An exhaustive history of policies that prioritize or otherwise impact energy efficiency and conservation measures is beyond the scope of this report; however, we present several important federal policies focused on energy efficiency and conservation, as well as several more recent state policies that set requirements for local governments and utilities in Oregon.

The Northwest Power Act (1980),[1] a federal law, prioritized energy efficiency as the primary method to meet future energy demands and encouraged utilities to adopt cost-effective measures rather than relying on new power plant construction. The Act also mandated the protection of fish and wildlife affected by Columbia River hydroelectric development and other Northwest waterways and created a fish and wildlife program dedicated to mitigating the environmental impacts of hydropower dams and ensuring that ecological concerns are integrated into energy system operations.

The Energy Policy Act (2005), a federal law, addressed energy production, conservation, and energy efficiency issues across the United States. The Act introduced a wide array of federal incentives for renewable energy development, promoted energy efficiency programs, and supported innovation in energy technologies. These incentives included tax credits for renewable energy projects, loan guarantees for energy infrastructure, and energy savings performance contracts for conservation measures at federal facilities. [2] While some provisions of the Energy Policy Act have since been superseded or expanded by more recent legislation, such as the ***Inflation Reduction Act (IRA) of 2022***,[3] the framework continues to inform and support energy policy in Oregon and across the country.

The Energy Independence and Security Act (2007),[4] a federal law, was designed to enhance the nation's energy security through renewable energy sources and energy efficiency standards. The Act introduced national standards for federal agencies, the automotive industry, and other sectors, prioritizing technology advancements in transportation energy, such as biofuels, electric vehicles, and renewable energy technologies. Energy efficiency provisions encouraged federal agencies and the private sector to integrate energy-saving practices such as improving fuel efficiency for vehicles, implementing stricter energy codes for buildings, and designing energy-efficient products.[5]

The Oregon Renewable Portfolio Standard (2007) was first adopted in 2007 and expanded in 2016 (***Senate Bill 838*** and ***1547***, respectively). The RPS set requirements for electric utilities to procure increasing percentages of their electricity from qualifying renewable resources, such as, wind, solar, biomass, and small hydropower. Large investor-owned utilities, like Pacific Power, must meet a RPS target of 50% renewable energy by 2040, while large consumer-owned utilities, such as EWEB, must reach 25% by 2025, as long as achieving the target does not

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[1] Northwest Power and Conservation Council, *"Northwest Power Act,"* https://www.nwcouncil.org/reports/columbia-river-history/northwestpoweract/

[2] U.S. Federal Legislation, *"H.R.6 - Energy Policy Act of 2005,"* 2005. https://www.congress.gov/bill/109th-congress/house-bill/6

[3] U.S. Department of Energy, "Inflation Reduction Act of 2022," Sep. 2023. https://www.energy.gov/lpo/inflation-reduction-act-2022

[4] U.S Environmental Protection Agency, "Summary of the Energy Independence and Security Act," Dec. 2007. https://www.epa.gov/laws-regulations/summary-energy-independence-and-security-act

[5] Oregon Department of Energy, *"Biennial Energy Report – Chapter 6: Energy Efficiency,"* http://www.oregon.gov/energy/Data-and-Reports/Documents/BER-Chapter-6-Energy-Efficiency.pdf

force them to reduce their Tier 1 purchases from BPA. Smaller utilities, such as EPUD and Lane Electric Cooperative, are obligated to secure at least 5% of their electricity from renewables starting in 2025, with the same protection of their Tier 1 allocation as above, reflecting the program's tiered approach to renewable energy adoption across Oregon.[1]

Governor Brown Executive Order 20-04 Oregon Climate Action Plan (2020),[2] a state policy, directed Oregon's state agencies to accelerate actions to reduce greenhouse gas (GHG) emissions and regulate climate change impacts by mandating a broad set of actions across energy, transportation, land use, and public health sectors to achieve Oregon's climate and resiliency objectives.[3],[4],

Oregon Clean Energy Targets Bill (2021) is a state law that sets clean energy targets, and mandates increasing percent reductions in GHG emissions relative to a baseline. PGE, Pacific Power, and Electricity Service Suppliers[5,6]must reduce GHG emissions resulting from electricity sold in Oregon to: 80% below baseline emissions by 2030, 90% below baseline emissions by 2035, and 100% below baseline emissions 2040.[7]

The Inflation Reduction Act (IRA, 2022) established or expanded several categories of tax credits and incentives related to energy efficiency and energy conservation, including consumer tax credits for energy efficiency investments, clean energy systems, and alternative fueling infrastructure; tax credits and deductions for developers meeting certain standards or achieving energy usage reductions; and tax credits for purchases of qualified electric vehicles. The IRA was a reconciliation bill with the original legislation slated to allow these provisions to continue until 2032.

The One Big Beautiful Bill Act (OBBBA, 2025) sped up the expiration of several tax credits incentivizing investments in energy efficiency and conservation as specified in the IRA (2022), including consumer tax credits for energy efficiency investments (including for residential solar and storage) and the electric vehicle tax credits.

2.4 Policies Supporting Local Energy Resiliency Efforts

This section highlights recent state policies dedicated funding to or indicated funding priorities for local energy resilience projects. ***Section 2.5*** identifies areas where Lane County might expect funding or project opportunities in the near future.

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[1] Oregon Department of Energy, *"Renewable Portfolio Standard,"* https://www.oregon.gov/energy/energy-oregon/pages/renewable-portfolio-standard.aspx

[2] Office of the Governor, State of Oregon, *"Executive Order No. 20-04,"* 2020. https://www.oregon.gov/gov/eo/eo_20-04.pdf

[3] Oregon Public Utility Commission, *"Executive Order 20-04,"* https://www.oregon.gov/puc/utilities/pages/executiveorder20-04.aspx

[4] Oregon Environmental Council, *"Oregon Climate Action Plan,"* http://oeconline.org/oregon-climate-action-plan/

[5] Lane County utilities are not listed in the Oregon Clean Energy Targets Bill (2021).

[6] Oregon Public Utility Commission, *"Electric Service Suppliers (ESS),"* https://www.oregon.gov/puc/utilities/Pages/Electric-Service-Suppliers-%28ESS%29.aspx?wp4092=so%3a%5b%5b69265%2c1%5d%5d#g_faa39146_6eff_42e4_891d_19e6d591c610

[7] Oregon Department of Environmental Quality, *"Clean Energy Targets,"* https://www.oregon.gov/deq/ghgp/pages/clean-energy-targets.aspx

Oregon HB 3409 (2023), a state law, was a major omnibus bill[1] that declared a state climate emergency and introduced several new policies and programs related to climate, energy, and the environment. The bill proposes resilience hubs and directs the Oregon Department of Human Services (DHS) to provide financial and other support for development of these hubs in Oregon. The bill requires ODOE to "reduce […] barriers to home energy efficiency and resilience," and otherwise states that resilience can be a benefit to communities.[2]

Oregon HB 3630 (2023), a state law, directed the ODOE to expand energy planning and customer support through new programs, grants, and a centralized information portal.[3] It required ODOE to develop and periodically update a comprehensive statewide energy strategy. HB3630 also authorized counties to develop energy resilience plans and incorporate them into their natural hazard mitigation plans, while requiring public utilities to use reasonable efforts to provide counties with requested energy-infrastructure information. This bill also established an assistance program for energy projects in environmental justice communities (implemented by ODOE as the Community Navigator Program[4]) and authorized a grant program to help counties cover the cost of developing qualifying energy resilience plans; nineteen counties applied to participate in the program providing up to $50,000 per county, with plans due by June 30, 2026.[5] In addition, HB 3630 established programs supporting home energy-efficiency upgrades and electrification rebates (HOMES and HEAR) and directed ODOE to create a one-stop resource to help Oregonians navigate incentives, technical assistance, contractors, and financing, now provided through the Hub for Incentive Programs + Projects in Oregon (HIPPO).[6]

The Oregon Energy Strategy (2025) was developed by ODOE as directed in HB 3630 and was submitted to the Governor and Legislature in November 2025. The Strategy outlines a comprehensive plan for achieving a clean, reliable, and affordable energy future in Oregon across different sectors and pathways.[7] The Strategy emphasizes strengthening resilience across all levels of the energy system and notes that several types of targeted investments—including grid hardening and modernization, batteries and other distributed resources, and weatherization—can enhance resilience. The Strategy does not establish or mandate any specific measures for Lane County; however, it provides information on the State's strategic direction and possible future opportunities. We discuss potential opportunities for Lane County in alignment with The Strategy in ***Section 2.5***.

Governor Kotek's Executive Order 25-29 Reducing Greenhouse Gas Emissions and Advancing Oregon's Clean Energy Future (2025) furthered Oregon's commitment to reduce emissions and transition to a clean energy economy.[8] The Order emphasizes implementation of

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[1] Oregon HB 3409 was an omnibus bill, meaning that it is a single legislative document that was passed and includes several distinct, smaller bills.
[2] *Oregon Legislative Assembly, "House Bill 3409 (2023 Regular Session),"* 2023. https://olis.oregonlegislature.gov/liz/2023R1/Measures/Overview/HB3409
[3] Oregon Legislative Assembly, *"House Bill 3630 (2023 Regular Session),"* 2023. https://olis.oregonlegislature.gov/liz/2023R1/Measures/Overview/HB3630
[4] Oregon Department of Energy, *"Community Navigator Program,"* https://www.oregon.gov/energy/resources/Pages/Community-Navigator.aspx
[5] Oregon Department of Energy, *"County Energy Resilience Program,"* https://www.oregon.gov/energy/safety-resiliency/Pages/County-Resilience.aspx
[6] Oregon Department of Energy, *"Oregon Incentives Hub — About,"* https://incentives.oregon.gov/about
[7] Oregon Department of Energy, *"Oregon Energy Strategy,"* Nov. 2025 https://www.oregon.gov/energy/Data-and-Reports/Documents/Oregon-Energy-Strategy.pdf
[8] State of Oregon, *"Executive Order No. 25-29,"* Nov. 2025. https://www.documentcloud.org/documents/26287253-eo-25-29/

the Oregon Energy Strategy's five least-cost pathways while prioritizing affordable, reliable clean energy and resilience. Key provisions include advancing energy efficiency, facilitating renewable energy project development, growing a resilient clean energy economy, and improving accountability and tribal engagement.

2.5 Opportunities for Lane County Communities to Follow State-Level Strategies

Lane County has several opportunities to pursue planning and policy development that align with state-level strategy. ***Chapter 9*** reviews existing energy and resilience plans for the county and localities. The current state level strategies can be used as a guide to update local and county strategies. Major areas of current state-level strategy that could align with county of city action are outlined below:

Investments in renewable energy development, demand management, and infrastructure. Several state-level strategies, including the ***Oregon Energy Strategy*** and ***Executive Order 25-29***, promote investments in renewables to meet growing electricity demand and electrification goals. State-level strategies also underscore that generation expansion requires investment in transmission and distribution system infrastructure to expand network capacity and optimize existing capacity. Demand flexibility is highlighted in the Oregon Energy Strategy as a way to increase reliability, support renewable energy procurement, and potentially lessen environmental and cost burdens. Specific gaps and opportunities relevant to this area of potential state support are discussed in ***Sections 4.2***, ***4.3***, and ***4.4***, and ***Chapter 7***.

Strengthening system resilience through targeted investments, including backup power options for critical infrastructure (system hardening). Critical infrastructure can benefit from mobile sources of firm, ***dispatchable power***, like energy storage, during outages. A better understanding of the potential impacts of grid outages or other adverse events on critical infrastructure and the role of different backup power arrangements could help inform county risk mitigation. Access to affordable, secure, or renewable backup power options also dovetails with the ***Oregon Governor's Resiliency 2025 Vision*** published in 2018, which focuses on a critical energy infrastructure hub to "prevent and mitigate catastrophic failure and ensure fuel supplies and alternate energy sources are available to responders and the public."[1] Specific gaps and opportunities relevant to this area of potential state support are discussed across ***Chapter 4***, ***Chapter 5***, and ***Chapter 6***, and ***Section 8.3***.

Expansion and enhancement of electric vehicle charging infrastructure. The Oregon Department of Transportation Climate Action Plan notes that expanding electric vehicle infrastructure along major thoroughfares could align with growing county- and state-level electric vehicle adoption and meet public demand for charging stations. Growing electric vehicle adoption can support state climate and decarbonization goals if managed in a way that prioritizes renewable electricity sources and is integrated with demand-side resource planning.[2] Adoption of zero- and low-emission vehicles could alleviate impacts of ambient air pollution. One of the main sources of funding for charging infrastructure in Oregon comes under the National Electric Vehicle Infrastructure (NEVI) program, which was established under the 2021

[1] State Library of Oregon, *"Oregon Energy Strategy,"* Oct. 2018. https://digitalcollections.library.oregon.gov/nodes/view/121526

[2] Massachusetts Institute of Technology, *"Are electric vehicles definitely better for the climate than gas-powered cars?"* Oct. 2022. https://climate.mit.edu/ask-mit/are-electric-vehicles-definitely-better-climate-gas-powered-cars

Bipartisan Infrastructure Law and provides Oregon with $52 million over five years for implementing charging infrastructure. Oregon has completed one round of funding solicitations for NEVI and plans to roll out projects along several main roads or highways including I-5 and US101 in Lane County[1]; the second solicitation phase is currently under way. Electrification of other transportation infrastructure, such as public bus transportation, has been identified in ***Executive Order 25-29*** and could complement efforts to expand charging infrastructure.[2] While enabling electric vehicle adoption is a state strategy, ***Section 4.2.1*** describes that most localities have opted instead to focus on conservation by supporting bikeable and pedestrian-safe city planning. The supply chain for critical minerals needed to make electric vehicle batteries is an area of major concern both in terms of environmental impacts, energy security, and human rights.[3] Specific gaps and opportunities relevant to this area of potential state support are discussed in ***Section 4.2***.



Figure 31: Electric Vehicles Charging in Downtown Portland[4]

Expanding access to residential energy efficiency and weatherization services and programs. Oregon has recently strengthened the policy foundation for energy efficiency and weatherization through ***HB 3409,***[5]the ***Oregon Energy Strategy***, and ***Executive Order 23-04,***[6]

[1] Oregon Department of Transportation, *"National Electric Vehicle Infrastructure Program in Oregon,"* Apr. 2026. https://www.oregon.gov/odot/climate/pages/nevi.aspx

[2] State of Oregon, ibid.

[3] National Public Radio, *"How 'modern-day slavery' in the Congo powers the rechargeable battery economy,"* Feb. 2023. https://www.npr.org/sections/goatsandsoda/2023/02/01/1152893248/red-cobalt-congo-drc-mining-siddharth-kara

[4] Image from Oregon Public Broadcasting, *"Oregon prepares to reopen popular EV rebate program,"* May 2025. https://www.opb.org/article/2025/05/05/oregon-electric-vehicle-program-rebate-evs-cars-environment/

[5] *Oregon Legislative Assembly, "House Bill 3409 (2023 Regular Session),"* 2023. https://olis.oregonlegislature.gov/liz/2023R1/Measures/Overview/HB3409

[6] State of Oregon Law Library, *"Executive Order No. 23-04,"* Jan. 2023. https://cdm17027.contentdm.oclc.org/digital/collection/p17027coll11/id/524/rec/1

which directs state agencies to accelerate building decarbonization and reduce energy burden for low-income households. Building on these directives, Lane County could explore targeted or expanded retrofit incentives for income-qualified residents, partnerships with community action agencies to scale weatherization outreach, and local utility demand-side management funding to subsidize insulation, air-sealing, and heat-pump installations. Specific gaps and opportunities relevant to this area of potential state support are discussed in ***Section 4.3***.

Job creation and workforce development for energy transitions. The ***Oregon Energy Strategy*** is focused on pairing state energy policy objectives with economic and workforce development goals. It highlights the state's potential to pilot and deploy emerging technologies and strengthen its leadership in the energy sector. ***Executive Order 20-04*** similarly stresses that clean energy research and development is linked to broader state competitiveness by acting as a potential catalyst for attracting investments. The ***Oregon Department of Transportation Climate Action Plan*** and ***Climate Protection Program*** also note that expansion of clean energy infrastructure can support green job creation and encourage workforce development. Existing workforce-related efforts in cities in Lane County are summarized in ***Chapter 9***.

Exploring alternative fuels for hard-to-electrify sectors. The ***Oregon Energy Strategy*** positions alternative fuels—including those with lower lifecycle greenhouse gas emissions such as biofuels and synthetic or electricity-based fuels ("e-fuels")—as a necessary part of an energy procurement strategy to meet state decarbonization goals in sectors that are challenging to electrify. Alternative fuel development also aligns with the ***Oregon Clean Fuels Program***, which requires fuel suppliers to reduce the carbon intensity of fuels. ***Executive Order 25-29*** specifically directs Oregon's Department of Environmental Quality and the Environmental Quality Commission to pursue rulemakings that strengthen the Clean Fuels Program, such as strengthening carbon-intensity reduction requirements for certain transportation fuels. Lane County's agricultural and forestry industries could have an important role to play in the state's alternative fuels strategy, such as supplying waste for biogas and woody biomass for advanced biofuels, pursuing or incentivizing farming techniques that lower the carbon intensity of crops, and sequestering carbon through forest preservation or planting trees. This document does not discuss alternative fuels, with the exception of biomass energy potential in ***Section 7.3***.

PART II
Lane County Utilities



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Part II: Glossary and Acronyms

Advanced Distribution Management System (ADMS): An integrated software platform that monitors, analyzes, and optimizes distribution system operations in real time by combining outage management, supervisory control, and advanced grid applications.

Advanced Metering Infrastructure (AMI): An integrated platform of smart meters, communications networks, and data management system that enables two-way communication between utilities and customers.

Annual Deficit: When forecasted regional load obligations exceed available, reliable generation capacity over a one-year period.

APPA: American Public Power Association

Asset Management System (AMS): A system that tracks the condition, performance, and lifecycle of utility assets to support maintenance, replacement, and investment decisions.

Average Megawatt (aMW): One million watts delivered continuously 24 hours a day for a year.

Avoided Cost Methodology: The cost a utility would have otherwise incurred to generate or procure energy from another source. Used to set compensation rates for customer-generated electricity fed back to the grid.

BPA: Bonneville Power Administration

Bulk System: Refers to the parts of the grid concerned with large-scale generation and transmission

CAIDI: Customer Average Interruption Duration Index

CAISO: California ISO

Capital Plan (System Upgrade Plan or Asset Plan): A utility's systematic process used to identify assets requiring replacement, upgrade, or new purchase over the planning horizon.

Cascadia Subduction Zone (CSZ): A 700-mile fault about 70 to 100 miles west of the Pacific coastline that extends from northern California to British Columbia.

CESER: DOE Office of Cybersecurity, Energy Security, and Emergency Response

Community Wildfire Protection Plan (CWPP): A collaborative, community-based document that identifies a community's wildfire risks, priorities, and mitigation actions to protect life, property, and critical infrastructure, enhance ecosystem health, and improve safety for residents and first responders. Lane County is currently in the process of updating the 2020 CWPP.

COU: consumer-owned utility

Day-ahead Market: A wholesale electricity market in which participants buy and sell electricity for the next operating day, based on forecasted demand and generation.

Demand Response (DR): Voluntary utility programs that reduce or shift customer electricity use during peak conditions, prompted by grid reliability concerns or high wholesale prices.

Distributed Energy Resource Management System (DERMS): A platform that monitors and controls distributed energy resources to support grid reliability, efficiency, and coordination.

EDAM: Extended Day-Ahead Market

EIA: U.S. Energy Information Administration

Energy Conservation: Changing habits or behaviors to decrease energy use. For example, setting a thermostat cooler in winter and warmer in summer so that less energy is used for heating and cooling.

Energy Efficiency (EE): The ability to use less energy to do the same things by adopting better materials or technologies. For example, improving home insulation so that it takes less energy to keep the home at a comfortable temperature.

Enhanced Powerline Safety Settings (EPSS): An automated de-energization of power lines using reclosers to detect and cut power to a line when a wildfire hazard is detected.

Exposure: The extent to which assets, systems, or populations are located in areas where they may be affected by a hazard.

Fault Location, Isolation, and Service Restoration (FLISR): An automated approach to detecting faults, isolating affected sections, and restoring service to unaffected areas of the grid.

FEMA: Federal Emergency Management Agency

Geographic Information System (GIS): A spatial database that maps and manages the physical location and attributes of assets and infrastructure.

Hazard Intensity: The severity or magnitude of a hazard event when it occurs.

Hazard Probability: The likelihood or frequency that a hazard will occur in a given location and time.

Hosting Capacity: Maximum amount of distributed energy resources that can be added to an electric distribution system without requiring infrastructure upgrades or compromising power quality, safety, and reliability.

Integrated Resource Plan: A utility's long-term roadmap for reliably and cost-effectively meeting forecasted electricity demand by modeling future load and resource scenarios, evaluating costs, risks, and policies, and selecting a preferred portfolio.

Intelligent Electronic Devices (IEDs): Microprocessor-based devices that perform protection, control, monitoring, and communication functions in power systems.

Interconnection Queue: The list of power producers waiting to connect to the grid.

IOU: investor-owned utility

ISO: independent system operator

N-1 Circuit-level Reliability: The ability of a utility to remain operational in the instance of a single component failure.

NARUC: National Association of Regulatory Utility Commissioners

NERC: North American Electric Reliability Corporation

NHMP: Lane County Natural Hazards Mitigation Plan

ODF: Oregon Department of Forestry

Operational Reliability: The ability of the grid to withstand sudden disturbances, including faults or unexpected loss of equipment, without triggering uncontrolled cascading outages or damaging infrastructure.

Outage Management System (OMS): A system that detects, analyzes, and manages power outages to support restoration planning and customer communication.

Peak Demand: The short periods when electricity use on the grid reaches its maximum.

Peak Management: Utility strategies to anticipate and mitigate short-duration spikes in electricity demand to reduce system strain and cost impacts.

Peak Shaving: The customer practice of reducing electricity demand by switching to the use of on-site energy storage or generation systems during periods of peak demand to reduce their electricity costs without having to reduce their usage

PNUCC: Pacific Northwest Utilities Conference Committee

Power Market Restructuring: Reforming energy systems with the goal of enabling/enhancing competition, and efficiency.

Public Safety Power Shutoff (PSPS): A preemptive shutdown of powerlines expected to face critical weather to prevent potential wildfire ignitions from the electric system.

Quantitative Wildfire Risk Assessment (QWRA): A standardized, regional-scale framework that quantifies wildfire risk by integrating burn probability, fire intensity, and asset exposure/susceptibility, to prioritize mitigation actions.

Rate Driver: A primary factor or cost component that causes an increase or change in the rates charged to customers.

RCEA: Redwood Coast Energy Authority

Real-time Market: A wholesale electricity market that lets participants buy and sell electricity the day it will be used to handle unexpected fluctuations.

Resource Adequacy: The capability of the power system to always meet total end-use customer demand and energy needs, including during planned and unplanned outages.

Risk: Potential for an adverse outcome when a hazard acts on a vulnerable system.

Rolling Blackout/ Rotational Load Shedding: When utilities have to reduce loads on the system because there is not generation. To prevent any one group of customers from being out of service for too long, the utility will rotate where and for whom they turn off power.

RTO: regional transmission operator

SAIDI: System Average Interruption Duration Index

SAIFI: System Average Interruption Frequency Index

SPP: Southwest Power Pool

Strategic Plan (utilities): A utility's plan documenting high-level goals, the actions that the utility will take to meet those goals, and usually the metrics to be used to measure success.

Supervisory Control and Data Acquisition (SCADA): A system used to monitor, control, and collect real-time data from utility infrastructure such as substations, feeders, and field devices.

Susceptibility: The tendency of exposed assets, systems or populations to be damaged by a hazard (sensitivity), combined with their ability to resist, respond to, and recover from hazard impacts (resilience).

Volt/Var Optimization (VVO): A set of control strategies that optimize voltage and reactive power on distribution systems to improve efficiency, reliability, and power quality.

Vulnerability: The degree to which an energy system can be damaged or degraded when exposed to a hazard. Vulnerability is determined by exposure and susceptibility.

WECC: Western Electricity Coordinating Council

WEIM: Western Energy Imbalance Market

WEIS: Western Energy Imbalance Service

Wholesale Power Market: The buying and selling of electricity within a geographic region among electricity generators, electric utilities, and electricity traders before it is eventually sold for consumers.

Wildfire Mitigation Plan (WMP): A formal, utility-driven document that details the strategies, actions, and investments to manage wildfire risk and guide response. Lane County utilities present an annual WMP to the Oregon PUC.

WPP: Western Power Pool

WRAP: Western Resource Adequacy Program

Part II: Lane County Utilities Preface

The job of electric utilities is to maintain balance: the balance of electricity load and generation to keep the grid working, and the balance of costs and revenues to keep their organization working (***Figure 32***). They maintain these balances while working within the constraints of regulations (***Chapter 2***), the broader regional grid system (***Chapter 3***), customer expectations (***Chapter 4***), environmental realities (***Chapter 5***), and available technologies (***Chapter 6***).

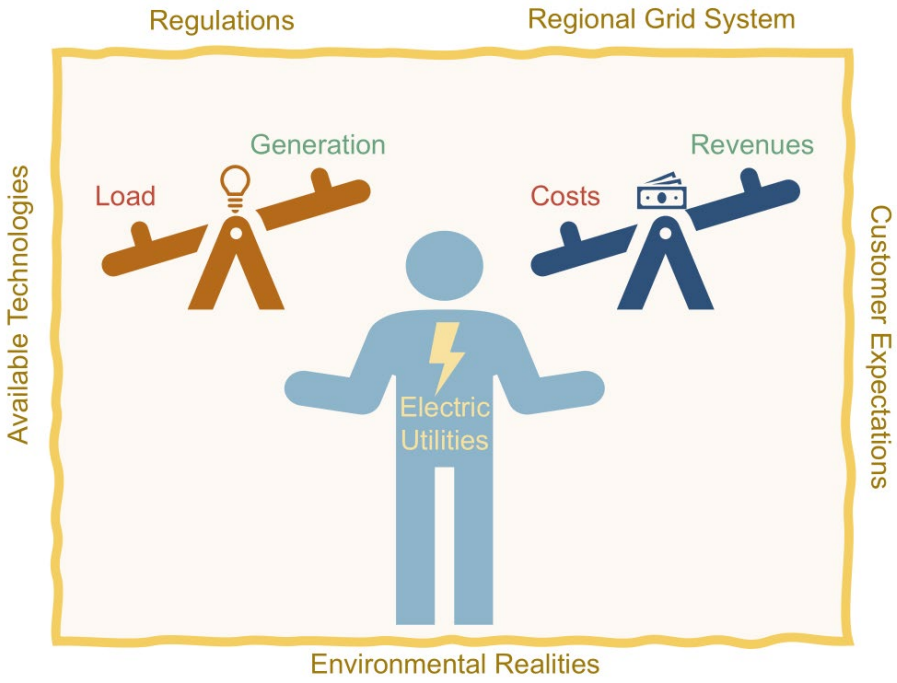


Figure 32: The Balancing Act of Utilities

The balancing of load and generation happens across a variety of timescales (***Figure 33***). At every instant, load and generation need to match for the grid to continue to function. Every time you turn a light on, the load on the grid increases by a tiny amount. It does so too quickly for any person to "turn on" the equivalent amount of generation. This sort of instantaneous balancing is done automatically by the technologies that make up the grid[1]. For larger fluctuations over longer periods of time, on the order of hours to days, grid operators are responsible for maintaining the balance of generation and load. They do so by "dispatching"—turning on/off—generation resources, controlling loads, purchasing electricity on the market, or implementing other management strategies. On even longer timescales, from weeks and months to years, a larger group of people is responsible for maintaining balance. Planners and analysts use historic load information, weather forecasts, system information, and other resources to predict loads,

[1] To learn more about this instantaneous balancing, see resources on electric grid inertia, synchronous generators, and automatic grid controls, such as:

- Denholm, Paul, Trieu Mai, Rick Wallace Kenyon, Ben Kroposki, and Mark O'Malley. 2020.
- Inertia and the Power Grid: A Guide Without the Spin. Golden, CO: National Renewable
- Energy Laboratory. NREL/TP-6120-73856. https://www.nlr.gov/docs/fy20osti/73856.pdf.

inform operators, and make decisions about how to balance generation and load within the constraints of the grid equipment. Regional planning groups that include utilities, independent power producers, state officials, and others are responsible for ensuring that enough generation and transmission resources are available to meet electricity demand. Having enough generation to meet estimated is called ***resource adequacy*** (see ***Section 3.2***).

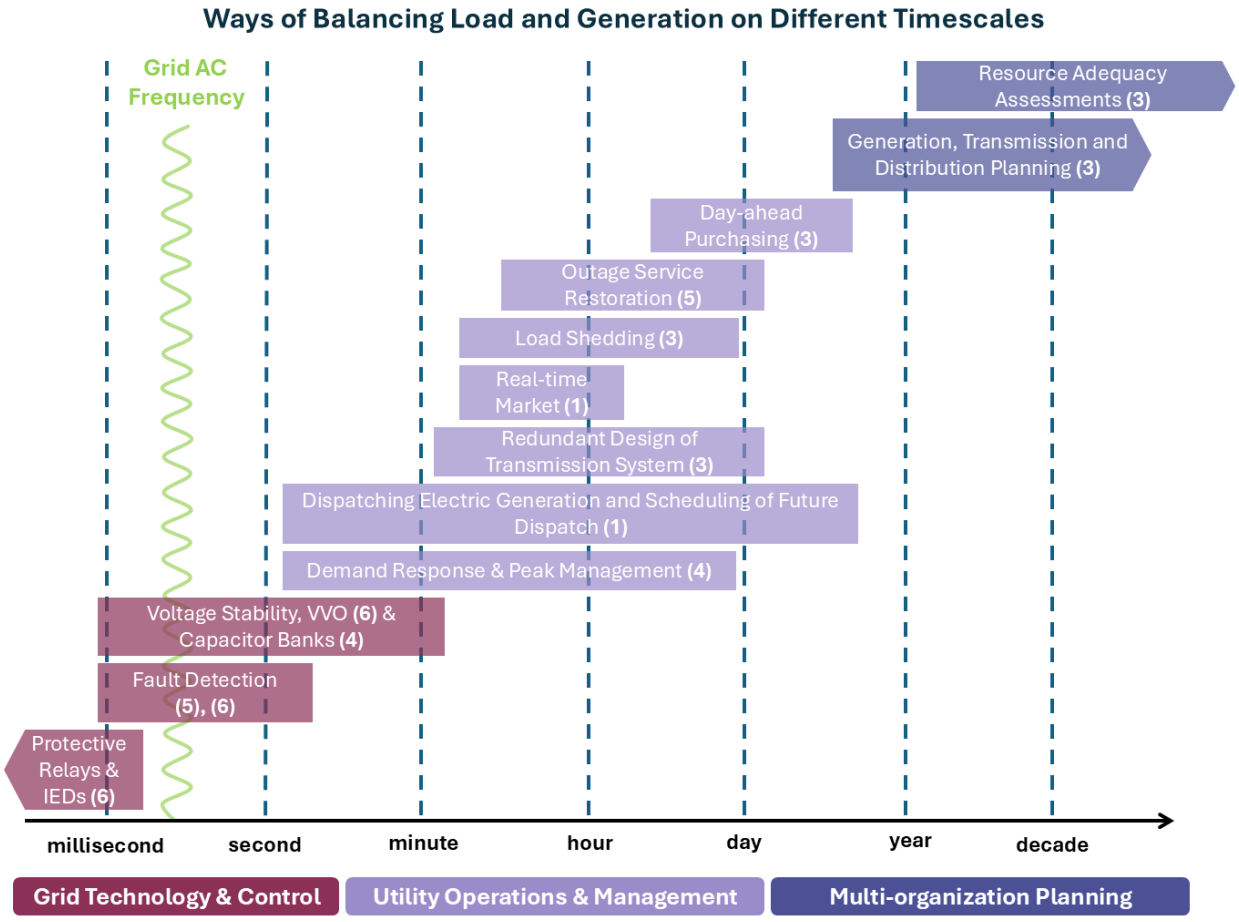


Figure 33: Ways of Balancing Load and Generation on Different Timescales

Chapters in Part II of this Handbook are organized by the external factors that utilities face, including regional dynamics, customer expectations, hazards, and available technologies. For each factor, we discuss the impacts on the utility and what utilities can do to manage those impacts while still balancing both load and generation, and costs and revenues.

Chapter 3

Regional Dynamics Impacting Lane County Utilities

Haley Ross and Ian Hermanson

*Lane County utilities face challenges that stem from a regional system of technologies, actors, and policies as described in **Chapter 1** and **Chapter 2**. In this section, we discuss how Lane County utilities deal with four of those challenges: Western electricity market restructuring, regional resource adequacy, local and regional operational adequacy, and increasing costs. For Lane County, resource adequacy may eventually pose a threat to reliability, but is not one that we have seen to-date. Reliability risks due to lack of transmission redundancy are present in some parts of the county. The likely sources of distribution reliability challenges include heavily vegetated terrain and hard-to-reach service lines.*

3.1 Power Market Restructuring

California ISO (CAISO), a California-based independent system operator (ISO), and Southwest Power Pool (SPP), a regional transmission operator (RTO) based in the central United States, operate regional real-time and day-ahead energy markets that compete for voluntary membership from large utilities and balancing authorities. Since 2014, BPA participated in CAISO's Western Energy Imbalance Market (WEIM), a real-time energy market representing nearly 80% of the Western Interconnection's energy demand.[1] SPP launched a comparable ***real-time market*** in 2021, called the Western Energy Imbalance Service (WEIS) market. In the early 2020s, both CAISO and SPP began developing ***day-ahead market*** expansions to their respective real-time markets. CAISO launched the Extended Day-Ahead Market (EDAM) on May 1st, 2026, while SPP plans to launch an alternative day-ahead market called Markets+ in 2027. After a lengthy decision process, the Bonneville Power Administration (BPA) announced in 2025 that it would leave WEIM to join the new SPP Markets+ day-ahead market.[2] Many large Western investor-owned utilities (IOUs), including Pacific Power and Portland General Electric (PGE), chose to join CAISO's day-ahead market. While a Pacific Northwest power market shift will have regional impacts, the specific effects remain uncertain.

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[1] California ISO, *"ISO Western Energy Imbalance Market Benefits Report Q3 2025,"* Oct. 2025. https://www.westernenergymarkets.com/documents/iso-western-energy-imbalance-market-benefits-report-q3-2025.pdf

[2] OregonLive, *"BPA opts to join controversial energy market despite criticism that it will raise rates,"* May 2025. https://www.oregonlive.com/environment/2025/05/bpa-opts-to-join-controversial-energy-market-despite-criticism-that-it-will-raise-rates.html

Under BPA's founding statute, BPA will continue to prioritize sales to Pacific Northwest consumer-owned utilities (COUs) through long-term contracts, including Lane County utilities. But the new market split means many large utilities neighboring BPA territory will now operate in a different market than the BPA.

Additionally, a different and expanded set of customers outside BPA's territory—primarily utilities operating within SPP's Markets+ footprint—may gain streamlined market access to BPA hydropower. At the same time, CAISO-based utilities will face new costs and market complexities when buying BPA power.

The BPA's move could impact Lane County utilities by influencing regional wholesale electricity costs. Multiple analyses, including a BPA commissioned study, found that BPA leaving CAISO to join SPP could raise costs for Pacific Northwest ratepayers.[1,2] Some Oregon and Washington legislators, public utility commissioners, and major IOUs (including Pacific Power) are concerned BPA's decision could impact Western Interconnection grid reliability and complicate coordination efforts (including making it hard to address transmission constraints).[3] BPA officials argue that because CAISO is partially governed by the California Legislature, California has excessive governmental control over western energy exchange. SPP is governed by a board of power producers and utilities.[3] Emerald People's Utility District (EPUD) has expressed support for BPA's decision, citing concerns with organized markets.[4]

SPP Markets+ will be rolled out in two waves, one that will go live in 2027, and the second in 2028. BPA expects to begin operating within SPP during the second wave in October 2028.[5] Because the consequences of BPA's decision are not fully understood, the resulting regional long-term uncertainty could complicate decision-making for small utilities that rely on BPA power, including which, if any, day-ahead market to participate in.

3.2 Resource Adequacy

The North American Electric Reliability Corporation (NERC) defines ***resource adequacy*** as having sufficient generating and transmission facilities to "provide customers with a continuous supply of electricity at the proper voltage and frequency, virtually all of the time"[6] If generation and transmission capacity are insufficient to meet demand, load must decrease to keep grid physics intact and electricity flowing to end users. If the Pacific Northwest were to face generation or transmission capacity shortages, utilities could be responsible for facilitating the

[1] OregonLive, ibid.
[2] Washington State Standard, *"BPA announces intention to split with California and join new Southwest energy market,"* Mar. 2025. https://washingtonstatestandard.com/2025/03/10/bpa-announces-intention-to-split-with-california-and-join-new-southwest-energy-market/
[3] OregonLive, *"BPA plan to leave Western energy market sparks worries of rate increases,"* Mar. 2025. https://www.oregonlive.com/pacific-northwest-news/2025/03/bpa-plan-to-leave-western-energy-market-sparks-worries-of-rate-increases.html
[4] Eugene Water & Electric Board (EPUD), *"A Balanced Look, Part 5,"* https://www.epud.org/a-balanced-look-part-5/
[5] Washington State Standard, *"BPA announces intention to split with California and join new Southwest energy market,"* Mar. 2025. https://washingtonstatestandard.com/2025/03/10/bpa-announces-intention-to-split-with-california-and-join-new-southwest-energy-market/
[6] North American Electric Reliability Corporation (NERC), *"Understanding the Grid,"* Sep. 2025. https://www.nerc.com/globalassets/who-we-are/september-2025-understanding-the-grid.pdf

necessary decrease in load. During a minor shortage, utilities would likely call for residential customers to conserve energy and for industrial customers to go offline (see ***Section 4.3*** for more on demand response). During a major shortage, utilities may need to institute rolling blackouts. A ***rolling blackout***, also known as ***rotational load shedding***, is when a utility cuts service to different areas, one or a few at a time, to reduce load. Utilities will periodically change which areas area shut off to reduce the outage duration for any given customer.

3.3 Studies of Resource Adequacy in the Pacific Northwest

This section reviews four major investigations into Pacific Northwest resource adequacy and find that while the Pacific Northwest is likely to be resource adequate in the next 1-3 years, depending on both the rate of generation resource additions and load growth—both of which are highly uncertain—there could be resource adequacy challenges in the future. We then discuss how Lane County utilities could prepare and respond to a potential resource inadequacy event.

Understanding if a region is and will remain resource adequate requires ***two main pieces of data***:

1. How much load there is and will be.
2. How much generating capacity there is and will be.

For this reason, all resource adequacy studies try to predict a wide range of scenarios to characterize both load and generation over the study's time horizon. The different methods and assumptions used to make these predictions naturally lead to different results. However, overall trends for the Pacific Northwest are consistent: ***increasing uncertainty in load growth projections and the rate of new generation additions could increase risk of resource adequacy shortfalls over time.***

Resource adequacy studies identify when and how much additional generation or transmission capacity that ***bulk system*** planners must bring online to support long-term grid reliability. These studies are a preliminary assessment of the system's future and a starting point in the planning process. Other studies, such as capacity expansion planning, are used to determine the location or type of generation facilities needed to meet future demand.

Load and generation predictions are challenging because both vary moment to moment, day to day, month to month, and season to season. On cold, dark winter mornings, people typically turn up their electric furnaces, heat pumps, water heaters, and lights, causing demand to be higher than it would be later in the day when people are at work, later in the winter when the sun rises earlier, later in the year on mild summer mornings when the house can be passively heated and lit. Hydropower generation peaks in spring when snowmelt fills reservoirs and declines in fall after summer demand depletes reservoirs. Extreme summer heat can decrease the power generated by thermal resources like natural gas.[1] Solar and wind generation also vary seasonally. Wind generation, for example, peaks during the blustery spring and fall seasons, and short and cloudy winter days reduce solar output.

[1] Pacific Northwest National Laboratory, *"Extreme Heat, Hurricanes, Wildfires: How Summers' Extremes Disrupt the Power Grid,"* Jul. 2024. https://www.pnnl.gov/news-media/extreme-heat-hurricanes-wildfires-how-summers-extremes-disrupt-power-grid

In addition to quantifying load and generation, resource adequacy studies define the time period, assume weather conditions, and predict the type and number of new generation sources. All these assumptions add uncertainty. Many of the studies reviewed in this section include a low-probability, worst-case scenario.

We examined study results from several Pacific Northwest grid planning entities. Study footprints and methodologies varied. Key study factors are summarized in ***Table 10***.

Table 10: Comparison of PNW Resource Adequacy Reports Methods, Assumptions, and Findings

Study Source	Study Year(s)	Method[1]	Key Assumptions	Findings
Bonneville Power Administration (BPA)[2]	2024–2025	Deterministic: Compares generation to load under conservative assumptions	Focused on federal contractual load only Assumes dry weather conditions	Annual deficits from 426 aMW in 2026 to 1012 aMW 2035
Northwest Power and Conservation Council (NWPCC)[3]	2029	Statistical: Counts percentage of scenarios in which resources fail to meet resource adequacy targets	Current trend load growth scenario High data center load growth scenario Slow energy efficiency gain scenario	Meet resource adequacy targets under current load trend, but not other scenarios
Pacific Northwest Utilities Conference Committee (PNUCC)[4]	2025–2035	Deterministic: Compares regional load to known generation	Normal weather conditions Exclude generations owned by independent power producers Exclude imports from other regions	Annual deficits of 595 aMW starting 2026/27 to 9,505 aMW by 2034/35
Western Electricity Coordinating Council (WECC)[5,6]	2028	Statistical: Measures overlap of statistically likely generation and load curves	Gen/load curves built off historical data + growth forecast. Imports used to balance system in full analysis	Curves completely overlap indicating high risk for region. But in full 2024-2034 analysis if new generation online as planned actual shortfall risk minimized

[1] Deterministic methods asses resource adequacy using relatively stable, fixed assumptions about how the power system whereas statistical methods use data and advanced modeling to capture uncertainty. U.S. Department of Energy, *"Resource Adequacy Report,"* Jul. 2025. https://www.energy.gov/documents/resource-adequacy-report

[2] Bonneville Power Administration, *"Pacific Northwest Loads and Resources Study (2025 White Book),"* May 2025. https://www.bpa.gov/-/media/Aep/power/white-book/2025-whitebook.pdf

[3] Northwest Power and Conservation Council, *"Pacific Northwest Power Supply Adequacy Assessment for 2029 (2024-4),"* Aug. 2024.https://www.nwcouncil.org/fs/18853/2024-4.pdf

[4] Pacific Northwest Utilities Conference Committee, *"Northwest Regional Forecast of Power Loads and Resources,"* Apr. 2025. https://www.pnucc.org/wp-content/uploads/2025-PNUCC-Northwest-Regional-Forecast-final.pdf

[5] Western Electricity Coordinating Council (WECC), *"Western Assessment of Resource Adequacy 2024,"* https://feature.wecc.org/wara/

[6] Western Electricity Coordinating Council, *"2024 Western Assessment of Resource Adequacy Appendix,"* Jan. 2025. https://www.wecc.org/sites/default/files/documents/products/2025/2024%20WARA%20Appendix.pdf

What is an average megawatt (aMW)?

An aMW represents the energy deficit over a year (in megawatt-hours [MWh]) divided by the number of hours in a year (8,760) to give a power rating to the deficit. One aMW is equivalent to one million watts being consumed 24 hours a day for a year.

BPA: 2025 Pacific Northwest Loads and Resources Study (The White Book)

BPA publishes an annual 10-year assessment of the Pacific Northwest region's loads and generation resources as "a planning tool and data source for customers, regional interests and the Columbia River Treaty studies."[1][2] The most recent version was published in May 2025. BPA's forecast covers the Pacific Northwest as defined in the Northwest Power Act, which includes Washington, Oregon, Idaho and parts of Montana, Wyoming, California, Nevada, and Utah.[3]

Study Results

BPA forecasts annual deficits over the study period ranging from 426 average MW (aMW) in 2026 up to 1012 aMW in 2035.

Methodology

BPA forecasts load growth deterministically. This means BPA assumes that a scenario will occur with 100% certainty, which is a common modeling choice in power system planning. BPA's forecast is based on a combination of long-term contractual obligations, as well as individual forecasts for each load-serving entity in the Pacific Northwest with a BPA contract. BPA's forecast for total firm system load increase over 2026–2035 is 4.3%, which is significantly higher than the 0.24% increase forecasted by BPA in the 2024 White Book covering 2025–2034.[4] This significant change exemplifies increasing regional load growth uncertainty; however, BPA does not specify exactly which factors are the cause for the change in forecast. Generation forecasts are based on historical generation data from existing resources in the federal system. Importantly, when system surpluses or deficits are calculated, "firm water conditions" are assumed. Firm water is defined as the tenth percentile (P10) of monthly system output calculated from historical data running from October 1989 to September 2018. This means that the deficits that BPA predicts happen under a scenario that assumes extremely dry conditions.

Caveats and Limitations

BPA's conservative method of using firm water (P10) levels of hydropower availability for their forecast means that every month there is a 90% chance that actual hydropower generation outputs will be higher than forecasted. If there is more generation with the same load (for instance, if water levels were closer to the average, P50), then the system would not face operational deficits. BPA's report shows the difference between P10 and high-water level (P90) is at a minimum ~850 aMW in any given month, which is a large spread, enough to power over 640,000 homes continuously for the month and is approximately double the forecasted deficit for 2026.

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[1] Bonneville Power Administration, *"2025 Pacific Northwest Loads and Resources Study,"* May 2025. https://www.bpa.gov/-/media/Aep/power/white-book/2025-whitebook.pdf

[2] The Columbia River Treaty is an international agreement between the United States and Canada established in 1961 that cooperatively manages the Columbia River Basin. In 2018 efforts began to modernize the agreement focusing on flood risk management, reliable and economic hydropower generation, and improving the ecosystem. That effort is ongoing and includes studies to inform treaty negotiations, via the U.S. Department of State, *"Columbia River Treaty,"* https://www.state.gov/bureau-of-western-hemisphere-affairs/columbia-river-treaty/

[3] Northwest Power and Conservation Council, *"Defining the Region,"* https://www.nwcouncil.org/2021powerplan_defining-region/

[4] Bonneville Power Administration, *"2024 Pacific Northwest Loads and Resources Study,"* Aug. 2024. https://www.bpa.gov/-/media/Aep/power/white-book/2024-white-book.pdf

NWPCC: Pacific Northwest Power Supply Adequacy Assessment for 2029

The ***Northwest Power and Conservation Council (NWPCC; the Council)*** is a collaborative partnership involving BPA, other federal agencies, and the states of Washington, Oregon, Idaho, and Montana[1]. The Council is responsible for ensuring long-term energy reliability and sustainability through policy coordination and regional planning. The Northwest Power Act directs the Council to produce 20-year demand forecasts.[1] The Council's ***Power Supply Adequacy Assessment***[2] evaluates the effectiveness of new resources recommended by their 2021 ***Northwest Power Plan***[3] at addressing regional energy needs in 2029. The Council is currently preparing the next ***Northwest Power Plan***, which is to be published as a draft in mid-2026 and will cover the Pacific Northwest as defined in the ***Northwest Power Act***.

Study Results

NWPCC analyzed three scenarios:

Scenario 1: reference scenario representing demand and generation forecasts that align with current trends

Scenario 2: a high data center load growth scenario where data center load is 1,590 aMW higher than the reference case

Scenario 3: a scenario where energy efficiency gains are 300 aMW less than the 1,300 aMW that are called for in the 2021 Northwest Power Plan.

The Council found that while the reference scenario easily met all resource adequacy targets (described below), the other two scenarios fell short. The shortfall in the energy efficiency gains scenario failed to meet two of the four resources adequacy targets, while the high data center growth case failed to meet all four.

Methodology

To assess power supply adequacy, the Council simulates system operations for a full year with different combinations of river flows, temperatures (which relate to demand), and wind and solar generation output. This results in a large dataset that can statistically assess the likelihood of the system to meet its four resource adequacy targets: frequency, duration, power magnitude, and energy magnitude:

The frequency target sets a less than 1-in-10-year chance of an energy shortfall event.

The duration target sets a less than 1-in-40-year chance of any energy shortfall event lasting 8 hours or more.

The power magnitude target sets a less than 1-in-40-year chance that a shortfall will be more than 1,200 MW.

The energy magnitude target sets a less than 1-in-40-year chance the energy shortfall in any year will be greater than 9,600 MWh.

These thresholds relate to the expected ability of identified emergency measures (such as relying on expensive, rarely used resources) to meet the need without resorting to extreme measures that directly impact customers such as rolling brownouts.

Caveats and Limitations

NWPCC takes a conservative approach to imports, setting summer and winter limits to avoid relying on external purchases from neighboring regions when power may be unavailable. The region may be more secure than the Council predicts, though neighboring regions also face uncertainties.

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[1] Northwest Power and Conservation Council, *"Northwest Power Act,"* https://www.nwcouncil.org/reports/columbia-river-history/northwestpoweract/

[2] Northwest Power and Conservation Council, *"Pacific Northwest Power Supply Adequacy Assessment for 2029,"* Aug. 2024. https://www.nwcouncil.org/fs/18853/2024-4.pdf

[3] Northwest Power and Conservation Council, *"2021 Northwest Power Plan,"* Mar. 2022. https://www.nwcouncil.org/fs/17680/2021powerplan_2022-3.pdf

PNUCC: Northwest Regional Forecast of Power Loads and Resources August 2025 through July 2035

The ***Pacific Northwest Utilities Conference Committee (PNUCC)*** "is a not-for-profit trade association of consumer-owned and investor-owned electric utilities and other power industry partners that share a common interest in the efficacy and reliability of the Northwest Power system."[1] PNUCC members include 60 utilities including ***Blachly-Lane Electric Cooperative, EPUD***, ***Eugene Water & Electric Board (EWEB)***, ***Lane Electric Co-op***, and ***Pacific Power***.[2] PNUCC's analysis[3] covers the Pacific Northwest as defined in the Northwest Power Act.

Study Results

PNUCC finds that the region will have average annual energy deficits starting in the 2026–2027 planning year of 595 aMW. Forecasted deficits increase to 6,324 aMW by 2030–2031 and 9,505 aMW 2034–2035 due primarily to growth in load over time, as well as smaller contributions from an assumed decline in contractual imports, and known retirements of the existing generation fleet.

Methodology

PNUCC's approach is deterministic, comparing the loads forecasted by BPA, the Northwest utilities, and by "certain non-generating public utilities," to current and committed (i.e., additions under construction) generating resources. PNUCC uses "normal" weather conditions for their load forecast estimates, and excludes "non-firm" generating resources, such as those owned by independent power producers, or imports from generators outside the region that aren't contractually binding. One unique aspect of this report is it includes detailed breakdowns of planned generating resource additions, what kind of technology they are, the year they are planned for, and the planned capacity.

Caveats and Limitations

PNUCC's results do not consider planned generation resources, which could reduce predicted deficits. PNUCC expresses concern over the high rate of expected load growth (an increase of over 30% over the next decade) and the ability of utilities to construct the necessary resources on time. However, PNUCC also identifies creative private partnerships with data center owners that could help alleviate load growth challenges. PNUCC does not account for weather-driven extremes.

[1] Pacific Northwest Utilities Conference Committee, *"About PNUCC,"* https://www.pnucc.org/about-pnucc/

[2] Pacific Northwest Utilities Conference Committee, *"Member Directory,"* https://www.pnucc.org/about-pnucc/member-directory/

[3] Pacific Northwest Utilities Conference Committee, *"2025 Northwest Regional Forecast of Power Loads and Resources,"* Apr. 2025. https://www.pnucc.org/wp-content/uploads/2025-PNUCC-Northwest-Regional-Forecast-final.pdf

WECC: Western Assessment of Resource Adequacy 2024

Every year, the ***Western Electricity Coordinating Council (WECC)*** publishes a 10-year resource adequacy assessment for the western United States.[1,2] The most recent 2024–2034 report covers the entire Western Interconnection and includes isolated load and generation comparisons for specific planning regions.[1] The Pacific Northwest falls into what WECC calls the northwest-northwest (NW-NW) region which includes British Columbia, the Pacific Northwest, and small portions of Idaho and Northern California.

Results

The 2024–2034 report shows that if planned generation resource additions are completed on schedule, the risk for generation shortfalls in the NW-NW region is minimal over the study window. However, risks increase if new generation projects are not completed on schedule. The report used several resource addition scenarios, where 100%, 95%, 85%, and 55% of all planned additions are on schedule. WECC reports the results for these cases based on the number of demand-at-risk hours observed, that is the number of hours when demand for electricity is expected to exceed supply and there is a risk of an energy shortfall. For the 100% case, the total number of demand-at-risk hours was small—just 89 out of a total of 87,600 hours studied across WECC. However, in the other scenarios, demand-at-risk hours were more significant, so WECC reports demand-at-risk hours by year. Because no single10-year totals were presented for the other cases, we focus on the 2034 results, when considering the other cases. Because of this, it should be noted that the actual number of demand-at-risk hours will be higher than the values presented, but focusing on the 2034 results gives an idea of the trend. In the 95% case, the demand-at-risk hours across WECC in 2034 is 91. Of those, 82 hours came from the NW-NW region. In the 85% scenario, 129 hours are at risk across WECC in 2034, of which 87 come from the NW-NW region. In the 55% scenario, 952 hours are at risk in 2034, of which 787 hours come from the NW-NW region, highlighting the importance that as many generating resources are added on time as possible.

Methodology

WECC uses a probabilistic assessment that generates a bell curve of statistically likely generation and demand curves for each balancing area for 2028. To demonstrate how these curves are created, we will focus on the load curve. The process for the generation curve is similar; except each generation type is modeled individually and then all generation types are combined into a single generation probability curve. WECC uses historic load data to calculate a load probability curve for every hour of the year. These curves are combined with a 10-year load forecast that aggregates load forecasts from every balancing area (which are much bigger than balancing authority areas) in WECC. The resulting load probability curves show how often different load values are expected throughout the year. Where load and generation curves overlap represents the risk of an energy shortfall because it means that there were scenarios in which the load was equal to or greater than the generation. The more the curves overlap, the greater the risk. WECC sets the acceptable overlap threshold at 0.027% for any given hour, equivalent to one day in ten years.

Caveats and Limitations

Because both hydropower and wind have wide availability curves, the region's demand and supply curves overlap completely, resulting in greater shortfall risks. However, this local analysis does not consider power imports from other regions. WECC's report shows that if planned generation resource additions are completed on schedule, the risk for generation shortfalls in the NW-NW region is minimal over the 2024–2034 study window. However, risk increases if new generation projects are not completed on schedule.

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[1] Western Electricity Coordinating Council (WECC), *"Western Assessment of Resource Adequacy 2024,"* https://feature.wecc.org/wara/

[2] WECC also publishes a public-facing explanation that can be found at Western Electricity Coordinating Council, *"Western Assessment of Resource Adequacy Appendix,"* Jan. 2025. https://www.wecc.org/sites/default/files/documents/products/2025/2024%20WARA%20Appendix.pdf

3.3.1 Resource Adequacy Studies Key Takeaways

Together, these four reports characterize a Pacific Northwest that:

1. Can easily balance load and generation in the near term (1–3 years) but faces significant uncertainty in the ability to maintain balance in the future.
2. Has sufficient plans to expand generation resources to meet forecasted demand.
    a. If new generation additions are behind schedule challenges will likely arise. Generation additions can be hindered by supply chain issues, challenges getting permission to connect to the grid (referred to as the ***interconnection queue***), siting concerns, and increases in development costs (see ***Section 4.4***)
3. Faces highly uncertain load growth that will depend on factors like data center development, electric vehicle adoption, building electrification, and continued economic growth.
    a. If load growth (discussed further in ***Section 4.2*** for Lane County) is faster than forecasted, future resource adequacy challenges are more likely.

Reporting from Oregon Public Broadcasting in May 2025 highlighted that BPA's interconnection queue took 15 years for new generation projects to get approval to interconnect.[1] In 2024 the BPA has implemented changes to their study process to reduce the backlog by studying projects in clusters instead of individually, which will help mitigate study delays.[2]

Many entities in the Pacific Northwest—from researchers to state governments—are exploring novel solutions to combat resource adequacy challenges. For example, a recent study by Sylvan Energy suggested that requiring new large loads to curtail their demand could protect other customers from major impacts of generation supply shortages.[3] Washington state is exploring strategies such as incentivizing utilities to develop new transmission, exploring microgrids and other distributed energy sources that can bypass the interconnection queue, and attempting to streamline state permitting for new energy projects.[4] ***Executive Order 25-29 Reducing Greenhouse Gas Emissions and Advancing Oregon's Clean Energy Future***, signed by Governor Tina Kotek in 2025, seeks to address siting concerns in Oregon (see ***Chapter 2***).

3.3.2 How Being Resource Inadequate Could Impact Lane County Utilities

While resource adequacy is generally a planning metric, in real terms, being resource inadequate can translate into operational challenges, some of which can impact local utilities

[1] Oregon Public Broadcasting, *"How the Pacific Northwest's dream of green energy fell apart,"* May 2025. https://www.opb.org/article/2025/05/12/oregon-washington-green-energy-bonneville/

[2] American Public Power Association, *"BPA Implements Interconnection Reforms to Clear Queue Backlog,"* July 2024. https://www.publicpower.org/periodical/article/bpa-implements-interconnection-reforms-clear-queue-backlog

[3] GridLab, *"Near-Term Winter Resource Adequacy Challenges in the Pacific Northwest: A Review of E3's Northwest RA Study Phase 1 and Independent Evaluation of Near-Term Winter Challenges,"* Jan. 2026. https://gridlab.org/portfolio-item/pnw_nearterm_winterra/

[4] ProPublica, *"Our Reporting Showed Washington Ranks Last in Green Energy Growth. Now the State Is Working to Speed It Up."* Jan. 2026. https://www.propublica.org/article/washington-renewable-energy-projects-grid-upgrades

and customers. Because maintaining grid frequency is dependent on matching load and generation, a shortfall in generation would drop system wide frequency below the defined normal U.S. system frequency of 60 Hz, which could damage customer equipment and generators. If a 1-to-2 day generation and load forecast predicts a generation shortfall, the relevant balancing authority (in this case BPA) would take several steps to prevent customers from losing power. The actions associated with these steps would impact utilities in Lane County and their customers. The U.S. Department of Energy (DOE) has published a document explaining what these steps are and why they happen in great detail. We have summarized and adapted DOE's publication in ***Table 11***.[1] The steps described below are not a specific plan or operating procedure, but a characterization of what responses to a generation shortfall event might look like in Lane County.

Table 11: High-level summary of likely responses to a generation shortfall event

Timeline	Balancing Authority (BPA) Actions	Lane County Utility Actions and Experiences
Pre-Emergency: Concerning forecast issued	• Issue an alert about the situation • Suspend grid maintenance to maximize generation and transmission capacity • May ask customers to voluntarily reduce consumption, especially during peak demand hours	• Go on alert for a potential emergency, perhaps by placing key staff on standby
Level 1 Emergency: Initial declaration	• Call for all power generation sources to come online, regardless of costs • Increase imports from other regions	• Maintain an alert posture • Prepare for higher generation costs that would result from the emergency call for some or all their demand within Tier 2 category
Level 2 Emergency: When initial steps appear insufficient	• Trigger demand response programs that disconnect large industrial loads that contractually agreed to do so • Possibly issue a wide public appeal for all customers to reduce power consumption	• Communicate the urgent need for conservation to customers • Continue to be exposed to higher generation prices • Prepare for the possibility of level 3 emergency • Automatic/automated load disconnections may occur if there is an unexpected loss of generation or other disturbance

[1] U.S. Department of Energy, Office of Cybersecurity, Energy Security, and Emergency Response, *"How it Works: The Role of a Balancing Authority,"* https://www.energy.gov/sites/default/files/2023-08/Balancing%20Authority%20Backgrounder_2022-Formatted_041723_508.pdf

Timeline	Balancing Authority (BPA) Actions	Lane County Utility Actions and Experiences
Level 3 Emergency: Measurable decline in system frequency	• Call on utilities to shed a specified load MW quantity, which involves disconnecting some homes or businesses whose demand adds up to the request	• Initiate pre-established load shedding procedures by disconnecting circuits in a rotation across utility territory resulting in "rolling blackouts" or "rolling brownouts."[1]

3.3.3 Other Resource Adequacy Efforts

The ***Western Power Pool (WPP)*** is launching the ***Western Resource Adequacy Program (WRAP)***, which establishes shared standards for capacity planning and supply sufficiency across participating utilities. WRAP is the first regional program in the west focused on reliability planning and compliance.[2] WRAP aims to improve understanding of regional resource needs and supply and enable members to collaborate to efficiently use current and future resources. WRAP has two parts, a near term (7 month) forecast, and an operational component that allows members to pool and share resources.[3] Financial penalties will apply if a member fails to meet contract obligations. WRAP is not an organized market and is intended to be compatible with both CAISO- and SPP-operated markets.[4] Full WRAP implementation has faced delays as several balancing authorities and utilities have withdrawn from voluntary participation. BPA remains a participant, while utilities such as Pacific Power and EWEB exited over concerns around the timing of financial risks such as BPA contracts and the development of regional day-ahead markets.[5]

3.4 Operational Reliability

Operational reliability refers to the grid's ability to withstand sudden disturbances such as short circuits or acute extreme weather events,[6] and depends on factors including the design and implementation of power system protection schemes, class and placement of infrastructure (poles, lines, substations, etc.), and redundancy. This section describes available levels of redundancy at the transmission level and explores public reliability data at the distribution level for Lane County.

[1] Information about best practices for utilities to minimize the consequences of rolling blackouts on customers can be found in ***Section 4.4.1***.
[2] Federal Energy Regulatory Commission (FERC), *"Western Energy Markets Explainer,"* https://www.ferc.gov/OPP/western-markets-explainer
[3] Western Power Pool, *"WPP Notice to WRAP Resource Adequacy Participants Committee"* Oct. 2025 https://www.westernpowerpool.org/news/wpp-notice-to-wrap-resource-adequacy-participants
[4] Federal Energy Regulatory Commission (FERC), *"Reliability Explainer,"* https://www.ferc.gov/reliability-explainer
[5] RTO Insider, *"PacifiCorp Next to Leave WRAP After Raising Concerns,"* Oct. 2025. www.rtoinsider.com/118598-pacificorp-next-withdraw-wrap/
[6] North American Electric Reliability Corporation, *"Understanding the Grid,"* Sep. 2025. https://www.nerc.com/globalassets/who-we-are/september-2025-understanding-the-grid.pdf

3.4.1 Transmission System Reliability

While most power outages originate on the distribution system,[1] transmission infrastructure also plays a role in system reliability. Though U.S. distribution and transmission grid designs differ, distribution systems are often designed radially, with power lines extending outward from a central node. Transmission systems are normally designed as a mesh network, where multiple routes connect locations, however, occasionally radial branches occur. The redundancy of mesh networks means that if one route is interrupted, power can continue to flow to the same area via an alternate path. Using this general understanding, we can recognize where Lane County has more resilient infrastructure, and where there may be vulnerabilities.

Mapping Lane County transmission line voltages and routes (***Figure 34***) provides insight into local grid capacity and where power interruptions would have the greatest impact. In addition, understanding the operator and service areas (***Figure 35***) of each transmission line can reveal if the line serves a local or regional purpose.

[1] National Laboratory of the Rockies, *"Top 10 Things To Know About Power Grid Reliability,"* Jan. 2024. https://www.nlr.gov/news/detail/program/2024/top-10-things-to-know-about-power-grid-reliability

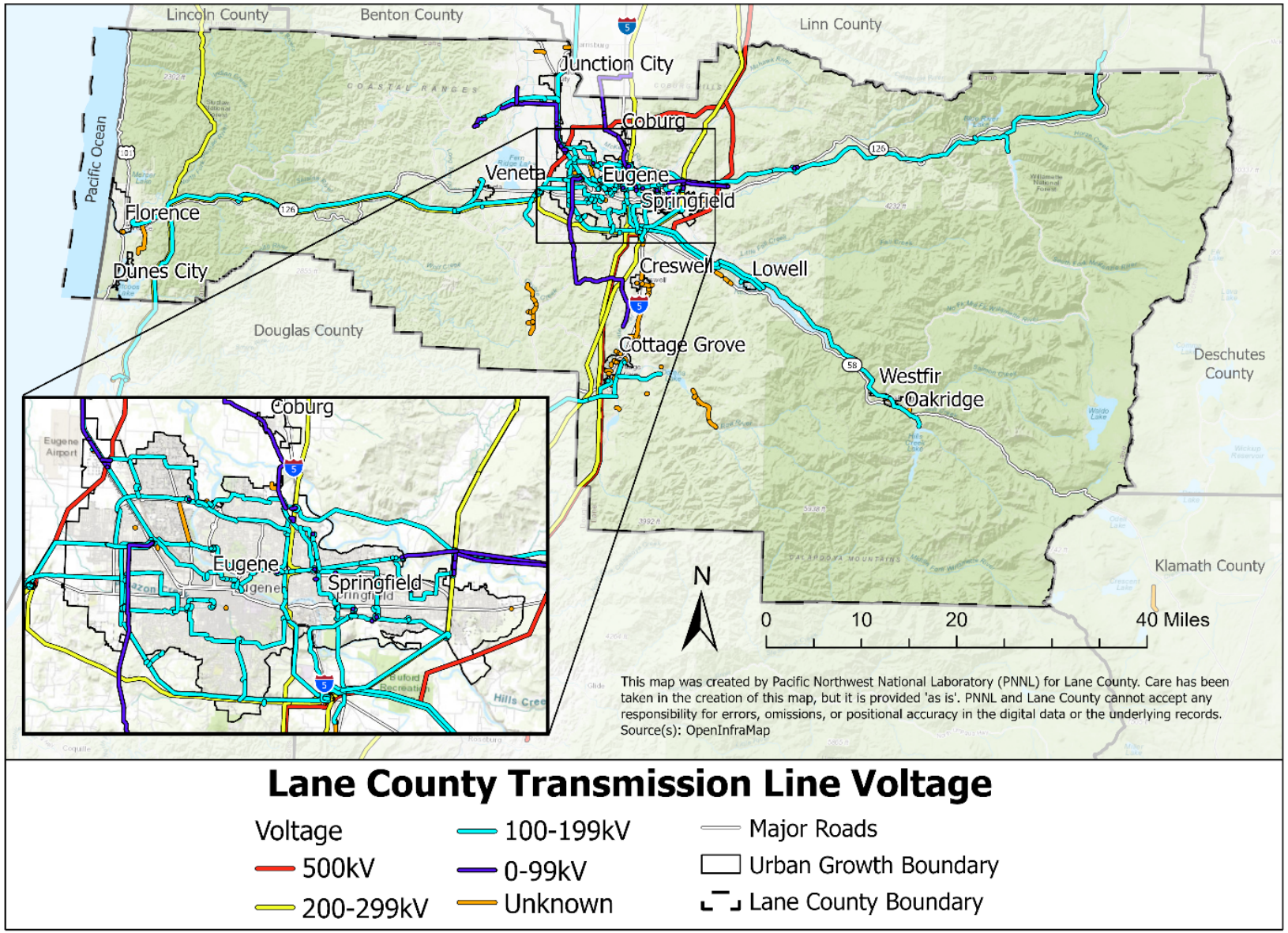


Figure 34: Map of Transmission Infrastructure for Lane County[1]

[1] Data (as of March 2026) from Open Infrastructure Map, https://openinframap.org/#2/26/12

Figure 34 shows five high-voltage transmission lines enter Lane County from the north. Two of these transmission lines are double circuit—an infrastructure configuration in which two separate lines share each tower—providing seven total paths for power to flow into the county from the north. To the south, transmission lines cross the Lane County boundary in four places. Two of these lines are double circuit, totaling six paths for power to flow into Lane County from the south.

While a similar number of transmission routes serve Lane County from north and south, the voltage of these lines varies. Higher voltage lines generally carry more power and over longer distances due to reduced heat losses. Voltage classes of transmission lines are defined in kilovolts (kV), where a higher number represents a higher voltage and higher power transfer capacity. From the north, two lines are 500 kV, four are 200–299 kV, and one is 100–199 kV. From the south, only one line is 500 kV, three are 200–299kV, and two are 100–199 kV. Overall, Lane County has greater power transfer capacity from the north than from the south, indicating that Lane County likely gets a higher fraction of its energy from generation sources to the north.

Eugene and Springfield are served by a dense mesh of transmission infrastructure, and Florence and Cottage Grove are served by multiple transmission routes. The city of Oakridge, communities in the McKenzie River Valley, and communities around Veneta and Elmira are served by only one 115 kV transmission line, increasing likelihood of disruption. Oakridge and the McKenzie River Valley are served by long-distance radial transmission lines and face the highest disruption risk because they cannot benefit from the redundancy of the mesh-network.

Figure 35 labels Lane County transmission line operators. Cross-referencing ***Figure 34*** with ***Figure 35*** shows that BPA operates most of the lines that cross Lane County's boarders. Pacific Power only operates three transmission lines: a 200–299 kV line exiting to the north, a >400 kV line exiting to the south, and a 200–299 kV line exiting to the south.

Within the county, the operators of different lines are more diverse, reflecting the different utilities' needs to serve their local customers. Relatively inexpensive, low-voltage transmission lines are typically used to carry power over short distances to smaller loads. Distribution utilities, use low-voltage transmission lines to transfer power from major interregional substations to customers with minimal power loss. All the lines that do not cross the county border are operated by local distribution utilities, are 100–199 kV or 200–299 kV, travel short to moderate distances, and serve small to medium local loads.

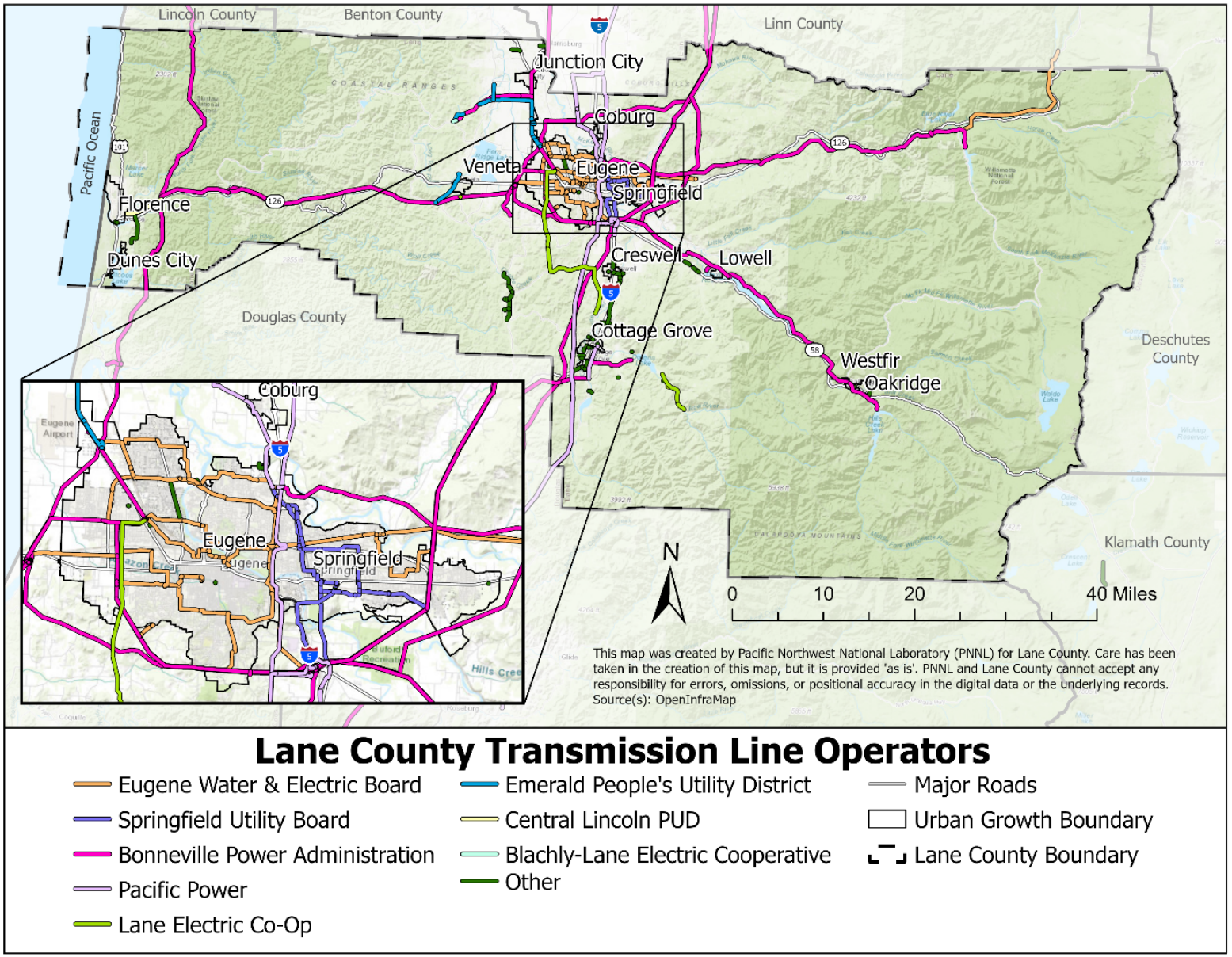


Figure 35: Map of Transmission Line Operators in Lane County[1] (as of March 2026)

[1] Data (as of March 2026) from Open Infrastructure Map, https://openinframap.org/#2/26/12

3.4.2 Distribution System Reliability

Reliability of the distribution system is generally measured through three major metrics. Those are:

- The ***System Average Interruption Duration Index (SAIDI)*** measures the average minutes of interruption experienced by each customer
- The ***System Average Interruption Frequency Index (SAIFI)*** measures the average number of interruptions experienced by each customer.
- The ***Customer Average Interruption Duration Index (CAIDI)*** measures the average interruption (time to restoration) length experienced by the average customer, and is calculated by dividing the SAIDI score by the SAIFI score.[1]

For all three metrics, lower numbers represent better performance.

Investor-owned utilities must submit—and many others voluntarily submit—reliability data to the ***U.S. Energy Information Administration (EIA)*** through an annual survey called Form EIA-861. These results are public. Small utilities may use a short version of the form, called EIA-861s, that is submitted less frequently and includes less reliability data. Since Lane County's small COUs submit Form EIA-861s data, they are not required to submit every year, resulting in years without reported results.

Figure 36, ***Figure 37***, and ***Figure 38*** plot distribution reliability data for six Lane County utilities submitted to the EIA between 2013 and 2024. Data for utilities with service territories beyond Lane County, like Pacific Power, represents results for their entire service area, not just Lane County. EIA national average data is only available from 2014 through 2024. Utility data in ***Figure 36***, ***Figure 37***, and ***Figure 38*** excludes outages that occurred during major event days[2], such as severe weather, to provide a more accurate understanding of day-to-day reliability. But utilities in this dataset use different metrics to identify major event days, which means results may not be a true apples-to-apples comparison of performance.

[1] U.S. Energy Information Administration, *"Electric Power Annual – Table EPA 11.1 (Electric Power Industry Summary Statistics),"* 2025. https://www.eia.gov/electricity/annual/html/epa_11_01.html

[2] Oregon has formally adopted the definition of major event days formally laid out in IEEE 1366-2012, which defines a major event day as one where the SAIDI exceeds a statistical threshold value called T_{MED}, which is calculated based on a logarithmic normalization of historic SAIDI values. Because of this, some severe weather events may trigger a major event day, while others may not depending on their impact on customer outages, via Oregon Secretary of State, *"Public Utility Commission,"* https://secure.sos.state.or.us/oard/viewSingleRule.action?ruleVrsnRsn=221205, Electrical and Electronics Engineers Standards Association, *"IEEE Guide for Electric Power Distribution Reliability Indices,"* 2012. https://standards.ieee.org/ieee/1366/4602/

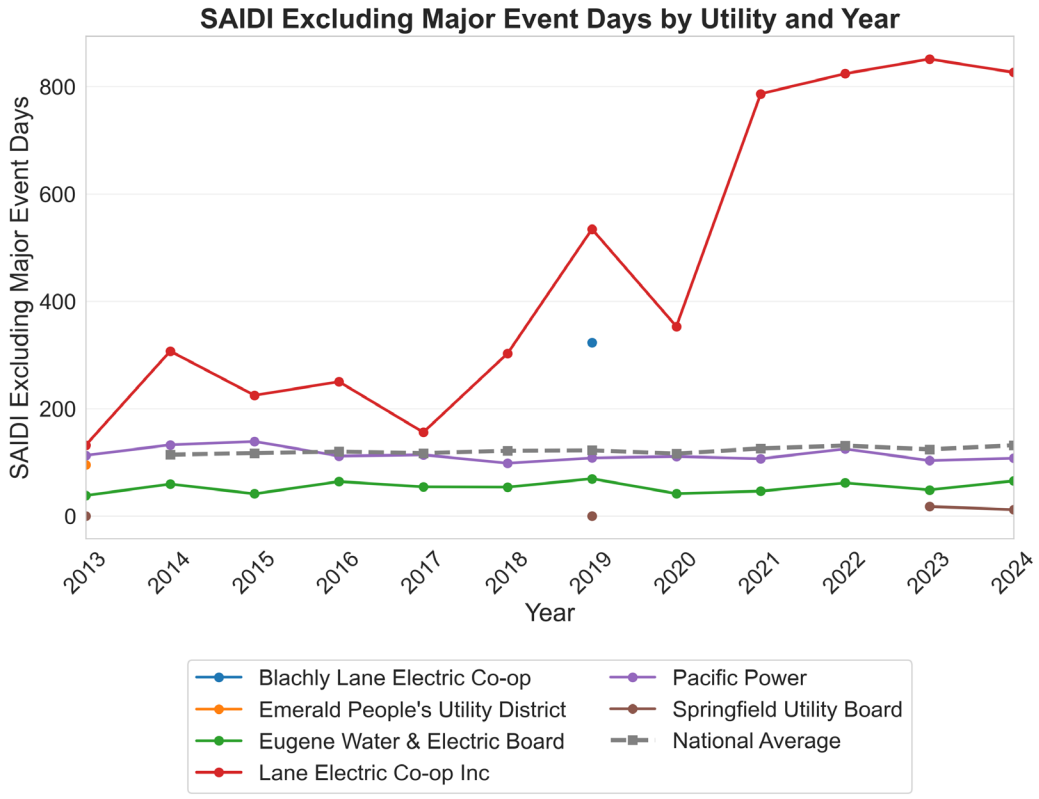


Figure 36: Annual Lane County SAIDI Data Reported to EIA vs National Average

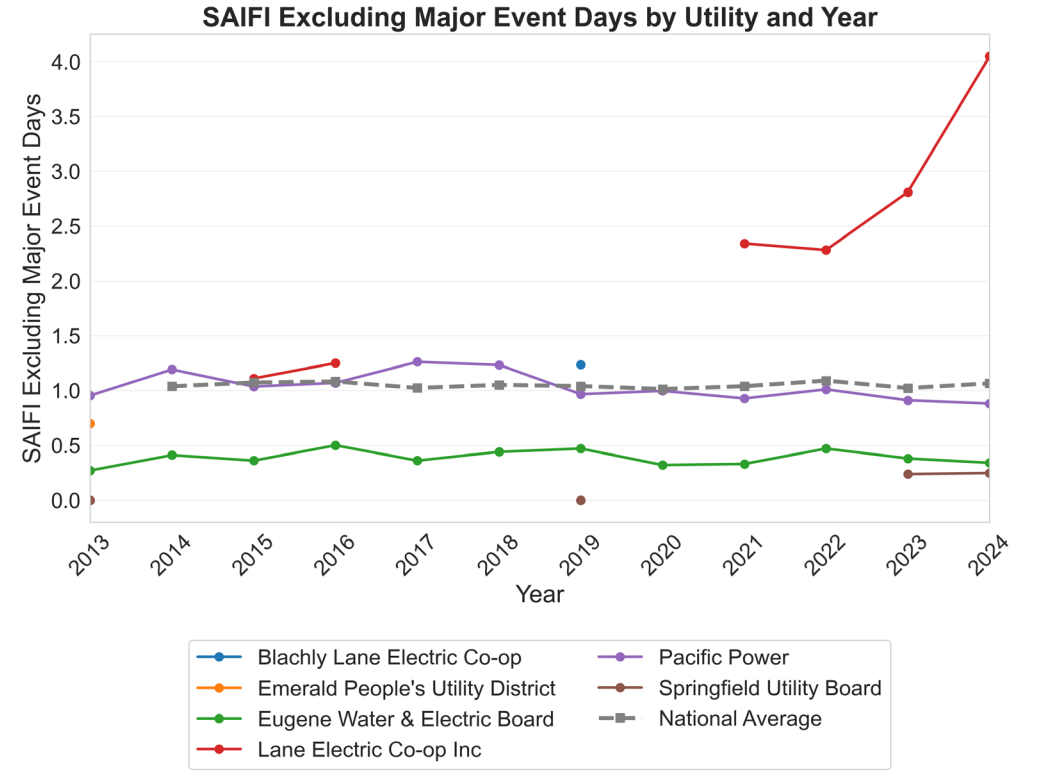


Figure 37: Annual Lane County SAIFI Data Reported to EIA vs National Average

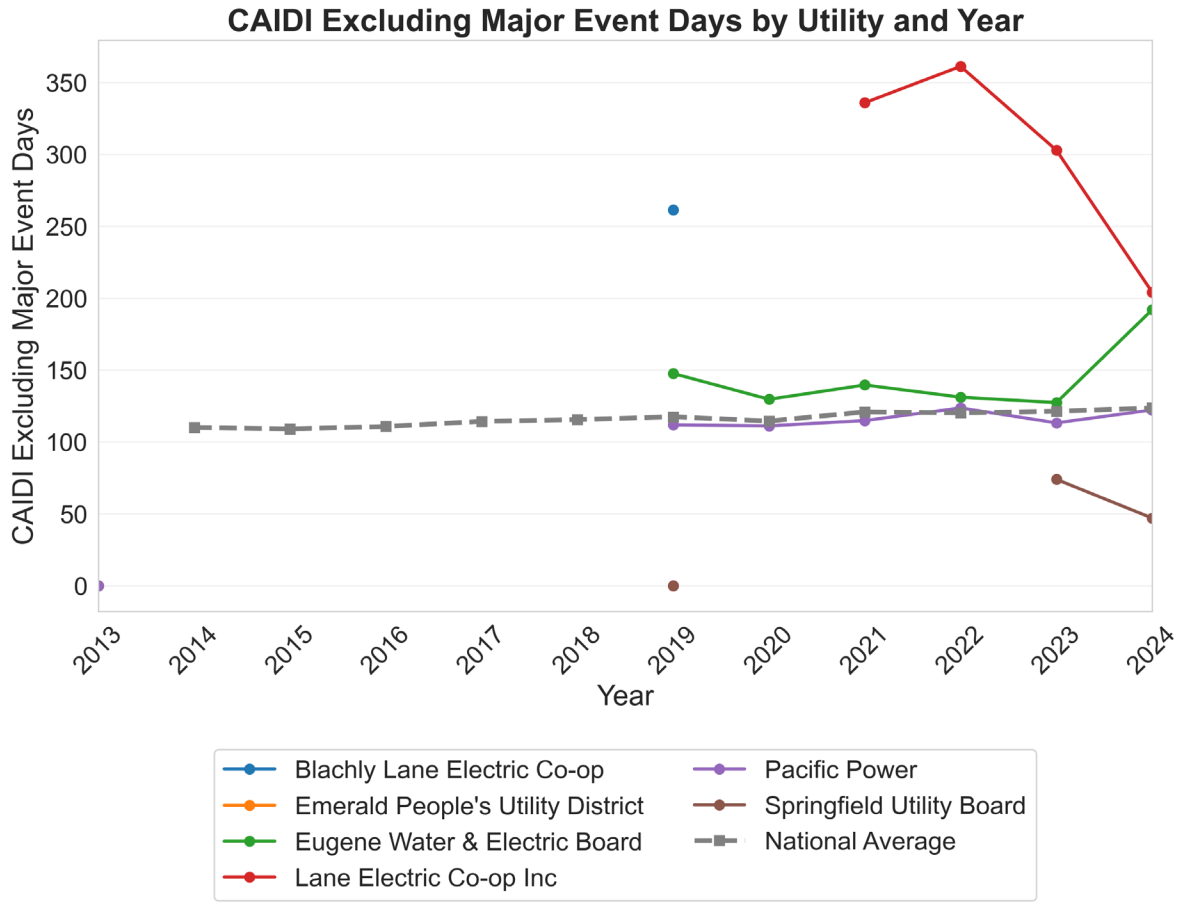


Figure 38: Annual Lane County CAIDI Data Reported to EIA vs National Average

Figure 36, ***Figure 37***, and ***Figure 38*** show that EWEB, Pacific Power, and Springfield Utility Board (SUB) have historically performed below or near the national average for all three reliability metrics. These three utilities experience similar outage numbers and durations of as the national average, or they are performing better by having fewer outages of shorter durations both overall and on a per customer basis than the national average. While EPUD data was only available from 2013 and CAIDI data is missing, the available data shows that EPUD performed near the national average.

Data for Blachly-Lane is only available for 2019, and shows that while SAIFI was near average, SAIDI and CAIDI were significantly above. This could indicate that in 2019 Blachly-Lane had an average number of outages but took more time than average to restore power.

Lane Electric performed consistently above the national average for all three metrics during available data years. This indicates Lane Electric customers experienced more outages that lasted longer on a system and a per-customer basis than the average U.S. utility. While we do not have enough information to determine exactly why Lane Electric is an outlier, Lane Electric's reliability challenges may be partially related to transmission supply. ***Figure 39***, a map of Lane County's transmission infrastructure overlayed with Lane County utility service territories, shows that the eastern half of Lane County, primarily Lane Electric service territory, is served by two long radial transmission lines. Because there is no transmission redundancy, an outage on either transmission line will interrupt power for all the customers.

Because Lane Electric is a small, rural utility, they maintain a lot of equipment to serve relatively few customers, with approximately 9 customers connected per mile of infrastructure. For comparison, EWEB has approximately 76 customers/mile, and SUB has 44 according to publicly reported values of miles of infrastructure and numbers of customers. Only Blachly-Lane has a similar rural system to Lane Electric's with about 4 customers/mile. One outage will more heavily impact their customer averages than a less rural utility. Lane Electric's service territory is also spread out compared to others in the county, which can lengthen response times. Their equipment runs through hard-to-access topography and is heavily tree covered which may result in more tree- and animal-caused outages that are hard to restore.

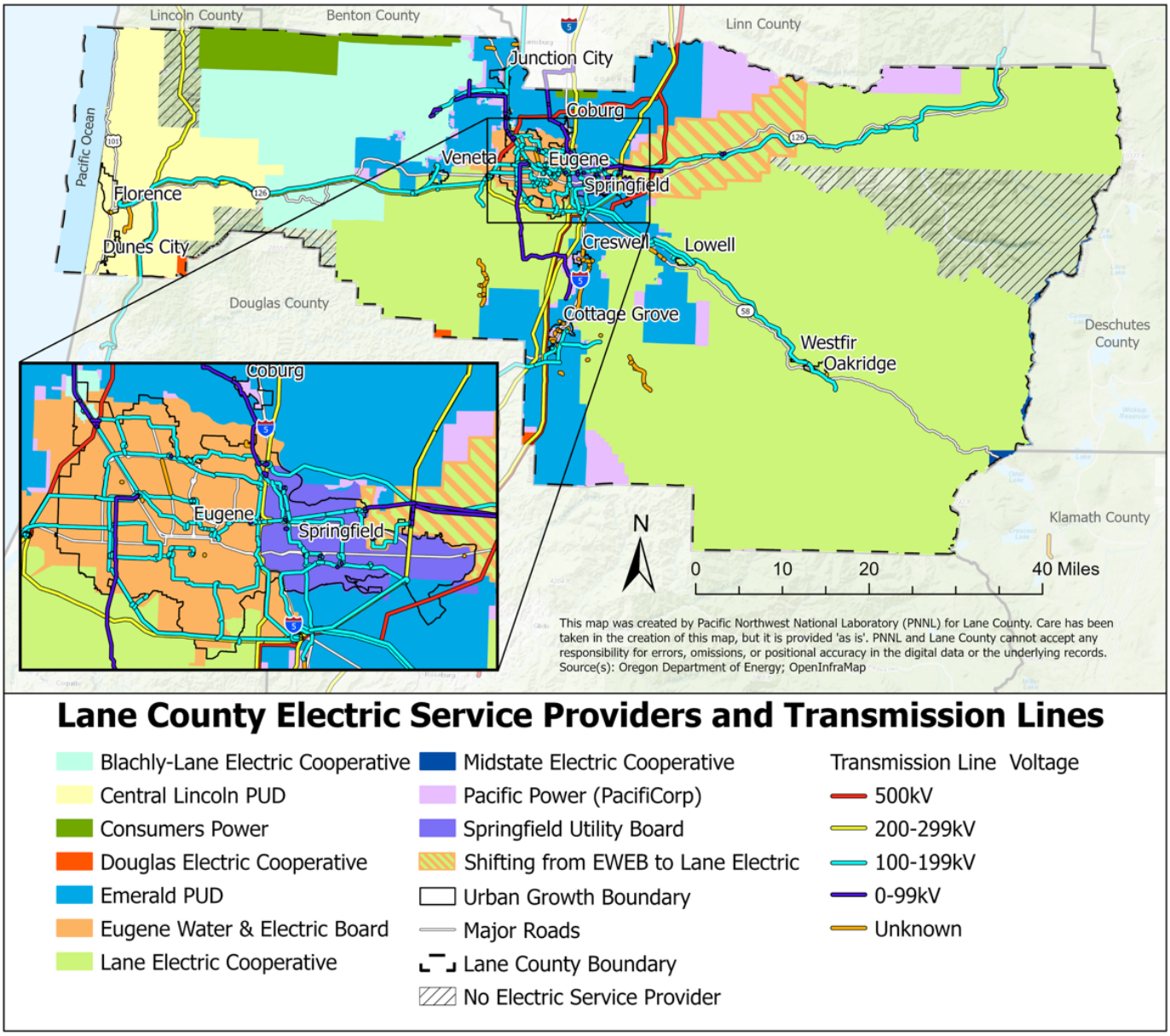


Figure 39: Map of Utility Service Territories and Transmission Infrastructure for Lane County[1,2]

3.5 Regional and National Rate Drivers

While Lane County utility rates are ultimately set by the local distribution utility, they are impacted by several forces beyond local control. The average U.S. electricity rate has steadily

[1] Data (as of March 2026) from Oregon Department of Energy, https://www.oregon.gov/energy/Pages/default.aspx
[2] Data (as of March 2026) from Open Infrastructure Map, https://openinframap.org/#2/26/12

increased since 2020.[1,2] While Oregon's average electricity rate is below the national average (see ***Section 3.5.2***), the state has experienced a significant (26.2%) rate increase over the last four years—a similar rate of change to the 26.7% national rate increase over the same period.[3] Customers of the large IOUs, PGE and Pacific Power, saw typical residential customer average bills increase by 50–60% between 2020 and 2024. Both PGE and Pacific Power are proposing further rate increases to the Oregon PUC. The Oregon Department of Energy identifies three primary drivers of rising consumer rates, which often interact: ongoing infrastructure investments compounded by inflation, rising power costs, and increased costs to mitigate and respond to wildfires and extreme weather.

3.5.1 Ongoing Infrastructure Investments Compounded by Inflation

Electric utilities must constantly invest in grid infrastructure to replace aging equipment, maintain reliability, and support system resilience. Routine equipment and material costs have grown due to inflation and supply chain disruptions. The Oregon DOE reports that since 2020, the cost of power poles increased 35%, overhead conductors 45%, underground power cables 79%, and single-phase transformers by nearly 200%. Longer lead times and supply delays further increase project costs. Utilities must increase customer rates to recover these investment costs. Annual nominal and inflation-adjusted average electricity prices in the United States are shown in ***Figure 40:*** U.S. Average Electricity Prices, 2010-2024. While national-average retail electricity prices have increased in nominal terms, real prices (adjusted to account for inflation) have generally decreased[4].

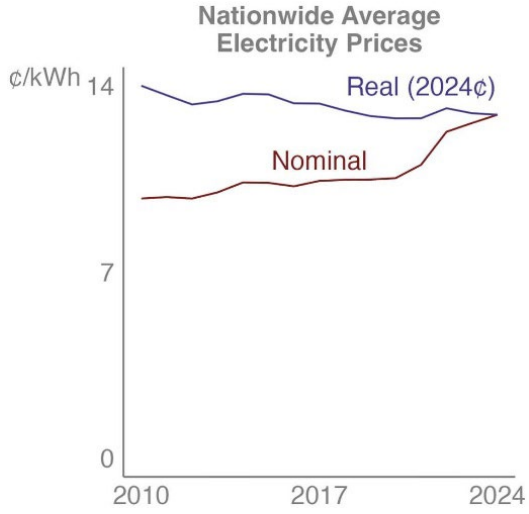


Figure 40: U.S. Average Electricity Prices, 2010-2024
Annual Nominal and Real (Inflation-Adjusted)[5]

[1] Janine Benner *et al.*, "2024 Biennial Energy Report," Oregon Department of Energy, Nov. 2024. https://www.oregon.gov/energy/Data-and-Reports/Documents/2024-Biennial-Energy-Report.pdf
[2] U.S. Energy Information Administration, "U.S. electricity prices continue steady increase," May 2025. https://www.eia.gov/todayinenergy/detail.php?id=65284
[3] U.S. Energy Information Administration (EIA), *"Electric Power Monthly,"* https://www.eia.gov/electricity/monthly/epm_table_grapher.php?quot=&t=table_5_03
[4] Lawrence Berkeley National Laboratory, *"Factors Influencing Recent Trends in Retail Electricity Prices in the United States,"* Oct. 2025. https://emp.lbl.gov/publications/factors-influencing-recent-trends
[5] Image from Lawrence Berkeley National Laboratory, https://emp.lbl.gov/publications/factors-influencing-recent-trends

3.5.2 Rising power costs

Utility power costs include the price of electricity and the cost of fuel (such as natural gas) for utility-owned power plants. Despite recent BPA rate increases (see ***Section 1.5.1***), federal hydropower is less expensive than other wholesale power sources. Northwest IOUs rely less on BPA contracts and more on short-term wholesale purchases and natural gas power plants, increasing their exposure to wholesale market volatility and fluctuating power costs.[1] International changes in energy and fuel prices and unexpected events such as pandemic-related supply disruptions or international market uncertainty can significantly impact wholesale power prices and increase customer energy rates.[1] Oregon COU rate increases are smaller than IOU increases because they rely primarily on relatively low-cost BPA hydroelectric power.

3.5.3 Increased costs to mitigate and respond to wildfires and extreme weather

Wildfires and extreme weather events like droughts, floods, and heatwaves are increasing in frequency and severity in the Pacific Northwest.[2] Infrastructure upgrades for mitigating natural disaster risk and equipment and labor expenditures for recovering from natural disasters add significant cost pressures on Oregon utilities.[3] Utilities must invest in wildfire risk and extreme weather mitigation, infrastructure hardening, and respond to and recover from damage caused by extreme events, as well as respond to regulatory measures, policies, and insurance requirements. Wildfires, ice storms, and other natural hazards have also contributed to rising insurance costs, as utilities face greater financial liability. Lane County Emergency Management staff estimated that the 2024 ice storm cost the county's electric utilities almost $33 million. We discuss the impacts of natural hazards further in ***Chapter 5***.

[1] Janine Benner *et al.*, "2024 Biennial Energy Report," Oregon Department of Energy, Nov. 2024. https://www.oregon.gov/energy/Data-and-Reports/Documents/2024-Biennial-Energy-Report.pdf
[2] U.S. Department of Agriculture (USDA), Climate Hubs, *"Climate Change Impacts in the Northwest,"* https://www.climatehubs.usda.gov/hubs/northwest/topic/climate-change-impacts-northwest; https://uw.pressbooks.pub/nwforestryresearch/chapter/history-of-wildfires-and-policy-progression/; https://www.sciencedirect.com/science/article/pii/S0378112725007704
[3] Oregon Department of Energy, *"Biennial Energy Report 2024 (E101 section, p. 54),"* 2024. https://www.oregon.gov/energy/Data-and-Reports/Documents/2024-BER-E101.pdf#page=54

Chapter 4

Expectations of Lane County Utilities

Ali Trueworthy

Lane County utilities strive to meet evolving customer and stakeholder expectations while managing the constraints of the regional grid system. These expectations include, but are not limited to, expectations of affordable service, ability to serve changing loads, efficiency and conservation, and reliability and resilience. Each of these expectations adds a unique challenge to the utility's ability to balance costs and revenues and/or load and generation. The challenges they present often overlap. In this section, we present a variety of utility best practices related to maintaining the balance costs and revenues and/or load and generation while meeting customer and stakeholder expectations. We document some of the current practices implemented in Lane County and identify areas where there are opportunities or improvements.

4.1 Maintaining Affordable Services

Customers expect affordable services from their utilities. ***Affordability*** for an individual customer depends on rates and rate structures, but also on their individual income (see ***Section 8.1*** for map of ***energy burden*** in Lane County). The income generated from customer rates is the primary source of revenue for distribution utilities. As such, a utility, especially a COU, strives to maintain affordability while also balancing costs.

Cost factors are only partially within the control of local utilities. Rates are driven by many factors (discussed in ***Section 3.5***) including the costs of maintaining infrastructure and mitigating and responding to hazard events, especially in the context of inflation, emerging technologies, extreme weather, and aging existing assets. In interviews with Lane County utilities (see ***Appendix A– Utility Interviews***), 50% of utility representatives expressed uncertainty about the future existence of financial backstops like the ***Federal Emergency Management Agency (FEMA)*** and other grant assistance. Without such backstops, the financial challenges associated with natural hazard events would be compounded for Lane County utilities. That said, there are steps that utilities can take to mitigate the impacts of financial pressures and maintain affordable service.

4.1.1 Best Practices for Maintaining Affordable Service

The ***American Public Power Association*** provides a convenient checklist for utilities striving to maintain operational excellence and financial health (reproduced on the next page). These practices happen within the utility, though may be tracked by the governing board or council members. The American Public Power Association divides best practices into three categories, shown in ***Figure 41***:

1. Focus on key targets and financial areas
2. Establish fair and equitable rate structures
3. Use regular reporting to maintain transparency.

Focus on Key Targets and Financial Areas

- Encourage employees and decision makers to learn the purpose of the balance sheet and income statement and the important information they convey.
- Identify key financial targets and how they work together to support short- and long-term **financial goals**.
- Review **metrics** that include minimum cash reserve requirements, rate of return, debt coverage ratio, debt-to-equity ratio, and age of system.
- Adopt sound **financial policies** that support the key financial targets and take action when targets are not met.
- Conduct periodic reviews of **industry benchmarks** to help ensure operational financial efficiencies. Refer to Financial and Operating Rations of Public Power Utilities as a guide.
- Conduct annual assessment of **capital needs** and update **strategic capital plan** accordingly.
- Research and evaluate state and federal **funding opportunites** that support capital goals.
- Ensure the **budget** supports the necessary revenues to achieve financial goals and capital reinvestment.
- Ensure any payments in lieu of taxes (aka, PILOT or transfers to the city) are based on a sound, defendable formula.

Establish Fair and Equitable Rate Structures

- Ensure the necessary **expertise** is available to help establish fair and equitable rates.
- Ensure **rate structures** include components for proper fixed and variable cost recovery such as customer (fixed), demand, and kWh (energy) charges, as well as a power cost adjustment (PCA).
- Implement continuous education and improvement of rate structures to account for **innovative rate design** as the industry changes.
- Implement technologies like **AMI** to provide data and the means to develop more robust rate structures for fair cost recovery.
- Develop detailed **policies on customer connections** (line extension, connection, and impact fees), additional large loads (e.g. electric vehicle charging infrastructure and data centers), and distributed generation.

Use Regular Reporting to Maintain Transparency

- Implement internal controls to ensure financial reporting is accurate with proper documentation and complies with applicable laws and regulations.
- Ensure transparancy by making financial data **available online** and at **public meetings**, providing open and honest dialogue with residents to encourage trust.
- Commit to timely **financial reporting**, such as providing monthly reports to decsion makers.
- Conduct an **annual audit**, perfomed by an independent professional organization, at the end of each fiscal year.

Figure 41: Best Practices for Maintaining Good Financial Health for Public Electric Utilities[1]

[1] Information from the American Public Power Association, reproduced verbatim.

Focus on Key Targets and Financial Areas

A utility's focus on key targets and financial areas includes foundational operational practices like analyzing financial statements, budgeting, tracking key financial metrics, and ensuring timely maintenance.[1] In addition, it includes more in-depth planning endeavors. These endeavors help utilities identify feasible timelines for investment, maintenance, and adoption of new technologies or strategies. Planning can reduce risk, minimize unplanned costs, and support the prioritization of actions, ultimately helping the utility maintain affordable services.

Strategic Planning

Strategic plans provide the guiding strategy for subsequent planning or decision-making. ***Utility strategic planning*** typically includes high-level goals, actions the utility will take to meet those goals, and sometimes metrics for measuring progress toward goals. While utilities might do their own strategic planning, cities or towns also engage in planning related to their energy systems.[2] We discuss city plans in Lane County and best practices for community strategic energy planning in ***Sub-Section 9.1.1***. When utilities and the municipalities they serve have strong working relationships, they can align their strategic energy plans.

Capital Planning

Capital planning, also known as ***system upgrade planning*** or ***asset planning***, is focused on utility infrastructure and assets. A ***capital plan*** identifies what assets need replacement or upgrades in the coming years. The plan usually prioritizes asset upgrades based on the estimated probability and impact of failures, the estimated cost and impact of upgrading an asset, and feedback from the board or customers. Utilities consider how their capital needs align with available capital to determine how many projects can be undertaken and on what timeline. If there are discrepancies between needed and available capital, the utility must explore other options such as rate changes or grants. For COUs, the prioritization and approval of projects is typically overseen by the board and therefore is available for public review. For IOUs, utilities usually need to submit their capital plans to their Public Utilities Commission (PUC).

Integrated Resource Planning

An ***integrated resource plan*** is a roadmap for meeting forecasted electricity demand. Historically, integrated resource plans have been focused on the bulk power system, but it is becoming more common for distribution utilities with generation resources to create these plans.[3] We discuss integrated resource plans, also sometimes called ***integrated distribution plans***,[4] in more detail in ***Section 4.2***.

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[1] J. Keen *et al.*, "Distribution Capacity Expansion Planning: Current Practice, Opportunities, and Decision Support," National Laboratory of The Rockies, NREL/TP-6A40-83892, 1898008, MainId:84665, Nov. 2022. doi: 10.2172/1898008.

[2] American Public Power Association, *"Public Power Forward: A Guide to Utility Operational Excellence,"* 2025. https://www.publicpower.org/resource/public-power-forward-guide-utility-operational-excellence

[3] U.S. Department of Energy, *"COMMUNITY GREENING: HOW TO DEVELOP A STRATEGIC ENERGY PLAN,"* Feb. 2010. https://docs.nlr.gov/docs/fy10osti/45652.pdf

[4] Lawrence Berkeley National Laboratory, *"Best Practices in Integrated Resource Planning: A guide for planners developing the electricity resource mix of the future,"* Nov. 2024. https://emp.lbl.gov/publications/best-practices-integrated-resource

IOUs in Oregon are required by the Oregon PUC to submit an integrated resource plan every two years.[1] The process includes establishing and modeling feasible future scenarios for both generation and load. DOE promotes best practices for integrated resource planning developed by researchers and practitioners from Synapse Energy Economics Inc. and Lawerence Berkeley National Lab. The 50 best practices span the categories of stakeholder engagement, resource adequacy, developing model inputs, designing scenarios and sensitivities, running models, evaluating portfolio results, communicating transparently to regulators and stakeholders, and aligning the integrated resource planning process with other utility proceedings.[2]

Establish Fair and Equitable Rate Structures

While the best practices in the category ***focus on key targets and financial areas*** relate to keeping operational costs manageable, the best practices in the category ***establish fair and equitable rate structures*** relate to keeping revenues adequate and acceptable. Practices include rate design informed by data collection and policy setting for customer connections.

Rate Design

Rate design is an important part of maintaining fair and equitable rate structures. ***Sub-Section 1.5.2*** describes the different types of rates and rate structures. Utilities implement different types of charges (with fixed, energy, and demand charges being the most common) at different rates or rate schedules that determine when (e.g., in the summer vs. winter) and to whom (e.g., commercial vs. residential users) the charges apply. Different rate structures can be used to pursue differnt goals or incentivize different consumptive habits.

Generally, utilities can pursue fairness in rate design by making the charges to a customer reflect the cost of serving that customer. Because utilities experience different costs, there is not a rate structure that is universally fair. Some utilities might choose to vary a fixed charge based on customer-specific factors like income or the number of families at a residence in an effort to reduce the energy cost burden on vulnerable customers. Such programs are often mandated by a government or board. Best practices say that the utilities should have the expertise available to examine different rate structures, use data to explore options, and track innovations in the industry. The American Public Power Association provides several rate design case studies from COUs across the United States.[3]

Ratepayers are the primary (often only) source of income for the utility, and rate structures are the main lever that utilities have to influence customer use behavior. For that reason, the utility rate data presented in ***Sub-Section 1.5.2*** is a useful to examine Lane County utilities pursuit of fairness in rates design (this section), rates for large new customers (see ***Sub-Section 4.1.2***), and rates encouraging energy efficiency and conservation (see ***Section 4.3***).

Connection Policies

When it comes to distribution planning, utilities are faced with complex decisions about which strategies to implement, where, and when. In addition, they face questions about who bears the

[1] Oregon Public Utility Commission, *"Energy – Planning"*, https://www.oregon.gov/puc/utilities/pages/energy-planning.aspx
[2] U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, ibid.
[3] American Public Power Association, *"Public Power Rate Design Case Studies"*, https://www.publicpower.org/resource/public-power-rate-design-case-studies

costs of interconnections and distribution upgrades. When a customer wants to connect to the grid, or to increase their consumption in such a way that it would require distribution upgrades, the utility may require that customer to bear a portion of the costs of those upgrades. This is more often true for components that only serve the customer or the customer and a few others (like a transformer or feeder), and less often true for major upgrades like replacing a line with one of increased capacity.

Recently, the practice of passing upgrades costs on to customers has been called into question for a variety of reasons, including the way that it could stifle electrification and/or equitable adoption of electrified heating, cooling, or efficiency measure. Critics have also noted that the practice can deter industry or businesses from locating in certain areas. Because the grid is a system that so many people use and rely on, determining how to fairly distribute the costs of maintaining and improving the grid is central to utility policy and rate setting.

Assistance, Rebate, and Monitoring Programs

Utilities can help their customers with their bills through income-based energy assistance programs. There are national programs like the Low-Income Home Energy Assistance Program (LIHEAP)[1] that utilities can help their customers find, but utilities may also run their own programs. Some utilities set aside some of their operating budget to financially assist their low-income customers, while others have programs that customers can donate to to help their neighbors. Some utilities partner with local organizations to offer payment assistance. Rebate programs for energy efficiency measures can help customers take the steps necessary to reduce their home energy bills.

If utilities have AMI, utilities can use the data in their rate setting to understand the impacts of certain measures on different customers and explore options for fairer rate setting.

Use Regular Reporting to Maintain Transparency

The final category of actions for maintaining affordable service and good financial health is ***use regular reporting to maintain transparency***. This category includes practices related to documenting, reporting, and auditing financial metrics.

Budgets, Audits, Reports, and Newsletters

Reports can take many forms, but publicly available budgets, audits, reports, and newsletters are some typical modes that utilities might use to communicate their financial situation. Budgets are typically annual, but a utility may be required to give quarterly budget updates to their board. Audits by outside organizations are also commonly annual and may be required by the board or a PUC. Annual reports and/or newsletters are flexible ways of communicating with customers.

4.1.2 Approaches Applied in Lane County

This section presents the best practices implemented by Lane County utilities. The assessment of utility practices is based on publicly available information only and does not judge the quality or impact of the practices for each specific utility.

[1] Low-Income Home Energy Assistance Program, *"What is LIHEAP,"* https://www.liheap.org/about

Focus on Key Targets and Financial Areas

Table 12 shows which utilities have strategic, capital, and integrated resource plans. Larger utilities have more planning capabilities, with EWEB and SUB being the only two utilities with all three plans available. EPUD has a strategic plan, and though they do not have an official capital plan available on their website, they have previously provided updates on capital project outlooks on their website.[1] EPUD is also notable for their Resource Planning Citizen Advisory Committee. This committee, according to their website, "meets to review Emerald's long-term energy resource plans and makes recommendations on resource acquisition proposals."[2] EPUD maintains an accessible set of policies and procedures on their website that includes investment policy, power risk management policy, customer service policy, and more.

EWEB's strategic plan is for 10 years from 2018 to 2028, and SUB and EPUD both have 5-year strategic plans. While Pacific Power does not have a strategic plan, they produce both an integrated resource plan and a clean energy plan as required by the Oregon PUC. The clean energy plan tracks their progress toward meeting the ***Oregon Clean Energy Targets Bill*** passed in 2021 and discussed in ***Sub-Section 2.3***.

Table 12: Plans Produced by Lane County Utilities
where ✓ indicates the document exists and — indicates no confirmation of document existence.

	Strategic Plan	Capital/ System Upgrade Plan	Integrated Resource Plan
EWEB	✓[3]	✓[4]	✓[5]
SUB	✓[6]	✓[7]	✓[8]
EPUD	✓[9]	—	✓[10]
Central Lincoln PUD	—[11]	—	—
Lane Electric	—	—	—
Pacific Power	—	✓[12]	✓[13]
Blachly-Lane	—	—	—

[1] Emerald People's Utility District, *"Mid-Year Update"*, https://www.epud.org/mid-year-update/
[2] Public Power Council, *"Public Power Rate Design Case Studies"*, https://www.epud.org/community/citizen-advisory-committee/
[3] Eugene Water & Electric Board, *"2018–2028 Strategic Plan (2021–2024 Update)"*, Jul. 2026. https://www.eweb.org/documents/Reports%20and%20Publications/eweb_strategic_plan_2018_2028_2021_2022_2023_2024_update.pdf
[4] Eugene Water & Electric Board, *"Rebuilding 10 Substations in 10 Years"*, www.eweb.org/historic-mitigation-concepts/electric-reliability-projects/rebuilding-10-substations-in-10-years
[5] Eugene Water & Electric Board, *"Integrated Resource Planning"*, https://www.eweb.org/your-public-utility/power-supply/energy-planning/integrated-resource-planning
[6] Springfield Utility Board, *"5 Years 5 Goals 2025-2030 Strategic Plan,"* 2025. https://www.subutil.com/wp-content/uploads/SUB-Strategic-Plan-2024-fin-lores.pdf
[7] Springfield Utility Board, *"Electric Projects,"* https://www.subutil.com/electric-projects/
[8] Springfield Utility Board, "*Integrated Resource Plan 2025,"* https://www.subutil.com/wp-content/uploads/2025-SUB-Integrated-Resource-Plan_FINAL.pdf
[9] Emerald People's Utility District, Strategic Plan, "2020 Strategic Plan," 2020. https://www.epud.org/wp-content/uploads/2020-Strategic-Plan_finalSML.pdf
[10] Not publicly available
[11] Central Lincoln PUD does not have a strategic plan, but their business strategies are outlined on their website: https://clpud.org/about-us/vision-mission-values-business-strategies/
[12] PacifiCorp, *"Transmission Projects"*, https://www.pacificorp.com/transmission/transmission-projects.html
[13] Pacific Power. "2025 Integrated Resource Plan," https://www.pacificorp.com/energy/integrated-resource-plan.html

Establish Fair and Equitable Rate Structures

In 2025, the State of Oregon passed ***Oregon HB 3179 (2025)***, the ***FAIR Energy Act (Fairness and Affordability in Residential Energy Regulation)*** which adds rate transparency requirements for IOUs (see ***Sections 2.3*** and ***2.4***). The policy does not apply to COUs, whose community ownership and elected board members are in place to maintain acceptable rate structures. The policy requires the Oregon PUC to consider the cumulative economic impact of an electric or natural gas company's proposed residential rate change. If deemed unfair, the utility may be required to modify rate changes. Aspects of the law aim to limit how frequently utilities can raise rates, prevent rate increases during high-demand months, and communicate incoming rate changes.[1]

Rate Design

Rate structures for COUs must be proposed to and approved by the utility's board. The board can direct the utility to consider alternate rate structures. ***Sub-Section 1.5.2*** shows the residential and commercial rate structures for each utility. In Lane County, all utilities have experience with all three of the different rate types (fixed, energy, and demand). For residential rates, all utilities implement a fixed charge, typically to distribute fixed operation costs to customers, regardless of electricity usage. Demand charges in Lane County are reserved for commercial customers, and sometimes (like for EPUD), only large commercial customers. ***Section 4.3*** discusses demand response programs, which may include demand charges.

Connection Policies

Within their customer policies, Lane County utilities outline costs incurred by new and substantially growing customers. These policies generally take the same form for all Lane County utilities: the utilities provide a cost estimate for the customer that defines the upfront charges that the customer is responsible for. Upfront charges cover components such as transformers or line extensions. Utility policy allows the utility to make determinations on a case-by-case basis. The policies are intended to protect the utilities' existing customers (especially residential customers) from bearing costs driven by large industrial or commercial users.

Lane County utilities protect customers from shouldering the costs of new customers is through new large load policies. For example, EPUD's new large load policy makes clear that loads over 1MW and introduced after 2013 are responsible for paying for power at the non-federal resource, or Tier 2, rates. Because EPUD uses all their allotted Tier 1 power, any new loads will be met at Tier 2 rates. As the percentage of electricity purchased at Tier 2 rates increases, the average cost of electricity purchased by EPUD will increase. Their policies ensure that this additional cost is recovered not through rate increases for all their existing customers, but through EPUD's charges to the new customer. EPUD's policy concludes, "District reserves the right to pass through any costs incurred that are driven solely by a [new large load] customer."[2]

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[1] Oregon Governor's Office, *"Governor Kotek Signs Bills to Lower Energy Costs for Oregonians"*, Aug. 2025. https://apps.oregon.gov/oregon-newsroom/OR/GOV/Posts/Post/governor-kotek-signs-bills-to-lower-energy-costs-for-oregonians

[2] Emerald People's Utility District, *"Emerald PUD Customer Service Policies and Procedures,"* Mar. 2026. https://www.epud.org/wp-content/uploads/Customer-Service-Customer-Service-Policy-Procedures-2026-MAR-17-Final.pdf

From BPA's perspective (see ***Section 2.1***), the threshold for being considered a new large load is 10 MW, but some Lane County utilities set lower thresholds. Most utilities use the metric of *average additional load over a 12-month period* to determine if a customer constitutes a new large load, and most utilities do not give those loads access to Tier 1 rates. Finer details of each utility's policies vary slightly, and threshold as of 2025 are shown in ***Table 13***.

Table 13: Utility Policies for New Large Loads or Existing Increasing Loads

	Threshold for New Large Loads	Location of Policy
EWEB	10 MW	Customer Service Policy, Appendix B, Section D
SUB	5 MW	Board Policies, Section V, Chapter VIII New Large Single Load; Board Policies, Section I, 4-1-1 Electric Construction Development Charges;
EPUD	1 MW	Customer Service Policy Section 15. Miscellaneous Service Charges and Section 16. New Large Loads
Central Lincoln	5 MW new or 9 MW increase	Single-Family Residential Guidelines and Standards; Commercial Guidelines and Standards; October 2025 Rate Schedule
Lane Electric	50 kVa	Construction Requirements and Guidelines; Electric Service Rules and Regulations
Pacific Power	N/A	Oregon Rates and Tariffs
Blachly-Lane	1 MW ("NLL") and 10 MW ("NLSL")	Board Policies 1410 Power Sales Agreements NLSL; 1405 Line Extensions; 1315 Membership and Service Requirements

What about connecting data centers to the grid in Lane County?

A potential source of new large loads that has been getting a lot of attention recently is data centers. While there are not public plans for data centers in Lane County, popular news coverage has brought the issue to the fore. Pacific Power, the only IOU that serves both regionally and in Lane County, has some new policies for large-load customers that are meant to protect the broader customer base. In late 2024, the Oregon PUC approved Pacific Power's rate charge that penalizes large-load customers for energy use that does not align with the forecasted energy use that they submit to the utility. This policy is meant to prevent situations where the utility invests in grid infrastructure that is inappropriate for the load they need to serve. It was opposed by data center companies and interest groups, but went into effect in February 2025 under the name "Excess Demand Charge and Capacity Reservation Charge."[1] Pacific Power has also eliminated their "line extension allowance" for new customers seeking service over 25 MW. This change means that large customers will have to take on a larger share of the grid investments necessary to serve them. As policies change for investor-owned utilities in Oregon, updates can be found on the Oregon PUC website.[2]

The issue of data centers highlights an important difference between IOUs and COUs. COUs have little-to-no incentive to absorb the infrastructure costs of serving new loads, especially in Oregon where those utilities have preferential rights to BPA's Tier 1 resource. For IOUs, the situation is a bit more complicated. When IOUs make capital investments, they can use those investments to justify rate increases across their customer base. In Oregon, IOU rate changes must be approved by the PUC. So, in some cases, IOUs might be inclined to take on a higher portion of the costs of new service so that they can then get rate increases approved and ultimately increase return to their investors. That has not seemingly been the case for PacificCorp, as exemplified by rule changes discussed in the previous paragraph.

Assistance, Rebate, and Monitoring Programs

Table 14 shows other utility practices related to fair and equitable rate structures. All utilities in Lane County have assistance programs for low-income customers, as well as incentives and rebate programs. EWEB, EPUD, Central Lincoln PUD, and Blachly-Lane have low-income assistance programs that are funded partially by the utility's budget and partially by customer donations. SUB and Central Lincoln PUD partner with a local organization to provide assistance. All utilities have information on their websites that helps customers to connect to state/federal assistance opportunities. Although most utilities use AMI, the extent to which utilities use their AMI data for rate design is unknown (see ***Chapter 6*** for more on AMI).

[1] Data Center Dynamics, *"Oregon Regulators Approve PacifiCorp Penalties for High-Load Energy Users Despite Industry Pushback"*, Dec. 2024. https://www.datacenterdynamics.com/en/news/oregon-regulators-approve-pacificorp-penalties-for-high-load-energy-users-despite-industry-pushback/

[2] Oregon Public Utility Commission, *"Large Customer Demand"*, https://www.oregon.gov/puc/utilities/pages/large-load.aspx

Table 14: Fair and Equitable Rate Structures Practices Adopted by Lane County Utilities
where ✓ indicates the document exists and — indicates no confirmation of document existence

	Low- Income Assistance	AMI	Incentives and Rebates
EWEB	✓[1]	✓[2]	✓[3]
SUB	✓[4]	✓[5]	✓[6]
EPUD	✓[7]	✓[8]	✓[9]
Central Lincoln	✓[10]	✓[11,12]	✓[13]
Lane Electric	✓[14]	✓[15]	✓[16]
Pacific Power	✓[17]	✓[18]	✓[19]
Blachly-Lane	✓[20]	—	✓[21]

[1] Eugene Water & Electric Board, *"Income-Based Assistance,"* www.eweb.org/bill-assistance

[2] Eugene Water & Electric Board, *"Common Questions about Smart Meters,"* www.eweb.org/projects/smart-meters-and-smart-grid/smart-meter-faqs

[3] Eugene Water & Electric Board, *"Rebates & Savings,"* www.eweb.org/rebates-and-savings

[4] Suburban Utility Board, *"Payment Assistance,"* https://www.subutil.com/customer-service/account-services/payment-assistance/

[5] Springfield Utility Board, "*Integrated Resource Plan 2025,"* https://www.subutil.com/wp-content/uploads/2025-SUB-Integrated-Resource-Plan_FINAL.pdf

[6] Springfield Utility Board, *"Rebates & Loans,"* https://www.subutil.com/conservation/for-your-home/rebates-loans/

[7] Emerald People's Utility District, *"Payment Assistance Programs,"* https://www.epud.org/my-account/payment-assistance-programs/

[8] Emerald People's Utility District, Strategic Plan, "2020 Strategic Plan," 2020. https://www.epud.org/wp-content/uploads/2020-Strategic-Plan_finalSML.pdf

[9] Emerald People's Utility District, *"Residential Incentive Programs,"* https://www.epud.org/energy-efficiency/energy-incentive-programs/residential-incentive-programs/

[10] Central Lincoln People's Utility District, *"Energy Assistance,"* https://clpud.org/customer-information/energy-assistance/

[11] Oregon Department of Energy, *"People Case Study,"* 2018. https://www.oregon.gov/energy/safety-resiliency/Documents/People-Case-Study.pdf

[12] U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability, *"Central Lincoln People's Utility District Smart Grid Team 2020 Program," DOE*. https://www.energy.gov/node/2664646

[13] Central Lincoln People's Utility District, *"Energy Efficiency,"* https://clpud.org/energy-efficiency/

[14] Lane Electric Cooperative, *"Low Income Home Energy Assistance Program (LIHEAP),"* https://www.laneelectric.com/your-account/payment-assistance-programs/low-income-home-energy-assistance-program/

[15] Lane Electric Cooperative, *"New Meter Update,"* https://laneelectric.com/new-meter-update/

[16] Lane Electric Cooperative, *"Energy Saving Programs,"* https://laneelectric.com/programs-services/current-programs/

[17] Pacific Power, *"Bill Payment Assistance,"* https://www.pacificpower.net/my-account/payments/bill-payment-assistance.html

[18] PacifiCorp, *"Smart Meters,"* https://www.pacificpower.net/my-account/energy-usage/smart-meters.html

[19] Pacific Power, *"Incentive list,"* https://www.pacificpower.net/savings-energy-choices/business/wattsmart-efficiency-incentives-washington/wa-incentive-lists.html

[20] Blachly-Lane Electric Cooperative, *"Energy Assistance,"* https://www.blachlylane.coop/your-account/payment-options/energy-assistance/

[21] Blachly-Lane Electric Cooperative, *"Conservation,"* https://www.blachlylane.coop/conservation/

Use Regular Reporting to Maintain Transparency

Table 15 shows utility practices related to transparency, including publicly available budgets, audits, annual reports, or newsletters. While Pacific Power does not have these publications available on their website, there are similar documents available with public records request from the Oregon PUC. All the COUs in Lane County have at least one of the publications, and EWEB is the only utility to publish them all. It should be noted that smaller utilities may be able to cover the same information in fewer documents. COU budgets are typically approved by the boards, so they are always accessible via board meeting packets, even if they are not published directly on the website. For some utilities, a report may exist but is not directly linked on their website. For example, SUB conducts annual audits according to their board policy, but they are not available on SUB's website.

Table 15: Practice Adopted by Lane County Utilities Related to Customer Transparency
where ✓ indicates the document exists and — indicates no confirmation of document existence

	Publicly Available Budget (Annual+)	Publicly Available Audit (Annual+)	Publicly Available Report (Annual+)	Newsletter
EWEB	✓	✓	✓	✓
SUB	✓	—	—	✓
EPUD	✓	✓	—	✓
Central Lincoln PUD	—	✓	—	—
Lane Electric	—	—	✓	✓
Pacific Power	—	—	—	—
Blachly-Lane	—	✓[1]	✓	—

4.1.3 Gaps and Opportunities

Lane County utilities, on average, offer low rates compared to both the state and national averages (see ***Figure 21***). That said, they and their customers still face many of the same cost pressures as other utilities within the region and nation. Lane County utilities implement many of the recommended best practices for maintaining financial health; however, there are opportunities for improvement. Continuation and improvement of these practices may be better achieved in the near term through:

Planning Support for smaller utilities for strategic and/or capital planning efforts

Rate design studies that explore options for meeting utility goals

Increased accessibility of utility planning documents

[1] Note that Blachly-Lane audits are available to customers upon request.

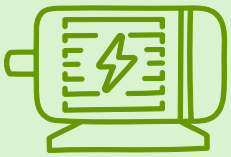
4.2 Serving Changing Electric Load

The distribution utility needs to make sure that the combination of loads and generation on their grid does not damage any of their equipment, cause outages, or lead to excess costs for their customers. As we have discussed, imbalances of load and generation can cause problems for the grid. However, there are other constraints as well. ***Figure 42*** outlines the three types of load constraints, their technological origins, and the ways that they are typically dealt with.

What aspects of the electric grid can limit load growth or new generation?

Building new homes, businesses, or electricity generation changes the way power flows on the grid. Limitations of one or more components can make adding to the grid difficult. Below are reasons why your utility might limit new construction.

1. The amount of load and generation need to match



There must be enough total generation to exactly match total load every minute of every day.

If the load and generation don't match, it **could harm the generators** and **cause outages** for customers.

It is the job of bulk (transmission) **grid planners** to predict loads in the long term and make sure that there is **enough generation to serve loads**.
Planning horizons typically look out 20 years or more and involve the construction of new electric generation

2. Grid components can only handle certain voltages



The voltage drop along lines that are **too long** or have **too much load** can lead to low **voltage issues** at the end of a line, far from the generation or substation.

Conversely, **too much generation** on a distribution line, such as generation from solar panels, can cause over-voltage.

Distribution utilities can manage voltage issues by adding **a range of different components**, such as capacitor banks, or by replacing the line.
Due to the wide range of potential solutions, voltage issues are generally the easiest and least expensive to resolve. For that reason, the planning horizon for these issues can be as little as months to a few years in the future.

3. Grid components are limited by temperature



Every piece of equipment, including transformers, wires, fuses, circuit breakers, and more, has a temperature rating.

Thermal issues arise when **too much current** passes through a piece of equipment and causes it to get **too hot**. The temperature can physically damage the equipment.

Fixing thermal issues typically requires **utilities** to **replace the piece of equipment** or add new substations or lines. These actions can be expensive, so it is best to plan ahead to avoid placing too much load on a component.
Planning horizons for these issues tend to be 1 -10 year.

Figure 42: Types of Physical Constraints on the Electric Grid that can Limit Load Growth

Of the distribution utilities that were interviewed in the early stages of this work (see ***Appendix A***), only one expressed concern about serving load growth within their service territory, while another noted that they do not have general capacity concerns, but are worried about their ability to serve step function industrial growth. "Step function" refers to a significant increase in load all at once, as opposed to steady load growth over time. ***Figure 43*** gives examples of customer actions that might result in gradual/steady changes to load, small steps, and large steps.

Gradual	Small Step	Large Step
•Home efficiency improvements •Energy conservation efforts •Small changes in household consumption habits, such as appliances •Population growth	•Electric vehicle chargers •Heating electrification •Rooftop/ residential solar	•New industrial developments •New housing developments •New commerical developments

Figure 43: Examples of Gradual, Small Step, and Large Step Load Growth

Gradual changes come from trends in habits at the household level, like adoption of home efficiency measures, efforts to save energy, and the adoption of different appliances such as replacing a gas stove with an electric one. They also come from population trends—more occupied houses lead to more electricity use. Utilities can track gradual trends using year-to-year data. Those trends can help them to predict when usage might approach a threshold for their system. They can use those predictions in capital planning (see ***Section 4.1)***

Small step changes in load might be the least predictable, depending on utility policies (for instance, if a utility doesn't require customers to inform the utility of the customer's adoption of an electric vehicle charger or heat pump). The size of the change in load is small, meaning that it is likely to only pose challenges for utility assets that are nearer to the end user, such as transformers, unless an asset is already near capacity.

Large step changes are predictable in the short term, in that new developments go through long planning processes, so they are unlikely to come as a surprise to utilities. However, large step changes are harder to predict long-term, as they are usually brought on by singular events rather than long-term trends. For instance, the sale of a property might initiate industrial development, or the election of new city councilors might inspire the reinvigoration of a commercial district. These are the sorts of changes to load growth that might require substantial investment in or planning of grid infrastructure.

In the case of step changes (large or small) to load, any upgrades to the distribution grid needed to serve that load are paid for according to the policies in place by the utility. The costs could fall on the customer, the utility (and therefore passed on to utility customers), government subsidies, or a combination thereof.

This section reports potential indicators of changes to load within Lane County and overviews the best practices for distribution utilities preparing for changing loads. Examples of how Lane

County utilities are moving toward adoption of best practices are presented, and opportunities for improvement are identified.

4.2.1 Indications of Changing Load in Lane County

Table 16, ***Table 17***, and ***Table 18*** indicate which cities in Lane County have goals, strategies, or published plans related to different factors that could lead to changes in load. The information in these tables is from published plans from each city (***Appendix B***). It is important to note that the date of creation of these plans varies widely, engagement associated with their creation varies, and cities use the plans in different ways. Whether or not a certain strategy is found in these plans should not be interpreted as a firm indicator of community interest or action.

The tables indicate whether a strategy will increase or decrease load, and the extent to which the city is pursuing the strategy using the following key:

↓↓ = actively pursuing strategies that will decrease load

↓ = assuming, predicting, or passively mentioning strategies that will decrease load

0 = not mentioned

↑ = assuming, predicting, or passively mentioning strategies that will increase loads

↑↑ = actively pursuing strategies that will increase loads

For example, "↓↓" is used for energy efficiency if a city wrote about a strategy for energy efficiency that they are actively pursuing. If, instead, the city only mentions energy efficiency as a possible strategy or predicts that their residents would adopt certain energy efficiency measures, "↓" is used.

Gradual Changes

Table 16 shows which communities have plans that could result in gradual changes in load. Lowell, Eugene, and Florence have energy efficiency strategies, and all cities include energy conservation in their plans, with Coburg, Cottage Grove, Creswell, Eugene, Junction City, Lowell, Oakridge, Springfield, and Westfir having specific goals or strategies. It is notable that energy conservation is Goal 13 of statewide planning goals, and many cities model their Comprehensive Plans off the statewide plan.[1] Conservation measures vary, but include things like encouraging pedestrian and bike paths, public transit, energy efficient land use planning, and waste management. Veneta and Lowell are actively trying to draw in new residents, while Coburg, Creswell, Eugene, Florence, and Springfield acknowledge population growth is likely.

[1] Oregon Planning Goal 13: Energy Conservation. Department of Land Conservation and Development. OAR 660-015-0000(13) https://www.oregon.gov/lcd/op/pages/goal-13.aspx

Table 16: Pursuit of Strategies Related to Gradual Changes in Load, by City

	Energy Efficiency	Energy Conservation	Population Growth
Coburg	↓	↓↓	↑
Cottage Grove	0	↓↓	0
Creswell	0	↓↓	↑
Dunes City	0	↓	0
Eugene	↓↓	↓↓	↑
Florence	↓↓	↓	↑
Junction City	0	↓↓	0
Lowell	↓↓	↓↓	↑↑
Oakridge	0	↓↓	0
Springfield	↓	↓↓	↑
Veneta	0	↓	↑↑
Westfir	0	↓↓	0

Small Step Changes

Table 17 shows which communities have plans that could result in small step changes in load. For small step loads, Eugene is the only city actively pursuing strategies to increase electric vehicle adoption. Junction City notes that though the use of electric home heating is popular in the region, their residents are switching to natural gas. It is notable that the most recent update to the Junction City Comprehensive Plan is from 2010. Overall, home heating electrification is not commonly mentioned in city plans.

Most cities mention the possibility of exploring distributed solar options, but Cottage Grove, Eugene, and Junction City are the only three actively pursuing solar as part of a broader strategy. Cottage Grove's Strategy 19 in their Vision and Action Plan is "Be a leader in the development, adoption and utilization of clean, alternative energy sources and water resources." They call out plans to investigate solar power potential at their wastewater treatment plant, and they aim to "establish a policy to incentivize the use of solar panels for at least some percentage of new homes' and new commercial and public buildings' power source."

Eugene's 2010 Community Climate and Energy Action Plan calls for expanding local renewable energy, as does their 2017 Comprehensive Plan. Junction City's 2013 Comprehensive Plan discusses "presently exploring the economic feasibility of using a solar collection system to heat water used in the community swimming pool."—although that section of the plan was last updated in 2010. They also encourage the use of solar water heating in homes. This is not the same as distributed solar electricity production through photovoltaic solar panels, but it would reduce electric demand from water heaters. Most cities at least mention solar potential. While distributed solar could pose some challenges for the grid (discussed in ***Sub-Section 4.4.2***), in the context of load growth, installations would result in decreases.

Table 17: Pursuit of Strategies Related to Small Step Changes in Load, by City

	Vehicle Electrification	Home Heating Electrification	Distributed Solar
Coburg	0	0	↓
Cottage Grove	0	0	↓↓
Creswell	↑	0	↓
Dunes City	0	0	↓
Eugene	↑↑	0	↓↓
Florence	0	0	↓
Junction City	0	↓	↓↓
Lowell	0	↑	↓
Oakridge	0	0	↓
Springfield	↑	0	↓
Veneta	↑	0	0
Westfir	0	0	0

Large Step Changes

Table 18 shows which communities have plans that could result in large step changes in load. Large step changes are popular in city plans. Cottage Grove, Dunes City, Florence, and Westfir are the only cities with specific growth goals and associated action plans for only two of the three forms of growth: industrial, housing, or commercial growth. All cities at least mention commercial growth in their plans. Eugene, Creswell, Junction City, and Springfield are actively pursuing industrial, housing, and commercial growth. Coburg, Eugene, Lowell, and Veneta are predicting or actively pursuing growth in all three categories as well.

Table 18: Pursuit of Strategies Related to Large Step Changes in Load, by City

	Industrial Growth	Housing Growth	Commercial Growth
Coburg	↑	↑	↑↑
Cottage Grove	↑	0	↑
Creswell	↑↑	↑↑	↑↑
Dunes City	0	↑	↑
Eugene	↑	↑	↑↑
Florence	0	↑↑	↑↑
Junction City	↑↑	↑↑	↑↑
Lowell	↑	↑↑	↑
Oakridge	0	↑↑	↑↑
Springfield	↑↑	↑↑	↑↑
Veneta	↑↑	↑	↑↑
Westfir	↑	0	↑

Historic Trends

Another way to see indicators of electricity use within Lane County is in the historic trends of electricity sales. ***Figure 44*** shows a plot of the annual electricity sales for Lane County's utilities. Also note that the y-axis is in log scale. Most of the utilities have not experienced significant load growth in the past 20 years. Some have even experienced decreases.

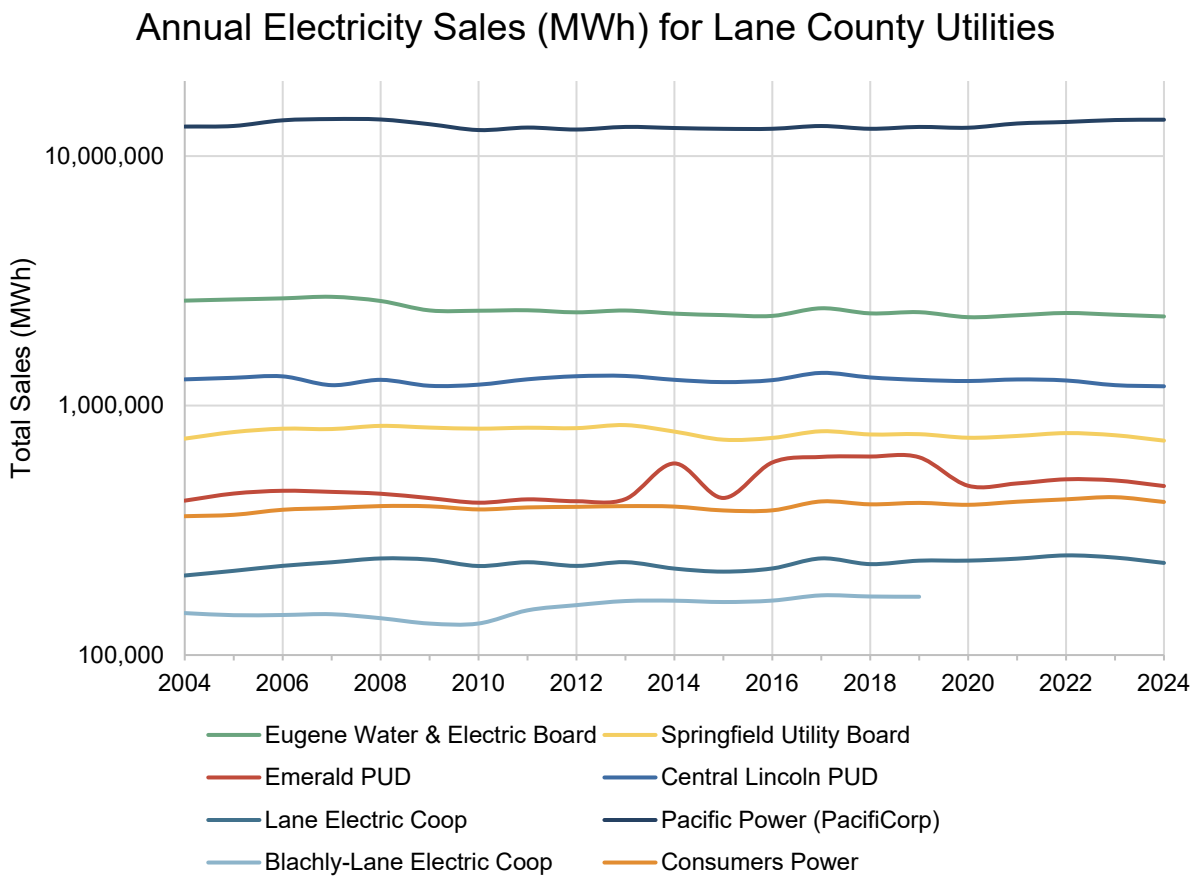


Figure 44: Annual Electricity Sales for Lane County Utilities, 2004–2024[1]

Due to the introduction of distributed energy resources such as residential solar or battery storage and the electrification of vehicles and heating systems, utilities are challenged to manage uncertainty in the size, location, and timing of future loads. In the Willamette Valley, higher temperature extremes in the summer and milder winters with occasional extreme winter weather events are leading to changes in heating and cooling patterns. Some Lane County utilities are beginning to see their highest loads (peak loads) in summer rather than in winter. Winter peaks have been historically typical. The uncertainties around electric load call for more innovative, dynamic, and cost-effective solutions for future capacity needs.[2] The local uncertainty is reflective of the broader regional uncertainty discussed in Section 3.3.

[1] Data from Energy Information Administration Form EIA-861 https://www.eia.gov/electricity/data/eia861/ Blachly-Lane Electric Co-Op only provided data through 2019.
[2] J. Keen *et al.*, "Distribution Capacity Expansion Planning: Current Practice, Opportunities, and Decision Support," NREL/TP-6A40-83892, 1898008, MainId:84665, Nov. 2022. doi: 10.2172/1898008

Ultimately, future loads depend on actions taken within Lane County at individual, community, and county levels, and depend on how people choose to use and regulate energy. The data presented here suggests that there may not be a pressing need to serve significant load growth. However, cities have many goals related to industrial, housing, and commercial growth. Achieving these goals could result in large step changes in load on specific parts of the grid. Additional data collection to estimate future loads is beyond the scope of this Handbook. ***Section 4.2.2*** discusses the ways in which geographically specific load forecasts are becoming more important for utilities.

4.2.2 Best Practices for Serving Changing Loads

The best practices for distribution utilities to serve changing loads are evolving as the situations that drive changes in load evolve. ***Figure 45*** is from a publication that describes existing practices, gaps, and opportunities in distribution grid planning, and shows the "existing" framework for distribution system planning alongside their proposed "future" framework.[1] There are several key differences between the frameworks that indicate gaps in existing utility practice. The "future" framework highlights how best practices can evolve to fill those gaps.

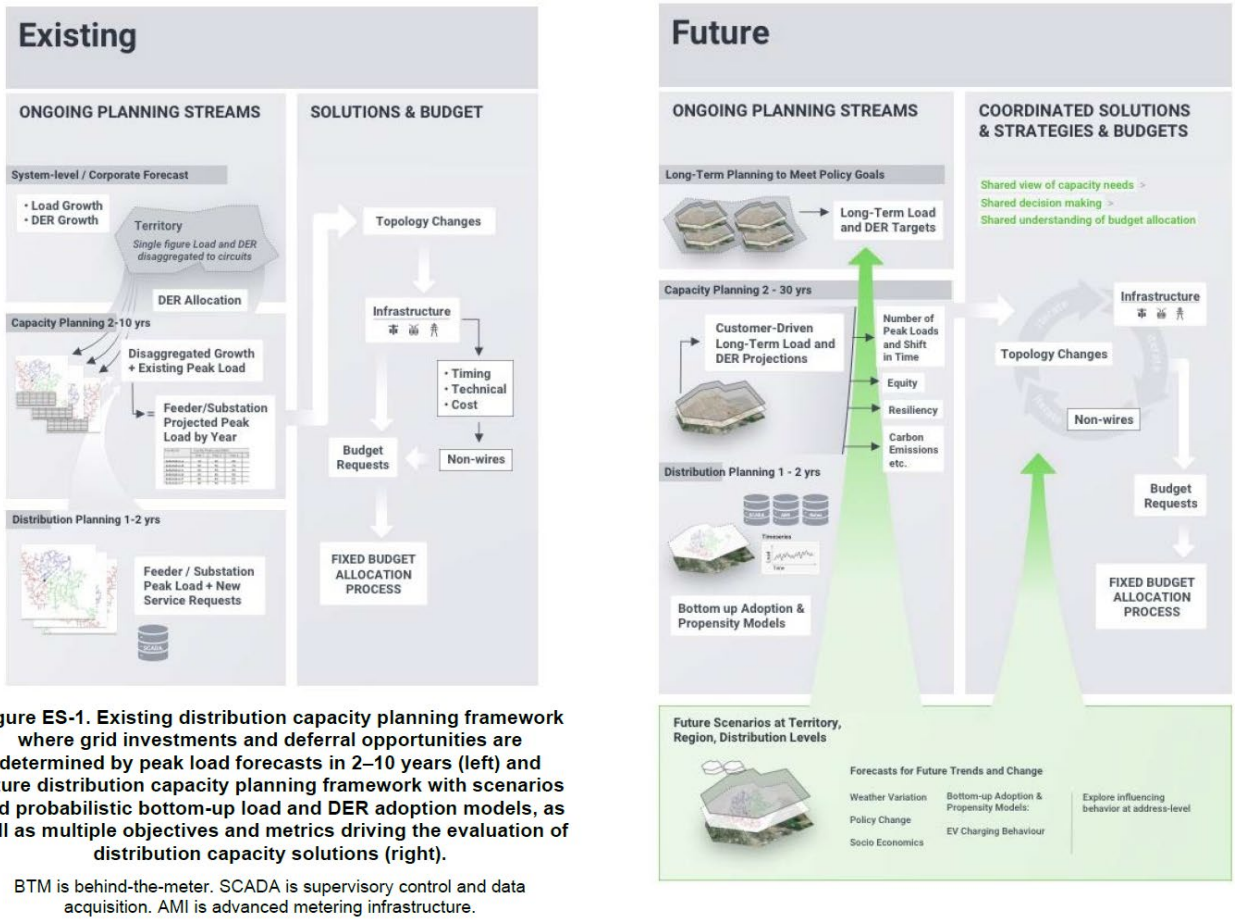


Figure ES-1. Existing distribution capacity planning framework where grid investments and deferral opportunities are determined by peak load forecasts in 2–10 years (left) and future distribution capacity planning framework with scenarios and probabilistic bottom-up load and DER adoption models, as well as multiple objectives and metrics driving the evaluation of distribution capacity solutions (right).

BTM is behind-the-meter. SCADA is supervisory control and data acquisition. AMI is advanced metering infrastructure.

Figure 45: Existing vs. Future Approaches to Distribution System Planning

[1] Image from J. Keen *et al.*, ibid.

The "future" framework for distribution system planning shown in ***Figure 45*** includes best practices related to load forecasting, planning timelines, scenario development, technology integration, and metrics.

Customer-driven, bottom-up load forecasting

Load forecasts are predictions of future loads. The "existing" framework uses system-level load forecasts. This means that the forecasts are typically single-number forecasts for load growth and distributed energy resource (DER) growth, estimated for a utility's entire service territory. System-level load forecasts typically come from long-term trends in customer usage. In the "future" framework, the load forecasts are bottom-up and geospatially granular. This means that the forecasts come from predictions of individual behavior or adoption of technologies by customers within the utility's service territory. Those behavioral changes can give location-specific estimates of load growth. For large step growth, it is important for utilities to work with city planners to stay informed about potential developments.

Longer planning timelines that align with government policies

Planning long-term to meet policy goals set out by local, state, or federal governments help the utilities to align with those government goals. Currently, as discussed in ***Chapter 2***, Oregon's Renewable Portfolio Standards, Clean Energy Targets, and Senate Bill 762 are important policies with which utilities should align their planning. The "future" framework suggests utilities extend capacity planning timelines out from 10 years to 30 years.

Integrated planning and scenario development

The "future" framework outlines a planning approach that is more coordinated between utility departments. The coordination leads to the exploration of solutions and strategies that are topological (related to the way power flows on the grid, dictated by switches and controls), infrastructural, and non-wire (battery energy storage, demand response, or energy efficiency). The introduction of future scenarios to the planning process helps utilities to investigate the impacts of implementing various combinations of these strategies.

Advanced data and technology integration

Integrated data and technology enable a utility to collect data and use that data to guide decision making across departments. For example, in ***Sub-Section 4.1.2***, we show which utilities have AMI systems but note that we do not know if those utilities use the systems for rate design. Beyond rate design, AMI data can be used for distribution capacity planning, although it rarely is.[1] There is a need to ensure that new data collection technologies are paired with data management and decision-making frameworks, so that the data can be utilized. On the flip side, it is important that the decision to adopt new technologies is supported by good data.

Additional metrics to align with stakeholders

Additional metrics of success for distribution planning can lead to decision-making frameworks that reflect the diverse set of stakeholders. Currently, most utilities make decisions that minimize utility capital and operational costs while maintaining ***N-1 circuit-level reliability*** (the ability to remain operational in the instance of a single component failure). In the "future" framework,

[1] J. Keen *et al.*, ibid.

utilities weigh other metrics such as ***hosting capacity***, cost of service and avoided costs, resiliency, equity, energy efficiency, and/or greenhouse gas emissions. Utility governing bodies can direct utilities about what metrics to prioritize. Similarly, they may give the utility guidance about how to prioritize potential projects. For example, EWEB's 2018–2028 strategic plan directs electricity investments to "be managed by prioritizing high-customer impact assets and those systems that increase resiliency to community-critical locations."[1]

4.2.3 Approaches Applied in Lane County

Generally, Lane County utilities implement planning processes closer to the "Existing" process shown in ***Figure 45***. We do not have sufficiently detailed information about utility practices to compare them to the five categories of best practices discussed, though we do highlight a few specific practices.

The utilities that published Integrated Resource Plans (***Table 12***) all engaged in some level of load forecasting, but the depth of their analyses varies. For example, SUB produced a forecast of annual average power demand that extended historical trends,[2] whereas EWEB has undertaken more substantial modeling and analyses to make predictions about total demand, peaks, and suitable resources.[3] For the other utilities, BPA and/or PNGC (a generation and transmission cooperative co-owned by 25 PNW distribution utilities) make forecasts of total annual power delivery to the distribution utilities.[4] The load forecasts being used by Lane County utilities for resource planning do not consider address-level load changes within the distribution system.

As noted in ***Sub-Section 4.1.2***, existing utility plans are on the order of 5-10 years. We cannot speak to individual utilities' scenario development or integration of data and technology. When it comes to integrating metrics of stakeholder interest, we similarly cannot speak to individual utility approaches. That said, at the state level, steps are being taken to add performance metrics. ***Oregon SB 688 – Performance-Based Regulation of Electric Utilities*** (effective January 2026) allows for performance-based regulation of electric companies to better align the electric utility's operations with the public's interests. Performance outcomes of interest include reliability, affordability, renewable energy adoption, and wildfire safety.[5] Avoided cost metrics are applied by all utilities for setting net metering rates (see ***Sub-Section 4.4.2***).

4.2.4 Gaps and Opportunities

Lane County utilities have been serving loads that, for the past two decades, have changed very little. However, changes to loads, both in terms of quantity and timing, are expected in the near future. These changes could be driven by electrification, adoption of distributed energy resources, change to weather patterns, efficiency and conservation efforts, state and federal

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[1] Eugene Water & Electric Board, *"Eugene Water & Electric Board 2018-2028 Strategic Plan,"* https://www.eweb.org/documents/Reports%20and%20Publications/eweb_strategic_plan_2018_2028_2021_2022_2023_2024_update.pdf

[2] Springfield Utility Board, *"SUB 2025 Integrated Resource Plan,"* 2025. https://www.subutil.com/wp-content/uploads/2025-SUB-Integrated-Resource-Plan_FINAL.pdf

[3] Eugene Water & Electric Board, *"Integrated Resource Planning,"* www.eweb.org/projects/energy-supply-planning

[4] PNGC Power, https://www.pngcpower.com/

[5] Oregon Legislative Information, *"2025 Regular Session – SB 688 Enrolled,"* https://olis.oregonlegislature.gov/liz/2025R1/Measures/Overview/SB688

policies, development, and more. Lane County utilities could benefit from exploring evolving best practices, and local and county governments could support the adoption of best practices. Some opportunities for utilities or the organizations who collaborate with or support utilities include:

Countywide load forecasts and a load forecasting approach that can provide bottom-up estimates for each service area.

Planning integration between county, city, or community priorities within a service territory and utility plans, forecasting, and rate design.

Improved grid planning processes for some or all utilities:

- Beginning with utilities that have near-term concerns about serving load growth.
- Creating guidelines for utilities interested in improving grid planning processes that include estimates of costs, workforce needs, technology needs, etc. to build their understanding of the risks and potential benefits of more detailed distribution planning.
- Fostering collaborations between utilities and city planners to keep well informed of potential developments or other step changes to load within a city.
- Support utilities and electric boards in adopting planning metrics such as hosting capacity, cost of service and avoided costs, resiliency, equity, energy efficiency, and/or greenhouse gas emissions.

Evaluation of utilities based on their adoption of best practices for distribution planning and making improvement plans with individual utilities. This would include analysis of how well utility planning aligns with policy timeframes, how utilities perform planning and scenarios development, utility data and technology integration, and utility metric adoption.

Peak load scenarios prediction can help Lane County utilities prepare for peak load situations without requiring full load forecasts.

4.3 Promoting Energy Efficiency, Conservation, and Peak Management

Promoting energy efficiency and conservation are priorities at state and local levels. By some estimates, energy efficiency has the potential to cut U.S. energy use in half.[1] In the Northwest, efficiency measures have been promoted by BPA, utilities, federal and state standards, the Northwest Energy Efficiency Alliance, and the market (people electing to purchase products with higher efficiencies). Whereas ***energy efficiency*** is concerned with using less energy to do the same things, ***energy conservation*** is concerned with replacing habits or practices with less energy intensive ones.

The Northwest Power and Conservation Council tracks "savings" from energy efficiency measures, shown in ***Figure 46***. The Council assumes that energy demand is given (i.e., people would use energy for the same things regardless of whether the efficiency measure was in place) and that cause-and-effect of energy efficiency can be clearly established, both of which are assumptions with meaningful limitations. That said, what ***Figure 46*** makes clear is that utility efficiency programs can have meaningful impacts in terms of electricity use. Today, energy

[1]American Council for an Energy-Efficient Economy, "*Halfway There: Energy Efficiency Can Cut Energy Use and Greenhouse Gas Emissions in Half by 2050."* Sep. 2019. https://www.aceee.org/research-report/u1907

efficiency is increasingly considered an energy resource and a means of avoiding the need to build additional generation.

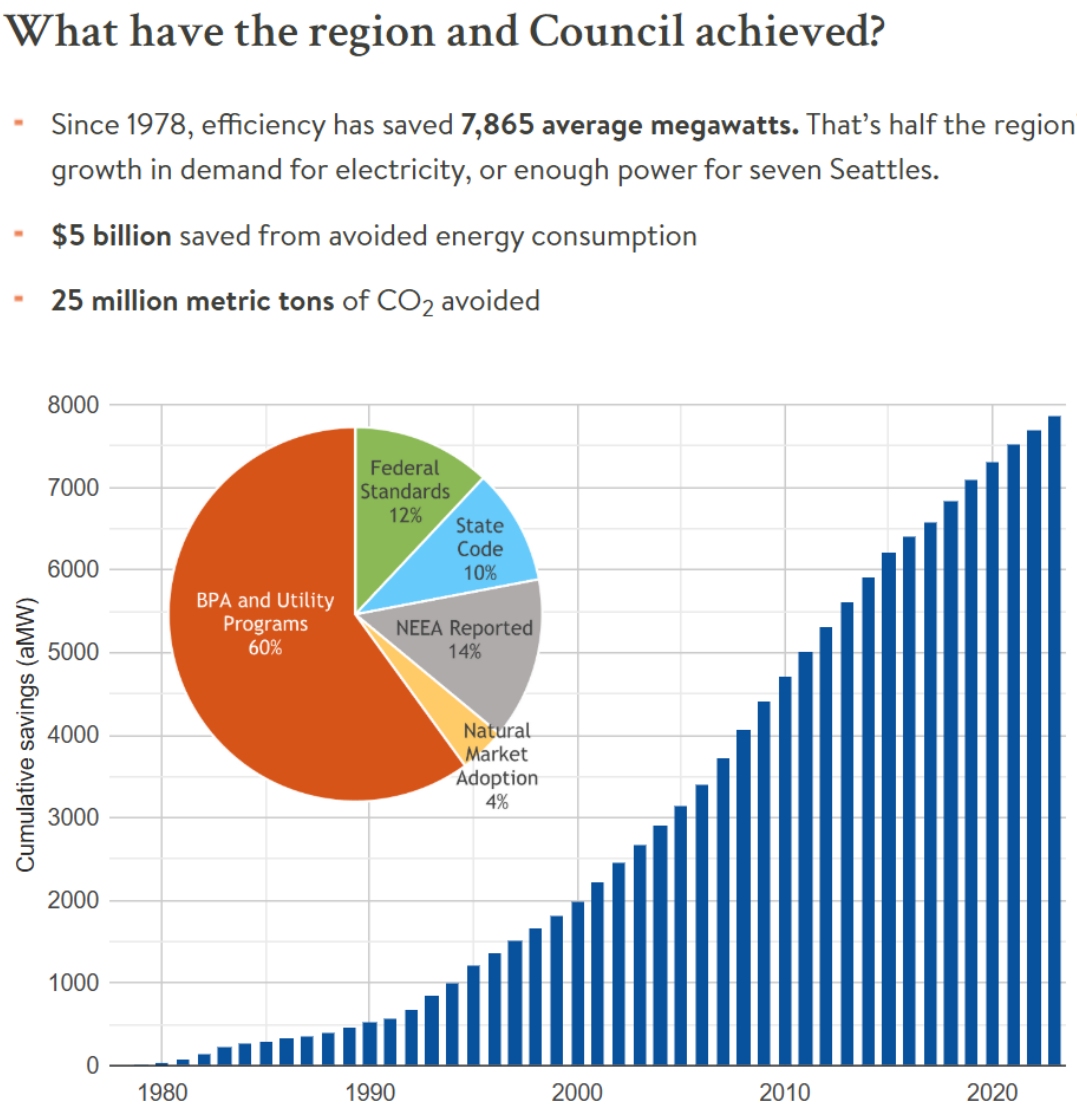


Figure 46: Impacts of Energy Efficiency Programs in the Pacific Northwest[1]

Improving energy efficiency and conservation is not necessarily in the direct interest of the utility. After all, they generate revenue through the sales of electricity. For that reason, federal, state, and local policies have a major influence on what programs utilities might take on. Studies show that national energy efficiency standards lead to hundreds of dollars in savings for the average consumer per year.[2,3] Utility-related policies and programs typically come from the state level.

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[1] Image from Northwest Power and Conservation Council, *"Energy Efficiency,"* https://www.nwcouncil.org/energy/energy-topics/energy-efficiency/

[2] Public Interest Research Group, *Reducing costs across America,* August 25, 2024. https://pirg.org/resources/reducing-costs-across-america/

[3] Andrew deLaski and Joanna Mauer, "Energy-Saving States of America: How Every State Benefits from National Appliance Standards," Feb. 2017.

As a state, Oregon ranks 9th on the American Council for an Energy-Efficient Economy's 2025 State Score Card.[1] This score card ranks states according to the strength of their energy efficiency policies, incentives and standards related to utility programs, construction, and the transportation sector. The study notes that the benefits of energy efficiency programs are "most pronounced where states and utilities have invested in energy efficiency as a resource by factoring efficiency as an integral part of utility energy resource planning and decision making in much the same way as resources such as power plants, wind turbines, and solar panels."

Energy conservation efforts from community or individual perspectives include things like planning bikeable cities and then choosing to walk or bike instead of drive. They deal with questions about how and for what ends humans use energy. In 1974 the State of Oregon Adopted Statewide Planning Goal 13: Energy Conservation.[2] The goal directs: "Land and uses developed on the land shall be managed and controlled so as to maximize the conservation of all forms of energy, based upon sound economic principles."

Utilities might encourage conservation through modern ***peak management*** practices. Historically, utilities responded to peak loads with new transmission or generation capacity. Now, given the suite of distribution side and consumer grid technologies, utilities have options to encourage alternative usage patterns. In this section we discuss best practices for energy efficiency, conservation, and peak management by utilities. We then consider practices applied by utilities in Lane County and future opportunities for improvement.

Why might utilities implement energy efficiency or conservation programs?

A utility might choose to implement programs to reduce energy usage. There are four main motivations for utilities to introduce these programs:

1. The utility has a physical asset on the distribution network that is working at or near capacity (as described in ***Figure 42***). In some cases, implementing demand response programs could reduce peak loads and avoid the need for costly upgrades.
2. The utility wants to avoid buying electricity at high costs from the market. For Lane County's utilities who buy power securely within their Tier 1 allotment, this is an unlikely driver, but for utilities buying substantial amounts of Tier 2 power or buying from the market, reducing customer demand could save money for both the utility and the customers.
3. The utility might want to increase revenues by selling on the market. If customers use less power, a utility with generation assets could have more power available to sell on the market. In most circumstances, utilities can sell on the market at higher rates than they would sell to their customers. Given that many Lane County utilities do not have generation assets, this is an unlikely driver for them.
4. A utility might be required (or incentivized) by federal, state, local, utility commission, or board of director policies to implement demand response or energy efficiency programs.

[1] American Council for an Energy Efficient Economy, *2025 State Energy Scorecard,* Mach 18, 2025. https://www.aceee.org/research-report/u2502

[2] Oregon Planning Department of Land Conservation and Development, "Goal1 13: Energy Conservation," https://www.oregon.gov/lcd/op/pages/goal-13.aspx

4.3.1 Best Practices

Utilities have levers to promote energy efficiency and conservation both within their organization and with their customer base. These include rate structures (see ***Sub-Section 1.5.2*** for rate schedules for Lane County Utilities and ***Section 4.1*** for an introduction to rate design); demand response strategies; formal board policies that promote efficiency; and educational, outreach, or incentive programs.

Rate Structures for Energy Efficiency and Conservation

Of the basic rate structures introduced in ***Sub-Section 1.5.2***, rising block energy charges are the most direct way to penalize high energy use. With rising block rates, the more energy a customer uses in a month, the more they pay for each unit of energy. Demand charges may lead to reductions, but they can be difficult to understand for consumers.[1] Moreover, demand charges are intended to reduce peak demand, so are best aimed at the customers that contribute to peaks. More rate structures are discussed in the next section on demand response.

Demand Response and Peak Management

In ***demand response*** programs, the utility essentially pays customers not to use electricity at certain times, typically during ***peak demand***. Demand Response programs can take several forms, typically categorized as incentive-based or price-based (***Figure 47***). Incentive-based programs offer direct compensation to consumers who join the program and shift their demand. Price-based programs use price signals or tariffs that increase prices when demand is high. These could include demand charges, but unlike normal demand charges, customers typically have a choice about whether they want to participate in demand response programs. ***Table 19*** gives a description of each type of program.

[1] American Public Power Association, *"Peak Load Management Strategies for Public Power,"* https://www.publicpower.org/resource/peak-load-management-strategies-public-power

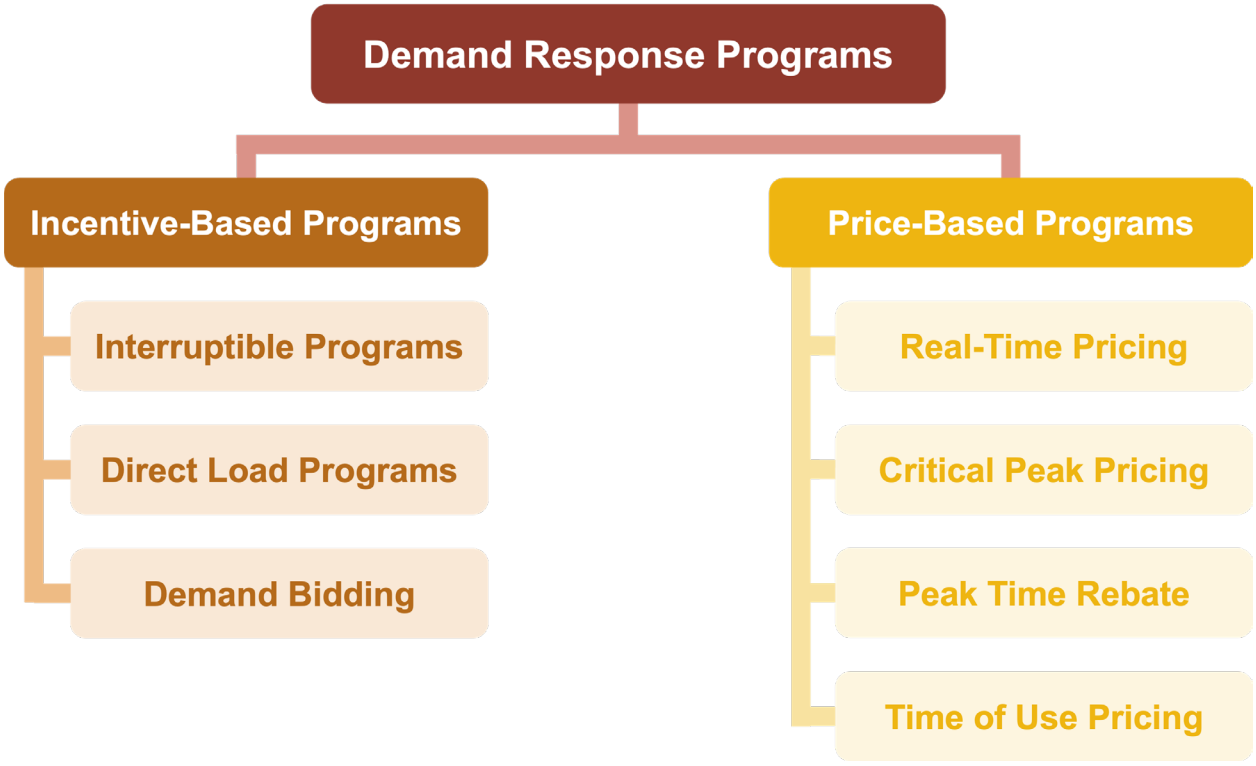


Figure 47: Types of Demand Response Programs[1]

[1] Figure adapted from U. Zafar, S. Bayhan, and A. Sanfilippo, "Home Energy Management System Concepts, Configurations, and Technologies for the Smart Grid," *IEEE Access*, vol. 8, pp. 119271–119286, 2020, doi: 10.1109/ACCESS.2020.3005244.

Table 19: Overview of Demand Response Programs

Program Type	Description	Typical Customer	Technology Requirements (Minimum)
Interruptible Load	Customer agrees to reduce their usage— "shed load"—during instances of high demand. They are compensated for their status as "interruptible loads," regardless of whether they are interrupted during a high-demand event.	Commercial, industrial, and public facilities; typically with at least 100kW of usage that can be powered down on command. Opt-in programs	Minimal—can be done by a grid operator making a phone call. Can also be automated using metering and load control technology
Direct Load	The utility has the direct ability to control customer use, such as demand from appliances. For residential customers, this might mean increasing the temperature on a refrigerator by a few degrees or reducing power to an air conditioning unit. Customers are offered incentives based on participation in program, not based on actual use reductions.	Can be applied to any customer, usually on an opt-in basis	A two-way meter with load control technology
Demand Bidding	Customers "bid" by offering to reduce their usage for a certain price paid by the utility. The utility then pays the customer the agreed upon amount and the customer reduces their demand.	Commercial, industrial, and public facilities; typically with at least 100kW of usage that can be powered down on command. Opt-in programs	Customer meter that can be remotely read by the utility
Real-Time Pricing	The cost of electricity is established on some regular, relatively short interval (e.g. hourly). Usually, off-peak prices are less than regular rates, giving customers that can shift their loads the opportunity to save.	Can be applied to any customer, usually on an opt-in basis	Customer meters that log hourly usage and can be remotely read by the utility, real-time demand tracking from the utility with cost model integration
Critical Peak Pricing	The utility determines times throughout the year when peaks are expected and notifies customers of increased rates during those times. Usually, off-peak prices are less than regular rates, giving customers that can shift their loads the opportunity to save.	Can be applied to any customer, usually on an opt-in basis	Customer meters that log hourly usage
Peak Time Rebate	Utilities establish a baseline energy usage for a customer, and if the customer uses electricity below that baseline during a high-demand event, they are paid a rebate (usually per kWh) by the utility. Usually, customers are notified of a peak event by text, call, or email.	Can be applied to any customer, usually on an opt-in basis	Customer meters that log hourly usage
Time of Use Pricing	The cost of electricity is more for peak times than for off-peak times. The rates and times at which those rates are applied is determined in rate schedule.	Can be applied to any customer rate schedule	Customer meters that log hourly usage

In an interruptible load program, a customer (usually commercial, industrial, or public facilities) agrees to reduce their usage—"shed load"—during instances of high demand (this is usually in non-emergency situations or situations where the distribution utility is required to shed load by BPA as discussed in ***Section 3.2***). These customers are compensated for their status as "interruptible loads," regardless of whether they are interrupted during a high-demand event. Typically, an interruptible load customer has at least 100kW of usage that can be powered down on command. The technology supporting interruptible load programs can be as simple as a telephone (the grid operator calls the customer) or can be a part of an automated metering and load control system. Because of their simplicity, interruptible load programs are the most used demand response programs.

While many of the programs in ***Table 19*** only require advanced metering technologies, they can be made more effective with additional technologies. For example, residential customers might change their behaviors as part of demand response programs, but there are a variety of technologies (like smart thermostats) that can help them.

Beyond technology requirements, demand response programs also vary in the necessary effort to stand up the program. For instance, the demand bidding program requires that there is a real-time market to which customers can bid. On the other hand, time of use pricing can fit easily into a utility's existing rate-setting practice. When choosing a demand response program, a utility weighs the required effort and technology investment against the peak management benefits. The utility can predict potential benefits by modeling scenarios using historic data and various levels of customer participation. They may choose to survey customers to gauge interest in participation before introducing a program.

Demand response programs can lead individual residents or businesses to implement a technique called "peak shaving." ***Peak shaving*** is when the customer reduces their electricity demand on the grid by switching to the use of on-site energy storage or generation systems during periods of peak demand to reduce their electricity costs without having to reduce their usage. Peak shaving is a customer response to demand response programs, not a utility strategy; however, it may be helpful for distribution planning purposes for the utility to be aware of which customers implement peak shaving strategies. Customers without energy storage or generation systems may respond to demand response programs by reducing consumption or moving high-energy activities (like running the dishwasher or charging an EV) to off-peak hours. Utility-owned or operated distributed energy resources can also be used for peak management and are discussed further in ***Section 4.4***.

Formal Board Policies for Energy Efficiency and Conservation

For COUs, the board of directors plays a significant role in determining utility priorities, goals, and direction. Formal board policies prioritizing energy efficiency and/or conservation are a way to steer the utility toward efficiency, conservation, or demand response measures.

Education, Outreach, and Incentives

Customer efficiency incentive programs can take several forms including cash rebates, financing assistance, and/or energy audit programs (***Figure 48***). These incentives might apply to things like smart thermostats, weatherization, electric vehicle chargers, and lighting upgrades.

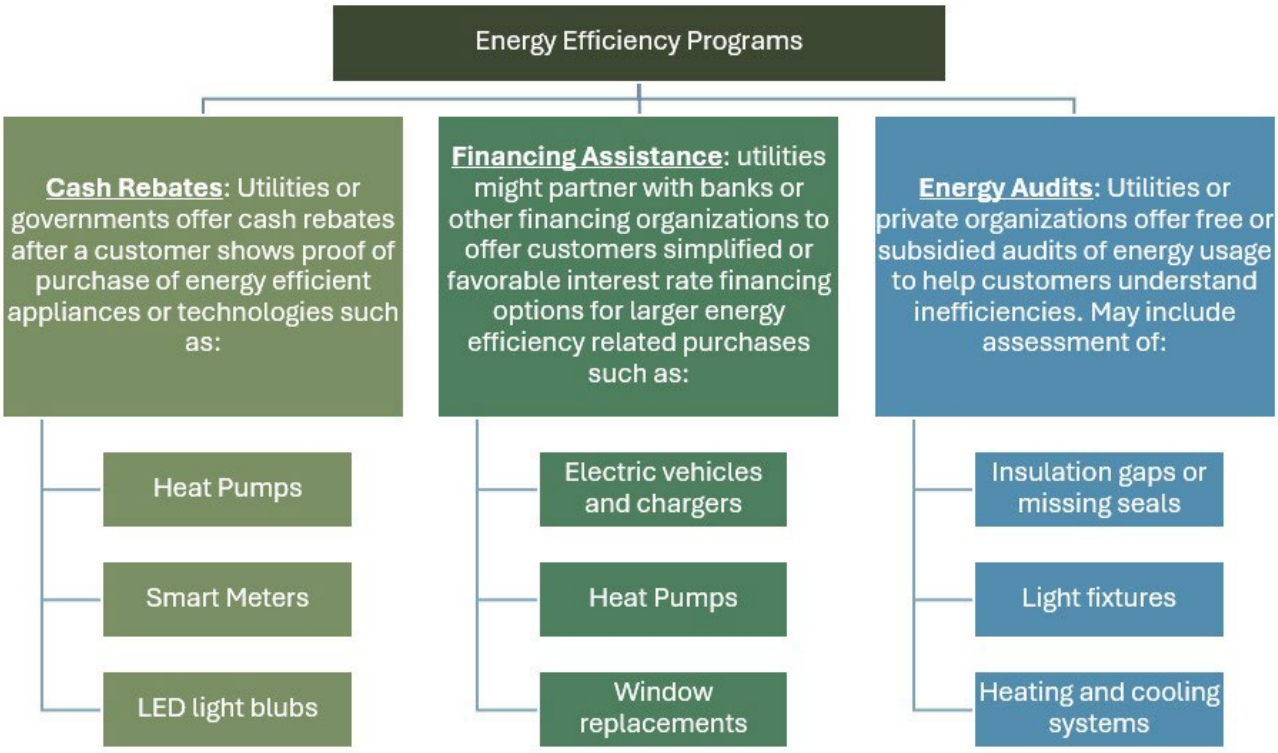


Figure 48: Overview of Energy Efficiency Programs

Utilities, or utility websites, are one of the primary places that many people go for information about electricity. Utilities can supply resources on their websites promoting efficiency and conservation, including informational resources, connections to government programs, and details about utility efficiency programs. They can host educational events and reach their customers via newsletter. In some cases, utilities will provide lists of contractors who install certain equipment or who meet certain energy efficiency standards.

4.3.2 Approaches Applied in Lane County

The ***Northwest Power Act*** requires that the ***Northwest Power and Conservation Council*** prioritizes energy efficiency and conservation in their resource strategy for the Pacific Northwest, BPA, the Northwest Energy Efficiency Alliance, and the Energy Trust of Oregon are all organizations working to meet the Northwest Power and Conservation Council's energy efficiency targets. BPA funds energy efficiency programs for their preferred customers through the Energy Smart Reserved Power Program, and the Energy Trust of Oregon funds programs for customers of the state's IOUs. A list of available incentives can be found online on the Oregon Department of Energy's ***Energy Hub for Incentives Programs + Projects in Oregon***.[1]

In Lane County, peak management through demand response and energy efficiency strategies could be impactful for utilities with Load Following product contracts with BPA (SUB, Central Lincoln PUD, Lane Electric, Blachly-Lane, and in 2028 EPUD) and utilities that are using electricity beyond their Tier 1 allotment (EWEB and EPUD). Given that Load Following contracts include demand charges, reducing peak demand can decrease those demand charges. That said, implementing programs may prove more costly than the charges. For utilities beyond their

[1] Oregon Department of Energy, *"Incentive Finder,"* https://incentives.oregon.gov

Tier 1 allotment, power provided during peak demand comes at a higher cost (Tier 2 or market rate) than base Tier 1 power. In these cases, if peak management strategies can be implemented at a lower cost per kWh than Tier 2 or market rates, they stand to save the utility and their customers money. For all utilities, regardless of their BPA contracts, peak management and energy efficiency programs have the potential to decrease consumption in ways that reduce or defer the need for infrastructure upgrades, but fully understanding that possibility requires detailed, spatially resolved information about loads and individual grid component capacities.

Table 20 shows which Lane County utilities offer energy efficiency related programs/ services. Lane County utilities ubiquitously offer education and outreach, customer connections to external incentives, and internal incentive programs (some supported by BPA). Though only EWEB, SUB, and EPUD have easy-to-access customer energy audit programs on their websites, there are other programs in Oregon that offer the service. Pacific Power doesn't offer audits specifically, but customers can access detailed records of their own energy use online. Those records come with customized tips for energy savings. Pacific Power is the only Lane County utility that offers demand response programs, with commercial and industrial incentives programs and voluntary time-of-use programs for residential customers. In their strategic plans, EWEB, SUB, and EPUD mention that, to meet future goals, they want to explore options related to demand response. EWEB recently completed a Demand Side Potential Assessment, looking at conservation potential, demand response potential, electrification potential and solar PV potential[1].

Table 20: Energy Efficiency Actions Implemented by Lane County Utilities
✓ indicates the utility currently offers or implements the action/program and — indicates the action/program was not identified or is not currently offered.

	Efficiency as a board policy or prominent strategy	Education and outreach	Connect customers to external incentives	Internal incentives programs	Customer energy audits	Demand Response
EWEB	✓	✓	✓	✓	✓	—
SUB	✓	✓	✓	✓	✓	—
EPUD	✓	✓	✓	✓	✓	—
Central Lincoln PUD	—	✓	✓	✓	—	—
Lane Electric	—	✓	✓	✓	—	—
Pacific Power	—	✓	✓	✓	—	✓
Blachly-Lane	—	✓	✓	✓	—	—

[1] Eugene Water & Electric Board, *"EWEB Climate Guidebook."* https://www.eweb.org/climate-guidebook

EWEB, SUB and EPUD include energy efficiency as a stated central aim in either their board policy (SUB, EWEB) or strategic plan (EPUD). SUB's Board Policy Manual encourages rate design modifications to promote energy efficiency and "encourages staff to pursue actions that encourage energy efficiency where practicable—including, but not limited to, offering home energy audits, publicizing the financial and environmental benefits associated with making home energy efficiency improvements, and educating homeowners about all existing federal and state incentives, including the availability of low-cost loans, that make energy efficiency improvements more affordable." SUB already implements seasonal rising block charges (***Table 6***), and that costs are different in summer vs. winter. Lane Electric and Blachly-Lane also implement rising block energy charges.

EPUD's strategic plan discusses their previous demand response pilots, through which they determined that despite the potential savings, the costs for rolling out the programs and for retrofitting homes were too large to offer the program permanently.[1] Nevertheless, their strategic plan acknowledges the need to further explore incentives, time-of-use rates, and other demand management options.

4.3.3 Gaps and Opportunities

For Lane County's COUs, there are numerous opportunities to investigate energy efficiency, conservation, and demand management strategies, especially with the utilities who have documented their interest (EWEB, SUB, EPUD).

- ***Rate design studies*** for demand response and energy efficiency program options that model customer response scenarios, energy savings, and utility costs
- ***Assess the potential*** of energy efficiency and conservation across the county, modeling different customer behavior scenarios
- ***Collaborative peak management programs*** could enable multiple utilities to stand up peak management programs while sharing the costs of staff training, customer outreach, and other expenses associated with initiating and running the program
- ***Demand response operational training*** for all the utilities, aimed at helping them to minimize the costs of implementing demand response or other energy efficiency/ conservation programs; and for customers, aimed at helping them to participate in programs and adopt the associated technologies
- ***Educational efforts and surveys*** of Lane County electricity consumers can help utilities to understand their customers' desire to participate in energy efficiency or conservation programs

4.4 Investing in Energy Resilience and Generation

As we have noted in previous sections, Lane County's COUs have priority access to BPA electricity from the federal dam system. This electricity comes at a price that does not necessarily incentivize utilities to build their own generation within the county or buy from any other provider because that power will likely cost more than Tier 1 power. During normal operating conditions, this situation enables Lane County utilities to keep rates relatively low (see ***Sub-Section 1.5.2*** for rates). However, when we consider the resilience of Lane County's

[1] Emerald People's Utility District, *"2020 Strategic Plan,"* Jul. 2020. https://www.epud.org/wp-content/uploads/2020-Strategic-Plan_finalSML.pdf

energy system, the lack of incentives to build out generation compounds the dilemma that challenges all resilience investments: it can be difficult to commit funds today to prepare for potential future disaster events. In ***Chapter 5*** we discuss specific hazards in detail and the best practices for utilities to reduce risk and improve their resilience to those hazards. In this section, we review several general resilience measures that are relevant across all hazard types.

4.4.1 Best Practices

The following best practices for utilities. That said, boosting energy resilience is only the utilities' responsibility. Individuals, governments, organizations, and others also have roles (see ***Chapter 9***). For their part, utilities can work to manage risks to the system, perform customer outreach to understand willingness to pay for resilience investments, track vulnerable populations within their service territories, and support the development of distributed generation.

Risk Management and Hardening

Risk management strategies involve identifying and assessing risk, planning risk mitigations, and communicating risks to the public and relevant stakeholders. Guidance and toolkits for utilities interested in pursuing risk management strategies can be found from the American Public Power Association.[1] Risk management strategies applied to system assets can serve as an input to the distribution system planning discussed in ***Section 4.1***, helping utilities to identify their most at-risk assets and how they can mitigate that risk. Having built a deeper understanding of risk, utilities can take measures to harden infrastructure against those risks (see ***Section 6.1*** for a description of grid hardening strategies).

Customer Outreach

Efforts to build resilience can be costly and might not always provide immediate benefits to customers. For example, undergrounding an electric line reduces the risk that the line is damaged during a storm as well as the risk that the line causes a wildfire. However, the costs of undergrounding a line are typically high, and the benefits to customers during normal operating conditions are minimal. Customer surveys can help utilities gauge how willing the customers are to pay for risk-mitigating investments. Surveys can also serve to inform customers about risks.

Valuing Resilience

Utilities should build frameworks for valuing resilience measures by thinking about long term costs and benefits and the value that customers place on maintaining service, especially in times of extreme weather. While there is not a single framework considered to be the best practice for valuing resilience, it is an active area of research and development.[2] Frameworks for specific technologies or hazard events have been proposed. They include the valuation of resilience during extreme temperature events,[3] the valuation of the resilience benefits provided

[1] American Public Power Association, *Risk Management Toolkit for Public Power Utilities.* https://www.publicpower.org/resource/risk-management-toolkit-public-power-utilities

[2] Poudel, Shiva et al. *A Framework to Design Consumer-Centric Operational Strategies for Resilience Enhancement*, IEEE Transactions on Industry Applications, September 25, 2023/ https://ieeexplore.ieee.org/abstract/document/10262165

[3] "A valuation framework for customers impacted by extreme temperature-related outages," *Appl. Energy*, vol. 368, p. 123450, Aug. 2024, https://doi.org/10.1016/j.apenergy.2024.123450

by different forms of solar PV generation,[1] and the valuation of resilience benefits from utility building retrofit programs.[2] Frameworks for valuing resilience should be locally relevant, built with customer engagement, and transparent.

Customer Vulnerability Tracking and Load Shedding Preparedness

Utilities can help to mitigate the impacts of outages for their customers if they know what customers are especially vulnerable. They should track factors such as who among their customers has a well for water (well pumps require electricity), uses electric medical devices, or has limitations on mobility. They can use that knowledge to prioritize system recovery efforts, connect their most vulnerable customers to further assistance, or prioritize areas of investment in distributed generation, back-up power, or microgrid technologies. Utilities can use these lists to avoid turning off power to vulnerable customers during emergency load shedding events like those described in ***Section 3.2***.

Winter Storm Uri, which hit Texas in 2021, was a real-world demonstration of what the third level of emergency load shedding event could look like. The after-action reporting from the Americal Public Power Association[3] offers some lessons for utilities. The report emphasizes that although load shedding procedures are in place for many utilites, they are rarely used and in need of refinement. Steps such as regularly updating critical infrastructure and customer lists, evaluating potential enhancements to existing load shedding computation and software tools, and performing regular drills, simulations, or table-top exercises can all help a utility be better prepared and reduce impacts on their customers (***Figure 49***).

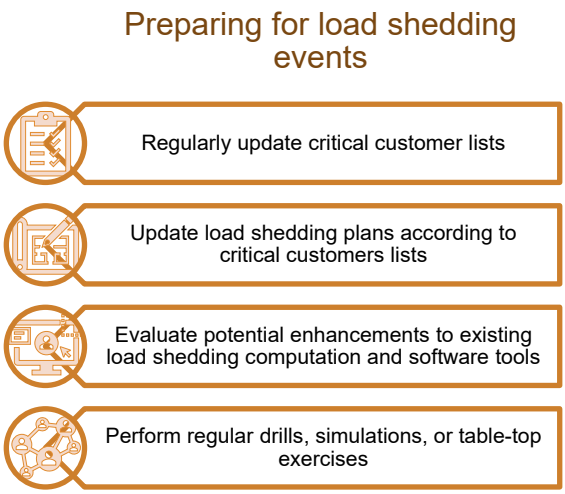


Figure 49: Utility Best Practices to Prepare for Emergency Load Shedding Events[4]

[1] K. Mongird, J. Alam, A. Somani, A. Ifebigh, and D. Roepke-contractor, "Achieving Cooperative Community Equitable Solar Sources (ACCESS) Valuation Report: A Guide for Electric Co-ops," Feb. 2021. ACCESS-Report-PNNL-Valuation-of-Solar-February-2021.pdf

[2] Rohini Srivastava, Amber Wood, and Emily Garfunkel, "Valuing Resilience Benefits in Utility Building Retrofit Programs," American Council for an Energy-Efficient Economy, Mar. 2024. Valuing Resilience Benefits in Utility Building Retrofit Programs | ACEEE

[3] American Public Power Association, *Electric System Load Shedding*, https://www.publicpower.org/system/files/documents/Electric-System-Load-Shedding.pdf

[4] Information from https://www.publicpower.org/system/files/documents/Electric-System-Load-Shedding.pdf

Distributed Energy Resources

The ***National Association of Regulatory Utility Commissioners*** defines a distributed energy resource (DER) as:

> "*a resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load. Examples of different types of distributed energy resources include solar photovoltaic (PV), wind, combined heat and power (CHP), energy storage, demand response (DR), electric vehicles (EVs), microgrids, and energy efficiency (EE).*"[1]

DERs can provide resilience benefits if they are able to operate during an outage. Developers, local governments, private property owners, utilities and other organizations might consider investing in distributed energy resources, but since there are not yet standardized approaches for valuing energy resilience, it can be difficult to determine who covers what costs.[2] Utilities can support DER developments by providing clear net metering and interconnection policies.

Blackstart resources for system resilience

Blackstart resources can restart the power grid after it has experienced a blackout. Blackstart capability can be developed and maintained through investments in specific, usually inverter-based, generation resources that have the capabilities to start without the support of the grid. Microgrids can also serve as a blackstart resources and operate islanded from the rest of the grid during a blackout. Blackstarting the grid is not just a matter of "turning things back on." As the grid comes back online—even just in a local area—the same physical dynamics discussed in ***Section 3.2*** apply. Load and generation must be balanced. Therefore, a system with blackstart capabilities must be able to control the restarting of both generation and the connected loads. Imagine, if you have one small generation source, but hundreds of homes are electrically connected to that source, the source might become quickly overloaded and fail in minutes (or seconds!) after it restarts.

4.4.2 Approaches Applied in Lane County

Risk management, customer outreach, and valuing resilience

In the areas of risk management, customer outreach, and valuing resilience, we are unable to characterize approaches applied by Lane County utilities. That said, in the area of valuing resilience, we know there is an emerging interest among utility and local officials to improve their shared understanding of the value of resilience, as well as that of the residents of Lane County. Lane County utilities have a variety of approaches to risk management documented in

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[1] NARUC Staff Subcommittee on Rate Design, "NARUC Manual Distributed Energy Resources Rate Design and Compensation," The National Association of Regulatory Utility Commissioners, Washington, DC, Nov. 2016. NARUC Manual on Distributed Energy Rate Design and Compensation

[2] W. Rickerson, J. Gillis, and M. Bulkeley, *The value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices*, National Renewable Energy Laboratory, June 2024. https://docs.nlr.gov/docs/fy24osti/90139.pdf

policies,[1] strategic efforts,[2] and hazard specific documents that we discuss in greater detail in ***Chapter 5***. EWEB has published multiple versions of a Climate Guidebook that synthesizes how they expect climate change to impact the resiliency of the utility.[3] EPUD has recently surveyed their customers about their interest in resilience investments.

Customer vulnerability tracking and load shedding preparedness

In the area of customer vulnerability tracking, only one of Lane County's utilities—that we know of given publicly available data sources—actively collects information on residents most vulnerable to outages. EWEB encourages customers who rely on electrically powered medical devices to contact their customer service team to be placed on the utility's Critical Care list.[4] The remaining utilities do not actively track medically vulnerable customers and instead encourage those individuals to prepare for emergencies independently, such as by having a generator or battery backup available.[5] Notably, EWEB and SUB offer a generator loan program to help customers enhance their personal resilience during outages.[6]

Distributed Energy Resources

In the areas of distributed energy resources, we see in ***Figure 68*** that there is a significant amount of residential solar within Lane County. In fact, 6,313.7 MWh of solar energy was generated by residential systems in Lane County in 2022.[7] All Lane County utilities have both net metering and generation interconnection policies. ***Table 21*** shows the maximum allowed size of a residential solar installation (first column). It is mandated by the state that utilities allow residential installations of 25kW AC/ 200kW Nameplate or smaller.[8] Most utilities use that threshold as their maximum, but EPUD allows larger installations.

Table 21 also shows the rates (as of 2026) for net metering and the rates for direct generation. Net metering rates are the rates that the utility pays customers for the excess solar generation that they add to the grid. Direct generation rates are the rates that the utility pays other non-residential distributed solar installations for the power they put onto the grid. The fourth column of ***Table 21*** gives the methodology that the utility uses to set the rates. All utilities use an ***avoided cost methodology*** which is the practice of setting compensation rates based on the cost the utility would have otherwise incurred to generate or purchase that energy from another source. In other words, customers are compensated at the rate the utility "avoids" paying by receiving the customer's solar generation instead of procuring that power itself.

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[1] E.g., "POWER RISK MANAGEMENT POLICY," Emerald People's Utility District, Feb. 2022.
[2] Eugene Water & Electric Board, *"SD20 Annual Enterprise Risk Management (ERM) Update,"* Jul. 2025. https://www.eweb.org/documents/board-meetings/2025/07-08-25/corr_sd20_annual_enterprise_risk_management_update.pdf
[3] Eugene Water & Electric Board, *"EWEB Climate Guidebook,"* Climate Guidebook | EWEB
[4] Eugene Water & Electric Board, "*Common Questions During a Power Outage*," www.eweb.org/outages-and-safety/power-outages/common-questions
[5] Blachly Lane, *"Outage Preparedness,"* https://www.blachlylane.coop/outages-safety/outage-center/outage-preparedness/
[6] Springfield Utility Board, *"Springfield Utility Board Offers Generator Loan Programs to Enhance Customer Resilience,"* Feb. 2025. https://www.subutil.com/news-releases/springfield-utility-board-offers-generator-loan-programs-to-enhance-customer-resilience/ ; https://www.eweb.org/backuppower
[7] Abundant Solar, *"Experience Solar Abundance at Your Home,"* https://www.abundantsolar.com/services/residential-solar/
[8] Oregon Legislative Assembly, "ORS 757.300 – Net metering facility allowed to connect to public utility," 2025. https://oregon.public.law/statutes/ors_757.300

All utilities have programs that allow customers to choose renewable energy. Most programs take the form of a surcharge added to the customer's bill either as a block charge (meaning the customer pays a set rate for a pre-determined block of renewable generation) or as an upcharge per kWh used. The rates are listed in the final column of ***Table 21***.
Central Lincoln PUD has incentives for various types of distributed systems, including battery storage, small hydropower, solar electric, and wind electric. They also started a community solar project in 2019 that allows customers to purchase shares of a shared solar installation rather than installing rooftop panels.[1] Then, each month, participating customers receive bill credits for the solar energy their portion of the solar installation generated. The project was funded in part through grants from the Bonneville Environmental Foundation and the Oregon Department of Energy, which allowed panels to be offered at a fraction of the cost of traditional rooftop installations. The program has since sold out of available panels, however the project features a live dashboard showing the generation from the existing solar panels.[2]

EPUD operates the ***GREEN Grant program***,[3] which is a voluntary customer-funded program that provides up to $40,000 annually for the construction of new renewable energy projects at eligible schools and non-profit organizations within EPUD's service territory. GREEN subscribers vote to select the winning project each year. Past recipients include a 10.78 kW solar array installed on a farm. EWEB has a similar program[4].

[1] Central Lincoln People Utility District, *"Central Lincoln Community Soar Project,"* https://clpud.org/energy-efficiency/renewable-energy-programs/central-lincoln-solar/
[2] Central Lincoln People Utility District, Solar Edge, https://monitoringstg.solaredge.com/mfe/flutter/kiosk/index.html?guid=987ef6fb-c035-425f-b3c4-0adff4e9d781
[3] Emerald People's Utility District, *"Grant Program,"* https://www.epud.org/energy-efficiency/renewable-energy-program/grant-program/
[4] Eugene Water & Electric Board, *"Greenpower Grants"* https://www.eweb.org/environment-and-climate/green-options/greenpower

Table 21: 2026 Lane County Utilities Residential Solar Installation Size, Rates, and Rate-setting Methodology

	Maximum Residential Size	2026 Net Metering Rate	2026 Direct Generation Rate	Rate Setting Methodology	2026 Customer Choice Rate
EWEB[1,2]	25 kW AC	$0.0399/kWh	$0.0634/ kWh	Avoided cost	+$0.01/ kWh or by block
SUB[3]	200 kW Nameplate/ 25kW AC	$0.03493/kWh	Established by PPA	Avoided cost	+$0.0110/kWh
EPUD[4]	75 kW*	Established by Net Metering Agreement	Established by PPA	Avoided cost	+$0.008/kWh
Central Lincoln PUD[5,6,7]	200 kW Nameplate/ 25kW AC	$0.0423/kWh	Established by PPA	Avoided cost, calculated each odd-numbered year	N/A
Lane Electric[8]	30 kW**	$0.0349/kWh**			100kWh block for +$2
Pacific Power[9,10,11]	25 kW AC	$0.0473/kWh (what expired credits are valued at) and $0.14204/kWh (credited monthly)***	N/A	Avoided cost	TOU: on-peak +$0.2053/kWh, off-peak 0.0247/kWh Blue Sky Block: 100 kWh block for +$1.95 Blue Sky Usage: $0.0626/kWh (basic) + $0.013/kWh (wind/solar)
Blachly-Lane[12]	25 kW AC	Between $0.0226 and $0.04983/kWh	N/A	Avoided cost, differing per month	100kWh block for +$2 or 1000kWh block for +$15

* for a single phase inverter, rated capacities increase for larger service types
** The maximum residential size and net metering rate were assumed using the utility's online solar calculator tool options
*** Pacific Power does not pay customers directly for excess solar generation. Instead, excess energy is credited at the full retail rate as a cumulative kilowatt-hour credit applied to future monthly bills. Any unused credits remaining at the end of the annual billing cycle (March) are transferred to Pacific Power's low-income assistance program at the utility's avoided cost rate rather than paid out to the customer.

[1] Oregon Legislative Assembly, "ORS 757.300 – Net metering facility allowed to connect to public utility," 2025. https://oregon.public.law/statutes/ors_757.300
[2] Eugene Water & Electric Board, *"Solar Generation Rates,"* www.eweb.org/environment-and-climate/solar-electric/solar-generation-rates
[3] Springfield Utility Board, *"ECOchoice,"* https://www.subutil.com/conservation/ecochoice/
[4] Emerald People's Utility District, *"Solar Electric Program,"* https://www.epud.org/energy-efficiency/solar-programs/solar-electric-program/
[5] Central Lincoln People Utility District, *"All-Electric Service Rate Schedules,"* Oct. 2025. https://clpud.org/wp-content/uploads/All-Electric-Service-Rate-Schedules-Oct-1-2025.pdf
[6] Central Lincoln People Utility District, *"Net Metered Customers Policy,"* Nov. 2025. https://clpud.org/wp-content/uploads/Net-Metered-Customers-Policy-rev-Nov-2025.pdf
[7] Central Lincoln People Utility District, *"All-Electric Service Rate Schedules,"* Oct. 2025. https://clpud.org/wp-content/uploads/All-Electric-Service-Rate-Schedules-Oct-1-2025.pdf
[8] Lane Electric, *"Rooftop Solar,"* https://www.laneelectric.com/energy-efficiency/renewable-energy/rooftop-solar/
[9] PacifiCorp, *"Private generation,"* https://www.pacificorp.com/energy/private-generation.html
[10] Pacific Power, *"OREGON STANDARD AVOIDED COST RATES,"* Sep. 2025. https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/purpa/Standard_Avoided_Cost_Rates_Avoided_Cost_Purchases_From_Eligible_Qualifying_Facilities.pdf
[11] Pacific Power, *"Oregon Price Summary,"* Apr. 2026. https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/Oregon_Price_Summary.pdf
[12] Blachly Lane *"Electric Rates,"* Apr. 2026. https://www.blachlylane.coop/your-account/electric-rates/

Blackstart resources for system resilience

Currently, none of the generation resources in Lane County (listed in ***Table 9***) can provide blackstart capabilities. This means that, in the event of a regional grid outage (see ***Section 3.3*** for discussion of the likelihood of such an event), none of the generation resources in Lane County would be able to deliver electricity to end users. Because so much of Lane County's electricity comes from outside the county, in the event of a regional outage, the generation sources within Lane County could not come close to meeting the demand within the county. Therefore, the grid would not be able to stay balanced and operating. To be able to use the local generation in the case of an outage, the available generation resources would have to be electrically connected to a limited amount of load (likely critical facilities discussed in ***Section 8.3***). Doing this would require the design of a microgrid that can be islanded from the rest of the grid during an outage.

4.4.3 Gaps and Opportunities

General resilience and local generation efforts are difficult to characterize completely with the available public information, but given that many of these best practices are novel or emerging, there are numerous opportunities to support their implementation.

Risk management evaluations for utilities can enable assessment and improvement of risk management practices. As we will discuss further in ***Section 5.2***, asset-specific risk assessment and mitigation is especially important for minimizing natural hazard risk impacts.

Multi-utility customer outreach campaigns can be more cost effective for utilities who want to assess their customers' willingness to pay for resilience measures.

Value of Resilience Models can quantify and integrate numerous metrics that capture the value of resilience to communities in Lane County. A quantified measure of resilience benefits can then be used by decision makers to decide if the measure is worth its costs.

Critical customer tracking and load shedding plans updated yearly and shared between utilities and the county could help to keep both parties informed of specific vulnerable populations within the county and plans to serve those populations. Utilities and/or external assessors could explore options for integration of load shedding software tools. The county could integrate utilities' load shedding plans into emergency response drills and emergency plans.

Islanded resources and blackstart planning could provide the ability to supply some electricity in the event of a regional outage or other emergency situation using existing generation within the county. We further discuss such planning as it relates to wildfire mitigation and critical facilities in ***Sections 5.2*** and ***8.3***, respectively.

Chapter 5

Utility Hazard Mitigation and Preparedness

Brooke Marten, Tasnima Naoshin, Ian Hermanson, Candace Briggs, and Ali Trueworthy

This chapter discusses the hazard posed by wildfires, earthquakes, winter storms, and physical and cyber security threats. These hazards were selected because of the risk they pose to Lane County utilities and grid reliability. Where possible, hazard probability and intensity are reviewed, and the best utility practices for risk mitigation are outlined. This section begins with an overview of weather monitoring capabilities in Lane County because weather monitoring is critical to natural hazard mitigation.

Risk to any person, population, facility, utility asset, or other entity is a function of hazard and ***vulnerability*** (***Figure 50***). For example, the wildfire risk to a building would be the probability and probable intensity of a fire around the building, multiplied by the building's ***exposure*** and ***susceptibility*** to a fire.



Figure 50: The Defining Factors of Risk[1,2]

[1] Based on J. H. Scott, M. P. Thompson, and D. E. Calkin, "A wildfire risk assessment framework for land and resource management," *Gen Tech Rep RMRS-GTR-315 US Dep. Agric. For. Serv. Rocky Mt. Res. Stn. 83 P*, vol. 315, 2013, doi: 10.2737/rmrs-gtr-315.

[2] Based on Oregon Department of Natural Hazard Department of Land Conservation and Development *"Natural Hazards Mitigation Planning,"* https://www.oregon.gov/lcd/nh/pages/mitigation-planning.aspx

5.1 Weather Monitoring to Prepare for Weather-Related Hazards

Our interviews with Lane County utilities revealed that weather monitoring is increasingly critical, but Lane County's systems are underdeveloped. Utilities recognize gaps in local data coverage and see operational and safety benefits to improving weather and fire modeling capabilities. Frequent extreme weather and wildfire events created concern.

Most Lane County utilities rely on external data sources such as the ***National Oceanic and Atmospheric Administration (NOAA)***, the ***National Weather Service (NWS)*** and the ***Oregon Department of Forestry (ODF)*** for forecasts and warnings. Some utilities depend exclusively on these state and federal systems. Pacific Power and EWEB maintain the most developed internal weather networks (mapped in ***Figure 51***), while some smaller utilities operate basic local sensors mentioned in their wildfire mitigation plans (not mapped in ***Figure 51***).

Figure 51 displays all existing weather monitoring stations in Lane County along with their operators. Wildfire mitigation plans, utility websites and google maps were used to compile a dataset of weather monitoring station locations. There are 19 weather monitoring stations in the County, with eight of those in the Eugene-Springfield metropolitan area. Pacific Power has the most extensive network with nine stations in Lane County.[1] EWEB operates two[2] NWS operates three at the Eugene, Creswell, and Florence airports.[3] Pacific Power and EWEB operate their own weather stations, and some other utilities have low-cost weather sensors placed within their territory. Currently, Pacific Power and EWEB do not share data from those stations with other utilities but have expressed openness to doing so. The University of Oregon weather station is used by the University to prepare for outdoor events[4] and data is available online.

ALERTWest is a situational awareness platform using cameras and sensors for AI wildfire detection.[5] It is used to coordinate wildfire detection across more than 50 agencies in Oregon, including local governments, utilities, and federal land managers.[6] EWEB hosts one camera in the ALERTWest network on their Carmen Smith Hydropower Facility. Data from four ALERTWest stations in Lane County is publicly available. Coverage gaps are especially pronounced in rural and high-risk wildfire zones, leaving limited visibility into localized conditions.[7]

Integration of weather data into operations (e.g. PSPS decisions, predictive modeling) is inconsistent across Lane County utilities. ***Table 22*** summarizes utility monitoring assets and capabilities, as well as data gaps identified through a review of utility wildfire mitigation plans.

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[1] Pacific Power, Weather Awareness System, https://pacificpowerweather.com/?company=Pacific%20Power

[2] Western Weather, *"Eugene Water & Electric Board Weather,"* https://eweb.westernweathergroup.com/

[3] Federal Aviation Administration, National Weather Service, *"ASOS/AWOS Stations Portland-Vancouver Metro NWS Weblinks"* https://cdn.weathertogether.net/wp-content/uploads/sites/36/2022/03/05122201/ASOS-AWOS_Stations_Portland-Vancouver-Metro_NWS-Webinks_Updated-2022-03-05a.pdf?utm

[4] University of Oregon, "UO weather station means timely forecasts for Eugene campus, public," Nov. 2025. https://news.uoregon.edu/content/uo-weather-station-means-timely-forecasts-eugene-campus-public

[5] ALERTWest, https://www.alertwest.org/about

[6] https://ohaz.uoregon.edu/wildfire-cameras/

[7] A. M. Coleman *et al.*, "Current Best Practices on Wildfire Risk Reduction for Electric Transmission and Distribution Systems," Nov. 2025. https://www.pnnl.gov/projects/wildfire-risk-resilience/best-practices

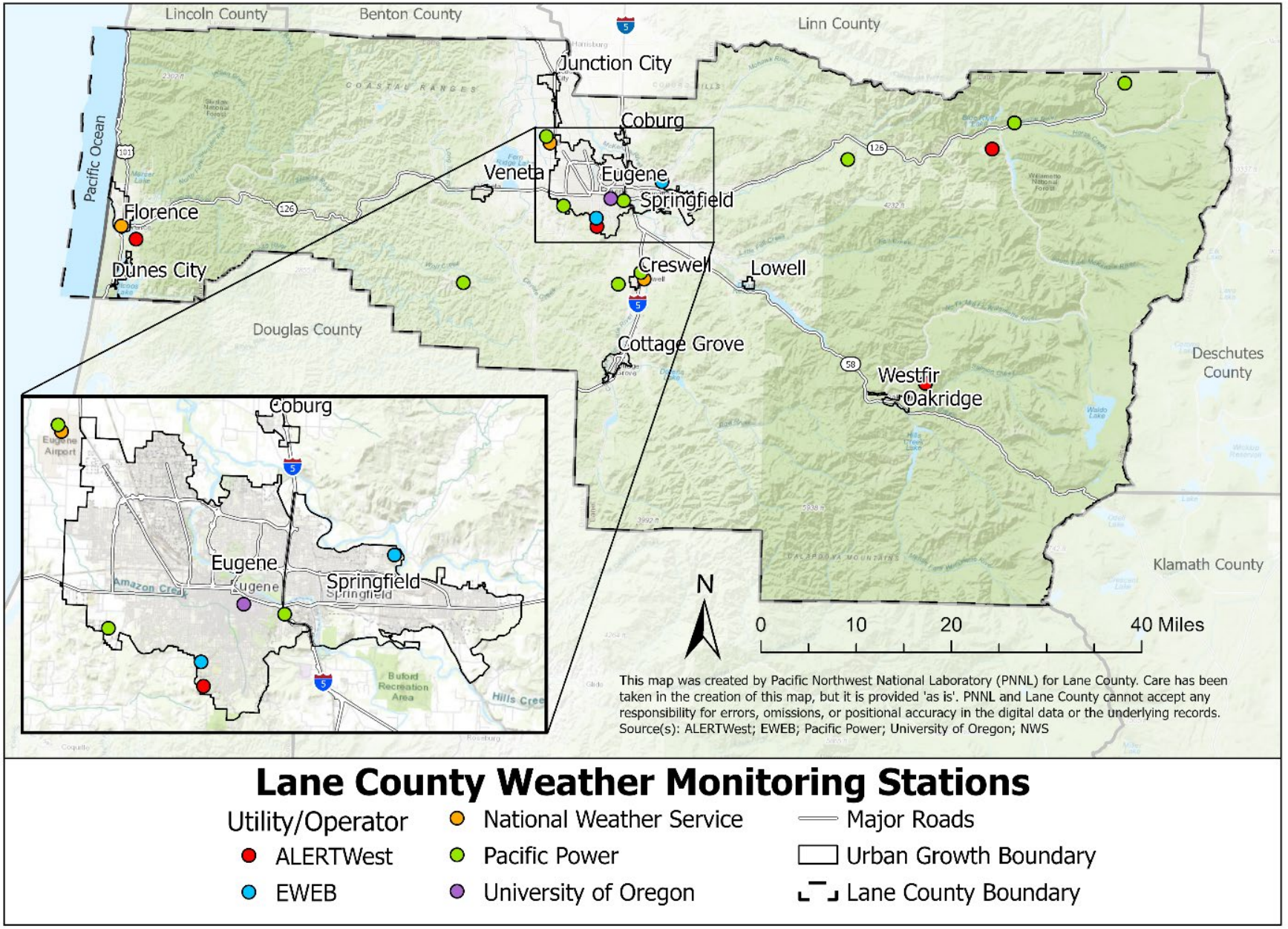


Figure 51: Weather Monitoring Stations in Lane County with Utility or Operator (as of 2026).

Weather monitoring and forecasting serve different purposes. Local weather monitoring can give immediate, local data about conditions on the ground. This data could impact operational decisions such as when and where to send crews or whether to de-energize a specific line (e.g., due to high local winds). Local monitoring data is not typically sophisticated enough to make forecasts but can add granularity to local forecasts. For example, a national forecast might predict the general start time of a storm, while a local asset would provide information about exactly when winds increase. For weather forecasts, utilities rely on larger regional and national networks.

Table 22: Lane County Utility Monitoring Capabilities and Data Sources and Gaps

Utility	Weather Monitoring Assets	Monitoring Capabilities	Primary Forecasting System	Gaps/Limitations
EWEB	2+ in-house weather stations.	Localized forecasting (3-day and extended), AI-based ignition detection, and real-time wind/humidity tracking.	Western Weather (custom forecasting), local and regional NWS stations, ALERTWest network.	Coverage limited to parts of South Eugene and upriver corridor; relies partly on external station data.
SUB	No in-house weather stations.	Uses SCADA alarms and management alerts for operational readiness. Reacts to red flag warnings and local advisories.	NWS/NOAA alerts and local emergency partners.	No local weather data collection; limited automation.
EPUD	No in-house weather stations.	Uses GIS platform integrating evacuation zones and active fires with utility assets. Receives red flag warnings from NOAA.	NOAA/NWS alerts, state/local emergency feeds, ODF evacuation and fire maps.	No proprietary weather sensors or modeling; dependent on external feeds; lacks granular local data.
Central Lincoln PUD	No in-house weather stations	Handheld weather monitoring by field crew for wind & relative humidity during high fire risk. Tracks red flag warnings.	NOAA/NWS and general weather apps/websites.	No permanent sensors or modeling, handheld data is limited to point in time, relies heavily on external forecasts.
Lane Electric[8]	No in-house weather stations.	Has quantitative GIS-based wildfire risk analysis at system, substation, and infrastructure levels.	NWS, ODF, and other utilities/agencies.	No local monitoring capability; reliant on regional forecasts; lacks real-time weather inputs for operations.
Pacific Power	Extensive network of ~100 weather stations: micro, remote, and portable units.	Conducts 10-minute weather observations (temp, humidity, wind speed/direction/gusts). Performs predictive fire and weather modeling.	Internal meteorologist team analyzes internal and NOAA data.	Most advanced in region, though still limited by regional coverage boundaries.
Blachly-Lane	Owns several low-cost weather stations installed at substations.	Tracks temperature, wind speed/direction, humidity, and barometric pressure. Provides local, near-real-time data.	USFS Wildland Fire Assessment System (WFAS), NWS, NOAA Weather & Hazards Viewer, ODF Fire Precaution Levels.	Stations are low-end, limited accuracy; sparse coverage outside substations. Data is not integrated into predictive modeling.

Lane County utilities report a growing urgency to strengthen weather and wildfire monitoring as climate-related hazards intensify. Of these hazards, utilities view wildfires as the highest-impact threat. Utilities generally agree that improved access to real-time, localized data on wind, humidity, and temperature, integrated directly into GIS and operational systems is needed to support power outage management decisions, prevention strategies, and crew safety. Many utilities are exploring improved detection tools—such as AI-based fire cameras, remote sensors, and custom forecasting—and are increasingly collaborating with state agencies, universities, and neighboring utilities to share data and modeling resources. However, most utilities acknowledge that current capabilities are limited or uneven across the region. Utilities have a shared interest in a coordinated regional monitoring framework that expands coverage, enhances predictive capability, and supports long-term system resilience.

5.2 Wildfires

Frequent droughts, changing wind patterns, and rising global temperatures have increased both the frequency and severity of wildfires in the Pacific Northwest. ***Figure 52*** shows annual wildfire counts and acres burned since 2010, revealing a clear upward trend over the past decade. Transmission and distribution-level grid infrastructure can both ignite and be damaged by wildfires, posing significant risks to public safety. While distribution systems cause more wildfire ignitions than transmission systems, transmission infrastructure often ignites more catastrophic fires due to high voltages and remote terrain.[1]

Lane County and utilities have pursued several planning endeavors associated with assessing and mitigating wildfire risk, resulting in the Lane County Natural Hazards Mitigation Plan (NHMP)[2] and the ***Community Wildfire Protection Plan (CWPP)***.[3] Lane County's NHMP identifies both the probability of wildfire in Lane County and Lane County's vulnerability to wildfire to be high. Dry conditions and forested landscapes contribute to the high probability of wildfire. An extensive wildland-urban interface—the area shared by human developments and undeveloped wild lands—is responsible for the high vulnerability. A high wildfire risk can have consequences like home loss, vegetation loss, soil damage, wildlife death, food and habitat loss, and air pollution.

[1] A. M. Coleman *et al.*, *"Current Best Practices on Wildfire Risk Reduction for Electric Transmission and Distribution Systems,"* Nov. 2025. https://www.pnnl.gov/projects/wildfire-risk-resilience/best-practices

[2] Lane County, Oregon, *"Lane County Multi-Jurisdictional Natural Hazard Mitigation Plan,"* Version 4, 2023.https://www.lanecountyor.gov/government/county_departments/emergency_management/planning/mitigation_plan

[3] Lane County, *"Lane County Community Wildfire Protection Plan (CWPP)"* https://www.lanecountyor.gov/cms/One.aspx?portalId=3585881&pageId=4278759



Figure 52: Oregon Number of Wildfires[1] and Acres Burned[1], 2010–2025

Lane County's CWPP includes a wildfire risk assessment and an associated action plan focused on coordination, fuels management, and community education and support. The risk assessment for the CWPP relies on data from the Oregon Wildfire Risk Explorer,[2] which presents information from the 2023 PNW ***Quantitative Wildfire Risk Assessment (QWRA)***, performed by researchers at Oregon State University and the U.S. Forest Service.[3]

The QWRA quantifies "integrated expected wildfire risk" geospatially across Lane County. That risk metric combines the burn probability of a land area along with the presence and susceptibility of transmission lines, substations, and power plants (among other infrastructure). It does not, however, quantify risk to specific utility assets. ***Figure 53*** maps wildfire burn probability as defined by the QWRA as the average annual likelihood of wildfire. The highest burn probabilities are in eastern and southeastern Lane County, with the lowest probabilities of 0% can be seen in the Eugene/Springfield area.

[1] National Interagency Coordination Center, *"National Interagency Coordination Center Wildland Fire Summary and Statistics Annual Report 2025,"* 2025. https://www.nifc.gov/sites/default/files/NICC/2-Predictive%20Services/Intelligence/Annual%20Reports/2025/annual_report_2025_0.pdf

[2] Oregon Explorer, *"Wildfire Risk,"* https://hub.oregonexplorer.info/pages/wildfire

[3] Andy McEvoy, Chris Dunn, and Ian Rickert, *"2023 PNW Quantitative Wildfire Risk Assessment Methods,"* 2023. https://oe.oregonexplorer.info/externalcontent/wildfire/PNW_QWRA_2023Methods.pdf

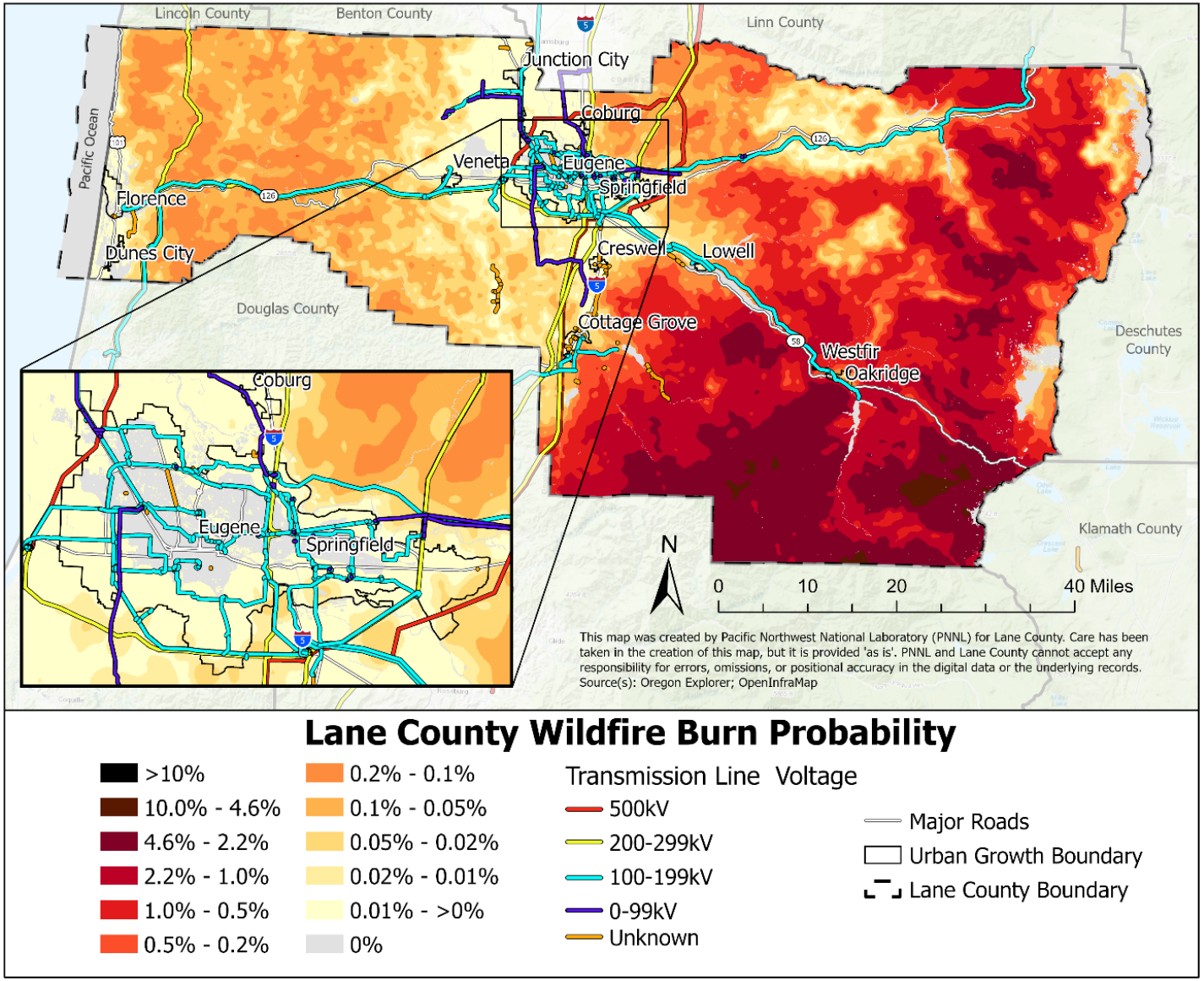


Figure 53: Lane County Wildfire Burn Probability.[1, 2]

[1] Data (as of March 2026) from Open Infrastructure Map, https://openinframap.org/#2/26/12

[2] Data (as of 2023) from Oregon Explorer Natural Resources Digital Library, https://hub.oregonexplorer.info/maps/OSUGISci::oregon-burn-probability-2023/about

We used QWRA's burn probability data to quantify the burn probability by land area for each of Lane County's electric utilities (***Figure 54***). Lane Electric and Pacific Power, utilities with predominantly rural service areas South of Eugene and in East Lane County, have the highest percentages of their territory land with burn probabilities over 1%. SUB has the lowest burn probabilities across their area with nearly 95% of land falling below 0.02% probability.

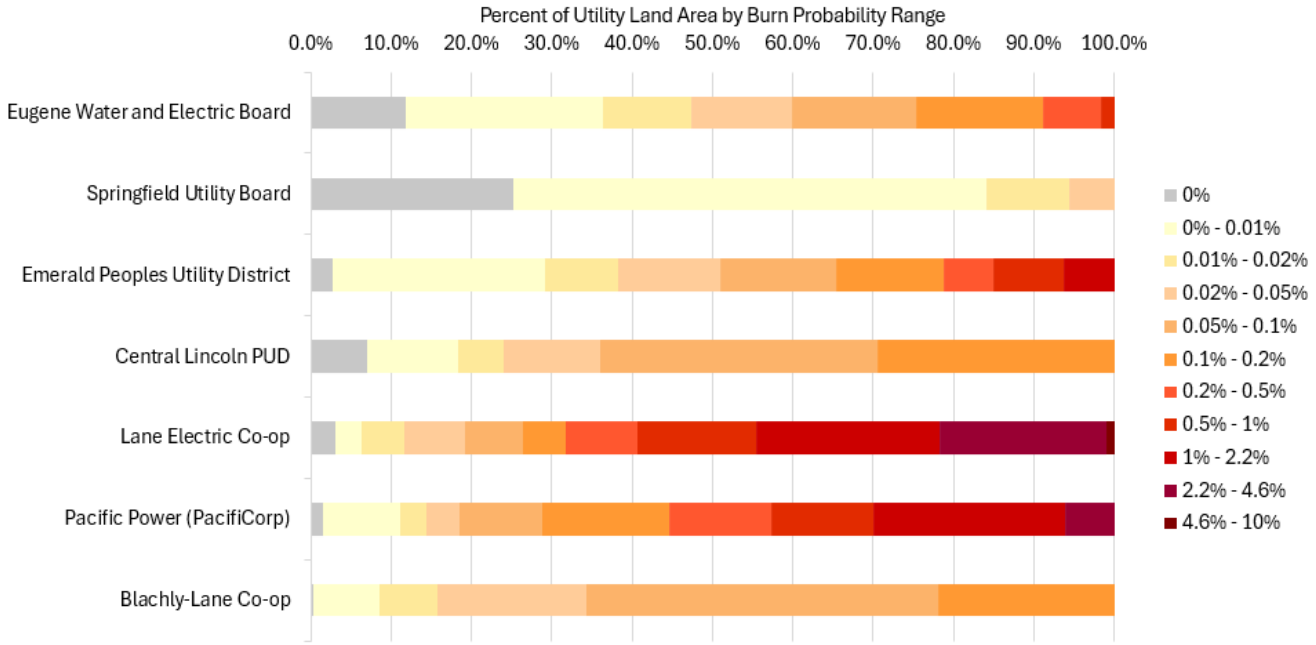


Figure 54: Percent of Utility Land that Falls into Burn Probability Bins[1]
Average Annual Wildfire Likelihood

Regardless of the probability of wildfires within their service territories, Lane County's electric utilities are required to submit ***Wildfire Mitigation Plans (WMPs)*** to the Oregon Public Utilities Commission, as mandated by ***Oregon Senate Bill 762***[2] This bill passed in 2021 following the 2020 Labor Day fires, which were the most destructive wildfires in Oregon's history, and included the Holiday Farm Fire in Lane County. The Holiday Farm Fire burned 173,439 acres on both the North and South sides of Highway 126 and the McKenzie River, caused the death of one person, and devastated the community of Blue River, OR.[3,4]

Although full investigations of the Holiday Farm Fire have not yet been released, news from ongoing litigation (February 2026) highlights the role and potential liability of electric utilities in wildfire scenarios. In a lawsuit claiming negligence of BPA, EWEB, and Lane Electric, evidence presented from the U.S. Forest Investigations indicates that the Holiday Farm Fire ignited in two

[1] Data from Andy McEvoy, Chris Dunn, and Ian Rickert, *"2023 PNW Quantitative Wildfire Risk Assessment Methods,"* 2023.
https://oe.oregonexplorer.info/externalcontent/wildfire/PNW_QWRA_2023Methods.pdf
[2] *Senate Bill 762*. 2021. https://olis.oregonlegislature.gov/liz/2021R1/Measures/Overview/SB762
[3] Courthouse News Service *"Court trims federal immunity in Oregon wildfire suit,"* Feb. 2026.
https://courthousenews.com/court-trims-federal-immunity-in-oregon-wildfire-suit
[4] U.S. Department of Agriculture, *"Holiday Farm Fire,"*
https://www.fs.usda.gov/r06/willamette/fire/info/holiday-farm-fire

separate places: one where a de-energized EWEB line was pushed by a fallen tree into an energized Lane Electric Line and one where a tree fell onto a BPA line, pushing it into ground vegetation.[1] Avoiding utility-caused wildfire ignitions is a top priority for utility wildfire mitigation. That said, utilities also have the responsibility to minimize the damage to their infrastructure from wildfires (regardless of the cause) and to protect their workers during and after wildfire events as they are restoring electricity (see ***Figure 55***). WMPs are plans for meeting these three responsibilities.



Figure 55: Electric Utility Wildfire Risk Mitigation Responsibilities

Senate Bill 762 directed $220 million toward building fire-adapted communities, strengthening emergency response, and reducing fuels on the landscape.[2] Since, Oregon State Fire Marshals have funded numerous risk reduction projects across the state[3] (including Lane County's Community Wildfire Grants[4]), the Oregon Department of Energy has introduced a Resilience Grant Program for utilities,[5] and numerous other funding and legislative efforts have emerged to

[1] J. Adame, Lookout Eugene-Springfield, *"BPA 'willfully spoiled evidence' at ignition site of Holiday Farm Fire, judge says,"* Feb. 2026. https://lookouteugene-springfield.com/story/justice/2026/02/27/bpa-willfully-spoiled-evidence-at-ignition-site-of-holiday-farm-fire-judge-says/

[2] *Senate Bill 762*. 2021. https://olis.oregonlegislature.gov/liz/2021R1/Measures/Overview/SB762

[3] J. Hendricks, "*Protect What We Love"*, Jan. 2024. https://storymaps.arcgis.com/stories/9caebfe159c54fe3a1bd73e09acc68c4

[4] Lane County, *"Community Wildfire Grants,"* https://www.lanecountyor.gov/government/county_departments/public_works/land_management_division/community_wildfire_grants

[5] Oregon Department of Energy, *"Grid Resilience Grant Program,"* https://www.oregon.gov/energy/Incentives/Pages/Grid-Resilience-Grant-Program.aspx

prepare and protect communities from the risks brought on by wildfires. Support for wildfire mitigation is also becoming central to federal legislation and grantmaking. The implementation of the best practices for utilities that we describe below may be supported by these funding sources.

Wildfire mitigation and preparedness add costs for utilities in multiple ways, which can be especially difficult for COUs like those in Lane County. Direct spending on wildfire mitigation currently is ~2-5% of utility capital spending, but the year-over-year spending for wildfire mitigation is growing.[1] Other costs include contributions to state wildfire funds, liability (especially for utility-caused fires) and increased insurance costs, and the increased cost of capital due to the increased risk that utilties face. We discuss best practices for minimizing the impacts of these costs as well.

5.2.1 Best Practices

Science and best practices for utility wildfire mitigation are constantly improving. The best practices we present in this section come from a 2025 publication from Pacific Northwest National Laboratory that draws "from publicly available utility WMPs from the United States and Canada, recent findings from wildfire risk reduction research, and industry engagement."[2] The publication was funded by and created in response to ***Trump Executive Order 14308: Empowering Commonsense Wildfire Prevention and Response***.[3] In their WMP, SUB writes "SUB is aware of the need to act on wildfire risk management planning despite the lack of an industry framework and operational specifics." Their perception of the unsettled state of the science and practice of wildfire mitigation planning is accurate. There are not yet industry standard frameworks or specific best practices. Instead, we have a menu of common practices that can be combined and innovated upon as appropriate for the individual utility (***Figure 56***).

Wildfire risk mitigation and preparedness activities happen before, during, and after a wildfire event, and involve dealing with the additional costs incurred from mitigation and preparedness measures.

Pre-event Mitigations: The pre-event phase begins years before the event, and the activities in this phase may last years. This phase is concerned with anticipating risk (e.g., risk modeling, weather forecasting, inspections, benchmarking), proactively decreasing vulnerability and the probability of utility-caused ignitions (e.g., system hardening, vegetation management, asset management, supply chain management), and increasing preparedness of different human actors (e.g., employee training, multi-entity coordination, customer engagement).

During Event Practices: During a wildfire, utilities first implement their emergency response then move into service restoration. They need to make real-time decisions to minimize public safety impacts, infrastructure damage, and overall risk. Utilities rely on weather monitoring tools, grid data, and system surveliance to rapidly assess conditions. Based on this information, utilities can deploy teams, adjust grid settings, or de-energize specific portions of the power system. A variety of technology and operations options support during-event wildfire response.

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[1] Barlow J.T., Powell D.W., Kincaid J.B., Abernethy-Cannellla K.G., and Boff D.S., "Utility wildfire industry trends review," Pacific Northwest National Laboratory, PNNL-SA211619, 2025.
[2] A. M. Coleman *et al.*, "Current Best Practices on Wildfire Risk Reduction for Electric Transmission and Distribution Systems," Nov. 2025. https://www.pnnl.gov/projects/wildfire-risk-resilience/best-practices
[3] J. Wendel, *NEW PNNL Report Aids Utilities in Preparing for Wildfires,* Pacific Northwest National Laboratory, January 14, 2026. https://www.pnnl.gov/publications/new-pnnl-report-aids-utilities-preparing-wildfires



Figure 56: Best Practices for Utility Resilience to Wildfires[1]

Post-event Recovery: Post-event, utilities focus on inspection, restoration, and recovery to safely restore electricity and improve future system resilience.[1] After-action reporting and emergency preparedness planning are important for making sure that lessons from the event can be internalized and used to improve future responses.

Cost impacts: Ways for mitigating the impacts of the additional costs associated with wildfire damage or mitigations include cost-sharing arrangements, prioritization of measures based on cost and impact, and collaborations with landowners or other utilities.

Figure 57 illustrates the system performance during each phase and the types of activities that occur. ***Figure 56*** lists specific measures that are considered best practices within each phase. Details about each of these measures, including descriptions, applications, risk management benefits, implementation challenges, examples, and potential future directions, are provided in Coleman et al. (2025).[2] ***Chapter 6*** describes many of the specific technologies that can support those measures and activities that are considered best practices within each phase.

[1] Information from A. M. Coleman *et al.*, ibid.
[2] Adapted from A. M. Coleman *et al.*, ibid.

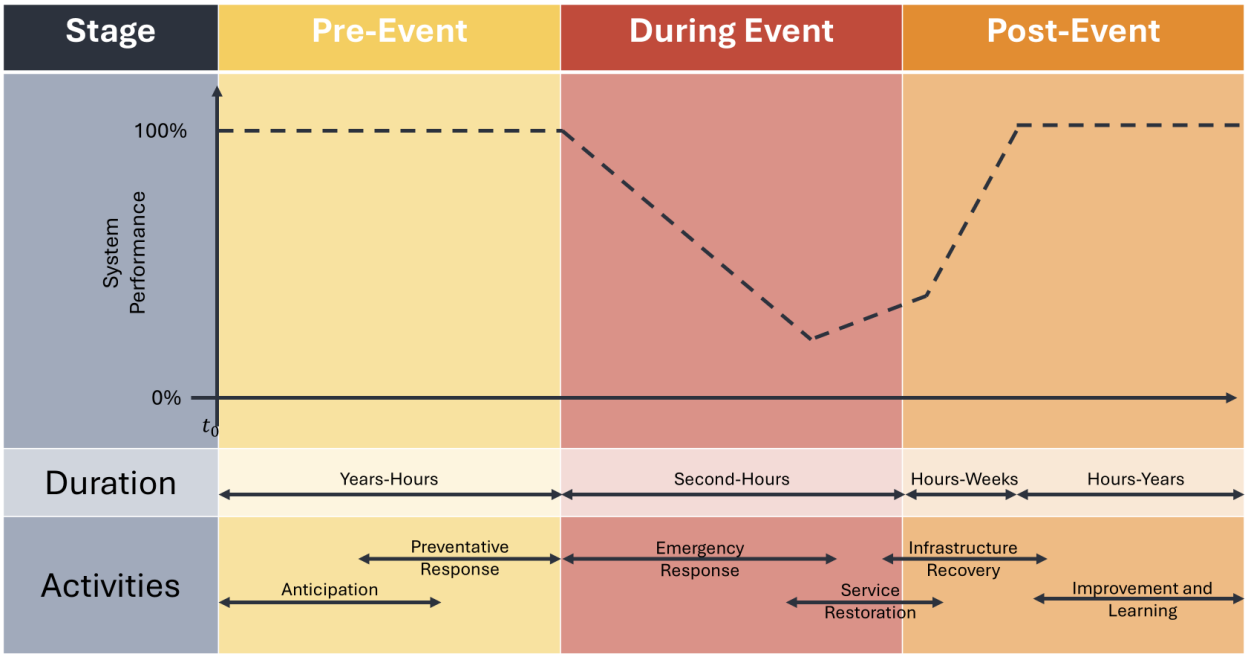


Figure 57: Impact Event Timeline for Risk and Resilience Mitigation

Scientists, technology developers, utilities, regulators, and other stakeholders continue to improve and establish best practices. Technological improvements will become available to utilities, fragility curves will support a better understanding of the susceptibility of different utility assets to wildfires, and risk forecasting will continue to improve with each fire season. Keeping up with changes to best practices may be difficult for small utilities, but support can be provided by interest groups, governments, and technical assistance. Planning on a regular cycle should include learning about new and emerging practices.

5.2.2 Mitigation Approaches Applied in Lane County

Each utility in Lane County has a WMP, although the methods they used to create the WMPs vary. They are all required to include a risk analysis, mitigation strategies, engagement strategies, and performance tracking plans. Full guidance for WMPs is provided by the Oregon

PUC.[1] In this section, we analyze WMPs from Lane County's utilities, including EWEB,[2] SUB,[3] EPUD,[4] Central Lincoln PUD,[5] Lane Electric,[6] Blachly-Lane,[7] and Pacific Power.[8]

Table 24 through ***Table 36*** show wildfire mitigation and preparedness strategies, along with whether individual utilities are using those strategies according to their WMPs, and ***Table 23*** provides a key for interpreting those tables.

Table 23: Key for Interpreting the Letters and Colors in ***Table 24*** through ***Table 36***.

A	Active: The utility is actively and presently pursuing this strategy
P	Planned: The utility is planning to pursue this strategy, or they are currently testing pilots
C	Considered: The utility is considering the feasibility, costs, and impacts or this strategy and/or its appropriateness of implementation. This strategy may be mentioned in the WMP, but not integrated into mitigation planning
N	Not Mentioned: The utility does not mention this strategy in their WMP

Pre-event Mitigations

Pre-event mitigations account for most of the wildfire mitigation and preparedness best practices. This aligns with the primary goal of wildfire mitigation planning: to prevent utility-caused ignition. Lane County utility pre-event mitigation practices are shown in ***Table 24*** through ***Table 31***.

Planning, Evaluation, and Analysis

Table 24 shows major planning, evaluation, and analysis practices implemented by Lane County utilities. All Lane County utilities have WMPs, and all those WMPs acknowledge ***public safety power shut-offs (PSPS)*** as a wildfire mitigation strategy and document their PSPS protocol. In Lane County, only EWEB and Lane Electric have ever implemented protocol (on September 9–11, 2022). ***Enhanced Powerline Safety Settings (EPSS)*** are only specifically mentioned in two utility documents (Blachly-Lane and Pacific Power); however all utilities note

[1] Oregon Secretary of State, *"Public Utility Commission,"* https://secure.sos.state.or.us/oard/displayDivisionRules.action;JSESSIONID_OARD=4mtRkVPeSQBwhz4pSboXaOWPII_TcRrYQgvfPfJee5OmbLpczZ9D!99228750?selectedDivision=6618

[2] Eugene Water & Electric Board, *"Eugene Water Electric Board 2025 Wildfire Mitigation Plan",* Apr. 2025. https://www.eweb.org/outages-and-safety/wildfire-safety-and-prevention

[3] Springfield Utility Board, *"Springfield Utility Board Wildfire Mitigation Plan",* Apr. 2022. https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq105828.pdf

[4] Emerald People's Utility District, *"Wildfire Mitigation & Response Plan",* May 2022. https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq165613.pdf

[5] Central Lincoln PUD, *"WILDFIRE MITIGATION PLAN,"* 2025. https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq334620113.pdf

[6] Lane Electric, *"Wildfire Hazard Mitigation Plan",* Sep. 2024. https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq332023120.pdf

[7] Blachly Lane Electric Co-op, *"Blachly-Lane Electric Cooperative WILDFIRE MITIGATION PLAN",* Jun. 2025. https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq340789036.pdf

[8] PacifiCorp, *"2026-2028 PacifiCorp Oregon Wildfire Mitigation Plan",* Dec. 2025. https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/wildfire-mitigation/oregon/UM2207_2026-2028_WMP.pdf

their abilities to set their protective equipment (relays and reclosers) to be more sensitive during fire season, which constitutes EPSS.

Only EWEB mention hiring independent evaluators to review utility wildfire mitigation processes. Pacific Power notes that upon completion of the next wildfire risk model, third party consultants will review and evaluate its current modeling strategy and compare that strategy to industry best practices. Independent evaluations can be expensive and time-consuming because external consultants must learn the details of utility system and operational processes. That said, if utilities need additional support for mitigation planning, independent evaluation can be a good choice.

Consequence analysis is the analysis of the potential harms of a utility-caused ignition. While there is no standard workflow for performing consequence analysis and quantifying potential impacts can be challenging, consequence analysis could help utilities justify mitigation investments like grid hardening. Pacific Power is the only utility WMP to mention regular consequence analysis, which is incorporated into their wildfire risk modeling that considers risk to be the product of wildfire consequence and wildfire likelihood.

Table 24: Wildfire; Planning, Evaluation, and Analysis.

	EWEB	EPUD	SUB	Blachly-Lane	Lane Electric	Central	Pacific Power
WMPs	A	A	A	A	A	A	A
Independent Process and System Evaluation	A	N	N	N	N	N	P
EPSS and PSPS integration	A	A	A	A	A	A	A
Consequence Analysis	N	N	N	N	N	N	A

Asset and Supply Chain Management

Asset management practices (***Table 25***) involve evaluating the status of utility assets. All Lane County utilities include some form of an asset inventory in their WMPs, but only some evaluate asset risk. Evaluation of asset health and risk could help utilities better prioritize investments. While all utilities do proactive inspections, only three use advanced inspection technologies such as unmanned aerial vehicles, LiDAR, or thermographic imaging of equipment (i.e., infrared inspections).

Table 25: Wildfire; Asset Management and Health

	EWEB	EPUD	SUB	Blachly-Lane	Lane Electric	Central	Pacific Power
Asset Inventories	A	A	A	A	A	A	A
Evaluation of Asset Health and Risk	A	N	N	N	A	A	A
Proactive Inspections	A	A	A	A	A	A	A
Advanced Inspection Technology	A	N	N	A	N	N	A

Supply Chain Management (***Table 26***) involves maintaining up-to-date knowledge of the availability, sources, and pricing of electrical infrastructure. Utilities can collaborate and share information about new components or technologies through shared databases. Supply Plan management is barely discussed in Lane County WMPs. EPUD, a utility with a relatively large service area, mentions the importance of geographic distribution of spare components (see ***Figure 58***). Implementing a distributed component storage approach helps to ensure that components are available when and where they are needed. For utilities with smaller service territories, this might not be a priority. Pacific Power emphasizes the value of sharing information with other utilities, noting that a goal of its mutual aid program is to exchange best practices and technologies that strengthen the industry's ability to prepare for and respond to emergencies. The company also cites its participation in the Oregon Wildfire and Electric Collaborative as a forum to share lessons learned with other utilities, though it does not specify whether a formal shared database exists.



Figure 58 EPUD's pole storage

Table 26: Wildfire; Supply Chain Management

	EWEB	EPUD	SUB	Blachly-Lane	Lane Electric	Central	Pacific Power
Electrical Component Supply Chain Management	N	A	N	N	N	N	N
Shared Asset and Technology Database	N	N	N	N	N	N	A
Geographic Distribution of Spares to Reduce Risk/ Hazards	N	A	N	N	N	N	N

Hardening and Grid Modernization

Utility plans for infrastructure hardening and control reveal information and capacity gaps (***Table 27***). Undergrounding was consistently identified as an effective but expensive wildfire

mitigation measure, though some utilities have other motivations to underground lines. The cities of Lowell and Veneta both prioritize undergrounding as a community resilience strategy (see ***Table 59*** in ***Section 9.2***). Most utilities prioritize higher-risk assets for undergrounding.

All utilities mention covering or insulating conductors ("tree wires") as a mitigation measure. The layer of insulation (compared to standard bare wires) allows wires to withstand initial contact with vegetation or debris. Covering conductors is often cheaper than undergrounding but does come with challenges. Covers can hide power line degradation, trap moisture, and add weight.[1]

All utilities identified pole upgrades as a potential mitigation strategy, but approaches varied. Many mentioned reviewing pole options, and some utilities are actively replacing certain poles. Some utilities mentioned lightning arresters and wildlife guards. Bird nests on pole structures can exceed pole weight limits, and nest materials contacting electrical equipment can cause outages. To address this, EWEB installed 28 Osprey nesting platforms throughout their service territory. This unique approach redirects nesting activity away from electric infrastructure while preserving habitat.

Table 27: Wildfire; System Hardening

	EWEB	EPUD	SUB	Blachly-Lane	Lane Electric	Central	Pacific Power
Undergrounding	A	C	C	A	A	A	A
Covered Conductors/ Reconducting	A	C	A	A	A	A	A
Advanced Conductors	C	C	C	C	C	A	A
Reinforcement of Poles and Structures	A	A	C	A	C	A	A
Lightning Arresters & Shield Wires	A	C	N	N	N	N	N
Wildlife Guards	A	A	N	A	N	N	N

Sectionalizing and Islanding as well as topology optimization (***Table 28***) are system level mitigation strategies that go relatively undiscussed in Lane County utility WMPs. Sectionalizing and Islanding refer to a utility's ability to separate a section of the grid independent of the rest of the grid—sectionalizing typically refers to a section that can be independently de-energized whereas islanding refers to a section that can be energized independent of the larger grid. Topology optimization is an approach used to design the physical layout of the grid to mitigate or reduce the impacts of PSPS events. This can be done by strategically sectionalizing, islanding, or adding redundant power flow pathways. These mitigation strategies involve complex planning and operation and are generally considered secondary measures to be implemented after extreme risks are addressed. Additionally, these approaches might not always make geographical sense. For instance, EPUD notes that their "electric facilities are also likely to cross boundaries of evacuation zones as they are created and adjusted during a wildfire

[1] Intelligent Network Diagnostic Technology. *"To insulate or not – The Hidden Risks of Covered Conductors".* Aug. 2025. https://ind-technology.com/news/to-insulate-or-not-insulate-that-is-the-question/

event. Therefore, it is unlikely that there will be an isolation point (e.g., recloser, switch, fuse) at a weather zone or evacuation zone boundary. As a result, operational responses will likely affect District energy facilities and customers in areas beyond just the area of immediate concern."[1] Pacific Power's WMP discusses use of sectionalizing as a mitigation strategy through their use of relay devices that automatically sectionalize the grid to protect downstream circuit segments.

Lane County utilities mention proactive equipment and device settings, adaptive reclosers, and advanced fire-safe devices for monitoring and control to varying extents across WMPs. These three technology categories allow utilities to cautiously automate and monitor equipment and control schemes during high-risk periods. Some of the specific technologies are described in ***Chapter 6***, while details on the application, benefits, and challenges of these mitigation strategies can be found in Coleman et al. (2025).[2] Generally speaking, they are all strategies that allow more cautions equipment monitoring and control schemes during high-risk periods, in increasingly automated ways. As technology and practices in these areas evolve, utilities should actively monitor new developments.

Table 28: Wildfire; Grid Modernization

	EWEB	EPUD	SUB	Blachly-Lane	Lane Electric	Central	Pacific Power
Sectionalizing and Islanding	N	C	N	N	N	N	C
Proactive Equipment, Device Settings, & Fast-trip Systems	A	A	C	C	A	A	A
Adaptive Reclosers	A	A	N	A	A	A	A
Advanced Fire-Safe Devices for Monitoring and Control	A	A	N	C	A	N	A
Topology Optimization	N	N	N	N	N	N	N

Vegetation Management

Table 29 shows utility implementation of various vegetation management practices. Trimming and inspection cycles are effective industry standards defined and required by the NESC and OPUC to mitigate utility-caused ignitions. Integrated vegetation management is a long-term species management approach that includes site assessment, control, evaluation, and maintenance. None of the Lane County utilities participate in vegetation management accreditation programs. Only EWEB and EPUD mention cooperative agreements with other land managers (e.g. government agencies, conservation organizations, and private landowners) in their WMPs. Central Lincoln compares annual vegetation-trimming investments with tree-related outages to evaluate the cost effectiveness of its trimming program.

[1] Emerald People's Utility District, *"Wildfire Mitigation & Response Plan,"* May 2022. https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq165613.pdf

[2] A. M. Coleman *et al.*, *"Current Best Practices on Wildfire Risk Reduction for Electric Transmission and Distribution Systems,"* Feb. 2026. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-38528.pdf

Table 29: Wildfire; Vegetation Management

	EWEB	EPUD	SUB	Blachly-Lane	Lane Electric	Central	Pacific Power
Industry Standards	A	A	A	A	A	A	A
Integrated Vegetation Management	A	N	N	A	N	N	A
Accreditation Programs	N	N	N	N	N	N	N
Cooperative Agreements	A	A	N	N	N	N	N

Hazard Modeling and Forecasting

Table 30 shows practices related to hazard and weather modeling and forecasting. Nearly all utilities use QWRA data to characterize the wildfire risk in their service territories. Only EWEB and Lane Electric completed data- or image-driven wildfire risk assessments, which require capacity to manage large datasets, analytics, or GIS tools. Utilities lacking the technical or funding capacity for a full data-driven risk assessment sometimes rely on expert perspectives from their employees who work in the field to identify high risk assets.

Most of the Lane County utilities do not have wildfire spread models that can help them predict how specific ignitions could impact electrical assets and communities, in-house simulation capabilities, or practices to detect emerging wildfire risk. The QWRA data that utilities use is from 2023 even though wildfire risk prediction is based on probabilistic models and therefore requires data inputs on a yearly basis. Lane Electric documents significant fires up to 2024, but they are not quantitatively integrated into their risk assessment.

During a recent wildfire event, Pacific Power used wildfire spread and consequence modeling to identify the circuits of risk several days in advance of the wildfire threat. As a result, they could identify the areas where extreme winds and extreme fire potential risk existed and could consider that in their PSPS decision making. Pacific Power also recently implemented FireSight, a commercially available wildfire simulation tool that combines the utility's asset information with public data (i.e., community characteristics, terrain, vegetation, and weather) to forecast the consequence or impact of a potential wildfire from a given ignition point. Pacific Power's WMP describes how the utility has its own Meteorology Department for managing day-to-day threats, providing recommended changes to operations based on conditions, and identifying and subsequently closing forecasting data gaps. All utilities use red flag warnings to inform their decision making, but only EWEB, Blachly-Lane, and Pacific Power have any of their own weather monitoring infrastructure.

Table 30: Wildfire; Hazard Modeling, Weather Forecasting and Modeling

	EWEB	EPUD	SUB	Blachly-Lane	Lane Electric	Central	Pacific Power
Wildfire Spread Models	C	N	N	N	N	N	A
Landscape Wildfire Simulation Systems	P	N	N	N	N	N	A
Detection of Emerging Risk	P	N	N	N	N	N	N
Weather Monitoring Infrastructure and Data Management	A	N	N	A	N	N	A
Red Flag Warnings	A	A	A	A	A	A	A

Training, Coordination, Benchmarking, and Engagement

About half of Lane County utilities have some wildfire-related training or tabletop exercises for their employees, while all mention some form of coordination or mutual aid agreements in their WMPs. Customer engagement was a part of most, but not all, WMPs, and EWEB, Blachly-Lane, and Pacific Power highlighted utility benchmarking practices.

Table 31: Wildfire; Training, Coordination, Benchmarking, Engagement

	EWEB	EPUD	SUB	Blachly-Lane	Lane Electric	Central	Pacific Power
Tabletop Exercises and Training	A	N	N	A	P	A	A
Coordination and Mutual Aid Agreements	A	A	A	A	A	A	A
Utility Benchmarking	A	N	N	A	N	N	A
Customer Engagement and Planning	A	N	N	A	A	A	A

During-event Best Practices

During a wildfire event, utilities can continue to take steps to reduce risk to assets, customers and employees. Lane County utility during-event mitigation practices are shown in ***Table 32*** through ***Table 34***.

Situational Awareness and Operations

Enhanced situational awareness strategies include data collection and integration processes that enable "comprehensive understanding of the working environment, including real-time wildfire risk and weather, fuel, and system conditions."[1] Such comprehensive integration was

[1] A. M. Coleman *et al.*, ibid.

not apparent in any of the WMPs. However, achieving improved situational awareness using daily risk forecasts was an articulated goal articulated in Pacific Power's WMP.

All utilities include plans for activating PSPS, engaging customers during an event, and de-energizing lines to mitigate further incidents (***Table 32***).

Table 32: Wildfire; Situational Awareness & Operations

	EWEB	EPUD	SUB	Blachly-Lane	Lane Electric	Central	Pacific Power
Enhanced Situational Awareness	C	N	N	C	N	N	A
Enhanced EPSS Controls and PSPS Activation	A	A	A	A	A	A	A
Customer Engagement and Resourcing	A	A	A	A	A	A	A
De-energization as a Mitigation Practice	A	A	A	A	A	A	A

Monitoring Tools and Assessments

All utilities rely on publicly provided weather monitoring and emergency alert systems for meteorological data, and as discussed, Pacific Power has its own Meteorology Department. For the most part, utilities do not use or plan to use visual surveillance system or overhead remote sensing during events. However, Pacific Power does have a continuous improvement strategy targeting an expanded camera network to enable better visibility across its service territory. Most utilities have a network of sensors throughout their system (SCADA) that can provide basic information about the status of assets through the measurement of voltage, current, and frequency. Pacific Power is also considering how remote sensing technology could augment and inform traditional vegetation management inspections (***Table 33***).

Table 33: Wildfire; Monitoring Tools and Assessments

	EWEB	EPUD	SUB	Blachly-Lane	Lane Electric	Central	Pacific Power
Meteorological Data and Risk Modeling	A	A	A	A	A	A	A
Visual Surveillance Systems	A	N	N	N	N	N	A
Grid Sensor Networks	A	A	A	C	A	A	A
Overhead Remote Sensing	N	N	N	A	N	N	C

Adaptive Grid Operations

Almost all Lane County utilities outline different device settings used in high risk and wildfire event scenarios in their WMPs. Many have adaptive reclosers that can automatically or

remotely change settings (***Table 34***). Utilities' consideration or implementation of fire-safe devices mostly includes the replacement (or consideration of replacement) of conventional expulsion fuses with fire-safe current-limiting fuses or reclosers because conventional fuses expel hot particles when they are operated.

Table 34: Wildfire; Adaptive Grid Operations

	EWEB	EPUD	SUB	Blachly-Lane	Lane Electric	Central	Pacific Power
Protective Equipment, Device Settings, and Fast-Trip Systems	A	A	N	A	A	A	A
Adaptive Reclosers	A	A	N	C	A	A	A
Advanced Fire-Safe Devices for Monitoring and Controls	A	P	C	C	N	C	A

Post-Event Recovery

Lane County utility WMPs vary in their post-event planning, especially for actions beyond system restoration. Reporting, metrics tracking, and improving emergency plans based on lessons learned are all important aspects contributing to continuous improvement in the face of wildfire risk. Post-fire vegetation management is not specifically discussed in many of the WMPs, but general vegetation management practices are discussed (usually in detail). Lane County utility post-event mitigation practices are shown in ***Table 35***.

Table 35: Wildfire; Post-event Recovery

	EWEB	EPUD	SUB	Blachly-Lane	Lane Electric	Central	Pacific Power
System Inspection and Restoration	A	A	A	A	A	A	A
Post-fire Vegetation Management	A	N	N	N	N	N	N
Reassess Vulnerabilities and Update Priorities	A	N	A	A	N	A	A
After-Action Reporting	A	A	N	A	A	N	A
Tracking Performance Metrics	A	N	A	A	N	A	A

Cost Mitigations

Wildfire mitigations can be costly, but few of Lane County's utilities mention cost mitigation measures in their WMPs (***Table 36***). Except for Pacific Power, none mention cost share arrangements, and few indicate how they prioritize actions. There are a few mentions of landowner or cross-utility collaborations. For example, Pacific Power has a Tree Voucher Program where landowners can receive tree replacement vouchers. Overall, the utilities seemed to approach their WMPs—and the mitigations in them—independently. However,

EWEB led tabletop PSPS exercises in 2024 and 2025, extending invitations to other utilities to participate. Pacific Power participates in a range of cross-utility collaborative events including IEEE working groups related to protection for wildfire risk and joint IOU meetings.

Table 36: Wildfire; Cost Mitigations

	EWEB	EPUD	SUB	Blachly-Lane	Lane Electric	Central	Pacific Power
Cost Share Arrangements	N	N	N	N	N	N	A
Cost vs. Impact Prioritization	N	N	N	N	C	C	A
Landowner Collaboration	A	N	N	A	P	N	A
Cross-utility Collaboration	A	N	N	A	N	N	N

5.2.3 Gaps and Opportunities

Overall, utility WMPs vary in both approach and quality, and county residents and risk managers would likely benefit from a guided, uniform approach. Lane County utilities include many basic mitigation strategies in their WMPs but have yet to plan integration of more advanced systems or practices. This status is commensurate with their relatively small sizes and with the state of knowledge on best practices. To reiterate, the best practices presented in ***Chapter 5*** constitute a menu of options more than a checklist of must-haves. None-the-less, there are some places where additional efforts or collaboration across utilities could create widespread benefit.

Wildfire Risk Assessments based on the most up to date information are foundational to wildfire mitigation planning. The basic process of risk assessment can be improved through;

- **Improved Hazard Characterization:** Burn probability and fire intensity estimates based on trends analysis, historic information, and up-to-date geospatial data, modeled on an annual basis
- **Improved Vulnerability Characterization:** vulnerability of individual utility assets based on their location, age, exposure, material, and asset type
- Upgrade and system hardening recommendations based on risk assessment

Consequence Analysis Framework to help utilities and local governments understand the consequences of utility caused ignitions

Collaborative WMP Innovation performed by utilities, local government, and subject matter experts can help to fill some of the gaps that are apparent in current WMPs. Because many of the gaps are common among Lane County's COUs, a collaborative process is likely to have wide benefit and potential cost savings. Steps to such a process could include:

- **WMP evaluation:** A deeper look at existing WMPs than is provided in this document to assess each utility's status and needs
- **WMP template development:** Collaborative design of a WMP template that all utilities can use, making it easier for other stakeholders to understand, compare, and learn from WMPs

- **WMP integration plans:** WMP plans and mitigations will change as new information on best practices becomes available. As utilities make system changes, they will often need to make corresponding operational changes. For example, if a utility replaces bare wire conductors with cover conductors, there is reduced risk that those covered conductors will ignite a fire. For that reason, a utility might choose to increase the wind speed threshold at which they implement PSPS. A choice to do something like this should be made over the course of multiple years and informed by utility data. Tracking data, implemented mitigations, and WMP changes over the years requires that WMPs are integrated into existing utility processes.
- **Supply chain management database development and benchmarking:** Collaboration between utilities to track component prices, availability, costs and benefits of implementation, and geographic distribution within Lane County. A database, and the process of updating the database could provide a central location and opportunity for utilities to share their experiences with different system hardening, engineering, and monitoring technologies
- **Weather monitoring**: Deploying additional local weather stations that can be monitored by all utilities
- **After-action reporting standardization:** Creating a standard after-action report template can set customer and stakeholder expectations for what utilities need to provide and customers and stakeholders expect to see following a wildfire event
- **Training and tabletop exercises:** collaborations for training can reduce costs and enable sharing of lessons learned
- **Customer engagement:** Develop customer resources that all utilities in Lane County can use

Sectionalizing and islanding planning may expose opportunities to isolate high-risk/ critical portions of the grid in emergency situations

Enhanced Situational Awareness would include the adoption of new monitoring technologies and the integration of the data into operational decision-making.

Wildfire spread models can be complex and require expertise to create and interpret Therefore, it is best for utilities to collaborate and request state/regional support

Cost sharing arrangements could be explored by interested utilities and local governments

5.3 Earthquakes

Earthquakes and seismic activity can cause severe ground shaking, soil liquefaction, and landslides. Depending on intensity, secondary impacts can include flooding, dam failures, and tsunamis. In Lane County, earthquakes could originate from four primary sources: the offshore ***Cascadia Subduction Zone (CSZ)***, the oceanic Juan de Fuca plate, the continental North American plate, and renewed volcanic activity in the Cascades Mountains. Seismic activity from the CSZ and the North American plate can impact all regions of the county, although extents may vary. The Juan de Fuca plate would particularly impact coastal regions, while volcanic activity would heavily impact inland regions.[1] The greatest hazard comes from the occurrence of a megathrust earthquake on the CSZ. ***Figure 59*** displays the predicted earthquake intensity of

[1] Data from Oregon Department of Land Conservation and Development, *"Oregon Natural Hazards Mitigation Plan,"* Sep. 2020. https://www.oregon.gov/lcd/nh/pages/mitigation-planning.aspx

a CSZ event across Lane County. Seismic severity is highest near the coastline, rated “Severe,” and gradually decreases inland to “Very Strong” and “Strong.”

In Lane County, coastal communities are at highest risk from a CSZ earthquake. Florence, Glenada, and areas along the Siuslaw River estuary are expected to experience the greatest impacts from severe ground shaking, tsunami inundation, and liquification. The Willamette Valley is expected to experience greater impacts than the Cascades region of the county, which is more likely to be impacted by low magnitude crustal earthquakes. The Willamette Valley in particular faces moderate to very high susceptibility to ground shaking amplification—a phenomenon where seismic waves increase in intensity as they travel through the ground. The Lane County NHMP identifies three areas in the valley as very high susceptibility: east of Highway 99 around Junction City, along Highway 126 East between Springfield and Walterville, and southeast of the metropolitan area along Highway 58 and Interstate 5 near Pleasant Hill and east of Creswell.

The probability of damage from seismic shaking was recently increased in the non-coastal portion of Lane County, due to newly discovered faults. In the state NHMP, earthquake risk in Lane County is given the highest possible hazard classification.[1] The county NHMP assigns the region a catastrophic hazard classification. Multiple utilities identify their systems—including poles, transformers, substations—to be susceptible to moderate to high risk from earthquakes, with severe events leading to projected outage durations of weeks to months.[2]

[1] Oregon Department of Land Conservation and Development, ibid.

[2] Lane County Emergency Management, *“Lane County Multi-Jurisdictional Natural Hazards Mitigation Plan,”* Oct. 2023. https://cdnsm5-hosted.civiclive.com/UserFiles/Servers/Server_3585797/File/Government/County%20Departments/Emergency%20Management/Hazard%20Mitigation%20Plan/20180828__MASTER_MJ-NHMPUpdate_Final.pdf

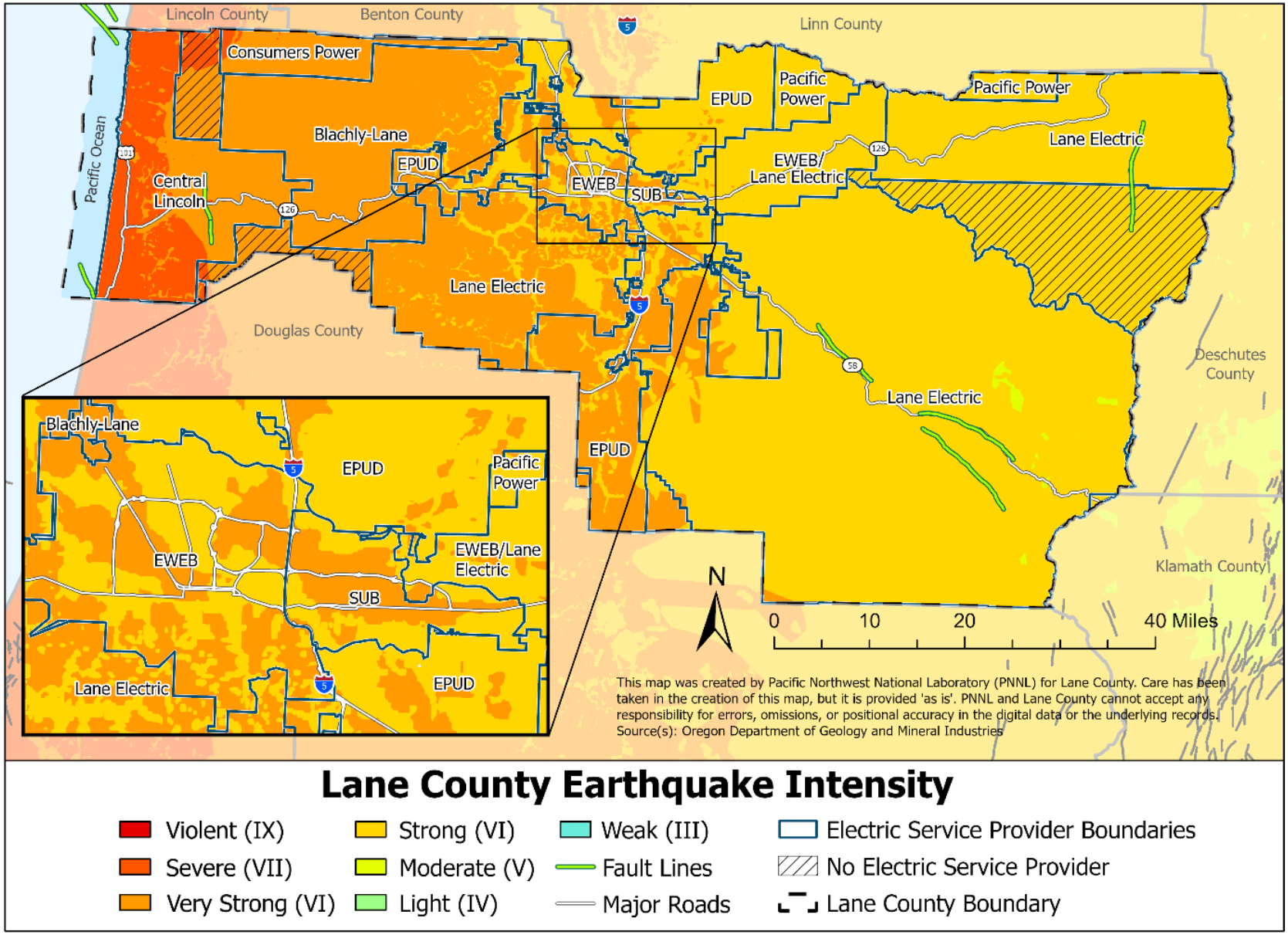


Figure 59: Estimated Severity of Earthquake Amplification (Ground-Shaking) in Lane County[1]

[1] Data from Oregon Department of Geology and Mineral Industries, Oregon HazVu, Statewide Geohazard Viewer. https://gis.dogami.oregon.gov/maps/hazvu/

5.3.1 Best Practices

Best practices for utility earthquake resilience were synthesized primarily from the Oregon Department of Energy's Guidebook for Local Energy Resilience[1], a report from the Oregon Seismic Safety Policy Advisory Commission on risk and recovery from a Cascadia Subduction Zone event[2], and a DOE-sponsored report on multi-hazard resilience of the United States electricity system.[3]

A megathrust CSZ event is expected to cause a range of severe and sudden energy system impacts. The duration of these impacts is uncertain, which makes it difficult to predict recovery needs and timeline. Most utilities' earthquake risk mitigation strategies consist of pre-event actions and planning to reduce vulnerabilities and enable a flexible response. Earthquake risk mitigation focuses primarily on the resilience of infrastructure assets, coordination with key emergency preparedness stakeholders, and establishing preparedness plans for staff and the community. ***Figure 60*** lists specific measures and activities that are considered best practices for utility earthquake resilience at each phase of a disaster.

Pre-Event Mitigation: Seismic design standards and regulations regarding siting, design, construction, and safe operation are periodically updated to reflect new hazard assessment information. Key utility facilities—such as powerhouses, operation centers, substations, transmission towers, and distribution poles—should be upgraded to adhere to current standards.[4] Critical electrical infrastructure should not be sited in high liquefaction risk areas, when possible.[5] Utilities can evaluate assets in high-risk areas for relocation, retrofit, replacement or redundancy if already sited or built. Sensors can provide remote monitoring and advanced warning capabilities. Similarly, remote or manual shutdown procedures can be established to increase operational flexibility and protect energy infrastructure from cascading impacts. Critical engineering records should be digitized and made accessible in case of potential system shutdowns post-event.[6]

Additionally, coordination with key emergency preparedness stakeholders is essential for an earthquake event. Pre-event, utilities can connect with local government and communities to integrate existing emergency plans, determine contingency plans for critical public services and hubs, and make strategic investments to prioritize service in the event of disaster. Local or back-up generation capabilities can be expanded to provide power in case of grid-wide impacts. Utilities, in conjunction with local or state agencies, can establish mutual aid agreements with providers outside of the region, creating a pathway to quickly mobilize skilled personnel and materials to aid in recovery post-event.

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[1] L. Koho *et al.*, *"Oregon Guidebook for Local Energy Resilience: for small and medium electric utilities,"* 2019. https://www.oregon.gov/energy/safety-resiliency/Documents/Oregon-Resilience-Guidebook-COUs.pdf

[2] Oregon Seismic Safety Policy Advisory Commission, *"Oregon Resilience Plan,"* 2013. https://www.oregon.gov/oem/Documents/Oregon_Resilience_Plan_Final.pdf

[3] B. Preston *et al. "Resilience of the U.S. Electricity System: A Multi-Hazard Perspective,"* Oakridge National Laboratory, Aug. 2016. https://www.energy.gov/sites/prod/files/2017/01/f34/Resilience%20of%20the%20U.S.%20Electricity%20System%20A%20Multi-Hazard%20Perspective.pdf

[4] B. L. Preston *et al.*, ibid.

[5] L. Koho *et al.*, ibid.

[6] Oregon Department of Energy, *"Oregon Resilience Guidebook Deep Dive: State Emergency Management Planning,"* Jun. 2019. https://www.oregon.gov/energy/safety-resiliency/Documents/State-Emergency-Management-Planning-Deep-Dive.pdf

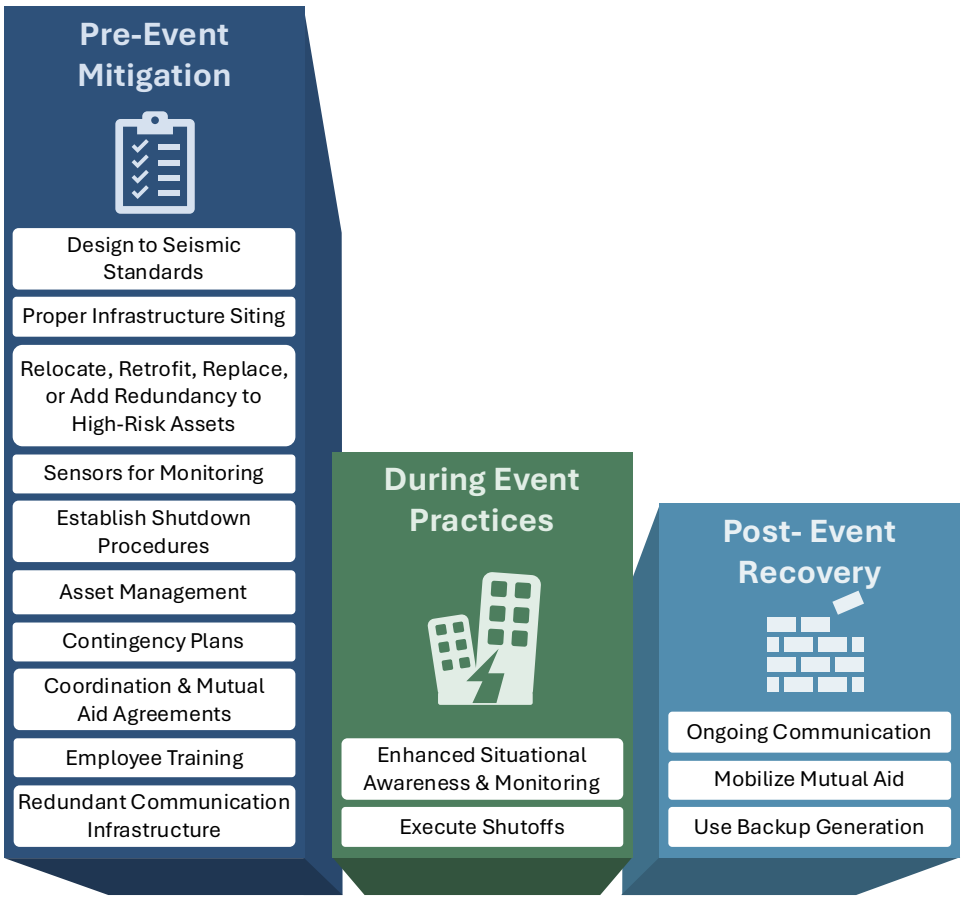


Figure 60: Best Practices for Utility Resilience to Earthquakes[1]

A final pre-event mitigation best practice is to provide preparedness plans and resources for staff and the local community. Employee training, interagency tabletop exercises, and associated resources can produce a more coordinated, streamlined response in the event of a disaster. Equipping staff and facilities with redundant communication devices, such as satellite phones and radios, can help maintain critical operations post-event.

During Event Practices: During an earthquake, utilities must promptly implement measures to protect public safety and minimize infrastructure damage. Real-time monitoring systems are essential for maintaining situational awareness and providing advanced alerts and data regarding seismic activity and associated risks. Controlled shutdown procedures are another critical practice, enabling utilities to isolate affected parts of the system, prevent cascading blackouts, and protect vulnerable assets. Backup generation systems will play an important role in ensuring essential services can continue to function.

Post-Event Recovery: Post-event, utilities should conduct comprehensive inspections to identify damage, prioritize repairs, and ensure safety before restoring electricity across affected areas. Maintaining clear public communication channels is vital to inform communities about

[1] Information from Oregon Seismic Safety Policy Advisory Commission ibid.

repair timelines, available resources, and safety precautions. Mutual aid agreements could be used to expedite longer-term recovery efforts. While recovery is underway, backup generation systems continue to provide temporary energy solutions for critical services until primary infrastructure is repaired or replaced.

5.3.2 Mitigation Approaches Applied in Lane County

This section summarizes Lane County utility earthquake resilience practices across pre-event, during-event, and post-event phases (***Table 37***, ***Table 38***, ***Table 39***, respectively). Findings are based on publicly available materials from EWEB,[1,2,3,4,5] EPUD,[6,7] SUB,[8,9,10] Blachly-Lane,[11] and Central Lincoln.[12] We were unable to locate specific plans from Lane Electric, but references the emergency preparedness sections of their website when applicable.

Pre-Event Earthquake Best Practices Applied in Lane County

Design to Seismic Standards: One of the most documented pre-event practices across Lane County utilities is ensuring that new electrical system components meet updated seismic design standards. EWEB, EPUD, SUB, Blachly-Lane, and Central Lincoln PUD all discuss plans to expand service and address growth through future facilities, substations, and/or transmission and distribution lines. New construction is expected to adhere to updated and improved infrastructure engineering standards.

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[1] Eugene Water & Electric Board, *"2018-2028 Strategic Plan,"* 2024. https://www.eweb.org/documents/Reports%20and%20Publications/eweb_strategic_plan_2018_2028_2021_2022_2023_2024_update.pdf

[2] Oregon Department of Energy, *"Oregon Resilience Case Study,"* 2018. https://www.oregon.gov/energy/safety-resiliency/Documents/DERS-Microgrids-Case-Study.pdf

[3] Oregon Department of Energy, *"2024 Biennial Energy Report: Energy 101"*, Nov. 2024. https://www.oregon.gov/energy/Data-and-Reports/Documents/2024-BER-E101.pdf#page=94

[4] Oregon Public Broadcasting, *"How Lane County Electric Utilities Deal with Wildfire Danger"*, Jul. 2025. https://www.opb.org/article/2025/07/21/lane-county-electricty-utilities-wildfire-oregon-fire/

[5] Eugene Water & Electric Board, *"EWEB'S Business Management System," Multi* https://www.eweb.org/documents/Reports%20and%20Publications/2025_organizational_goals.pdf

[6] Emerald People's Utility District, *"2020 Strategic Plan"*, 2020. https://www.epud.org/wp-content/uploads/2020-Strategic-Plan_finalSML.pdf

[7] Lane County, Oregon, *"Lane County Multi-Jurisdictional Natural Hazard Mitigation Plan,"* Version 4, 2023.https://www.lanecountyor.gov/government/county_departments/emergency_management/planning/mitigation_plan

[8] Springfield Utility Board, *"Strategic Plan 2024"*. https://www.subutil.com/wp-content/uploads/SUB-Strategic-Plan-2024-fin-lores.pdf

[9] Springfield Utility Board, *"Budget & Strategic Plans,"* https://www.subutil.com/about-us/budget-strategic/

[10] Springfield Utility Board, *"Emergency Operations Plan," 2025.* https://www.subutil.com/wp-content/uploads/SUBEmergencyOperationsPlanBASICPLAN_March2025.pdf

[11] Blachly-Lane Addendum provided in *"Lane County Multi-Jurisdictional Natural Hazard Mitigation Plan," Lane* County, Oregon, Version 4, 2023. https://cdnsm5-hosted.civiclive.com/UserFiles/Servers/Server_3585797/Image/Government/County%20Departments/Emergency%20Management/Planning%20Page/Lane%20County%20MNHMP%20V4_Full%20Plan%20(2).pdf

[12] Central Lincoln People's Utility District, *"Central Lincoln PUD Addendum to the Lincoln County Multi-jurisdictional Mazard Mitigation Plan"*. https://www.co.lincoln.or.us/DocumentCenter/View/1101/Volume-II---Central-Lincoln-PUD-Addendum-PDF

Proper Infrastructure Siting: In their addendum to the Lincoln County Hazards Mitigation Plan, Central Lincoln PUD discusses the possibility of constructing a new headquarters facility to provide safety and continuity of operations after a Cascadia event. Similarly, in their 2020 Strategic Plan, EPUD explores the possibility of developing a backup headquarters location, as the current headquarters is subject to flood risk from nearby waterways. Although the primary risk mitigated through EPUD's action is not earthquake-related, the site of a backup headquarters building can be selected to address seismic risk as well. SUB is in the process of updating acquisition plans for future facilities, which could be an opportunity to incorporate seismic risk as a criteria for site selection.

Relocate, Retrofit, Replace, or Add Redundancy to High-Risk Assets: EWEB, EPUD, SUB, Blachly-Lane, and Central Lincoln PUD all document system hardening projects, such as distribution system upgrades and seismic retrofits to substations and facilities, to mitigate earthquake risk. EWEB plans to "prioritize links between local generation and essential services," while EPUD has added redundancy to their system through new feeder ties and alternating feeds. EPUD also plans to retrofit major substation and headquarters facilities to meet current seismic standards. New substations from SUB add additional power for growth areas but also add redundancy and reliability to their existing service area. Central Lincoln PUD lists priorities of strengthening their grids through redundancy and looped systems, modernizing systems and components, undergrounding high-risk overhead lines, evaluating relocation of utility infrastructure, and seismic retrofits. Blachly-Lane is in the process of retrofitting legacy infrastructure with resilient materials and improved standards.

Asset Management: SUB has documented efforts to increase remote operational capabilities in the event of a disaster, through the implementation of a mobile device management program and procurement of a disaster recovery system.

Contingency Plans: EWEB has documented goals in their Business Management System to improve disruption response plans and mitigate consequential risks through business continuity and resiliency efforts.

Coordination and Mutual Aid Agreements: SUB, EWEB, Central Lincoln, and EPUD reference mutual aid as a potential action to undertake in the event of a disaster, whether that is an earthquake, winter storm, or other hazard event. These same utilities are part of the Western Regional Mutual Assistance Agreement (WRMAA).[1] Mutual aid is integrated into SUB's 2025 Emergency Operations Plan and listed as a goal in EPUD's 2020 Strategic Plan. All utilities emphasize the importance of coordination.

Employee Training: SUB and EWEB document current staff training through FEMA Incident Command Structure, an emergency management framework that can be applied in the event of an earthquake, as well as other hazards. Central Lincoln PUD participates in county tabletop exercises, but they are indicated to be for seasonal weather hazards only. Additional tabletop exercises could be implemented to train earthquake-specific coordination and response.

Redundant Communication Infrastructure: SUB has documented efforts to expand crisis communications and emergency communications plans, which may include redundant communication infrastructure. SUB's efforts to increase remote operational capabilities also illustrate their commitment to preserving communication in the event of an emergency.

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[1] *"Western Region Mutual Assistance Agreement for Electric and Natural Gas Utilities,"* 2003. https://www.westernenergy.org/wp-content/uploads/2024/08/western-region-mutual-assistance-agreement.pdf

Table 37: Documented pre-event earthquake mitigation approaches by Lane County utilities *where ✓ indicates the implementation of the best practice was inferred through document review and — indicates the best practice was not documented but may still be used.*

	EWEB	EPUD	SUB	Blachly-Lane	Lane Electric	Central
Design to Seismic Standards	✓	✓	✓	✓	—	✓
Proper Infrastructure Siting	—	✓	—	—	—	✓
Relocate, Retrofit, Replace, or Add Redundancy to High-Risk Assets	✓	✓	✓	✓	—	✓
Sensors for Monitoring	✓	—	—	—	—	—
Establish Shutdown Procedures	—	—	—	—	—	—
Asset Management	—	—	✓	—	—	—
Contingency Plans	✓	—	—	—	—	—
Coordination and Mutual Aid Agreements[1]	✓	✓	✓	—	—	✓
Employee Training	—	—	✓	—	—	—
Redundant Communication Infrastructure	—	—	✓	—	—	—

During-Event Earthquake Best Practices Applied in Lane County

Execute Shutoffs: EWEB, EPUD, and Blachly-Lane have documented a transition to automated reclosers, a technology that helps facilitate power shutoffs when a fault is detected.

Table 38: Documented during event earthquake mitigation approaches by Lane County utilities *where ✓ indicates the implementation of the best practice was inferred through document review and — indicates the best practice was not documented but may still be used.*

	EWEB	EPUD	SUB	Blachly-Lane	Lane Electric	Central
Enhanced Situational Awareness and Monitoring	—	—	—	—	—	—
Execute Shutoffs	✓	✓	—	✓	—	—

[1] Utilities that participate in the Western Region Mutual Assistance Agreement (WRMAA). See https://www.westernenergy.org/wrmaa-resources/

Post-Event Earthquake Best Practices Applied in Lane County

Ongoing Communication: All Lane County utilities maintain real-time outage maps for customer reference. EPUD and EWEB have documented goals of improving customer communication during service disruptions, with EPUD aiming to provide information on estimated restoration times. SUB has documented goals of enhancing their outage reporting system, utilizing new communication technologies to reach customers, and expanding their crisis and emergency communications plan.

Mobilize Mutual Aid: EPUD and SUB have documented plans and procedures on mobilizing mutual aid resources in the event of a disaster. Even though, EWEB, EPUD, SUB, and Central Lincoln, are part of the Western Regional Mutual Assistance Agreement (WRMAA),[1] documents do not explicitly describe how they would mobilize mutual aid in the event of an earthquake.

Use Backup Generation: EPUD has made efforts to increase local generation through landfill gas generators, residential and commercial solar, and a community solar program. These sources have the potential to be utilized as backup generation. EWEB's strategic plan emphasizes a goal of increasing local capability to generate emergency power for critical community loads. Accordingly, EWEB has installed back-up power capabilities to support the operation of emergency wells in case of large-scale water service disruption at various educational facilities, conducted a microgrid pilot project, and runs the Backup Power Program – an affordable loan program to help customers purchase backup power systems.

Table 39: Documented Post-Event Earthquake mitigation approaches by Lane County utilities *where ✓ indicates the implementation of the best practice was inferred through document review and — indicates the best practice was not documented but may still be used.*

	EWEB	EPUD	SUB	Blachly-Lane	Lane Electric	Central
Ongoing Communication	✓	✓	✓	✓	✓	✓
Mobilize Mutual Aid	—	✓	✓	—	—	—
Use Backup Generation	✓	✓	—	—	—	—

5.3.3 Gaps and Opportunities

Overall, Lane County utilities appear to implement some foundational earthquake resilience practices, primarily pre-event strategies such as using updated design standards and relocating, retrofitting, replacing, or adding redundancy to high-risk areas. All utilities maintain outage maps and prioritize customer communication. Besides these practices, however, it is difficult to evaluate gaps in utilities' earthquake risk management strategies because they are not documented in a uniform way. An initial opportunity for improvement is to:

[1] *"Western Region Mutual Assistance Agreement for Electric and Natural Gas Utilities,"* 2003. https://www.westernenergy.org/wp-content/uploads/2024/08/western-region-mutual-assistance-agreement.pdf

Standardize earthquake risk management planning for utilities so that widely accessible mitigation plans exist that can inform local governments, customers, and other utilities.

5.4 Winter Storms

Winter storms bring heavy snowfall, ice and freezing rain, extreme cold, and wind chill conditions. When coupled with rapid snowmelt, secondary impacts can include flooding and landslides. Lane County experiences winter storms annually, though storm behavior can vary between the valley, coastal, and Cascade regions of the county. Ice accumulation and snowfall from winter storms are more common in the Cascade region of the county. The valley region experiences less heavy snowfall, but is more susceptible to strong winds, extreme cold, and ice accumulation. The coast region rarely experiences snowfall, with winter storms typically bringing strong winds, rain, and hazardous coastal conditions.[1,2]

Ice accumulation on utility poles and lines can damage electricity distribution infrastructure and lead to widespread outages. Storms can also lead to downed vegetation, posing additional risk to transmission and distribution infrastructure. Extreme weather conditions and impacts to transportation routes delay power restoration during outages. January 2024 ice storms caused multiple outages lasting multiple days in Lane County. Major utilities such as SUB and EWEB experienced outages in nearly half their meters, while more than 90% of EPUD customers lost service. Restoring power took up to two weeks, as tens of transformers, hundreds of poles, and thousands of feet of wire needed to be replaced. Related utility ice storm reports are available for EWEB,[3] EPUD,[4] and SUB.[5]

As discussed in Lane County's NHMP,[6] Lane County faces a high probability of winter storms and is highly vulnerable to winter storm effects, per both county and state assessments. Winter storms occur at least once per year in the county, and the valley region historically experiences a severe winter storm once every 3–4 years. As of 2020, however, there is no statewide program to study the impacts of winter storms in Oregon, so the probability of regional winter storm events is unknown. The county NHMP assigns a Level 3 Critical Severity hazard classification to winter storms, citing risk to public safety and infrastructure failure.

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[1] Blachly-Lane Addendum provided in *"Lane County Multi-Jurisdictional Natural Hazard Mitigation Plan," Lane* County, Oregon, Version 4, 2023. https://cdnsm5-hosted.civiclive.com/UserFiles/Servers/Server_3585797/Image/Government/County%20Departments/Emergency%20Management/Planning%20Page/Lane%20County%20MNHMP%20V4_Full%20Plan%20(2).pdf

[2] Oregon Department of Emergency Management, *"COMPREHENSIVE EMERGENCY MANAGEMENT PLAN,"* Sep. 2025. https://www.oregon.gov/oem/Documents/2025-2030_Oregon_Natural_Hazards_Mitigation_All-Chapters.pdf

[3] Eugene Water & Electric Board, *"The Big Freeze 2024: After Action Report"*. www.eweb.org/your-public-utility/news/the-big-freeze-2024-after-action-report

[4] Emerald People's Utility District, *"Ice Storm Post Event Analysis"*. https://www.epud.org/ice-storm-post-event-analysis/

[5] Springfield Utility Board, *"2024 Ice Storm Summary and After Action Reporting,"* https://www.subutil.com/news-releases/2024-ice-storm-summary-and-after-action-reporting/

[6] *Lane* County Oregon, *"Lane County Multi-Jurisdictional Natural Hazard Mitigation Plan,"* Version 4, 2023.https://cdnsm5-hosted.civiclive.com/UserFiles/Servers/Server_3585797/Image/Government/County%20Departments/Emergency%20Management/Planning%20Page/Lane%20County%20MNHMP%20V4_Full%20Plan%20(2).pdf

5.4.1 Best Practices

There are several strategies that utilities can take to mitigate the risks caused by winter storms. Best practices for utilities managing winter storm hazards pre-event, during event, and post-event are offered in several documents including the National Lab of the Rockies' (NLR) document titled "Current Practices in Distribution Utility Resilience Planning for Winter Storms,"[1] The Center for Climate and Energy Solutions' document titled "Resilience Strategies for Power Outages,"[2] and in the Oregon Guidebook for Local Energy Resilience.[3] ***Figure 61*** lists specific measures and activities that are considered best practices for utility resilience to winter storms at each phase of a disaster.

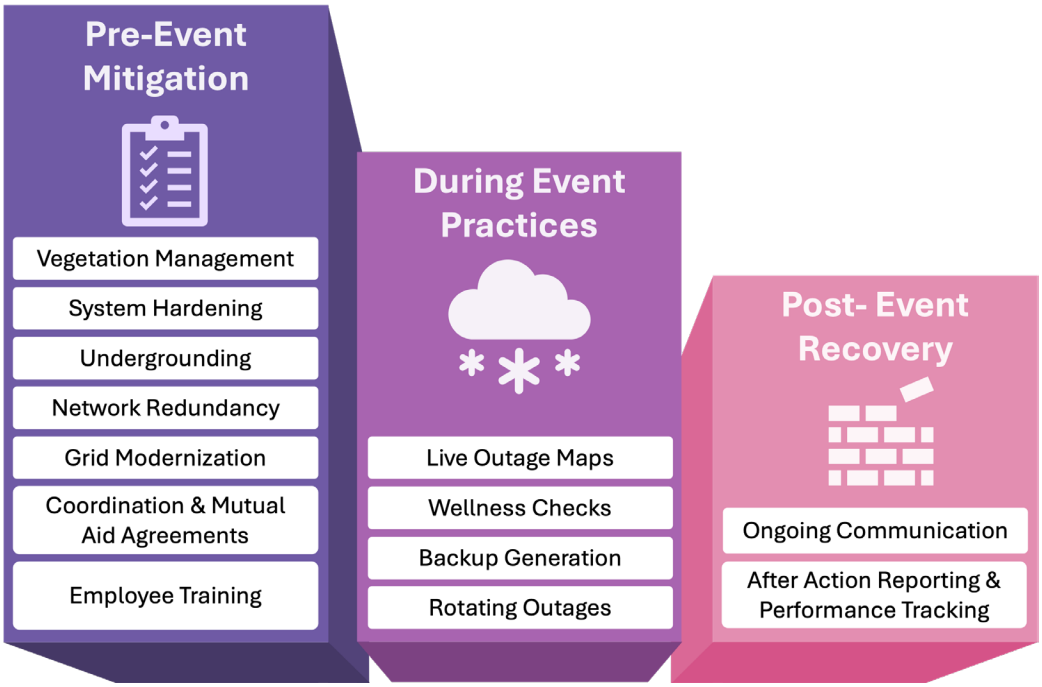


Figure 61: Best Practices for Utility Resilience to Winter Storms[4, 5, 6]

Pre-Event Mitigation: The NLR report provides several long-term mitigation strategies including vegetation management, system hardening and undergrounding, network redundancy, and grid modernization. Short-term operational strategies, focused on communication and response, can reduce impacts and streamline recovery during and after an event. Long-term resiliency investments in energy infrastructure increase the overall resiliency of the system. Vegetation management strategies, such as tree trimming and installation of tree-resistant

[1] J. Keen *et al., "Current Practices in Distribution Utility Resilience Planning for Winter Storms,"* NREL/TP--6A40-88974, 2478837, MainId:89753, Aug. 2024. https://www.osti.gov/servlets/purl/2478837/
[2] Center for Climate and Energy Solutions, *"RESILIENCE STRATEGIES FOR POWER OUTAGES,"* Aug. 2019. https://www.c2es.org/document/resilience-strategies-for-power-outages/
[3] Koho *et al.*, *"Oregon Guidebook for Local Energy Resilience: for small and medium electric utilities,"* 2019. https://www.oregon.gov/energy/safety-resiliency/Documents/Oregon-Resilience-Guidebook-COUs.pdf
[4] Information from J. Keen *et al.*, ibid.
[5] Information from L. Koho *et al.*, ibid.
[6] Information from Center for Climate and Energy Solutions, ibid.

conductors, can reduce the number of power outages caused by branches falling on power lines during a storm. System hardening strategies, such as upgrading distribution system components for increased structural capability in the face of wind gusts and ice accumulation. Undergrounding distribution lines completely prevents wind- or ice-induced failure. Network redundancy ensures that critical hubs and infrastructure retain service in the event of a partial outage. Grid modernization can improve a utility's ability to gather data and respond to impacts. Examples of grid modernization technologies include advanced metering infrastructure (AMI), ***supervisory control and data acquisition (SCADA)*** systems, fault location isolation and service restoration (FLISR), and remote facility control. Additional modernization technologies are discussed in ***Chapter 6***. Finally, investments in distributed energy resources, such as backup generators and portable energy stations, can assist communities during long-lasting power outages.[1]

Outside of electricity system upgrades and operations, utilities can further aid in winter storm resilience by through coordination and mutual aid agreements with other agencies and formalizing employee training (e.g., Incident Command System training). Mutual aid agreements can provide utilities with much-needed personnel and resources to restore service quickly and efficiently. Both the NLR report and The Oregon Guidebook for Local Energy Resilience[2] discuss how utilities aid overall risk mitigation by establishing mutual aid agreements with other utilities throughout the state, region, and country. Utilities can deploy Incident Command System (ICS) training, which prepares staff to implement emergency response operations.

During Event Practices: Short-term operational strategies can reduce impacts and streamline system recovery. NLR's report on utility resilience planning for winter storms notes the importance of maintaining an accurate outage map to inform customers. Other during-event best practices include customer wellness checks (i.e., emergency outreach programs for vulnerable customers like the elderly or medically fragile), use of backup generation (e.g., distribution of portable generators), and implementation of rotating outages. Utilities can record vulnerable customers (see ***Section 3.4***) and prioritize those customers for wellness checks, communication, and power restoration. Portable backup generators and rotating outages can be deployed in the case of inadequate generation or transmission outages.

Post-Event Recovery: After a winter storm, ongoing communication is essential to inform customers about estimated restoration times and available resources.[1, 2, 3] Development of "Situation Reports", often termed "After Action" reports, is another post-event best practice that encourages utilities to assess their winter weather response. Situation reports help utilities understand their strengths, weaknesses, and lessons learned to improve storm preparedness.

5.4.2 Mitigation Approaches Applied in Lane County

This section summarizes Lane County utility winter storm resilience practices across pre-event, during-event, and post-event phases (***Table 40***, ***Table 41***, and ***Table 42***, respectively). Findings are based on publicly available materials (e.g., after-action reports, capital improvement plans,

[1] J. Keen *et al.*, ibid
[2] L. Koho *et al.*, ibid.
[3] Center for Climate and Energy Solutions, *"Resilience Strategies For Power Outages,"* Aug. 2018. https://www.c2es.org/wp-content/uploads/2018/08/resilience-strategies-power-outages.pdf

and utility websites) available for EWEB,[1,2,3,4,5] EPUD,[6,7] SUB,[8,9] Blachly-Lane,[10,11] Lane Electric,[12,13,14] and Central Lincoln.[15,16,17] Where a practice is marked "not documented," it indicates it was not identified in reviewed sources, not necessarily that the utility does not perform the activity.

Pre-Event Winter Storm Best Practices Applied in Lane County

Across Lane County utilities, the most documented pre-event mitigation approaches are vegetation management, hardening upgrades, undergrounding, and selective efforts to increase system redundancy. The extent to which these strategies are formalized varies by utility. In general, larger utilities appear to provide more explicit documentation of winter storm mitigation activities, while smaller cooperatives more often reference related actions through broader reliability or wildfire mitigation efforts rather than through winter storm specific planning.

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[1] Eugene Water & Electric Board, *"The Big Freeze 2024: After Action Report"* https://www.eweb.org/your-public-utility/news/the-big-freeze-2024-after-action-report
[2] Eugene Water & Electric Board, *"Ramping Up on Electric Infrastructure Investments"*https://www.eweb.org/your-public-utility/news/ramping-up-on-electric-infrastructure-investments
[3] Eugene Water & Electric Board, *"Largest Transformer Order in EWEB History Begins New Era of Substation Rebuilds"* https://www.eweb.org/your-public-utility/news/largest-transformer-order-in-eweb-history-begins-new-era-of-substation-rebuilds
[4] Eugene Water & Electric Board, *"EWEB's Climate Principles"* https://www.eweb.org/environment-and-climate/climate-guidebook/ewebs-climate-principles
[5] Eugene Water & Electric Board, *"Power Outage Map"* https://www.eweb.org/outages-and-safety/power-outages/power-outage-map
[6] Emerald People's Utility District, *"Ice Storm Post-Event Analysis"*, May 2024. https://www.epud.org/wp-content/uploads/Ice-Storm-Post-Event-Analysis-05-28-24.pdf
[7] Emerald People's Utility District, *"2024 Ice Storm ETRs"* https://www.epud.org/2024-ice-storm-etrs/
[8] Springfield Utility Board, *"January 2024 Ice Storm After Action Report and Improvement Plan"* https://www.subutil.com/wp-content/uploads/SUB-January-2024-Ice-Storm-After-Action-Report-and-Improvement-Plan.pdf
[9] Springfield Utility Board, *"After Action Report: January 2024 Storm"* https://www.subutil.com/wp-content/uploads/Springfield-Utility-Board-AAR-January-2024-Storm.pdf
[10] Blachly-Lane Electric Cooperative, *"Outage Preparedness"* https://www.blachlylane.coop/outages-safety/outage-center/outage-preparedness/
[11] Blachly-Lane Electric Cooperative, *"Outage Map"* https://www.blachlylane.coop/outages-safety/outage-center/outage-map/
[12] Lane Electric Cooperative, *"Emergency Outage Preparedness"* https://www.laneelectric.com/outages-safety/outage-center/emergency-outage-preparedness/
[13] Lane Electric Cooperative, *"Vegetation Management"* https://www.laneelectric.com/member-services/vegetation-management/
[14] Lane Electric Cooperative, *"Outage Map Status"* https://www.laneelectric.com/outages-safety/outage-center/outage-map-status/
[15] Central Lincoln People's Utility District, *"Volume II – Central Lincoln PUD Addendum"* https://www.co.lincoln.or.us/DocumentCenter/View/1101/Volume-II---Central-Lincoln-PUD-Addendum-PDF
[16] Central Lincoln People's Utility District, *"Outage Map"* https://clpud.org/customer-information/outages/outage-map/
[17] Central Lincoln People's Utility District, *"Outage Information"* https://clpud.org/customer-information/outages/outage-information/

Vegetation Management: Among the utilities reviewed, vegetation management is one of the most consistently documented strategies. EWEB, EPUD, Blachly-Lane, Lane Electric, and Central Lincoln PUD all reference vegetation management in some form, reflecting its importance as a frontline measure for reducing outages caused by falling limbs and tree contact during ice and wind events. In several cases, however, vegetation management is described more broadly as part of routine reliability or wildfire risk reduction rather than as a winter-storm-specific strategy. This suggests that, in Lane County, vegetation management functions as a cross-hazard resilience measure with benefits for both wildfire and winter storm risk.

System Hardening: EWEB provides one of the clearest examples of active winter storm mitigation investment, having secured FEMA funding to support hardening upgrades and targeted undergrounding projects intended to reduce damage from future ice storms.[1] EPUD similarly identifies undergrounding and system enhancement as important resilience measures, and its January 2024 ice storm post-event analysis notes that newer underground facilities experienced comparatively little damage during that storm.[2] At the same time, EPUD also notes that undergrounding is not feasible in all locations due to rocky soils and high costs, highlighting a challenge likely relevant in other parts of the county as well. Central Lincoln PUD also documents ongoing underground conversions,[3] while Lane Electric and Blachly-Lane reference undergrounding or hardening more indirectly through wildfire-related mitigation activities that may also improve winter storm resilience.[4, 5]

Network Redundancy: Compared with vegetation management and undergrounding, network redundancy is less uniformly documented but still appears in several utility materials. EWEB[1] and Central Lincoln PUD[3] identify redundancy as part of their resilience approach, and EPUD's January 2024 ice storm post-event analysis also points to increased redundancy as a needed system improvement.[2] By contrast, SUB's after-action materials identify insufficient redundant assets and backup capability as a key weakness during the ice storm response,[6,7] suggesting that this remains an area of uneven implementation across Lane County utilities.

Grid Modernization: Other best practices appear less consistently documented. Grid modernization is not commonly described as a winter-storm resilience strategy across utilities, however the Central Lincoln PUD Hazard Mitigation Plan does include a mitigation action focused on modernizing the transmission, substation, and distribution system infrastructure.[3]

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[1] Eugene Water & Electric Board, *"Ramping Up on Electric Infrastructure Investments"*, Mar. 2023.https://www.eweb.org/your-public-utility/news/ramping-up-on-electric-infrastructure-investments

[2] Emerald People's Utility District, *"Ice Storm Post-Event Analysis"*, May 2024. https://www.epud.org/wp-content/uploads/Ice-Storm-Post-Event-Analysis-05-28-24.pdf

[3] Central Lincoln People's Utility District, *"Central Lincoln PUD Addendum to the Lincoln County Multi-Jurisdictional Haard Mitigation Plan,"* https://www.co.lincoln.or.us/DocumentCenter/View/1101/Volume-II---Central-Lincoln-PUD-Addendum-PDF

[4] Blachly-Lane Electric Cooperative, *"Blachly-Lane Electric Cooperative Wildfire Mitigation Plan," May 2022.* https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq82616.pdf

[5] Lane Electric Cooperative, *"Manager's Message – June 2025,"* https://www.laneelectric.com/news-releases/managers-message-june-2025/

[6] Springfield Utility Board, *"January 2024 Ice Storm After Action Report and Improvement Plan,"* https://www.subutil.com/wp-content/uploads/SUB-January-2024-Ice-Storm-After-Action-Report-and-Improvement-Plan.pdf

[7] Springfield Utility Board, *"After Action Report: January 2024 Storm,"* https://www.subutil.com/wp-content/uploads/Springfield-Utility-Board-AAR-January-2024-Storm.pdf

Coordination and Mutual Aid Agreements: Mutual aid agreements are documented for EWEB,[1] EPUD,[2] SUB,[6] and Central Lincoln PUD,[2] indicating that external restoration support is an important regional resilience mechanism, particularly for severe events that overwhelm local staffing capacity. As described in ***Section 5.4.2***, these utilities are also part of the Western Regional Mutual Assistance Agreement (WRMAA).[3]

Employee Training: In contrast, formal Incident Command System employee training appears to be less consistently embedded. EWEB[1] documents active ICS-related preparedness, while EPUD[2] and SUB[6] both identify ICS-related refinements or training gaps in their post-event analyses. This suggests that, while some utilities are using incident command structures during storm response, the degree of formalization and training varies substantially.

Overall, pre-event mitigation in Lane County shows the strongest alignment around traditional infrastructure and vegetation strategies, while more organizational and advanced resilience practices, such as employee training, grid modernization, and formal redundancy planning, appear less consistently documented across all utilities.

Table 40: Documented Pre-event Winter-Storm Resilience Practices by Lane County Utilities
(A = active; P = planned; C = considered; N = not documented)

	EWEB	EPUD	SUB	Blachly-Lane	Lane Electric	Central
Vegetation Management	A	A	N	A	A	A
System Hardening	A	C	N	A	A	N
Undergrounding	A	P	N	A	A	A
Network Redundancy	A	C	N	A	N	A
Grid Modernization	N	N	N	N	N	A
Coordination & Mutual Aid Agreements	A	A	A	N	N	A
Employee Training	A	C	N	N	N	N

During-Event Winter Storm Best Practices Applied in Lane County

Live Outage Maps: During winter storm events, the most consistently documented utility practices in Lane County are customer outage maps. EWEB, SUB, Blachly-Lane, Lane Electric, and Central Lincoln PUD all provide outage maps or online outage information, and EPUD

[1] Eugene Water & Electric Board, *"The Big Freeze 2024: After Action Report,"* https://www.eweb.org/your-public-utility/news/the-big-freeze-2024-after-action-report
[2] Central Lincoln People's Utility District, *"Public Power Helping Public Power,"* https://clpud.org/2026/01/public-power-helping-public-power/
[3] *"Western Region Mutual Assistance Agreement for Electric and Natural Gas Utilities,"* 2003. https://www.westernenergy.org/wp-content/uploads/2024/08/western-region-mutual-assistance-agreement.pdf

identified development of a customer-facing outage map as a planned improvement following the ice storm that occurred in January 2024.[1] This suggests that real-time or near-real-time outage visibility is becoming a baseline customer service expectation across Lane County utilities. At the same time, after-action reporting indicates that simply having an outage map is not always sufficient; performance, accuracy, and restoration detail remain important issues. EWEB, for example, identified the need to improve outage map functionality following the January 2024 ice storm.[2] This points to a broader implementation gap between the existence of customer-facing tools and their effectiveness during high-impact events.

Wellness Checks, Backup Generation, and Rotating Outages: By comparison, more resource-intensive practices such as wellness checks, backup generator deployment, and rotating outages are much less commonly documented. Of the reviewed utilities, EWEB documentation of the 2024 ice storm indicated that small portable emergency generators were deployed to homes that house operators, and the utility's liaison office worked with Lane County Public Health on welfare checks during the storm.[3] These actions align closely with best practices for supporting medically vulnerable customers and reducing hardship during prolonged outages, but similar programs were not identified in publicly available materials for the other utilities. This may indicate that these activities are less common, more limited in scope, or coordinated through county or community partners rather than utility-led programs. For example, Lane Council of Governments Senior & Disability Services reports it conducts proactive risk assessments and emergency outreach to case-managed medically vulnerable residents, coordinating support and referrals through the Emergency Operations Center and the state Emergency Response System. Rotating outages were not mentioned in the reviewed utility documents. This absence is notable but not surprising, as the most severe winter storm impacts in Lane County appear to be driven primarily by physical damage to distribution infrastructure rather than by system-wide generation shortages requiring managed load shedding. As a result, during-event utility practice in Lane County is centered more on damage response and outage communication than on demand-management measures.

Taken together, these patterns suggest that during-event practice across Lane County utilities is strongest around customer outage awareness, but less developed or publicly documented in direct customer support interventions for prolonged outages.

[1] Emerald People's Utility District, *"Ice Storm Post-Event Analysis"*, May 2024. https://www.epud.org/wp-content/uploads/Ice-Storm-Post-Event-Analysis-05-28-24.pdf
[2] Eugene Water & Electric Board, ibid.
[3] Eugene Water & Electric Board, ibid.

Table 41: Documented during event winter-storm resilience practices by Lane County utilities
(A = active; P = planned; C = considered; N = not documented)

	EWEB	EPUD	SUB	Blachly-Lane	Lane Electric	Central
Live Outage Maps	A	P	A	A	A	A
Wellness Checks	A	N	N	N	N	N
Backup Generation	A	N	N	N	N	N
Rotating Outages	N	N	N	N	N	N

Post-Event Winter Storm Best Practices Applied in Lane County

Ongoing Communication: Most of the reviewed utilities document some form of post-event customer communication, whether through websites, social media, alerts, news media, or radio. EWEB, EPUD, SUB, Blachly-Lane, and Lane Electric all provide evidence of at least some communication mechanisms to keep customers informed during or after outages, while Central Lincoln PUD's communication appears to rely more narrowly on customers checking utility social media or website updates.[1] Across utilities, communication challenges emerge as a recurring theme. EWEB's after-action report identified failures in its text message update system and noted the need for clearer messaging about repair priorities and improved outreach to upriver customers.[2] EPUD and SUB similarly identified communication as an area needing improvement, with SUB specifically noting that communication lacked adequate frequency, format, and detail during the event.[3] These findings suggest that while customer communication is widely recognized as essential, major winter storms continue to expose weaknesses in message delivery systems and public-facing restoration information.

After Action Reporting & Performance Tracking: The use of formal after-action reports is inconsistent. EWEB,[4] EPUD,[5] and SUB[6] all produced post-event documentation that assessed response performance and identified lessons learned and improvement actions. In contrast, no after-action report was identified in reviewed materials for Blachly-Lane, Lane Electric, or Central Lincoln PUD. While the absence of a publicly available report does not necessarily mean that no internal review occurred, it does suggest a less visible or less formalized post-

[1] Central Lincoln People's Utility District, *"Outage Information,"* https://clpud.org/customer-information/outages/outage-information/
[2] Eugene Water & Electric Board, *"The Big Freeze 2024: After Action Report"*, Apr. 2024. https://www.eweb.org/your-public-utility/news/the-big-freeze-2024-after-action-report
[3] Springfield Utility Board, *"January 2024 Ice Storm After Action Report and Improvement Plan"*. https://www.subutil.com/wp-content/uploads/SUB-January-2024-Ice-Storm-After-Action-Report-and-Improvement-Plan.pdf
[4] Eugene Water & Electric Board, ibid.
[5] Emerald People's Utility District, ibid.
[6] Springfield Utility Board, ibid.

event evaluation process. This is an important distinction, because after-action reporting helps utilities move beyond immediate restoration and into longer-term resilience improvement.

Overall, post-event practices in Lane County show broad recognition of the importance of customer communication but also reveal persistent communication shortcomings during major outages. Meanwhile, formal after-action assessment appears to be an area where implementation is less consistent across utilities, with larger or more highly resourced utilities appearing more likely to document lessons learned and identify follow-up actions.

Table 42: Documented post-event winter-storm resilience practices by Lane County utilities *(A = active; P = planned; C = considered; N = not documented)*

	EWEB	EPUD	SUB	Blachly	Lane Electric	Central
Ongoing Communication	A	A	P	A	A	N
After-Action Reporting & Performance Tracking	A	A	A	N	N	N

5.4.3 Gaps and Opportunities

Overall, Lane County utilities appear to implement several foundational winter storm resilience practices, particularly vegetation management, selective undergrounding, and outage communication (i.e., maps and customer updates). However, implementation is uneven across utilities, and more advanced or formalized practices are less consistently documented. There are several common gaps, which suggest opportunities for improvement and collaboration:

- ***Standardized winter storm resilience planning*** could help utilities and customers understand what mitigation, response, and recovery measures are in place.
- ***Redundancy, backup power, and operational coordination*** appear to be uneven across utilities and may warrant additional planning, particularly for prolonged outages and services to critical populations.
- ***Standardized after-action reporting*** and communication practices could help utilities evaluate storm response more consistently and improve customer-facing information during future events.

5.5 Extreme Heat

The National Oceanic and Atmospheric Administration (NOAA) reported that 2014 to 2024 have been the warmest years on record, which spans 1850 to 2024.[1] This trend holds true for Lane County, which has experienced an average warming of approximately 0.03°F per year over the last 46 years. Lane County's average annual temperature is projected to continue growing at an

[1] NOAA National Centers for Environmental Information, *"Global Climate Report – Annual 2024 (Global Monthly Climate Report 202413)"* https://www.ncei.noaa.gov/access/monitoring/monthly-report/global/202413

increasing rate,[1] with an average warming of approximately 0.07°F per year projected over the next 73 years (***Figure 62*** and ***Figure 63***).

Extreme heat can have a several different effects on utility assets. Because the power system is designed to operate within certain thermal limits, extreme heat can cause protective equipment to trip, leading to grid faults or component damage. Extreme heat can reduce generation, transmission, or distribution equipment efficiency, and may require that utilities derate—that is, reduce the available capacity of—equipment.[2] Generation is less efficient when extreme heat events occur. Powerplants that rely on water for cooling lose efficiency as cooling-water temperatures rise, and solar panel efficiency declines if the ambient temperature is too hot.[3] Higher ambient temperatures increase the vibration of the electrons, which slows their transport in powerlines and leads to more energy loss. Heat also limits the ability of equipment to shed internally generated heat, lowering the safe operating capacity of equipment.[4] Overall, a Los Angeles County grid vulnerability assessment found that most grid components were projected to experience between 2 and 20% capacity loss as air temperatures exceed 104 °F. Damage to utility equipment from extreme heat is covered in detail by Guddanti et al., (2024).[5]

[1] GEOS Institute, *"Climate Trends Primer: Lane County, Oregon"*, May. 2021. https://climatereadycommunities.org/wp-content/uploads/2021/10/Lane-County-Climate-Trends-Primer.pdf

[2] Pacific Northwest National Laboratory, *"Emerging Best Practices for Electric Utility Planning with Climate Variability," May 2023.* https://www.pnnl.gov/sites/default/files/media/file/Final%20Report%206_7_2023.pdf

[3] Pacific Northwest National Laboratory, *"Extreme Heat, Hurricanes, Wildfires: How Summer Extremes Disrupt the Power Grid," Jul. 2024.* https://www.pnnl.gov/news-media/extreme-heat-hurricanes-wildfires-how-summers-extremes-disrupt-power-grid

[4] California Energy Commission, *"CLIMATE CHANGE IN LOS ANGELES COUNTY: GRID VULNERABILITY TO EXTREME HEAT"*, Aug. 2018. https://www.energy.ca.gov/sites/default/files/2019-11/Energy_CCCA4-CEC-2018-013_ADA.pdf

[5] Oregon Department of Energy, *"Energy Sector Overview / CCCA4 Technical Report (CEC-2018-013)"*, Nov. 2019. https://doi.org/10.48550/arXiv.2410.08425

Figure 62: Lane County's Historical Average Annual Temperature and Projected Average Annual Temperature[1] *(gridMET METDATA)* (MACAv2-METDATA; GFDL-ESM2M; RCP 8.5) for 2026–2099

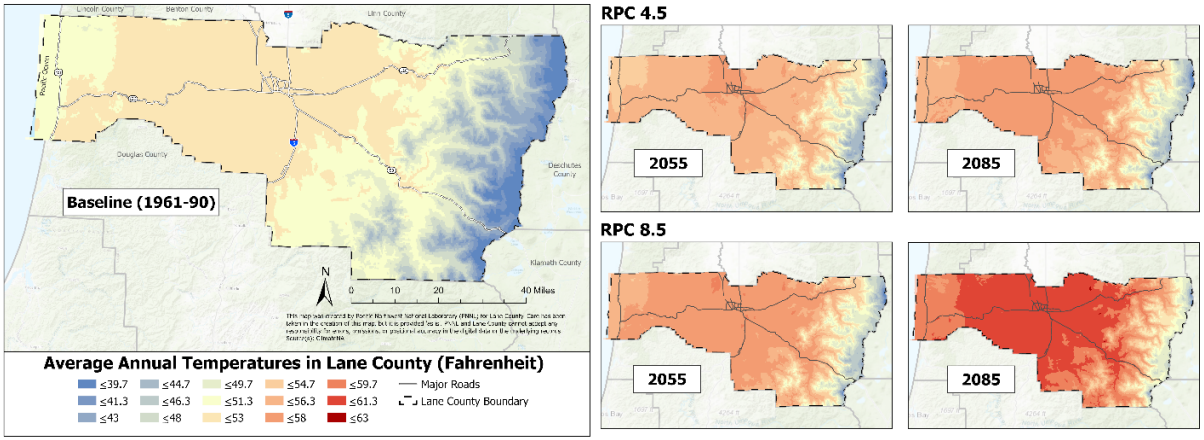


Figure 63: Baseline and Future Projected Mean Annual Temperature Across Lane County
Baseline historical timeframe (1961–1990) and two future years (2055 and 2085) each with two different future scenarios: Representative Concentration Pathways (RCP) 4.5, which considers intermediate greenhouse gas reduction success, and RCP 8.5, which represents the business-as-usual projection [2,3]

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[1] Data from Climate Toolbox, https://climatetoolbox.org/tool/Data-Download

[2] Figure adapted from GEOS Institute, *"Climate Trends Primer: Lane County, Oregon"*, May. 2021. https://climatereadycommunities.org/wp-content/uploads/2021/10/Lane-County-Climate-Trends-Primer.pdf

[3] Data from Wang, T., Hamann, A., Spittlehouse, D. L., & Carroll, C. (2016). *ClimateNA (Version 7.70)* [Software]. University of British Columbia. https://climatena.ca/

5.5.1 Best Practices

Best practices for utility extreme heat resilience were synthesized primarily from a PNNL report that compiles best practices for forecasting, resource planning, asset planning, and contingency planning under climate variability;[1] a California Energy Commission-funded technical assessment of Los Angeles County's grid vulnerability to extreme heat;[2] an extreme heat playbook produced by the U.S. Department of Housing and Urban Development;[3] and a recent newsletter article publication, which discusses demand-side strategies to manage heat-driven load and reduce heat stress on infrastructure.[4] ***Figure 64*** lists specific measures and activities that are considered best practices for utility extreme heat resilience at each phase of a disaster.

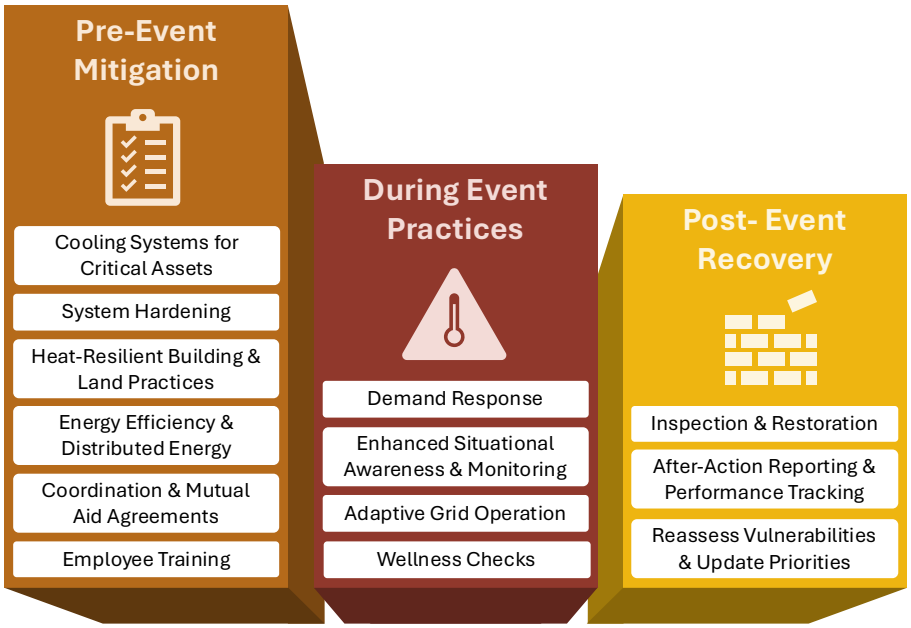


Figure 64: Best Practices for Utility Resilience to Extreme Heat[5, 6, 7, 8]

[1] Pacific Northwest National Laboratory, *"Emerging Best Practices for Electric Utility Planning with Climate Variability"*, May. 2023. https://www.pnnl.gov/sites/default/files/media/file/Final%20Report%206_7_2023.pdf

[2] California Energy Commission, *"Climate Change in Los Angeles County: Grid Vulnerability to Extreme Heat"*, Aug. 2018. https://www.energy.ca.gov/sites/default/files/2019-11/Energy_CCCA4-CEC-2018-013_ADA.pdf

[3] U.S. Department of Housing and Urban Development, *"Extreme Heat Playbook"*, 2025. https://eelp.law.harvard.edu/wp-content/uploads/2025/01/777218685-U-S-Department-of-Housing-and-Urban-Development-s-Extreme-Heat-Playbook.pdf

[4] Baranek, K., Ramirez, A., & Mendelson, Z. (2025). Integrated approaches to urban heat mitigation: Utility infrastructure, building efficiency, and their socioeconomic impacts. *Climate and Energy, 41*(10), 1–10. https://doi.org/10.1002/gas.22457

[5] Pacific Northwest National Laboratory, ibid.

[6] California Energy Commission, ibid.

[7] U.S. Department of Housing and Urban Development, ibid.

[8] Baranek, K., Ramirez, A., & Mendelson, Z. Ibid.

Pre-Event Mitigation: A range of pre-event best practices can be used by utilities to reduce heat exposure and system stress before an event occurs. Equipment cooling systems can prevent damage to heat sensitive critical utility infrastructure assets (i.e., degraded performance or reduced capacity) improved. The California Energy Commission report notes that substations can be adapted with improved heat sinks, forced air, or water-cooling systems.[2]

System hardening approaches are another best practice utilities can use to prepare infrastructure for extreme heat events. Critical equipment (i.e., poles, conductors, transformers, substation equipment) can be upgraded or replaced to meet higher design standards including broader temperature ratings.[1]

Another mitigation approach is mitigating electricity demand surges during extreme heat events. To lessen energy burden during extreme heat events caused by the corresponding increased use of mechanical cooling (e.g., air conditioning), changes to land use and building construction approaches could be considered. Examples of heat-resilient building and land practices include the use of reflective materials, enhanced insulation, passive cooling techniques, and urban tree canopy cover.[3] These interventions are not inherently utility driven and are most effective when urban planners, utilities, and governmental entities collaborate.[4] Another approach to reducing the electricity demand during an extreme heat event is through energy efficiency improvements,[2] which utilities can support through targeted programs like audits, retrofits, and HVAC upgrades.[1, 3] Weatherization programs and heat pump installations can also mitigate health impacts from extreme heat by keeping homes cool, while reducing energy consumption.[1, 2]

Use of energy efficiency and distributed energy strategies can also prevent electric grid overload during extreme heat events. These non-wire alternatives include decentralized generation, microgrids, virtual power plants, and increased storage as approaches to reduce reliance on long transmission paths that are susceptible to extreme heat impacts.[3, 4, 5]

Before an extreme heat event, utilities can also form regional cooperation and grid-coordination agreements to rapidly share capacity by exporting power from unaffected, lower-demand and high-supply areas to the heat-impacted regions in the case of an extreme heat event.[6]

Like many of the other natural hazard events that pose risks to utilities, employee trainings are a best practice that mitigates extreme heat risk prior to the event. Utility personnel should conduct emergency training, drills, and preparedness education to ensure field and operations staff can respond safely and effectively during heat-drive system stress.[4]

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[1] Oak Ridge National Laboratory, *"Health and Household-Related Benefits Attributable to the Weatherization Assistance Program,"* Sep. 2014. https://weatherization.ornl.gov/wp-content/uploads/pdf/WAPRetroEvalFinalReports/ORNL_TM-2014_345.pdf

[2] Rocky Mountain Institute, *"Why Heat Pumps Are the Answer to Heat Waves,"* Aug. 2021. https://rmi.org/why-heat-pumps-are-the-answer-to-heat-waves/

[3] Pacific Northwest National Laboratory, ibid.

[4] Virtual Peaker, *"Using Virtual Power Plants To Meet Demand During Heat Waves,"* Jul. 2025. https://www.pnnl.gov/sites/default/files/media/file/Final%20Report%206_7_2023.pdf

[5] PreventionWeb, *"Sharing Risk to Avoid Power Outages in an Era of Extreme Weather,"* Aug. 2024. https://virtual-peaker.com/blog/using-virtual-power-plants-to-meet-demand-during-heat-waves/

[6] The American Society of Mechanical Engineers, *"Preparing the Grid to Deal with the Heat,"* Nov. 2017. https://www.preventionweb.net/news/sharing-risk-avoid-power-outages-era-extreme-weather

During Event Practices: During an event, demand response programs can alleviate heat-driven grid strain by encouraging temporary reduced use of electricity for nonessential purposes during peak heat periods.[4,1]

The use of enhanced situational awareness and monitoring is a during-event best practice outlined in PNNL's Emerging Best Practices for Electric Utility Planning with Climate Variability report. Tools such as ***geographic information systems (GIS)***, distribution system supervisory control and data acquisition (DSCADA), ***fault location, isolation and service restoration systems (FLISR)***, ***volt-var optimization (VVO)***, voltage stabilization (e.g., SVC STATCOM), outage management system, and network monitoring devices allow utilities to quickly identify stressed system parts in real time, shift or reduce load, stabilize voltage during demand spikes, detect failures, and isolate problems.[4]

When experiencing extreme heat events, utilities should adjust operations for the high-temperature conditions, which often coincide with peak loads and reduced equipment performance. For example, in anticipation of the increased demand for electricity, a utility may elect to limit the length of a planned outage during high heat weather or cancel planned maintenance when temperatures exceed certain thresholds.[2]

Like other hazards, utilities can record vulnerable customers and prioritize those customers for wellness checks, communication, and power restoration.

Post-Event Recovery: The PNNL's Emerging Best Practices for Electric Utility Planning with Climate Variability report outlines several post-event best practices.[4] One of which, is inspection and restoration through the use of an asset damage assessment to document what occurred, quantify impacts, and identify system weaknesses revealed by the heat event. Utilities are also encouraged to share lessons learned from extreme heat events to support smaller and rural utilities' ability to navigate these hazards through after-action reporting and performance tracking. Lastly, after an extreme heat event, utilities should reassess system vulnerabilities and upgrade priorities by comparing observed impacts (e.g., outages, load, equipment performance) against prior assumptions and then update risk assessments and corresponding upgrade priorities.

5.5.2 Mitigation Approaches Applied in Lane County

This section summarizes how Lane County-area electric utilities apply extreme heat best practices across the pre-event, during-event, and post-event phases (***Table 43***, ***Table 44***, ***Table 45***, respectively). Findings are based on publicly available materials (e.g., strategic plans,

[1] Energized, *"Why Maintenance Outages Happen When It's Hot,"* Jul. 2024. https://www.asme.org/topics-resources/content/preparing-grid-deal-the-heat
[2] Energized, ibid.

reports, and utility websites) available for EWEB,[1,2,3,4,5,6] EPUD,[7,8] SUB,[9,10] Blachly-Lane,[11] Central Lincoln.[12] A practice marked "not documented" was not identified in reviewed sources but may still be practiced by the utility.

Pre-Event Extreme Heat Best Practices Applied in Lane County

System Hardening: System hardening and equipment upgrades are documented by EPUD, SUB, Blachly-Lane, and Central Lincoln PUD in their respective strategic plans and natural hazard mitigation plans. The majority of hardening projects are undertaken to increase earthquake and winter storm resilience, but actions such as conductor upgrades can add resilience for extreme heat events as well. However, other potential upgrades specific to extreme heat concerns are not well-documented.

Energy Efficiency & Distributed Energy: All Lane County utilities offer rebate programs for residential energy efficiency measures, including weatherization, heat pumps, and appliances. EPUD, EWEB, Blachly-Lane, and Central Lincoln PUD provide rebate programs for commercial, industrial, and agricultural customers. Such programs can help reduce electricity demand from air conditioning and refrigeration during heat waves. EPUD and SUB offer free energy audits for their residential customers. EWEB and EPUD describe plans and efforts to bring local generation sources, such as residential solar, into their systems. Central Lincoln PUD also

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[1] Eugene Water & Electric Board, *"2018–2028 Strategic Plan (2021–2024 Update),"* Sep. 2024. https://www.eweb.org/documents/Reports%20and%20Publications/eweb_strategic_plan_2018_2028_2021_2022_2023_2024_update.pdf

[2] Eugene Water & Electric Board, *"EWEB's Business Management System"*. Aug. 2025. https://www.eweb.org/documents/Reports%20and%20Publications/2025_organizational_goals.pdf

[3] Oregon Department of Energy, *"OREGON RESILIENCE CASE STUDY BUSINESS CONTINUITY PLANNING: DERS & MICROGRIDS,"* 2018. https://www.oregon.gov/energy/safety-resiliency/Documents/DERS-Microgrids-Case-Study.pdf

[4] Oregon Public Broadcasting, *"How Lane County Electric Utilities Deal with Wildfire Danger,"* Jul. 2025. https://www.opb.org/article/2025/07/21/lane-county-electricty-utilities-wildfire-oregon-fire/

[5] Oregon Department of Energy, *"2024 Biennial Energy Report: Energy 101"*. 2024. https://www.oregon.gov/energy/Data-and-Reports/Documents/2024-BER-E101.pdf

[6] Eugene Water & Electric Board, *"Integrated Resource Planning"*. https://www.eweb.org/your-public-utility/power-supply/energy-planning/integrated-resource-planning

[7] Emerald People's Utility District, *"2020 Strategic Plan"*. Jul. 2020. https://www.epud.org/wp-content/uploads/2020-Strategic-Plan_finalSML.pdf

[8] EPUD Addendum provided in "Lane County Multi-Jurisdictional Natural Hazard Mitigation Plan," Lane County, Oregon, Version 4, 2023. https://cdnsm5-hosted.civiclive.com/UserFiles/Servers/Server_3585797/Image/Government/County%20Departments/Emergency%20Management/Planning%20Page/Lane%20County%20MNHMP%20V4_Full%20Plan%20(2).pdf

[9] https://www.subutil.com/wp-content/uploads/SUB-Strategic-Plan-2024-fin-lores.pdf

[10] Springfield Utility Board, *"2025-2030 Strategic Plan"* https://www.subutil.com/about-us/budget-strategic/

[11] Blachly-Lane Addendum provided in "Lane County Multi-Jurisdictional Natural Hazard Mitigation Plan," Lane County, Oregon, Version 4, 2023. https://cdnsm5-hosted.civiclive.com/UserFiles/Servers/Server_3585797/Image/Government/County%20Departments/Emergency%20Management/Planning%20Page/Lane%20County%20MNHMP%20V4_Full%20Plan%20(2).pdf

[12] Central Lincoln People's Utility District, "*Central Lincoln PUD Addendum to the Lincoln County Multi-Jurisdictional Hazard Mitigation Plan"*, 2020. https://www.co.lincoln.or.us/DocumentCenter/View/1101/Volume-II---Central-Lincoln-PUD-Addendum-PDF

offers a rebate program for qualifying renewable energy systems, including solar and battery storage.

Coordination and Mutual Aid Agreements: EPUD and Central Lincoln PUD document general regional cooperation efforts in the form of integration with county and state response plans and participating in interagency tabletop exercises. However, regional cooperation in the form of grid-coordination agreements, capacity sharing, and other operational responses specific to extreme heat events is not documented. Despite the lack of mention of mutual aid specific to extreme heat events, EWEB, EPUD, SUB, and Central Lincoln, are part of the Western Regional Mutual Assistance Agreement (WRMAA).[1]

Employee Training: SUB is executing an initiative to provide formalized safety and emergency preparedness training to staff through FEMA's Incident Command System curriculum. Central Lincoln PUD participates in interagency tabletop exercises on seasonal weather hazards, although it is not clear whether extreme heat is an included hazard. Other utilities have not publicly documented staff training initiatives.

Table 43: Documented pre-event extreme heat mitigation approaches by Lane County utilities *where ✓ indicates the implementation of the best practice was inferred through document review and — indicates the best practice was not documented but may still be used by the utility.*

	EWEB	EPUD	SUB	Blachly-Lane	Lane Electric	Central
Cooling Systems for Critical Assets	—	—	—	—	—	—
System Hardening	—	✓	✓	✓	—	✓
Heat-Resilient Building and Land Practices	—	—	—	—	—	—
Energy Efficiency & Distributed Energy	✓	✓	✓	✓	✓	✓
Coordination & Mutual Aid Agreements	✓	✓	✓	—	—	✓
Employee Training	—	—	✓	—	—	✓

During-Event Extreme Heat Best Practices Applied in Lane County

Demand Response: In their most recent integrated resource plan, EWEB identified demand response as an emerging opportunity, and as of 2025, has completed an initial program

[1] "Western Region Mutual Assistance Agreement for Electric and Natural Gas Utilities," 2003. https://www.westernenergy.org/wp-content/uploads/2024/08/western-region-mutual-assistance-agreement.pdf

assessment. However, none of the Lane County utilities currently make use of a demand response program (see ***Section 4.3***).

Enhanced Situational Awareness & Monitoring: EWEB and Blachly-Lane have documented efforts to install technologies that are better equipped to deal with transient outages, such as automated reclosers and fault location, isolation and service restoration systems. These technologies are typically installed as general grid modernization efforts but can improve operational performance during extreme heat events as well.

Adaptive Grid Operation: No utilities document adaptive grid operation during high temperature conditions.

Wellness Checks: As discussed in ***Section 5.4.2***, EWEB is the only utility that explicitly documents using welfare checks and distributing portable generators, and this is was during a winter storm, not an extreme heat event.[1] Similar programs were not identified in publicly available materials for the other utilities.

Table 44: Documented during-event extreme heat mitigation approaches by Lane County utilities

where ✓ indicates the implementation of the best practice was inferred through document review and — indicates the best practice was not documented but may still be used by the utility.

	EWEB	EPUD	SUB	Blachly-Lane	Lane Electric	Central
Demand Response	✓	—	—	—	—	—
Enhanced Situational Awareness & Monitoring	✓	✓	—	✓	—	—
Adaptive Grid Operation	—	—	—	—	—	—
Wellness Checks	✓	—	—	—	—	—

Post-Event Extreme Heat Best Practices Applied in Lane County

There was no publicly available indication of use of the post-event best practices across Lane County utilities for extreme heat events. However, utilities have used these practices after wildfires (and, in some cases, winter storms): ***Inspection & Restoration***, ***After-Action Reporting & Performance Tracking***, ***Reassess Vulnerabilities & Upgrade Priorities*** (see ***Sections 5.2.2 and 5.4.2***). These approaches should also be applied after extreme heat events.

[1] Eugene Water & Electric Board, *"The Big Freeze 2024: After Action Report,"* Apr. 2024. https://www.eweb.org/your-public-utility/news/the-big-freeze-2024-after-action-report

Table 45: Documented post-event extreme heat mitigation approaches by Lane County utilities *where ✓ indicates the implementation of the best practice was inferred through document review and — indicates the best practice was not documented but may still be used by the utility.*

	EWEB	EPUD	SUB	Blachly-Lane	Lane Electric	Central
Inspection & Restoration	—	—	—	—	—	—
After-Action Reporting & Performance Tracking	—	—	—	—	—	—
Reassess Vulnerabilities & Upgrade Priorities	—	—	—	—	—	—

5.5.3 Gaps and Opportunities

Overall, Lane County utilities appear to implement several foundational extreme heat best practices, particularly grid hardening and equipment upgrades, energy efficiency programs, and grid monitoring and automation tools. However, these actions are rarely framed or documented as extreme heat mitigation, and extreme heat is not consistently identified as a priority hazard in utility planning. For example, in Volume II of the Lane County NHMP, the utility-focused hazard lists for Blachly-Lane Electric Co-op, Consumers Power Inc., and EPUD include winter storms, wildfires, windstorms, earthquakes, volcanoes, and floods, but do not include extreme heat.[1] As a result, current efforts that may incidentally improve extreme heat resilience may not be targeted, tracked, or scaled to match projected extreme heat risk. These gaps suggest several opportunities for improvement and collaboration:

Utilities could ***assess their risk to extreme heat-related vulnerabilities*** (e.g., peak-load stress, equipment temperature limits) and incorporate extreme heat into hazard mitigation plans, emergency plans, and capital planning.

5.6 Digital and Physical Asset Security

Utilities increasingly face security challenges regarding physical and digital assets. Common cyberattacks such as phishing, ransomware, man-in-the-middle attacks, and wiper attacks can leak sensitive information to bad actors and breach protected systems. Upgrades to smart grid technologies, pursued by many utilities to improve service, can introduce further risk through inherent cyber vulnerabilities and require appropriate management.[2] Physical attacks on utility assets are also a concern, with DOE reporting at least 175 instances of physical attacks or

[1] "Lane County Multi-Jurisdictional Natural Hazard Mitigation Plan," Lane County, Oregon, Version 4, 2023. https://cdnsm5-hosted.civiclive.com/UserFiles/Servers/Server_3585797/Image/Government/County%20Departments/Emergency%20Management/Planning%20Page/Lane%20County%20MNHMP%20V4_Full%20Plan%20(2).pdf

[2] Kansas Legislative Research Department, *"Grid Security,"* Dec. 2024. https://klrd.gov/2024/12/18/grid-security/

threats against critical grid infrastructure in 2024.[1] Critical technology infrastructure, such as information technology and operational technology, exist to ensure the protection of private information and reliable operation of assets. However, technologies must be combined with a variety of best practices to ensure the security of utility assets and service.

5.6.1 Best Practices

The North American Electricity Reliability Corporation (NERC) Critical Infrastructure Protection Roadmap establishes baseline requirements for utilities on topics of physical and cyber security.[2] Started in 2005, the Critical Infrastructure Protection Roadmap continues to evolve. Currently, it provides guidance to utilities on twelve infrastructure protection requirements, covering topics such as personnel training, security controls, management of physical and electronic access, incident reporting, and more.

Many physical and cybersecurity best practices are also provided by the American Public Power Association (APPA),[3] the DOE Office of Cybersecurity, Energy Security, and Emergency Response (CESER),[4] and the National Association of Regulatory Utility Commissioners (NARUC).[5] Common risk mitigation efforts listed by the APPA include employee training, encryption and VPN usage, multifactor authentication, and continuous monitoring.[6] ***Figure 65*** lists specific measures and activities that are considered best practices for cyber and physical asset security.

Pre-Event Mitigation: Preparation is key to reducing vulnerabilities in both physical and digital infrastructure. Utilities should use cyber hygiene practices, such as asset identification, configuration management, defensible network topologies, vulnerability management, disciplined patching (see the NERC Critical Infrastructure Protection Roadmap for more details). Other high-priority mitigation approaches recommended by NERC include: use of multifactor authentication, protection of public network communications, and ongoing risk monitoring for areas with large loads, such as distributed energy resource aggregators and electric vehicle supply equipment. In APPA's Cybersecurity Resource Guide for Public Power Utilities, the first recommendation is to develop an organizational understanding of the cybersecurity risks associated with the business context.

Other best practices include: asset risk assessment, development and sharing of organizational cybersecurity policies and procedures, and establishment of organizational cybersecurity roles and responsibilities.[3]

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[1] National Rural Utilities Cooperative Finance Corporation, *"Physical Security Concerns Grow Across the Utility Industry,"* May 2023. https://www.nrucfc.coop/content/solutions/en/stories/energy-tech/physical-security-concerns-grow-across-the-utility-industry.html

[2] North American Electric Reliability Corporation, *"NERC Critical Infrastructure Protection Roadmap,"* Jan. 2026. https://www.nerc.com/globalassets/our-work/reports/special-reports/nerc_cip_roadmap_01122026.pdf

[3] American Public Power Association, *"Cybersecurity Resource Guide For Public Power Utilities,"* https://www.publicpower.org/resource/cybersecurity-resource-guide-public-power-utilities

[4] U.S. Department of Energy, *"Cybersecurity,"* Office of Cybersecurity, Energy Security, and Emergency Response (CESER). https://www.energy.gov/ceser/cybersecurity

[5] National Association of Regulatory Utility Commissioners, *"Cybersecurity for Utility Regulators."* https://www.naruc.org/core-sectors/critical-infrastructure-and-cybersecurity/cybersecurity-for-utility-regulators/

[6] American Public Power Association, *"Common Cyber Risks and How to Mitigate Them." Oct. 2025.* https://www.publicpower.org/periodical/article/common-cyber-risks-and-how-mitigate-them

APPA's Cybersecurity Resource Guide for Public Power Utilities[1] recommends protecting at-risk assets through use of the following best practices: maintaining and controlling audit logs and supporting artifacts, encrypting sensitive data during transit and at rest, frequently testing, updating, and automating security software updates, advocating for cybersecurity professional development, training, and awareness, using security software, regularly backing up and storing data, and generating formal policies for electronic file and device disposal. Finally, after identifying and protecting, APPA's Cybersecurity Resource Guide for Public Power Utilities recommends detection best practices: monitoring for unauthorized access and investigating all unusual network activities.

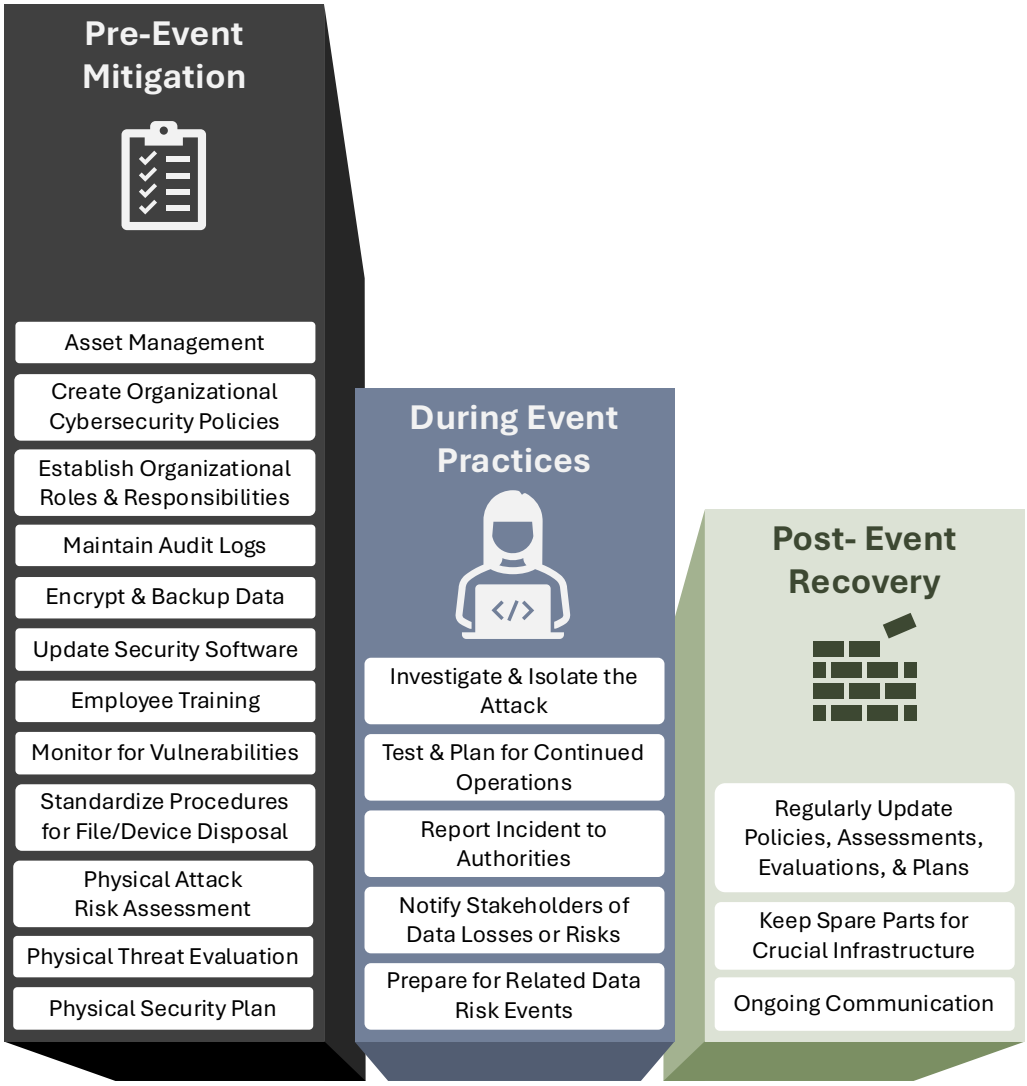


Figure 65: Best Practices for Utility Resilience to Digital and Material Asset Security.[2]

[1] American Public Power Association, ibid.
[2] Information from American Public Power Association, ibid.

NERC established a reliability standard (CIP-014-3)[1] that outlines requirements applicable to utilities seeking to implement physical security best practices. Four requirements apply in the pre-event mitigation stage: (1) perform periodic physical-attack risk assessments for applicable transmission assets (e.g., substations and primary control centers); (2) obtain unaffiliated third-party verification of the risk assessment; (3) conduct a threat and vulnerability evaluation that considers facility-specific characteristics, prior attack history, and threat warnings and intelligence from sources such as law enforcement; and (4) develop and implement a documented physical security plan that includes measures designed to deter, detect, delay, assess, communicate, and respond, including coordination with law enforcement and an execution timeline.

During Event Practices: APPA's Cybersecurity Resource Guide for Public Power Utilities[1] offers recommendations for responding to a detected cybersecurity incident: investigating and isolating the attack, testing and planning for continuity of operations, reporting incidents and attacks to applicable authorities, notifying stakeholders of data losses or data risks, and preparing for additional events that put data at risk. These align with the best practices for physical security events; the DOE's Energy Sector-Specific Plan highlights the importance of rapidly identifying, assessing, and responding to cascading effects during incidents.

Post-Event Recovery: APPA's Cybersecurity Resource Guide for Public Power Utilities also offers several tips related to response and recovery from cybersecurity incidents including: regularly updating cybersecurity policies and capturing lessons learned, keeping spare parts and equipment affected by an event, managing public relations, and continually informing stakeholders of all response and recovery activities. Similarly, for physical security events, the DOE's Energy Sector-Specific Plan highlights the importance of learning after incidents have occurred; as such, similar updates to any established risk assessment, threat and vulnerability evaluation, and physical security plan are also recommended.

5.6.2 Mitigation Approaches Applied in Lane County

This section summarizes how Lane County–area electric utilities apply digital and material asset security best practices across the pre-event, during-event, and post-event phases (***Table 46***, ***Table 47***, and ***Table 48***, respectively). Findings are based on publicly available materials (e.g., strategic plans, memos, and emergency operations plans) available for EWEB,[2] EPUD,[3] and SUB.[4,5] Where a practice is marked "not documented," it indicates it was not identified in reviewed sources, not necessarily that the utility does not perform the activity.

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[1] North American Electric Reliability Corporation, *"CIP-014-3 — Physical Security."* June. 2022. www.nerc.com/globalassets/standards/reliability-standards/cip/cip-014-3.pdf

[2] Eugene Water Electric Board, *"SD20 Annual Enterprise Risk Management (ERM) Update,"* Jul. 2025. https://www.eweb.org/documents/board-meetings/2025/07-08-25/corr_sd20_annual_enterprise_risk_management_update.pdf

[3] Emerald People's Utility District, *"Long-Term Strategic Plan 2020,"* Jul. 2020. https://www.epud.org/wp-content/uploads/2020-Strategic-Plan_finalSML.pdf

[4] Springfield Utility Board, *"Emergency Operations Plan 2025," Mar. 2025.* https://www.subutil.com/wp-content/uploads/SUBEmergencyOperationsPlanBASICPLAN_March2025.pdf

[5] Springfield Utility Board, *"2025-2030 Strategic Plan,"* https://www.subutil.com/wp-content/uploads/SUB-Strategic-Plan-2024-fin-lores.pdf

Pre-Event Digital and Material Asset Security Best Practices Applied in Lane County

The degree of publicly available documentation generally correlates with utility size, with larger utilities providing more detailed descriptions of their cybersecurity posture and smaller utilities providing little specific information. Lane Electric, Central Lincoln PUD, and Blachly-Lane do not discuss cybersecurity or physical security initiatives in their public-facing materials.

Asset Management: Asset inventory is documented by EWEB and EPUD. EWEB describes multi-year efforts to categorize data and maintain it within an accurate system inventory as part of broader cyber and data asset security work. EPUD references a survey of system assets as part of its operational planning. No comparable inventory efforts were identified in publicly available materials for the remaining utilities.

Create Organizational Cybersecurity Policies: Cybersecurity policy development is documented by EWEB and EPUD. EWEB reports that an enhanced cybersecurity policy is being finalized to establish safeguards and guidelines for all staff. EPUD commits to implementing staff training and new security technology to protect data integrity and confidentiality. SUB's Emergency Operations Plan (EOP) does not describe cybersecurity-specific policies, though it identifies cyber-attack as a covered hazard within its broader emergency management framework.

Establish Organizational Roles and Responsibilities: Cybersecurity roles and responsibilities are the most broadly documented pre-event practice, with evidence from EWEB, EPUD, and SUB. EWEB describes plans to develop training on cyber and data security expectations to ensure all employees understand the risks and their role in mitigating them. EPUD has increased its internal IT capabilities in recent years, including adding a separate department with experienced staff dedicated to IT and cybersecurity functions. SUB's EOP defines a detailed command structure with assigned roles and responsibilities, including positions such as Incident Commander, Safety Officer, and Liaison Officer, that apply across all covered hazards including cyber attack. However, none of the three utilities document cybersecurity-specific roles in their publicly available materials.

Encrypt and Backup Data: Data encryption and backup are documented by EWEB and EPUD. EWEB describes migrating sensitive data and backup capabilities to fully redundant cloud environments, adding data center redundancy, and using Multi-Factor Authentication. EPUD's strategic plan describes a move toward cloud-based technologies to ensure system continuity.

Identify Risks to Assets: EWEB describes considerable focus on identifying and mitigating organizational risk across information systems infrastructure, applications, and data security.

Update Security Software: EWEB is also the only utility to document the use of security software updates; a memo describes ongoing monitoring of aging software and infrastructure and a pivot toward creation of an enhanced cybersecurity program.

Employee Training: EWEB and EPUD document the importance of cybersecurity training to educate staff on the risks and mitigation strategies associated with new security technology.

Monitor for Vulnerabilities: SUB is the only utility to discuss vulnerability monitoring; the utility's EOP describes prevention activities including improved surveillance and security, as well

as protection activities involving awareness of threats and vulnerabilities to critical facilities and the expansion of voluntary security-related information sharing between government agencies.

Physical Attack Risk Assessment, Threat Evaluation, and Security Plan: Physical security practices are documented by EWEB and SUB. EWEB maintains a Physical Security Program, which suggests the presence of associated risk assessments, threat evaluations, and security plans. SUB's EOP addresses physical security through its prevention and protection frameworks, including deterrence operations, inspections, investigations to determine the nature and source of threats, and continuity of operations planning.

There was no publicly available indication of best practices, ***Maintain Audit Logs*** and ***Standardize Procedures for File/Device Disposal***. These practices may be documented internally by the utilities.

Table 46: Documented pre-event digital and material asset security resilience practices by Lane County utilities

where ✓ indicates the implementation of the best practice was inferred through document review and — indicates the best practice was not documented, however the utility may still use.

	EWEB	EPUD	SUB	Blachly-Lane	Lane Electric	Central
Asset Management	✓	✓	—	—	—	—
Create Organizational Cybersecurity Policies	✓	✓	—	—	—	—
Establish Organizational Roles and Responsibilities	✓	✓	✓	—	—	—
Maintain Audit Logs	—	—	—	—	—	—
Encrypt and Backup Data	✓	✓	—	—	—	—
Update Security Software	✓	—	—	—	—	—
Employee Training	✓	✓	—	—	—	—
Monitor for Vulnerabilities	—	—	✓	—	—	—
Standardize Procedures for File/Device Disposal	—	—	—	—	—	—
Physical Attack Risk Assessment	✓	—	✓	—	—	—
Physical Threat Evaluation	✓	—	✓	—	—	—
Physical Security Plan	✓	—	✓	—	—	—

During Event Digital and Material Asset Security Best Practices Applied in Lane County

During-event practices are minimally documented across Lane County utilities. Of the five during-event best practices identified in the literature, only two appear in reviewed materials:

Test and Plan for Continued Operations: EWEB describes business continuity planning that includes practicing data and systems recovery from backup tools and maintaining tested plans to operate without technology. EPUD's strategic plan states that secondary systems will be in place to quickly take over in the event of site loss, reflecting a focus on continuity through infrastructure redundancy, though it does not describe testing of these capabilities.

Report Incident to Authorities: SUB's EOP, while not specific to cyber-or physical-security attacks, assigns the Safety Officer and Liaison Officer responsibility for required notifications to OSHA, the Oregon Public Utility Commission, the Oregon Emergency Response System, and other government agencies. While not discussed in utility documents, the federal Cyber Incident Reporting for Critical Infrastructure Act (CIRCIA) directs the Cybersecurity and Infrastructure Security Agency (CISA) to require covered critical-infrastructure entities (potentially including utilities) to report covered cyber incidents to CISA generally within 72 hours (and certain ransom payments within 24 hours), once CISA's implementing regulations take effect.[1]

Notify Stakeholder of Data Losses or Risks: Similar to the best practices on reporting incidents to authorities, utility documentation does not outline how customers would be notified of potential data losses or risks, but the Oregon Consumer Information Protection Act (OCIPA) generally requires entities to provide a notice of a qualifying breach of security involving personal information to affected Oregon consumers without unreasonable delay and within the state's required 45 day timeframe). It is assumed that all utilities are aware of this responsibility.[2]

There was no publicly available indication of use of two of the during event mitigation best practices, ***Investigate and Isolate the Attack*** and ***Prepare for Related Data Risk Events*** by any of the utilities.

[1] Cybersecurity & Infrastructure Security Agency, *"Cyber Incident Reporting for Critical Infrastructure Act of 2022 (CIRCIA),"* https://www.cisa.gov/topics/cyber-threats-and-advisories/information-sharing/cyber-incident-reporting-critical-infrastructure-act-2022-circia

[2] Oregon Department of Consumer and Business Services, *"Oregon Consumer Information Protection Act,"* https://dfr.oregon.gov/business/Documents/4117.pdf

Table 47: Documented during event digital and material asset security resilience practices by Lane County utilities

where ✓ indicates the implementation of the best practice was inferred through document review and — indicates the best practice was not documented, however the utility may still use.

	EWEB	EPUD	SUB	Blachly-Lane	Lane Electric	Central
Investigate and Isolate the Attack	—	—	—	—	—	—
Test and Plan for Continued Operations	✓	✓	—	—	—	—
Report Incident to Authorities	✓	✓	✓	✓	✓	✓
Notify Stakeholders of Data Losses or Risks	✓	✓	✓	✓	✓	✓
Prepare for Related Data Risk Events	—	—	—	—	—	—

Post-Event Digital and Material Asset Security Best Practices Applied in Lane County

Regularly Update Policies, Assessments, Evaluations and Plans: EWEB's strategic plan notes that security resources need to evolve with changing vulnerabilities. EPUD describes leveraging its IT department to ensure the organization stays current with best IT practices. SUB takes a more structured approach, committing to annual reviews of the EOP and tasking its Liaison Officer with facilitating debriefing meetings to capture lessons learned and identify areas for improvement after an emergency incident has occurred.

Keep Spare Parts for Crucial Infrastructure: *While discussed in the context of wildfire hazards, (see* ***Section 5.2.2****), EPUD WMP* mentions the importance of geographic distribution of spare components.[1]

There was no publicly available indication of use of one of the post-event mitigation best practices *(****Ongoing Communication****)* by any of the utilities.

[1] Emerald People's Utility District, *"Wildfire Mitigation & Response Plan,"* May 2022. https://edocs.puc.state.or.us/efdocs/HAQ/ro14haq165613.pdf

Table 48: Documented post-event digital and material asset security resilience practices by Lane County utilities

where ✓ indicates the implementation of the best practice was inferred through document review and — indicates the best practice was not documented, however the utility may still use.

	EWEB	EPUD	SUB	Blachly-Lane	Lane Electric	Central
Regularly Update Policies, Assessments, Evaluations and Plans	✓	✓	✓	—	—	—
Keep Spare Parts for Crucial Infrastructure	—	✓	—	—	—	—
Ongoing Communciation	—	—	—	—	—	—

5.6.3 Gaps and Opportunities

Similar to earthquake and winter storm hazard mitigation, with the information available, it is difficult to evaluate gaps in utilities' digital and asset security risk mitigation strategies. That said, because cyber and physical security threats are human-caused, it may be that utilities do not share information about their mitigation strategies publicly. Initial opportunities for improvement include:

Utilities could expand their implemented ***digital and asset security risk mitigation strategies*** to consider what to do after the incident.

Regional coordination or resource sharing could help smaller utilities adequately plan for digital and asset security risks.

Chapter 6

Available Technologies for Grid Modernization

Amanda Krelling and Kaiyu Sun

Enhancing grid resilience can be supported by a portfolio of solutions that strengthen physical assets, improve operational flexibility, and build the utility's capacity to anticipate and respond to disruptions. Utilities across Lane County are at varying stages of modernization, depending on their size, resources, and regional risks. In this section, to support decision-making and planning, we present a suite of technologies available to utilities for improving reliability and resilience.

The technologies and strategies presented in this section are organized into four groups (***Figure 66***). Technology groups do not prescribe a strict order of implementation. Instead, they provide a general framework for how technologies relate and enable one another. For example, some of the items in Group 1 list provide the foundational communication needed for many of the technologies in Groups 2 and beyond. Similarly, remote devices from Group 2 can be altered to provide the automatic operation discussed in Group 3. Much of the data, visibility, automation and control that is provided by items in Groups 1–3 allows the integrated grid management of Group 4. A utility can benefit from technologies incrementally, deploying them in specific areas or at specific times to suit their needs.

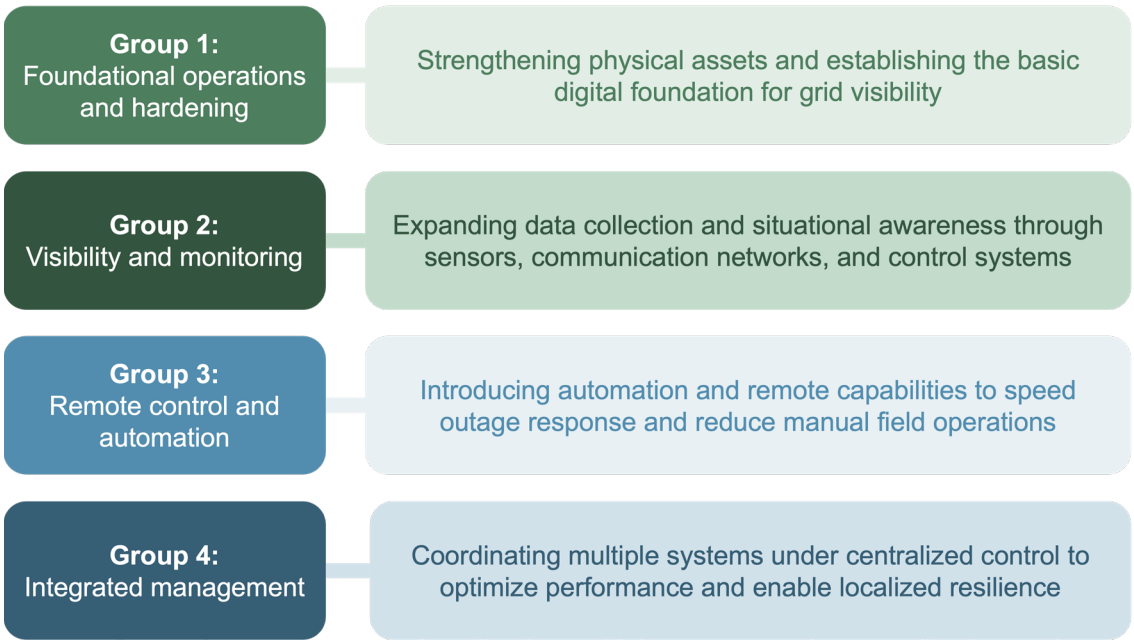


Figure 66: Groups of Technologies to Enhance Grid Resilience

Table 49 summarizes the technologies and solutions available within each technology group. The table will help utilities quickly determine:

Which technologies are already in place.

What operational capabilities technologies provide.

What additional upgrades could enhance system resilience.

Which technologies must be implemented first, based on prerequisite dependencies.

The technology dependencies presented in ***Table 49*** reflect typical implementation pathways. However, actual requirements may vary depending on the level of system complexity, integration, and operational objectives. Some technologies can be deployed in a standalone or limited configuration with fewer prerequisites, while more advanced, fully integrated implementation may require additional foundational systems. Utilities should therefore interpret these dependencies as indicative rather than absolute and consider their specific system architecture and deployment goals when evaluating technology sequencing.

Table 49: Technology Pathway: Key Solutions and Supporting Capabilities by Group

ID	Technology / Solution	Goal	Required Hardware / Software	Prerequisite Technology IDs
Group 1: Foundational operations and hardening				
1.1	Grid hardening	Enhance resistance to storms, wildfires, and other hazards	Pole upgrade, covered/ spacer/underground cables, fire-resistant materials	None
1.2	GIS feeder mapping	Map the location of all feeder components, such as lines, poles, and transformers	GIS software	None
1.3	Substation metering and basic SCADA deployment	Monitor substation electrical data	SCADA server, RTUs, substation sensors and meters, communications links	None
1.4	Communication network upgrade	Connect all field devices quickly and reliably	Fiber, radio, or LTE routers; network gear	None
1.5	SCADA-controlled breakers and RTUs	Control substation devices remotely	Motor-operated breakers, RTUs, radios/fiber	1.3, 1.4
Group 2: Visibility and monitoring				
2.1	Line sensors and remote fault indicators	Automatically indicate faulted line segments	Feeder-mounted current/voltage sensors, wireless indicators	1.3 (if integrated centrally), 1.4
2.2	Advanced Metering Infrastructure (AMI)	Collect real-time customer outage and usage data	Smart meters; head-end, meter data management software	1.4
2.3	AMI-OMS integration	Automatically assist with real time outage management	OMS software integrated with AMI	2.2
Group 3: Remote control and automation				

ID	Technology / Solution	Goal	Required Hardware / Software	Prerequisite Technology IDs
3.1	Automated sectionalizers and programmable reclosers	Automatically clear temporary faults	Intelligent recloser/ sectionalizer controls, IEDs	1.5
3.2	AMS with condition data	Track equipment health and schedule maintenance	Asset sensors, AMS software	1.2
3.3	IEDs	Automate local protection decisions	Upgraded relays, microprocessor controllers	1.3, 1.4
Group 4: Integrated management				
4.1	ADMS deployment	Manage all grid data and control from one system	ADMS platform, data historian, integration servers	1.2, 1.5, 2.2
4.2	FLISR	Automatically isolate faults and restore service	FLISR software module, field-device logic	1.5, 4.1
4.3	VVO	Maintain voltage, reduce peak demand, customer usage and energy losses	Smart capacitors, voltage regulators, VVO software	1.5, 4.1
4.4	DERMS	Monitor and coordinate distributed energy resources, including storage and EVs	DERMS software, telemetry for devices	1.5, 4.1
4.5	Front-of-the-meter battery systems	Store energy for grid support or emergencies	Battery banks, converters, battery management systems, controls	1.4
4.6	Microgrids	Maintain critical loads during grid failure	Microgrid controller, PCC switchgear, communications gateway	1.5, 4.1

The following subsections examine each group in detail, summarizing the benefits, challenges, and implementation considerations associated with the corresponding technologies.

6.1 Group 1: Foundational Operations and Hardening

This group focuses on strengthening distribution system infrastructure and establishing the digital tools needed for effective system management. Utilities commonly invest in grid infrastructure hardening measures to reduce the likelihood of equipment damage from storms, wildfires, or other events. In addition, strategically implementing hardening measures can help address the challenges of aging infrastructure. These actions can lower the frequency of outages and decrease restoration time and repair costs when events do occur. Hardening efforts are typically prioritized in areas vulnerable to environmental hazards or where critical facilities depend on uninterrupted service.

6.1.1 Technology Benefits and Challenges

Table 50 presents the Group 1 technologies and strategies with their key benefits and implementation challenges.

Table 50: Technologies, Benefits, and Challenges in Group 1: Foundational Operations and Hardening

Technology / Solution	Benefits	Challenges
Undergrounding overhead lines: Relocate overhead electrical lines below ground	• Can improve reliability and safety by shielding lines from hazards such as wind, vegetation, ice and wildfire	• High installation and repair costs • Difficult access for maintenance • Vulnerability to flooding, seismic activity, and excavation damage
Installing spacer cable or covered conductors: Upgrade facilities with advanced conductors to reduce exposure to hazards	• Less expensive and often faster alternative to undergrounding • Can improve reliability and safety by reducing exposure • Often applied where vegetation management is impractical	• Requires higher upfront investment relative to traditional bare conductors • Requires more robust supporting structures due to added weight
Replacing poles: Upgrade or replace existing utility poles with stronger, larger, or more durable materials such as steel, composite, or fire-resistant wood	• Increases structural strength and resistance to wind, fire, and impact loads • Reduces pole failures and restoration time after storms	• High material and labor costs • Long replacement timelines • Logistical constraints for transport and installation in remote areas
GIS: Digitally map network assets and topology	• Improves planning, maintenance, visualization	• Requires accurate, regularly updated asset data
Substation metering: Measure voltage, current, and power at substations	• Provides visibility into substation performance and loading • Supports early fault detection	• Limited visibility beyond substation boundaries • Integration with control systems may be required
SCADA deployment: Establish real-time monitoring of substation devices	• Enables real-time system visibility • Enables faster response to abnormal conditions	• High deployment and integration cost • Requires ongoing cybersecurity management • Requires reliable communication networks
Communication network upgrade: Expand fiber, radio, or LTE connectivity for data exchange between field devices and control centers	• Provides the data backbone for real-time control and automation; • Improves coordination between substations and field equipment	• Expensive to deploy and maintain; • Terrain can limit coverage and bandwidth
RTUs: Field devices that connect sensors and breakers to SCADA	• Enables remote control • Allows operators to isolate faults remotely • Enables data transmission • Reduces field crew dispatches	• Requires reliable communication networks • Requires power supply

Grid hardening can include undergrounding electric lines, installing spacer cable or covered conductors, and replacing poles. These efforts can make the grid more resilient to extreme weather and other physical hazards.

In parallel to hardening efforts, utilities can begin digitizing their asset information by implementing GIS and, in some cases, substation-level metering and SCADA systems. A digital inventory of assets allows for better planning, maintenance tracking, and coordination with future data systems such as SCADA and OMS.

Substation metering provides real-time data on voltage, current, and power flows, helping utilities identify equipment loading, performance trends, and early signs of faults or voltage irregularities. When paired with a basic SCADA platform, this information can be transmitted directly to a control center, enabling operators to visualize the operating condition of substations, monitor breaker status, and respond faster to abnormal events. These early digital investments provide the visibility, situational awareness, and data organization required to build more advanced automation and control capabilities in subsequent phases. However, to support these new control capabilities, utilities must also strengthen their communication networks, ensuring that substations, field devices, and control centers can exchange data quickly and reliably.

6.1.2 Regional Experiences with Technologies

Several large investor-owned and regional utilities have publicly reported multi-year performance data on conductor hardening measures. Utilities such as Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), Pacific Power (PacifiCorp), Bear Valley Electric Service (BVES), and Liberty Utilities have demonstrated the effectiveness of specific hardening measures in reducing outage risks. According to their experience, wire insulation provides a cost-effective alternative to undergrounding (about half the cost) but reduces wildfire risk by 60% to 90% compared to up to 99% for underground systems. These utilities have often adopted covered conductors as an intermediate solution to areas where undergrounding is impractical or expensive.[1] Pacific Power also reported that circuits upgraded with spacer cable systems achieved up to a 90% reduction in vegetation- and animal-related outages between 2007 and 2022 in high-risk areas.[2]

Pacific Power has launched a targeted and expansive grid hardening initiative designed to reduce risks.[3] The program prioritizes replacing overhead lines in locations where wildfire ignitions could have especially severe impacts, using fire-resistant components such as covered conductors and undergrounded circuits, and substituting wooden poles with steel and composite poles. For example, in the Grants Pass area,[4] the utility is rebuilding over 500 miles of distribution lines across multiple segments. In the “Riverbanks” segment alone, 70 miles of bare conductors will be replaced with tree-wire and 1,550 wooden poles with steel poles. These

[1] U.S. Department of Energy Grid Deployment Office, “*Utility Wires Investments”,* Sept. 2024. https://www.energy.gov/sites/default/files/2024-11/111524_Utility_Wires_Investments.pdf
[2] PacifiCorp. *“2022 WMP Update Progress Report”,* 2022. https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/wildfire-mitigation/2022_WMP_Update_Attachment_6_CC_Effectiveness_Workstream_R0.pdf
[3] Pacific Power. *“Strengthening our system, reducing risks”*. https://www.pacificpower.net/outages-safety/wildfire-safety/reducing-risks.html
[4] Pacific Power. *“Grants Pass system resiliency”.* https://www.pacificpower.net/outages-safety/wildfire-safety/reducing-risks/grants-pass.html

projects involve collaboration with local agencies and federal land management partners and are partially funded through DOE grants.

Reported costs for grid hardening and conductor upgrade programs vary significantly depending on the project scope. Based on recent utility findings and pilot projects, installation of covered conductors and spacer cable systems typically ranges from approximately $200K per mile to $1,350K per mile, with more comprehensive proposals reaching up to $2,140K per mile.[1] Pacific Power's pilot projects indicate costs from roughly $200K per mile[1] to $700K per mile, while Liberty Utilities reports approximately $1,220K per mile for covered conductor installations.[2] From SCE's experience, inspection and vegetation management activities are substantially lower, ranging from $0.12 per transmission line mile to $52.7 per distribution line mile, depending on line type and inspection method.[3] Actual costs are highly site-specific and depend on factors such as pole condition, span length, terrain, access constraints, labor markets, wildfire risk classification, and whether projects are bundled with broader system upgrades.[1]

6.2 Group 2: Visibility and Monitoring

Building on the foundation of physical hardening and basic digital mapping, the next group focuses on enhancing situational awareness and operational visibility across the distribution system. These technologies allow utilities to see, measure, and track grid conditions in real time, enabling a faster and more informed response to outages and performance issues.

6.2.1 Technology Benefits and Challenges

Key upgrades in this group include line sensors and smart fault indicators, which automatically detect and locate faults along feeders, and ***Advanced Metering Infrastructure (AMI)***, which provides two-way communication with customer meters for near-real-time usage and outage data. When integrated with an ***Outage Management System (OMS)***, AMI data helps visualize where and when outages occur, allowing operators to confirm customer impacts and prioritize restoration. At this stage, some utilities also begin deploying remote-controlled switches and reclosers, not yet for full automation but to extend visibility and enable manual remote operation through SCADA or radio control. These devices serve as a bridge between monitoring and automation, allowing operators to isolate faults and restore service faster even before advanced automation systems are in place.

Table 51 summarizes the key technologies introduced in this group, highlighting their primary benefits and implementation challenges.

[1] Heide Caswell, *"Response to CPUC Data Request 1,"* PacificCorp, Data Request Response, Mar. 2019. https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/wildfire-mitigation/responses-issued/Response_to_CPUC_WMP_Team_Data_Request_Set_1_March_4_2019.pdf

[2] *"2023-2025 WMP,"* Joint IOU Covered Conductor Working Group Report. https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=53548&shareable=true

[3] Southern California Edison, *"2020-2022 Wildfire Mitigation Plan",* Feb. 2020. https://www.sce.com/sites/default/files/AEM/Wildfire%20Mitigation%20Plan/SCE's%202020-2022%20Wildfire%20Mitigation%20Plan%20-%20Revision%2003.pdf

Table 51: Technologies, Benefits, and Challenges in Group 2: Visibility and Monitoring

Technology / Solution	Benefits	Challenges
Line sensors and smart fault indicators: Measure current, voltage, and faults with feeder-mounted devices	• Automatically locates faults • Reduces restoration time	• Requires reliable communication networks • Requires power supply • Limited effectiveness without full feeder coverage
AMI: Provide two-way data between customers and the utility via smart meters and communication systems	• Enables real-time collection of customer outage and usage data • Supports remote meter reading • Can improve outage detection accuracy	• High installation cost • Data management complexity • Potential cybersecurity and privacy concerns
AMI-OMS integration: Links AMI outage data with OMS software	• Provides automatic outage visualization and confirmation of customer impacts • Can improve restoration prioritization and communication	• Integration across platforms can be complex • Requires accurate GIS and meter connectivity data

6.2.2 Regional Experience with Technologies

Emerald PUD's reliability program offers a clear example of how Group 2 technologies can significantly strengthen distribution system performance. By deploying reclosers equipped with integrated voltage sensors on all six bushings, EPUD gains detailed, real-time visibility into feeder conditions without relying on external Potential Transformers (PTs) or complex field wiring. These devices provide continuous monitoring of voltage and current, enabling precise fault characterization, improved protection settings, and more informed decision-making during switching and outage events. The reclosers' communication capabilities allow integration with EPUD's SCADA system, giving engineers centralized oversight of both field and substation devices while supporting rapid remote diagnostics and event-log analysis after faults.[1] These enhancements have reduced the need for manual inspections, shortened restoration times, and improved overall situational awareness, which are important benefits for a small utility with limited staff and a heavily forested service area.

6.3 Group 3: Remote Control and Automation

With technologies and strategies from this group, utilities progress from simply observing system conditions to actively controlling and automating distribution operations. Building on the visibility and data infrastructure developed in earlier stages, these equipment and software allow utilities to respond to faults and changing grid conditions in near real time.

[1] NOJA Power. *"How Emerald PUD Improved their Network Reliability"*, Aug. 2021. https://www.nojapower.com.au/expertise/2021/how-EPUD-improved-their-network-reliability

6.3.1 Technology Benefits and Challenges

Table 52 summarizes the key technologies introduced in this group, outlining their main benefits and implementation challenges.

Table 52: Technologies, Benefits, and Challenges in Group 3: Remote Control and Automation

Technology / Solution	Benefits	Challenges
Automated sectionalizers and programmable reclosers: Detect and isolate faults automatically via intelligent field devices	• Automatically isolates faulted sections and restores power to unaffected areas • Can significantly reduce outage duration	• Requires reliable communication networks and protection • High cost per device • Requires periodic maintenance and firmware updates
AMS with asset condition data: Tracks equipment health using sensors and predictive analytics	• Allows proactive maintenance and replacement before failures occur • Can reduce downtime and asset lifecycle costs	• High upfront investment in sensors and software • Requires data standardization and skilled staff for analysis
IEDs: Informs decision-making via protection relays and controllers with embedded logic	• Provide fast, localized response to abnormal conditions, improving reliability and protection coordination	• High upfront investment in sensors and software • Requires data standardization and skilled staff for analysis

Automated sectionalizers and programmable reclosers enable feeders to detect and isolate faults autonomously, clearing temporary disturbances and restoring power without human intervention. These devices form the foundation of automated fault management and help minimize outage duration and service interruptions.

Enhanced connectivity allows for the integration of systems such as OMS, SCADA, and GIS into a single operational view, giving operators a unified platform to monitor and manage network performance. At the same time, ***Asset Management Systems (AMS)*** collect and analyze condition data from equipment sensors, allowing utilities to plan maintenance proactively rather than reactively. ***Intelligent Electronic Devices (IEDs)*** extend local decision-making by embedding protection logic directly into field equipment, enabling faster and more precise control actions. Together, these technologies represent a transition from manual and centralized operations to automated, coordinated control.

Deploying remote control and automation increases cybersecurity risks by expanding the utility's digital exposure. Networked reclosers, IEDs, and sensors can become entry points for unauthorized access if communications are not properly secured, potentially allowing attackers to disrupt operations, manipulate settings, disable protections, or obtain confidential data. Mitigating these risks requires a risk-based cybersecurity approach that includes strong access controls, secure network architecture, continuous monitoring, incident response planning, and periodic reassessment as technologies and threats evolve.[1]

[1] U.S. Department of Energy. *"Energy Sector Cybersecurity Framework Implementation Guidance,"* Jan. 2015. https://www.energy.gov/ceser/articles/energy-sector-cybersecurity-framework-implementation-guidance

6.3.2 Regional Experience with Technologies

Avista Utilities services parts of eastern Washington, northern Idaho, and western Montana, the utility has implemented advanced grid automation systems that integrate both remote-controlled switching and automated outage detection.[1] Through its Spokane Smart Circuits Project, the utility installed 36 midline reclosers and 124 smart switches connected via a Tropos wireless mesh network, enabling remote fault detection, isolation, and power restoration without manual field intervention. This system allows automatic power rerouting to minimize outage duration and improve reliability. In the Pullman Smart Grid Demonstration Project, Avista expanded these capabilities by linking 34 reclosers and 30 capacitor banks to a private broadband communications network integrated with AMI. The AMI system enables real-time outage detection and confirmation of service restoration.

6.4 Group 4: Integrated Management

By adopting technologies and strategies from this group, utilities evolve from operating independent systems to managing them in a coordinated, data-driven, and integrated environment. The focus shifts from responding to events to proactively optimizing system performance and maintaining stability under a wider range of conditions. This group of technologies enables utilities to merge information from multiple sources (e.g., operations, assets, distributed resources, and customer endpoints) into a unified operational view, allowing more efficient, flexible, and resilient grid management.

6.4.1 Technology Benefits and Challenges

Table 53 summarizes the key technologies introduced in this group, highlighting their main benefits and implementation challenges.

Table 53: Technologies, Benefits, and Challenges in Group 4: Integrated Management

Technology / Solution	Benefits	Challenges
ADMS: Integrated platform combining SCADA, OMS, and GIS for real-time control and optimization	• Provides centralized visibility and control of grid operations • Supports advanced applications such as FLISR and VVO for faster restoration and improved efficiency	• High implementation and integration cost • Requires accurate network models, data synchronization, and staff training
FLISR: Software and field logic that automate fault detection and reconfiguration	• Enables automatic isolation of faults and rapid restoration of service to unaffected areas • Can reduce outage duration and improve reliability indices	• Dependent on communication reliability, accurate system data, and sufficient automated field devices

[1] HITACHI Energy, *"Avista Utilities - At the forefront of Smart Grid 2.0,"* https://www.hitachienergy.com/us/en/news-and-events/customer-stories/avista-utilities-at-the-forefront-of-smart-grid-2-0

Technology / Solution	Benefits	Challenges
VVO: Automated control of voltage regulators and capacitor banks to maintain efficient voltage profiles	• Maintains voltage • Can reduce peak demand, customer usage and energy losses	• Requires fine-tuning and coordination with load variability • May require advanced metering and communication systems
DERMS: Platform that monitors and controls distributed energy resources including PV, batteries, and EVs	• Enables coordination of local generation and storage to support grid stability, flexibility, and peak load management	• Complex integration with diverse devices and communication protocols • Regulatory and interoperability challenges
Front-of-the-meter battery systems: Utility-scale storage installed at substations or feeder ends	• Can provide energy balancing, peak shaving, and emergency backup	• High capital and maintenance costs • May have limited storage duration and battery lifecycle constraints
Microgrid controllers: Systems that manage distributed resources and loads to maintain service during grid outages	• Maintain critical loads during grid failure • Can improve local resilience and energy independence	• Requires complex protection and synchronization schemes • Significant installation and control system costs

A key component of this phase is the ***Advanced Distribution Management System (ADMS)***, which integrates SCADA, OMS, and GIS data into a single platform for centralized monitoring and control. The ADMS provides the operational environment needed to support a range of advanced applications, such as FLISR and VVO. FLISR automatically detects and isolates faults while restoring service to unaffected areas, while VVO continuously manages voltage and reactive power to improve power quality and reduce energy losses. The addition of a ***Distributed Energy Resource Management System (DERMS)*** further extends visibility and control to distributed generation and storage, allowing coordinated operation of solar PV, batteries, and electric vehicles as grid-supporting assets.

Utilities can also deploy front-of-the-meter battery systems at substations or feeder ends to support grid balancing, provide emergency power, and enable black-start capabilities during outages. Combined with microgrid controllers and islanding capability, these systems ensure that critical facilities can remain powered even when disconnected from the main grid.

Reported costs for monitoring and control technologies such as ADMS, FLISR, and DERMS are commonly expressed on a per-customer-account basis and vary depending on system scope, included functionalities, and whether O&M costs are incorporated.[1] Based on recent utility filings, standalone ADMS investments can range from approximately $14.3[2] to $19.9[3] per

[1] Lawrence Berkeley National Laboratory, *"Monitoring and Control Technologies Resilience Investment Guide,"* Sep. 2024. https://www.energy.gov/sites/default/files/2024-11/111524_Monitoring_and_Control_Technologies.pdf

[2] Northern States Power Company (Xcel Energy), *"INTEGRATED DISTRIBUTION PLAN 2022–2031,"* Minnesota Public Utilities Commission, Minneapolis, MN, Docket No. E002/M-21-694, 2021.

[3] Long Island Power Authority (LIPA). *"LIPA-PSEG Long Island 5-Year Strategic Roadmap (2023 to 2027)",* https://www.lipower.org/wp-content/uploads/2023/03/2.6-Consideration-of-Approval-of-the-5-Year-Strategic-Roadmap.pdf

customer account, while DERMS investments range from approximately $10.7[1] to $14.8 per customer account (excluding O&M costs). FLISR implementations have been reported at approximately $32.4 per customer account. More comprehensive grid modernization programs that bundle multiple technologies and supporting infrastructure show significantly higher costs, ranging from approximately $206.3[2] to $280.0[3] per customer account. Actual costs depend on factors such as system size, legacy IT integration requirements, communications upgrades, cybersecurity enhancements, regulatory treatment, and the breadth of technologies deployed under a given program.

6.4.2 Regional Experience with Technologies

An example of these advanced capabilities in practice is PG&E's EPIC 3.11 multi-customer microgrid demonstration at the Arcata-Eureka Airport. Developed in partnership with the Redwood Coast Energy Authority (RCEA), the project integrates a 2.2-MW solar array and a 2.3 MW, 8.9-MWh battery system with a dedicated microgrid controller and SCADA interface capable of supporting seamless transitions between grid-connected and islanded operation. The microgrid supplies several critical facilities, including the regional airport and the U.S. Coast Guard Air Station, and is designed to maintain nearly continuous renewable power during extended outages.

Through real-time coordination between PG&E's distribution control center and RCEA's generation assets, the project tests the interoperability of utility-owned infrastructure and third-party-controlled DERs under both normal and emergency conditions. Beyond demonstrating technical feasibility, the initiative also develops engineering standards, protection schemes, testing protocols, and experimental tariffs needed to operate front-of-the-meter, multi-customer microgrids. These foundational elements provide a replicable model for other utilities and communities seeking to enhance local resilience through integrated microgrid solutions.

[1] Consumers Energy, *"Electric Distribution Infrastructure Investment Plan (2021-25),"* Jun. 2021. https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t000000NiZGDAA3

[2] Duke Energy Florida, *"Duke Energy Storm Protection Plan,"* https://www.psc.state.fl.us/storm-protection-plans

[3] National Grid, Massachusetts, *"Future Grid Plan: Empowering Massachusetts by Building a Smarter, Stronger, Cleaner and More Equitable Energy Future,"* Sep. 2023. https://www.nationalgridus.com/media/pdfs/our-company/massachusetts-grid-modernization/future-grid-full-plan-sept2023.pdf

PART III

Community Energy Baseline



Image Source: Northwest Digital Heritage

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Part III: Glossary and Acronyms

Annual Technology Baseline (ATB): NLR's pre-populated framework that provides cost and performance projections for electric generation technologies across varying fuel price scenarios and site conditions.

Biomass Resource Potential: An assessment of the amount of biomass feedstocks (i.e., forest and agricultural residues and other organic wastes) available at a specific location that can be converted into useful energy.

BRIC: Baseline Resilience Indicators for Communities

CARRI: Community and Regional Resilience Institute

CART: Communities Advancing Resilience Toolkit

CDC: Centers for Disease Control and Prevention

COAD: Lane Community Organizations Active in Disaster

Community Energy Plan: A community-level roadmap that sets near- and long-term energy goals, coordinates related plans (e.g., land use, transportation, climate), and serves as guidance document for a community's policy and decision-making processes.

Community Resilience: A community's capacity to prepare for, withstand, and recover from hazards.

Community Resilience Plan: A roadmap that prepares a community to prevent, mitigate, respond to, and recover from disruptive events.

Comprehensive Plan: The community's master plan guiding the social, economic, and physical development of the community to best promote public health, safety, order, convenience, prosperity and general welfare.

Critical Facilities: Buildings and infrastructure that provide essential lifeline services and must remain operational during emergencies.

Critical Load: The power required to operate essential equipment or facilities during a grid outage.

EIA: U.S. Energy Information Administration

Emergency Operations Plan (EOP): A jurisdiction's plan for preparing for and responding to emergencies, defining roles, coordination, communication, evacuation, and continuity of operations.

Emissions Target: A formal goal to reduce greenhouse gas emissions by a specified amount and date.

Energy Burden: The share of household income spent on energy.

EPA: Environmental Protection Agency

Expected Annual Loss: The average annual impact from 18 natural hazards that considers both the economic losses to buildings and agriculture as well as injuries and fatalities to populations.

Landfill Gas (LFG): The gas generated as organic waste breaks down in landfills that is typically about 50% methane and 50% carbon dioxide.

LCDC: Land Conservation and Development Commission

Levelized Cost of Energy (LCOE): The discounted average cost per unit of electricity over a project's life, which is calculated by dividing the present value of all capital, fuel, and operations and maintenance costs by total lifetime generation.

NGO: Nongovernmental organizations

NIST: National Institute of Standards and Technology

RAPT: Resilience Analysis and Planning Tool

SLOPE: NLR's State and Local Planning for Energy tool

Social Vulnerability: A community's susceptibility to harm from hazards; in the NRI, it is quantified using a ***Social Vulnerability Index (SVI)***, which aggregates socioeconomic and demographic variables.

Solar Resource Potential: An assessment of the amount of solar radiation available at a specific location that can be converted into useful energy.

System Advisor Model (SAM): NLR's free software that models the performance and financial metrics of energy projects.

UNDRR: United Nations Office for Disaster Risk Reduction

Wind Resource Potential: An assessment of the kinetic wind energy available at a specific location that can be converted into useful energy.

Part III: Community Energy Baseline Preface

The third and final part of this Handbook deals with community resources, vulnerabilities, goals, and plans related to electricity and resilience. While utilities have a significant role in maintaining the affordability, reliability, and resilience of the electric system, they are by no means the only group responsible for and participating in such efforts. Developers, landowners, or residents might choose to invest in local generation projects (***Chapter 7***), communities might prioritize different buildings or neighborhoods for upgrades (***Chapter 8)***, and local governments might make plans, set goals, or enact policies that align with their vision for a good energy future (***Chapter 9***). Even for changes that utilities can make, like integrating DERs or upgrading infrastructure, there are local factors that may guide or constrain those changes. The following three sections present some of those local factors that impact investor, community, local government, and utility decisions about energy.



Figure 67. Lane County with city logos.

Chapter 7

Local Electricity Generation Resource Availability

Candace Briggs and Ian Hermanson

In this section, we estimate the technical and economic potential to generate electricity from local Lane County energy resources. Local energy resources are naturally occurring within Lane County, and include solar, wind, biomass, hydropower, geothermal, and marine energy. Existing local Lane County energy generation facilities are documented in ***Section 1.6.2****.*

Lane County might consider developing new utility- and small-scale generation facilities to harness local energy resources. This analysis maps energy resource availability across Lane County and outlines hypothetical local solar and wind project requirements and performance. The information provided can be used as a quick reference when considering new projects. We do not recommend specific sites or technologies and instead aim to present information that can guide future study priorities.

Our analysis is limited to solar, wind, and biomass. Geothermal energy resources are not considered technically feasible in Lane County, and new hydroelectric development is limited by environmental and regulatory constraints. Marine energy technologies, including tidal and wave energy, have not reached commercial maturity. While Lane County has existing natural gas power plants, natural gas is an imported fuel that is not available locally, and therefore the resource potential is not subject to geographical analysis.

What metric do we use to compare generation types?

Levelized cost of energy (LCOE), expressed as cost per unit electricity ($/kWh), is a summary metric used to compare the economic performance of different energy generation technologies. LCOE represents the discounted average cost per unit of electricity over a project's life and is calculated by dividing the present value of all capital, fuel, and operation and maintenance costs by total lifetime generation.[1] While LCOE enables comparisons across technologies and is a useful tool for long-term planning and investment decisions, LCOE has well-documented limitations and does not represent costs for grid integration, metrics of system reliability or dispatchability, or environmental or social impacts of large-scale deployments.

[1] U.S. Department of Energy, *"Solar Radiation Basics",* https://www.energy.gov/eere/solar/solar-radiation-basics

NLR provides a variety of publicly available web applications to assess renewable energy technology potential for a given location. We use these applications in our analyses.

- ***NLR's PVWatts Calculator*** estimates electricity generation and cost for a potential PV installation. We used PVWatts to compare solar installations in central Eugene.
- ***NLR's Electricity Annual Technology Baseline (ATB)*** provides energy technology cost and performance parameters projected through 2050 for a variety of scenarios. We used the ATB to estimate solar and wind technology LCOE based on Lane County's resource.
- ***NLR's System Advisor Model (SAM)*** is a techno-economic modeling tool that estimates the performance, financial viability, and levelized cost of energy of renewable energy projects. We used SAM to model a wind turbine in Lane County's valley region.
- ***NLR's State and Local Planning for Energy (SLOPE)*** tool is a geospatial analysis application that provides high-resolution data on energy technical potential, generation, and costs at the state and county levels. We do not use SLOPE in this analysis.

7.1 Solar Resource Potential

7.1.1 Resource Overview

PV developments are frequently categorized as residential-, commercial-, and utility-scale (illustrated in ***Figure 67***). The scale of a solar installation is defined by its peak (or rated) capacity, typically measured in kW or MW, which represents the maximum power the system can produce under ideal sunlight conditions. The actual energy output depends on orientation, shading, efficiency, temperature, and other factors. Solar panels operate more efficiently when orientated directly toward the sun. Solar-tracking technology can rotate a panel along one or two axes to follow the sun and increase efficiency, but that technology comes at a higher capital cost.



Figure 68: PV Scale Comparison[1,2]

7.1.2 Local Potential

The potential for PV technology depends on how much solar energy a location receives from the sun. Solar resource is commonly measured by irradiance (instantaneous solar power on an

[1] Data from Abundant Solar. https://www.abundantsolar.com/services/residential-solar/
[2] Data from U.S. Department of Energy. https://www.energy.gov/eere/solar/solar-radiation-basics.

area in W/m^2) or insolation (the cumulative solar energy on an area over a given period in kWh/m^2/day, month, or year). Insolation better represents potential PV electricity generation and is typically used in resource potential maps. ***Figure 68*** maps long-term average solar insolation across Lane County using data from SolarGIS (2021),[1] a private company that offers the free Global Solar Atlas for preliminary planning. Solar insolation in Lane County ranges from 2.85-4.32 kWh/m^2/day with lower values near the coast and higher values towards the east edge of the county. Solar in the Eugene and Springfield areas ranges between 3.75–4.00 kWh/m^2/day.

Table 54 shows the production of several hypothetical solar PV installations in central Eugene. A 4kW, residential-scale, roof-mounted, PV system typically occupies around 28 m² and represents a common installation size. In central Eugene, NLR's PVWatts Calculator[2] estimates such a system would generate 4,400 to 5,000 kWh annually, meeting about half of the average annual electricity consumption of a Lane County household.[3] In the same central Eugene location, a hypothetical 1 MW single-axis tracking, ground-mounted, utility-scale system would generate 1,260,000 to 1,460,000 kWh annually, enough to power 111 to 129 homes. This utility-scale installation would require 2.8 to 4.2 acres of open land.[4, 5] By comparison, 1 MW of distributed residential rooftop solar, about 250 individual 4 kW systems, would require about 1.8 acres of combined roof area and produce 1,100,000 to 1,240,000 kWh annually, enough to power 97 to 109 average Lane County households.

The 1 MW utility-scale system generates 10–20% more electricity because single-axis tracking increases daily solar exposure and ground-mounted systems can be optimally oriented and spaced to minimize shading and maximize output. But utility-scale ground-mounted systems require substantially more land to accommodate row spacing, access roads, and maintenance. Rooftop solar is more space efficient but produces less electricity per installed PV capacity.

NLR's 2024 ATB defines ten PV resource classes to represent solar resource quality at a given location. PV Resource Class 1 corresponds to the highest-quality solar resource, while Class 10 represents the lowest. The Eugene area falls into Class 9. For each resource class, the ATB provides technology-specific performance and cost projections for utility-, commercial- and residential-scale PV systems. 2022 is the baseline year for 2024 ATB projections. Base year estimates are derived from modeled cost data benchmarked against industry and historical market data. The ATB projects future costs for new energy technology installations through 2035 and 2050 under three scenarios:

Conservative: Lower research and development investment slows technology improvement. Costs largely stay the same as the baseline year.

Moderate: Research and development investment continues at current levels. Technology incrementally improves without major breakthroughs.

Advanced: Increased research and development investment accelerates innovation. Cost and performance improvements are consistent with historical technological advancement.

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[1] Data from SolarGIS. https://solargis.com/

[2] PVWatts. Calculator. https://pvwatts.nlr.gov/

[3] Oregon Department of Energy, *"Lane County",* Oct. 2024. https://energyinfo.oregon.gov/energy-profiles-2024/lane

[4] M. Bolinger and G. Bolinger, "Land Requirements for Utility-Scale PV: An Empirical Update on Power and Energy Density," *IEEE J. Photovolt.*, vol. 12, no. 2, pp. 589–594, Mar. 2022, https://www.doi.10.1109/JPHOTOV.2021.3136805.

[5] Sunsave *"4kW solar panel systems: an expert guide",* May 2026. https://www.sunsave.energy/solar-panels-advice/system-size/4kw-solar-system

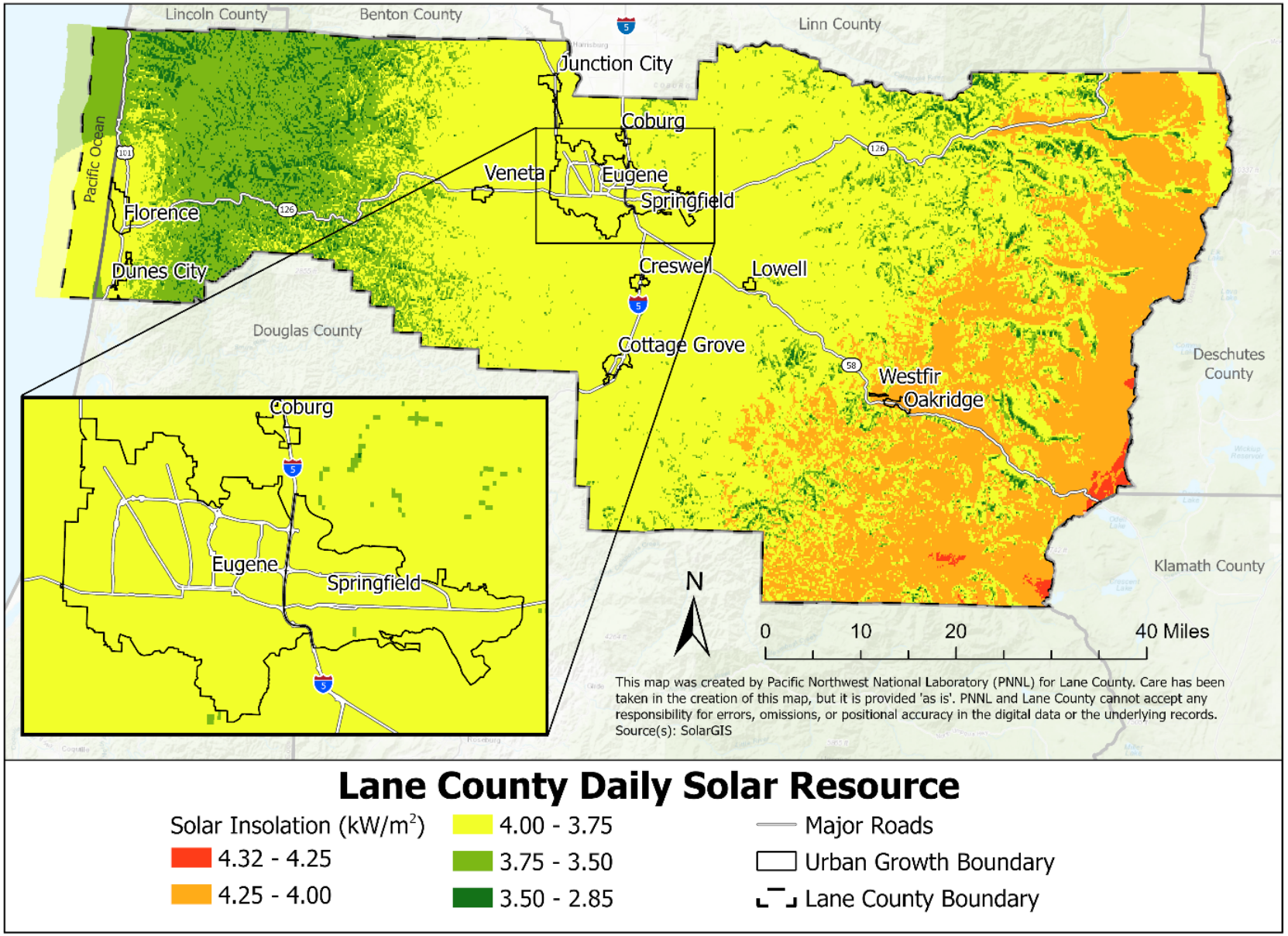


Figure 69: Daily Average Solar Insolation in Lane County, Oregon[1]

[1] Data accessed September 2025 from SolarGIS, https://solargis.com/

Table 54: Central Eugene Solar PV Installation Comparison

System Type	Capacity	Space Needed[1]	Annual Production (kWh)	Households Powered per year
Distributed Rooftop - Single System	4 kW	28 m²	4,400–5,000	0.5 (or 1 household for half a year)
Distributed Rooftop - Aggregate	1 MW (250 × 4 kW systems)	1.1 acres 7,000 m²	1,100,000–1,240,000	97–109
Utility-Scale Ground 1-Axis tracking	1 MW	2.8–4.2 acres 11,334–17,000 m²	1,260,000–1,460,000	111–129

7.1.3 Economic Feasibility

Figure 69 compares the Resource Class 9 utility- and commercial-scale PV installation 2022 baseline and 2050 projection for conservative, moderate, and advanced technology scenarios. 2026 BPA Tier 1 Rates and the U.S. Energy Information Administration's (EIA) NW Average Electricity LCOE are provided for reference. These will likely change by 2050. In 2022, commercial PV installations are significantly more expensive than utility-scale installations (note that in 2022, all utility-scale estimates exactly overlap). Utility-scale PV benefits from economies of scale, including bulk infrastructure purchases and the distribution of fixed costs across a larger capacity.[1] While 2022 utility-scale PV is more expensive than BPA Tier 1 Rates, utility-scale PV is comparable to 2022 NW average electricity LCOE. In 2050, commercial-scale PV is projected to narrow the cost gap with utility-scale PV.

[1] Utility Dive. *"Utility-scale solar is significantly cheaper than rooftop. Does that make it better?"* Jul. 2015. https://www.utilitydive.com/news/utility-scale-solar-is-significantly-cheaper-than-rooftop-does-that-make-i/402517/

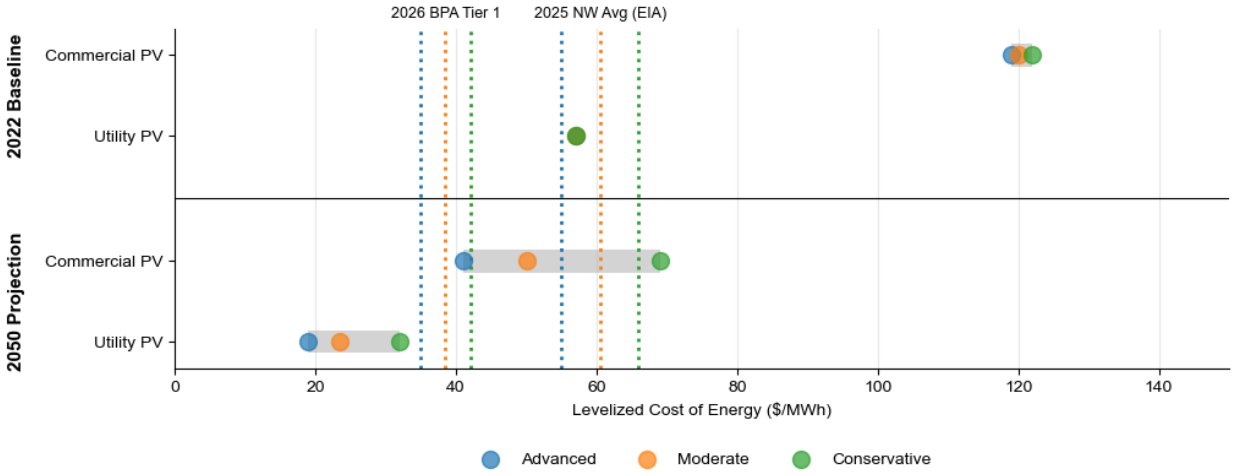


Figure 70: Commercial and Utility-Scale Solar LCOE vs BPA Tier 1[1] and NW Average (2025) LCOE[2]

Technological advancements, improved efficiency, and continued cost reductions are expected to make both utility- and commercial-scale PV installations economically competitive with BPA Tier 1 rates and Northwest wholesale electricity. Even when solar is not cost-competitive, it can still provide grid resilience benefits that are difficult to quanity, as noted in ***Section 4.4***.

7.2 Wind Resource Potential

7.2.1 Resource Overview

Wind turbine size is generally defined by two dimensions: hub height (the distance from the ground to the center of the rotor) and rotor diameter (the span of the blades). Increasing hub height or rotor diameter increases turbine generating capacity. Greater hub heights access stronger winds at higher elevations, and larger rotor diameters can collect energy from a larger area. Over the past two decades, the hub height and rotor diameter of newly installed utility-scale wind turbines have steadily increased.[3] Turbines are often grouped together into grid-connected wind farms.

Wind turbines can be installed onshore or offshore, on floating, moored platforms in the ocean. There are also fixed-bottom offshore wind turbines that stand on platforms that are fixed to the bottom of the ocean, but the steep continential shelf on the west coast of the United States prohibits the use of fixed-bottom technology. Large offshore turbines typically have higher hub heights and larger rotor diameters than onshore turbines. Offshore wind speeds are stronger, more consistent, and less turbulent than onshore winds. As a result, offshore turbines generate substantially more energy than onshore turbunes (see ***Figure 71***), albeit with a greater capital and operational expense.[4]

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[1] Data from Bonneville Power Administration, *"Provider of Choice Policy Record of Decision,"* Mar. 2024. https://www.bpa.gov/

[2] Data from Energy Information Administration, *"Forecast Wholesale Power Prices and Retail Electricity Prices Rise Modestly in 2025,"* Jan. 2025. https://www.eia.gov/todayinenergy/detail.php?id=64384

[3] https://www.energy.gov/cmei/articles/wind-turbines-bigger-better

[4] P. Joshi and C. Gokhale-Welch, *"Fundamentals of Wind Energy,"* Nov. 2022. https://docs.nlr.gov/docs/fy23osti/84501.pdf

The generating capacity of a single wind turbine ranges widely. A small 10 kW wind turbine can power a single building. ***Figure 70*** is a photo of a 10 kW wind turbine installed by the University of Oregon in 2013 to power the Charleston Marine Life Center at the Oregon Institute of Marine Biology. The turbine shut down in 2022. The largest operating turbine is 15 MW, and even larger designs are in development. ***Figure 71*** illustrates onshore and offshore wind turbine sizes.



Figure 71: University of Oregon 10 kW Wind Turbine[1]

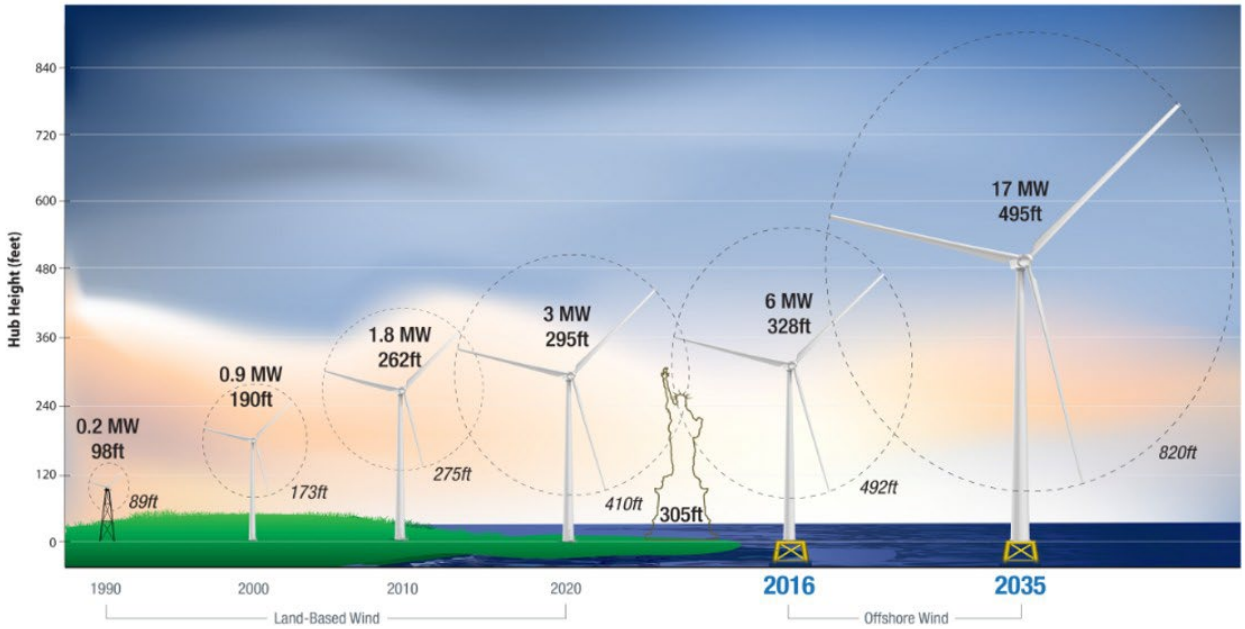


Figure 72: Wind Turbine Capacity, Hub Height, and Rotor Diameter[2]

7.2.2 Local Potential

Wind energy is typically quantified via the metric of annual average wind speed in meters per second (m/s) measured 100 m above sea level. ***Figure 72*** shows this wind speed metric across Lane County using long-tem averaged data from Global Wind Atlas.[3] Most of Lane County has

[1] Image from University of Oregon. https://cpfm.uoregon.edu/windturbine-sustainability
[2] Image from U.S. Department of Energy. https://www.energy.gov/cmei/articles/wind-turbines-bigger-better
[3] Global Wind Atlas. https://globalwindatlas.info/en/

average annual wind speeds around 2–6 m/s, with the highest speeds in the northeast near the Three Sisters Mountains. Offshore, winds are stronger, averaging 8–10 m/s.

Estimating the land requirements of a single wind turbine is difficult as turbine fooprint varies by turbine model and regulations. Wind farm land requirements vary significantly with layout, size, topography, wind regime, and other factors. A NLR study calculated an average wind farm capacity density of 19–145 acres/MW.[1] Given this wide range, land requirements acerage was not estimated in this analysis.

[1] National Laboratory of the Rockies, *"Wind Energy,"* U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, NREL/FS-7A40-67181, May 2018. https://docs.nlr.gov/docs/fy18osti/67181.pdf

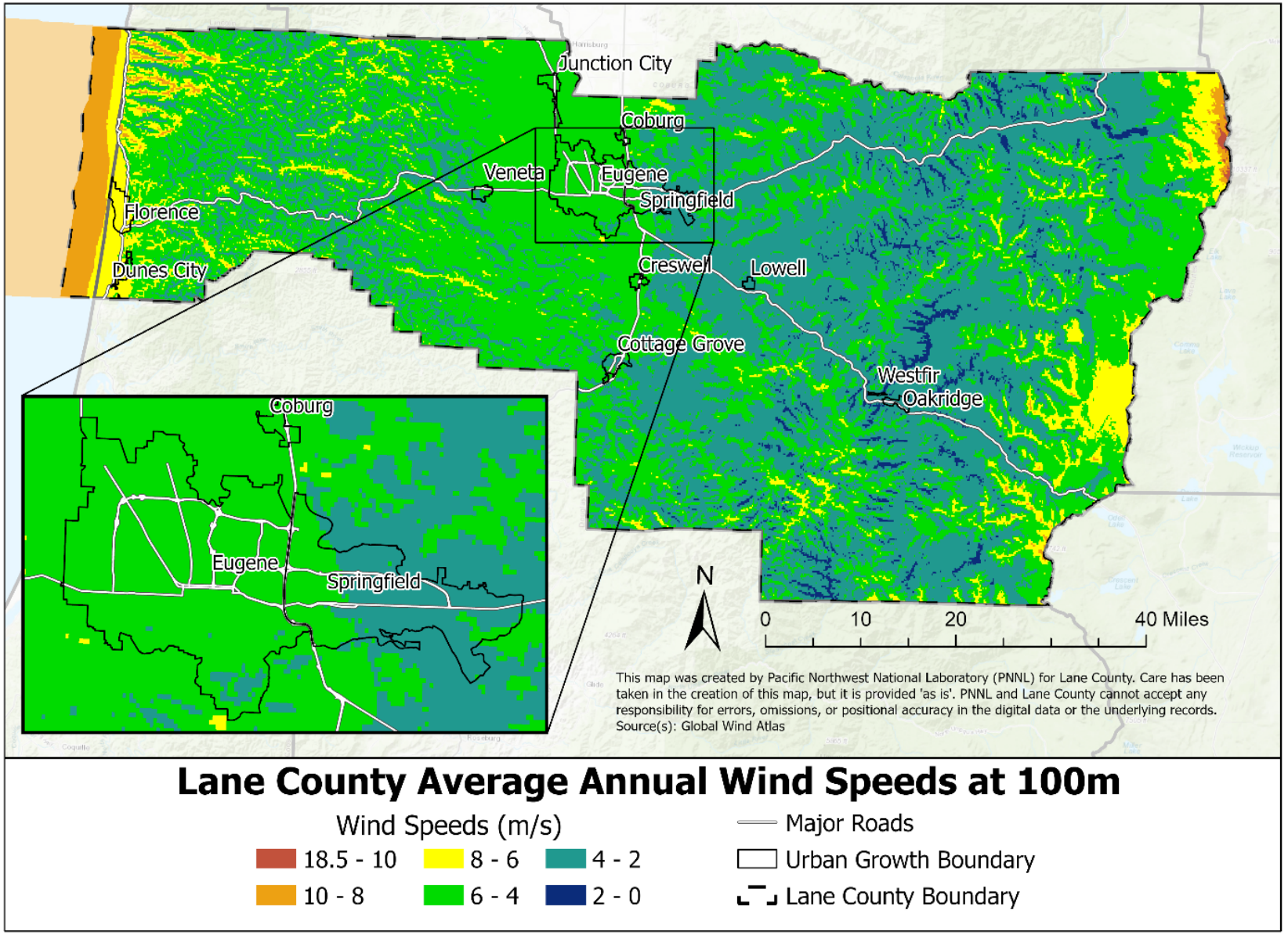


Figure 73: Annual Average Wind Speeds at 100m in Lane County, Oregon[1]

[1] Data accessed September 2025 from Global Wind Atlas. https://globalwindatlas.info/en/

Table 55 summarizes SAM model results for an onshore wind installation in the Eugene area and an offshore wind turbine off the coast just north of Florence. For onshore sites, Lane County's wind conditions are well suited to the industry-standard 1.5 MW General Electric turbine with a 100 m hub height. SAM estimates that a single 1.5 MW turbine in the Eugene area would generate around 2,370 MWh annually,[1] enough to power 209 average Lane County households.[2] A small onshore wind farm of nine turbines arranged in a simple three-by-three layout would produce roughly 21,060 MWh per year, sufficient for about 1,858 homes. For offshore scenarios, SAM estimates that a single 5 MW, 100 m hub height NLR reference turbine located 10 miles offshore would generate about 17,630 MWh per year,[1] powering roughly 1,555 homes. While individual turbine output varies widley by size and location, both onshore and offshore wind installations could contribute meaningful electricity generation in Lane County.

Table 55: Eugene Area Wind Turbine Installation Comparison[3]

System Type	Capacity	Hub Height (m)	Rotor Diameter (m)	Annual Production (MWh)	Households Powered per year
GE 1.5 sle turbine (land-based single system)	1.5 MW	80	77	2,370	209
GE 1.5 sle turbine (land-based aggregate)	13.5 MW (9 × 1.5 MW systems)	80	77	21,060	1,858
NLR Offshore Reference Turbine	5 MW	100	126	17,630	1,555

7.2.3 Economic Feasibility

Figure 73 compares onshore and offshore 200 MW wind farm installations' 2022 baseline and 2050 projections for conservative, moderate, and advanced scenarios (see ***Section 7.1*** for scenario descriptions). 2026 BPA Tier 1 Rates and EIA NW Average Electricity LCOE are provided for reference. In Lane County, land-based wind falls into ATB Wind Speed Class 10, the lowest across all classes. NLR classifies turbines by four technology configurations, and ATB Technology Configuration 4 is the only configuration suitable for wind speeds as low as those in Lane County. A single ATB Configuration 4 turbine has a capacity of 6 MW, corresponding to 34 turbines for a 200 MW farm. Smaller projects would incur higher per-unit costs due to reduced economies of scale.

Off the Oregon Coast, conditions fall into Wind Speed Class 6, with 7.9 m/s average wind speeds. In 2022, offshore wind installations have a significantly higher LCOE than onshore wind due to installation and maintenance costs,[4] but by 2050, that LCOE gap is projected to close as

[1] National Laboratory of the Rockies, System Advisor Model (SAM). https://sam.nlr.gov/
[2] Oregon Department of Energy, *"Lane County",* Oct. 2024. https://energyinfo.oregon.gov/energy-profiles-2024/lane
[3] Data from National Lab of the Rockies https://sam.nlr.gov/ and Oregon Department of Energy https://energyinfo.oregon.gov/energy-profiles-2024/lane
[4] National Laboratory of the Rockies. Annual Technology Baseline (ATB). 2024. https://atb.nlr.gov/electricity/2024/data

offshore technology matures and deployments scale.[1] In 2022, the LCOE of both offshore and onshore wind exceeds 2026 BPA Tier 1 prices and 2025 NW Average electricity LCOE.

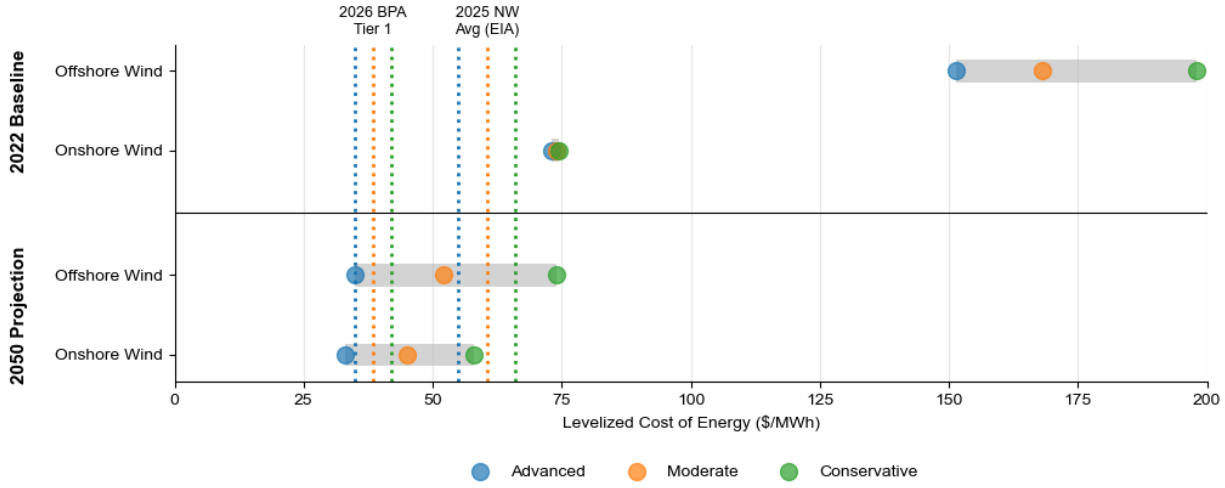


Figure 74: Offshore and Onshore Wind vs BPA Tier 1[2] and NW Average (2025) LCOE[3]

Like solar, ATB projections suggest that as wind energy technology matures it will become increasingly cost competitive with existing NW electricity sources. Similar to solar energy, wind can provide grid resilience benefits even when not cost competitive.

7.3 Biomass Resource Potential

Biomass energy is produced by burning organic materials, converting organic materials into fuels, or burning biogas. Biomass feedstocks include crops grown specifically for energy use, agricultural byproducts like stalks and leaves, timber and forestry byproducts, algae, wood processing byproducts like sawdust and pulp, and municipal waste like garbage, food waste, sewage, and manure. Organic materials can be combusted on site or distributed to a facility. Biogas is methane or carbon dioxide produced during the decomposition sewage, garbage, or manure and can be burned to produce energy or generate electricity.[4]

In Oregon, the industrial sector is the largest producer and consumer of biomass energy.[5] Wood and wood waste is Oregon's primary source of biomass, and biomass energy consumption has grown steadily since 2002 due to increased demand for biofuels. In 2014, NLR mapped the total quantity in tons of solid biomass resources per Square Kilometer in the United States by county

[1] International Renewable Energy Agency. *"Offshore Wind: From 83 GW Today to 2,000 GW by 2050",* Sept. 2025. https://www.irena.org/News/articles/2025/Sep/Offshore-Wind-From-83-GW-Today-to-2000-GW-by-2050

[2] Data from Bonneville Power Administration, *"Provider of Choice Policy Record of Decision,"* Mar. 2024. https://www.bpa.gov/

[3] Data from Energy Information Administration, *"Forecast Wholesale Power Prices and Retail Electricity Prices Rise Modestly in 2025,"* Jan. 2025. https://www.eia.gov/todayinenergy/detail.php?id=64384

[4] U.S. Energy Information Administration, *"Biomass explained,"* https://www.eia.gov/energyexplained/biomass/biomass-and-the-environment.php

[5] Janine Benner *et al.*, "*2024 Biennial Energy Report,"* Oregon Department of Energy, Nov. 2024. https://www.oregon.gov/energy/Data-and-Reports/Documents/2024-Biennial-Energy-Report.pdf

(***Figure 74***). Lane County contains a relatively high concentration of solid biomass resources. Cascades wildfires since 2014 may have reduced Oregon's concentration of solid biomass.

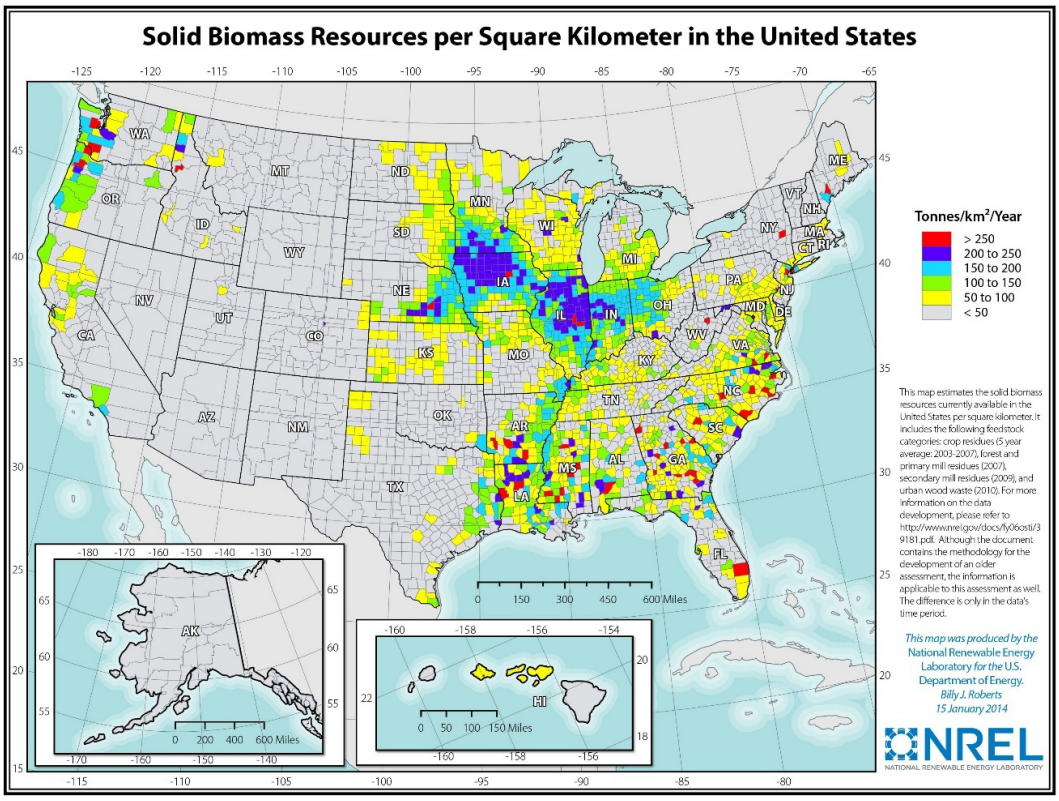


Figure 75: U.S. Biomass Resource per Square Kilometer[1]

Burning biomass releases greenhouse gases. Wood smoke contains harmful pollutants such as carbon monoxide and particulate matter which pose risks to local cardiovascular health. Burning municipal solid waste reduces landfill volume, but releases chemicals and other substances contained in the waste into the air. The U.S. Environmental Protection Agency (EPA) requires waste-to-energy plants to include air pollution control devices. Lane County has several biomass facilities discussed in ***Section 1.6***. Recently, members of the public in the Eugene area have expressed deep concerns about biomass facilities.[2]

As wildfires become increasingly prevalent, interest has grown in collecting byproducts from wildfire mitigation and cleanup for use as biomass feedstocks. Collecting woody waste from utility vegetation management could support wildfire resilience while supplying biomass resource. Integrating biomass feedstock recovery with wildfire management requires more research and planning to determine feasibility. Region-specific strategies and coordinated multi-use approaches are important.[3]

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[1] Originally published in research by the National Laboratory of the Rockies (formerly the National Renewable Energy Laboratory, NREL) https://www.nlr.gov/docs/libraries/gds-maps/solid-us-biomass-resources-per-square-kilometer.jpg?sfvrsn=f2baee94_2

[2] Whole Community News. *"EWEB asked to drop 'dirty' biomass from portfolio,"* 2025. https://wholecommunity.news/2025/09/06/eweb-asked-to-drop-dirty-biomass-from-portfolio/

[3] International Energy Agency Bioenergy, *"Wildfire Resilience and Biomass Supply,"* Aug. 2024. https://www.ieabioenergy.com/blog/publications/wildfire-resilience-and-biomass-supply

Chapter 8

Geospatial Data to Inform Project Prioritization

Candace Briggs, Amanda Krelling, Kaiyu Sun, and Ali Trueworthy

As Lane County government, utilities, and partners ideate, prioritize, and select energy projects and strategies, they will consider where within the county projects are most needed. There are numerous factors that can be used to indicate priority areas for different types of projects. In this section, we use datasets of socio-economic metrics and locations of critical facilities to explore potential priority areas within Lane County for work aimed at 1) maintaining affordable energy service, 2) boosting electricity system resilience, and 3) enhancing backup power availability. These project aims are not mutually exclusive, and the metrics alone cannot determine where a project or strategy should be implemented.

8.1 Priority Areas for Maintaining Affordable Energy Service

It is especially important to maintain affordable energy services in areas where people already experience economic difficulties and may be struggling to afford energy. Metrics used to show these economic difficulties include ***housing energy burden*** and ***social vulnerability index*** (***Section 8.2***).

The ***housing energy burden*** metric is derived from the U.S. Department of Energy's Low-Income Energy Affordability Tool developed by NLR. This tool combines data from the U.S. Census Bureau and the U.S. Energy Information Administration to estimate the percentage of household income spent on home energy costs. Data comes from the 2016-2020 5-year American Community Survey. NLR classifies energy burdens into three categories: low (<3.8% of household income), medium (3.8–6.0%), and high (>6.0%). A low burden reflects relatively affordable energy costs, a medium burden indicates moderate financial strain from energy expenses, and a high burden indicates that households spend a large share of their income on energy.

Figure 75 shows Lane County's housing energy burden by census tract. In Lane County, approximately 31,500 residents—about 8% of the county's 2020 population—live within census tracts categorized as having a medium housing energy burden. These areas are distributed across both urban and rural parts of the county, with roughly a third of affected households located within EWEB's service territory in Eugene. The remaining medium-burden areas are dispersed throughout rural regions served by a mix of Blachly-Lane Electric, EPUD, Lane

Electric, Pacific Power, and Central Lincoln PUD. Several of these tracts span multiple utility territories, reflecting how energy affordability challenges extend across jurisdictional and service boundaries rather than being concentrated in one provider's area. No Census Tracts in Lane County fall into the high energy burden category. Values for housing energy burden in ***Figure 75*** range from 0% (light green) to 5% (light gray), and utility boundaries are shown in black.

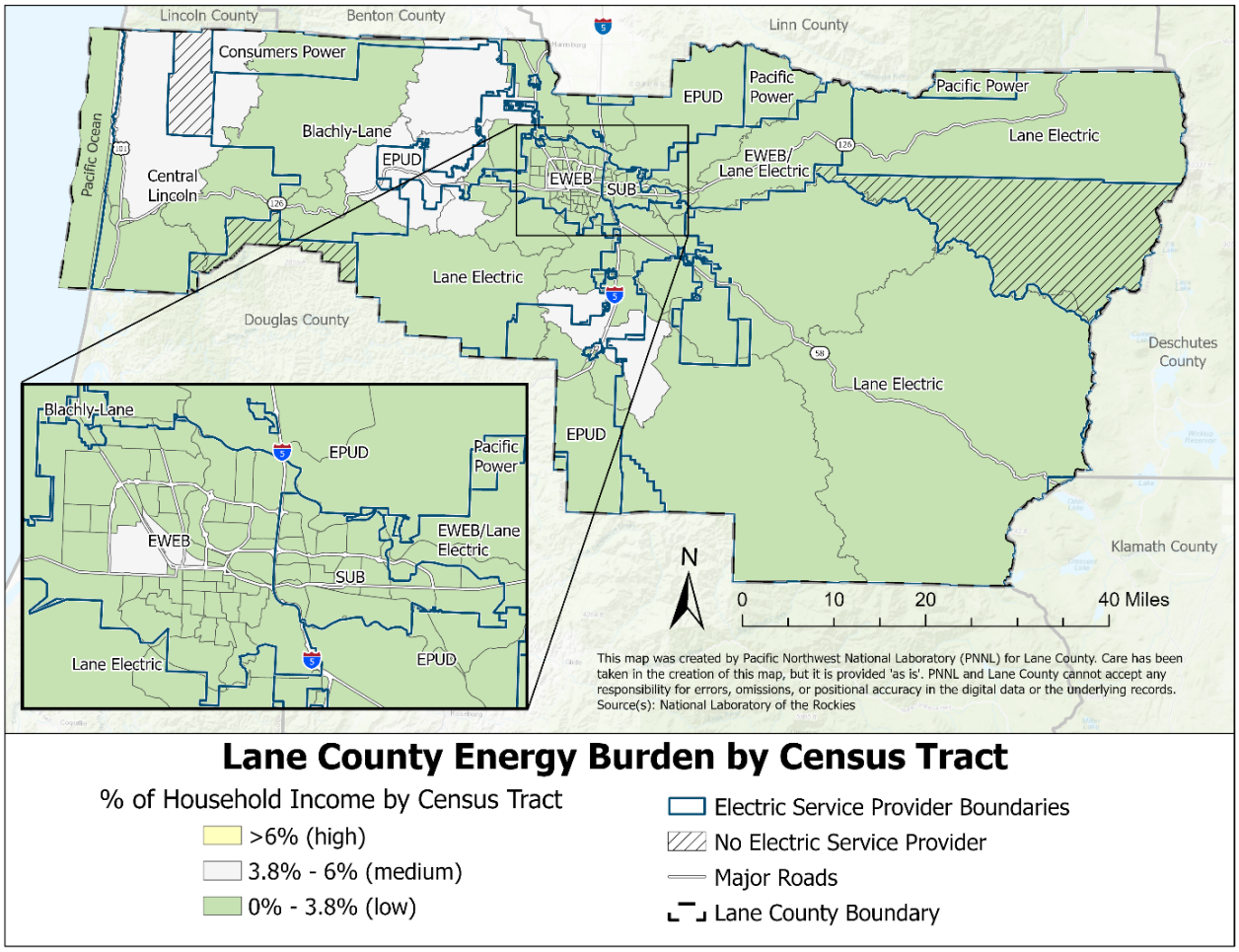


Figure 76: Lane County Household Energy Burden by Census Tract[1]

8.2 Priority Areas for Reducing Hazard Impacts

Projects aimed at reducing the impacts of, and vulnerability to, natural hazards might be prioritized in places where vulnerability is already high. To characterize high vulnerability to natural hazards, we map two multi-variable metrics: Social Vulnerability Index and Expected Annual Loss.

[1] Data from National Lab of the Rockies *"Energy Affordability - Household Energy and Transportation Burden".* State and Local Planning for Energy. https://maps.nlr.gov/slope/data-viewer?filters=%5B%5D&layer=eej.household-energy-burden&year=2020&res=county

The Social Vulnerability Index (SVI) is a metric developed by the Centers for Disease Control and Prevention (CDC) designed to identify communities that are at higher risk to hazards and community-level stressors such as natural disasters, disease outbreaks, or chemical exposures.[1] Overall vulnerability is calculated based on 16 U.S. Census variables grouped into 4 categories: Socioeconomic Status, Household Characteristics, Racial & Ethnic Minority, and Housing Type & Transportation. Vulnerability is ranked as a percentile from 0 to 1, with values closer to 1 representing higher vulnerability. Data to create the current SVI comes from 5-year averages of the American Community Survey between 2018-2022.[2]

Lane County's overall social vulnerability score of 0.74 indicates medium-to-high vulnerability. ***Figure 76*** displays Lane County's social vulnerability by census tract. Urban areas exhibit a mix of high, medium, and low vulnerability, while rural areas generally fall in the mid-range. Eleven census tracts are in the highest vulnerability category (100%-80% indicating higher vulnerability than 100%-80% of other census tracts), including nine urban and two rural tracts. Across the four SVI themes, the highest-risk tracts show mid-to-high vulnerability for social economic status, household characteristics, and housing type/transportation, and low-to-mid vulnerability for ethnic minority status. Drivers of high risk in Lane County tracts that score in the top 90th percentile are social economic status, housing type, and transportation.

[1] Agency for Toxic Substances and Disease Registry, *"Social Vulnerability Index,"* July 2024. https://www.atsdr.cdc.gov/place-health/php/svi/index.html

[2] U.S. Census Bureau, *"2018-2022 ACS 5-year Estimates,"* Nov. 2023. https://www.census.gov/programs-surveys/acs/technical-documentation/table-and-geography-changes/2022/5-year.html

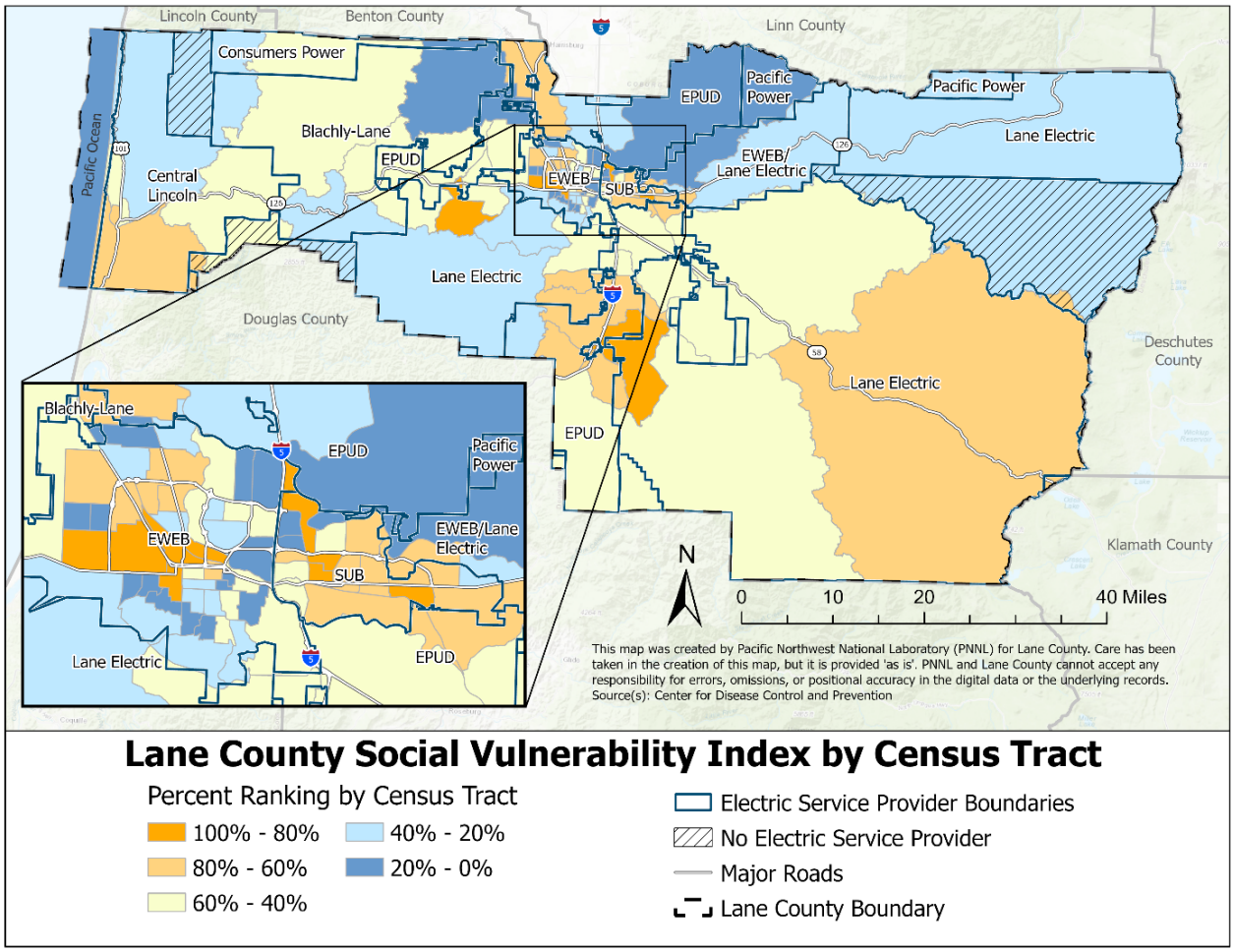


Figure 77: Lane County Social Vulnerability Index by Census Tract *where utility boundaries are overlaid in black.*[1]

Expected annual loss represents the "average economic loss in dollars resulting from natural hazards each year."[2] These losses reflect the potential impact on buildings, agricultural assets, and populations exposed to hazard events. They do not account for indirect economic losses, such as the loss of trees or wildlife during fires. A wide range of hazards are considered in this calculation including avalanche, coastal flooding, cold wave, drought, earthquake, hail, heat wave, hurricane, ice storm, landslide, lightning, river flooding, strong winds, tornado, tsunami, volcanic activity, wildfire, and/or winter weather. Expected annual loss is calculated independently for buildings, agricultural assets, and populations. Buildings and agriculture losses are measured in dollars, and population losses are measured in injuries and fatalities. Data to create the current expected annual loss scores comes from 5-year averages of the American Community Survey between 2018-2022.[3]

FEMA ranked counties across the United States as a percentile from 0-1 with 0 being low expected annual loss and 1 being high expected annual loss. Lane County has an expected

[1] Data from Agency for Toxic Substances and Disease Registry, ibid.
[2] Federal Emergency Management Agency, *"Natural Risk Index for Natural Hazards,"* Dec. 2025. https://www.fema.gov/flood-maps/products-tools/national-risk-index
[3] U.S. Census Bureau, ibid.

annual loss score of 0.96 at the county level. ***Figure 77*** shows the distribution of expected annual loss by census tract. There are three tracts classified in the "very high" category—two within EWEB, and one within SUB service territory. 20 tracts are classified in the "relatively high" category across rural and urban areas. Most of the estimated losses are associated with buildings, while expected losses to population and agricultural assets are low. The hazards contributing to this risk profile include coastal flooding in a few coastal tracts, high expected losses from earthquakes across all tracts, and moderate losses from ice storms countywide. Additional contributors include mixed levels of riverine flooding risk across tracts and elevated landslide risk in several rural western areas. Lightning-related risk is shown as historically moderate but with low expected annual losses, and wildfire risk likewise displays historically moderate values with low expected annual loss.[2] The low expected annual loss due to lightning and wildfire is mostly because these hazards have historically happened in places with less human-made infrastructure.

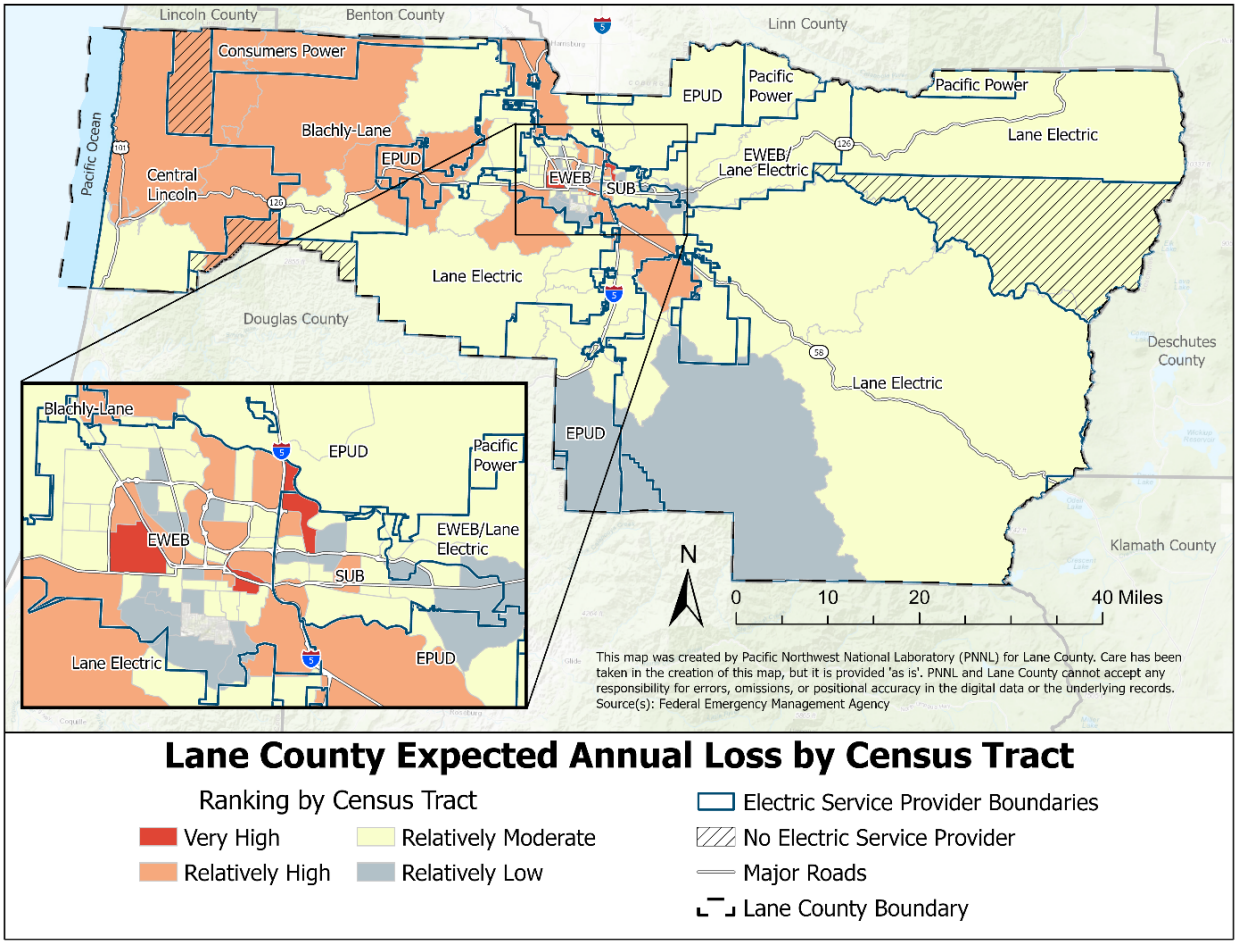


Figure 78: Lane County Expected Annual Loss to Natural Hazards by Census Tract.[1]

SVI and expected annual loss might be considered in a variety of ways when prioritizing projects. While SVI might indicate places where it is especially important to provide continuous electric service, expected annual loss might add context to where to place (or avoid placing) significant new infrastructure.

[1] Data from Federal Emergency Management Agency, *"FEMA National Risk Index Expected Annual Loss,"* July 2022. https://resilience.climate.gov/maps/fema-national-risk-index-expected-annual-loss/about

8.3 Priority Areas for Enhancing Backup Power Capabilities

Backup power—electricity that is available even when the larger electric grid is down—is an essential part of disaster response and recovery. For some, maintaining access to electricity can be essential for human health and safety. When considering where to build out backup power capabilities and how to most effectively use available local generation, understanding the location of critical facilities and the status of their available backup power is essential.

Critical facilities are buildings and infrastructure assets that provide essential services (i.e., lifelines) necessary to protect public health, safety, and welfare during normal operations and emergency conditions.[1] A facility may be considered critical based on the consequences of service disruption, the population served, the duration of acceptable downtime, and/or its role in emergency response recovery. Criteria typically include whether the facility supports life-sustaining functions (e.g., hospitals), emergency coordination (e.g., emergency operation centers), public safety (e.g., fire and police stations), or essential utilities (e.g., water and wastewater treatment plants). Additional factors may include dependency relationships with other infrastructure and the facility's importance to vulnerable populations.[2] ***Figure 78*** illustrates the preparation, response, and recovery cycle for critical facilities.

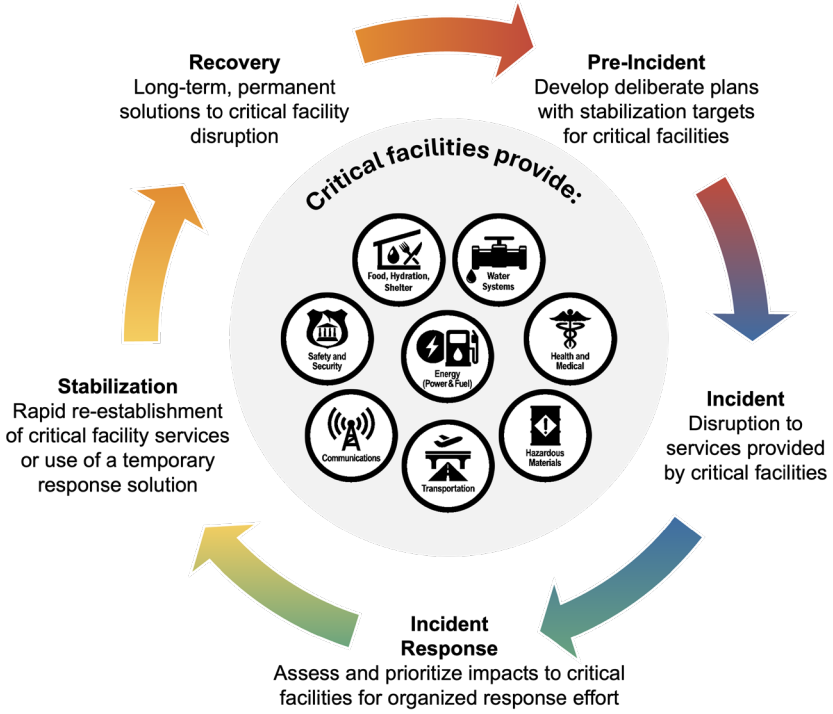


Figure 79: Lifeline Response and Stabilization Process Supporting Critical Facilities[3]

[1] Inter-agency Network for Education in Emergencies, *"Critical facilities,"* https://inee.org/eie-glossary/critical-facilities

[2] Institute for Policy Research & Engagement., *"Solar + storage microgrid feasibility: Final report prepared for Josephine County Emergency Management and Energy Trust of Oregon.,"* University of Oregon, School of Planning, Public Policy, and Management, Mar. 2022. https://scholarsbank.uoregon.edu/server/api/core/bitstreams/7c730e49-8915-42ff-aa40-4c998ff1bf08/content

[3] Information from Federal Emergency Management Agency, *"Community Lifelines,"* Feb. 2025. https://www.fema.gov/emergency-managers/practitioners/lifelines-toolkit/community-lifelines

Mapping critical facilities helps visualize their geographic distribution relative to hazards, infrastructure networks, and energy systems. This spatial understanding supports identification of service gaps, clustering of high-priority assets, and areas where resilience investments may have greater impact. Mapping also enables assessment of proximity to substations, feeders, floodplains, wildfire risk zones, and transportation corridors, which supports coordinated planning and resource allocation. At the time of writing this document, Lane County and the national laboratory researchers providing support through the E2C program are working together to collect and curate data on critical facilities in Lane County. Here, we include some preliminary data and discussion of important energy related data points.

Figure 79 shows the fire stations and fire district boundaries. ***Figure 80*** illustrates travel distances along the road network from locations across Lane County to the nearest hospital and ambulance service areas. The maps highlight strong coverage in and around the Eugene-Springfield metropolitan area, where emergency service facilities are concentrated and travel distances are relatively short. In contrast, large portions of eastern Lane County, characterized by mountainous terrain and lower population density, are outside of fire districts and show significantly longer travel distances to hospitals, indicating greater isolation from emergency response resources.

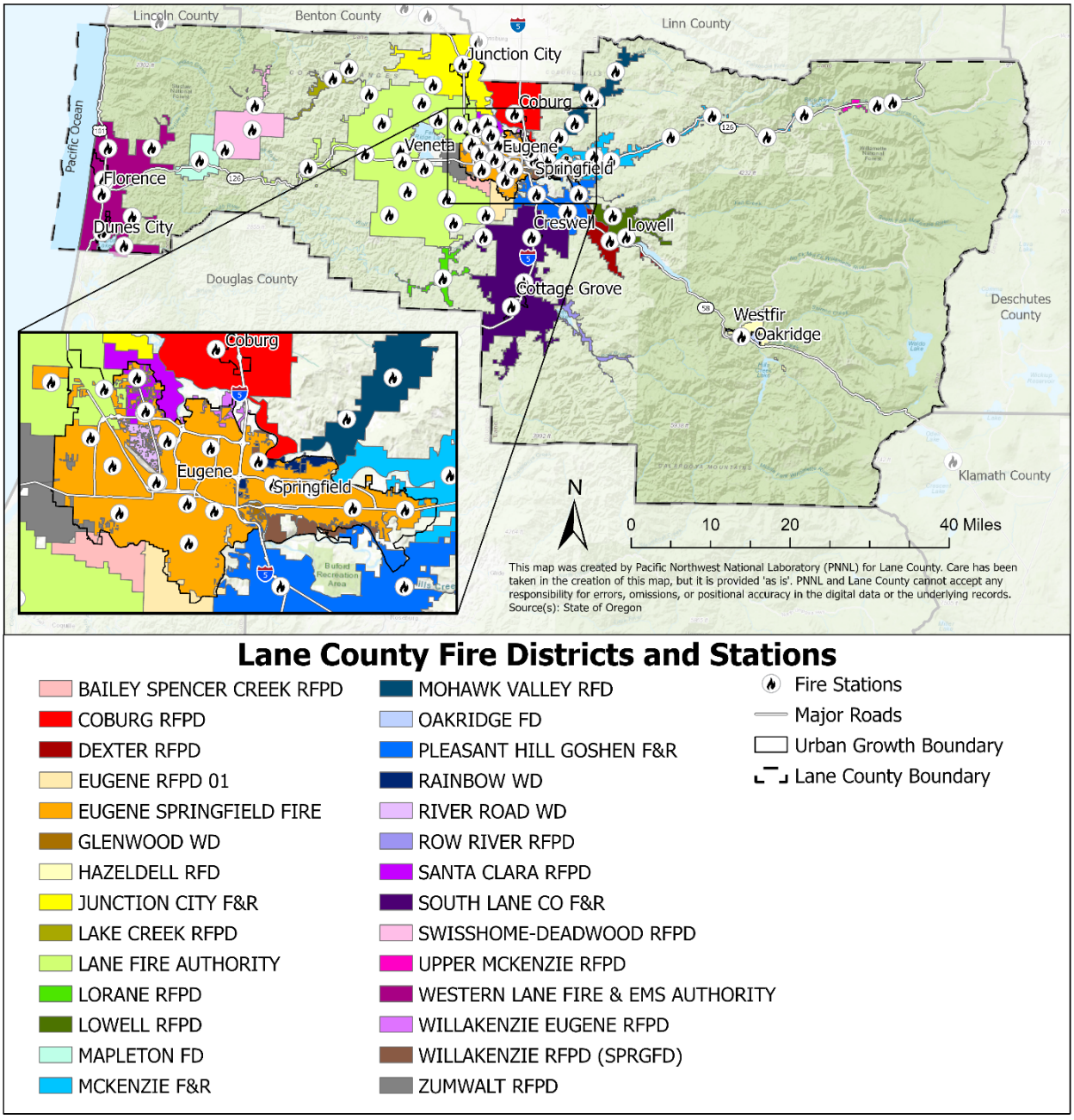


Figure 80: Lane County Fire Districts and Stations[1]

[1] Information (as of April 2019) from Lane County, *"Fire Departments & Fire Districts,"* https://storymaps.arcgis.com/stories/727d8aadc1b24160adf4c227dbff93e9

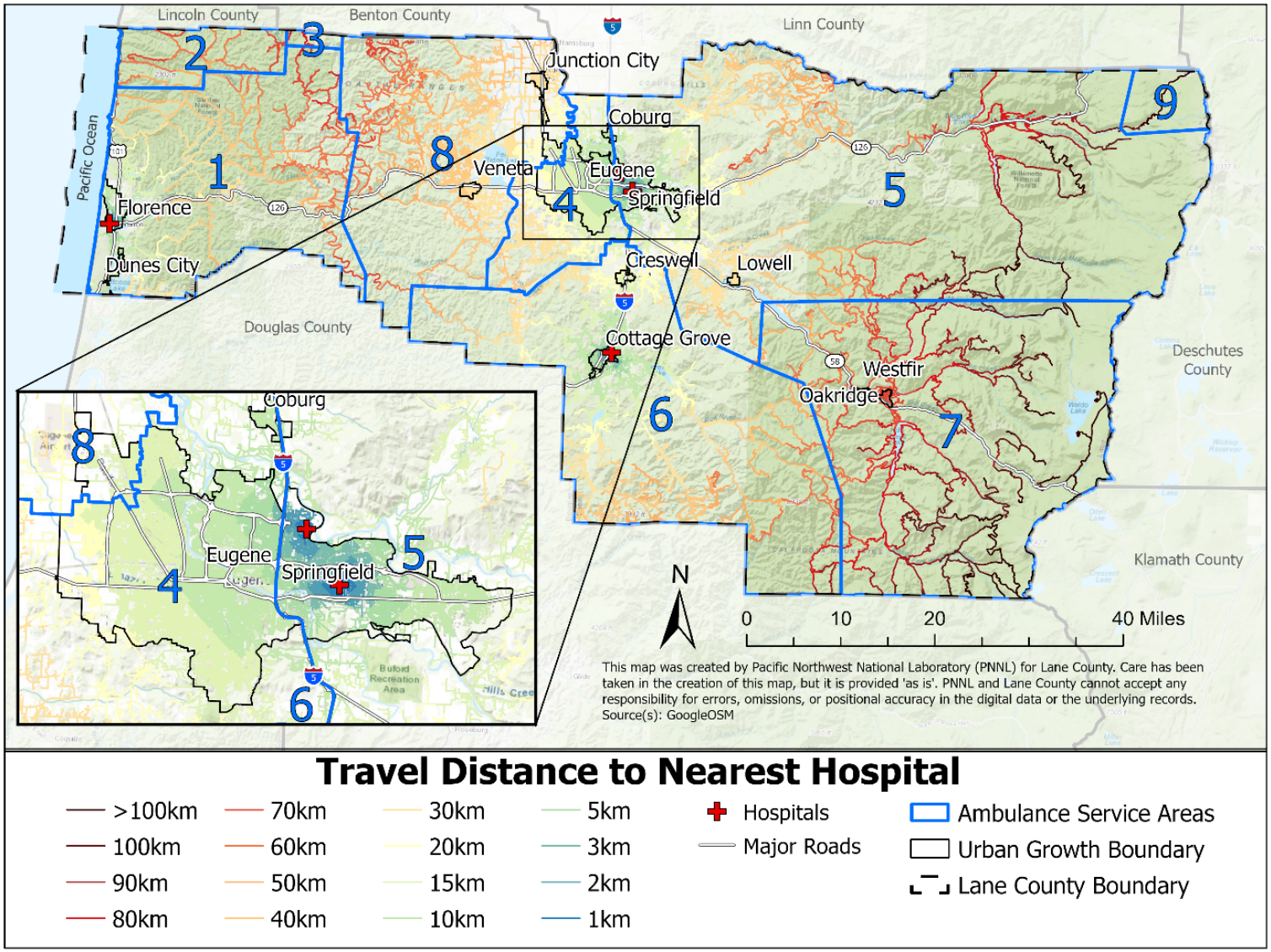


Figure 81: Travel Distance Along Roads in Lane County to Nearest Hospital[1,2]

[1] Data from Lane County *"Lane County Ambulance Service Areas and Response Time Zones,"* https://lcgisorg.maps.arcgis.com/apps/webappviewer/index.html?id=f91b9c407f1744bd88ce08a40949e4b8

[2] Data from OpenStreetMap. https://www.openstreetmap.org/#map=4/38.01/-95.84

Lane County residents receive water from public water systems or rely on wells. About 329,000 of the approximately 382,500 individuals in Lane County are served by public water systems.[1] The remaining 14% of Lane County residents rely on well water. In most power outage scenarios, residents served by water utilities will still have access to water for hours to days without power because elevated storage tanks maintain water pressure in public water systems. However, residents who access wells through electric submersible pumps (the most common method) would almost immediately lose access to their water in a power outage. Without backup power, these residents have to rely on previously stored water until power is restored. Only resients with suitably sized portable or standby backup power woud be able to continune pumping water from their well during an outage. ***Figure 81*** maps public water systems across Lane County.

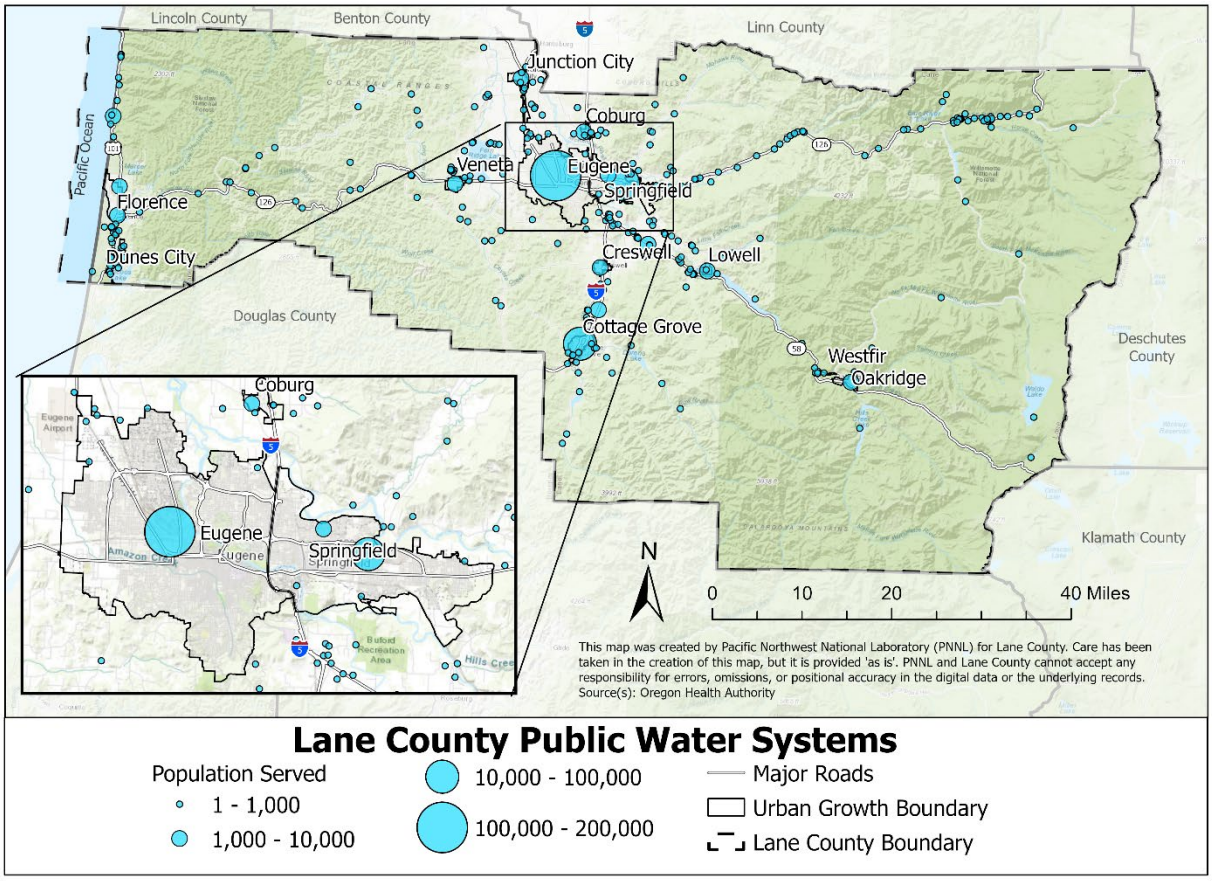


Figure 82: Lane County Public Water Systems[1]

Collecting consistent data on critical facilities is essential to evaluate resilience and energy security. Lane County, with support from national laboratory researchers, is undertaking an effort to better understand the vulnerability of key critical facilities and to support emergency preparedness and response planning across the county. ***Table 56*** summarizes key data metrics that support this assessment, describing why each metric matters and how it can be used by utilities, emergency managers, facility operators, and planners.

[1] Oregon Health Authority, *"Oregon Public Water Systems,"* https://experience.arcgis.com/experience/02c5d88395404ad081884c98067a3565#data_s=where%3AdataSource_1-pws_active_5534%3APWS%3D'00967'&zoom_to_selection=true

The metrics described in ***Table 56*** represent examples of information that can help evaluate facility resilience and operational needs during disruptions. The County is refining its data collection approach to focus on the types of information that are most useful and feasible to obtain, based on local priorities and stakeholder input. Lane County's efforts to identify and characterize critical facilities are also informed by the requirements of ***Oregon House Bill 3630 (HB 3630)***,[1] which directs electric utilities and local partners to improve planning for energy resilience at facilities that provide essential community services.

Identifying and characterizing critical facilities in Lane County presents several challenges. Definitions of "critical" may vary across agencies, and facility roles can change depending on the type and scale of disruption. Data availability is often inconsistent, outdated, or incomplete, particularly for backup power capacity, fuel storage duration, and actual ***critical load*** requirements. In addition, some operational details may be sensitive or restricted due to security considerations, limiting data sharing across jurisdictions. The county's large geographic area and mix of urban, rural, and remote communities further complicate consistent assessment. Addressing these challenges requires cross-agency coordination, standardized data collection practices, and periodic updates to ensure that resilience planning reflects current conditions and emerging risks.

Table 56: Key Metrics for Assessing Critical Facility Resilience

Metric	Why This Information Matters	Who Can Use it and for What
Backup power availability (Yes/No)	Identifies whether a facility can operate during grid outages	Emergency managers to assess vulnerability; utilities to prioritize restoration sequencing
Backup power capacity (kW)	Determines whether the generator can support full or partial facility loads	Facility managers to assess adequacy; planners to identify need for upgrades
Generator fuel type (diesel, natural gas, propane)	Influences fuel availability during emergencies and supply chain risks	Emergency management and fuel suppliers for contingency planning
On-site fuel storage duration (hours/days at full load)	Indicates how long operations can be sustained without refueling	County emergency planners to plan fuel logistics; facilities to identify storage gaps
Fuel consumption rate (gallons/hour at load)	Enables estimation of resupply frequency during extended outages	Logistics coordinators to schedule fuel deliveries
Critical load requirement (kW)	Defines the minimum power needed to maintain essential services	Resilience planners to design microgrids or targeted backup systems
Outage tolerance threshold (maximum downtime acceptable)	Clarifies how quickly power must be restored to avoid severe impacts	Utilities for restoration prioritization; emergency managers for contingency planning
Interconnection details (feeder, substation, voltage level)	Shows infrastructure dependencies and potential single points of failure	Utilities for system hardening and contingency planning
Occupancy and population served	Reflects scale of impact if the facility becomes inoperable	Emergency managers for prioritization and evacuation planning

[1] Oregon State Legislature, *"2023 Regular Session,"* https://olis.oregonlegislature.gov/liz/2023R1/Measures/Overview/HB3630

Chapter 9

Community Energy and Resilience Planning

Brooke Marten and Ali Trueworthy

Local governments are increasingly undertaking energy or resilience planning initiatives. These initiatives can give strategic direction for projects, policies, and coordinated action within a community. Often, they include a community's goals or vision along with strategy areas or policy recommendations for reaching those goals. Community plans related to economic growth, transportation, and electrification can impact how much electricity and/or fuel a community uses.

In this section, we provide best practices for community energy planning and community resilience planning. The best practices are concerned with the planning process rather than the plans themselves. Then we review existing resilience and energy planning by drawing from a variety of plan types from cities and communities in Lane County. By reviewing these plans, we aim to: (1) Build a wider understanding of community energy and resilience goals across the county, (2) Identify common energy related policies and strategies being pursued across the county, and (3) Assess how the electric system is considered in resilience and energy planning. All plans that we reference are listed in ***Appendix B***.

9.1 Best Practices

Best Practices for community energy planning and for community resilience planning are outlined in this section.

9.1.1 Community Energy Planning

Community energy plans, which are sometimes also called "strategic energy plans", are roadmaps for achieving community energy goals in both the near and long term. Often, community energy planning is initiated or led by local authorities but completed by a broader group of stakeholders. A major part of strategic energy planning is coordinating other plans as they relate to the energy system. Sometimes strategic energy plans are part of larger plans such as master plans or climate action plans. Benefits from strategic energy planning can include cost savings for consumers, avoided infrastructure development need, and reduced pollution.[1]

[1] Lawrence Berkeley National Laboratory, *"Best Practices in Integrated Resource Planning: A guide for planners developing the electricity resource mix of the future,"* Nov. 2024. https://emp.lbl.gov/publications/best-practices-integrated-resource

The U.S. Department of Energy's strategic energy planning process is shown in ***Figure 82***.

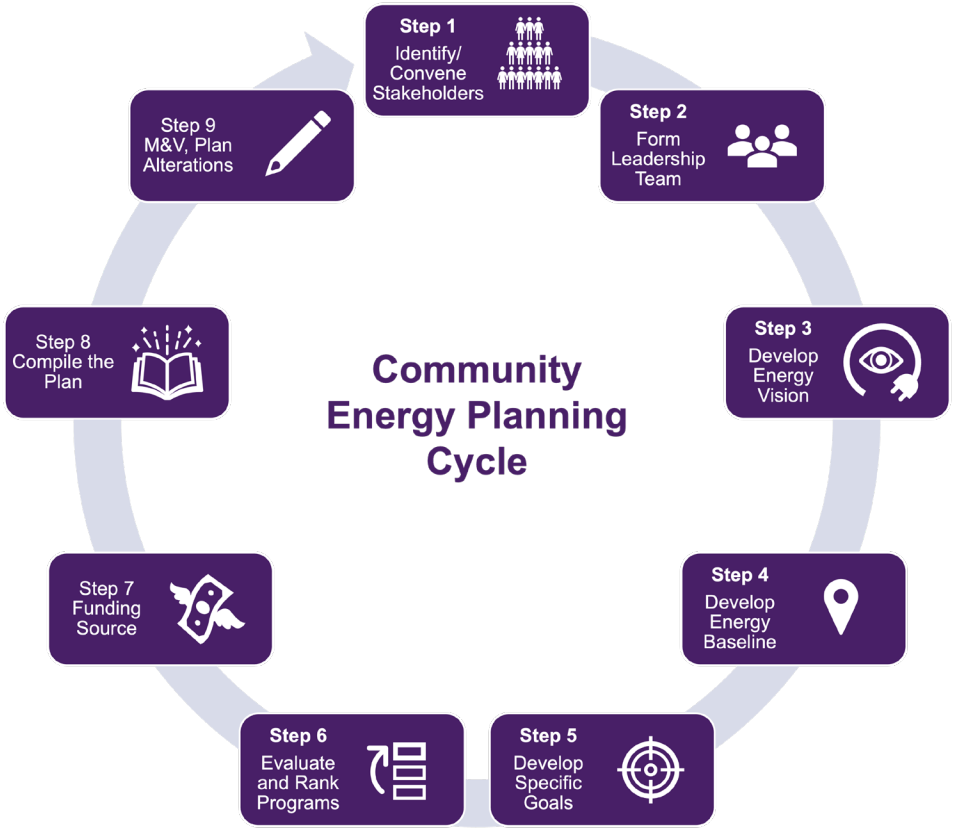


Figure 83: Nine-Step Community Energy Planning Cycle[1]

The nine-step, cyclical process is similar to processes published by others.[2, 3, 4] DOE's nine-step process includes:

Step 1 – Identify/Convene Stakeholders: This step involves identifying and bringing together stakeholders such as local government, utilities, businesses, nongovernmental organizations (NGOs), residents, and "energy champions" (i.e., those interested in planning and energy savings). Ongoing, inclusive engagement with these stakeholders using strategies such as meetings, surveys, and digital tools (e.g., websites, email lists, social media, texting) helps to build trust and ensures community input is incorporated throughout the process.

[1] Figure adapted from U.S. Department of Energy, *"COMMUNITY GREENING: HOW TO DEVELOP A STRATEGIC ENERGY PLAN,"* Feb. 2010. https://docs.nlr.gov/docs/fy10osti/45652.pdf
[2] Public Service Commission of Wisconsin, *"Energy Planning Basics,"* https://psc.wi.gov/Pages/ServiceType/OEI/EnergyPlanning.aspx
[3] K. Arkema, K. Grantham, D. Rose, and A. Trueworthy, *"Deployment Readiness Framework Subtask 1.1 (Literature Review),"* Pacific Northwest National Laboratory, PNNL-33575, 1896960, Aug. 2022. https://www.doi.10.2172/1896960.
[4] U.S. Department of Energy, *"Guide to Community Energy Strategic Planning,"* Mar. 2013. https://www.energy.gov/sites/prod/files/2014/05/f15/cesp_guide.pdf

Step 2 – Form Leadership Team: This step involves establishing a cross-sector leadership team with decision-making authority and the ability to gather stakeholders, acquire funding, and promote the project. The team often includes relevant municipal departments and dedicated external advocates, each with clear roles to ensure transparency and accountability.

Step 3 – Develop Energy Vision: This step involves creating an energy vision that reflects community priorities such as efficiency, renewable energy adoptions, resilience, and/or affordability. The vision clarifies the plan's scope and direction. A vision answers the question: "What do we want our energy system to look like in 20 years?" Or it might be a simple list of priorities. Most importantly, the vision should be something that will keep participants inspired throughout the planning process and beyond.

Step 4 – Develop Energy Baseline: This step involves collecting and organizing data on energy use, costs, and emissions across all sectors deemed relevant to the established energy vision. The baseline data characterizes where the community is relative to their vision. The data collection process may include working with utilities and energy auditors, reviewing utility bills and equipment data, documenting assumptions and data quality, and preparing a business-as-usual forecast to compare against proposed actions.

Step 5 – Develop Specific Goals: This step involves translating the vision and baseline into specific, measurable, achievable, relevant, and time-bound (SMART) goals with defined metrics and timelines. The goals span short, intermediate, and long-term horizons, identify responsible parties and preliminary budgets, and are validated through community engagement and an understanding of zoning and other constraints.

Step 6 – Evaluate and Rank Programs: This step involves identifying potential projects and policies and assessing them using evaluation criteria such as effectiveness, timeframe, feasibility, and co-benefits such as social equity and economic development. A transparent scoring and ranking framework used to prioritize near-term actions and to phase more complex projects over time as resources and capacity allow.

Step 7 – Funding Source: This step involves developing a funding and financing strategy that could involve a range of funding sources (e.g., grants, utility incentives, committed municipal budget support), and financing tools matched to project types and timelines. If an immediate funding source is unavailable, free programs and/or partnerships that provide their own funding should be prioritized.

Step 8 – Compile the Plan: This step involves consolidating the baseline, goals, prioritized actions, and performance metrics into a formal plan for adoption by the governing body. Prior to adoption, the leadership team should re-engage the broader group of stakeholders and interested community members. After adoption, the document can guide the community's policy- and decision-making.

Step 9 – Measurement & Verification (M&V) and Plan Alterations: This step involves establishing measurement and verification protocols to quantify achieved energy savings and assess ongoing plan performance. A regular reporting cadence allows for, if necessary, adjustments to targets, re-ranking of actions, and reallocation of resources. The team might choose a timeline for when to reconvene to assess progress and eventually restart the process as their situation changes.

Local Government Role in Strategic Energy Planning

There has been some academic research about the capacity of local authorities to steward strategic energy planning. Multiple studies note that local authorities acting in the energy space tend to apply ad hoc and opportunistic approaches to energy projects while struggling to achieve strategic direction,[1, 2] but a more recent study looking at efforts in Denmark shows success in aligning strategic plans and energy projects.[3] This research exemplifies that, like many of the other best practices presented in this document, best practices for community energy planning are currently being researched and improved.

In ***Figure 83***, we show some of the services that can be expected of a strategic energy planning body (i.e., the stakeholders leading a strategic energy planning process) alongside some of the functions municipal or county governments often play. The purpose of ***Figure 83*** is to exemplify some of the ways that the existing roles and services of local governments can make them well suited to lead energy planning. That said, other community leaders may initiate, lead, or steward community energy planning. The important thing is that they can facilitate progress toward the energy vision.

[1] L. Allman, P. Fleming, and A. Wallace, “The progress of English and Welsh local authorities in addressing climate change,” *Local Environ.*, vol. 9, no. 3, pp. 271–283, Jun. 2004. https://www.doi.10.1080/1354983042000219379.

[2] C. S. E. Bale, T. J. Foxon, M. J. Hannon, and W. F. Gale, “Strategic energy planning within local authorities in the UK: A study of the city of Leeds,” *Energy Policy*, vol. 48, pp. 242–251, Sep. 2012. https://www.doi.10.1016/j.enpol.2012.05.019.

[3] L. Krog, “How municipalities act under the new paradigm for energy planning,” *Sustain. Cities Soc.*, vol. 47, p. 101511, May 2019, doi: https://www.doi.10.1016/j.scs.2019.101511.

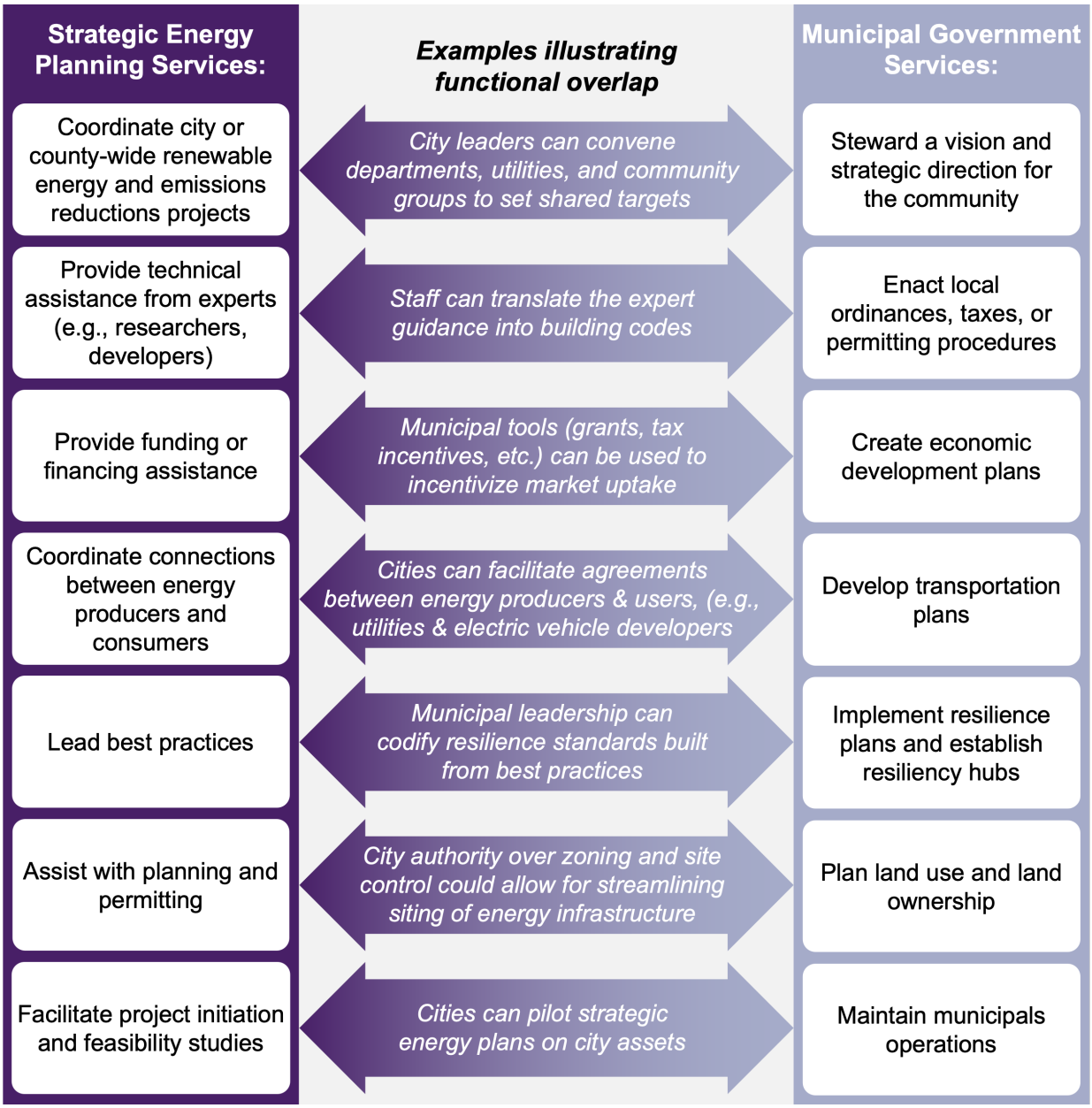


Figure 84: Summary of Strategic Energy Planning and Municipal Government Services and their Functional Overlap

9.1.2 Community Resilience Planning

Community resilience plans are strategic frameworks designed to prepare for, mitigate, respond to, and recover from disruptive events. A resilience plan sets performance goals for the built environment based on the community's social needs such as human health, safety, and general welfare, addresses vulnerabilities, and integrates both structural (e.g., temporary repair or retrofits) and non-structural solutions (e.g., change to land use policy).

The National Institute of Standards and Technology (NIST) has developed useful products for community resilience planning including a Community Resilience Planning Guide for Buildings

and Infrastructure Systems. Volume one of this document[1] outlines a six-step approach to community resilience planning. Volume two of this document[2] outlines how to characterize a community's social and economic dimensions, dependencies and consequences potentially associated with building and infrastructure system decisions, the performance of buildings and infrastructure (i.e., transportation systems, energy systems, communications systems, water and wastewater systems), and community resilience metrics. Additionally, NIST provides Guide Briefs[3] that summarize the best practices that align with each of the steps in the recommended six-step approach and a companion playbook[4] that provides more detail on what specific actions communities can take when establishing their own community resilience plan (note that templates are also available). The six-step community resilience planning process is shown in ***Figure 84***.

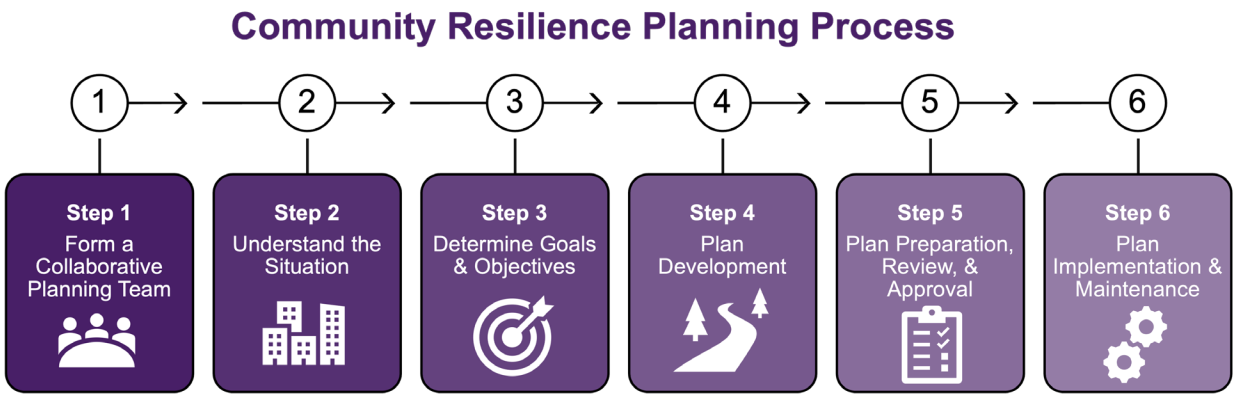


Figure 85: Six-Step Community Resilience Planning Process[5]

More information on what each step entails can be found in volume I of NIST's Community Resilience Planning guide for Buildings and infrastructure System.[1] The publication also highlights other community resilience guidance that is available including: SPUR Framework,[6] Baseline Resilience Indicators for Communities (BRIC),[7] the Community and Regional

[1] Community Resilience Group, *"Community resilience planning guide for buildings and infrastructure systems : volume I,"* National Institute of Standards and Technology, NIST SP 1190v1, May 2016. https://www.doi.10.6028/NIST.SP.1190v1.

[2] Community Resilience Group, *"Community resilience planning guide for buildings and infrastructure systems : volume II,"* National Institute of Standards and Technology, NIST SP 1190v2, May 2016. https://www.doi.10.6028/NIST.SP.1190v2.

[3] National Institute of Standards and Technology, *"Development and Implementation of the Community Resilience Planning Guides,"* https://www.nist.gov/community-resilience/planning-guide

[4] National Institute of Standards and Technology, Community Resilience Program, *"community resilience planning guide for buildings and infrastructure systems: A Playbook,"* National Institute of Standards and Technology, Oct. 2020. https://www.doi.10.6028/NIST.SP.1190GB-16.

[5] Figure adapted from Community Resilience Group, "Community resilience planning guide for buildings and infrastructure systems : volume II," National Institute of Standards and Technology, NIST SP 1190v2, May 2016. https://www.doi.10.6028/NIST.SP.1190v2.

[6] San Francisco Planning + Urban Research Association (SPUR). *"Defining resilience: what San Francisco needs from its seismic mitigation policies,"* Feb. 2009. https://www.spur.org/sites/default/files/2020-03/SPUR_Defining_Resilience.pdf

[7] S. L. Cutter, K. D. Ash, and C. T. Emrich, "The geographies of community disaster resilience," *Glob. Environ. Change*, vol. 29, pp. 65–77, Nov. 2014. https://www.doi.10.1016/j.gloenvcha.2014.08.005.

Resilience Institute (CARRI) framework,[1] the Oregon Resilience Plan,[2] NOAA's Coastal Resilience Index tool,[3] and Communities Advancing Resilience Toolkit (CART).[4] Since publication of the NIST planning guidance, additional community resilience resources have been released and include, but are not limited to: Community Disaster Resilience Planning for Heritage Resources,[5] the United Nations Office for Disaster Risk Reduction (UNDRR) Disaster Resilience Scorecard for Cities,[6] the Resilient Cities Network Guidebook for Community Resilience,[7] and FEMA's Resilience Analysis and Planning Tool (RAPT).[8]

Local Government Role in Community Resilience Planning

Local governments are well-positioned to lead community resilience planning due to their unique authority and established roles within the community.[9,10] Local governments are already responsible for efforts such as land-use planning, hazard mitigation, and economic development. These responsibilities allow them to coordinate and collaborate effectively with relevant entities, ensuring that resilience goals integrate seamlessly into existing plans. For example, Natural Hazard Mitigation Plans (NHMPs), which are a distinct planning product from community resilience plans, identify natural hazards, assess vulnerabilities through risk assessment, and establish a mitigation strategy to reduce risk. NHMPs are generally a prerequisite for receiving FEMA hazard mitigation funding and can complement and inform community resilience planning.

In addition, municipalities often own or regulate key buildings and infrastructure systems, making it easier to access data, identify risks, and engage the appropriate stakeholders. Local

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[1] Meridian Institute, *"Community and Regional Resilience Institute (CARRI),"* https://merid.org/case-studies/community-and-regional-resilience-institute/

[2] Oregon Seismic Safety Policy Advisory Commission, *"The Oregon Resilience Plan: Reducing Risk and Improving Recovery for the Next Cascadia Earthquake and Tsunami,"* Feb. 2013. https://www.oregon.gov/oem/documents/oregon_resilience_plan_final.pdf

[3] U.S. Climate Resilience Toolkit, *"Coastal Resilience Index."* https://toolkit.climate.gov/tool/coastal-resilience-index

[4] R. L. Pfefferbaum, B. Pfefferbaum, R. L. Van Horn, R. W. Klomp, F. H. Norris, and D. B. Reissman, "The Communities Advancing Resilience Toolkit (CART): An Intervention to Build Community Resilience to Disasters," *J. Public Health Manag. Pract.*, vol. 19, no. 3, p. 250, Jun. 2013. https://www.doi.10.1097/PHH.0b013e318268aed8.

[5] University of Oregon Institute for Policy Research and Engagement and Oregon Heritage*, "Community disaster resilience planning for heritage resources,"* Sep. 2020. https://www.oregon.gov/oprd/OH/Documents/CDRHR_GuidebookWeb.pdf

[6] United Nations Office for Disaster Risk Reduction, *"Disaster Resilience Scorecard for Cities,"* https://mcr2030.undrr.org/disaster-resilience-scorecard-cities

[7] B. Bryant, K. Pierce, Y. Ahn, N. Echeverria, and A. Rustow, *"Guidebook for Community Resilience,"* Dec. 2025. https://resilientcitiesnetwork.org/wp-content/uploads/2025/12/Guidebook-for-Community-Resilience.pdf

[8] Federal Emergency Management Agency, *"Resilience Analysis and Planning Tool (RAPT)"* https://www.fema.gov/emergency-managers/practitioners/resilience-analysis-and-planning-tool

[9] Community Resilience Group, *"Community resilience planning guide for buildings and infrastructure systems : volume I,"* National Institute of Standards and Technology, NIST SP 1190v1, May 2016. https://www.doi.10.6028/NIST.SP.1190v1.

[10] O. Cohen, A. Goldberg, M. Lahad, and L. Aharonson-Daniel, "Building resilience: The relationship between information provided by municipal authorities during emergency situations and community resilience," *Technol. Forecast. Soc. Change*, vol. 121, pp. 119–125, Aug. 2017. https://www.doi.10.1016/j.techfore.2016.11.008.

governments are tasked with implementing community building codes, statutes, and broader community planning efforts, providing them with the tools for effective resilience plan implementation.

While having a dedicated community resilience office is ideal for streamlining the planning process, this may not always be feasible due to resource constraints. However, this limitation should not hinder the development of robust resilience plans. Other capable stakeholders, such as community organizations or regional partnerships, can lead the planning team if they can provide the necessary leadership and oversight.

The foundational services essential to successful community resilience planning include:

- Engaging diverse stakeholders at all community levels
- Assessing risks and identifying critical buildings and infrastructure
- Establishing recovery goals for essential community functions
- Integrating resilience goals with existing community plans
- Identifying and prioritize implementable resilience actions
- Documenting and formalize the comprehensive resilience plan
- Updating resilience plans regularly to reflect changing needs.

9.2 Approaches Applied in Lane County

While few communities in Lane County have formal community energy or resilience plans, many have adopted climate plans, emergency operations plans, and natural hazard mitigation plans (***Table 57***). Additionally, seven of the communities in Lane County have identified buildings that could serve as Resilience Hubs to support their communities through an EPA-funded effort.[1] Note that other facilities may be considered community resilience hubs outside of the scope of that effort.

At the county level, Lane County has implemented several key frameworks: an Internal Operations Climate Action Plan,[2] a Greenhouse Gas Reduction Plan,[3] and a Climate Adaption and Resilience Plan,[4] all of which incorporate elements of strategic energy planning. In terms of county-level resilience planning, the Lane Regional Resiliency Collaborative works to "link, leverage, and align community resources (e.g., county, city, special district, nonprofit, private

[1] U.S. Environmental Protection Agency, *"Target Setting."* https://www.epa.gov/green-power-markets/target-setting

[2] Good Company, *"Lane County, Oregon Climate Action Plan Phase 1: Operational Greenhouse Gas Inventory Fiscal Year 2021,"* Jul. 2022. https://cdnsm5-hosted.civiclive.com/UserFiles/Servers/Server_3585797/File/Government/County%20Departments/County%20Administration/Climate%20Action%20Plan/Lane-County_CAP-Ops%20Approved.pdf

[3] L. Cook and A. Corvello, *"Lane County, Oregon Climate Action Plan: Phase 2 Community Greenhouse Gas Mitigation Action Plan"*. https://cdnsm5-hosted.civiclive.com/UserFiles/Servers/Server_3585797/File/Government/County%20Departments/County%20Administration/Climate%20Action%20Plan/Background%20Docs/Lane%20County-CAP%20Part2-GHG%20Reduction.pdf

[4] S. Adams and M. McRae, *"Lane County, Oregon Climate Action Plan Phase 3: Community Climate Resilience Plan,"* Dec. 2022. https://www.beyondtoxics.org/wp-content/uploads/2022/09/LaneCo_DRAFT_ClimateActionPlan_Phase3_CommunityClimateActionPlan.pdf

sector, etc.) across Lane County using a whole community framework."[1,2] Additionally, Lane County continues to update its Multi-Jurisdictional Natural Hazard Mitigation Plan,[3] which aims is to identify, assess, and reduce Lane County's natural hazards risks. The Lane County ***Emergency Operations Plan***[4] focuses on disaster preparedness through coordinated activities, including protection, prevention, mitigation, response, and recovery activities.

On a broader scale, the State of Oregon offers a suite of resources related to resilience planning[5] and maintains a statewide energy strategy document.[6] Furthermore, Energy Trust of Oregon provides a Strategic Plan focused on accelerating the adoption of clean energy solutions, reducing energy costs, and delivering community-centered benefits.[7] While county- and state-level plans are valuable, they may not always align with the unique needs and capabilities of individual cities.

[1] Lane County, *"Lane Regional Resiliency Collaborative,"* https://www.lanecountyor.gov/government/county_departments/emergency_management/committees___coalitions/lane_regional_resiliency_collaborative

[2] "*Lane Regional Resiliency Collaborative*," https://cdnsm5-hosted.civiclive.com/UserFiles/Servers/Server_3585797/File/Government/County%20Departments/Emergency%20Management/LRRC/Why%20We%20Need%20the%20LRRC.pdf

[3] Lane County, Oregon, *"Lane County Multi-Jurisdictional Natural Hazard Mitigation Plan,"* Version 4, 2023.https://www.lanecountyor.gov/government/county_departments/emergency_management/planning/mitigation_plan

[4] Lane County, *"Lane County Emergency Operations Plan,"* 2024. https://cdnsm5-hosted.civiclive.com/UserFiles/Servers/Server_3585797/File/2024_EOP%20Base%20Plan-Final.pdf?_gl=1*mkguub*_ga*OTA0MjE5ODg5LjE3NTYzOTY0Mjk.*_ga_G30BCGQ9RY*czE3ODMzOTg4NDgkbzI1JGcxJHQxNzgzMzk5ODg3JGozNCRsMCRoMA..&_gl=1*mkguub*_ga*OTA0MjE5ODg5LjE3NTYzOTY0Mjk.*_ga_G30BCGQ9RY*czE3ODMzOTg4NDgkbzI1JGcxJHQxNzgzMzk5ODg3JGozNCRsMCRoMA..

[5] Oregon State Parks, *"Disaster Preparedness, Recovery & Resilience,"* https://www.oregon.gov/oprd/OH/Pages/DisasterPrep.aspx

[6] Oregon Department of Energy, *"Oregon Energy Strategy,"* Nov. 2025. https://www.oregon.gov/energy/Data-and-Reports/Documents/Oregon-Energy-Strategy.pdf

[7] EnergyTrust of Oregon, *"Energy Trust of Oregon Strategic Plan 2025-2030,"* 2025. https://www.energytrust.org/wp-content/uploads/2025/01/Energy-Trust-Final-2025-2030-Strategic-Plan-1.pdf

Table 57: Summary of Lane County's Cities' Strategic Energy and Community Resilience Plans *where ✓ indicates the document exists, — indicates the document's existence could not be confirmed and * indicates these cities participate in Lane County's NHMP*

	Community Energy Plan	Community Resilience Plan	Climate Plan	Emergency Operations Plan	Natural Hazard Mitigation Plan
Lane County	—	✓ [1]	✓ [1,2,3]	✓ [4]	✓ [5]
Coburg	—	—	—	—	✓* [5]
Cottage Grove	—	✓ [6]	—	✓ [7]	✓ [8]
Creswell	—	—	—	✓ [9]	✓* [5]
Dunes City	—	—	—	—	✓* [5]
Eugene	—	✓ [10]	✓ [11]	✓ [12]	✓ [13]
Florence	—	—	—	—	✓* [5]
Junction City	—	—	—	—	—
Lowell	—	—	—	—	✓* [5]
Oakridge	—	—	—	—	✓* [5]
Springfield	—	—	—	✓ [12]	✓ [13]
Veneta	—	—	—	✓ [14]	✓* [5]
Westfir	—	—	—	—	✓* [5]

[1] S. Adams and M. McRae, *"Lane County, Oregon Climate Action Plan Phase 3: Community Climate Resilience Plan,"* Dec. 2022. https://cdnsm5-hosted.civiclive.com/UserFiles/Servers/Server_3585797/File/Government/BCC/2022/2022_AGENDAS/121322agenda/T.9.A.pdf

[2] Good Company, *"Lane County, Oregon Climate Action Plan Phase 1: Operational Greenhouse Gas Inventory Fiscal Year 2021,"* Jul. 2022. https://cdnsm5-hosted.civiclive.com/UserFiles/Servers/Server_3585797/File/Government/County%20Departments/County%20Administration/Climate%20Action%20Plan/Lane%20County-FY21-GHG-Ops-final.pdf

[3] L. Cook and A. Corvello, *"Lane County, Oregon Climate Action Plan: Phase 2 Community Greenhouse Gas Mitigation Action Plan".* https://cdnsm5-hosted.civiclive.com/UserFiles/Servers/Server_3585797/File/Government/County%20Departments/County%20Administration/Climate%20Action%20Plan/Background%20Docs/Lane%20County-CAP%20Part2-GHG%20Reduction.pdf

[4] Lane County, *"Lane County Emergency Operations Plan,"* 2024. https://www.lanecounty.org/UserFiles/Servers/Server_3585797/File/2024_EOP%20Base%20Plan-Final.pdf?_gl=1*1xwvs8j*_ga*MTI2NDkxNzAzMS4xNzc5NDkxNTM3*_ga_G30BCGQ9RY*czE3Nzk0OTE1MzYkbzEkZzEkdDE3Nzk0OTI2NzQkajUzJGwwJGgw

[5] Lane County, Oregon, *"Lane County Multi-Jurisdictional Natural Hazard Mitigation Plan,"* Version 4, 2023. https://cdnsm5-hosted.civiclive.com/UserFiles/Servers/Server_3585797/Image/Government/County%20Departments/Emergency%20Management/Planning%20Page/Lane%20County%20MNHMP%20V4_Full%20Plan%20(2).pdf

[6] Institute for Policy Research & Engagement, University of Oregon, *"Disaster Resilience Plan for Heritage Resources in Cottage Grove,"* Sept. 2020. https://www.oregon.gov/oprd/OH/Documents/CottageGroveResilience_ReportWeb.pdf

[7] *"City of Cottage Grove Emergency Operations Plan,"* Feb. 2016. https://www.cottagegroveor.gov/DocumentCenter/View/555/Cottagegrove_eop2016_basicplanpublic

[8] *"City of Cottage Grove Natural Hazards Mitigation Plan,"* 2016. https://www.cottagegroveor.gov/DocumentCenter/View/1001/cottage_grove_nhmp_final_3-30-17

[9] *"City of Creswell Emergency Operations Plan,"* 2018. https://core-docs.s3.us-east-1.amazonaws.com/documents/asset/uploaded_file/4294/city/3608572/Creswell_Emergency_Operations_Plan_Adopted_July_9_2018.pdf

[10] https://www.eugene-or.gov/5438/Resilience

[11] *"Eugene Community Climate Action Plan 2.0: Playbook for Eugene's Climate,"* City of Eugene, Eugene, Oregon, 2019. https://www.eugene-or.gov/DocumentCenter/View/48138/CAP20-Full-Document-w-Appendices

[12] *"Eugene-Springfield Multi-Jurisdictional Emergency Operations Plan,"* Jun., 2023. https://www.eugene-or.gov/DocumentCenter/View/72418/Eugene-and-Springfield-Multi-jurisdictional-Emergency-Operations-Plan-2023

[13] *"Eugene-Springfield Multi-Jurisdictional Natural Hazards Mitigation Plan,"* Jan., 2020. https://www.eugene-or.gov/DocumentCenter/View/48415/Eugene-SpringfieldAreaMJNHMP2020?bidId=

[14] *"City/LFA Emergency Operations Plan,"* Nov.2016. https://www.venetaoregon.gov/DocumentCenter/View/456/Lane-Fire-Authority-Emergency-Operations-Plan-PDF?utm

9.2.1 Community Energy Planning, Goals, And Policies

Across Lane County, energy objectives are distributed among climate plans, comprehensive plans, and sector plans rather than consolidated in stand-alone strategic energy plans. Some of the most common energy related goals and strategies set by municipal governments are listed in ***Table 58***, along with which cities within Lane County have adopted those goals and strategies.

At the county level, the Greenhouse Gas Reduction Plan establishes a portfolio of strategies targeting reductions in the County's energy consumption ranging in scope from electric vehicle adoption, electric grid decarbonization, electrification of residential appliances, and energy efficiency and conservation.[1] Additionally, Lane County's Rural Comprehensive Plan includes energy conservation as an explicit goal, directing Lane County to promote efficient land use, buildings, and transportation; provide public education and interjurisdictional collaboration related to energy conservation; and develop financial incentives to support energy-efficient projects.[2]

Individual municipalities reflect similar energy goals in their comprehensive plans as articulated in the county and state energy planning documents, however they vary in their level of specificity and corresponding policy actions.

As the largest city in Lane County, Eugene's planning documents are the most prescriptive with respect to energy planning. To progress towards achieving the fossil fuel and emissions reduction targets set in Eugene's Climate Recovery Ordinance, the Community Climate Action Plan 2.0[3] outlines both current and future actions related to reducing emissions associated with energy used in buildings, transportation fuels, and consumption. Specifically, to reduce the emissions associated with energy used in buildings, *current actions* are focused on energy efficiency programs, smart metering, community outreach on energy audits, and building upgrades, and *future actions* are focused on advancing state building codes to energy-efficient standards, incentivizing electrification, and supporting electric vehicle charging infrastructure.

Other cities advance energy goals through ***Comprehensive Plan*** policies and utility partnerships. It's important to note, however, that many Oregon communities' Comprehensive Plans originated in the late 1970s and early 1980s and have been updated irregularly through post-acknowledgement plan amendments, making it difficult to determine how current specific energy policies are without reviewing adoption and amendment records (***Table 58***).

[1] L. Cook and A. Corvello, ibid.

[2] Lane County, *"Rural Comprehensive Plan: General Plan Policies 1984,"* https://www.lanecounty.org/common/pages/DisplayFile.aspx?itemId=6477350

[3] City of Eugene, Eugene, Oregon, *"Eugene Community Climate Action Plan 2.0: Playbook for Eugene's Climate,"* 2019. https://www.eugene-or.gov/DocumentCenter/View/48138/CAP20-Full-Document-w-Appendices

Table 58: Summary of Energy Planning Documents and Policies for Lane County Cities

Cottage Grove	The city aims to be a leader in the development, adoption, and utilization of clean, alternative energy sources, which includes pursuing actions related to implementing forward-looking energy policy, pursuing grants for project execution, developing pilot projects, establishing solar panel incentives, and encouraging resource conservation. Another strategy of the city's is to track, support and encourage sustainable development. One way this is being pursued is using a local "Nobel Prize" for citizens that design or implement successful energy-conservation ideas and actions.[1]
Coburg	The city has goals "to provide for the housing needs of the citizens of the State", which includes a policy to encourage the incorporation of energy efficiency standards in the existing housing stock, and "to conserve energy", which includes policies where the city shall consider the energy use implications in all land use decisions, and encourage residents to utilize Pacific Power's free home energy audit.[2]
Creswell	The city has eight energy conservation policies that include: developer utilization of energy-efficient design approaches, land-use strategies (i.e., higher residential densities near commercial areas), coordination with utilities to encourage the use of weatherization approaches to conserve energy, and continuous monitoring of state/federal policy to align local development and operations with long-term energy goals.[3] More broadly, economic development is part of the community's Five-year Strategic Plan,[4] which has implications on the community's energy use planning.
Dunes City	The city's comprehensive plan includes a policy requiring the city to cooperate with Central Lincoln People's Utility District to assist residents in reducing their energy consumption through conservation practices.[5]
Florence	The city's "Energy Facilities and Conservation" chapter in their Comprehensive Plan promotes renewable energy (i.e., wind and solar energy) and land use and transportation planning policies that will conserve energy, while recognizing constraints for their adoption (i.e., height limits, setbacks, etc.).[6] A unique recommendation from Florence's Comprehensive Plan is to consider the ways that trees and foliage provide a natural windbreak that acts to conserve energy when planning residential developments. Trees provide energy efficiency benefits for heating in cool, windy places like the Oregon Coast, but can also provide energy efficiency benefits for cooling in warm, sunny areas like the Valley and Cascades. [6]
Junction City	The city's energy planning efforts seek to conserve energy while also lowering the cost of energy consumption in city facilities. To do so, the city's zoning ordinance encourages the reduced use of petroleum-based fuel and has a program to replace streetlights with higher efficiency models. Additionally, the city is actively exploring opportunities to use solar energy to heat the community swimming pool and create biofuels locally.[7]

[1] Cottage Grove, *"Cottage Grove 2037 VISION AND ACTION PLAN,"* May 2008. https://scholarsbank.uoregon.edu/server/api/core/bitstreams/e2cf9b36-0616-48f2-9a12-7ee00eeaf222/content

[2] City of Coburg Oregon, *"Comprehensive Plan,"* https://www.coburgoregon.gov/planning/page/comprehensive-plan

[3] City of Creswell, "Comprehensive Land Use Plan," https://www.ci.creswell.or.us/page/comprehensive-land-use-plan

[4] City of Creswell, *"FIVE-YEAR STRATEGIC PLAN 2022-2027"* https://files-backend.assets.thrillshare.com/documents/asset/uploaded_file/4294/City/3d40946d-24d6-4249-bed9-68db89d2f6db/City_of_Creswell_Five-Year_Strategic_Plan_2022.pdf?disposition=inline

[5] Dunes City, *"Comprehensive Plan," Oct*. 2013. https://www.dunescity.gov/_files/ugd/2f17cf_c5b0cc7e2f9a4b69a5edbac2267bf1b5.pdf

[6] City of Florence, *"FLORENCE REALIATION 2020 COMPREHENSIVE PLAN,"* July 2018. https://www.ci.florence.or.us/DocumentCenter/View/2041/Florence-Realization-2020-Comprehensive-Plan-2018-Update-PDF

[7] Junction City *"2013 Comprehensive Plan,"* https://www.junctioncityoregon.gov/vertical/sites/%7BE865F063-52B6-4191-89A3-

Lowell	Like many other cities in Lane County, Lowell has a community goal of energy conservation in alignment with the broader statewide Land Conservation and Development Commission goals and guidelines. As such, the community promotes the use of techniques such as efficient land use patterns, effective housing rehabilitation and construction methods, the use of alternative energy sources (e.g., solar), and energy efficient transportation policies. Other energy-related policies in the comprehensive plan require new utility lines be placed underground, encourage the conversion of existing overhead utilities to underground service, and encourage the adoption of energy conservation practices in public facilities.[1]
Oakridge	The city also has the goal of energy conservation, which the comprehensive plan states will be supported by the following: individual energy conservation promoted through governmental programs, taxation incentives, educational programs, land use regulations (e.g., higher density dwelling construction), building codes (e.g., require highly insulative building materials), transportation planning (e.g., well-thought out city design to decrease the transportation distance between residences and common destination points), and exploration of renewable energy options available in the region (e.g., geothermal and solar).[2]
Springfield	The city's comprehensive plan has implementation strategies outlined for its policies and recommends considering the use of incentives for promoting the adoption of renewable energy.[3] Additionally, Springfield's 2035 Transportation System Plan has a policy requiring the consideration of environmental impacts of the overall transportation system, which has associated actions related to corridor planning and consideration of alternative energy infrastructure needs (i.e., electric vehicle charging stations).[4]
Veneta	The city's comprehensive plan claims that through avoiding urban sprawl, energy conservation will be achieved, however other than policies requiring that electric lines be placed underground for service extensions to new land development and, when feasible, in existing commercial areas, there are not explicit policies related to energy planning and energy conservation.[5]
Westfir	Like several of the other communities in Lane County, Westfir has a goal encouraging energy conservation through education programs and structural weatherization. Strategies for achieving this goal mentioned in the comprehensive plan include effective land use and land development, public educational efforts to encourage energy conservation and alternative energy source adoption, reducing city building energy use (i.e., proper insulation and weatherization), and making information about relevant tax incentives available to residents). Other goals in the comprehensive plan relate to housing, where policy requires coordination of housing rehabilitation efforts with energy conservation action (i.e., insulation and weatherization programs). When infrastructure expansions are being planned, projects that would require a distribution system upgrade must be directly negotiated with Lane Electrical Cooperative, Inc.[6]

FB88287BBBED%7D/uploads/2012_Comprehensive_Plan_acknowledged_by_DLCD_-_AMENDED_2016.pdf

[1] City of Lowell *"COMPREHENSIVE PLAN 2005,"* 2005. https://www.lowelloregon.gov/sites/default/files/fileattachments/community_development/page/4601/exhibit_e_comp_plan_update.pdf

[2] City of Oakridge, *"AN ORDINANCE AMENDING THE OAKRIDGE COMPREHENSIVE,"* https://www.ci.oakridge.or.us/media/14986

[3] City of Springfield, *"SPRINGFILED COMPREHENSIVE PLAN,"* July 2022. https://springfield-or.gov/wp-content/uploads/2022/08/Vol.-1-Springfield-Comprehensive-Plan.pdf

[4] City of Springfield, *"2035 Transportation System Plan"* Jan 2021. https://www.springfield-or.gov/wp-content/uploads/2021/04/FINAL-Springfield-TSP-4_22_20-corrected-4.30.21.pdf

[5] City of Veneta, *"VENETA COMPREHENSIVE PLAN ODINANCE No. 523,"* Sep. 2000. https://www.venetaoregon.gov/DocumentCenter/View/1153/Comprehensive-Plan---Effective-September-2024

[6] City of Westfir, *"Westfir Comprehensive Plan"* Jun. 2002. https://www.ci.westfir.or.us/wp-content/uploads/2022/02/2002-Comprehensive-Plan.pdf

Overall, across Lane County, energy planning is embedded in climate, comprehensive, and sector-specific plans. County-level planning prioritizes demand reduction, electrification, grid decarbonization, electric vehicle adoption, and efficient land use and transportation. Cities mirror these levers through utility programs and their comprehensive plan policies. This is likely because many of the local government-level energy planning strategies are modeled after state-wide goals and requirements put forth by the Land Conservation and Development Commission (LCDC), which includes goals "to conserve energy" and "to provide and encourage a safe, convenient and economic transportation system" which stipulates that a transportation plan shall conserve energy.[1] Common policy approaches to achieve the goals of energy conservation include focusing on energy efficiency, improving building performance, targeted renewables, and land-use measures that curb urban sprawl and lower demand (summarized in ***Table 59***).

[1] U.S. Department of Energy, *"COMMUNITY GREENING: HOW TO DEVELOP A STRATEGIC ENERGY PLAN,"* Feb. 2010. https://docs.nlr.gov/docs/fy10osti/45652.pdf

Table 59: Summary of the Energy-Related Goals and Strategies Utilized Throughout Lane County

where ✓ indicates the goal or strategy is discussed in at least one of the jurisdiction's reviewed documents and — indicates the goal or strategy was not identified in the review of available documents, which are listed in ***Error! Reference source not found.****.*

	Emissions targets	Energy conservation in building/ land use planning	Energy conservation in transportation planning	Electric vehicle infrastructure	Encourage renewable energy	Specific guidance for renewables development	Support renewable energy workforce/ education	Community support for energy audits	Under-ground electric lines
Lane County	✓	✓	✓	✓	✓	✓	✓	—	—
Coburg	—	✓	✓	—	✓	—	—	✓	—
Cottage Grove	—	—	—	—	✓	—	—	—	—
Creswell	—	✓	✓	—	✓	—	✓	—	—
Dunes City	—	✓	—	—	✓	—	—	—	—
Eugene	✓	✓	✓	✓	✓	✓	✓	✓	—
Florence	✓	✓	✓	—	✓	—	✓	—	—
Junction City	—	—	✓	—	✓	—	—	—	—
Lowell	—	✓	✓	—	✓	—	—	—	✓
Oakridge	—	✓	✓	—	—	—	✓	—	—
Springfield	—	✓	✓	✓	✓	—	✓	—	—
Veneta	—	✓	✓	—	—	—	—	—	✓
Westfir	—	✓	—	—	✓	—	✓	—	—

9.2.2 Community Resilience Planning, Priorities, and Strategies

The following section summarizes the community resilience-related plans, priorities, and strategies currently in place across the county. Like energy planning, resilience planning is more mature at the county level in Lane County and serves as the connective tissue for cities with limited capacity to develop their own resilience plans.

One driver of this county-level emphasis is recent state support for energy resilience planning through legislation (HB 3630), which provides up to $50,000 per county to develop an energy resilience plan.[1] Although not all Oregon counties are participating in the energy resilience grant program, potentially due to remaining funding gaps even with the grant and/or capacity constraints, Lane County is participating. As part of Lane County's fulfillment of the energy resilience grant from ODOE, national laboratory partners are assisting with data collection and estimates related to critical facility energy used (see ***Chapter 8***).

Lane County's Climate Adaption and Resilience Plan outlines 21 strategies the County plans to use to become more climate resilient. The strategies address critical areas such as wildfire risk reduction, green infrastructure, renewable energy storage, urban heat mitigation, personal preparedness programs, and climate-resilient housing. Broadly, these strategies emphasize building resilience through infrastructure upgrades, community engagement, policy support, and environmental restoration while prioritizing vulnerable populations across Lane County.[2] Lane County also has an Emergency Operations Plan that establishes a framework and procedures for coordinating response and short-term recovery during emergencies.[3]

Alongside formal government strategies, the Lane Community Organizations Active in Disaster (COAD) convenes nonprofits, businesses, community organizations, and volunteers to coordinate assistance before, during, and after disasters. Guided by its own Emergency Operations Plan and partnering with city and county emergency managers, Lane COAD complements official response when state or regional resources are not yet mobilized or have demobilized.[4]

At the municipal scale, adoption of resilience plans is mixed; among the twelve cities, five have a Community Resilience Plan, Emergency Operations Plan (EOP), NHMP, and/or a dedicated resilience section in their Comprehensive Plan. Additionally, 8 cities participate in Lane County's NHMP (***Table 60***):[5]

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[1] Oregon Department of Energy, *"County Energy Resilience Grant Program,"* https://www.oregon.gov/energy/safety-resiliency/Pages/County-Resilience.aspx

[2] Good Company, *"Lane County, Oregon Climate Action Plan Phase 1: Operational Greenhouse Gas Inventory Fiscal Year 2021,"* Jul. 2022. https://cdnsm5-hosted.civiclive.com/UserFiles/Servers/Server_3585797/File/Government/County%20Departments/County%20Administration/Climate%20Action%20Plan/Lane-County_CAP-Ops%20Approved.pdf

[3] "Lane County Emergency Operations Plan," Lane County, 2024. Lane County Emergency Operations Plan," Lane County, 2024. https://cdnsm5-hosted.civiclive.com/UserFiles/Servers/Server_3585797/File/2024_EOP%20Base%20Plan-Final.pdf?_gl=1*y1j3bz*_ga*OTA0MjE5ODg5LjE3NTYzOTY0Mjk.*_ga_G30BCGQ9RY*czE3ODM0NTc3MTAkbzI2JGcwJHQxNzgzNDU3NzEwJGo2MCRsMCRoMA..&_gl=1*y1j3bz*_ga*OTA0MjE5ODg5LjE3NTYzOTY0Mjk.*_ga_G30BCGQ9RY*czE3ODM0NTc3MTAkbzI2JGcwJHQxNzgzNDU3NzEwJGo2MCRsMCRoMA..

[4] *"Lane County Com unity Organizations Active in Disaster"* Dec. 2016. https://drive.google.com/file/d/1hQTERv-i7Pu-vMEMixjfglNTeLJRDgKi/view?pli=1

[5] Lane County, Oregon, *"Lane County Multi-Jurisdictional Natural Hazard Mitigation Plan,"* Version 4, 2023.https://www.lanecountyor.gov/government/county_departments/emergency_management/planning/mitigation_plan

Table 60: Lane County Cities' Resilience Plans, Priority Hazards, and Mitigation Actions

Cottage Grove	The Disaster Resilience Plan for Heritage Resources in Cottage Grove assesses risks to culturally and economically significant assets and is intended to serve as a pilot to model disaster resilience planning for other communities in Oregon.[1] This document included a review of existing Cottage Grove resilience planning documents including the NHMP,[2] which promotes public policy design to protect the community from nine assessed hazards, and the EOP, which provides guidelines for immediate hazard response. The EOP addresses the following hazards, listed from highest to lowest priority: riverine flood, severe weather, earthquake, hazardous materials incident, dam failure flood, wildfire, landslide, terrorism / cyberattack, volcano.[3]
Coburg	The city participates in Lane County's NHMP; Volume II Section 1 highlights the city's top three hazards (winter storm, extreme weather, and earthquake) and mitigation priorities including retrofitting and replacing water storage, a city hall seismic assessment, and enhancements to the community emergency center.[4]
Creswell	The city has an EOP that outlines roles, responsibilities, and procedures for response and recovery for 12 identified hazards ranked in the following order from highest to lowest: winter storm, windstorm, hazardous material incident, flood, earthquake, landslide, wildfire, drought, dam failure, pandemic, volcano, tsunami.[5] Creswell also participates in Lane County's NHMP; Volume II Section 2 highlights the city's top three hazards (winter storm, windstorm, and flood) and mitigation priorities including a project to connect to a transmission line, relocation of and retrofit to parts of the water system, resiliency analyses, building retrofits, and undergrounding.[4]
Dunes City	The city participates in Lane County's NHMP; Volume II Section 3 highlights the city's top three hazards (windstorm, earthquake, and winter storm) and mitigation priorities including building retrofits, improving evacuation and emergency access, water flow and quality monitoring, slope stabilization and increased requirements for landslide mitigation, and stormwater infrastructure upgrades.[4]
Eugene	The city's Community Climate Action Plan 2.0 includes a dedicated resilience chapter,[6] with current actions addressing local food systems, emergency water supply, infectious disease surveillance, and stormwater management. Future actions are focused on cooling and smoke refuge centers, fire prevention programs, and climate-adaptive floodplain management.
Florence	The city participates in Lane County's NHMP; Volume II Section 4 highlights the city's top three hazards (windstorm, wildfire, and tsunami) and mitigation priorities including development of a regional public agency emergency fueling facility, slope stabilization projects, siren updates, utility undergrounding, and fire-preparedness education.[4]
Lowell	The city participates in Lane County's NHMP; Volume II Section 5 highlights the city's top three hazards (drought, flood, and extreme heat) and mitigation priorities including water system repairs and storage

[1] Institute for Policy Research & Engagement, University of Oregon, *"Disaster Resilience Plan for Heritage Resources in Cottage Grove,"* Sept. 2020. https://www.oregon.gov/oprd/OH/Documents/CottageGroveResilience_ReportWeb.pdf

[2] City of Cottage Grove, *"Natural Hazards Mitigation Plan,"* https://cottagegroveor.gov/DocumentCenter/View/1001/cottage_grove_nhmp_final_3-30-17

[3] City of Cottage Grove, *"EMERGENCY OPERATIONS PLAN,"* Feb. 2015. https://www.cottagegroveor.gov/DocumentCenter/View/555/Cottagegrove_eop2016_basicplanpublic

[4] Lane County, Oregon, *"Lane County Multi-Jurisdictional Natural Hazard Mitigation Plan,"* Version 4, 2023.https://www.lanecountyor.gov/government/county_departments/emergency_management/planning/mitigation_plan

[5] City of Creswell, *"Emergency Operations Plan,"* Jul. 2018. https://core-docs.s3.us-east-1.amazonaws.com/documents/asset/uploaded_file/4294/city/3608572/Creswell_Emergency_Operations_Plan_Adopted_July_9_2018.pdf

[6] City of Eugene, *"Eugene's Community Climate Action Plan 2.0: Playbook for Eugene's Climate Journey,"* Feb. 2019. https://www.eugene-or.gov/DocumentCenter/View/48138/CAP20-Full-Document-w-Appendices

	projects, generator and electrical service improvements, developing a citywide evacuation plan, wildfire fuels reduction, landslide hazard mapping, and establishing a resilience hub building.[4]
Oakridge	The city does not have an explicit resilience plan or EOP, but participates in the Lane County's NHMP; Volume II Section 6 highlights the city's top three hazards (wildfire, flood, and winter storm) and mitigation priorities including building retrofits, establishing an emergency operations center, expanding local fuel and storage of emergency supplies, levee repairs, water system upgrades and repairs, improving the city's emergency communications system, power infrastructure upgrades, increased hazard education, airport runway repairs, wildfire fuels reduction and increased wildfire defense space.[1] Additionally, a recent news article highlighted the city's efforts to bolster local infrastructure and emergency services to improve community resilience.[2]
Springfield	The city's resilience planning is addressed in the Eugene-Springfield Multi-Jurisdictional Emergency Operations Plan.[3] The Plan's purpose is to establish a comprehensive, all-hazard approach to protect the safety, health, and welfare of the community by outlining the prevention, protection, mitigation, response, and recovery activities. Additionally, the Eugene-Springfield Natural Hazards Mitigation Plan, which reviewed natural hazards relevant to the area and assessed the regions vulnerability, finding "very high" risks for geomagnetic disturbance, and earthquake natural hazards, and "high" risks for winter storms, droughts, wildfires, and windstorms. Recommended mitigation actions for these high-risk hazards include upgrading local transportation infrastructure for seismic conditions, retrofitting critical facilities, conducting an emergency fuels assessment, increasing fuel capacity, seismically retrofitting the Eugene fueling station, reducing wildfire fuels, performing maintenance on defective trees, and developing of a city evacuation plan.[3]
Veneta	The city's Economic Development Strategy includes resilience in its visioning and goal setting, stating that the city "aspires to be a close-knit community that is prepared to respond to natural, economic, and manmade disasters." Additionally, each broader goal in the development strategy has resilience implications which include creation of: close-knit social networks, an emergency response protocol, local recovery initiatives, diverse industries, infrastructure redundancy, increased resident mobility, and robust infrastructure.[4] The City's EOP is another resource available pertaining to the community's resilience planning.[5] Additionally, Veneta participates in Lane County's NHMP; Volume II Section 7 highlights the city's top three hazards (winter storm, wildfire, and windstorm) and mitigation priorities including an all-hazards threat assessment of city facilities and seismic building retrofits.[1]
Westfir	The city participates in Lane County's NHMP; Volume II Section 8 highlights the city's top three hazards (wildfire, winter storm, and drought) and mitigation priorities including a new fire station and city hall buildings, fuels reduction and increasing defensible space, developing additional water storage, mitigation for flood-prone properties, and drainage improvements.[1]

Across Lane County, cities often use multi-hazard frameworks for resilience planning (i.e., EOPs and NHMPs) to coordinate prevention, protection, mitigation, response, and recovery

[1] Lane County, Oregon, *"Lane County Multi-Jurisdictional Natural Hazard Mitigation Plan,"* Version 4, 2023.https://www.lanecountyor.gov/government/county_departments/emergency_management/planning/mitigation_plan

[2] Ellie Graham, *"Resilience planning, food access, trails grants discussed at Oakridge city council meeting,"* Highway 58 Herald, https://highway58herald.org/resilience-planning-food-access-trails-grants-discussed-at-oakridge-city-council-meeting/

[3] City of Eugene, City of Springfield, *"Eugene-Springfield Area Multi-Jurisdictional NATURAL HAARDS MITIGATION PLAN,"* Jan. 2020. https://www.eugene-or.gov/DocumentCenter/View/48415/Eugene-SpringfieldAreaMJNHMP2020?bidId=

[4] City of Veneta, *"Economic Development Strategy 2021 - 2025",* https://www.venetaoregon.gov/DocumentCenter/View/276/Economic-Development-Strategy-Plan-2021-to-2025-PDF

[5] City of Veneta, *"City/LFA Emergency Operations Plan"* Dec. 2016. https://www.venetaoregon.gov/DocumentCenter/View/456/Lane-Fire-Authority-Emergency-Operations-Plan-PDF?utm

from hazards. While some strategies are aimed at limiting exposure in high-risk zones (i.e., land-use and code measures) other strategies involve place-based investments (i.e., resilience hubs, emergency water supply, cooling and smoke refuge centers, often paired with renewable energy and storage for backup power). Reviewed resilience plans also emphasize implementing green infrastructure, stormwater and floodplain management, and upgrading critical facilities, and coupling these actions with public education, cross-jurisdiction collaboration, and a deliberate focus on vulnerable populations.

Overall, local resilience plans have limited engagement with the electricity system. They do not characterize grid resilience, nor do they characterize the community's vulnerability to grid outages. In Lane County's NHMP, outages are considered a consequence of other hazards, such as winter storms.

9.3 Gaps and Opportunities in Community Energy and Resilience Planning Approaches Applied in Lane County

Lane County has strong county-level frameworks for energy and resilience planning, and several cities have their own plans. However, many cities still lack stand-alone energy and resilience plans and instead rely on energy and resilience goals and strategies discussed in comprehensive plans, EOP, and NHMP documents.

The four largest cities by population (Eugene, Springfield, Cottage Grove, and Florence) have invested in local resilience planning. This pattern is common in literature; larger cities, which often have more resources and exposure to a wider array of hazards, are more engaged in resilience planning.[1]

Dedicated community energy plans provide a coordinated roadmap that aligns land use, buildings, and transportation with energy planning strategies (e.g., efficiency improvements, electrification, renewables adoption, grid needs). Similarly, stand-alone resilience plans complement EOPs and NHMPs by coordinating whole-community actions across prevention, protection, mitigation, response, and recovery steps, particularly for cross-sector priorities that are not typically addressed in depth in hazard-focused planning.

There is an opportunity for more individual communities in Lane County to develop stand-alone energy and resilience plans. They might considering implementing ***specific renewable energy guidelines*** beyond the general encouragement for renewables that they now offer. Opportunities for grants related to energy and resilience planning may arise, such as the resilience hub development effort.[2] Looking to the Oregon Energy Strategies discussed in ***Section 2.5***, cities might find states support for actions like ***energy workforce development, collaborative electric vehicle infrastructure planning,*** and ***utility-government collaboration*** on system hardening, and sectionalizing and islanding opportunities. As they develop their own plans, communities can also adopt their own effective energy and resilience strategies already implemented by peer jurisdictions across Lane County.

[1] J. M. Keenan, "Types and forms of resilience in local planning in the U.S.: Who does what?," *Environ. Sci. Policy*, vol. 88, pp. 116–123, Oct. 2018, doi: 10.1016/j.envsci.2018.06.015.
[2] Oregon Department of Human Services, *"Resilience Hubs and Networks Grant,"* https://www.oregon.gov/odhs/emergency-management/pages/resilience-grants.aspx

Opportunities for Improving Lane County Electric System Affordability, Reliability, and Resilience

Ali Trueworthy

The purpose of this document is two-fold. First, it serves to help leaders, community decision makers, and the interested residents of Lane County establish a baseline understanding of their electric system. Second, it identifies some existing gaps and opportunities for action to improve the affordability, reliability, and resilience of the county.

Throughout this document, we present best practices for utilities and communities aiming to improve their electricity systems. We identify opportunities for improvement by comparing existing known practices to best practices. In this section, we summarize the opportunities that are presented throughout this Handbook. In total, we outline 24 opportunities across four categories:

- ***Utility Studies and Programs*** includes opportunities that can be undertaken by the utilities (with or without support) to create results that are useful for the utilities and their customers.
- ***Collaborative Evaluation, Planning, and Framework Development*** includes opportunities that necessitate and take advantage of the benefits of collaborative approaches. Each opportunity involves establishing plans or processes for sustained collaboration.
- ***Public Accessibility, Education, and Outreach*** includes opportunities focused on public participation and/or data collection to benefit the public.
- ***Countywide Modeling*** includes opportunities that can be implemented relatively uniformly across the county and do not require specific utility data or action. These opportunities generally involve the creation of information that can be used or implemented by multiple parties across the county.

The categories are used to organize themes, not to rank opportunities. Opportunities are not prioritized within or across categories. The opportunities that we present can be used to pursue future actions, grants, or technical support. As part of the Power Lane County project, staff from Lane County, the Center for Rural Livelihoods, and three U.S. Department of Energy national laboratories will engage utilities and other stakeholders to further develop a topic for the remaining two years of the project, including selecting which of these opportunities will be advanced with the project scope, drawing from this initial set of opportunities. Between one and three of the outlined opportunities will be able to be part of Power Lane County. None-the-less, we provide the broader list to inform future project pursuits.

Funding for future projects might come from within the community, state grants, federal grants, or technical assistance programs. ***Table 61*** lists some common funding sources.

Table 61: Common Funding Sources

Funder	Source	Link
U.S. Department of Energy	Technical assistance programs	https://www.energy.gov/cmei/technical-assistance
U.S. Department of Energy	Office of State and Community Energy Programs grants	https://www.energy.gov/cmei/scep/office-state-and-community-energy-programs
Oregon Department of Energy	Incentives and grants programs	https://www.oregon.gov/energy/Incentives/Pages/default.aspx
U.S. Federal Emergency Management Agency	Building Resilient Infrastructure and Communities	https://www.fema.gov/grants/mitigation/learn/building-resilient-infrastructure-communities
U.S. Department of Agriculture	Energy Programs	https://www.rd.usda.gov/programs-services/energy-programs
American Public Power Association	DEED grants (utilities only)	https://www.publicpower.org/deed-funding-utilities

For each opportunity, we include the details described in ***Table 62***. Of the 24 identified opportunities, four relate to utility studies and programs (***Table 63***), eight relate to collaborative evaluation, planning, and framework development (***Table 64***), five relate to public accessibility, education, and outreach (***Table 65***), and seven relate to countywide modeling (***Table 66***).

Table 62: Description of Details provided for all Opportunities

Detail	Description
Level of Effort (LOE)	The amount of effort required to complete the task on a scale of high (H), medium (M), low (L)
Performing Entity	The group or groups that are needed to perform the tasks associated with the opportunity
Implementing Entity	The group or groups who will implement the outcomes or use the information that results from the opportunity
Beneficiary	The group or group who stands to benefit from implementation
Challenges	The challenges that groups might face in implementing the opportunity. We identify challenges from a pre-defined list: • ***Complexity:*** the opportunity requires complex sets of technologies, skills, effort, etc. • ***Data:*** the opportunity requires the collection and curation of significant amounts of difficult-to-access data • ***Capacity:*** the opportunity requires levels of effort that are difficult to commit for the entities involved • ***Funding:*** the opportunity is expensive and there is no apparent funder • ***Expertise:*** the entities involved may not have the expertise needed • ***Information:*** there is missing information that could prevent full completion of the tasks associated with the opportunity • ***Uncertainty:*** the benefits are uncertain • ***Coordination:*** the opportunity requires coordination between many groups and/or in new ways
State Alignment	Does the opportunity align with areas of interest put forth by the state and identified in ***Section 2.5*** Here we indicate “yes” if this is a project that aligns with current state priorities and therefore may be suited for funding support through the state of Oregon.
Associated Objectives	The goals associated with the opportunity, which include: • Affordability • Reliability • Resilience • Fairness • Energy efficiency (“efficiency”) • Energy conservation (“conservation”) • Wildfire mitigation

Utility Studies and Programs

Table 63: Description of the Four Utility Studies and Programs Opportunities

#	Level of Effort	Opportunity	Performing Entity	Implementing Entity	Beneficiary	Challenges	State	Associated Goals
1	Medium	Rate Design Studies	Utilities, technical experts	Utilities	Customers, utilities	Capacity	Yes	Affordability, fairness, efficiency
2	High	Sectionalizing, Islanding, and Blackstart Studies	Utilities, county, cities, critical facilities, local IPPs, technical experts	Utilities	Critical facilities, General resilience	Complexity, data requirements, expertise, coordination, funding	Yes	Resilience, wildfire mitigation
3	Medium	Collaborative peak management programs	Utilities, coordination support	Utilities	Utilities, customers	Coordination	No	Affordability, conservation
4	Low	Demand response operational training	Utilities, technical experts, coordination support	Utilities	Utilities, customers	Capacity, funding, uncertainty	Yes	Affordability, efficiency
5	Medium	Enhance Situational Awareness	Utilities, technical experts	Utilities	Utilities, customers	Complexity, expertise	Yes	Reliability, resilience, wildfire mitigation

1) Rate Design Studies

Rate design studies can explore ways for utilities to pursue some or all their goals through thoughtful rate-setting. Goals might include energy conservation, reduced peak energy use, fairness to customers, or increased revenue for capital projects. In this document, we introduce rate structures in ***Chapter 1*** and discuss a variety of rate options throughout Chapter 4. Rate design studies allow for utilities to estimate future costs and revenues associated with changes to their rate schedules

2) Sectionalizing, Islanding, and Blackstart Studies

Sectionalizing, Islanding, and Blackstart studies would include the identification of areas of the grid that would benefit from the capability to isolate from the rest of the grid. This sort of isolation can be desirable in several circumstances, such as if one section of the grid poses a high wildfire risk and would be beneficial to de-energize without de-energizing other parts of the grid (sectionalizing). Alternatively, the ability to keep a portion of the grid energized if the wider grid faces outages or shortfalls (islanding) can be important for maintaining electricity service to critical infrastructure. If the broader grid goes down, blackstart capabilities would enable utilities to use the existing local generation to restart an isolated portion of the grid, such as an area connecting an existing generation source to nearby critical facilities. We discuss technologies and practices related to this opportunity in ***Sections 4.4***, ***5.2***, and ***8.3***, and ***Chapter 6***.

3) Collaborative Peak Management Programs

Collaborative peak management programs could enable multiple utilities to establish programs while sharing the costs of staff training, customer outreach, and other expenses associated with initiating and running the program. These programs are discussed in ***Section 4.3***.

4) Demand Response Operational Training

Demand response operational training for utilities can help minimize the costs of implementing demand response or other energy efficiency or conservation programs. For customers, training can help them participate in programs and adopt the associated technologies. Sharing the costs and effort of such trainings between utilities can save time and money. We discuss demand response further in ***Section 4.3***.

5) Enhance Situational Awareness

Situational awareness includes real-time monitoring of weather and system conditions. Improving situational awareness can help utilities make more informed decisions, and, in some cases, automate decisions. Numerous modern technologies can provide these capabilities (see ***Section 6.2*** and ***6.3***).

Collaborative Evaluation, Planning, and Framework Development

Table 64: Description of the eight collaborative evaluation, planning, and framework development opportunities.

#	Level of Effort	Opportunity	Performing Entity	Implementing Entity	Beneficiary	Challenges	State	Associated Goals
6	Medium	Utility evaluations and improvement plans for distribution planning and risk management	Technical experts, utilities, county	Utilities	Customers, utilities	Capacity, coordination funding, information	No	Affordability, resilience, reliability
7	Medium	Critical customer tracking and load shedding planning	Utilities, customers, county, cities	Utilities, county	Critical customers	Data, coordination	Yes	Resilience
8	Medium	Consequence analysis framework	Utilities, emergency planners, technical experts	Utilities, emergency planners	Public	Expertise, capacity, data	No	Resilience
9	High	Collaborative wildfire mitigation plan innovation	Technical experts, utilities, emergency planners, county, cities	Utilities, emergency planners, county, cities	Public, utilities, county	Capacity, coordination, expertise	Yes	Wildfire mitigation, resilience
10	Low	Cost sharing arrangements for risk mitigation	Utilities	Utilities, cities	Utilities, customers	Coordination, uncertainty	No	Affordability, resilience
11	High	Collaborative grid planning process development	Utilities, cities, county	Utilities, county cities	County, cities, utilities	Coordination, expertise, capacity	No	Affordability, reliability, resilience
12	High	Local energy and resilience planning	Cities, county	Cities, county	Cities, public	Capacity, coordination, uncertainty	No	Reliability, resilience, fairness
13	Medium	Electric vehicle infrastructure planning	Cities, county utilities, public	Cities, county, or individual property owners	Electric vehicle drivers, public	Capacity, funding	Yes	Reliability

6) Utility Evaluation and Improvement Plans

Evaluating utilities based on their adoption of best practices for distribution planning and/ or risk management can facilitate improvements to plans and practices. For distribution planning, evaluation might include how well utility planning aligns with policy timeframes, how utilities perform planning and scenario development, how well utility data and technology are integrated, and how utilities adopt metrics (see ***Section 4.2***). For risk management, evaluation might further explore how the best practices outlined throughout ***Chapter 5*** are implemented. Utilities might undertake the evaluation and improvement planning themselves or reach out to the third party of experts.

7) Critical Customer Tracking and Load Shedding

Updating critical customer tracking and load shedding plans annually and sharing them between utilities and the county would help keep both parties informed about vulnerable populations in the county and how those populations will be served. Utilities and/or external assessors could explore options for integration of load shedding software tools. The county could integrate utilities' load shedding plans in emergency response drills and emergency plans. We discuss load shedding in ***Section 3.2*** and Critical Facilities in ***Section 8.3***.

8) Consequence Analysis Framework

Consequence analysis is the analysis of the potential harms of a utility-caused wildfire ignition (or other hazards). While there is no standard workflow for performing consequence analysis, and quantifying potential impacts can be challenging, consequence analysis could help utilities justify investments like grid hardening. We discuss consequence analysis in ***Section 5.2***.

9) Collaborative Wildfire Mitigation Plan Innovation

Collaborative Wildfire Mitigation Plan (WMP) innovation between utilities in the county can improve the wildfire mitigation planning process. Because Lane County's COUs have similar gaps in their WMPs, a collaborative process is likely to have wide benefit and potential cost savings. Steps to such a process could include: WMP evaluation, WMP template development, WMP integration plans, supply chain management database development and benchmarking, weather monitoring, after-action reporting standardization, training and tabletop exercises, and customer engagement. We discuss wildfire mitigation planning in ***Section 5.2***.

10) Cost Sharing Arrangements for Risk Mitigation

Cost sharing arrangements could be explored by interested utilities and local governments for wildfire mitigation activities. We discuss wildfire mitigation activities in ***Section 5.2***. This scope option would focus on evaluating practical and equitable approaches for utilities and local governments to share the costs of risk mitigation activities, including identifying eligible activities, potential funding mechanisms, and basic implementation considerations.

11) Collaborative Grid Planning Process Development

Collaborative grid planning process development includes establishing a process by which utilities could work with cities, the county, developers, and other stakeholders for distribution grid planning. This could foster collaborations between utilities and city planners to keep well-

informed of potential developments or other step changes to load within a city. A process could also support utilities and electric boards in adopting planning metrics that are important to their customers and stakeholders, such as hosting capacity, cost of service and avoided costs, resiliency, equity, energy efficiency, and/or environmental impacts. We discuss this type of distribution planning in ***Section 4.2.***

12) Local Energy Resilience Planning

Most cities in Lane County do not have plans related to their energy systems. A more directed and sustained planning effort in these cities and communities could clarify local goals, priorities, and feasible actions related to energy and electricity. We discuss energy and resilience planning in ***Chapter 9***.

13) Electric Vehicle Infrastructure Planning

City or county level electric vehicle infrastructure planning could help prepare Lane County for increases in electric vehicle adoption. Furthermore, infrastructure planning in collaboration with utilities could help to minimize the number of grid upgrades needed to serve electric vehicles and to allow the utilities to harness opportunities to integrate electric vehicle infrastructure as a distributed energy resource for demand management. Electric vehicle planning aligns closely with Oregon's State Energy Strategy, discussed in ***Chapter 2***.

Public Accessibility, Education, and Outreach

Table 65: Description of the Five Public Accessibility, Education, and Outreach Opportunities

#	Level of Effort	Opportunity	Performing Entity	Implementing Entity	Beneficiary	Challenges	State	Associated Goals
14	Medium	Energy workforce development	Cities, county	Cities, local organizations	Cities, public	Expertise, uncertainty, capacity	Yes	Affordability
15	Low	Increased access to utility planning documents	Utilities	Utilities	Public	Capacity	No	Fairness, affordability
16	Medium	Public demand response interest surveys	County, cities, third party	Utilities, utility boards	Public, utilities, utility boards	Capacity	No	Reliability, affordability, conservation
17	Medium	Assessment of customer willingness to pay for resilience measures	County, cities, third party	Utilities, utility boards	Public, utilities, utility boards	Capacity, expertise	No	Resilience, affordability
18	Low	Specific renewable energy guidelines/ goals	Cities	Cities	Cities	Expertise, capacity	No	Resilience

14) Energy Workforce Development

New energy technologies and Oregon's Energy Strategy require a skilled energy workforce. Strengthening that workforce in Lane County could expand access to well-paying local jobs. Oregon's Clean Energy Workforce Coalition, launched in 2022, aims to help build the local energy workforce and could be a key partner. Initial efforts in Lane County should engage the Coalition and other stakeholders to identify local needs and opportunities. See ***Chapter 2*** for further discussion.

15) Increased Access to Utility Planning Documents

While researching this Handbook, we found that some utility documents were much easier to access than others. Cities, the county, utility boards, and customers can encourage utilities to make their planning documents more accessible to the public so customers and other stakeholders can stay informed and have meaningful opportunities to participate. Accessibility is foundational to transparency and discussed in ***Section 4.1***.

16) Public Demand Response Interest Survey

For the most part, Lane County utilities do not implement demand response programs. This is because pf the limited potential financial benefits, uncertain levels of customer interest, and necessary technological investment. As electricity costs change, demand response programs might become more appealing for utilities. Surveying interest in demand response among residential, commercial, and industrial customers could help utilities estimate likely participation and plan accordingly. Surveys can also educate the public of the potential benefits and limitations of such programs. Further discussion of demand response is in ***Section 4.3***.

17) Customer Willingness to Pay Assessment

Investments in grid resilience can be costly. The costs are paid up front, and the benefits might be far off in the future. Fundamentally, many resilience efforts are about preparing for disaster events that could happen tomorrow—or 50 years from now. Utilities must make decisions about what events they prepare for, and how much money they spend on those preparations. For COUs especially, surveying their customers' willingness to pay for resilience investments can help utilities understand how their customers weigh risks relative to future benefits. Pursuing this opportunity could help utilities predict what kind of rate increases might be acceptable to customers in exchange for a more resilient system. Willingness to pay is further discussed in ***Section 4.4***.

18) Specific Renewable Energy Guidelines/ Goals

While many cities in Lane County have general goals to boost renewable energy, few have tangible guidelines or actionable goals. If renewable energy remains a priority for cities, they might consider developing more specific guidelines and goals. City implementation of energy planning is further discussed in ***Chapter 9***.

Countywide Modeling

Table 66: Description of the Seven Countywide Modeling Opportunities

#	Level of Effort	Opportunity	Performing Entity	Implementing Entity	Beneficiary	Challenges	State	Associated Goals
19	Hight	Countywide load forecasting	Technical experts, utilities, county, cities	Utilities, county, cities	Utilities	Expertise, complexity, data	No	Reliability, affordability
20	Medium	Peak load scenarios investigations	Technical experts, utilities, county, cities, IPPs	Utilities, customers, owners of DER	Utilities, public	Expertise, data	No	Reliability, resilience, affordability
21	Medium	Modeling of countywide energy efficiency and conservation scenarios	Technical experts, utilities, county, cities	County, cities, utilities	Public	Expertise, capacity, uncertainty, data	No	Efficiency, conservation
22	High	Valuing resilience	Technical experts, utilities, county, cities, public	Utility boards, utilities, county, cities	Utilities, customers	Expertise, capacity, information	No	Resilience, affordability
23	Medium	Wildfire risk assessment	Technical experts	Utilities, emergency planners	Utilities, public	Expertise, data	No	Wildfire mitigation, resilience
24	High	Wildfire spread models	Technical experts	Utilities, emergency planners	Utilities, public	Expertise, capacity, funding, data	No	Wildfire mitigation, resilience
25	Medium	Geospatial data tracking to support project prioritization	County, cities, technical experts	County	County, cities, public	Data, capacity	No	Resilience

19) Countywide Load Forecasting

Electricity use in Lane County has remained relatively stable over the past few decades. However, with trends in electrification and city and county development goals, changes may be on the horizon. Forecasting future electric loads can help utilities prepare. See ***Section 4.2*** for more information on load forecasting.

20) Peak Load Scenarios Investigations

Investigating future peak load scenarios can give utilities similar insights to those gleaned from load forecasting, but with simpler models. Estimating future peak loads involves building an understanding of where, and under what circumstances (e.g. weather, customer behavior) electricity demand will be highest. And in those circumstances, how high utilities should expect loads to be. Having a better idea of this information can help utilities prepare to serve changing loads. See ***Section 4.2*** for more on peak loads.

21) Countywide Energy Efficiency and Conservation Scenarios

Energy efficiency and conservation measures can help to offset increasing loads from electrification or development. A study investigating different energy efficiency and conservation scenarios can help cities, the county, and utilities understand the capacity for such an offset and further inform the need for infrastructure investments. See ***Section 4.3*** for more information.

22) Valuing Resilience

Resilience measures come at clear costs, but their benefits are often harder to quantify because they can be indirect, in the future, and somewhat subjective. Developing methods to value the benefits of resilience measures in Lane County would help local governments and utilities evaluate options systematically and communicate the tradeoffs of resilience measures clearly. These methods should reflect the unique needs and preferences of Lane County utility customers. See ***Section 4.4*** for more details.

23) Wildfire Risk Assessment

Lane County's wildfire risk models are out of date and not specific to utility assets. Improving estimates of wildfire probability and intensity across the landscape and translating those results into a risk metric that explicitly accounts for utility infrastructure would enable utilities to base wildfire mitigation plans on more accurate, asset-specific risk assessments. See ***Section 5.2*** for more details.

24) Wildfire Spread Models

Wildfire spread models are models that utilities can use in real-time during a fire to predict how the fire will spread. It can inform their decisions to send out crews, de-energize lines, or take other mitigative measures. See ***Section 5.2*** for more details.

25) Geospatial Data Tracking

Chapter 8 includes a small subset of geospatial data that could inform future decisions about where to dedicate electricity system improvement efforts. Continuing to collect such data, expanding the type of data collected, and developing prioritization methods can further support decision making.

Appendix A – Utility Interviews

In the Summer of 2024, we conducted interviews with representatives from Lane County's utilities. Those interviews helped us to understand challenges as the utilities experience them. Participating utilities included EWEB, SUB, EPUD, Lane Electric, Blachly-Lane, and Pacific Power. Interview questions are shown in ***Table 67***.

Table 67: Utility Interview Questions

Topic	Question
Priorities	What are your priorities?
Strengths	What do you consider to be a strength of your utility? Alternatively, could you tell us about a recent success?
Needs	Can you tell us about some of the current challenges your utility is facing?
	What is your biggest concern as a utility? What keeps you awake at night?
	What resiliency or reliability projects are on your wish list?
Hazard Response	Are there any (more) documents that we should be aware of that outline your approach to hazard response?
	What are your primary concerns related to wildfires, winter storms, or other natural hazard events? Which of these hazards are most concerning/damaging?
	Do you have a good understanding of which of your assets are most at risk to wildfire and storm hazards?
Looking Ahead	Looking ahead, do you have any concerns around capacity, costs, or load growth either within your service area or in the county or region more broadly?
	Do you make future load predictions? If so, what is your approach? How often do you do so?
	What type of BPA product are you purchasing? How are you managing BPA price increases?
E2C Expectations	Given the brief introduction you were given to the E2C project recently, was there anything that piqued your interest, that you were hoping to learn more about, or that you would like to become more involved in?
Coordination	We understand that there are a number of organizations, such as OPUDA and ORECA that help to coordinate between utilities and other stakeholders. How does your utility coordinate with other utilities inside and outside Lane County? Do you see any opportunities for coordination?

Common priorities that utilities repeatedly emphasized were:

- Safety
- Resilience
- Reliability
- Affordability
- Engagement with new technology
- Attention to aging infrastructure

These priorities, in general, align well with the priorities of Lane County and the E2C project. There were also common themes in what the utilities saw as their strengths, including their workforce's ability to respond to disruptions and their attentiveness to their communities. As we examine challenges and the options to address those challenges, it is important to leverage and maintain these strengths.

The common challenges and needs mentioned by the utilities during interviews are shown in ***Table 68*** along with a short description and the section in which we discuss the issue in detail.

Table 68: Challenges and Needs Identified in Utility Interviews

Challenge/ Need	Description	Percent Utilities	Section(s)
Rate Pressure	Utilities want to keep prices affordable while addressing their operational needs in a time of increasing costs	100%	4.1
Wildfires	Wildfires pose risks to assets and challenges of operational strategies and safety of employees and customers	100%	5.2
New Technology	Technology options are changing fast and it is difficult to keep up and understand potential benefits and risks	66%	6.1 - 6.4
Financial Backstops	Historically, COUs have federal and state support to respond to disasters or fund investments. This support currently feels uncertain.	50%	5.1
Monitoring	Monitoring both weather and system assets can influence decision making. Many utilities desire improved monitoring systems	50%	5.1
Regional Impacts	Retail utilities are subject to changes at the regional level. Utilities acknowledged future capacity issues at a regional level as a topic of concern.	50%	3.1 - 3.4
Peak Management	Large spikes in demand can be challenging, both technologically and financially. Utilities want to explore strategies for dealing with those peaks.	33%	4.3

Appendix B Community Plans

Below is a summary of the planning documents reviewed for the analysis conducted in ***Sub-Section 4.2.1***, which evaluates load growth potential, and ***Section 9.2***, which reviews the strategic energy planning and community resilience planning across Lane County.

Lane County

- Lane County Strategic Plan 2025-2027 - https://cdnsm5-hosted.civiclive.com/UserFiles/Servers/Server_3585797/Image/Government/County%20Departments/County%20Administration/Lane%20County%20Strategic%20Planning/2025-2027/Lane%20County%20Strategic%20Plan%202025-2027%20-%20ENGLISH.pdf
- Lane County, Oregon Climate Action Plan Phase 1: Operational Greenhouse Gas Inventory - https://cdnsm5-hosted.civiclive.com/UserFiles/Servers/Server_3585797/File/Government/County%20Departments/County%20Administration/Climate%20Action%20Plan/Lane%20County-FY21-GHG-Ops-final.pdf
- Lane County, Oregon Climate Action Plan Phase 2: Community Greenhouse Gas Mitigation Action Plan - https://cdnsm5-hosted.civiclive.com/UserFiles/Servers/Server_3585797/File/Government/County%20Departments/County%20Administration/Climate%20Action%20Plan/Background%20Docs/Lane%20County-CAP%20Part2-GHG%20Reduction.pdf
- Lane County, Oregon Climate Action Plan Phase 3: Community Climate Resilience Plan - https://cdnsm5-hosted.civiclive.com/UserFiles/Servers/Server_3585797/File/Government/BCC/2022/2022_AGENDAS/121322agenda/T.9.A.pdf
- Lane County Rural Comprehensive Plan - https://www.lanecounty.org/common/pages/DisplayFile.aspx?itemId=6477350
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