2020 BIENNIAL ENERGY REPORT

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Executive Summary

In 2017, the Oregon Department of Energy, recognizing that the energy world has changed dramatically since the 1970s, introduced House Bill 2343 to the Legislature. The bill charged the department with developing a new Biennial Energy Report to inform local, state, regional, and federal energy policy development and energy planning and investments. The report – based on analysis of data and information collected and compiled by the Oregon Department of Energy – provides a comprehensive review of energy resources, policies, trends, and forecasts, and what they mean for Oregon.

What You Can Expect to See in the 2020 Biennial Energy Report

The 2020 report takes a different approach than the inaugural 2018 Biennial Energy Report, which provided deep policy dives on a handful of important energy topics — including climate change, renewable energy, transportation, energy resilience, energy efficiency, and consumer protection. This 2020 report follows recommendations by energy stakeholders to provide shorter briefs on a wider array of energy topics — from energy in the agriculture sector to what's next for alternative fuels to the effects of the COVID-19 pandemic on energy, and more.

Many sections show that Oregon is on a path toward transitioning to a cleaner, low carbon future. Data and examples included in the report illustrate sustained investments in energy efficiency, affordability, renewable energy, and resource conservation. These efforts have positioned Oregon to successfully tackle today's energy challenges, which are driven by growing adoption from consumers for cleaner energy, economic innovation, and emerging technologies.

The report begins by looking at **Energy by the Numbers**—detailed information on Oregon's overall and sector-based energy use, energy production and generation, energy expenditures, and the strategies Oregon has employed to meet growing energy needs. New in 2020 is an energy flow diagram, illustrating energy production and imports to eventual end-use.

Next up is a **Timeline of Energy History in Oregon,** starting with the Missoula Floods that formed our state and ending with 2020's latest events — including the closure of Oregon's only coal power plant and new actions to tackle climate change.

The **Energy 101** section aims to help readers understand the first part of the energy story: how energy is produced, used, and transformed. Information is meant to provide a foundation for those new to energy and those who are already steeped in the sector.

The **Resource and Technology Reviews** section highlights 23 energy resources and technologies — they cover the spectrum of tradition to innovative, from renewable resources to emerging technologies like microgrids and power-to-gas. The topics covered are prevalent in Oregon or of interest to ODOE's various stakeholders. Many of the technologies offer opportunities to invest in Oregon's economy by creating energy-related jobs, including those focused on restoring our energy systems when disruptions occur.

The final section includes more detailed **Policy Briefs** that cover decarbonization, the transition of the electric grid, innovation in the natural gas system, cleaner transportation options, and the built environment and Oregon's communities. The primary purpose of the report — and these policy briefs — is to inform energy policy development, energy planning and energy investments, and to identify opportunities to further Oregon's energy policies.

The Biennial Energy Report wraps up with a new summary of the process used to develop the report and **closing thoughts** on what's next. ODOE will kick off discussions in 2021 and reach out to hear new voices on recommendations for energy policy in Oregon over the next two years — and beyond.

The Biennial Energy Report may be found in its entirety at

https://energyinfo.oregon.gov/ber
or
www.oregon.gov/energy/Data-and-Reports/Pages/Reports-to-the-Legislature.aspx

The Department of Energy welcomes your comments and questions. Please contact our agency at askenergy@oregon.gov.

LETTER FROM THE DIRECTOR

The Oregon Department of Energy was formed in 1975 following the oil crisis of 1973. Gasoline prices surged by nearly 300 percent in just seven months; shaping day-to-day life, global politics, and economies for years. That energy crisis – and those that came before and after it – changed how Oregonians think about energy, the economy, and our relationship to natural resources.

It may be too soon to say if we are going through a similar crisis today. The events of the past year have upended our lives, from the COVID-19 global pandemic to the intense wildfires that caused unprecedented loss of life, public and private property, and hazardous air quality statewide. Without the significant reductions in greenhouse gas emissions needed to meet our climate change goals, should we expect the 2020 Oregon fire season to be the new normal?

Earlier this year, Governor Brown signed Executive Order 20-04, which directed state agencies, including the Oregon Department of Energy, to take action to fight climate change. We have already started working on the order's directives: developing new energy efficiency standards, strengthening Oregon's energy code, and supporting transportation electrification. We also continue to provide Oregonians with data and information on contemporary issues to help our communities understand and join the effort. Our 2018 Biennial Energy Report offered a deep dive into climate change and the effects of energy use in Oregon; for 2020, we take a closer look at the resources that power our state, decarbonization and innovation in various sectors, and programs and policies that move our state closer to our climate, energy, and equity goals.

This 2020 Biennial Energy Report looks a little different from our inaugural 2018 report. Even amid the challenges of COVID-19, our stakeholders and partners from across the state generously gave us their time and expertise in surveys, interviews, focus groups, and peer reviews to help us shape this report – and it is a better product thanks to their guidance.

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Some of the feedback we heard was to continue to provide data visuals and to create shorter briefs on a greater variety of topics. The *overall* report isn't a quick read, but we hope the shorter sections and technology reviews can serve as helpful standalone resources.

In our 2018 Biennial Energy Report, I wrote that when it came time to publish this 2020 edition, we wanted "to be able to tell a new story about energy in Oregon and about the progress we've made on the state's most pressing energy and climate issues." While we are still not on track to meet our climate goals – and current events are making things seem even more challenging – I feel hopeful.

In addition to laying out really cool energy data, we share some stories in this report that highlight the very best of Oregon. A group of nonprofit partners are collaborating on a "car share" program to test electric tractors across Oregon's diverse agricultural producers. Cities and counties are leading the way by adopting community energy and climate action plans. Oregon State University students and faculty are researching how agriculture and renewable solar can marry for mutual benefit of the farmers, crops, and solar panels. The Portland Clean Energy Fund is providing dedicated funding for climate actions that also advance racial and social justice for communities that are too often left behind.

We hope everyday Oregonians, policy and decision-makers, local leaders, and energy experts use the stories, data, and information in this report as a platform for more informed conversations and to draw on as they address the energy challenges we face today.

Together, Oregonians will continue to take meaningful steps toward a clean energy future. And as the Oregon Department of Energy turns toward its 46th year serving Oregonians, we'll continue our work to support a safe, equitable, clean, and sustainable energy future.

Janine Benner

Director, Oregon Department of Energy

Tribal Land Acknowledgement

The Oregon Department of Energy and its staff acknowledge that indigenous tribes and bands have been with the lands that we inhabit today in the Willamette Valley and throughout Oregon and the Northwest for time immemorial. ODOE's office are in Salem, Oregon, the land of the Kalapuya, who today are represented by the Confederated Tribes of the Grand Ronde and the Confederated Tribes of the Siletz Indians, and whose relationship with this land continues to this day.

About the Oregon Department of Energy

Our Mission

The Oregon Department of Energy helps Oregonians make informed decisions and maintain a resilient and affordable energy system. We advance solutions to shape an equitable clean energy transition, protect the environment and public health, and responsibly balance energy needs and impacts for current and future generations.

Our Values

- We listen and aspire to be inclusive and equitable in our work.
- We are ethical and conduct our work with integrity.
- We are accountable and fiscally responsible in our work and the decisions of our agency.
- We are innovative and focus on problem-solving to address the challenges and opportunities in Oregon's energy sector.
- We conduct our agency practices and processes in a transparent and fair way.

Our Position

On behalf of Oregonians across the state, the Oregon Department of Energy achieves its mission by providing:

- A Central Repository of Energy Data, Information, and Analysis
- A Venue for Problem-Solving Oregon's Energy Challenges
- Energy Education and Technical Assistance
- Regulation and Oversight
- Energy Programs and Activities

www.oregon.gov/energy

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Policy Briefs

ENERGY BY THE NUMBERS

Energy by the Numbers focuses on the metrics and data available to track how Oregon produces, purchases, and uses various types of energy.

Like the 2018 report, this includes energy use data by resource and by sector with data on electricity, transportation energy, and direct fuel use. Where possible, data showing how Oregon's energy system has changed over time has been included to provide context and history. New to this report is the energy flow diagram in Oregon, which is a visual summary of how energy is produced, imported, and used. This chart follows each resource through the energy flow. We also discuss energy production — where and what kind of energy Oregon produces, where and how we generate electricity, and what direct use and transportation fuels are produced in state. Oregon is a leading producer of renewable energy and this section explains why and how.

Readers will find data on what Oregon spends on energy, how energy costs burden Oregonians differently across the state, and what the energy industry gives back to Oregon in terms of jobs. The section also demonstrates how energy efficiency continues to serve as an important resource for Oregon. It concludes with highlights on the four end use sectors: residential, commercial, industrial, and transportation, including energy use, expenditures, and GHG emissions – and how each sector uses energy to provide goods and services.

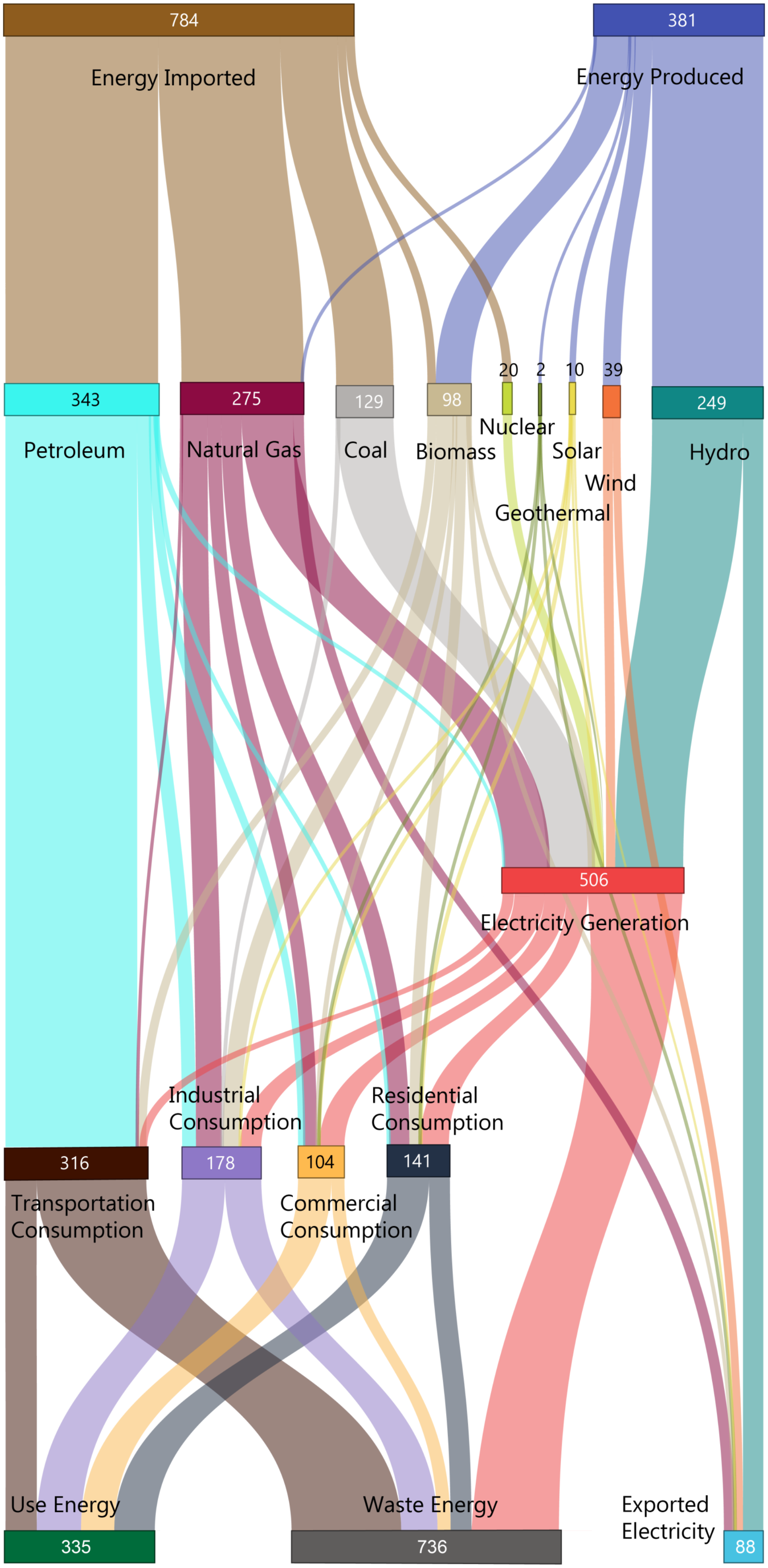
Trends and What's New:

- Oregon has vast energy efficiency potential, but in the last two years the region hasn't been meeting the Northwest Power and Conservation Council's Seventh Power Plan goals for savings in electricity.
- Oregon exports more than half the wind, waste, and geothermal electricity we generate, and 38 percent of the hydropower.
- Oregonians spent more on energy in 2018 than in 2016, mostly due to an increase in the price of transportation fuels.
- Oregon has taken many steps to reduce greenhouse gas emissions, but the state is not on track to meet interim GHG emission reduction goals of 10 percent below 1990 levels by 2020. Transportation sector emissions have been on the rise since 2016.

Data Information

The Biennial Energy Report relies on a variety of data sources, such as the federal Energy Information Administration and the Northwest Energy Efficiency Alliance as well as local data compiled by state agencies. Each data set has strengths and limitations. The energy by the numbers section of the BER is divided into topics and each topic includes references to aid readers in finding source data. Some of the topics rely on data from multiple sources that has been analyzed and compiled to provide insights.

Understanding Oregon's Energy Story



Oregon's energy story has evolved over time thanks to new technologies, resource availability shifts, and policy changes. While the Pacific Northwest has a long history of using hydropower, 20 years ago, solar- and wind-generated energy was scarce.

Today, Oregon's energy resources are diverse. In the chart at left, start at the top to see imported energy and energy produced in Oregon.[1] **The numbers represent trillions of Btus of energy.**

The energy lines flow down to show the different types of resources (hydro, natural gas, solar, and others), and where they end up in Oregon's energy story — from transportation fuels to the natural gas and electricity that supplies homes and businesses. Some energy ultimately goes unused and some is exported to other states.

Btu

A **British Thermal Unit** is a measurement of the heat content of fuels or energy sources. Btu offers a common unit of measurement that can be used to count and compare different energy sources or fuels. Fuels are converted from physical units of measurement, such as weight or volume, into Btu to more easily evaluate data and show changes over time.

The chart provides a macro level look at the energy Oregonians consume, import, and export. Energy imports includes all imported energy, both in raw form or after transformation into other usable forms. For example, some resources are used to create electricity, which is then distributed to different sectors. Other resources are transported to sectors to be consumed as direct use fuels.

The flow to "waste energy" includes all of the energy that is not harnessed, from the point of extraction to the point of use. This includes energy lost as heat during combustion or transformation into electricity, transmission losses, and many other factors.

Energy Sources Used in Oregon

Solar. Photovoltaic technology converts energy radiating from the sun into electricity. Solar systems are located on homes, businesses, and large utility-scale arrays. As of 2018, there are more than 15,000 active residential solar systems in Oregon.[2]

Nuclear. Generated electricity from a nuclear reactor where thermal energy is released from the fission of nuclear fuel. Oregon's nuclear power comes from the Columbia Generating Station in Washington State, and the electricity produced is marketed by the Bonneville Power Administration.

Hydropower. Electricity generation harnessed from the natural flow of water through dams. Oregon has 65 large hydropower facilities, including four federal facilities on the Columbia River that span the Oregon and Washington border, and two facilities that span the Oregon and Idaho border.[3]

Wind. Generation of electricity by the force of wind turning turbines. As of 2018, Oregon has 44 operating facilities in the state with a total capacity of 3,383 MW.[4]

Geothermal. Energy extracted from hot water or steam from natural underground sources can be used for water/space heating or the generation of electricity. Oregon has two geothermal electric generation facilities with a capacity of 23.8 MW.[4]

Natural gas. Fossil fuel extracted from beneath the earth's surface. Oregon has a single natural gas field located in Mist. Oregon imports most of the natural gas it consumes for electricity and as a direct fuel. There are 18 natural gas electricity generation facilities with a combined capacity of 4,140 MW.[4] Natural gas is used directly for residential, commercial, industrial and transportation uses.

Coal. Combustible rock is burned for industrial processes and to create electricity. Oregon had one coal-generated power plant, the 575 MW Boardman facility, which closed in October 2020.[5] The state also imports coal-generated electricity from neighboring states.

Biomass. Includes all renewable biogas and biofuels derived from the energy of plants and animals. Wood and wood waste is Oregon's greatest source of biomass, which is used for space heating, cooking, electricity generation, and transportation. Oregon has 16 biomass and 25 biogas operating facilities converting waste products to electricity.[4] Oregon also produces plant-derived ethanol fuel and biodiesel from used cooking oil to be used as transportation fuels.

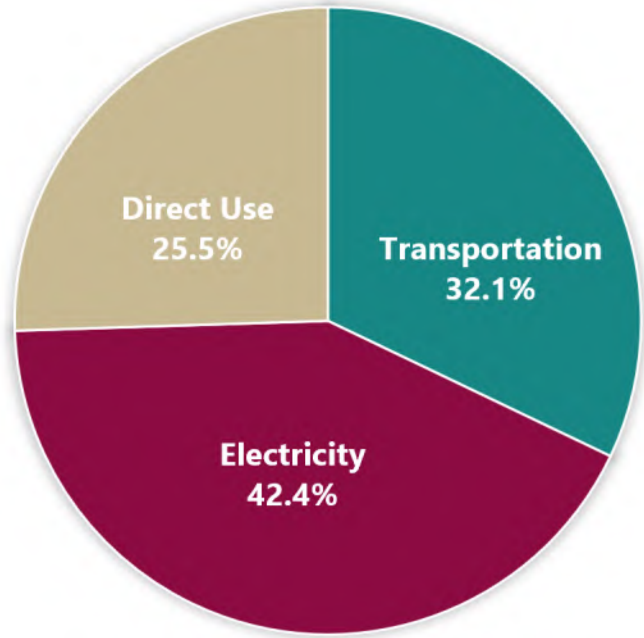
Petroleum. Fossil fuel extracted from beneath the earth's crust that includes gasoline, diesel, heating oil, lubricants, and other fuels we use for space heating, industrial equipment and transportation. Oregon imports the petroleum that it uses.

Energy Use in Oregon

Consumption by Source

Oregon relies on energy from a variety of resources. We import energy like transportation fuels, natural gas, propane, and other fuels. We use electricity from both in- and out-of-state sources—including coal, natural gas, nuclear, hydropower, wind, and other renewable resources.[1]

For this introduction to Oregon's energy use, the report sorts energy into three main categories:



42.4%

of Oregon's 2018 energy consumption

Electricity: this is where most people begin when thinking about energy—the critical resource that powers our day-to-day lives. The electricity Oregonians use comes from facilities across the western United States and in Oregon. This percentage also accounts for source fuels that come from out of state, such as natural gas, but generate electricity in-state.

25.5%

of Oregon's 2018 energy consumption

Direct Use Fuels: this category includes fuel oil and natural gas used to heat homes and commercial spaces, fuels used for other residential purposes, such as gas stoves, solar thermal heating, and fuels used directly in industrial processes.

32.1%

of Oregon's 2018 energy consumption

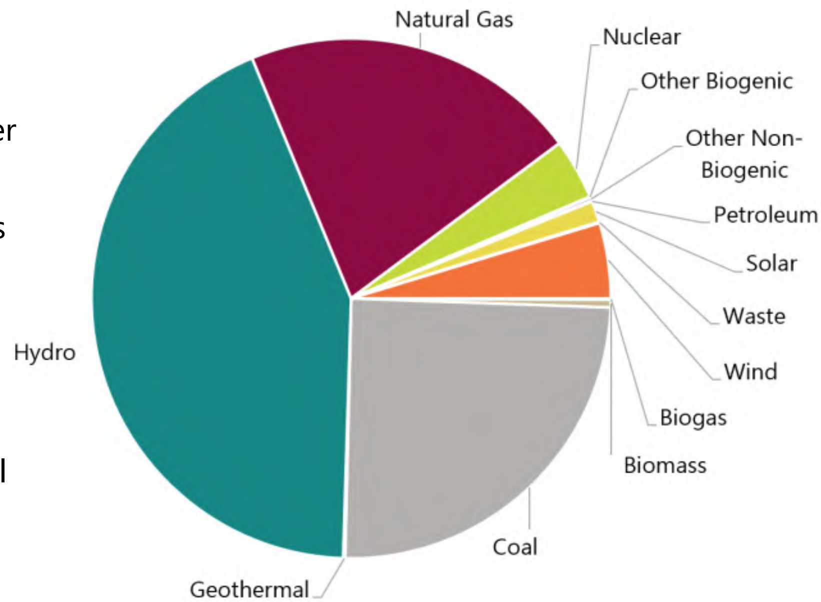
Transportation Fuels: this includes personal, passenger, and commercial vehicles, both on and off the roads, plus airplanes, boats, barges, ships, and trains. Nearly all transportation-related sources of energy are imported from out of state for in-state use.

Note to readers: *the methodology for calculating source energy has been updated since the 2018 Biennial Energy Report. The new methodology aligns with U.S. EIA efficiency values for electricity generation, attributing a greater source energy for hydroelectric generation than in the previous report. The overall consumption in Btus for Transportation and Direct Use fuels has not dropped since 2016, rather the portion of use attributed to electricity has grown.*

Electricity

42.4% **of Oregon's 2018 energy consumption**

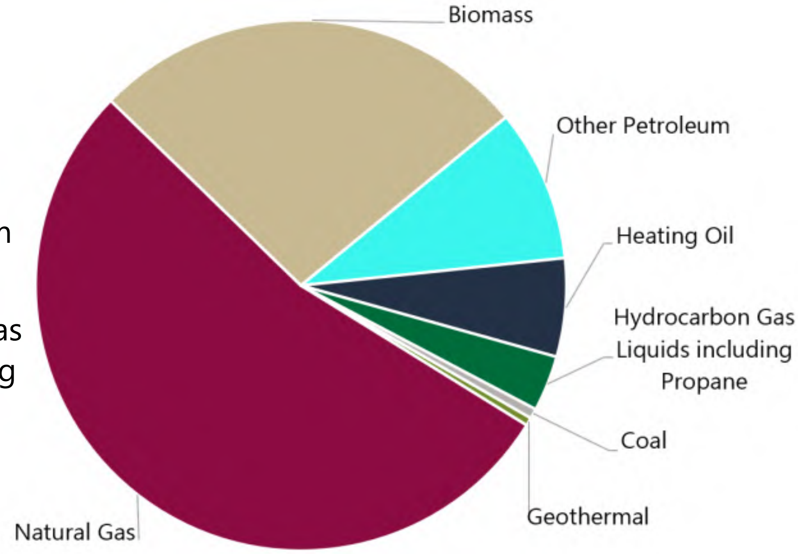
43.3%	Hydropower
24.8%	Coal
21.1%	Natural Gas
4.7%	Wind
3.8%	Nuclear
1.3%	Solar
0.5%	Biomass
0.1%	Geothermal
0.1%	Biogas



Direct Use Fuels

25.5% **of Oregon's 2018 energy consumption**

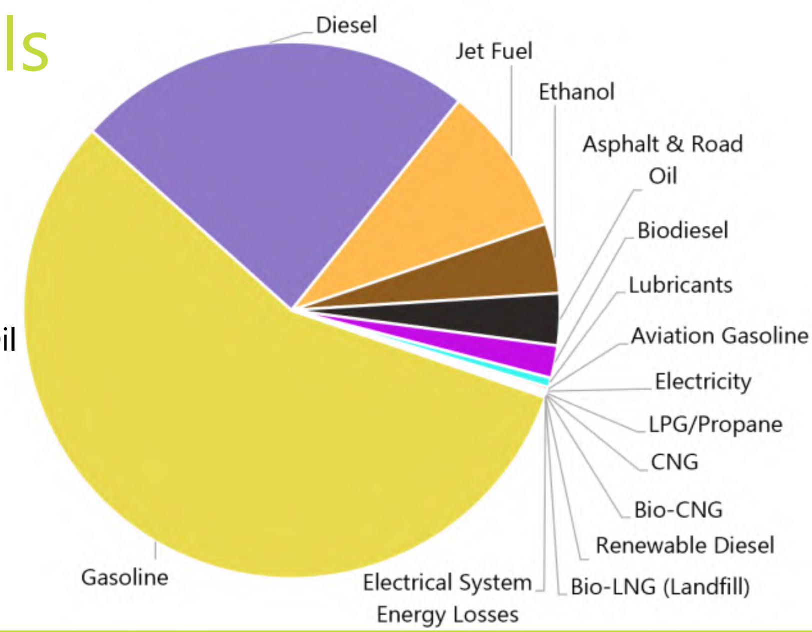
53.5%	Natural Gas
26.8%	Biomass
9.3%	Other Petroleum
6%	Heating Oil
3.4%	Hydrocarbon Gas Liquids Including Propane
0.6%	Coal
0.5%	Geothermal



Transportation Fuels

32.1% **of Oregon's 2018 energy consumption**

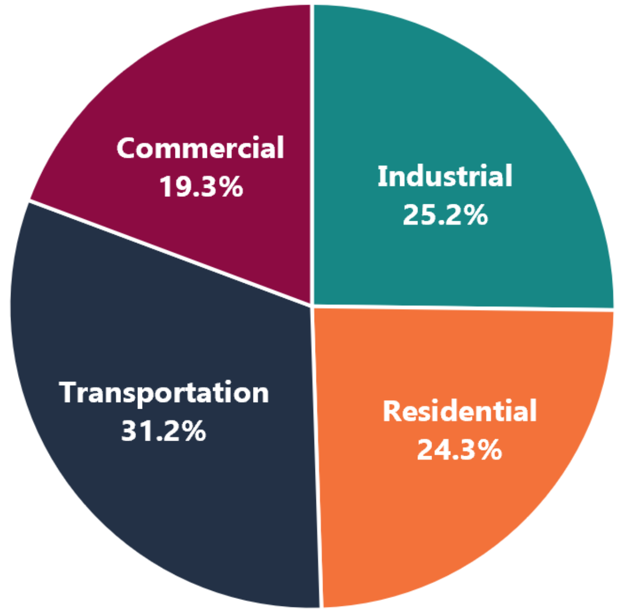
56.4%	Gasoline
24.1%	Diesel
9.0%	Jet Fuel
4.2%	Ethanol
3.1%	Asphalt, Road Oil
2%	Biodiesel
0.6%	Lubricants
0.2%	Aviation Gas
0.1%	Electricity



Note to readers: *Fuel percentages are rounded to the nearest tenth and not all are listed. .*

Energy Use in Oregon

Consumption by Sector



Energy consumption is also tracked by how it is used among four main end-use sectors: Residential, Commercial, Transportation, and Industrial.

In Oregon in 2018, those four sectors combined consumed 1,015 trillion Btu of energy, not including waste energy, as discussed early in Oregon's Energy Story.[1]

24.3%

of Oregon's 2018 energy consumption

Residential: this category includes single family, multi-family, and manufactured homes for Oregonians. Energy is used for lighting, to heat and cool living space, cooking, and appliances. Electricity is the most used energy resource in homes – with heat pumps, electric furnaces, and electric resistance heaters as examples of primary electric heat options.

19.3%

of Oregon's 2018 energy consumption

Commercial: this category includes businesses that provide goods and services, government and office buildings, grocery stores, and shopping malls. Energy is used to heat and cool spaces, power equipment, and illuminate facilities. It is Oregon's smallest energy-consuming sector, supported by the adoption of advanced energy codes, energy efficiency programs, and advancements in equipment and processes.

25.2%

of Oregon's 2018 energy consumption

Industrial: this category includes facilities used to produce, process, and manufacture products – including agriculture, fishing, forestry, manufacturing equipment, mining and energy production. Energy powers industrial equipment and machinery to manufacture products. This sector has seen contractions in aluminum, forestry, and manufacturing – with improvements in efficiency of industrial facilities and equipment.

31.2%

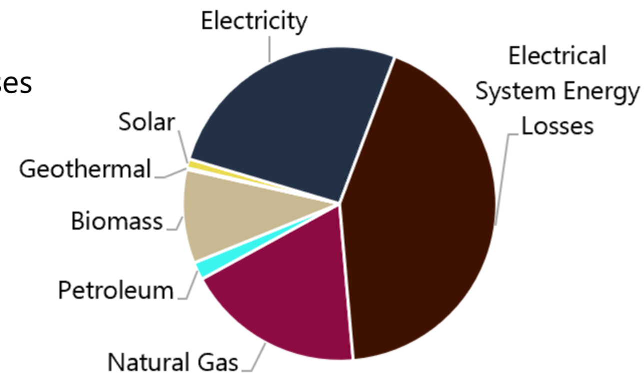
of Oregon's 2018 energy consumption

Transportation: Personal cars, fleets, shipments, airline travel, and more make up Oregon's transportation energy use. Petroleum is the most used resource and the largest contributor of greenhouse gas emissions in Oregon. Electric vehicle and alternative fuels like electricity and biofuels, zero-emission vehicle technology are now a growing part of this sector

Residential

24.3% of Oregon's 2018 energy consumption

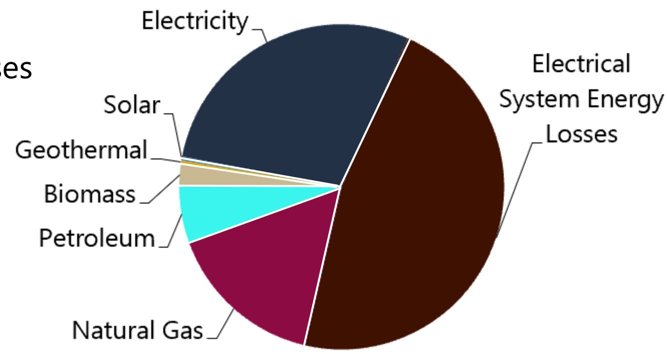
42.9%	Electrical System Losses
26.2%	Electricity
18.4%	Natural Gas
9.6%	Biomass
1.8%	Petroleum
0.9%	Solar
0.2%	Geothermal



Commercial

19.3% of Oregon's 2018 energy consumption

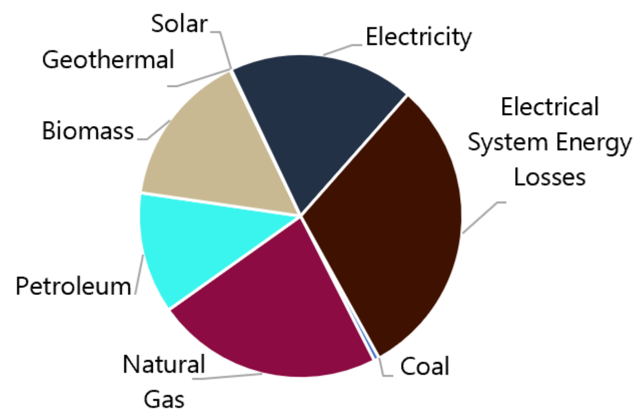
47.0%	Electrical System Losses
28.7%	Electricity
15.8%	Natural Gas
5.8%	Petroleum
2.0%	Biomass
0.4%	Geothermal
0.4%	Solar



Industrial

25.2% of Oregon's 2018 energy consumption

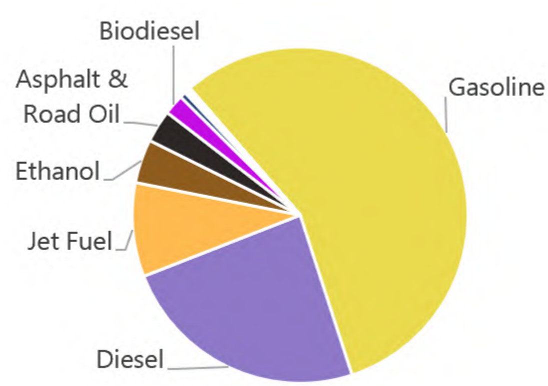
30.4%	Electrical System Losses
22.7%	Natural Gas
18.6%	Electricity
15.5%	Biomass
12.1%	Petroleum
0.6%	Coal
0.1%	Geothermal



Transportation

31.2% of Oregon's 2018 energy consumption

56.4%	Gasoline
24.1%	Diesel
9.0%	Jet Fuel
4.2%	Ethanol
3.1%	Asphalt, Road Oil
2.0%	Biodiesel



Note to readers: *Generation and transmission of electricity results in energy losses that are estimated and included in EIA consumption data. All percentages are rounded to the nearest tenth and not all are listed..*

Energy Use in Oregon

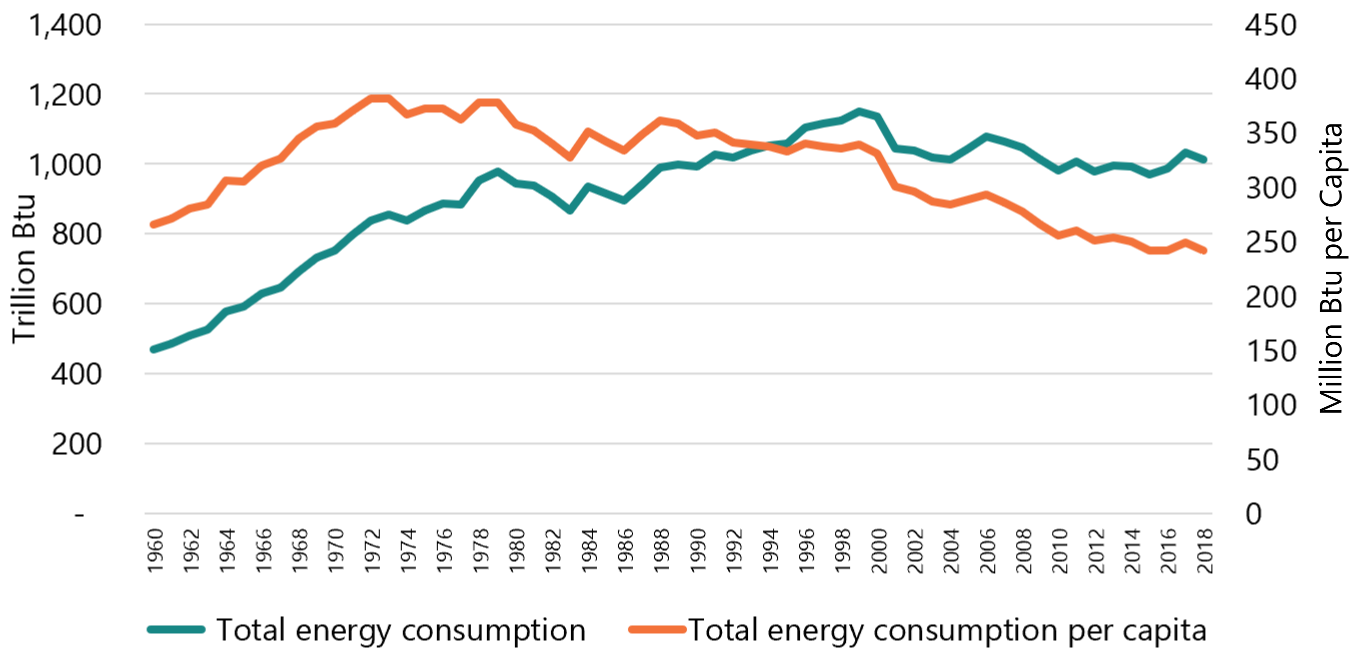
Oregon's Energy Consumption Over Time

13th

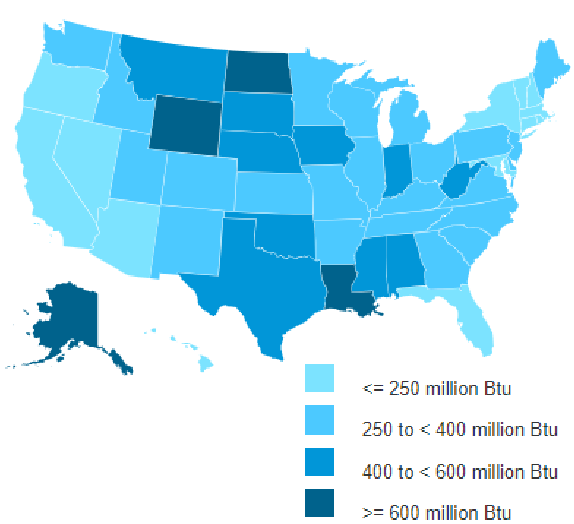
Oregon's rank for lowest per capita energy use in 2018 — the lowest in the Pacific Northwest.

Oregon saw an overall trend of increased energy use for almost four decades—an average of 3.6 percent growth per year from 1960 to 1999. During that time, we shifted from a reliance on fuel oil and wood to increased usage of natural gas and electricity in our homes and businesses. Oregon reached our highest consumption of energy in 1999. Since then, total energy use has been decreasing. The amount of energy we used in Oregon declined by 12.5 percent between 2000 and 2015. Energy consumption per capita does not directly correlate with overall energy use. In the last 20 years, Oregon has had steady population increase, during a period of slight decline in overall energy consumption. This translates to a steady decrease in energy consumption per capita.[2]

Oregon's Total Energy Consumption and Per Capita Energy Consumption Over Time



U.S. Per Capita Consumption



Energy Efficiency

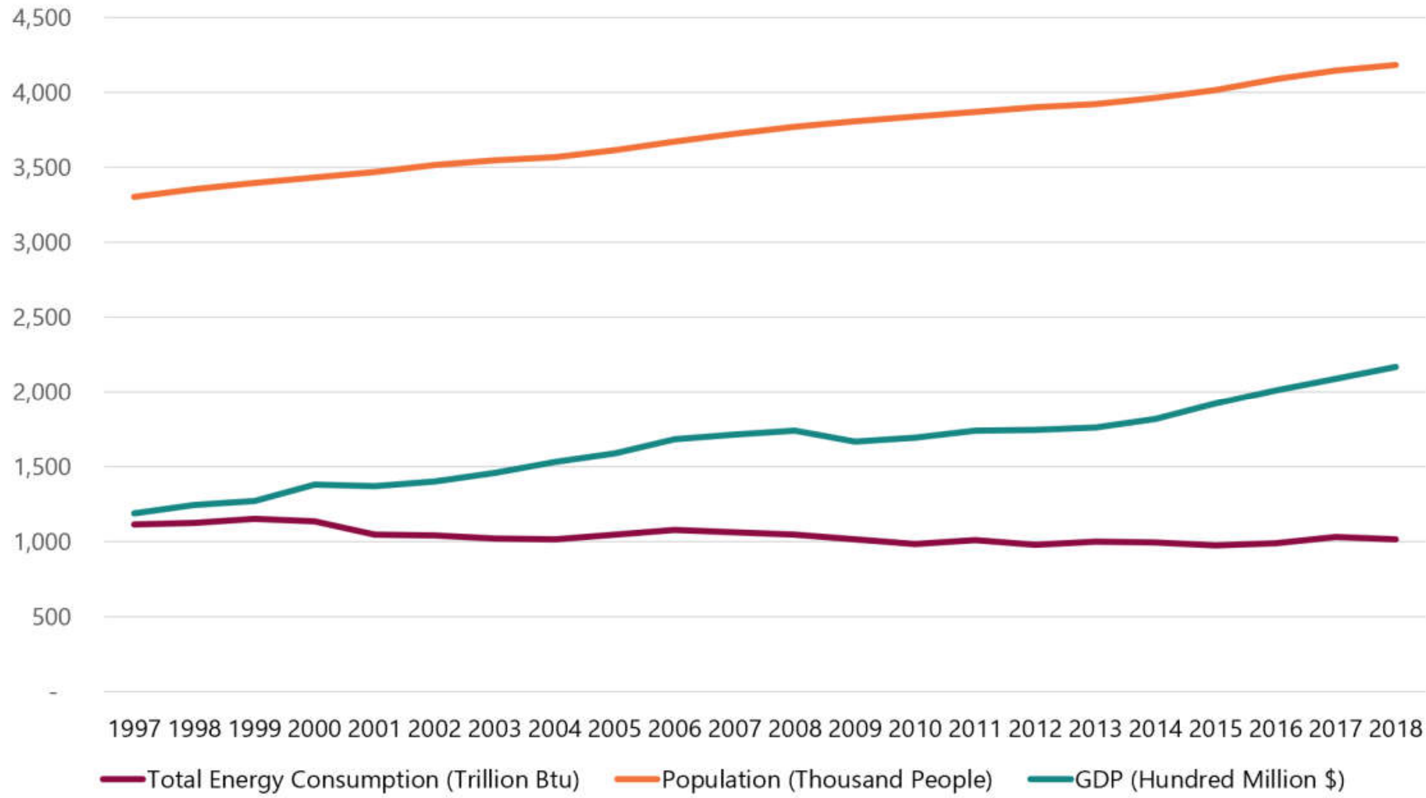
While energy efficiency is not "consumed" like other resources, it is the second largest resource available in Oregon after hydropower. Efforts to increase energy efficiency effectively reduce overall energy consumption. Historically, Oregon has consistently met increased demand for electricity by implementing energy efficiency strategies. Learn more later in this report.

Energy Use in Oregon

Energy Consumption and Economic and Population Growth

Energy efficiency and changes in our economy have led to decreases in Oregon's total and per capita energy use over time. Oregon's emphasis on energy efficiency has helped reduce both total and per capita energy use despite an increasing population, thereby avoiding the need to build new electricity generation plants. The graph below shows that since about 2000, economic growth (measured by gross domestic product or GDP) does not correlate with increases in energy consumption. In fact, as the economy and our population have grown, our energy consumption has stayed relatively flat with a slight decline.[2]

Oregon's GDP, Population, and Energy Consumption by Year



This displays all three data sets on the same axis; refer to the legend to find the units for each. This chart allows us to review the overall trends of population, energy consumption, and GDP in comparison to each other. The chart is not adjusted for inflation.

Consumption & Use

In the energy sector, *consumption* typically describes the amount of energy used. *Use* sometimes has the same meaning, but is often specifically applied when talking about the purpose of energy. For example, a home's annual electricity *consumption* goes toward a variety of *uses* like lighting, heating, and appliances. Or a furnace is *used* for heating but *consumes* electricity and natural gas. For this report, consumption and use are included in a wide variety of ways and sometimes interchangeably.

Electricity Use

Resources Used for Oregon's Electricity Mix

In 2018, Oregon used 51.1 million megawatt hours (MWh) of electricity from both in-state and out-of-state sources. Hydropower, coal, and natural gas make up the bulk of Oregon's electricity resources, commonly called resource mix, although the share of each resource is constantly changing and evolving.

Oregon's only coal plant, Boardman, ceased operations in October 2020, and renewable energy makes up an increasingly larger share of the mix each year. The five largest sources of electricity are labeled; the other resources are each under 2 percent.[1]

25%

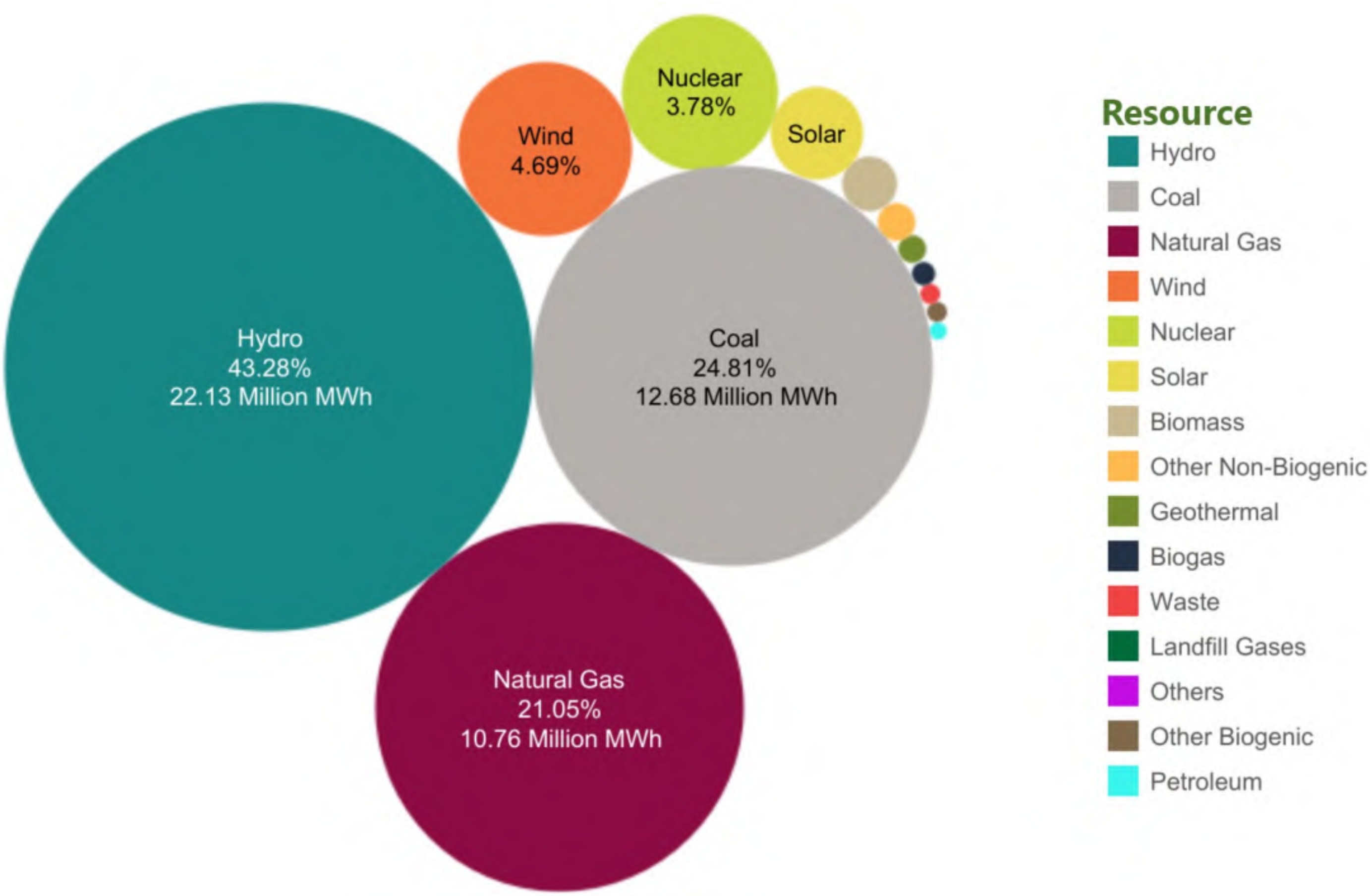
Percentage of Oregon's 2018 electricity mix that came from coal.

2030

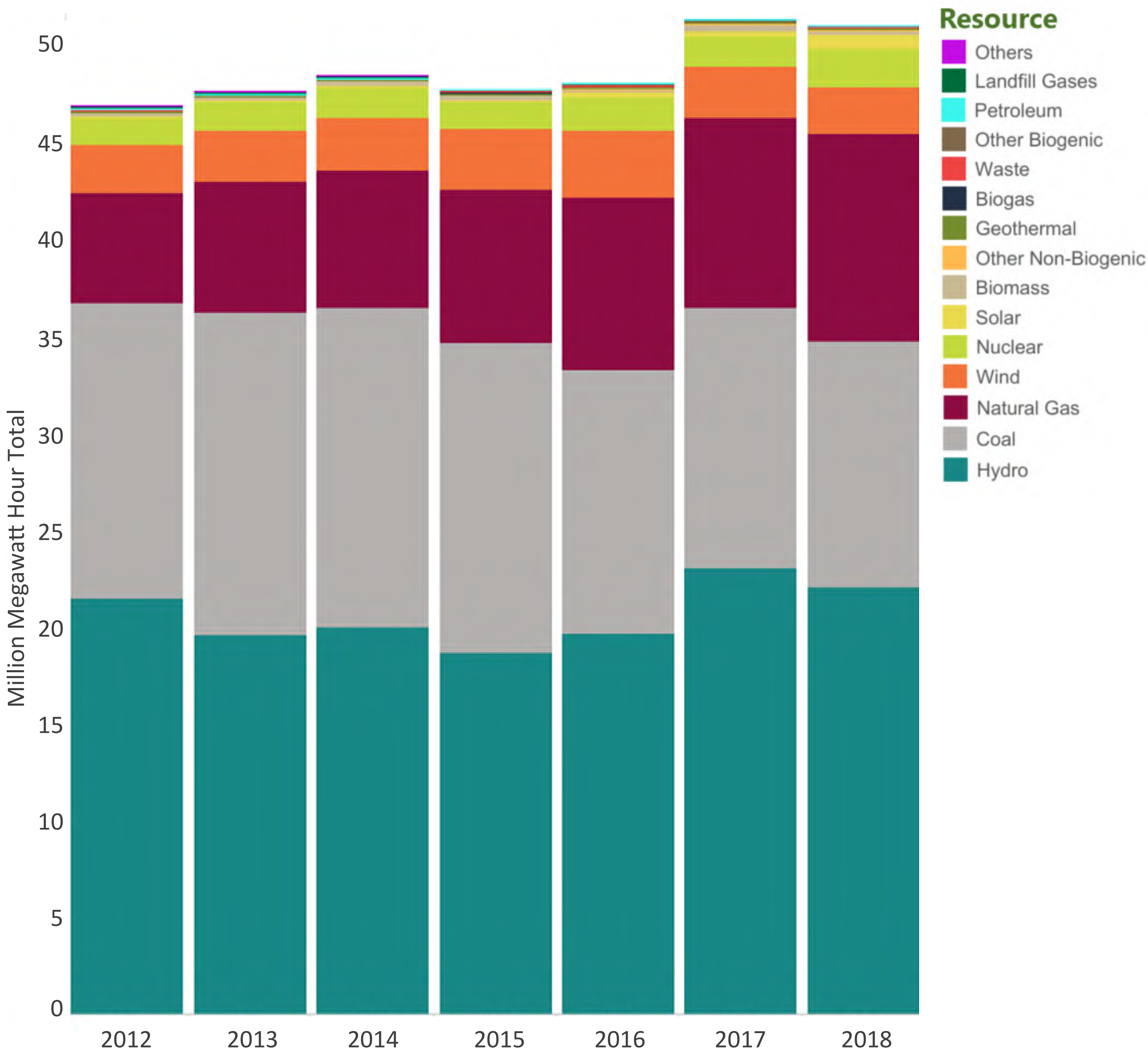
Year by which Oregon's two largest utilities will no longer be able to generate or contract for electricity from coal for use by Oregon consumers.

Resources Used to Generate Oregon's Electricity

Based on 2018 data, this chart shows the energy resources used to generate the electricity that is sold to Oregon's utility customers.



Oregon's Electricity Mix Over Time



Learn more about Oregon's Electricity Resource Mix

The Oregon Department of Energy updates the state's electricity resource mix each year. On the agency's website, find the state's overall mix, a map of generation facilities, electricity mixes by utility, greenhouse gas emissions, and more.

www.tinyurl.com/OregonERM

Electricity Imports and Exports

Oregon is blessed with an abundance of renewable energy resources and is one of the leading producers of renewable energy in the country. In part because of this, and in part due to electricity markets, we end up exporting significant amounts of the renewable electricity generated in state.

Oregon imports all the petroleum, coal, and almost all of the natural gas fuels used to generate electricity at in-state facilities. Oregon does not have any coal mines and only extracts natural gas at one facility in Oregon.

Oregon also imports electricity from all over the western U.S.; this imported electricity comes from various resources.[2]

Oregon Exports

68% of wind generation

66% of geothermal generation

38% of hydroelectric generation

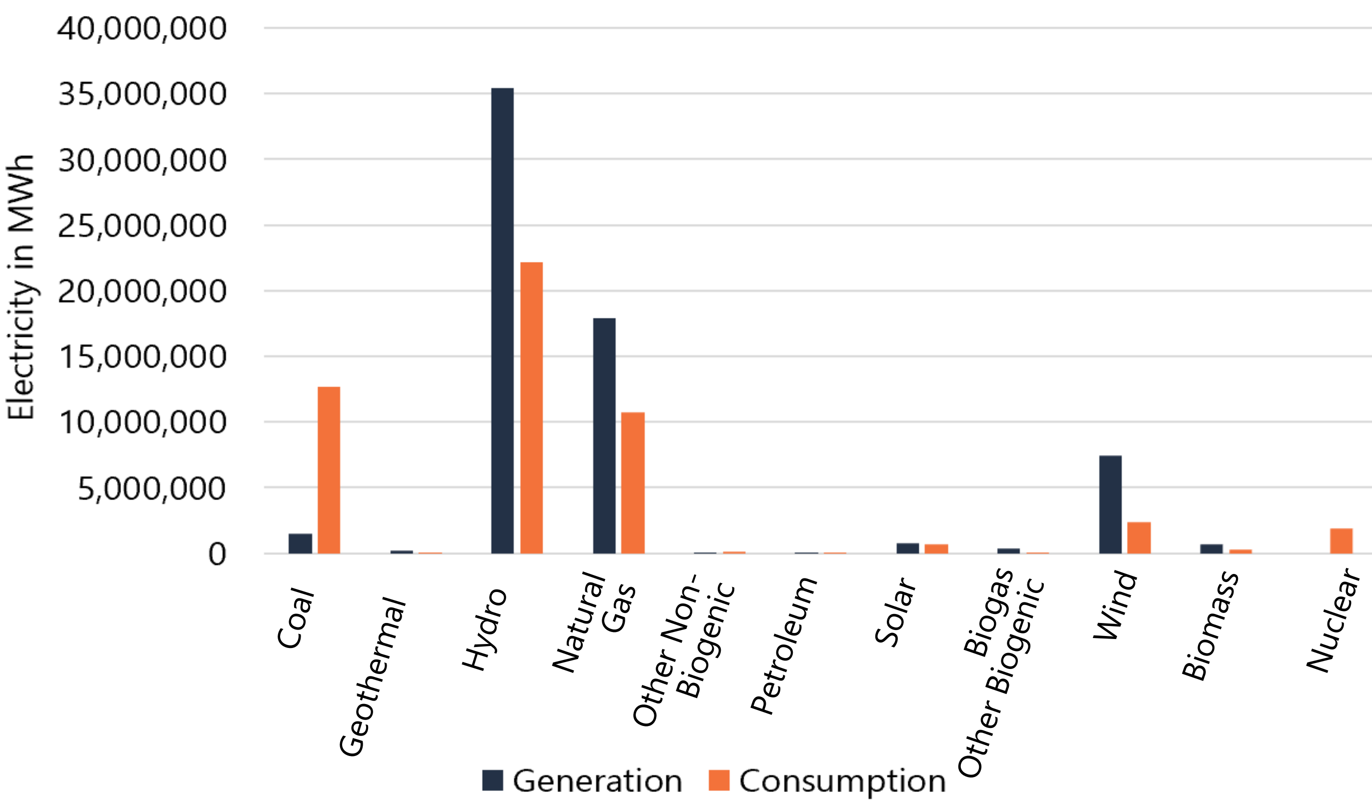
12% of solar generation

Oregon Imports

88% of coal based electricity

100% of nuclear electricity

Oregon's Electricity Generation and Consumption (2018)

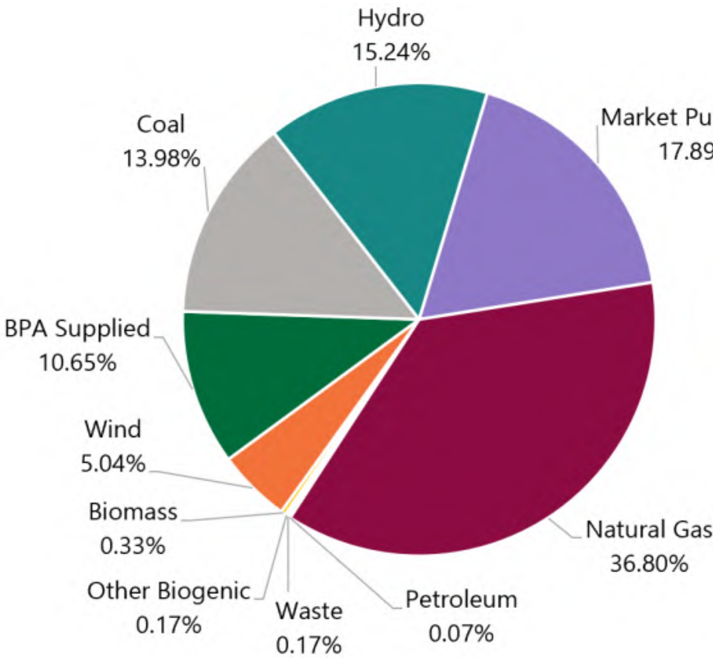


Megawatt (MW): One million watts of electricity capacity—the equivalent of 1,340 horsepower, or enough power to simultaneously illuminate 25,000 standard 40 Watt lightbulbs. **Megawatt Hour (MWh):** A unit of measurement for energy output that represents the amount of energy supplied continuously by 1 MW of capacity for one hour. **Average Megawatt (aMW):** Represents 1 MW of energy delivered continuously 24 hours/day for one year, or 8,760 MWh.

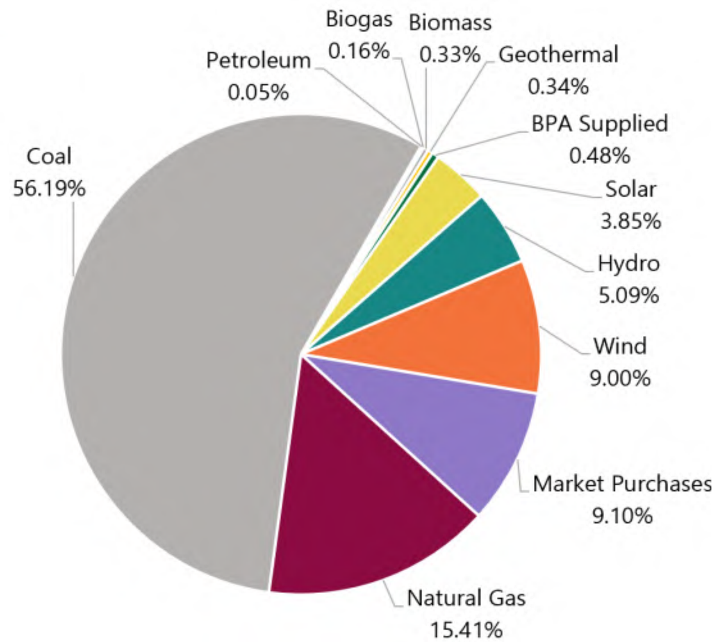
Electricity Use

Investor-Owned Utility Resource Mix

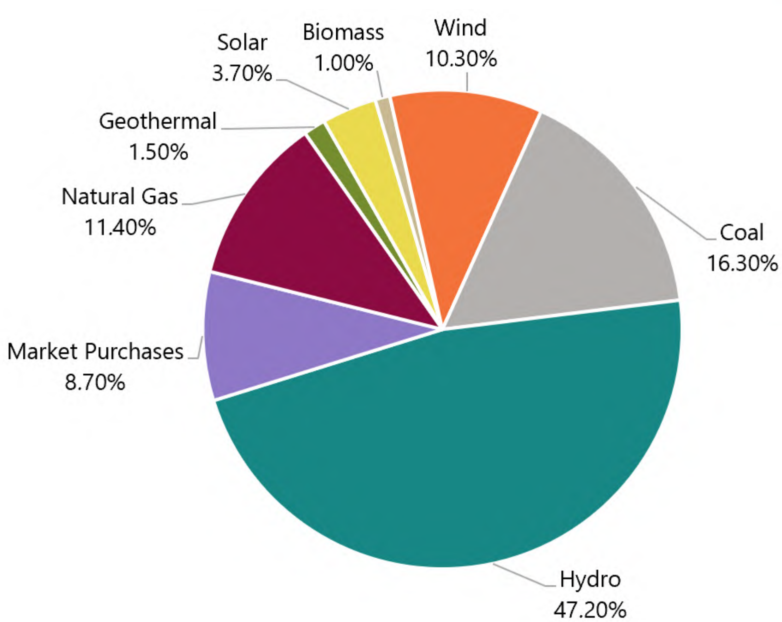
The resources utilities use to generate electricity consumed in Oregon vary depending on the utility provider. The electricity resource mixes for Oregon's three investor-owned utilities are shown below. Only 2018 data is shown for each utility; mixes will fluctuate year to year depending on the availability of certain resources like hydro. The information below includes real-time supplemental market purchases of electricity that utilities make to meet demand.[1]



Portland General Electric 2018



Pacific Power 2018

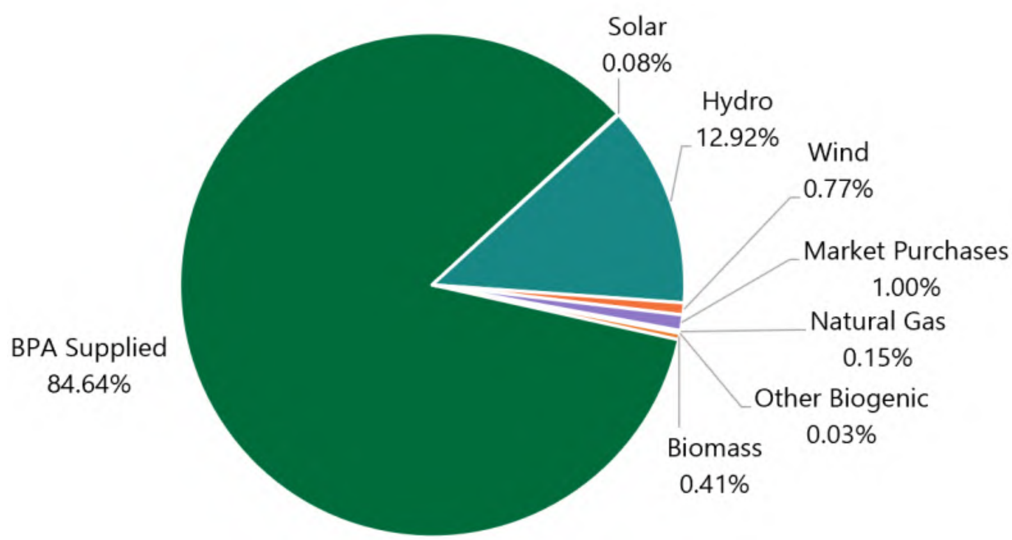


Idaho Power 2018

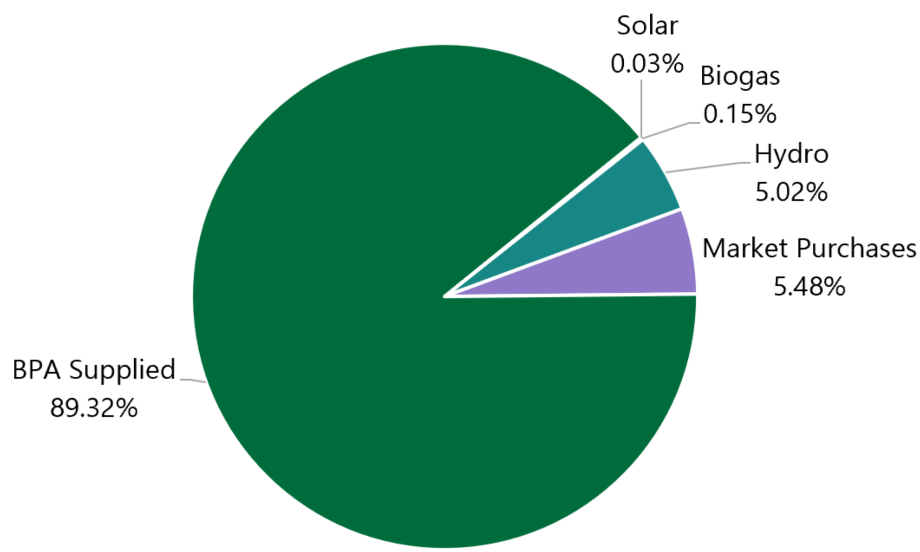
Electricity Use

Consumer-Owned Utility Resource Mix

The electricity resource mixes for the Eugene Water & Electric Board (the largest consumer-owned utility) and a composite of other COUs operating in Oregon are below. Only 2018 data is shown for the utilities; mixes will fluctuate year to year depending on the availability of certain resources like hydro. The information below includes real-time supplemental market purchases of electricity that utilities make to meet demand; these purchases are called "unspecified" because the exact mix delivered to COUs is not part of the purchase agreement and is therefore uncertain.[1]



Eugene Water & Electric Board
2018



Composite of Consumer-Owned Utilities
(not including EWEB)
2018

Did You Know?

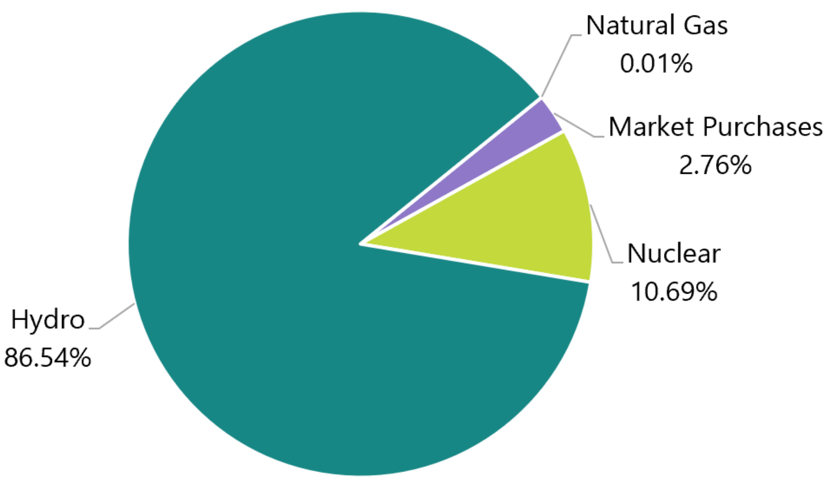
While the majority of power supplied by Oregon's consumer-owned utilities comes from the Bonneville Power Administration, COUs have also invested in their own energy-generation sources. For example, Central Lincoln People's Utility District on the central Oregon coast has community solar available, and the Eugene Water & Electric Board supplies some of its electricity from utility-operated dams.

Thanks to the BPA-supplied power and their own resources, COU electricity mixes have very low greenhouse gas emissions.

Electricity Use

Bonneville Power Administration and Market Purchases

Consumer-owned utilities in Oregon purchase most of their electricity from the Bonneville Power Administration, a federal agency that markets wholesale electric power from 31 federal hydroelectric facilities in the Northwest, a non-federal nuclear power plant, and several other small non-federal power plants. The dams generating the hydroelectric power are operated by the U.S. Army Corps of Engineers and the Bureau of Reclamation. BPA provides about 28 percent of the electricity used in the Northwest.[1]

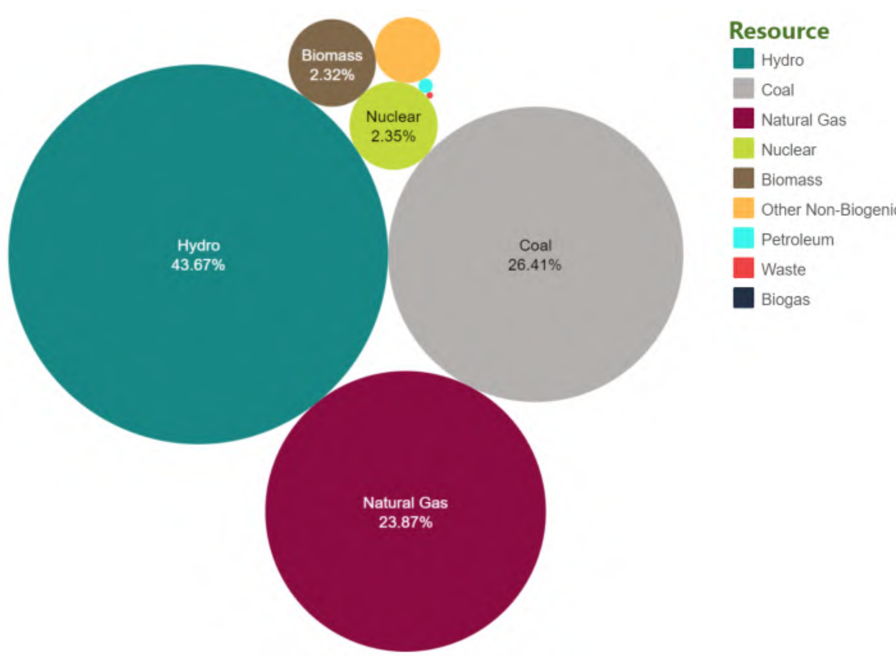


Bonneville Power Administration 2018

Oregon electricity generation facilities sell electricity to Oregon utilities and the regional power market. Oregon electric utilities own facilities that generate power, but they also purchase power from the regional market to meet customer demand with the lowest-cost resources available at any given time. The chart below illustrates the resources of 2018 market purchases.

Some utilities make “unspecified” market purchases to meet their demand. The utilities purchase the electricity on the power market and may not know the resource or facility that generated it. The mix shown here applies to all contracted unspecific market purchases in Oregon, totaling 8 million megawatt hours in 2018.[1]

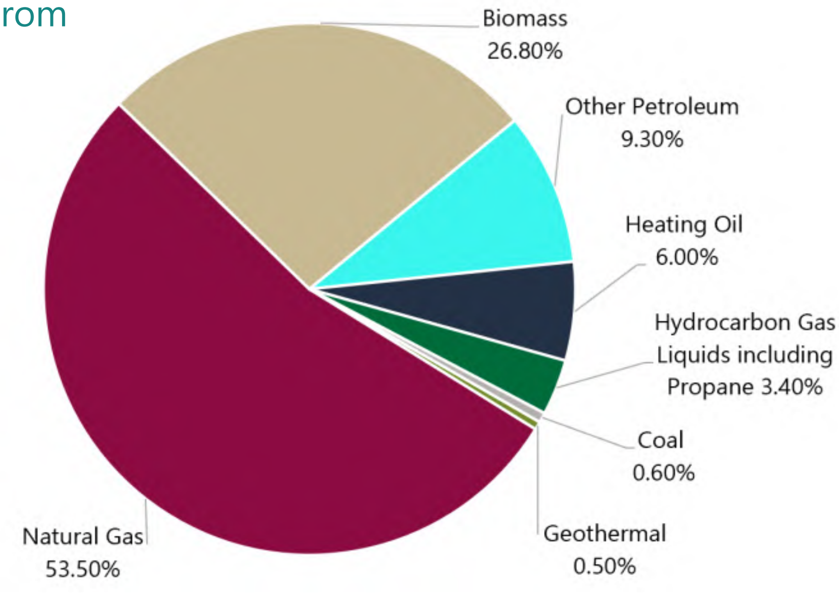
Electricity Market Purchases 2018



Direct Use Fuels

What We Use and Where it Comes From

In 2018, Oregon used 251.5 trillion Btu of direct use fuels to cook, heat buildings, and support commercial and industrial processes. Direct use fuels make up about 26 percent of the total energy consumption in Oregon. Direct use fuels include fuels that are used at the site in the residential, commercial, and industrial sectors. These do not include fuels used to generate electricity or support the transportation sector.[1 2]



Natural Gas. A gaseous mixture of hydrocarbon compounds, primarily methane, natural gas is a fossil energy source from beneath the earth's surface that is produced abundantly in the United States. Natural gas is used directly for space and water heating, cooking, and many agricultural, commercial, and industrial processes. Renewable natural gas is made by capturing methane from food waste, agricultural manure, landfills and wastewater treatment plants. Natural Gas exploration, extraction, production, and transportation has an effect on the environment.

In 2018, Oregon used 134.5 trillion Btu of natural gas for direct uses — nearly all of it imported from Canada and the Rocky Mountain states. The Pacific Northwest's only natural gas extraction facility is located outside of the town of Mist, Oregon and is owned and operated by NW Natural, one of three investor-owned gas companies serving the state. The Mist field produced 0.53 trillion Btu of natural gas in 2018, which represents 0.2 percent of Oregon's use.[3 4]

Natural Gas Consumption by Sector

Commercial Sector | 31 trillion Btu
Residential Sector | 46 trillion Btu
Industrial Sector | 58 trillion Btu[5 6]

Biomass. Biomass in an organic material that comes from plants and animals that is burned to create energy. Biomass is considered a renewable source of energy, and comes from resources like wood, agricultural crops and waste, food or yard waste, and animal and human waste. The organic waste materials are collected and used to make energy that can be used on site or distributed to a utility instead of filling space in a landfill. While some biomass sources are the same as biogas, biomass also commonly refers to end-products such as wood chips, wood pellets, and charcoal that are used for thermal energy.

In 2018, Oregon consumed 67.5 trillion Btu of biomass as a direct use fuel.[7] Oregon has 15 wood and wood waste biomass-generating facilities. The biomass fuel contributions come primarily in the form of wood and wood waste, but there are also 25 agricultural waste, landfill gas, and wastewater biogas generating facilities.[8] Many industrial facilities in Oregon use woody biomass to generate electricity from products that would normally be wasted. Biomass is also used as a thermal energy source at commercial facilities, including schools and hospitals. About 7 percent of Oregon households heat their homes primarily with wood.[9]

Biomass Consumption by Sector

Commercial Sector | 4 trillion Btu

Residential Sector | 23.8 trillion Btu

Industrial Sector | 39.7 trillion Btu[10 11]

Heating Oil. Heating oil is a petroleum distillate fuel that is used for primarily building space heating; some buildings also use it to heat water. Because space heating is the primary use for heating oil, demand is highly seasonal, and it is affected by the weather. Most Oregon heating oil use occurs during the heating season: October through March.

In 2018, Oregon used 15 trillion Btu of heating oil for direct uses, and almost 2 percent of Oregon homes use fuel oil for heating.[12] It is also used in commercial and industrial buildings. Oregon does not produce any heating oil in the state, so most of Oregon's petroleum supply comes from refineries in Washington.[13] Exploration, extraction, production, and transportation of oil has a significant effect on the environment. Oil leaks and spills at extraction sites, in transportation on ships and trains, and from oil tanks on Oregon properties can contaminate soil and groundwater.

Biodiesel heating oil is becoming more readily available in Oregon. Biodiesel heating oil is a renewable fuel made from vegetable oils, like soy and canola, that are grown domestically. Biofuels are mixed with regular heating oil at 5 to 20 percent to create a cleaner burning alternative fuel. The mixes can be used by typical oil furnaces in homes, but increasing the portion of vegetable oils in the blends does require adjustments to home oil furnaces.

Heating Oil Consumption by Sector

Commercial Sector | 3.01 trillion Btu

Residential Sector | 1.49 trillion Btu

Industrial Sector | 10.5 trillion Btu [14 15]

Oregon History: Heating Oil Tanks

Oil was a popular fuel for heating pre-1960 residential and commercial properties. The Oregon Department of Environmental Quality estimates that a total of 200,000 underground heating oil tanks were installed in Oregon. Its use has declined dramatically and many underground tanks have been abandoned in place, often still containing oil. Underground tanks can leak and pollute groundwater, create harmful vapors, and ruin water wells or surface water. DEQ oversees the decommissioning and cleanup of underground heating oil tanks, which are usually found when homes are sold. More than 50,000 underground heating oil tanks have been reported to DEQ, including 1,707 in 2019.[22]

Learn more: www.oregon.gov/DEQ

Hydrocarbon Gas Liquids and Propane. HGLs are gases at atmospheric pressure and liquids under higher pressures, which can also be liquefied by cooling. Their versatility and high energy density in liquid form make them useful for many purposes, including as feedstock in petrochemical plants, as fuel for heating or cooking, and as transportation fuels, additives, or diluent. Propane is a hydrocarbon gas liquid that can also be used to power buses, locomotives, forklifts, taxis, farm tractors, backyard barbeques, and Zamboni machines at ice skating rinks. Propane remains a viable fuel over long periods of storage, making it a common backup fuel for essential facilities such as hospitals and a potential resource in emergency response to an event. Propane is a byproduct of natural gas production, and the environmental effects of its generation are similar to the challenges of natural gas mentioned above. As U.S. natural gas production has increased, the supply of propane has followed, making it an affordable and attractive option for many Oregonians.

Propane consumed in Oregon is imported. Based on the available data on propane production, imports, exports, and transportation, the Pacific Propane Gas Association estimates that more than 95 percent of the propane consumed in Oregon is sourced from natural gas processing plants in Alberta and British Columbia, Canada.[16]

Oregon consumed 8.5 trillion Btu of propane in 2018 as a direct use fuel. Consumption increased 5 percent between 2017 and 2018, and by 29 percent between 2008 to 2018.[17] Almost 2 percent of Oregon residents use to heat their homes, and even more use it for cooking.[18] While Propane use on-road as a transportation fuel is a small segment of the total fuel usage in Oregon, school districts have embraced propane as a fuel for bus fleets. There were an estimated 8,257 school buses in Oregon in 2019, and 1,159 — about 14 percent — were fueled by propane (the national average is 4 percent). Portland Public Schools has been using propane school buses for 30 years and is one of the largest school propane fleets in the country.[19]

Hydrocarbon Gas Liquids and Propane Consumption by Sector

Commercial Sector | 3.5 trillion Btu

Residential Sector | 2.9 trillion Btu

Industrial Sector | 2 trillion Btu [20 21]

Geothermal. In 2018, Oregonians consumed 0.55 trillion Btu of geothermal energy to make electricity.[23] While geothermal is often used to generate electricity, it can also be used for thermal energy applications such as heating spaces and keeping bridges and sidewalks from icing over. The residential, commercial, and industrial sectors used 1.3 trillion Btu of geothermal energy to heat and cool spaces in Oregon.[24]

Coal. Coal is imported to Oregon to use as a direct fuel in the industrial sector. Oregon imported 1.4 trillion Btu of coal from neighboring states in 2018. Use of coal as a direct fuel in Oregon has declined by 84 percent since 1960.[25]

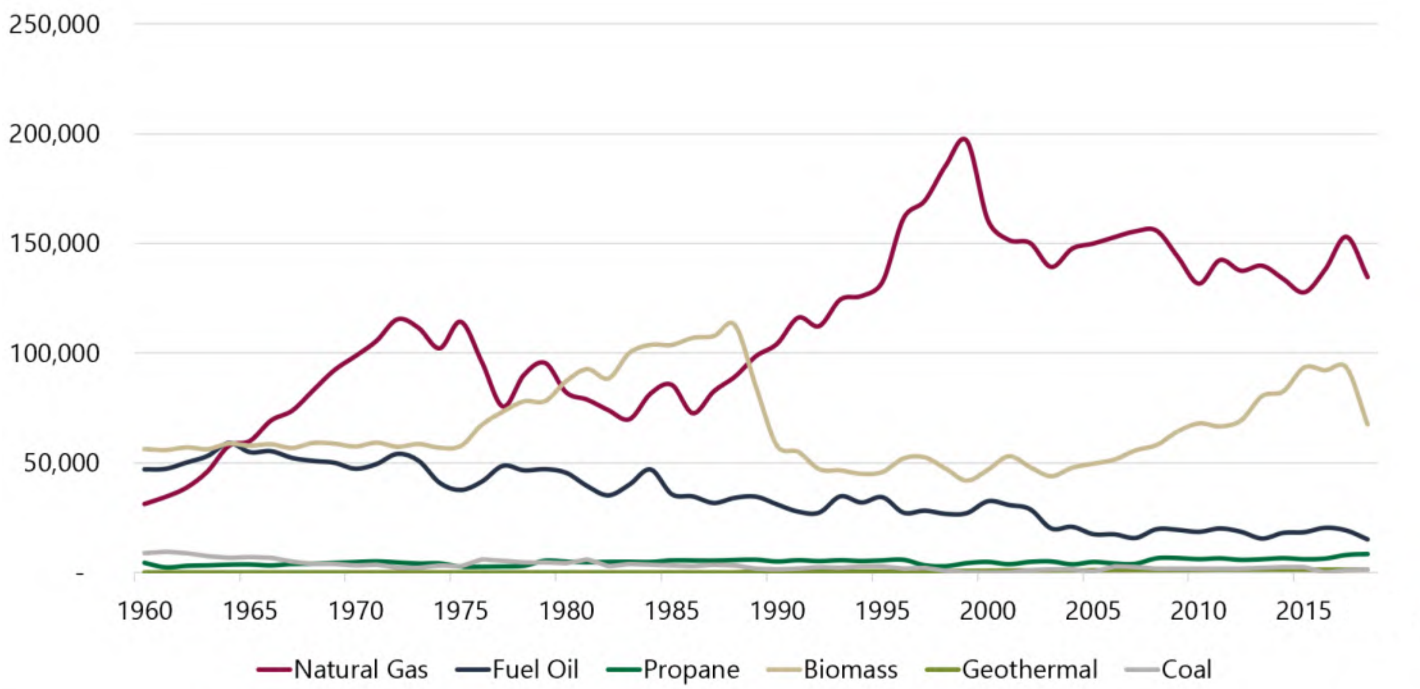
Geothermal and coal direct use fuels represent just over 1 percent of Oregon's direct use fuels.[1]

Direct Use Fuels

Direct Use Fuels Over Time

Oregon's energy consumption has evolved over time. For direct use fuels in Oregon, that has meant decreasing wood and fuel oil use and an increased use of natural gas. The chart below uses data from the U.S Energy Information Administration to compare total consumption of direct use fuel types in Oregon's residential, commercial, and industrial sectors from 1960 to 2018. This chart does not include transportation fuels or fuels used to generate electricity used in the residential, commercial, and industrial sectors.[1]

Oregon Direct Use Fuels Consumption: 1960-2018 (Billion Btu)



Over time, as natural gas and electricity have replaced the use of coal and oil to heat homes and businesses in Oregon, coal and fuel oil have steadily declined as heating sources.

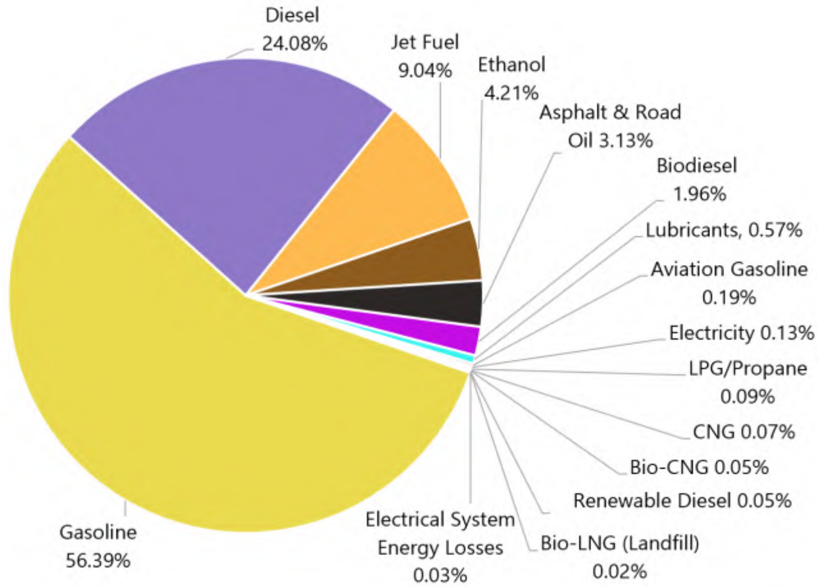
Geothermal consumption is one of the smallest of Oregon's direct use fuels in the chart. EIA began tracking geothermal consumption in 1989 with 0.38 trillion Btu. In 2018, Oregon consumed over 2.8 trillion Btu of energy from geothermal, an increase of 637% over that 30-year period.[2]

Biomass energy consumption in Oregon has increased steadily since 2002, due almost entirely to increased demand for biofuels. Biomass resources may be converted to biofuels such as ethanol, biodiesel, and other biomass-based diesel fuels. Oregon also consumes a significant amount of biomass energy from secondary waste products, like lumber mill residue, logging slash, and animal manure.

Transportation Fuels

What We Use

Oregon's transportation sector uses 31 percent — or 316 trillion Btu — of the energy consumed in Oregon. Transportation was the largest share of energy use among the sectors in 2018.[1] The transportation fuels consumed in Oregon are used in a variety of ways:



Gasoline. Petroleum product used by cars, motorcycles, light trucks, airplanes, and boats.

Diesel. Petroleum product used by trucks, buses, trains, boats, and ships.

Petroleum-based products make up 93 percent of Oregon's transportation fuel use.

Ethanol. Fuel produced from agricultural crops or wood that is blended with gasoline and used by cars and trucks.

Biodiesel. Fuel from organic oils and fats that can be blended with diesel fuel (up to 20 percent) and used by trucks, buses, trains, boats.

Electricity. Powers some public mass transit systems and electric vehicles.

Propane. Fuel from the natural gas and oil refinery process and used by cars, buses, and trucks.

Natural Gas. Compressed and liquefied natural gas used by cars, buses, trucks, and ships.

Renewable Natural Gas. Biogas from agricultural waste, wastewater, or garbage collected and refined to power natural gas cars and trucks.

Renewable Diesel. Fuel from organic oils and fats using a different production process than biodiesel to power diesel vehicles.[2 3]

The U.S. Energy Information Administration tracks transportation sector consumption. The Oregon Department of Energy analyzes data from the Oregon Department of Transportation's fuel tax program and the Department of Environmental Quality's Clean Fuels Program to determine Oregon-specific transportation fuel sector and on-road transportation fuel consumption. In 2018, petroleum-based products accounted for 93 percent of fuel consumed in the transportation sector; biofuels like ethanol, biodiesel, and renewable diesel accounted for 6 percent; and electricity, and natural gas accounted for 0.3 percent of the fuels consumed.[4]

Learn more about where Oregon's transportation fuels come from in the Energy 101 section of this report.

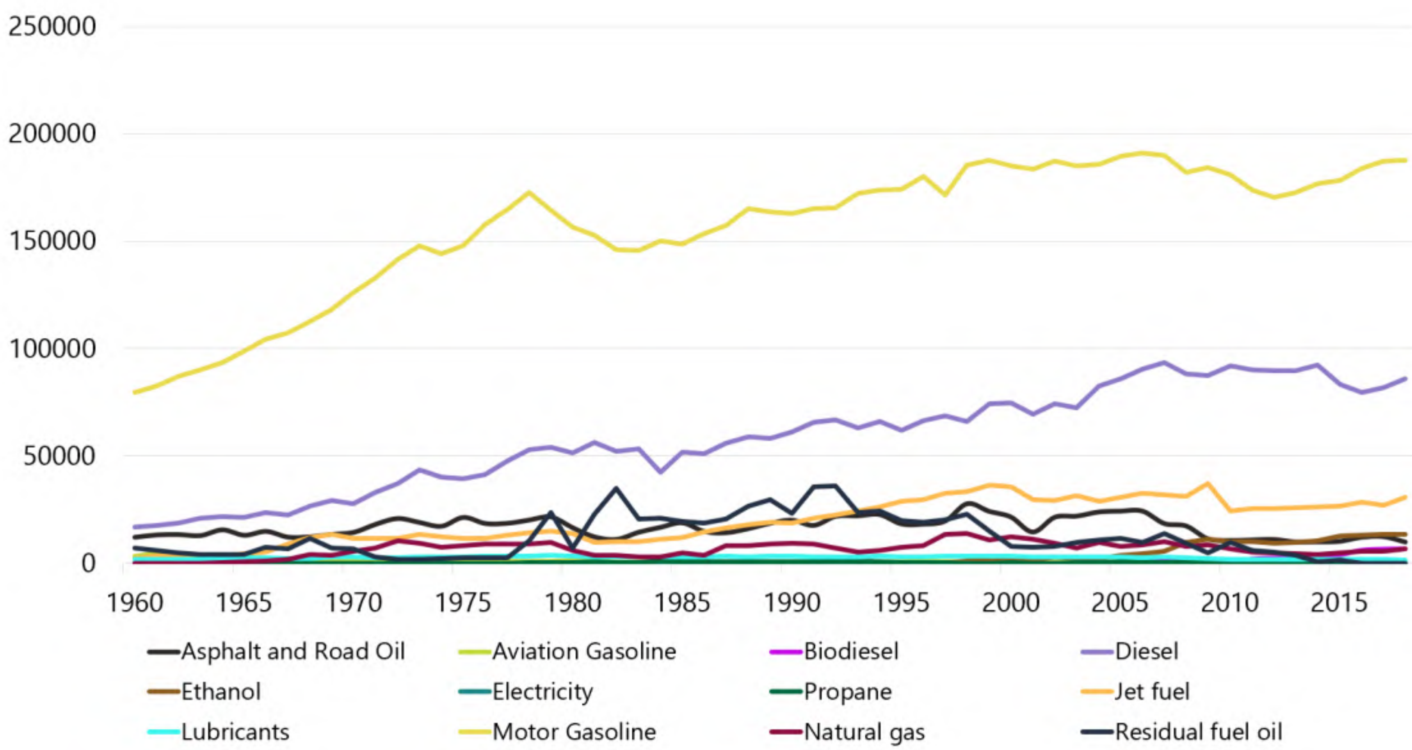
Transportation Fuels

Use Over Time

The U.S. Energy Information Administration has tracked national energy consumption and individual state consumption since 1960. In Oregon and nationally, overall transportation consumption increased between 1960 to 2018. In 1960, Oregon's transportation sector consumed 111 trillion Btu of energy compared to 316 trillion Btu in 2018 — a 185 percent increase in transportation energy consumption over that time.[5]

Petroleum product consumption has steadily increased over time and currently dominates the transportation fuel use in Oregon. Nearly all transportation fuels are imported into Oregon. In 2018, just 2 percent of transportation fuel used in Oregon was produced in the state, including 7.3 trillion Btu of biodiesel and fuel ethanol.[6] Oregon electric utilities provided 0.42 trillion Btu of electricity to fuel zero-emission vehicles in 2018, about 0.2 trillion Btu or 48 percent of which was produced from Oregon resources.[7] Oregon does not have crude oil reserves or refineries to process petroleum, so over 90 percent of the petroleum products delivered to and consumed in Oregon come from four refineries in Washington state. Crude oil used at Washington refineries comes from Alaska, western Canada, and North Dakota.

Oregon Transportation Sector Consumption: 1960-2018 (Billion Btu)



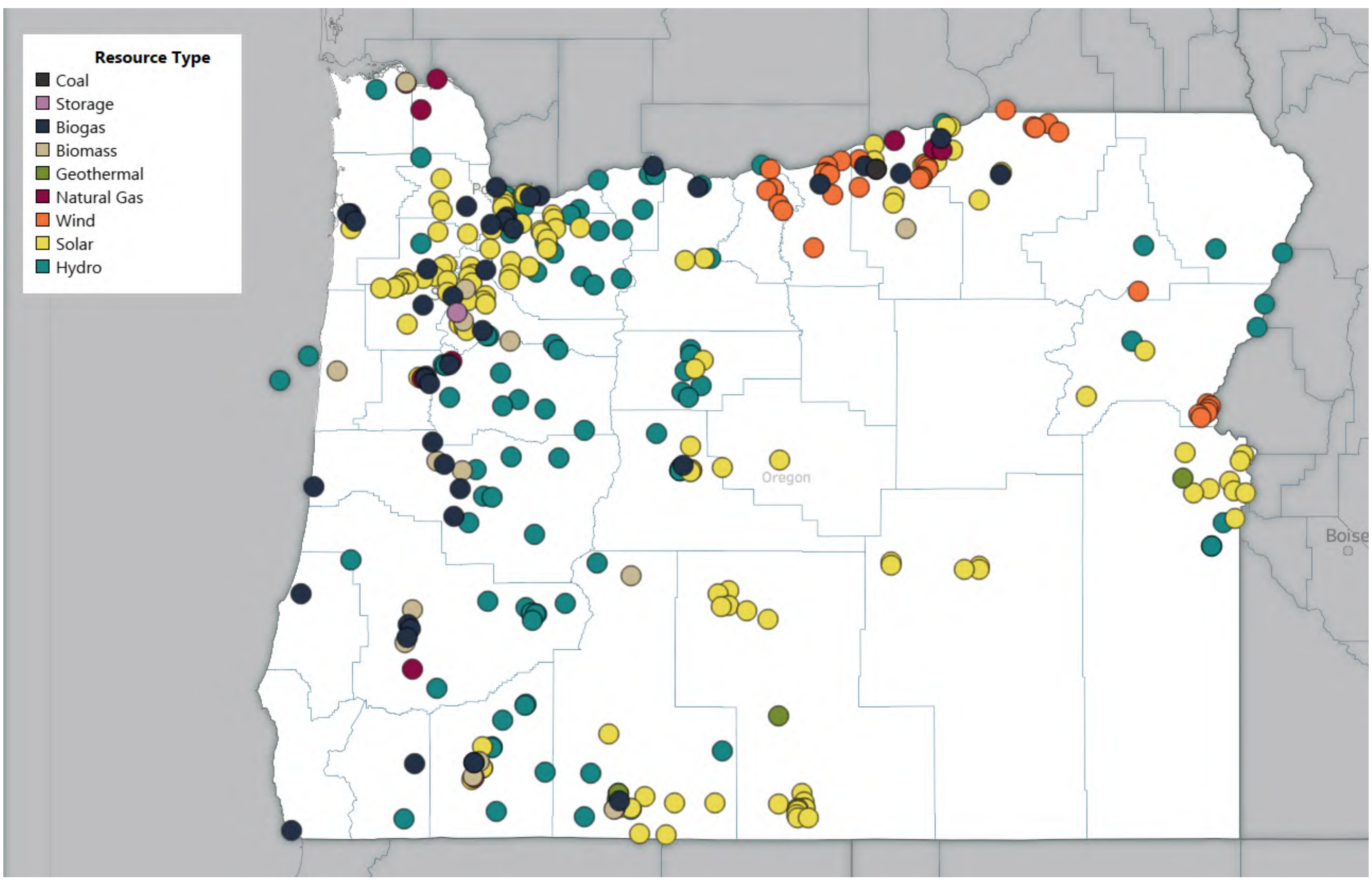
Oregon is exploring how to promote the use of more renewable natural gas, electricity, and biofuels in the transportation sector. Adoption of these Oregon-generated alternative transportation fuel options will allow Oregonians to consume less imported energy.

Learn more about alternative transportation fuel use in Oregon in the Policy Briefs section of this report.

Energy Production

Energy produced in Oregon comes from a variety of resources and facilities across the state. The Oregon Department of Energy is developing an Oregon Energy Dashboard, which will contain an inventory of facilities that produce energy in Oregon. ODOE expects the dashboard to be available in late 2020 on the agency's website, and will include standalone electric generation facilities supplying electricity to Oregon's grid, as well as primary energy production facilities that produce resources including natural gas, liquid biofuels, and biogas. The dashboard will show data on location, capacity, and annual production for these facilities in Oregon compiled from a variety of sources, including the U.S. Energy Information Administration and utility data. The dashboard will be complementary to ODOE's Oregon Solar Dashboard, which shows utility-scale solar facilities and behind-the-meter residential and commercial solar installations in Oregon. Data from the dashboard were used to inform analysis in multiple sections of the *Biennial Energy Report,* including developing summary statistics for each electricity generation resource and providing data for Policy Briefs.

The following map is derived from the dashboard and shows the locations of all 293 energy production facilities in Oregon, including two wave test centers off the Oregon coast. The online version of the dashboard will allow users to select resource types or individual facilities to see statistics including generation capacity and average annual production.

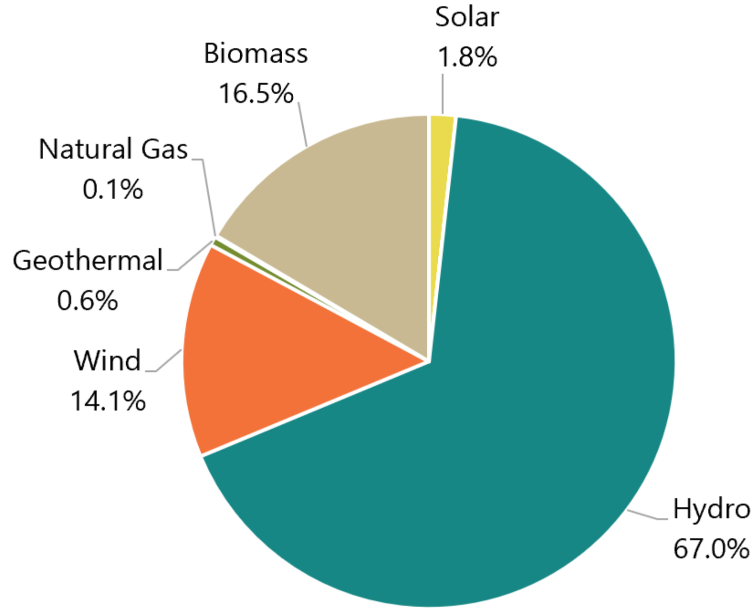


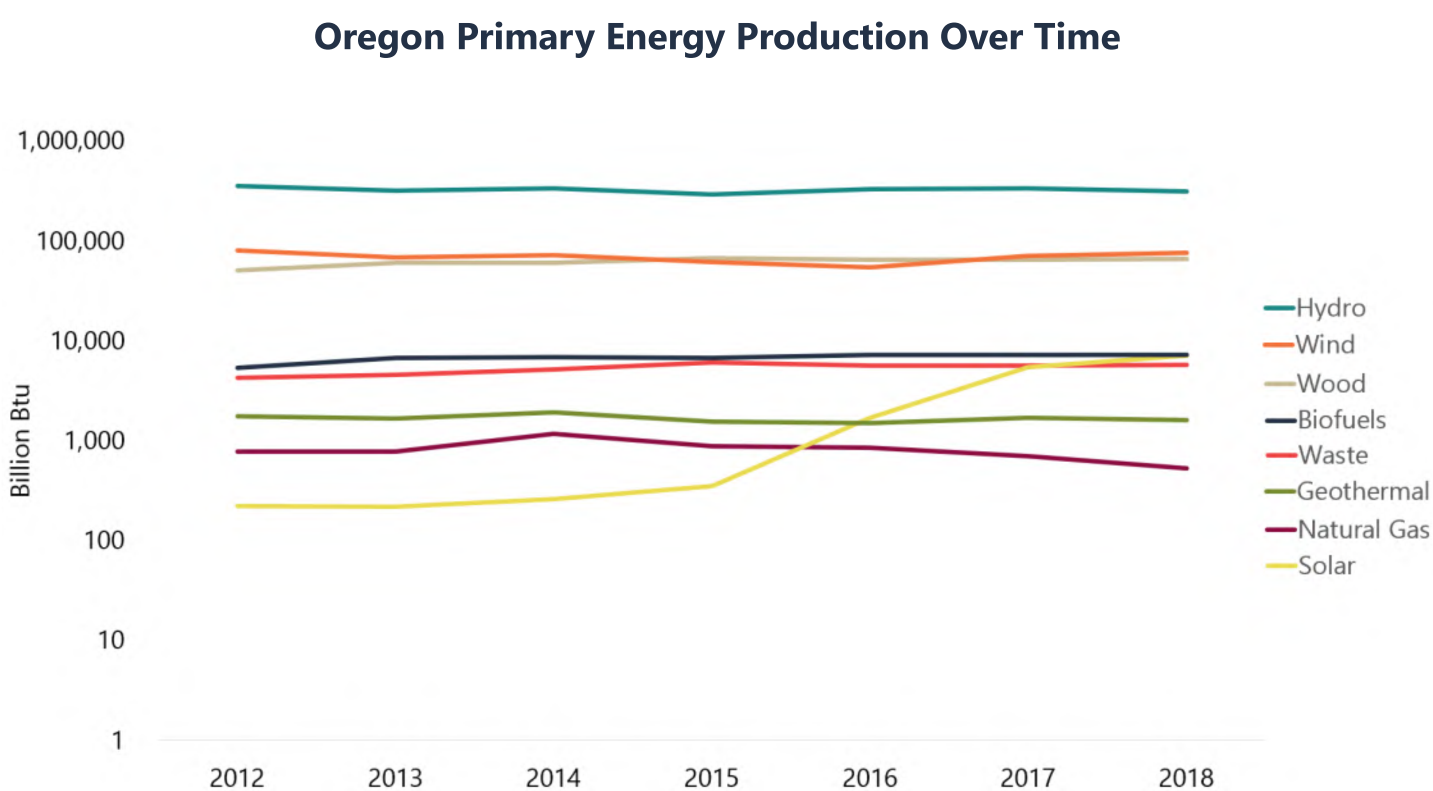
Energy Production

Overview

Primary energy production represents energy that is collected from Oregon's natural resources — it does not include energy that is imported for consumption or electricity generation in Oregon.

The chart at right shows primary energy production in Oregon in 2018. Almost all the solar, wind, geothermal, and hydro primary energy is converted to *secondary* energy as electricity. Some of the biomass is used to make a variety of renewable fuels and some is combusted to produce heat and electricity.[1 3]

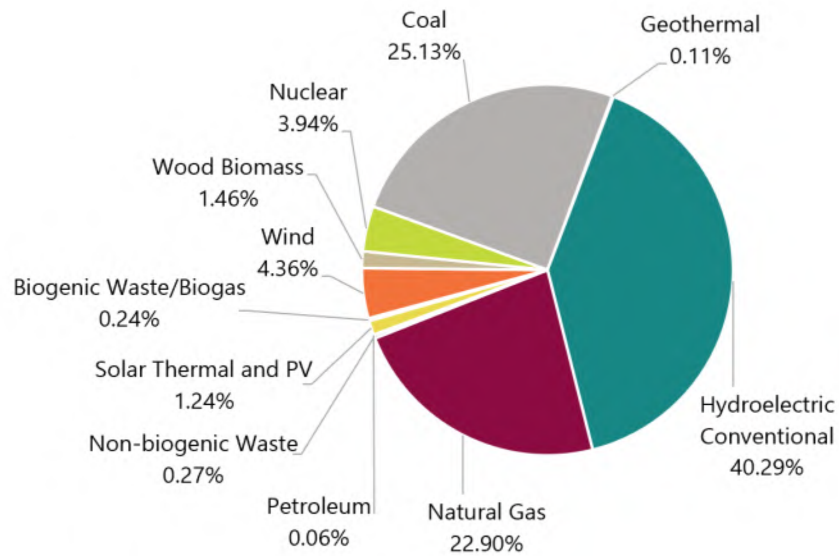




The chart above uses a logarithmic scale to more clearly compare energy production in the last six years. In a normal scale, the smaller contributors would lack detail and the annual variation in the larger contributors, such as hydro, would be more apparent Solar power has been steadily increasing since 2012 with accelerated increases starting in 2015. Since 2014, natural gas production has slowly been declining.[2]

Energy Production

Electricity



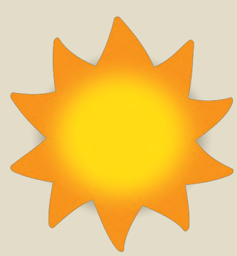
Oregon generates electricity from a variety of resources — hydropower, natural gas, and wind are the largest. In 2018, over 40 percent of Oregon's electricity generation came from hydroelectric facilities.[1] Oregon has 94 hydro facilities, including 12 large facilities with a production capacity of 100 megawatts or more.[2] Oregon is the second largest producer of hydroelectric power in the U.S. after Washington.[3]

Electricity not consumed in Oregon is exported to neighboring states. Oregon's abundance of renewable electricity can be used in Oregon or sold the energy market to utilities in other states.

Resources like hydropower, wind and solar vary in their production based on the time of day and season. Many Oregon utilities also use resources like natural gas and coal to generate electricity in Oregon or they purchase electricity from neighboring states as needed to meet customer demand. Electricity from natural gas and coal can be purchased at attractive rates that to help utilities deliver electricity cost effectively and serve varying loads.

Oregon energy generation facilities import fuels like coal and natural gas from out of state. Oregon has a single site in Mist that produces natural gas, but is used primarily for natural gas storage. Oregon has no coal or petroleum resource extraction facilities

Utility-Scale Solar in Oregon



In February 2018, Oregon's Energy Facility Siting Council approved its first EFSC-jurisdictional solar energy facility. When built, the Boardman Solar Energy Facility will have a peak generating capacity of 75 megawatts.

In April 2020 EFSC approved a second solar facility, the 303-megawatt Bakeoven Solar Project, and as of October 2020 is reviewing five additional facilities (plus two facilities that include wind and solar).

64.3 Million

Megawatt hours of electricity generated in Oregon in 2018.[4]

51.1 Million

Megawatt hours of electricity consumed in Oregon in 2018.[4]

70%

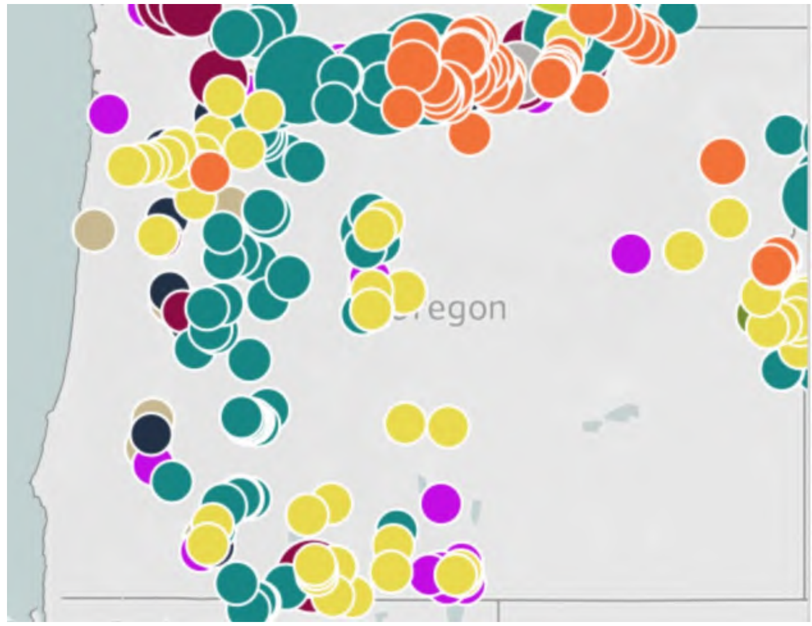
Percentage of Oregon's electricity generation that comes from renewable resources.[5]

79%

Percentage of Oregon's electricity generation that is used in-state.[6]

Energy Production

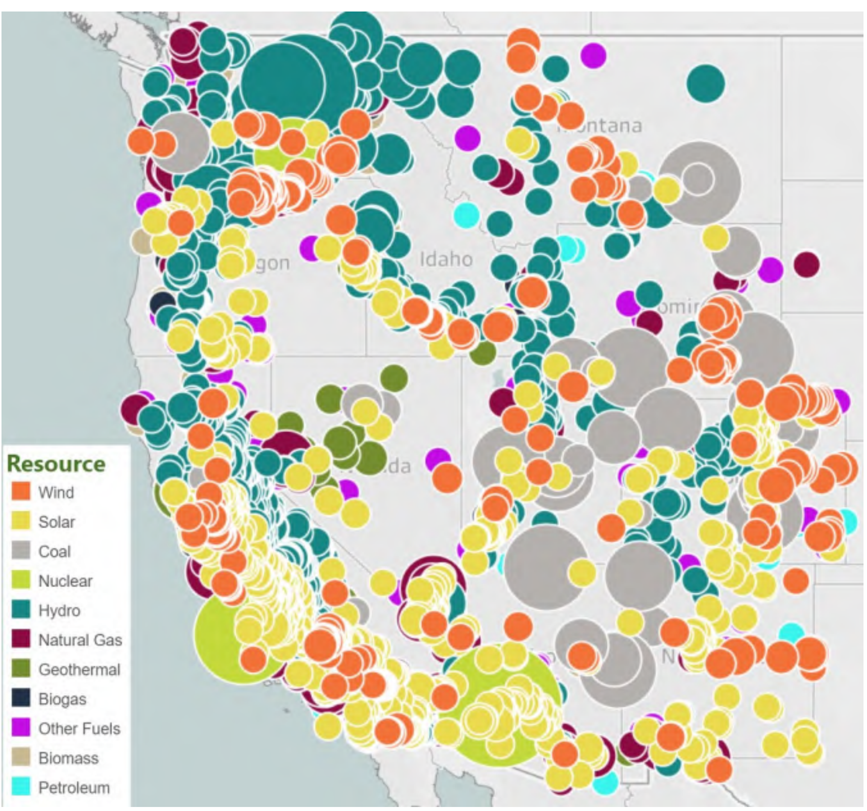
Electric Facilities



The map of Oregon at right shows where electricity generation sites are in the state. Facilities owned by Oregon utilities are included, as are third-party owned facilities, which can contract with utilities to provide power to Oregon consumers or sell their electricity on the open energy market. Note that the color of the circles corresponds to the resource used to generate electricity (see below), and the size of the circle is in relation to generation capacity of that facility.

Electricity used by Oregonians can come from facilities across the western United States. We rely on hydroelectric power produced on the Columbia River, access nuclear power from the Columbia Generating Station in Washington and wind turbines on the Columbia River Plateau, and use electricity generated at coal-powered facilities located in several western states.[7]

The map below shows the various electricity generation sources in the Western Electricity Coordinating Council. The WECC is a nonprofit organization that focuses on systemwide electricity reliability and security across a geographic region known as the Western Interconnection. This diverse region includes Oregon and most of the intermountain west and parts of Canada.[8]



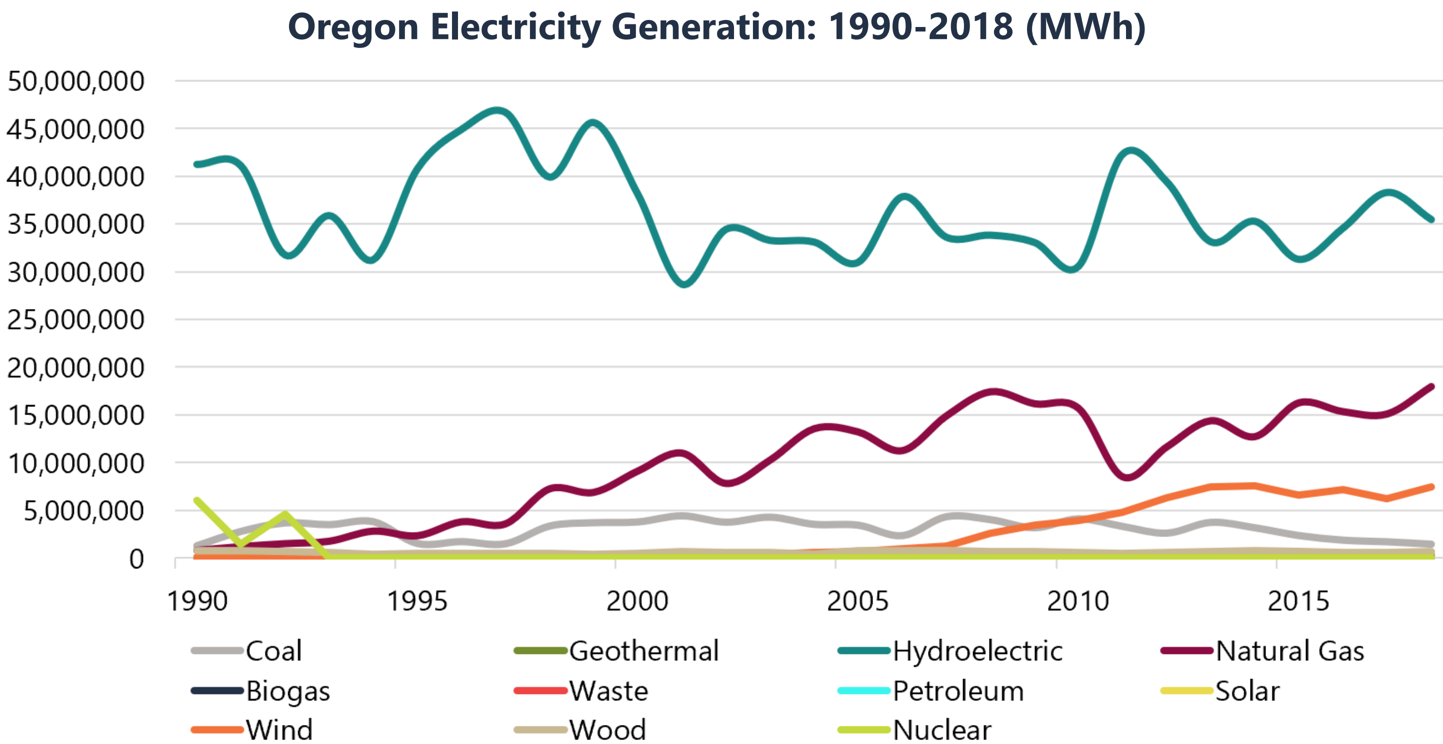
The map uses data from the U.S. Energy Information Administration and includes facilities with a nameplate capacity of 1 megawatt or greater.[9] Not all resources or facilities shown on the map contribute to Oregon's overall fuel mix, but many are available when Oregon utilities purchase electricity on the open market.

In the same way, electricity generated in Oregon may be sold through the energy market to support electricity needs in other states.

Energy Production

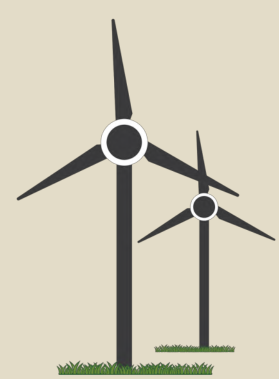
Electricity Over Time

Oregon's electricity generation has changed over the years. Hydropower, which is Oregon's largest electricity resource, varies year-over-year as the amount of electricity produced depends upon water flow, volume, and pressure. Oregon hydropower reached a generation high in 1997 of 46.7 million MWh. Wind and natural gas have both seen a gradual increase in generation over time. As of 2018, natural gas is the second largest share of Oregon's energy production, at 17.9 million MWh. Coal generation has been steadily declining since 2010. Solar has increased each year since 2011, and is expected to continue to grow following increased investment by utilities.[10]



Wind Power in Oregon

Oregon's first approved state-jurisdictional wind facility was the Stateline Wind Project in Umatilla County. Stateline was approved in 2001, and continues to operate nearly 20 years later.

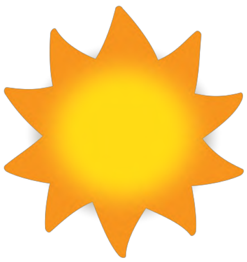


In May 2019, the Energy Facility Siting Council approved an amendment for the facility's Site Certificate to allow the wind facility to "re-power." Re-powering a wind facility can mean replacing existing wind turbine blades and nacelles (the part that hold the mechanical components). This allows turbines to continue generating electricity more efficiently, often with lower required wind speeds.

Energy Production

Renewable Electricity

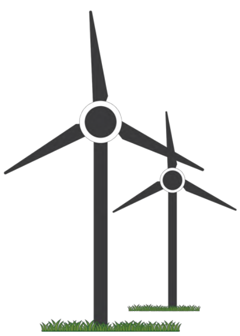
Renewable electricity in Oregon has grown due to customer demand, dramatic decreases in costs, and policies like Oregon's Renewable Portfolio Standard and the City of Portland's goal of net-zero carbon emissions by 2050.



2012 Generation	2015 Generation	2018 Generation
6,400 MWh	24,200 MWh	571,700 MWh

12% of Oregon's solar generation was exported in 2018.[1]

Solar is Oregon's fastest growing electricity resource.[2]



2012 Generation	2015 Generation	2018 Generation
6.3 Million MWh	6.6 Million MWh	7.4 Million MWh

68% of Oregon's wind generation was exported in 2018.[1]

Oregon has 12 state-jurisdiction wind facilities approved, operating, or under review, plus 2 wind and solar facilities.[2]

2012 Generation	2015 Generation	2018 Generation
39.4 Million MWh	31.2 Million MWh	35.4 Million MWh

38% of Oregon's hydropower generation was exported in 2018.[1]

In some Oregon utility territories, hydropower provides over 90% of consumers' electricity.[2]

Energy Production

Direct Use Fuels

Direct use fuels are fuels used at the customer site, rather than in the generation of electricity, in the residential, commercial and industrial sectors. Direct use fuels include fuel oil and natural gas used to heat homes and commercial spaces, fuel for gas stoves, solar thermal heating, and fuels used directly in industrial processes.

Oregon currently produces small amounts of direct use fuels; most fuels consumed are imported into the state. In 2018, Oregon used 251 trillion Btu of direct use fuels or about 26 percent of the total energy consumed in Oregon.[3] The majority of Oregon's energy production comes from energy sources like hydropower, wind and solar, but Oregon does have direct use fuel sources. Biomass is the most-produced direct use fuel in Oregon. The production numbers below demonstrate fuels Oregon consumes directly (all fuels produced to create electricity have been removed). For example, in 2018 Oregon produced 2.25 trillion Btu of geothermal energy, but in the chart we are only showing the 1.3 trillion Btu that was used as a direct fuel:[1,2]

100%

Percentage of Oregon geothermal energy consumption that is produced in-state.

15

Number of woody biomass energy facilities in Oregon in 2018.

27%

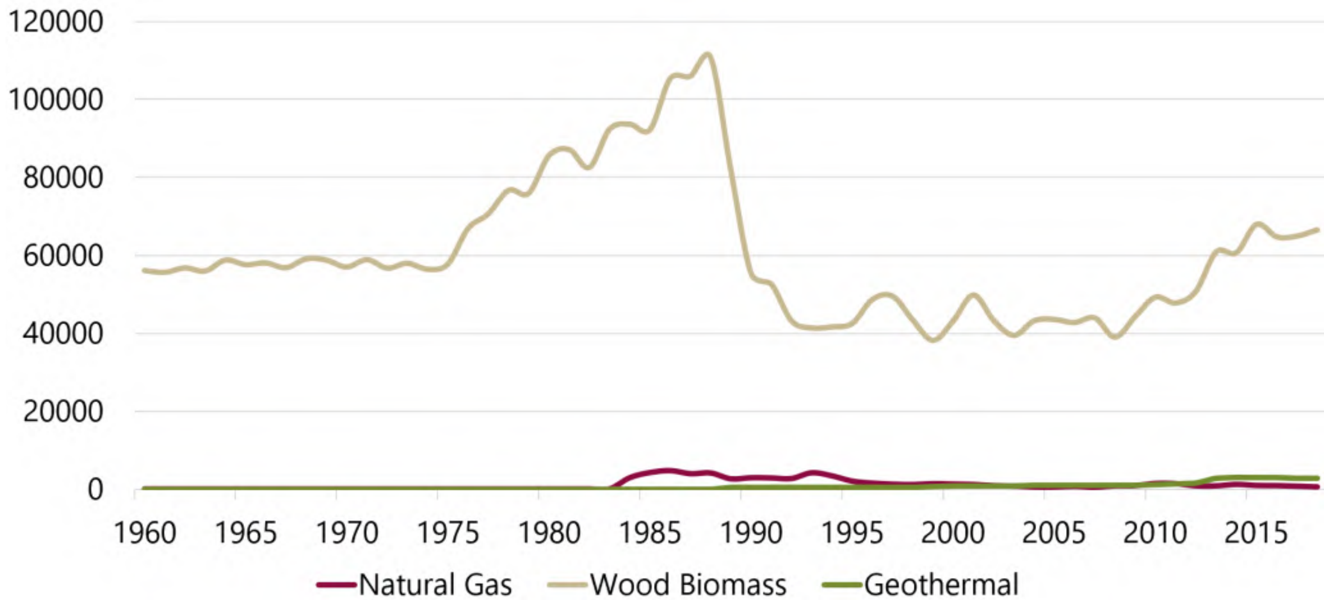
Percentage of Oregon overall direct use fuels consumption that is produced in-state.

Production & Consumption of Direct Use Fuels in 2018 (trillion Btu)

Resource	Consumption in Oregon	Oregon Production	Imported	Percent of Consumption Produced in Oregon
Geothermal	1.3	1.3	0	100%
Natural Gas	134.5	0	134.5	0%
Biomass	67.5	66.5	1	99%
Other Petroleum	23.3	0	23.5	0%
Heating Oil	15	0	15	0%
Hydrocarbon Gas & Liquids/ Propane	8.5	0	8.5	0%
Coal	1.4	0	1.4	0%
Totals	**251.5**	**67.8**	**183.88**	**27%**

Wood biomass has been Oregon's largest direct fuel production source since 1960. In 1988, wood production hit a high of 111 trillion Btu of production. Thirty years later, Oregon's production was 67 trillion Btu — a 40 percent decrease in production.[4]

Direct Use Fuel Energy Production in Oregon, 1960-2018 (billion Btu)



Natural Gas:

Oregon imports most of the natural gas we use from Canada and the Rocky Mountain states. The Pacific Northwest's only natural gas production is at a location outside of the town of Mist, northwest of Portland. The field is owned and operated by NW Natural Gas, one of three investor-owned gas companies serving the state. The Mist field produced 499 million cubic feet of natural gas or 0.5 trillion Btu of energy in 2018, representing 0.2 percent of Oregon's natural gas use in that year.[5,6] The Mist facility hit a production peak of 4.7 trillion Btu in 1986.[7] Mist is used primarily for natural gas storage today. Natural gas extracted from and stored at the facility is used to generate electricity. NW Natural pumps natural gas into the underground rock formations for use during cold weather events and to help balance additions and withdrawals to its pipeline system.

Renewable Natural Gas:

Renewable natural gas is a fuel derived from biogas or methane collected from municipal waste streams such as garbage, wastewater, and waste food as well as agricultural waste streams like manure. Redirecting these waste streams into controlled processes for optimization, capture, and utilization of the methane can be economically, socially, and environmentally beneficial to Oregon.[8] Currently, one RNG project is operational in Oregon, and four others are expected to come online in 2020 or 2021.[19] RNG alone has the potential to replace 10-20 percent of the natural gas being imported from out of state.[9] NW Natural and the City of Portland have partnered to collect Biogas emissions from the City of Portland's wastewater treatment plant and convert it to renewable natural gas that will be put in a NW Natural pipeline and into vehicles. It is estimated that the renewable natural gas generated from Portland's plant will replace 1.34 million gallons of diesel fuel with enough natural gas to run 154 garbage trucks for an entire year.[10]

A 2018 ODOE study found that up to 20% of Oregon's natural gas needs could be met with renewable natural gas.

Solar Thermal:

In addition to generating electricity, solar thermal energy is a resource used directly in Oregon homes. Solar thermal systems capture energy from the sun to provide water heating and space heating in buildings. Most systems installed in Oregon are solar water heating systems that provide supplemental energy to residential water heaters offsetting up to 70 percent of the households' water heating bills. In the last ten years, residential solar water heating systems have declined from over 300 installations per year to fewer than 100 installations per year. They make up a very small portion of Oregon's annual direct use energy total and are not represented in available energy production data.

Geothermal Energy:

More than 2,000 thermal wells and springs deliver direct heat to buildings, communities, and other facilities in Oregon.

Direct use geothermal energy uses hot water or steam from reservoirs below the earth's surface piped to end users for water or space heating.[11] Oregon produced 2.8 trillion Btu of geothermal energy in 2018 and 1.3 trillion Btu of it was consumed as a direct use fuel.[12,13] For decades, the city of Klamath Falls has used geothermal heat sources to heat buildings, residences, pools, and even sidewalks. Schools and hospitals in Lakeview use a geothermal well system to heat some buildings.

Other examples of direct use of geothermal heat in the state include drying agricultural products, aquaculture (raising fish), heating greenhouses, and heating swimming pools. There are more than 2,000 thermal wells and springs delivering direct heat to buildings, communities, and other facilities in Oregon.[14]

Biomass Wood Pellets and Charcoal Briquettes:

Oregon produced 66.5 trillion Btu of wood energy in 2018.[15] Residual material or waste from forest harvest and mill operations is converted into useful retail products. Wood pellets are manufactured from timber waste and used for residential and commercial heating. Charcoal briquettes and cooking pellets use timber waste to create a fuel source for cooking. Oregon manufacturers convert timber waste that would typically go into a landfill into these retail fuel sources for space heating and cooking. Wood waste is also burned in the manufacturing process as the products are heated up to remove moisture. Springfield, Oregon is home to one of Kingsford's manufacturing plants and is one of the largest charcoal briquettes plants in the western United States.[16] These wood waste derived products are biomass energy sources; biomass energy is energy from plants and plant-derived materials. Wood is the largest biomass energy resource in Oregon.[17] Oregon has 15 woody biomass power facilities, primarily in the wood-products industry.[18]

Energy Jobs: Springfield, Oregon is home to one of the largest charcoal briquette plants in the western U.S.

Learn more about direct use fuels in the Technology Review, Energy 101, and Policy Brief sections of this report.

Production

Transportation Fuels

Oregon's transportation sector consumed 316 trillion Btu of energy in 2018.[1] Two percent of transportation fuel used in Oregon was produced in the state in 2018. Oregon produces 37 percent of the biofuels the transportation sector uses, and biofuels make up 6 percent of Oregon's consumption of transportation fuels. In-state production of transportation fuels is in the generation of ethanol and biodiesel.

Electricity is also a growing source of transportation fuel, Oregon consumed 0.42 trillion Btu of electricity in 2018 or about 0.13% of total transportation consumption. An estimated 0.20 trillion Btu of electricity comes from Oregon-generated electricity.[2,3,4]

5%

Biodiesel blend is used in nearly all heavy-duty vehicles both on and off the highway.

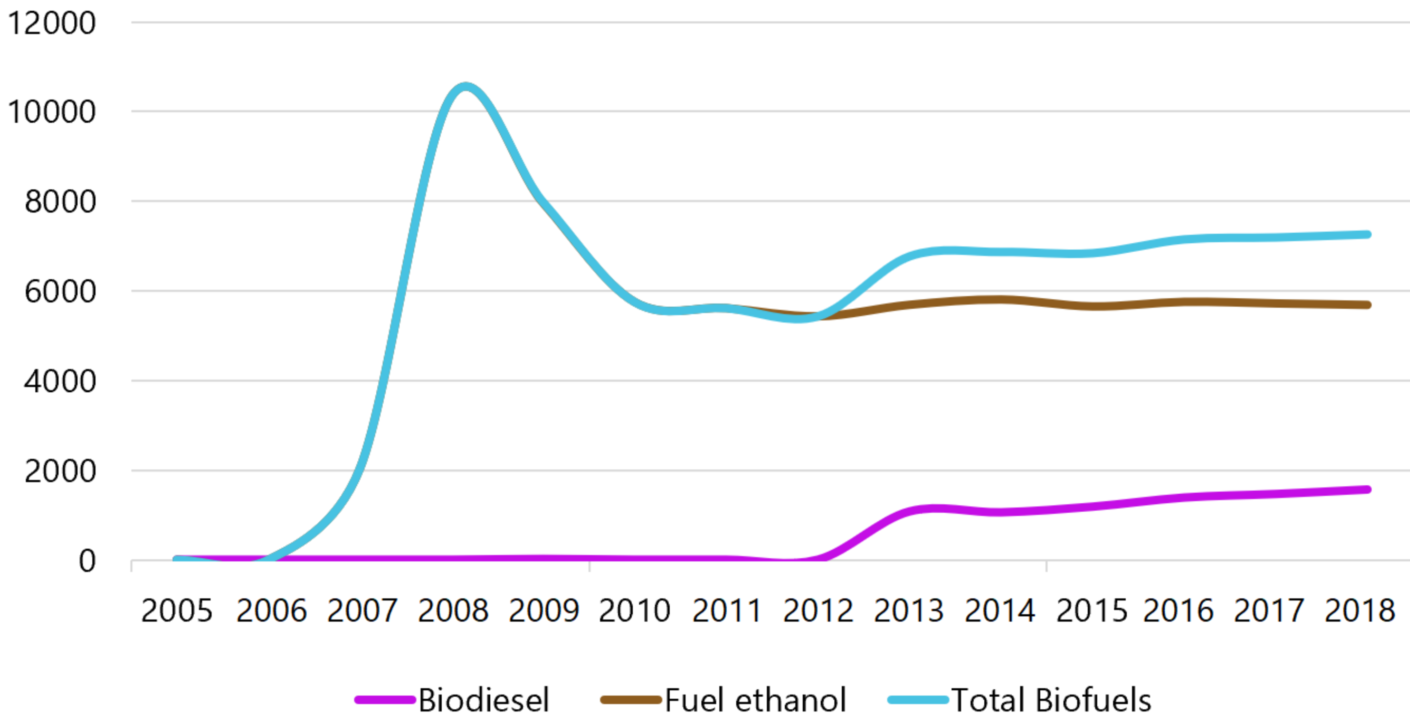
10%

Ethanol blend fuel is used in a majority of light-duty vehicles in Oregon.

Production & Consumption of Transportation Fuels in 2018 (trillion Btu)

Resource	Consumption in Oregon	Oregon Production	Imported	% of Consumption Produced in Oregon
Biodiesel	6.18	1.6	4.61	25%
Fuel Ethanol	13.31	5.7	7.62	43%
Gasoline	178.24	0	178.24	0%
Diesel	76.12	0	76.12	0%
Jet Fuel	28.57	0	28.57	0%
Asphalt & Road Oil	9.9	0	9.9	0%
Lubricants	1.8	0	1.8	0%
Aviation Gasoline	0.61	0	0.61	0%
Electricity (gge)	0.42	0.2	0.22	48%
LPG/Propane	0.27	0	0.27	0%
Compressed Natural Gas	0.21	0	0.21	0%
Bio-CNG	0.17	0	0.17	0%
Renewable Diesel	0.15	0	0.15	0%
LNG (Landfill)	0.05	0	0.05	0%
Totals	**316**	**7.3**	**308.7**	**2%**

Transportation Energy Production in Oregon, 2005-2018 (billion Btu)[5]



Ethanol

Oregon began producing fuel ethanol in 2007, and had its largest production year in 2008 with 10.3 trillion Btu of energy created. In 2018, Oregon produced 5.7 trillion Btu of ethanol.[6] Oregon has one commercial ethanol producer — the Columbia Pacific Ethanol production plant in Boardman — and it is the largest transportation fuel producer in the state. Carbon dioxide emissions from the plant are captured and used by the food and beverage industry, turning emissions into a beverage-grade liquid used to carbonate soft drinks and make dry ice.[7]

Biodiesel

The U.S. Energy Information Administration began tracking Oregon biodiesel production in 2013. In 2018, Oregon produced 1.6 trillion Btu of biodiesel. SeQuential Pacific Biodiesel is the second largest producer of transportation fuels in Oregon, and produces biodiesel from used cooking oil from local restaurants and businesses.[8] About 85 percent of the fuel SeQuential produces is sold in -state as part of a biodiesel blend, while the remainder is exported to regional neighbors Washington, California, Hawaii, and British Columbia.[9]

Renewable Natural Gas

This emerging biofuel that captures methane from waste streams has potential to displace some transportation fuels in Oregon.

Learn more about transportation fuels in the Technology Review, Energy 101, and Policy Brief sections of this report.

Energy Facility Siting in Oregon

Oregon's Energy Facility Siting Council is a governor-appointed body that oversees the siting of energy facilities in the state, and is staffed by the Oregon Department of Energy. The types and sizes of energy projects subject to EFSC jurisdiction have changed over time. While the bulk of applications have been for electric generation projects, EFSC has also reviewed site certificate applications for electrical energy transmission, pipelines, nuclear research reactors, ethanol production, liquified natural gas storage, and many others. More recently, EFSC has reviewed battery storage as part of other energy projects, even though battery storage is not by itself state jurisdictional.

EFSC also has ongoing responsibility for approved sites, including monitoring projects going into construction and operation, and reviewing site certificate amendment requests.

49

Total number of site certificates issued by EFSC — **37** are still valid.

18.5 Gigawatts

Capacity of EFSC-approved electricity facilities. Nearly **4.8 GW** is renewable.

2.5 Gigawatts

Capacity of renewable electricity generation under review or approved to begin construction.

"Site certificate" — under ORS 469.300(26) — means the binding agreement between the State of Oregon and the applicant, authorizing the applicant to construct and operate a facility on an approved site, incorporating all conditions imposed by the council on the applicant.

Renewable Electricity EFSC Projects Summary (Megawatts)

Status	Wind	Solar	Geothermal	Hydro	Total MW
Active					
Operational	2,220	-	-	-	2,220
In Construction	894	-	-	-	894
Approved	200	777	-	-	977
Under Review	350	1,223	-	-	1,573
Subtotal	**3,664**	**2,000**	**-**	**-**	**5,664**
Inactive					
Approval Expired	640	-	35	-	675
Decommissioned	-	-	-	-	-
Denied	-	-	-	80	80
Withdrawn	2,445	-	180	200	2,825
Subtotal	**3,085**	**-**	**215**	**280**	**3,580**
Total MW	**6,749**	**2,000**	**215**	**280**	**9,244**

Non-Renewable Electricity EFSC Projects Summary (Megawatts)

Status	Coal	Nuclear	Natural Gas	Other*	Total MW
Active					
Operational	550**	-	3,237	51	3,838
In Construction	-	-	415	-	415
Approved	-	-	-	-	-
Under Review	-	-	-	-	-
Subtotal	**550**	**-**	**3,652**	**51**	**4,253**
Inactive					
Approval Expired	109	5,040	3,221	38	8,408
Decommissioned	-	1,130	-	-	1,130
Denied	-	-	-	-	-
Withdrawn	431	-	5,147	109	5,687
Subtotal	**540**	**6,170**	**8,368**	**147**	**15,225**
Total MW	**1,090**	**6,170**	**12,020**	**198**	**19,478**

**Other includes waste steam cogeneration, mill waste cogeneration, and biomass.*
***This is the Boardman Coal Plant, which ceased operation in October 2020.*

Non-Electricity Generation EFSC Projects Summary (Number) — Part 1

Status	Research Reactors & ISFSI*	Electric Transmission Line	Natural Gas Storage	Liquefied NG Storage	Total Projects
Active					
Operational	3	1	1	-	5
Under Review	-	2**	-	-	2
Subtotal	**3**	**3**	**1**	**-**	**7**
Inactive					
Withdrawn	-	1	-	2	3
Subtotal	**-**	**1**	**-**	**2**	**3**
Total MW	**3**	**4**	**1**	**2**	**10**

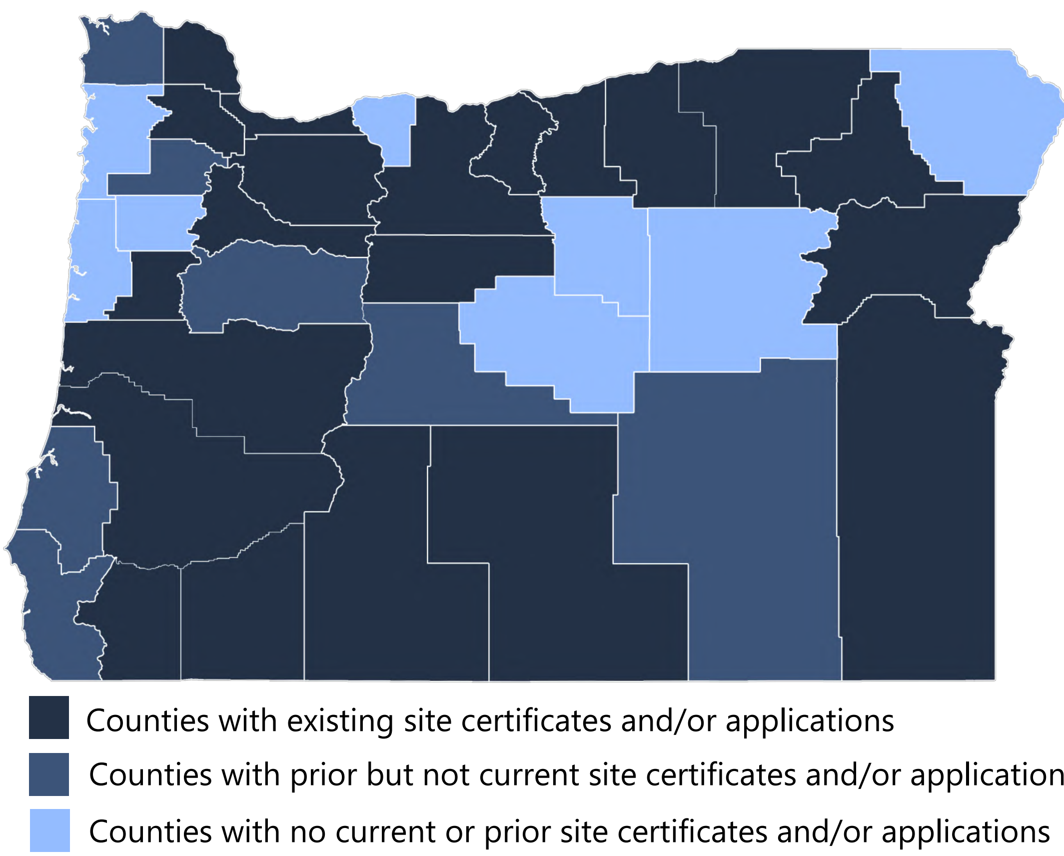
**Portland General Electric's Independent Spent Fuel Storage Installation Facility at decommissioned Trojan Power Plant.*
***One of these is an amendment to the existing in-service Eugene to Medford 500 kV transmission line.*

Non-Electricity Generation EFSC Projects Summary (Number) — Part 2

Status	Natural Gas Pipeline	Ethanol Production	Total Projects
Active			
Operational	2	1	3
Under Review	-	-	0
Subtotal	**2**	**1**	**3**
Inactive			
Withdrawn	-	1	1
Subtotal	**-**	**1**	**1**
Total MW	**2**	**2**	**4**

Total Projects (Parts 1 and 2)	**14**

Oregon Counties with State Jurisdictional Energy Projects



More information on Oregon's state-jurisdictional energy projects is available online:

tinyurl.com/EFSC-projects

Energy Costs & Economy

What We Spend

Oregon spent $11.7 billion on energy in 2016 – the lowest amount since 2005. In 2018, Oregon spent $14.2 billion, with increases each year since 2016.[1] This includes electricity and fuel for homes and businesses, industrial energy uses, and petroleum used in the transportation sector. Transportation accounts for more than half of our state's energy expenditures and sees the largest swings in price. The variability in what we spend on energy is driven primarily by transportation fuel costs. Oregonians send about $5.4 billion of our transportation dollars each year to other states and countries where extraction, processing, and refining of transportation fuels occurs.

$14.2 billion

Oregonians spent on energy in 2018.[1]

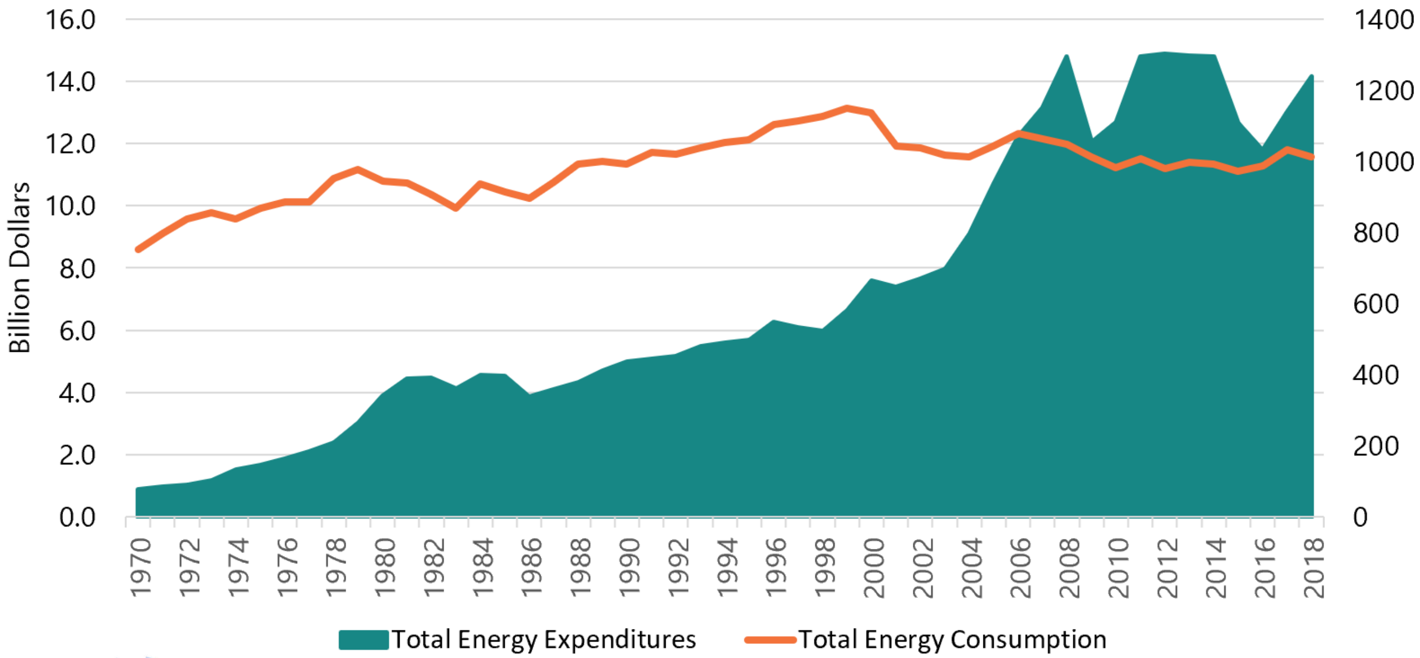
8.85 cents

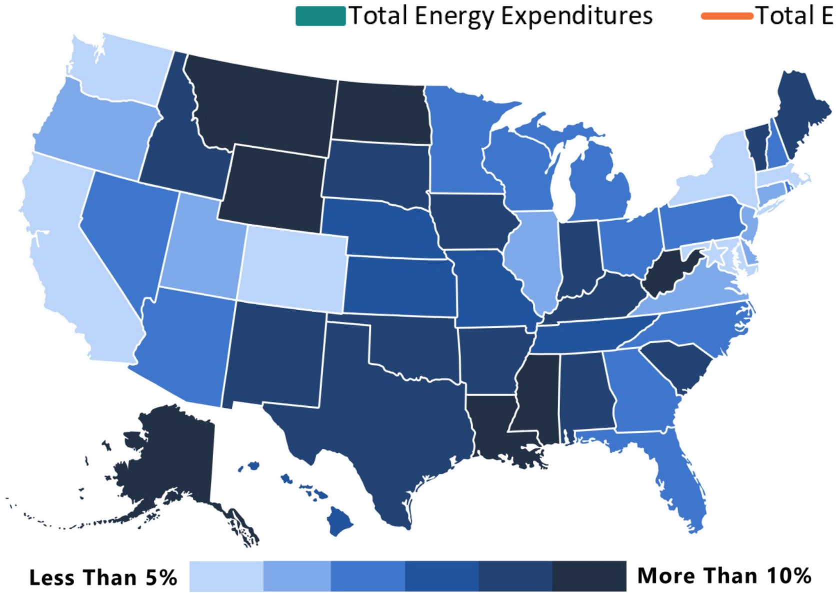
Oregon's average retail price per kilowatt hour of electricity in 2018.[2]

5.9%

Percentage of Oregon's GDP spent on energy in 2018.[1]

Oregon's Total Energy Expenditures vs. Total Energy Consumption[1]



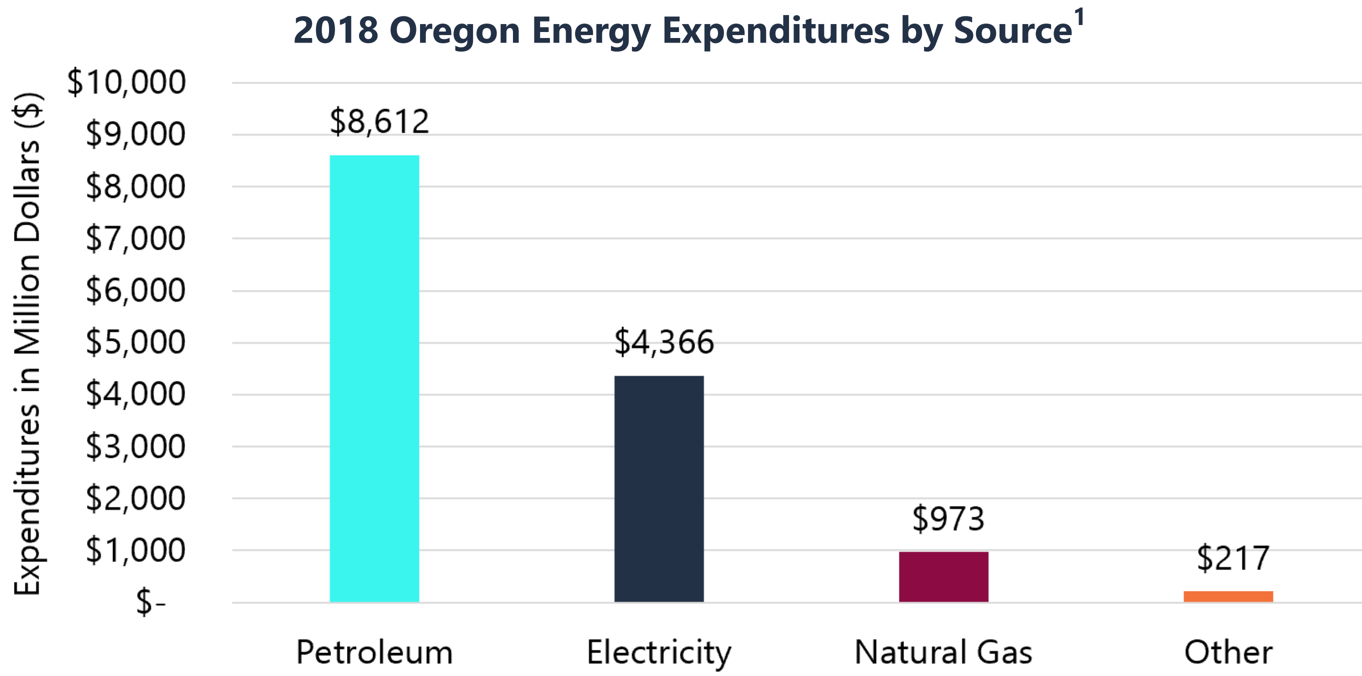


State Total Energy Expenditures as a Percentage of State Gross Domestic Product (2018)[1]

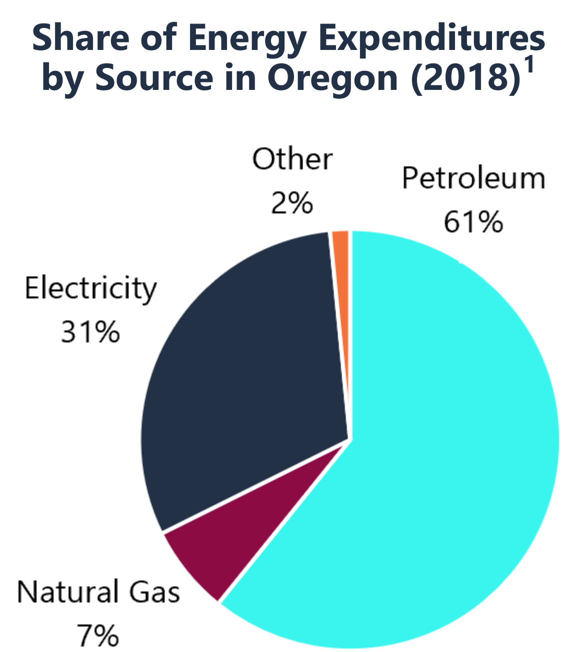
Energy Costs & Economy

Oregon Energy Expenditures by Source

Oregon's energy expenditures of $14.2 billion can be divided among three main source categories; electricity, direct use of natural gas, and petroleum products.[1] A small portion of Oregon's energy expenditures do not fall into the three main categories. These include industrial, commercial, and residential expenditures on other energy sources for uses other than electricity generation. In Oregon, these sources include wood, waste, and some coal.



The petroleum products category is dominated by transportation fuels. Transportation fuels account for $7,667 million in expenditures and include some natural gas and electricity expenditures. As shown in the sector-based comparison later in this section, transportation energy use is the largest portion of Oregon's overall energy use.



The price of electricity has remained consistent due, in large part, to Oregon's vast hydroelectric resources.[2] Natural gas makes up a smaller portion of the expenditures and therefore its price variability has less effect on Oregon's overall expenditures. Petroleum products, however, experience a high level of price volatility with impacts from global market pressures as well as from more localized taxes and storage and distribution costs. Increased cost per unit of energy in petroleum products in 2018 gives the petroleum category an outsized portion of the annual energy expenditures.

Energy Costs & Economy

Energy Burden

Home energy burden is the percent of household income spent on home energy bills. Energy bills include electricity, natural gas, and other home heating fuels, and are compared to the total income of the people in that household. If a household is spending greater than 6 percent of their income on home energy costs, they are considered burdened.[4] The energy affordability gap is the difference between a household's actual energy costs and an "affordable" energy burden level equal to six percent of the household's income. With so many low-income Oregonians facing significant energy burden, Oregon's energy affordability gap is estimated to be over $289 million per year, or eight times the federal funding Oregon receives for energy assistance.[5] For more information on energy burden, see the Energy 101 section of this report.

3x

Nationally, low-income households spend three times more of their income on energy costs compared to the median spending of non low-income households.[1]

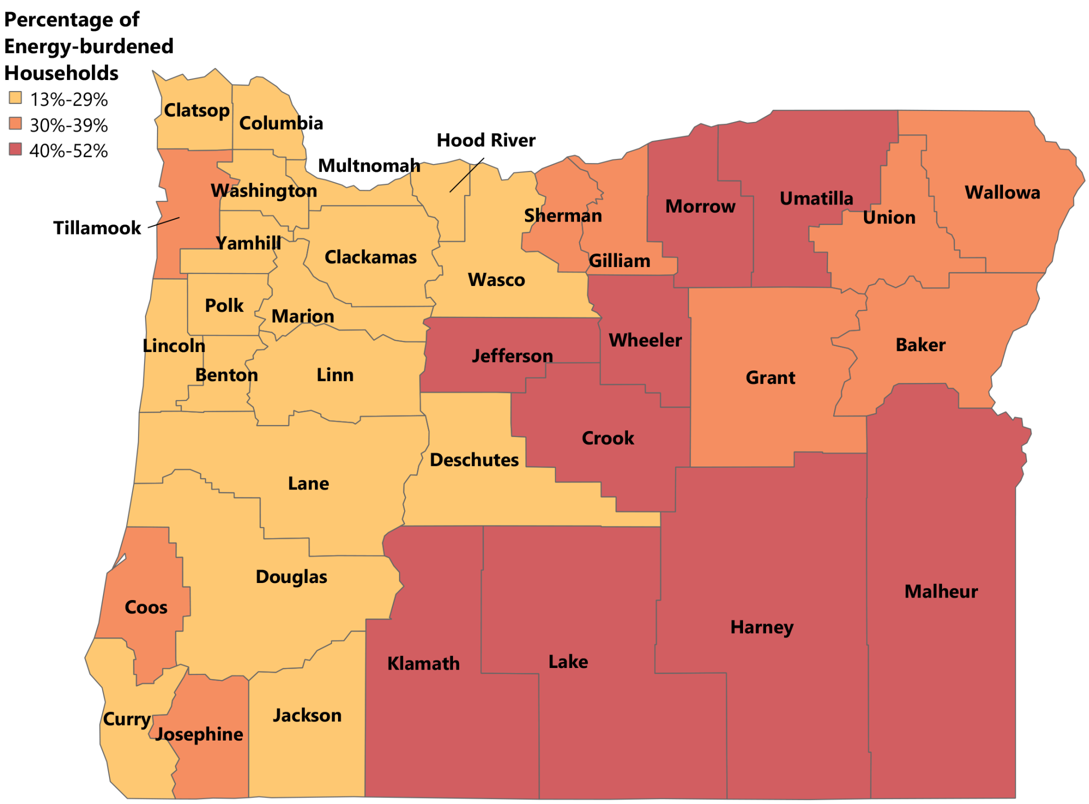
391,263

Number of Oregon households that were energy burdened in 2019.[2]

25%

Percentage of all Oregon households that were energy burdened in 2019.[3]

Percentage of Oregon Households Considered Energy Burdened and Earning 200 Percent or Below Federal Poverty Level by County[6]



Transportation burden represents the total annual transportation costs of households in comparison to income of the household.[7] Home and transportation energy burdens are combined to discuss the whole energy burden of a household — and both are important indicators of affordability for Oregonians.

Below are three cities in Oregon with different median incomes and remaining income after housing and transportation costs. Please note low-income households are not specifically identified in this tool shown. In Oregon there can be a significant mix of income levels in an area, so the tool may not accurately identify all low-income households. To learn more about the Housing + Transportation Affordability Index and look up your own town, please visit **htaindex.cnt.org/map/**

Portland, OR: Median Household Income $60,286

Average Housing + Transportation Costs % Income

Factoring in both housing *and* transportation costs provides a more comprehensive way of thinking about the cost of housing and true affordability.

Transportation Costs

In dispersed areas, people need to own more vehicles and rely upon driving them farther distances which also drives up the cost of living.

Baker City, OR: Median Household Income $41,098

Average Housing + Transportation Costs % Income

Factoring in both housing *and* transportation costs provides a more comprehensive way of thinking about the cost of housing and true affordability.

Transportation Costs

In dispersed areas, people need to own more vehicles and rely upon driving them farther distances which also drives up the cost of living.

Coos Bay, OR: Median Household Income $38,605

Average Housing + Transportation Costs % Income

Factoring in both housing *and* transportation costs provides a more comprehensive way of thinking about the cost of housing and true affordability.

Transportation Costs

In dispersed areas, people need to own more vehicles and rely upon driving them farther distances which also drives up the cost of living.

The Oregon Department of Transportation is developing public transportation solutions to increase the affordability of Oregon communities. Learn more about ODOT's innovative solutions in its Oregon Public Transportation Plan: **tinyurl.com/ODOT-OPTP**

Energy Costs & Economy

Energy Jobs

Oregonians hold a number of jobs in the energy industry — from energy utility workers to wind turbine technicians to solar installers.

Energy employment is often sorted into traditional energy, energy efficiency, and motor vehicles jobs. In Oregon, most energy-industry employees work in energy efficiency, including high-efficiency and traditional HVAC, renewable heating and cooling firms, and others.

Dive in to more details about energy jobs in Oregon in the Energy 101 section of this report.

96,728

Number of Oregonians employed in the energy industry in 2019.[1]

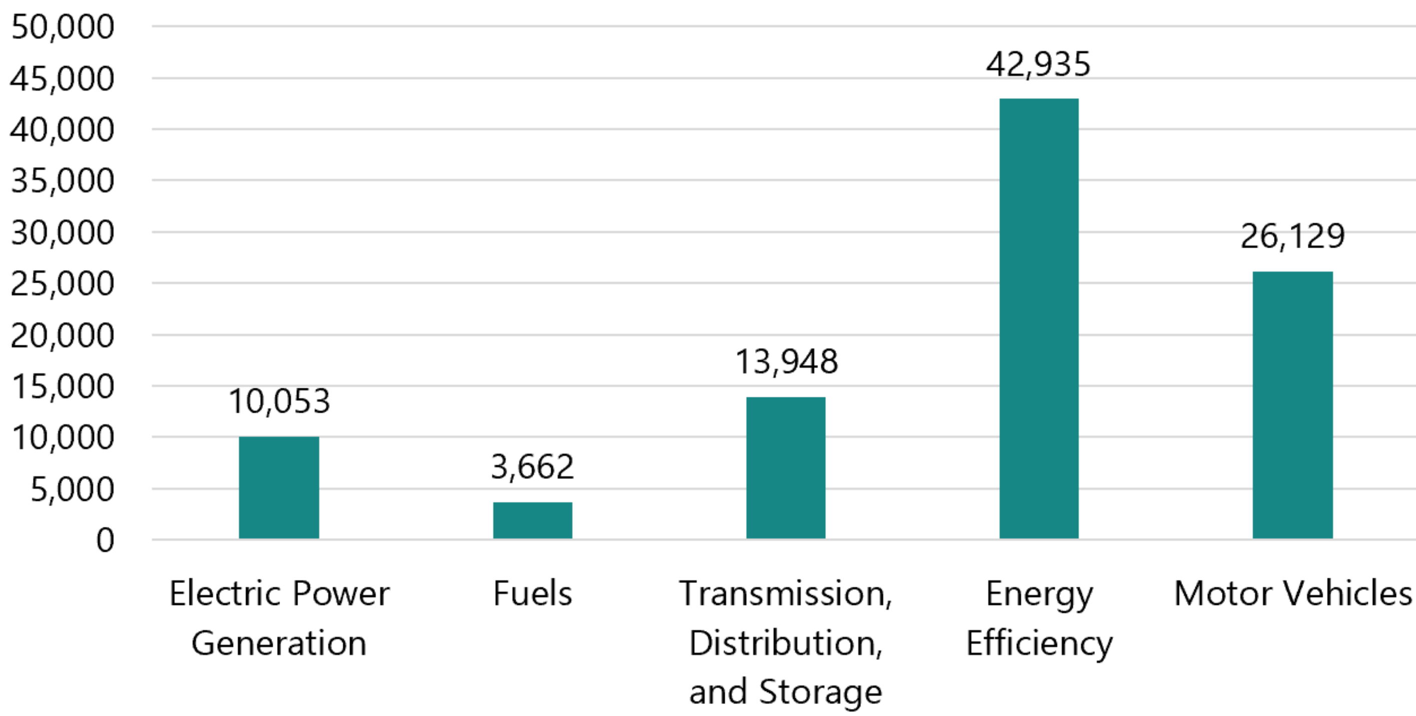
55,406

Number of clean energy jobs in Oregon in 2019.

3,200

Number of clean energy jobs added in July 2020 nationwide following the COVID-19 economic downturn in the early spring.

Number of Energy Jobs in Oregon by Type (2019)[1]



Nationally, 249,983 people work in the solar industry; Oregon makes up about 2.3 percent of those jobs, with 166 solar companies operating in the state. In 2019, 5,759 Oregonians worked on solar projects. The industry added 96 new solar jobs in Oregon in 2019, resulting in 2.6 percent job growth.[2]

Energy Efficiency

Oregon's Second Largest Resource

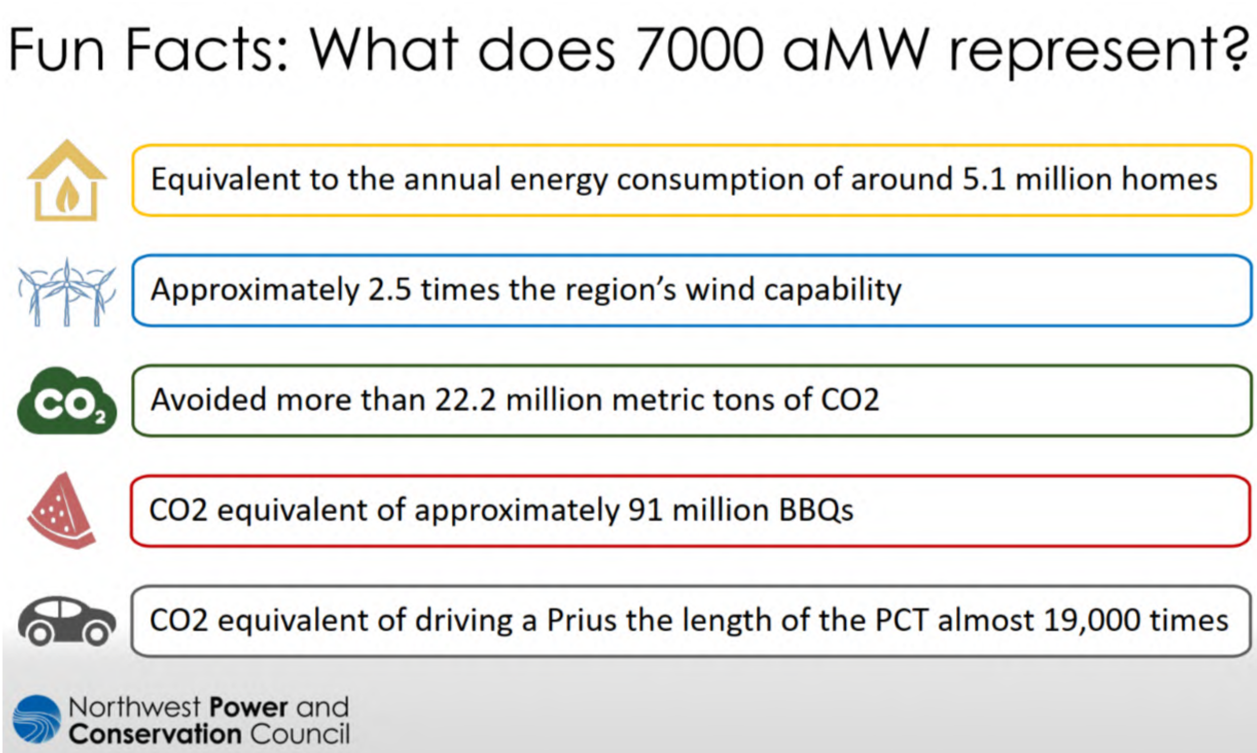
Energy efficiency plays a critical role in our state. It is the second largest resource in Oregon after hydropower, and Oregon has consistently met increased demand for electricity by implementing energy efficiency strategies. The Northwest Power & Conservation Council reports that since 1978, the Pacific Northwest has produced about 7,000 average megawatts (aMW) of savings through efficiency programs and improvements.[1] That's more electricity than the whole state of Oregon uses in a year.

9th

Oregon's 2019 rank among U.S. states for energy efficiency by the American Council for an Energy Efficient Economy.[2]

13

Years in a row that Oregon has landed in the top 10 most energy efficient states.[2]



Over the past decade, Oregon reduced per capita energy use despite our state population growing, and energy efficiency is one reason why. Oregon's gains in energy efficiency have been helped by federal appliance standards, state policies and programs, natural gas and electric utility programs, Energy Trust of Oregon utility programs, and other nongovernmental organizations. For the region's cumulative savings, 60 percent comes from utility and Bonneville Power Administration programs. Energy efficiency gains are cumulative and continue paying dividends for our region over time.

Learn more about energy efficiency in the Energy 101 section of this report.

Energy Efficiency

Oregon Electricity Savings

The Northwest Power & Conservation Council's Seventh Power Plan, published in 2016, concludes that cost-effective efficiency can meet a large amount of new load growth in the region – allowing Oregon to grow without needing significant new electricity resources. The plan calls on the region to develop new energy efficiency programs equivalent to acquiring 4,300 average megawatts of power by 2035. Integrated Resource Plans from Oregon's large electric utilities also identify energy efficiency as a key strategy they will use to meet demand over their planning horizon.

The Regional Conservation Progress Report to the Northwest Power and Conservation Council in September 2020, however, demonstrates that there is significant cost-effective energy efficiency in the electric sector still available, but that regional energy efficiency in the electric sector is on a downward trend – this means that each subsequent year of the Plan will deliver fewer savings.

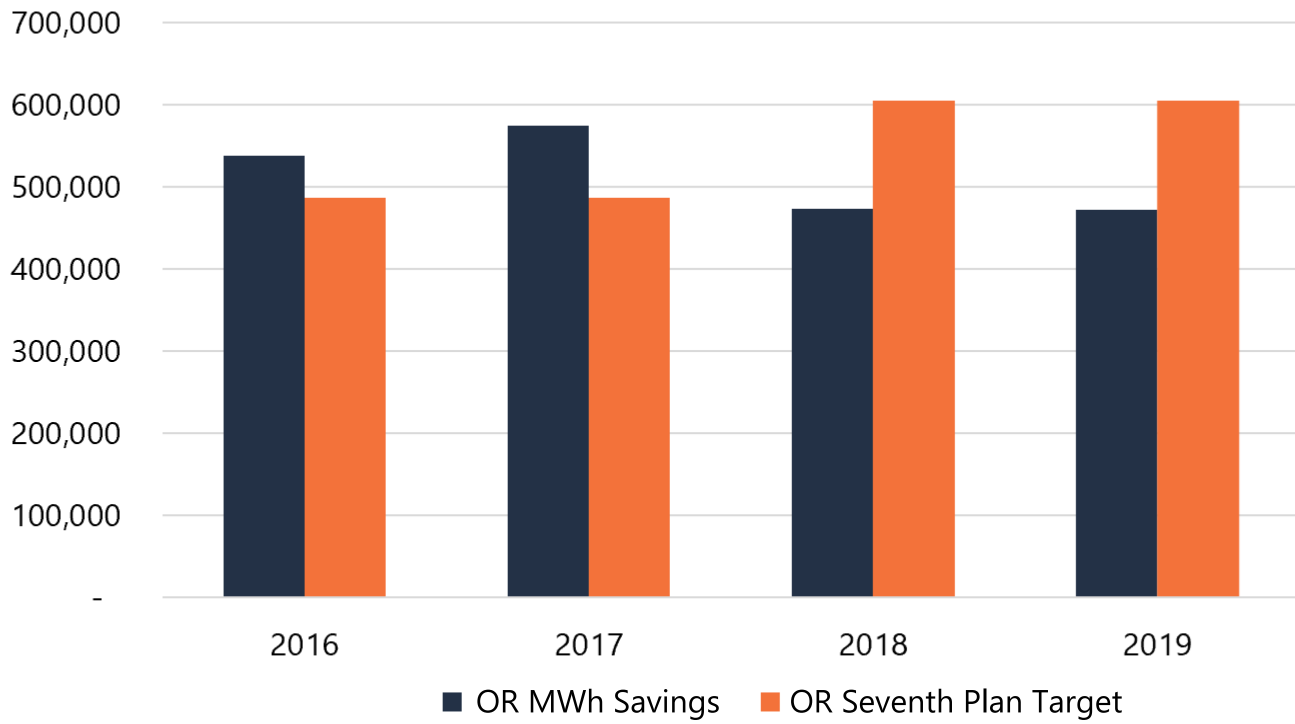
7,000

Average megawatts of regional electricity savings from energy efficiency (1978-2019).

2,200

Average megawatts of Oregon electricity savings from energy efficiency (1978-2019).

Oregon Electricity Savings and Estimated Share of the Seventh Power Plan Goal



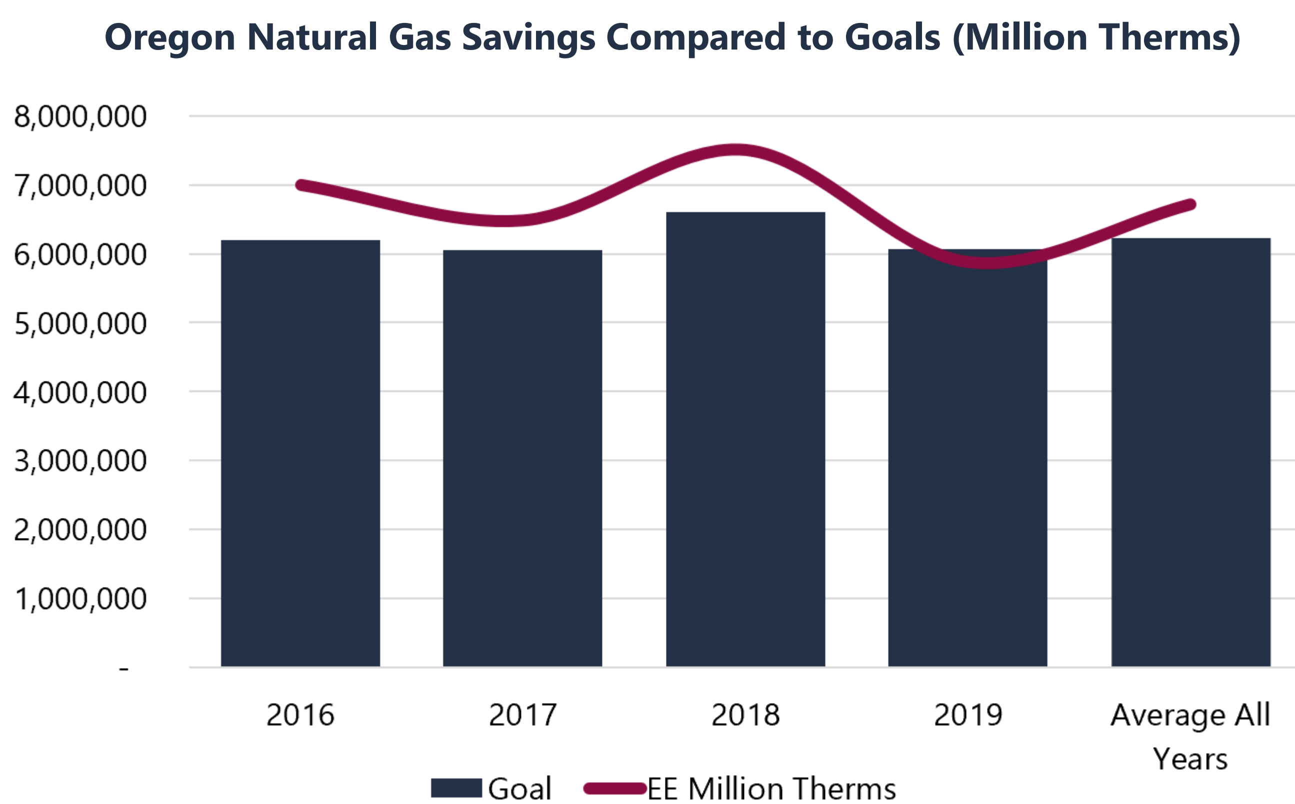
The savings in the chart above are a sum of reported savings by utility, Bonneville Power Administration, and Energy Trust of Oregon programs.

Energy Efficiency

Oregon Natural Gas Savings

Natural gas goals are developed in each utility's Integrated Resource Plan submitted to the Oregon Public Utility Commission. Natural Gas utilities' savings exceeded goals from 2016-2018 with a slight decline in 2019.[3] Energy Trust of Oregon implements energy efficiency programs for natural gas utilities. Programs are funded by customer rates, and cost effectiveness tests of natural gas measures assures that efficiency investments cost less than building new natural gas resources.

For more about cost-effectiveness, see Chapter 6 of the *2018 Biennial Energy Report.*



Integrated Resource Planning

From the Oregon Public Utility Commission's website:

Oregon was one of the first states to require utilities to file integrated resource plans (IRPs). The IRP presents a utility's current plan to meet the future energy and capacity needs of its customers through a "least-cost, least-risk" combination of energy generation and demand reduction. The plan includes estimates of those future energy needs, analysis of the resources available to meet those needs, and the activities required to secure those resources. What began thirty years ago as a simple report by each utility has grown into a large, stakeholder-driven process that results in a comprehensive and strategic document that drives utility investments, programs, and activities.

Learn more: **www.oregon.gov/puc/utilities/Pages/Energy-Planning.aspx**

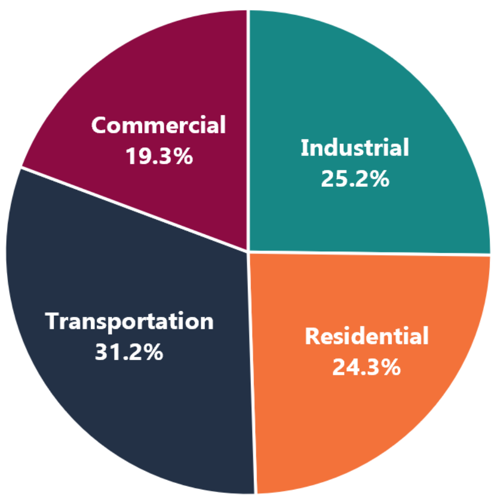
Energy End Use Sectors

Consumption

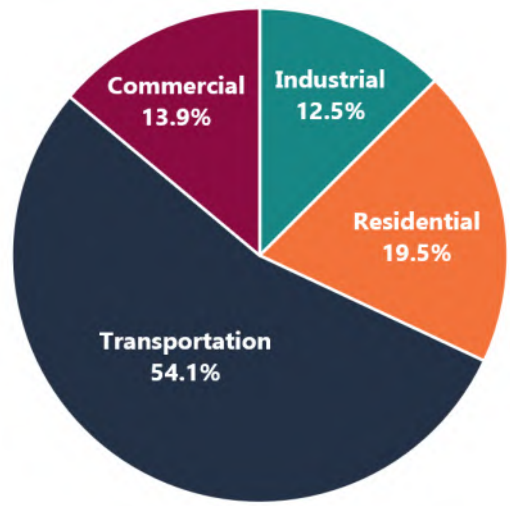
As noted early in this section, energy metrics are commonly divided into four end-use sectors: residential, commercial, industrial, and transportation.

Consumption and cost of energy varies across the sectors. In 2018, transportation accounted for 31 percent of energy consumption and 54 percent of expenditures due to higher per-unit cost of transportation fuels. The industrial sector used a quarter of the total energy but accounted for only 12 percent of expenditures due to cheaper per unit costs relative to the other sectors.[1]

Oregon Consumption by End-Use Sector (2018)

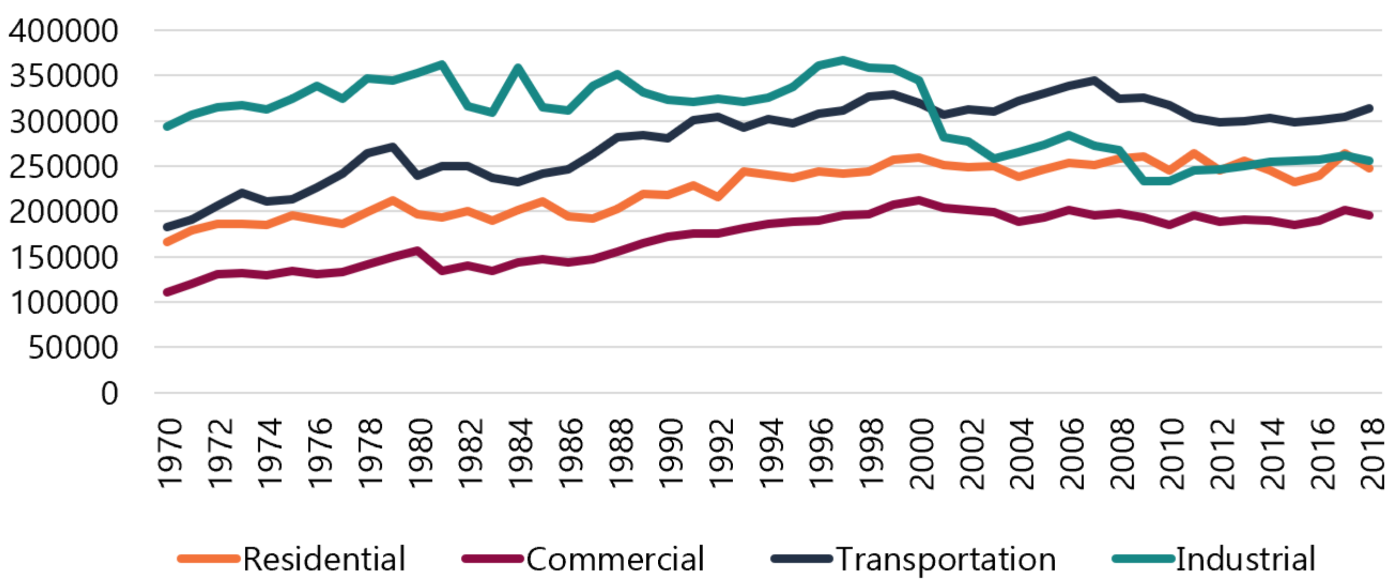


Oregon Expenditures by End-Use Sector (2018)



Energy consumption in the industrial sector dropped significantly in the late 1990s, largely related to Oregon aluminum smelters closing. Energy consumption across all sectors has remained relatively steady in recent years. Increased population, GDP, and vehicle miles traveled, which all increase energy use, have been offset by efficiency gains and a shift toward less energy intensive industries.

Oregon Consumption by Sector Over Time (Billion Btu)[2]



Energy End Use Sectors

Expenditures

Oregonians' 2018 energy expenditures can be separated by sector. While the transportation sector represents 31 percent of energy consumption, it accounts for more than half of expenditures due to the much higher per-unit cost of transportation fuels. Because nearly all our transportation fuel is imported, most of this money goes out of state.

While Oregon's residential, commercial, and industrial sectors have experienced gradual increases in spending, transportation sector expenditures reflect both increasing consumption and price volatility in the transportation fuels market.

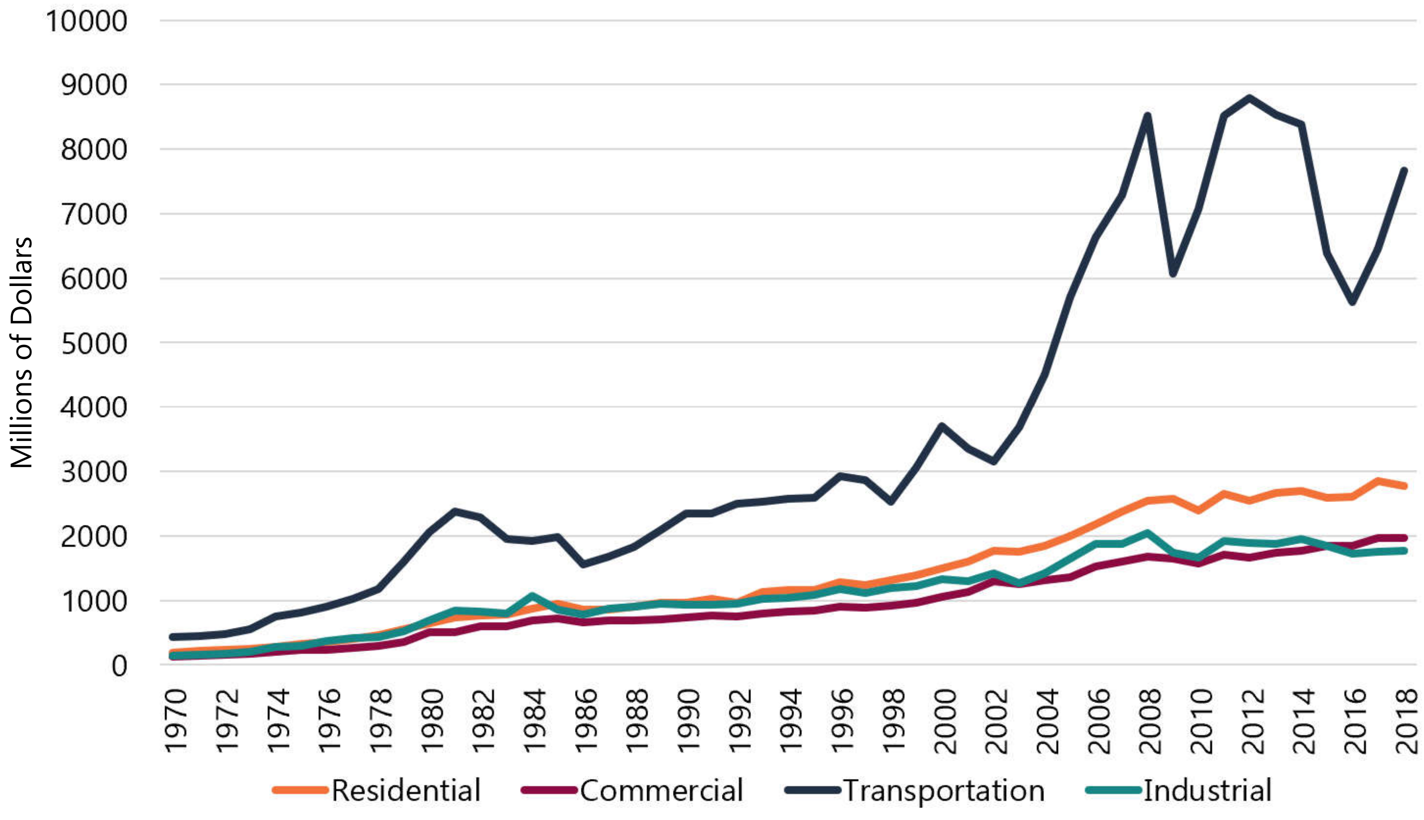
$3,388

Per capita (per person) energy expenditures in Oregon in 2018.[3]

43rd

Oregon's rank in the U.S. for per capita energy expenditures.[3]

Oregon's Total Energy Expenditures by Sector Over Time[4]



The U.S. EIA reports prices in current dollars per million Btu and expenditures in current dollars — the chart is not adjusted for inflation.
Learn more: https://www.eia.gov/state/seds/

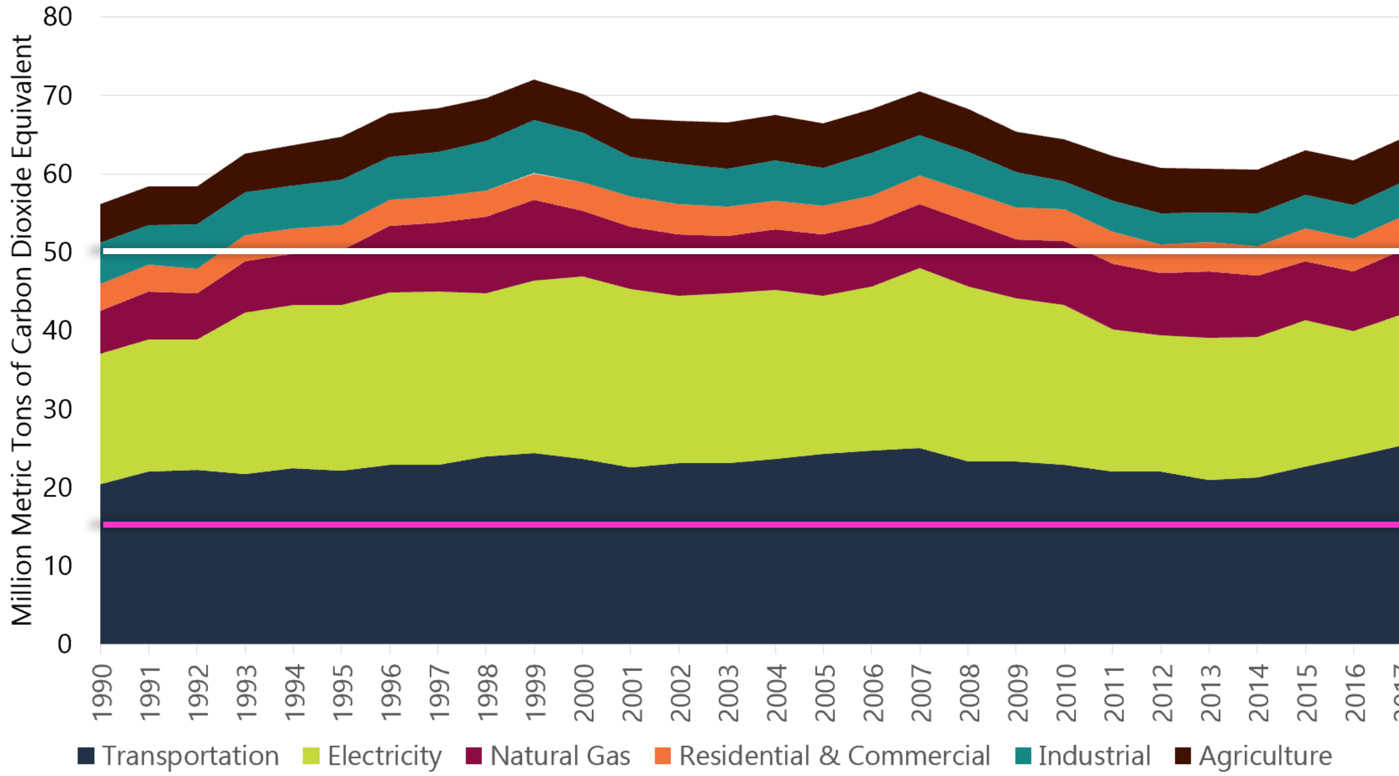
Learn more about Oregon's changing transportation sector in the Energy 101 and Policy Briefs sections of this report. Hint: alternative fuels are often less expensive both for the fuels themselves and associated vehicle maintenance.

Energy End Use Sectors

Greenhouse Gas Emissions

Greenhouse gas emissions can be categorized in multiple ways, by the productive use that creates emissions, by the sector that use falls within, and by the source of the emissions. Most of Oregon's GHG emissions come from the energy we use every day. The data presented here is based on the Oregon Department of Environmental Quality's GHG emissions inventory. When analyzing the data, various methods of categorization can reveal new insights.

Oregon Greenhouse Gas Emissions by Source Over Time[5]



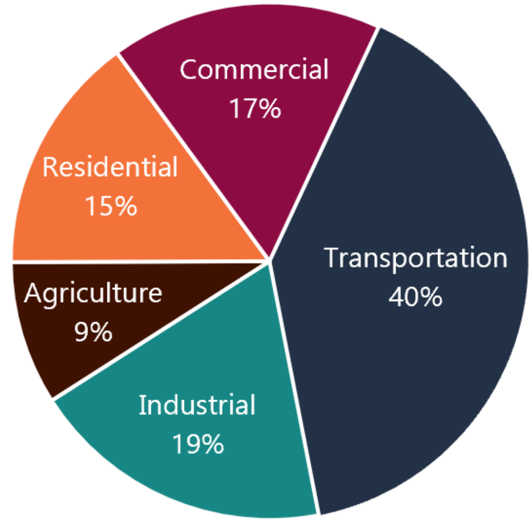
The values for Electricity and Natural Gas above include use for each of the end use sectors: Agriculture, Industrial, and Residential & Commercial. The GHG effects of each sector are lower because that use is accounted for in the Natural Gas and Electricity Use values. Electricity emissions increased from 1990 through about 2007, and has seen a steady decline in the last 10 years. The Agricultural, Industrial, Residential & Commercial, and Natural Gas areas in the chart remain at relatively consistent thickness over the recent 20-year period. Transportation emissions have grown as a share of Oregon's statewide total GHG emissions. Transportation went from 35 percent of the statewide total in 2014 to 40 percent in 2017, while electricity use emissions decreased from 30 percent to 26 percent. All other sectors stayed relatively constant over the same period. While total transportation emissions have fluctuated over the years, GHG emissions per vehicle have gone down thanks to improved fuel efficiency.[6]

The target year for Oregon to reduce GHG emissions by 75 percent below 1990 levels is 2050. This goal is shown as a pink line on the chart. There is also an interim goal to reduce emissions by 10 percent below 1990 levels by 2020, shown in white.

Energy End Use Sectors

GHG Emissions by Sector

Greenhouse Gas Emissions by Sector (2017)[5]



Earlier in this Biennial Energy Report, data is broken out into four sectors — transportation, residential, commercial, and industrial. For greenhouse gas emissions, data is also broken out for the agricultural sector (which is typically included in industrial).

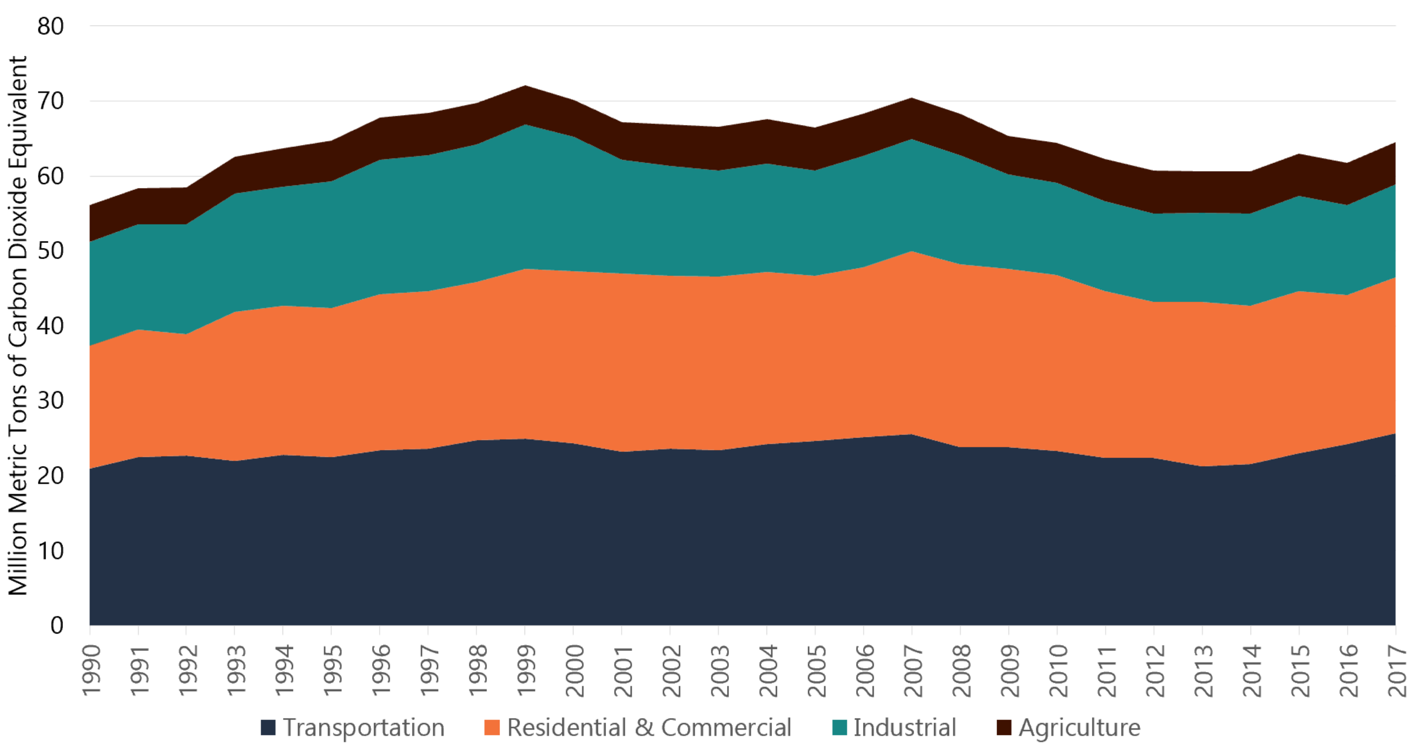
Agriculture GHGs. Primarily from waste streams like methane and nitrogen-based fertilizers for soil management. This sector is distinct because emissions primarily come from methane and nitrous oxide, versus carbon dioxide.

Industrial GHGs. In addition to emissions from electricity generation and natural gas direct use, GHG emissions in the industrial sector come primarily from non-transportation petroleum combustion, industrial waste and wastewater, and manufacturing.

Commercial & Residential GHGs. In addition to emissions from electricity generation and natural gas direct use, GHG emissions in this sector stem primarily from fuel oil for heating and emissions from waste and wastewater.

Transportation GHGs. The state's largest single source of GHG emissions, primarily from direct combustion of petroleum products, including emissions from on- and off-highway vehicles (like vehicles used in the industrial, agricultural or commercial sectors). Of the emissions generated, about 62 percent are from passenger cars and trucks, while about 27 percent are from heavy-duty vehicles.[6]

Oregon Greenhouse Gas Emissions by Sector Over Time[5]



Energy End Use Sectors

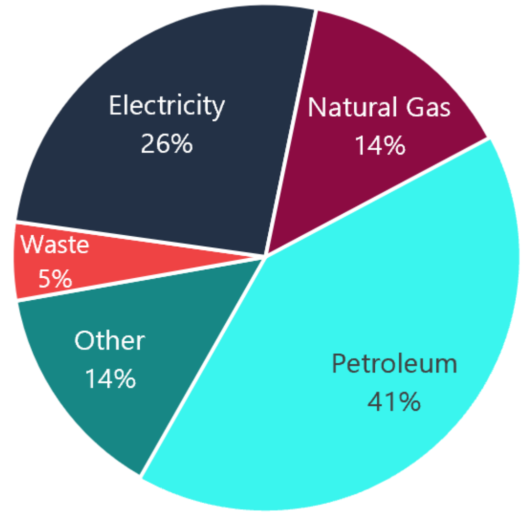
GHG Emissions by Resource

Greenhouse gas data can also be shown by resource, which shows that petroleum products are the largest source of emissions. This correlates to transportation representing the largest sector source of Oregon's GHG emissions.

Petroleum. This represents transportation fuels including diesel, gasoline, propane for on- and off-highway use, equipment use, and jet fuels.

Electricity. This accounts for electricity used in all sectors, which is down from 30 percent in 2015 and includes emissions associated with generation of electricity used in the state, regardless of where it is generated. Emissions from electricity generated in Oregon but used out of state are not included.

Greenhouse Gas Emissions by Resource (2017)[5]

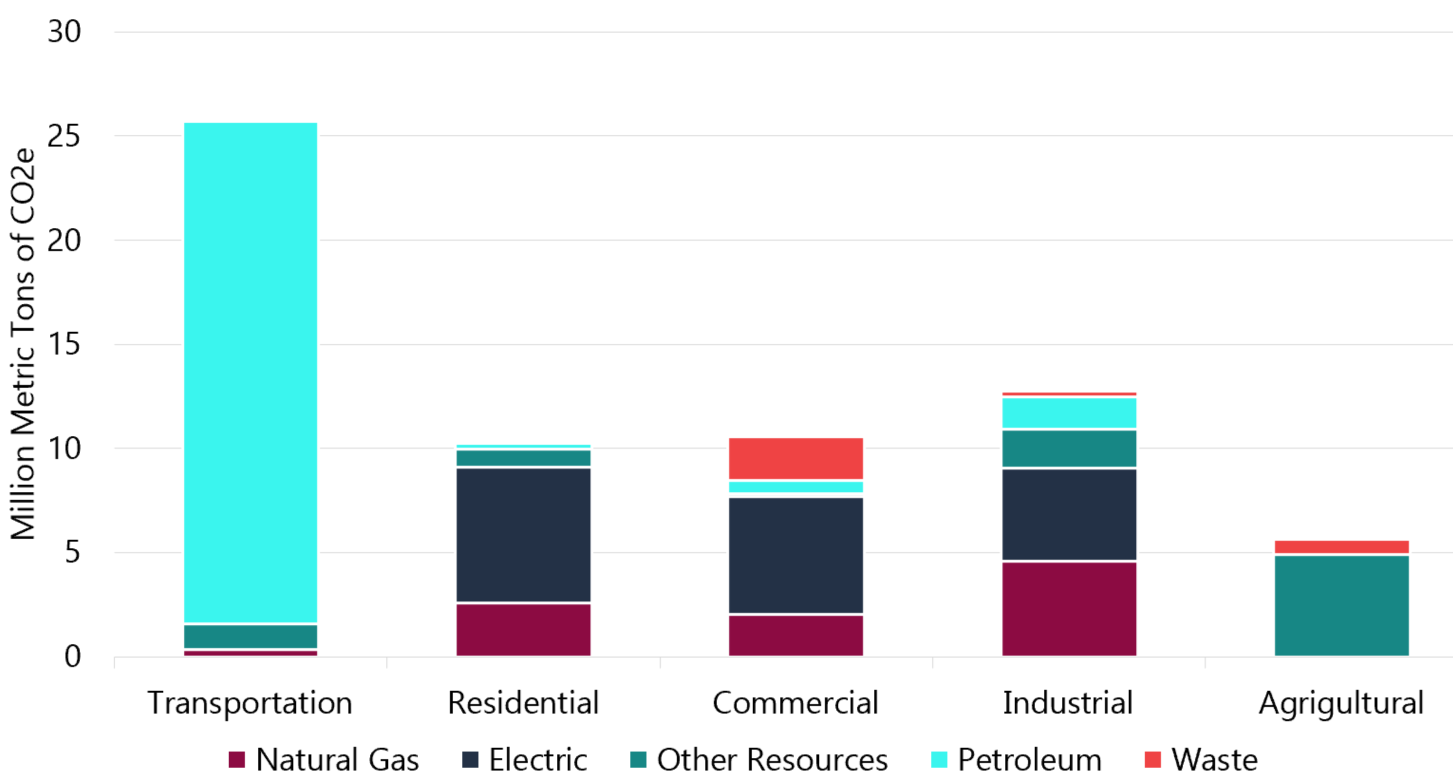


Natural Gas. Direct use of natural gas in all sectors, plus fugitive emissions from distribution. It does not include emissions associated with natural gas-fired power plants.

Other. This category includes uses specific to a sector's activity, such as fertilizer, cement and soda ash production and consumption, semiconductor manufacturing, use of refrigerants and solvents, etc.

Waste. Treatment of waste products from the various sectors including landfill waste and agricultural waste. Some of these emissions result from the combustion of waste.

Oregon Greenhouse Gas Emissions by Sector and Resource (2017)[5]

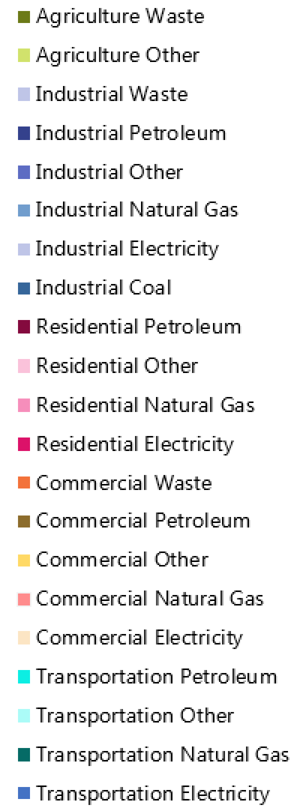


Energy End Use Sectors

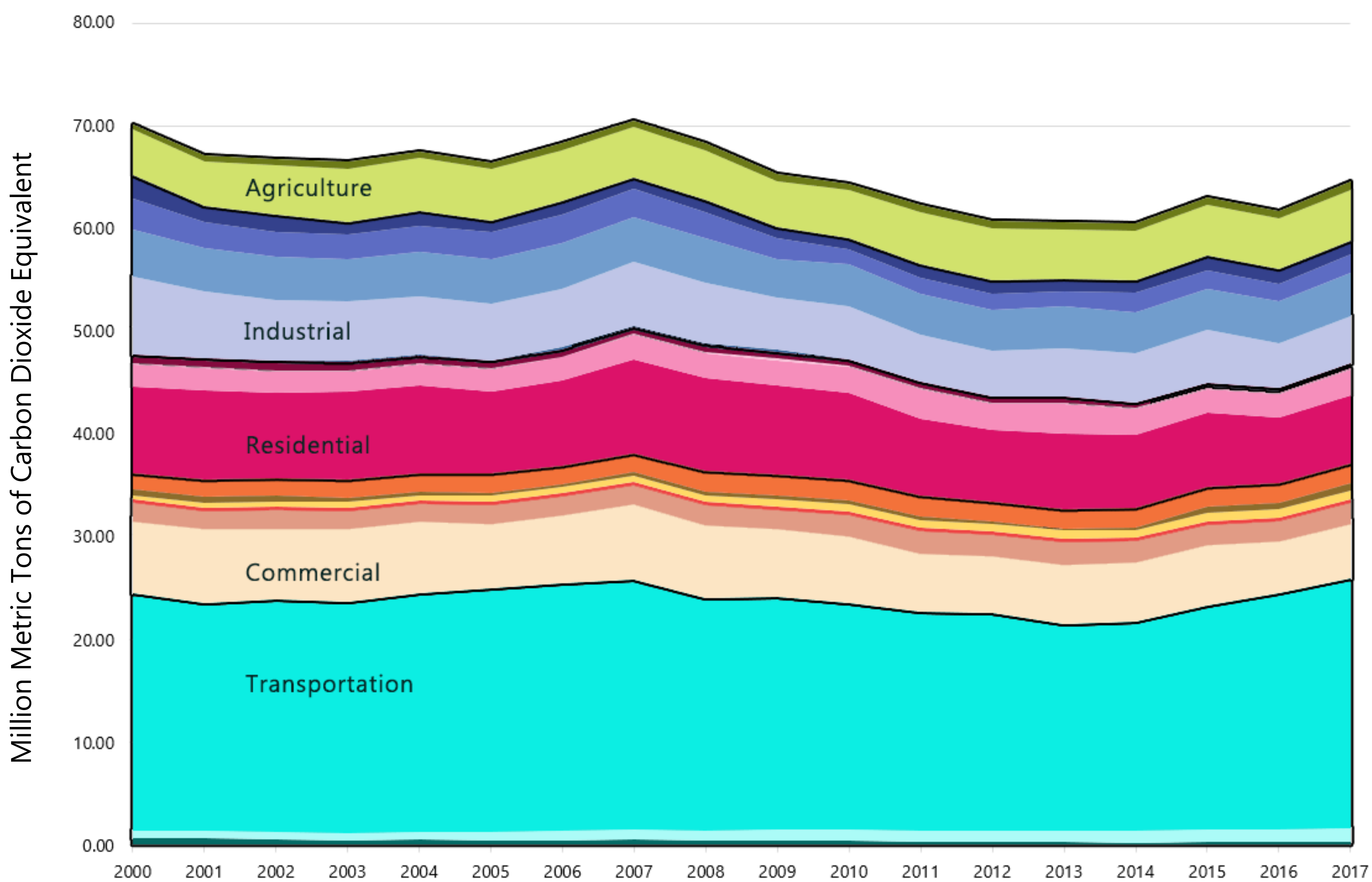
GHG Emissions by Resource

Viewing this data over time results in a complex chart that shows the variety of emission sources. This level of analysis can help policy makers identify the types of emissions and sectors to target in order to meet emission reduction goals.

Using the legend at right, data is grouped by sector, and then similar shaded colors within those sectors identify the sources. For example, petroleum is the largest source within the transportation sector. In the commercial, residential, and industrial sectors, electricity is the largest resource.



Oregon Greenhouse Gas Emissions by Sector and Resource Over Time (2017)[5]



Sector Profiles

Residential

24.3%

Residential sector's share of Oregon's energy use.

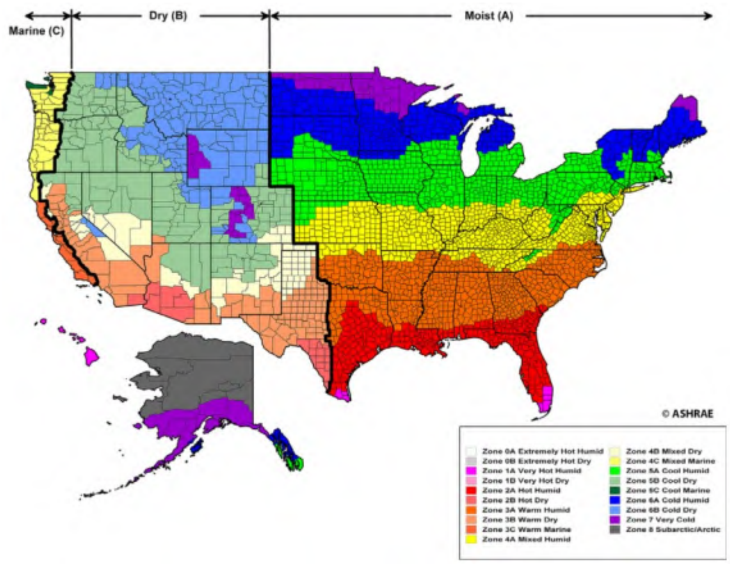
1.6 Million

Number of housing units in Oregon. (2018)[1]

The residential sector consists of living quarters for private households. Common uses of energy associated with this sector include space heating, water heating, air conditioning, lighting, refrigeration, cooking, and appliances. Residential energy use is closely tied to weather, housing vintage (decade a home is built), and type of housing.

Weather

Oregon is divided by two climate zones with different energy needs and weather patterns. The map to the right from The American Society of Heating, Refrigerating and Air-Conditioning Engineers demonstrates the climates zones in the U.S.[2] In Oregon, west of the Cascade mountain range is a temperate mixed marine climate zone in yellow. East of the Cascade mountain range in green, is a cool dry climate with more heating and cooling days, requiring more heating and cooling energy use. Buildings in Eastern Oregon have a higher average energy use index, meaning they typically use more energy per square foot.



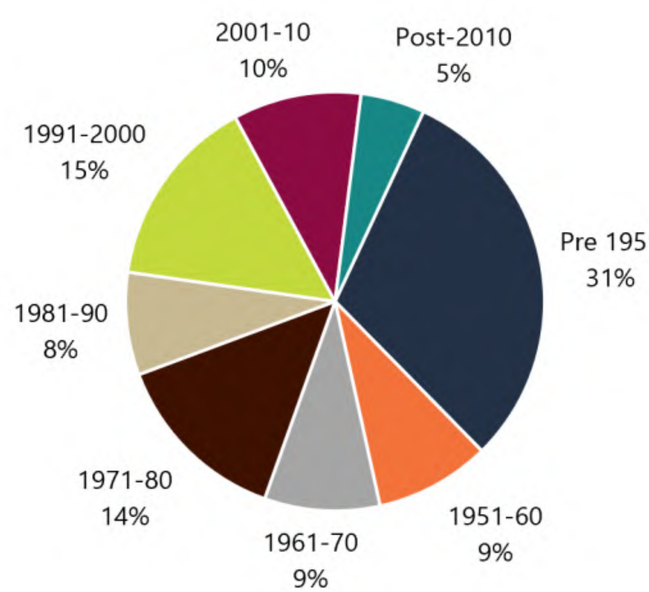
Vintage

The residential sector includes new construction and existing construction — and energy use is very different between them, especially when comparing a newly built home to a decades-old home. Oregon's residential energy code has made significant performance increases since Oregon's first energy code in 1974.

Older homes with less insulation and older equipment use more energy for heating and cooling than newer, more efficient homes. Home vintage can indicate opportunities for updating heating and cooling equipment, water heating, insulation, windows, and house weatherization.[3]

About 71 percent of all homes are pre-1990.

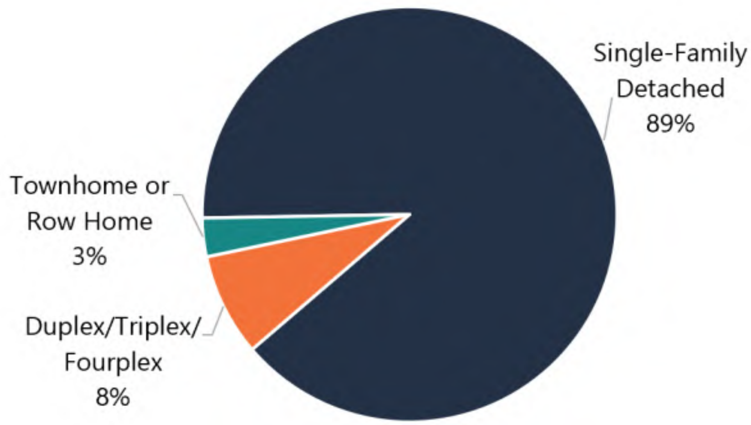
Oregon Homes by Vintage[4]



Type of Housing

Single-family detached homes comprise more than 80 percent of Oregon's single-family housing stock. Attached homes can use less energy for heating and cooling because they have less surface area exposed to the elements.

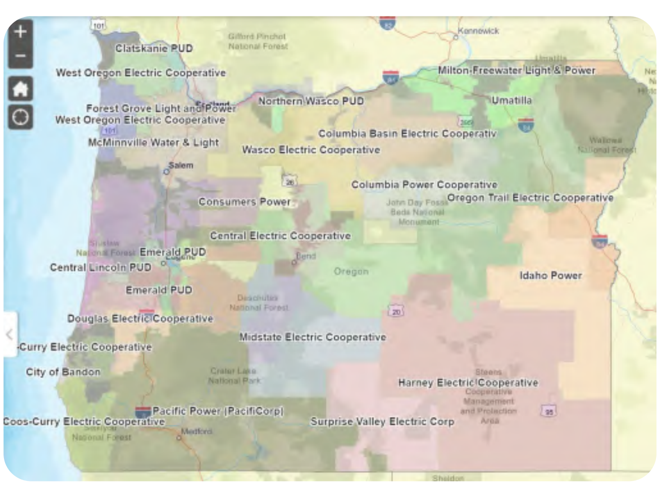
Oregon Housing Types[4]



Ownership and Vintage

Another way to look at housing stock in Oregon is by ownership and vintage across the region. Oregon's northwest region has the largest number of housing units, as well as the highest percentage of rental units. The distribution also shows most housing units were built prior to year 2000, with half being built prior to 1980. Ownership is not necessarily a factor in energy use, but it can affect investment in retrofits that can reduce energy costs of older homes.[4]

Region	Total Occupied Housing Units	Share of Units That Are Rental Properties	Share of Units That Are Pre-1980 Homes	Share of Units That Are Pre-2000 Homes
East Oregon	209,655	35%	49%	78%
NW Oregon	1,176,679	39%	55%	83%
SW Oregon	205,501	35%	53%	82%
All of Oregon	1,591,835	38%	54%	82%



Looking for your local utility? Use the Oregon Department of Energy's online lookup tool:
www.tinyurl.com/FindYourUtility

Residential Energy Efficiency

Oregon's energy efficiency programs and policies save residential customers energy and money while increasing household comfort. If average residential energy consumption per person remained constant at 1990 levels, total energy consumption would have been 26 percent higher — about 1,600 average megawatts — according to the Northwest Power and Conservation Council. Regional annual residential per capita electricity use in 2015 was about 1,000 kilowatt-hours per year lower than in 1990, a 20 percent reduction.[6]

There is room for improvement when it comes to energy saving opportunities for homes. The Northwest Power and Conservation Council's 2019 Annual Regional Conservation Progress Report lays out these opportunities:

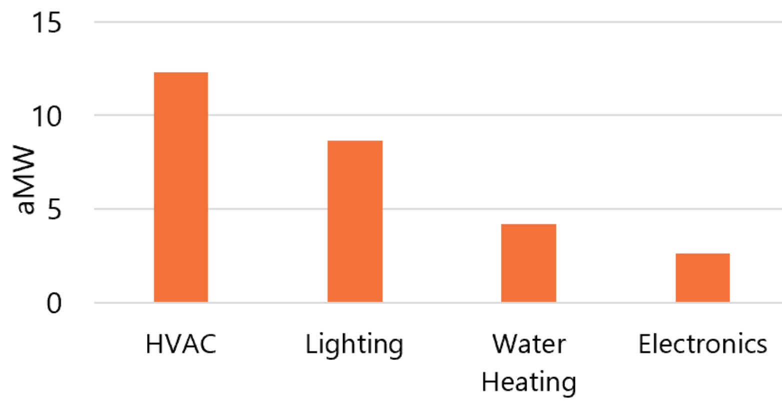
Lighting. 42 percent of Oregon homes have converted to Compact Fluorescents or LED lighting — more than half retain older, less efficient lighting.[8]

Heating, Ventilation and Air Conditioning. 57 percent of homes in the region have furnaces. Upgrading an electric furnace to a heat pump can cut heating electricity use in half.[8]

Electronics. Homes have a lot of electronic devices, and most of them are plugged in all the time. Simple controls that turn off equipment when nobody is in the room can significantly reduce energy use.[8]

Water Heating. Just 2 percent of homes in the region have upgraded to a heat pump water heater. A heat pump water heater can reduce the electricity used to heat water by half or better.[7 8]

Oregon Residential Savings Potential (aMW)
NWPCC Seventh Power Plan



The chart at right shows savings potential in average megawatts if the options above were adopted. A typical Oregon home uses about 12,000 kwh each year. These savings projections are equal to the electricity use of more than 20,000 homes.[6]

Trends in Single Family Housing[8]

- LEDs have increased from less than 1 percent six years ago to nearly a quarter of all installed bulbs.
- Connected lighting, bulbs that connect to home Wi-Fi, are found in 2 percent of homes.
- 7 percent of homes have smart thermostats.
- More homes are using gas equipment for primary heating, water heating, and cooking.
- More homes are using efficient heating and cooling equipment.
- Television technology has changed and improved in efficiency from an average power draw of 112 watts down to 83 watts.
- Tests reveal that homes on average are becoming tighter with less air leakage.

Residential Heating and Cooling

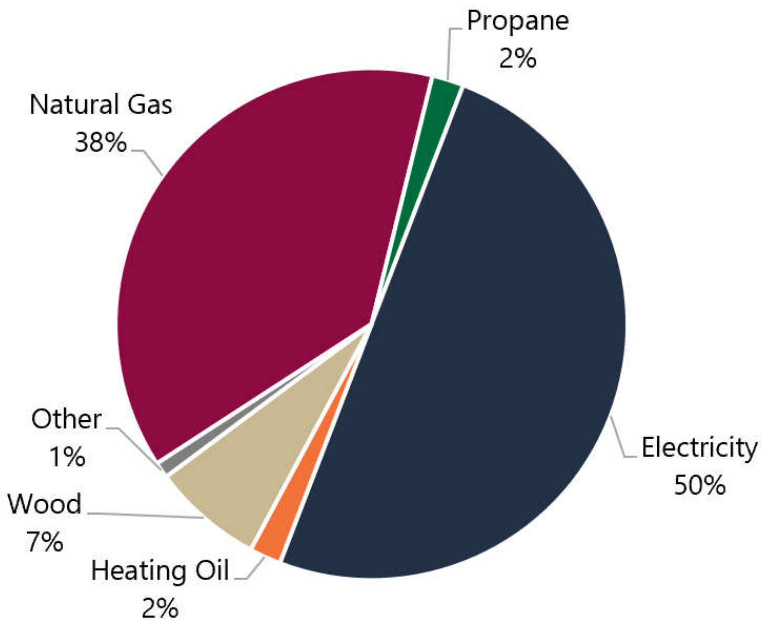
More than half of Oregon homes heat with electricity. Cooling types vary among Oregon homes, and the percentage of homes using air conditioning increased from 42 to 57 percent between 2012 and 2017.[9]

12,642 kWh

Average annual residential electricity use in Oregon in 2018.

673 therms

Average annual residential natural gas use in Oregon in 2018.

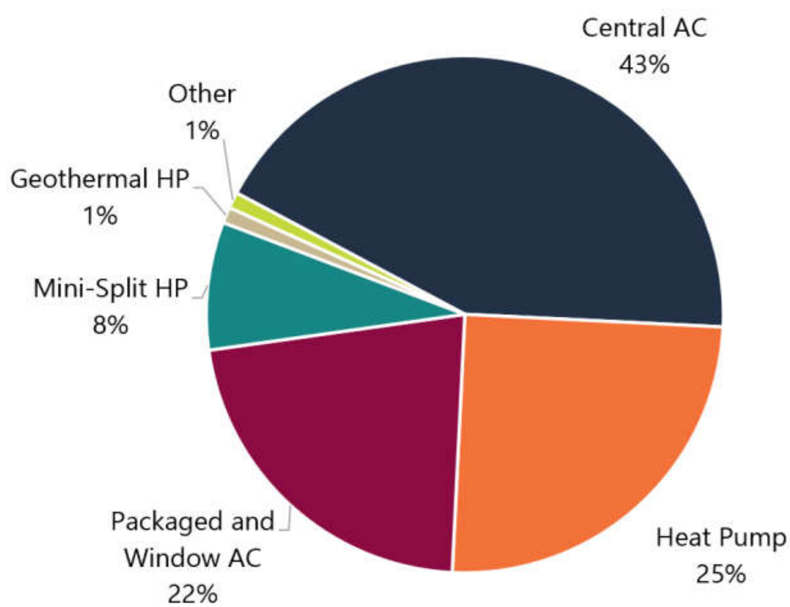


Average Heating Types Across Oregon Homes[9]

County Profiles

The web version of this report provides county-by-county energy information:

energyinfo.oregon.gov/ber



Average Cooling Types Across Oregon Homes[9]

Sector Profiles

Commercial

The commercial sector is diverse and includes buildings of various types and sizes, such as offices and businesses, government, schools and other public buildings, hospitals and care facilities, hotels, malls, warehouses, restaurants, and places of worship and public assembly. Total floor area of common commercial space types in our region is approximately 3.4 billion square feet, with an average annual growth of approximately 1.9 percent since 1990.[1] The commercial sector is distributed across buildings of various sizes, with buildings less than 5,000 square feet accounting for nearly as much total area as buildings greater than 100,000 square feet.[2]

19.3%

Commercial sector's share of Oregon's energy use.

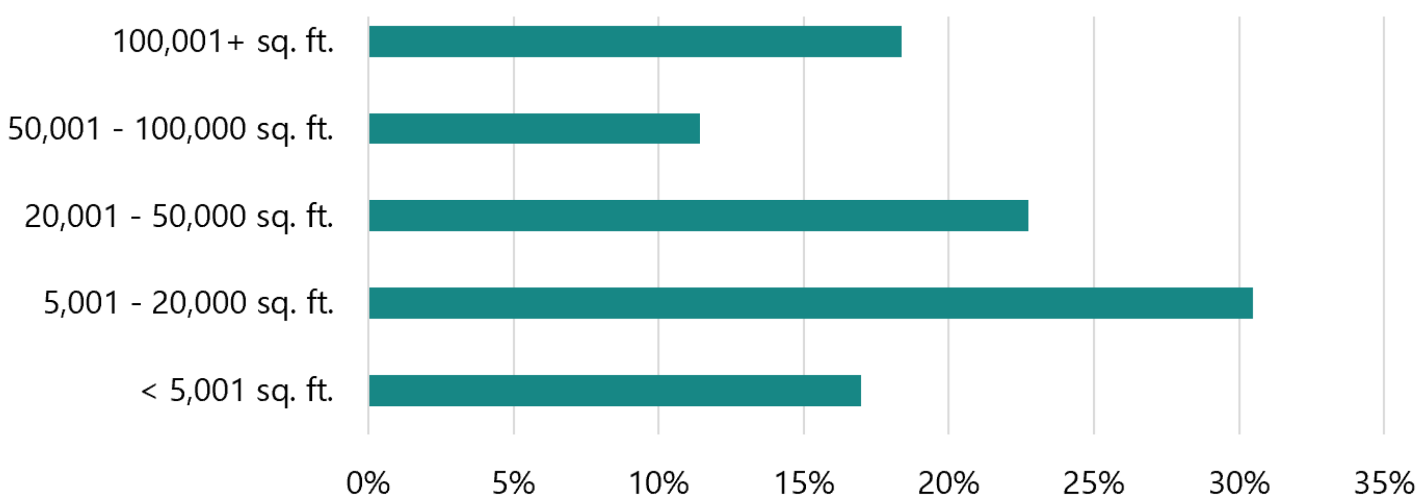
7.6%

Percentage reduction in energy use by the sector since 2000.[4]

64%

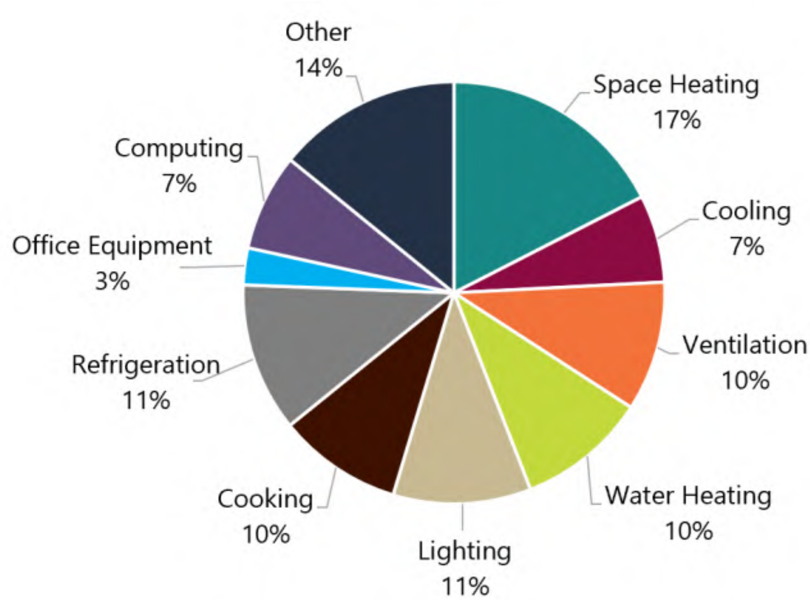
Percentage of northwest buildings that were built before 1990.[3]

Distribution of Regional Floor Space by Building Size in the Northwest



Regional Commercial Energy End Uses

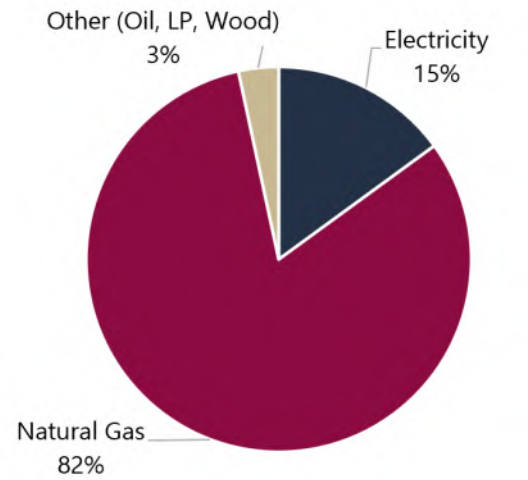
In our region, energy — from all sources, including electricity, natural gas, or other fuels — is used for HVAC, lighting, computing, and other commercial needs.[5]



Energy Use

Heating, cooling, and ventilation, which are responsible for the largest share of electricity and natural gas use in a commercial building, are provided through central systems, individual units, or a combination of both. The majority of commercial spaces in our region continue to use natural gas as a fuel source; however, recent studies suggest a shift toward a greater percentage of electrically heated spaces in new construction.[7] Over 95 percent of commercial buildings use electricity or natural gas for heating.

Oregon Commercial Building Primary Heating System Type[6]



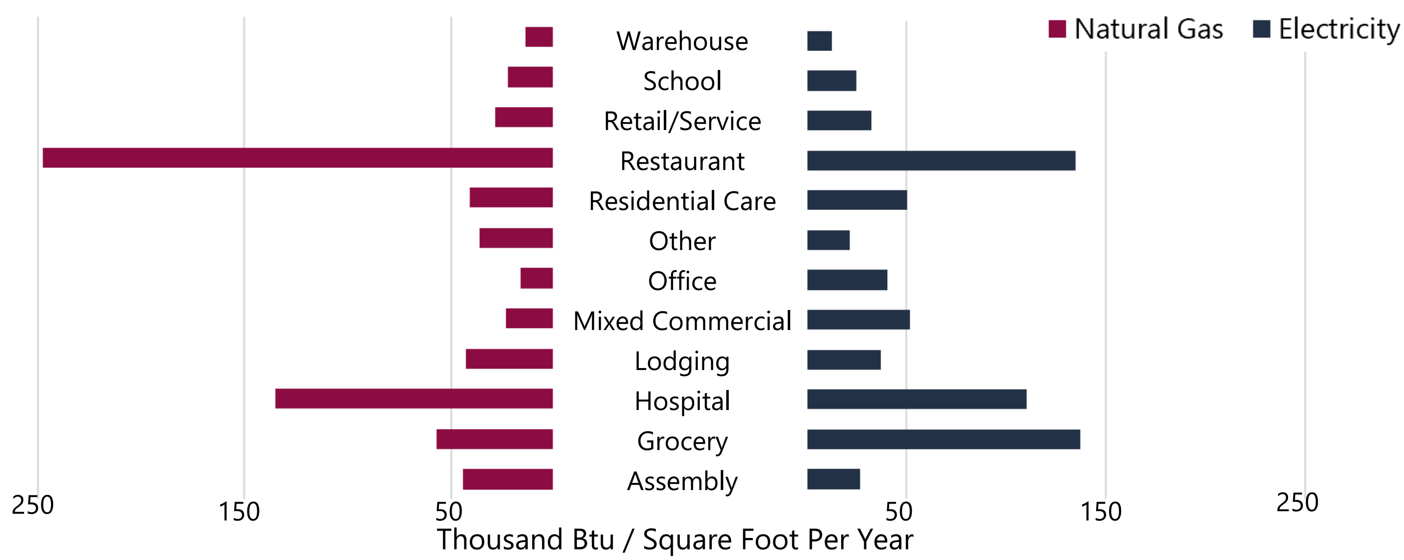
Lighting is the third largest share of energy use for commercial buildings. Efficiency and type of lighting are evolving as incandescent and fluorescent lighting is replaced with energy-efficient LEDs. Refrigeration and cooking use a lot of energy, with refrigeration accounting for about 18 percent of overall electricity use and cooking accounting for about 25 percent of natural gas use in commercial buildings in the Northwest.[8 9]

Energy Performance

Energy Performance is often measured by comparing a building's annual energy use to its size, and depends on a building's construction, equipment efficiency, operation, and location. This metric combines all energy consumption (like electricity and natural gas) into common units that are normalized to building area, and commonly uses units of kBtu per square foot per year. This is often referred to as a building's EUI, or Energy Use Intensity. In commercial buildings, floor space, the type of building, and its activities drive energy use.

Financial incentives, improved building code and appliance standards, and energy efficiency programs are helping commercial buildings improve energy performance. The Portland Commercial Energy Performance Reporting policy requires buildings to benchmark and report annual energy use.[11]

Energy Use Intensity by Building Type[10]



Sector Profiles

Industrial

The industrial sector includes all facilities and equipment used for producing, processing, or assembling goods. The U.S. Energy Information Administration defines the industrial sector to include manufacturing, agriculture, construction, fishing, forestry, and mining (which includes oil and natural gas extraction).[1]

Every industry uses energy, but three industries account for most of the total U.S. industrial sector energy consumption. The U.S. Energy Information Administration estimates that in 2019, the bulk chemical industry (the largest industrial consumer of energy), the refining industry, and the mining industry combined accounted for about 58 percent of total U.S. industrial sector energy consumption.[2]

25.2%

Industrial sector's share of Oregon's energy use.

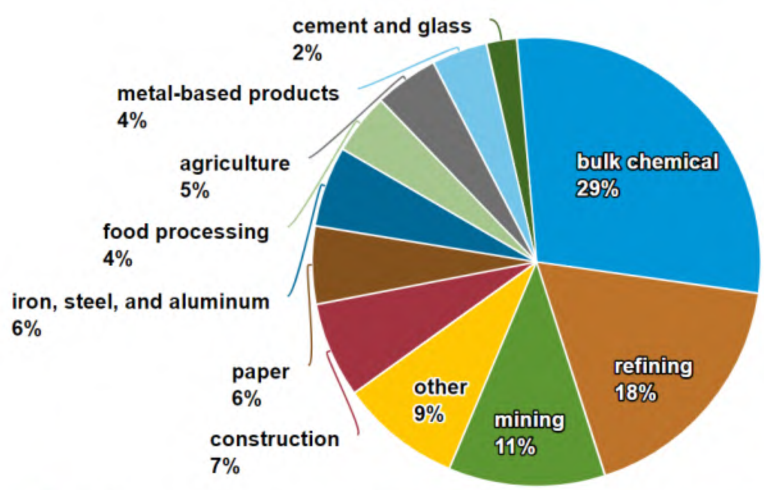
22%

Oregon industrial sector's share of 2018 state GDP.[4]

70%

Manufacturing's share of Oregon's industrial GDP.[4]

U.S. Industrial Sector Energy Consumption by Type of Industry (2019)[2]



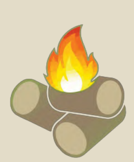
eia Note: Includes electricity purchases and energy sources used as feedstocks for making products. *Other* includes wood products (2%), plastics products (1%), and all others (6%).

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2020*, Tables 24-34, January 2020

Oregon has no petroleum refining, little bulk chemicals processing, and limited mining. Oregon's industrial economy includes other (wood products, computers, and electronics included here), construction, paper, food processing, and agriculture.

Energy is used in a wide variety of ways in industrial facilities. Fuels fire furnaces and boilers to provide process heat, e.g., steam to dry, heat, or separate product flows. Electricity powers motor systems that pump fluids and compress gases or air and move them around, as well as cooling/refrigeration, lighting, and appliances.

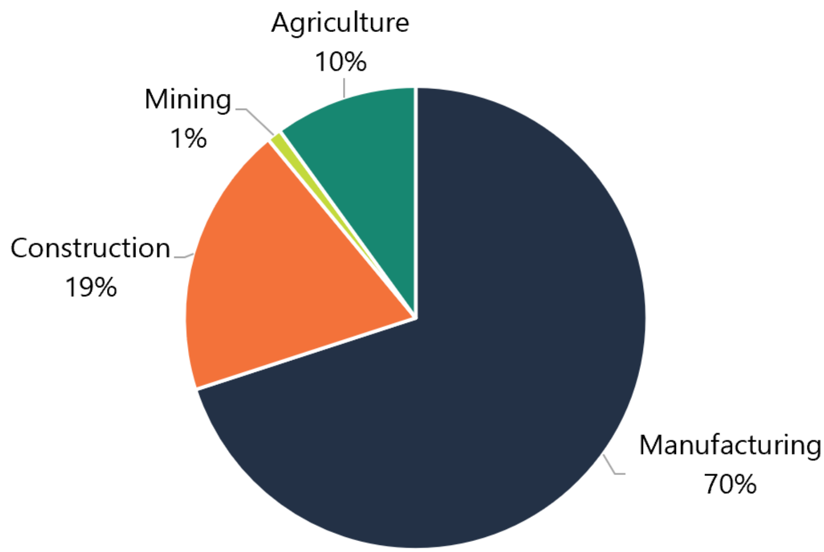
Despite the range of energy end uses, just a few pieces of equipment consume most of the fuel or electricity in most plants. Typical industrial facilities use the greatest amount of electricity for motor systems followed by process heating and cooling. Process heating, boiler fuel, and combined heat and power processes typically use the largest amounts of fuel.[3]



Oregon has five operating wood pellet manufacturing facilities with a combined production capacity of more than 250,000 tons per year, or about 2 percent of the nation's total.[5]

The majority of Oregon's gross domestic product (GDP) is from non-energy intensive businesses. Around one-seventh of Oregon's 2018 GDP came from manufacturing, with computers and electronic products accounting for almost half of the state's manufacturing GDP.[6] Computer and electronic manufacturing have relatively low energy intensity especially relative to their high value. However, Oregon's industrial sector energy does include agriculture, food processing, and forestry/forest products manufacturing, which tend to be energy intensive. Many forest products/paper operations in Oregon offset natural gas for heat and electricity from the grid by using residual woody biomass/ black liquor for cogeneration of electricity and steam for process heat.[5]

Industrial GDP Broken Down by Subsector[4]

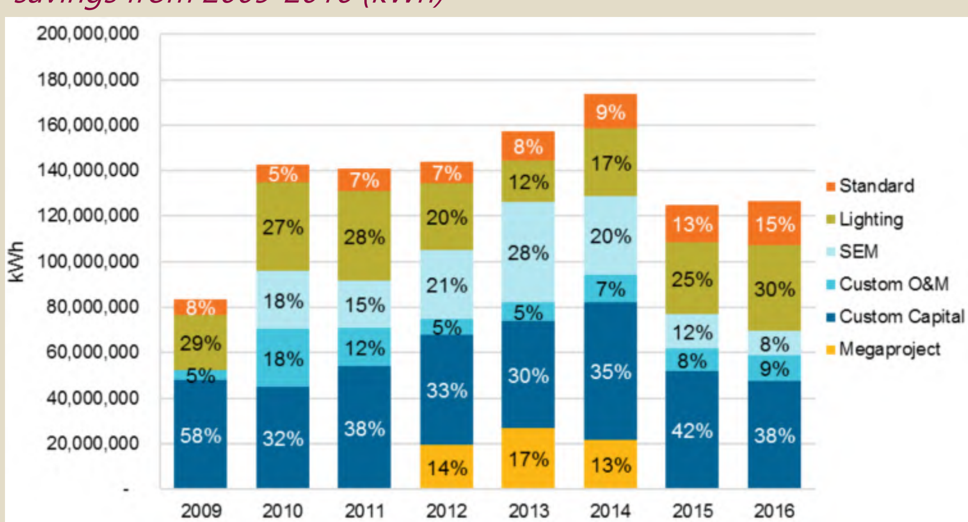


Oregon Industrial Sector Efficiency Insights

Energy Trust of Oregon published a report in 2017 describing production efficiency trends in the industrial and agricultural sector.[7] The report looked at systems, markets, and sources savings over a seven-year period. While Energy Trust's report does not quantify or characterize the entire industrial sector in Oregon, it does provide some insights regarding the industrial sector's energy use. For 2016, lighting, compressed air, refrigeration, primary process, and irrigation were the top five electricity energy efficiency measures for kWh savings. Steam, primary processes, and greenhouses were the top three gas efficiency measures in therms savings.

When Energy Trust was recruiting industrial firms to take part in Strategic Energy Management 2020 cohorts, they found an increasing focus on comprehensive energy management strategies among firms.

This chart from Energy Trust's report shows electric sources of savings from 2009-2016 (kWh)[7]



Sector Profiles

Agriculture

3.5%

Agriculture's share of energy use in Oregon's industrial sector.

225

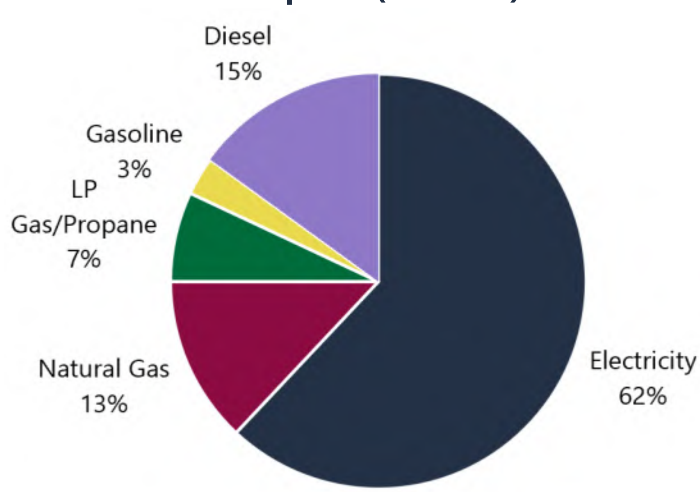
Approximate number of commodities produced in Oregon.[1]

Agriculture is an important part of Oregon's economy and is especially important to many local communities across the state. Oregon is the number one producer in the U.S. of hazelnuts, Christmas trees, and a number of different seeds.[2] ODOE estimates that Oregon agriculture annual direct energy use is about 8,900 billion Btus of energy,[3] or 3.5 percent of total Industrial Sector energy use,[4] and a little less than 1 percent of total U.S. agriculture direct energy usage.[5]

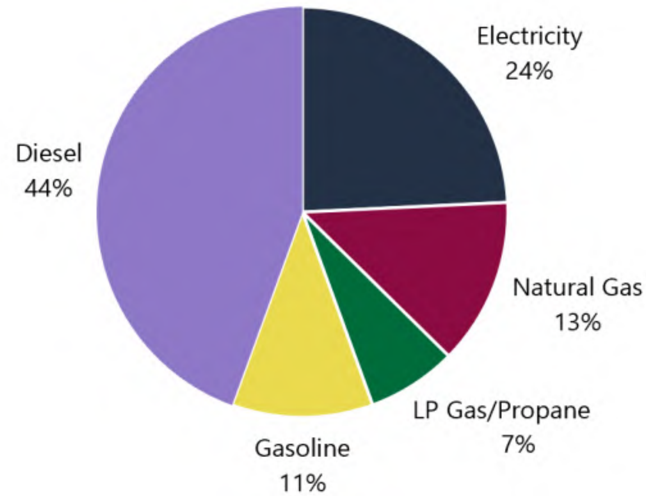
This represents the first time the Oregon Department of Energy has estimated agriculture energy usage. It was challenging to find complete, accurate, and vetted datasets for the various fuels used. ODOE used a mix of state agency, utility, and industry trade association sources by fuel type to generate the estimates. Most of the data was not generated for the purpose of reporting on agriculture energy consumption, meaning that much of the data is not collected or compiled for the agricultural sector but is aggregated with data for other industries. Where possible, the agency used 2018 data to be consistent with industrial sector EIA data, but used 2019 and even a small amount of 2020 data in order to get a full year of reliable data when 2018 data was not available. Though the numbers are estimates, ODOE is confident in the relative size and fuel mix used in comparative analysis and will continue to refine the data in the future.

In 2016, the U.S. agricultural sector consumed about 1,872,000 billion Btu of total energy, or about 1.9 percent of total U.S. primary energy consumption. About 60 percent of the energy was consumed directly on farms and ranches, while the other 40 percent was consumed indirectly in the form of fertilizer and pesticides. Farms and ranches used a variety of direct energy fuels: diesel, electricity, natural gas, gasoline, and liquefied petroleum gas/propane.[6] Despite some variability, neither U.S. agriculture total energy usage nor the fuel mix has changed dramatically over the last decade.[7]

Oregon Estimated Agriculture Energy Consumption (2018-20)[8]



U.S. Energy Consumption in Agriculture (2016)[6]



Sector Profiles

Transportation

The transportation sector covers the movement of goods, services, and people—including passenger and commercial vehicles, trains, aircraft, boats, barges, and ships. Fuel, mostly in the form of petroleum products, is used directly for transportation vehicles and to fuel equipment.

Transportation fuel costs tend to be higher in Oregon because of the region's distance from fuel supplies and a limited number of refineries. The largest portion of the transportation sector's energy use comes from passenger vehicles — and in Oregon, passenger vehicles are older than the national average. The percentage of SUVs and pickup trucks registered in Oregon is greater than national average.

31.2%

Transportation sector's share of Oregon's energy use.

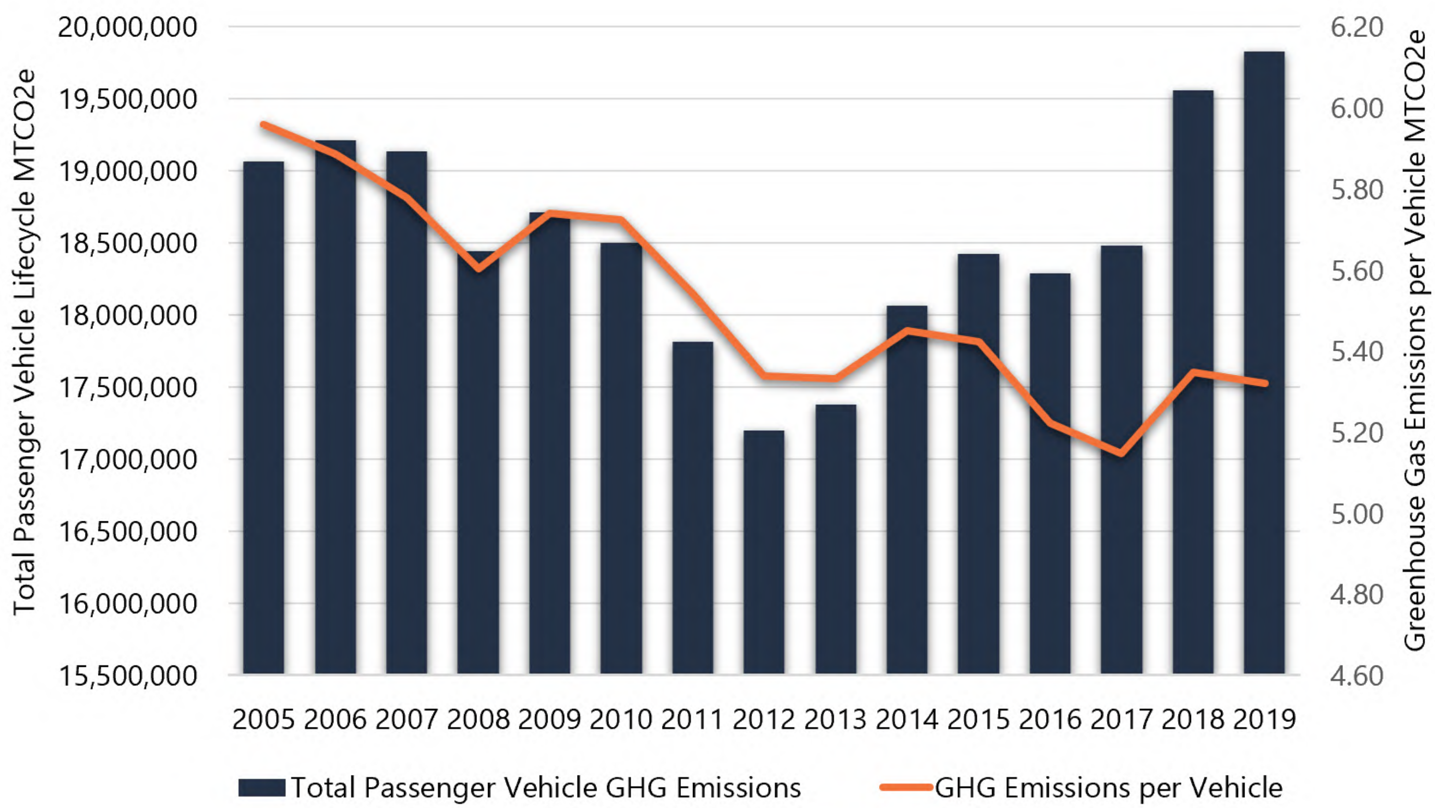
2005 Vehicle

Used 493 gallons of fuel, emitting 5.93 million metric tons of CO2 equivalent per year. (Typical model.)[1]

2019 Vehicle

Used 450 gallons of fuel, emitting 5.32 million metric tons of CO2 equivalent per year. (Typical model.)[1]

Total Passenger Vehicle Lifecycle Emissions and Greenhouse Gas Emissions per Vehicle (Million Tons of Carbon Dioxide Equivalent)



Of the transportation fuels, gasoline creates the largest amount of greenhouse gas emissions — over 19 million metric tons of carbon dioxide equivalent in 2019. Diesel is the second largest contributor of emissions at almost 8 million metric tons of CO2 equivalent. Increased consumption of lower-emitting and renewable fuel sources such as electricity, biodiesel, renewable natural gas, and renewable diesel present an opportunity to reduce emissions from the transportation sector.[2]

Transportation Fast Facts

In 2019, nearly 1.7 billion gallons of gasoline powered vehicles on Oregon roads.[3]

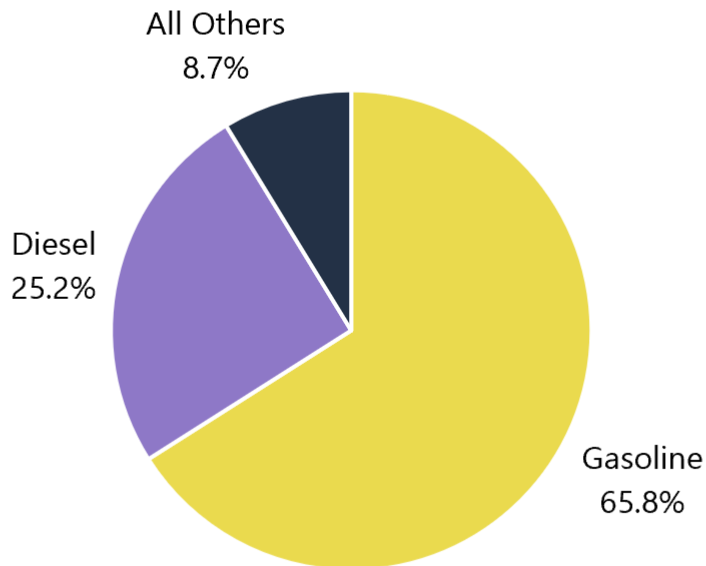
That's over 398 gallons per Oregonian.

The typical Oregon household has at least two cars.[4]

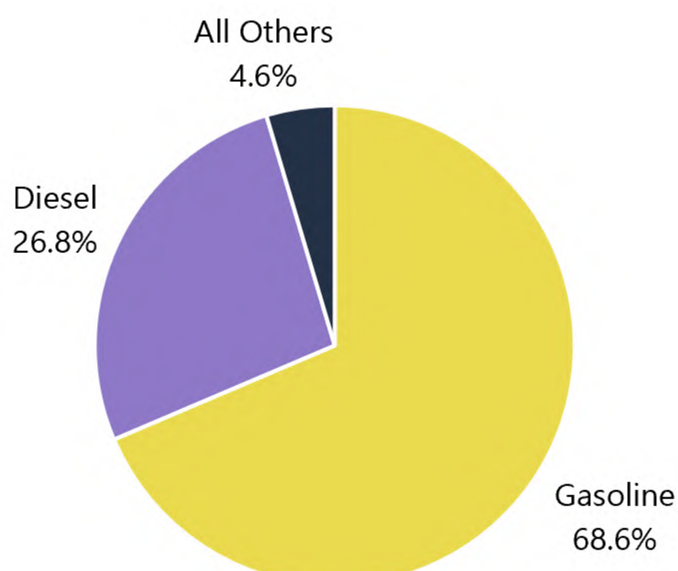
The average retail price of gasoline was $3.02 in 2019.[5]

For electric vehicle drivers, no matter where a car is fueled in Oregon, drivers are reducing greenhouse gas emissions by 50 to 95 percent by fueling with electricity.[6]

Percent of On-Highway Consumption in Oregon (2019)



Percent of Greenhouse Gas Emissions Among Fuel Types (2019)



Learn more about transportation in Oregon in the Technology Review and Policy Briefs sections of this Biennial Energy Report.

Electric Vehicles

January 2011: **672 registered EVs**

June 2020: **31,977 registered EVs**

More than 30,000 EVs in 10 Years

- In 2017, Governor Brown set a target to have at least 50,000 registered electric vehicles on Oregon roads by the end of 2020.[4]
- In 2019, the Oregon Legislature passed Senate Bill 1044, which included additional long-term EV adoption targets.[5]
- Increased adoption and use of electric vehicles is one strategy for reducing Oregon's GHG emissions, fuel consumption, and overall transportation costs for Oregonians.[6]

Oregon EVs by the Numbers

3,726,401 registered passenger vehicles

31,977 registered electric vehicles

0.86% of registered vehicles are EVs[1]

11,726 are plug-in hybrid EVs

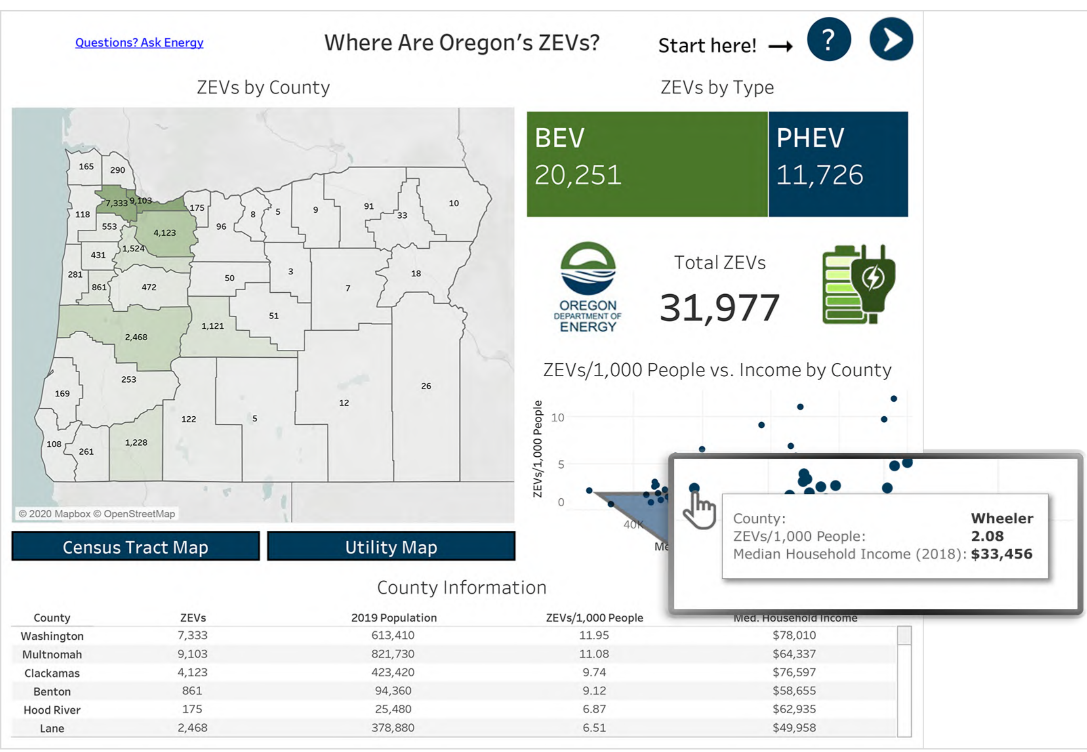
Oregon's EV Charging

9 charging networks

1,796 public EV chargers[3]

650 charging locations

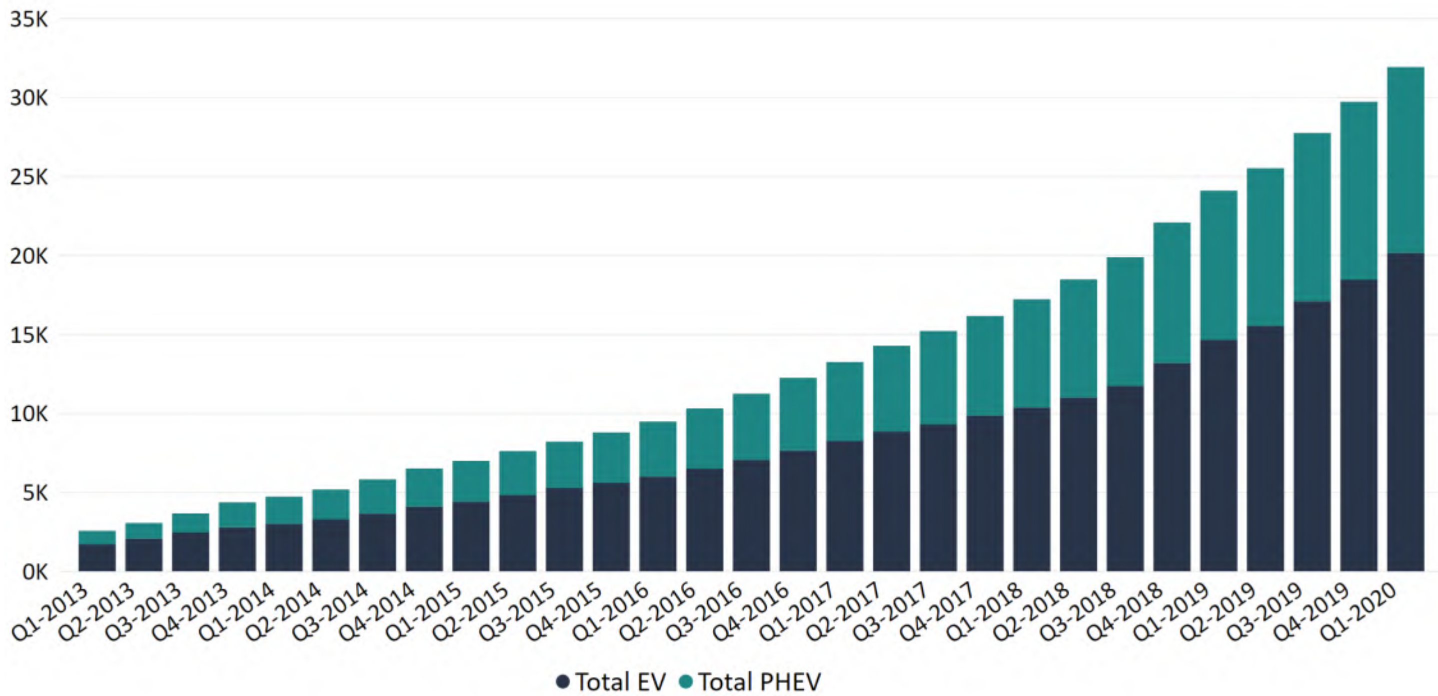
Oregon Electric Vehicle Dashboard



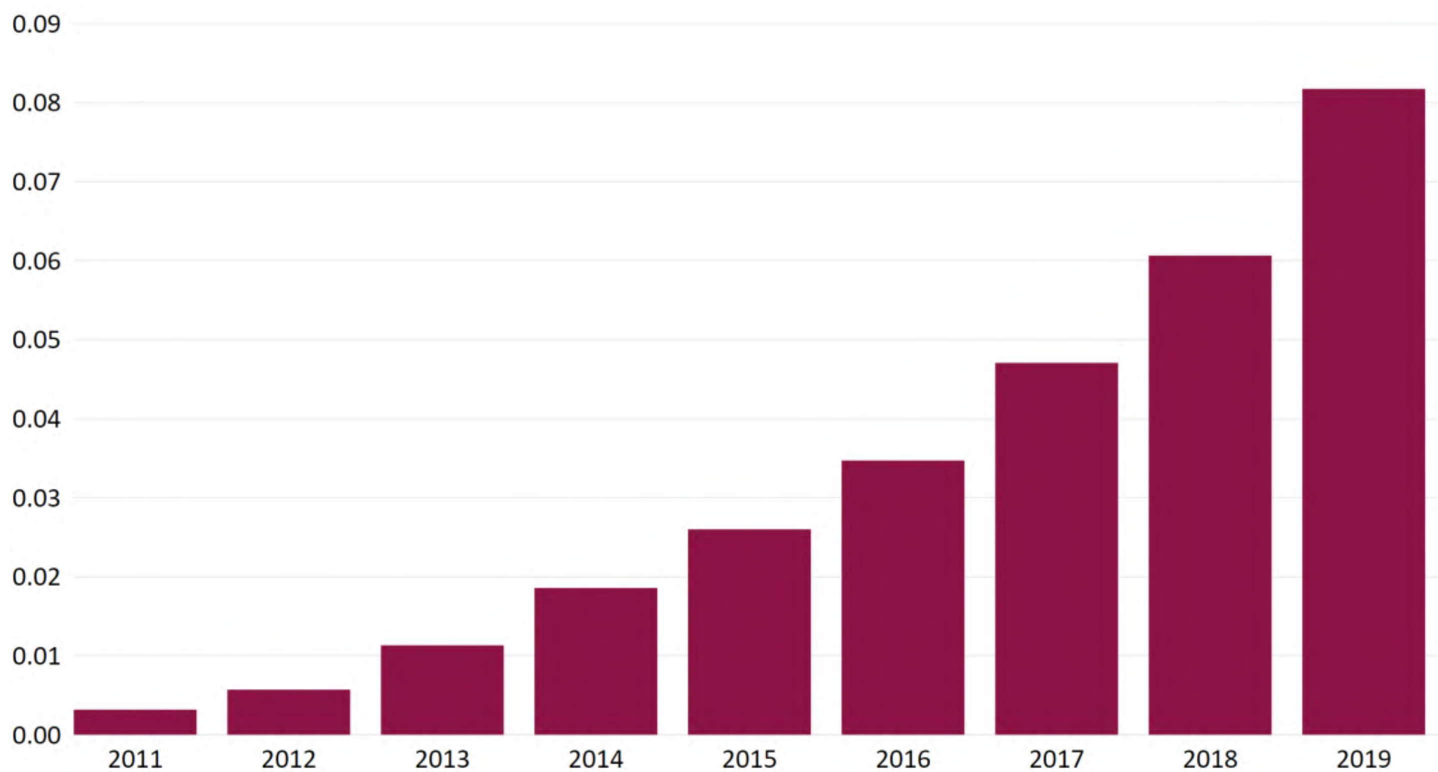
In September 2020, the Oregon Department of Energy launched a new interactive Electric Vehicle Dashboard, which shows county-by-county EV adoption information, popular EV models, and other data. The dashboard also includes a calculator to show Oregonians estimated savings by making the switch to an EV.

www.tinyurl.com/OregonEVDashboard

Cumulative Oregon EVs and PHEVs by Quarter Year (2013—Q1 2020)



EVs and PHEVs as a Percent of Total Fleet by Year



Learn more about EVs in the Technology Review and Policy Briefs sections of this Biennial Energy Report.

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We hope this timeline of Oregon's energy history will serve as a useful reference for readers as they review sections of this report, especially where we discuss energy data over time.

There are six notable entries from just the last two years — what will be added by the time we publish the 2022 *Biennial Energy Report*?

Energy history is being made.

Introduction

Oregon's energy system has evolved based on the state's natural resources and in response to events like technology development and energy crises. Native American tribes, as the original inhabitants of Oregon, have had their land base significantly diminished or completely removed – this altered the way natural resources were traditionally managed and has resulted in an enduring change in the landscape that influences the options for our energy system today. Over time, deliberate policy choices helped create not only our energy system but also shaped our society. In order to help shed light on how we got to where we are today, this timeline includes a number of events that unfolded over time and policy choices that Oregon's leaders and citizens have made in response to these events. A better understanding of how we got to where we are can help us more effectively manage the energy opportunities and challenges of today and tomorrow.

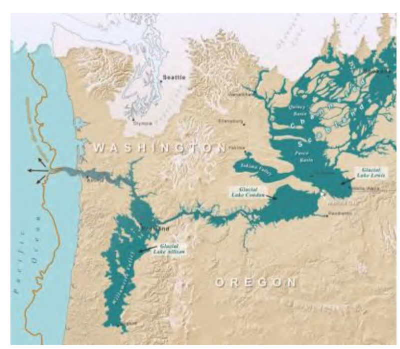
Indigenous tribes and bands have been with the lands that we inhabit today in the Willamette Valley and throughout Oregon and the Northwest since time immemorial. It is impossible to understand Oregon or U.S. history, geography, or government without having essential understandings of the rich culture and contributions of Native peoples. We would like to express our respect to the First Peoples of this land, the nine federally recognized tribes of Oregon: Burns Paiute Tribe, Confederated Tribes of Coos, Lower Umpqua & Siuslaw, Confederated Tribes of Grand Ronde, Confederated Tribes of Siletz Indians, Confederated Tribes of the Umatilla Indian Reservation, Confederated Tribes of the Warm Springs Reservation, Coquille Indian Tribe, Cow Creek Band of Umpqua Tribe of Indians, and Klamath Tribes. ODOE's office is in Salem, Oregon, the land of the Kalapuya, who today are represented by the Confederated Tribes of the Grand Ronde and the Confederated Tribes of the Siletz Indians, and whose relationship with this land continues to this day.

Timeline of Oregon's Energy History

Event

Energy policies enacted at state and federal levels

18,000 to 15,000 years ago – During the last ice age, the Missoula Floods, possibly the largest discharges of water in the history of the earth, shape the Columbia River Gorge and the Willamette Valley.[1]



Missoula Flood Paths, courtesy of Washington Geological Survey.

16,500 years ago – Archeological remains and artifacts – the oldest radiocarbon dated evidence of humans in North America – are found where Cooper's Ferry, ID, now stands. This region is also known to the Nez Perce Tribe as the site of an ancient village named Nip.[2]

Over 6,000 years ago – Archeological evidence shows Northwest Indians fishing for salmon at Kettle Falls on the upper Columbia River.[3]

1700 – On January 26th, a magnitude 8+ earthquake occurs along the Cascadia Subduction Zone, causing a tsunami that floods coastal communities in Oregon. Knowledge of these events appears in Tribal oral history. This is the most recent Cascadia earthquake, which have happened about 234 years apart on average over the last 10,000 years.[4]

1855 – U.S. Government signs Treaty of Wasco, Columbia River, Oregon Territory with the Taih, Wyam, Tenino, & Dock-Spus Bands of the Walla-Walla and the Dalles, Ki-Gal-Twal-La, and the Dog River Bands of the Wasco who are forcibly removed to reservations.[5] The Treaty of 1855 reserved and guaranteed the right to continue to take fish on both their reservations and at all "usual and accustomed fishing places." This Treaty continues to provide legal foundation for securing and furthering fishing rights for contemporary members of the Confederated Tribes of the Umatilla Indian Reservation, the Confederated Tribes of the Warm Springs Reservation of Oregon, the Confederated Tribes and Bands of the Yakama Nation, and the Nez Perce Tribe.[6]

"The exclusive right of taking fish in the streams running through and bordering said reservation is hereby secured to said Indians; and at all other usual and accustomed stations, in common with citizens of the United States."[7] - *Excerpt from the Warm Springs treaty*

Left- Gustav Sohon's depiction of the 1855 treaty gathering, courtesy of the Washington State Historical Society.

1859 – Oregon becomes the 33rd state.[8]

1860 – Portland Gas Light Co. lights up part of downtown with gas streetlights from coal gas. It becomes Northwest Natural Gas Company in 1958.[9]

1878 – The Wadatika Band of Northern Paiutes abandon the Malheur Reservation to escape conflict. Upon return, the reservation becomes "Public Domain" and tribal members establish a makeshift encampment on the outskirts of the town of Burns, OR. The Burns Paiute Tribe, descendants of the Wadatika Band, regains reservation land in Harney County in 1972. [10]

1879 – Thomas Edison invents the light bulb.[11]

1883 – American inventor Charles Fritts creates the first working selenium solar cell – the ancestor of modern solar cells.[12]

1889 – The first long-distance transmission line in North America is energized between the generating station at Willamette Falls in Oregon City and Portland.[13] Three years later, the Willamette Falls Electric Company becomes Portland General Electric (PGE).[14]

1889 – McMinnville Water and Light becomes Oregon's first municipally-owned utility.[15]

1890-1910 – Coal mining occurs in Coos Bay area, the only area in Oregon to produce coal commercially.[16]

1910 – Pacific Power & Light is formed from the merger of several financially troubled utilities in the Pacific Northwest. PP&L eventually becomes PacifiCorp.[17]

1911 – Public Utility Act of 1911 in Oregon extends the jurisdiction of the existing Railroad Commission to utilities and transportation regulation.[18]

1914-1918, World War I – Newly electrified industries in the northwest, including shipbuilding, lumber, machinery, and woolens, help fuel America's contribution to the allied victory in World War I.[19]

1919 – Oregon passes the first per-gallon tax on gasoline, at a rate of one cent per gallon.[20]

1920 – Congress passes the Federal Water Power Act, which creates the Federal Power Commission to regulate the construction, operation, and maintenance of non-federal hydroelectric power projects. The Federal Power Commission becomes the Federal Energy Regulatory Commission (FERC) in 1977.[21]

1935 – President Roosevelt establishes the Rural Electrification Administration by Executive Order. The next year, Congress passes the Rural Electrification Act, providing funding to bring electricity to farms.[22] In a speech two years later at the dedication of a new electric cooperative (or co-op), Roosevelt states, "Electricity is a modern necessity of life, not a luxury."[23] At the time, only 27 percent of Oregon farms have electricity. By 1940, 59 percent of farms in Oregon have electricity.[24]

Milk machine exhibit as part of OAC Extension Service's Farm Electrification Exhibit, 1950-1959, courtesy of OSU.

1937 – Congress passes the Bonneville Project Act and creates a temporary agency, the Bonneville Power Project, to market and transmit power from federal hydropower projects and "give preference and priority" to public bodies and cooperatives. Construction of Bonneville Dam is completed in 1938.[25] The Bonneville Power Project is renamed the Bonneville Power Administration in 1940.[26]

1940 – First aluminum smelter in the northwest, owned by the Aluminum Company of America (Alcoa) near Vancouver, WA becomes operational. Attracted by an abundance of low-cost electricity, more than a dozen aluminum plants across the northwest support the production of warplanes for World War II. Aluminum smelters buy electricity directly from Bonneville, becoming known as direct service industries or DSIs.[27]

1941 – Grand Coulee Dam, the largest concrete structure ever built at the time, begins operation. It is estimated that electricity from this dam provides enough power to produce the aluminum in about one-third of the planes built during World War II.[28] The construction inundates an important, historic fishing ground at Kettle Falls under Lake Roosevelt in Washington state. The three-day gathering before the falls are flooded is called the Ceremony of Tears. A First Salmon Ceremony, to call salmon back, continues to be held at Kettle Falls even though construction of the dam ended migration of salmon.[29]

Left- Colville women, Ceremony of Tears, 1939, courtesy of UW Special Collections. Above- Modern day salmon ceremony at Kettle Falls, courtesy of The Nelson Daily.

1944 – The word's first plutonium production reactor begins operations at the Hanford site, near Richland, Washington, as part of the Manhattan Project. This site is approximately 30 miles from Oregon along the Columbia River. Plutonium production ended in 1989, and the Hanford site is now one of the largest and most expensive cleanup sites in the country.[30]

1946 – Congress passes the Atomic Energy Act of 1946, establishing the Atomic Energy Commission. The AEC would take over responsibility of United States nuclear development from the Manhattan Engineer District. The purpose of the AEC is to promote the use of atomic energy for peaceful purposes.[31]

1954 – The Western Oregon Indian Termination Act terminates federal recognition of 61 tribes. The Klamath Termination Act terminates federal recognition of the Klamath Tribes.[32] After many years of work by tribal members, federal recognition of these tribal governments is restored: Confederated Tribes of Siletz Indians (1977), Cow Creek Band of Umpqua Tribe of Indians (1982), Confederated Tribes of Grand Ronde (1983), Confederated Tribes of Coos, Lower Umpqua and Siuslaw Indians (1984), the Klamath Tribes (1986), and Coquille Indian Tribe (1989).[33]

1954 – Two Oregonians, Daryl Chapin and Gerald Pearson, both graduates of Willamette University, help invent the first solar cell using silicon.[34]

Solar technology inventors Gerald L. Pearson, Daryl M. Chapin, and Calvin S. Fuller, courtesy of solarcellcentral.com

1954 – Congress passes the Atomic Energy Act of 1954, permitting private ownership of nuclear materials and the sale of nuclear power.[35]

1957 – Construction of The Dalles Dam is completed. While the project contributes to flood control, navigation, power generation, and irrigation, it also submerges Celilo Falls, an important Native American fishing area with settlements and trading villages in the oldest continuously inhabited place in the region.[36]

1959 – An amendment to the Federal Atomic Energy Act allows states to control radiation hazards. Oregon subsequently enters into an agreement with the federal government under which the state assumed certain regulatory authority.[37 38]

1961 – Nick Holonyak Jr., employed at General Electric, develops the first light-emitting diode that emitted light in the visible part of the frequency range. It was a red LED.[39]

1964 – The United States and Canada implement the Columbia River Treaty to provide flood control and optimize hydropower generation within the Columbia River Basin.[40]

1969 – In *U.S. v. Oregon* the U.S. District Court rules that the Nez Perce, Umatilla, Warm Springs, and Yakama tribes that negotiated the Treaty of 1855 have "an absolute right" and are entitled to "a fair share" of the fish produced by the Columbia River system.[41] This continues to be an on-going Federal court proceeding and fisheries in the Columbia River have been managed subject to provisions under the jurisdiction of the federal court.[42]

1969 – Governor McCall establishes the Nuclear Siting Task Force of the Nuclear Development Coordinating Committee by Executive Order. The Task Force is created to approve the location of nuclear power plants consistent with Oregon's environmental protections.

1970 – Congress passes the Clean Air Act to protect public health and welfare from air pollution from power plants, motor vehicles, and industrial facilities.[43]

1971 – The Oregon Legislature creates the Nuclear and Thermal Energy Council to regulate the siting of nuclear and coal-fired generating plants larger than 200 megawatts. This Council eventually becomes Energy Facilities Siting Council (EFSC) in 1975.[44]

1971 – The 1,130 MW Trojan Nuclear Power Plant proposed by PGE in Columbia County receives a site certificate from the Nuclear and Thermal Energy Council.[45]

1973 – Arab oil embargo leads to a quadrupling of oil prices, rationing of gasoline, and eventually efforts by U.S. policymakers to reduce the country's dependence on foreign oil.[46]

Portland during the early morning hours of pumping when gas was limited to five gallons per car on a first-come, first served basis, courtesy of David Falconer/EPA/US National Archives.

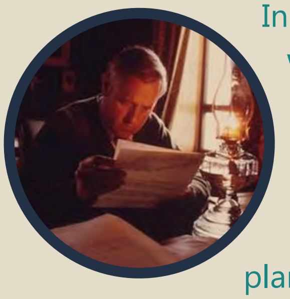
"The 1973 Oil Embargo acutely strained a U.S. economy that had grown increasingly dependent on foreign oil. The efforts of President Richard M. Nixon's administration to end the embargo signaled a complex shift in the global financial balance of power to oil-producing states and triggered a slew of U.S. attempts to address the foreign policy challenges emanating from long-term dependence on foreign oil." - *U.S. Department of State, Office of the Historian.*[47]

1973 – President Nixon establishes the Federal Energy Office within the Office of the President to help coordinate the American response to the Arab oil embargo. This office evolved into the Federal Energy Administration the following year, before becoming part of the newly established U.S. Department of Energy in 1977. [48]

1973 – The Oregon Legislature passes SB 100 creating a comprehensive land use planning system in the state.[49] Land use planning shapes the development of Oregon's landscape, affecting everything from transportation patterns to how energy facilities are sited in Oregon.

1973 – Congress passes the Endangered Species Act to provide for the conservation of ecosystems upon which threatened and endangered species of fish, wildlife, and plants depend.[50]

1973 – The Oregon Office of Energy Research and Planning writes the first Biennial Energy Plan (now known as the Biennial Energy Report), called "Transitions: A Book on Future Energy).[51]



In his introduction to the 1977 reprint of this report, Governor McCall wrote, "As governor of Oregon at the time this document was prepared, I believed that there was a role in state government for bold new ideas and for innovative, long-range planning. I was aware of the controversy which would surround this report, but I also knew that Oregon had just experienced its first dramatic energy crisis and that we needed new planning tools that would help us better understand and modify the relationships between energy and our natural and human systems… Transition is a bold document. It challenges the people of this state to create their own future rather than having it arbitrarily imposed upon them, by special interests and external events. I knew the people of Oregon could respond to such a challenge. They had already responded gallantly with dramatic conservation achievements during the energy crisis of 1973-74."[52]

1974 – Oregon Uniform Building Code first includes thermal insulation requirements for buildings.[53]

1974 – In *U.S. v Washington* the U.S. District Court rules in Washington that the Nez Perce, Umatilla, Warm Springs, and Yakama tribes' "fair share" means half of the harvestable fish in the Columbia River. The Ninth Circuit Court of Appeals later upheld this decision in 1975.[54]

1975 – Congress passes the Energy Policy Conservation Act (EPCA), creating the Strategic Petroleum Reserve, Corporate Average Fuel Economy (CAFE) standards for cars and light trucks (18 mpg for model year 1978), state energy conservation programs, and energy efficiency targets for consumer products. To reduce U.S. dependence on oil, the law also creates incentives for coal mining and calls for conversion of oil and gas facilities to coal.[55]

1975 – Lower Granite Dam on the Snake River and Libby Dam on the Kootenai in Montana, the last of the mainstem dams on the Federal Columbia River Power System, are constructed.[56]

1975 – Oregon Legislature creates the Oregon Department of Energy and the Energy Facility Siting Council. EFSC is charged with overseeing the siting, construction and operation energy facilities in a manner consistent with the protection of public health and safety and in compliance with the energy policy while protecting Oregon's environment. The department is formed to promote energy conservation and development of renewable energy sources and to provide staff support for EFSC.

Current day Oregon Department of Energy offices and the Energy Facility Siting Council visiting the Boardman Solar Energy site.

Emerging from the energy shortages of the early 1970s, Oregon policymakers were focused on energy scarcity, energy independence, and the influence that Oregonians could have over their energy futures. The themes of scarcity, sustainability, energy efficiency, and energy education are embedded in ODOE's authorizing statute (ORS 469.010), passed in 1975. The two findings contained in the statute are: "The Legislative Assembly finds and declares that:

- Continued growth in demand for nonrenewable energy forms poses a serious and immediate, as well as future, problem. It is essential that future generations not be left a legacy of vanished or depleted resources, resulting in massive environmental, social and financial impact.
- It is the goal of Oregon to promote the efficient use of energy resources and to develop permanently sustainable energy resources. The need exists for comprehensive state leadership in energy production, distribution, and utilization."[57]

1975 – EFSC approves the 550 MW Boardman Coal Plant proposed by PGE in Morrow County. The Plant is eventually constructed and placed into service in 1980.[58]

1976 – Commercial operation begins at PGE's Trojan Nuclear Power Plant; at 1,100 MW it is the largest plant of its kind at the time. The plant is licensed to run for 30 years.[59]

1977 – The Yakama, Umatilla, Warm Springs, and Nez Perce tribes form the Columbia River Inter-Tribal Fish Commission (CRITFC) for the purpose of reversing the decline of salmon, lamprey, and sturgeon, protecting fishing rights, sharing salmon culture, and providing fishery services.[60]

Yakama Chairman Watson Totus signed the CRITFC constitution on behalf of his tribe in 1977, courtesy of www.critfc.org.

1977 – Congress passes the Department of Energy Organization Act, creating the U.S. Department of Energy and bringing together federal energy activities under one agency.[61]

1978 – Congress passes National Energy Conservation Policy Act, which establishes the federal Residential Conservation Service, requires large electric and natural gas utilities to provide residential energy audits to their customers, creates a matching grant program providing funding for energy audits and energy saving retrofits in nonprofit institutional buildings (colleges, schools, and hospitals), requires that some appliance efficiency targets become mandatory, and encourages lending institutions to offer extended mortgage credit for the purchase of energy efficient homes.[62]

1978 – Oregon's Residential Energy Tax Credit begins. The following year, the Business Energy Tax Credit begins.[63]

1979 – Accident at Three Mile Island nuclear plant in Pennsylvania draws worldwide attention and focus on nuclear power and its potential safety issues.[64]

1980 – Oregon voters pass an initiative 53-47 percent that prohibits the licensing of a new nuclear power plant unless it is approved by the voters and only if there is a permanent repository licensed by the federal government for disposal of high-level radioactive waste. There is still no permanent repository for disposal of high-level radioactive waste in the US.[65]

1980 – Congress passes the Pacific Northwest Electric Power Planning and Conservation Act (also known as the NW Power Act). The Act establishes the Pacific Northwest Electric Power and Conservation Planning Council (later named NW Power and Conservation Council), and directs the Council to adopt a regional energy conservation and electric power plan, as well as a program to protect, mitigate, and enhance fish and wildlife affected by hydropower on the Columbia River and its tributaries. It also establishes provisions that the BPA Administrator must follow in selling power, acquiring resources, implementing energy conservation measures, and setting rates.[66]

Unfinished WPPSS Unit 5 near Satsop, WA, courtesy of www.historylink.org.

According to the NW Power and Conservation Council, a critical factor to passing the NW Power Act was the region's "disastrous" efforts, led by the Washington Public Power Supply System (WPPSS, or "Whoops) and Bonneville Power Administration, to build five nuclear power plants in the 1970s. "Utilities based their decision in part on inaccurate Northwest electricity load forecasts. Only one of the plants, the currently operating Columbia Generating Station, was ever completed. Due to exorbitant cost overruns, utilities abandoned or mothballed the other four plants prior to completion. Two of the unfinished plants were responsible for one of the largest bond defaults in the history of the nation, while the Bonneville Power Administration backed the financing for the other three plants. And, from 1978 to 1984, BPA was forced to raise its rates by 418 percent (adjusted for inflation) to pay for the cost of these plants. Even today…BPA pays millions of dollars a year on debt service for two of the unfinished plants."[67]

1983 – EFSC approves its first renewable energy project, a 40 MW (850 40-80 kW turbines) proposal by Wind Energy Specialist for a site in Curry County. This facility was never constructed.

1983 – Northwest Power Planning Council produces Model Conservation Standards for the region, including guidance for energy efficiency codes and conservation programs. The model asserts that "to ensure that the region captures all regional cost-effective savings, utilities should secure proportional savings from hard to reach populations." [68]

1984 – Through a ballot measure, voters in Oregon create the Oregon Citizens' Utility Board (CUB) to advocate on behalf of residential customers of investor-owned utilities in Oregon.[69]

1984 – Columbia Generating Station nuclear power plant, located on the Hanford site near Richland, Washington, becomes operational.[70]

1985 – The Hood River Conservation Project, funded by Bonneville Power Administration and operated by Pacific Power, helps prove that conservation was a viable energy resource that could be considered on equal ground with supply-side options in the Northwest.[71]

1986 – Oregon voters approve a ballot measure finalizing a three-person, Governor-appointed Public Utility Commission of Oregon to replace the single commissioner system previously in place.[72]

1986 – Chernobyl nuclear plant meltdown and steam explosion releases radioactivity into the atmosphere and becomes the worst nuclear accident in history. [73]

1988 – NASA climate scientist James Hansen testifies before Congress and warns about the dangers of global warming. [74] Meanwhile, the Intergovernmental Panel on Climate Change (IPCC), an intergovernmental body of the United Nations, is established to provide objective scientific information about climate change.[75]

1989 – Oregon requires investor-owned utilities (IOU) to conduct Integrated Resource Plans (IRPs), putting energy efficiency on equal footing with traditional generation resources.[76]

1990 – Congress passes the Clean Air Act Amendments of 1990 to curb acid rain, urban air pollution, toxic air emissions, and stratospheric ozone depletion.[77] Two-thirds of the sulfur dioxide emissions that cause acid rain come from fossil fuel power plants.[78] By 2019, the acid rain program had reduced SO2 emissions from power plants by 92 percent and NOx by 85 percent.[79]

1991 – Snake River Sockeye Salmon are listed as an endangered species pursuant to the Endangered Species Act.[80] Between 1991 and 2005, 13 species of salmon or steelhead and four other fish within the Columbia River Basin, are listed for protection under the Endangered Species Act.[81]

1992 – Congress passes Energy Policy Act of 1992. Considered in the wake of the Persian Gulf War, the bill promotes energy efficiency and alternative fuels. [82]

1993 – After a series of mechanical problems, PGE permanently shutters the Trojan Nuclear Power Plant. [83]

1994 – The Hermiston Generating Project becomes the first natural gas facility to receive a site certificate from EFSC. The 468 MW plant begins operation in 1996.

The Hermiston Generating Plant provides power for nearly 500,000 households in the Pacific NW, courtesy of Perennial Power.

1997 – Portland General Electric, the utility with the most Oregon ratepayers, is bought by Enron for $2.1 billion and the assumption of $1.1 billion in debt.[84]

1997 – World powers, including the U.S., sign the Kyoto Protocol, committing industrialized countries, and economies in transition, to limit and reduce GHG emissions in accordance with individual targets. The Protocol goes into effect on 2005.[85]

1997 – Oregon becomes the first state in the country to establish a price on carbon with the EFSC CO2 standard. It requires power plants to avoid, displace, or sequester a portion of their CO2 emissions; applicants can pay a fee to offset these emissions.[86] The fees are used by The Climate Trust to purchase offsets.

1997 – Northwest Energy Efficiency Alliance (NEEA) is formed to promote energy efficiency through market transformation. [87]

1997 – Released in Japan in 1997 and worldwide in 2000, the Toyota Prius becomes the world's first mass-produced hybrid electric vehicle.[88]

1999 – EPA issues the Regional Haze Rule to reduce the pollution that causes visibility impairment in national parks and wilderness areas. EPA requires states to submit regional haze plans in 2007.[89] The expense of complying with this plan contributes to the early closure of the Boardman Coal Plant, which is shuttered in 2020.

1999 – Oregon legislature passes SB 1149, creating the Public Purpose Charge for energy efficiency, renewable and low-income energy programs and partially deregulating the electric sector by authorizing long-term direct access for certain large retail customers of IOUs.[90]

1999 – Oregon legislature passes HB 3219, requiring electric utilities to allow net metering so that customers can generate onsite renewable resources and reduce their electricity bills.[91]

2001 – The Western Energy Crisis of 2001 causes power shortages in California and skyrocketing electricity prices across the west, including Oregon. Wholesale energy prices in the PNW briefly jumped to over $1,300 per megawatt hour, much higher than the typical price of under $50 per MWh. New efforts at deregulation, combined with historic drought conditions and market manipulation contributed to the crisis.[92]

2001 - Enron engages in criminal market manipulation, exacerbating the energy crisis. Enron's collapse leads to many PGE employees losing their jobs and much of their retirement savings.[93]

2001 – By the end of the year, 10 aluminum smelters in the NW are shutdown. This direct service industry goes from using a high of about 3,000 aMW in 1995 to about 300 aMW by 2006.[94]

2001 – The EFSC-approved Stateline Wind Project in Umatilla County becomes first utility-scale wind energy facility built in Oregon. The 222 MW facility has 229 turbines, each 440' tall.[95]

2002 – Oregon becomes the first state to install solar panels on its state capitol building.[96]

2002 – Energy Trust of Oregon begins operation to administer energy efficiency and renewable energy programs for investor owned utilities.[97]

Wind turbine construction in Oregon.

2004 – Decommissioning of the Trojan Nuclear Power Plant is completed. The spent nuclear fuel remains onsite and is expected to stay onsite until there is a federally-approved repository for this material. The cooling tower is demolished two years later.[98]

2005 – Congress passes the Energy Policy Act of 2005. Among other things, this bill gives FERC explicit and "exclusive" authority to approve onshore LNG terminal siting applications.[99]

2006 – Jordan Cove and Pacific Connector pipeline are proposed as an LNG import terminal in Coos County, OR.[100]

2007 – Oregon legislature establishes Oregon's first greenhouse gas reduction goals and creates the Oregon Global Warming Commission.[101]

KeepOregonCool
Oregon Global Warming Commission

2007 – Oregon legislature passes SB 838, requiring the state's largest utilities to provide 25 percent of retail sales from eligible renewable sources by 2025.[102]

2008 – Ratepayer concerns contribute to an agreement by PGE to close the Boardman Coal Plant, which had been scheduled to operate until 2040, by the end of 2020. This is the first time a utility agrees to voluntarily close a coal plant in the U.S.[103]

2009 – Congress passes the American Recovery and Reinvestment Act, investing millions of dollars in states for clean energy and energy efficiency.[104]

2010 – Klamath Hydroelectric Settlement Agreement that is signed by PacifiCorp, several tribes, Oregon, California, and stakeholders. Through a surcharge, Oregon customers will help pay for Oregon's share of dam removal costs. Timing of the dam removal is uncertain.[105]

Signing the Klamath agreements, from left, PacifiCorp Chairman and CEO Greg Abel, Interior Secretary Ken Salazar, Governor Arnold Schwarzenegger and Governor Ted Kulongoski. Photo courtesy Office of Governor Schwarzenegger and ENS.

2011 – Fukushima nuclear power plant accident in Japan is caused by a 9.0 earthquake and subsequent 40-foot tsunami that knocks out the electrical generation for the coolant pumps, resulting in core meltdowns at three units, the release of radioactive material, the evacuation of thousands of people, and the establishment of an uninhabitable exclusions zone.[106] Cleanup is expected to cost at least $75 billion and as much as $660 billion and take 30-40 years.[107]

2011 – Drive Oregon (now known as Forth) is incorporated by local business leaders and receives $1.2 million in seed funding from the Oregon Legislature via the Oregon Innovation Council to grow Oregon's electric vehicle industry. [108]

2012 – Obama Administration finalizes agreement with 13 large automakers to increase CAFE standards to 54.5 miles per gallon for cars and light-duty trucks by model year 2025.[109]

2012 – Jordan Cove and Pacific Connector pipeline revises plans to build an LNG import terminal in Coos County, and instead proposes an *export* terminal.[110]

2014 – Sunset of Oregon's Business Energy Tax Credit. Under this program, ODOE certified almost 25,000 projects that helped save energy, displace conventional energy sources, or generate renewable energy.[111]

2015 – 195 countries join the Paris Agreement, bringing together developed and developing nations in committing to keep global temperature rise well below 2°C (3.6°F).[112]

2015 – Volkswagen pleads guilty to emissions-cheating scandal.[113]

Volkswagen created Electrify America with $2 billion in funding as part of its emissions scam settlement with the U.S. and California. Pictured above, an Electrify America EV charging bank in Hood River, OR, courtesy of Columbia Insight. Photo by Jurgen Hess.

2016 – After years of planning, DEQ launches the Oregon Clean Fuels Program to reduce the carbon intensity of Oregon's transportation fuels by 10% over 10 years.[114]

2016 – Oregon adopts a 50 percent renewable portfolio standard and becomes the first state to legislatively mandate an end to coal in the state's electricity mix by 2030 with the passage of SB 1547, the Clean Electricity and Coal Transition Plan. This law also created a community solar program with requirements for low-income customer participation.[115]

2017 – Oregon's Residential Energy Tax Credit expires. Over the lifetime of this program, more than 15,000 solar projects are approved, with a production estimate of about 75 million kWh/year.[116]

2017 – With the passage of the Keep Oregon Moving Act (HB 2017), Oregon adopts an Electric Vehicle Rebate program that includes a "Charge Ahead" component for low-income participants.[117] Oregon Governor Kate Brown issues Executive Orders 17-20[118] and 17-21[119] to reduce greenhouse gas emissions by accelerating energy efficiency in Oregon's built environment and accelerating zero emission vehicle adoption.

GO ELECTRIC OREGON

2017 – The first utility-scale solar PV project larger than 50 MW in Oregon, the 56 MW Gala Solar project in Crook County, begins commercial operation. Just one year later, the Boardman Solar Project, with a capacity of 75 MW, receives a site certificate from EFSC. The project has not yet begun construction.[120]

2019 – Oregon legislature passes HB 2618 creating ODOE's Solar + Storage Rebate Program. The program issues rebates for solar electric systems and paired solar and solar storage systems. At least 25 percent of available rebate dollars are set aside for low- or moderate-income residential customers and low-income service providers.[121]

2019 – For the first time since 1952, U.S. domestic production of primary energy surpasses consumption and the country exports more energy than it imports.[122]

2020 – Oregon Governor Kate Brown issues Executive Order 20-04 Directing State Agencies to Take Actions to Reduce and Regulate Greenhouse Gas Emissions.[123]

2020 – Oregon has 31,977 registered electric vehicles as of July 1.[124]

2020 – The Boardman Coal Plant, Oregon's only coal power plant, closes on October 15.[125]

2020 – Construction underway on multiple large utility-scale wind and solar energy projects, including the Wheatridge Renewable Energy Facilities in Morrow County, the Montague Wind and Solar Projects in Gilliam County, and the Golden Hills Wind Facility in Sherman County.[126]

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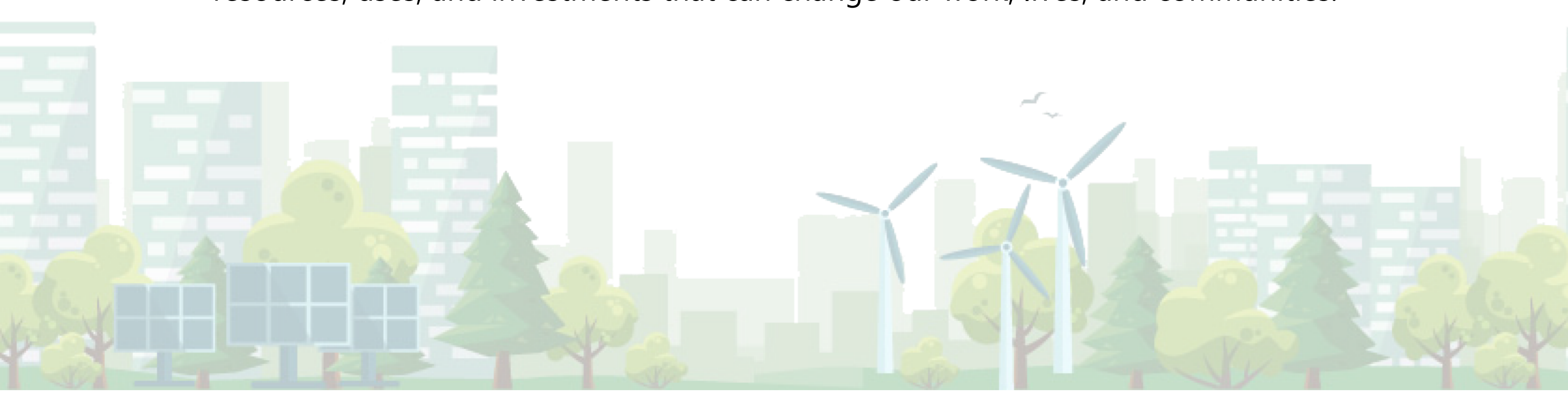
ENERGY 101

Just about everything involves energy. It is a part of our daily lives, blending into the background of driving a car, turning on a computer, firing up a grill, or heating a home.

The 2018 *Biennial Energy Report* focused on foundational data and information about energy in Oregon. For 2020, ODOE asked stakeholders and the public what other context and information would be helpful and then leveraged ODOE expertise on a variety of topics including transportation, facility siting and permitting, nuclear safety and emergency preparedness, energy efficiency, renewable energy, electricity, and natural gas.

This section is intended to help the reader understand the first part of the energy story: how energy is produced, used, and transformed. This includes fundamental information for people new to energy or specific energy topics, along with those looking for data or a central place to help tell the story of how energy systems affect their work and interests. Energy policy is complex and, without being armed with technical information and understanding, it is sometimes difficult to be part of the conversations. The Energy 101 topics in this section are intended to help create a more diverse and inclusive conversation and to build our energy future together by bringing more stakeholders to the table. Narratives range from basic information about where our transportation and natural gas resources come from and how they get to consumers, to the role that codes, standards, and net-zero buildings play in reducing overall energy use. Several topics are directly linked to specific policy briefs included later in this report on complex concepts like resource adequacy and clean and zero-emission standards. This section also gives readers necessary background to understand the data and trends in Energy by the Numbers and cross-sectional discussions on climate, equity in renewable energy, and grid-interactive efficient buildings.

The second part of the story is how energy systems affect the lives of Oregonians. Information in this section includes an explanation of energy bills and how net metering works for technologies like rooftop solar. Readers can then learn more about the very real challenges of energy burden in our state, along with the growth and opportunities of clean energy jobs in Oregon. It is through foundational understanding of fundamental energy concepts that readers can make informed choices about the energy resources, uses, and investments that can change our work, lives, and communities.



Energy 101: Energy Production in Oregon

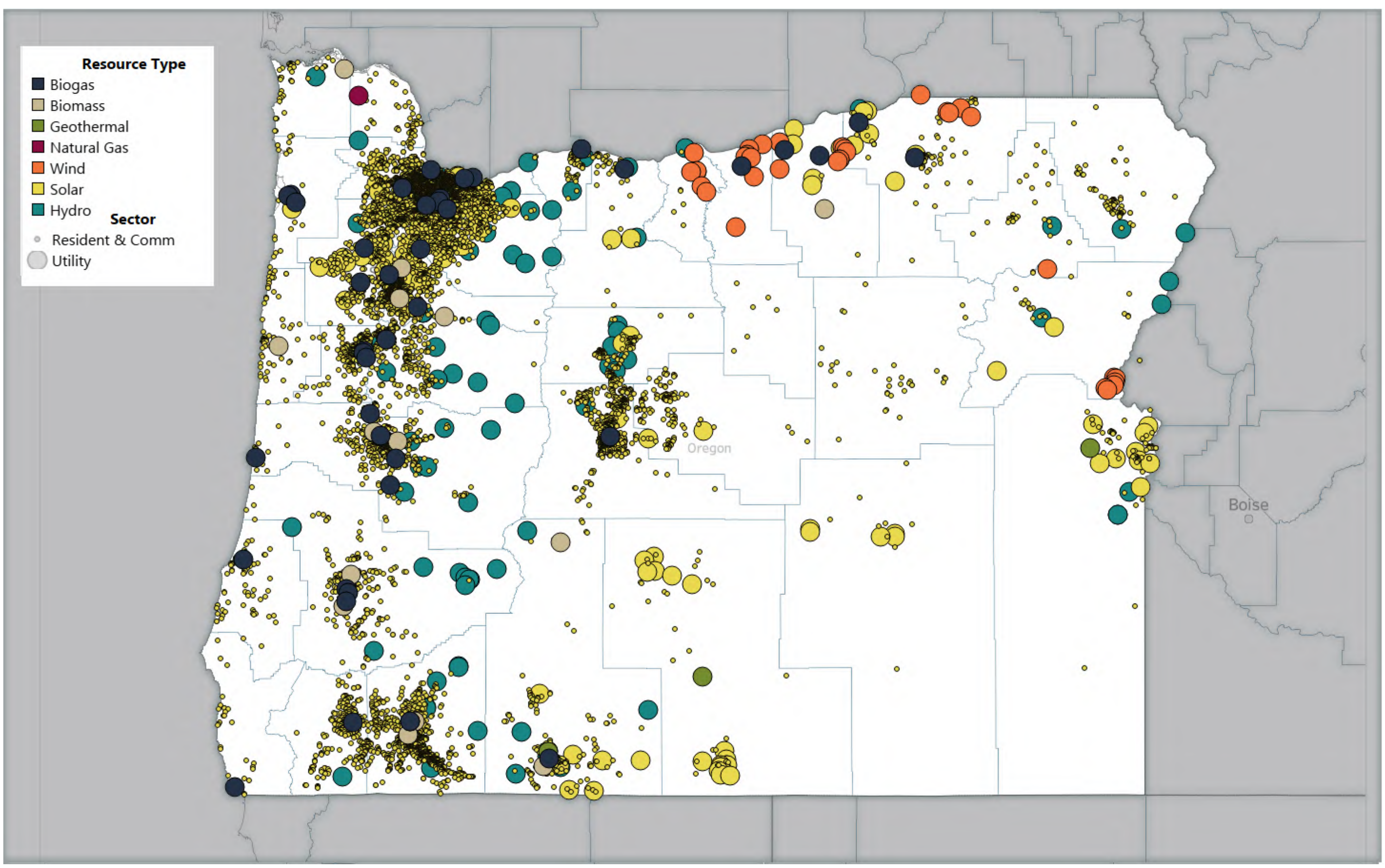
In this *2020 Biennial Energy Report*, energy production is divided into three categories – electricity, direct use fuels, and transportation fuels – with specific information on the types of energy produced in Oregon, along with more general information about the environmental effects of each resource no matter where it is produced. Other portions of the report also go into more detail about the benefits, effects, and tradeoffs associated with various resources.

Oregon ranks 33rd in the country for energy production.

Oregon ranks 4th in the country for total non-combustible renewable energy production.

Primary energy is used to describe energy sources in the form that they are extracted or collected from the environment that can be directly converted into a use while *secondary energy* describes energy that has been converted from its primary form into a second form for transportation or storage. This type of energy goes through multiple transformations before that energy is used. For example, sunlight, fuel oil, natural gas, wind, running water, and coal are all considered primary energy. Once energy has undergone a transformation, sunlight, wind, and running water into electricity, for example, or natural gas to steam, the resulting energy is secondary energy. Energy can undergo multiple transformations and each transformation creates losses due to inefficiencies in the process.

Figure 1: Primary Energy Production Facilities in Oregon[1 2]



Energy Production Categories

Electricity. Much of the electricity generated in-state uses Oregon-based natural resources – wind or hydropower, for example. Oregon energy facilities also generate electricity using raw materials from out of state. All of the coal and almost all of the natural gas used at Oregon's large scale in-state coal and natural gas power plants is imported. Oregon does produce renewable natural gas and biofuels that are used to generate electricity, they are also sometimes used for combined heat and power at mainly commercial and industrial facilities in Oregon. See the Energy by the Numbers section for more details about electricity generation and consumption in Oregon.

Direct Use Fuels. Direct use fuels include small amounts of natural gas and a variety of biofuels produced in-state: hog fuel (wood chips) used for industrial heat, commercial wood pellets for commercial industrial heat, renewable natural gas and other biofuels used for combined heat and power, and others.

Transportation Fuels. Oregon produces about 25 percent of the biofuels our transportation system uses; overall, biofuels make up 6.4 percent of Oregon's use of transportation fuels.

Site vs. Source Energy

When tracking energy flow through complex distribution systems, the energy sector draws boundaries to prevent double counting. Typically, those boundaries are referenced using site energy and source energy. *Site energy* accounting refers to energy measured from the point of delivery to a building or facility – for example, utility bills measure site energy. *Source energy* accounting refers to the total amount of raw energy needed to supply a site; for natural gas this would include the original amount of fuel extracted to supply the quantity of energy used at a site, including any losses incurred through transport, storage, and delivery of the energy. For example, the source energy for a power plant that uses natural gas to provide electricity would include the amount of energy extracted for that purpose, any transportation losses in transit to the power plant, the heat lost during generation due to inefficiencies in the process, plus transmission and other losses from transporting the electricity to the eventual end use.

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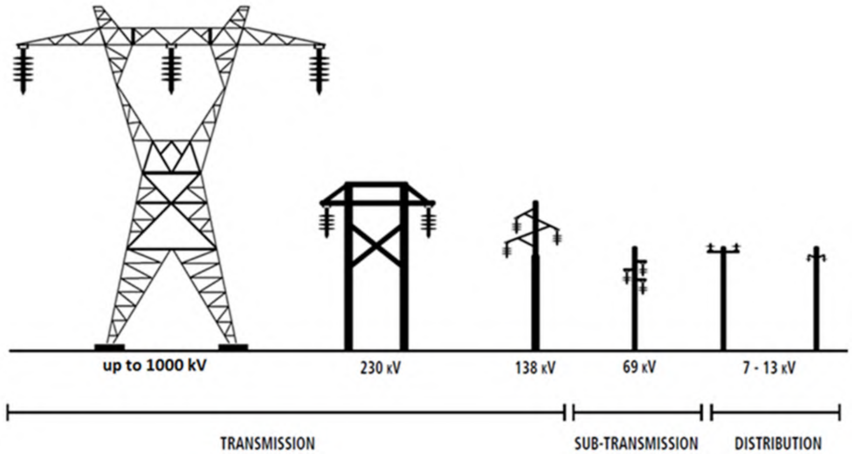
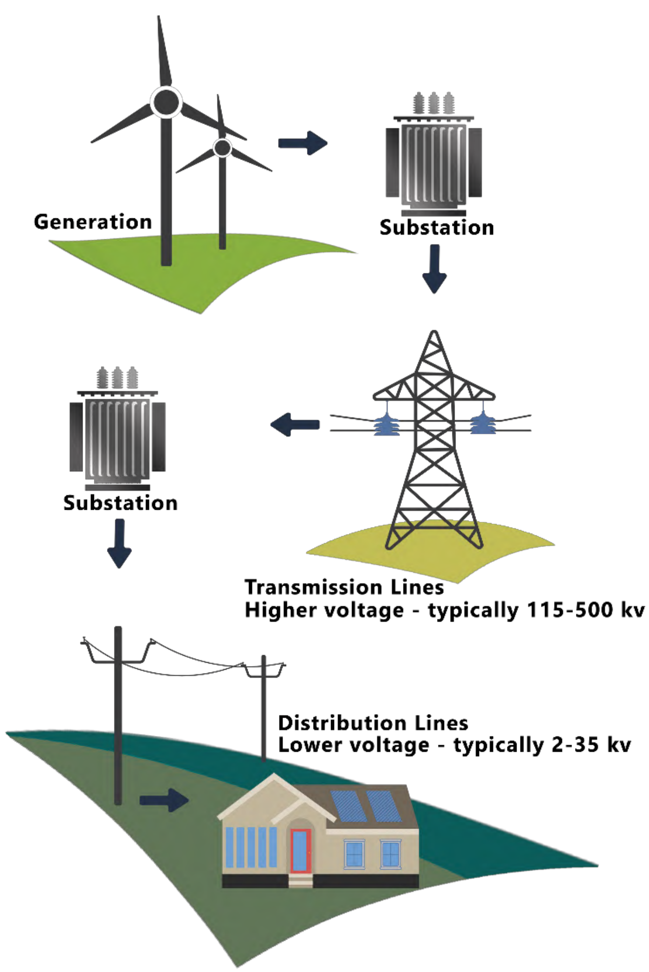
Energy 101: Electricity Transmission

Figure 1: Typical Sizes of Transmission and Distribution Systems



Transmission lines move large volumes of high-voltage electricity across long distances and are needed to connect large distant generating resources to electricity customers (also known as load centers). Transmission lines create a networked system by interconnecting a variety of load centers to generating resources. Most generators are located long distances from the towns, cities, counties, and rural areas they serve – for example, customers along Oregon's coast often receive their power from distant generation east of the Coast Range. This transmission network is generally referred to as "the grid," and more specifically referred to as the "Bulk Power System," or the "Bulk Transmission System" when discussing high-voltage transmission lines.

Figure 2: Electricity Supply Chain

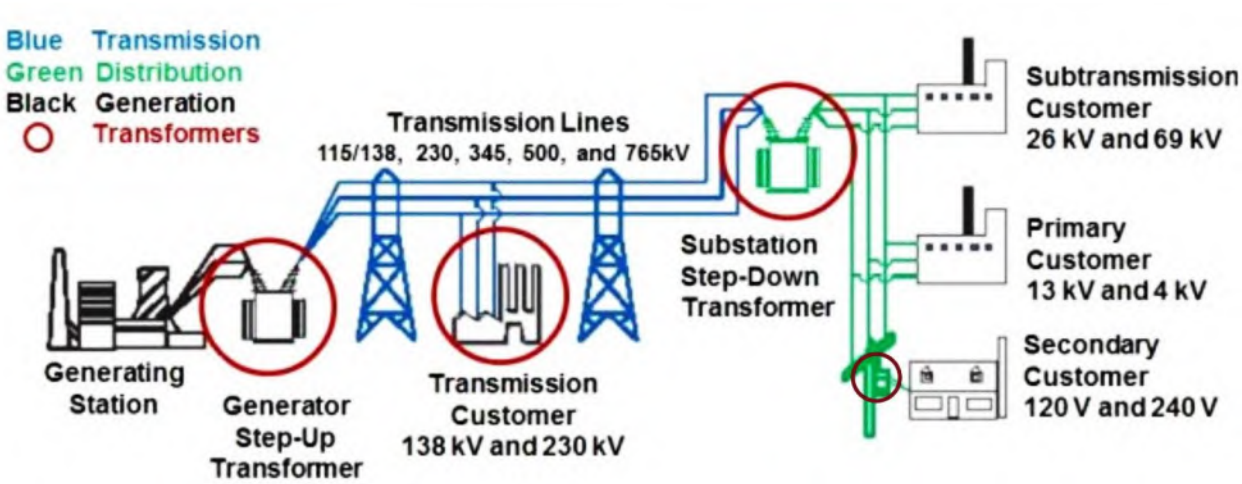


Transmission lines are critical to the delivery of large amounts of power to customers from electricity generating resources across a geographic footprint. The transmission network serves many important functions, including providing access to diverse energy resources, helping to ensure reliable electricity, and allowing generating resources to be centrally located and used to serve demand across a region. For example, as a sponsor of the proposed Boardman to Hemingway transmission line project, Idaho Power Company has described the need for that transmission line as:

> *Existing transmission lines between the Pacific Northwest and Idaho Power's service area can't carry any more energy when it is needed most. The Boardman to Hemingway line will provide the ability to deliver approximately 1,000 megawatts of clean, affordable power in each direction, helping meet customer needs, especially during summer months when air conditioning creates peak demand.*[1]

Electricity travels long distances most effectively and efficiently at high voltages. Generators produce electricity, and "step-up" transformers increase the voltage of electricity to travel along high-voltage transmission lines. Then, to decrease the voltage back down to the levels required to serve customers, the electricity passes through "step-down" transformers before being consumed by end users.

Figure 3: Detailed Electricity Supply Chain[3]



Transmission vs. Distribution Line

Connected to the other side of transmission lines and step-down transformers are the distribution lines, which carry lower voltage electricity shorter distances (i.e. the last few miles, to the grid's distribution system customers). These are the wires that connect customers to the grid and supply them with electricity. The transmission and distribution systems are distinguished by the voltage level of the wires — a measurement of the capacity of the lines to carry energy. The transmission network is comprised of higher voltage lines – typically 115 kV to 500 kV (including lines that connect generation to the bulk transmission system – "gen-tie" lines); the distribution network is comprised of lower voltage lines typically between 2 kV and 35 kV.[i 2 3] Transmission lines are carried on larger towers, such as the ones paralleling Interstate 5 through much of the Willamette Valley, while distribution lines are often carried on smaller wooden poles like those running up and down the streets of many residential neighborhoods.

A standard wall outlet delivers 120 volts. Six percent of the voltage of a 2 kV distribution line, or 0.02 percent the voltage of a 500 kV transmission line.

Pacific Northwest Transmission Lines: Location and Ownership

Connecting large generating resources to customers requires a great deal of transmission infrastructure – thousands of miles in Oregon and across the Pacific Northwest and over 360,000 miles nationwide.[4] Oregon is located within the high voltage grid called the Western Interconnection. The Western Interconnection footprint is a vast area covering Montana, Wyoming, Colorado, New Mexico, Washington, Oregon, California, Nevada, Idaho, Utah, the Canadian provinces of British

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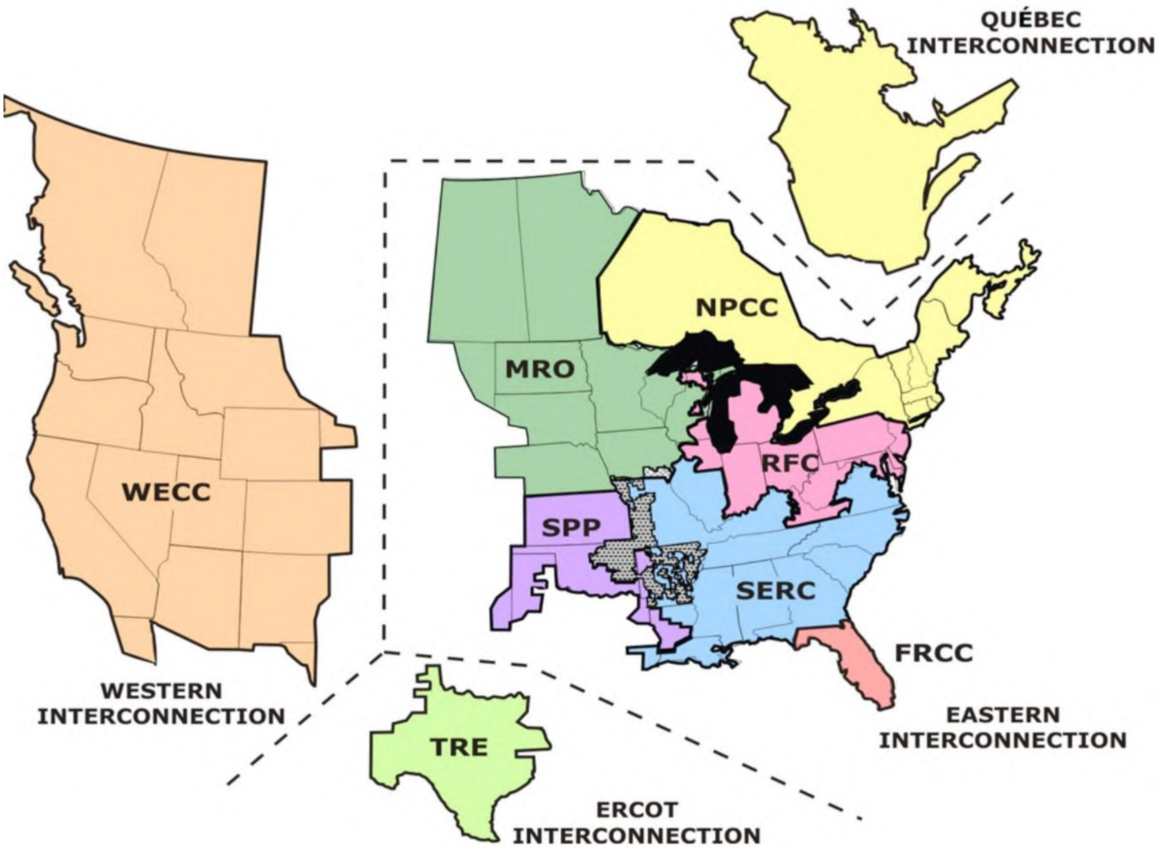
[i] Subtransmission lines comprise the medium voltages (typically between 35 kV and 115 kV, though these can sometimes be classified as part of the bulk transmission network).

Columbia and Alberta, and Northern Baja, Mexico. The Western Electricity Coordinating Council (WECC) is the regional entity responsible for promoting reliability and security across this area, coordinating with approximately 345 member organizations.[5] The WECC also enforces mandatory reliability standards for the electric power industry in the Western Interconnection pursuant to delegated authority from the North American Electric Reliability Corporation (NERC), which is responsible for compliance and enforcement of NERC electricity safety and reliability standards. In addition to the Western Interconnection, there are three other interconnections across the U.S. and Canada: the Eastern Interconnection, the ERCOT Interconnection in Texas (Electric Reliability Council of Texas), and the Quebec Interconnection in Canada.

Figure 4: Four Interconnections in North America[5]



Transmission Lines in the Pacific Northwest

Figure 5: Transmission Lines in the Western Electricity Coordinating Council[6]

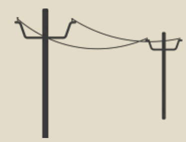
Adapted from the WECC Interconnection Map

The largest owner of transmission lines in the Pacific Northwest is the Bonneville Power Administration (BPA), a federal power marketing administration.[7] The largest owner of transmission lines in the Western Interconnection is PacifiCorp.[8] Other large owners of transmission lines in the region include: Idaho Power, Avista, Puget Sound Energy, and Portland General Electric. Many additional entities across the Pacific Northwest own smaller amounts of transmission lines, including Oregon consumer-owned utilities such as: Harney Electric Coop, Central Electric Coop, Eugene Water & Electric Board, Central Lincoln PUD, Coos-Curry Electric Coop, and Tillamook PUD. Approximations for total mileages by owner is shown in Table 1.

Table 1: Miles of Transmission Lines by Owner

Owner	Transmission Line Miles
Bonneville Power Administration[9]	15,209
PacifiCorp[10]	16,600
Idaho Power[11]	4,857
Avista[12]	2,770
Puget Sound Energy[13]	2,608
Portland General Electric[14]	1,264
Harney Electric Co-op[15]	350
Central Electric Co-op[16]	185
Eugene Water & Electric Board[17]	129
Coos-Curry Electric Co-op[18]	52
Tillamook People's Utility District[19]	15.7

If you stretched all of Portland General Electric's transmission lines end-to-end, they would stretch from Portland to Denver, CO.



The electric power industry contains a diverse mix of entities such as investor-owned utilities (e.g. PacifiCorp, Portland General Electric, and Idaho Power), cooperatives (e.g. Harney, Central Electric, Coos-Curry), municipals (e.g. Eugene Water and Electric Board), peoples utility districts (e.g. Tillamook), federal power marketing administrations (e.g. Bonneville Power Administration), and independent power producers (e.g. Avangrid Renewables). Some entities own and operate assets across all segments of the power grid – generation, transmission, and distribution systems. Other entities own and operate assets in only one of these segments, such as only generation, only transmission, or only distribution.

Transmission line owners and operators are often affiliated with the same utilities that own and operate power generation to provide customers with electricity.

Figure 6: BPA Transmission System and Federal Dams[20]

3PA owns and operates 15,239 circuit miles of transmission lines across a six-state region that forms the backbone for delivering power rom 31 federal hydroelectric dams in the Northwest. Both the Federal Columbia River Power System and Transmission System require egular and strategic investment to ensure a cost-effective level of reliability.

However, federal regulations adopted in 1996[ii] to promote competition and ensure non-utility generation resources have open access to transmission service require the employees of transmission line entities to be functionally and administratively separate from a utility's marketing and merchant employees (those involved with supplying generation to utility customers).[iii] [21] [22] [23] These Federal regulations also require transmission line owners to provide transmission users with timely and accurate transmission market data to support open competition for transmission service requests from utility and non-utility generation resources. Transmission line owners do this through an online platform called the Open Access Same-time Information System, or OASIS.[24]

Transmission line entities can also be unaffiliated with utilities. For example, BPA (not a utility) owns and operates approximately 75 percent of the transmission lines in the Pacific Northwest,[25] whereas the California Independent System Operator operates all the transmission lines in California, but does not own them.

Planning and Building Transmission Lines

The western grid is a complex system that delivers power from generators to households and businesses across western states and provinces. Robust planning is necessary to ensure the western grid maintains safe and reliable operations over time with changes in population, economic activity, technology and public policy. Transmission planning occurs at the level of individual transmission owners and is critical to regional planning entities that assess the capacity, reliability, and the potential need for transmission expansion projects. These planning efforts produce recommendations on new transmission lines that are necessary to maintain the reliability of the grid.

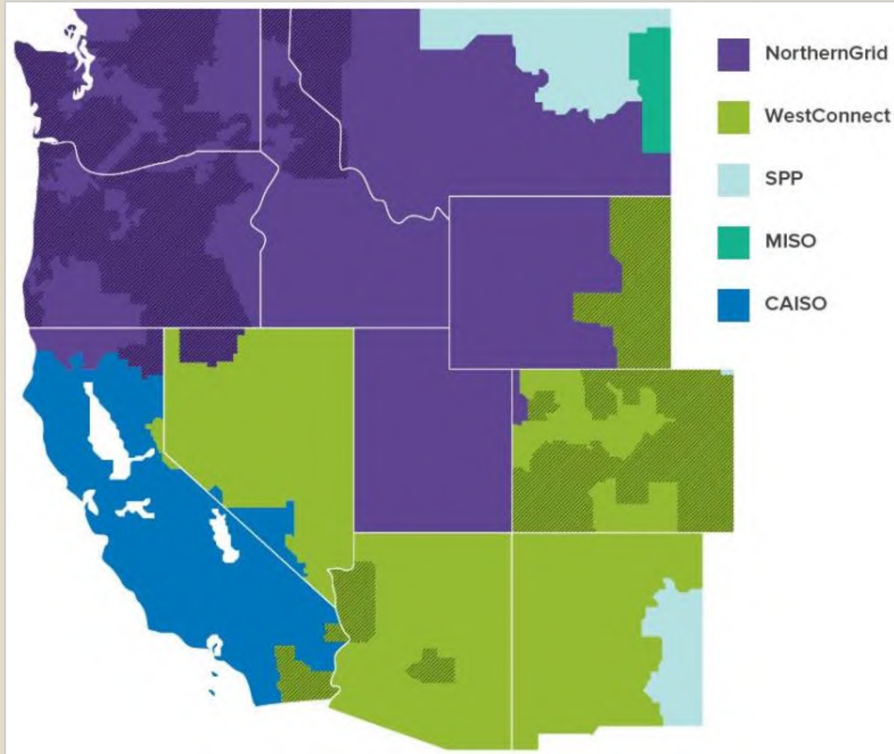
Pacific Northwest Planning Entities and Operators

In Oregon and the Pacific Northwest, regional transmission operations and regional transmission planning are controlled by different entities – individual transmission owners control the operations and pricing for sending power across their lines, and the Pacific NW's regional transmission entity, NorthernGrid, is responsible for developing the regional transmission plan. In other regions of the country, regional transmission organizations or independent system operators, such as CAISO in California, do both planning and operations. RTOs and ISOs control operations and prices for sending power across transmission lines within their region and are also responsible for developing regional transmission plans.

[ii] Federal Energy Regulatory Commission Orders 888 and 889 directed public utilities regulated under the Federal Power Act to separate their power merchant functions from their transmission reliability functions; unbundle transmission and ancillary services from wholesale power services; and set separate rates for wholesale generation, transmission, and ancillary services.

[iii] While the FERC orders that promote competition and open access transmission service do not apply directly to BPA, their intention is to promote a national policy of open transmission access. Thus, BPA elected to separate its power and transmission operations and unbundle its rates in a manner consistent with the Federal directives concerning open access transmission service. BPA develops its transmission rates in separate proceedings from its power rates.

NorthernGrid



NorthernGrid is the new regional transmission planning entity for the Pacific Northwest and Intermountain West. It launched on January 1, 2020, and combines and replaces the previous regional transmission planning entities for the Pacific Northwest – ColumbiaGrid, and the Intermountain West - Northern Tier Transmission Group. NorthernGrid began facilitating compliance with FERC transmission planning and reliability requirements on April 1, 2020.

NorthernGrid is staffed through a service agreement with the Northwest Power Pool, and has a large association of members that include Bonneville Power Administration and regulated investor owned utilities and non-regulated consumer owned utilities from Oregon, Washington, Idaho, Montana, Wyoming, Utah, and a small portion of northern California - along with non-member participation from state and tribal governments from those states.

NorthernGrid's transmission planning activities are orchestrated and implemented through several committees that conduct or assist the planning, coordination, and development of the regional transmission plan required by FERC. Together, these committees and the regional planning process provide value to the region's transmission planning and reliability through:

- Collaborative transmission planning for the Pacific Northwest and Intermountain West region
- A common set of transmission data and assumptions
- A single stakeholder forum

The cost of transmission lines is ultimately paid by utility ratepayers, and therefore state utility commissions – entities that monitor and regulate the investment decisions of privately-owned utilities, like the Oregon Public Utility Commission also have a role in the transmission planning process. Other entities involved in the planning and approval of new transmission lines include the various federal, state, and local authorities with jurisdiction over any permits that must be granted before new transmission lines are constructed.

Allocating Costs of Transmission Lines

Building transmission lines is a very capital intensive and expensive process; new transmission lines can cost upwards of $1 million per mile for a new aboveground line.[26] Underground transmission lines can reduce risks associated with wildfires and threats to wildlife, but can be as much as 10 to 15 times the cost of aboveground lines.[27] However transmission lines are constructed, there are processes to determine who bears the initial costs of new transmission lines and how those costs are allocated and recovered in customer rates, depending on which state and federal authorities have jurisdiction to regulate transmission rates.

Before the Federal Energy Regulatory Commission adopted Orders 888 and 889, to promote competition and ensure non-utility generating resources have open access to transmission service (1996), the power industry mainly consisted of utilities that owned and operated generation resources and transmission lines without any separation of the utility employees working on either side.[28] This meant local utility companies often exercised control over the construction and operation of all the transmission lines and nearly all the generating resources (non-utility entities also develop and own some generation) necessary to serve customers within the territories of their systems. Single entities controlling investment decisions in both transmission and generation assets made the determination of who will build and pay for new transmission lines relatively easy – the local utility (after approval from its state regulator), and consequently, that utility's customers. While this traditional paradigm was relatively straightforward and convenient, it also prompted concerns about whether the transmission sides of utilities were providing transmission service in favor of their own generators and discriminating against the generators of other utilities and non-utility generators (such as independent power producers).[29]

Independent Power Producers

IPPs are non-utility entities that own electricity generation. They sell their power wholesale to utilities and power marketers (such as BPA) through bilateral negotiations of long-term contracts and spot transactions in wholesale markets. A subset of IPPs, which must register with the PUC as Electricity Service Suppliers, provide retail power to certain large commercial and industrial customers.

With the anti-competitive concern in mind, Congress changed the traditional transmission paradigm with its passage of the Energy Policy Act of 1992.[30] FERC's 1996 orders carried out the act's goals, and as a result, utilities have separated their transmission functions from their generation functions to help ensure generators owned by other utilities and IPPs receive open and non-discriminatory access to the transmission services they need. Open access can increase competition between utilities and IPPs for building new generation. While open access competition can lead to lower cost generation, it can also create complexities in allocating costs among generators and transmission owners.

Regional Transmission Markets

Pacific Northwest utilities and IPPs account for and pay for the transmission of power across the region through bilateral agreements with the owners and operators of transmission lines. This is in contrast to other regions of the U.S. where power transmission is accounted and paid for through the oversight and operations of a Regional Transmission Operator (RTO).

FERC Order 888 (1996) was adopted to promote competition and ensure non-utility generating resources have open access to transmission service, which prompted the concept of RTOs.[31] Before that, electricity across the country was bought and sold through bilateral transactions and power pool agreements (e.g. Northwest Power Pool).[32] After open access requirements were established, several groups of transmission owners across the country formed Independent System Operators (similar function of RTOs) to operate the transmission system independently of wholesale market participants and develop innovative procedures to equitably manage transmission services.[33]

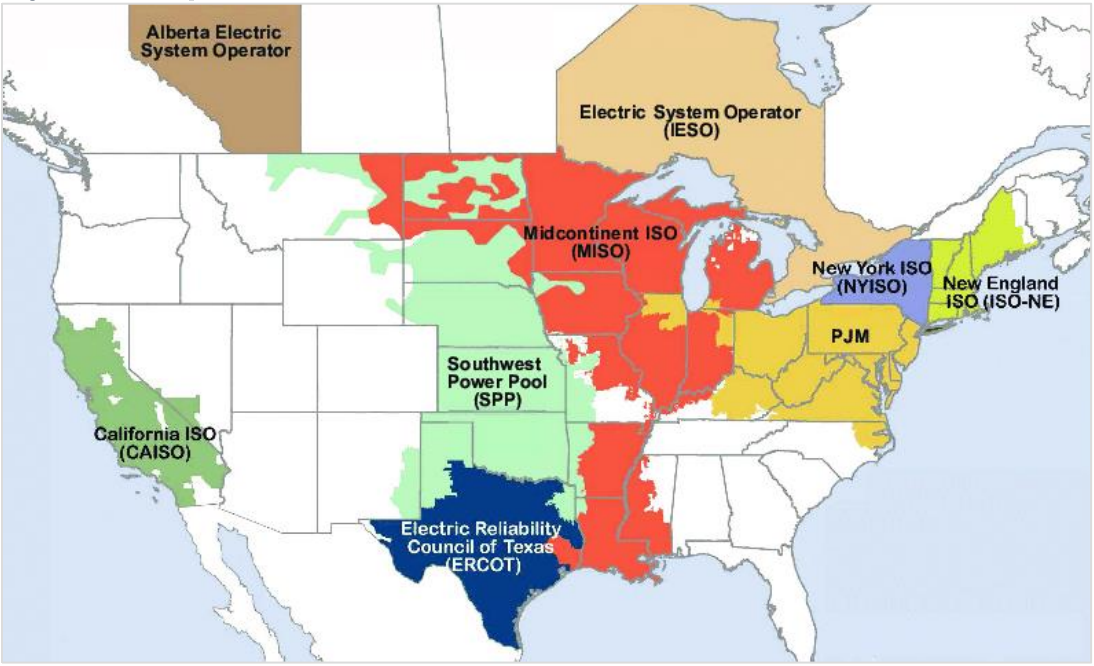
FERC Order 2000 (1999) furthered the goal of Order 888 by encouraging utilities across the country to join RTOs.[iv] [34] FERC's efforts, along with the efforts of industry and various states, led to the voluntary formation of many of RTOs (see map of current RTOs/ISOs below). RTOs and ISOs developed energy and ancillary services markets for buyers and sellers to bid for or offer generation. Energy markets are where electricity is bought and sold to meet load forecasts.[35] Ancillary services provide electricity resources that help balance the transmission system, including regulation functions that help stabilize the electricity system and reserve services that serve as backup power generation in the event additional electricity generation is required.[36] The bid-based markets are used by the RTOs and ISOs to determine the most economic dispatch of generating resources to meet customer loads.

The Northwest Power Pool

The NWPP is a voluntary organization comprised of major generating utilities serving the Northwestern U.S. and Canada. With the goal of working toward cooperative power system solutions for the benefit of its members, NWPP works on a range of topics, including arrangements for the sharing of generation supplies necessary to meet NERC reliability standards and serving as a central forum for addressing transmission concerns of its members.

[iv] FERC Order 2000 – "On May 13, 1999, the Commission proposed a rule on Regional Transmission Organizations (RTOs) that identified and discussed our concerns with the traditional means of grid management. In that Notice of Proposed Rulemaking (NOPR), the Commission reviewed evidence that traditional management of the transmission grid by vertically integrated electric utilities was inadequate to support the efficient and reliable operation that is needed for the continued development of competitive electricity markets, and that continued discrimination in the provision of transmission services by vertically integrated utilities may also be impeding fully competitive electricity markets. These problems may be depriving the Nation of the benefits of lower prices and enhanced reliability."

Figure 7: Map of RTOs and ISOs[37]



Today, two-thirds of the nation's electricity load is served in RTO and ISO regions, while major portions of the country continue to operate under more traditional bilateral market structures, notably the West (including the Pacific Northwest, but excluding California) and the Southeast.

Drivers Affecting Transmission Systems in Oregon and the U.S.

Technology advancements and policies are driving changes to the transmission system. Below are examples of current and developing topics that transmission planners and operators are considering as they make plans for upgrading the bulk transmission system.

- **Increasing Renewables.** Cost-effective solar and wind resources have been driving the need for new, relatively short gen-tie lines to interconnect to the bulk transmission grid,[38] and in some cases (such as PacifiCorp's Energy Gateway project) the need for new, much longer bulk transmission lines to deliver the electricity they generate to distant loads.[39]
- **Coal Retirements.** The number of operating coal plants has been declining[40] and analysis shows that downward trend will continue[41] while more cost-effective power generation is being added. This is giving rise to changes where generators are located and means bulk transmission lines that connect new generating resources to customer load centers may see increases in electricity traffic, while other bulk transmission lines that had been sending coal power to load centers may see reduced traffic.[42] Changing power flows can impact availability of transmission capacity, transmission congestion issues, and transmission planning.
- **Batteries.** Batteries are increasing in use due to declining costs and because they can be strategically located to improve operational efficiency of the grid. When batteries are located close to loads, they can be charged during off-peak hours to store electricity produced by distant generators, and then discharge locally during peak hours.[43] Using batteries to store electricity near load centers in advance of when it is needed has been investigated by Portland General Electric and others, and can avoid the need to utilize portions of precious peak-hour transmission capacity to deliver electricity to customers at critical times of the day.[44]
- **Distributed Energy Resources (DERs)**. The deployment and optimization of DERs will further the ability of local distribution systems to self-supply marginal portions of their overall power needs. Distributed Energy Resource is an umbrella term used to refer to any resource

interconnected to the distribution grid of a local utility, such as rooftop solar, diesel generators, energy efficiency, demand response, electric vehicles, and hardware or software control systems to communicate with the grid and/or optimize usage of other DERs.[45] As the potential for DERs expands, there will be an increasing need for utilities to evaluate DERs in their plans for new generation and transmission system capacity.

- **Increased Electrification.** Clean energy goals and requirements driven by customer preferences and state policy choices across the West may spur increased electrification of energy needs that have traditionally been met by non-electric energy supplies – such as transportation fuels and home heating. Increased demand for electricity can be met with increased energy efficiency, optimization of existing generating resources, and new generating resources – which could have implications for the bulk transmission system across the West and needs for new bulk transmission capacity.[46]

Learn more about some of these efforts, including Distribution System Planning and Energy Markets, in fellow Energy 101s, Policy Briefs, and Technology Reviews.

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Energy 101: Natural Gas

Natural gas is a fossil energy source that formed beneath the surface of the earth millions to hundreds of millions of years ago. This gas was formed from the remains of plants and animals that built up in thick layers on the earth's surface and ocean floors. Over time these layers were buried under sand, silt, and rock. Pressure and heat changed some of this carbon and hydrogen-rich material into coal, some into oil (petroleum), and some into natural gas.[1]

Natural gas is a combustible mixture of hydrocarbon gases. While natural gas is formed primarily of methane, it can also include ethane, propane, butane, and pentane. The composition of natural gas can vary widely before it is refined or processed.[2]

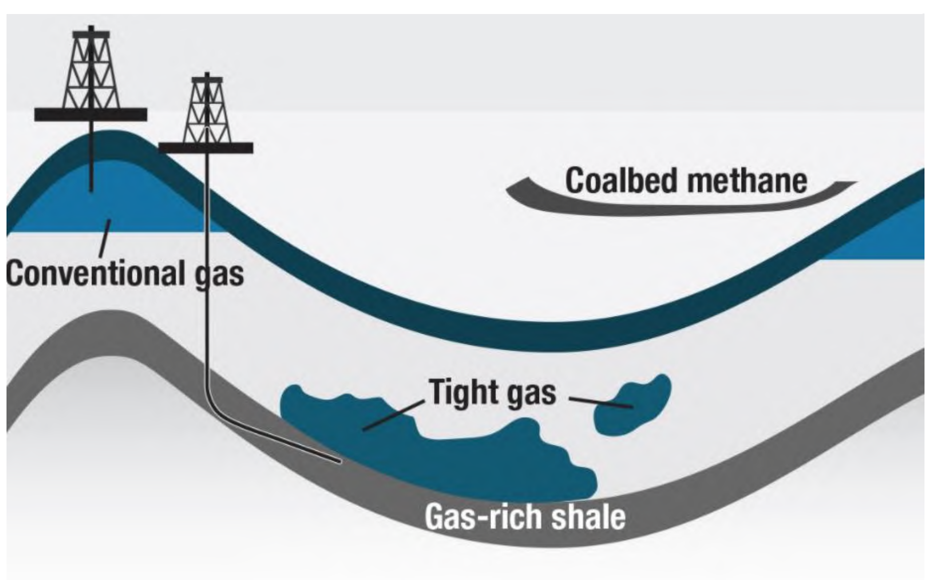
In its refined or processed form that is delivered to homes, commercial businesses, industry, and in small amounts to the transportation sector, natural gas is made up of almost pure methane, a molecule that has one carbon atom and four hydrogen atoms and is often referred to by its chemical representation CH4. Natural gas is called "dry" when it is pure methane and "wet" when it contains other liquid natural gases like butane and ethane, usually around 15 percent of the mixture.[3]

Natural gas is clear and odorless. Natural gas companies add a chemical called mercaptan, which gives the gas a distinctive smell of rotten eggs. Because humans can detect mercaptan at very low levels, the smell serves as a safety mechanism, enabling quick and easy detection of leaking natural gas. Natural gas providers are required to odorize all service and distribution lines. Some of the larger natural gas transmission lines are also odorized, but this is not required.[4]

Where is Natural Gas Found?

Natural gas can be found and extracted from several sources. It is sometimes found in large cracks and spaces between layers of rock and is referred to as conventional natural gas. In other places, natural gas is found in the tiny pores or spaces within shale, sandstone and other sedimentary rock. Natural gas found in shale formations, called plays, is referred to as shale gas and gas found in sandstone or limestone formations is referred to as tight gas. Collectively, shale and tight gas are sometimes referred to as unconventional natural gas. Natural gas can also be found with crude oil deposits, referred to as associated natural gas. Another type of natural gas is found in coal

Figure 1: Where Natural Gas is Found[5]



deposits and is referred to as coalbed methane.[5]

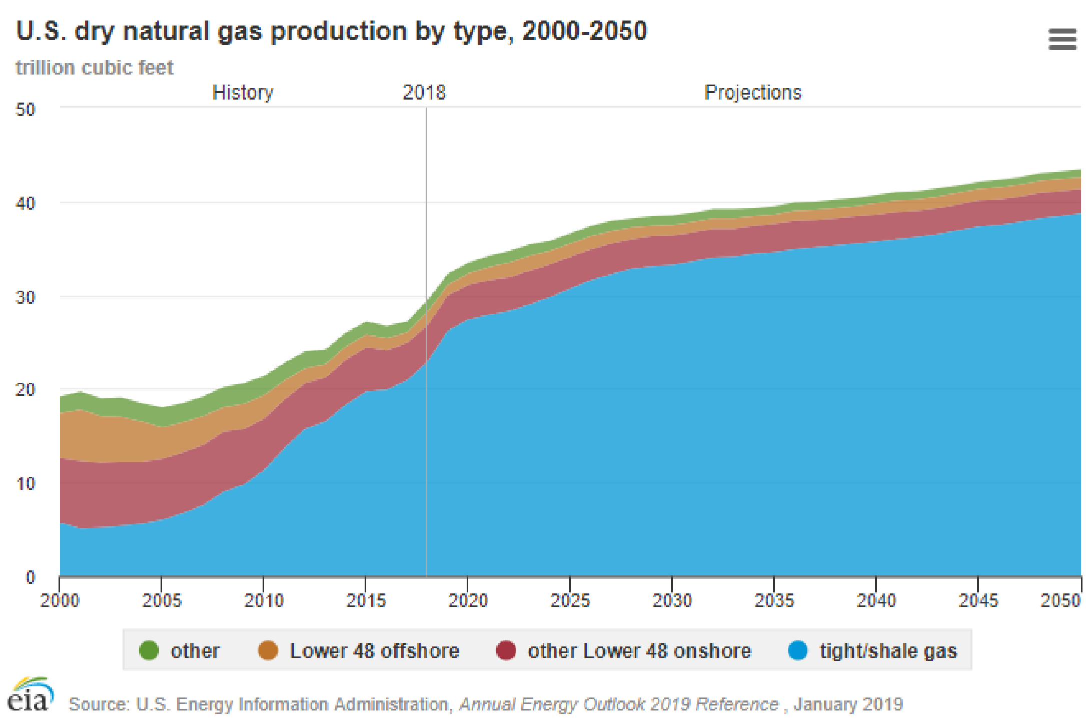
Hydraulic fracturing has made vast quantities of natural gas available that were previously economically inaccessible. The United States is ranked number one in production of natural gas and Canada is ranked number four in the world.

Table 1: World Natural Gas Production Rankings[6]

World Production – 381 Bcf/d (10.8 Bcm/d) (2018, preliminary)		
Rank	**Country**	**Percentage of Total**
1	United States	22%
2	Russia	18%
3	Iran	6%
4	Canada	5%
5	Qatar	4%

Most of the natural gas extracted and processed in the U.S. today and in the foreseeable future is from tight and shale gas plays.[7]

Figure 2: U.S. Dry Natural Gas Production by Type, 2000-2050[8]



Like in the U.S., Canadian shale and tight resource production is growing, helping to offset declines in conventional production.
In 2014, shale gas accounted for approximately 4 percent of total Canadian natural gas production while tight gas accounted for 47 percent. In 2018, Canada's average marketable production was 29 percent conventional and 71 percent unconventional, which includes shale, tight, and coalbed methane.[9] By 2035 the Canada Energy Regulator (CER, formerly the National Energy Board) expects tight and shale gas production together will represent 80 percent of Canada's natural gas production.[10]

Natural Gas Production

Because conventional oil and gas have accumulated in natural reservoirs and are typically in high-permeability source rocks, they can be acquired by vertical or directional drilling methods. A drill is attached to a series of pipes and is rotated at high speed into the underlying rock formations. Drilling mud is circulated into the hole to counter the pressure from below and cleanse the wellbore of rock fragments. When the drilling is done, a steel casing is inserted into the wellbore. Sections of the steel casing pipe are perforated with holes to allow oil or natural gas to rise to the surface by using the natural pressure from the well and pumping operations.

Unconventional gas production in formations of low-permeability shale, sandstone, or limestone requires hydraulic fracturing, often referred to as "fracking." Fracking has been used in the industry for over 150 years; the first patent for it was obtained in 1865 for an improvement in artesian well development called exploding torpedoes.[11] Hydraulic fracturing in vertical wells has been used for over 50 years to improve the flow of oil or gas from conventional reservoirs.[12] The practice of horizontal drilling combined with multiple usages of hydraulic fracturing in a single well was pioneered in the late 1980s and continued to evolve into the next century. As can be seen in Figure 2 above, as horizontal drilling and hydraulic fracturing technology was further perfected around 2005, the unconventional natural gas boom began. The technique made extracting unconventional shale and tight gas fields economically feasible.

As illustrated in Figure 1, accessing shale and tight oil plays that are in layers or pockets requires drilling a vertical well and then angling the drill and pipe toward the resource from the side rather than from above. This enables access to a greater area of the resource and can make the well more productive. Wells can be drilled for miles both vertically and horizontally. After the well has been drilled, hydraulic fracturing uses water, chemicals, and sand at high pressure to create or widen existing cracks in the rock formations and pressurizes the gas (or oil) so that it can flow more easily to the surface. This hydraulic fracturing fluid is composed of water, proppant (typically sand) to keep the newly formed rock fractures open, and chemicals.

A public website known as **FracFocus** was established by members of the fracking industry. Reporting to the FracFocus web site is mandatory in some states and voluntary in others, and lists specific materials used in many, but not all, hydraulically fractured wells. Specific formulations of some chemicals are considered trade secrets and are exempt from reporting on the site.[13]

The amount of fluid varies by site due to rock formation, the operator, whether the well is vertical or horizontal, and the number of portions or stages of the well to be fractured. Water can be up to 97 percent of the fluid used and the amount of water per well can be anywhere from 1.5 million gallons to 16 million gallons.[14] The chemicals are added for different purposes, based on the rock type and other considerations. Acids, for example, are used to dissolve minerals to help fossil fuels flow more easily; biocides eliminate bacteria; gelling agents help carry proppants into fractures; and corrosion inhibitors prevent steel parts of the well from being damaged by fracking fluid. The Environmental Protection Agency identified 1,084 different chemicals used in fracking formulas between 2005 and

2013. Common ingredients include methanol, ethylene glycol, and propargyl alcohol. Those chemicals, along with many others used in fracking fluid, are considered hazardous to human health.[15]

Much of the water and chemical additives remain deep underground in the geologic formation from which the oil or gas was extracted. However, some of the fluid returns to the surface and is referred to as "produced water", which is fracking fluid mixed with water or brine from the formation.[16] After a well is finished or brought online, large volumes of produced water are created. The produced water is typically disposed of by injecting it into the ground in the same geologic formation that the oil or gas was extracted from by wells designed for this purpose. In some cases, produced water can be treated and reused to hydraulically fracture another well. If the produced water is deemed to meet regulatory standards, the water can be discharged into local watersheds and (unless they include diesel fuel) fracking solutions are exempt from EPA regulation under the Safe Drinking Water Act.[17] Practices vary between regions, depending on regulations, geologic conditions, and water availability.[18]

Hydraulic fracturing requires a lot of heavy equipment such as high-pressure and high-volume pumps, blenders for fracking fluids, storage tanks for water, sand, chemicals, and wastewater – along with high-powered drilling rigs, casing, and drilling pipe. Typically, all the equipment, fluids, sand, and chemicals must be brought in and taken away by large heavy-duty trucks during well development, well production, and well re-fracking activity, resulting in an average of four thousand to 16 thousand trips per well (depending on the basin where the drilling activity is located).[19]

Naturally Occurring Radioactive Materials and Oregon Disposal

Natural radioactivity is present throughout the earth's crust, associated with uranium and thorium and their decay products. Certain industrial activities, like hydraulic fracturing, can result in the collection of such naturally occurring radioactive materials ("NORM") in the production water. When the water is brought to the surface for processing and reuse, the equipment used to collect, process, filter, and use the water concentrates these radionuclides in pipes, filters, sludges, or other equipment. When NORM is processed and concentrated, it is called technologically enhanced naturally occurring radioactive material, or "TENORM." TENORM wastes are not regulated federally, so it is up to each state to determine how best to manage such wastes. The increase in oil and gas fracking in recent decades led to an increase in TENORM wastes and presents a new challenge for radioactive waste management in North America.[20]

In September of 2019, a citizen tip alerted ODOE to the fact that a hazardous-waste landfill in Gilliam County had accepted about two and a half million pounds of likely TENORM waste over an approximately three-year period. The waste came from the Bakken Oil Fields, primarily in North Dakota. Because Oregon law prohibits disposal of radioactive waste within the state,[21] in February 2020, ODOE determined that this incident violated the state's prohibition on disposal of such material and issued a Notice of Violation to the landfill operator.[22]

ODOE is now working with the landfill operator and the public to assess the risk that this waste poses to Oregonians and to take steps to ensure that similar waste is not disposed of in Oregon in the future.[23] [24]

Processing Natural Gas

Once brought to the surface, natural gas must be processed to meet pipeline standards. Unrefined natural gas contains many contaminants that would damage natural gas pipelines that deliver processed gas. Some low-grade processing may be done at or near the production site, known as the wellhead. Unprocessed gas is transported from the wellhead to a central collection point using gathering pipelines. These pipelines generally operate at low pressures and flows and are smaller in diameter than transmission lines. The U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration estimates that there are 240,000 miles of gathering pipelines in the nation.[25] A complex gathering system can consist of thousands of miles of pipes, interconnecting the processing plant with upwards of 100 wells in the area.

Before natural gas can be injected into transmission and distribution lines it must meet quality and purity standards. Therefore, most natural gas is processed in the region where it was sourced. This processing consists of separating all the various hydrocarbons and fluids from the methane to produce what is called pipeline-quality, dry natural gas. Associated hydrocarbons, known as natural gas liquids, including ethane, propane, butane, isobutane, and natural gasoline, are also separated and refined at these raw gas processing facilities. Processing natural gas to pipeline quality can be very complex and will vary depending on the contents of the gas. It usually involves four main processes to remove and separate its contents:

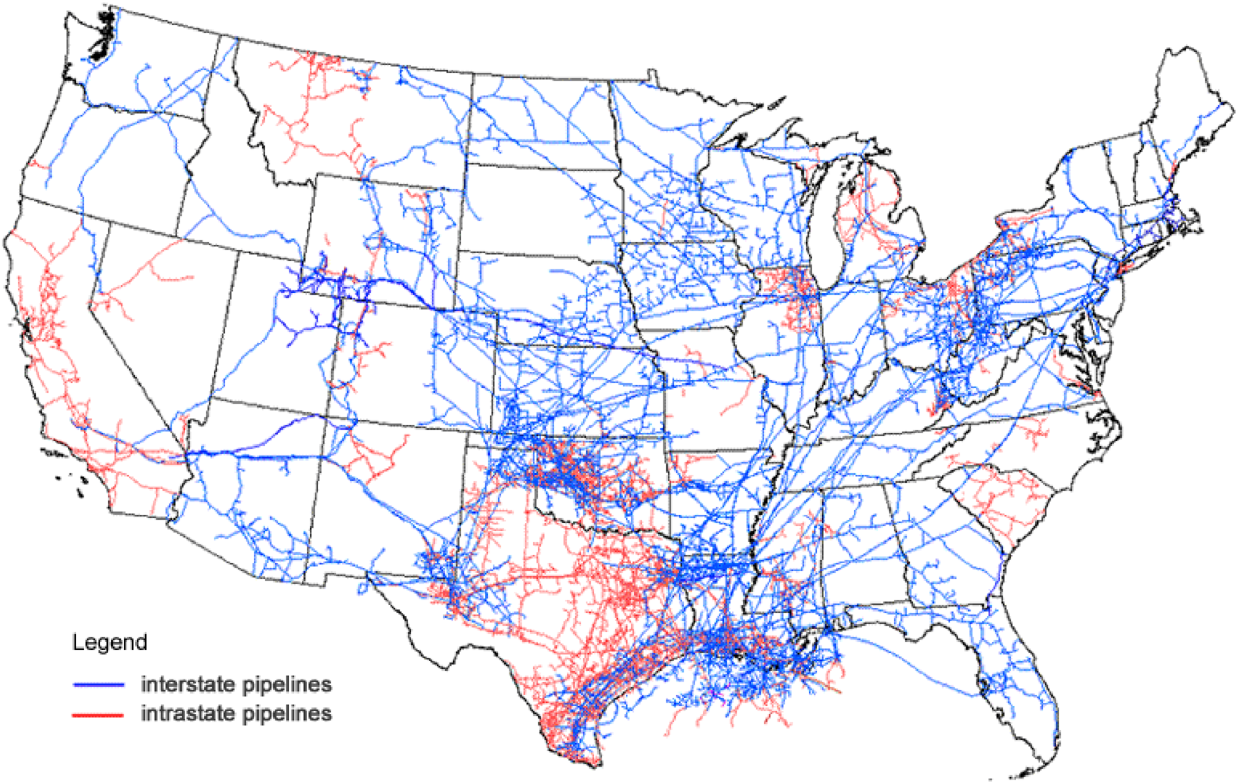
- Oil and Condensate Removal
- Water Removal
- Separation of Natural Gas Liquids
- Sulfur and Carbon Dioxide Removal

In addition to the four processes above, heaters and scrubbers are installed, usually at or near the wellhead. The scrubbers serve primarily to remove sand and other large-particle impurities. The heaters ensure that the temperature of the gas does not drop too low. With natural gas that contains even low quantities of water, natural gas hydrates can form when temperatures drop. These hydrates are solid or semi-solid compounds, resembling ice-like crystals. Should these hydrates accumulate, they can impede the passage of natural gas through valves and gathering systems.[26]

As mentioned above, propane or liquid propane gas is a by-product of natural gas processing. In the United States about half the propane consumed is from natural gas processing, the other half is from crude oil refining.[27]

After processing, the pipeline-quality natural gas is injected into gas transmission pipelines and transported to the end users, often hundreds of miles away from the wellheads and processing facilities. These pipelines are wide-diameter, high pressure interstate pipelines. Compressor stations (or pumping stations) keep the gas flowing through the system. These stations are typically powered by the natural gas in the pipeline itself. As is illustrated in Figure 3, the Northwest has far fewer transmission pipelines than other regions of the country.

Figure 3: U.S. Natural Gas Transmissions Pipeline System[28]



Source: U.S. Energy Information Administration, *About U.S. Natural Gas Pipelines*

Environmental Impacts of Natural Gas

Natural gas is relatively clean burning and results in fewer emissions of all types of air pollutants, including carbon dioxide (CO2), during combustion than burning coal or petroleum products to produce an equal amount of energy.[29] For example, about 117 pounds of CO2 are produced per million British thermal units (MMBtu) equivalent of natural gas, compared with more than 200 pounds of CO2 per MMBtu of coal, and more than 160 pounds per MMBtu of distillate fuel oil. The cleaner burning properties of natural gas have contributed to the increased use of natural gas as a lower emission option for electricity generation and transportation fuels in the United States.[30]

The increased supply and lower price of natural gas, along with its lower toxic and greenhouse gas (GHG) emissions, has resulted in several coal-sourced electric generating plants to switch to natural gas. According to data from the U.S. Energy Information Administration (EIA), 121 U.S. coal-fired power plants were repurposed to burn other types of fuels between 2011 and 2019, 103 of which were converted to or replaced by natural gas-fired plants. At the end of 2010, 316.8 gigawatts (GW) of coal-fired capacity existed in the United States, but by the end of 2019, 49.2 GW of that amount was retired.[31]

While natural gas has lower emissions when combusted than coal or distillate fuels, natural gas primarily consists of methane – an extremely volatile GHG with high global warming potential when released into the air without combusting, or what is known as fugitive emissions. Methane radiates 28-36 times more global warming potential energy per ton in the atmosphere than CO2.[32] Typically, the greatest percentage of GHG emissions from natural gas occur when combusting the gas. The remaining percentage of lifecycle emissions occurs at the wellhead, processing, transporting, and final distribution of the gas. As natural gas can easily leak from pipelines and abandoned wells, the lifecycle GHG emissions of natural gas can increase significantly if leakage is high.

In 2018, natural gas use in the residential and commercial sectors accounted for nearly 80 percent of CO2 emissions for direct fuel use, mainly used for heating and cooking.[33] The U.S. Environmental Protection Agency estimates that in 2018, methane emissions from natural gas and petroleum systems and from abandoned oil and gas wells were the source of about 29 percent of total U.S. methane emissions and about 3 percent of total U.S. GHG emissions.[34] When comparing lifecycle GHG emissions, methane leakage reduces the overall benefits of cleaner burning natural gas.[35]

Natural gas exploration, drilling, and production also pose other environmental impacts. Drilling a natural gas well on land may require clearing and leveling an area around the well site. Well drilling activities produce air pollution and may disturb people, wildlife, and water resources. Laying pipelines that transport natural gas from wells usually requires clearing land to bury the pipe. Natural gas production can also produce large volumes of contaminated water. This water requires proper handling, storage, and treatment so that it does not pollute land and other waters. Natural gas wells and pipelines often have engines to run equipment and compressors, which produce air pollutants and noise.[36]

Some oil wells also produce natural gas, and where it is not economical to transport the gas, it is burned (flared) or vented at well sites. Emissions associated with flaring and venting are referred to as fugitive gas emissions. Flaring produces CO2, carbon monoxide, sulfur dioxide, nitrogen oxides, and many other toxic compounds, depending on the chemical composition of the natural gas and on how well the natural gas burns in the flare. Venting simply releases the methane and any other contaminants into the atmosphere. While flaring can reduce overall emissions by converting methane into CO2, it is still the most carbon intensive part of producing oil.[37] In 2016, the U.S. Environmental Protection Agency issued standards aimed at reducing these emissions; however, in August 2020 the EPA, under a new administration, rolled back some requirements and rescinded others, easing methane reduction requirements for the industry.[38] These fugitive emissions account for 6 percent of global GHG emissions every year.[39]

Regulations and Standards for the Natural Gas Industry

There are several organizations that oversee, monitor, regulate, and set standards for the natural gas industry; some are identified below.

Domestic natural gas markets, particularly interstate markets, are regulated in part by the Federal Energy Regulatory Commission. For the most part natural gas moves by pipeline in the U.S. and the safety of those pipelines is in the jurisdiction of the Department of Transportation's Office of Pipeline Safety. The Energy Information Administration collects and publishes data on the industry.

In Oregon, the Oregon Public Utility Commission reviews filings and designs programs to:

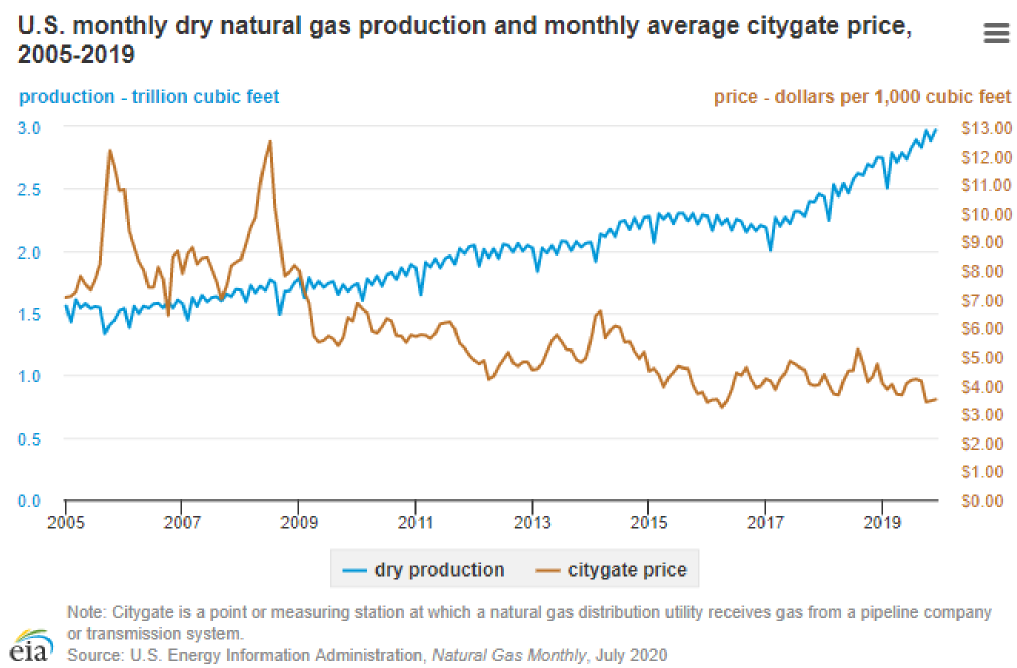
- Ensure safety, reliability, and quality of essential utility services.
- Scrutinize utility costs, risks, and performance to ensure just and reasonable rates for customers.
- Manage customer and community choices to ensure value for everyone.

- Anticipate, inform, and integrate policy, industry, market, and technology changes as the utility sector evolves.[40]

Increased Natural Gas Production and Reduced Prices

Since 2005, U.S. natural gas production has nearly doubled due to the new accessibility of the nation's shale and tight gas formations brought on by the evolution of horizontal drilling and hydraulic fracturing techniques.

Figure 4: U.S. Dry Natural Gas Production and Citygate Price[41]



As with most commodities, increases in natural gas supply usually result in lower prices and decreases in supply can lead to higher prices. Conversely, increases in demand generally lead to higher prices and higher prices tend to lower demand. Higher prices can also encourage production, while lower prices tend to have opposite effects.[42]

Three major supply-side factors affect prices:

- Amount of natural gas production.
- Level of natural gas in storage.
- Volumes of natural gas imports, exports, and transmission capacity.

Three major demand-side factors affect prices:

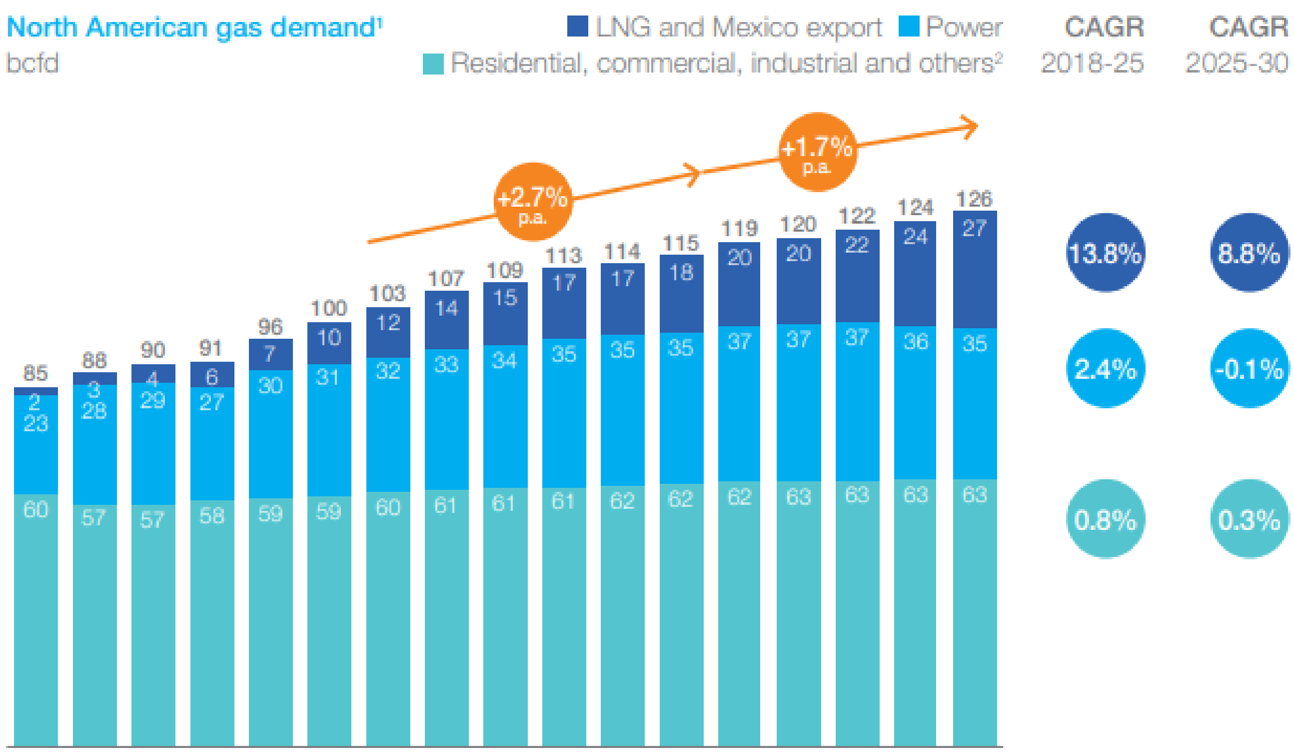
- Variations in winter and summer weather.
- Level of economic growth.
- Availability and prices of other fuels.[43]

Crude oil and petroleum product markets respond quickly and often dramatically to world events, but natural gas markets have tended to be driven by regional factors and have been less connected to the international market. This is because natural gas is less fungible than oil, meaning that crude oil and petroleum products can be more easily moved and in much larger quantities from one location to another creating more of a global market. Transporting for most natural gas is done with pipelines which makes it more difficult to move over long distances and restricts widespread trading opportunities.

Liquefied Natural Gas (LNG) is the cooled-down (-260 degrees F) liquid form of natural gas. This denser form makes it easier to transport and provides the additional safety of non-pressurized transport. More countries have supported investments in the development of LNG, including infrastructure to receive shipments and deliver gas into pipelines. This has led to LNG increasingly becoming a global commodity.[44] A flood of new supply in the last decade, due in large part to the start of U.S. exports in 2016, has helped make the flow of those seaborne cargoes more frequent, global, and flexible.[45]

As can be seen in the chart below, U.S. natural gas is seeing increased demand from both LNG exports and electricity (power) generated from natural gas. These increases are expected to continue out to 2030.[46]

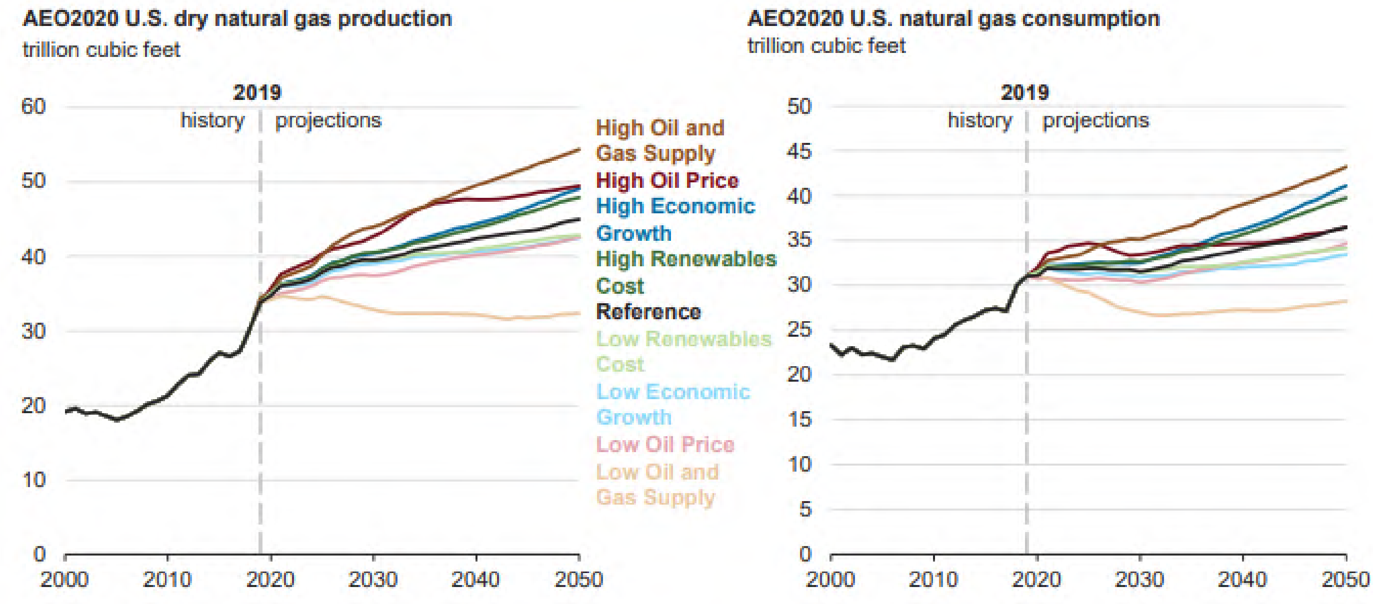
Figure 5: North American Natural Gas Demand – Historical and Forecast by Year[47]



1 Dry gas consumption in US and Canada 2 Includes pipe, plant, lease, and natural gas vehicles (NGVs)
Source: McKinsey Energy Insights Global Energy Perspective Model; EIA; NEB

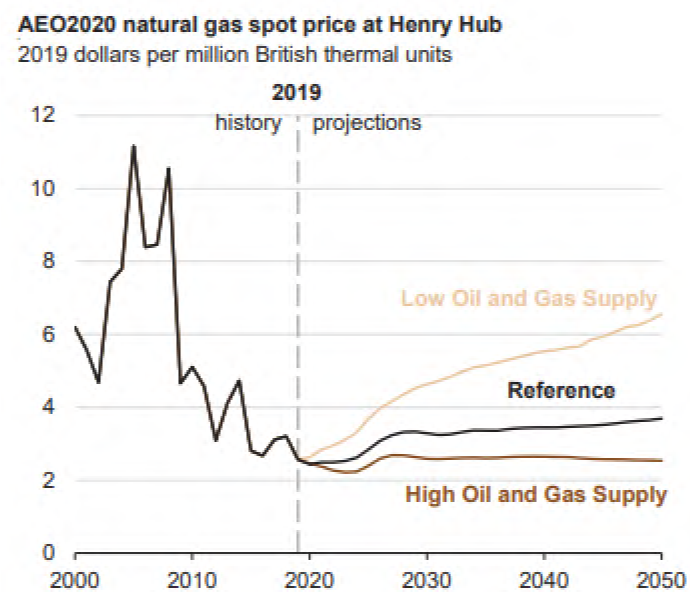
The U.S. Energy Information Administration (EIA) estimates several scenarios below for natural gas production and consumption in the U.S., with most of them showing an increase in consumption and production.

Figure 6: Energy Information Administration Annual Energy Outlook 2020 – Natural Gas Forecasts[48]



The Energy Information Administration, in its 2020 Annual Energy Outlook, estimates in its reference case that growing demand in domestic and export markets leads to increasing natural gas prices.

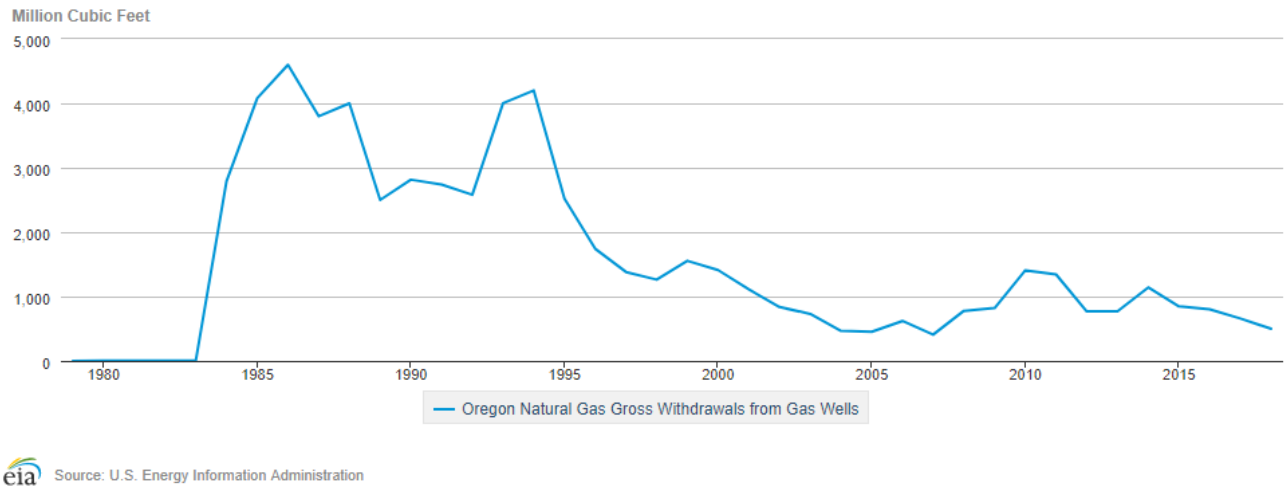
Figure 7: Natural Gas Historical and Forecast Spot Prices – EIA Chart[49]



Oregon's Sources of Natural Gas

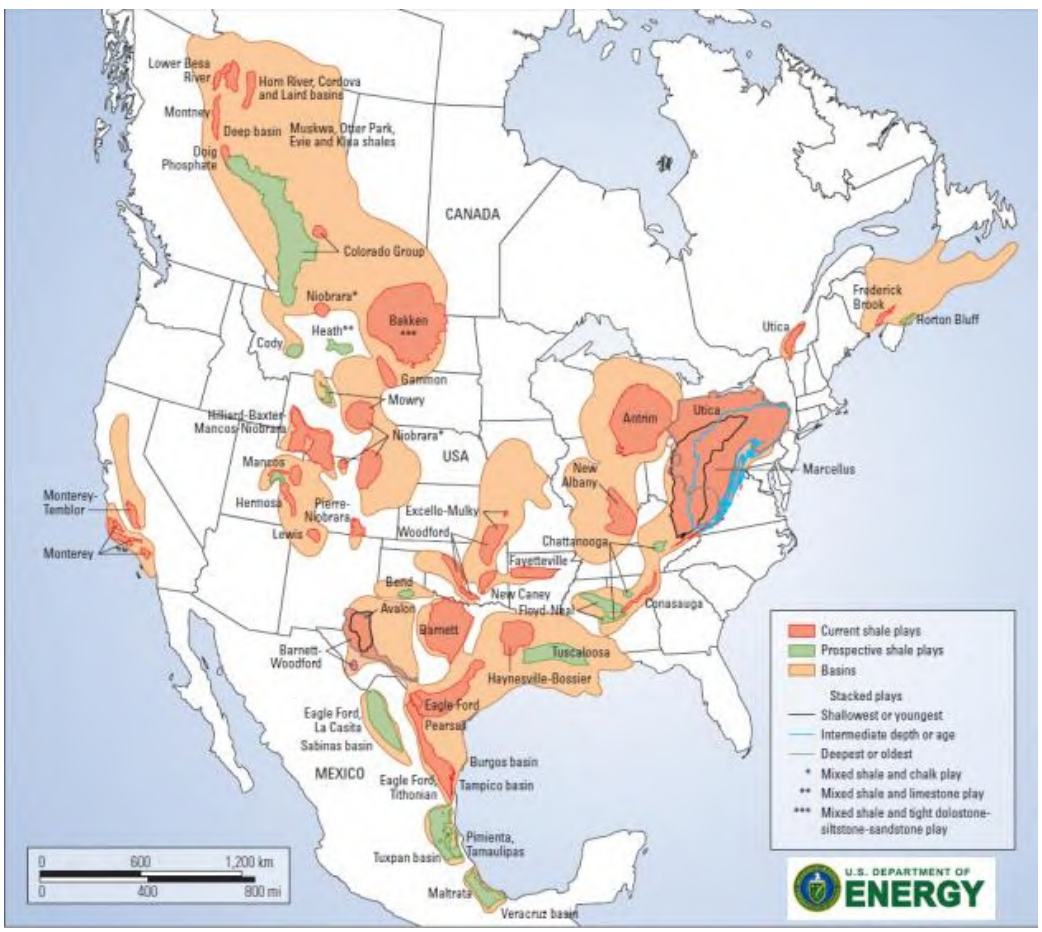
Oregon has very little in natural gas reserves. In 2018 the Mist field produced 499 MMBtu with 14 wells that accounted for less than 0.002 percent of the nation's natural gas production[50] and 0.2 percent of Oregon's total consumption[51] of natural gas. Oregon has never been a major producer of natural gas and has seen reduced rates for the last 30 years compared to the first twelve years of operation of the Mist gas field site. The field is not extensive, but the gas is at relatively shallow pockets (2200 feet) with a solid dome above it and saltwater below. This geology is good for gas storage and that is its main purpose today. Natural gas is pumped into the field in off-peak times such as summer, when prices are lower; and during times of high demand the pumps are reversed, and the gas is recovered to supplement regional supplies.

Figure 8: Oregon Natural Gas Production – Energy Information Administration[52]



As illustrated in Figure 9, there are no major sources of natural gas in the Northwest.

Figure 9: North American Natural Gas Basins - EIA[53]



In 2018, more than 90 percent of the natural gas that the United States consumed was produced in the U.S.[54] Most of the remaining 10 percent was imported from Canada. Because there are no major natural gas basins in Oregon, the natural gas that is consumed in the state must be brought in from outside of the state's borders. Due to Canada's proximity, natural gas resources, and mature infrastructure, most natural gas consumed in Oregon (up to two thirds) – depending on demand and market conditions – is imported from Canada.[55]

Three transmission pipelines provide gas transport to and through our region from major supply basins in the Rockies, Northern Alberta, and Northern British Columbia.

Figure 10: Natural Gas Major Transmission Pipelines[56]

Figure 11: Northwest Pipelines, Storage, and Natural Gas Trading Hubs[57]

The Enbridge BC Pipeline (1,776 miles, shown in red in Figure 11) serves as the main natural gas transmission line for natural gas development in British Columbia, Canada. It goes south from Fort Nelson to the U.S.-Canada border at Huntingdon-Sumas, a major natural gas trading hub. The pipeline transports about 60 percent of the natural gas produced in British Columbia and has been the backbone of B.C.'s natural gas industry since 1957. The pipeline also supplies about 50 percent of the natural gas demand in Idaho, Oregon, and Washington.[58]

The Williams Northwest Pipeline system (shown in dark blue in Figure 11) was started more than 60 years ago and has grown from 1,500 miles to a 4,000-mile bi-directional transmission system crossing the states of Washington, Oregon, Idaho, Wyoming, Utah, and Colorado. This system provides access to British Columbia sourced natural gas (where it connects to the Enbridge BC Pipeline at the U.S.-

Canada border), Alberta sourced gas (via the connection shown in purple), U.S. Rocky Mountain gas, and San Juan Basin gas supplies.[59]

The TransCanada (TC) Energy pipeline Gas Transmission Northwest (GTN) System Pipeline (shown in purple in Figure 11) begins at the U.S.-Canadian border in Idaho at the Kingsgate hub and travels south through the south east corner of Washington and then through central Oregon to the California border. The 1,378-mile pipeline delivers gas to the Pacific Northwest and California and has been in operation since 1961.[60] This border crossing provides access to the AECO-C/Nova Inventory Transfer market center that is located in Alberta and is a major long-distance transportation system which transports natural gas to points throughout Canada and to the United States. Alberta is the major Canadian exporter of natural gas to the U.S. and historically produces 90 percent of Canada's natural gas.[61]

There are several regional market hubs in the Pacific Northwest. Natural gas hubs are typically near or at gas infrastructure networks such as major pipelines and liquified natural gas terminals. A hub is used as a central pricing point for the network's natural gas.

AECO – This hub was described above and is in Alberta.

Rockies – This hub represents several locations on the southern end of the NWP system in the Rocky Mountain Region. The system sources Rocky Mountain natural gas-producing areas in Colorado, Utah, New Mexico, and Wyoming.

Sumas/Huntingdon – The Sumas, Washington pricing point is on the border and gives our region access to Canadian production from predominately Northern British Columbia.

Malin – This pricing point in Malin, Oregon, is on the California/Oregon Border where TC Energy's GTN and Pacific Gas & Electric company connect.

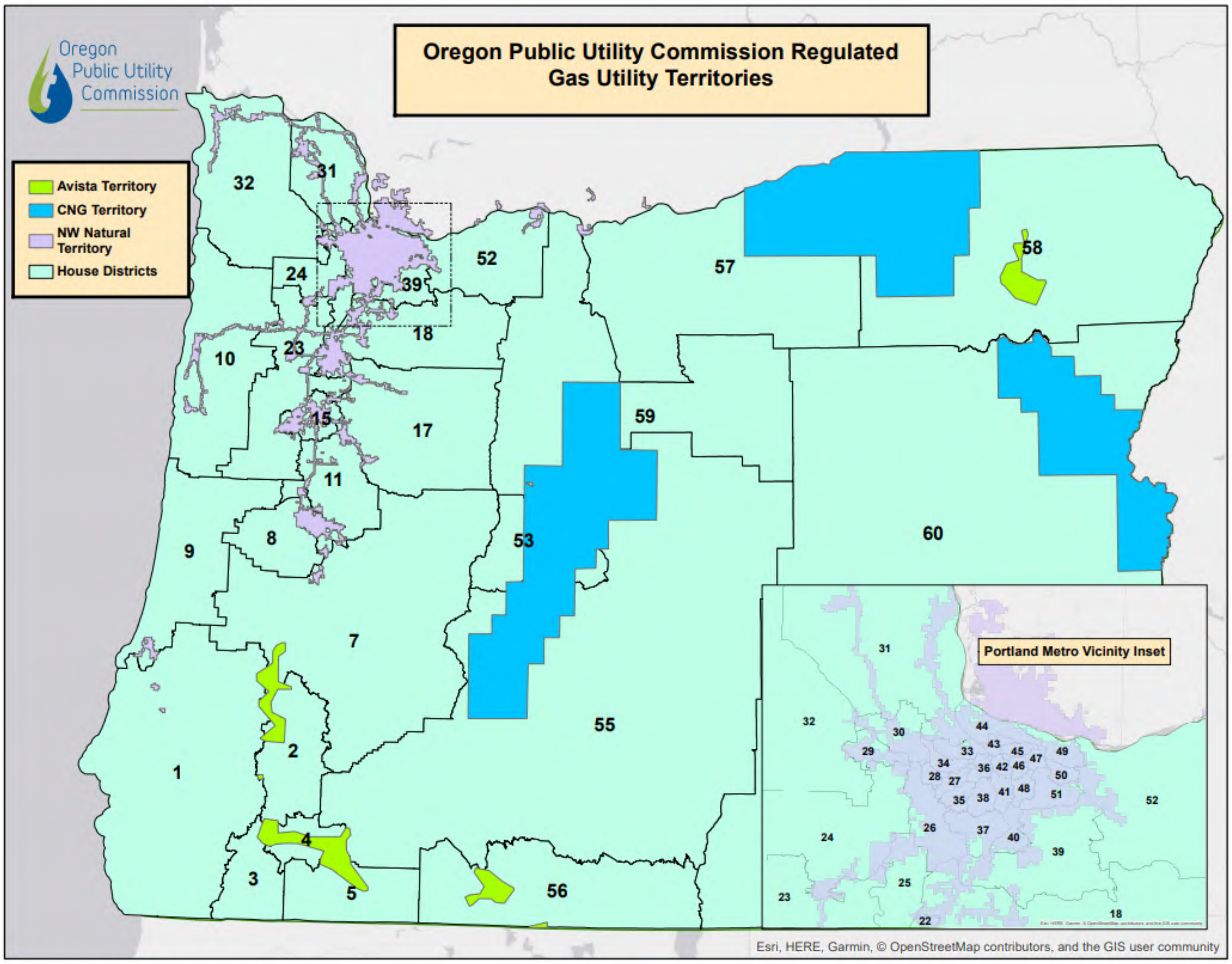
Station 2 – Located at the center of the Enbridge Westcoast Pipeline system connecting to northern British Columbia natural gas production.

Stanfield – Located near the Washington/Oregon border at the intersection of the NWP and GTN pipelines.

Kingsgate – Located at the U.S./Canadian border in northern Idaho where the GTN pipeline connects with the TC Energy's Foothills pipeline.

Three companies provide natural gas service in Oregon, Avista Corporation, Cascade Natural Gas, and NW Natural. See Figure 12 below for the location of their service territories.

Figure 12: Natural Gas Utility Service Territories[62]



These companies have a joint in-state workforce of over 1,160 employees serving more than 780,000 residential, commercial, and industrial natural gas customers.[63]

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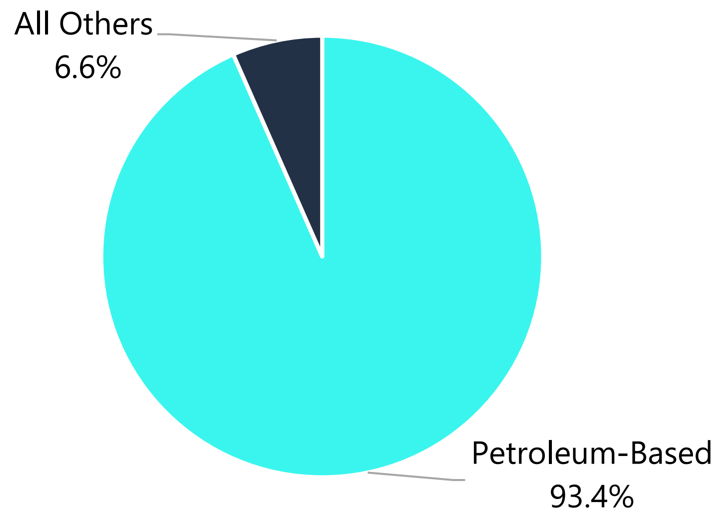
Energy 101: Oregon's Petroleum-Based Transportation Fuels

Introduction

In 2018, Oregon's petroleum-based transportation fuels – gasoline, diesel, jet fuel, aviation fuel, and lubricants processed from crude oil[i] – accounted for 93.4 percent of Oregon's transportation fuel consumption, with 6.6 percent of the fuels coming from alternative sources. For on-highway fuels, alternative fuel use is on the rise; it has increased from 1.2 percent in 2005 to 8.7 percent in 2019.[1]

Figure 1: Petroleum-Based vs. Alternative Fuels in Oregon (2018)[1]



Low-carbon transportation fuels such as renewable diesel and electricity show great promise of increasing market share, but it has been a slow process to transition the transportation fleet and install the necessary infrastructure to enable increased adoption of these fuels. While petroleum-based fuels will continue to play a major role in the transportation sector, gasoline and diesel fuel's combined share of total transportation energy consumption in the U.S. is expected to decrease from 84 percent in 2019 to an estimated 74 percent in 2050.[2]

The Pacific Northwest has no crude oil resources and is isolated from the nation's major petroleum production regions in Texas, North Dakota, and Alberta, Canada. Because of this lack of resources and the added cost of getting the crude here, the region pays more for transportation fuels than many parts of the country. Over the last 10 years the mix of crude resources that feeds into northwest refineries has changed, resulting in changes in how crude oil gets here for processing and refinement. Large amounts of crude are now delivered by rail, and most of these crude rail shipments travel through the Columbia River Gorge and Portland before moving up to Washington refineries. Since 2011, Washington refineries have seen increased amounts of crude from the Canadian oil sands.[17,18] This crude has a higher carbon intensity than other crude resources, meaning more greenhouse gas emissions are emitted per gallon of fuel, because it requires more greenhouse gas-emitting energy to extract and process.

[i] This also includes asphalt and road oil, which are not technically fuels, but are processed from crude oil and used in the development and upkeep of roads and highways. The U.S. Department of Energy's Energy Information Administration includes these as "transportation fuels."

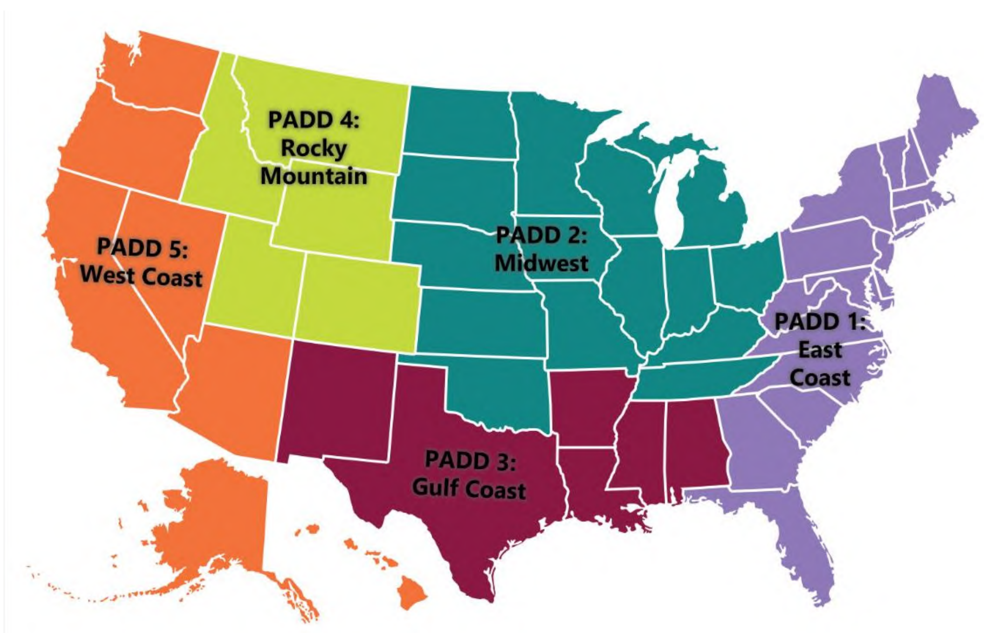
Overview

All petroleum fuels are derived from crude oil, which is called a fossil fuel because it is a mixture of hydrocarbons that formed from the remains of animals and plants (diatoms) that lived millions of years ago. Crude oil is found in liquid or gaseous form in underground pools or reservoirs, and within sedimentary rocks. It can also be found near the earth's surface in tar or oil sands. Crude oils vary in color due to their distinct chemical compositions. Two of the most important attributes when comparing the qualities of different crude oils are sulfur content and density. These have implications for how easily the crude can be extracted, processed, and refined. All of this has implications for greenhouse gas emissions and costs associated with the entire process from extraction to refinement.

Crude oil is extracted using several methods depending on the geology of where it is located. Once extracted, some crude oils, such as oil sands, need to be processed before they can be transported to a refinery or other processor. Crude is transported to refineries by pipeline, water vessel, rail, and sometimes truck.

Refineries separate the different parts of crude oil by selective boiling and condensation (distillation), which separates it into different liquids and gases, and then they blend or add other oils and liquids during processing to produce finished products. In addition to producing petroleum products such as gasoline, diesel fuel, heating oil, jet fuel, waxes, lubricating oils, and asphalt, the process also results in several byproducts that are used in other industries. These petroleum fuels are then transported, typically by pipeline or water vessel, to terminals where they are then shipped, usually by truck, to fueling stations.

Figure 2: Petroleum Administration for Defense Districts (PADDs)

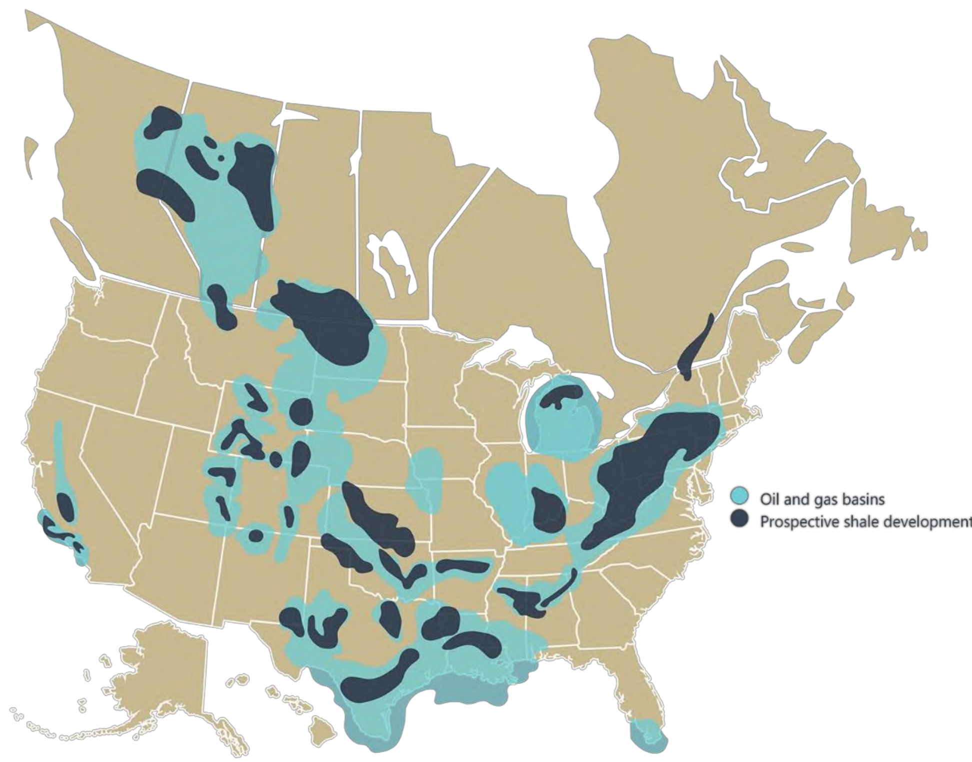


Crude oil and petroleum product movements are tracked across the U.S. through five geographically divided areas of the country called Petroleum Administration Defense Districts – or PADDs. The districts themselves were initially created in World War II to track and ration gasoline. Since 1950 the PADDs have been used to collect data and information to better assess and understand the supply and demand of the domestic petroleum business.[3] Oregon is part of PADD 5, a region that includes the western states of California, Arizona, Nevada, Oregon, Washington, Alaska, and Hawaii. There are six distinct regional markets within PADD 5: Southern California and Southern Nevada; Northern California and Northern Nevada; Arizona; Hawaii; Alaska; and the Pacific Northwest, which consists of Washington and Oregon.

There are 22 operating petroleum refineries in PADD 5, five of which are located on the Puget Sound in Washington state. These five refineries provide more than 90 percent of the refined petroleum products used in Oregon.[4] The remaining less than 10 percent comes from the San Francisco Bay Area and PADD 4 refineries in Salt Lake City, Utah, but can change to include other sources.[5]

Crude Oil Sources for Washington Refineries

Figure 3: Oil and Gas Basins and Prospective Shale Development



The Northwest region has no major oil basins or shale plays and therefore must import crude oil from other states and countries to Washington's refineries to be processed into petroleum products (Figure 3 at right).

Figure 4 provides information on Pacific Northwest crude resources since 2011. The data presented here is a composite of multiple data sources to build a picture of crude oil resource trends over the last nine years,and is based on publicly-available data. Comprehensive domestic crude oil input information into the five refineries in Washington has been inconsistent over the last nine years and is not available for 2012 to 2014 and 2016. As such, the data from these years are not included in the figure below. Since late 2016, quarterly data on all crude oil movement inputs has been collected and published. However, these reports do not make a distinction between Canadian conventional and Canadian oil sands.

Figure 4: Washington Refinery Crude Inputs by Year[6]

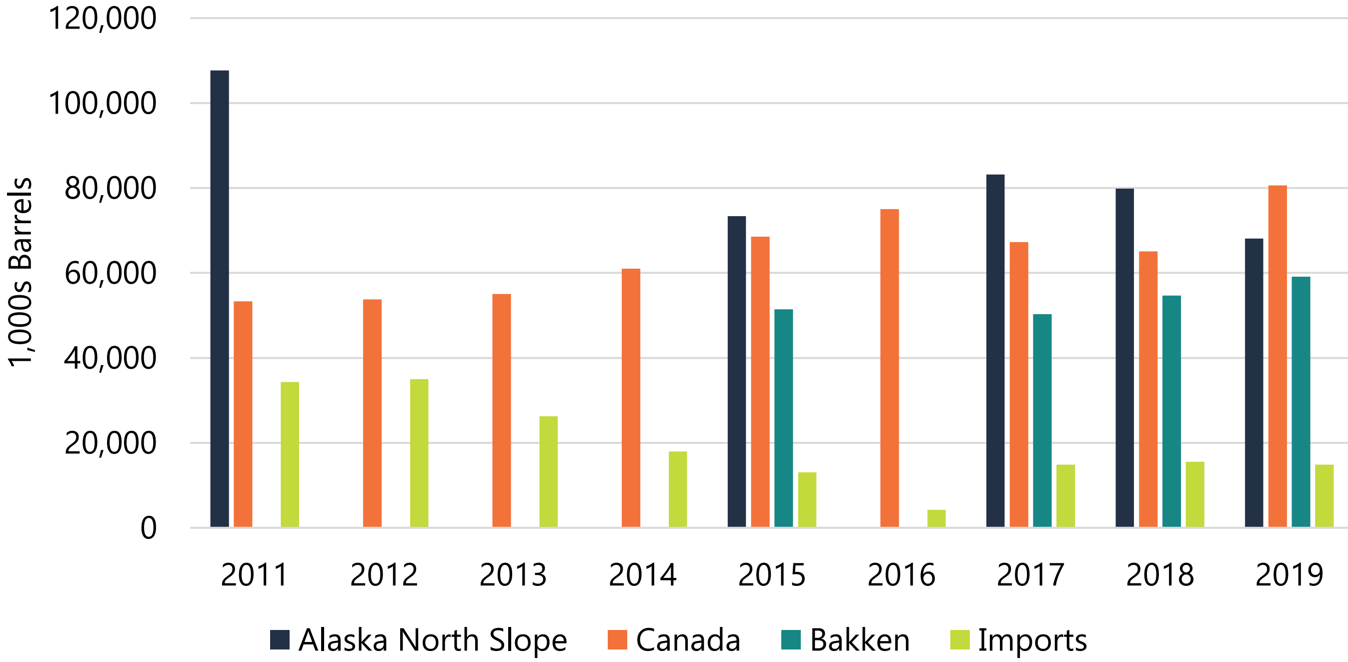
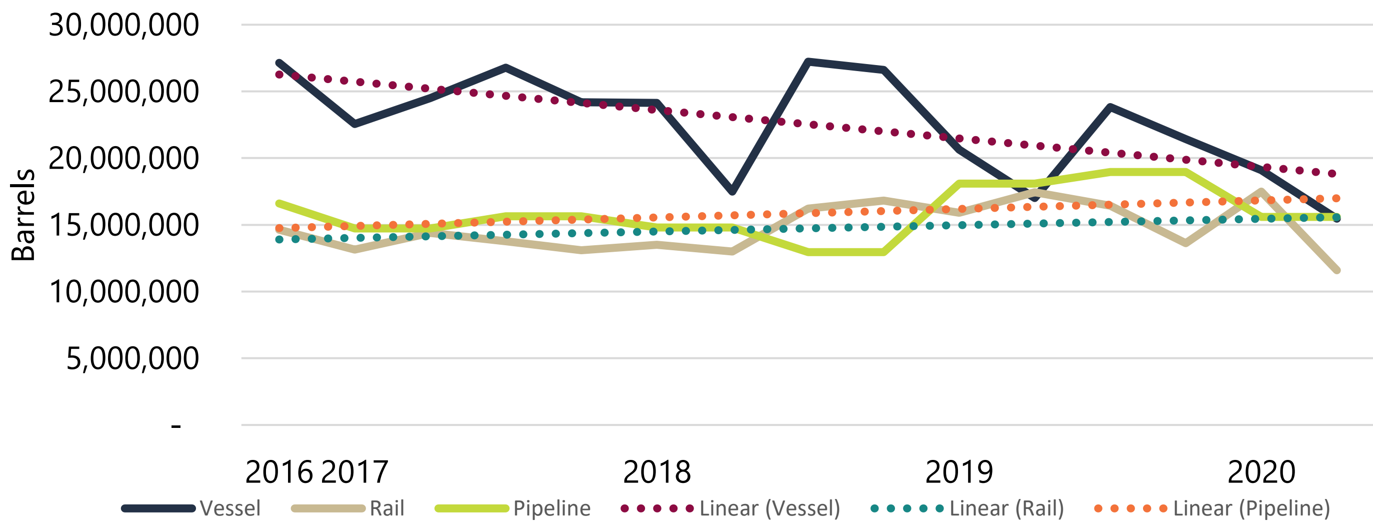


Figure 4 shows that crude oil resources for Oregon's transportation fuels are increasingly originating in Canada and the Bakken oil fields in North Dakota with decreasing amounts from the Alaskan North Slope and off-continent crude oil importers such as Russia and Saudi Arabia. Crude from North Dakota increased dramatically from zero barrels delivered in 2011 to over 59 million barrels delivered in 2019, for a 27 percent share of total crude oil delivered. In this same time period, Canadian crude oil barrels delivered increased by 34 percent, from a 27 percent share to a 36 percent share of total crude.

Apart from Canada, the top five importers, for the 2011 to 2019 time period, in order are: Russia, Saudi Arabia, Angola, Argentina, and Brazil. Over this time, 19 other countries have delivered crude oil product to the five refineries in Washington in lesser quantities. Overall, off-continent imports have decreased by 60 percent between 2011 and 2019 from 37.2 million barrels to 14.8 million barrels.[7]

Figure 5 illustrates trends in crude oil shipments to Washington refineries by shipment type and origin. Shipments by vessel include Alaska North Slope and foreign shipments from countries like Russia and Saudi Arabia. As can be seen by the dotted trend lines in the chart, crude oils delivered by vessel are trending down and crude oils delivered by pipeline and rail are trending up.

Figure 5: Washington Crude Oil Deliveries[8]



2016 data only available for Q4.

Carbon Intensities of Different Sources of Crude

Lifecycle greenhouse gas emissions from petroleum production can be very different from source to source. Crude oils will have high GHG emissions per unit of energy produced if they rely on energy-intensive production methods or do not apply effective controls to fugitive emissions sources. In contrast, some crude oil sources can have lower greenhouse gas emissions if they rely on less energy-intensive production methods and have controls.[9]

Table 1 shows values used in 2015 by the Oregon Clean Fuels Program to set carbon intensity values, for gasoline and diesel as part of their analysis. These values represent the lifecycle GHG emissions from initial exploration to the refinery gate. As can be seen, the GHG emissions from Canadian oil sands are the most carbon-intensive of all crude oil resources refined in Washington state, followed by Alaska North Slope crude oil, and then Russian crude oil.

Table 1: Average Crude Oil Carbon Intensity by Geographic Crude Oil Source[10]

Crude Source	Average Crude Carbon Intensity (gCO2e/MJ)[ii]
Oil Sands Canadian	23.88
Alaska	15.91
Russia	11.36
Bakken	9.73
Argentina	9.72
Saudi Arabia	9.24
Ecuador	9.19
Conventional Canadian	8.4
Brazil	5.87

[ii] MJ is the abbreviation for Megajoule, which is a measurement of energy. MJ is the standard for quantifying greenhouse gas in relation to energy units in the transportation sector. A MJ is equal to 947.82 Btus or British Thermal Units. A Btu is the amount of energy required to increase the temperature of one pound of water by one-degree Fahrenheit.

Oregon Clean Fuels Program Makes a Difference

In 2020, the City of Ashland installed free public EV chargers using Oregon Clean Fuels Program credits.

In 2009, the Oregon Legislature adopted a new low-carbon fuel standard focused on reducing greenhouse gas emissions from the state's transportation sector, and tasked the Oregon Department of Environmental Quality to implement the new standard. In 2016, the Oregon Clean Fuels Program was born, with a goal to reduce transportation GHG emissions by 10 percent by 2025.

DEQ's Oregon Clean Fuels Program Manager Cory Ann Wind joined the Oregon Department of Energy in October 2020 to record a *Grounded* podcast episode about the program. "Oregon's program can seem complex," said Wind. "But what it comes down to is being a system of credits and deficits for businesses participating in the program."

The Clean Fuels Program takes into consideration the varied types of fuels that enter Oregon, since 100 percent of petroleum fuels are imported into the state, and develops a statewide carbon intensity average. Fuel providers participate in the program and earn credits for fuels that are less carbon intense than the statewide standard, or earn deficits for fuels that are more carbon intense. The providers are required to "retire" credits that are equal to the deficits they create – so a business that has more deficits than credits can purchase extra credits from a business that has credits to spare. The revenue from the credits sold pays for projects that lower GHGs, such as electric fleets and charging stations.

The standard changes annually to become more stringent to further reduce transportation GHGs. When the program began in 2016, it required a 0.25 percent reduction in carbon intensity. Now in its fifth year, the program requires a 2.5 percent reduction – this means those high-intensity fuels create more deficits that will need to be offset.

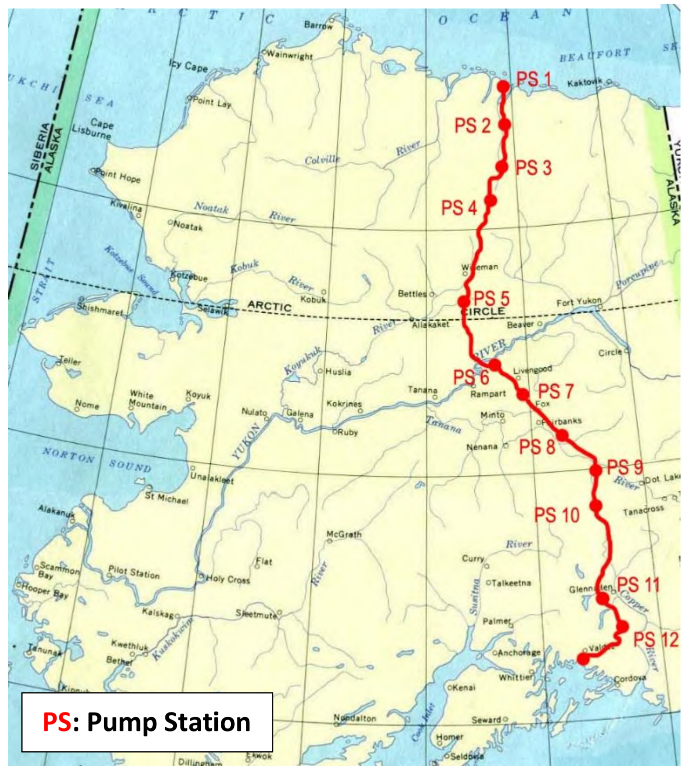
From the start of the program through the end of March 2020, the Oregon Clean Fuels Program has reduced GHG emissions by over 4.3 million metric tons. Going forward, Oregon DEQ will continue its good work to support cleaner air and a healthier environment for future Oregonians. Learn more about the program on DEQ's website: www.oregon.gov/deq

Tune in to hear Cory Ann's full *Grounded* podcast episode on your favorite podcast app or on ODOE's blog: https://energyinfo.oregon.gov

Alaskan North Slope Crude Oil

Alaskan North Slope (ANS) crude oil is sourced from fields in the Prudhoe Bay area in the Arctic Circle. It is then transported across Alaska about 800 miles in the Trans Alaskan Pipeline System to the Valdez Marine Terminal, where it is loaded onto marine vessels and delivered to several ports. Alaskan crude oil makes a 1,400-mile journey to arrive at the five Northwest refineries. ANS crude oil has a relatively high carbon content and is typically the second-highest carbon intensity of the crude oils refined in the Pacific Northwest – only Canadian oil sands have a higher carbon intensity. Much of the lifecycle carbon from ANS fuel is due to the fossil energy expended to explore, drill, process, and store the crude oil in the harsh conditions of the Prudhoe Bay region as well as the two-stage transport of the fuel to the Northwest market.

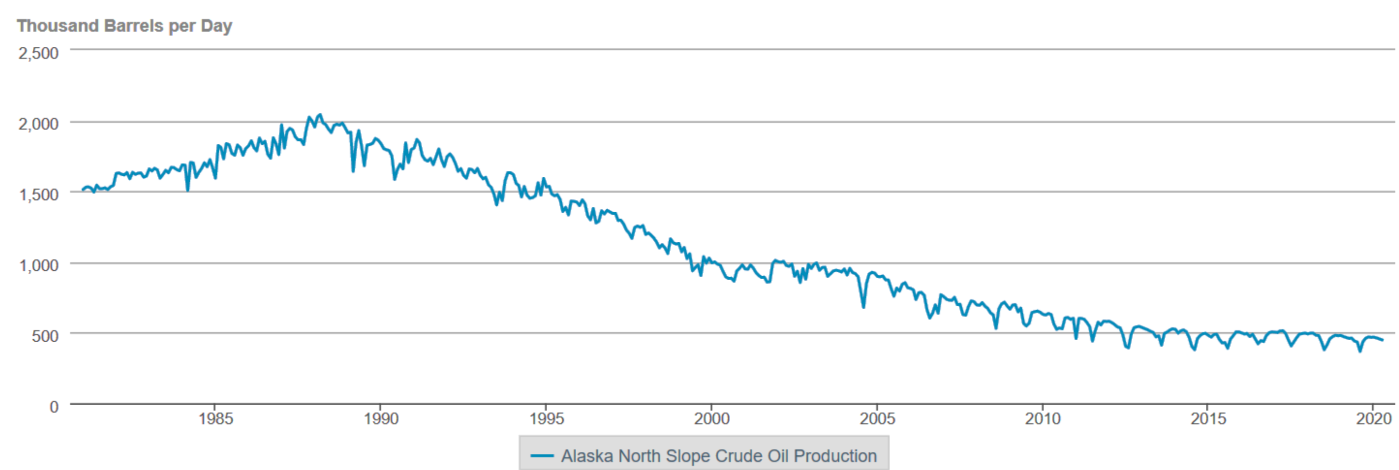
Figure 6: Trans-Alaska Pipeline System



Solcom House: map in the public domain.

One of the primary reasons for the reduction of ANS crude oil going to Northwest refineries is that production has declined since 1988. Once producing over 2 million barrels a day, the field only averaged 466 thousand barrels a day in 2019 (a decline of over 75 percent).[11] In 2003, ANS accounted for 90 percent of Washington refinery crude oil inputs,[12] and by 2019 it had decreased to 31 percent (a decrease of 66 percent). Between 2017 and 2019 alone there was approximately an 18 percent decrease in Alaskan crude oil imported into Washington State refineries.[13]

Figure 7: Alaska North Slope Crude Oil Production[14]



Source: U.S. Energy Information Administration

Canadian Crude Oil

Canada was ranked fourth in production of petroleum in the world in 2018, behind the United States, Russia, and Saudi Arabia.[15] Canada is the largest source of crude oil imports to the U.S., and accounted for 36 percent of crude oil inputs into Northwest refineries in 2019.

Canadian crude oil is imported to all five PADDs in the U.S. Despite Canada being the largest source of imports to our region, PADD 5 receives only a small percentage (about 6 percent in 2019) of Canadian crude oil imported into the U.S.

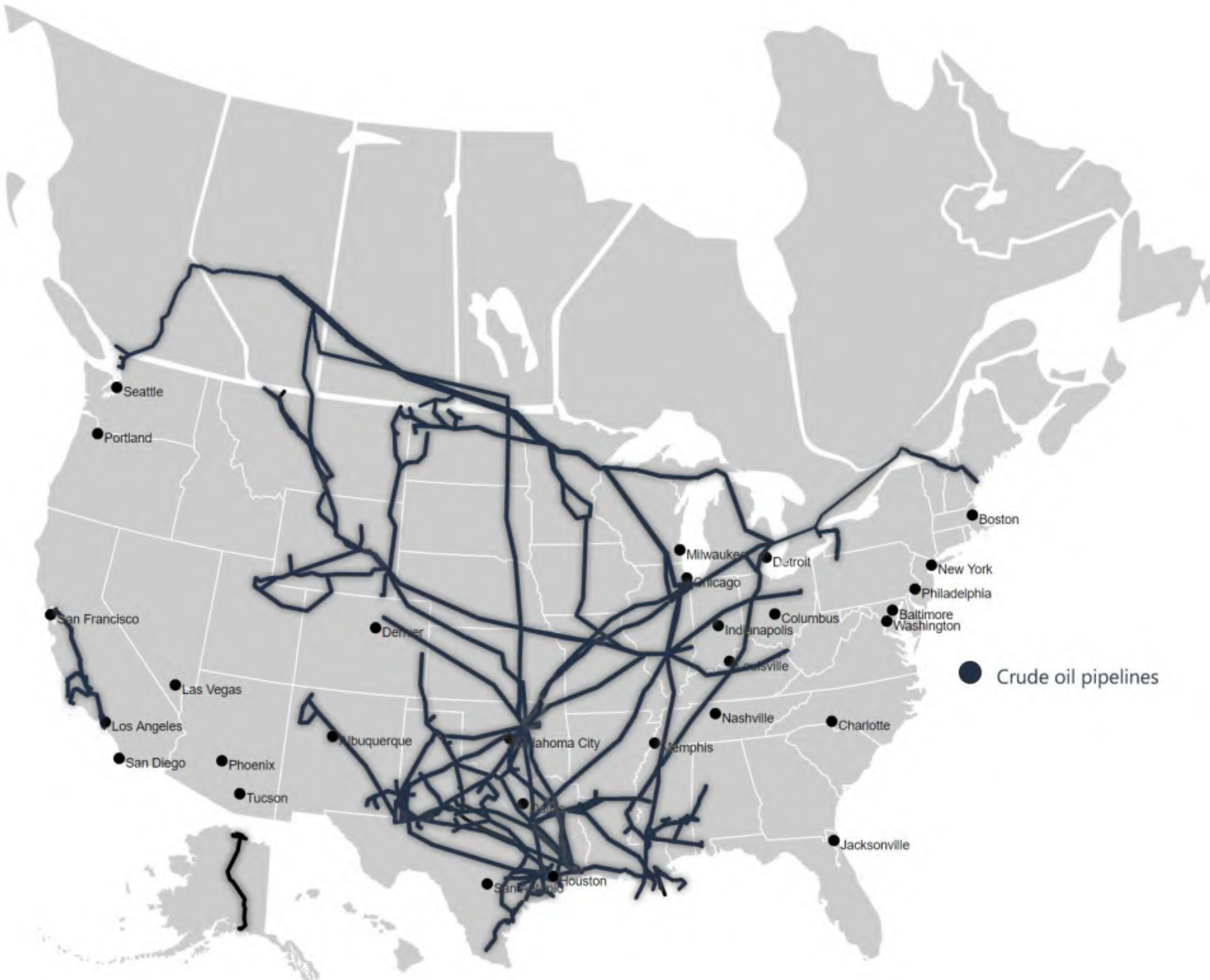
Table 2: Canadian Crude Oil Imports by PADD (1,000s of Barrels/Year)[16]

	2014	2015	2016	2017	2018	2019
PADD1	102,546	92,196	77,372	73,555	75,774	80,488
PADD2	712,605	758,347	788,469	859,480	903,077	927,144
PADD3	70,536	123,494	133,324	144,615	180,246	181,106
PADD4	90,356	101,637	96,485	97,061	111,103	111,976
PADD5	75,946	80,943	85,420	83,196	83,007	89,858

The Canadian crude oil imported to Washington refineries is sourced primarily from Alberta. The oil sands in this province are about 96 percent of the province's proved (recoverable) oil reserves and accounted for 64 percent of Canada's oil production in 2018.[17] From 2011 to 2015 imports of Canadian crude oil to Washington refineries from Alberta increased by 36 percent, and oil sands crude increased from 7 percent[18] to 11 percent, from 14.2 million barrels to 22.4 million barrels.[19] Overall, Canadian imports to Washington refineries increased by 15 percent from 2015 to 2019. While the exact percentage of oil sands crude out of the total imported crude oil from Canada in 2019 is not publicly available, a recent report from the U.S. Energy Information Administration (EIA) states that the growth in Canada's liquid fuels production come from these oil sand sources.[20] Therefore, it is likely that oil sands imports will increase as a share of the Washington refinery input crude mix.

Oil sands are a mixture of sand, water, clay, and a type of oil called bitumen. Extracting bitumen is very energy intensive, which makes this form of crude oil highly carbon intensive[21] and therefore emits the highest lifecycle GHG emissions of any of the crude oilsthat are input into the five Washington refineries.[22] Alberta oil sands crude oil is three times more carbon intensive than conventional Canadian crude oil. In addition, extracting and processing bitumen has environmental effects, including air, land, and water pollutants that can affect the health of the area's residents.

Figure 8: Crude Oil Pipelines in North America



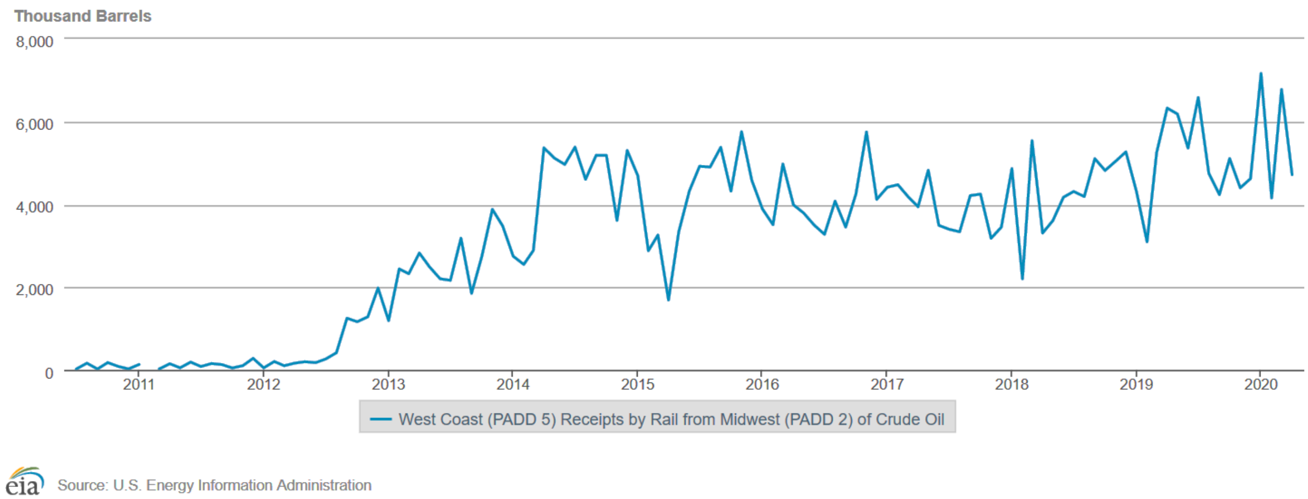
Canadian crude oil is primarily transported to the Washington refineries via the Trans Mountain Pipeline System. This system has been in operation since 1953 and spans approximately 715 miles. Beginning in Edmonton, Alberta the pipeline terminates in Burnaby, British Columbia on the western coast. Twenty-three active pump stations located along the pipeline route maintain the line's approximately 300,000 barrel per day capacity flowing at a speed of approximately five miles per hour. At the Sumas delivery point in Abbotsford, BC, the Trans Mountain Pipeline connects with the Trans Mountain Puget Sound Pipeline, a system that has been shipping Canadian crude oil products since 1954 to Washington refineries in Anacortes, Cherry Point, and Ferndale. This 69-mile pipeline system has a capacity for up to 240,000 barrels per day. Because these pipelines have been operating at capacity for many years, rail now supplements transport of the crude oil to Washington refineries.

Bakken Shale Oil

The Bakken shale, a region of oil located in Eastern Montana and Western North Dakota as well as parts of Saskatchewan and Manitoba, was discovered in 1951. Oil shale is oil-infused rock formations, which were not cost-effective to recover on a large scale until the introduction of modern horizontal drilling and hydraulic fracturing techniques about a decade ago.[23] The Bakken shale became commercially viable about the same time crude supplies from Alaska were declining and the Canadian

Trans Mountain Pipeline had reached capacity. Refiners in Washington state began to import Bakken oil to meet their input needs. Because there are few pipelines in or near the Bakken formation, much of its crude oil is transported by rail, including to the refineries in Washington.

Figure 9: West Coast (PADD 5) Receipts by Rail from Midwest (PADD 2) of Crude Oil[24]



Bakken crude oil has averaged 25 percent of Washington refineries crude oil input from 2017 through 2019.[25] The journey of about 1,600 miles from the Williston oil basin in North Dakota to the refineries in Washington includes a stretch through Oregon's Columbia River Gorge and then on into Portland. From 2018 to 2020 Q2, an average of 1,665 rail tank cars per week carrying an average of 49 million gallons of crude oil have made this rail journey.[26] Some additional crude oil is shipped through Oregon to destinations in California.

Figure 10: Estimated Crude Oil by Rail (January - March 2020)[27]

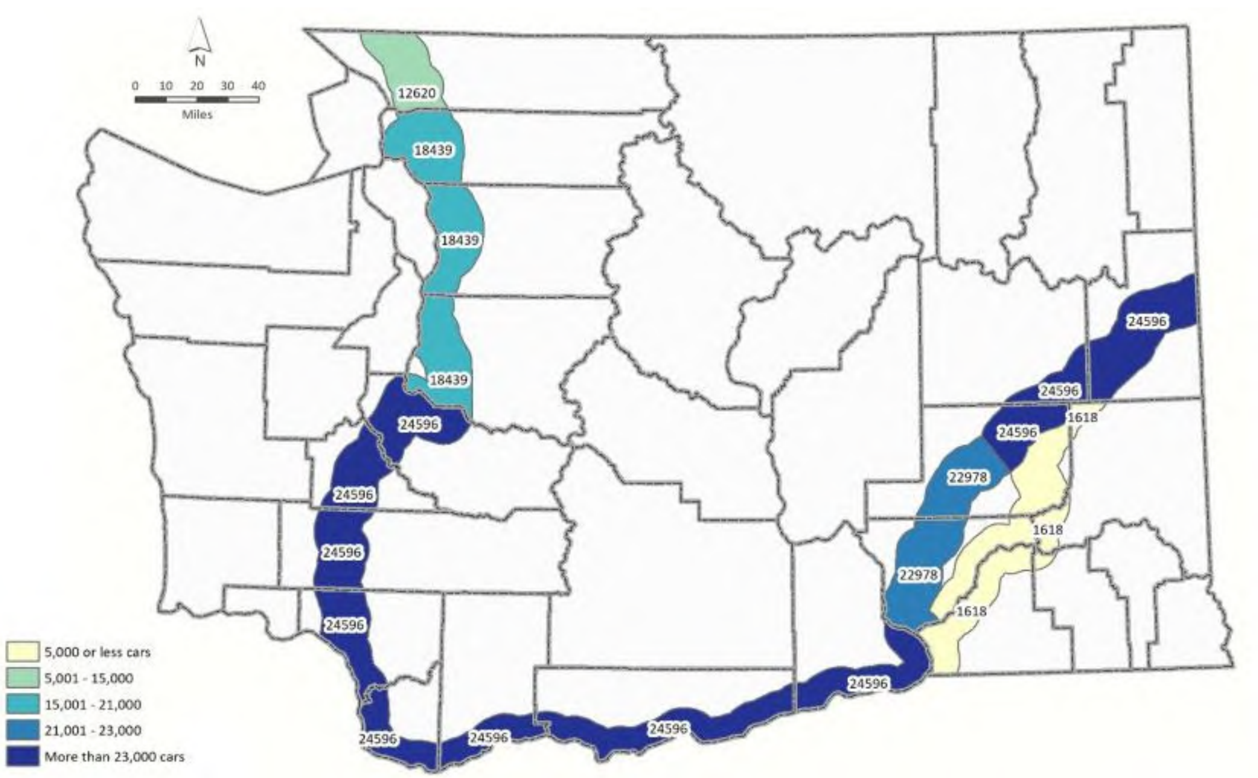
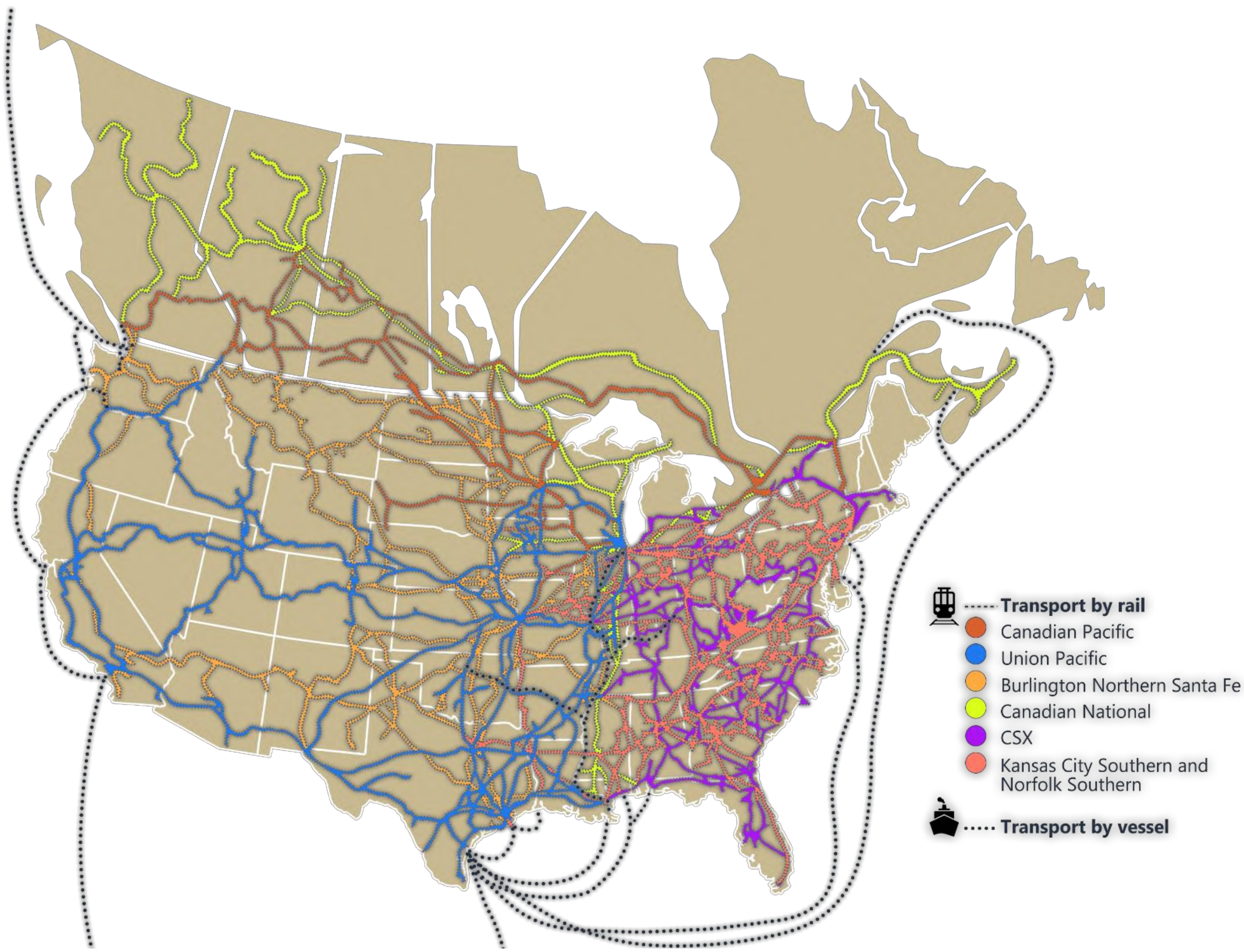


Figure 11: Oil Transport by Rail and Vessel in North America



Crude Oil Costs to Washington Refineries

Crude oil costs to the Washington refineries are not publicly available, however EIA does track refinery crude acquisition costs by PADD. The table below presents data from 2017 to 2019 and represents the composite cost of domestic and imported crude oil by PADD. Only PADD 1 on the east coast has higher costs than the west coast. PADDs 2 and 4 are significantly lower at 14 and 17.5 percent less, respectively. A large part of our increased cost is the lack of available in-region crude oil resources and therefore the increased transportation costs to get the imported crude oil here.

As illustrated in the map in Figures 2 and 3, PADDs 2, 3, and 4 have abundant crude oil resources while PADD 5 is geographically isolated from crude oil resources and must be transported over great distances to get to the region's refineries.

Table 3: Composite Cost of Domestic and Imported Crude Oil Acquisition Price by PADD[28]

	2017	2018	2019	Average	Percent Difference to PADD 5
PADD 1	$53.87	$69.64	$65.02	$62.84	-0.7%
PADD 2	$48.63	$57.85	$54.59	$53.69	14.0%
PADD 3	$50.73	$65.95	$60.19	$58.96	5.5%
PADD 4	$47.19	$55.01	$52.26	$51.49	17.5%
PADD 5	$53.08	$69.81	$64.34	$62.41	N/A

Not only is PADD 5 isolated from major crude oil resource regions as mentioned above, it is also geographically isolated from other refining centers such as the Gulf Coast, where 52 percent of U. S. refining capacity is located.[29]

The Pacific Northwest region's refineries produce about as much gasoline as the region consumes, creating a tight market.[30] This, coupled with the higher crude oil prices, cause PADD 5 (excluding California) to have the highest prices for gasoline in the nation. PADDs 1 through 4 from 2017 to 2019 averaged 12 to 22 percent lower retail gasoline prices than PADD 5.

Table 4: Composite Costs of Retail Conventional Gasoline by PADD[31]

	2017	2018	2019	Average	% Difference to PADD 5
PADD 1	2.358	2.639	2.488	2.50	-15.9%
PADD 2	2.297	2.577	2.456	2.44	-17.6%
PADD 3	2.184	2.456	2.281	2.31	-22.2%
PADD 4	2.407	2.775	2.646	2.61	-12.0%
PADD 5 *(minus California)*	2.718	3.113	3.069	2.97	N/A

The market is not as tight for diesel, with Pacific Northwest refiners producing more diesel than the region consumes, and therefore exporting diesel out of the region. Even though the region is oversupplied with diesel, the cost of the crude resource is still higher than the other PADDs, making diesel costs 4.7 to 12.3 percent higher than PADDs 1 through 4.

Table 5: Composite Cost of Retail Diesel On-Highway Costs by PADD[32]

	2017	2018	2019	Average	% Difference to PADD 5
PADD 1	2.681	3.19	3.081	2.98	-5.0%
PADD 2	2.596	3.11	2.955	2.89	-8.1%
PADD 3	2.484	2.96	2.819	2.75	-12.3%
PADD 4	2.712	3.222	3.043	2.99	-4.7%
PADD 5 *(minus California)*	2.833	3.354	3.233	3.14	

Producing Petroleum Products

About 90 percent of petroleum products consumed in Oregon are produced by the Puget Sound refineries in Washington.[33] Washington has the fifth highest oil refining capacity of any state. As of 2018, there are five refineries in Washington with a joint capacity of 651,700 barrels per day (b/d).[34]

Table 6: Refineries in Washington State[35]

Location	Current Owner	Year Constructed	Major Products	Current Capacity (b/d)
Cherry Point	BP West Coast Products LLC	1971	Gasoline, Diesel, Jet Fuel, Calcinated Coke, Biomass Based Diesel	242,000
Anacortes	Shell Oil Products U.S.	1957	Gasoline, Diesel, Jet Fuel, Propane, Coke, Sulfur	145,000
Anacortes	Tesoro Refining & Marketing Co	1955	Gasoline, Diesel, Turbine & Jet Fuel, Liquid Petroleum Gas, Residual Fuel Oil	119,000
Ferndale	Phillips 66 Company	1954	Gasoline, Diesel, Jet Fuel, Liquid Petroleum, Residual Fuel Oil	105,000
Tacoma	U.S. Oil & Refining Co	1957	Gasoline, Diesel, Jet Fuel, Marine Fuel, Gas Oils, Emulsified & Road Asphalt	40,700

Delivery of Refined Petroleum Products for End Use

About 90 percent of Oregon's transportation fuels are produced by the refineries in Washington and delivered via the Olympic pipeline and barge to seven Portland-area terminals. These terminals receive, store, blend, and transfer petroleum products.

Most of the remaining ten percent is delivered by barge,[36] and a very small amount by rail. Some of this product flows in a pipeline south to Eugene, and in another pipeline to the Portland International Airport. The Eugene distribution hub serves southern, central, and eastern Oregon. Additionally, over 240 towboats with tank barges carry refined petroleum products from the BP, the Chevron, and the Phillips 66 marine docks in the Portland area; and deliver it up the Columbia River to Pasco, Washington to service eastern communities in Washington, Oregon, and Idaho.[37]

Oregon receives less than 10 percent of the state's refined petroleum products from refineries in Salt Lake City, Utah and the San Francisco Bay Area.[38] From Salt Lake City, the refineries transport product via Tesoro's Salt Lake Products Pipeline System to a distribution terminal in Pasco. From the Pasco facility, fuel is trucked into Oregon to service eastern Oregon communities. California Bay Area refineries supply minimal quantities of fuel to a Chico, California terminal and then the fuel is trucked into Oregon to supply southern Oregon communities.[39] An estimated 1,500 tanker trucks deliver fuel throughout the state to about 2,400 fueling locations.[40]

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Energy 101: Energy Facility Siting and Permitting

New energy projects in Oregon are typically proposed and developed by utilities or independent developers. The federal government also owns and operates large scale energy projects in Oregon. For example, the Bonneville Power Administration, a federal government agency, owns and operates much of the high-voltage electric transmission system in Oregon and other neighboring states; and the U.S. Army Corps of Engineers and U.S. Bureau of Reclamation own and operate hydroelectric dams on the Columbia River. The state of Oregon regulates the siting of certain energy projects, but does not own or operate energy projects.

Energy Project Siting

> **Siting vs. Permitting**
>
> **Siting**: refers to the location, or site, of proposed energy facilities, and typically refers to the process by which those locations are selected.
>
> **Permitting**: refers to the process for a facility to obtain permits that demonstrate compliance with laws and regulations to construct and operate an energy facility.

The process of assessing exactly where to propose and build an energy project, the size of such a project, and even the type of energy project (wind or solar, for example) is highly complex. Years in advance, project developers must consider forecasted demand and spend considerable time and money conducting market studies, engineering assessments, real estate rights and land acquisition, environmental and cultural resources studies, transmission interconnection studies, and other assessments. Electricity generation projects must be close enough to available transmission capacity to move electricity to where it is needed for homes and businesses. Natural gas pipelines must be able to move gas from where it is produced to where it is used in homes or factories. Wind energy projects must be located in areas with adequate wind resources, and solar energy projects must be located in areas with sufficient sunlight and available land. Ethanol projects must consider availability of feedstock and transportation costs. Developers of high-voltage electric transmission lines must consider multiple environmental factors and land-ownership constraints. Other types of energy projects must be located in areas with specific geographic features, such as geothermal power facilities or the NW Natural Mist underground natural gas storage facility in Columbia County, which was developed at a specific location with unique geology.

The length of time for developing and completing major energy projects is such that the demand for a specific type of project can change mid-way through the development process. A natural gas power plant may be proposed as a baseload facility, but based on changing market demand, might switch technology and application to a "peaker" facility, which can ramp up or down electricity production to balance variable renewable resources. A facility originally proposed as a wind energy generation project may add a solar photovoltaic and battery storage component, based on changing customer or market demand. For example, the Wheatridge Renewable Energy Facility in Morrow County was originally proposed and permitted by Energy Facility Siting Council (EFSC) as a wind energy facility, and through EFSC-authorized site certificate amendments, added both solar PV and battery storage components to the project.[1]

Considering the challenges of developing large-scale energy projects, and particularly renewable energy projects, ODOE and the U.S. Department of Defense have recently partnered to develop the Oregon Renewable Energy Siting Assessment project.

Energy Siting and Military Training and Operations

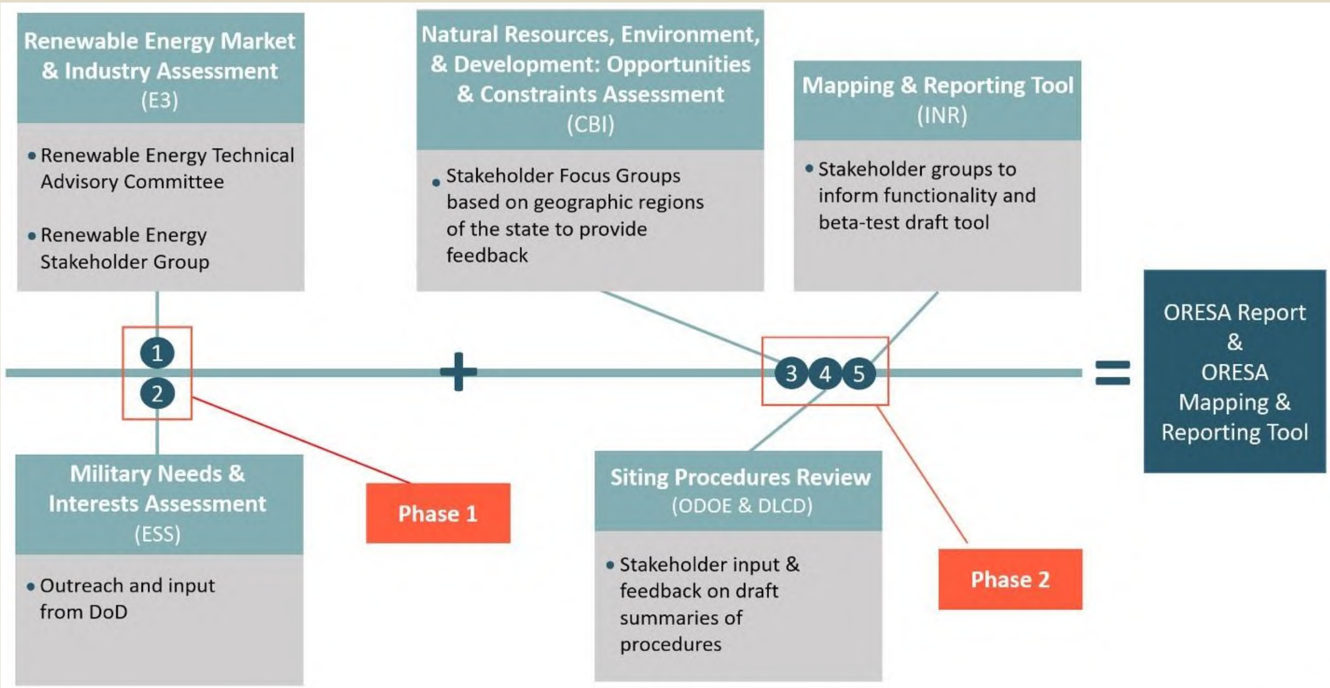
The State of Oregon and the United States Department of Defense (DoD) have a long history of working together to develop a stronger Oregon while fostering national security. Oregon is host to a number of unique and vital military capabilities in the form of installations, training & testing ranges, military training routes (MTRs), and Federal Aviation Administration (FAA) designated Special Use Airspace (SUA). The DoD's use of training areas and facilities in Oregon fulfill Congressionally mandated national security and military readiness obligations.

Facilities such as the Naval Weapons Systems Training Facility (NWSTF) Boardman, Camp Rilea, Camp Umatilla, Portland Air National Guard Base, Kingsley Field Air National Guard Base, and many other facilities within the state play a vital role in preparing active duty, reservist, and National Guard military personnel to meet the many security challenges faced globally and at home in the U.S.[2] For example, the FAA has designated airspace to allow military pilots to safely conduct training while limiting exposure to other non-participating aircraft.[3] Incompatible development within these airspaces may increase safety risks and reduce the usability of the airspace for its designed purposes.

As articulated in the 2018 National Defense Strategy, the variety and velocity of global threats continues to rapidly evolve.[4] We must anticipate, prepare, and mitigate risks to our critical defense, government, and economic infrastructure. In this environment, maintaining secure access to energy resources is critical to the execution of national security priorities, and ensuring the energy resilience of our military installations and defense critical electric infrastructure that support them.

Establishing compatibility between military installations and activities and the communities surrounding them is essential for preserving military mission capability, the health of local economies and industries, and the quality of life for residents. The DoD's Office of Economic Adjustment (OEA) supports states and communities to foster compatibility between land, air, and sea uses.[5] OEA is funding the Oregon Renewable Energy Siting Assessment (ORESA), a $1.1 million grant awarded to the Oregon Department of Energy, working with the Department of Land Conservation & Development and Oregon State University's Institute for Natural Resources. The project is also being supported by consulting firms with expertise in renewable energy, military compatibility, land use, and environmental, natural, and cultural resources.

There are two ORESA Project Deliverables: (1) ORESA Report and (2) ORESA Mapping and Reporting Tool. OEA's overarching goal is to support military compatibility through coordination and creation of outreach materials with local, regional, and state agencies to help raise awareness about the military through the ORESA project. Key project goals are to create relevant educational tools for stakeholders, agencies, local governments, and policy makers about renewable energy development, military training and operational areas, economic/community benefits, land use considerations, natural, cultural, and environmental resources, and other regulatory requirements. Key project objectives are baselining data, information, and perspectives to create a transparent, consistent collection of trusted, accurate information in Oregon, without recommendations or endorsements, and noting where information may be imprecise or uncertain. To develop these deliverables, there are five project components.



At the time of publication of this report in November 2020, the ORESA project is in Phase 1.

Learn more:

www.oregon.gov/energy/energy-oregon/Pages/ORESA.aspx

Energy Project Permitting

It may take a project developer many years of assessment and study before a specific project location and design is selected and a permitting proposal is filed with the applicable regulatory agency. Regulatory review and approval of energy projects in Oregon can be subject to the jurisdiction of federal, state, Tribal, or local governments, depending on the type of energy project, the size of the project, and the location. Some projects must receive permits from multiple agencies of federal, state, and local governments, and frequently, all three. Any project proposed on or crossing Tribal reservation land would require approval from the Tribal Government.

Federal Permitting

The federal government has primary permitting authority over certain proposed energy projects, as granted to it by Congress. This includes interstate natural gas pipelines, liquefied natural gas (LNG) terminals, and hydropower dams on navigable waters of the United States. For these types of projects, the Federal Energy Regulatory Commission (FERC) is typically the lead federal agency for permitting review.[6] As mentioned above, the federal government itself can be the developer and owner of energy projects; BPA builds and operates high-voltage transmission lines in Oregon and other neighboring states, and other federal agencies own and operate hydropower dams on the Columbia River. Energy projects, including generation and transmission, proposed by independent developers or utilities can be located on, or cross, land owned by the federal government – in Oregon, typically the Bureau of Land Management or U.S. Forest Service.[7] In this case, the project developer would need a permit and land lease from the federal government. Finally, many energy projects may need specific permits or an authorization from a federal agency, such as a permit related to the U.S. Endangered Species Act, or a wetland or waterway permit from the U.S. Army Corps of Engineers. In all of these examples, state or local permits may also be required before an energy project can be built and operated in Oregon.

Typically, energy projects subject to federal permitting must complete an environmental review under the National Environmental Policy Act. NEPA was enacted in 1970 and provides a framework for conducting an environmental impact assessment in order to ensure that decision-makers have full information regarding a government agency's actions and how those actions may affect the environment. NEPA directs federal agencies that are planning projects or issuing permits to conduct environmental reviews that consider the anticipated impacts of the proposed project on the environment.[8] Environmental impact assessments under NEPA are conducted in an open process with opportunities for public input.

Tribal Government Permitting

Any energy project proposed on, or crossing, Tribal reservation land must secure permits and land lease authorizations directly from the Tribal Government. State and local permitting processes are not applicable on Tribal reservation land. The nine federally-recognized Tribes in Oregon have different requirements and processes. The Legislative Commission on Indian Services (LCIS) supports coordination between state agencies and the nine federally recognized Tribal governments in Oregon.[9]

Eminent Domain Authority

Transmission lines and pipelines may be eligible for eminent domain condemnation authority. Eminent domain refers to the authority of governments to take private property for public use, or condemnation, following fair compensation.[10] Utilities are authorized to condemn private property for use in locating transmission lines and pipelines. Eminent domain is reviewed by FERC for federal-jurisdiction projects such as interstate pipelines,[11] and by the PUC for non-federal jurisdiction projects, such as intrastate pipelines and transmission lines. Both processes also involve court decisions and independent property valuations.

State Permitting

Certain energy projects in Oregon must receive permits from the state of Oregon. Most large energy projects subject to state jurisdiction are permitted through the Energy Facility Siting Council (EFSC), which is staffed by ODOE's Energy Facility Siting Division. EFSC jurisdiction, however, does not include hydropower or energy projects located in Oregon's territorial sea. Hydropower projects, including pumped-storage hydropower projects, are subject to permitting through the Oregon Water Resources Commission, Oregon Water Resources Department, and FERC.[12] Energy projects proposed in Oregon's territorial sea are subject to permitting processes at multiple agencies including Oregon Department of State Lands (DSL) and Oregon Department of Land Conservation and Development (DLCD).[13] Finally, it is important to note that as described in the federal government section above, certain energy projects may also require specific permits from multiple state agencies. For example, natural gas power plants are typically subject to EFSC jurisdiction for siting permits and would also be subject to Oregon Department of Environmental Quality (DEQ) jurisdiction for air quality permits.

Energy Facility Siting Council

The state has permitting jurisdiction through EFSC for certain energy projects based on statute.[14] The types of energy projects that are permitted through the EFSC process include most natural gas power plants, large utility-scale wind and solar projects, certain high-voltage electric transmission lines, intrastate natural gas pipelines, natural gas storage facilities, nuclear installations, large ethanol production facilities, and a few less-common energy facilities such as synthetic fuel plants and uranium mills or mill tailing disposal facilities. EFSC functions as an independent decision-making body on energy facility applications and EFSC rulemakings.

The Energy Facility Siting Council is responsible for overseeing the development of large electric generating facilities, high voltage transmission lines, gas pipelines, radioactive waste disposal sites, and other projects. The Council has seven members who are appointed by the Governor and confirmed by the Oregon Senate. Appointees are selected to ensure broad geographic representation. EFSC members seek to understand, evaluate, and deliberate complex issues associated with proposed facilities and how those facilities affect people, habitat, and communities. Council meetings are open to the public, and public involvement is built into the Council's review. The volunteer Council members receive reimbursements for travel and meal expenses when they are performing Council business. Oregon Department of Energy employees serve as staff to the Council, handling the ongoing work related to the regulation of energy facilities. Staff are energy experts who research issues involved with locating, building, and operating large energy facilities. They make recommendations to the Council based on their research and analysis

EFSC members are limited to two four-year terms, and as such, there are regular openings on the Council. Those interested in applying to serve on the Council are encouraged to contact the Governor's Executive Appointments office or submit an interest form:

https://www.oregon.gov/gov/admin/Pages/How_To_Apply.aspx

An EFSC review incorporates local government land use permitting decisions into its process. EFSC review also includes certain other state agency permits – mostly related to water use that would typically be issued by the Oregon Water Resources Department, and permits related to wetlands and waterway impacts that would be issued by DSL. As noted above, EFSC review does not include jurisdiction over federally-delegated air or water quality permits, which remain the authority of DEQ under delegation from EPA.[1] EFSC review also does not include certain other ministerial permits that may be required for an energy project, such as a local government building permit; a developer would need to obtain these types of permits separately. However, EFSC does remind developers of their compliance obligations with all applicable local, state, and federal regulations as a condition of a site certificate. The condition allows EFSC to support those agencies in any efforts needed to ensure those compliance obligations outside of EFSC's jurisdiction are met.

The EFSC review process involves coordination between the Council and its staff, and other state agencies that have specific expertise in potential impacts of a proposed energy project and can support EFSC's review of compliance with applicable standards and rules. Typically, this includes state agencies such as Oregon Department of Fish and Wildlife, the State Historic Preservation Office, Department of State Lands, and Oregon Water Resources Department. Additionally, EFSC and staff work with local governments when conducting the review to ensure that issues of concern to a local government are considered in the review, as applicable. EFSC and staff work with Tribal Governments to review potential issues of concern to the Tribe. EFSC and its staff may meet in-person with Tribal Government staff or, if there is interest, with Tribal Council itself, during such a review. The EFSC process also allows for cost-recovery, including for Tribal Governments, for time spent reviewing application materials.

EFSC's jurisdiction and standards have evolved over time. For example, all energy generation facilities used to be subject to a standard that required demonstration of need. That standard was eliminated in 1997 by the legislature for all generating facilities and replaced with a reliance upon competition in the market.[15]

Local Government Permitting

Energy projects that are not subject to EFSC jurisdiction must receive land use approvals from city or county governments. As noted above, state law establishes which types of energy projects are permitted by EFSC, and which types of projects are permitted by local governments. Electric distribution lines and natural gas distribution pipelines must receive a permit from city and county governments. Larger energy projects subject to local government jurisdiction typically require a conditional use permit from a local planning department or planning commission. However, counties (and cities) may have zoning regulations that allow the establishment of small energy projects subject only to a zoning permit or other type of review, without requiring a conditional use permit. Battery

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[1] EFSC jurisdiction specifically excludes "federally-delegated permits," which are permits and other requirements of the federal government, typically EPA, that are delegated to states to administer on behalf of the federal government. For energy projects, this typically includes air quality permits established by the federal Clean Air Act. It also includes permits related to stormwater discharge and runoff, typically considered in the National Pollutant Discharge Elimination System ("NPDES") permits. Both examples here remain the jurisdiction of DEQ.

storage projects are always local jurisdiction for permitting, unless a developer seeks a permit for battery storage as part of an EFSC jurisdictional energy project.

Changing Jurisdiction and Permitting Requirements

The 2018 Biennial Energy Report included an overview of the need to balance between energy development and the protection of important resources.[16] This section summarizes the thresholds for federal, state, and local permitting jurisdiction. In 2019, the Oregon Legislature passed, and the Governor signed into law, changes to the jurisdictional thresholds for energy projects, which affects where a project developer must go to get a permit – EFSC or a local government. The legislation, House Bill 2329, also created two categories of renewable energy projects within county jurisdiction, and added additional environmental review requirements and procedural steps to the county land use review process for the new tier of county-level jurisdiction. HB 2329 went into effect on January 1, 2020. [17]

Local jurisdictions reviewing projects under HB 2329 authority apply the standard land use requirements from local codes and other applicable state requirements, and are also subject to new criteria and procedures as established in HB 2329, including the following[18]:

- Notification to the following agencies upon receipt of an application:
  - Oregon Department of Fish and Wildlife;
  - Oregon Department of Energy;
  - State Historic Preservation Office;
  - Oregon Department of Aviation;
  - United States Department of Defense; and
  - Federally recognized Indian tribes that may be affected by the project
- Fish and wildlife habitat evaluation and necessary mitigation, including consultation with ODFW
- Historic, cultural, and archeological evaluation and potential mitigation
- Decommissioning assessment and financial assurances as specified by the county
- Energy Facility Siting Council standards that the county determines applicable
- A developer or local government can defer authority to the Energy Facility Siting Council

Table 1 below summarizes the current primary permitting jurisdictional authority for renewable energy projects in Oregon. The first category, reflected in the "County" column, shows what types of projects counties must review under applicable land use standards. The second (and new) category established by HB 2329, reflects the new increased size of energy projects reviewed at the county level, but that are subject to both local standards and the new criteria in the box above. Note that the table only shows the *primary* permitting authority, and that projects may require multiple permits from multiple agencies. For example, a wind power project, if under 150 MW, would be subject to county-jurisdiction primary permitting; however, that project may also require a removal-fill permit for impacts to wetlands, which would be issued by Department of State Lands.

Table 1: Renewable Energy Project Primary Permitting Jurisdictional Thresholds

Renewable Energy Project Type	Primary Permitting Authority					
	County	County with HB 2329	EFSC[19]	Oregon Water Resources Commission	Oregon Department of State Lands	Federal Government
Solar Photovoltaic[20] ***High Value Farmland***	< = 100 acres	> 100 acres & < = 160 acres	> 160 acres	N/A	N/A	N/A
Arable Farmland	< = 100 acres	> 100 acres & < = 1,280 acres	> 1,280 acres (2 sq. miles)	N/A	N/A	N/A
Other Land	< = 320 acres	> 320 acres & < = 1,920 acres	> 1,920 acres (3 sq. miles)	N/A	N/A	N/A
Onshore Wind	N/A	< = 150 MW	> 150 MW	N/A	N/A	N/A
Geothermal	N/A	< = 55.5 MW	> 55.5 MW	N/A	N/A	N/A
Biomass	< 6 BBTU/day	N/A	> 6 BBTU/day	N/A	N/A	N/A
Offshore (wind and wave)	N/A	N/A	N/A	N/A	< = 3 Miles Offshore[21]	> 3 Miles & < = 200 Offshore (Bureau of Ocean Energy Management)
Battery Storage	All projects	N/A	N/A[22]	N/A	N/A	N/A
Hydroelectric	N/A	N/A	N/A	Projects in waters of the state[23]	N/A	Projects in waters of the US (FERC)
Pumped Hydroelectric	N/A	N/A	N/A	Certain projects	N/A	All projects (FERC)

Another feature of HB 2329 is that for energy projects considered under local government siting jurisdiction, a developer may opt-in to EFSC's permitting process and authority. A local government also has the ability to transfer permitting jurisdiction for energy projects to EFSC. So far, no developer or local government has exercised the option of transferring authority over to EFSC. Since HB 2329 went into effect, ODOE has received notice of three projects that would have been EFSC jurisdictional prior to HB 2329, but will now be moving forward under county review.

Since HB 2329 went into effect, the following renewable energy projects, all above the county jurisdictional thresholds, have been submitted to EFSC for review:[24]

- **Montague Wind Power Facility** in Gilliam County. Amendment 5 to an existing Site Certificate for a wind and solar facility, with 202 MW of wind currently in operation. The amendment seeks approval for expansion into an area to be used by solar facility components from approximately 1,800 acres to 2,700 acres.
- **Archway Solar Energy Facility** in Lake County. This is a proposed 400 MW solar project using up to 3,650 acres.
- **Bonanza Energy Facility** in Klamath County. This is a proposed 150 to 300 MW solar project with up to 1,100 MW of battery storage using up to 2,733 acres.
- **Wagon Trail Solar Project** in Morrow County. This is a proposed 500 MW solar project using up to 5,957 acres.
- **Nolin Hills Wind Power Project** in Umatilla County. This is a proposed 350 MW wind project with up to 117 turbines at a maximum blade tip height of 656 feet. The project may also include solar or battery storage.

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[3] https://www.faa.gov/air_traffic/publications/atpubs/aip_html/part2_enr_section_5.1.html

[4] https://dod.defense.gov/Portals/1/Documents/pubs/2018-National-Defense-Strategy-Summary.pdf

[5] https://www.oea.gov/

[6] Federal Energy Regulatory Commission, What is FERC?, https://www.ferc.gov/about/what-ferc/what-ferc-does

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[8] The Council on Environmental Quality, National Environmental Policy Act, https://ceq.doe.gov/index.html

[9] Legislative Commission on Indian Services, https://www.oregonlegislature.gov/cis

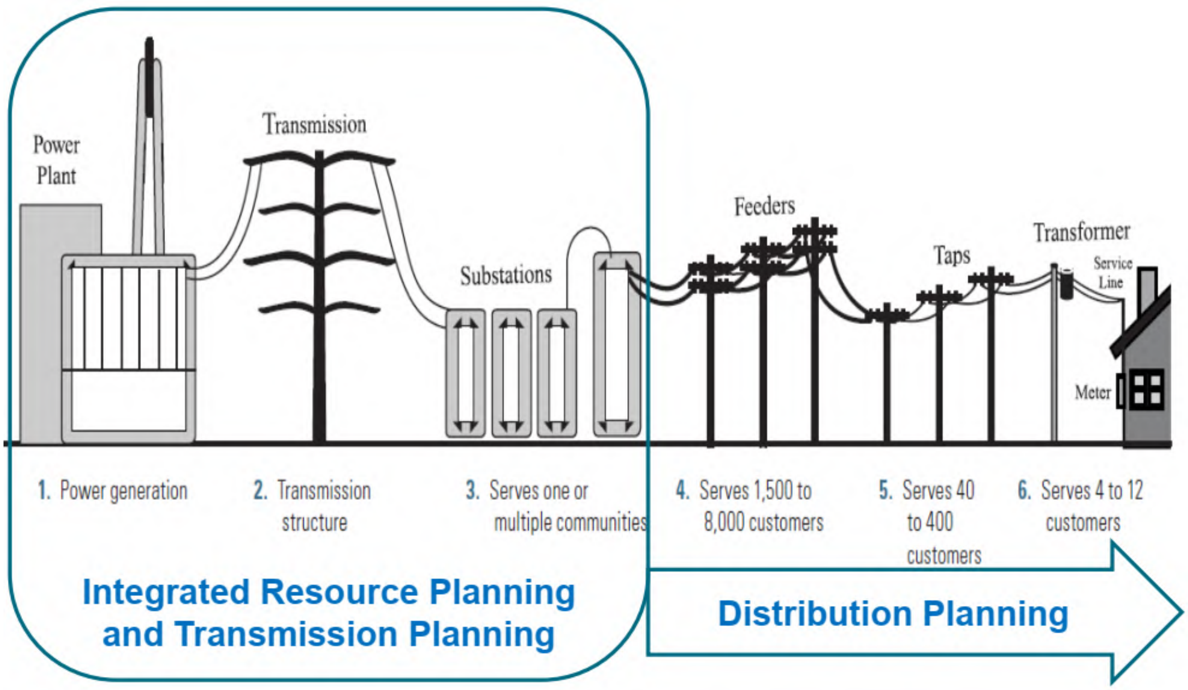
[10] ORS chapter 35 addresses eminent domain, broadly.
[11] See, for example, Federal Energy Regulatory Commission, An Interstate Natural Gas Facility on My Land? What do I need to Know? Page 18 (August 2015) https://www.ferc.gov/sites/default/files/2020-04/AnInterstateNatualGasFacility.WhatYouNeedToKnow.pdf
[12] https://www.oregon.gov/owrd/programs/WaterRights/HE/Pages/default.aspx
[13] Additional information can be found in Oregon's Territorial Sea Plan, Part 5. https://www.oregon.gov/lcd/OCMP/Documents/TSP_Part5_FINAL_2019Combined.pdf
[14] Oregon Revised Statute 469.300(11)(a).
[15] Oregon Revised Statute 469.310. 1997 Oregon Laws, chapter 428, section 1. HB 3283
[16] 2018 Biennial Energy Report – Chapter 3 – Page 27 - https://energyinfo.oregon.gov/ber
[17] Oregon State Legislature - https://olis.oregonlegislature.gov/liz/2019R1/Measures/Overview/HB2329
[18] Oregon Revised Statute 215.446
[19] Statutory thresholds for renewable energy facilities under Oregon Energy Facility Siting Council jurisdiction are established under Oregon Revised Statute 469.300(11)(a)(A), (D), (G) and (J).
[20] The definitions for "high value farmland," "arable land," and "other land" are found at ORS 469.300(11)(a)
[21] Oregon Revised Statute 274.870 - 274.895
[22] The Oregon Energy Facility Siting Council reviews battery storage projects only as part of other large-scale energy projects.
[23] Oregon Revised Statute 543.010 - 543.060
[24] https://www.oregon.gov/energy/facilities-safety/facilities/Pages/Facilities-Under-EFSC.aspx

Energy 101: Electricity Distribution System Planning

The power grid is generally divided into three segments that require continuous planning and investments to maintain reliable electric service: 1) bulk transmission systems; 2) generation and load resources; and 3) distribution systems.

The distribution system (or distribution grid) is responsible for delivering power the "last mile" to retail customers (though this can sometimes stretch further than one mile, especially in rural areas). Homes and businesses receive electric service by physically connecting to the poles and wires of the distribution system running up and down the streets of their neighborhoods. The distribution system receives power at substations from the bulk transmission system (see Figure 1 below).

Figure 1 – Three Segments of Grid Planning[1]



The reliable delivery of power to customers requires effective planning for investments to expand and maintain the grid, and the processes and activities for distribution system planning are evolving.[2] Utilities have always engaged in some level of planning for investment in their distribution system.[3] Emerging technologies, however, are increasingly providing customers and utilities with new opportunities to optimize how electricity is supplied and managed across the distribution grid. These technologies include advanced digital communication and control infrastructure and distributed energy resources. There are unique opportunities to shape the future of the electric system through investments and planning at the distribution system level.

Learn more about Advanced Meter Infrastructure in the Energy 101 and Technology Review sections

In recent years, electric utilities across the country have been evolving traditional distribution system planning through the development of distribution resource planning to integrate distributed energy resources (DERs). In 2013, California was one of the first states to require its utilities to engage in distribution resource planning with the passage of AB 327.[4] That bill required the state's IOUs to develop distribution resource plans that included the following five elements to integrate DERs, some variation of which are at the core of distribution resource planning across the country:[5]

1. Evaluation of the locational costs and benefits of DERs.
2. Identification of standardized tariffs, contracts, or other pricing mechanisms for the deployment of cost-effective DERs.
3. Proposal for the integration of existing statewide programs, incentives, and tariffs focused on DERs (e.g., net metering) in a manner that maximizes the locational benefits and minimizes the incremental costs of deploying DERs.
4. Identification of incremental utility distribution investments necessary to integrate cost-effective DERs to yield net benefits for the grid.
5. Identification of barriers to the deployment of DERs.

More recently, several other states (including New York, Hawaii, and Minnesota) have also explored the development of more comprehensive distribution system planning and distribution resource planning. There is no one-size fits all approach, and states vary in their approaches and use of terminology.

Distribution System Planning vs. Distribution Resource Planning

The terms Distribution System Planning (DSP) and Distribution Resource Planning (DRP) are used inconsistently in the electric sector. For this section, the term **Distribution System Planning** refers to all utility planning activities to maintain and upgrade the distribution system itself (i.e., the poles, wires, substations). **Distribution Resource Planning** refers specifically to an emerging subset of distribution planning intended to optimize the use of distributed energy resources connected to that system (e.g., solar, battery storage, flexible loads).

Background on Traditional Distribution System Planning

Historically, most distribution systems have been designed to deliver electricity from a substation (which receives power from the bulk system) to the retail customer. Traditional distribution planning largely consisted of forecasting changes in customer loads served by this distribution system; planning upgrades and extensions to distribution lines based on load forecasts; and developing a schedule for replacing distribution equipment as it reached the end of its useful life, became obsolete, was damaged, or failed.[6] Because of this relatively straightforward approach to assessing necessary upgrades and operational needs, this process involved relatively few stakeholders, and utilities largely designed and accomplished their plans internally.[7]

Drivers of Distribution Resource Planning

Over the last decade, the traditional one-way flow of power over the distribution grid to customers has been changing as the commercial availability of DERs capable of generating or storing electricity on the distribution system has increased.[8] This increases the likelihood for bi-directional power flows on the distribution system.[9] For example, a customer with rooftop solar or a battery has the potential to export electricity onto the grid. Customers also increasingly have access to new technologies (e.g., smart thermostats and water heaters) which can be operated dynamically to optimize their usage based on two-way communication flows to respond to grid conditions. Distribution resource planning can benefit these customers by giving them more transparent insights into the costs and benefits of adopting DERs.

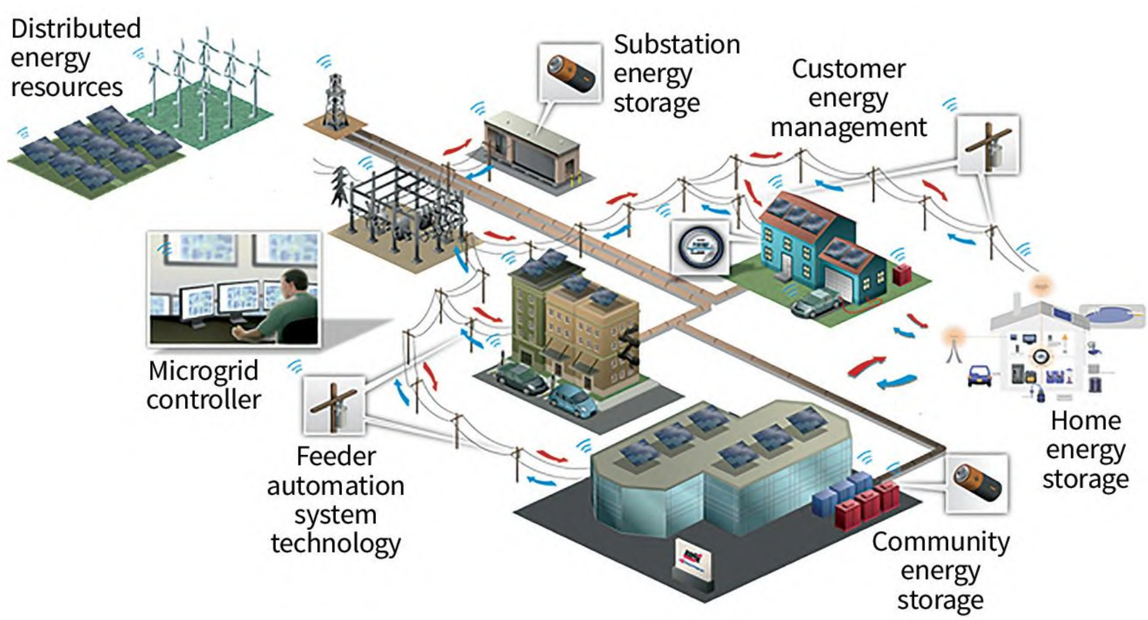
The process of distribution resource planning is also intended to help utilities develop a framework for better understanding of the total costs and benefits of these DERs (whether customer- or utility-owned) on the distribution grid. For example, it can help utilities make better informed decisions about deploying solar or battery resources on the distribution grid, closer to load, that can be used to better align generation and the provision of ancillary services with customer needs on their system. In addition, distribution resource planning can help utilities assess and realize net benefits (inclusive of costs) to the distribution system from DER deployments in areas that can delay or reduce investments otherwise needed to upgrade or maintain the system. DERs also have the potential to benefit the bulk power system by providing local support that helps maintain stability of the overall grid.[10]

What's a DER?

Distributed energy resource is an umbrella term used to refer to any resource interconnected to the distribution grid of a local utility. While definitions vary on the range of resources included, the Oregon Department of Energy considers DERs to be inclusive of the following:

- Generation sources (e.g., rooftop solar or diesel generators)
- Technologies that modify demand on the distribution system (e.g., energy efficiency and demand response)
- Electric vehicles and associated charging infrastructure; energy storage technologies (e.g. distributed batteries)
- Hardware or software control systems used to communicate with the grid and/or to optimize the usage of other DERs

Figure 2 – Example Vision of an Advanced/Modern Distribution System[11]



Learn more about the benefits of advanced communication and control technologies and DERs in the Grid-interactive Buildings Policy Brief.

What Does This Mean for Oregon Utility Customers?

Distribution system planning in other states has enabled the strategic deployment of more DERs on the distribution grid. Broadly, DERs have the potential to provide many benefits to customers, including enabling them to self-supply some of their own electricity, support decarbonization of the grid, and provide some amount of resilient on-site power in the event of grid outages. In the case of electric vehicles, DERs can provide some customers with a cleaner and cheaper mode of transportation that can be conveniently fueled with electricity generated on site. Collectively, customers can also leverage DERs to interact in new ways with the grid and their utility, potentially saving money for themselves while helping to support the grid. For example, many utilities are beginning to explore the concept of leveraging aggregated deployments of DERs across the distribution grid to operate as a "virtual power plant" to help manage the grid.[12]

There are, however, equity considerations. For customers to acquire DERs it often requires an up-front capital investment, which can present a significant barrier to many customers. This has the potential to limit the ability of disadvantaged customers to benefit from these technologies. A more robust and inclusive distribution system planning process (see more on PUC Docket UM 2005 below) to optimize the deployment of DERs could help to address these equity considerations.

PGE's Smart Grid Test Bed: DERs in Action

Portland General Electric's Smart Grid Test Bed is a large, innovative pilot project that is allowing the utility to accelerate its vision for a clean energy future by partnering with thousands of customers across three different areas of its distribution grid: North Portland, Hillsboro, and Milwaukie.[13] The Test Bed was borne out of the utility's 2016 IRP and was known as the Demand Response Test Bed, intended to serve as a proving ground for the utility to deploy demand response resources at scale.[14] Since then, the Test Bed has evolved into a national example of how utilities can engage with customers to harness the power of distributed energy resources such as—rooftop solar, batteries, smart thermostats and water heaters, EVs, and EV charging.[15]

Since launching in 2019, PGE's primary focus within the Test Bed has been on engagement with its customers. The engagement has been designed to help them rethink how they use energy through new technologies, programs, and products while allowing them to retain control over their comfort levels and access to affordable, reliable, and clean energy.[16] The utility has also invested in distribution system upgrades to feeders and substations to increase automation functionality, upgrade sensors and communication systems, and facilitate the transformation of the distribution system from a one-way to two-way flow of energy and information.

In July 2020, PGE announced the launch of a new pilot program within the Test Bed to incentivize the installation of 525 residential battery storage systems that the utility can dispatch as a "virtual power plant" contributing up to 4 MW of energy to the grid.[17] The effort will allow PGE to optimize the use of renewable energy on its system, while also providing participating customers with an energy resilience resource that can be relied upon in the event of a grid outage.[18]

While PGE continues to operate the Test Bed as a pilot program, the utility is learning lessons that will inform how it engages in distribution resource planning systemwide in the future to achieve its clean energy goals. In the meantime, it remains an innovative example of a utility leaning into the use of DERs to meet grid needs and the needs of its customers.

"The PGE Smart Grid Test Bed represents a leap forward in the relationship between customers and their energy providers . . . PGE is on a path to building a model that energy providers everywhere can learn from and replicate."[19]

– Jon Wellinghoff, Former Chairman, FERC

Distribution Planning for IOUs in Oregon

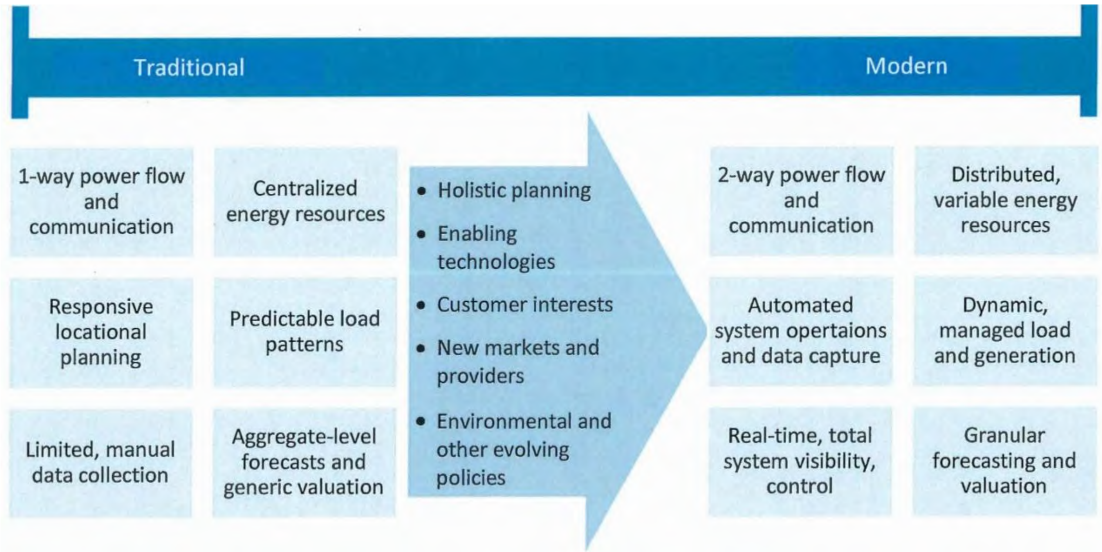
As DER adoption increases in Oregon, utilities are likely to seek ways to maximize the benefits of these resources on their distribution systems, whether utility- or customer-owned. The state currently has no standardized approach to distribution resource planning, and every utility is likely to have a unique adoption rate for DERs that could influence its need for developing such a planning framework. In 2019, Oregon PUC staff released a white paper that recommended developing a distribution system planning process that can leverage DERs to help meet system needs.[20]

In its whitepaper, PUC staff identified that there has been less rigorous engagement in distribution system planning processes and investment decisions and identified four driving factors.[21] First, PUC staff and stakeholders have had less visibility into these planning processes because they have been internal to the utility and traditionally focused on smaller investments to meet short-term reliability needs. Second, there have been few opportunities for engagement *before* these investments occur, with the primary mechanism for engagement occurring in the review of aggregate distribution investments *after* they have been made through the rate case process. Third, the PUC identified 11 different ongoing simultaneous planning processes, reports, policies, and programs that were related to the distribution system, making it difficult for stakeholders to stay informed. Lastly, these planning processes increasingly leverage emerging smart grid technologies and DERs whose technical nature can create barriers to efficient stakeholder engagement.

In addition, the PUC identified a need to better understand the costs and benefits associated with investments in the distribution system, and how those costs and benefits could be leveraged to provide maximum value to all customers, as a motivating factor for its investigation of distribution system planning more broadly.[22] The white paper also cites several trends of increased commercial availability of advanced controls, sensors, communications, automation equipment, and other DERs. All these important issues contributed to the PUC's decision to open Docket UM 2005 in March 2019 to investigate the benefits of a more robust and transparent distribution system planning process for Oregon's investor-owned utilities (Portland General Electric, PacifiCorp, and Idaho Power Company).[23]

The following graphic illustrates PUC staff's initial vision for how distribution system planning could evolve:

Figure 3: Oregon PUC Vision for Transforming to an Advanced/Modern Distribution System[19]



PUC staff have acknowledged that the breadth of technical, financial, policy, and planning issues implicated by distribution system planning may be challenging to reconcile. However, due to the quickly evolving nature of the discussion in the industry, they have decided to proceed with the understanding that some of the discussion may be iterative and require parties to adapt to evolving information.

One of the first steps was to develop a baseline of current activities that interact with distribution systems followed by an exploration of new opportunities through engagement with a robust stakeholder group. That engagement sought to identify the perspectives of various stakeholders, the potential direct implications of distribution system planning, and national best practices in the valuation of the benefits provided by DERs.

PUC Docket UM 2005: Next Steps

As it explores the development of enhanced distribution planning that's more robust, strategic, and adaptive, the PUC remains committed to ensuring that utilities maintain a safe, affordable, and reliable power system.[24] The PUC has also committed to streamlining distribution planning with other planning efforts and promoting more inclusive and meaningful stakeholder engagement in distribution planning.[25] The draft long-term goals for distribution planning as proposed by PUC staff are:[26]

- **Distribution System.** Promote the reliability, safety, security, quality, and efficiency of the distribution system for all customers.
- **Customers.** Be customer-focused and promote inclusion of underserved communities.
- **Optimize.** Ensure optimized operation of the distribution system.
- **Accelerate DERs.** Accelerate integration of DERs and other clean energy technologies.
- **Regulatory.** Strive for regulatory efficiency through aligned, streamlined processes.

In October 2020, the PUC issued a proposed draft of its "Distribution System Planning Guidelines" within UM 2005, with the intent of finalizing the guidelines in 2021. The proposal details the scope of the initial plans to be developed by investor-owned utilities to include: baseline data and distribution system assessment, DER and load forecasting, plans for hosting capacity analysis for individual distribution feeder lines, community engagement plan, identification of grids needs and solutions to meet those needs, and near- and long-term action plans. The proposal also recommends a deadline of October 15, 2021, pending a commission order, for IOUs to file their initial plans with the PUC, with recurring filings every other year thereafter (for more information, see PUC Docket UM 2005).

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Energy 101: Resource Adequacy

We consume energy daily: when we charge our phones, flip a light switch, turn up the furnace to heat our homes, or fill up our car at the gas station. In terms of total end-use fuels consumed by Oregonians, 31 percent of the energy comes in the form of liquid transportation fuels (e.g., gasoline and diesel); 42 percent is electricity; and 26 percent is direct use of fuel oil or natural gas (e.g., for home heating or industrial processes).

Storing End-Use Fuels: Gasoline, Natural Gas, and Electricity

Electricity must be generated and delivered across a large transmission and distribution system, just in time to meet consumer demand. This differs significantly from other end-use fuels (and differs from virtually all other commodities and consumer products) that can be produced at an operationally or economically optimal time, and then stored for consumption at a later point in time.

This section refers to "end-use fuels" because of the important differences between primary energy sources and the end-use fuels that consumers actually consume to power their everyday lives. For example, crude oil is a natural resource extracted from the earth. This primary energy source must be refined into gasoline before it can be used in a vehicle. That gasoline, once refined from the original energy source, can be (and is) stored in large volumes as the end-use fuel that Oregonians consume. Similarly, natural gas, once captured and processed for injection into storage tanks or pipelines, is the end-use fuel that Oregonians consume in their homes and businesses.

Electricity is quite different. The primary energy sources used to generate electricity vary considerably – from the gravitational potential energy stored in volumes of water at altitude, to the nuclear potential energy contained within uranium isotopes, to the thermal kinetic energy of solar energy. A wall outlet cannot use that water, uranium, or solar energy until it has been converted into electricity—the end-use fuel.

Think about gasoline. What does it look like? Chances are you are imagining a physical volume of a brownish-colored liquid. You can literally fill a jar on the table in front of you with gasoline or diesel fuel, the two liquid fuels that predominantly power our transportation systems. Liquids are easily stored in large volumes. Think about natural gas or propane. What does it look like? This one is a bit more challenging, but you might imagine filling a balloon in front of you with some volume of natural gas, or a propane tank attached to your grill. Pipeline networks and large tanks can store vast quantities of these gaseous end-use fuels.

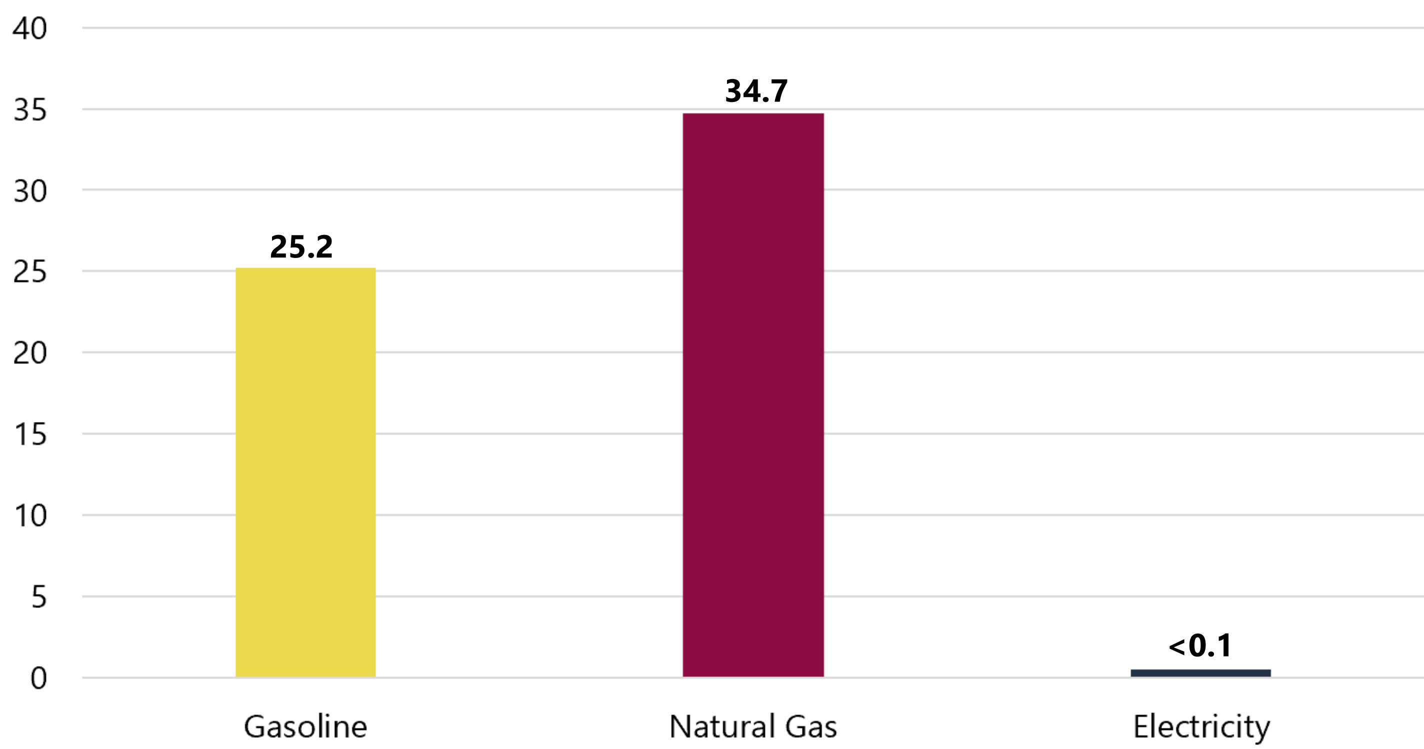
Now think about electricity. What does it look like exactly? Where might you store it? You might imagine a standard AA battery, which stores approximately 3 watt-hours (or 0.003 kWh) of energy.[1] The average residential customer in Oregon would need 9,000 AA batteries to power their house for a single day.[i] So while there are ways to store electricity, those storage systems have historically been limited in their ability to efficiently store energy over a long duration or in

[i] In 2018, the average residential customer of Oregon's investor-owned utilities consumed 10,151 kWh of electricity over the course of the entire year, or approximately 27.8 kWh per day. (OPUC Utility Statistics Book)

large volumes (e.g., batteries), and/or cost a lot of money per unit of energy stored (such as large capital projects like a pumped hydro facility that stores water for use at a later time). As a result, nearly all electricity is consumed at the same instant that it is generated at a power plant. This simple physical reality of electricity as an end-use fuel, compared to liquid and gaseous fuels, has had an enormous effect on the infrastructure required to meet end-use consumer demand.

The consumption of end-use fuels of all kinds varies throughout the day, across different seasons, and from year to year. This variability in consumption must be met by changes in the available supply of energy to meet those needs. The flexibility in the availability of supply to match real-time, end-use consumption is assisted by storage systems in the case of liquid or gaseous fuels. For example, a gas station has significant volumes of gasoline stored on site, ready and available for consumption when a car pulls up to the pump. Meanwhile, a network of large tanks and an extensive underground pipeline system filled with natural gas acts as a massive storage system that is connected homes or businesses, ready to supply end-use fuel on-demand for a stove, furnace, or other appliance. Distributed storage systems (i.e., systems that are typically distributed closer to the end-use consumer than the source of production of the fuel) can be sized and adjusted as needed to ensure that adequate supply exists to meet fluctuating demand at all times. In short, these storage systems provide a significant buffer to accommodate fluctuations in end-use demand and allow for a more optimized operation of upstream extraction, production, and delivery systems.

Figure 1: Days of End-Use Fuel Storage in the U.S. Based on Average Daily U.S. Consumption by Fuel Type[2]



Derived from U.S. EIA data comparing average volumes of stored energy to average daily consumption for total gasoline (barrels consumed vs. weekly stocks); natural gas (mcf consumed vs. working natural gas in storage); and electricity (MWh of daily consumption vs. MWh of stored electricity).

The basic fact that electricity cannot be easily stored in large volumes, however, has resulted in a vastly different organization of the systems to deliver fuel to consumers. The electric system is sized to be able to satisfy the largest requirements for electricity—called peak demands—at all times, even though consumers use less (oftentimes significantly less) during most hours of the year. This results in an electric generation and delivery system that is, by design, underutilized much of the time, especially when compared to other end-use fuels, such as natural gas[ii] and gasoline.[3] This might manifest as a power plant that only operates at full output 50 percent of the hours of the year, or a transmission line that operates at less than full capacity. The natural rhythms of society result in changes in our demand for electricity over different hours of the day and months of the year — so that excess capacity must essentially be on standby, ready when needed to meet demand when it spikes.

As a result, the concept of peak demand over various time durations (hourly, daily, monthly, annually) has more effect on the design and the cost of electric delivery systems than it does with other types of end-use fuel delivery infrastructure systems. For this reason, capacity planning takes on an outsized role in the electric sector. Capacity planning is the process that grid planners and utilities must undertake to ensure that adequate generating capacity is online and operational to serve peak demand in the future. Increasingly, grid planners and utilities also have to consider "net peaks" within a day. Net peaks refer to the difference between forecasted electric demand and the electricity produced by variable output renewables, most notably solar, and may require the grid to have more flexible resources.[4] Given the lead time required if it is determined that new generating capacity resources need to be developed (which can take several years or longer), this type of planning must attempt to forecast the future, taking into account potential variability in demand for power over different times of day and year or from year to year; changes to the supply of available power (e.g., a drought year may result in much less hydropower output than average); the impact of different weather patterns on consumption; and the near-term effects of longer-term factors, like climate change and an increasing electrification of end-uses (e.g., transportation electrification or conversion from a gas furnace to an electric heat pump).

These types of forecasts, involving a multitude of critical variables, are necessarily uncertain. The lack of end-use fuel storage in the electric system allows little room for error if utilities miss by forecasting less electric demand than what actually occurs. This creates a reasonable bias in favor of conservative forecasting to avoid having too little power available to serve demand in the years ahead. The alternative could be a system that fails to deliver enough electricity to customers and results in limited, or even widespread, blackouts.

Resource Adequacy

Collectively, the electric industry applies the term Resource Adequacy to the evaluation of whether a particular utility, area of the grid, or region has adequate electric generating resources available to meet future demand for electricity at different times (e.g., times of day, seasons, or years) and under various conditions (e.g., temperature extremes or precipitation patterns), including an additional

[ii] Note that while peak demand also has a significant impact on the natural gas system, it is fundamentally different because of the ability to store the end-use fuel throughout the delivery system from the point of gas collection or extraction, through the transmission and distribution system, and up to the point of consumption by consumers.

reserve margin to account for demand excursions or unexpected outages. This is sometimes thought of as demonstrating the *long-term supply reliability* for the power system, as measured over a period of several years. RA standards, meanwhile, have been developed to ensure the uniformity of this evaluation process. In many states, standards are applied by an Independent System Operator (e.g., CAISO in California) with a wide geographic view of the electric grid across multiple utility service territories. Because of other constraints on the system, such as transmission congestion, some states evaluate RA on both a system-wide and a locational basis.

Resource Adequacy (or RA) is the term that grid planners and utilities use to refer to the evaluation of whether adequate generating capacity will be available to meet forecasted demand over the next several years (typically from one to five years).

Table 1 below helps to illustrate the different timescales of power reliability, and distinguishes what is meant by RA as compared to other types of reliability:

Table 1: Power System Reliability Over Different Timescales [5]

Short-term ***(< 1 minute)***	**System Stability**	Short-term reliability (e.g., frequency response) focused on grid stability over very short time intervals
Medium-term ***(Hourly or Daily)***	**System Balancing**	Medium-term reliability focused on managing imbalances on the system like those that occur between a day-ahead forecast and real-time conditions
Long-term ***(1 to 5 years)***	**Resource Adequacy**	Long-term reliability focused on seasonal or year-to-year mismatches between supply-and-demand

Ultimately, when a utility, state, or region evaluates RA, they are asking themselves: what level of risk are we willing to accept that inadequate generating capacity will be available to meet future customer demand for electricity over the next several years? Because forecasting the future is necessarily uncertain, the evaluation of RA and development of new capacity resources ahead of expected need is an inexact process that requires balancing the risk of under-building resources and having a shortage of power available vs. the cost to consumers of potentially over-building to ensure that power is available when it is needed.

Evaluating and Maintaining Resource Adequacy

There is currently no statewide organized program for the evaluation or maintenance of resource adequacy in Oregon. Discussions are currently underway to consider the development of a more formal approach (described below).

Evaluating Resource Adequacy

Many individual utilities independently evaluate their own adequacy to serve their customers. Meanwhile, the Northwest Power and Conservation Council (NWPCC) annually develops a long-term regional assessment of RA that evaluates the adequacy of the power supply in the Pacific Northwest, five years in the future.[6] The goal of the NWPCC's RA assessment is to "establish a resource adequacy framework for the Pacific Northwest to provide a clear, consistent, and unambiguous means of answering the question of whether the region has adequate deliverable resources to meet its load reliably and to develop an effective implementation framework."[7] The assessment includes existing resources, expected future energy efficiency savings, and only those planned resources that have already been sited and licensed.[8] This is intended to provide a signal to the region of the status of RA with adequate lead time for individual utilities or third-party developers to develop new capacity resources ahead of any forecasted shortfalls.

This is a *regional* assessment, the development of which is informed by contributions from utilities, state agencies, and other stakeholders from across the northwest.[9] [10] Due to differences in hourly, daily, and seasonal electricity consumption patterns across different regions, synergies can often be achieved by evaluating the electric system over a wider geographic footprint. For example, one area of the region may experience its annual peak demand for electricity during cold winter mornings, while another area's peak might occur during the summer months when air-conditioning or irrigation pump loads are highest.

Maintaining Resource Adequacy

Individual utilities and their regulators (the Oregon Public Utility Commission in the case of investor-owned utilities, or individual governing boards in the case of consumer-owned utilities) in the northwest evaluate RA to meet future demand in their territories. Utility-specific efforts will often incorporate the NWPCC's assessment as an input that reflects the broader regional availability of generating resources in the years ahead. This can be important for a utility that is weighing the risks of relying upon capacity available on the market to meet some share of its expected demand. Ultimately, however, individual utilities are responsible for maintaining resource adequacy to ensure that they can serve the demand of their customers.

Customer Choice and Resource Adequacy

In recent years, there has been increasing interest in customer choice programs in the electric sector. Many of these efforts stem from the broader deregulation movement in the 1990s. In Oregon, certain commercial and industrial customers have had access since that time to choose their retail provider of electricity through participation in Long-Term Direct Access (LTDA) agreements, which allow independent power producers to register with the PUC as electricity service suppliers (or ESSs) to deliver retail service in lieu of a utility.[11] Meanwhile, in the last decade,[12] California has seen a surge in the number of municipal and county governments forming Community Choice Aggregation (CCA) programs to exercise choice over their community's retail electricity provider.[iii]

Whether participating in LTDA as a commercial or industrial customer, or forming a CCA, customers are often motivated by actual or perceived cost-savings or other benefits associated with the exercise of choosing their retail electricity provider. For example, the customer(s) may seek an electricity

[iii] California's CCA example is particularly relevant to this discussion given the challenges that state has faced in recent years specifically regarding the role of CCAs in contributing to the maintenance of Resource Adequacy. It is important to note, however, that Oregon law does <u>not</u> allow for the formation of CCAs.

resource mix that includes higher levels of renewable resources than the incumbent utility provides, or may seek to source power from more locally-sited projects.

How should retail choice customers contribute toward Resource Adequacy?

As described above, the maintenance of resource adequacy requires evaluation at both the regional and utility-specific levels. Utilities often need to engage in the inexact science of forecasting future customer demand to plan for new generating capacity. This becomes more challenging when customers "exit" the utility's service territory (e.g., pursuant to LTDA, CCAs, or another customer choice program) to be served by a third-party. Who, in those cases, is responsible for procuring adequate capacity to ensure that RA is maintained?

This issue has emerged as a critical one in California given the scale of CCA formation in the state in recent years—21 CCAs operating across the state now serve more than 10 million retail customers.[13] After wrestling with the issue for several years, the California PUC recently stepped in to establish a central buyer framework for RA that requires the state's largest IOUs to procure the necessary capacity to meet projected load within their service territory boundaries, whether or not that load is served by CCAs.[14]

RA also surfaced as an issue in Oregon in 2019 as part of a broader, holistic investigation begun by the OPUC in June 2019 exploring the costs and benefits of Oregon's LTDA programs. For more information on this and other related ongoing issues, see Oregon PUC Docket UM 2024.[15]

What's Next for Resource Adequacy in Oregon

The electric system in the northwest has delivered incredibly reliable power to Oregonians for decades. This is in no small part due to the robustness of the Federal Columbia River Power System, which provides the foundation of the region's electric system. Increasing constraints on that hydropower system, widespread retirement of coal plants across the west, and increases in variable renewable energy generation have combined to create new concerns about maintaining RA in the years ahead. As intended, the NWPCC's regional assessment of RA has sent a signal that the region could be short of capacity by the mid-2020s. Being short of capacity could mean that the power system lacks the resources to meet demand at all times, which would increase the potential for rolling blackouts.[16]

Hydropower: An outsized contribution to maintaining RA in the Pacific Northwest

The federal hydropower system has made a unique contribution to maintaining power system reliability in the northwest for much of the last century. Since the 1930s, the federal government has made substantial investments to develop the hydropower resources in the region, which now total over 22,000 MW of nameplate capacity, with the capability of providing 9,818 MW of sustained peak capacity in January (the region's highest electricity-use month) even during years with low water conditions. Non-federal hydropower resources, meanwhile, can provide an additional 11,336 MW of sustained peak capacity in January. Combined, these hydropower resources account for 54 percent of the region's total sustained peak capacity in January, and can account for an even greater share of the region's sustained peak capacity during non-critical water conditions.[17]

Northwest hydropower has provided the foundation of our electric system for decades and has historically provided a large share of the region's annual energy. In many respects, this has afforded the northwest electric sector with significant advantages not found elsewhere in the United States—in addition to often having an abundance of low cost, carbon-free energy to meet demand, the robustness of the hydropower system has been able to meet a significant amount of the region's capacity need. This has played a significant role in enabling the region (so far) to avoid the need for a more formalized approach to evaluating RA, such as those that exist in other regions.

As a result of the changes in the sector and continued, albeit modest, regional load growth, many of the state's largest utilities and BPA have recently joined together under the auspices of the Northwest Power Pool to explore the development of a formalized regional RA program, focused on short-term adequacy (from a period of days and weeks to months). The effort kicked off publicly in October 2019 when the NWPP convened a widely attended Northwest Resource Adequacy Symposium.[18] The future remains uncertain with respect to the successful launch of an NWPP-led regional RA program. It is expected that the effort will result in the release of a final proposed design of such a program in 2021, with implementation to occur over the following several years.[19]

Unlike the current process for evaluating regional RA in the northwest—where the NWPCC's assessment informs the region of the long-term status of RA (from a few years to 20 years into the future), but individual utilities procure resources to meet their own capacity needs—the type of program being developed by the NWPP is expected to formalize a short-term regional assessment of RA that would be contractually binding on individual participating utilities and electricity service providers. Those entities would voluntarily join the program, but then would have a contractual legal obligation to procure their apportioned share of capacity resources necessary, as assessed by the NWPP, to maintain overall regional RA in the short-term (from a period of days and weeks to months).[20]

There are also emerging discussions within Docket UM 2024 at the Oregon PUC about a proposed process to explore the development of an Oregon-specific RA program as a potential interim solution until the adoption of an organized, regional program.[21] [22] The NWPCC's regional assessment, in either case, would still provide complementary, valuable insight into the long-term adequacy of the power supply in the northwest.

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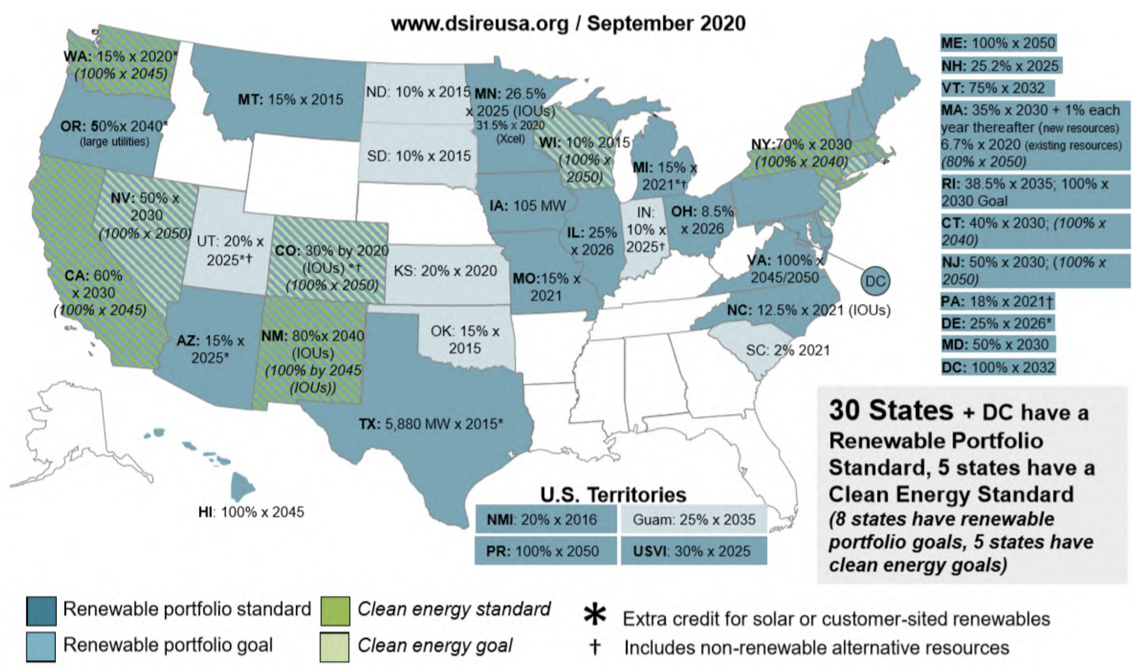
Energy 101: Clean and Renewable Standards

Portfolio standards require utilities and other energy suppliers to procure a certain minimum amount of their energy portfolio from eligible resources. These policies create demand for targeted energy resources, increase their development and use, and help to overcome market barriers to adoption, thereby enabling society to capture the environmental, economic, and other benefits associated with these resources.[1] Portfolio standards can come in many forms and cover different energy resources. For example, energy efficiency standards help drive adoption of energy saving technologies and practices,[2] and low-carbon or clean fuel standards help incentivize innovation and adoption of less carbon intensive direct-use or transportation fuels.[3] Two similar types of portfolio standards are in use today in the electricity sector: Renewable Portfolio Standards (RPS) and Clean Energy Standards (CES).[i] Currently 30 states and the District of Columbia have some form of RPS, CES, or a combination of the two; a further eight states have non-binding renewable portfolio goals.[4]

Figure 1: Renewable and Clean Energy Standards in the United States



Note: Virginia and Maine 100% RPS programs have unclear guidelines about qualifying resources and may be considered 100% clean energy standards.

In addition to states, sub-state jurisdictions like municipalities and counties, as well as individual electricity suppliers also set electricity portfolio standards or goals.[5] While RPS and CES policies are similar in their goals, there are key differences between them. This section describes and compares RPS and CES policies. For a discussion of emerging trends in RPS and CES policies see the Renewable and Zero-Emissions Standards Policy Brief.

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[i] Renewable portfolio standards may also be referred to as renewable energy standards or renewable electricity standards. Likewise, alternative names for clean energy standards include clean electricity standards and zero-emission standards.

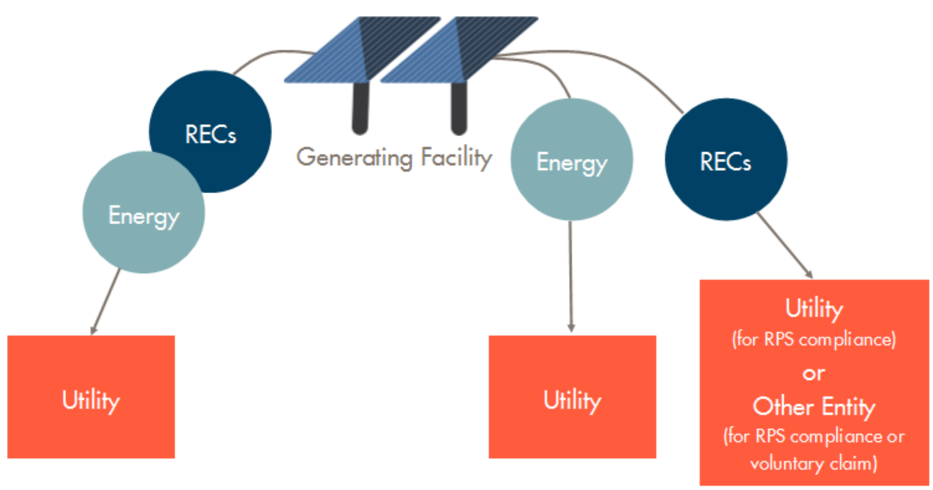
Renewable Portfolio Standards

An RPS requires electricity suppliers to procure a minimum amount of electricity from eligible *renewable resources*.[ii] [6] The primary purpose of an RPS is to increase the development and use of renewable energy sources for electricity generation. There are a number of reasons why a state or jurisdiction might want to increase renewable electricity generation, including reducing emissions of pollutants to meet environmental and climate goals, diversifying the electricity grid, developing new industries, and providing new opportunities for local workforces. It is important to note that while an RPS can be a key policy in supporting climate change mitigation and economic goals, the primary purpose of an RPS is to increase generation from renewable energy resources; an RPS does not specifically target climate goals like reducing emissions.

State RPS policies can vary widely across several design elements including RPS targets, the sectors and electricity suppliers they include, and resource eligibility. Many states, like Oregon, set RPS targets as a percentage of retail electric sales.[7] Other states, like Iowa and Texas, require specific amounts of renewable electricity capacity rather than percentages.[8] RPS policies target the electricity sector, but do not address other parts of the energy sector such as direct-use fuels or transportation fuels. RPS requirements generally apply to retail energy suppliers and frequently apply only to investor-owned utilities (IOUs), though many states also include requirements for energy service suppliers, municipalities, and electric cooperatives – sometimes with lower targets.

Resources eligible for an RPS can vary depending on the goals of the policy, the types of resources jurisdictions want to promote, and how jurisdictions define a renewable resource. Eligible resources for an RPS always include wind, solar, and geothermal resources. Several states also include resources such as biomass, landfill gas, hydrokinetic marine (wave and tidal) energy, combined heat and power, and even energy efficiency. Hydropower resource eligibility is frequently determined based on the type and age of the facility. Many RPS policies aim to incentivize the development of *new* renewable resources, and therefore make older facilities ineligible, such as Oregon's treatment of its legacy hydropower.[9] Some RPS policies include more specific requirements, called carve-outs, which require a certain percentage of the overall renewable electricity requirement to be met with a specific technology to incentivize the deployment of particular technologies, resources, or market segments.

Figure 2: Bundled vs. Unbundles Renewable Energy Certificates



RPS policies use a renewable energy certificate (REC) trading system to track compliance with RPS goals and to reduce the cost to comply with the RPS. A REC is a tradeable certificate that represents the ownership property rights (similar to intellectual property rights) to renewable attributes

[ii] An alternative to an RPS, which requires compliance, is a renewable energy goal which is non-binding.

of one-megawatt hour (1 MWh) of qualifying renewable electricity delivered to the grid. Once electricity is on a utility grid it is not possible to physically trace the electricity back to its origin, so RECs play an important role in accounting, tracking, and assigning ownership to renewable electricity generation and use. A REC can be sold together with electricity delivered, called a "bundled REC," and the buyer can make a claim of consuming renewable electricity. A REC can also be sold separately from the associated electricity, called an "unbundled REC," in which case the buyer of the REC can make a claim of consuming renewable electricity while the buyer of the physical electricity cannot. An electricity supplier that generates more renewable electricity than its RPS requirement may either trade or sell RECs to other electricity suppliers who do not have enough RPS-eligible electricity to meet their RPS requirements. Depending on the state, RECs can also be banked for future compliance use.

Benefits and Costs of RPS Policies

RPS policies, along with other state and federal policies and federal tax credits, are one of the key policy drivers for renewable energy growth in the United States. States have generally met established RPS goals, and approximately half of renewable energy deployment since 2000 is associated with state RPS requirements.[iii] [10] However, the role of RPS policies as a driver of renewable electricity deployment has diminished over time as states with RPS programs have met or exceeded targets and states without RPS programs have also deployed renewable resources, in part due to favorable economics for renewables.[11] In 2018, renewable electricity deployment associated with meeting RPS requirements represented just under 30 percent of all U.S. renewable energy capacity additions.[12]

Research estimating the costs and benefits of RPS policies has identified that benefits tend to outweigh costs. A study by the Lawrence Berkeley National Laboratory (LBNL) found that national costs of RPS compliance between 2010 and 2013 were approximately $1 billion, which is on average less than 2 percent of average statewide electricity rates. At the same time, estimated benefits from reduced carbon emissions and public health benefits came to an average of $5.2 billion (a more than 5 to 1 benefit to cost ratio).[13] A second LBNL study forecasted future costs and benefits under existing RPS policies in 2016 compared to a scenario of no RPS policies.[14] The study found that between 2015 and 2050 RPS benefits outweighed costs even when considering the highest cost and lowest benefit outcomes; the study estimated high-end costs of 0.75¢ per kWh, while air pollution benefits, health benefits, and greenhouse gas reduction benefits totaled at least 2.4¢ per kWh (a more than 3 to 1 benefit to cost ratio).[15] Most RPS policies also have cost containment provisions. For example, the Oregon RPS has two mechanisms that serve as cost protections for Oregon consumers: a compliance cost cap of 4 percent of the utility's annual revenue requirement, and an alternative compliance payment (ACP) mechanism that sets an annual per megawatt-hour rate utilities can pay in lieu of procuring renewable resources.[16]

[iii] A Lawrence Berkeley National Laboratory study identified that while state RPS policies are associated with increased renewable deployment, it is challenging to directly attribute this increase to RPS policies.

Oregon's Renewable Portfolio Standard

Oregon established its RPS in 2007 with Senate Bill 838. The RPS required Oregon's large utilities to provide 25 percent of retail sales from eligible renewable sources by 2025, with interim goals along the way. The RPS defines large utilities as those that provide 3 percent or more of total state retail electricity sales; currently Portland General Electric, PacifiCorp, and the Eugene Water & Electric Board meet this threshold. The state's smaller utilities had lower targets, depending on the percent share of the state's total retail electricity load they supplied. In 2016, Oregon increased its RPS requirements from 25 percent by 2025 to 50 percent by 2040 in Senate Bill 1547 (Oregon Clean Electricity and Coal Transition Plan). The 50 percent target only applies to large investor-owned utilities that provide 3 percent or more of total state retail electricity sales. Compliance for consumer-owned utilities, including EWEB and small investor-owned utilities supplying less than 3 percent of total state retail electricity sales, was capped at 25 percent by 2025.

Eligible resources for the Oregon RPS include solar, wind, marine hydrokinetic, geothermal, certain biomass sources, some hydropower, and hydrogen gas. The Oregon RPS restricts eligibility in most cases to facilities built after January 1, 1995 to encourage development of new renewable resources. SB 1547 also created another type of REC (Thermal RECs or T-RECs). Thermal energy generated at a facility that also generates electricity using RPS-eligible biomass sources is also eligible for the RPS (for more information about the Oregon RPS, see the 2018 ODOE *Biennial Energy Report*).

Clean Electricity Standards

A clean electricity standard refers to a portfolio standard that requires electricity suppliers to procure a certain amount of electricity from "*clean" zero- or low-carbon emitting resources*.[17] CES policies are typically technology-neutral, and may include procurement from resources including hydropower, nuclear energy, coal or natural gas fitted with carbon capture, and other low- or zero-emission technologies, as well as renewables. The primary purpose of a CES is to increase the use of carbon-free sources for electricity generation in order to set and meet more ambitious carbon reduction and climate policies. Like RPS policies, CES can help achieve other goals such as increasing renewable electricity generation, diversifying the electricity grid, developing new industries, and providing new opportunities for local workforces. However, the primary goal is to decarbonize electricity generation. The argument for CES policies is that they allow jurisdictions a wider scope to set and meet more ambitious targets for carbon-free electricity, create a backstop against future growth of fossil fuels, and signal demand for emerging carbon-free technologies to the market.[18]

Compliance tracking and cost containment for CES policies may vary depending on the goals of a jurisdiction. One method is to adopt a similar credit system as an RPS that assigns credits per MWh of clean electricity generation to represent ownership property rights associated with clean electricity attributes. Alternatively, CES policies could adopt a tiered credit structure that awards credits of different values to different resource types, as is the case in New York which uses both RECs and Zero Emission Credits.[19] Another alternative, which some research suggests could increase efficiency, is a credit system based on emissions rates rather than technology type.[20] Under this method, facilities would be compared on an emissions rate basis to a reference type of emitting generator, either a new coal plant or some type of natural gas plant, and would receive credits accordingly. Some jurisdictions may opt to forego credit systems and mandate compliance without a credit trading plan. Regardless of the design, policymakers will face several tradeoffs and must consider the most appropriate path to meet their specific goals.

Benefits and Costs of CES Policies

CES policies have not been in place for as long as RPS policies, so detailed research on costs and benefits is less available. That said, in theory a CES has potential to achieve an equivalent level of emissions reductions as an RPS at lower cost because a greater number of technologies will compete to reduce emissions, which increases market efficiency and lowers overall compliance costs for a given level of emissions reduction.[21] CES policies can, however, include non-emitting generation resources like nuclear power, or fossil generation with carbon capture; which can have associated economic, environmental, and public health costs.

Washington Clean Electricity Standard[22]

In 2019, Washington state passed the Clean Energy Transformation Act (CETA). CETA requires all retail sales of electricity be “greenhouse gas neutral” by 2030, and by 2045, 100 percent of retail sales of electricity must be from either RPS-eligible renewables or from “non-emitting” resources. The bill defines “non-emitting” resources as resources that do not emit greenhouse gases as a by-product of energy generation. The difference between the 2030 target and the 2045 target is that, for the period between 2030 and 2045, utilities can meet up to 20 percent of their compliance with alternative compliance measures, including alternative compliance payments, purchasing unbundled RECs, or investing in additional energy efficiency projects.

Clean Energy Standards[23]

The term Clean Energy Standard is often used synonymously with Clean Electricity Standard. A Clean Energy Standard, however, can apply to energy resources beyond those used for electricity generation. The purpose of a Clean Energy Standard is to have a policy that requires clean energy targets across all energy resources, including electricity but also energy resources for direct use like space heating, industrial processes, and transportation. Many states have multiple standards to cover all energy sectors, like energy efficiency standards and clean fuel standards, but an umbrella Clean Energy Standard would cover all sectors. While there are no states with an umbrella Clean Energy Standard, there are municipalities that have adopted Clean Energy *Targets*. For example, in 2017, Multnomah County and the City of Portland adopted a resolution to meet 100 percent of community-wide electricity needs with renewable resource by 2035, and all energy needs by 2050.

Comparison of RPS and CES Policies

While the terms RPS and CES are sometimes used interchangeably, there are meaningful material differences between the two policies. Primarily, RPS policies aim to incentivize the development of *new* renewable resources, and exclude generation sources that are not considered "renewable," but that may be low-carbon or zero-carbon emitting resources such as nuclear power or fossil fuel-generated electricity with carbon capture and storage (CCS) technology. CES policies, on the other hand, aim more directly to reduce carbon emissions by incorporating low- or zero-carbon emitting resources regardless of whether or not they meet the definition of renewable energy.

Table 1: Primary and Secondary Objectives of Different Standards

Policy	Objectives
Renewable Portfolio Standard	Primary: Increase renewable electricity resources Secondary: Meet climate, environmental, and other goals
Clean Electricity Standard	Primary: Reduce GHG emissions in electricity generation Secondary: Technology adoption goals (e.g., renewable energy resources)
Clean Energy Standard	Primary: Reduce GHG emissions in all energy use (electricity, direct use, and transportation fuels) Secondary: Technology adoption goals (e.g., renewable energy resources)

**Note: Some jurisdictions have renewable goals or clean goals, which have the same objectives but are voluntary rather than mandatory.*

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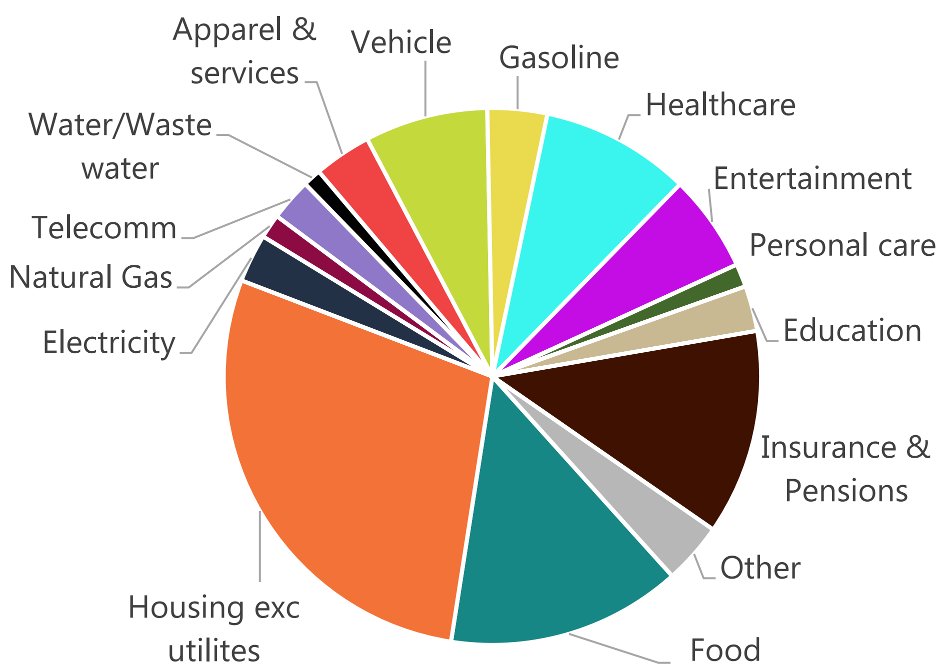
Energy 101: Bill Basics

Energy is part of everyone's household budget. Lighting, heating, cooling, cooking, and refrigeration all require energy in the forms of electricity and direct use fuels like natural gas, propane, fuel oil, and even wood. Water and wastewater have a big energy component because of the energy needed to obtain, distribute, and treat water. Transportation has an energy bill too, every time you buy gasoline or plug in your electric car. Telecommunications, from internet to TV to cell phones, all require electricity to operate and provide the services used a part of our daily lives.[1]

Figure 1: Typical Share of Household Expenses



This section looks at Oregonians' typical main energy costs: electricity, natural gas, and transportation.

Energy Bill Basics

The key to deciphering charges on an energy bill is understanding the terminology used to describe each charge. Following are some general energy terms and types of charges that apply to most energy bills:

Meter. Meters measure how much energy is consumed. Some electric utilities are updating their meters to "smart meters," which help track when energy is used in addition to how much.

Rate Schedule. Rates vary between residential, commercial, and industrial customers, based on the type of service and the maximum demand. More than one rate can be used for the energy a building or facility uses. Schedules can be created for specific uses, like traffic signals, streetlights, irrigation and drainage pumping, or for time-of-day service or special pilot programs like demand response.

Every Utility Bill has certain things in common:

Basic Charge or Service Charge. A minimum cost of service, regardless of the amount of energy used. This funds some of the utility provider's costs like maintenance and customer support.

Use Charge. Utilities charge by how much energy is used, measured in kilowatt hours for electricity, and therms for natural gas. There are additional types of use charges that are explained later in this section.

Dates of Service. The date range when the charges were incurred.

Balance. The previous months charges, any payments and current balance will be shown.

Location of Service. The address or other identifying information for the account.

Taxes and Fees. City, county, and/or state taxes may be applied to your utility bill. Specific fees, such as low-income assistance and the Public Purpose Charge, are described in other locations.

Some utility bills include the following:

Voluntary Green Energy Plans. Some electric and natural gas utilities offer programs for customers who want to support renewable energy development. In Figure 2, the customer is enrolled in PGE's Green Source program. Oregon's two largest electric utilities have the country's highest participation rates in voluntary green energy programs.[2] NW Natural's Smart Energy Program, the nation's first voluntary offset program, procures offsets from regional renewable projects.

Low Income Assistance. This charge provides funding for low-income residential customers who are unable to pay their electric bills in times of crisis.

Investor Owned Utilities may have additional types of charges because of how they are regulated.

Adjustments. Investor-owned utility rates are regulated by the Public Utility Commission and changes to the rates must go through an oversight process. These rate adjustments are for a particular purpose. The reason for the adjustment must be reviewed and approved by the PUC. Each utility has its own set of rate adjustments, some are credits, and some are charges.

Public Purpose Charge. For PGE and Pacific Power, a 3 percent Public Purpose Charge is added to each bill. This charge funds energy efficiency projects, renewable resources, weatherization for low-income households and energy efficiency improvements. It also funds an energy efficiency program for schools. NW Natural, Cascade, and Avista natural gas companies also have a public purpose charge to fund energy efficiency programs. Energy Trust of Oregon administers a portion of the Public Purpose Charge and the Natural Gas programs. Oregon Housing and Community Services receives a share of the Public Purpose Charge for programs and School Districts receive Public Purpose Charge funds directly from PGE or Pacific Power.

Figures 2 and 3 below are sample electric and natural gas bills, plus additional common types of charges. Detailed descriptions of each type of charge can usually be found on each utility's website. If a charge on your bill is not shown here, refer to your utility's website or contact customer support for more information.

Residential Electric Bills

Use Charges:

Demand Charges. Utility customers are charged based on the maximum amount of electricity they use. Utilities may add demand charges, particularly for commercial and industrial customers, based on the customer's highest electricity use during a particular time interval (usually 15 minutes). Customers with large equipment that uses significant electricity may incur high demand charges.

Transmission & Distribution Charges. These charges fund the utility's costs to bring power to the customers including installation and maintenance of utility poles, lines, transmission towers, and other equipment.

Adjustments:

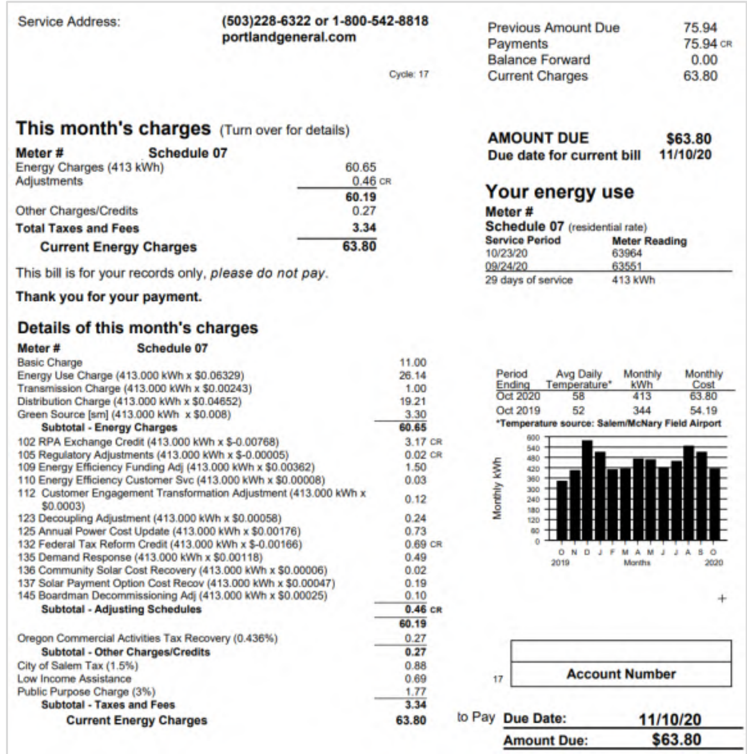
Regional Power Act (RPA) Exchange Credit. Residential, farm, and farm irrigation and drainage pumping service types are eligible for this credit which passes benefits from a settlement between the utility and the BPA on to the customer.

Regulatory Adjustments. This credit reflects the effects of regulatory adjustments, such as net gains from property transaction or costs associated with implementing SB 1149. This adjustment is non-recurring and therefore varies.

Energy Efficiency Funding Adjustment. This charge funds new energy efficiency measures for the programs administered by the Energy Trust of Oregon. These programs are available to customers of investor-owned utilities.

Energy Efficiency Customer Service. This charge funds activities to assist customers with project facilitation, technical assistance,

Figure 2: Sample Residential Bill: Investor-Owned Electric Utility



Service Address: (503)228-6322 or 1-800-542-8818 portlandgeneral.com Cycle: 17

Previous Amount Due	75.94
Payments	75.94 CR
Balance Forward	0.00
Current Charges	63.80

This month's charges (Turn over for details)

Meter # Schedule 07

Energy Charges (413 kWh)	60.65
Adjustments	0.46 CR
	60.19
Other Charges/Credits	0.27
Total Taxes and Fees	3.34
Current Energy Charges	63.80

This bill is for your records only, *please do not pay*.

Thank you for your payment.

AMOUNT DUE $63.80
Due date for current bill 11/10/20

Your energy use
Meter #
Schedule 07 (residential rate)

Service Period	Meter Reading
10/23/20	63964
09/24/20	63551
29 days of service	413 kWh

Details of this month's charges

Meter # Schedule 07

Basic Charge	11.00
Energy Use Charge (413.000 kWh x $0.06329)	26.14
Transmission Charge (413.000 kWh x $0.00243)	1.00
Distribution Charge (413.000 kWh x $0.04652)	19.21
Green Source [sm] (413.000 kWh x $0.008)	3.30
Subtotal - Energy Charges	60.65
102 RPA Exchange Credit (413.000 kWh x $-0.00768)	3.17 CR
105 Regulatory Adjustments (413.000 kWh x $-0.00005)	0.02 CR
109 Energy Efficiency Funding Adj (413.000 kWh x $0.00362)	1.50
110 Energy Efficiency Customer Svc (413.000 kWh x $0.00008)	0.03
112 Customer Engagement Transformation Adjustment (413.000 kWh x $0.0003)	0.12
123 Decoupling Adjustment (413.000 kWh x $0.00058)	0.24
125 Annual Power Cost Update (413.000 kWh x $0.00176)	0.73
132 Federal Tax Reform Credit (413.000 kWh x $-0.00166)	0.69 CR
135 Demand Response (413.000 kWh x $0.00118)	0.49
136 Community Solar Cost Recovery (413.000 kWh x $0.00006)	0.02
137 Solar Payment Option Cost Recov (413.000 kWh x $0.00047)	0.19
145 Boardman Decommissioning Adj (413.000 kWh x $0.00025)	0.10
Subtotal - Adjusting Schedules	0.46 CR
	60.19
Oregon Commercial Activities Tax Recovery (0.436%)	0.27
Subtotal - Other Charges/Credits	0.27
City of Salem Tax (1.5%)	0.88
Low Income Assistance	0.69
Public Purpose Charge (3%)	1.77
Subtotal - Taxes and Fees	3.34
Current Energy Charges	63.80

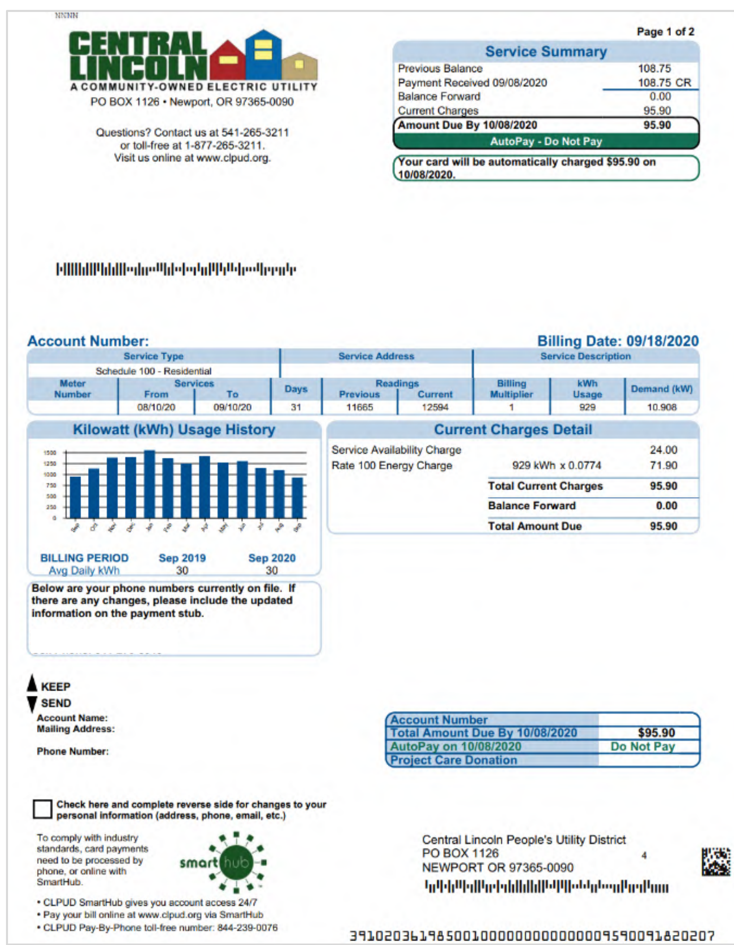
Period Ending	Avg Daily Temperature*	Monthly kWh	Monthly Cost
Oct 2020	58	413	63.80
Oct 2019	52	344	54.19

*Temperature source: Salem/McNary Field Airport

17 Account Number

to Pay Due Date: 11/10/20
Amount Due: $63.80

Figure 3: Sample Residential Bill: Consumer-Owned Electric Utility



CENTRAL LINCOLN
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PO BOX 1126 • Newport, OR 97365-0090

Questions? Contact us at 541-265-3211 or toll-free at 1-877-265-3211. Visit us online at www.clpud.org.

Page 1 of 2

Service Summary

Previous Balance	108.75
Payment Received 09/08/2020	108.75 CR
Balance Forward	0.00
Current Charges	95.90
Amount Due By 10/08/2020	95.90

AutoPay - Do Not Pay

Your card will be automatically charged $95.90 on 10/08/2020.

Account Number: Billing Date: 09/18/2020

Service Type: Schedule 100 - Residential | Service Address | Service Description

Meter Number	Services From	Services To	Days	Readings Previous	Readings Current	Billing Multiplier	kWh Usage	Demand (kW)
	08/10/20	09/10/20	31	11665	12594	1	929	10.908

Kilowatt (kWh) Usage History

BILLING PERIOD	Sep 2019	Sep 2020
Avg Daily kWh	30	30

Current Charges Detail

Service Availability Charge		24.00
Rate 100 Energy Charge	929 kWh x 0.0774	71.90
	Total Current Charges	95.90
	Balance Forward	0.00
	Total Amount Due	95.90

Below are your phone numbers currently on file. If there are any changes, please include the updated information on the payment stub.

KEEP
SEND

Account Name:
Mailing Address:
Phone Number:

Account Number	
Total Amount Due By 10/08/2020	$95.90
AutoPay on 10/08/2020	Do Not Pay
Project Care Donation	

Check here and complete reverse side for changes to your personal information (address, phone, email, etc.)

To comply with industry standards, card payments need to be processed by phone, or online with SmartHub.

• CLPUD SmartHub gives you account access 24/7
• Pay your bill online at www.clpud.org via SmartHub
• CLPUD Pay-By-Phone toll-free number: 844-239-0076

Central Lincoln People's Utility District
PO BOX 1126
NEWPORT OR 97365-0090

391020361985001000000000000009590091820207 education, and support for programs administered by the Energy Trust of Oregon.

Customer Engagement Transformation Adjustment. This charge funds PGE's Customer Engagement and Transformation Project.[3]

Decoupling Adjustment. This rate adjustment allows for charges to mitigate a portion of the transmission distribution and fixed generation revenue variations caused by variations in customer energy usage.

Demand Response Cost Recovery. This charge recovers the expenses for demand response pilot programs not included in other rates.

Solar Payment Option Cost Recovery. This charge recovers costs for the Solar Payment Option pilot not included in other rates.

Spent Fuel Adjustment. This credit passes on excess funds from the Trojan Nuclear Decommissioning Trust fund and any ongoing refunds from the USDOE.

Boardman Decommissioning Adjustment. This charge funds the decommissioning expenses related to the Boardman power plant.

Time-Of-Use*.* The charge for electricity can change depending on the time of day. The day is broken into periods of time designated 'on-peak' or periods where many customers use increased amounts of energy, and 'off-peak' or periods where customers consistently use less energy. On-peak energy use results in increased energy costs per kWh.

Other fees for low-income assistance and the Public Purpose Charge are explained above.

Commercial Electric Bills

Larger electric customers, like businesses and schools, have other charges that may show up on their bills.[4]

Use Charges:

Load Size Charge. This rate is in addition to the basic use charge and accounts for additional and larger equipment needed to provide larger service connection.

Demand Charge. see previous definition

Delivery Charge. This charge covers costs related to electricity poles, lines, transformers, and other equipment used to deliver electricity.

Supply Energy Charge. This covers costs of supplying electricity based on the number of kWh used. For Pacific Power there are two rates, the rate for use between 1 and 1,000 kWh is lower to encourage customers to save energy.

Adjustments:

Federal Tax Act Adjustment. This credit passes on deferred tax savings associated with the 2017 Federal Tax act.

Oregon Corporate Activities Tax Adjustment. This charge covers taxes paid because of the Oregon Corporate Activity Tax.

Fees:

Public Purpose Charge. See definition at the beginning of this section.

Energy Conservation Charge. This is a state mandated charge covering energy conservation measures related to the Oregon Renewable Energy Act.

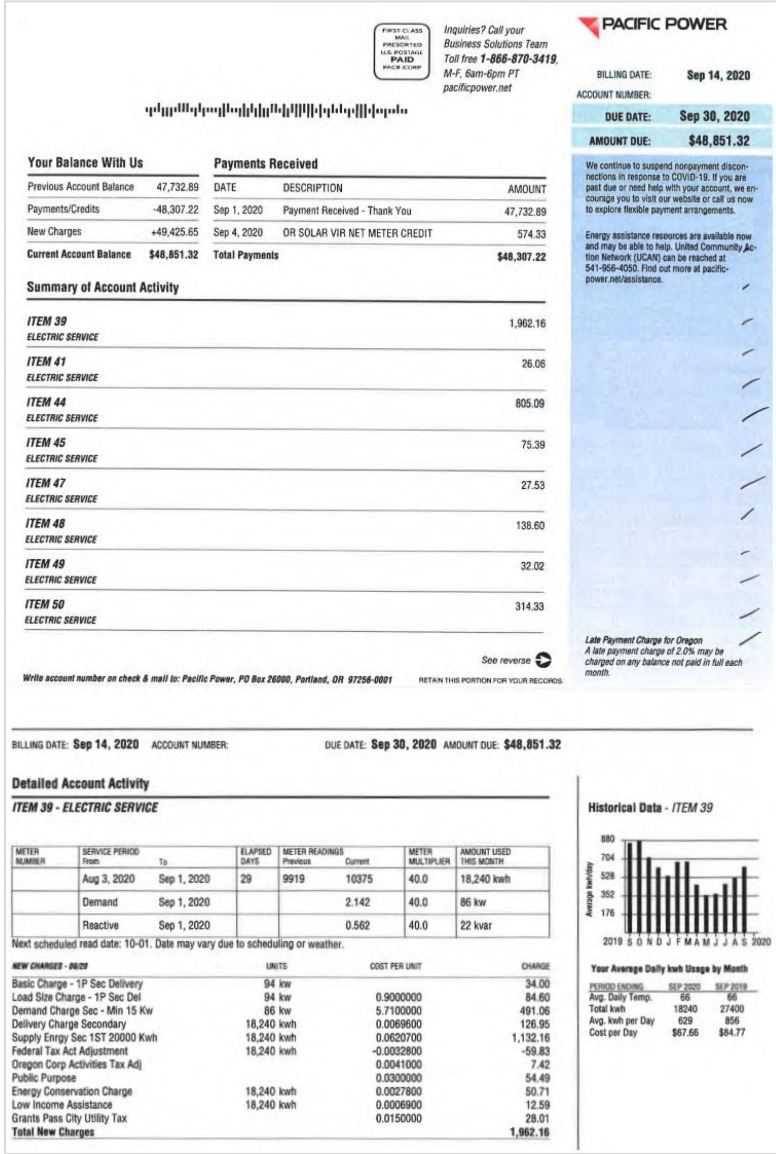
Other Charges Large Electricity Consumers May See:

Power Factor. Electricity; often charged for separately on commercial and industrial bills. Some large power customers may see power factor charges on their electric bill. Power factor is the ratio of working power to apparent power. Working power is the actual power used to run equipment and apparent power is the combination of working power and additional power resulting from an inductive load like a motor. Utilities work with customers to maximize power factor to ensure the full benefit of their electricity use, with the additional advantage of supporting longer equipment life. Managing power factor can reduce or eliminate power factor charges because it makes managing demand easier for utilities.

Ratcheting or Declining Rates. Some utilities offer increasing or declining rates as the amount of energy purchased increases. This type of rate can be used to incentivize reductions in energy use in the case of ratcheting rates. Typically, commercial and industrial customers have high enough use to take advantage of declining rates. In Oregon, some electric utilities offer ratcheting rates, while some natural gas utilities offer declining rates.

Interruptible Energy Rates. Some utilities offer a discount to large customers that are willing to have their services temporarily interrupted by the utility. This allows utilities to better manage demand across their network of customers. Both natural gas and electric utilities may offer this type of rate.

Figure 4: Sample Commercial Bill: Investor-Owned Electric Utility



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PACIFIC POWER

BILLING DATE: **Sep 14, 2020**

ACCOUNT NUMBER:

DUE DATE: Sep 30, 2020

AMOUNT DUE: $48,851.32

We continue to suspend nonpayment disconnections in response to COVID-19. If you are past due or need help with your account, we encourage you to visit our website or call us now to explore flexible payment arrangements.

Energy assistance resources are available now and may be able to help. United Community Action Network (UCAN) can be reached at 541-956-4050. Find out more at pacificpower.net/assistance.

Your Balance With Us

Previous Account Balance	47,732.89
Payments/Credits	-48,307.22
New Charges	+49,425.65
Current Account Balance	**$48,851.32**

Payments Received

DATE	DESCRIPTION	AMOUNT
Sep 1, 2020	Payment Received - Thank You	47,732.89
Sep 4, 2020	OR SOLAR VIR NET METER CREDIT	574.33
Total Payments		**$48,307.22**

Summary of Account Activity

ITEM 39 ELECTRIC SERVICE	1,962.16
ITEM 41 ELECTRIC SERVICE	26.06
ITEM 44 ELECTRIC SERVICE	805.09
ITEM 45 ELECTRIC SERVICE	75.39
ITEM 47 ELECTRIC SERVICE	27.53
ITEM 48 ELECTRIC SERVICE	138.60
ITEM 49 ELECTRIC SERVICE	32.02
ITEM 50 ELECTRIC SERVICE	314.33

See reverse

Late Payment Charge for Oregon
A late payment charge of 2.0% may be charged on any balance not paid in full each month.

Write account number on check & mail to: Pacific Power, PO Box 26000, Portland, OR 97256-0001

RETAIN THIS PORTION FOR YOUR RECORDS

BILLING DATE: **Sep 14, 2020** ACCOUNT NUMBER: DUE DATE: **Sep 30, 2020** AMOUNT DUE: **$48,851.32**

Detailed Account Activity

ITEM 39 - ELECTRIC SERVICE

METER NUMBER	SERVICE PERIOD From	To	ELAPSED DAYS	METER READINGS Previous	Current	METER MULTIPLIER	AMOUNT USED THIS MONTH
	Aug 3, 2020	Sep 1, 2020	29	9919	10375	40.0	18,240 kwh
	Demand	Sep 1, 2020			2.142	40.0	86 kw
	Reactive	Sep 1, 2020			0.562	40.0	22 kvar

Next scheduled read date: 10-01. Date may vary due to scheduling or weather.

NEW CHARGES - 09/20	UNITS	COST PER UNIT	CHARGE
Basic Charge - 1P Sec Delivery	94 kw		34.00
Load Size Charge - 1P Sec Del	94 kw	0.9000000	84.60
Demand Charge Sec - Min 15 Kw	86 kw	5.7100000	491.06
Delivery Charge Secondary	18,240 kwh	0.0069600	126.95
Supply Enrgy Sec 1ST 20000 Kwh	18,240 kwh	0.0620700	1,132.16
Federal Tax Act Adjustment	18,240 kwh	-0.0032800	-59.83
Oregon Corp Activities Tax Adj		0.0041000	7.42
Public Purpose		0.0300000	54.49
Energy Conservation Charge	18,240 kwh	0.0027800	50.71
Low Income Assistance	18,240 kwh	0.0006900	12.59
Grants Pass City Utility Tax		0.0150000	28.01
Total New Charges			**1,962.16**

Historical Data - *ITEM 39*

Your Average Daily kwh Usage by Month

PERIOD ENDING	SEP 2020	SEP 2019
Avg. Daily Temp.	66	66
Total kwh	18240	27400
Avg. kwh per Day	629	856
Cost per Day	$67.66	$84.77

Natural Gas Bills: Residential and Commercial

Monthly Service Charge. A minimum cost of service, regardless of the amount of energy used. This funds some of the utility provider's costs like maintenance and customer support. The base charge will vary depending on the type of service.

Natural Gas Usage. Delivered via pipeline, natural gas is metered and measured in therms. One therm is equivalent to 100,000 Btu or 100 cubic feet of natural gas. For natural gas this measurement indicates both the volume of natural gas used as well as the quantity of energy consumed.

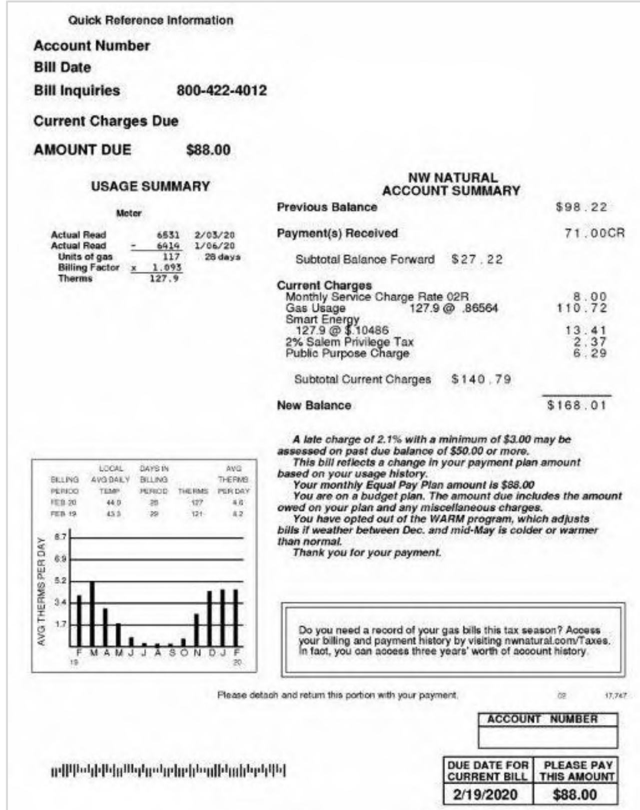
Declining Rate. The first 10,000 therms are charged at a higher rate than the next 5,670.9 therms on the commercial bill. This provides a discount to large consumers.[5]

Firm Service Distribution Cap, Pipeline Cap, and Storage Charges. As part of this rate schedule the service is 'firm' which means that it cannot be interrupted by the utility, and additional charges allow the utility to recover costs for distribution (pumping, meters, and other equipment), pipeline maintenance, and storage of natural gas. All these costs are greater for maintaining commercial supply than for residential, therefore they show up as line item costs in the commercial bill.

Smart Energy. This is NW Natural's voluntary green energy program. See definition at the beginning of this section.

Public Purpose Charge. See definition at the beginning of this section.

Figure 5: Sample Residential Bill: Investor-Owned Natural Gas Utility



Quick Reference Information

Account Number
Bill Date
Bill Inquiries 800-422-4012
Current Charges Due
AMOUNT DUE $88.00

USAGE SUMMARY

Meter

Actual Read	6531	2/03/20
Actual Read	- 6414	1/06/20
Units of gas	117	28 days
Billing Factor	x 1.093	
Therms	127.9	

NW NATURAL ACCOUNT SUMMARY

Previous Balance		$98.22
Payment(s) Received		71.00CR
Subtotal Balance Forward	$27.22	
Current Charges		
Monthly Service Charge Rate 02R		8.00
Gas Usage 127.9 @ .86564		110.72
Smart Energy 127.9 @ $.10486		13.41
2% Salem Privilege Tax		2.37
Public Purpose Charge		6.29
Subtotal Current Charges	$140.79	
New Balance		$168.01

A late charge of 2.1% with a minimum of $3.00 may be assessed on past due balance of $50.00 or more.
This bill reflects a change in your payment plan amount based on your usage history.
Your monthly Equal Pay Plan amount is $88.00
You are on a budget plan. The amount due includes the amount owed on your plan and any miscellaneous charges.
You have opted out of the WARM program, which adjusts bills if weather between Dec. and mid-May is colder or warmer than normal.
Thank you for your payment.

BILLING PERIOD	LOCAL AVG DAILY TEMP	DAYS IN BILLING PERIOD	THERMS	AVG THERMS PER DAY
FEB 20	44.0	28	127	4.6
FEB 19	43.3	29	121	4.2

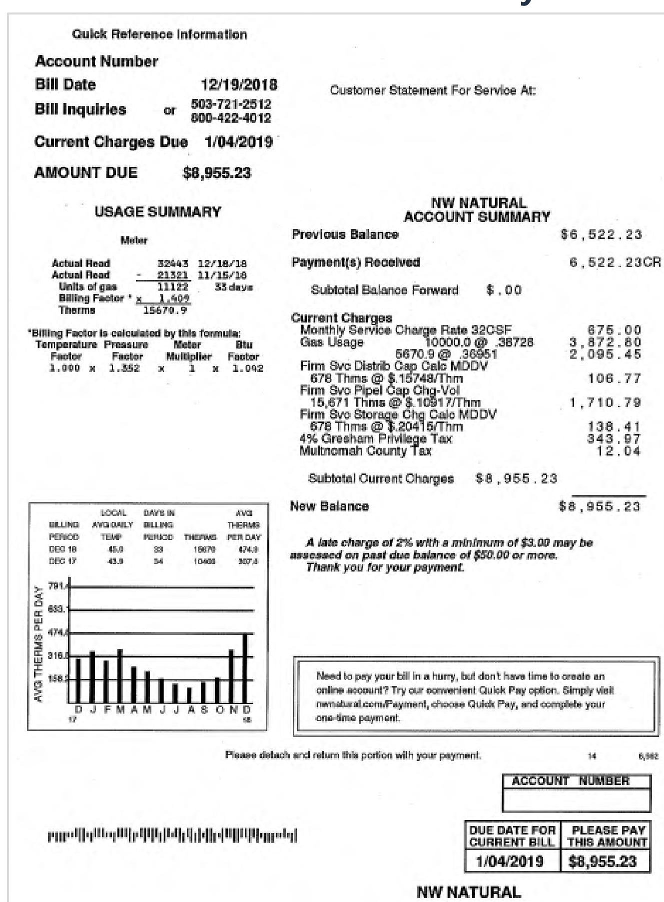
Do you need a record of your gas bills this tax season? Access your billing and payment history by visiting nwnatural.com/Taxes. In fact, you can access three years' worth of account history.

Please detach and return this portion with your payment. 02 17,747

ACCOUNT NUMBER

DUE DATE FOR CURRENT BILL	PLEASE PAY THIS AMOUNT
2/19/2020	$88.00

Figure 6: Sample Commercial Bill: Investor-Owned Natural Gas Utility



Quick Reference Information

Account Number
Bill Date 12/19/2018
Bill Inquiries 503-721-2512 or 800-422-4012
Current Charges Due 1/04/2019
AMOUNT DUE $8,955.23

Customer Statement For Service At:

USAGE SUMMARY

Meter

Actual Read	32443	12/18/18
Actual Read	- 21321	11/15/18
Units of gas	11122	33 days
Billing Factor *	x 1.409	
Therms	15670.9	

*Billing Factor is calculated by this formula:

Temperature Factor		Pressure Factor		Meter Multiplier		Btu Factor
1.000	x	1.352	x	1	x	1.042

NW NATURAL ACCOUNT SUMMARY

Previous Balance		$6,522.23
Payment(s) Received		6,522.23CR
Subtotal Balance Forward	$.00	
Current Charges		
Monthly Service Charge Rate 32CSF		675.00
Gas Usage 10000.0 @ .38728		3,872.80
5670.9 @ .36951		2,095.45
Firm Svc Distrib Cap Calc MDDV 678 Thms @ $.15748/Thm		106.77
Firm Svc Pipel Cap Chg-Vol 15,671 Thms @ $.10917/Thm		1,710.79
Firm Svc Storage Chg Calc MDDV 678 Thms @ $.20415/Thm		138.41
4% Gresham Privilege Tax		343.97
Multnomah County Tax		12.04
Subtotal Current Charges	$8,955.23	
New Balance		$8,955.23

A late charge of 2% with a minimum of $3.00 may be assessed on past due balance of $50.00 or more.
Thank you for your payment.

BILLING PERIOD	LOCAL AVG DAILY TEMP	DAYS IN BILLING PERIOD	THERMS	AVG THERMS PER DAY
DEC 18	45.0	33	15670	474.9
DEC 17	43.9	34	10406	307.8

Need to pay your bill in a hurry, but don't have time to create an online account? Try our convenient Quick Pay option. Simply visit nwnatural.com/Payment, choose Quick Pay, and complete your one-time payment.

Please detach and return this portion with your payment. 14 6,982

ACCOUNT NUMBER

DUE DATE FOR CURRENT BILL	PLEASE PAY THIS AMOUNT
1/04/2019	$8,955.23

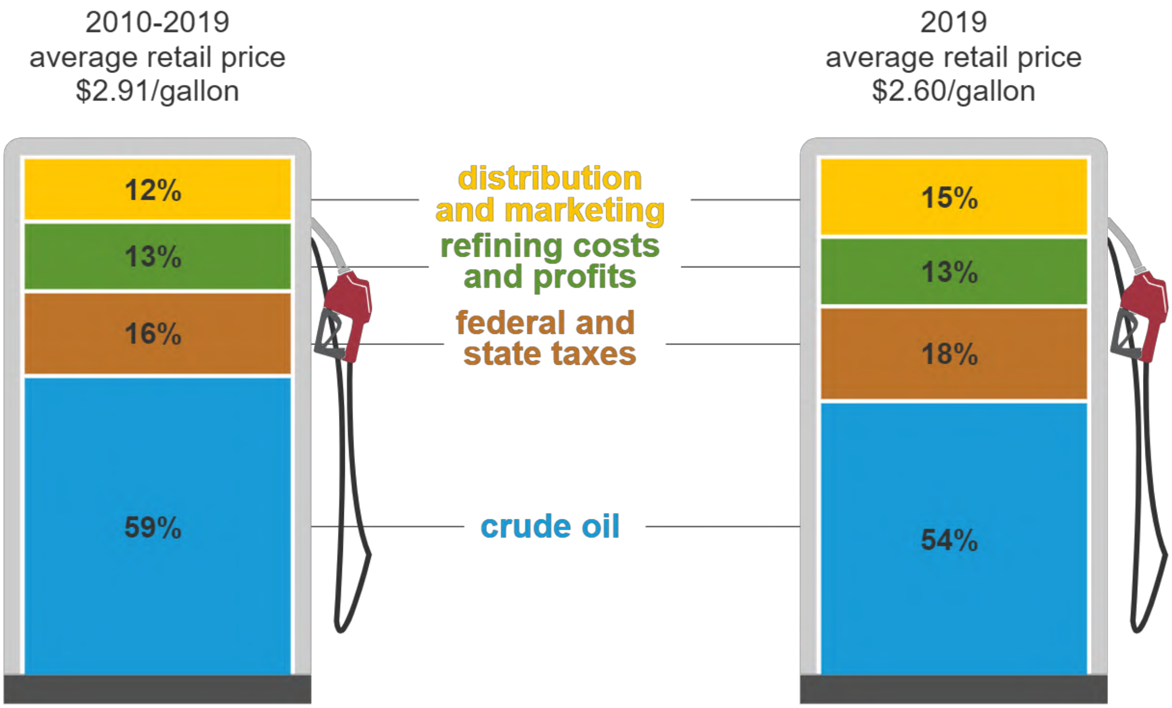
NW NATURAL

Transportation Energy Costs

Transportation energy is typically discussed in terms of petroleum products and, for most households, this means gasoline. Diesel, electricity, and biofuels are also used for transportation. Typically, the only additional charge on petroleum products is for taxes. However, other factors influence the price of fuel.

Fuel Tax. State taxes are levied on transportation fuels by the gallon to fund the creation, preservation, and maintenance of Oregon's roads and highways. Some cities also levy taxes on fuels by the gallon to preserve and maintain local roads.

Figure 7: What We Pay for Per Gallon of Retail Regular Grade Gasoline[6]



For electric vehicle drivers, transportation energy costs will appear in their home electricity bills (for at-home charging). On the road, EV drivers may have access to free charging at some locations, or pay-as-you-go at other stations (See the EV Charging Technology Review for more).

Cutting Costs: Energy Efficiency

Energy use, and therefore cost, is affected by more than just the behavior of the energy consumers. The efficiency of the equipment (home heating and ventilation units, vehicles, etc.) also makes an impact on the rate of energy consumption. For example, the age and efficiency of heating and air conditioning equipment, lighting, and appliances in a building can drastically increase or reduce the overall energy bills for a home or building. In addition, the structure itself can impact the energy consumption of a building. Double or triple pane windows are far more efficient than single pane windows at preventing heat transfer, which allows for hot summer weather to infiltrate a home in the summer, increasing air conditioning needs, and allowing the heat inside a building to escape to the outdoors during the cool months of winter.

Homeowners and rental property owners have the option to pursue incentive programs through their utility to improve the efficiency of their properties. Those interested in purchasing high efficiency vehicles may also be eligible for incentives or tax credits. Learn more about energy efficiency policies and programs in Oregon in the Energy Efficiency Policy Brief.

REFERENCES

[1] US Bureau of Labor Statistics 2020

[2] *Top Ten Utility Green Pricing Programs (2018 data)* (Rep.). (2020, September 23). Retrieved October 6, 2020, from NREL website: https://www.nrel.gov/analysis/assets/pdfs/top-ten-utility-green-pricing.pdf

[3] Regulatory Documents | PGE. (2020). Retrieved October, 2020, from https://www.portlandgeneral.com/our-company/regulatory-documents/tariff

[4] Bill Glossary. (2020). Retrieved October, 2020, from https://www.pacificpower.net/my-account/billing-options/bill-glossary.html

[5] Adjustment Schedules. (2017). Retrieved October, 2020, from https://www.nwnatural.com/AboutNWNatural/RatesAndRegulations/OregonTariffBook/AdjustmentSchedules/

[6] Factors Affecting Gasoline Prices. (2020, February 2). Retrieved October, 2020, from https://www.eia.gov/energyexplained/gasoline/factors-affecting-gasoline-prices.php

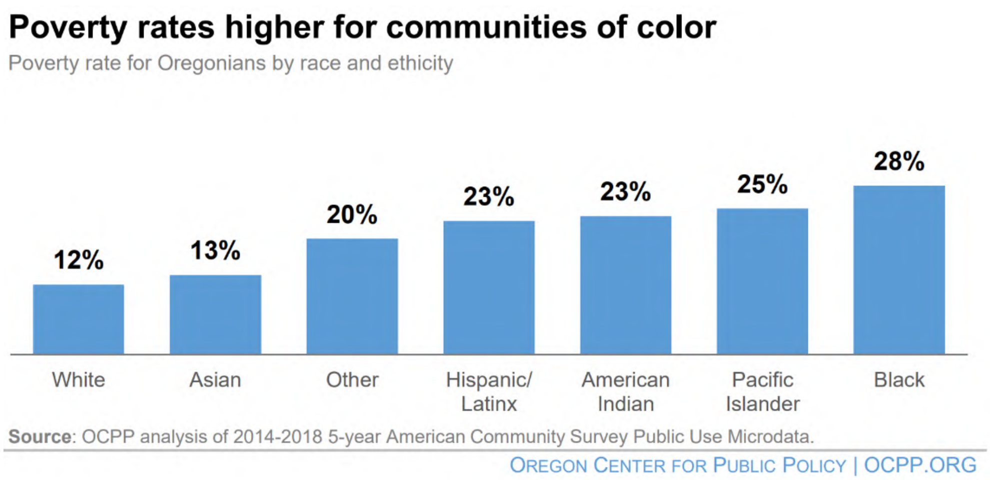
Energy 101: Equity and Energy Burden

Equity

In 2020, Governor Kate Brown's Office of Diversity, Equity, and Inclusion directed state agencies to consider equity when making decisions regarding state resources through an Equity Framework.[1] The Framework provides a definition of equity acknowledging that not all people, or all communities, are starting from the same place due to historic and current systems of oppression. Equity is the effort to provide different levels of support based on an individual's or group's needs in order to achieve fair outcomes. Equity actionably empowers communities most affected by systemic oppression and requires the redistribution of resources, power, and opportunity to those communities.[2] Equity has been mostly explored in the energy industry through consideration of affordability and access to different types of energy resources.

Certain demographic groups — people of color, women, Oregonians with a disability, and rural communities — face greater obstacles.[3] In 2018, 13 percent of Oregonians had income levels below the federally defined poverty threshold, representing 516,000 Oregonians, including 134,000 children.[4] Poverty rates in communities of color were as much as double the poverty rate for white Oregonians from 2014-2018.[5] There are 156,000 households in Oregon on the edge of homelessness, who spend at least 50 percent of their income on rent and have a range of risks that make their house insecure – unexpected medical bills, a lay-off, utility shut-off, or a car repair.[6]

Figure 1: Poverty Rates in Oregon for Communities of Color[7]



Low-income households, communities of color, and rural communities in Oregon frequently experience higher energy burdens than the average household and are disproportionately affected by the effects of climate change.[8] Housing and transportation burdens significantly impact the affordability of living in the state of Oregon, and are just a part of a wide range of issues households with low incomes face (e.g. housing costs, transportation, groceries, medical expenses, and other basic needs).[9]

Energy Burden

Energy burden is the percentage of household income spent on energy and transportation costs as an indication of energy affordability. Note that much of the data and discussion here is based on analysis prior to the Covid-19 Pandemic – Oregon energy burden challenges are magnified by job losses, health concerns, and an economic recession.[10]

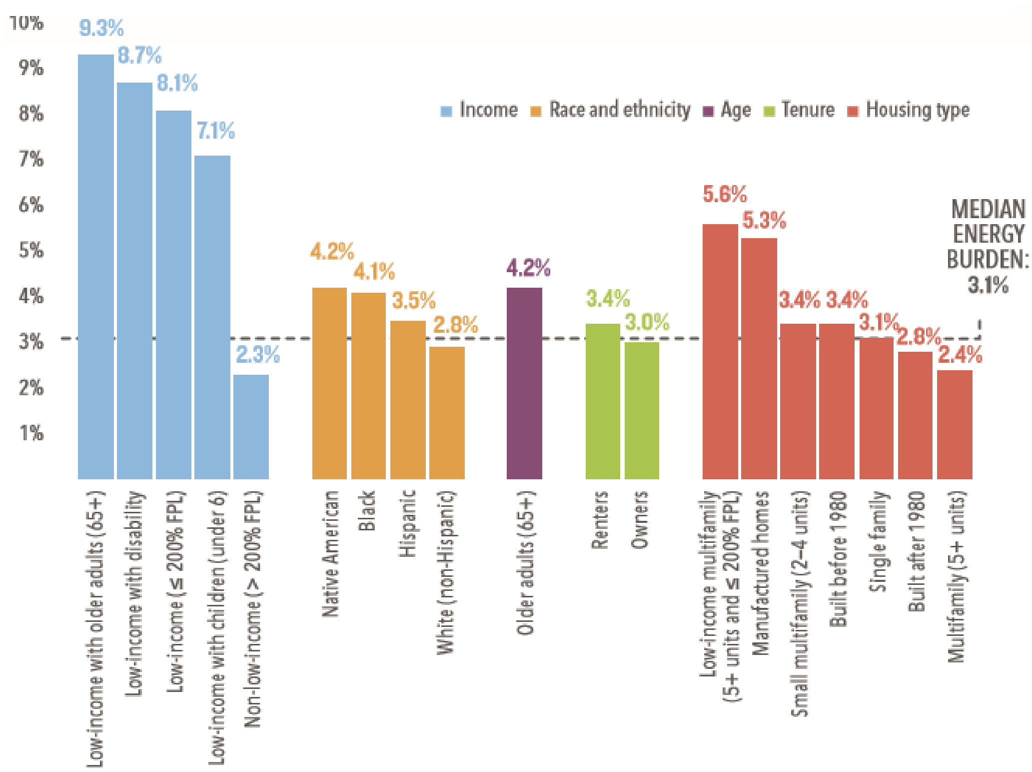
Home energy burden focuses on energy bills for a home in comparison to the total income of the household. If a household is spending greater than 6 percent of their income on home energy costs, they are considered burdened.[11] If a household is spending 10 percent or more of their income on home energy costs, they are considered severely energy burdened.[12] High home energy burdens put people at risk of falling behind on payments and being disconnected from service due to nonpayment.[13]

Transportation burden is represented by the total annual transportation costs of households in comparison to income of the household. Transportation costs can be affected by specific factors like auto ownership, auto use, and transit use. Household and neighborhood characteristics of where someone lives, such as household density and access to services and jobs, also influence how much someone drives, which affects their costs.[14] Another metric that provides insight into a household's transportation costs is vehicle miles traveled (VMT). VMT is the total distance traveled by all motor vehicles in a specified system of roads for a given time. VMT cost is the fuel, maintenance, and repair costs of the measured travel.[15]

Home Energy Burden in Oregon

The American Council for an Energy Efficient Economy (ACEEE) conducted a study of 25 cities to assess home energy burden in low-income and underserved communities. This national study found that U.S. households spend an average of 3.1 percent of their income on home energy bills.[16] The figure below shows energy burden findings by subgroup – low-income households, Black, Hispanic, Native American, renters, and older adult households all have disproportionately higher home energy burdens than the national median household.[17] Note that many highly burdened groups are intersectional, meaning that they can face compounding, intersecting causes of inequality and injustice, with energy burden potentially representing just one facet of inequity.[18]

Figure 2: National Energy Burden Across Subgroups[18]



National energy burdens across subgroups (i.e., income, race and ethnicity, age, tenure, and housing type) compared to the national median energy burden

The annual Home Energy

Affordability Gap (HEAG) Analysis evaluates home energy burden nationally and in states, including Oregon. The energy affordability gap is the difference between a household's actual energy costs and an "affordable" energy burden level – which is considered to be six percent of the household's income.[19] HEAG data informs Oregon Housing and Community Services' Affordable Housing Assessment Tool, which classifies 391,263 of Oregon's 1,591,835 households as struggling to pay their energy bills – indicating that about 25 percent of Oregon households are energy burdened.[20] In addition, 100,456 households with incomes below 50 percent of the Federal Poverty Level paid an average of 23 percent of their annual income for their home energy bills.[21]

Drivers of High Home Energy Burden

To understand how Oregonians could overcome home energy burden, it is helpful to understand the drivers for high home energy burden. Energy burden involves two key components: energy costs and income. Low-income households typically pay less overall on energy bills compared to average households, but they pay more for energy as a percentage of their income. This is both an economic and a housing energy efficiency concern. Table 1 below categorizes drivers of high home energy burdens as physical drivers, socio-economic drivers, behavioral drivers, and policy-related drivers.

Table 1: Key Drivers of High Home Energy Burden

Drivers	Examples of factors that affect energy burden
Physical	• Housing age (i.e. older homes are often less energy efficient) • Housing type (e.g. manufactured homes, single family, and multifamily) • Heating and cooling system (e.g. system type, fuel type, and fuel cost) • Building envelope (e.g. poor insulation, leaky roofs, inefficient and/or poorly maintained heating and cooling systems (HVAC), and/or inadequate air sealing) • Appliances and lighting efficiency (e.g. large-scale appliance such as refrigerators, washing machines, and dishwashers) • Topography and location (e.g. climate, urban heat islands) • Climate change and weather extremes that raise the need for heating and cooling
Socio-economic	• Chronic economic hardship due to persistent low income • Sudden economic hardship (e.g. severe illness, unemployment, or disaster event) • Inability to afford (or difficulty affording) up-front costs of energy efficiency investments • Difficulty qualifying for credit of financing options to make efficiency investments due to financial and other systemic barriers • Systemic inequalities relating to race and/or ethnicity, income, disability, or other factors

Behavioral	• Information barriers relating to available bill assistance and energy efficiency programs and relating to knowledge of energy conservation measures • Lack of trust and/or uncertainty about investments and/or savings • Lack of cultural competence in outreach and education programs • Increased energy use due to occupant age, number of people in the household, health-related needs, or disability
Policy-related	• Insufficient or inaccessible policies and programs for bill assistance, energy efficiency, and weatherization for low-income households • Utility rate design practices, such as high customer fixed charges, that limit customers' ability to respond to high bills through energy efficiency or conservation

Table adapted from ACEEE Study on Energy Burden[22]

Looking specifically at housing type as a potential physical driver of home energy burden, most Oregonians – about 65 percent – live in single family detached units and about 35 percent of households in Oregon live in multifamily or other housing.[23] Home energy burden decreases on average for households in large multifamily housing, and home energy burden increases on average for households living in manufactured or mobile housing.[24]

Supporting Oregonians to Overcome Home Energy Burden

Experiencing high home energy burdens may affect the mental and physical health of families by increasing financial stress. Energy Burden may also be an indicator of poor efficiency of a home. If homes are not properly heated, cooled, or ventilated because of the efficiency of the home or because a family can't afford to do so, it may lead to cases of asthma, respiratory problems, heart disease, arthritis, and rheumatism.[25] Children and the elderly are most susceptible to these negative health conditions.[26] Increasing investment in energy efficiency programs to encourage retrofits is a strategy that can complement bill assistance and weatherization programs to help reduce high energy burdens in underserved communities.[27]

To address energy burden and the affordability gap, Oregon invests in programs for bill assistance and weatherization. In addition, energy efficiency, renewable energy, and utility rate design have been or may be used to support energy burdened households.

Energy Bill Assistance Programs

Oregon Housing and Community Services (OHCS) administers programs for the State of Oregon that provide a variety of housing stabilization services, including weatherization and assistance with energy utilities. OHCS delivers these programs primarily through grants, contracts, and loan agreements with community action agencies or local community providers. [28]

Split Incentives and Rental Properties[29]

Typically, energy efficiency programs pay incentives to homeowners and businesses to encourage retrofits and efficiency upgrades. In the case of rental properties, tenants may not be allowed to install equipment or upgrades. Landlords may not be financially compelled to save energy costs by installing efficiency measures because they don't pay the energy bill for the rented spaces. This is an example of inequity in efficiency programs, requiring programs to be designed to specifically address the unique circumstances.

Upstream incentives are paid to distributors and reduce the cost of an efficient product. Successful upstream incentives for landlords could involve a reduced price on more efficient equipment to install as part of regular maintenance, or if the incentive is very attractive, could inspire the early retirement of equipment instead of waiting until failure. Replace-on-failure doesn't always happen at an opportune time, and landlords or operators may have to make a quick decision on equipment and not have time to weigh the advantages of more efficient products.

Conversations with building owners about value can sometimes help them recognize the benefits of efficiency improvements, even if they don't get energy savings on their own bills. For example, the rent on a very efficient apartment may be higher, bringing more monthly revenue to the landlord and lower energy bills for the tenants. Non-energy benefits, such as comfort, quiet, and improved indoor air quality from efficiency and ventilation upgrades, can make their properties more attractive.

Energy bill assistance is typically provided on an as-needed basis and requires reapplication for future assistance. It also does not generally result in long-term or persistent savings. Energy bill assistance reduces energy burden by directly providing subsidies to assist low-income households in paying utility bills. The primary advantage of energy assistance is that it can provide immediate, emergency assistance to low-income households and avoid a shutdown of power.[30] Programs to alleviate energy burden commonly use income thresholds based upon state median income and federal poverty level to determine eligibility. The Oregon Housing and Community Services Department (OHCS) has income eligibility guidelines to demonstrate when households may be eligible for energy and weatherization assistance programs (see Table 2).

Table 2: Oregon Housing and Community Services Program Income Guidelines[31][32]

Weatherization Assistance Program		Energy Assistance Programs
At or below 200% of Federal Poverty Level		**At or below 60% of State Median Income**
Annual Income	**Household Size**	**Annual Gross Income***
$25,520	1	$25,983
$34,480	2	$33,978
$43,440	3	$41,973
$52,400	4	$49,967
$61,360	5	$57,962
$70,320	6	$65,957
$79,280	7	$67,456
$88,240	8	$68,955
$97,200	9	$70,454
$106,160	10	$71,953
$115,120	11	$73,452
$124,080	12	$74,951
$8,960	Each Additional Family Member	$1,499

Oregon Housing and Community Services (OHCS) administers two energy assistance programs; the federally funded Low-Income Home Energy Assistance Program (LIHEAP) and the ratepayer-funded Oregon Energy Assistance Program (OEAP). LIHEAP helps low-income consumers pay their home energy expenses. LIHEAP is a block grant, and Congress determines total funding annually, which is allocated to states and tribes using a formula. For 2020, Oregon received $39 million, including $671,578 in LIHEAP funds directly provided to federally recognized tribes in Oregon.[33] The LIHEAP program supported 374,098 Oregon households at less than 150 percent of federal poverty level,[34] covering 49,992 average annual low-income heating and cooling bills from households participating in the program.[35] LIHEAP provides home energy assistance to low-income Oregonians, especially households with the lowest incomes and the highest home energy need in relation to income. The purpose of this program is to supplement home heating and cooling costs. LIHEAP is a fuel blind energy assistance program provided on a first come first served basis. The LIHEAP program includes bill payment assistance, heating or cooling equipment repair and replacement, and energy education. Funding for this program comes from the United States Department of Health and Human Services.[36]

- $554 is the average affordability gap for energy burdened households that are less than 200 percent of the federal poverty level.[37]
- $289,334,345 is the total energy burden of the low-income population in Oregon. Determined

by the difference between a household's actual energy costs and an "affordable" energy burden level equal to six percent of the household's income.[38]

- 374,098 Oregon households at less than 150 percent of federal poverty level that received support[39]
- 49,992 average annual low-income heating and cooling bills covered by LIHEAP[40]

Klamath Tribes: Perspectives on Low-Income Home Energy Assistance[41]

The Klamath Tribes are one of the nine federally recognized Native American Nations in Oregon and consist of three tribes: the Klamath, Modoc, and Yahooskin. This highlight includes information that was coordinated with staff at the Klamath Tribes – ODOE is grateful for their assistance.

Oregon's LIHEAP allocation for 2020 included $671,578 directly for federally recognized tribes in Oregon. The Klamath Tribe was allocated $274,403.[42] The Klamath Tribes' Community Services Department manages the Low-Income Home Energy Assistance Program (LIHEAP) for the Klamath Tribes. LIHEAP provides heating assistance, cooling assistance, crisis assistance (e.g., when insufficient heating creates a life-threatening situation), and weatherization assistance. The Tribe reports that most requests for assistance are for weatherizing windows and adding insulation, and some Tribal members also request assistance for roof projects.

Demand for assistance under LIHEAP is approximately four times greater than available funding. The Community Services Department maintains a long waitlist, and many applicants wait an average of four years to receive services. Given funding constraints, only around 10 Klamath tribal households can be served each year. Each of these households receive services worth approximately $3,500, which is often insufficient to complete the requested amount of weatherization and repairs. Another challenge has to do with available contractors. Only a limited number of contractors qualified to perform these services are in Klamath County, and for many contractors outside of the county, the $3,500 value of any given project may be insufficient to cover their costs when those costs include travel time. Finally, there are barriers related to complexity of the process to obtain funding, procurement policies, and limited Tribal staff resources.

Ideas to help overcome these barriers have included interest in forming partnerships with non-tribal agencies. The Community Services Department administers between 10-12 programs annually and receives funding from over a dozen different sources. Department staff often work in several different roles to administer each program, as well as manage multiple projects, events, and services. Due to staff shortage and high workload, staff's ability to become experts in a specific area – such as procurement and contracting – is limited. Partnerships with non-profit organizations and local community action partnership agencies that are also working on weatherization, insulation, and other energy assistance could create opportunities for technical assistance and shared efforts in administrating projects. For example, the Tribes could identify eligible Tribal households and a non-tribal agency could coordinate with contractors to complete a broader set of weatherization projects. In addition, the Klamath Tribes have explored obtaining matching funds from state and local government to double the impact from funds obtained through their LIHEAP grants.

The Oregon Energy Assistance Program (OEAP) is a low-income electric bill payment assistance program funded by and for customers of Pacific Power and Portland General Electric. This program is designed to support customers and reduce service disconnections. Program priority assistance is focused on customers facing imminent electricity service disconnection.[43] In addition to OEAP, an inventory by OPUC and OHCS illustrates the wide range of over 400 programs across the state that provide bill assistance, bill discounts, and weatherization support.[44] All of Oregon's electric and natural gas utilities have funding and programs to help senior citizens or low-income customers pay their bills.[45] For example, NW Natural offers the Oregon Low Income Gas Program[46] and Avista offers the Low-Income Energy Rate Assistance Program for its gas customers.[47] Customer-contribution-based programs from gas companies include Winter Help from Cascade Natural Gas,[48] Project Share from Avista,[49] and Gas Assistance Programs from NW Natural.[50]

Community Action Agencies (CAA) are local non-profit organizations working to alleviate and eliminate poverty. OHCS provides funds to these local community agencies that provide bill payment assistance programs. These programs support low-income households to make their energy costs more affordable. They also help prevent the loss and restoration of home energy service. Payments are made to the utility company on the customer's behalf. Many of these Community Action Agencies also provide weatherization and energy efficiency services to low-income households. These services increase energy savings while making homes more comfortable.[51]

Considering Rate Design

Lower utility rates for lower income Oregonians could reduce energy burden by lowering the cost of energy for low-income households. In Oregon, this would require a restructuring of utility rates to account for income. SB 978 (2017) directed the PUC to facilitate a public process to examine how industry trends, technologies, and policy drivers affect the Commission's regulation of investor-owned energy utilities and, in turn, the utility business model.[52] The PUC's report on this public process noted that the Oregon Legislature may need to consider new ways to mitigate energy burden of low-income Oregonians in investor-owned utility service territory, including changes to ratemaking laws that currently limit the Commission's authority.[53] Other states have developed "Percentage of Income Payment Programs" or rate discount programs to address affordability gaps, and these types of programs were discussed by Oregon Public Utility Commission, Oregon Housing and Community Services, and stakeholders through a working group in 2018.[54] In 2020, the Oregon Legislature considered, but did not pass (after walk-outs prevented the quorums needed to hold votes on legislation), HB 4067, which would have allowed the PUC to consider differential energy burdens on low-income customers and other economic, social equity, or environmental justice factors that affect affordability for certain classes of customers.[55]

Weatherization Support

Weatherization assistance is an energy efficiency program targeting customers living in existing, and often older, residential and multifamily buildings. Weatherization services typically refers to programs that address the efficiency of the building envelope and building systems (such as unit heating, cooling, lighting, windows, and water heating) through energy audits and upgrades.[56] Weatherization programs specifically for moderate and low-income households are supported by utility, state, and federal funding. By providing financial assistance in the form of energy efficiency upgrades, weatherization programs can reduce the energy costs of low-income consumers. Oregon's state weatherization program is administered by OHCS, which contracts with local community action agencies to conduct energy audits and install energy efficiency measures for income-eligible households.[57]

Energy Efficiency

Energy efficiency measures can go beyond weatherization upgrades and further lower energy burden by reducing the amount of energy needed to provide the same level of energy services, such as lighting and heating for a home. One advantage of energy efficiency as a tool to reduce energy burden is that it results in persistent savings, or a continual reduction in energy burden, while also potentially providing non-energy benefits to the household, such as improved health, comfort and safety.[58] Energy efficiency home improvements may also result in reduced greenhouse gas emissions and increased health at a societal level.[59]

Energy efficiency projects are infrastructure investments to reduce energy use and associated household energy bills while increasing comfort of the home. Utilities invest ratepayer funds in energy efficiency programs to support customers and reduce potential demand for costly electricity generation facilities, which reduces utility system costs.[60] Disbursement of funds is often predicated on whether energy efficiency measures are cost-effective by comparing the energy savings against the utility avoiding costs of building new generation or other utility system upgrades. Regulators and utilities use cost-effectiveness tests to determine if financial support from utility ratepayers is reasonable.[61]

On-Site Renewable Energy

Renewable energy can also lower energy burden by reducing the amount of energy households must buy from the electric grid and thus lower their electric bill. Renewable energy can deliver persistent savings to the household and create societal benefits through greenhouse gas emissions reduction.[62]

Ten-Year Plan: Reducing the Energy Burden in Oregon Affordable Housing

Recognizing the importance of energy burden, in EO 17-20, Governor Brown directed Oregon Housing and Community Services, Oregon Department of Energy, and Oregon Public Utility Commission to publish the *Ten-Year Plan: Reducing the Energy Burden in Oregon Affordable Housing*, a report identifying the challenges of energy burden, current data, and potential solutions. The report found energy efficiency and weatherization programs may significantly reduce household energy burden by reducing the amount of energy needed to make the home comfortable year-round.[63] Additional solutions to investigate include: targeting multifamily buildings with energy efficiency investments, using demographic data in program evaluation, and strengthening low-income targets and goals for utility programs.[64]

Affordable Housing Assessment Tool

As directed by Governor Brown in EO 17-20, Oregon Housing and Community Services developed an Affordable Housing Assessment Tool to identify energy burden, community needs, and existing resources to inform policy makers, advocates, and the public that are evaluating potential solutions to the problem. The map provides information by county and locations of affordable housing, and has data filters to compare a variety of demographic and program data. Learn more:

http://bit.ly/OHCS_AHA

The Ten-Year Plan estimates cost effective energy efficiency improvements in housing for low income Oregonians would lead to $141,089,441 in total potential savings in energy costs.[65] While energy efficiency can alleviate a substantial portion of the energy burden by reducing energy costs, it does not alone solve the problem of energy burden problems. Energy burden involves two key components – energy costs and income – and energy efficiency does not involve the household's income or ability to pay. Energy efficiency, however, may also result in improved health of the occupants, habitability of their home, and significant greenhouse gas savings.[66]

10 Year Energy Burden Plan Key Findings:

- $141,089,441 total potential energy cost savings through cost-effective energy efficiency in low-income population[67]
- 488,065 metric tons CO_2e total potential GHG savings through cost-effective energy efficiency in low-income housing[68]

Transportation Energy Burden

Transportation related costs are important to understanding energy burden for households, and are often the second largest household expense after housing costs.[69] Transportation costs have typically involved costs related to transportation fuels, but are heavily determined by where people live and how easily they can access public transportation and alternative options. This is especially the case for households that are low-income or in poverty.[70]

Beyond transportation fuel costs, for many communities in Oregon, public transportation provides a basic, affordable travel option and vital access to employment, services, groceries, and education.[71] Where public transportation is inaccessible or inconvenient, heavy reliance on personal vehicles can mean higher household expenditures for vehicle, fuel, insurance, and maintenance.[72]

The Center for Neighborhood Technology (CNT) created the Housing + Transportation Affordability Index, which analyzes overall household costs including transportation and housing costs. Housing costs for owners include mortgage payments, real estate taxes, property insurance, utilities, heating fuels, mobile home costs, and condominium fees. For renters, housing costs amount to contract rent plus the estimated average monthly cost of utilities and heating fuels. CNT's housing cost calculation uses energy data that differs from other sources ODOE uses to examine household energy costs. Oregon County Profile data uses actual average electricity and natural gas use and cost from the Oregon Public Utility Commission and Oregon utilities serving the county.[73]

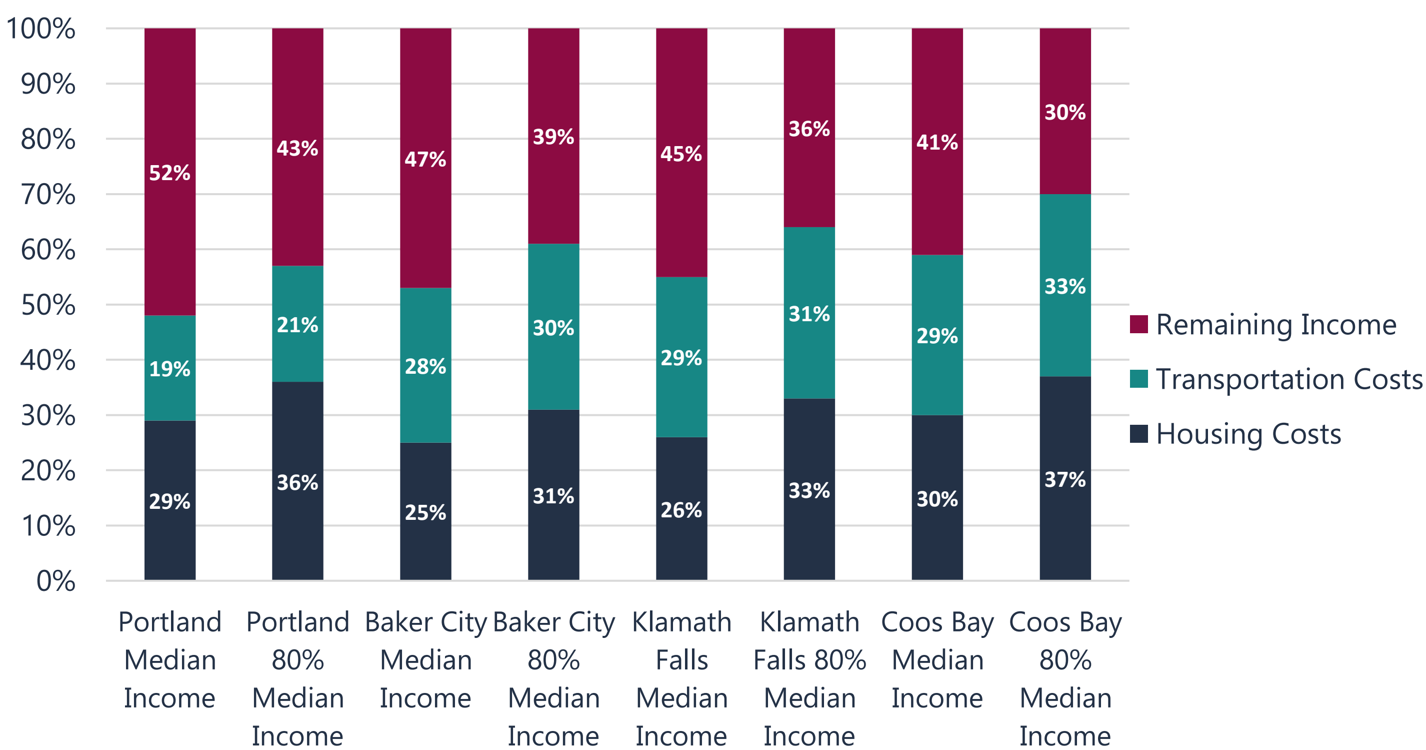
Transportation costs are modeled and combined based on auto ownership, auto use, and transit use for an area.[74] For purposes of this model, auto ownership includes average vehicles per household, auto use is vehicle miles traveled (VMT) per automobile, and transit use means the percent of commuters utilizing public transit.[75] Note that the VMT estimates from the national CNT source was used in this effort, which differs from VMT collected by ODOT. The CNT H&T data calculates VMT *per vehicle*, based on a model of urban, suburban, and rural driving habits combined with state population estimates. In comparison, ODOT calculates VMT *on roads*, as submitted annually to FHWA, by conducting physical counts of vehicles with sampling rates that favor state-owned roads.[76]

The Housing + Transportation Affordability Index recognizes the efficiency of communities and neighborhoods in their evaluation of housing and transportation costs. Compact neighborhoods with walkable streets, access to jobs, public transit, grocery stores and services have high location efficiency. These communities require less travel time, money, and greenhouse gas emissions for residents to meet their everyday needs.[77]

The Index analyzes median and moderate-income households – which are defined as 80 percent of median income households. Note that in some parts of Oregon, there can be a significant mix of income levels in an area – which may not provide an accurate count of low-income households. Based on the Housing + Transportation Affordability Index, CNT recommends total housing and transportation costs be no greater than 45 percent of a household's income to be considered affordable.[78] CNT includes payments for utilities and fuels, which encompasses the home energy burden analysis above that focuses on energy bill assistance, weatherization, energy efficiency, and other options to support Oregonians experiencing home energy burden. Note that above, when examining only household energy costs, greater than 6 percent of household income is considered home energy burdened.

The Housing + Transportation Affordability Index found that the number of communities considered affordable drops dramatically when the definition of affordability includes not just housing costs but transportation costs as well.[79] For Oregon, the index shows housing and transportation costs in households with median and 80 percent of median income in 20 Oregon metropolitan areas.[80] 80 percent of median incomes provides insight into households with lower income – for example, Portland's median income is $60,286 per year and 80 percent of median income is $48,229 per year – and demonstrates a greater percentage of these households spend their limited incomes on housing and transportation costs. Figure 3 provides examples across the state for housing and transportation costs in households with median and 80 percent of median income in Portland, Baker City, Klamath Falls, and Coos Bay.

Figure 3: H + T Affordability Analysis of Oregon Cities



Oregon Department of Transportation (ODOT) has described opportunities to reduce transportation burdens for Oregonians in its Public Transportation Plan.[81] As communities grow, more public transportation services are typically available, depending on total population, population density, and other factors. Transit services may begin in smaller communities by filling specific needs with demand response services, carpools, or contracted taxis. As a community grows, often more services and types of services are added, such as routed bus services or high capacity transit. In each case, the services available reflect the unique characteristics of the community and its history, funding, and prior decisions about public transportation.[82] In addition, strategies for networks of bikeways and pedestrian opportunities to connect to destinations and other modes of travel, including public transportation, can support a broader set of travel options for Oregonians.[83] ODOT partners with Department of Land Conservation and Development through the Transportation and Growth Management Program to provide funding to communities to support smart growth with the following principles:[84]

- Integrated multi-modal transportation and land use planning;
- Efficient use of land and resources;
- Well-designed, walkable communities;
- Good connections between local destinations;
- Pedestrian-, bike-, and transit-friendly development; and
- Stewardship of existing resources and investments.[85]

Every Miles Counts

The Every Mile Counts initiative is an effort to address greenhouse gas emissions in the transportation sector by four state agencies – led by the Oregon Department of Transportation in collaboration with the Oregon Department of Energy, Department of Environmental Quality, and Department of Conservation and Land Development. The workplan for the agencies includes actions to identify, address, and integrate equity into their activities in order to mitigate impacts on underserved communities. ODOT has contracted with Kerns & West to conduct cross-agency equity engagement workshops to better understand equity issues in the transportations sector that will inform the work of the Every Mile Counts initiative.[86] To learn more visit:

www.oregon.gov/odot/Programs/Pages/Every-Mile-Counts.aspx

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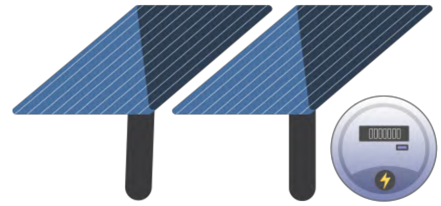
Energy 101: Net Metering



Net metering is a policy that enables an electric utility customer to receive value for the electricity that they generate on site. Onsite production is most commonly from a solar photovoltaic (PV) system and is used to reduce the amount of electricity the customer purchases from the utility. Because electric consumption and onsite generation do not always occur at the same time, net metering measures all onsite consumption and all excess generation (generation above what is being used at the time) in each billing period. That allows the electric utility to only bill the customer for the net electricity consumed during that period. To do this, the electric utility installs a special meter at the customer's site. During conditions when the solar production exceeds the onsite consumption, the customer's meter records the flow of excess energy onto the utility system. This excess generation is then subtracted from the customer's consumption of electricity from the utility system on the customer's electricity bill.

Laws and Rules Governing Net Metering in Oregon

Since 1999, Oregon law has required electric utilities to offer net metering to Oregon customers installing renewable energy systems up to 25 kilowatts (kW) in size.[1] This law was amended in 2005, enabling the Oregon Public Utility Commission to adopt rules allowing customers of investor-owned utilities to install larger systems.[2] In 2007, the Oregon PUC adopted net metering rules for Oregon investor-owned utilities, including an allowance for non-residential net metered projects up to 2 megawatts (MW) in size.[3] For consumer-owned utilities, net metering policies are developed by each COU's governing body or board.

Net Metering Differs Across Oregon Utilities

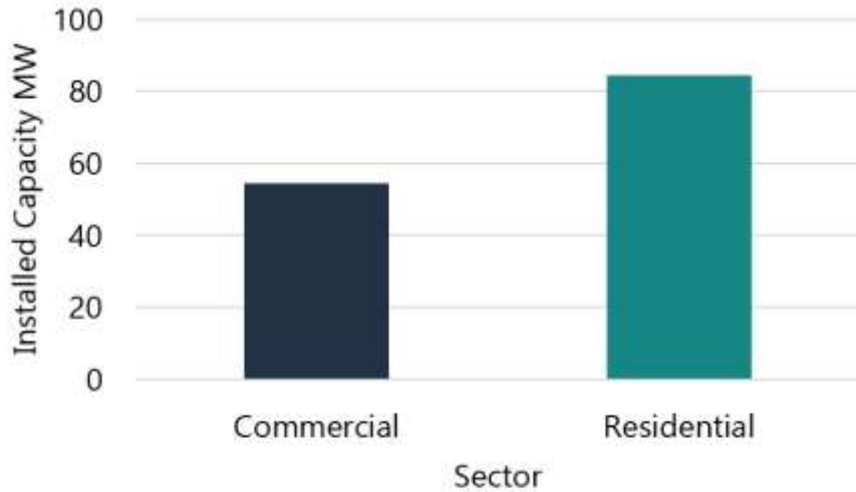
There are currently two big differences between net metering policies across the state. First is generator size: Oregon COUs are only required to offer net metering for systems up to 25 kW consistent with statute, while under PUC rules, the IOUs allow non-residential system sizes up to 2 MW.

Second is treatment of excess generation: Oregon statute directs utilities to offer net metering through which the customer is credited for onsite electricity production at the end of each billing cycle.[2] The statute also describes that excess generation at the end of the billing cycle may be reimbursed at the utilities' avoided cost of power.[2] Under PUC rules, the IOUs offer "annualized" net metering where, if the customer generates more than is consumed in a billing period, the excess generation may be applied to future consumption for up to one year. Excess generation credits remaining at the end of a 12-month period are forfeited by the utility customer and credited to Oregon's low-income assistance programs.[3] Annualized net metering enables solar net-metering customers to get closer to "net zero energy" by carrying forward the value of generation in the sunny summer and to offset consumption in the winter.

Net Metered Systems in Oregon

As of November 2019, there are more than 18,000 net metered PV systems in Oregon, including more than 16,700 for Oregon homes and more than 1,800 for commercial properties. Together these systems total about 140 MW of capacity.[4] Oregon statute allows for a variety of onsite generation technologies to qualify for net metering, though the vast majority of systems are solar electric generators.[2] For example, from 2002 through 2017 there were more than 15,000 applications approved for net metered residential PV systems in the Oregon Residential Energy Tax Credit Program, representing nearly all of the net metered systems in Oregon.[5] Over the same period, there were 56 applications for net metered wind generators and nine for net metered micro-hydro generators.

Figure 1: Total Capacity of Net Metered Systems by Sector in Oregon (as of November 2019)



Current Discussions in Net Metering

Solar is a variable resource, meaning it only generates electricity when the sun is shining and produces more or less electricity based on the amount of sunlight available. This can pose challenges for utilities integrating these variable resources into the grid, especially in high solar penetration markets like California and Hawaii; Hawaii has the highest penetration of residential solar in the U.S. with 19 percent of homes utilizing rooftop PV at the end of 2019.[6] System constraints may impede the ability to export solar energy onto the grid during period of peak solar output. Integration issues are most pronounced in the late afternoon and early evening when solar resources decline and loads on the electric system increase. In locations where solar is installed in large enough numbers to cause integration issues, there may be a need for the utility to install additional protective equipment.

In Oregon, solar generation is relatively small when compared to overall loads, resulting in few issues of integrating these resources onto the grid. For example, the 16,700 residential net metered PV systems have a combined nameplate capacity of about 85 MW on only about 1 percent of all households in Oregon.[7] 85 MW is about 1.1 percent of the peak load in Portland General Electric and Pacific Power territories combined. If 10 percent of all Oregon households installed net metered PV systems, it would result in about 1,225 MWs of additional capacity, or about 16.5 percent of the peak load experienced by PGE and Pacific Power combined.[8]

If 10 percent of all Oregon households installed net metered PV systems, it would add about 1,225 MWs of capacity.

It should be noted that net metered PV systems are not the only resources affecting solar integration. Utility scale solar projects contribute their peak output at the same time as most net metered systems, and the combined output of all resources must be considered. Energy storage systems, such as batteries paired with residential PV systems, have the potential to better support grid integration because they can help manage the variability of solar energy generation.[9]

To provide utilities with the support to manage the amount of variable resources on their systems, many states have established net metering capacity limits. These policies enable utilities to limit the number of net metered systems in their service territories. Oregon law allows utilities to limit the cumulative capacity of net metered systems to 0.5 percent of the historic single hour peak load for the utility. However, while PGE and Pacific Power have both surpassed this threshold, they continue to approve net metering applications. The aggregate capacity limit in Washington was also 0.5 percent of the utility's peak load until Senate Bill 5223 increased the threshold to 4 percent in 2019.[10] Other states have seen even more legislative adjustments to net metering limits. In Vermont, the aggregate capacity limit was raised from 2 percent of peak load in 2008 to 4 percent in 2011, and 15 percent in 2014 before the cap was eliminated in 2017.[11]

Equity Considerations

There is an equity concern with net metering. Utilities charge customers for the amount of electricity they use, but they also charge them a fixed monthly fee regardless of electricity use. If a net metering customer were to offset most or all of their electricity use with sufficient generation, they would pay only the fixed monthly fee. To the extent that a utility counts on variable rate revenue to cover fixed operating costs, net metering customers would not be contributing their fair share and would be subsidized by all other customers. The fact that many net metering households tend to be of higher income[12] brings up an equity issue by potentially shifting cost to low- and moderate-income customers.

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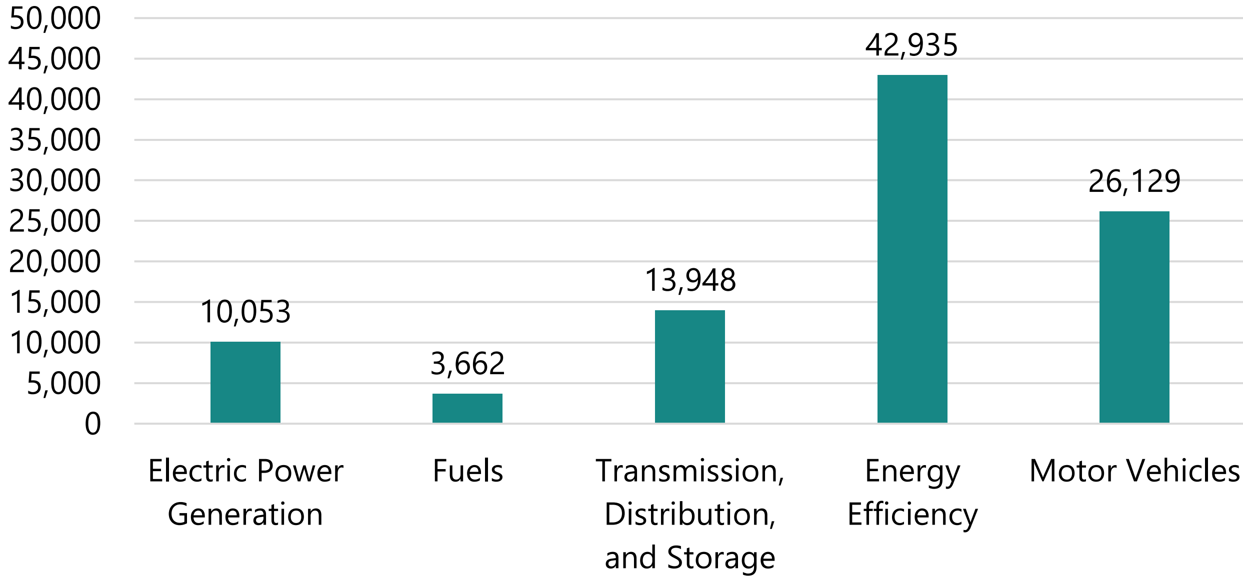
Energy 101: Energy Jobs in Oregon

In 2019, Oregon's energy industry employed 96,727 Oregonians.[1]

Figure 1: Energy Jobs in Oregon (2019)



The 2020 U.S. Energy and Employment Report, issued in 2020 by the National Association of State Energy Officials and Energy Futures Initiative, categorized figures for energy-related employment in the following groups: **traditional energy, energy efficiency**, and **motor vehicles**.

Traditional Energy Jobs

Electric Power Generation | Fuels | Transmission | Distribution | Storage

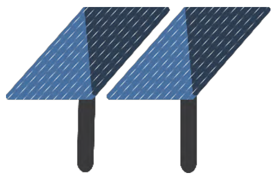
Oregon Traditional Energy Jobs: 27,663

In 2019, about 6.8 million U.S. jobs (4.6 percent of Americans) were in the traditional energy and energy efficiency sectors. Before the COVID-19 pandemic, electric power generation employers across the U.S. projected 4.8 percent job growth in 2020.[2] Potential energy job growth predictions were driven by strong employment growth in 2019 in natural gas (9.4 percent more jobs), solar (2.3 percent) and wind generation (3.2 percent), the fastest growing new sources of electricity.[3] In Oregon, about 1.4 percent of the state's employment is in the traditional energy sector.[4]

Electric Power Generation

The 2020 US Energy and Employment Report defines the electric power generation job category as, "all utility and non-utility employment across electric generating technologies, including fossil fuels, nuclear, and renewable energy technologies. Also included in the employment totals are any firms engaged in facility construction, turbine and other generation equipment manufacturing, operations and maintenance, and wholesale parts distribution for all electric generation technologies."[5]

Electric Power Generation Jobs in Oregon:[6]



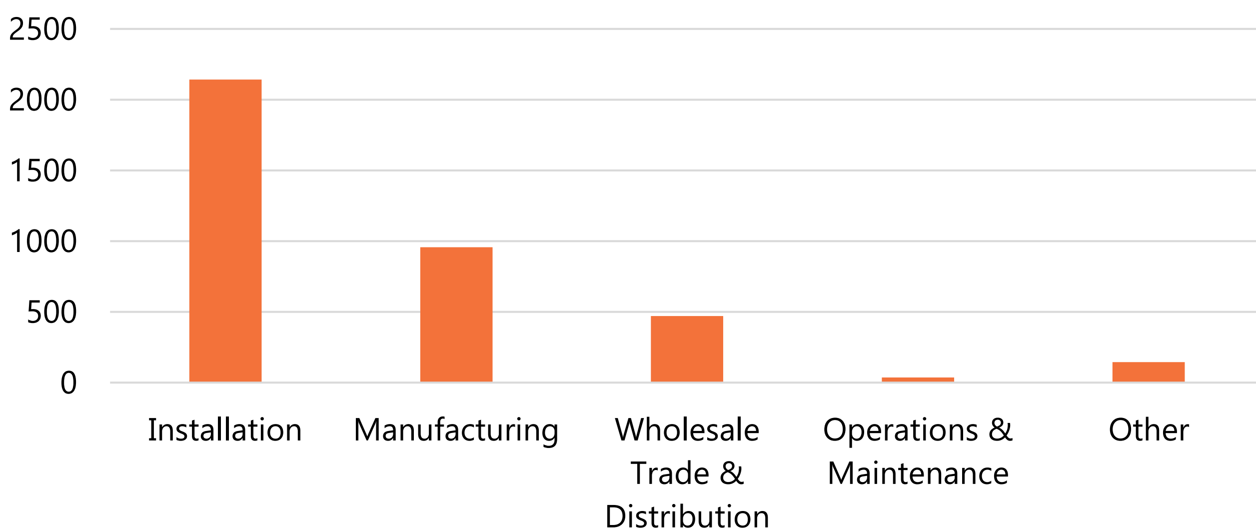
Solar Jobs: 5,759

Hydroelectric Jobs: 1,625

Wind Jobs: 1,407

Nationally, 249,983 people work in the solar industry;[7] Oregon makes up about 2.3 percent of those jobs, with 166 solar companies operating in the state.[8] In 2019, there were 3,750 Oregonians directly working on solar projects most of their time. The industry added 96 new solar jobs in Oregon in 2019, resulting in 2.6 percent job growth. The following chart demonstrates how the solar jobs in Oregon are categorized, with most of the jobs focused on installation of solar equipment.[9]

Figure 2: Oregon Solar Jobs by Sector



The electric power generation category also includes Oregonians employed in the construction and maintenance of facilities that convert resources to electricity, as well as the manufacturing of equipment for those facilities. In Oregon, that includes people building and maintaining natural gas-fired power plants, hydropower dams, and solar and wind facilities. Generating facilities represent 27 percent of jobs, while manufacturing represents 26 percent.[10]

Fuels

The 2020 US Energy and Employment Report defines the Fuels job category as, "all work related to fuel extraction, mining, and processing, including petroleum refineries and firms that support coal mining, oil, and gas field machinery manufacturing. Workers across both the forestry and agriculture sectors who support fuel production with corn ethanol, biodiesels, and fuel wood are also included in the fuel employment data."[11] The fuels sector employs 3,662 workers in Oregon. Woody biomass jobs – which include Oregonians in agriculture and forestry fields – make up the largest segment of fuel sector employment at 36.8 percent. In Oregon, there are 15 woody biomass power facilities, primarily burning wood from mills and land owned by the Bureau of Land Management to generate electricity.[12]

Petroleum products distribution is the next largest fuel employer in Oregon, with 570 jobs.[13] While the use of heating oil in homes has decreased in Oregon, demand from the transportation sector has maintained the employment need. Oregon has very little in-state production of direct use fuels, so most jobs are in transportation, storage, and retail. For example, the propane industry employs 328 people in Oregon in transportation, storage, and retail jobs.[14] Natural gas fuel extraction and distribution employs 162 Oregon workers. The state currently has one underground natural gas extraction facility in Mist, and 25 biogas facilities operating around the state capturing gases from agriculture waste, wastewater, and landfill waste.[15]

Transmission | Distribution | Storage

The 2020 US Energy and Employment Report defines the transmission, distribution, and storage jobs as those supporting, "infrastructure for electric power and fuel links energy supplies to intermediate and end users."[16] Transmission, distribution, and storage – the energy system that connects energy resources to end use consumers – employs 13,948 workers in Oregon. Construction jobs make up the largest percentage of jobs in this category, at 36.3 percent, as energy infrastructure is continually being built and maintained.

In 2019, Oregon's energy utilities employed 4,167 people.[17] Oregon has both privately and publicly owned energy utilities distributing natural gas and electricity to customers. Employment at utilities varies, including lineworkers and pipelayers, customer service representatives, government relations, management, and resource planning.

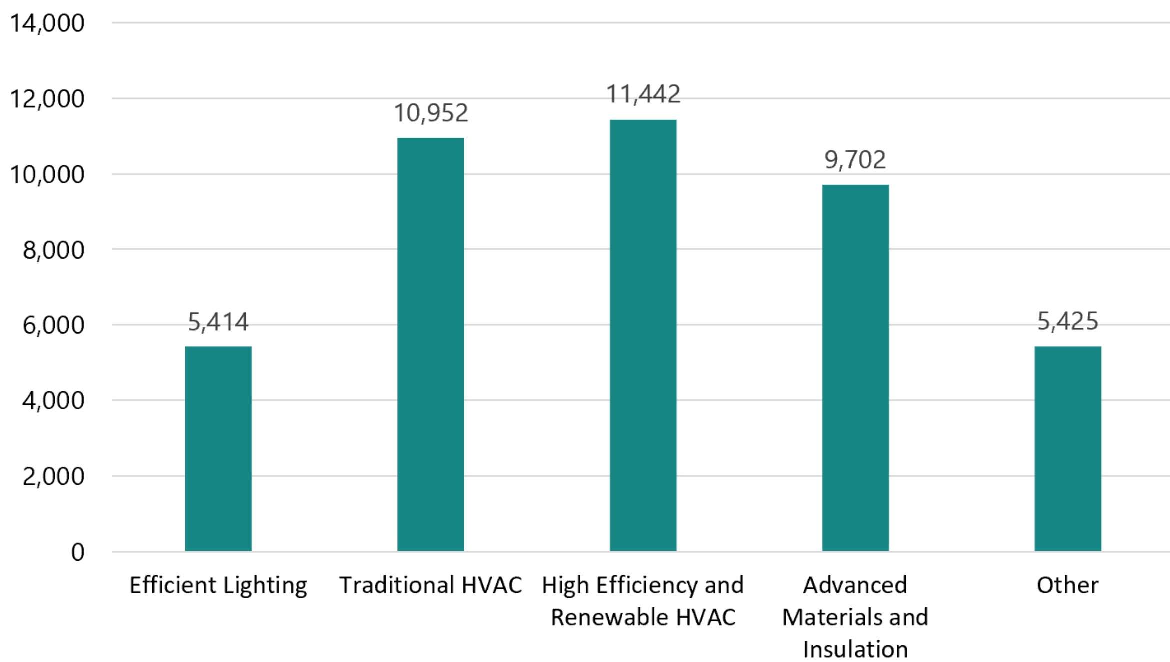
Energy Efficiency Jobs

Oregon Energy Efficiency Jobs: 42,935

Energy efficiency employment covers the production and installation of energy-saving products and services that reduce end-use energy consumption by Oregon homes and businesses. The largest number of these employees work in high efficiency HVAC and renewable heating and cooling firms, followed by traditional HVAC.

About 87 percent of energy efficiency jobs are in the construction industry, including efficient lighting, HVAC, advanced materials, and insulation.[18] These construction positions are not new to the industry, but are critical to marketing and implementing of energy efficiency measures. Many utility and government employees work in energy efficiency, but are categorized in other areas based on their employer. Similarly, utility employees working in energy efficiency are grouped as utility employees.

Figure 3: Energy Efficiency Jobs in Oregon



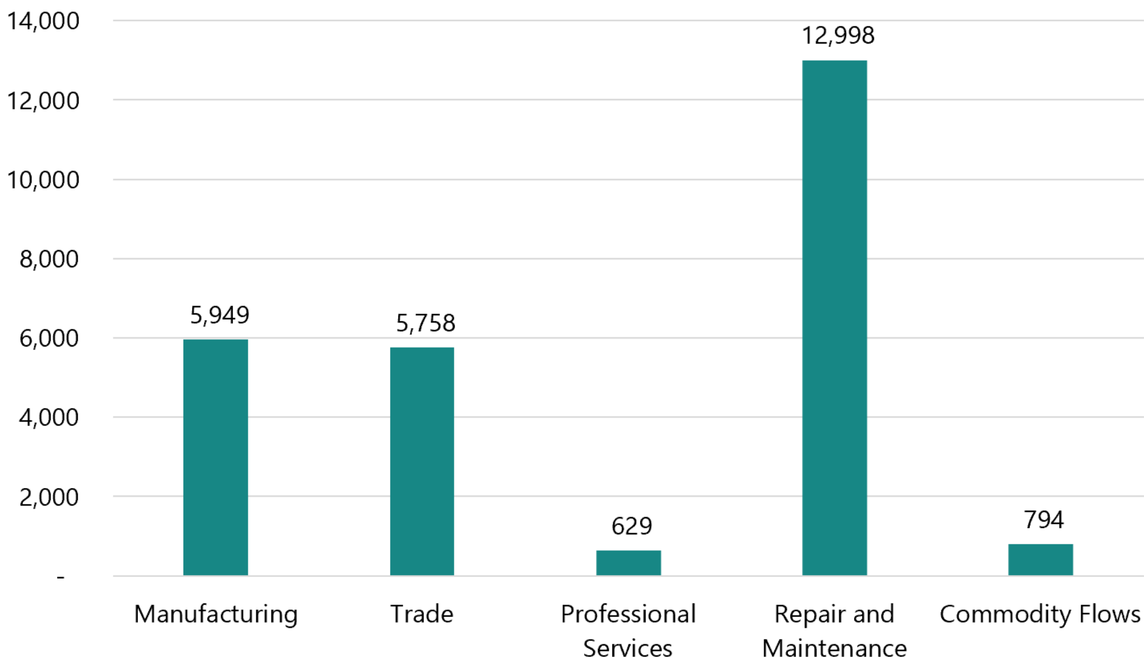
Motor Vehicles Jobs

Oregon Motor Vehicle Sector Jobs: 26,129

The motor vehicle sector employed 26,129 people in Oregon in 2019. Repair and maintenance is the area that employs the most people, followed by manufacturing.[19] In Oregon, there are about 4.1 million registered vehicles and 3.1 million licensed drivers, so the demand for qualified engineers and technicians remains high.[20] Electric vehicle adoption continues to increase, with 31,977 registered electric vehicles in Oregon as of July 1, 2020.

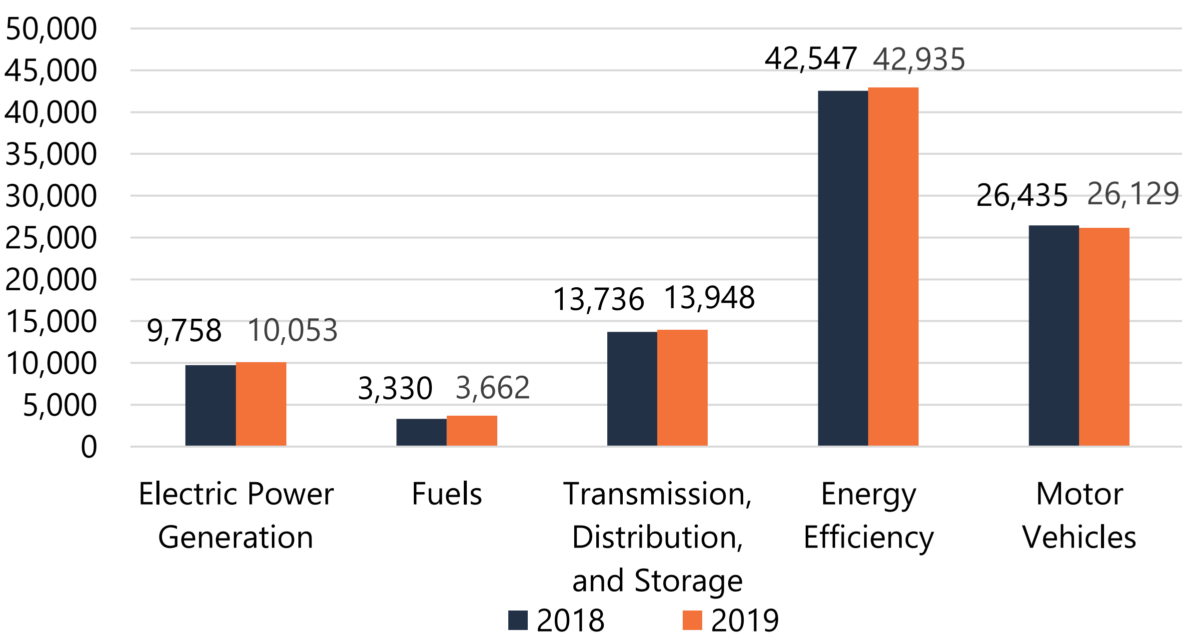
Learn more about electric vehicles in the Technology Review and Policy Brief sections.

Figure 4: Motor Vehicle Jobs in Oregon



Trends in Energy Sector Jobs

Figure 5: Energy Sector Job Growth in Oregon: 2018 vs. 2019



Energy Jobs: Oregon vs. National

Oregon's energy sector employment trends differ from the national energy sector.[21] For example, while Oregon has a lower percentage of jobs in fuels, the state outpaces the nation in the percent of energy efficiency jobs.

Table 1: U.S. Energy Jobs vs. Oregon Jobs

Energy Job	U.S. Total	U.S. %	Oregon Total	Oregon %
Electric Power Generation	799,742	10%	10,053	10%
Fuels	1,148,893	14%	3,662	4%
Transmission, Distribution, and Storage	1,383,647	17%	13,948	14%
Energy Efficiency	2,378,893	29%	42,935	44%
Motor Vehicles	2,556,492	31%	26,129	27%
Totals	**8,267,667**		**96,727**	

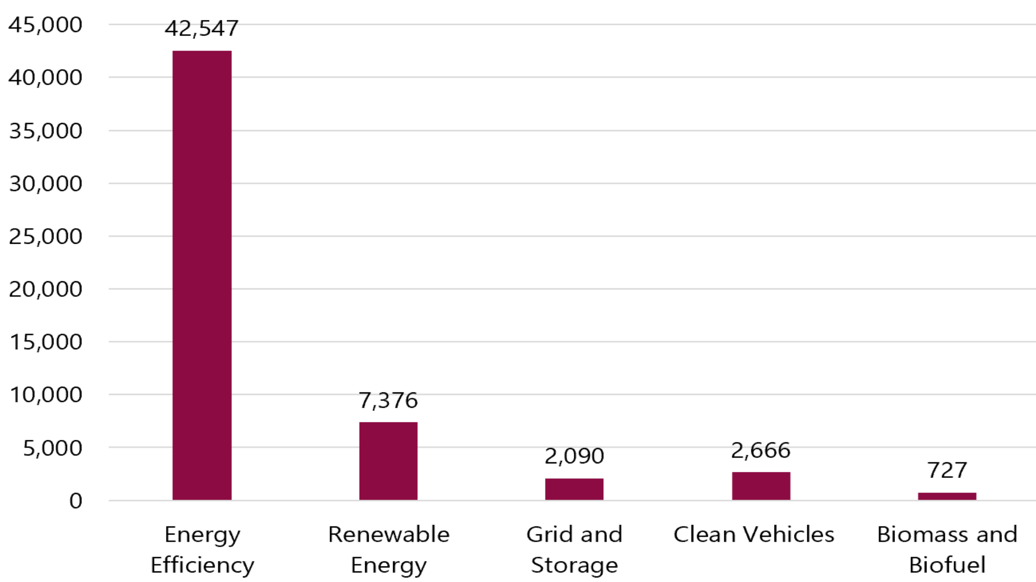
There are many factors that influence state energy employment. One of the most significant factors for Oregon is how our energy flows as we produce, import, and consume energy.

Clean Energy Jobs in Oregon

Oregon Clean Energy Jobs: 55,406

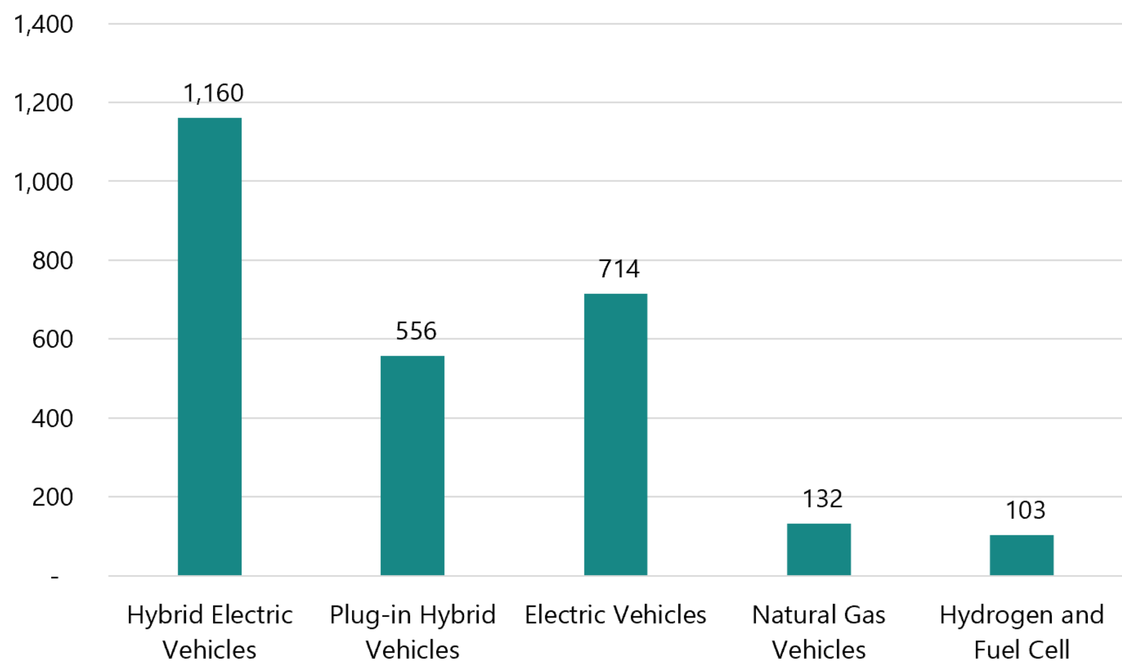
Oregonians in clean energy jobs – including renewable energy, energy efficiency, and resilience – work to reduce energy use and mitigate the environmental impacts of energy consumption. Oregon has seen significant growth in clean energy jobs with the development of solar, wind, and biofuel facilities, and through greater emphasis on improving the efficiency of our transportation sector and built environment. In Oregon, energy efficiency is the largest clean energy employer, followed by renewable energy.[22]

Figure 6: Clean Energy Jobs in Oregon



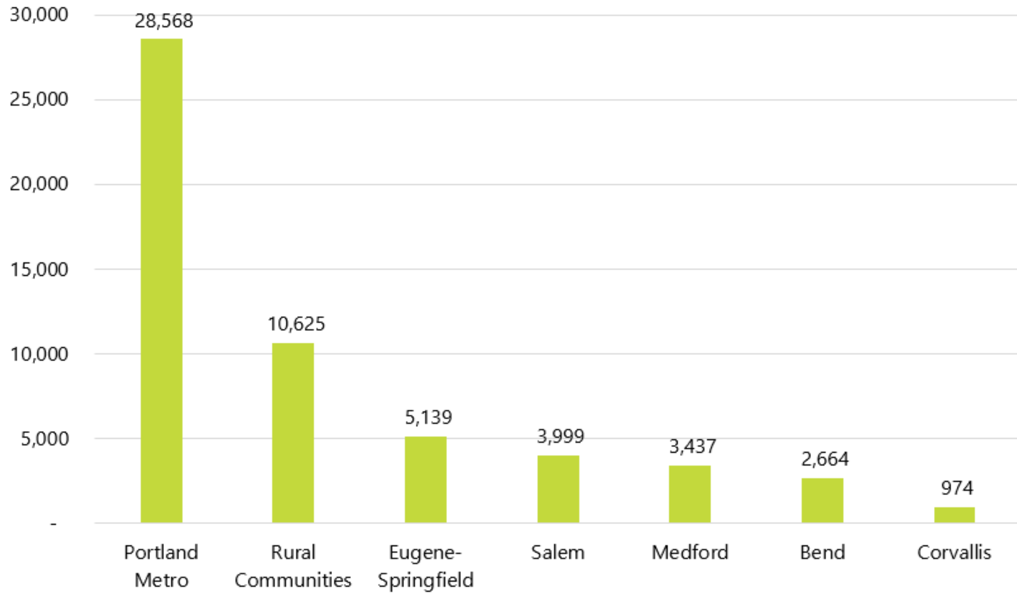
The clean vehicles category includes electric and other alternative transportation fuels options, which are increasing in popularity in Oregon and are important to reducing harmful greenhouse gas emissions and the state's dependence on imported fossil fuels. The growth of electric vehicle adoption may change employment in the motor vehicle industry. Scientists and engineers are needed to develop new technologies, and trades, like electricians, are needed to build infrastructure for home and business charging. The United States Bureau of Labor Statistics examined the potential for job growth nationally in the electric vehicle sector and found "new types of automobile manufacturing jobs will also be created; however, many of these jobs will be filled by current manufacturing employees or those that were displaced by recent downsizing of the automobile manufacturing industry."[23] Electric vehicles also have lower maintenance needs, therefore demand for automobile repair and maintenance jobs may decline as electric vehicles gain popularity. Clean vehicle jobs in Oregon are divided across a few transportation fuels options.[24]

Figure 7: Clean Vehicle Jobs in Oregon



The development of clean energy jobs has provided job growth in Oregon metro areas. Rural areas have also reaped benefits of clean energy job growth, as 10,625 rural Oregonians work in clean energy. Renewable energy infrastructure is often built in rural Oregon communities, which leads to new construction, utility, and maintenance jobs that can bolster local economies. [25]

Figure 8: Clean Energy Jobs in Oregon Urban and Rural Communities



Energy Jobs: Demographics and Equity

Nationally, energy sector jobs skew male and younger. Women make up 47 percent of the overall workforce, but just 23-32 percent of the energy workforce. Employees older than 55 make up 23 percent of the overall workforce, but just 13-21 percent of the energy workforce.[26]

In Oregon, the solar workforce also lacks some diversity, according to research conducted by the Solar Foundation. Women and people of color each represent 19 percent of Oregon's solar workforce. The foundation also found that in Oregon and Washington, women are significantly less likely to hold solar industry management positions compared to men – just 17.5 percent of management positions are held by women, while 82.5 percent are held by men. Additionally, 93.2 percent of management positions are held by white individuals, while 6.8 percent are held by Latinx individuals, 1.1 percent by Black or African American individuals, 1.1 percent by Asian individuals, and zero percent by Native Hawaiian, Pacific Islander, American Indian, or Alaskan Native individuals. Among the Oregon and Washington solar industry companies interviewed by the Solar Foundation, 17 percent have adopted strategies to increase ethnic, racial, female, and gender non-binary representation to address diversity concerns.[27]

A Changing Job Market

In the United States, the energy sector is adapting as energy costs change, and as we shift how we generate and use energy to reduce carbon emissions and meet industry and government clean energy goals. In 2019, the energy sector outperformed the American economy in job growth, representing 8 percent of new employment opportunities while making up only 5.6 percent of the overall workforce.[28]

In 2019, coal lost almost 8,000 jobs nationally. Natural gas generation added 9,100 jobs and renewable technologies created 10,900 new jobs. In the fuel sector, corn ethanol employment declined, but woody biomass and other biofuels increased. Natural gas employment growth continues to drive fuel employment increases nationally.[29]

Future of Energy Jobs

The energy sector is transitioning, and so is its workforce. Government, education facilities, and employers are investing in workforce development programs and early education to train current and future workers in new technologies in the clean energy sector, such as renewable energy engineering. Efforts are being made to diversify the energy sector and attract women and minorities into STEM careers.

The U.S. Department of Energy is fostering the development of future workers in the energy sector through its "JUMP into STEM" program, an online building science competition for undergraduate and graduate students at U.S. colleges and universities. The JUMP into STEM initiative seeks to inspire the next generation of building scientists, focusing on creative solutions and diversity in the building science field. The diversity objective is inclusive of an interdisciplinary mix of majors and representation by women and minorities. JUMP into STEM attracts students from majors such as computer science, data science, statistics, mathematics, physics, economics, sociology, meteorology, architecture, and various engineering disciplines in addition to the traditional building professional degrees of civil and mechanical engineering.[30] [31]

In Oregon, workforce training programs for electric vehicle charger installation and maintenance are designed to meet the growing need for EV infrastructure. Central Oregon Community College (COCC) offers automotive technology degrees and certificates on a range of vehicles, including a Hybrid Electric Vehicles Technician program and a Clean Energy Diesel Technician program. Tesla is partnering with COCC to recruit students to attend the company's 12-week START program, teaching students to become Tesla Technicians. Tesla has also worked with Linn Benton and Portland Community Colleges on the START program. [32]

Oregon Institute of Technology (OIT) was one of the first universities to offer a bachelor's degree in Renewable Energy Engineering and now offers a Master of Science in renewable energy engineering. Graduates of OIT's program go into engineering jobs "where a major emphasis is in power generation, power and energy systems design or applications, and energy conversion technologies."[33]

Home energy scoring policies and programs are creating a need for skilled home energy assessors. In Oregon, licensed and certified home energy assessors are trained to determine the efficiency of the home. The assessors assign residential buildings a home energy performance score using a scoring system developed by the U.S. DOE and adopted by the State of Oregon. Assessors are certified by the Oregon Department of Energy and licensed by the Oregon Construction Contractors Board after completing the training approved by ODOE. Currently, there are 180 assessors providing this service in Oregon – and more than 19,864 homes scored since 2018.[34] [35] [36] Not only has home energy scoring created new energy-related jobs, it has also given homeowners and homebuyers valuable energy information.

The State of Oregon STEM Investment Council seeks to increase the proficiency of Oregon students in advanced mathematics and science, and double the number of students who earn a post-secondary degree requiring proficiency in science, technology, engineering, or mathematics. The Oregon STEM Investment Council's Education Plan highlights the "unprecedented job and career opportunities to Oregonians students who've acquired the talent, passion, and initiative that come from studies in science, technology, engineering, and math (STEM)." These skills will lead to successful careers in electronics, software, biomedical research, and the clean energy sector. [37]

COVID-19 and Energy Jobs

The COVID-19 pandemic has created an economic recession affecting energy jobs across the country. As businesses and industry suspended operations in Spring 2020 during "stay home" orders, the national clean energy industry shed an estimated 594,300 jobs in March and April – a 17 percent decrease in clean energy employment that erased the job growth of 2019.[38]

Oregon lost an estimated 7,405 clean energy jobs in that time. The hardest-hit Oregon counties include Multnomah (1,771 jobs lost), Washington (1,654), Clackamas (513), and Lane (437).[39]

Manufacturing plants of clean energy products, building materials, lighting, solar panels, and wind turbine parts were temporarily closed or had to reduce operations. Many other energy sector workers were furloughed or underemployed, which is not captured in the total jobs losses previously mentioned. It is likely job losses in clean energy will continue unless significant investment is made to bolster the industry. Economic forecasts have projected the clean energy sector has the potential to lose a quarter of its workforce, or 850,000 jobs in 2020. [40]

U.S. energy sector recovery began over the summer of 2020 with modest growth. The clean energy sector added 3,200 jobs in July 2020 and many industries are at full operation with new protocols to address pandemic safety concerns and protect employees and customers. Oregon added 56 clean energy jobs in July 2020.[41]

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Energy 101: Energy Efficiency

Energy efficiency is doing the same work while using less energy. It involves an efficiency measure or method to reduce energy consumption by using less energy to attain the same output. Energy conservation reduces energy consumption in a different way – it minimizes activities that consume energy. There are many types of strategies, policies, and programs used to encourage or require energy efficiency, which are covered in depth in Chapter 6 of the 2018 *Biennial Energy Report*. This Energy Efficiency 101 provides a brief background and description of electric and natural gas energy efficiency policies and programs.

Energy Efficiency Policies

Electric Energy Efficiency Planning and Cost-Effectiveness

Energy efficiency and conservation are primary considerations in regional electricity planning. The 1980 Northwest Power Act (Power Act, Public Law 96-501)[1] prioritizes conservation as the first resource to develop for the region. The act established the Northwest Power and Conservation Council (NWPCC), which produces the Northwest Power Plan every five years. Each plan sets goals for electric energy efficiency, projects future power needs, and analyzes potential energy efficiency opportunities.[2] For more background about the power planning process, see the Council's summary "Regional Power Planning in the Pacific Northwest."[3]

> **839b(e)(1).** The plan shall, as provided in this paragraph, give priority to resource which the Council determines to be cost-effective. Priority shall be given: first, to Conservation; second, to renewable resources; third, to generating resources utilizing waste heat or other generating resources of high fuel conversion efficiency; and fourth, to all other resources.
>
> {Northwest Power Act, (4)(1), Stat. 2705}

The Power Act requires electric energy efficiency programs to acquire conservation and efficiency that has a lower cost than other resources, like new generation. This is called cost-effective resource acquisition and is the primary consideration for determining energy efficiency program funding.

The combined cost of an energy efficiency measure, including rebates, incentives, and customer costs is called Total Resource Cost, or TRC. If the TRC is less than the cost of new generation or production, the measure is deemed cost-effective. The Power Act also grants electric energy efficiency a 10 percent adder in the cost-effectiveness calculation. In other words, if the calculated cost of an energy efficiency measure is $100, the cost applied to the TRC calculation can be reduced ten percent to $90.[4]

Natural Gas Energy Efficiency

Oregon is served by three natural gas distribution utilities – Avista, Cascade, and NW Natural – and Energy Trust of Oregon is the administrator of most energy efficiency programs for these three utilities. Energy savings goals are developed through coordination between Energy Trust and the utilities; these goals are not part of the NWPCC Power Plan – which is focused on electricity planning. Each natural gas utility prepares an integrated resource plan (IRP) for a public process at the Public

Utility Commission, which includes system planning, demand and customer forecasts, future gas supply, and the role of energy efficiency as a resource in these scenarios.[i]

Cost-effectiveness evaluations in natural gas programs are based on resource acquisition – when an efficiency measure costs less than delivering natural gas to customers (also called "avoided cost") it is considered cost-effective.[ii] Cost-effective energy efficiency measures are ultimately paid for by all customers, like all other energy resources and services, through charges on their utility bills. These charges may be labeled as conservation investment, efficiency, or public purpose charge on customer bills. Energy efficiency programs for natural gas also include direct funding to community action agencies for income-based weatherization, which can include insulation, air sealing, and heating system repairs. Utilities may also operate financing promotions for new efficient equipment.

Natural gas utilities and Energy Trust have met or exceeded the energy efficiency goals established in their IRPs. Each year, they save about 6,000,000 therms of natural gas. What does six million therms of savings represent? Therms are the fuel units on natural gas utility bills used to measure consumption. According to the 2019 Oregon Public Utility Commission Statistics Book, the average residential customer uses 673 therms of natural gas per year.[5] This means that energy savings each year prevent the need to purchase an additional six million therms, which is equivalent to the average use of nearly 9,000 homes.

Learn more in the Energy 101 on Energy Bill Basics.

Innovative Programs to Support Energy Efficiency

Targeted Natural Gas Energy Efficiency

NW Natural is partnering with the Energy Trust of Oregon on a first-of-its-kind program to address peak events through targeted energy efficiency investments.[6] The pilot looks at the cost-effectiveness of targeted energy efficiency investments to reduce the effects of peak load on the distribution system. Energy efficiency reduces overall energy use, which can reduce the peak load requirements at a localized level. Reducing peak energy demand can delay or avoid the need to invest in additional infrastructure investments to meet the peak load. This benefits all natural gas customers by reducing overall costs to the utility. Energy efficiency programs can be combined with other programs, like demand response, to leverage additional savings on infrastructure investments.

Electricity Energy Efficiency Program Funding

Bonneville Power Administration and the consumer-owned utilities served by BPA efficiency programs have been delivering electricity savings for decades. Efficiency programs are funded through BPA wholesale power rates and by individual consumer-owned utility rates. Individual consumer-owned utilities self-fund energy efficiency measures and projects, which are supported by charges on customers' bills.[7]

Idaho Power, which serves a portion of eastern Oregon, operates a ratepayer-funded efficiency program for their Oregon and Idaho customers. Energy Trust of Oregon administers electricity energy efficiency programs on behalf of Portland General Electric and Pacific Power. Energy Trust programs

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[i] BER 2018 Ch 6

[ii] https://edocs.puc.state.or.us/efdocs/HAA/haa163419.pdf

are funded by a Public Purpose Charge (PPC) on customer bills established by law as a result of SB 1149 (1999).[8] This charge and the operation of Energy Trust began in 2002.[9] Energy Trust also receives incremental funding from PGE and Pacific Power customer rates to acquire efficiency beyond what is paid for by the Public Purpose Charge, as directed in SB 838 (2007). [10]

Oregon Housing and Community Services receives funding from the Public Purpose Charge for income-based weatherization programs. School districts receive direct funding from the PPC for energy efficiency and renewable energy projects.[11] For more detailed information about the Public Purpose Charge, see the biennial PPC Report to the Legislature.[iii] The Northwest Energy Efficiency Alliance (NEEA) develops market transformation efficiency, funded by Energy Trust and regional utilities. Their work creates future savings as new efficiency equipment is brought to market (see subsection below for more information on market transformation).

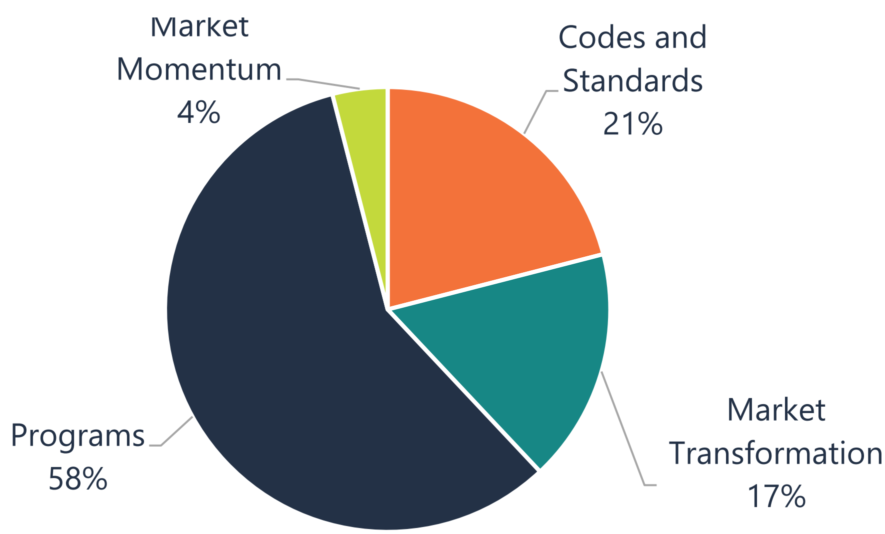
Savings targets for the region are in each Northwest Power Plan. 2021 is the final year for the 2016 Seventh Power Plan and the 2021 Power Plan production is underway. In September 2020, the Council received its annual Conservation Progress Report.[12] The NWPCC Conservation Progress Report shows that the various electric efficiency programs and practices across the region save energy, reduce greenhouse gases, and reduce the need for new electricity generation.[13]

NWPCC estimates that Oregon's share of the Seventh Power Plan target is about thirty percent of the total. Looking at savings from Oregon programs in relation to the estimated share of the target, Oregon is on a downward trend since 2017.

Market Transformation, Building Energy Codes, Appliance Standards, and Market Momentum

From 2000 to 2019, 21 percent of regional cumulative savings come from codes and standards. Seventeen percent came from activities like Northwest Energy Efficiency Alliance efforts that work to bring new technologies to market, known as market transformation.[14] Four percent of regional cumulative savings came from market momentum, which is a Bonneville Power Administration calculation of all the energy efficiency occurring that is not directly reported by utilities, energy efficiency programs, and NEEA market effects.[15]

Figure 1: 2000-2019 Regional Savings Share by Activity



The Northwest Energy Efficiency Alliance (NEEA) develops market transformation efficiency, funded by Energy Trust and regional utilities. Market transformation is accomplished when emerging technologies experience increased sales volumes that

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allow installers and manufacturers to achieve economies of scale.[16] The result is lower prices for consumers, which in turn supports more volume. Ideally this cycle continues until the technology becomes more affordable and widely adopted. NEEA's work creates future savings as new efficiency equipment is brought to market.[17] Over time, these new technologies can be incorporated in regulatory programs such as codes and standards. For example, NEEA provided research for clothes washer efficiency that helped create a federal standard.[18]

Energy codes to increase efficiency of new buildings are adopted statewide in Oregon as part of the building code adoption process.[19] Energy codes are a subset of building codes, which establish baseline requirements and govern building construction. Energy codes and standards set minimum efficiency requirements for new and renovated buildings, assuring reductions in energy use and emissions over the life of the building.[20] Oregon's Energy Building Code is among the strongest in the nation for both residential and commercial buildings.[21] Executive Order 20-04, issued by Governor Kate Brown in March 2020, charts a course for the next three code update cycles, and by 2030 new buildings in Oregon are expected to use 60 percent less energy than they did in 2006.[22]

Appliance and equipment efficiency standards improve energy efficiency and reduce energy costs. Federal efficiency standards completed through 2016 are expected to create utility bill savings for consumers estimated at more than $1 trillion by 2020 and more than $2 trillion by 2030.[23] For appliance and equipment efficiency standards that are not covered in Federal rules, Oregon has adopted appliance standards for products to provide additional energy and cost savings for consumers. The Oregon Department of Energy is updating efficiency standards for 11 new products, with legislative action underway to conform the new rules to Oregon's energy efficiency statutes.

There are several additional policies, programs, and strategies not covered in this section that are helping the state acquire energy efficiency, such as government leading by example and energy savings performance contracting (see Chapter 6 of the 2018 *Biennial Energy Report*). Looking forward, energy efficiency remains a cornerstone of Oregon energy policy and planning. The 2021 Northwest Power Plan is underway, and it will develop new goals for potential energy savings.

Energy efficiency programs are pathways to more than savings and avoided new generation and resources. An increased emphasis on diversity, equity, and inclusion is shaping programs to deliver to underserved communities. In addition, climate action planners look to efficiency as a key cost-effective method to reduce greenhouse gases. For more about energy efficiency policies see the Energy Efficiency Policy Brief.

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Energy 101: Codes and Standards

Codes and standards deliver energy efficiency at low cost. In 2019, 30 percent of the cumulative energy savings in the Pacific Northwest came from codes and standards.[1] Additionally, from 2000-2018, 11% of regional savings came from market transformation efforts by the Northwest Energy Efficiency Alliance (NEEA) – work that directly leads to updates of codes and standards.

Standards

Energy efficiency standards, also referred to as appliance standards, establish a minimum energy efficiency level that certain products must meet in order to be sold or installed. Manufacturers must design and test their products to ensure that performance levels are met, and typically must also label their products to indicate the appropriate information to the consumer. These standards protect consumers by saving energy and phasing out inefficient products that are costly to operate. Both the federal government and individual states have roles in establishing efficiency standards.

Energy efficiency standards are an important energy-saving tool as new buildings progressively become more efficient and as an increasing share of energy consumption comes from the products and appliances that are “plugged in” or movable, often called the “plug load.” Residential and commercial building energy codes have traditionally regulated space conditioning, water heating, and the building envelope, but not appliances that are part of a building’s plug load. The plug loads can represent as much as 30 percent of commercial building use.[2] For residential buildings, the appliances, electronics, and other known plug loads represent 20 percent or more of total electricity consumption in non-gas homes and 33 percent of electricity consumption in gas-heated homes.[3] Plug loads represent a significant portion of consumer energy consumption, and appliance standards support energy efficiency and greenhouse gas reductions to address this end-use.

Federal Standards Activity and Impact on Oregon

The federal government has set standards for appliances since the 1970s. Beginning with the Energy Policy and Conservation Act in 1975, the United States Department of Energy (USDOE) has developed test procedures, standards, and labeling requirements for consumer products. The National Appliance Energy Conservation Act of 1987 established standards for many common appliances and directed the USDOE to review and update these standards. The Energy Policy Act of 2005 established new standards for 16 products at the national level and directed the USDOE to set standards for an additional five. In 2007, the Energy Independence and Security Act provided new or updated standards for 13 products.[4]

Overall, the federal government has set standards for more than 60 products across various categories of residential, commercial, and industrial appliances, lighting, and plumbing products. Federal standards were estimated to save consumers $80 billion nationally in 2015, with $850 million savings for Oregonians in that same year.[5] Many of the products we use every day, such as refrigerators, dishwashers, and furnaces, have an energy efficiency standard. Overall, products covered by standards represent about 90 percent of home energy use, 60 percent of commercial building use, and 30 percent of industrial energy use.[6]

Federal appliance standards generally preempt state standards. Once the federal government creates a standard and it becomes effective, the federal standard applies to all states, and states may not establish a standard for that product that is different than the federal standard. For products that do not have national standards, states may create and enforce standards. If the federal government enacts standards for products that already have state-specific standards, states may only enforce their standards until the federal standards become effective. As noted in the previous section, many of Oregon's previously adopted standards have since been preempted by federal standards.

The **Appliance Standards Awareness Project** maintains a comprehensive summary of all federal standards, initial legislation, publication dates, effective dates, and future schedules.

appliance-standards.org/

At the federal level, standards have not advanced significantly since the last Biennial Energy Report. The USDOE has approved only five standards since 2016, and these were carried over from the previous executive administration. In 2019, the USDOE reversed a previously expanded definition of general service light bulbs, which allowed more lamps to continue their exclusion from efficiency standards.

The USDOE must review each national appliance standard every six years and publish either a proposed rule to update the standard or a determination that no change is warranted. As of August 2020, the USDOE has missed legal deadlines for twenty-eight product standards. Based on the current rate of progress, they will likely miss several more appliance standards deadlines by January 2021.[7]

Efficiency Standards Activity in Oregon

While some appliance standards are set at the federal level, there are also products that do not yet have a national standard and for which a new state standard could achieve meaningful energy and water savings and greenhouse gas reductions. Oregon has periodically enacted efficiency standards as a method of saving consumers money and saving energy.

Oregon first put standards in place in 2005, joining a list of just a few states to do so.[8] Starting with 11 product categories, Oregon added six more product categories in 2007 and in 2013 added three more. Thirteen of the products for which Oregon has established standards have since been pre-empted by standards adopted by the federal government.

State regulatory provisions relating to equipment energy efficiency, both substantive and procedural, are contained in both statute (ORS 469.229 through 469.261) and administrative rule (OAR 330-092). The definitions specifying which products are covered by state minimum energy efficiency standards, as well as the standards themselves, are currently contained in statute. Statute also includes authority for ODOE to adopt new standards and update existing standards in rule if certain criteria are met and requires legislation to be introduced at the next Legislative Assembly to bring state statute into conformance with any rule updates. Administratively, ODOE rules currently provide effective dates for standards, processes for manufacturers to register compliance and appeal findings of non-compliance, and labeling requirements for products. Recent Executive Orders 17-20 and 20-04 have directed ODOE to review and report on standards opportunities in Oregon and to adopt rules establishing standards for certain products. Please refer to the Policy Brief section of the Biennial Energy Report for additional information on recent state activity.

Energy Efficiency in Oregon Building Codes

Energy codes are part of the building code and provide requirements for new construction and renovations to improve the energy efficiency of the buildings. The energy code regulates building controls and building elements such as insulation, lighting applications, heating, ventilation, and air conditioning equipment. Architects, engineers, builders, and contractors must design and construct buildings to meet or exceed energy code requirements.

Figure 1: Status of State Energy Code Adoption for Residential Buildings[10]

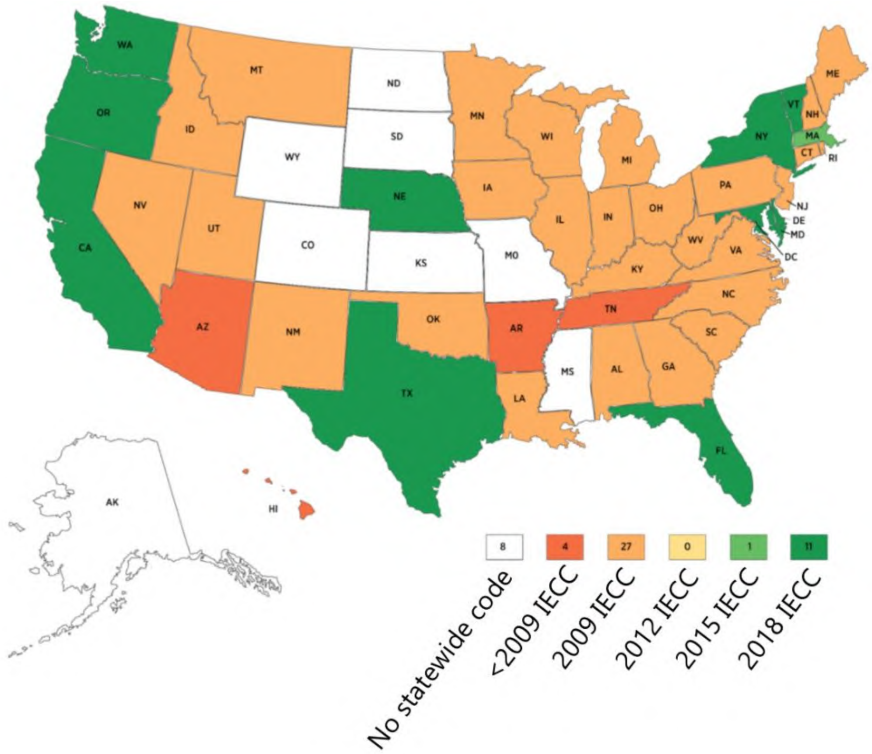
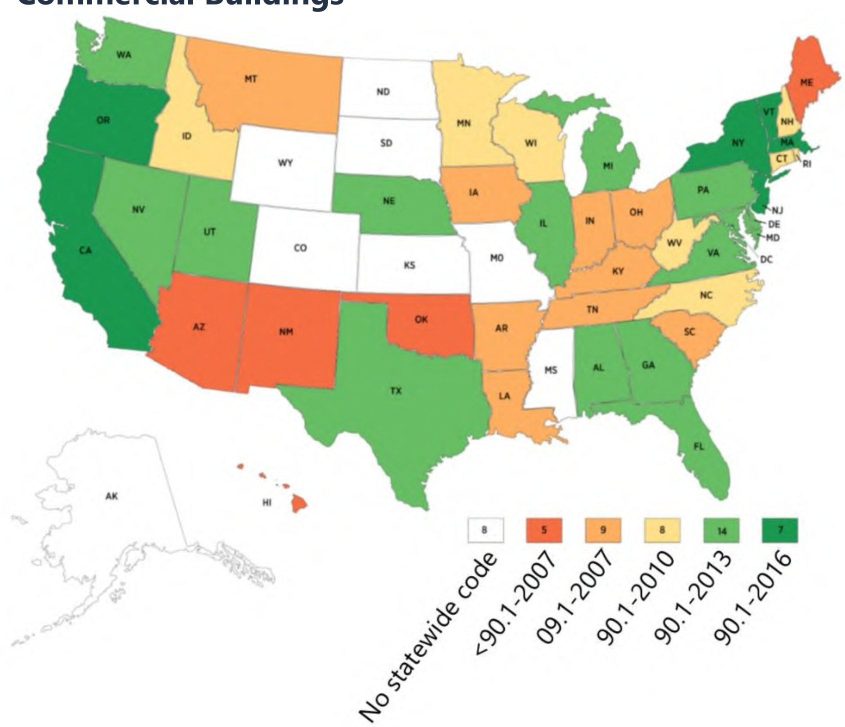


Figure 2: Status of State Energy Code Adoption for Commercial Buildings[10]



Unlike some appliance standards, energy codes are not set and enforced at the national level. Energy codes, and building codes in general, are established by states or local jurisdictions. There are, however, model energy codes that are developed nationally that states can look to for reference. These model energy codes include the International Energy Conservation Code (IECC) and ASHRAE Standard 90.1. States and jurisdictions may choose to adopt a wholesale version of the model codes, make local amendments, or develop a separate local code. Significant industry and public input for code development helps national organizations craft model codes that are adoptable and enforceable by jurisdictions. Local jurisdictions adopt codes through established state, county, city, or other jurisdictional process that are specific to that location. Enforcement, including plan review and inspection, is often performed through local building official departments.

Oregon looks to the most efficient model codes to create an energy code that is applicable and consistent across the state. Oregon's energy code is regulated and administered by the Building Codes Division within the Department of Consumer and Business Services, which works with building officials, technical committees, advisory boards, and the public to adopt, amend, and interpret the Chapter 13 energy efficiency provisions of the Oregon Structural Specialty Code (OSSC) and the Chapter 11 energy efficiency provisions of the Oregon Residential Specialty Code (ORSC).[9]

Oregon's statewide energy code dates back to 1974, when the Oregon Uniform Building Code first included thermal insulation requirements for buildings. Since then, Oregon has maintained and continued its status as a leader in energy efficiency codes. The USDOE produces a comparison chart for energy codes across the US.[10] Oregon is among the top dozen states for most-efficient residential and commercial codes. Note that like product standards, the west coast states have similar energy codes, making compliance more predictable for companies that build in those contiguous three states. One way that Oregon achieves savings in its current building code is by having an options menu for residential buildings that allows builders to make upgrades to heating, ventilation, and cooling equipment as a path to compliance. Upgrading the HVAC system is a popular and low-cost option for builders, and a leadership approach by Oregon when federal standards improvements are lagging industry practice.

The current commercial code is based on ASHRAE 90.1 in accordance with EO 17-20. Because ASHRAE 90.1 is updated every three years, Oregon can adopt subsequent versions each cycle. EO 17-20 requires the residential code to be equivalent to the USDOE Zero Energy Ready Home Ver.06 performance by 2023.

Reach Code 101

Oregon has a statewide code, meaning all jurisdictions have the same codes for construction, including life safety, plumbing, electrical, structural, and energy components. A jurisdiction may petition for a local amended code, but they must demonstrate that amendments will not weaken requirements or be an undue burden on industry.

Reach codes, or stretch codes, refer to codes that are purposely designed to go beyond the requirements of the base code. For energy efficiency, they require additional energy measures and provide templates for those wishing to exceed the base code requirements. Reach codes are often optional choices for builders or owners to pursue. For jurisdictions that want to offer an optional path for builders to improve efficiency in their communities, they may locally support a voluntary Reach Code that requires more efficiency. Reach codes can be designed to incorporate and test requirements that may become part of a future base code, preparing the market for components that may become mandatory in future years. Incentives can be coupled with reach code requirements to increase and reward participation.

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Net Zero Energy Buildings

While there is no universal definition and there are nuances to how net zero energy buildings are classified, a net zero building is generally understood to be a building that combines energy efficiency and renewable energy generation to consume only as much energy as can be produced through renewable resources over a specified time period. An important note is that net zero energy buildings still consume energy, and may at times draw energy from the electric grid and at other times supply energy to the grid. The concept of "net zero energy" indicates that over the course of a year, these balance out. Net zero energy buildings are also sometimes referred to as "zero net energy buildings" or simply "zero energy buildings."

Net zero performance is accomplished through a combination of high-performance building design features, energy-efficient operation, and on-site renewable energy generation. Some of the variations to net zero energy building classifications include:

Site-based net zero energy. A building that renewably generates as much energy as it uses, when measured at the building site (typically through utility meters). Site use energy in this case includes electricity, natural gas, and other fuels. Renewable electricity production would meet all of the building's site energy consumption by meeting the electricity needs and also offsetting any fuel use by generating equivalent additional electricity for the grid.

Source-based net zero energy. A building that renewably generates as much energy as it uses, as measured at the energy source. This definition attempts to incorporate the overall efficiencies of both energy generation and energy distribution. This approach commonly uses an average site-to-source conversion factor to do so. For example, if an electricity generation system is 33 percent efficient overall, then it takes approximately three units of energy at the generation source to deliver one unit of energy at the end-use. These average site-to-source factors can be appropriate for some sites or regions, but may not always be accurate for individual sites or regions with specific utility and generation resources.

Net zero energy with off-site generation. This definition is similar to either the site or source-based net zero energy approaches, but allows for some portion of the renewable energy to be generated off site. This can be beneficial for sites with limited capacity for renewable generation or sites where it is infeasible to install adequate renewable energy to offset building energy consumption.

Electricity-only net zero energy. This net zero energy approach accounts for only the electricity portion of a building's overall energy consumption when calculating the amount of renewable generation necessary to provide a net amount of electricity over the course of a year to offset all the electricity use in the building.

Net zero greenhouse gas emissions. This approach considers greenhouse gas emissions, rather than energy, when calculating offsets. There is a direct relationship between energy use and greenhouse gas emissions; however, this method accounts for the different greenhouse gas emissions factors and intensities of various energy sources.

Net zero energy ready. This is a general term for a building designed to operate with sufficiently low energy consumption such that it could be offset with on-site renewable generation, but that it does not yet have any renewable energy capacity. Often the infrastructure to accommodate future installation of renewables exists, but the actual renewables, such as solar photovoltaic, have yet to be installed.

There have been national efforts to better define and standardize net zero energy buildings, including by the United States Department of Energy.[1] ASHRAE is also currently undertaking an effort to define a "Standard Method of Evaluating Zero Energy Building Performance" through its Standard Project Committee 228P development work.[2] California has issued broad goals for net zero energy residential new construction by 2020 and commercial new construction by 2030, along with source-energy based definitions for net zero energy buildings.[3] California's Title 24 residential building code 150.1(c)(14) requires, as of January 2020, mandatory on-site solar photovoltaic systems sized to offset the home's electrical consumption, as determined by an equation in the code.[4] Efficiency advancements in building materials and equipment, coupled with photovoltaic technology improvements and cost reductions,[5] are bringing more frequent achievement of net zero energy buildings closer to reality. There are numerous examples of projects across the country that are verified or near-net zero energy, and the New Buildings Institute maintains an interactive "Getting to Zero" database which tracks verified and emerging net zero energy buildings.[6]

Net Zero Energy Building Policy

Many jurisdictions, building owners, and those in the architecture, engineering, and construction industries have embraced net zero energy buildings as a goal. However, there are many building types, particularly those with higher energy use intensities, such as restaurants, hospitals, and data centers, for which net zero energy remains mostly infeasible. In addition to technical energy efficiency limits, complications such as physical site constraints, site solar access, net-metering limitations, grid interconnection issues, fuel source limitations, affordability, and cost-effectiveness contribute to difficulty in achieving net zero energy buildings. As such, there is no "one size fits all" policy that states or municipalities can look to advance net zero energy building policy.

Building code advancements can help achieve progress toward net zero buildings, but must be accompanied by other efforts. The organization Architecture 2030 is advocating for net zero energy buildings through the 2030 Challenge[7] that targets progressive reductions toward net zero energy for new construction in 2030. Architecture 2030 has also developed the Zero Code[8] framework for net zero buildings along with guidance for the role of off-site renewable energy procurement for net zero energy buildings[9], which those interested in defining broader net zero energy policy can use. The net zero energy building inventory increases annually, and the presence of more net zero energy buildings in our future will rely upon continuing coordination between the design and construction communities, building code offices, energy utilities, regulatory government agencies, building owners, and others working together toward a common goal.

Oregon will see more net zero energy buildings in its future if communities, utilities, government, and others work together toward a common goal.

Yellowhawk Tribal Health Center Sustainability Shines

The Yellowhawk Tribal Health Center, located on the Confederated Tribes of the Umatilla Indian Reservation, is at the forefront of sustainability in Oregon. The health center is enrolled in Energy Trust of Oregon's Path to Net Zero. Not only is it the first emerging net zero energy health care building in Oregon, but it is the first tribal building to make this commitment as well.

Designed to operate at an efficiency 60 percent greater than typical buildings of its type and achieve an estimated $58,000 in annual energy cost savings, the health center has potential to reach net zero energy operation in the future with installation of additional solar panels. The infrastructure necessary for this has already been constructed on the roof of the building, so achieving net zero certification is well within reach for the health center. Energy saving features include efficient LED lighting, high-performance heating, ventilation and air-conditioning, and an improved building envelope.

States and jurisdictions, including Oregon, have included elements of net zero buildings in specific policy directives. Oregon Executive Order 17-20[10] targets equivalent performance to the U.S. DOE Zero Energy Ready Home specifications in the residential building code by 2023 and includes a directive for new state agency construction to be designed to be able to operate as carbon-neutral buildings after 2022. Executive Order 20-04[11] continues the trend toward increased efficiency in new construction and net zero energy buildings by targeting a 60 percent reduction in new building annual site consumption of energy by 2030, excluding electricity used for transportation or appliances, from a 2006 code baseline. This advancement in efficiency makes net zero energy achievable for some residences and building types, when coupled with installation of renewables.

Executive Order 17-20 also includes a requirement for solar-ready provisions in the building code to make future installations of onsite renewables more accessible for building owners, which was incorporated into the Oregon residential building code[12] for new construction in October 2020. As of 2019, the Oregon commercial energy code requires completion of the "2019 Oregon Zero Energy Ready Commercial Code Compliance Form" that, while not specifically requiring onsite or offsite renewables in the code, includes a requirement for an estimation of building energy consumption, renewables needed to achieve net zero energy, and the onsite renewable generation potential. This helps raise awareness of net zero energy buildings and what is needed to achieve that level of performance. Utility programs, energy policies, energy codes, voluntary performance standards, and interested building/homeowners all contribute to advancing net zero buildings.

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TECHNOLOGY REVIEWS

Rapid advancements in technology have responded to and pioneered changes in our state and across the world.

Often these resources and technologies are critical to the function of our society while also helping us work better and faster. Sometimes they also enable us to adapt — the onset of a global pandemic in 2020 has now made virtual meetings commonplace and changed how Oregonians conduct business. The resources and technologies presented in this section cover the spectrum of traditional to innovative, and demonstrate the breadth of technology that is integral to the production and management of our energy system.

Electricity generation technologies, such as wind and solar, are becoming more widely used and in many cases are now lower cost than more traditional technologies. And some newer technologies may be just around the corner while researchers, scientists, and businesses work to make them commercially viable. Tomorrow's energy resources may include electrolyzers to generate hydrogen fuel, offshore wind turbines, fuel cell electric vehicles that run on hydrogen and emit only water, or carbon capture and sequestration technologies that help industries capture and store harmful greenhouse gas emissions.

Automated metering infrastructure enables utilities to evaluate real-time data on customer electricity use so that they can optimize their systems and provide better value to their customers. Electric vehicles, battery storage, and smart appliances create opportunities for electric utilities to communicate with devices in homes and businesses to better balance new electricity loads while avoiding investments in expensive electricity generation. In some areas of Oregon, utilities are already communicating with customers and their smart devices to help better manage the grid.

There are trade-offs with these technologies. Some operate without emitting greenhouse gases or other air pollutants, but there are often emissions and environmental impacts associated with building and transporting them. For example, how do we plan for and manage the waste streams of new technologies when they reach the end of their useful life? Technologies like smart thermostats and rooftop solar can reduce energy costs or the effects of energy use for consumers, but not all Oregonians have access to these technologies — a significant equity issue that requires deep partnership with currently and historically underrepresented communities.

The technologies examined in the following pages are those that are prevalent in Oregon and of interest to stakeholders that ODOE heard from when putting together this report. Many of these technologies place Oregon and its communities on the forefront of a cleaner, more sustainable future. They help Oregon meet its climate and energy goals by enabling cleaner and more efficient fuels and resources. They offer opportunities to invest in Oregon's economy by creating energy-related jobs to maintain our energy system and develop new projects. They can make us more resilient by enabling us to maintain or restore our energy systems when disruptions occur. And beyond these opportunities and benefits — they are just so cool.

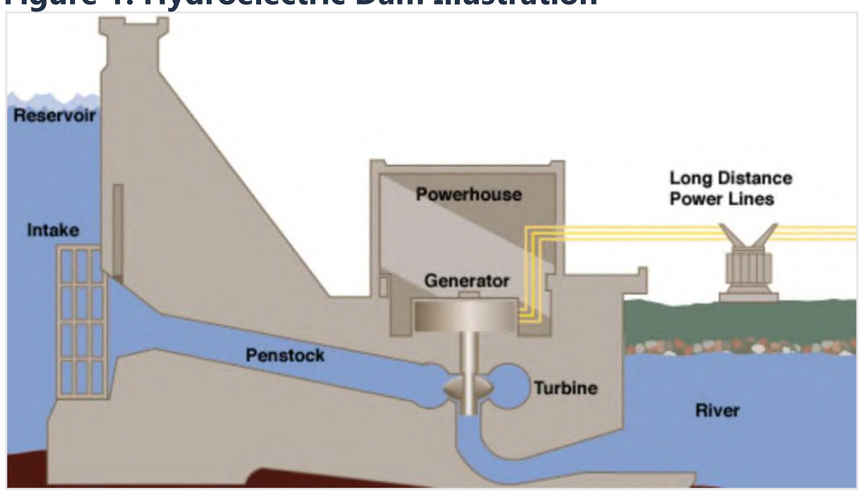
Resource Review: Hydropower

- Total Capacity in Oregon (2019): 8,303 MW
- Facilities in Oregon (0.03 to 2,160 MW) 94*
- Total Generation (2018): 35,442,773 MWh
- Total Consumption (2018): 22,125,769 MWh
- Total Exports (2018): 13,317,004 MWh

**Seven hydropower facilities cross state borders.*

Hydropower (or hydroelectric power) is a renewable energy resource that generates electricity from moving water. Because water can be stored behind dams, hydropower facilities can provide firm, or consistent, electricity output and can also ramp up or down quickly to provide grid balancing services. Hydropower projects are an important resource in the Pacific Northwest, providing low-cost, reliable power as well as other benefits like flood control and irrigation. Hydropower is the largest electricity generation source in Oregon and the largest source of electricity consumed in Oregon.[1]

Figure 1: Hydroelectric Dam Illustration[2]



Hydropower uses the movement of water powered by gravity to run electricity generator turbines; water flows downward through a pipe or channel called a penstock and pushes against the blades of a turbine to spin a generator. There are two main types of hydropower facilities: "run-of-river" systems that use the force of a river or stream's natural current to run hydro turbines, accounting for over two-thirds of hydropower in Oregon, and "storage systems," which use dams on rivers or streams to store water that can be released to run hydro turbines when needed.[2] Alternative hydropower projects are also in use that capture energy in irrigation or water supply pipes (see the conduit hydropower Technology Review). Hydropower generation is highly dependent on precipitation levels which can vary season to season and year to year.

Trends and Potential in Oregon

In 2018, ninety-four hydropower facilities[i] in Oregon generated over 35,000,000 MWh of electricity, accounting for 55.3 percent of generation[3] and 43.3 percent of consumption in Oregon.[4] Oregon is the second-largest hydropower producer in the U.S., behind Washington state. The state is also home to the oldest operational hydropower facility, the T.W. Sullivan facility on the Willamette River, which became operational in 1895.[5]

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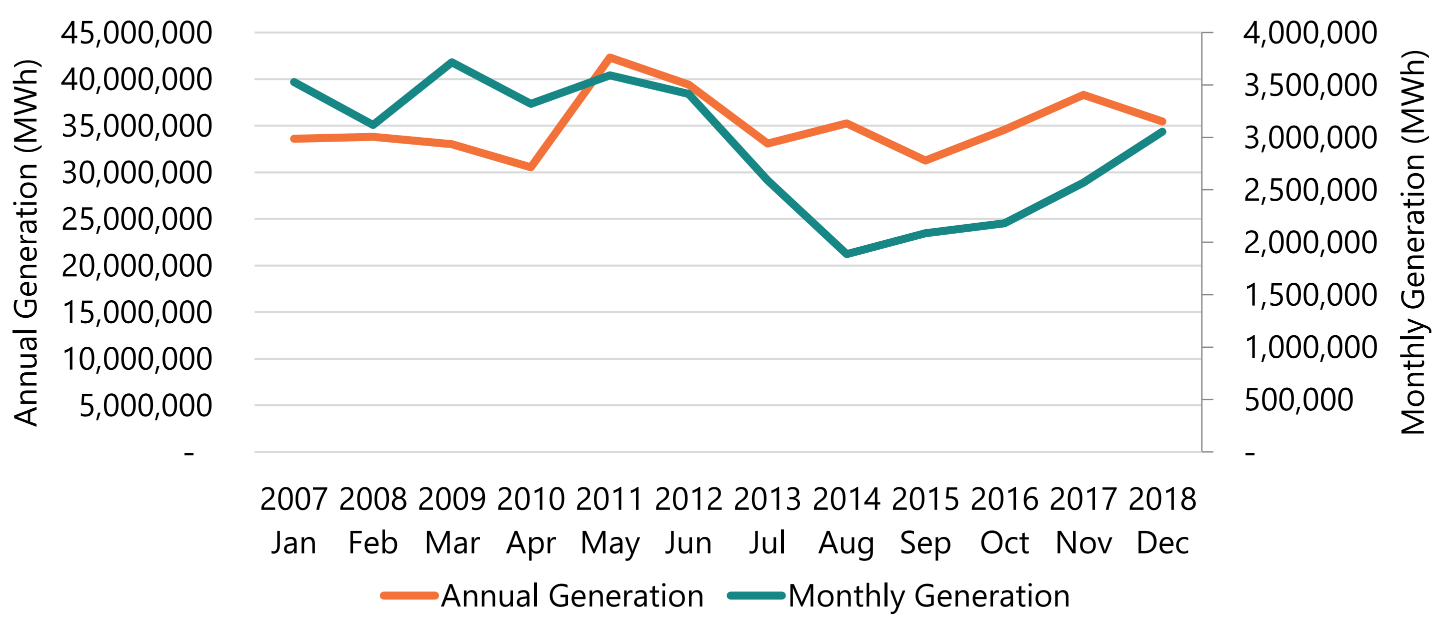
[i] The 94 facilities include 7 dams that span Oregon's border with neighboring states. Six of these dams serve customers in multiple states, but the dams are attributed solely to Oregon by the USDOE Energy Information Administration.

The majority of hydropower capacity (6,514 MW) in Oregon comes from 13 federal dams operated by the US Army Corps of Engineers and marketed by the Bonneville Power Administration (BPA), including nine that are wholly within Oregon and four facilities that span the Oregon and Washington border.[6] Four of these federal dams on the Columbia River, Bonneville, John Day, McNary, and The Dalles generated almost 27,000,000 MWh in 2018 accounting for 76 percent of Oregon hydropower generation.[ii] One additional federal facility, the 17 MW Green Springs facility is operated by the US Bureau of Reclamation. Investor-owned utilities operate a further 28 facilities with over 1,499 MW capacity, including two facilities owned by Idaho Power that border Oregon and Idaho[iii].[7] Independent power producers or consumer-owned utilities like the Eugene Water and Electric Board (EWEB) own the remaining 52 facilities that have a combined capacity of 273 MW, including one facility owned by Northern Wasco County People's Utility District at the Dalles Dam that borders Washington and Oregon; 26 of these facilities are under 1MW.[8]

Consumer-owned utilities including electric cooperatives, peoples' utility districts, and municipal utilities have a legal right of first refusal to purchase federal power at cost (which is called "preference").[9] The 39 consumer-owned utilities serving Oregonians largely rely on hydropower from BPA for a majority of their power, with most of them (referred to as full requirements customers) obtaining 100 percent of the power they sell to customers from BPA. These utilities have some of the lowest retail power rates in the country. Oregon's IOUs also deliver hydropower to their customers and to the wholesale market.

Oregon's hydropower capacity has not changed substantially in the past fifty years, with a majority of hydropower capacity developed before 1970.[10] As shown in Figure 2, hydropower generation varies annually, as well as seasonally within the year, largely due to changes in annual precipitation levels.

Figure 2: Oregon Annual and Monthly Average Hydropower Generation by Year



[ii] The EIA attributes all generation from these four federal dams to Oregon even though they border both Washington and Oregon. Not all electricity generated from these dams serves Oregon consumers.

[iii] A third dam, the Brownlee Dam, a 585.4 MW facility, borders Oregon and Idaho on the Snake River. EIA and the owner Idaho Power attribute all generation from this facility to Idaho so it is not included in the Oregon count of facilities.

Hydropower has been a primary source of electricity generation in Oregon for over a century. While no new large-scale hydropower projects have been developed for several decades, efficiency upgrades to existing hydroelectric plants continue to increase the generation of existing projects. New applications of hydropower technology, such as "micro-hydro" projects like in-pipe conduit turbines, are also being deployed. Hydropower can play an important role in integrating more solar and wind energy in Oregon as it is a stable and flexible power source that can be ramped up and down quickly and at low cost. This can help balance the variability of those other renewable resources. Although the resource is considered renewable, most generation from projects built before 1995 – often called "legacy hydro" – are not eligible for participation in the Oregon Renewable Portfolio Standard; only the incremental increase in generation attributable to efficiency upgrades can be used by utilities to meet renewable portfolio standard obligations.[11]

Non-Energy Implications

Hydropower is a carbon free renewable resource with a low lifecycle carbon footprint, with embedded greenhouse gas emissions from processes over the facility's lifecycle such as raw materials extraction, construction, and small ongoing emissions from operations.

Hydropower facilities provide significant benefits beyond zero emission electricity generation including: flood control, navigation, irrigation, and water supply, as well as providing recreational opportunities.[12] Local economic benefits from hydroelectric facilities come in the form of increased tax revenues and jobs.

Hydropower facilities have negative environmental impacts, including: changing stream flow and temperature which can negatively affect fish and wildlife habitat; altering sediment and nutrient regimens; and affecting the ability of anadromous fish to migrate from the river to the ocean and back.[13] Construction of dams inundates upriver land, potentially damaging cultural resources and agricultural lands. Operations of the dams also change natural water levels throughout the year.[14]

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Technology Review: Conduit Hydropower

• Total Capacity in Oregon:	35 MW (estimate)
• Facilities in Oregon (sized 10 kW to 5 MW)	25-30 (estimate)
• Generation and Consumption Data	Not Available

Conduit hydropower[1] refers to electricity generating systems that are incorporated into an existing diversion from a river or stream where the diversion is for a purpose other than generating electricity, such as watering crops or providing drinking water. The addition of generating capacity does not affect the delivery of water for the primary purpose. Conduit hydropower is distinguished from both impoundment systems, which rely on a dam and often a reservoir, and run-of-the-river systems in which a portion of a river's flow is diverted into a separate channel and run through a turbine before being returned to the river again. Because conduit generation systems are small relative to traditional hydropower generation resources such as the Columbia River dams, they are often grouped with other small impoundment and run-of-the-river systems under the term "micro hydropower."

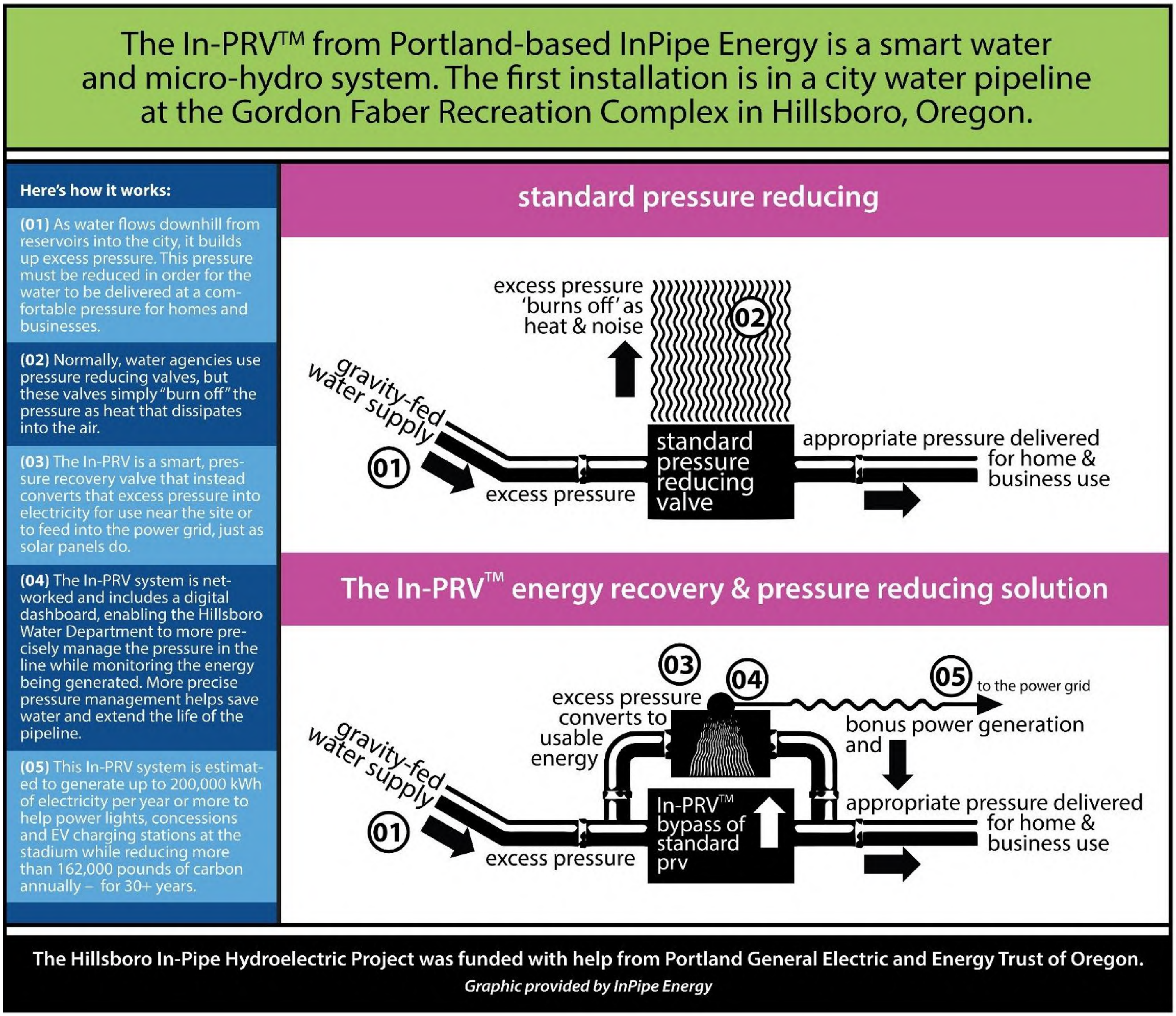
Adding conduit hydropower is relatively straightforward for piped delivery systems that already use pressure-release valves to step down the pressure as water gets closer to its final delivery point. Routing water flow through turbines rather than pressure-release valves in order to generate electricity can be an attractive option for both municipal drinking water systems whose water originates at a higher elevation than where it is delivered, and for farmers who receive piped water from an irrigation district and need to reduce the pressure of the water before it enters their irrigation systems.

Alternatively, conduit hydropower can be part of a more complicated system design or redesign. For example, irrigation modernization projects in Oregon may include the installation of several elements: fish screens, piping to replace existing irrigation canals or ditches, irrigation pivots to replace flood irrigation at the farm level, and turbines for generating electricity both at the irrigation district level and the farm level.

Trends and Potential in Oregon

Conduit hydropower uses existing, well-developed technologies, and has been developed or is under consideration in many locations around the state, including at municipal water facilities and as part of several irrigation modernization projects. Due to Oregon's geography, many irrigation districts and municipal water districts rely on mountain-fed rivers and streams. Therefore, many of these districts have the potential to generate energy by taking advantage of pressurization as water moves from higher elevations within their existing water delivery infrastructure, with additional engineering sometimes needed for districts with significant seasonal and daily variations in flow. As municipalities pursue climate and clean energy goals, interest is growing in exploring opportunities to install energy generation at locations where water districts currently use pressure release valves.

Figure 1: In October 2020, Hillsboro, Oregon celebrated its first electricity-generating water pipeline.[2]



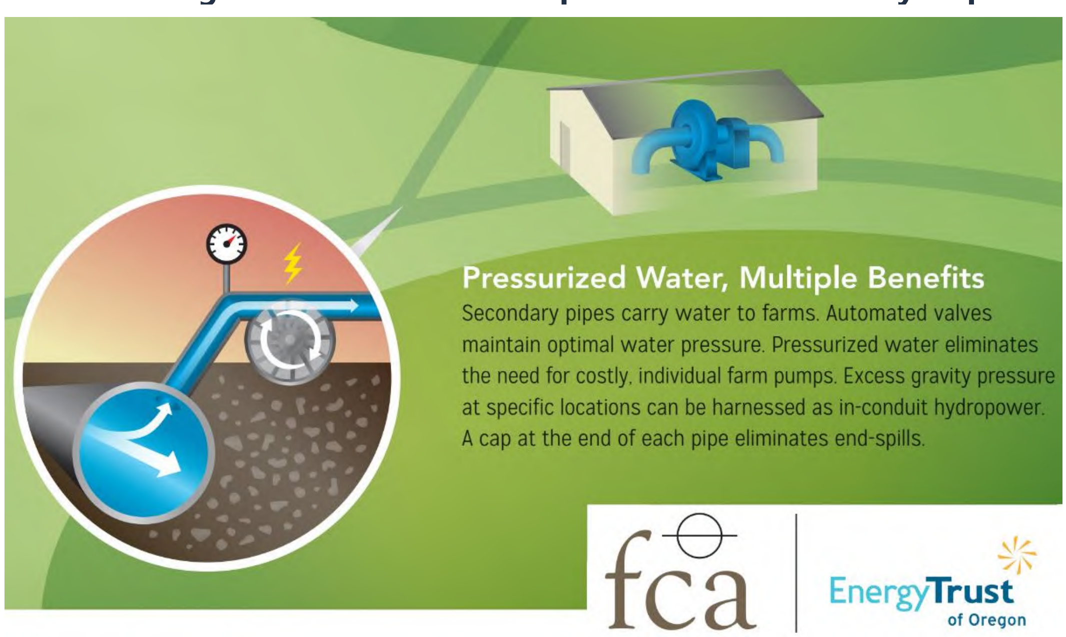
Generating electricity is a secondary benefit, not the primary driver, for irrigation modernization projects; rather, the priorities center around water: increasing stream flows, improving water quality, and ensuring that farmers receive water allocations throughout the growing season. Irrigation modernization projects are complex: they have multiple goals, include multiple components and typically happen in stages over several years; they involve multiple stakeholders, funders, and funding mechanisms; they are expensive due to the scale of the infrastructure involved; and they offer several economic, environmental and social benefits. Farmers Conservation Alliance, a non-governmental organization based in Hood River, has been working with irrigation districts on modernization projects for several years and has developed a strategy for bringing together a variety of stakeholders and funders to plan and help fund these projects.[3]

While the generation potential for conduit hydropower is modest compared to utility-scale generation facilities, irrigation modernization projects save energy on the farm by delivering pressurized water to farmers and reducing or even eliminating the need for pumps. Energy savings accompany pressurization from piping even when generation turbines are not installed as part of a project; FCA's analysis finds that energy savings for irrigation modernization projects typically exceed the generation potential.[4] Reducing electricity use associated with irrigation pumping could be helpful for rural utilities struggling to meet peak demands during summer heatwaves. Conduit hydropower is mostly located in rural areas and small communities of the state and has the potential to provide pressurized water and electricity when the grid is down, providing resilience benefits to local communities. Finally, conduit hydropower generation has few if any negative environmental impacts, as this form of generation causes no greenhouse gas emissions and irrigation modernization reduces energy use for pumping, which reduces emissions. Piping irrigation canals does not involve new water diversions or impoundments that block fish passage or negatively affect habitat.

Opportunities

Many of Oregon's irrigation districts are in some stage of implementing district-wide modernization projects; 25 Oregon irrigation districts are currently participating in Farmers Conservation Alliance's Irrigation Modernization Program. In a recent evaluation of 15 participating districts, FCA found that fully piping and pressurizing their systems would add 32 MW of electricity generation, in addition to generation capacity that is already installed in several districts. FCA's analysis found 101 potential hydroelectric sites across these 15 districts, 68 of which are under 100kW in size.[5] Oregon is one of a handful of states where a local entity has assessed the undeveloped resource potential for conduit hydropower, along with California, Colorado, and Massachusetts. According to the U.S. Department of Energy, a broad assessment of conduit hydropower opportunities is "difficult to perform because of the highly individual nature of each project."[6]

Figure 2: Energy Trust of Oregon and Farmers Conservation Alliance Illustrate Irrigation Modernization Option for In-Conduit Hydropower



Energy Trust of Oregon works closely with both municipal water districts and irrigation districts on conduit hydropower projects. As part of a partnership with Farmers Conservation Alliance, Energy Trust provides technical and financial support for irrigation modernization projects in order to leverage other funding sources. Energy Trust has designated irrigation hydropower as one of its focus areas under non-solar renewable energy, spending over $1.7 million to support 19 irrigation hydropower projects in 2019.[7]

A variety of state, federal, and non-governmental entities also provide funding to assist with irrigation modernization projects that include conduit hydropower. For example, the USDA Natural Resources Conservation Service is currently supporting irrigation modernization projects in Wallowa and Deschutes counties under the Regional Conservation Partnership Program,[8] and the 2019 Oregon Legislative Assembly appropriated funds for the Wallowa Lake Dam project.[9]

Barriers

Piping irrigation canals, which makes conduit hydropower possible for irrigation districts, is complex and expensive. Generation costs for conduit hydropower are often higher than the cost of other renewable energy resources, or of the cost of incumbent generation technologies. The avoided cost prices in power purchase agreements under the Public Utility Regulatory Policies Act (see Chapter 3 of ODOE's 2018 *Biennial Energy Report* for more information about PURPA) have decreased over time, which in turn decreases the amount of revenue for municipal water and irrigation districts wishing to sell power to an electric utility. Avoided costs do not take into account the energy resilience benefits, or non-energy conservation and economic development benefits to local communities.[10] [11] Many potential conduit hydropower projects are in remote locations, which means that additional transmission investments are often needed to interconnect to the utility grid. Additionally, projects located within consumer-owned utility service territories will need to pay wheeling charges if they wish to sell the electricity to an investor-owned utility. Costs associated with transmission, interconnection, and wheeling charges challenge the economic feasibility of many conduit hydropower projects.

See Energy 101 section for more about transmission and wheeling charges.

Energy generation is not the primary business for the entities who own the existing water infrastructure, which means a water or irrigation district may not recognize opportunities in their system or will need to hire external expertise to assist with hydropower system design and the electrical grid interconnection process. Conduit hydropower projects are much more common in Europe and Asia than in the U.S., and although Oregon is in the forefront of states working on irrigation modernization, in the case of water districts there are relatively few existing installations to use as examples.[12] While municipal water system conduit projects can achieve a positive net present value, in some cases the pay-back periods may be too long to compete successfully with other demands for scarce local government funds.[13]

Non-Energy Implications

For irrigation districts, conduit hydropower is often part of larger infrastructure projects that districts pursue primarily for other reasons, such as keeping more water in the stream to enhance or protect habitat for aquatic species or to improve the district's ability to deliver water to all of its members in low water years. Many irrigation districts in Oregon rely on aging infrastructure like open canals or ditches, which are vulnerable to water loss through evaporation and seepage, or to contamination from trash or animal waste. Piping irrigation canals can improve water quality both in-stream and on-farm for the farmers receiving piped water. On the other hand, replacing irrigation canals with buried pipes has been controversial in some communities which regard irrigation canals as scenic amenities. Switching from flood irrigation to pivots can cause changes to local hydrology by reducing or shifting the runoff that flows off one farmer's fields to another's fields, or into streams or aquifers.[14]

Conduit hydropower generation, whether installed in a drinking water system or as part of irrigation modernization, can produce more electricity than is needed on site. Power sales can provide a revenue stream that enables additional system improvements.[15] The energy savings and habitat improvements associated with irrigation modernization projects also provide economic benefits for the local community. By pressurizing the water that arrives on-farm, these projects reduce on-farm energy expenditures, which enables farm businesses to make investments to expand or improve their operations and helps to make farm businesses more economically sustainable for current and future generations. Proponents of irrigation modernization projects tout the potential benefits to the community from improving outdoor recreational opportunities on local streams and rivers.

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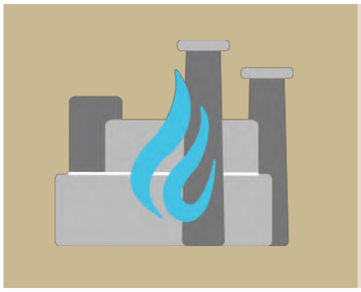
Resource Review: Natural Gas



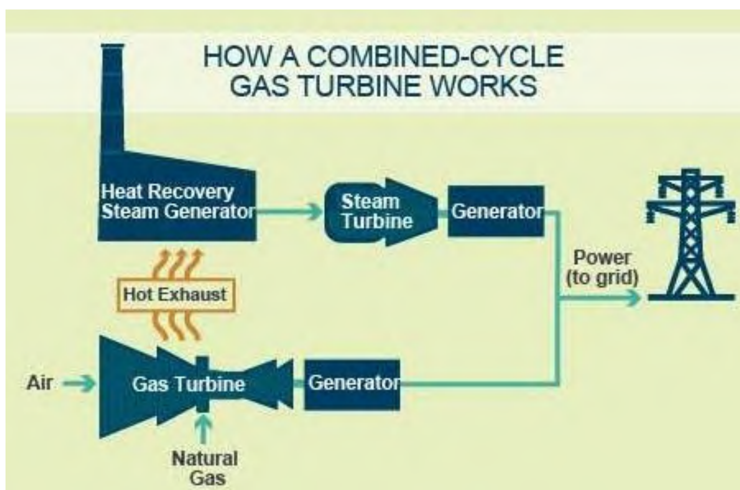
- Total Capacity in Oregon: 4,140 MW
- Facilities in Oregon (6.5 to 689 MW): 18
- Total Generation (2018): 17,922,777 MWh
- Total Consumption (2018): 10,876,934 MWh
- Total Exports (2018): 7,045,842 MWh

Natural gas is a versatile fossil fuel resource that can be used for generating electricity, heating residential spaces and water, cooking, transportation, and commercial and industrial processes. Technology advancements have led to increased production of natural gas, particularly from shale gas, and lower natural gas prices, which in turn has led to more natural gas electricity generation.[1] In 2019 in the United States, natural gas made up 32 percent of all energy use and 38 percent of all electricity generation, making it the most-used resource or fuel for electricity production.[2] In Oregon, natural gas is second to hydropower in electricity generated. In electricity consumed, natural gas is third to hydropower and coal because of natural gas electricity exports and coal-based electricity imports.[3]

Natural gas power plants combust natural gas to generate electricity. There are two main types of natural gas power plants: simple cycle combustion turbine plants and combined cycle combustion turbine plants.

Simple cycle combustion turbine plants are like jet engines — they combust natural gas under pressure forcing very high-temperature, high-pressure gas into a turbine, which spins to generate electricity; waste heat is expelled.[4] They operate with thermal efficiencies (the percent of fuel converted to electricity compared to what is released as heat waste) between 15 and 42 percent.[5]

Figure 1: How a Combined-Cycle Gas Turbine Works[6]



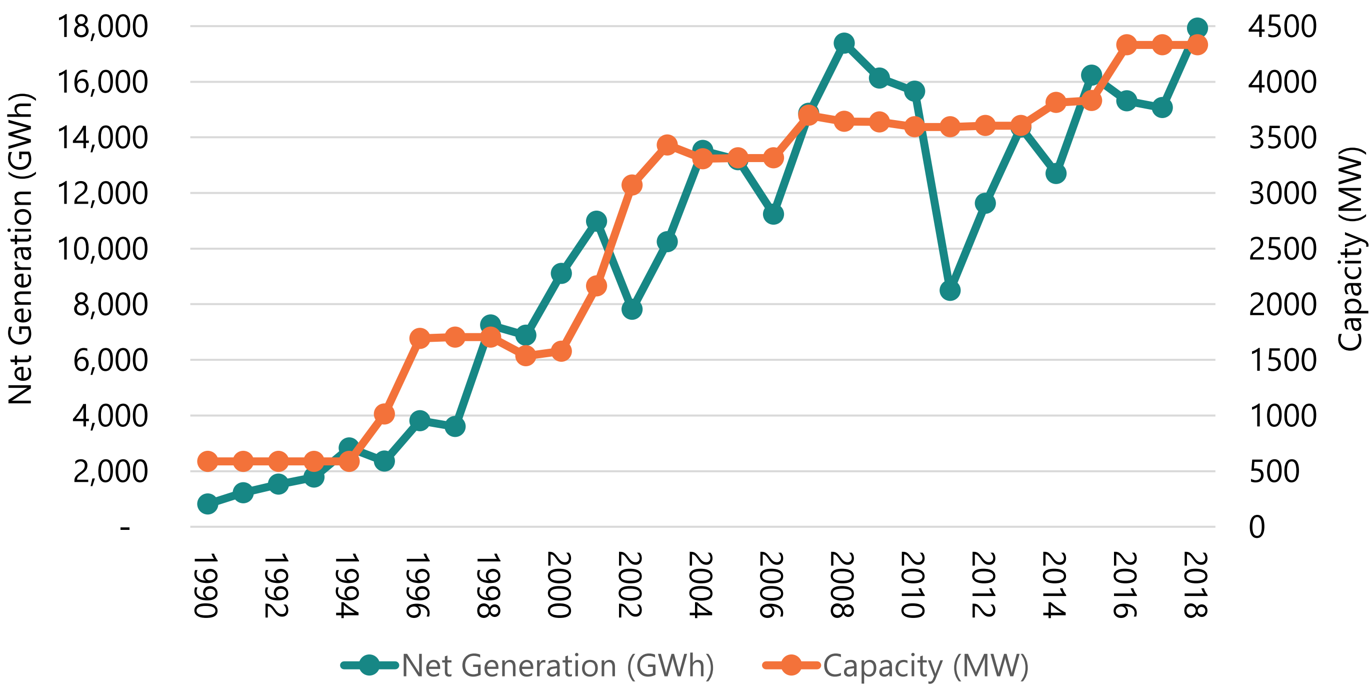
Combined cycle combustion turbine plants use a simple cycle combustion turbine for the first electricity generation cycle, but then capture the waste heat to drive a steam turbine to generate electricity in a second cycle.[7] Combined cycles operate with thermal efficiencies of 38 to 60 percent.[8] While simple cycles are less efficient, they are less expensive to build relative to other fossil generation resources and can be started and stopped quickly, making them more flexible.[9] Simple cycle combustion turbine plants are often referred to as "peaker plants" because they are used to serve peak electricity demand needs. Combined cycles are more efficient but also more capital intensive and take longer to start and stop, making them more likely to produce ongoing steady electricity that meets the baseload demand needs of the electricity system. Natural gas power plants may also use heat recovered from combustion for heating or industrial processes.

Oregon imports almost all the natural gas it uses. The Mist field in northwestern Oregon is the state's only natural gas field, and it produces a small amount of Oregon's usage (less than 500 million cubic feet of natural gas in 2018 or around two-tenths of 1 percent).[10] The rest of Oregon's natural gas comes through inter-state pipelines primarily from western Canada through Washington and from Nevada and Idaho.[11] In 2018, Oregon used 256 billion cubic feet of natural gas; 48 percent went to electricity generation.[12]

Trends and Potential in Oregon

In 2018, natural gas-based electricity made up 28 percent of Oregon's electricity generation and 21 percent of Oregon's energy consumption. [13] Generating capacity has grown substantially in the past two decades, with capacity almost tripling from 2000 to 2018.[14] Net generation has grown proportional to capacity but fluctuates from year to year. This is typically due to variations in annual hydropower generation; when hydropower generation is high, natural gas generation is lower and when hydropower is low, natural gas generation is higher.[15] This relationship highlights the flexible nature of natural gas electricity generation, which can serve as baseload for constant electricity supply, or as a flexible generator that can be turned on and off to meet fluctuating electricity consumption (load following) to balance the integration of variable renewable resources. Across the fleet of 18 generating facilities in Oregon, five facilities accounting for 954 MW capacity run as "peakers," operating less than 15 percent of the time on average in 2018. Nine facilities accounting for 3,149 MW ran as baseload, operating around 60 percent or more of the time on average in 2018. Three facilities generated electricity for industrial onsite consumption only and one facility did not generate electricity in 2018.[16] Because of the flexible nature of natural gas, it is often the fuel that supplies the last unit of electricity in a given hour; the marginal, price-setting resource.[i] [17]

Figure 2: Oregon Natural Gas Net Generation and Capacity by Year



[i] The marginal resource can vary, and in some hours may be renewables like hydropower, wind, or solar.

Natural gas electricity generation is likely to continue to be an important part of the electricity resource mix, especially as less efficient and higher emission coal plants are retired in the region.[18] Natural gas may also have an important role in facilitating higher levels of variable renewable resources on the grid as it can provide flexible, cost effective generation at times when renewable electricity cannot meet load. A recent study of low-carbon electricity scenarios suggested that natural gas generation may be key to meeting GHG emissions reductions goals "reliably and at least cost."[19]

In the Western Electricity Coordinating Council region of the northwest U.S., between 2020 and 2027, there are 15 proposed natural gas projects totaling approximately 6.2 GW of capacity.[20] Eleven of these are planned in California and Arizona, with two in Utah, one in New Mexico, and one in Oregon – the 415 MW Perennial Wind Chaser Station, a "peaker" plant that received a State site certificate and has started construction in Umatilla County for completion by 2023. Approximately half of this future capacity is for "peaker" plants (including Perennial Wind), and the rest are combined cycle combustion turbine baseload plants.

Non-Energy Implications

Natural gas is a fossil fuel made up primarily of methane, and its combustion for electricity or other uses results in greenhouse gas emissions. Carbon dioxide is the main pollutant associated with burning natural gas to produce energy; natural gas emits, on average, approximately 50-60 percent of the emissions associated with coal combustion.[21] Natural gas is methane, which is also a powerful GHG. Natural gas extraction, storage, and transportation can result in methane leaks (fugitive methane), which account for approximately 32 percent of U.S. methane emissions and about 4 percent of U.S. GHG emissions.[22] Natural gas companies in Oregon have taken measures to reduce fugitive emissions of methane, such as lining pipes and implementing monitoring and controls that reduce these emissions.[23]

Extraction of natural gas, including hydraulic fracturing (fracking) to access natural gas in shale formations, has additional environmental and public health impacts.[24] Hydraulic fracturing in particular consumes substantial amounts of fresh water, and can lead to induced seismic activity, ground and surface water contamination, and can have negative effects on air quality and land use.[25] Hydraulic fracturing can also produce materials contaminated with technologically enhanced naturally occurring radioactive materials.[26] Transportation of natural gas mostly occurs through pipelines, which can have land use impacts including disturbing sensitive environments, affecting waterways, and causing habitat fragmentation.[27]

Natural gas transportation, distribution, and electricity generation can have positive economic impacts in Oregon. Development of natural gas electricity generation projects and associated natural gas transportation pipelines can lead to increased employment and economic activity. In addition, as described above, natural gas generation can play an important role in supporting the integration of variable renewable resources and could play a near-term role in decarbonizing our economy.

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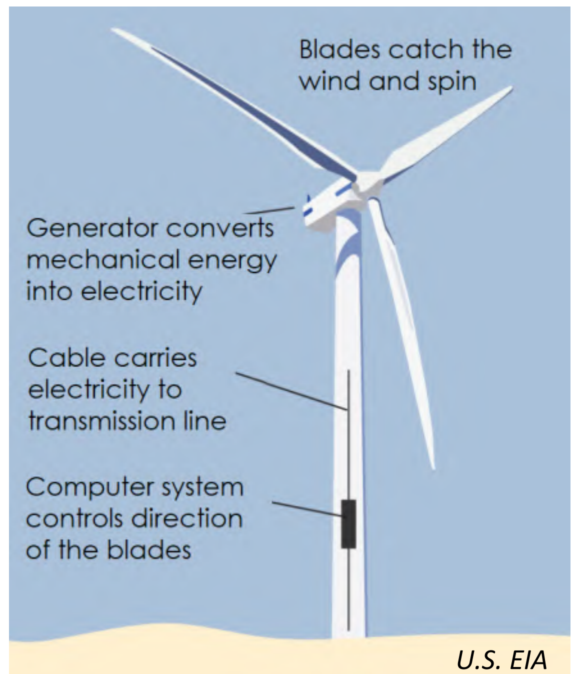
Resource Review: Wind Power

- Total MW Capacity in Oregon: 3,415 MW
- Facilities in Oregon (1.65 to 290 MW): 46 (3 under construction)
- Total Generation (2018): 7,447,442 MWh
- Total Consumption (2018): 2,396,878 MWh
- Total Exports (2018): 5,050,564 MWh

Wind turbine blades capture the wind's motion and transform that mechanical energy into electricity.[1] The average individual utility-scale wind turbine in Oregon has a capacity of 1.75 MW, with the largest at 3.6 MW.[2] While there are currently none in Oregon, offshore wind turbines use the same principle, but are sited off the coast where wind resources tend to be stronger and more constant.[3] Most offshore wind farms are in shallow waters where turbines are directly fixed to the seabed (fixed-bottom turbines).[4] Floating wind turbine farms that can take advantage of better wind resources in deeper waters are producing electricity in places like Portugal and Scotland.[5]

Figure 1: Horizontal-axis Wind Turbine[6]



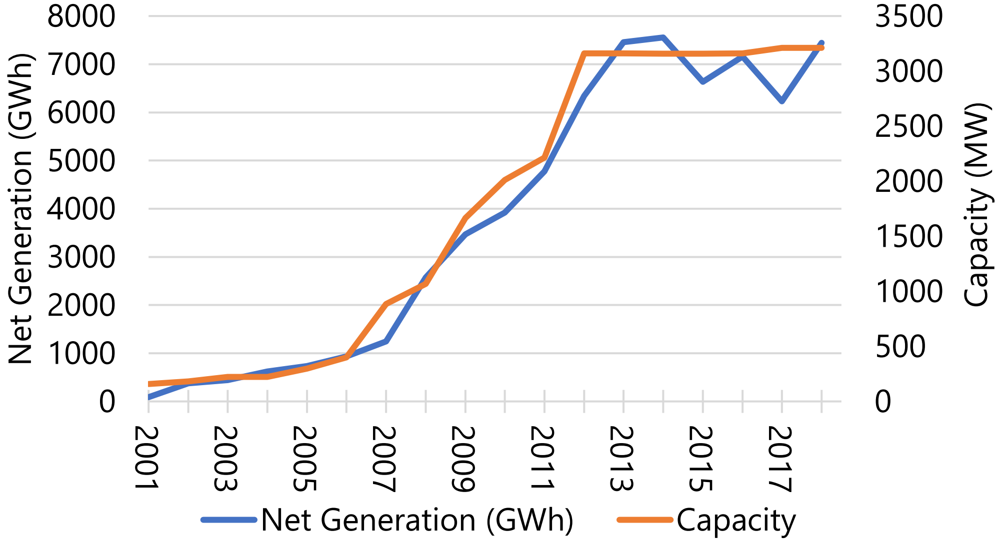
Trends and Potential in Oregon

Onshore wind is the second-largest zero carbon-emitting electricity resource in Oregon next to hydropower. Wind power makes up 11.6 percent of Oregon's electricity generation and 4.69 percent of Oregon's energy consumption.[7] Oregon wind capacity has grown substantially since construction of the state's first wind facility in 2001. With 3,415 MW of wind generation, Oregon is ninth nationally in terms of overall wind capacity and third among the 14 U.S. states in the Western Electricity Coordinating Council,[8] behind California and Colorado.[9] Most wind generation projects are large, utility-scale projects ranging in size from 1.6 MW to 300 MW.[10]

As of October 1, 2020, there are 46 existing wind farms and four state jurisdictional facilities under construction in Oregon totaling an additional 894 MW, with an additional 550 MW of wind projects approved or in review.[11] Developers are also upgrading turbines at many older facilities, a process called repowering. Repowering involves full or partial upgrades that can either increase maximum generation capacity, increase generation efficiency allowing turbines to generate more electricity per hour at given wind speeds, or both.[12] Oregon has approved repowering of four facilities to date.[13] The approved projects replace turbine components to increase turbine generation efficiency, but do not replace generators to increase maximum capacity.[14]

The majority (76 percent) of existing and planned wind utility-scale generation in Oregon lies on the Columbia River Plateau in Wasco, Sherman, Gilliam, Morrow, and Umatilla counties, with a few developments in Eastern Oregon. Development occurs in these regions due to the rich wind resources along the Gorge, as well as access to existing transmission infrastructure and capacity. Wind generation also varies depending on when the wind is blowing. Seasonally in Oregon, wind generates at its highest capacity during the spring and early summer months, with lowest generation capacity in the fall and winter.[15] During the day, wind generation in Oregon is at its highest in the evening.[16]

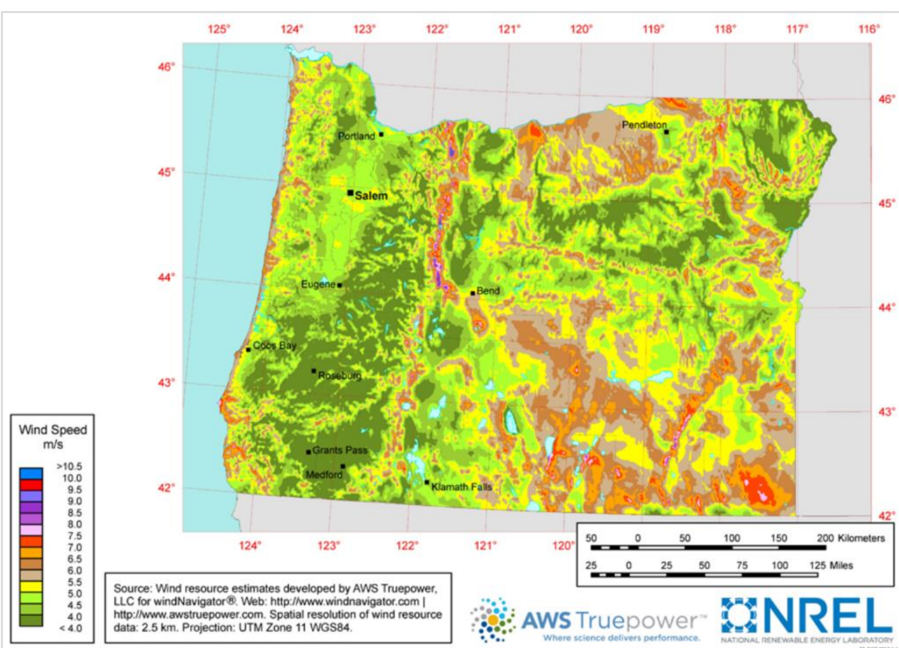
Figure 2: Wind Net Generation and Capacity in Oregon by Year[10]



Onshore Wind Potential

Despite significant wind development in the Columbia River Plateau, there are still substantial untapped wind resources in Oregon. A 2012 National Renewable Energy Laboratory (NREL) study indicates Oregon has technical potential for 27 GW of onshore wind power[i].[17] Much of this technical potential along the Cascades and in Southeastern Oregon is undeveloped due to challenges finding sites for projects and transmission corridors that meet the requirements to limit environmental effects from wind projects on sensitive environments and communities. Also, the cost of building transmission lines to link these remote areas to populated areas where electricity is needed, such as the Willamette Valley, is also a factor.[18 19] More potential exists on the Columbia River Plateau, but a high concentration of projects producing electricity at the same

Figure 3: Oregon Annual Average Wind Speed at 80 m



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[i] The Oregon Renewable Energy Siting Assessment project, funded by the U.S. Department of Defense and led by the Oregon Department of Energy, is due for completion in 2021, will provide additional insight into Oregon wind energy potential. https://www.oregon.gov/energy/energy-oregon/Pages/ORESA.aspx

time in the same geographic region can present challenges for grid integration and project economics; there is limited capacity on transmission lines and projects may not be able to sell the electricity they are producing or may get prices for electricity that are too low for a project to be economically viable.[20]

Offshore Wind Potential

Offshore wind is a rapidly growing resource, globally. Technological innovation, falling costs, and growing support from the public and private sectors have driven growth of global installed offshore wind capacity from 3 GW in 2010 to 29 GW in 2019.[21] While the United States has only one operational facility, the 30 MW Block Island Wind Farm in Rhode Island, NREL estimates the offshore wind project pipeline at 25.8 GW thanks to recent market activity and state procurement policies.[22] Oregon has some of the richest offshore wind resources in the nation, particularly off the Southern Coast, with an estimated technical potential of 62 GW.[23] While offshore wind holds significant technical potential, there are challenges to overcome. In addition to federal and state regulatory requirements, environmental concerns, transmission constraints, and concerns about effects on important economic and cultural activities, much of Oregon's potential is in waters deeper than 60 meters (197 feet), requiring floating turbine technology that is costly (additional discussion of these issues is provided in the offshore wind Policy Brief).[24]

Non-Energy Implications

Wind is a zero-carbon emitting resource with a low lifecycle carbon footprint. Minimal greenhouse gas emissions are associated with the product lifecycle, from raw materials extraction to decommissioning.[25] [26] Wind turbines can impact flora and fauna – in particular birds and bats can collide with wind turbine blades – however, newer designs have reduced collisions and fatalities.[27] Wind turbines can be more than 600 feet tall and can have a visual impact on the landscape. Wind turbines take up land, but Oregon has requirements to protect wildlife and agriculture, and developers often site projects in dryland agricultural areas that allow for farming to continue up to and around turbines.[28] In addition, transmission lines from facilities can similarly disturb sensitive environments, affect waterways, and cause habitat fragmentation.

Wind energy contributes significantly to the state and local economies. Wind projects generate property tax revenue for counties and additional revenue streams for landowners or farmers. Wind projects can take advantage of the Strategic Investment Program, which provides economic benefits to local communities. Wind energy projects also provide employment for over 1,000 Oregonians. [29] The average annual wage of a wind technician, one of the more common wind related jobs, is $52,910.[30] Oregon has several notable workforce preparation programs related to wind energy, such as the Columbia Gorge Community College Electro-Mechanical Technology program, that successfully prepare people for many of these jobs.[31]

Energy Jobs: The average annual wage of a wind technician is $52,910.

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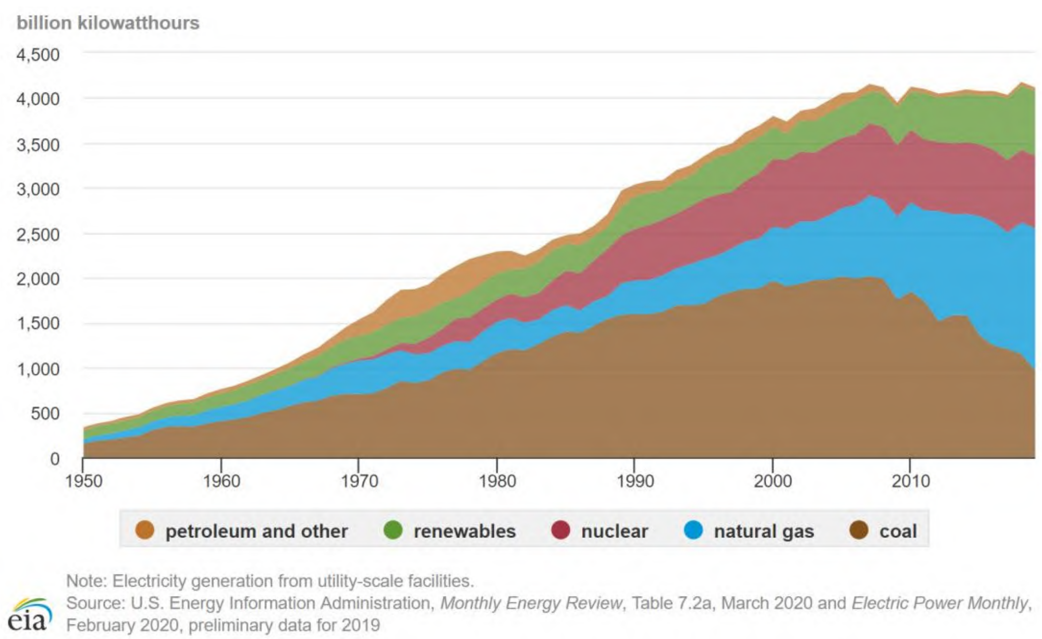
Resource Review: Coal

- Total Capacity in Oregon: 0 MW*
- Facilities in Oregon: 0*
- Total Generation (2018): 1,476,244 MWh
- Total Consumption (2018): 12,681,244 MWh
- Total Imports (2018): 11,204,853 MWh

**The 575-megawatt Boardman Coal Plant, which was Oregon's only coal plant, closed in October 2020.*

Coal is a fossil resource that has long been a primary fuel for electricity and industrial processes. In 2018, the electricity sector used 93 percent of coal consumed in the United States, and industrial processes used the remaining 7 percent.[1] While coal remains a major source of energy and electricity in the United States, coal use has fallen substantially in both the electricity and industrial sectors. In the electricity sector, coal has fallen from 48 percent of generation in 2008 to 27 percent of generation in 2018,[2] largely due to more available lower-cost natural gas and renewable electricity generation. In Oregon, coal is third behind hydropower and natural gas in electricity used, and fourth behind hydropower, natural gas, and wind in electricity generated.[3]

Figure 1: U.S. Electricity Generation by Major Energy Source, 1950-2019



To produce electricity, coal power plants burn coal to create steam that drives electricity-generating turbines. Coal is also used in industrial processes, primarily as heating sources for non-metallic mineral production (cement, glass, and ceramics) and food processing.[4] Coal can also be converted into gas or liquids for use as fuel, these fuels are known as synthetic fuels or "synfuels."[5] The Great Plains Synfuels Plant in North Dakota is the only commercial-scale facility making synthetic gas from coal; there are no commercial facilities producing liquid synfuel.[6] In the Western U.S., coal power plants range in size from 11 to 856 MW.

Coal mining occurs in 23 states, but five states account for over 70 percent of production: Wyoming, West Virginia, Pennsylvania, Illinois, and Kentucky.[7] Wyoming accounts for 40 percent of national coal production and is where the majority of coal used for electricity consumption in Oregon is mined. In many instances the mined coal must be transported around the country to be used as fuel in coal plants. Some plants, such as Montana's Colstrip, are purposely located near their coal fuel resource to reduce the costs of fuel transportation.

Trends and Potential in Oregon

The Boardman Coal Plant in Oregon, which began operating in 1980, is the only coal-fired power plant to have operated in Oregon. The owner of the plant, Portland General Electric, closed the plant on October 15, 2020.[8] The Boardman Coal Plant had capacity of 575[i] MW,[9] and in 2018 accounted for 2.3 percent of Oregon's electricity generation and 12 percent of the total coal-generated electricity used in Oregon.[10] The remaining 88 percent of coal electricity Oregonians use is imported from other states, and imports will continue to serve Oregon's electricity needs until 2030.[ii] Coal accounts for approximately 25 percent of Oregon's electricity consumption.[11]

PGE's Boardman Coal Plant closed on October 15, 2020.

In 2016, the Oregon Legislature passed the "Clean Electricity and Coal Transition" bill (SB 1547), which prohibits utilities in Oregon from charging their customers for coal-generated electricity through rates by 2030.[12] This will lead to the removal of the majority of electricity generated using coal from Oregon's electricity resource mix. However, some coal fuel may persist in the overall state electricity mix because SB 1547 did not exclude spot market purchases.[iii] In 2018, regional market purchases of coal accounted for approximately 4 percent of total electricity consumed in Oregon.[13] The electricity market nation-wide is also seeing a decline in coal generation as more coal plants retire due to concerns about climate impacts and difficulty competing against lower-cost natural gas and renewable electricity sources. Along with increasing retirements, currently there are no new coal plants planned for construction in the U.S. – the last planned facility, Plant Washington in Georgia, was cancelled in April 2020.[14]

Non-Energy Implications

Coal mining and consumption have well-documented, adverse effects on the environment and public health. While there is no coal mined in Oregon, underground and surface coal mining in other states can have serious effects on the surrounding environment.[15] Combustion of coal results in emissions that can affect human and environmental health. Coal is the United States' leading emitter of greenhouse gases from electricity generation, primarily carbon dioxide.[16] Coal combustion also emits

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[i] Reported capacity values for the Boardman plant vary depending on the source. USDOE's Energy Information Administration lists 642 MW, the Northwest Power and Conservation Council lists 601 MW, Oregon's Energy Facility Siting Council lists 550 MW, and PGE lists 575 MW.

[ii] With one exception that would enable rate-basing costs for up to five years after the plant has fully depreciated. This would apply exclusively to Colstrip plant in Montana

[iii] Spot market purchases are the procurement of electricity very near to the time it is needed. This can be within 15 minutes of delivery of the electricity up to a day ahead.

particulate matter and pollutants like mercury, sulfur dioxide, and nitrogen oxides which can cause acid rain, leach into soil and water, and have serious health impacts.[17] Coal power plants are disproportionately located near low-income communities and communities of color, so these impacts are felt most by vulnerable communities.[18]

Reduced use of coal and closure of coal plants will have economic costs and benefits. In some regions, coal retirements may affect electricity prices, but with competitive alternatives like natural gas and renewables, the magnitude and direction of the change is uncertain and coal plant closures may lead to reduced electricity prices and rates.[19] Some local economies may see reduced employment and loss of tax revenues from plant closures. Utilities and local governments, as well as regulators and planners, are working to mitigate these impacts and identify new opportunities. For example, in the ten years prior to the October 2020 closure of the Boardman Generating Station, PGE worked with a wide range of stakeholders to plan for the closure and reduce the local economic impacts. The utility has worked with plant employees to assist with their transition to new positions within PGE or elsewhere. Boardman's closure has been factored into PGE's resource planning since 2010 so the company could take steps to ensure reliable electric service to customers after the plant's shutdown.[20]

Oregon CUB: Reflecting on the Boardman Coal Plant Closure

The Oregon Citizens' Utility Board (CUB) was created in 1984 by ballot initiative to advocate on behalf of the residential customers of investor-owned utilities in Oregon. Like many other discussions that affect Oregon ratepayers, CUB was at the table in 2008 when Portland General Electric was considering the future of its only coal-generated power plant.

The Boardman Coal Plant was facing regional haze retrofit rules – rules designed to reduce haze to background levels in national parks and wilderness areas. Every five years, states have to show they are making reasonable progress toward reducing haze, and facilities like Boardman are required to consider the best available retrofit technology.

PGE considered several avenues, including a $600 million retrofit to meet the haze rule requirements, which would have meant running the plant until at least 2040 to recover its capital costs. CUB shared its concerns that not only would a $600 million retrofit be expensive for ratepayers, it would also mean the state's largest carbon emitter would continue operating for decades longer.

CUB Executive Director Bob Jenks was appointed to an advisory committee to look at the economic effects of the haze rule and how PGE could meet the requirements. An important factor in the haze rule is the life of the plant, and what would be the most cost-effective haze control options over its life. The advisory committee floated an interesting question: if PGE voluntarily closed the plant early, how would that change the dynamics of the haze rule and would it be cost-effective?

PGE modeled closing the plant in 2020, which showed that it was much lower-cost than completing a retrofit and running the plant to 2040. Ultimately, PGE agreed to close its plant early – it was the first time a utility agreed to voluntarily close a coal plant in the United States.

The Oregon Public Utility Commission, Department of Environmental Quality, and Environmental Quality Commission were all highly receptive to making it work and approved the closure to meet haze rule requirements and the least-cost risk to ratepayers. The plant closed in October 2020.

CUB's Bob Jenks reflected on the creativity and collaborative effort among PGE, State of Oregon agencies, and fellow advocacy groups to find the best solution moving forward. "A lot of people were out there pushing to make this change," said Jenks. "It really was a grassroots effort to find the best solution that works for everyone – the utility, its customers, and the environment."

Learn more about Oregon CUB: **https://oregoncub.org/**

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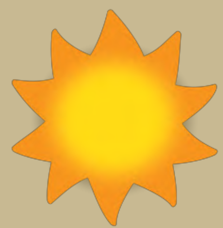
Resource Review: Solar Energy



• Total Capacity in Oregon (2019):[i]	592 MW
• Facilities in Oregon (2019): (1 kW to 56 MW)	18,000+ Residential/Commercial and 77 Utility-Scale
• Total Generation (2018):	776,000 MWh
• In-State Consumption (2018):	680,499 MWh
• Total Exports: (2018):	95,501 MWh

Solar energy is radiant light and heat from the Sun. Solar technologies harness this energy for electricity generation, space and water heating, and other uses. Solar energy is a renewable resource as the energy comes from the sun, however, because sunlight varies depending on location, time of day, season, and weather conditions, it is also an "intermittent" resource. Solar output in the United States more than doubled between 2015 and 2018 from 39 GWh to 93 GWh, and represented 2.23 percent of U.S. electricity generation in 2018.[1]

Solar photovoltaic (PV) cells are the most common technology for generating electricity from solar energy.[2] Solar PV cells absorb photons from sunlight and convert their energy into electric current. PV cells are connected together into panels for installation on rooftops or ground-mounted systems. The average solar panel has between a 200- and 400-watt capacity.[3] Joining panels together creates solar arrays, which can be virtually any size, from less than one kilowatt to hundreds of megawatts or more. The largest solar PV array in the United States is the 579 MW Solar Star facility in Kern County, California.[4] Solar electricity can also be produced by using mirrors to focus sunlight onto a container of fluid, which is then heated and converted to steam to run a generator turbine.[5] These are known as Concentrating Solar Power systems, and are generally used for large utility scale projects. There are no Concentrating Solar Power systems in Oregon.[ii]

Solar PV can provide electricity at different scales for different uses due to its modular nature. Residential solar PV typically consists of independent small arrays installed on home rooftops. Residential solar is usually grid connected and installed "behind-the-meter," meaning the array is on the customer's side of the electricity meter; electricity from the system is used on site with excess electricity passing through the meter to the grid.[6] Solar may also be used to power off-grid homes. The average residential solar array installed in Oregon in 2018 was 6.5 kW.[7]

Learn more about net metering in the Energy 101 section.

Commercial solar PV is also typically "behind-the-meter" but consists of larger arrays to serve the electricity needs of businesses. The average commercial

[i] Residential and commercial capacity is measured in megawatts of direct current (DC) and utility capacity is measured in megawatts of alternating current (AC).

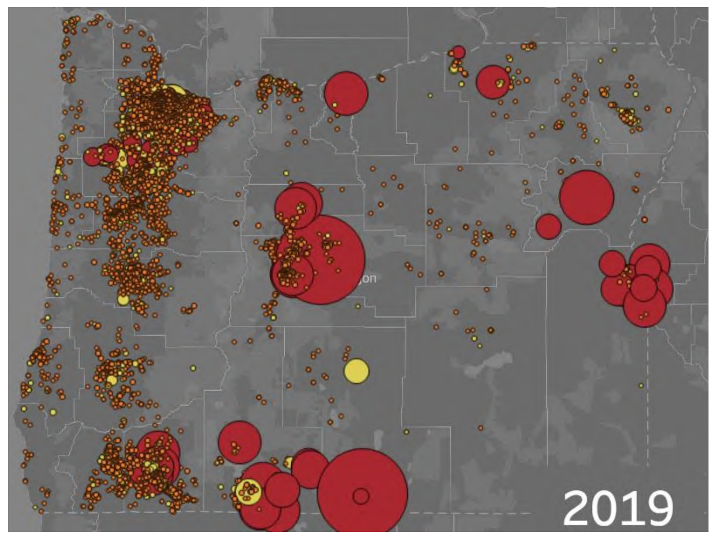
[ii] For more information about solar technologies see the U.S. Department of Energy Solar Technology Office's website: https://www.energy.gov/eere/solar/articles/solar-energy-technology-basics.

solar array installed in Oregon is 28 kW.[8] Utility-scale solar refers to large solar arrays, usually 1 MW or larger, installed to produce electricity for the electricity grid. Utilities and energy service suppliers own or purchase wholesale electricity from these arrays for sale to retail customers. Some large corporations also own or have contracts to purchase electricity from these arrays to serve their own electricity needs. A relatively new model of solar deployment is community solar. Community solar involves utilities, developers, nonprofits or other entities building solar systems that community members have the option to buy or lease part of, and then receive credits on their electric bills for their portion of the energy generated. Community solar provides access to the benefits and costs of solar to people who face barriers to accessing solar in conventional ways, for example due to lack of roof space or funding for upfront capital costs.[9]

Trends and Potential in Oregon

In 2018, utility-scale, commercial, and residential solar generated approximately 776,000 MWh or 1.2 percent of all electricity generated in Oregon (18th among all states). Oregonians consumed approximately 680,500 MWh accounting for 1.3 percent of all electricity consumed in Oregon.[iii] Oregon solar grew over five-fold between 2015 and 2019, with installed capacity growing from 91 MW to 592 MW, and generation increasing from 116,000 MWh to 776,000 MWh.[10] During this period, residential and commercial solar grew at a consistent rate. However, most growth in solar capacity came from utility-scale solar; in 2018 utility-scale solar accounted for 79 percent of solar generation, with commercial solar accounting for 13 percent and residential solar accounting for 8 percent.

Figure 1: Snapshot of ODOE's Oregon Solar Dashboard



www.tinyurl.com/OregonSolarDashboard

Solar energy is a viable resource throughout Oregon, generating electricity across the state. Residential and commercial solar is more common in regions with higher population density west of the Cascades. Utility-scale and large commercial solar is more common east of the Cascades and in Southern Oregon where solar resources are more abundant. The largest operating solar photovoltaic facility in Oregon is the 56 MW Gala facility in Crook County near Prineville, although several larger facilities have been approved or are under review. For example, the approved Bakeoven Solar Project in Wasco County near Maupin is expected to be 303 MW, and the proposed Obsidian Solar Center and the proposed Archway Solar Energy, both in Lake County, are proposed at 400 MW each.

A combination of policy and market factors is driving solar adoption. At the state level, Oregon has a long history of policy and program support for solar energy including net metering, utility ratepayer incentives, and tax credit and rebate programs to promote commercial and residential solar

[iii] Total 2018 Oregon electricity generation was approximately 64,300,000 MWh. Total 2018 Oregon electricity consumption was approximately 51,100,000 MWh

installation. The Oregon Renewable Portfolio Standard established a target of 50 percent renewables for the state's largest electric utilities by 2040. At the federal level, the investment tax credit (ITC) provided a 30 percent non-refundable tax credit for solar installations. The ITC dropped to 26 percent in 2020 and will phase out in 2022 unless renewed by Congress. Decreasing costs of solar have also driven solar adoption. Between 2010 and 2018, national residential solar installed system costs fell from an average of $7.34 per Watt (DC) to $2.70 per Watt (DC) and utility-scale solar installed system costs fell from an average of $5.08 per Watt (DC) to $1.10 per Watt (DC).[11] At times when it is available, energy produced by utility-scale solar is now cost competitive with fossil fuel generation in many cases.[12]

Oregon has significant solar generation potential, with a 2012 National Renewable Energy Laboratory (NREL) study estimating annual technical potential for solar in Oregon at 1,775 terawatt hours; Oregon's total 2018 electricity demand was around 51 terawatt hours.[13] This potential, coupled with improvements in solar technology and falling costs, means Oregon is likely to see increased development of solar resources. Due to variability in climate and geography, solar potential differs by region in Oregon, with regions east of the Cascades having up to 40 percent greater solar resources than regions west of the Cascades.[14] While there is substantial potential for solar, particularly in eastern and southeastern Oregon, there are constraints on this potential. Solar PV is an intermittent resource that generates only during daylight hours, presenting challenges to large-scale, cost-effective grid integration. Pairing solar with storage technologies can help overcome these challenges. Solar projects require large land areas, with NREL estimating solar needs between 3.2 and 6.1 acres per MW of capacity.[15] Solar development opportunities also need to be weighed against other land-use needs and potential effects on sensitive environments and communities from the large land footprint. Similarly, the need for transmission infrastructure to link these remote areas to electricity load centers, such as the Willamette Valley, will also require oversight and regulatory approvals that can increase the time and cost for future development.

Non-Energy Implications

Solar energy is a renewable, zero-emission resource with a low carbon footprint. Minimal greenhouse gas emissions are associated with processes over the product lifecycle, from raw materials extraction to decommissioning. Solar energy is an important resource for transitioning to a clean electricity system. Utility-scale solar projects, however, do require large areas of land, which may affect wildlife habitat and have implications for other potential uses of the land. In addition, transmission lines from remote facilities can similarly disturb sensitive environments, affect waterways, and cause habitat fragmentation. To address these issues, Oregon has implemented rules for siting solar projects, and several counties also have additional, specific rules regarding solar projects.

Learn more about solar and agriculture in the Policy Briefs section.

Solar PV can supplement grid electricity for residential and commercial customers, reducing their overall energy bills in some instances and increasing their access to clean electricity. Solar energy can have positive economic effects at the state and local level.

At a local level, solar projects can generate property tax revenue for counties, increase local economic activity, and contribute to local and state revenues. Solar projects can take advantage of the Strategic Investment Program, which provides economic benefits to local communities. Solar also has positive impacts on local employment, providing an estimated 5,700 jobs for Oregonians in 2019; [16] the median wage of a solar installation technician, one of the more common solar related jobs, is $44,890 per year.[17]

Energy Jobs: The median annual wage of a solar installation technician is $44,890.

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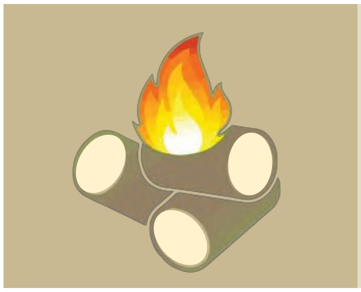
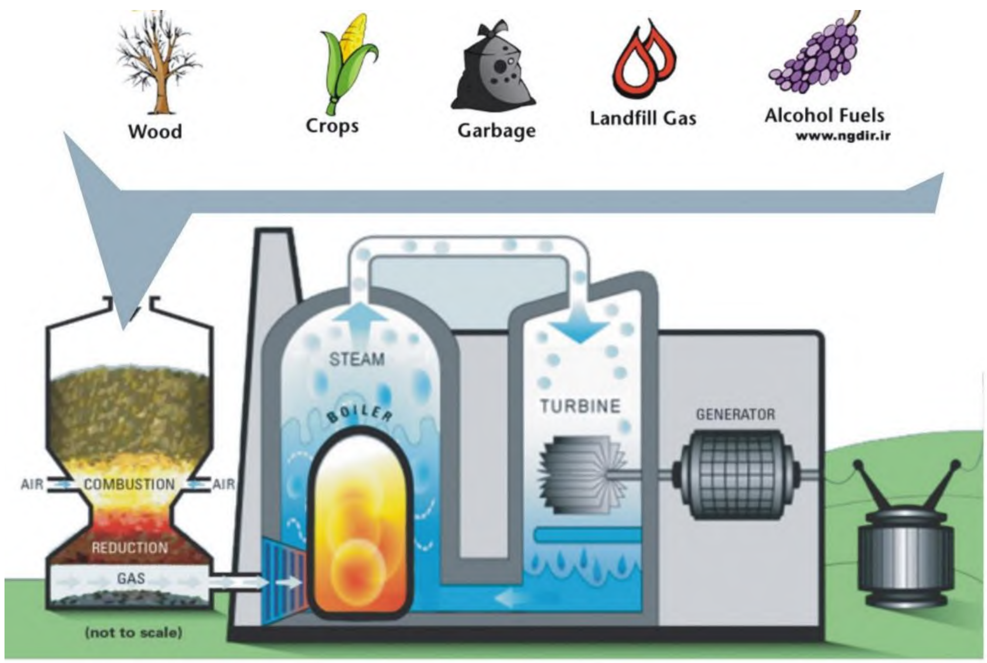
Resource Review: Biomass



- Total Capacity in Oregon: 288 MW
- Facilities in Oregon (1.5 to 51.5 MW): 16
- Total Generation (2018): 738,296 MWh
- Total Consumption (2018): 700,841 MWh
- Total Exports (2018): 37,454 MWh

Biomass is a renewable energy resource derived from organic matter produced as a byproduct of human or natural processes (e.g., logging or food production) or that is specifically grown for fuel.[1] The focus of this review is biomass for electricity generation, however, there are many energy uses for biomass, including conversion to biofuels like ethanol for powering transportation and burning for district heating and industrial processes.[i] Some forms of biomass like agricultural waste, landfill waste, and wastewater can also create biogas.

Figure 1: Types of Biomass[2]



Biomass can generate electricity in several ways. The most common systems use direct-fired combustion – burning wood material, agricultural or municipal waste, or other organic materials – to produce steam to spin a turbine. Direct-fired combustion of biomass is one of the oldest forms of energy generation known to humans.[3] Other systems include co-fired systems where existing coal plants use biomass as a substitute fuel, and biomass gasifiers that heat biomass into a flammable gas prior to combustion.[4] Biomass can also be converted to biogas or renewable natural gas that can be used for electricity generation or as a transportation fuel.[5] In 2017, biomass constituted 9 percent of the total non-hydropower renewable electricity generation in the U.S. (about 1.6 percent of total generation).[6]

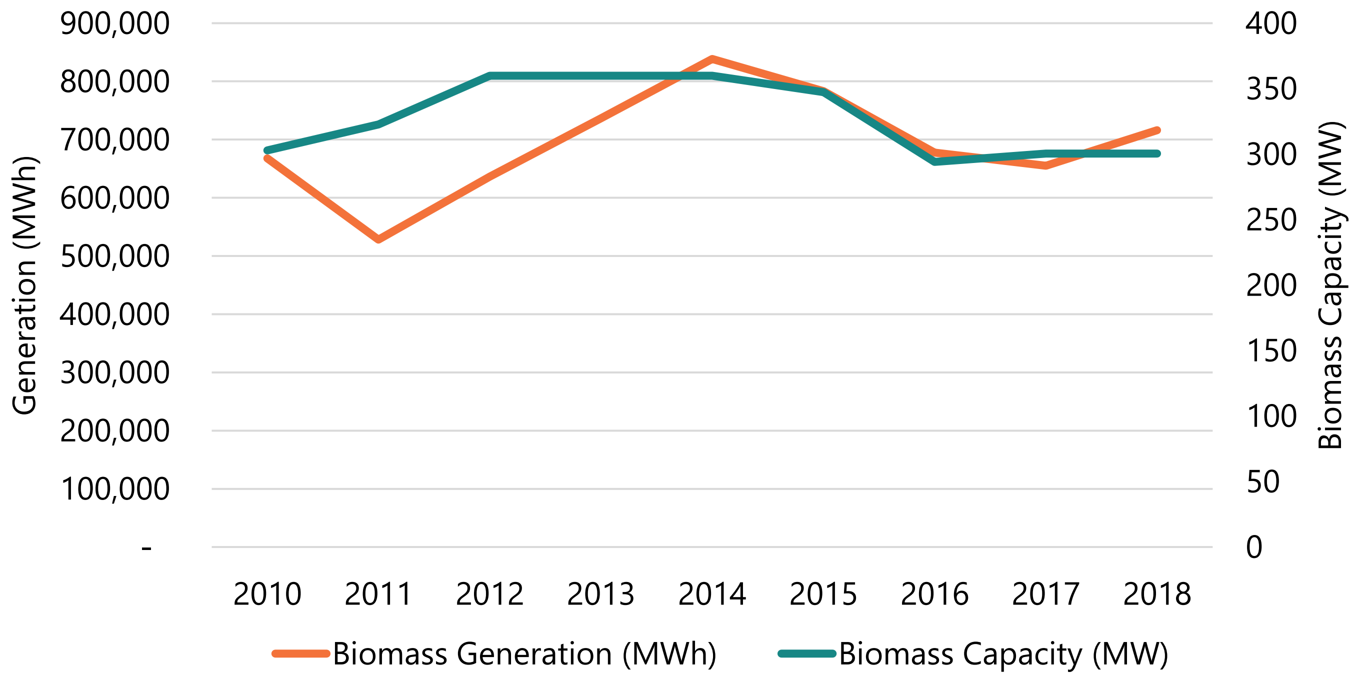
Trends and Potential in Oregon

Oregon ranks 19th among states in terms of biomass generating capacity.[7] In 2018, facilities in Oregon generated 738,296 MWh of electricity from direct-fired combustion of biomass, equivalent to 1.15

[i] District heating systems use a central plant to channel hot water or steam via a network of underground pipes to many buildings in an area.

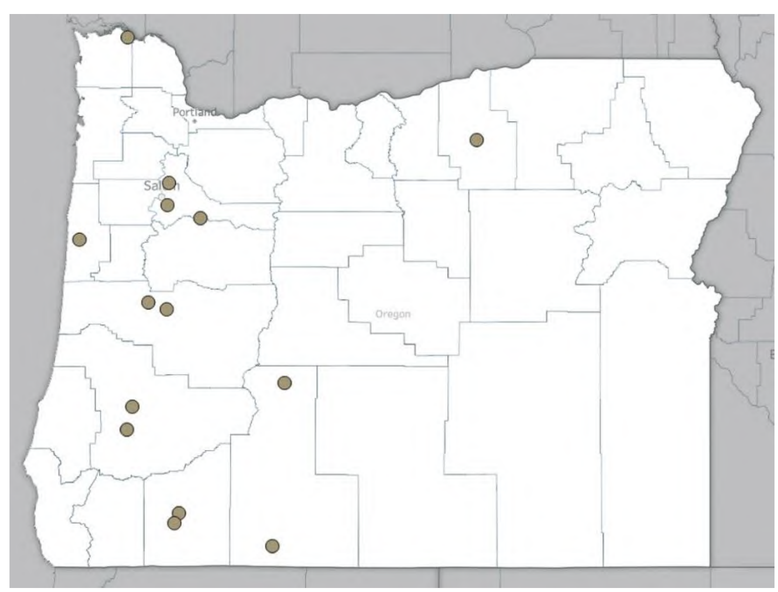
percent of Oregon's total electricity generation.[8] Biomass electricity accounted for 0.54 percent (276,589 MWh) of Oregon's retail electricity consumption. A further 424,532 MWh of electricity generated from biomass is consumed onsite by industrial or commercial facilities. There have been no new biomass facilities constructed since 2011.[9]

Figure 2: Oregon Biomass Generation and Capacity by Year



Sixteen facilities use direct-fired combustion of biomass to generate electricity in Oregon. Fifteen of these facilities, accounting for 92 percent of biomass electricity production, burn wood and wood byproducts, mostly from pulp and paper mills or lumber mills. Thirteen of the facilities are cogeneration facilities that also produce heat for onsite use. One biomass facility, the Covanta facility in Marion County, burns municipal solid waste.[ii] Transportation of biomass materials can be expensive, so facilities are typically located close to the source of materials. Facilities in Oregon are in eight counties that are primarily rural.

Figure 2: Biomass Facility Locations in Oregon



Availability of feedstock and facilities to combust resources, the economics of obtaining feedstock, and environmental impacts drive the potential for biomass generation. Oregon has substantial forestry and agricultural industries that produce potential feedstock for biomass facilities. In addition, material harvested as part of forest health activities and materials from municipal

[ii] The Covanta facility burns both organic municipal solid waste (classified as biomass), and inorganic waste. Generation from inorganic solid waste is not included in data reported.

waste are potential resources. In total these resources generate approximately 8.7 million dry-tons of feedstock, which is capable of generating 8.7 GWh in an average-efficiency generation technology.[10] The potential of these resources is constrained by factors such as transportation costs, land-use restrictions, and concerns about greenhouse gas emissions.[11]

Non-Energy Implications

Using biomass for electricity generation can reduce waste material and potentially reduce forest residue and decrease wildfire potential. Biomass direct-fire combustion can produce significant quantities of carbon dioxide and other emissions depending on the fuel and generation equipment used.[12] However, the biomatter (plants and trees) that are the source of biomass may capture some portion of carbon dioxide emitted potentially reducing the net carbon emissions.[13] A full understanding of the relative environmental effects and sustainability of biomass requires a comparison of systems to the effects of displaced or alternative sources of energy.[14] Biomass generation can also provide local and state economic benefits in terms of employment and providing additional revenue streams for industrial and agricultural industries.[15]

Bear Mountain Forest Products Creates Oregon Biofuel

Bear Mountain Forest Products, a biofuel company created in Oregon in 1988, currently employs 60 Oregonians. Bear Mountain converts wood waste materials from the lumber industry into wood fuel pellets, compressed wood fire logs, fire starters for use in wood burning stoves, fireplaces, and campfire and BBQ pellets. Lumber waste materials that would typically go to the landfill are kiln dried and processed into wood fuel products that are shipped to retailers across the country. Raw wood materials used to make the products come from the residual waste or sawdust of Oregon sawmills. Bear Mountain's manufacturing process leads to virtually no waste of the excess residual wood the company receives from lumber mills. Raw materials not used to make product, which is about 20 percent of the materials they get, fuel the company's dryer system to remove moisture from the wood during the manufacturing process.

Bear Mountain has two plants in Oregon. A Cascade Locks plant produces predominantly wood fuel pellets for home heating and cooking pellets used for barbecuing. The dryer uses wood waste for most of its fuel and propane as a supplemental fuel source. A Brownsville, Oregon plant has two dryer systems, one that uses natural gas and one that uses wood waste to dry the wood in the production process. The Brownsville plant produces mostly wood fuel pellets to heat homes.

In 2019, Bear Mountain turned 130,000 tons of wood waste from mostly Oregon sawmills into 117,000 tons of retail wood products. The company estimates that 60 percent of that product – or about 70,000 tons – is used in Oregon for home heating. At an average of 1.5 tons per home, the company estimates that it serves heating to 46,800 Oregon homes.

Learn more about Bear Mountain Forest Products:
https://lignetics.com/pages/bear-mountain-forest-products

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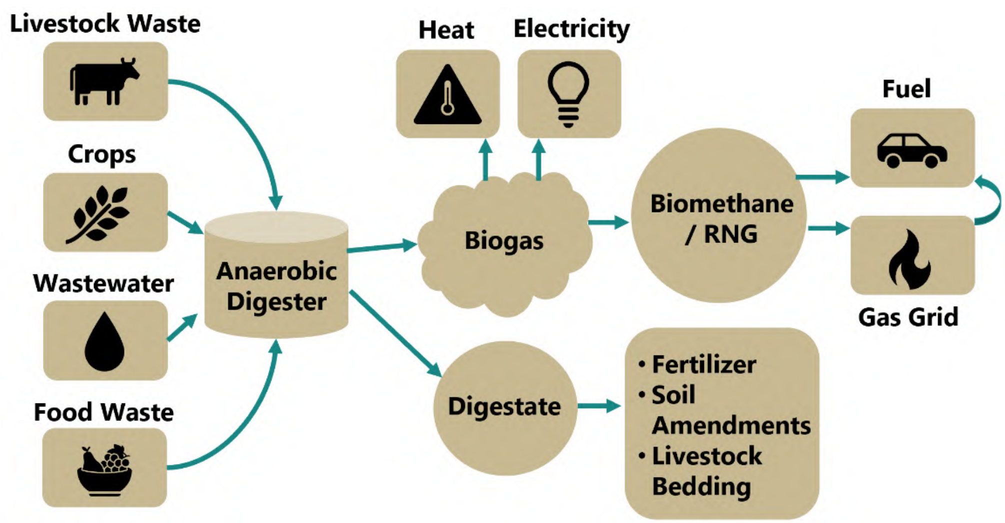
Resource Review: Biogas and Renewable Natural Gas

- Total MW Capacity in Oregon: 52.6 MW
- Facilities in Oregon (0.07 MW – 6.4 MW): 25
- Total Generation (2018): 299,000 MWh
- Total Consumption (2018): 55,589 MWh
- Total Exports (2018): 243,411 MWh

Biogas is a renewable energy source generated from decomposition of organic material. Facilities historically ignited or "flared" biogas to prevent release into the atmosphere, but when it is captured, facilities can use biogas to generate heat or electricity.[1] Refining biogas to a high concentration of methane creates a product interchangeable with conventional natural gas, termed renewable natural gas.

Figure 1: Anaerobic Digestion Pathways



Anaerobic digestion is the most common way to create biogas today.[2] When organic matter decomposes in an anaerobic environment (an environment without oxygen) it generates a gas that contains 40 to 75 percent methane.[3] Common biogas feedstocks include waste streams like livestock manure, food waste, wastewater, organic material in landfills, and crop or forestry residue.[4] Biogas can also come from other organic materials, such as dedicated crops or algae, grown specifically for this purpose.[5] These materials decompose in purpose-built anaerobic digesters or in existing facilities like landfills. Facilities can burn the resulting biogas in combustion engines that generate heat and/or electricity for use onsite or to sell onto the electricity grid. RNG is biogas that has been cleaned and conditioned to have a greater methane content – for example, NW Natural requires a methane content for pipeline gas of 97.3 percent. RNG can replace fossil natural gas to generate electricity or heat, or can be used as compressed natural gas for transportation fuel.[6] RNG can also be injected into existing natural gas transmission and distribution pipelines.

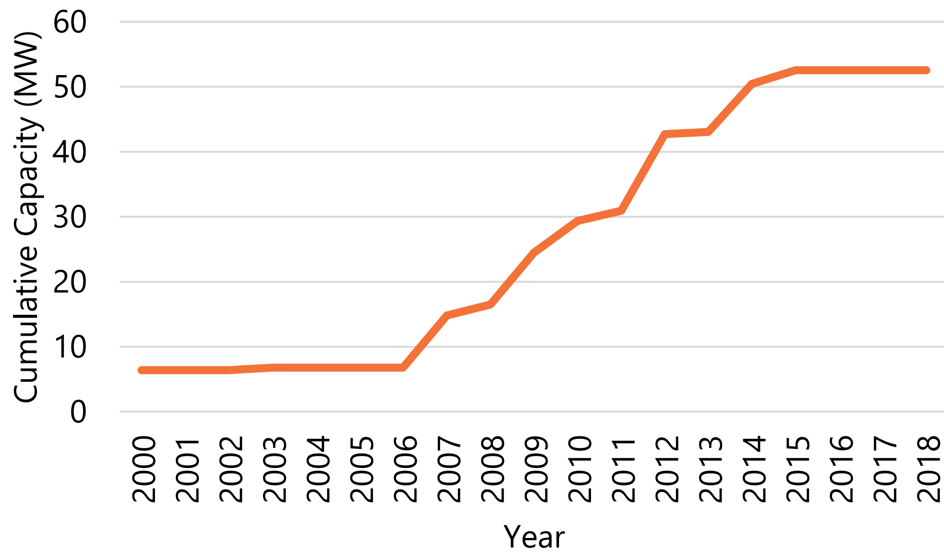
Biogas can also be created via thermal gasification, which is an overarching term for several methods that use heat to partially combust biomass, separating out combustible gases from the solid material. While plants using gasification technology for generating synthetic gas and liquid fuels from coal and biomass are in commercial use, there are no commercial-scale plants that use thermal gasification to produce

See Energy 101 and Policy Brief sections for more about renewable natural gas.

biogas for electricity generation or renewable natural gas in the U.S., although there are in other countries.[7]

Trends and Potential in Oregon

Figure 2: Biogas Cumulative Capacity (MW) in Oregon (2000-2018)



Oregon ranks 19th among states in biogas generating capacity.[8] In 2018, biogas-based electricity made up 0.46 percent of Oregon's electricity generation and 0.08 percent of Oregon's energy consumption, excluding electricity generated for use on site. [9] The first biogas generation facility in Oregon came online in 1992 and biogas has seen steadily increasing adoption with the most recent facility, The Dalles Wastewater Treatment Facility, becoming operational in 2015.[10]

Forty-nine facilities produce or have produced biogas in Oregon, including 26 wastewater treatment plants (WWTPs), 13 landfills, nine agricultural waste facilities, and one food waste facility.[11] Among these, 25 facilities generate electricity for commercial sale – 10 WWTPs, eight landfills, six agricultural waste facilities, and one food waste facility. Fourteen facilities are cogeneration facilities that use produced heat for facility operations. Biogas production and generation facilities are typically located close to or at the site of the source materials to reduce the cost of transportation. Biogas facilities in Oregon are in 12 counties that are both rural and urban.[12]

There is one operational RNG facility in Oregon today, the Threemile Canyon facility in Boardman, which creates RNG from dairy cow manure.[13] Four other facilities are scheduled to come online in 2020 or 2021: the Columbia Boulevard WWTP in Portland, the largest WWTP in the state;[14] the Metropolitan Wastewater Management Commission WWTP in Eugene;[15] the Shell Energies RNG project in Junction City;[16] and the Port of Tillamook Bay digester project in Lincoln City.[17]

Opportunities

A 2018 Oregon Department of Energy study inventoried biogas and RNG potential across six organic material pathways – waste food, agricultural manure, landfills, WWTPs, forest residue, and agricultural residue.[18] The study found the gross potential using anaerobic digestion technology alone is around 10 billion cubic feet of methane per year (approximately 4.6 percent of Oregon's annual natural gas use). Thermal gasification technology would

A 2018 ODOE study found that up to 20 percent of Oregon's natural gas needs could be met with renewable natural gas.

add an additional 40 billion cubic feet of methane potential per year, or 17.5 percent of Oregon's total yearly use of natural gas. Combined, these resources could generate energy equivalent to 49 trillion Btu, or up to 20 percent of Oregon's total natural gas needs. Despite this potential, there remain economic and technical barriers to biogas and RNG production and use. The costs relative to fossil natural gas are high, particularly with respect to the capital and operating costs of capturing and cleaning biogas.

To create a pathway to increasing production and use of RNG from biofuels, Oregon passed Senate Bill 98 in 2019, which allows natural gas utilities to invest in new RNG projects and procure RNG from existing projects. The bill also established voluntary targets of up to 30 percent RNG by 2050 for large natural gas utilities with over 200,000 customers (presently, only NW Natural exceeds the customer threshold).[19]

Non-Energy Implications

Biogas and RNG production and combustion do emit greenhouse gases. However, when replacing fossil natural gas or other fossil fuels, biogas and RNG can reduce overall greenhouse gas emissions and pollutants.[20] CO2 emissions from biogas and RNG are biogenic, meaning they are part of the natural carbon cycle; a portion of these emissions would have occurred naturally, and depending on the fuel source and process may be considered carbon neutral.[21] Biogas generation reduces methane emissions that would otherwise have been flared or emitted into the atmosphere. Collecting, cleaning, and using raw waste materials, such as manures that generate biogas for a productive energy use also reduces waste and can lead to reduced landfill needs and improved air and water quality. Biogas and RNG also improve domestic fuel diversity, have a positive effect on the economy, and strengthen resilience through construction and maintenance of infrastructure and increased supply of local fuel.[22]

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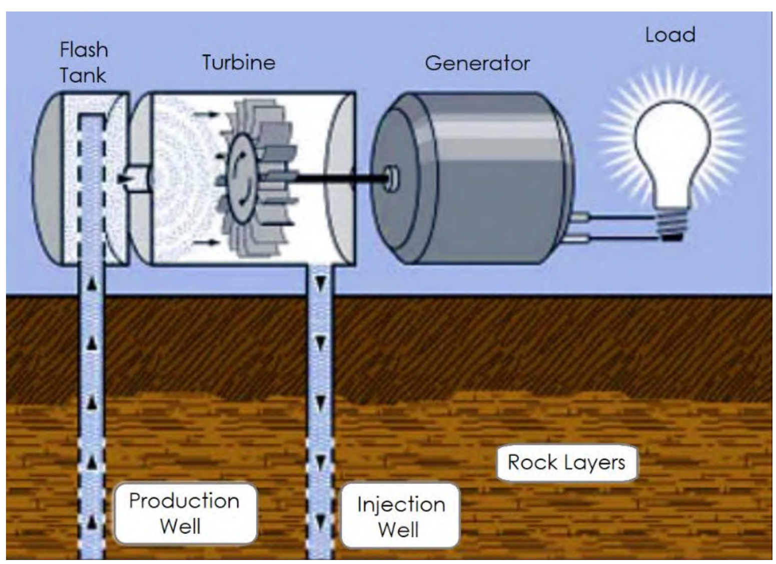
Resource Review: Geothermal Energy

- Total Capacity in Oregon: 26.9 MW
- Facilities in Oregon (1.75 to 22 MW): 3
- Total Generation (2018): 176,235 MWh
- Total Consumption (2018): 59,389 MWh
- Total Imports (2018): 116,846 MWh

Geothermal energy is a renewable resource from heat generated continuously within the earth. Geothermal energy can fuel electricity generation, as well as provide heating and cooling for buildings or industrial processes at small or large scales. The United States leads the world in installed geothermal electricity capacity with over 3 GW of capacity.[1] In 2019, geothermal power fueled approximately 0.4 percent of total U.S. utility-scale electricity generation.[2]

Geothermal energy is naturally occurring heat created from processes within the earth and stored in magma, rock, and hydrothermal (hot water or steam) reservoirs. To be a productive resource, the geothermal energy must be hot enough, be accessible, and have fluid present (usually water) either naturally or introduced by humans to conduct the heat.[3] Geothermal resources at different temperatures are useful for different applications. Direct use applications like heating buildings require water or steam temperatures between 120 and 390 degrees Fahrenheit.[4] Lower-temperature water can also act as an exchange medium to operate heat pumps for building heating and cooling. Geothermal electricity generation requires high temperatures – between 300 and 700 degrees.[5] Because these temperatures usually occur very far underground, there are limited accessible geothermal resources in the U.S. to produce electricity. However, in Oregon there are unique geological formations that bring geothermal heat sources like magma closer to the Earth's surface.[6]

Figure 1: Flash Steam Power Plant[8]



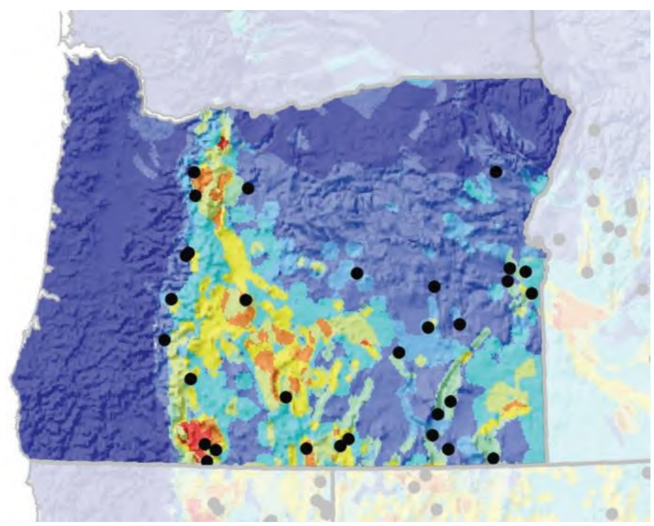
Geothermal electricity power plants typically use hydrothermal resources to generate electricity. Power plant operators drill production wells to access hydrothermal reservoirs, and bring hot water or steam to the surface.[7] There are three types of geothermal power plants in the U.S. Flash steam plants pipe hot water from deep wells to the surface and convert the water to steam to drive a generator turbine.[8] Binary cycle power plants, which can use water at lower temperatures than flash steam plants, also pipe hot water from deep wells to the surface. This water is used to transfer the heat from the water to a different liquid with a lower boiling point, which in turn creates steam to drive generator turbines.[9] A third type, dry steam, uses steam directly piped from below the surface to drive generator turbines.[10] Cooled water from these power plants can be injected back into the earth to be reused.

Because geothermal heat is a continuous resource, geothermal can provide consistent electricity generation, making it capable of operating as a dispatchable, firm resource.[11] Geothermal power plants are also relatively inexpensive on a per unit basis once constructed. However, geothermal energy is not in widespread use, primarily due to limitations in geographic availability of resources, challenges identifying productive resources, and high upfront costs of exploration and development.[12]

Trends and Potential in Oregon

Oregon has three geothermal power plants, but currently only two are actively generating energy. The first, completed in 2010, is the 1.75 MW Oregon Institute of Technology plant in Klamath Falls that generates electricity used on campus. The second, completed in 2012, is the Neal Hot Springs Geothermal Project near Vale, Oregon. This plant has a capacity of 22 MW and provides electricity to Idaho Power. A third plant, the 3.1 MW geothermal facility in Paisley, Oregon, became operational in 2015, but has not generated electricity since 2017 and it is unknown if it will restart operations. Geothermal electricity accounts for 0.3 percent of electricity generated in Oregon and 0.01 percent of electricity consumed in Oregon (not including onsite consumption). There are no proposed new geothermal plants in Oregon; however, exploration projects are underway at Newberry Crater in Deschutes County, and at Crump Geyser and Glass Butte in Lake County.

Figure 2: Potential Geothermal Resources[13]



Adapted from a USGS map showing geothermal resources in the U.S. Warmer colors equate higher favorability of geothermal potential. Black dots represent identified geothermal systems.

Accessible hydrothermal geothermal resources are concentrated in the western United States. In Oregon, a U.S. Geological Survey estimated 540 MW of potential capacity from identified conventional geothermal resources, and approximately 1,900 MW of potential from unidentified conventional resources.[13] The report also identified over 43,000 MW of potential capacity in Oregon from enhanced geothermal systems (EGS). EGS is an emerging technology that extracts geothermal energy without requiring naturally occurring water, which expands access to geothermal resources. An EGS system injects high pressure water into high temperature, dry rock, which enhances natural fractures in the rock. The injected water collects heat from the rock and then returns to the surface through a production well.[14] The Newberry Crater in Deschutes County has been a prominent site for research and demonstration of this technology.[15]

While there is substantial potential energy from geothermal resources, accessing and developing resources can be costly and challenging. Developing geothermal resources can be a lengthy and uncertain process requiring resource exploration; deep, high temperature drilling; and substantial construction infrastructure. These elements contribute to geothermal power projects generally having high capital and financing costs, estimated at two to three times higher than natural gas, onshore wind, or utility-scale solar.[16] [17]

Non-Energy Implications

Once constructed, geothermal electricity generation has near-zero carbon emissions and very low emissions of other pollutants.[18] In general, geothermal facilities also have a smaller land-use footprint than other renewable electricity generation resources like wind and solar.[19] Water is required for geothermal energy production and water resources can be depleted,[20] but extracted water can be injected back into the earth, which helps renew the geothermal resource but adds to the operating costs. Geothermal has lower average water use than other thermal power sources.[21] Drilling and groundwater extraction and injection can have environmental impacts including potential contamination of water sources, although there have been no reported cases of water contamination from geothermal sites in the United States.[22] Fluids produced from geothermal wells can also contain a variety of substances,[23] including potentially harmful chemicals and technologically enhanced naturally occurring radioactive materials.[24]

Geothermal projects can have positive economic benefits including increased employment and local tax revenues. For example, the Neal Hot Springs Geothermal Project employed approximately 150 people during construction and maintains approximately 12 full time positions.[25] Statewide in Oregon, geothermal is estimated to employ 27 people.[26]

Energy Jobs: Geothermal energy currently employs about 27 people in Oregon.

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Technology Review: Utility-Scale Storage

Peak Power Capacity in Oregon (2019):	5 MW
Facilities in Oregon (2019):	1 (5 MW)
Total Capacity of Storage Under Construction:	430 MW
Maximum Stored Energy in Oregon (2019):	1.25 MWh
Total Energy Discharged (2018):	545 MWh

Utility-scale storage (1 MW or greater) can provide additional capacity to the electric grid and affords electricity providers with many different opportunities to more flexibly manage their generation, transmission, and distribution systems.[1] Storage can also play a valuable role in decarbonizing the grid by optimizing the generation from resources that have varying levels of carbon emissions and providing fast-acting supplies of electricity to offset the use of natural gas peaker plants for the integration of renewable energy resources.[2]

Many different technologies can store and discharge electricity:

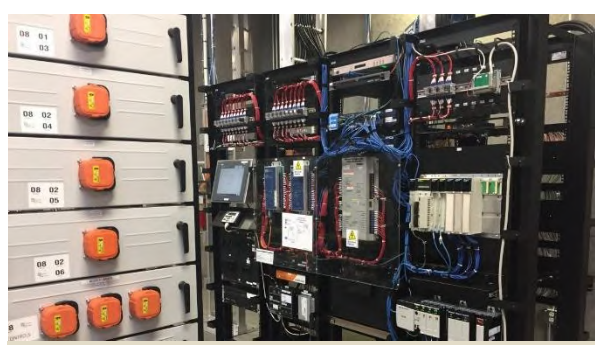
- mechanical storage makes use of gravity or kinetic force
- thermal storage makes use of heating or cooling materials
- chemical storage makes use of chemical and electrochemical reactions
- electro-magnetic storage makes use of electrical or magnetic fields[3]

See the Policy Brief section for more on energy storage and power-to-gas technologies.

Some of these technologies are relatively new such as hydrogen storage, while others are mature like pumped-hydro storage and lead-acid batteries.[4] Lithium-ion batteries have become a prominent form of utility-scale storage, accounting for 88 percent of new storage additions nationally since 2010,[5] and 90 percent of all utility scale battery storage additions.[6] This is partly due to advances and cost reductions related to the widespread usage of lithium-ion batteries in consumer goods and electric vehicles.[7] Each technology offers different benefits based on its specific characteristics and intended uses.[8] For example, a technology's maximum volume of discharge (MWh) at its maximum power rating (MW) can help determine if it is best suited to supply electricity to serve loads, or balance short term fluctuations in loads and generation on the electricity grid.[9]

Trends and Potential in Oregon

Oregon is currently ranked 24th among states in terms of energy storage capacity (MW),[10] with one operational utility-scale storage facility, PGE's Salem Smart Power Center – a standalone lithium-ion battery and inverter system with 5 MW capacity and 1.25 MWh of stored energy.[11] Numerous projects, however, are in various stages of development. To comply with HB 2193 (2015), which required investor-owned utilities to deploy at least 5 MWh of energy storage by 2020, PGE and PacifiCorp are



PGE's Salem Smart Power Center

developing projects that will add at least 82 MWh (25 MW capacity) of utility-scale storage and 17 MWh (6 MW capacity) of residential and other customer-sited storage.[i] [12] In addition to adding volumes of storage far beyond the requirements of HB 2193, utilities and developers are actively planning to add even larger volumes of utility-scale storage to the grid. Most of the new storage projects currently under development will be integrated with existing or planned generation facilities, although in the future we may also see stand-alone storage sited on the distribution system. Table 1 presents a list of proposed utility-scale storage projects in Oregon requiring state approval through the Energy Facilities Siting Council or federal approval through FERC; there are many other smaller storage projects that would require only local or county approval. Table 1 provides insight into the level of activity in energy storage development; however, it is not certain that all projects will be built.

Table 1: Approved or Proposed Pipeline for Utility-Scale Energy Storage in Oregon

Project Name	Technology	Paired with Generation	Size (MW/MWh*)	Status	Projected Operation Date
Bakeoven	Battery	Solar	100MW	State Approved	2023
Wheatridge II	Battery	Wind & Solar	30MW	State Approved	2025
Montague	Battery	Wind & Solar	100MW	State Approved	2023
Port Westward	Battery	Natural Gas	6MW	State Approved	2021
Obsidian Solar	Battery	Solar	50MW / 250MWh	State Application	TBA
Madras Solar	Battery	Solar	240MWh	State Application	TBA
Archway Solar	Battery	Solar	TBD	State Application	TBA
Bonanza Energy	Battery	Solar	1,100MW	State Application	TBA
Swan Lake Pumped Hydro	Pumped-hydro	No	400MW	FERC Approved	2025
Owyhee Pumped Hydro	Pumped-Hydro	No	600MW	FERC Application	TBA

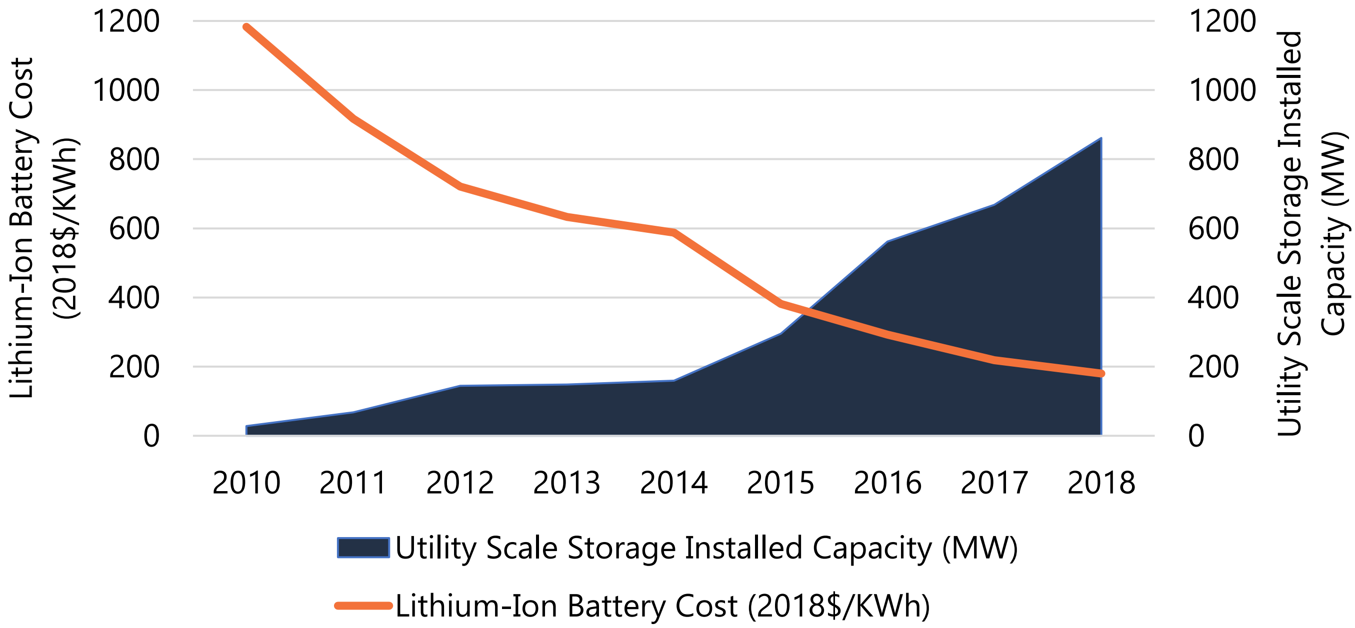
Sources: Oregon Energy Facility Siting Council[13]; Swan Lake Project website[14]

* Size is reported in MW and/or MWh depending on which was provided in the application to EFSC.

Utility-scale storage is undergoing rapid planning and development in Oregon. Until recently, most energy storage technologies were unproven or too expensive to deploy. Over the past decade, however, the costs of storage, particularly battery storage, have fallen substantially, making scalable grid-scale storage economically feasible.[15, 16]

[i] Not all HB 2193 projects will be completed in 2020.

Figure 1: Storage Cumulative Installations and Costs per kWh *(Sources: EIA, Bloomberg NEF)*



Federal and state policy support is driving additional deployment of storage in Oregon. At the federal level, the solar and storage Investment Tax Credit (ITC) incentivizes storage that is charged with renewable energy.[17] At the state level, the Strategic Investment Program provides property tax benefits to large scale energy developments, including storage. Smaller scale residential and commercial battery storage could also be aggregated by utilities or third-party aggregators as a grid-scale storage resource.

These incentives, combined with the dramatic reduction in costs for battery storage, have now led utilities to identify utility-scale storage as a cost-effective choice to meet their capacity needs. In 2016, neither PGE nor PacifiCorp identified utility-scale storage in their Integrated Resource Plan's preferred portfolios. Just three years later in 2019, both utilities included substantial energy storage assets in their plans. PacifiCorp's preferred plan includes nearly 600 MW of battery storage capacity by 2023, all co-located with new solar resources.[18] PGE's preferred plan includes nearly 240 MW of battery storage capacity by 2024.[19]

Non-Energy Implications

Storing electricity can provide environmental and public health benefits. Electricity storage can help reduce reliance on generation resources with high emissions of carbon and other harmful pollutants by charging with lower emission resources that then replaces electricity from higher emission resources; the most common case of this will be to replace more emission-intensive generation during peak load hours.[20] Battery storage is also a dense electricity resource that can lower land use impacts compared to some other resources.[21] Battery storage has environmental costs. Batteries use raw materials such as lithium and lead, which is often mined in regions with poor environmental and labor oversight.[22] These materials also present environmental hazards if they are not disposed of or recycled properly.[23] Other storage technologies like pumped-hydro storage can have substantial land use impacts.

Electricity storage can also have economic benefits. Storage can be charged when electricity prices are low and discharged when electricity prices are higher. Using batteries can help existing generation facilities operate more optimally, delaying or avoiding the need to build more generation resources.[24] Storage can also help optimize the use of existing transmission lines by moving electricity from generators to loads during off-peak hours when transmission rates and costs of generation can be less expensive than during peak hours.[25] This can help smooth electricity prices by better matching supply and demand across all hours of the day, and can reduce the need for large scale investment in costly generation and transmission infrastructure, which could translate into lower overall costs.[26] The energy storage industry is a growing industry that could bring local economic benefits in the form of increased economic activity and employment. In 2020, there were an estimated 1,284 jobs in energy storage in Oregon.[27]

Energy Jobs: In 2020, there are more than 1,200 energy storage jobs in Oregon.

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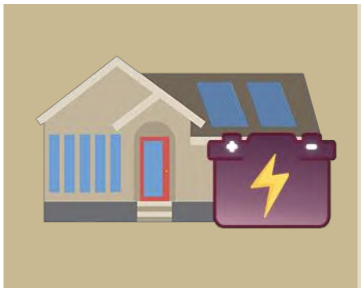
Technology Review: Residential Energy Storage



- Peak Power Capacity in Oregon: 670 kW[i]
- Facilities in Oregon: 291
- Maximum Stored Energy in Oregon: 1,440 kWh[i]
- Range of Sizes: 2.4 to 46 kWh

Residential battery storage systems[ii] are large rechargeable batteries designed to store and deliver electricity to a home. The batteries may be charged by the grid or with an onsite generator, such as a rooftop solar system. Controls allow the batteries to provide power to the home during a power outage or to supplement electricity use in the home. In cases where customers agree to allow the utility access to the battery, they can also be used by the utility to support grid operations.

Residential batteries are described based on their power rating and their energy storage capacity. Power rating is measured in kilowatts and is the maximum electrical output that a battery can deliver at any given time. Storage capacity is measured in kilowatt-hours and represents the duration of time a battery can discharge electricity before needing to be recharged, depending on the load. Often, the storage capacity of a residential system is sized to supply power for critical loads such as lighting and refrigeration. For example, a battery with a storage capacity of 12 kilowatt-hours could support a load of 2 kilowatts for six hours.

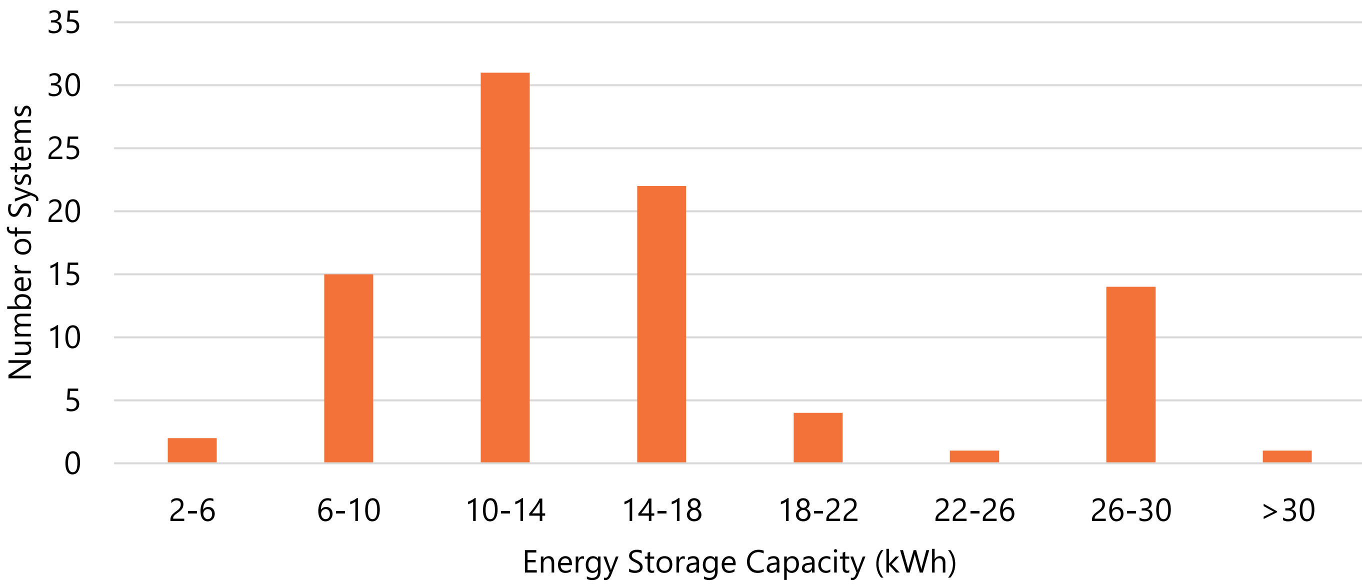
Trends and Potential in Oregon

There are at least 289 residential batteries in Oregon installed in conjunction with residential solar systems.[1] Seventy-two of these projects are off-grid dwellings where onsite generation and battery storage provide 100 percent of the electricity for the home. The cost of residential battery storage varies by system size and complexity. The average cost of a residential battery system in 2020 was $15,670. This does not include the cost of solar components if present. The storage capacity of residential batteries in Oregon ranges from 2.4 kWh to 46 kWh, with an average capacity of 11 kWh. Figure 1 demonstrates the range of residential battery sizes reported in Oregon between 2018 and September 2020.

[i] Estimated values for systems installed from 2018 – August 2020

[ii] The residential storage systems in this section are all installed in conjunction with residential rooftop solar projects. Additional residential energy storage systems may be installed as stand-alone systems but are not included in the data sets used in this report.

Figure 1: Range of Residential Battery Sizes in Oregon (2018-2020)



Residential battery systems provide multiple benefits for the owner and may also be used to provide services to local utilities and grid managers. Rocky Mountain Institute has identified 13 services batteries can provide to three distinct stakeholder groups: customers, utilities, and grid system operators. Services vary from grid stability support, meeting peak loads, more cost-effective management of transmission and distribution systems, and customer benefits including cost savings and backup power.[2]

Most residential battery systems are used to provide backup power to a home. For customers serviced by utilities that offer time-of-use rates – rates that vary depending on the time of day the electricity is consumed – battery systems can also be controlled in ways that help shift a home's consumption of utility power to hours when electricity rates are cheaper, which can provide savings on utility bills. Savings are dependent upon how much the time-of-use rates vary and the round-trip efficiency of the battery storage system.

Residential battery systems can also be configured to communicate with a utility. Utilities can then operate the battery as a resource to benefit their entire system. For example, utilities can use residential batteries to help meet peak loads, maintain local grid stability, optimize the generation from low-cost resources when available, or make use of excess renewables that would have otherwise gone unused. To realize these utility benefits, residential battery systems must be operated by a utility or configured to automatically respond to market signals that indicate a need for services on the grid. The different benefits battery systems can provide are often in competition. For example, a battery system operated by a utility to provide services to the grid may result in less capacity available for the homeowner in the event of a power outage. Agreements between utilities and homeowners may limit utility use of the battery system to ensure there is always adequate capacity to provide backup power to the homeowner. Portland General Electric has launched a pilot program to test utility operation of residential energy storage systems.[4]

Some of the functions provided to utilities by battery storage systems are known as *ancillary services*, which are services necessary or incidental to the transmission and delivery of electricity from generating facilities to retail electricity consumers. These include scheduling, load shaping, reactive power, voltage control, and energy balancing services.[3]

Opportunities

As of September 2020, the Oregon Department of Energy's Oregon Solar + Storage Rebate Program has provided rebates for 11 residential battery systems paired with solar.

Historically, deployment of residential battery systems has been limited by the up-front cost of the system; incentives are available that can help offset some of the up-front costs. In 2020, residential battery systems qualified for a federal tax credit equal to 26 percent of the project cost if they were installed in conjunction with a solar PV system and charged solely with solar energy. The federal tax credit will be reduced to 22 percent of system cost in 2021. As of September 2020, the Oregon Solar Plus Storage Rebate Program provided financial incentives for 11 residential battery systems paired with solar PV installations, with an additional 15 rebate reservations not yet completed.

Because most residential batteries in Oregon are used as backup power, there are also limitations on cost savings opportunities. Having backup power improves the resilience of a household but does not provide financial benefits on a customer's electric bill. As utilities work to modernize their distribution system infrastructure, utilities may be able to track electricity provided from batteries that could support programs that can realize cost savings for customers and the utility.

Portland General Electric is operating a pilot program that provides incentives for 525 residential battery systems contributing up to 4 MW of aggregated electricity to PGE's grid. These distributed battery systems will be operated to provide grid services to PGE and will also be available for the participants as backup power in the event of a power outage. The batteries may be operated individually or aggregated by PGE to serve as a virtual power plant.[4] The financial incentives are available to customers living within three neighborhoods participating in PGE's Smart Grid Test Bed, and will provide higher incentives to low- and moderate-income households to help ensure a more equitable distribution of benefits.[5] The pilot represents the first program by an Oregon utility to operate residential battery systems to provide grid services.

Barriers

Equitable access to the benefits of residential storage battery systems is a significant barrier for many Oregonians. At over $15,000, the typical up-front cost of an average storage battery system is out of reach for many Oregonians, particularly when most systems are currently only used for backup power. Enabling access to cost saving value streams could bridge the cost gap for some Oregonians, but for many, the existence of any up-front cost could prohibit access to residential batteries.

Non-Energy Implications

Residential battery systems can help support higher levels of renewable energy resources on the grid by providing services to grid operators and deferring investments in new fossil fuel generators.[6] Distributed residential storage systems can also be aggregated and operated by utilities in a similar way to utility-scale battery storage systems. In aggregate, these could help utilities meet their peak utility loads and optimize their generation resources. Battery systems also have resilience benefits during power outages. These benefits can be enhanced when they are paired with rooftop solar systems that allow batteries to be recharged without utility power – benefits that would increase in the event of a prolonged power outage.

Utility-scale storage is discussed in a separate Technology Review.

Batteries have several negative environmental and social impacts. These impacts include un-sustainable and/or un-ethical mining practices in some countries where raw materials are sourced,[7] hazardous material handling, and difficulties in recycling. In 2019, Tesla announced it will be adding a lithium-ion battery recycling facility to the company's battery Gigafactory in Nevada.[8]

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Resource Review: Nuclear

- Oregon Total Capacity and Facilities: 0
- Oregon Consumption (2018): 1,390,000 MWh

The United States is the world's largest producer of nuclear power, which supplies around 20 percent of the nation's electricity.

Nuclear energy comes from splitting atoms in a reactor to heat water into steam, which turns a turbine to generate electricity. Most commercial nuclear plants in the United States generate a large amount of electricity – 1,000 megawatts or more – which is comparable to the output of the Bonneville Dam. Nuclear power plants are firm resources, meaning they are designed to produce steady output 24 hours per day, most times of the year. The capacity factor of a power plant is an annualized measurement of how often the plant is operating at full power or maximum output. Annual capacity factors of nuclear power plants vary according to their refueling cycles. In large part this is because nuclear power plants are designed to operate for long periods between refueling, typically 1.5 or 2 years.[1]

Trends and Potential in Oregon

Only one nuclear plant – the Columbia Generating Station near Richland, WA – provides electricity to the Northwest grid and Oregon. It produces 3.8 percent of the electricity generated in Oregon and has a capacity factor of around 89 percent.[2]

Oregon's lone commercial nuclear power plant, Trojan, operated for 16 years and was shut down nearly 30 years ago. It was located along the Columbia River about 40 miles northwest of Portland. Trojan went on-line in May 1976. The plant was licensed to run for 30 years and generated 1,100 megawatts at full capacity. After a lengthy series of mechanical problems, Portland General Electric shut the plant down for economic reasons in November 1992 and permanently closed the plant in January 1993.[3]

Oregon law prohibits new nuclear power plants unless two conditions are met. The first is a finding from Oregon's Energy Facility Siting Council that the federal government has licensed a repository for the permanent disposal of commercial spent nuclear fuel (which has yet to occur). Then, if that condition is met, the second condition is that any proposal for a new nuclear power plant would go to a vote of Oregon residents. This law stems from an initiative passed by Oregon voters in 1980.[4]

Nuclear power plants cost far more to build than natural gas, wind, and solar facilities and have a history of cost overruns.[5] They also take much longer to permit and build. The nuclear industry is hopeful that a new technology – small modular reactors – can be quicker to develop and more price competitive. See the small modular reactors Technology Review for more information.

Currently, 95 nuclear reactors in 29 states generate nearly 20 percent of the electricity generated in the United States – that percentage has not changed since the 1990s.[6] Two new reactors are currently under construction in the United States at the Vogtle Plant Site in Georgia (at a combined estimated cost of $27.5 billion).[7]

However, America's nuclear "fleet" is shrinking. The number of operating plants is expected to decline during the next several years as more plants are shut down, primarily because of their age, and that maintenance costs cannot compete with the price of natural gas-fired plants.[8] Since electricity was first generated from a nuclear reactor in 1951, about 36 nuclear plants,[9] including Trojan in Oregon, have been shut down or decommissioned,[10] and others are likely to close over the next few years. However, some closures have been deferred in part as concerns about climate change have grown and the nuclear industry has made an argument to save greenhouse gas emissions-free energy generation.[11]

America's nuclear plants average 39 years of age, ranging between 4 and 51 years old. Most plants' operating licenses from the U.S. Nuclear Regulatory Commission will expire in the 2030s or 2040s, and six have operating licenses allowing them to operate into the 2050s.[12] Assuming the reactors will operate to the end of their license without extensions, the average lifespan of the existing inventory is 57 operating years.

Figure 1: Number of New Reactors in the United States by Decade[10]

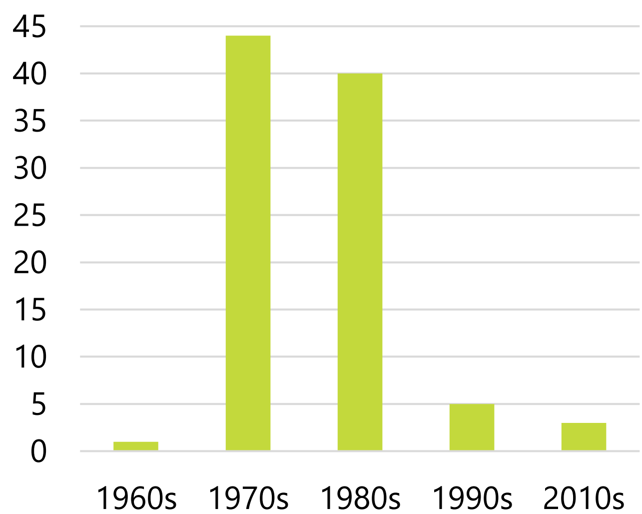
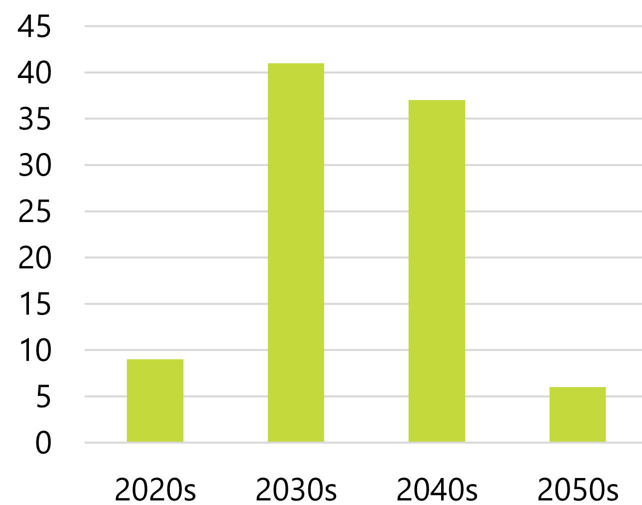


Figure 2: Number of Expiring Reactor Licenses in the United States by Decade[12]



Non-Energy Implications

Nuclear-based electricity production does not create carbon dioxide or other greenhouse gas (GHG) emissions.[13] The United Nations Intergovernmental Panel on Climate Change (IPCC) has said nuclear energy could play an important role in mitigating the effects of climate change if concerns regarding nuclear power, such as safety, economic efficiency, and waste management are effectively addressed. However, there are environmental impacts and GHG emissions from plant construction, plant operations, fuel procurement, and the thermal load of the cooling water being discharged into water bodies during operation.[14]

Nuclear power generation also creates a radioactive waste stream that persists for hundreds of thousands of years. There is no known technology that can shorten the amount of time the waste remains a risk to human health and the environment.[15] As a result, the plan for this waste is to store it in a central repository which will keep it far out of reach of humans and isolated from the environment. About 80,000 metric tons of spent nuclear fuel is currently stored onsite at reactor sites throughout the United States.[16] The federal government has been struggling for decades to site, construct, and operate a deep geologic permanent disposal facility for this fuel. The USDOE no longer predicts when such a facility may be available and ready to accept the radioactive waste.

Nuclear power also poses a risk of catastrophic accidents that doesn't exist with other forms of energy generation. The 1979 accident at Three Mile Island in Pennsylvania crippled the reactor and cost nearly one billion dollars in cleanup,[17] while the accidents at Chernobyl and Fukushima have had far-reaching consequences in terms of health impacts and environmental damage and have cost hundreds of billions of dollars each in cleanup.[18] [19] These accidents have reinforced a generational concern over safety by the public.[20]

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Technology Review: Small Modular Nuclear Reactors

- Total Capacity and Facilities in Oregon: 0
- Range of Potential Sizes: 60 – 250 MW per module

Oregon-based NuScale developed the first modular reactor to receive design approval by the U.S. Nuclear Regulatory Commission.

Small modular reactors (also referred to as SMRs), as the name implies, produce smaller amounts of electricity than typical nuclear reactors. Nuclear reactors use the heat generated from nuclear fusion to generate steam. The steam is then used to spin turbines, generating electricity. SMRs generate 300 megawatts (MW) or less of electricity per module[1] compared to traditional nuclear reactors of 1,000 MW or more per module (i.e., Columbia Generating Station in Washington state has a nameplate capacity of 1,207 MW). They are scalable to fit diverse energy needs, are factory-fabricated (both to save cost and time), and are equipped with passive/inherent safety systems.

Oregon-based NuScale Power is the first modular nuclear reactor to receive design approval from the U.S. Nuclear Regulatory Commission.[2] The SMR being designed by Oregon-based NuScale is expected to be able to safely shut down and self-cool indefinitely with no operator action, no AC or DC power, and no additional water.[3] SMR technology can be operated as a firm (or consistent) resource, but theoretically may also have some limited capability to vary its output based on changes in demand. [4]

While there are small, traditional nuclear reactors operating in the world, there are no new-generation SMRs yet in operation. The International Atomic Energy Agency reports that of the 50 or more designs being pursued, there are "four SMRs in advanced stages of construction in Argentina, China and Russia, and several existing and newcomer nuclear energy countries are conducting SMR research and development."[5]

Learn more about nuclear energy in the nuclear Technology Review.

Trends and Potential in Oregon

While Oregon law prohibits site certification of an SMR in the state,[6] Oregon is home to one of the world's leading SMR companies, NuScale. NuScale is based in Portland but traces its origins to Oregon State University. The company's goal is to develop a fully factory-fabricated module capable of generating 60 MW of electricity using a "safer, smaller, scalable" version of pressurized water reactor technology.[7]

On August 28, 2020, NuScale received a Final Safety Evaluation Report from the U.S. Nuclear Regulatory Commission. The Standard Design Approval from the NRC is anticipated to follow shortly. Both of these items signify NRC approval of the NuScale design. Final design certification is scheduled for August 2021.[8]

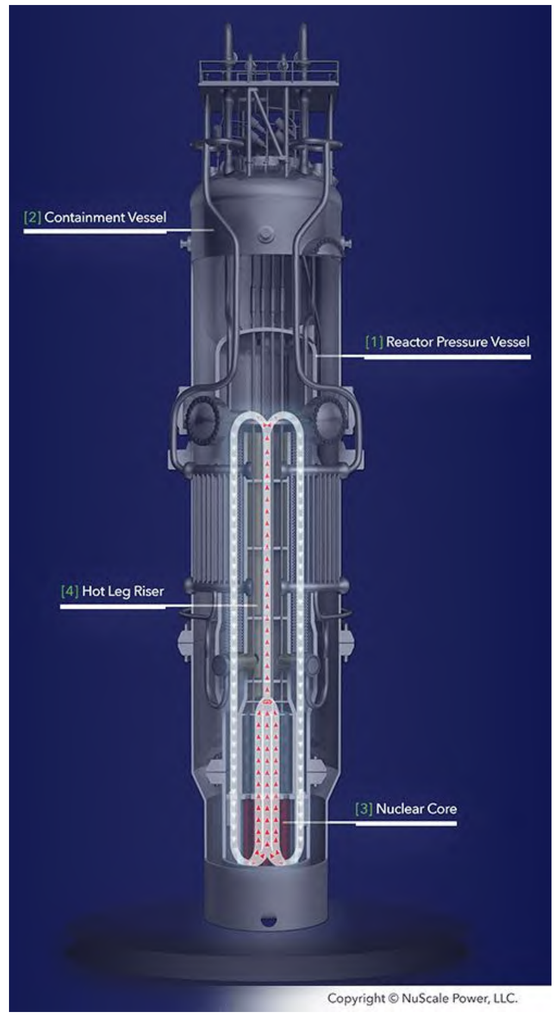
In June 2013, NuScale Power launched the Western Initiative for Nuclear (Program WIN), a broad, multi-western state collaboration to study the demonstration and deployment of a series of NuScale

SMR power plants in six western states. The first project to come out of Program WIN is a 12-module, 720 megawatt NuScale power plant that will be sited at the Idaho National Laboratory for the Utah Associated Municipal Power Systems' (UAMPS) Carbon Free Power Project. The first module is anticipated to be operational by mid-2029, with the remaining 11 modules to come online for full plant operation by 2030.[9] The plant will be operated by Energy Northwest.[10]

Opportunities

SMRs have been supported by the U.S. Department of Energy through research, development, and deployment support. The reactors are envisioned to vary in size from a few megawatts (called microreactors) up to hundreds of megawatts, and have the potential to be used in a variety of applications for power generation. They may also be able to provide resilient and reliable off-grid power directly to remote locations, including military installations and other national security infrastructure.[11]

Figure 1: Design Illustration of NuScale Power Modular Reactor



In addition to NuScale, 50 or more other entities, including Holtec International and TerraPower, are moving forward with their own designs.[12] The layouts, fuel sources, stage of development, and safety features vary widely.[13] The most advanced SMR project may be in China, where Chinergy has begun construction of twin 250 MW high temperature gas cooled reactors.[14]

Electrical utilities, industry groups, and government agencies throughout the world are investigating alternative uses for SMRs beyond electricity generation such as:

- Producing steam supply for industrial applications and district heating systems – as one example, China is developing small district heating reactors of 100-200 MW capacity, as the market for heating in northern China is now served almost exclusively by coal.[15]
- Making products such as hydrogen fuel and desalinated drinking water.[16]

Potential advantages of SMRs remain to be seen. However, the following are some differences between SMRs and typical large-scale nuclear reactors.

- The SMR designs may eliminate many of the technical safety issues inherent with large reactors.[17] Modular offsite construction allows more opportunities for inspections to catch construction defects before the reactor goes online. Since there is less centrally located fuel, there is less likelihood of a catastrophic release to the environment.

- SMRs may also have a role in community resilience. SMRs can start up from a completely de-energized condition without receiving energy from the grid; meaning SMRs can operate connected to the grid or independently during disasters.
- SMRs can be built underground, making them less vulnerable to extreme weather events, earthquakes, or intentional destructive acts.
- SMRs can store a decade's worth of fuel on site without the need for an external fuel supply; and a plant can stagger the refueling of its modules, allowing them to stay online and provide constant power to the grid without any disruptions.[18]

Barriers

Modular components, factory fabrication, and a much shorter construction duration should help control costs.[19] Whether that will make SMRs cost competitive is likely too early to answer at this point, as the final cost of construction is yet to be determined.

In Oregon, there are statutory barriers to siting unique to nuclear power. An SMR operator would have to show that there is a federal repository for the spent nuclear fuel and get approval through a statewide vote.[20]

Oregon has statutory barriers to siting nuclear power plants in the state. One barrier: Oregon voters would have to approve any nuclear facility.

Non-Energy Implications

The main advantage SMRs have over fossil fuel electric generation is that, like regular nuclear reactors, they do not directly produce greenhouse gases during their operation – they are carbon free (excluding fuel mining and processing, construction, and ancillary carbon emissions associated with operation and maintenance).[21] The United Nations Intergovernmental Panel on Climate Change has said nuclear energy could play an important role in mitigating the effects of climate change if concerns regarding nuclear power, such as safety, economic efficiency, and waste management are effectively addressed.

The use of SMRs will not alleviate the need for a solution to the nuclear waste issue. Instead, it will add to the inventory of spent nuclear fuel waiting for a disposal site.

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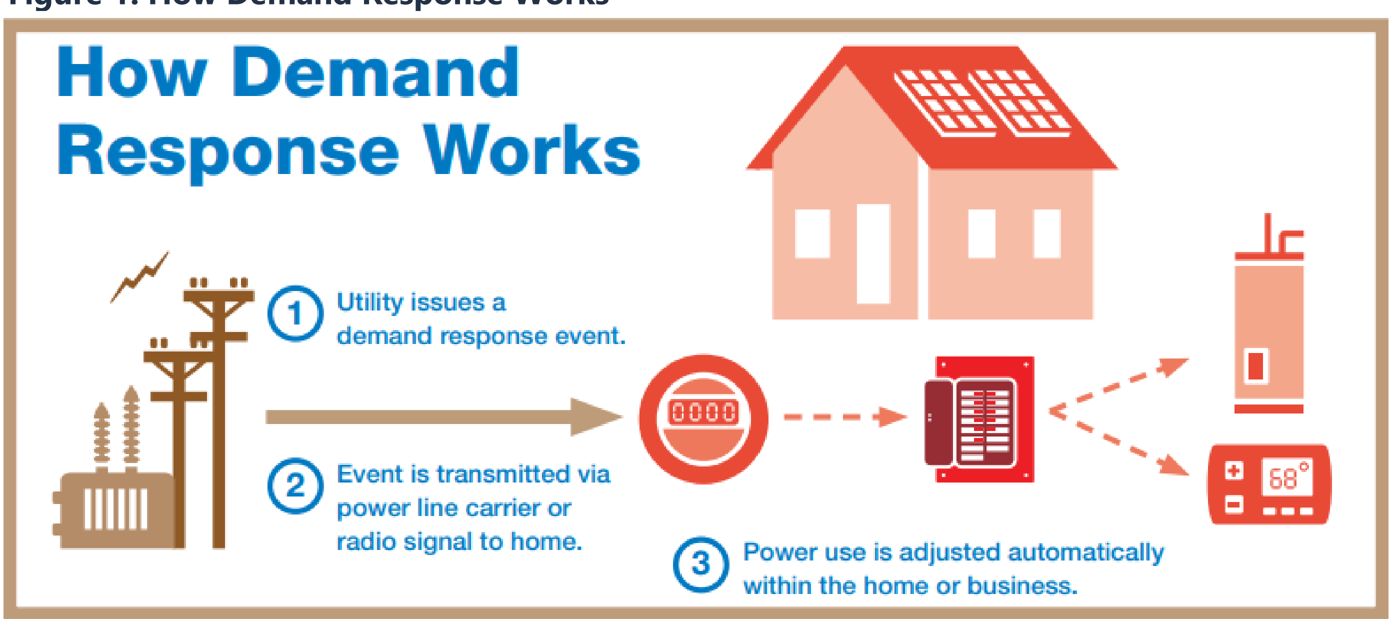
Technology Review: Demand Response

- The Northwest Power and Conservation Council's Seventh Power Plan identified demand response as the least-cost solution for providing new peaking capacity.[1 2]
- Portland General Electric's Smart Grid Test Bed is a nationally-recognized project looking to deploy demand response at-scale across three selected geographic areas.[3 4 5 6]

One strategy used by utilities to better align demand for electricity with the availability of supply is demand response, often referred to as DR, which refers to a deliberate change in a customer's normal electricity usage pattern in response to a change in price, contract, or request from a utility or grid operator. The electric system, as explored in greater detail elsewhere in this report, is unique in its relative lack of storage capabilities. As a result, electric infrastructure is necessarily designed and built to be capable of simultaneously generating and delivering to customers the electricity needed to meet peak demands. This infrastructure is only used to its full capacity for relatively few hours of the year (i.e., those when demand for electricity is exceptionally high relative to average use) and these hours contribute disproportionately to total system costs. It is within this context that demand response has traditionally been used by utilities and grid operators as an alternative to building additional capacity (either generation or transmission) to deliver more electricity to customers.[7]

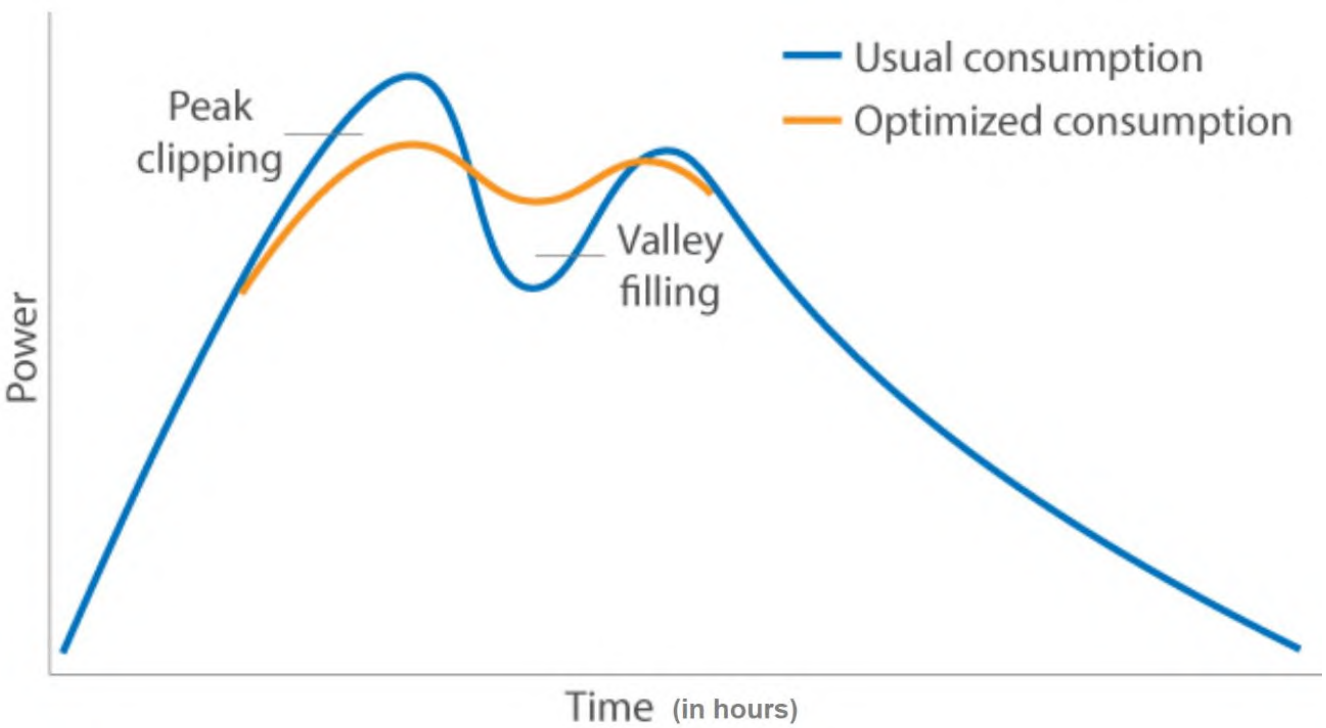
Utilities and grid operators sometimes find it more cost-effective to encourage or incentivize customers to adjust their demand rather than building new infrastructure to serve incremental peak demand. The result is typically a temporary, intentional change in electric consumption by an end-use customer in response to a request from a utility or grid operator, and the customer is then paid for this change.[8] Figure 1 from the Bonneville Power Administration illustrates how demand response technologies within the home can interact with the grid. Note that while the graphic indicates power is *automatically* adjusted, this is the exception not the rule and customer intervention is often still required:[9]

Figure 1: How Demand Response Works[9]



While demand response programs have typically encouraged or incentivized customers to *reduce* demand during system peak in the past, utilities and grid operators are seeing more opportunities to incentivize customers to instead *shift* their demand, which may increase demand during certain times. This is also referred to as demand response, and might occur for a variety of reasons, including: to avoid curtailing otherwise excess renewable generation, to adjust net load to alleviate operational ramping constraints, or to provide grid balancing services.[10] [11] Figure 2 from the Northwest Power and Conservation Council illustrates a demand curve (blue) and how demand response could hypothetically optimize the curve (orange) by flattening it to reduce the peak and minimizing the severity of the ramps in power output (up or down) required to meet changes in consumption:[12]

Figure 2: How Demand Response Can Help Meet Changes in Consumption



There are generally two broad categories of demand response resources: **(1) controllable DR resources:** resources that are controllable by the utility and can deliver a firm or dispatchable resource, and **(2) price-based DR resources:** resources that are considered non-firm because they are based upon mechanisms to induce customer changes in demand which may or may not materialize and are not directly controllable by the utility. While the Council did not include consideration of non-firm, price-based demand response resources in its Seventh Power Plan,[13] several Oregon utilities are actively exploring the potential for these resources and the Council has included them in its analysis that will inform the 2021 Power Plan.

In a Demand Response Potential Study published in 2019, BPA identified the following non-exhaustive, representative list of different types of demand response products by sector. It is reproduced in Table 1 to illustrate the wide range of products and technologies that can be deployed across sectors as demand response resources.[14]

Table 1: Types of Demand Response Products for Different Sectors

Sector	Types of Demand Response Products
Residential	**Direct Load Controls:** Water heating; space heating; central air conditioning; smart thermostats[i] **Tariff-Based:** Critical Peak Pricing **Event Notifications:** Behavioral demand response
Commercial	**Direct Load Controls:** Small and medium commercial spaces **Automated:** Lighting controls **Other:** Thermal storage; contractual demand curtailment
Industrial	**Tariff-Based:** Real-time pricing **Other:** Contractual demand curtailment
Commercial and Industrial	**Tariff-Based:** Interruptible tariff
Agricultural	**Direct Load Controls:** Irrigation
Utility System	**Other:** Demand voltage regulation / reduction

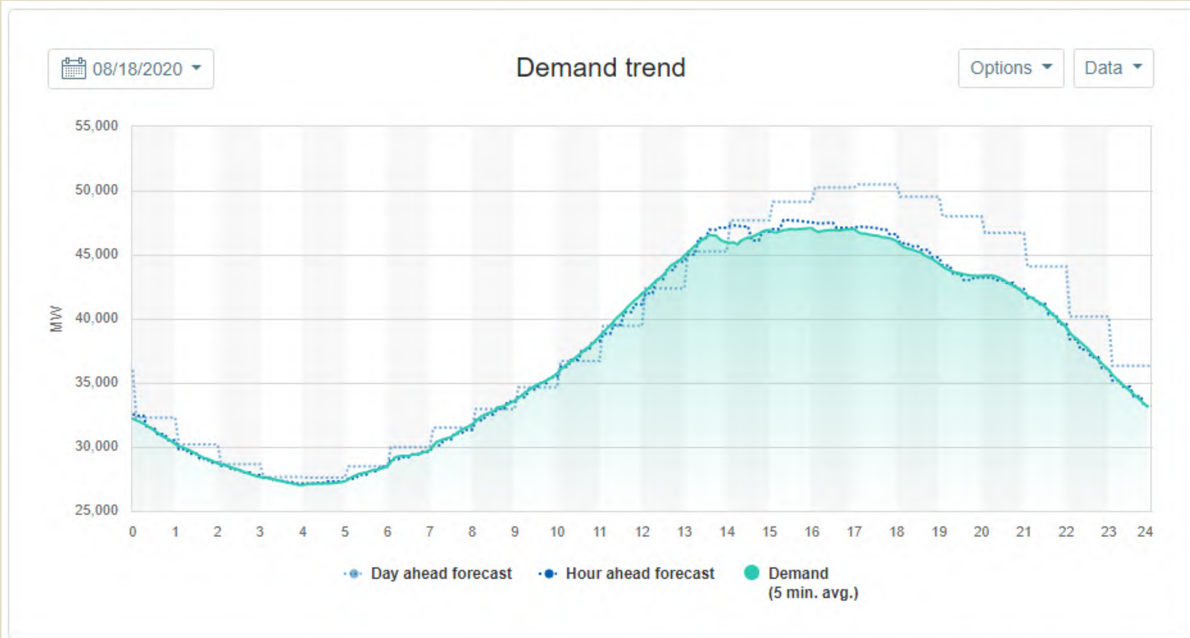
Demand Response in Action: CAISO Example

In August 2020, an extreme heat event affected much of the western United States and sent electric demand skyrocketing, particularly within the California Independent System Operator balancing area. For reasons not yet fully understood and still being investigated,[ii] CAISO was forced to institute rolling blackouts for several days to maintain grid stability.[15] [16] [17] In the days that followed, CAISO relied on demand response resources to help reduce the system's peak demand and avoid continued blackouts.[18] [19]

The CAISO demand curve below for August 18, 2020 reflects this success in averting additional blackouts.[20] The day-ahead demand forecast for that day expected demand to crest above 50,000 MW between the hours of 4 p.m. and 6 p.m. Note that CAISO's all-time peak demand (set in July 2006) was 50,270 MW.[21] As shown below, however, actual demand began to diverge significantly from the day-ahead forecast beginning around 2 p.m. and continuing through the remainder of the day. The actual peak demand for the day ended up occurring at 4 p.m. at 47,067 MW, or approximately 3,000 MW (or 6 percent) less than what had been forecasted.

[i] In the years ahead, it is likely that EV charging will present another opportunity for residential direct load control. For more information, see the electric vehicles Technology Review for more.

[ii] Note, however, that state agencies in California published *Preliminary Root Cause Analysis: Mid-August 2020 Heat Storm* in October 2020: http://www.caiso.com/Documents/Preliminary-Root-Cause-Analysis-Rotating-Outages-August-2020.pdf



So, what happened? How was CAISO able to reduce its expected peak demand by 6 percent in 24 hours and avoid the need for continued blackouts? Customer participation in demand response efforts played a large role. CAISO issued FlexAlerts,[22] which call upon customers to voluntarily reduce demand during critical hours, while utility-administered demand response programs were available that could compensate customers for reducing demand.

FLEX ALERT
FLEXALERT.ORG

A full accounting of exactly what type of demand response resources contributed to achieve this level of reduction is not yet available, but early indications suggest a robust customer response. Southern California Edison used its demand response programs to reduce peak demand by more than 800 MW, including the use of direct load control air conditioners and smart thermostats for more than 250,000 residential customers. Pacific Gas & Electric, meanwhile, achieved significant reductions by triggering interruptible service agreements in place with certain large commercial and industrial customers.[23] [24]

On that night of August 18, Steve Berberich, President and CEO of the CAISO, offered the following comments:[25] "Californians made tonight a success. Everyone pulled together and responded to our warning with action to avoid any interruption in electricity supplies."

"It is time to take demand response as seriously as we take the hardware solutions to grid reliability." [26]

~ Professor Severin Borenstein, Member, CAISO Board of Governors

Trends and Potential in Oregon

The Federal Columbia River Power System (FCRPS) has provided the foundation of the power system in Oregon and the region for over 80 years. The robustness of this system allows the northwest power sector to benefit from flexible, low-cost, zero-emissions hydropower and to largely avoid the types of capacity constraints that have led other regions of the country to develop significant demand response resources over the past decades. The Council has now identified a potential capacity deficit in the northwest within the next decade driven primarily by continued load growth, increasing constraints on the FCRPS, and coal plant retirements.

> *Learn more about resource adequacy in the Energy 101 section.*

Despite this future capacity deficit, and the Council's finding in the Seventh Power Plan that demand response resources are the least-cost solution[iii] for providing new peaking capacity,[27] the northwest "has yet to make substantial progress" on the development of new demand response resources according to the Council's Mid-Term Assessment of the Seventh Power Plan published in early 2019.[28] Council staff have recently finalized demand response supply curves for inclusion in the forthcoming 2021 Power Plan and find a significant amount of achievable potential across the northwest (over the 2022-2041 time horizon considered by that plan) that could meaningfully contribute to meeting the region's peak capacity needs in the years ahead.

Table 2: Achievable Demand Response Potential in the Northwest by Season

Season	Total Achievable Potential (MW) from 2022-2041 [29]	Achievable DR Potential as an Approximate Percentage of Regional Seasonal Peak Demand (2041) [30]	Top 3 Products by Achievable Potential (% of Regional Peak) [31]	Levelized Fixed-Cost of DR Potential (Weighted Average)[32]
Winter	2,761	9%	• Residential Electric Water Heating (3%) • Residential Heating (2%) • Demand Voltage Reduction (2%)	$39.52/kW-year[iv]
Summer	3,730	12%	• Residential Electric Water Heating (3%) • Agricultural Irrigation (3%) • Demand Voltage Reduction (2%)	$31.17/kW-year

[iii] The Power Council has identified the fixed-cost of DR potential in the range of $30 to $40/kW-year. By comparison, in Appendix H: Generating Resources of the Seventh Power Plan (see, pp. H11-H12), the Power Council estimated that a new combined-cycle combustion turbine (CCCT) with an in-operation date of 2020 would cost between $180 and $205/kW-year.

[iv] $/kW-year is a metric commonly used to estimate the annualized fixed cost of planning, building, and maintaining a capacity resource. This cost is fixed irrespective of whether the capacity resource is used to generate electricity. This is in contrast to $/kWh which is a metric commonly used to measure the variable levelized cost of actually generating electricity, which requires inclusion of an analysis of all fixed (e.g., capital costs) and variable costs (e.g., fuel costs).

Electric utilities in Oregon have identified significant demand response potential in their respective service territories,[33] [34] and recent planning efforts indicate that more resources are likely to be developed in the years ahead.[35] [36] For example, in the Action Plan for its 2019 Integrated Resource Plan, Portland General Electric forecasts a cumulative addition of 190 MW (summer) and 129 MW (winter) of demand response capacity in its business as usual case for 2023.[37] If developed, these resources could contribute 5.4 percent and 3.7 percent, respectively, toward PGE's summer and winter peak load as forecasted for 2023.[38] To put these Oregon-specific numbers in broader context, according to the Federal Energy Regulatory Commission, the percentage of demand response resources in national organized wholesale markets in 2018 was 29,674 MW, or 6.0 percent of total system peak.[39]

Opportunities

As recognized by the Council's Seventh Power Plan, there remain significant opportunities for demand response to contribute to meeting the needs of the electric sector in the northwest and in Oregon. Some key benefits include:

- **Low-Cost Capacity Resource:** As identified by the Seventh Plan, demand response resources can be a low-cost capacity resource ($/kW-year), which is likely to have additional value for the region in the years ahead given forecasts of a capacity deficit within the next decade.
- **Non-Wires Solution:** As with many other distributed resources, demand response resources can help utilities manage peak power flows and potentially eliminate or defer the need to build large centralized resources, such as new sources of generation or transmission and distribution upgrades.[40] [41]
- **Efficient Utilization of Existing Resources:** Demand response resources can improve the efficiency of the overall electric system by better aligning customer consumption with the actual costs of operating the system, often resulting in cost savings both for utilities and customers.[42] [43]
- **Renewables Integration:** The quick-responding demand flexibility that demand response resources provide can also help the grid by ramping loads up or down to integrate the variable output of wind and solar projects.[44] [45]

Barriers

While the potential and value of demand response has been identified in Oregon and across the region, there remain challenges to the deployment of demand response resources, including:

- **Valuation Framework:** There is no clear mechanism (e.g., standard contract, tariff, or market) for valuing and pricing the benefits that demand response—or other distributed resources—can deliver to the grid.[46] [47] [48]
- **Distributed Data Systems:** Depending on the type of resources deployed, utilities and customers may need to invest in new technologies to enable two-way communications between the grid and end-use customers.[49] [50] To the extent that these enabling technologies

are required, it is likely that access to these demand response resources will be distributed inequitably due to the up-front capital costs required and the disparate ability of individual customers to afford those investments.

- **Perceptions of Uncertainty:** From the utility perspective, the diversity of demand response resources (e.g., direct controls, voluntary customer actions, automated responses, etc.) can create concerns around a potential lack of clarity in communicating offerings to customers, and can create uncertainty about how firm the resources are going to be for meeting the utility's needs.[51] [52]
- **Customer Concerns:** From the customer perspective, concerns about adverse effects on business operations (for commercial and industrial customers) or comfort for residential customers (e.g., direct control of a thermostat) are potential barriers, as are concerns over privacy and information security.[53]

Non-Energy Implications

The deployment of demand response resources has potential implications beyond the energy sector. As with many distributed resources, demand response offers potential solutions to meeting the grid's needs without the development, and associated environmental impacts, of building new sources of generation or transmission and distribution upgrades. More unique to demand response are the potential privacy implications for customers and cybersecurity risks that stem from deploying two-way communication systems between the grid and customers.

Demand Response and Natural Gas

Demand response is not just used by electric utilities. Natural gas utilities also use demand response to ensure that there is sufficient fuel available to meet critical needs, such as heating during cold weather events. Natural gas is the largest source of direct fuel for heating in Oregon, and natural gas fuels power plants that provide electricity also used for heating. Natural gas consumption tends to peak during the coldest times of the year when natural gas is used to heat buildings and to generate electricity. Adding infrastructure to meet these types of infrequent peak demands are expensive investments for utilities and their customers.

Natural gas utility demand response programs use service agreements in which large industrial and commercial customers voluntarily allow their natural gas service to be occasionally interrupted, either partially or fully. This interruption could be for a few hours or days during extreme weather events or supply disruptions. Businesses that participate in demand response programs benefit from discounted rates for participating in the program. Customers can benefit from the cost savings the utility realizes by delaying or eliminating infrastructure upgrades due to a lower peak load. For example, NW Natural has enough participants in its demand response programs to interrupt approximately 9 percent of the gas it would otherwise have to deliver on extremely cold days, which reduces their need for infrastructure investments and any corresponding costs to their customers.[54]

With the advent of automated metering infrastructure and smart devices, natural gas utility demand response programs may be able to cost-effectively include residential and small commercial customers in demand response programs. Turning down a thermostat in a home by very small amounts across thousands of customers could be sufficient to reduce loads during peak hours while still maintaining sufficient energy supply. Local data collection coupled with smart devices could also allow natural gas utilities to monitor for localized issues on their distribution systems and address these with incremental load reductions. For example, equipment that can detect low pressure on a specific feeder line could help address the issue with location-specific demand response programs to reduce load in the area.

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Technology Review: Advanced Meter Infrastructure or "Smart" Meters

For much of the history of the utility industry, *mechanical meters* were used to measure energy consumption for billing purposes, with utilities dispatching personnel to manually read individual meters. There has been a significant increase (nationally and in Oregon) in the utilization of *automated meter reading* (also referred to as AMR) and more recently *digital smart meters* (also referred to as Advanced Metering Infrastructure, or AMI).

Automated meters use radio frequency waves to transmit data directly to a utility, eliminating the expense of meter-reading personnel. Automated meters may transmit data via secure networks, power line communications, or in some cases, short range transmissions may be read by a passing vehicle sent by the utility. Automated meter technologies are most commonly used by electric utilities, though they may also be used for gas and water meters. For example, Cascade Natural Gas uses AMR devices to enable drive-by reading of meters, which eliminates the need for utility personnel to enter customer properties.[1] AMI smart meter technologies can measure and transmit customer consumption and production data in sub-hourly time intervals. They also allow for two-way communications, which provides customers with more detailed information about their own consumption and also enables the utilities to control smart appliances such as water heaters, thermostats, and electric vehicle charging stations. In addition, smart meters allow utilities to more rapidly pinpoint outages, and thereby reduce response time and power outage durations.

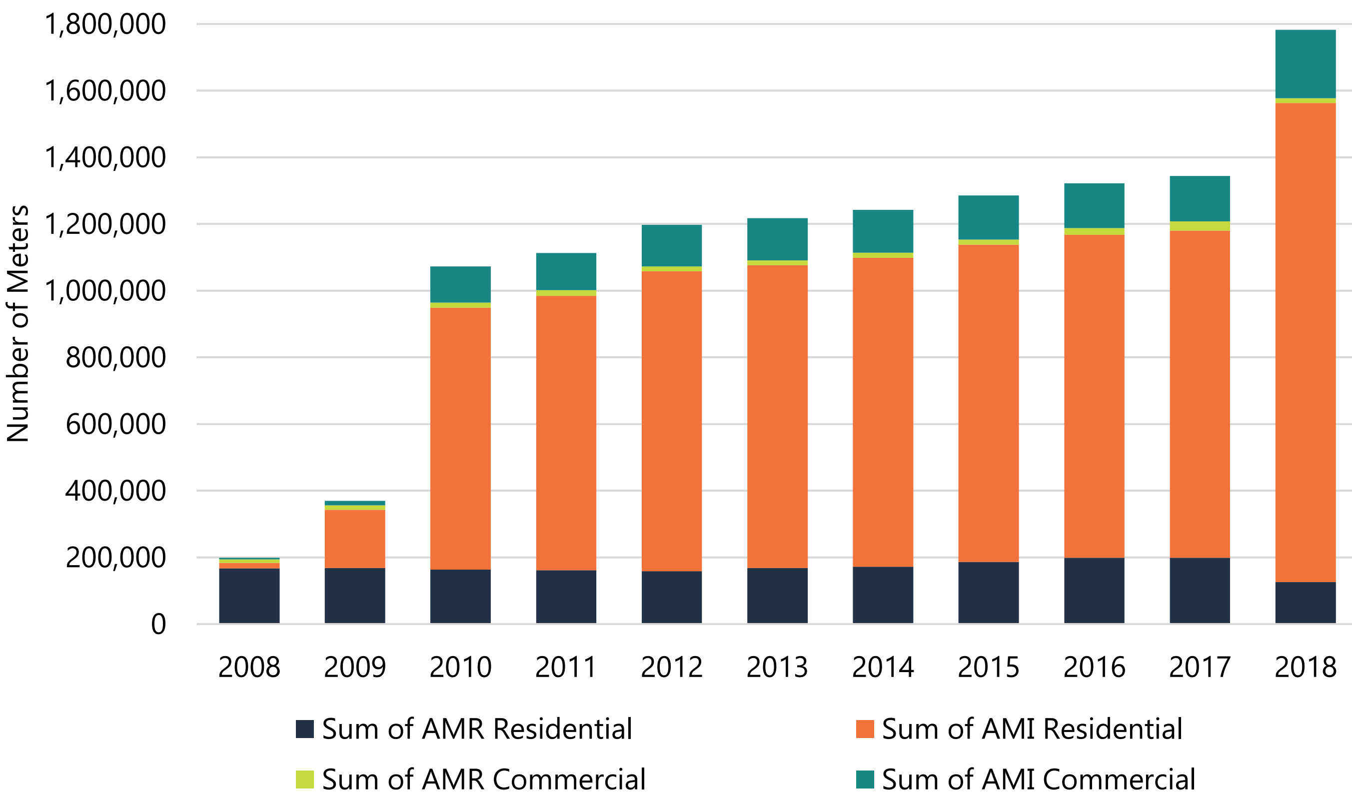
Two-way communication allows customers to opt in to utility programs that can lower their bills by optimizing smart appliances and devices. This can be accomplished by controlling when appliances and devices are used. For example, not allowing them to operate during high rate peak periods and shifting this load to lower priced off-peak hours. This can also allow utilities to better manage their system peak loads by effectively managing individual customer loads. For example, at peak system energy consumption on a very hot day, a utility could temporarily stop charging an electric vehicle to ensure there is sufficient energy to meet system cooling needs, and then allowing charging in the off-peak hours (i.e., overnight).[2]

Learn more in the Demand Response technology review.

Trends and Potential in Oregon

By the end of 2018, electric utilities had deployed smart meters to approximately 128 million customers across the United States, with the majority of those installations for residential customers. In Oregon over the same period, utilities have deployed nearly 1.8 million AMR and AMI meters, with more than 48 percent penetration among commercial and industrial customers, and 87 percent penetration among residential customers.[3] Figure 1 demonstrates the number of AMR and AMI meters installed in Oregon between 2008 and 2018. The reduction of residential AMR meters in 2018 is more than offset by the number of residential AMI meters, indicating a replacement of the older AMR technologies with new AMI smart meters.

Figure 1: Residential AMR and AMI Meters in Oregon by Year



Oregon's 87 percent residential penetration by 2018 of AMR and AMI technologies is on par with neighboring states with Washington at 72 percent, and California at 90 percent. Penetration of smart meters among Oregon's commercial customers (48 percent), however, is lower than neighboring states, with Washington and California at 67 percent and 90 percent respectively. The high penetration of smart meters for commercial and industrial customers in California is likely due to the requirement on utilities to institute *time-of-use rates* which enables customers and the utilities to lower their costs. Table 1 summarizes the penetration of AMR and AMI technologies by sector in Oregon, Washington and California.

Learn more about AMI in the Policy Briefs section.

Table 1: Penetration of AMR/AMI Meters (2018		
State	**Residential**	**Commercial & Industrial**
Oregon	87%	48%
Washington	72%	67%
California	90%	90%

Source: U.S. Energy Information Administration

Opportunities

AMI is a prerequisite for *Smart Grid,* which enables more effective use of existing electricity generation, transmission, and distribution assets. Such optimization can reduce costs for utilities, which ultimately result in stable or lower costs and better reliability for utility customers. Detailed energy consumption data that AMI provides is necessary for many smart grid technologies and programs. For example, smart meters provide the data needed for utility demand response programs that offer customers financial benefits to limit their consumption during times of heavy electricity demand. In Oregon, Portland General Electric and Pacific Power offer time-of-use rates as well as direct load control, which provide financial savings to customers willing to adjust when they use electricity.[4] Smart appliances can communicate with the utility, which in turn can send signals to those appliances to reduce or stop consuming energy during peak load time periods. In the future, smart appliances may use real-time market pricing information to determine when it is most cost-effective to operate. AMI can also help utilities better manage the distributed renewable electricity generation on their systems, such as rooftop solar. Smart meters provide data to help utilities do daily load following and allow them to better plan for the future needs of the distribution system. This improved data and planning are necessary to integrate higher levels of intermittent renewable energy onto the grid.

Learn more about distributed system planning in the Policy Briefs section.

Barriers

While smart meters can bring financial benefits to utilities and customers, there are significant upfront costs associated with replacing thousands of existing meters, in addition to other barriers to deployment and full utilization. One deployment barrier has been public perception of health risks associated with radio frequency radiation and data privacy issues associated with detailed electricity consumption records. Another barrier to full utilization of AMI technologies is a lack of installed smart appliances. Smart appliances may be configured to support grid operation in conjunction with smart meters; however, development of new products, product standards, and consumer adoption will be necessary to realize these benefits.

Non-Energy Implications

Smart meters play a critical role in improved operations, reliability, and planning of the electricity distribution systems. Better data collection and planning enables more efficient grid operations, which results in reduced GHG emissions.[5] These reductions are made possible through more effective use of existing fossil fuel resources, as well as integration of more renewable energy resources. GHG emissions can also be reduced by eliminating millions of miles of driving by utility personnel to read meters. The use of smart meters enables Portland General Electric to annually avoid 1.2 million miles of driving, which reduces CO2 emissions by 1.5 million pounds or nearly 700 metric tons.[6]

Eliminating millions of miles traveled by utility meter readers cuts transportation-related greenhouse gas emissions.

Widespread adoption of smart meters results in millions of existing mechanical meters being removed from service. Proper disposal of the old meters involves recycling as much of the materials as possible. Electric meters are composed of steel, glass, plastic, and non-ferrous metals, all of which can be recycled.

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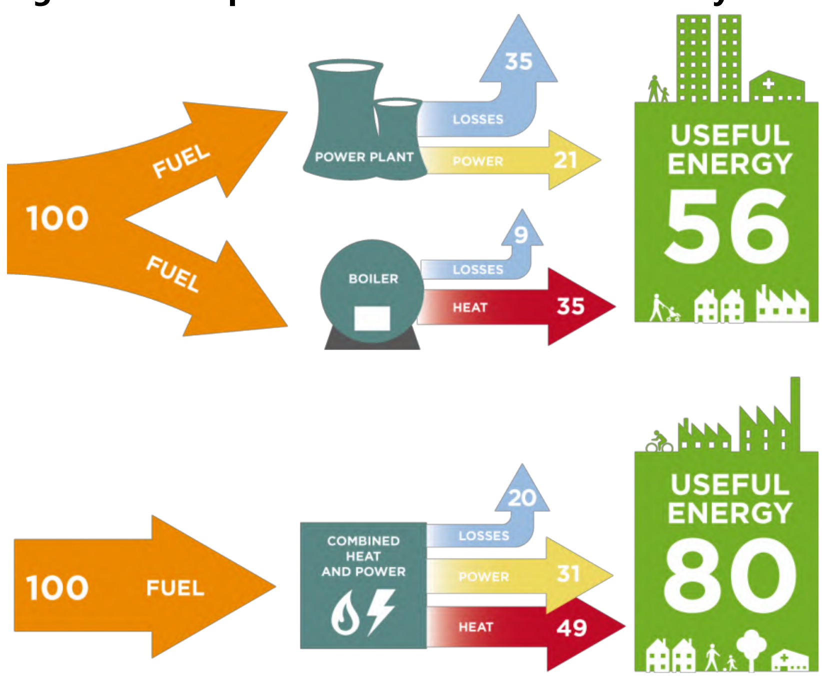
Technology Review: Combined Heat and Power

- Installed Capacity in Oregon: ~1,700 MW
- Sites in Oregon: 30+
- Sites range in size from a few hundred kilowatts to several hundred megawatts, and are located at a variety of industrial facilities like pulp and paper mills, lumber mills, wastewater treatment plants, and universities.[1 2 3]

Combined heat and power, also referred to as CHP or cogeneration, is a process where multiple forms of useful energy are generated from the same fuel source. Typically, CHP involves concurrent production of electricity and thermal energy, and the combined system results in an overall efficiency that is higher than if each were generated separately, as depicted in the theoretical illustration in Figure 1.

Figure 1: Example Combined Heat and Power System[4]



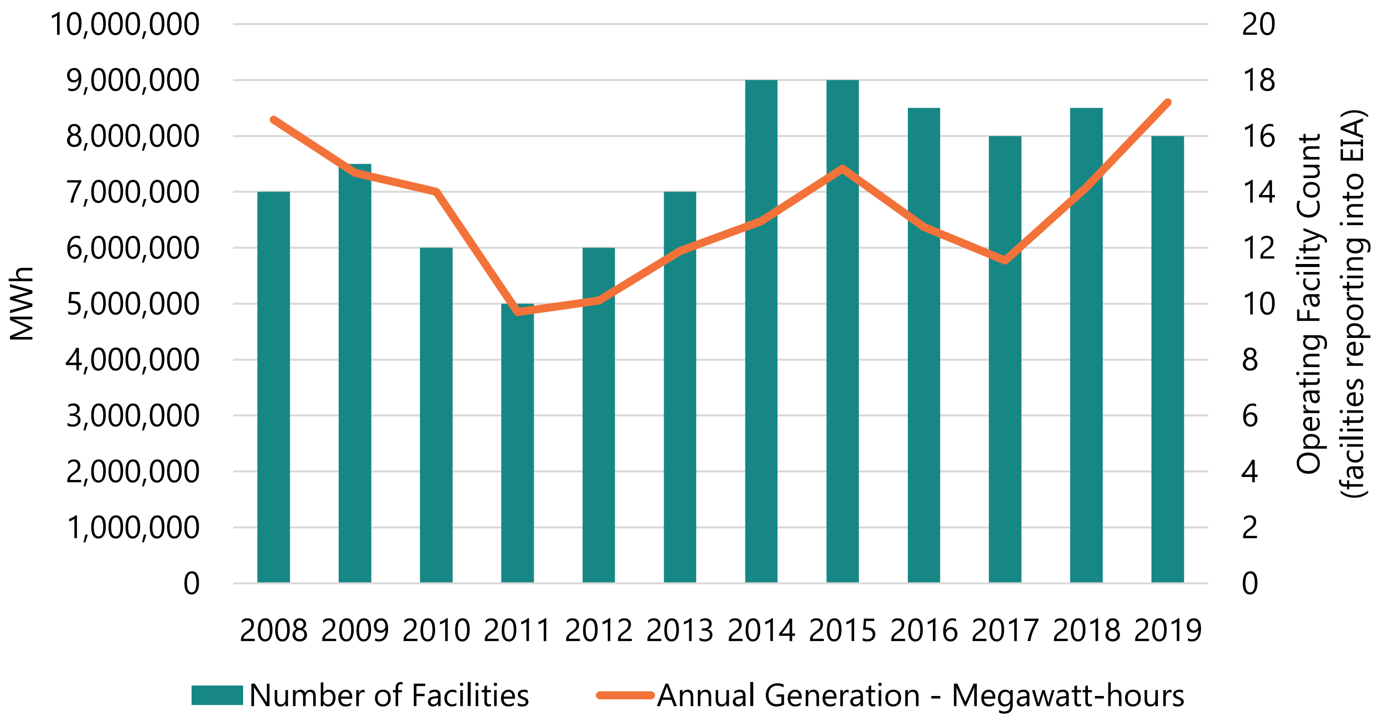
CHP systems can come in various forms and sizes. Some systems involve a first stage of fuel use for electricity generation with subsequent heat recovery to provide useful thermal energy. This configuration is known as a "topping cycle" CHP. In contrast, "bottoming cycle" CHP uses fuel to first provide thermal energy and the rejected heat is then used to generate electricity. CHP systems can employ gas turbines or reciprocating engines to power a generator, and heat exchangers and heat recovery equipment to provide useful thermal energy commonly in the form of steam or hot water. The combined process takes advantage of energy that is typically "wasted" to achieve improved overall efficiencies. CHP systems can range in size from 30 kW microturbines to large steam or gas turbines that power generators with capacity in the hundreds of megawatts.[5 6] Costs for CHP are variable and depend on system types and application, but they are generally on the order of $1,000/kW to $3,000/kW of installed generation capacity.[7 8]

CHP is not universally applicable, however. It is typically installed in locations with sufficient continuous demand for both electricity and thermal energy. These tend to be large, energy intensive industrial processes such as those in the metal, petroleum, paper, lumber, and chemical industries. However, CHP can also be applied to some commercial spaces such as hospitals. CHP systems are sometimes co-located with one or more end-users for the electricity and thermal outputs to maximize demand, continual operation, and efficiency. Excess electricity production can often be exported to the grid, but thermal energy presents a challenge to transport long distances. For this reason, CHP systems are commonly located very close to the point of thermal consumption, and systems must be sized appropriately to balance a site's thermal and electricity needs.

Trends and Potential in Oregon

Figure 2 illustrates the number of operational CHP facilities in Oregon reporting into the United States Energy Information Administration (EIA) by year and the associated electricity generation from these facilities (note: EIA data generally only includes facilities with greater than 1 MW capacity, as such there are a number of smaller facilities that are not included in the EIA database)[9].

Figure 2: Combined Heat and Power Facilities in Oregon by Year



CHP installation and operation are dependent on an appropriate site that can utilize the electricity and thermal output. Studies have shown that Oregon has technically and economically feasible CHP potential remaining across the industrial and commercial sectors.[10 11]

There are also examples where CHP systems can take advantage of biomass as a fuel, and in Oregon can potentially generate thermal renewable energy certificates (T-RECs) to contribute to the Oregon renewable portfolio standard, or RPS.[i] Traditional renewable energy certificates, or RECs, are created when electricity is produced using renewable fuels. T-RECs represent the thermal equivalent of a traditional REC. Both RECs and T-RECs represent a defined generation amount – 1 megawatt-hour and 3,412,000 Btu for RECs and T-RECs, respectively. In CHP systems that produce both electricity and thermal energy using RPS-eligible biomass as the feedstock, facility owners can earn credits for both the electricity and thermal outputs. These RECs and T-RECs can contribute to renewable facility operations and also provide the potential for monetization in a REC market to provide an incentive for renewable CHP operation. To date, Oregon has two CHP facilities – Seneca Sustainable Energy and the Gresham Wastewater Treatment Plant – that are certified as T-REC generators due to their renewably-sourced electricity and thermal energy generation.

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[i] See ODOE's 2018 Biennial Energy Report for more information on the Renewable Portfolio Standard and T-RECs.

Non-Energy Implications

CHP systems can also have non-energy implications. Improved energy efficiency and on-site electricity generation can lead to operational utility cost savings for owners. Some incentives may be available for CHP installation and operation to offset capital costs. Grid-interconnection, equipment maintenance, and operational expenses can present additional issues for CHPs owners to address. Onsite production of electricity and thermal energy can potentially offer the resilience benefits of local, distributed generation, but this can depend on the availability of fuel in an emergency situation. There are also environmental considerations for CHP. While cogeneration can represent an overall energy efficiency gain, in many cases it incorporates fossil fuel combustion that still contributes to GHG emissions and should be balanced against emissions intensity of a local grid when performing a GHG emissions accounting analysis. Also, as discussed above, where CHP systems use renewable fuel sources, RECs and T-RECs can serve as an additional benefit for system owners.

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Technology Review: Electric Vehicle Chargers

- Public Electric Vehicle Charge Points in Oregon: 1,796
- Public EV Charging Locations or Stations: 656
- Level 2 Chargers: 1,361
- DC Fast Chargers (Level 3): 384

Electric vehicle (EV) chargers are used to fuel electric vehicles. Over 80 percent of passenger EV charging occurs at home[1] by either plugging directly into a standard 110V socket (called Level 1 charging) or via a faster charging cable on a 220V plug (known as Level 2 charging). Many businesses and fleets also have Level 1 and 2 charging set up for their fleet vehicles, employees, or customers. There are also public chargers available throughout the state. Public charging can be Level 1, 2 or an even faster form of charging called DC fast charging (also referred to as DCFC or Level 3 charging), which are often located near common travel routes in the state, such as interstates and highways to the coast and central Oregon.

Overall charging times will vary depending on how much the battery has been depleted, the battery capacity, what type of charger is being used, and how much charge the driver needs to arrive at their destination. Most EVs come with a cord that will allow a vehicle owner to plug into a standard garage wall outlet. Depending on the distance traveled, it will take anywhere from a few minutes to over 10 hours to completely recharge the EV at two to five miles of range added per hour of charging. A driver can charge faster by installing a Level 2 charger, which uses 220V AC power, and supports 10 to 20 miles for every hour of charging.[2]

Unlike home or hotel charging, which generally occurs overnight, chargers used for travel beyond the battery range of the vehicle must be able to recharge in a relatively short amount of time so the traveler can get back on the road quickly. To accommodate this, DCFC stations are capable of charging at significantly higher rates than Level 1 and 2 chargers. Depending on how much the battery needs to be charged, using a DCFC rated up to 50 kW (the most common form of DC fast charger in Oregon), will add more than 80 miles of range in 30 minutes.[3] Electrify America's recently-completed Los Angeles to Washington DC charging corridor has fast chargers approximately every 70 miles along the route, an example of the sort of infrastructure needed to enable longer road trips in EVs.[4]

An all-electric TriMet bus recharges at the Sunset Transit Station in Hillsboro.
Photo courtesy of TriMet

There are two types of charging for electric medium-duty and heavy-duty vehicles: depot and on-route opportunity. Both technologies come with tradeoffs related to scheduling, maintenance, operations, and costs.[5] Depot-based charging involves charging vehicles at the garage or "depot" where the vehicle usually parks when not in service.

Learn more about medium- and heavy-duty vehicles and alternative fuels in the Policy Briefs section.

Vehicles using this method will require larger batteries to hold enough energy to complete their duty and return to the depot charger, and they typically require between one and four hours to charge depending on use, battery capacity, and charger type. Most of the current EV models for medium- and heavy-duty vehicles are used to travel from a central hub each day and return to that hub where they can be charged during off hours.

On-route opportunity-charging vehicles can charge during their scheduled service using chargers at layover terminals along their routes.[6] Vehicles using opportunity charging usually have batteries that hold a smaller amount of energy, but only require several minutes to fully charge, and can therefore continuously operate for longer periods of time. Depending on how quickly the user needs to refuel, some lighter-weight vehicles, like local delivery trucks and school buses, can also use standard 220 V charging outlets.

Charging done in the home or for fleet vehicles is generally paid for via the home or business owner's electricity bill. Public charging usually requires the user to pay for usage, although some chargers are free to the public. Users will pay for the charging either by credit card, smart phone application, payment over the phone, or through membership with a particular EV charging equipment owner.

Rates for electric fuel are set by the providers. The charging companies have different business models, so the amount it costs to charge at public stations ranges from free to $24 per session. Some pricing also includes the value of parking. Unlike the utility that supplies electricity to homes and business, which is overseen by regulatory bodies such as the Oregon Public Utility Commission or utility governing boards, non-utility companies operating chargers for EVs are not regulated by state or federal entities for the electricity that they provide.

Table 1: Charging Companies in Oregon

Nine charging companies operate in Oregon using a pay-to-charge model.[7]

Company	No. Charging Points
Blink	80
ChargePoint	62
Electrify America	16
EV Connect	7
Greenlots	8
OpConnect	6
Semaconnect	32
Tesla	56
Volta	26

Trends and Potential in Oregon

As of the end of 2018, Oregon ranked fourth in EV adoption per capita.[8] As of July 1, 2020 there are 31,977 registered electric vehicles in the state, and year-over-year adoption growth has been about 36 percent since 2015.[9] The number of charging station sites increased in Oregon by 63 percent between June 2015 and June 2020, and the number of connectors at each site has also increased, especially in the last two years.[10]

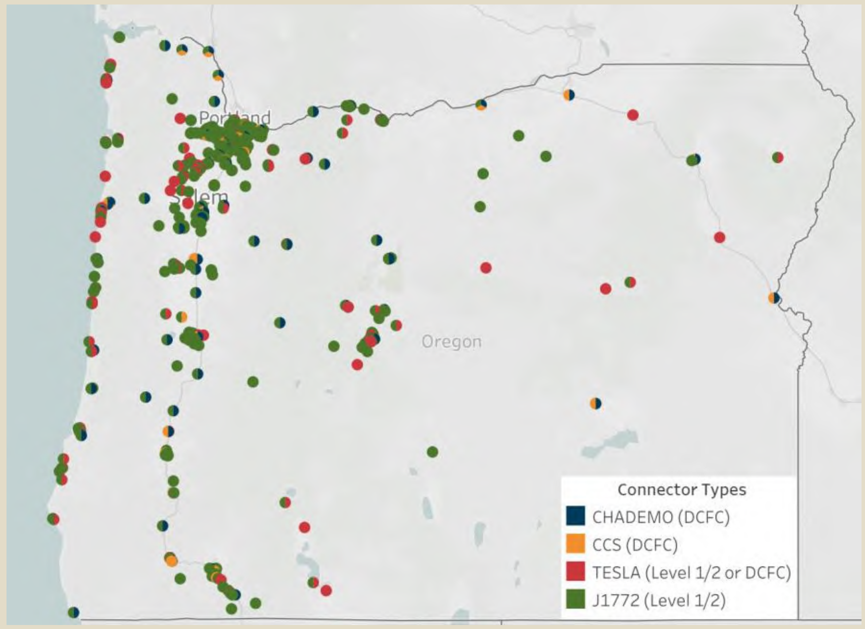
As of September 9, 2020, Oregon has 1,796 public charge points at 656 locations or stations. A station charger can have several charge points, just as a gas station has several pumps. Of these charging locations, 1,361 are Level 2 and 384 are DCFC.[11] This means there are approximately 23 zero-emission vehicles for every Level 2 charging point and 83 for every DCFC, most of which are located in the Willamette Valley.

Because much of the public EV charging is clustered around major travel corridors and population centers, many rural parts of Oregon lack access to public charging. There have been investments in frequent travel destinations, such as coastal cities along US 101. For example, ODOE and the Oregon Department of Transportation secured funding to develop the first major long-distance DCFC corridor in the United States: the West Coast Electric Highway. The West Coast Electric Highway is an extensive network of electric vehicle DCFC and Level 2 charging stations along the West Coast, from British Columbia to the California-Mexico border.[12]

The Oregon Department of Energy's **Electric Vehicle Dashboard** provides an interactive map showing detailed information for Level 2 and DCFC stations in Oregon, including payment information.

tinyurl.com/ODOEEVDashboard

There are also several smart phone apps that can help drivers locate stations.



Investments from many of the state's utilities are helping to increase EV charging across Oregon, including in rural parts of the state.[13] [14] [15] Many utilities use funds from the Department of Environmental Quality's Clean Fuels Program to procure and install chargers. Enrolled utilities receive credits for residential chargers that power EVs in their territory; the credits can be monetized for use by the utility.[16] In addition, many private companies are making investments in Oregon, including Electrify America and ChargePoint.[17] Some companies in Oregon help private business and housing owners install on-site EV charging and, if needed, establish a pay-to-use platform.[18]

Data is not readily available to determine the amount of private charging infrastructure; however, because most charging is done at home, it can be inferred that the majority of Oregon EV owners have access to charging at home. The lack of access to home charging can be a barrier for potential EV owners, as described below.

Opportunities

Investments in charging infrastructure by EV charging companies and utilities are a significant driver for increased adoption of EVs in the state. For example, Electrify America will establish Zero Emission

Vehicle (ZEV)[i] Investment Plans for two additional 30-month cycles. The State of Oregon submitted a proposal in August 2020 for investments in a third cycle.

Transportation Electrification Infrastructure Needs Analysis (TEINA)

The Oregon Department of Transportation, in collaboration with the Oregon Department of Energy, is undertaking a Transportation Electrification Infrastructure Needs Analysis (TEINA) study, as directed by Governor Brown's Executive Order 20-04, Directing State Agencies to Take Actions to Reduce and Regulate Greenhouse Gas Emissions. The TEINA study will assess transportation electrification charging infrastructure needs and gaps throughout Oregon, recognizing that convenient, accessible charging infrastructure is a critical driver accelerating Zero Emission Vehicle adoption and lowering greenhouse gas emissions. The study will highlight charging infrastructure needs for light-duty ZEVs in support of statewide adoption targets in SB 1044 (2019) and provide an overview of the charging infrastructure needs for other vehicle classes and use types, ranging from medium- and heavy-duty trucks and buses to e-bikes and e-scooters. The TEINA study will also suggest policy options and identify ways to expand charging infrastructure in Oregon to accelerate statewide transportation electrification. The outcome of this work will position Oregon to develop an overall ZEV charging infrastructure strategy that can help the state meet its transportation electrification goals.

Information Provided by the Oregon Department of Transportation

Barriers

The biggest barriers to increased EV infrastructure are costs to site and install a charger. In cases where chargers can simply be plugged into existing 110V outlets, there is no cost for the charging infrastructure. For businesses, and particularly those where medium- and heavy-duty vehicles are being charged, there is frequently a need to install a charger and upgrade the electrical service to the facility.

For public infrastructure, investments are generally made by EV service equipment suppliers or utilities. EV charging companies make investments in infrastructure in order to recoup their costs and potentially profit through the sale of the electric fuel. The profitability of these chargers depends, in part, on the amount of use and price to users. Not only is the number of users purchasing electricity critical to charging companies, but DC fast chargers are also subject to demand charges[ii] which can increase operational costs. Utilities also make investments in charging infrastructure and often recoup their costs through electric rates.

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[i] In Oregon, for the most part, ZEVs are all-electric or plug-in hybrid models. Hydrogen fuel cell vehicles are also considered ZEVs, but Oregon doesn't yet have hydrogen fueling infrastructure for that type of vehicle.

[ii] Because electricity is made just in time for use, many utilities have commercial and industrial rates that include a demand charge. This is a fee on the customer's bill for the highest amount of electricity use over the course of the billing cycle.

Another challenge in siting charging infrastructure is finding an appropriate site. A location will need sufficient electricity supply to power the charger, access to food and restrooms for drivers to use while waiting for a charge, and often cellular or internet access. Chargers also need to be located where drivers are traveling. The confluence of these needs can make finding appropriate sites and contracting with landowners a time-consuming and expensive process. Some charging companies have mitigated this by developing contracts with large retailers that would enable development of charging at any of the retailer's locations.

This bank of Tesla chargers was being installed at a northeast Salem shopping center in September 2020.

Non-Energy Implications

There aren't many studies or data readily available regarding environmental impacts of charging infrastructure. The equipment itself contains a housing, some conductors (usually copper or aluminum) and circuit boards, chips, controllers, and switches, like many other meters or appliances. Bringing the electric infrastructure to the site is often the biggest environmental impact, including cutting of concrete or parking surfaces, excavating, or installing conduit. Any negative environmental impacts of EV charging should be considered alongside the significant environmental benefits of the transportation electrification it supports.

EV charging technology is still relatively new, and upgradeability is an important consideration. In some cases, technological changes have made early chargers obsolete before they are worn out. With planning, the major infrastructure can be built to handle charging that is not yet available. Standards are being improved to allow equipment interoperability so that it may be reprogrammed with software improvements and minimal hardware changes.

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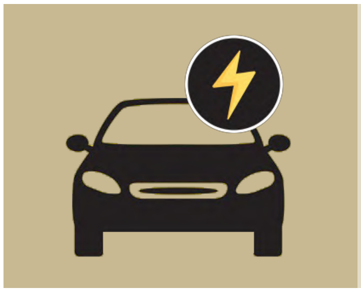
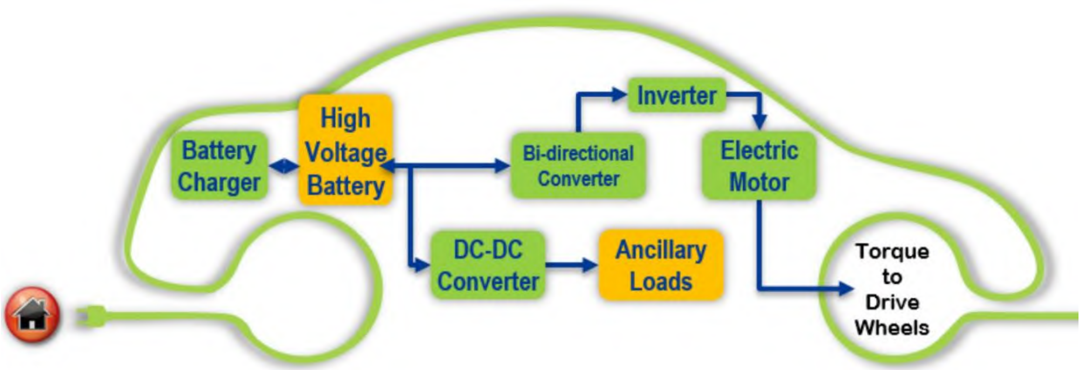
Technology Review: Electric Vehicles



- Number of electric vehicles registered in Oregon: 31,977[1]
- Number of battery electric vehicles in Oregon: 20,251[2]
- Number of plug-in hybrid EVs in Oregon: 11,726[3]
- Number of public EV chargers in Oregon: 1,796[4]

Electric vehicles use batteries, either fully or in part, to supply electric fuel to the vehicle. Batteries power one or more electric motors, which provide the force that propels the car. Battery electric vehicles (BEVs) exclusively use batteries to provide electricity as a fuel source. Plug-in hybrid electric vehicles (PHEVs) use a battery to power the vehicle for some distance before switching to either a standard gasoline-powered car or use a petroleum-fueled generator to power the battery. Unlike standard hybrid vehicles, both BEVs and PHEVs need to be plugged in to recharge the batteries. [5] A third form of electric vehicle – fuel cell electric vehicles – is discussed in the next Technology Review.

Figure 1: Electric Vehicle Drive System[6]



EVs are more energy efficient than their internal combustion engine counterparts. Standard gasoline vehicles lose over 60 percent of the fuel's energy, mostly due to heat loss during combustion and the friction of moving parts. Electric vehicles lose only about 20 percent of the energy from their electric components.[7] BEVs do not have combustion engines, so there is no need for oil changes, air filters, or belt replacements.[8] EVs also use regenerative braking, a technology that converts the kinetic motion of the vehicle into electricity, which can be used by the vehicle or stored in the battery. Because the regenerative braking system reduces this kinetic motion, the vehicles brake pads experience less friction and therefore less wear and tear. Owners do not have to replace brake pads as often, also reducing overall maintenance costs for EVs.[9] Fueling costs are about 25 percent of a typical average gasoline-powered vehicle.[10]

Trends and Potential in Oregon

Electric vehicle adoption has been steadily growing in Oregon. In 2015 there were just over 3,000 registered passenger EVs —by August 2020 there were more than 30,000.[11] BEVs show the highest rate of growth in Oregon, accounting for over 60 percent of total registered vehicles.[12] PHEV growth has held steady since 2018. The most popular light-duty models of vehicles in the U.S. are SUVs and pickup trucks.[13]

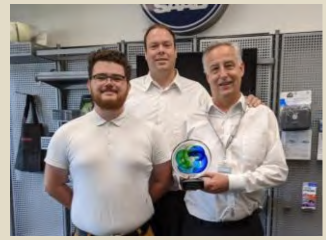
The most popular EV models in Oregon are the Tesla Model 3, Nissan LEAF, and Chevrolet Volt.[16]

Several manufacturers have released SUV EV models in the last several years, and many of those have indicated they will be releasing pickup truck models in the next few years.[14] The USDOE projects that BEVs will grow by 6 percent per year and PHEVs by 3.1 percent through 2050.[15]

Barriers to EV Adoption in Oregon

The upfront cost to purchase an EV remains higher than most gasoline-powered vehicles. For example, the electric format of a Hyundai Kona was nearly $17,000 more than its gasoline-powered counterpart.[17] Total available incentives in Oregon for this vehicle range from $10,000 to upwards of $12,500, which offsets a significant portion of the total difference in cost.[18] However, these incentives include a $7,500 federal tax credit, which is dependent on the purchaser's tax liability. Lower-income Oregonians with less tax liability may not be able to take advantage of this incentive. Oregonians also buy more used vehicles than the national average. While Oregon has a robust used EV market with EV registrations accounting for nearly 20 percent of all EVs, the availability of used models, particularly the ones in highest demand (SUVs and pickup trucks), will take some time to filter into the used vehicle market.

Platt Auto Group Meeting Oregon's Used EV Needs



In August 2020, the Oregon Department of Energy announced that Platt Auto Group was awarded a 2019 EV Leadership Award from Governor Kate Brown for helping to accelerate electric vehicle adoption in Oregon. Platt has been serving Oregon's electric vehicle community since 2013, when the auto dealer made the switch to focus exclusively on selling pre-owned EVs and educating customers about the benefits of going electric. Platt's business model of selling pre-owned stock helps expand access to more Oregonians, including lower-income families.

www.plattauto.com/

In addition to the higher up-front cost of EVs, the availability of the necessary fueling infrastructure can be a barrier to EV adoption. According to surveys conducted by Deloitte in 2018 and 2020, the lack of vehicle electricity fueling infrastructure overtook the high up-front cost as the number one concern consumers had about purchasing an EV.[19] Although investments in EV charging in Oregon have been steadily growing, the majority of charging infrastructure to date has been located in the Willamette Valley.[20] Lack of charging infrastructure in rural parts of the state may limit EV adoption in these areas. In addition, over 80 percent of EV charging is done at home.[21] Oregonians living in multi-unit dwellings and in homes that lack driveways or other ways to access charging will require additional charging infrastructure to meet their daily charging needs.

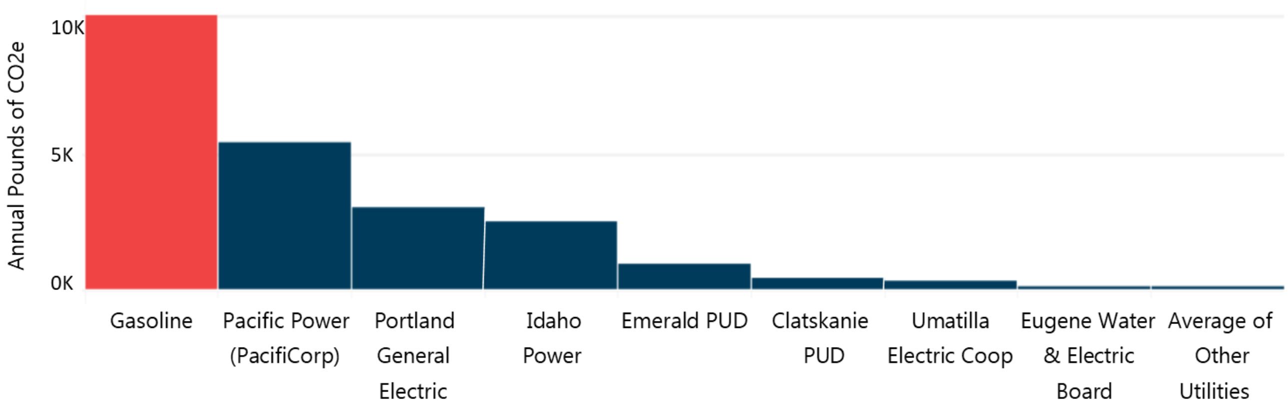
Learn more about EV models, charging, and incentives:

GoElectric.oregon.gov

Non-Energy Implications

EVs can reduce the environmental impacts of driving. EV adoption in the U.S. could reduce GHG emissions by 30 to 45 percent, depending on the mix of BEVs and PHEVs.[22] BEVs have no tailpipe emissions of greenhouse gases or air pollutants, and PHEVs emissions will depend on how often the vehicle uses gasoline for power. Emissions associated with electric fuel come from the source of electricity itself. In Oregon, no matter where an EV is charged, the overall greenhouse gas emissions will be lower than using gasoline. In many parts of Oregon where hydropower and nuclear are the predominant electricity generators, the GHG reduction potential is over 95 percent.[23] As Oregon utilities continue to add more low- and zero-carbon resources to generate electricity, the associated carbon emissions from powering an EV will continue to go down.

Figure 2: Annual EV Emissions by Oregon Utility vs. Gasoline Vehicle[23]



Emissions data is accurate as of 2018. Emissions from many utilities continue to decrease. ODOE will update this information annually. Bar chart emissions estimates are based on a 2020 gas-powered Hyundai Kona vs. a 2020 Hyundai Kona EV traveling 11,556 miles per year. All utilities in the "Average of Other Utilities" grouping have annual emissions less than 125 lbs CO2e.

In addition to GHG reductions, driving EVs reduces other air pollutants that are harmful to human health, such as nitrogen oxide and particulates.[24]

Most EV battery components can be recycled, but the separation of the different component materials is an expensive process. Most EV s are relatively new to the market and few vehicle batteries have reached the end of their useful lifetime, which limits the development of a battery-recycling market.[25] However, EV batteries are expected to last between 10-20 years as a power source for the EV, and after that, the batteries can be repurposed for other uses. Once they can no longer reliably power an EV, these batteries can be effectively used to do other tasks such as storing electricity to help manage the grid, or they can used in homes and business as an electricity resource for backup power and be charged by the grid or on-site solar panels. When batteries are no longer viable energy storage devices, about half of their materials can be recycled, but the remaining 50 percent may still enter local waste streams.[26] In 2019, the USDOE Office of Energy Efficiency & Renewable Energy announced the Phase 1 Winners of a Battery Recycling prize, which encourages technologies that profitably capture 90 percent of all lithium-based battery technologies in the U.S.[27]

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Technology Review: Fuel Cell Electric Vehicle (Hydrogen Cars)

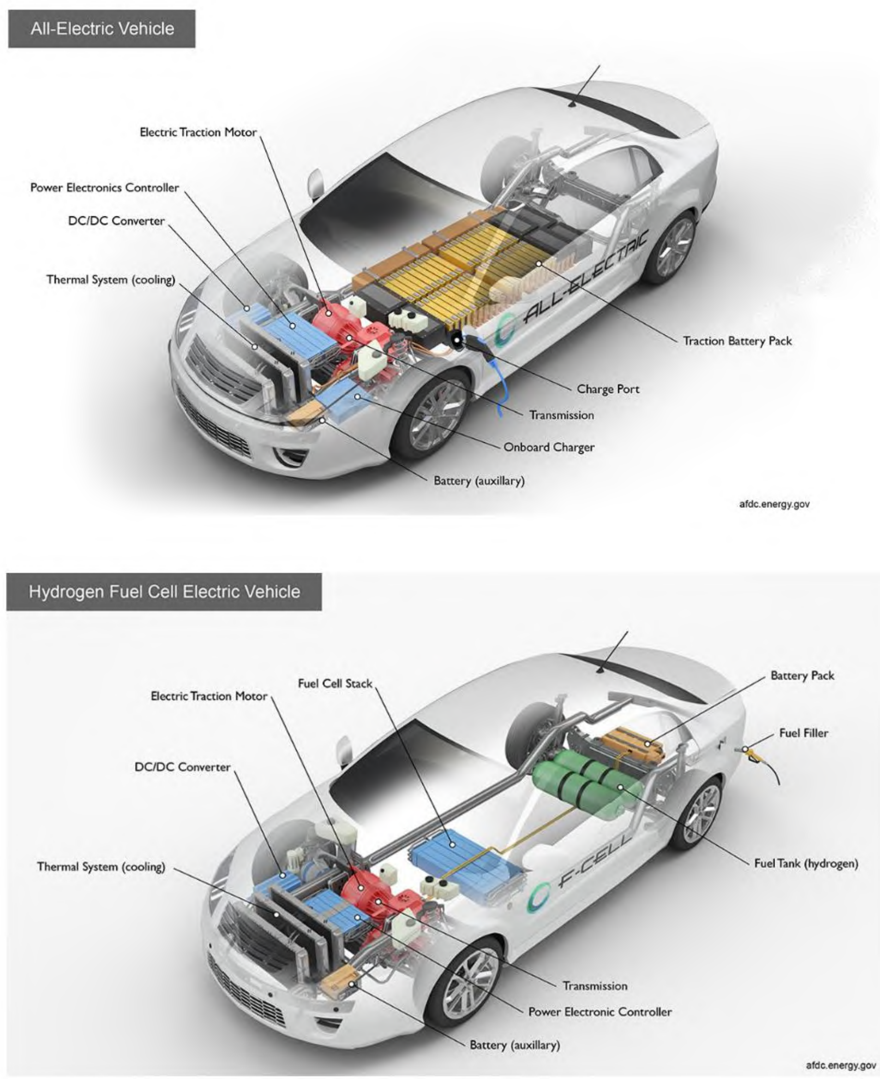
- Fuel cell vehicles registered in Oregon: 1
- Fueling facilities in Oregon: 0
- Fun fact: FCEVs emit only water from their tailpipes

Fuel cell electric vehicles (FCEV) or hydrogen vehicles, are similar to battery electric vehicles (BEV) because they are powered by an electric motor-based drivetrain. However, instead of a large pack of batteries as the source of the electric energy, FCEVs store energy as hydrogen in a fuel tank. Fuel cells use oxygen to split electrons from the hydrogen molecules to create the electric fuel that powers the vehicle, thus the name – Fuel Cell Electric Vehicles.

FCEVs have many of the same attributes as BEVs, including high torque (power directly to turn the wheels), quiet operation, and reduced emissions compared to conventional combustion engines. Unlike BEVs, FCEVs refuel at hydrogen fueling stations instead of plugging into a wall outlet or charger. FCEVs can refuel faster than most BEV recharging – about five minutes or less.[1] Where hydrogen fueling stations exist, FCEVs allow fast, centralized refueling like that of current gasoline-powered vehicles.

Like BEVs, FCEVs do not combust any fossil fuels and are therefore classified with BEVs as Zero Emission Vehicles. In fact, the chemical process of the fuel cell produces only heat and water.[3] Regarding safety of hydrogen as a fuel, some of hydrogen's properties make it safer to handle and use than fuels commonly in use today (non-toxic and dissipates quickly).[4]

Figure 1: All-Electric vs. Hydrogen Fuel Cell Vehicle[2]



Trends and Potential in Oregon

Although three models of FCEV vehicles are available for purchase in the U.S., most of these are sold in southern California where the most robust hydrogen fueling infrastructure exists.[5] Because there are not yet any hydrogen fueling stations in Oregon, the near-zero adoption rate of these vehicles is likely to continue in the near term. There may be greater near-term potential for FCEVs in the medium- and heavy-duty vehicle sectors. FCEVs offer the advantages of rapid refueling and lower overall vehicle weight compared to BEVs, which preserves the amount of payload a vehicle can carry. Due to these advantages and cost efficiencies in new fueling infrastructure for large fuel users, medium- and heavy-duty fleets may be some of the first vehicles in Oregon to adopt this technology.

FCEVs may also play a vital role in powering the freight sector. For example, the ultimate long-haul truck could have an electric drivetrain with both batteries and a fuel cell operating in tandem.[6] This could enable the truck to have the range and fueling advantages of a FCEV but add the benefits of regenerative braking capacity and some efficiency by optimizing the two systems for complex conditions such as steep grades.

FCEVs may offer the potential to help Oregon utilize more renewable electricity generation resources that may otherwise be spilled (hydro) or curtailed (such as wind). Hydrogen gas can be created by large-scale electrolyzers, which use electricity to split water into hydrogen and oxygen. The hydrogen can then be stored as a fuel for various uses, including powering FCEVs.

Learn more about alternative fuels, power-to-gas, and other transportation information in Energy by the Numbers, Energy 101, Policy Briefs, and other Technology Reviews.

Barriers

The largest challenges to FCEV adoption are access to both vehicles and fueling stations. There are currently only three passenger FCEV models, all mid-size sedans: Toyota Mirai, Hyundai NEXO, and Honda Clarity. These vehicles have been adopted mostly in Asia and southern California, where fueling infrastructure exists. Oregon has no authorized auto dealers for these cars, and there is no public or private hydrogen fueling infrastructure. In contrast, there are more than 1,600 public electric vehicle charging stations in Oregon and dozens of models of vehicles for sale.

Cost is another area where FCEVs may need to improve before they are widely accepted in the marketplace. The 2020 Toyota Mirai has a price of $56,209, more than twice the $26,155 price of a 2020 Toyota Camry Hybrid, which has similar attributes as mentioned above in Benefits of FCEVs.[7] In addition to capital cost, FCEV operating costs are expected to be notably higher than BEV and standard gasoline models for the foreseeable future. California reports the price of hydrogen has remained fairly stable at $16.50 per kg, which including the efficiency of hydrogen fuel cells is equivalent on a price per energy basis to $6.60 per gallon of gasoline.[8]

FCEV Model: Toyota Mirai
Photo courtesy: Dein Nordrhein-Westfalen

Non-Energy Implications

Currently, about 95 percent of hydrogen in the United States is made from "cracking natural gas,[i]" often as a biproduct of petroleum and fertilizer production. Therefore, while FCEVs have zero tailpipe emissions, the emissions associated with the extraction and production of the hydrogen fuel are approximately 230-260 grams/mile (as compared to 310-410 for small gasoline vehicles).[9] As discussed above, hydrogen can also be created using electricity, including surplus renewably-generated electricity. Similar to electric vehicles charged with renewable electricity, when hydrogen is produced from a renewable resource such as hydro, solar, or wind, FCEVs can approach zero emissions.

FCEVs are roughly two to two-and-a-half times more efficient than gasoline powered cars, meaning given the same amount of energy, the FCEV would travel at least twice as far. So even when the hydrogen does not come from renewable sources, fuel cell cars can still cut emissions by over 30 percent.[10] Depending on how it is made, hydrogen could also reduce lifecycle GHG emissions from the transportation sector when compared to gasoline vehicles, meaning FCEVs could help Oregon achieve its GHG emissions reduction goals.

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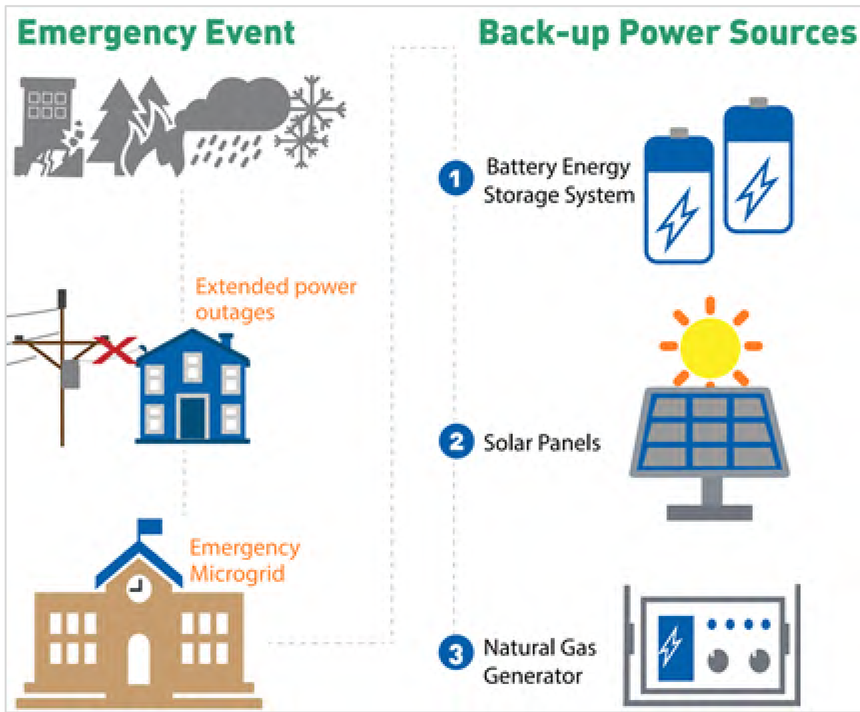
[i] "Cracking natural gas" is a chemical process using heat, pressure, and catalysts to break (or crack) long chain hydrocarbons into smaller chain hydrocarbons (often yielding excess hydrogen gas).

Technology Review: Resilient Microgrids

A microgrid is a group of interconnected end-use loads (ranging in size from a single home or building to an entire campus or even a city) and distributed energy resources (DERs) that act as a single controllable entity with respect to the larger electric grid. The key distinguishing characteristic of a microgrid is its ability to connect and disconnect from that larger grid so that it can operate either as a grid-connected resource or in island-mode to deliver power only to local loads.[1]

A wide range of energy technologies can be used to power a microgrid, and additional benefits can often be achieved by combining complementary technologies (e.g., pairing solar with an existing generator to prolong a limited supply of stored on-site fuel). The most common systems incorporate diesel or propane generators, though increasingly solar and battery storage systems are used.[2] Installation costs for these systems can vary widely depending on overall size, technologies used, the efficiency of the building(s) involved, and whether the system is designed to power all regular loads or only the most critical loads when operating in island-mode. [3] Figure 1 is adapted from a process flow diagram of a microgrid deployed by the Eugene Water and Electric Board to provide back-up power and to power a groundwater well during an emergency event.

Figure 1: Microgrid Process Flow (adapted from EWEB)[4]



Trends and Potential in Oregon

Microgrids in Oregon are employed in a wide range of situations today and most often rely on diesel or propane generators to provide emergency back-up power in case of a grid outage. These types of systems are especially common with certain types of commercial and industrial customers. Meanwhile, rapid declines in the cost for solar and battery storage systems have led to an emerging interest in the deployment of microgrid systems based on these technologies, particularly at facilities that provide critical lifeline services to communities. Notable recent deployments in the state include EWEB's project at Howard Elementary School in Eugene[5] and PGE's project at the Beaverton Public Safety Center.[6] [7] These types of microgrid projects can provide carbon-free power to support the continued delivery of critical lifeline services while avoiding the need to rely on imported liquid fuels or emit carbon.

Learn more about energy storage in fellow Technology Reviews.

Opportunities

Historically, many back-up generators have been installed by commercial and industrial customers that are uniquely sensitive to *any* potential disruption of power supply from the grid. Hospitals are one of the more common examples, where a routine two-hour grid outage caused by a severe storm could have significant adverse consequences for high-risk patients or sensitive medical equipment. Meanwhile, many advanced industrial processes (e.g., semiconductor manufacturing) are also susceptible to substantial adverse consequences resulting from even a minor grid outage. The following have been identified as the primary key benefits that microgrids can deliver:

- **Increased Power Reliability:** The traditional use for microgrids, usually utilizing diesel or propane generators, has been to provide increased power reliability for certain customers.[8]
- **Community Resilience:** Solar plus storage microgrid systems can provide significant community resilience benefits by supplying ongoing local power to critical community lifeline services during long-duration grid outages caused by high-impact, low-frequency events such as major seismic events, catastrophic wildfires, or cyberattacks.[i]
- **Local Clean Energy:** Solar-based microgrid systems can also help commercial and industrial customers[9] or communities to meet policy objectives around local renewable energy targets, carbon reductions, or green jobs.

Technology Barriers

While propane and diesel generator-based microgrids have been in use for many decades, and solar based systems have emerged in recent years, there remain significant barriers to the deployment of microgrid systems to achieve the benefits identified above. The following are the primary barriers to the deployment of microgrid systems:

- **Grid Reliability:** Most utility customers already enjoy an incredibly high level of power reliability from standard utility service (typically reliable power is provided 99.99 percent of the time) at a comparatively low cost, and therefore the added reliability provided by microgrids may not be necessary or warrant the added cost in many cases.[10]
- **Cost:** Depending on the size of the microgrid system needed, up-front capital costs can still present a major barrier to deployment even as solar and storage costs decline. The National Renewable Energy Laboratory estimates the range of costs to be \$2 to \$4 million per megawatt of installed capacity for a typical industrial or community microgrid system. Actual costs vary widely depending on the size of a project (from several kW to tens of MW) and the type(s) of technology included (diesel generators, solar, battery storage, etc.).[11]
- **Valuation Framework:** There is a lack of a standardized valuation framework (e.g., through market mechanisms or a standard tariff or contract) to value the benefits that microgrids can provide to maintain grid stability, shift electricity usage, and deliver community resilience.[12] [13]

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[i] For a more in-depth exploration of community energy resilience and the contribution that microgrids can provide, see the Oregon Guidebook for Local Energy Resilience.

Valuation of these benefits could help to offset costs.

Non-Energy Implications

Microgrids can have significant non-energy implications for Oregonians. For example, these systems can deliver community resilience benefits, as discussed above, to support system redundancy and the continued delivery of critical public services following a major event like an earthquake. These systems can also have environmental implications, including avoiding land use impacts by locating renewables on or in existing structures instead of on undisturbed land, or avoiding constituent air pollutants by displacing fossil generation.

Microgrids can support continued delivery of critical public services following a major event like an earthquake.

The deployment of microgrid projects can require significant up-front capital investments for generators, solar panels, battery systems, and microgrid controllers. As with many other technology-driven advancements in the energy sector, these up-front costs can result in inequitable access to the benefits provided by these systems.

Military Contributions to Energy Resilience

The Department of Defense must ensure energy resilience that supports mission assurance on our military installations. On March 16, 2016, DOD issued an energy resilience policy to address the risk of energy disruptions on military installations, and to require remedial actions to remove unacceptable energy resilience risks.[14] The policy requires installation commanders and mission operators to plan and have the capability to ensure available, reliable, and quality power to continuously accomplish DOD missions from military installations and facilities.

The Oregon Military Department (OMD) is developing a statewide energy resiliency plan as directed by Department of Defense Instruction 4170.11, Installation Energy Management. OMD established mission-based priorities for energy and water sustainability and resilience at the outset of the program, and desired a streamlined and cost-effective approach to sustainability and resilience. OMD will closely coordinate its sustainability and resilience initiatives, streamlining multiple program requirements to gain efficiency. The department will systematically improve sustainability and resilience at its facilities and installations located throughout the state. The plan focuses on elements in five performance areas: energy, water, solid waste, hazardous waste, and other sustainability practices.

An energy resiliency plan has been written for Camp Rilea Training Site and the Clatsop County Emergency Operations Center.

Emergency Operations Center, Building 7022

This Energy Resiliency Plan addresses emergency planning requirements specific to Camp Rilea energy system(s).[15] This plan addresses the electrical system, water system, wastewater system, and natural gas system. This plan satisfies the requirement to develop and maintain a preparedness plan contained in DoD Policy 92-1, "Department of Defense Energy Security Policy."[16] The Camp Rilea ERP has been completed and fulfills nearly all the requirements of the IEWP guidance which was released during the course of the project. Furthermore, in 2012, Camp Rilea became the first military installation to achieve Net Zero water. Today, Camp Rilea continues to implement strategies to achieve Net Zero energy and Net Zero waste.

OMD is now better equipped to achieve its goals by integrating, for example, sustainability and infrastructure resiliency goals and standardizing emergency energy and water equipment and systems for OMD armories. The various measures being implemented will result in significant cost and energy savings.

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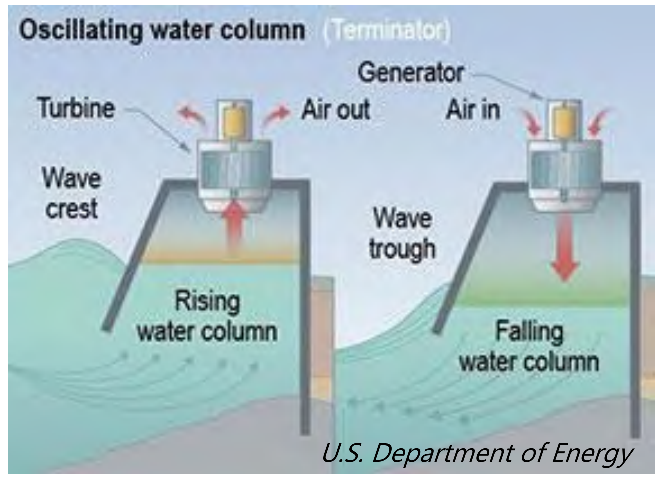
Resource Review: Marine Hydrokinetic Energy

Total MW Capacity in Oregon:	0
Facilities in Oregon:	2 test sites

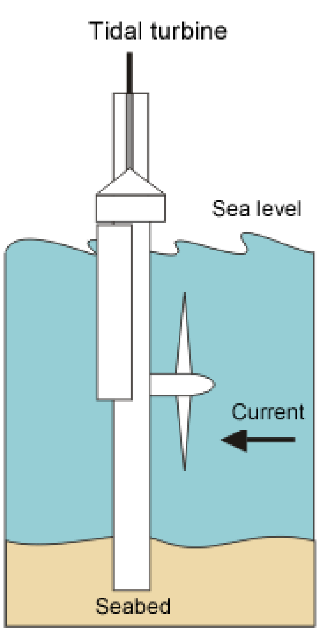
Marine energy is an emerging technology resource. There is one grid-connected facility in the United States.



U.S. Department of Energy

Marine hydrokinetic energy technologies capture energy from the movement of water in ocean waves, tides, and currents, or the heat energy in ocean waters, and then convert this energy into electricity.

Wave energy technologies extract energy from surface waves or from pressure fluctuations below the surface. An example of a wave energy technology is the oscillating water column, which uses the rise and fall of waves to push air through a turbine (pictured at right). Other wave technologies include overtopping devices, attenuators, and wave surge converters.[1] Wave energy technologies are still in early development. The largest operational grid connected facility in the world is the 3 MW Sotenäs plant in Sweden[2]; there are no large-scale grid connected wave energy facilities in the United States. The PacWave South facility near Newport, Oregon, with a potential capacity of 20 MW, will be the largest grid connected wave energy testing facility in the world and first of its kind in the United States when it becomes operational in 2022.[3]



U.S. Energy Information Administration

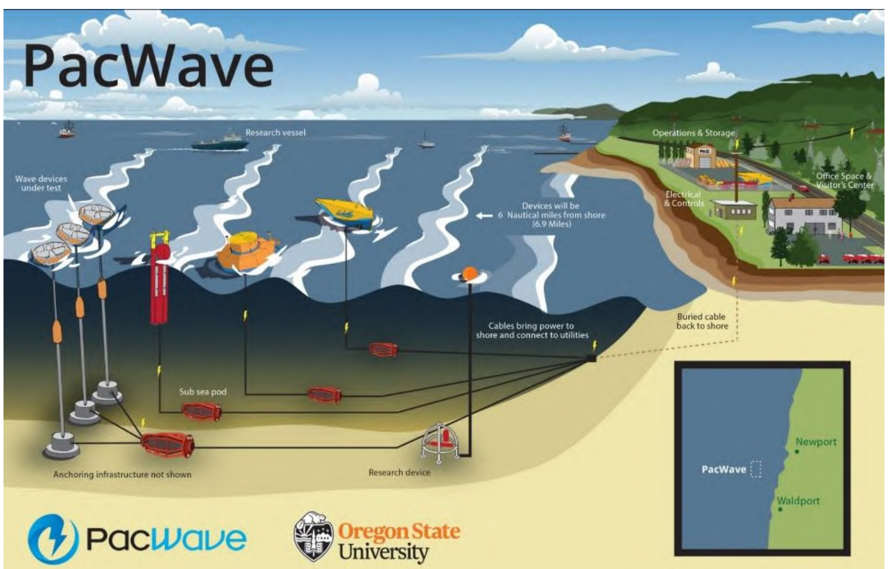
Tide and current energy technologies capture kinetic energy from the ebb and flow of tides or the flow of ocean currents and convert this energy into electricity. An example of a tidal or current technology is the axial flow turbine (pictured at left), which operates in a similar way to a wind turbine but uses water current rather than air current to spin a turbine. Other marine technologies include dams, tidal barrages, attenuators, and ocean thermal converters. Some tidal generation technologies have existed at a large scale for some time; tidal barrages (high-capacity dam-like structures that allow water into a reservoir at high tide then release water at low tide) have been in large scale use since the 1960s.[4] The largest operational tidal facility in the world is the Siwha Lake Tidal Power Station, a 254 MW tidal barrage facility in South Korea.[5] The United States has no operational, grid-connected tidal energy facilities.

Trends and Potential in Oregon

While marine hydrokinetic energy is still an emerging technology sector, as costs decrease and demand for zero carbon-emitting resources continues to grow, marine hydrokinetic energy could become a prominent resource due to its unique characteristics. Like other renewables, marine hydrokinetic energy is variable in nature. However, due to the physics of the ocean, it is highly predictable and consistent in its variability. The predictable, consistent nature of marine hydrokinetic energy could make it a reliable complementary resource to other renewable technologies with less predictable and more variable generation. The combination of a diverse array of renewables including marine hydrokinetic energy could be a possible replacement for baseload generation.[6] In addition, marine hydrokinetic energy sources have potential to supply local energy resilience and electric grid reliability benefits.

Opportunities

In the United States, the West Coast (and Oregon in particular) has some of the best marine energy resources.[7] A 2011 study from Electric Power Research Institute estimated the potential of wave energy in the U.S. at 143 terawatt hours,[8] and a recent National Renewable Energy Laboratory study identified Oregon as the highest-ranking region for long-term wave energy development in the United States.[9] The Oregon coast also has available onshore transmission capacity, owned by the Bonneville Power Administration, that can transport electricity to serve load.[10] A recent study estimated 2 GW of additional generation could be accommodated across the coast.[11]



Learn more about PacWave: http://pacwaveenergy.org/

In addition to available resources, Oregon is a global leader in research and development of marine hydrokinetic energy technologies. Oregon State University leads these efforts as a member of the Pacific Marine Energy Center, a consortium of regional universities. OSU maintains two USDOE-funded test sites near Newport, Oregon.[12] The first, PacWave North, is an autonomous test site for small-scale, prototype technologies. The second site, PacWave South, due to become operational in 2022, will have capacity for grid connected testing for projects totaling up to 20 MW in generation. A team of Oregon State University engineering graduates won the 2016 Wave Energy Prize from the USDOE for innovations in wave energy design that would improve the wave device's efficiency, which ultimately can lead to cost reductions for this type of technology.[13] Finally, Portland-based Vigor Industrial constructed a 1.5 MW wave buoy electricity generator, which is currently deployed off the Hawaiian island of Oahu for testing.[14]

Barriers

While there is substantial potential for marine hydrokinetic energy in Oregon, these technologies face technical, economic, and policy challenges to commercial deployment at a large scale. Marine hydrokinetic energy technologies face significant engineering challenges associated with generating power from fluctuating, low-velocity waves and currents in a turbulent and corrosive ocean environment.[15] They also face very high costs compared to other renewable and incumbent energy technologies. Research and development costs, as well as high capital and operating costs, drive up the overall expense of marine hydrokinetic energy.[16] These costs may fall as the technologies mature. Another challenge for marine hydrokinetic energy lies in identifying and permitting facility sites, which requires technical knowledge and approvals across multiple state and federal agencies (additional details are provided in the Offshore Wind 101 in this report).[17] The USDOE, in partnership with organizations like PMEC, are working to overcome these and other barriers through advancing research and development of marine hydrokinetic technologies and reducing barriers to technology deployment.[18]

Non-Energy Implications

Marine energy projects are zero-carbon emitting resources with a low lifecycle carbon footprint, comparable with other renewable resources.[19] However, the deployment of marine hydrokinetic devices will inevitably involve contact with the physical marine landscape, flora, fauna, and existing marine activities like commercial fishing and tourism. Research to evaluate the effects of these interactions is ongoing and an important element to the technology's development and adoption.[20]

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Technology Review: Carbon Capture and Storage

Carbon capture and storage is an emerging technology, capable of preventing a large amount of the carbon dioxide generated by a fossil fuel power plant from being released into the atmosphere. Carbon capture and storage (CCS)—also known as carbon capture and sequestration—is the process of:

1. Capturing or separating carbon dioxide from energy-related and industrial emission sources;
2. Transporting the removed CO2; and
3. Storing the removed CO2 in geological formations for long-term isolation from the atmosphere.[1]

CCS is most suitable for large stationary emission sources of CO2, including: coal and natural gas power plants, ethanol plants, cement plants, refineries, and iron and steel plants.[2] The CO2 that is captured can be stored in deep onshore or offshore geological formations (e.g., saline aquifers). Using the same technologies developed by the oil and gas industry, storage of CO2 has been proven to be technologically feasible.[1] When applying CCS to coal-fired power plants, CO2 can be removed before or after combustion; for natural gas power plants, CO2 is removed post-combustion.

Trends and Potential in Oregon

There are currently no large-scale projects (capturing more than one metric ton of carbon dioxide per year) in Oregon. There are currently six operating and five planned projects in the United States. Worldwide, there are another 13 operating projects and two planned projects.[2]

Energy experts and the Intergovernmental Panel on Climate Change (the leading body of climate scientists) have found that adding CCS to fossil fuel power plants is an important tool to help decarbonize and meet our greenhouse gas emission reduction goals, particularly to achieve net-zero emissions. While natural gas power plants can emit 50 percent less carbon dioxide than coal-fired power plants, they still release relatively high amounts of greenhouse gases, on average 0.92 pounds per kWh of electricity, compared to 2.21 pounds per kWh on average for coal plant.[3] Adding CCS to natural gas plants can reduce GHG emissions by up to 95 percent.[4] For example, the 40 MW Bellingham natural gas combined cycle power plant in Massachusetts demonstrated the technical viability of CCS. From 1991 to 2005, the facility captured 85 to 95 percent of the CO2 that it would have otherwise released to the atmosphere.[4] While Oregon's only coal plant closed in 2020 and therefore is not a candidate for CCS, the technology could be applied to Oregon's natural gas plants. Because Oregon utilities will still be able to source electricity from coal plants outside of Oregon until 2030,[i] CCS could be applied to those plants to reduce their GHG emissions and help Oregon meet its reduction goals.[5]

Adding carbon capture and storage to natural gas plants can reduce emissions by up to 95 percent.

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[i] With one exception that would enable rate-basing costs for up to five years after the plant has fully depreciated. This would apply exclusively to the Colstrip plant in Montana.

Opportunities

CCS technology is currently commercially available for coal-fired power plants and natural gas combined cycle power plants, and engineers expect the market to expand within the next few years.[4, 6] Significant technological advances, such as new CO2 capture technologies, are expected to drive down current CCS costs for natural gas plants.[7 8] The USE IT Act, passed by the U.S. Senate, would provide financial support and speed up federal approval for future CCS projects.[9] Since 2018, the federal government has provided national tax credits through the Internal Revenue Code Section 45Q, and several states provide credits (e.g., California, Texas, Louisiana, Montana, and North Dakota).[10 11]

Several natural gas CCS projects are being developed in the west, many of which are supported by external funding, such as from the U.S. Department of Energy. These include the Mustang Station of Golden Spread Electric Cooperative in Denver, Colorado and the California Resources Corporation's Elk Hills Power Plant in Kern County, California.[12] Companies are also identifying ways to "upcycle" captured CO2 by turning it into carbon composites that can be used to make products—from wind turbine blades to bicycles—or by mixing it with industrial waste (such as coal ash) to make concrete. [9]

Barriers

The main barriers to CCS include: (1) the high capital and the operation and maintenance costs of CCS projects; and (2) the lack of a price on carbon to provide additional market value of CCS activities. Incentives, carbon prices, and/or a carbon cap-and-trade program would support wider deployment of CCS, which would help create economic efficiencies and potentially significant cost decreases. Without an incentive or carbon price signal there is not an economic reason to install CCS, which can currently add 25 to 90 percent to the capital cost of a project.[2] As of 2017, the estimated cost of CCS ranges from $48 to $104 per metric ton of CO2.[2] In California, this is less than the cost of avoided CO2 emissions under the state's carbon cap-and-trade market, which ranged from $58 to $121 per metric ton. Adding CCS has been estimated to add 2 to 5 cents per kWh to the cost of electricity.

Non-Energy Implications

The major societal and environmental benefit of CCS is the reduction of atmospheric levels of CO2, while continuing to use fossil fuels to supply energy. Deployment of CCS supports a clean energy transition and can provide new job opportunities.[4] The main risk posed by CCS is potential leakage of CO2 during CO2 capture and storage. Ensuring that CO2 is being captured and stored properly is necessary to achieve the CO2 sequestration benefits offered by CCS.

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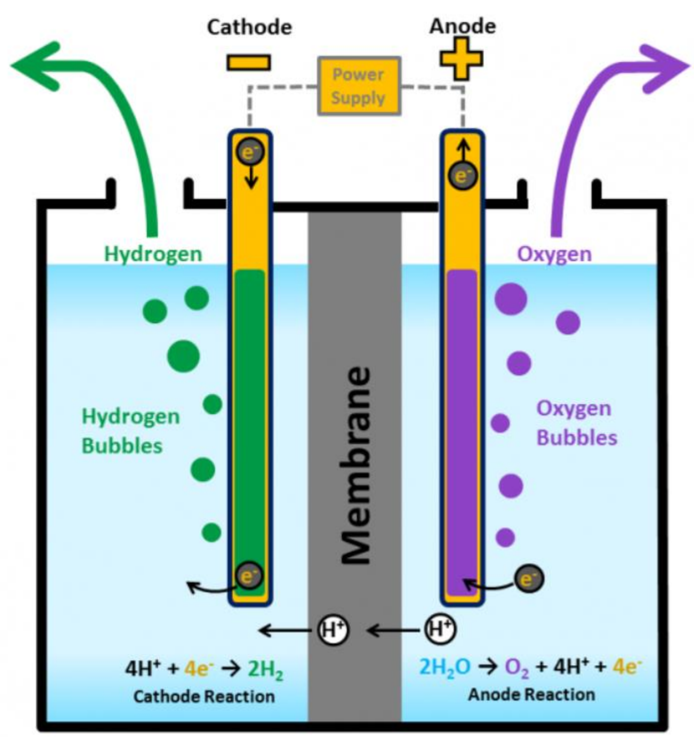
Technology Review: Power-to-Gas

- Established technology in Europe; emerging in the U.S.
- NW Natural and Eugene Water & Electric Board and Bonneville Environmental Foundation are evaluating an 8.5 MW project opportunity in Oregon.
- Douglas County PUD in Washington is planning a 5 MW facility[1 2]

Power-to-gas (PtG) describes the process of using electricity to split water into hydrogen and oxygen to produce hydrogen gas (H2) that can be used as a combustion fuel like natural gas or in a number of industrial processes. The hydrogen can also be mixed with carbon dioxide via a process called methanation to produce synthetic natural gas that can serve as a direct replacement for fossil-based natural gas. Hydrogen is currently used in a number of industrial processes – it is a fundamental input for manufacturing ammonia, which is then used for fertilizer production; it is used to process crude oil into refined fuels, like gasoline and diesel; and it is also used as a ”redactor agent” in the metallurgic industry.[3]

Most of the hydrogen produced in the world today is derived from steam reformation of fossil-based natural gas. Not only is PtG is an emerging alternative to the reformation of natural gas to produce hydrogen, but numerous potential end uses for hydrogen are emerging in the power and transportation sectors.

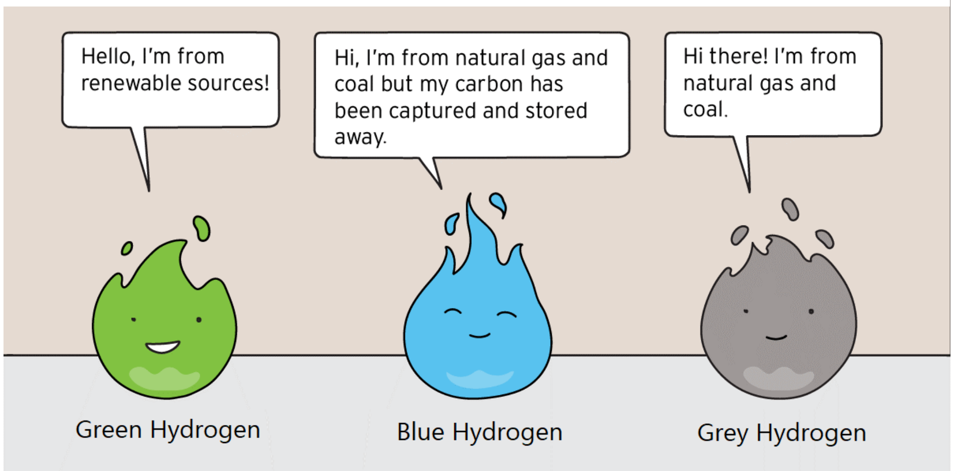
Figure 1: Alkaline Electrolyzer Illustration[4]



Power-to-gas works by using a decades-old technology called an electrolyzer, which uses electricity to split water into its hydrogen and oxygen components. The two most common types of electrolyzers are alkaline electrolyzers, which have been in use since the 1920s, and polymer electrolyte membrane (PEM) electrolyzers, introduced in the 1960s.[4] PEM electrolyzers offer benefits over alkaline units such as operating range and size, but they have a higher capital cost and a shorter lifetime.[5]

Natural gas reformation produces carbon dioxide as a byproduct, the primary greenhouse gas (GHG) causing climate change, and the hydrogen produced from this process is sometimes referred to as “grey” hydrogen. Electrolysis results only in hydrogen, oxygen, and heat, although the type of electricity used to power the electrolyzer may have other associated emissions (e.g., if natural gas or coal power is used). When the electrolysis is powered by renewable electricity, however, the resultant hydrogen is also considered renewable, in most cases greenhouse gas emissions-free, and is often referred to as

Figure 2: Green, Blue, and Grey Hydrogen Explained[9]



"green" hydrogen. "Blue" hydrogen is produced using methane reformation followed by carbon capture and sequestration[6] (see the Carbon Capture and Sequestration Technology Review), which reduces the overall GHG emissions.[7] [8] Once created, hydrogen can be stored as a compressed gas or used to charge fuel cells, either of which can be used to generate electricity at a later time, injected into the natural gas system for direct fuel use, or even as a fuel for a wide variety of vehicles.

Trends and Potential in Oregon

PtG electrolyzers can be built wherever there is electricity available to power the equipment and an adequate source of water. One of the biggest barriers to wider deployment of PtG in Oregon and in the U.S. is the cost. Hydrogen produced using PtG electrolyzer technology is much more expensive than hydrogen produced via natural gas reformation, and the two biggest costs are the electrolyzer and the electricity used to power the process. For this reason, PtG is most cost effective when the price of the electricity used to power the process is very low. For example, in California, where solar generation increasingly exceeds demand in the middle of the day during the mild weather of the spring months, electricity providers sometimes sell this power at zero, or even negative, cost. In some cases, they are even required to curtail, or turn off, solar output when there is surplus power relative to demand. The Pacific Northwest currently has more limited circumstances when this type of low-cost, or zero-cost, surplus electricity is available, mostly during the spring season when wind and some thermal generation may be curtailed.[10]

While still expensive, the costs of electrolyzers are falling – costs for alkaline electrolyzers made in North America and Europe dropped more than 40 percent between 2014 and 2019.[11] Still, to compete with the costs of producing hydrogen from the reformation of natural gas, the manufacture of electrolyzers would need to continue to scale up and costs would need to decline further. The U.S. Department of Energy indicates that to become cost competitive, the cost of producing green (or blue) hydrogen must be lowered by a factor of four.[12]

Another costly consideration is storage and transportation of hydrogen. While experts expect that hydrogen could displace between 5 and 15 percent of natural gas in a natural gas pipeline,[13] volumes greater than that would require new, separate pipelines and other infrastructure. For hydrogen not bound for a pipeline, it must be stored and transported, both of which can add considerable cost. Hydrogen stored as a gas is typically compressed and then placed in high-pressure tanks, whereas hydrogen stored as a liquid requires cryogenic temperatures. The current cost of liquified hydrogen storage can exceed the cost of producing the hydrogen[14] and the U.S. Department of Energy's

Hydrogen and Fuel Cell Technologies Office is focused on addressing the challenges associated with cost effective high-density storage of hydrogen.[15]

There are no PtG projects currently operational in Oregon, though there is interest from utilities such as NW Natural and Eugene Water and Electric Board, which have teamed up with Bonneville Environmental Foundation to develop a PtG pilot project in Oregon. The project is still in the conceptual phase, but current plans are for an approximately 8.5 MW electrolyzer located in Eugene, sited near industrial facilities capturing CO2, which would be used to methanate the hydrogen before injecting it into the natural gas pipeline.[16] Other electric utilities have also shown interest in PtG and hydrogen; for example Portland General Electric's 2018 deep decarbonization study included a scenario with over 2,000 MW of hydrogen electrolysis by 2050 as a way to consume excess renewable electricity to produce decarbonized pipeline gas, which would play a role in decarbonizing the transportation and direct fuel use sectors.[17]

Methanation is a process where hydrogen and carbon dioxide – potentially CO2 that was captured from other power generation or industrial processes – are combined to create methane, which is freely interchangeable with natural gas as a fuel.[19]

A key benefit of PtG is that it can play a role in the decarbonization of the direct fuel use and transportation fuel sectors. Hydrogen can be used in some applications as a direct substitute for natural gas, such as injecting into a natural gas pipeline (up to 15 percent of the volume of gas in the pipeline).[18] It can also be used to create synthetic natural gas through "methanation," a process where hydrogen and carbon dioxide – potentially CO2 that was captured from other power generation or industrial processes – are combined to create methane, which is freely interchangeable with natural gas as a fuel.[19] By displacing natural gas, hydrogen can help to reduce GHG emissions from sectors that are difficult to decarbonize, such as transportation, stationary fuel use, and heavy industry.

For more on reducing emissions from other sectors, energy storage, and power-to-gas technology, see the Technology Reviews and Policy Brief sections of this report.

PtG is also a potential end use for excess renewable electricity generation that would otherwise be curtailed or shut off. While Oregon currently has limited amounts of curtailed renewable energy, there is potential for increasing amounts in the future. In PGE's 2018 deep decarbonization study,[20] the utility indicated that planning and policy choices made on how to decarbonize all energy sectors may lead to increased amounts of excess renewables generation, which could be used by PtG or other end uses, such as storage applications or demand response resources. PtG applications could soak up that excess electricity, thereby providing a storage benefit to renewable electricity providers or as a resource for direct use or transportation fuels. For example, Douglas County Public Utility District in Washington state has partnered with Cummins to build a 5 MW PEM electrolyzer that will be able to use excess electricity from one of the PUDs' hydropower dams to create green hydrogen. The project is expected to be operational in 2021.[21]

BloombergNEF estimates that scaling up the hydrogen economy globally will require an estimated USD $150 billion in subsidies through 2030. There are few policies in place to support PtG and hydrogen development in the U.S. Thus, while the technology used in PtG is established and there are few technical barriers to further commercialization, the larger challenge of cost to develop PtG at scale is significant. Low- or zero-cost electricity is likely a requirement to make the technology cost effective in many, though not all, applications. The opportunities for this are currently limited; lacking subsidies or incentives, future availability will largely depend on the degree to which renewable electricity is added to the system.

Non-Energy Implications

One of the most significant non-energy implications of PtG is that it can reduce GHG emissions across multiple sectors. Green hydrogen can replace grey hydrogen created using fossil fuels (either through reformation or electrolysis powered by fossil electricity) as well as supplement or even replace direct-use natural gas and petroleum in buildings, replace gasoline and diesel fuel in the transportation sector, and in heavy industry applications. According to a recent study by the Fuel Cell and Hydrogen Energy Association, by 2050 PtG and hydrogen could reduce U.S. GHG emissions by 16 percent while also reducing NOx (nitrogen oxides) emissions by 36 percent and providing 3.4 million jobs.[22]

Energy jobs: PtG and hydrogen tech could reduce GHG emissions and provide 3.4 million jobs.

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POLICY BRIEFS

The primary purpose of the Biennial Energy Report is to inform local, state, regional, and federal energy policy development, energy planning, and energy investments, and to identify opportunities to further the state's energy policies.

In service of ODOE's role as the central repository within state government for the collection of data on energy resources, the report collects and analyzes critical data and information to provide a comprehensive and state-wide view of the energy sector. The term "energy" includes many intersecting systems that generate and distribute electricity to end-users, and that store and distribute fuels for home-heating, industrial processes, and transportation. It also includes the critical infrastructure, facilities, planning, and energy management that support these systems. A key consideration in analyzing the energy system is effects that it has on public health, the environment, and communities across the state. It is long past time to examine and address where our energy choices do not provide equitable distribution of benefits and burdens to Oregonians.

This section of the report provides insights on emerging energy trends, opportunities, and barriers in the energy sector. ODOE began the development of this portion of the report by listening – and then identifying the critical energy questions and issues that we heard from stakeholders, policy makers, and the public. ODOE applied a data and equity lens in determining topics for this policy briefs section of the report – are these questions being asked by people or entities that have historically not been at the table? Do we have the data and information to help answer these questions? The topics covered in the following pages also seek to answer some of the questions frequently heard by multiple people or entities; many energy stakeholders confirmed to ODOE that they were hearing similar questions and about similar information gaps: *How is the state addressing climate change and what can be done to improve the resilience of the energy sector? How are Oregon's farmers and ranchers reducing energy use and greenhouse gas emissions? What types of opportunities exist to reduce fuel use and fuel costs for the freight sector? What are the trends and potential for offshore wind and power-to-gas in Oregon? How can the state address equitable access to renewable energy for all Oregonians? How has COVID-19 affected the energy sector?*

These policy briefs can be read as standalone documents, and there are cues in each discussion to point the reader to information and data found in other parts of the report that can provide additional background and insight. This collection of policy briefs is not comprehensive – it is a snapshot of analysis for key questions in the lead up to the publication of this report. Staff at ODOE are engaged in research and analysis on other topics that are not covered in this section, and energy expertise exists in other agencies and outside state government as well. As ODOE wraps up production on the 2020 Biennial Energy Report we continue to listen, and new topics are already beginning to emerge as potential questions to address for the 2022 Biennial Energy Report.

Policy Brief: Climate Change and Oregon Update

The pace of climate change has accelerated as society continues to emit large quantities of greenhouse gases (GHG) into the atmosphere. These emissions trap heat in the earth's atmosphere, warming the climate, shifting its patterns, and increasing the frequency of extreme events, such as heatwaves, droughts, wildfires, and flooding from extreme precipitation (see Climate Vulnerability Assessment Policy Brief). In May 2020, the concentration of atmospheric carbon dioxide was the highest monthly average ever recorded, and global temperatures were tied for the highest May temperatures in over 140 years of recordkeeping.[1,2] The National Oceanic and Atmospheric Administration expects the year 2020 to rank as one of the hottest on record.[3]

Extensive research has shown that a 2°C (3.6°F) increase in global average temperatures would result in significant and unprecedented risks to society and the environment.[4] Oregon's current GHG emissions trajectory is contributing to that global limit, threatening human health, livelihoods, and ways of life (see 2018 *Biennial Energy Report* Chapter 2 - Climate Change for more information). Communities across Oregon are already suffering from more extreme weather events and air pollution resulting from GHG emissions and wildfires.[5,6]

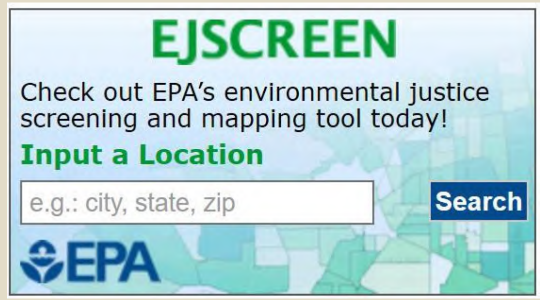
How energy is generated and used heavily affects—and is affected by—climate change. In Oregon, about 80 percent of the state's GHG emissions come from the amount and type of energy Oregonians use every day.[7] This section:

1. Provides an update on the state's efforts to address climate change.
2. Describes new climate goals, policies, and local actions that have emerged since the 2018 Biennial Energy Report.
3. Sets these efforts in context of the state's economy-wide GHG emissions.

"Deep decarbonization" of Oregon's sectors—which generally means an 80 percent reduction in economy-wide GHG emissions below 1990 levels by 2050—remains one of the state's most important challenges. Oregon's communities, culture, and resources face serious consequences in the absence of such efforts. [5,6]

Much more work is needed—and is underway—to not just create a clean energy transition, but to create an equitable one. An equitable clean energy transition will distribute clean energy across society (providing access by both low- and high-income households of all races and ethnicities), geographically (including rural, urban, and coastal communities), and across time (including measures to significantly reduce GHG emissions now to benefit both current and future generations, which face growing climate risks).[4,8] In Oregon, the median household income for people of color is about 30 percent less than for white households.[9,10] Meanwhile, people of color and low-income households across the nation have a disproportionally high energy burden—the percentage of income spent on home energy costs—compared to other households. In Oregon, Washington, California, Alaska, and Hawaii, the median home energy burden is nearly three times as high for low-income households than other households.[11] These and other groups have historically been underserved by public programs and investments, making them more vulnerable than other Oregonians to the impacts of climate change. For example, over time, inequities have left some communities—including people of color, low-income, indigenous, and rural communities—with less resilient housing, more exposure to heatwaves, and fewer transportation options.[12,13] The state could strengthen its approach to decarbonization by incorporating an equity lens to identify common barriers that affect those communities and minimize the disproportionate effects of climate change on their physical, financial, and cultural wellbeing. To do so, the state needs to more deeply engage with these communities in public processes and design policies and practices that enable them to benefit from climate policies. Assessing current policies and practices with an equity lens and using tools, such as the U.S. Environmental Protection Agency's "EJScreen," can help.

Environmental Justice



Oregon's Environmental Justice Task Force defines *environmental justice* as "equal protection from environmental and health hazards, and meaningful public participation in decisions that affect the environment in which people live, work, learn, practice spirituality, and play."[14] Oregon's environmental justice handbook describes that the first step government agencies and other organizations should take is understanding the likely area of impact resulting from the policy, action, or decision that is being considered.[15] Government agencies and other organizations can use EPA's environmental justice screen tool ("EJScreen") to assist in learning more about potential environmental justice communities in Oregon.[16] This mapping and screening tool is based on nationally consistent data that combines environmental and demographic indicators in maps and reports. All of the EJScreen indicators are publicly-available data. EJScreen simply provides a way to display this information and includes a method for combining environmental and demographic indicators into EJ indexes. For example, EPA's tool can help identify areas with minority or low-income populations, potential environmental quality issues, or a combination of environmental and demographic indicators that are greater than usual.[17] Screening tools, like EJScreen, should only be used for a "screening-level" look – which is a useful first step in understanding or highlighting locations that may be candidates for further review. However, it is essential to remember that screening-level results do not, by themselves, determine the existence or absence of environmental justice concerns in a given location and they do not provide a risk assessment.[18] Find out more by visiting:

https://www.epa.gov/ejscreen

Decarbonizing Oregon's economy and energy systems is not only critical to mitigate climate change and avoid damaging climate impacts but also provides a wide array of opportunities or "co-benefits" for communities and businesses throughout Oregon. As shown throughout this Biennial Energy Report, transitioning to cleaner energy resources and technologies provides more reliable energy, increased energy independence (keeping more energy-related revenues in the local economy), new living-wage jobs, sustainable transportation options, and reduced operating and maintenance costs. Shifting to a clean energy economy also improves air quality, significantly reducing the prevalence of respiratory and cardiovascular diseases, and lowering medical costs. For example, if all new passenger vehicles in ten U.S. states[i] were zero-emission vehicles, then improvements in air quality would result in an estimated $24 billion in health savings, more than 2,000 fewer premature deaths, and more than 200,000 fewer missed days of work each year.[19]

Oregon's GHG Reduction Goals and Climate Commitments

Over the last 30 years, Oregon has taken significant actions to help mitigate climate change. In 1997, Oregon became the first state to establish a price on carbon by requiring new energy facilities' emissions to be 17 percent below the most efficient natural gas-fired facility operating in the country or pay for equivalent offsets.[20] Thirteen years ago, Oregon established its first GHG reduction goals and created the Oregon Global Warming Commission to steward the state's progress and advise on mitigation strategies. In 2007, Oregon's Legislature established ambitious goals to arrest the growth of GHG emissions by 2010, reduce emissions by at least 10 percent below 1990 levels by 2020, and reduce emissions by at least 75 percent below 1990 levels by 2050.[21] After establishing a renewable portfolio standard (RPS) in 2007, Oregon doubled it in 2016 to 50 percent by 2040.[22] Oregon also became the first state in the country to legislatively mandate an end to coal in the state's electricity mix, passed the nation's second most stringent carbon fuel standard, and has been aggressively pursuing transportation electrification through rebates, planning, and incentive programs.[23,24,25]

Despite this progress, Oregon is not on track to meet its GHG reduction goals set in 2007 (ORS 468A.200-250; and also see Chapter 2 – Climate Change of the 2018 BER).[7,21] Based on preliminary data from 2017, annual statewide emissions totaled 64 million tons, significantly higher than the 2007 targets of 50 million tons per year by 2020 and 14 million tons per year by 2050. Over the last ten years GHG emission levels have remained relatively stagnant and have yet to fall below 60 million tons per year.[7]

Since the 2018 Biennial Energy Report, the state has made extensive efforts to help address this gap. In March 2020, through Executive Order 20-04, Governor Kate Brown issued a broad and ambitious directive to state agencies to take actions within their existing statutory authorities to cost-effectively reduce emissions and address the impacts of climate change, particularly for disproportionately impacted communities.[26] Executive Order 20-04 established new science-based goals to reduce GHG emissions in Oregon by 45 percent below 1990 levels by 2035 and by 80 percent below 1990 levels by 2050.

In 2020, Oregon established new GHG reduction goals:

- By 2035, achieve GHG levels that are 45 percent below 1990 levels
- By 2050, achieve GHG levels that are 80 percent below 1990 levels

New Climate Policies

Activities across sectors and sources, from transportation and energy generation to energy use in buildings, all consume energy and contribute to the amount of GHGs released to the atmosphere. Products that we consume or use—such as food, plastics, concrete, and other materials—also generate GHG emissions during their production, and long after their disposal as they decay. Since

[i] Including Oregon, California, Connecticut, Maine, Maryland, Massachusetts, New Jersey, New York, Rhode Island, and Vermont—ten U.S. states that have adopted programs for zero-emission vehicles.

the 2018 BER, several significant climate policies emerged from executive orders and legislation to reduce GHG emissions across Oregon's economy. Table 1 sets these policies in the context of the state's GHG emissions, by sector.

Executive Orders

Executive Order 20-04 directed all state agencies to consider climate change in all their work and to accelerate the reduction of GHG emissions. Several of its directives focus on reducing emissions from **transportation**—responsible for the largest share of Oregon's emissions (see Table 1). The order called for a rapid conversion of the state's fleet to zero-emission vehicles and expansion of charging infrastructure for public buildings, and incorporation of GHG emissions reduction performance metrics into the Statewide Transportation Strategy. It directed the Oregon Department of Transportation to evaluate the effect of transportation projects on emissions and use the results to inform its planning processes. In response, ODOT established a Climate Office to integrate climate change into transportation planning across the state.[27]

The order directed the doubling of the clean fuel standard administered by DEQ, requiring reductions in average carbon intensity of transportation fuels used in Oregon of at least 20 percent (relative to 2015), and of at least 25 percent by 2035, making it one of the most ambitious standards in the nation. The order also directed DEQ and the Environmental Quality Commission (EQC) to develop and implement by January 1, 2022 a cap and reduce program for GHG emissions from large stationary sources; transportation fuels, including gasoline and diesel fuels; and other liquid and gaseous fuels, including natural gas.[28] Methane emissions from landfills, which have 25 times more global warming potential than carbon dioxide, will now be regulated by DEQ, consistent with the most stringent regional standards.[29] Finally, DEQ and the EQC were directed to engage with industry to help reduce food waste by 50 percent by 2030.

To help reduce emissions in the **electricity sector**, the order directed Oregon's Public Utility Commission to explore pathways for utilities to decarbonize, support the electrification of transportation, address differential energy burdens and environmental justice issues, and vulnerabilities to wildfire risk. To improve energy efficiency in **residential and commercial** spaces, the order directed ODOE to update and make appliance standards equal to the best in the nation, establishing standards for ten different electrical appliances, ranging from portable spas to commercial dishwashers. ODOE began implementing this directive by establishing a formal rulemaking process in May 2020 and expects these standards to, in the year 2025, result in an annual reduction of approximately 76,500 metric tons of carbon dioxide and annual savings of more than $35 million in utility bills.[30] In addition, the order directed Oregon's Building Codes Division, in cooperation with ODOE, to advance residential and commercial building codes for new construction that represent at least a 60 percent reduction in energy use from 2006 code levels by 2030.

Regarding **natural and working lands**, the order directed the Global Warming Commission to develop a proposal for setting new goals to reduce emissions and sequester carbon dioxide (see Policy Brief on Agriculture and Greenhouse Gas Emissions).

To support an equitable clean energy transition across sectors, Executive Order 20-04 established an Interagency Workgroup on Climate Impacts to Impacted Communities. The Workgroup will develop climate policy and a climate justice strategy that benefits frontline communities who face disproportionate effects of climate change, such as displacement, adverse health effects, job loss, and property damage. Meanwhile, the 2020 update to the Interagency Climate Adaptation Framework, led by the Department of Land Conservation and Development, highlighted the importance of addressing diversity, equity, and inclusion in all climate work.[31] The framework advises agencies to follow the Oregon Health Authority's upcoming Climate Equity Blueprint to help guide the planning and implementation of climate change adaptation strategies.[32]

Finally, Executive Order 19-01 served to enhance community resilience, in rural and urban communities alike, by establishing a coordinated response to Oregon's growing wildfire risk, amplified by climate change.[33]

Legislation

During the 2019 and 2020 Oregon legislative sessions, legislation was passed that reduces GHGs by promoting clean energy resources and technologies and revising land-use regulations. Several of these bills work to decarbonize the transportation sector, including **Senate Bill 1044**, which created goals to promote use of zero-emission vehicles, electric school buses, and electric state fleets.[34] It also required ODOE to submit a report by September 15, 2021 on the status of these efforts and to make recommendations on how to improve the state's efforts. **House Bill 2007** established more stringent diesel emission standards in the Portland metropolitan area for medium- and heavy-duty trucks and buses—reducing emissions and harmful air pollutants.[35] **House Bill 2001** revised residential zoning to create more affordable housing options by allowing more dense development of housing, such as duplexes, four-plexes, etc. In most cases this could increase the use of public transportation and reduce the amount of vehicle miles traveled in communities.[36]

To increase solar power generation and energy storage, **House Bill 2618** created a $1.5 million rebate program administered by ODOE to reduce the cost of solar power and energy storage infrastructure primarily for residential customers.[37] The program offers rebates for the purchase, construction, or installation of solar electric systems and paired solar and storage systems. To help improve equitable access of solar power, at least 25 percent of available rebate dollars were reserved for low- and moderate-income residential customers and low-income service providers. As of October 2020, over half of the committed funding for the program is for projects owned by low- and middle-income residents or low-income service providers.[38] **House Bill 2496** added energy efficiency as an option to meet an existing requirement that 1.5 percent of improvement contracts on public buildings costing over $5 million be spent on green energy technology—including solar, geothermal systems, and battery storage—or on woody biomass technology.[39] By increasing community resilience to climate hazards and natural disasters, all of these bills also enhance the state's ability to adapt to climate change impacts (see the following Climate Vulnerability Assessment Policy Brief).

To help decarbonize the natural gas industry, **Senate Bill 98** allows all Oregon gas utilities to bring renewable natural gas (RNG) to Oregonians by investing in RNG production and/or entering into contracts to purchase RNG. RNG can be generated from waste resources such as agricultural manure, wastewater, and other waste streams. [40] An ODOE study in 2018 found that Oregon could have enough resources to replace up to 20 percent of the state's total yearly use of natural gas with RNG. Although largely symbolic, as there is currently no hydraulic fracturing ("fracking") or offshore drilling in Oregon, **House Bill 2623** enabled a five-year ban on fracking to explore for oil and natural gas, while **Senate Bill 256** banned offshore oil drilling. [41, 42]

Table 1: Summary of New Climate Policies by Sector, Mechanism, and GHG Emissions Related Targets

Sector & Contribution to State Emissions	Policy	Mechanism to Reduce Emissions	Key Goals or Actions to Reduce Emissions
Transportation (39%)	EO 20-04	Promote zero-emission vehicles	Support transportation electrification and analyze infrastructure needs, especially for rural areas.
			Statewide plan for procuring state agency zero-emission vehicles.
		Advance clean fuel standard & credits	By 2030 and 2035, reduce the carbon intensity of transportation fuel by 20% and 25%, respectively, below 2015 levels. Advance methods to generate/aggregate utilities' clean fuel credits.
		Regulate allowable GHG emissions	Cap and reduce GHG emissions from transportation fuels, including gasoline and diesel.
		Assist local governments	Provide financial and technical assistance to metropolitan planning areas to align transportation and land use plans with state GHG goals.
	SB 1044	Promote zero-emission vehicles	Collect, analyze, and report on zero-emission vehicles data; and make recommendations if state is not meeting sales targets.
			Allow school districts located in PGE and Pacific Power service territories to use public purpose charge funds for fleet audits, electric vehicles and charging stations. By 2025/2029, zero-emission vehicles to make up at least 25%/100% of all new state-owned or leased light-duty vehicles.
	HB 2007	Phase out older, emissions-intensive trucks	In Portland metropolitan area only, by 2023, all diesel-powered medium- and heavy-duty trucks must run on engines from 1997 or newer. By 2029, all medium-/heavy-duty trucks must run on an engine from 2010/2007 or newer.
	HB 2001	Adjust land-use requirements	Allow for denser housing options to help reduce vehicle miles traveled.

Sector & Contribution to State Emissions	Policy	Mechanism to Reduce Emissions	Key Goals or Actions to Reduce Emissions
Electricity Generation & Transmission (26%)	EO 20-04	Prioritize GHG reduction	Determines that it is in the interest of utility customers to reduce GHG emissions consistent with EO goals; directs PUC, when carrying out its regulatory functions, to advance decarbonization in the utility sector.
	SB 2618	Provide solar rebates	Reduce the cost of residential rooftop solar generation/storage, particularly for low-/middle-income households.
	HB 2496	Allocate funding	Revised the rules requiring 1.5% of public building improvement contracts to be spent on green energy technologies to include energy efficiency.
Natural Gas (12%)	EO 20-04	Regulate allowable GHG emissions	Cap and reduce GHG emissions from natural gas.
	SB 98	Provide low-carbon fuels	Allow large utilities to provide up to 30% of renewable natural gas in pipelines by 2050, and rate-base some costs.
Residential & Commercial Buildings (7%)	EO 20-04	Advance codes & standards	Reduce energy use by 60% in new construction from 2006 levels.
			Set stronger energy efficiency standards for products.
		Reduce waste	Engage with food retailers and manufactures to help reduce overall food waste by 50% by 2030.
Industrial (7%)	EO 20-04	Regulate allowable GHG emissions	Cap and reduce GHG emissions from large stationary sources.
		Reduce waste	Engage with industry to help reduce overall food waste by 50% by 2030.
Agriculture (9%)	EO 20-04	Develop carbon goals	Develop carbon sequestration goals for agricultural lands.
Natural and Working Lands*	EO 20-04	Develop carbon goals	Develop a proposal for setting a goal for emissions reductions and carbon sequestration from natural and working lands.
		Regulate landfills	Significantly reduce methane emissions from landfills.

*Note: *Emissions from land-use and land use change other than some emissions associated with agricultural land use are not currently included in the state's GHG inventory.*

Pathways for Deep Decarbonization

Although Oregon's new policies are slated to reduce GHG emissions, much more work is needed to reach Oregon's goals and transition to a clean energy economy. State and regional studies on deep decarbonization serve as valuable tools to identify and analyze multiple possible avenues to cost-effectively reduce emissions across sectors. Since the 2018 Biennial Energy Report, two major studies have evaluated and highlighted strategies to help decarbonize Oregon's economy.

In 2019, the Clean Energy Transition Institute (CETI) commissioned a regional study to examine how Oregon, Washington, Idaho, and Montana can transition to a clean energy economy. The study, *Meeting the Challenge of Our Time: Pathways to a Clean Energy Future for the Northwest*, identified strategies to reduce GHG emissions in the region's energy systems—including all infrastructure that produces, converts, delivers, and consumes energy—by 86 percent below 1990 levels by 2050.[43] CETI's research identified five key strategies to decarbonize Oregon's economy:

- Upgrade the electric grid to run on nearly 100 percent clean energy, such that all electricity generation is carbon-free. Under this strategy, gas-fired generation can use biogas, renewable natural gas, or other synthetic fuels (see section on Natural Gas for more information on the carbon impacts of this fuel).
- Increase energy efficiency (decreasing the amount of energy required to provide energy services, such as powering an appliance; see the section on the Built Environment for more information on how energy efficiency can reduce GHG emissions).
- Reduce the emissions-intensity of liquid and gaseous fuels (see the section on Transportation Fuels for more information on how the carbon-intensity of these fuels can be reduced);
- Electrify transportation by significantly increasing the number of vehicles that run on electricity rather than fossil fuel, including light-, medium-, and heavy-duty vehicles (see the section on Electric Vehicles and Alternative Fuels for more information on the evolution of zero-emission vehicles).
- Capture carbon dioxide from a facility where it is being emitted, otherwise known as carbon capture and storage (CSS; see the CSS Technology Review to learn more about this emerging technology), or remove carbon dioxide from the atmosphere, otherwise known as carbon sequestration (e.g., by increasing and/or protecting forested areas).

See other Policy Briefs, Technology Reviews, and Energy 101s for more on many of these topics, including natural gas, electric vehicles, and carbon capture and storage.

In November 2018, NW Natural gas company commissioned the country's first decarbonization study addressing how to reduce emissions while meeting peak demand for winter heating, which is largely supplied directly by natural gas.[44] The study, *Pacific Northwest Pathways to 2050*, completed by E3, found that the region's GHG emissions reduction goals could be met in part by adding 30 percent renewable natural gas to pipelines for home heating. Renewable natural gas turns wastewater, agricultural manure, landfill waste, food waste, and residential material from forest and agricultural harvests into usable energy and provides the additional benefit of reducing overall waste.

In September 2018, the Pacific Coast Collaborative—a multi-state partnership for information sharing and collaborative action between Oregon, California, Washington, and British Columbia—released a vision and roadmap for a low-carbon transportation system across the region. [45] A key goal of the roadmap is to make low-carbon transportation accessible and affordable to all by facilitating partnerships among state and city governments, car manufacturers, and dealers. Decarbonizing transportation, which makes up nearly 40 percent of the state's emissions, is particularly challenging as GHG emissions from motor vehicles are difficult to reduce.[7] Without significant changes in the types of motor vehicles and transportation fuels used by people and businesses in Oregon, and/or the number of vehicle miles traveled, the state will not meet its GHG reduction goals.

Overall, complementing sector-based strategies, a state-wide program to cap-and-trade GHG emissions is still the most effective framework to decarbonize Oregon's economy in a cost-efficient and timely manner. Cap-and-trade programs have been successful in California, the northeastern U.S., the European Union, as well as in other countries across the globe, and can incorporate special programs to ensure a just transition for underrepresented groups (see 2018 Biennial Energy Report for more detailed information). For example, since its inception in 2013, California's cap-and-trade program has generated nearly $22 billion in auction proceeds, 57 percent of which are being reinvested to benefit low-income and disadvantaged communities throughout the state, while increasing jobs and growing their economy.[46,47] In 2008, British Columbia established a revenue-neutral carbon tax program, currently with a rate of $35 per metric ton of carbon dioxide—one of the highest rates in the world. Even with this carbon price, the province's GDP has met or exceeded the Canadian national average.[48] The rate has increased by $5 per metric ton annually and will reach $50 per metric ton in 2021.[48] Over its first seven years, the program is estimated to have reduced GHG emissions by up to 15 percent from what they would have been without the program.[49]

In Oregon, during the 2019 and 2020 Legislative Sessions, the legislature considered statewide cap-and-trade legislation (HB 2020, SB 1530, and HB 4167) to pursue comprehensive, low-cost emissions reductions at levels that could achieve the state's emissions goals.[50,51,52] Though legislation had support in both chambers in 2019 and 2020, walk-outs prevented the quorums necessary to hold the votes.

Local, Regional, and Tribal Government Climate Action in Oregon

City and County Actions to Mitigate and Prepare for Climate Change

Many local jurisdictions are taking actions to reduce GHG emissions across sectors to support a clean energy transition and help mitigate climate change. These actions are usually described in climate action plans or combined with sustainability plans. Climate action plans typically include:

(1) An inventory of all GHG emissions by major source or sector (such as transportation, electrical generation, buildings, etc.);
(2) Goals expressed as a percentage reduction in GHG emissions compared to a baseline year; and
(3) A portfolio of strategies to achieve these goals.

Meanwhile, some local jurisdictions are also taking actions to increase their resilience to the impacts of climate change. These include efforts to assess the vulnerability of their residents, services, or infrastructure to climate change-related hazards through a localized vulnerability assessment (see

Climate Vulnerability Assessment Policy Brief). Some cities and counties have also identified what are known as resilience or adaptation strategies to help prepare for, cope with, or bounce back from, climate hazards or related events. These measures can be provided in stand-alone plans, included in climate action plans, or incorporated into natural hazard mitigation plans.

ODOE conducted a search for publicly available information on mitigation and resilience actions taken by cities and counties in Oregon with populations of at least 20,000, and the findings are categorized in Table 2. Currently, 43 percent of larger cities in Oregon have set—or are in the process of setting—a GHG emissions reduction goal. Twenty-two percent of larger counties have done the same. Similarly, nearly half of cities and a quarter of counties have, or are in the process of conducting, an inventory of GHG emissions. Overall, many local jurisdictions in Oregon with climate action plans seek to achieve net-zero GHG emissions by 2050, which is in line with Oregon's state goal to reduce emissions by 80 percent by 2050. Achieving net-zero emissions requires that GHG emissions resulting from human activity are as close to zero as possible, and that any remaining human-caused emissions are canceled out by removing GHGs from the atmosphere, through increased carbon sequestration (e.g., by acquiring and restoring forests to store carbon; adjusting agricultural practices, such as weatherizing cropland; or removing carbon dioxide from the air through advanced technologies).[53,54]

Nearly all city and county climate action plans have explored ways to reduce emissions from transportation and land use, mainly by Metropolitan Planning Organization scenario planning that combines land use planning (e.g., adjusting zoning regulations) and transportation planning to increase low- and zero-carbon modes of transportation (e.g., alternative modes such as walking, biking, public transit, and electric vehicles).[55,56] Many plans also include fleet procurement practices. Nearly all these plans have also focused on decarbonizing electricity generation, typically by increasing the supply of clean and renewable energy sources (i.e., increased local electricity generation by solar, wind, geothermal, and hydropower). Most plans have explored how to reduce emissions by increasing energy efficiency in buildings and by reducing the consumption of materials that emit high amounts of GHGs during their production, use, or after their disposal. Finally, three city plans—Portland, Corvallis, and Milwaukie—and one county plan—Multnomah—included actions to sequester carbon.

A higher proportion of county planning efforts focus on adaptation, such as assessing vulnerability or identifying strategies to prepare for the impacts of climate change, rather than focusing on mitigating GHGs. The opposite is true for cities, whereby a higher proportion of city plans focus on efforts to mitigate GHGs rather than adapt to climate change.

Equity issues have been incorporated into several city plans, particularly in cities' mitigation rather than resilience plans. Plans that incorporate an equity lens often involve stakeholder engagement to identify barriers and strategies that can increase equitable access to clean energy. To help improve a community's overall well-being, some plans, such as Milwaukie's climate action plan, have identified and ranked the "co-benefits" of each mitigation or adaptation strategy. For example, strategies were evaluated based on the extent they generated city revenue or avoided costs, leveraged existing city policies, were valued by community members, and provided opportunities for social equity.[57] Table 2 characterizes the goals and focus areas of city and county climate mitigation and adaptation related plans, ordered by population size. Table 2 also notes whether a jurisdiction's GHG mitigation goals are community-wide (e.g., pertaining to both public and private sectors) or specific to government-owned facilities (e.g., city-owned buildings or fleets). The table also notes if a jurisdiction's GHG inventory and goal-setting have been completed or are in progress, and which focus areas were included in the plans.

Table 2: Jurisdictions in Oregon Taking Climate Change Actions

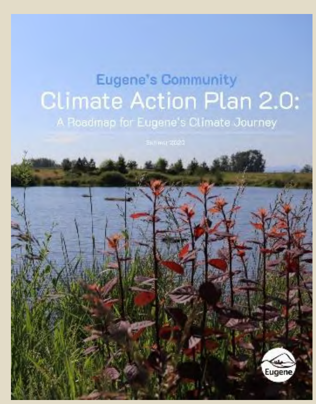
✓ = completed/ included; ↪ = in progress	Climate Mitigation								Climate Adaptation			
	GHG Mitigation Goal	GHG Inventory	Focus Areas: Transportation & Land Use	Renewable Energy	Buildings	Materials Management	Carbon Sequestration	Equity	Focus Areas: Vulnerability Assessment	Adaptation/Resilience Strategies	Natural Hazard Mitigation*	Equity
CITIES												
Portland 58,59,60,61	Reduce GHG emissions by 80% of 1990 levels by 2050 (community-wide)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Eugene 62,63,64	Reduce fossil fuel use by 50% of 2010 levels by 2030; Reduce GHG emissions by 7.6% annually (community-wide)	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓
Salem 65,66,67	↪	✓									✓	
Gresham 68,69	Achieve 100% renewable energy by 2030 (scale not stated/set)	↪							✓	✓		
Hillsboro 70,71	Achieve 100% of electricity and natural gas used by city facilities sourced from renewable energy by 2030. 100%/40% of city-owned fleet to consist of zero-emission light-/medium- and heavy-duty vehicles	✓	✓	✓	✓							

Beaverton [72,73,74]	Achieve net-zero emissions by 2050 (community-wide)	✓	✓	✓	✓	✓		✓			✓	
Bend [75]	Reduce fossil fuel use by 40% by 2030 and by 70% by 2050 (community-wide)	✓	✓	✓	✓	✓		✓	✓	✓		✓
Springfield [76,77,64]		✓							✓		✓	
Corvallis [78,79]	Reduce GHG emissions by 75% of 1990 levels by 2050 (community-wide)	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓
Lake Oswego [80]	Achieve net-zero emissions by 2050 (community-wide)	✓	✓	✓	✓	✓		✓	✓	✓		✓
Grants Pass [81]											✓	
West Linn [82,83]	Reduce GHG emissions from city facilities and operations by 80% and from buildings and houses by 50% by 2040	✓	✓	✓	✓	✓		✓				
Forest Grove [84]	↪	↪	✓		✓	✓						
Ashland [85,86]	Achieve net-zero emissions in city operations by 2030; Reduce fossil fuel used for city operations by 50%/100% by 2030/2050	✓	✓	✓	✓	✓		✓	✓			✓
Milwaukie [57,87]	Achieve net-zero emissions by 2050 (community-wide)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
COUNTIES												
Multnomah [58,59,60]	Reduce GHG emissions by 80% of 1990 levels by 2050 (community-wide)	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
Washington [88]		✓										
Clackamas [89,90,91]	Achieve net-zero emissions by 2050 (community-wide)	↪							↪	↪	✓	

Lane [92,93]	↪	↪								
Jackson [94]								✓ **		
Yamhill [95]										✓
Benton [79,96,97,98]	Reduce GHG emissions (from government facilities and operations) by 75% of 1990 levels by 2050	✓	✓	✓	✓	✓		✓ **		✓
Josephine [81]										✓
Clatsop [99,100]								✓ **	↪	
Malheur [101]										✓
Tillamook [99, 102]								✓ **		✓
Hood River [103,104]	Replace 30%/50%/80% power generated from fossil fuels with clean energy in buildings, water systems, and transportation by 2030/2040/2050 (community-wide)	✓	✓	✓	✓	✓			✓	✓
Jefferson [105]										✓
Crook [106]								✓	✓*	
Curry [107]										✓

*Note: Only Natural Hazard Mitigation Plans that address climate change hazards are included. *Focused on health. **Focused on transportation.*

Eugene's Climate Action Plan 2.0: Equity in Action



In 2010, the City of Eugene passed its first-ever Community Climate and Energy Action Plan, which focused on reducing greenhouse gas emissions and fossil fuel use, and identifying strategies to help the community adapt to climate change. In 2016, the Eugene City Council finalized its climate goals and adopted them into city code, so the City decided to update its action plan to align with those goals.

Staff began working on an update to the plan in 2018 with a special focus on equity. Traditionally, climate action plans are heavily influenced by climate experts – and Eugene recognized the need to bring in community members from underserved or marginalized communities, as they are often the communities most affected by climate change.

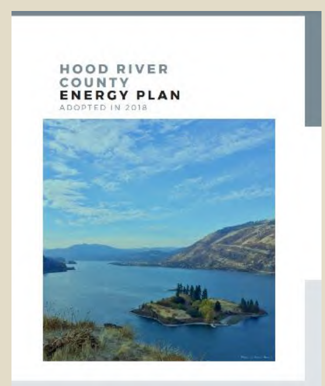
Eugene worked with the Urban Sustainability Director's Network to connect with other cities that have successfully merged climate and equity to identify what might work for Eugene. Following outreach efforts to underserved communities and an application process, the City named six representatives to an Equity Panel for the action plan development.

The Equity Panel took a unique storytelling approach to ensure everyone's voice could be heard, and to honor panel members as experts of their own lived experience. That storytelling helped shape recommendations for the updated action plan, while also focusing on the science behind those recommendations.

Forming the panel didn't just benefit development of the action plan – it also helped the participants better understand how to access government. One Spanish-speaking panel member noted that she can bring what she learned back to her community so they can have a voice across government issues. The City plans to see how the Equity Panel structure could be used in other government planning processes to continue elevating diverse voices.

Eugene's Climate Action Plan 2.0 passed unanimously by the Eugene City Council on July 29, 2020.[57]

Hood River County Plans for its Energy Future



Hood River County is home to incredible fruit orchards, world-class recreation, sweeping Columbia River Gorge views, and more. Each year, the community's way of life is threatened by an array of potential disasters, including wildfires, ice storms, and utility power shutoffs that are likely to increase in frequency and severity with climate change. These events can cause power outages and fuel shortages that could lead to devastating health, safety, and economic impacts.

Recognizing these and other growing risks, Hood River County looked to their energy systems for solutions. In 2016, Hood River County, the City of Hood River, the Port of Hood River, and the Port of Cascade Locks joined in partnership with other local stakeholders to develop the Hood River County Energy Plan. Through the planning process, the community learned that energy technologies and strategies offered unprecedented opportunities to mitigate power outages, reduce long term energy costs, keep dollars local, and create a healthier environment. Relying on principles of community benefit and expanding access to those benefits, the Plan sets community wide goals to reduce fossil fuel use in the county, while improving resilience and energy independence through more local energy production and storage, alternative transportation fuels, walkable streets, robust public transit, and efficient buildings.

Following adoption of the Energy Plan, the community established the Hood River County Energy Council in 2019, which serves as an advisory body for the various agencies, partners, citizens, businesses, and others who are committed to helping Hood River County achieve its goals. The Council works closely with state and local partners to develop and access resources for projects that achieve multiple community benefits. The Energy Plan and Energy Council empowers the community with a voice in decisions about their energy systems. The Energy Council is staffed by the Mid-Columbia Economic Development District.

Much of the Energy Council's work to date focuses on understanding and mitigating the threats posed by disasters – in particular, preparing for at least two weeks without electricity or liquid fuel in the event of a Cascadia Subduction Zone earthquake. One example is collaboration with Energy Trust of Oregon to design solar plus storage microgrid preliminary design and feasibility studies at nine critical facilities in the county, such as government buildings, food banks, and schools that could maintain power for up to two weeks in the event of an extended power outage. This work reflects research Energy Trust is doing to define energy resilience, expand access to solar plus storage microgrids, and identify funding sources for these systems in Oregon. Other examples of Energy Council work include supporting governing bodies in "leading by example" in their buildings and fleet, and exploring creative partnerships to increase access to energy efficiency among energy burdened residents.

Content provided by the Mid-Columbia Economic Development District.[103]

Key Federal Actions to Mitigate and Prepare for Climate Change

In June 2020, the House Select Committee on the Climate Crisis put forth Congress's largest, most comprehensive climate plan—*The Congressional Action Plan for a Clean Energy Economy and a Healthy, Resilient, and Just America*.[108] The plan underscores the need for environmental and climate justice to be embedded into laws and government decision-making. The plan incorporated an extensive amount of input from stakeholders, including elected officials, tribal leaders, scientists, business representatives, policy experts, and individuals representing communities on the front lines of climate change. The State of Oregon provided extensive input.[109] The overall goal of the Congressional climate action plan's recommendations is to achieve net-zero GHG emissions in the United States by 2050, which aligns with Oregon's state goals and those of many of its local jurisdictions, as well as the recommendations set forth by the United Nations Intergovernmental Panel on Climate Change—the leading body of climate scientists.

Tribal Actions to Prepare for Climate Change

By altering ecosystems, the supply of First Foods, and landscapes, climate change disproportionately affects indigenous communities, threatening their cultural heritage, natural resources, and lifeways. Tribes in Oregon have already been experiencing firsthand the impacts of climate change on traditional First Foods, such as native salmon and steelhead populations (see Chapter 2 in 2018 *Biennial Energy Report*).[110] Over recent decades, tribes have been taking measures that not only increase their resilience to the impacts of climate change, but also reduce their carbon footprint. Several tribes have expanded their supply of renewable energy sources to increase their energy independence, reduce energy costs and GHG emissions, and generate sources of revenue.

Since the 2018 *Biennial Energy Report*, the Confederated Tribes of Umatilla Indian Reservation (CTUIR) opened the first tribally owned building set to achieve net-zero emissions. Serving as the Tribe's healthcare and wellness center, the new Yellowhawk facility will supply all its annual energy use through onsite solar panels. Sixty percent more efficient than a comparable new health care facility, the building will save an estimated 646,000 kilowatt-hours of electricity per year, equivalent to about $58,000 in annual energy cost savings that can now be invested in the community.[111] Yellowhawk was supported by the Energy Trust of Oregon and is the first tribal building to enroll in the Trust's Path to Net Zero program.

Affiliated Tribes of Northwest Indians Climate Change Program

The mission of the Affiliated Tribes of NW Indians (ATNI) is to provide a forum for sharing information on matters of interest to its member Tribes, develop consensus on matters of mutual importance, assist member Tribes in their governmental and programmatic development consistent with their goals for self-determination and self-sufficiency, and provide for effective public relations and education program with the non-Indian communities. ATNI includes 57 tribes from Oregon, Washington, Idaho, California, and Alaska.

The ATNI Climate Change program goals involve:

- Ensuring ATNI member Tribes are engaged and aware of federal, state, and tribal climate change programs;
- Serving as a clearing house for and coordinator of tribal and intertribal efforts;
- Supporting ATNI's participation in regional, national, and international climate policy, adaptation, and mitigation efforts;
- Supporting ATNI member Tribes in identifying and securing Climate Change funding.

Over the years, ATNI has provided testimony and expertise to the Oregon legislature and state agencies on climate change, water, and other natural resource issues.

In 2018, the CTUIR also developed a "sun trap" or array of solar panels that supply 100 percent of the electricity for three CTUIR owned buildings—the Tribe's field station, public transit center, and maintenance shop.[112] These solar panels increase the Tribe's energy independence, yielding nearly $12,000 in annual energy cost savings and nearly 23 metric tons of GHG emissions reductions per year.[113]

In 2020, the Confederated Tribes of Coos, Lower Umpqua and Siuslaw Indians (CTCLUSI) initiated a project to rehabilitate 19 housing complexes, increasing their livability and sustainability by installing energy efficiency upgrades and ductless heat pumps.[114] Tribes in Oregon have also partnered with the University of Oregon and Oregon State University to develop guidance material and inter-tribal networks to assess local climate impacts and increase resiliency.[115,116,117,118]

Figure 1: Yellowhawk Tribal Health Center on the Path to Net Zero Emissions[119]

Figure 2: Confederated Tribes of the Umatilla Indian Reservation's "sun trap" solar array[112]

Other Climate Actions in Oregon

Numerous local and regional partnerships have continued to emerge in the wake of the 2015 Paris Agreement, a global agreement to limit global average temperature increases from climate change this century to below 2°C (3.6°F) and pursue efforts to limit warming to 1.5°C (2.7ºF) above pre-industrial levels.[120]

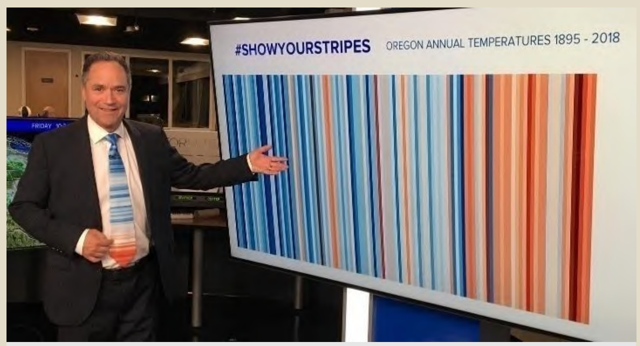
These public-private partnerships and coalitions, including Renew Oregon, the U.S. Climate Alliance, and others, have grown in recent years. In 2019, Nike, one of Oregon's largest companies in terms of revenue and number of employees, launched its "Move to Zero" initiative aiming to achieve zero carbon emissions and zero waste in company manufacturing and operations.[121] To achieve this goal, Nike plans to power its owned and operated facilities with 100 percent renewable energy by 2025, reduce carbon emissions across its global supply chain by 30 percent by 2030, divert 99 percent of footwear manufacturing waste from landfills, and divert 1 billion plastic bottles each year from landfills to create its products. In 2020, Intel, along with other technology companies headquartered in the region, pledged to reach 100 percent renewable energy use and zero waste by 2030.[122]

In the wake of the 2020 COVID-19 global outbreak and the nation's outcry against systematic racism, local and national governments have called for increased climate and racial justice, highlighting the strong link between the two. In June 2020, Portland passed a climate emergency declaration focused on communities most affected by climate change, including Black, Indigenous, and communities of color and their youth.[123] In collaboration with Multnomah County, frontline communities, and youth-led organizations, the City of Portland pledged to establish and convene a new initiative by the fall of 2020 to identify and implement strategies that advance climate justice.

Also in June 2020, Portland General Electric partnered with 36 local and regional organizations, including ODOE and ODOT, to urge Oregon's Congressional Delegation to invest potential COVID-19 related stimulus dollars in clean energy infrastructure. The letter emphasized investments to lower the costs of zero-emission vehicles and increase the accessibility of associated charging infrastructure, actions that are key to reducing Oregon's GHG emissions while bolstering the local economy and increasing equitable access to clean energy.[124]

#ShowYourStripes

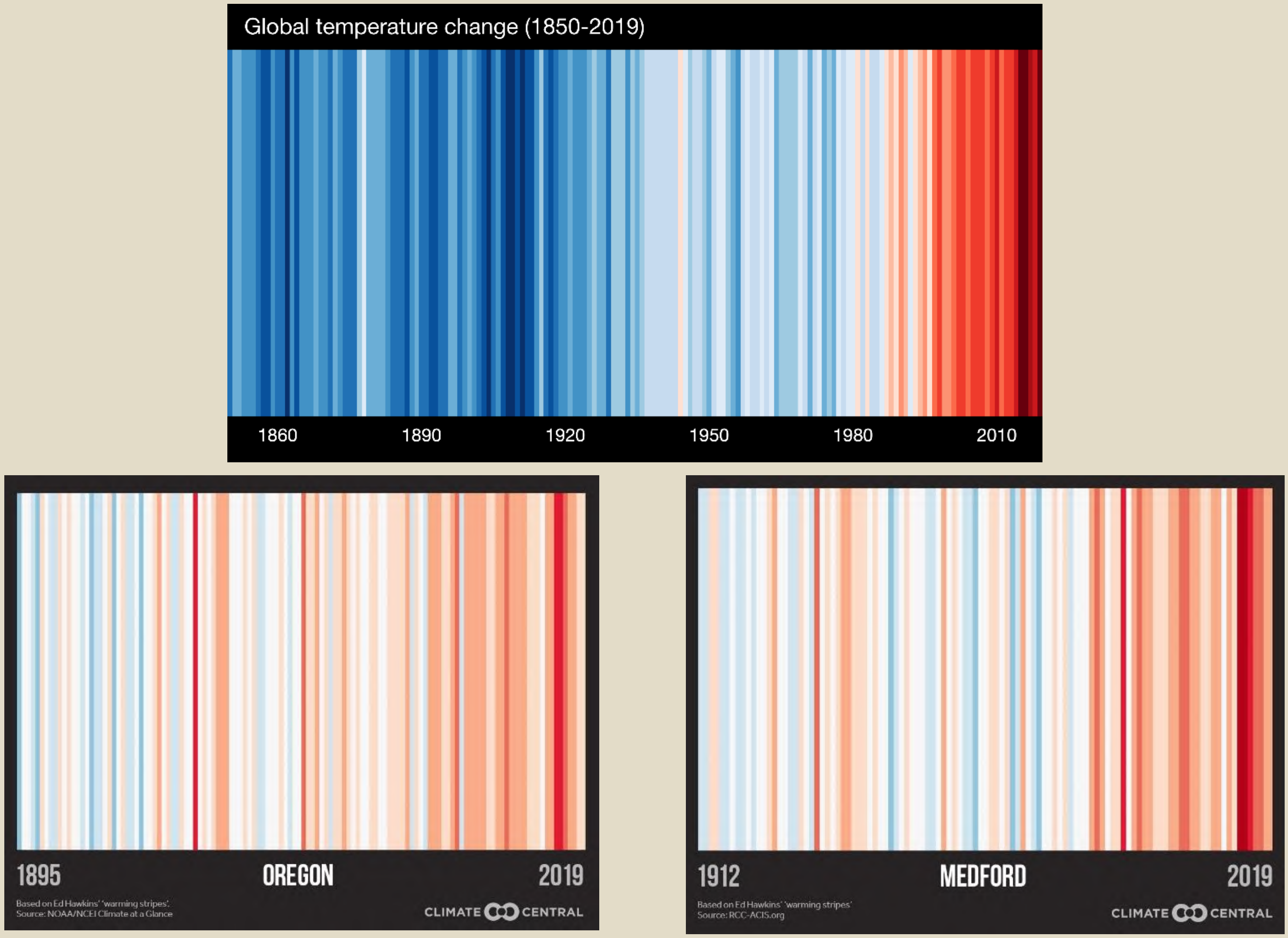
Although public awareness about climate change has increased substantially over the years, gaps remain in public understanding of the many risks posed by a warming climate. While two out of three Americans are worried about climate change, less than half think it will harm them personally.[125] Meteorologists, who serve as trusted translators of science to local communities, have united to help improve the public's understanding of the risks that climate change pose to all of us.[126]



Portland Meteorologist Matt Zaffino Shows His Stripes[130]

June 2020 marked the third year of the #MetsUnite and #ShowYourStripes awareness campaign, whereby hundreds of meteorologists across the country show the "Warming Stripes" of their city, state, country, or globe—images that spread across social media, as well as on ties, shirts, earrings, coffee mugs, cars, and even face masks. [127] Developed by climate scientist Ed Hawkins, these stripes show an area's annual temperature anomalies, meaning the difference in annual temperature from its long-term average. The transition of mostly blue to mainly red stripes show a clear warming trend.

Warming stripes for the globe, state of Oregon, and City of Medford [128,129]



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Policy Brief: Climate Vulnerability Assessment

Carbon dioxide and other greenhouse gases (GHGs) trap the sun's heat in the earth's atmosphere. This greenhouse effect changes the earth's climate—increasing air and water temperatures, shifting precipitation patterns, wildfires, raising sea levels, and increasing the frequency and intensity of extreme weather events (such as heat waves, heavy downpours, and droughts).[1] These **climate hazards** can damage and degrade critical infrastructure and interrupt planning processes—threatening the availability, reliability, and affordability of energy resources. For example, hotter summer temperatures can increase the need for air conditioning, while changing precipitation patterns can shift when hydropower is available. Wildfires, and flooding from heavy precipitation that causes landslides, can damage power lines and substations, increasing the frequency of service interruptions like brownouts and blackouts. These hazards can also block roads, disrupting the distribution of transportation fuels. Furthermore, climate hazards complicate planning and power management that help ensure Oregonians' seasonal energy needs are met.

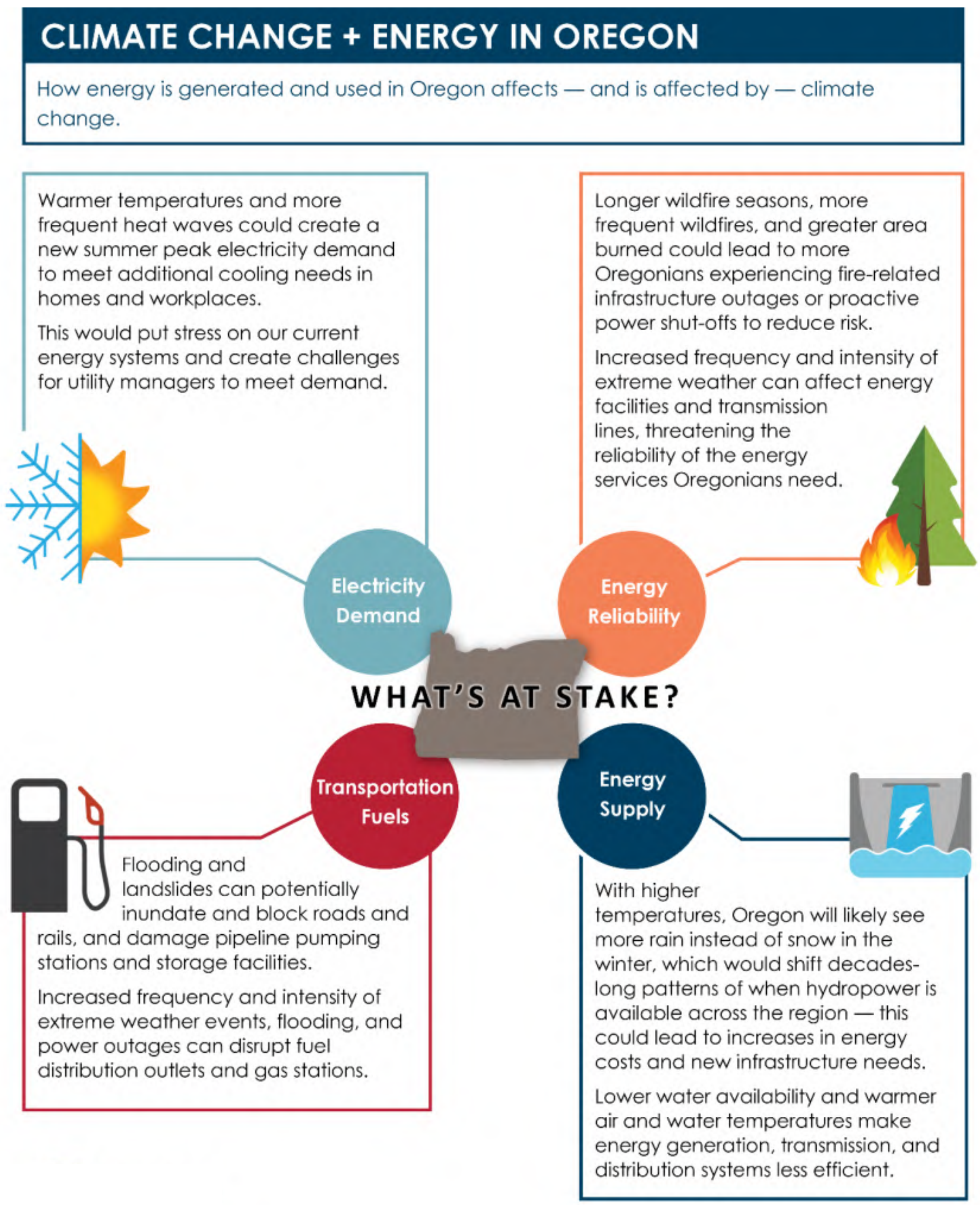
Preparing Energy Systems for Climate Change

Oregon's energy sector consists of many interacting systems that generate and distribute electricity to end-users, and that store and distribute fuels for home-heating, industrial processes, and transportation. These energy systems are supported by critical infrastructure, facilities, planning, and energy management needed to provide energy resources to Oregonians. Climate change is expected to affect several dimensions of Oregon's energy sector, and it may not be feasible to protect infrastructure everywhere or to prepare for worst-case climate conditions. Given the high costs of updating and maintaining energy systems, characterizing their vulnerability is important, particularly to protect high-risk assets. As such, a climate vulnerability assessment is generally the first step to prepare for climate hazards in what is typically known as "climate adaptation" planning. The subsequent steps of adaptation planning include: identifying projects to reduce risk and adapt to the most impactful vulnerabilities, conducting a cost-benefit analysis on the identified projects, prioritizing the adaptation projects, developing a funding strategy, and then implementing the projects in priority order.

A climate vulnerability assessment is a systematic process to analyze the degree of risk posed by different climate hazards to various systems and assets. An assessment provides information about the magnitude and timing of climate threats at the geographic scale and level of detail that planners and policymakers need to identify and prioritize adaptation strategies and actions for high-risk assets. These types of assessments have been on the rise by various entities and scales. For example, in July 2020, the California Public Utilities Commission proposed that all their regulated energy utilities conduct climate vulnerability assessments to provide safe and reliable energy services.[2]

The Oregon Department of Energy is developing a comprehensive state-specific climate vulnerability assessment for the energy sector. The analysis will include an evaluation of the risks and vulnerabilities to infrastructure and planning processes—inclusive of electric, natural gas, and liquid fuels production and delivery systems. This study will help identify and anticipate the sector's vulnerabilities, so that the energy sector may better meet its objectives to produce safe and reliable energy. The assessment should provide a strong foundation for identifying gaps and opportunities to make investments that maximize community energy resilience and serve as a template for other sectors.

As described in Governor Brown's recent Executive Order 20-04, climate change will have a disproportionate effect on certain communities—particularly Black, Indigenous, and people of color, low-income, rural, and coastal communities—that have been traditionally underrepresented in public processes and typically have fewer resources for adapting to climate change (see Climate Update Policy Brief). Stakeholder engagement is explicitly included as part of the climate vulnerability assessment to incorporate equity concerns and assess the extent to which risks may disproportionately affect these traditionally underserved and vulnerable groups. As the assessment moves forward, ODOE will also engage with the Environmental Justice Task Force and the newly created Interagency Workgroup on Climate Impacts to Impacted Communities to ensure that the needs of vulnerable and underserved communities are front and center.



Conducting a Climate Vulnerability Assessment

Conducting a climate vulnerability assessment is a process to: 1) identify relevant climate hazards, 2) assess the respective risks they pose to a sector's systems and portfolio of assets, and 3) prioritize vulnerabilities to help inform risk-reduction strategies. The same general process can be followed for all sectors and geographical scales (e.g., at the organization, city, state, or national level). An assessment typically includes the following key steps: [3, 4, 5]

Hazard Identification:

- Identify relevant climate hazards and potential impacts that may undermine or harm the sector's systems and assets.
- Indicate the observed and projected magnitude and timing of each climate hazard. This information on the emerging and expected changes of each identified climate hazard is included in the following **climate outlook** sections.

Risk Assessment:

- Assess the likelihood of each climate hazard happening.
- Assess the potential consequences (impacts) of each climate hazard on each key system/asset.
- Assess the level of risk posed by each climate hazard to each key system/asset, by integrating likelihoods and consequences.
- Assess the sector's "adaptive capacity," which is its ability to respond to risks based on experience and existing resources.
- Indicate the extent to which risks may disproportionately affect traditionally underserved and vulnerable groups (e.g., people of color and Indigenous, low-income, and rural communities).
- Identify potential implications for the sector's broader goals (e.g., to increase community resilience, reduce GHG emissions, etc.).
- Assess the vulnerability level posed by each climate hazard to each key system/asset, as well as to underserved and vulnerable groups.

Vulnerability Prioritization:

- Rank the sector's vulnerabilities, based on the above inputs.

Information on hazard identification is presented in the following sections. The remaining steps will be captured in ODOE's upcoming full climate vulnerability assessment, to be conducted in 2021.

Identifying Climate Hazards Facing Oregon's Energy Systems

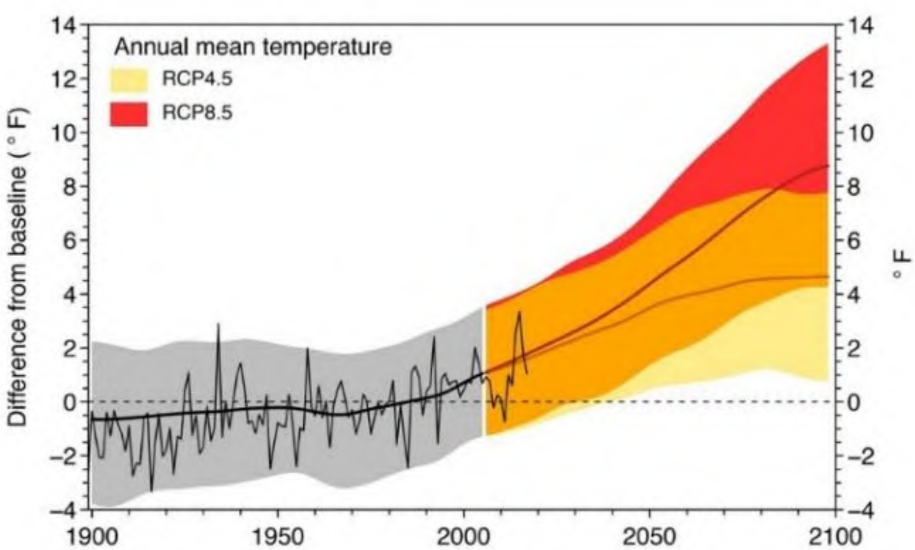
This section identifies example climate hazards, their potential impact on Oregon's energy systems, and climate outlook in the coming decades.

Table 1 illustrates the potential impacts that the following key hazards pose to Oregon's energy systems:

- Increasing air and water temperatures, and extreme heat.
- Shifting precipitation patterns, reduced snowfall, and extreme precipitation.
- Increased incidence of drought.
- Increase in wildfire frequency and intensity.
- Rising sea levels and more frequent coastal flooding.

Climate outlooks are characterized by both recorded observations of climate conditions and projected changes in future conditions, based on climate science. Observations (or measurements) from recent decades demonstrate how climate hazards have already begun to change in response to the significant amounts of GHGs emitted in the post-industrial era. Meanwhile, projections of emerging climate conditions show the magnitude by which we can expect hazards to change in the coming decades. Projections of future climate conditions depend on the amount of heat-trapping gases that continue to be emitted into the atmosphere. Standardized scenarios—known as representative concentration pathways (RCPs)—are used to project future conditions based on different possible amounts of GHG emissions.[6] RCP8.5 represents a scenario of continuingly high, "business-as-usual" emissions, resulting in an average of approximately 3°F (1.7°C) of global warming by 2050 (relative to 1986-2015).[7] RCP4.5 represents a lower emissions scenario resulting in an average of 2°F (1.1°C) of global warming by 2050. These scenarios lead to divergent impacts over time, particularly after 2050 (see Figure 1).

Figure 1: Average annual temperatures in Oregon; observed and projected.



The dashed black line represents the historical average temperature (1970-1999), while the solid yellow and red lines show the average projected increase in annual average temperature over the 21st century, under low and high emissions, respectively. Yellow and red shading represents the range of potential increase in average temperatures in future years.[8]

Table 1: Potential Impacts of Climate Change on Oregon's Energy Sector

Vulnerabilities Posed by Climate Hazards		
Electricity Generation	**All Sources**	Increasing summer temperatures and more frequent heatwaves increase the demand for residential and commercial space cooling and degrade reliability, which could lead to increases in energy costs and new infrastructure needs.[9, 10, 11]
	Hydropower	Variability in the timing and amount of precipitation could make energy supply forecasting and power planning more difficult, and lead to higher energy costs and new infrastructure needs. [11] A higher proportion of precipitation falling as rain than snow, reduced summer precipitation, and extended droughts will affect the availability of hydropower.[11, 12, 13, 14]
	Thermoelectric Power (*Natural Gas, Geothermal, Nuclear*)	Increasing air and water temperatures can make thermoelectric energy generation less efficient, increasing operating costs.[10, 15] Decreasing water supply for cooling (caused by more precipitation falling as rain than snow or drought) could reduce the capacity of thermoelectric power during summer months.[9, 16] Inland flooding from heavy precipitation events and runoff can damage infrastructure, threatening reliability.[9, 16]
	Solar and Wind Power	Extreme temperatures can temporarily reduce solar power output.[9, 17] Inland flooding from heavy precipitation events and runoff can damage infrastructure, threatening reliability.[10, 16] Smoke from wildfires can reduce solar power output.[18]
	Bioenergy	Damage from extreme temperatures or droughts could reduce the supply of some crops used for biofuel production.[9, 16]
Electric Grid	**Transmission & Distribution Lines**	Increasing average and extreme temperatures, and more frequent heatwaves, can make transmission lines less efficient.[10, 15] Longer wildfire seasons, more frequent wildfires, and greater area burned can damage infrastructure and lead to more forced outages or public safety power shutoffs.[10, 16, 19]
Heating Fuel Supply and Distribution	**Natural Gas and Oil Supply Stations and Pipeline System**	Inland flooding from heavy precipitation can block roads/railways and damage supply stations and pipelines, hindering access to fuels. [10, 16] In some areas, coastal flooding from sea level rise could pose similar risks.[10, 16]
Transportation Fuel Supply and Distribution	**Oil and Gasoline Supply Stations and Distribution System**	Inland flooding from heavy precipitation can block roads/railways and damage supply stations and pipelines, hindering access to fuels. [10, 16] In some areas, coastal flooding from sea level rise could pose similar risks.[10, 16]

Increasing Air and Water Temperatures, and Extreme Heat

Unlike most of the United States, many areas of Oregon experience mild summers and have historically had winter-peaking electric systems, meaning that highest electricity demand typically occurs in winter during the heating season. Warmer temperatures and more frequent heat waves could create a new statewide summer peak electricity demand to meet additional cooling needs in homes and workplaces. [9, 10, 11] Since 1990, the number of households in Washington, Oregon, and California using air conditioning has doubled.[20] As temperatures rise year-round, the incidence of hot summer days and heat waves will continue to grow and create more air conditioning load. This will create equity concerns by putting stress on low-income Oregonians and families who don't have access to, or can't afford, air conditioning.[21] It will also put additional stress on our electricity systems and create new challenges for utility managers to meet electricity demand; however, additional investments in solar power—which is most readily available during the summer—could help meet additional demand. Additional resources could be required to ensure that an adequate supply of energy is available. The Northwest Power and Conservation Council has been working to incorporate projections of emerging climate conditions into load (electricity demand) forecasting to improve resource adequacy (electricity supply) planning. This work will be incorporated into the Council's 2021 Power Plan, which will inform the region's resource planning for the next 20 years (see Policy Brief on Resource Adequacy).[22, 23] Unfortunately, warming temperatures can also affect the performance and longevity of transmission and distribution lines.

Warming temperatures can also increase the temperature of water bodies affecting cooling for thermoelectric power facilities.[10, 15] Thermoelectric power facilities, such as natural gas generation facilities, require water or air for cooling and can be sensitive to increases in ambient temperatures. [15, 24] Even small changes in temperatures could result in efficiency losses that may make operation more costly. For example, one study found that most natural gas fired power plants are designed to operate at 59°F (15°C); above this threshold, the capacity of a combined-cycle natural gas plant could be reduced by 0.7 percent per 1.8°F (1°C) increase in ambient temperature and the capacity of a simple-cycle plant could be reduced by 1 percent per 1.8°F (1°C) increase.[25] Reductions in output decrease the amount of consistent power that natural gas plants contribute to the overall daily supply of electricity and during peak times when the electricity system needs to ramp up quickly (e.g., in the afternoon on very hot days when people get home from work). However, new generation capacity for wind and solar power—which are less affected by increasing temperatures and decreased water availability—could help offset capacity losses and help ensure adequate supply.[16]

Climate Outlook: In Oregon, temperatures have risen by approximately 2°F (1.1ºC) since the beginning of the 20th century, and the pace of warming has been accelerating since the 1970s (see Figure 1 above).[26] Temperatures are expected to continue to rise during all four seasons (see Figure 2 below). The average projected rise in Oregon's annual average temperature by 2050 is 3.6ºF (2°C) under RCP4.5 and 5.0ºF (2.8°C) under RCP8.5; by 2080, the rise increases to 4.6ºF (2.6°C) under RCP4.5 and 8.2ºF (4.6°C) under RCP8.5 (all compared to a 1970-1999 baseline; Figure 1). By 2050, average winter temperatures (in December through February) are projected to increase by 3.3ºF (1.8ºC) under RCP4.5 and 4.5ºF (2.5ºC) under RCP8.5, while average summer temperatures (in June through August) are projected to increase by 4.5ºF (2.5ºC) under RCP4.5 and 6.3ºF (3.5ºC) under RCP8.5.[27]

Figure 2 shows the geographical spread of increasing temperatures. [8] Summers are projected to warm by a larger magnitude than other seasons. During the summer and fall, inland areas warm more than coastal areas. During the winter and spring, higher elevation areas tend to warm more than lower elevation areas due to the warming effects of reduced snow cover. Figure 2 shows values under the lower emissions scenario (RCP4.5), whereby the increase in temperature would be approximately 47 percent higher under the higher emissions scenario (RCP8.5).[28] For example, under RCP8.5, hotspots in Oregon may face increases in average temperature of over 6°F (10.8°C) in the coming decades.

Historically (e.g., from 1970 to 1999), most areas in Oregon experienced about 30 "hot days" per year—days with a daily high temperature above 86°F.[8] If GHG emissions are not significantly mitigated, the incidence of hot days could double in the coming decades. By mid-century, the number of hot days is expected to rise by at least an additional 30 hot days per year across most of Oregon, except in the mountainous areas or along the coast (Figure 3).[8]

Figure 2: Projected increase in average annual temperature from historical period (1985-2014) to mid-century (2030-2059), under RCP4.5 for: (a) December-January-February (winter), (b) march-April-May (spring), (c) June-July-August (summer), and (d) September-October-November (fall).[8]

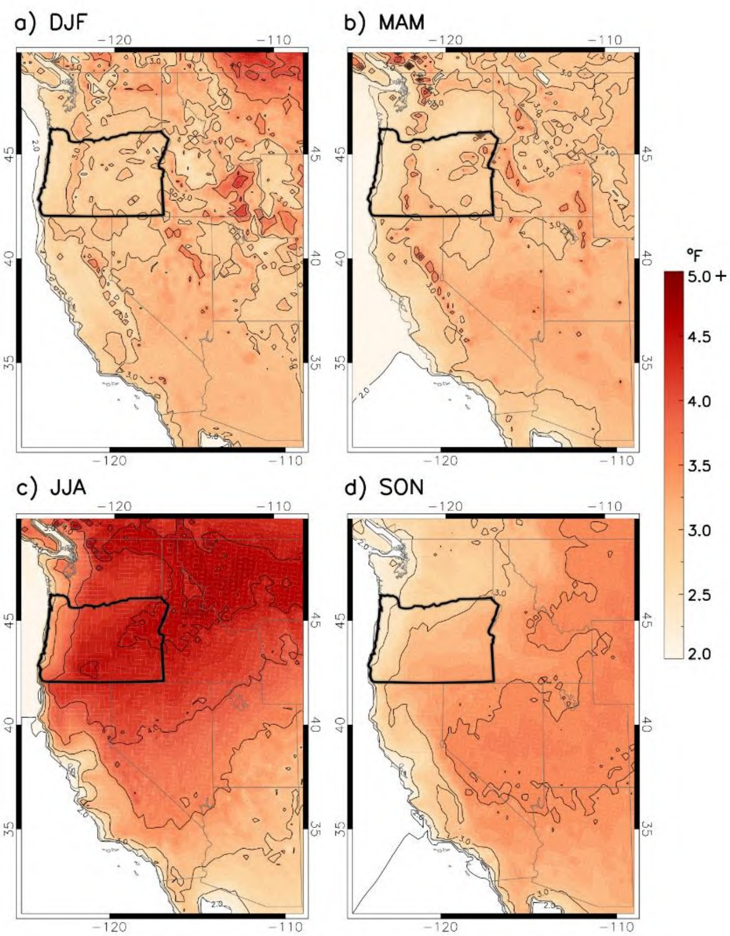
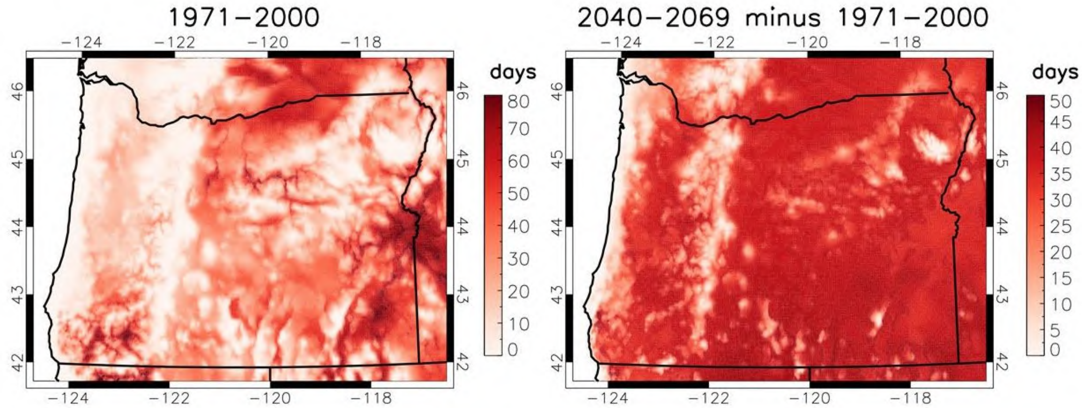
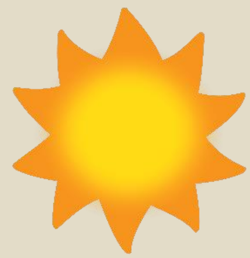


Figure 3: Number of hot days (with daily high temperatures above 86°F) observed (1971-2000; left). Additional number of hot days expected to occur by mid-century (right), under RCP8.5.[8]



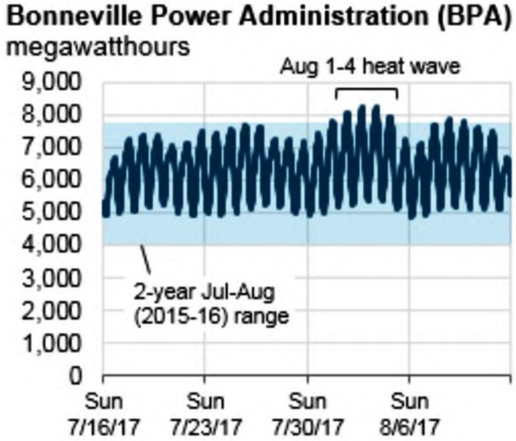
Heatwaves and Air Conditioning

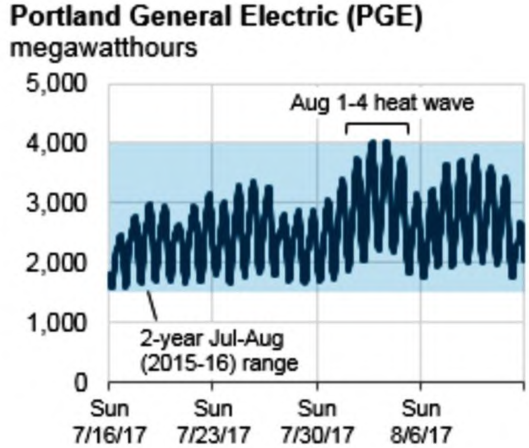


During the August 1-4, 2017 heatwave, Oregon experienced record-high electricity demand. In Portland, temperatures reached 105°F, which was 23°F higher than the 30-year average for the high on that day (from 1981 to 2010).[21] Throughout the heatwave, the Bonneville Power Administration broke its summer peak demand record of 7,861 MW from 2014 and reached an unprecedented peak of 8,226 MW (see Figure 4). Portland General Electric, which serves nearly half of Oregon's population, set a new summer peak demand record of 3,967 MW—only 100 MW below its all-time peak demand of 4,073 MW on December 1998.[21] As climate change continues to increase the frequency of extreme temperatures and heatwaves in Oregon, such instances of peak demand for air conditioning will likely become more common.

Extreme temperatures are responsible for the largest number of weather-related deaths. One study projected that the number of heat-related deaths in the United States will increase by over 50 percent by 2050 under our current GHG emissions trajectory.[29] The growing need for air conditioning poses serious equity implications across the country, where Black, Hispanic, Indigenous, and/or low-income households are less likely to have access. For example, August 2020 marks the 25th anniversary of the deadly five-day heatwave in Chicago that killed 700 people, disproportionately affecting Black residents.[30] In the short-term, to better serve these communities during extreme temperatures, some cities have offered to subsidize utility bills, provide or repair air conditioners, open more cooling centers, and provide parked air-conditioned buses to help passersby cool off.[31]

Figure 4: Hourly electric demand, July-August 2017.[21]





Shifting Precipitation Patterns, Reduced Snowfall, and Extreme Precipitation

With higher temperatures, precipitation becomes more unpredictable. Oregon will likely see a higher proportion of precipitation falling as rain instead of snow in the winter, shifting decades-long patterns of when hydropower is available across the region. Together, seasonal changes in the amount of precipitation and reduced snowpack are likely to result in higher winter flows, earlier peak spring runoff, and lower summer flows, increasing the amount of hydropower that is available in the winter and early spring (November through May) but decreasing the amount available in the late spring and summer (June through October).[12, 32] As summer temperatures and loads grow, this may create an imbalance between the amount of hydropower that is available and needed in the summer months, particularly in July and August. The increased variability in the timing and amount of precipitation may also make forecasting energy supply more difficult, which could complicate power planning in many areas of the state—over both the short-term (0 to 5 years) and long-term (up to 20 years).[11,13] Because hydropower is the dominant source of electricity in Oregon, increased precipitation variability could affect the entire electricity power market, including utilities that are less reliant on hydropower. For example, in 2000, below-average snowpack and above-average late summer temperatures reduced the availability of hydropower in Oregon and across the northwest. Most of the region's electric utilities incurred higher costs due to the increased need for spot-market prices, losses which were later incorporated into long-term adjustments to increase rates.[33]

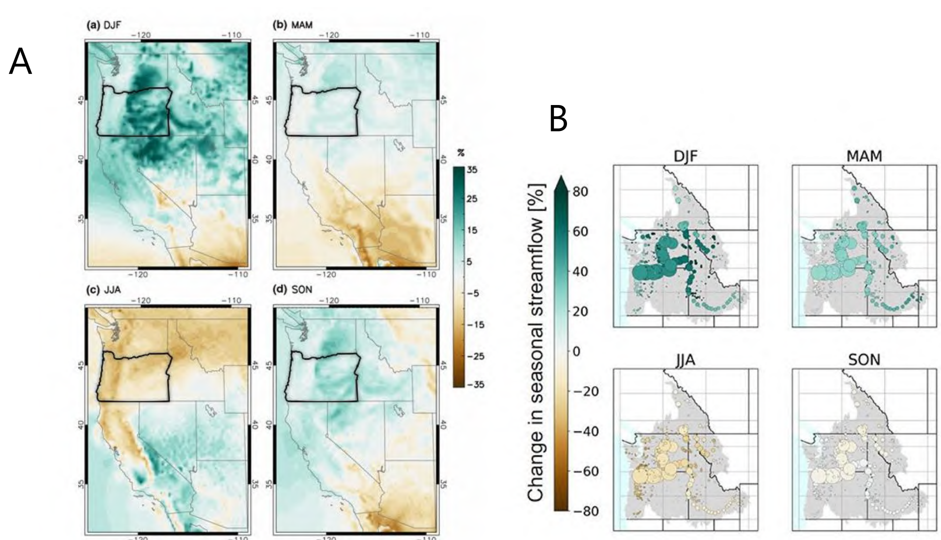
Changing precipitation patterns are also likely to increase the frequency and intensity of heavy precipitation events. By flooding and blocking roads, these events can disrupt the distribution of fuels for home-heating and transportation needs. They can also damage transmission lines, threatening the reliability of energy services. For example, in February 2020, Oregon declared a state of emergency after extreme rainfall—up to 400 percent of normal February precipitation—flooded northeast Oregon and covered some areas in 4-6 inches of mud.[34, 35] Several roads and highways were blocked and interstate 84 was closed for six days.[36] Umatilla Electric Cooperative experienced extensive damage, including lost electrical wiring systems and 172 poles, as well as damage to conductors and 42 miles of electrical lines, resulting in a loss of power to 146 households.[36]

Climate Outlook: Although the average annual amount of precipitation is expected to increase slightly (about 8 percent by 2100 under RPC8.5), the seasonal amount of precipitation is expected to change significantly (see Figure 5A). While moderately wetter winter conditions are expected (particularly in Eastern Oregon), drier summer conditions are expected (particularly in Western Oregon).[8] While the percent change in winter precipitation is higher in Eastern Oregon (see Figure 5A), the absolute increase in the number of inches of precipitation is expected to increase more in Western Oregon.[37]

Meanwhile, warming temperatures decrease the number of days with freezing temperatures. This causes more precipitation to fall as rain instead of snow and decreases winter snowpack over time, which affects seasonal streamflows.[13] By 2020, snowpack in the Columbia basin is estimated to have decreased by at least 10 percent since the 1980s and may decrease by up to 70 percent by the 2050s.[i, 12] As a result of changes in precipitation and snowpack, by 2030, streamflow in the Columbia River Basin is expected to increase in the winter and decrease in the spring and summer. By 2030, spring and summer streamflow may decrease by more than 20 percent and by 10 percent, respectively (see Figure 5B). These shifting precipitation patterns are likely to exacerbate the already high year-to-year variability in streamflows. Figure 6 illustrates the already high natural variability in surface water flows (see the gray lines) alongside average flows and expected changes to flows imposed by climate change.

Increases in winter streamflows will increase flood risk in river basin areas.[8] Extreme precipitation events are also expected to become more frequent and intense, particularly in Eastern Oregon. For example, the wettest day in 100 days is expected to result in approximately 6 percent more precipitation in Western Oregon, and 12 percent more precipitation in Eastern Oregon.[8]

Figure 5: (A) Projected percent increase in seasonal precipitation from historical period (1985-2014) to mid-century (2030-2059) under RCP8.5 for: (a) December-January-February (winter), (b) March-April-May (spring), (c) June-July-August (summer), and (d) September-October-November (fall). From Rupp et al. 2017 and used with permission.[28] (B) Projected changes in seasonal streamflow in the Columbia River Basin by the 2030s compared to the historical period (1976-2005).[12]

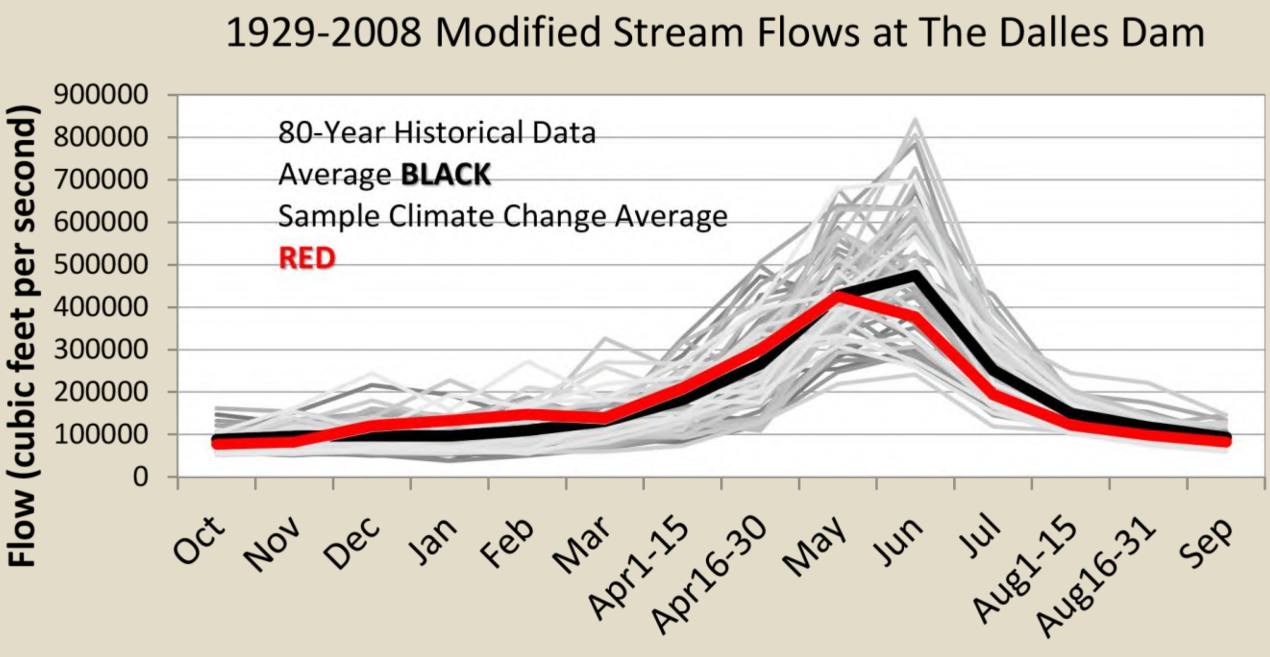


[i] Snowpack is measured by the amount of snow water equivalent on the first day of April averaged over a twenty-year timeframe.

Compounding Effects of Climate Change on Hydropower

By altering precipitation patterns, climate change is expected to shift the seasonal availability of hydropower in the Pacific Northwest—resulting in more generation in the winter and early spring (November through May) and less generation in the late spring and summer (June through October; see Figure 6).[12, 32] At the same time, climate change is expected to increase temperatures year-round, reducing the need for electricity to warm buildings in the winter and increasing the need for electricity to cool buildings in the summer. These compounding factors may result in a net surplus of hydropower in the winter, decreased generation in the spring, and potentially a net deficit in hydropower in the summer. Overall, these changes are not expected to greatly affect Bonneville's ability to meet average annual load nor greatly affect its total yearly revenue, although further analysis of the net effect of future electricity demand, market conditions, and management practices is needed.[32]

Figure 6: Shift in seasonal hydropower generation in the Pacific Northwest.[38]

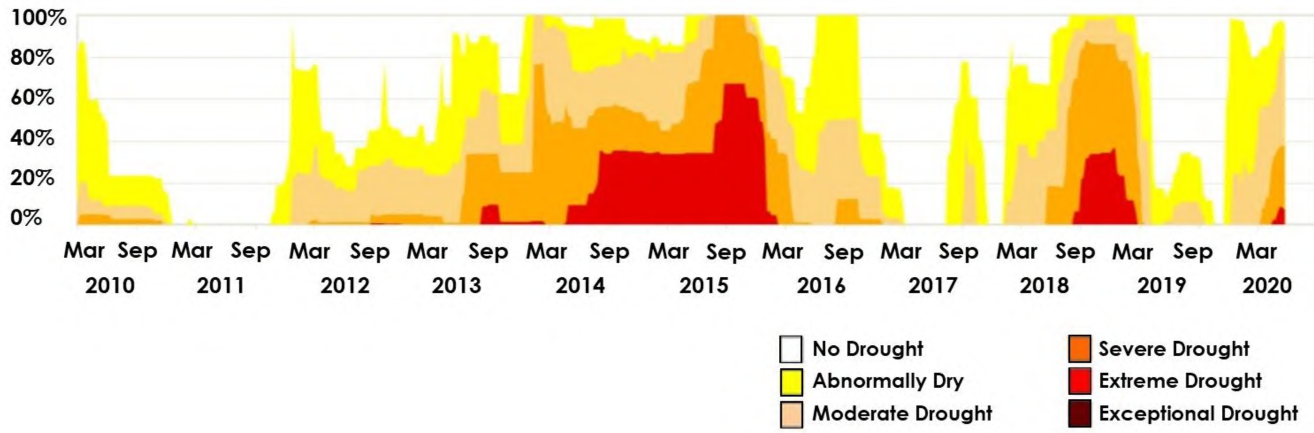


Increased Incidence of Drought

Together, shifting precipitation patterns (reducing snowpack) and rising temperatures (increasing evapotranspiration and aridity) can increase the incidence of drought. Droughts can reduce the amount of water available for hydropower, as well as for thermoelectric plants that require water for cooling. When droughts coincide with heatwaves, peaking power plants, which tend to emit high levels of GHGs, may be dispatched to meet increased electricity demand for air conditioning. For example, between 2001 and 2015, a study focused on the Western region estimated that droughts reduced average monthly in-state hydropower generation by 11 percent, increasing the generation of electricity from natural gas by 17 percent and coal by 9 percent to meet demand.[14] This led to an estimated total increase of 13.5 million tons of carbon dioxide emissions (11 percent of the state's total) from 2001 to 2015.[14] Drought conditions also increase the risk of wildfire (see Increase in Wildfire Frequency and Intensity subsection below).

Climate Outlook: In terms of summer soil moisture, the past 20 years were the driest on record for many areas across the western United States.[39] Nearly 50 percent of this trend was driven by climate change resulting from human-caused GHG emissions.[39] Using a series of drought indices shows that a large percentage of land in Oregon experienced drought conditions throughout the last ten years (see Figure 7).[40] In the coming decades, Oregon is expected to experience a substantial increase in the geographic boundary, frequency, and intensity of summertime droughts.[41] In terms of geographic boundary, the percentage of dry area in the summer season in the Pacific Northwest is expected to increase from about 25 percent to over 50 percent by 2050, under both emissions scenarios.[41]

Figure 7: Drought severity index: percentage of land experiencing drought conditions in Oregon from 2010 to 2020.[40]



Increase in Wildfire Frequency and Intensity

Population growth and development in forested areas, forest management practices, and climate change have amplified wildfire risk in Oregon. Increasing temperatures, declining snowpack, and earlier spring snowmelt increase the aridity of forests and the incidence of tree disease outbreaks (e.g., from the mountain pine beetle), weakening trees and fueling wildfires. In Oregon, the 2012, 2014, 2017, and 2020 fire seasons were among the most severe, in terms of acres burned, and those years also saw some of the warmest summers on record.[8] Over the last ten years, an average of nearly 1,000 fires burned per year on protected land alone in Oregon.[42]

Wildfires can damage wooden transmission poles and other energy infrastructure, and the associated heat and debris can degrade transmission line capacity.[16] Longer wildfire seasons, more frequent wildfires, and greater area burned could lead to more fire-related infrastructure outages or voluntary de-energization of power lines to reduce risk, threatening the reliability of energy services that Oregonians depend on. To help provide back-up power and avoid power shutoffs, some utilities and customers in the west, particularly in California, have increased their use of diesel generators, which emit large amounts of GHGs and particulates that pollute the air, and actually increase the risk of igniting additional fires.[43] Meanwhile, the increasing threat of fire risk to reliability has resulted in hundreds of new permits for residential solar power and storage systems in some of California's most impacted communities as customers seek to avoid the disruption caused by blackouts from voluntary de-energizations.[44] A combination of increased residential/commercial solar power and storage and the advancement of clean (low- to zero-carbon emitting) community-scale microgrids could significantly improve community energy resilience to outages in the future (see the Microgrid and Resilience Technology Review for more). As intense smoke from large wildfires can temporarily block light—reducing the efficiency of solar panels (e.g., by up to 30 percent in California during the outbreak of fires in mid-September, 2020)—new technologies may be needed either to provide complementary generation output or to provide longer duration storage of solar power (e.g., batteries or hydrogen).[44]

A rise in the frequency of fires can also increase the chance of simultaneous events. In August 2017, Oregon fought 17 fires at the same time and declared a state of emergency. These fires blocked the Columbia River crossing of Interstate 5 and several sections of Interstate 84, making it more challenging to transport fuels across the state.[45] In 2020, Oregon experienced its most damaging fire season in history with over 34 simultaneous fires.[46] The 2020 wildfires burned more than one million acres across the Interstate 5 corridor, exposing nearly the entire state to hazardous air quality, and forcing hundreds of thousands of households to either evacuate or lose power. Nearly a dozen Oregonians were killed.[47] As wildfires release substantial carbon emissions into the atmosphere, their growth will further aggravate climate change and air quality. For example, GHG emissions from the September 2020 wildfires may have surpassed annual transportation emissions—which account for nearly 40 percent of Oregon's annual emissions.[48]

Climate Outlook: Wildfire risk has increased dramatically over recent decades. In the Pacific Northwest, the length of fire seasons nearly doubled each decade, from 23 days in the 1970s, to 43 days in the 1980s, and again to 84 days in the 1990s. By the 2000s, fire season length averaged 116 days.[19] From 1984 to 2015, human-caused climate change nearly doubled the expected area burned in western U.S. forests.[49]

Increasing temperatures, declining snowpack, and earlier spring snowmelt will continue to lead to longer wildfire seasons, more frequent wildfires, and greater area burned. Wildfire risk is expected to increase across the state, particularly in the Willamette Valley and Eastern Oregon.[50] One indicator is the number of days with extreme fire risk—summer days when vegetation is exceptionally dry, providing fuel for fires. These can be defined as days (in June, July, and August) when the average moisture in vegetation over a 100-hour period is among the driest (e.g., below the 3rd percentile of days in the historical period).[8] Extreme fire risk days are expected to increase the most (by up to 14 days per year) in Eastern Oregon and across the Willamette Valley (Figure 8).[8] As the number and extent of wildfires grow, so does the amount of wildfire smoke, which aggravates a series of health problems, including asthma, heat attacks, and influenza (see Figure 9).[51]

Figure 8: Projected increase in extreme fire risk days per year by mid-century (2040-2069) compared to the historical period (1971-2000).[8]

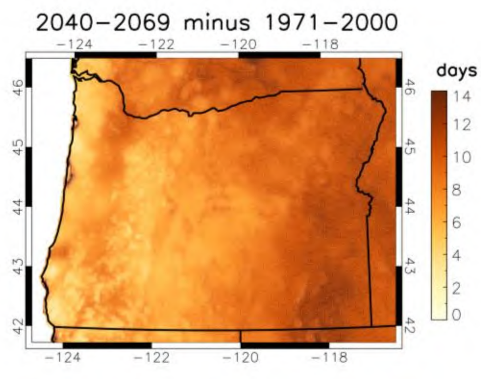
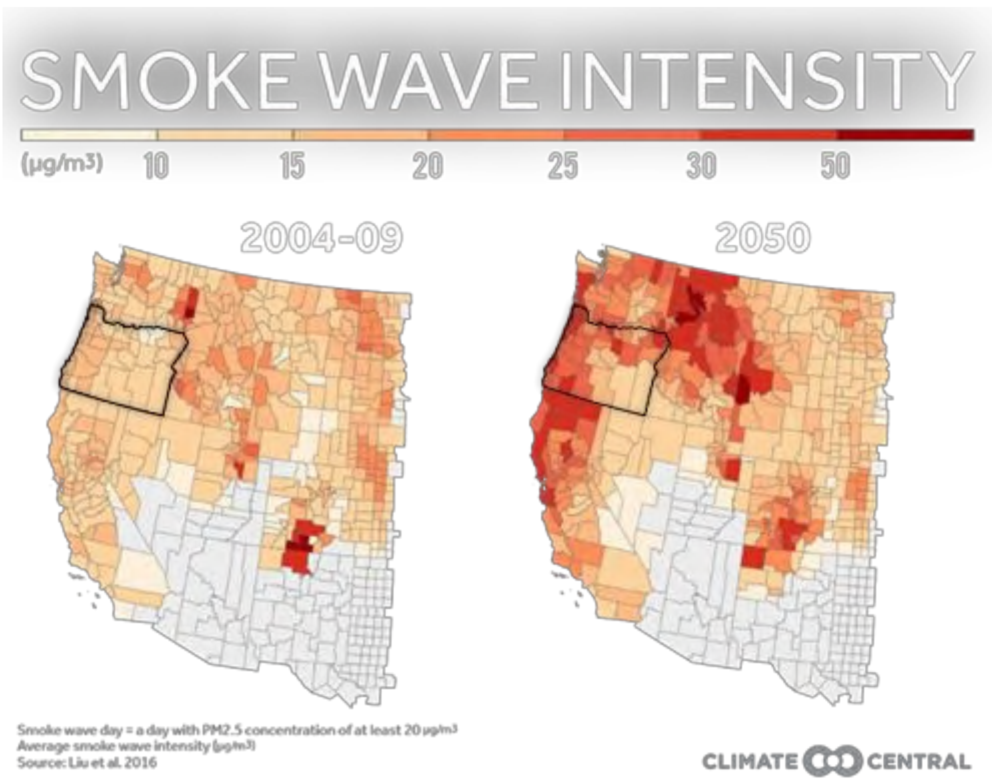


Figure 9: Average smoke wave intensity in the recent past compared to projected smoke intensity in 2050.[51] Under the Air Quality Index (AQI), an AQI less than 50 (equivalent to 12 micrograms per cubic meter, μg/m³) represents good air quality, whereas an AQI greater than100 (35.5 μg/m³) becomes unhealthy for sensitive groups.



Rising Sea Levels and More Frequent Coastal Flooding

Sea level rise not only inundates coastal areas over time, but also elevates the height of tides and storm surges, increasing the severity and frequency of coastal flooding. The relative amount of sea level rise facing a given location is driven by a combination of local, regional, and global factors—from land subsidence to ocean circulation patterns to the loss and distribution of water previously stored on Greenland's and Antarctica's ice-sheets. Coastal flooding, amplified by sea level rise, can aggravate erosion, damage buildings, block roads and bridges and ports, and release toxins from contaminated sites. Significant sea level rise also threatens low-lying urban areas like Portland that are hydrologically connected to—but not directly along—the coast.

Sea level rise primarily threatens Oregon's energy systems by damaging energy-related infrastructure, blocking roads and railways, and corroding assets in low-lying areas. For example, Central Lincoln People's Utility District has six electric substation sites located within the 1-in-100-year flood—with a 1 percent chance of occurring per year. The utility has elevated two of these substations and is currently relocating another one that floods regularly to a higher elevation nearby. Sea level rise can also expose low-lying natural gas and petroleum ports, pipelines, and storage facilities to more frequent flooding and greater rates of erosion. This could hinder the distribution of fuels for home-heating and transportation, disrupting access by Oregonians.

Climate Outlook: Because much of Oregon's coastline is undergoing geological land uplift, sea levels are expected to rise more slowly along the state's coastlines compared to other regions of the country. However, because mean sea level serves as a platform, even a small amount of rise can significantly increase the frequency and extent of flooding from tides and storm surges (e.g., as shown in Figure 11). The amount of emerging sea level rise varies along Oregon's coastline (see Table 2 and Figure 10). On average, the Oregon coastline is expected to experience nearly a foot of sea level rise by 2050. The local amount of sea level rise varies across the Oregon coastline, for example by 2050 a median rise of 5.1 inches is expected in Astoria, 10.2 inches in South Beach, and 7.9 inches in Charleston.[52]

As a result of median projected sea level rise, by 2050, the frequency of the local 1-in-100 flood level is expected to double in Astoria, and occur eight times as often in South Beach and four times as often in Charleston. By the same time, the height of the local 1-in-10-year flood level—with a 10 percent chance of occurring per year—is expected to increase from 3.3 feet to 3.7 feet in Astoria, from 3.4 feet to 4.3 feet in South Beach, and from 3.1 feet to 3.7 feet in Charleston, above the average high tide line.[53, 54] Sea level rise is also increasing the number of tidal (or "nuisance") flooding events, whereby water levels exceed local thresholds for minor impacts, such as blocking roads or clogging sewage systems. Over the next 30 years, the number of nuisance flooding events is expected to rise by three- to five-fold, increasing to 20 events per year in Astoria, 32 in South Beach, and 22 in Charleston.[55]

Increased flooding exposes more assets to water damage and closures. For example, four feet of flooding above the average high tide line—from any combination of sea level rise, storm surge, and/or tidal flooding—would threaten 6,000 Oregonians residing in low-lying areas, as well as 138 miles of road, over 30 hazardous waste sites, 19 wastewater sites, and 15 sewage plants.[54] Clatsop is the most exposed county in Oregon—with over 3,000 people, 60 miles of road, and four sewage plants at risk— followed by Coos, Tillamook, Lincoln, and Clackamas counties.[54]

The extent of sea level rise and increase in the frequency of coastal flooding will continue to grow in the coming decades and throughout the 21st century. Planning with sea level rise in mind is particularly important as coastal infrastructure—like ports, bridges, roads, and rails—tend to have long lifespans (e.g., 20 to 100+ years), often beyond their original design life.[56]

Table 2: The likely range (17th to 83rd percentiles) of local sea level rise projections under continuingly high, "business-as-usual" emissions (RCP8.5), in inches.[52]

	2030	2050	2100
Toke Point, WA	2.0–4.3	4.7–9.8	15.3–31.5
Astoria	1.2–3.1	2.8–7.9	11.4–27.6
South Beach	4.0–6.3	7.9–13.0	21.7–37.8
Charleston	2.4–4.7	5.1–10.2	16.1–33.1
Port Orford	2.4–4.7	5.5–10.6	16.9–33.5
Crescent City, CA	0.8–2.8	2.8–7.5	10.6–27.6

Figure 10: Median sea level rise projections under the low (RCP4.5, top bar) and high (RCP8.5, bottom bar) emissions scenarios, in inches.[52, 27]

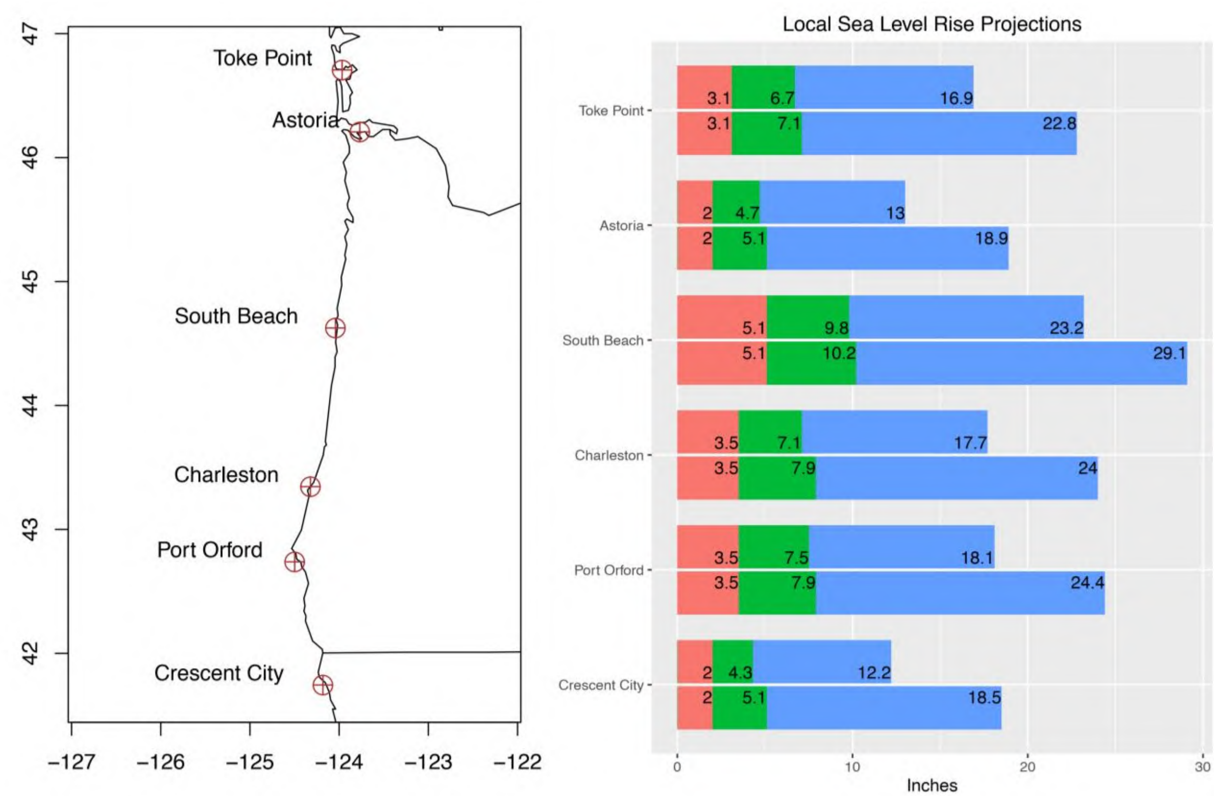


Figure 11: Wildfire in Oregon (left); tidal flooding in Nehalem, Oregon (right).

Next Steps

As illustrated above, climate change poses a series of direct and indirect risks to Oregon's energy systems and assets, threatening the sector's ability to provide safe, reliable, and affordable energy. Identifying and addressing the sector's key vulnerabilities can help it prepare—and help all Oregonians thrive—in a changing climate. As described above, a climate vulnerability assessment is a systematic process to analyze the degree of risk posed by different climate hazards to various sectors, systems, and assets—allowing planners and policymakers to identify and prioritize adaptation strategies. This section of the BER included the first steps of conducting a climate vulnerability assessment: namely, identifying relevant climate hazards, potential impacts that may undermine or harm energy systems and assets, and the outlook for these hazards in the years ahead. In 2021, ODOE will expand on this section to develop a full climate vulnerability assessment focused on Oregon's energy systems to help identify high-risk assets. This work will: quantify the level of risk posed by each hazard to each key system or asset; assess the sector's ability to respond to these risks; indicate the extent to which risks may disproportionately affect traditionally underserved and vulnerable communities; identify potential implications for the sector's broader goals; and assess and rank the sector's vulnerabilities to inform planners and policymakers. ODOE has initiated the assessment by beginning to gather input from energy stakeholders regarding how they view climate change as a threat to their energy systems; and what actions are being taken or planned to integrate climate risk information into planning, management, design, and other decision-making processes. Throughout the assessment process, ODOE will continue to meet with stakeholders from across the energy sector to incorporate this climate risk information.

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Policy Brief: Wildfire Mitigation Planning

> **"This is truly the bellwether for climate change on the West Coast. And this is a wake-up call for all of us that we have got to do everything in our power to tackle climate change."**
>
> Governor Kate Brown
> September 13, 2020[5]

Despite Oregon's reputation for having a lot of precipitation, much of the state often experiences arid conditions, especially during summer months.[1] Even the Willamette Valley and coastal areas of the state can experience drought conditions, despite having relatively high average annual precipitation levels.[2] As a result, no area of Oregon is immune to wildfires, as Oregonians were unfortunately reminded in September 2020. A combination of widespread drought conditions, high temperatures, and low humidity levels across much of western Oregon were met by anomalous east winds from September 7 through September 9, 2020.[3] These conditions led the National Weather Service to designate areas around Salem and the northern Willamette Valley as having "extremely critical fire weather" – the first time that such a designation has ever been declared in western Oregon.[4] The result was several catastrophic wildfires stretching from the Rogue Valley to the central Oregon Coast to the greater Portland metro area; the fires severely affected Oregon communities, including loss of life, destruction of built structures, large-scale evacuations, damage to electric system infrastructure, significant disruptions of electric service, and hazardous air quality.[i] While the degree to which the severity of these particular fires can be attributed to climate change is unknown, the frequency and the severity of wildfires in Oregon and across the American West are expected to increase as a result of climate change in the years ahead (see Climate Vulnerability Assessment section).

The relevance of this climate reality to the electric utility sector has come sharply into focus in the last several years, predominantly driven by events in California and affirmed by the catastrophic fires in Oregon in 2020. In 2007, several catastrophic wildfires in Southern California were found by the California Public Utilities Commission to have been ignited by electric infrastructure owned and operated by San Diego Gas & Electric.[6] More recently, the Camp Fire in 2018 resulted in most of the town of Paradise, CA being destroyed, and 85 of the town's residents perished. Subsequent investigations found that the tragic fire was caused by a poorly maintained 115-kV transmission line owned and operated by Pacific Gas & Electric.[7]

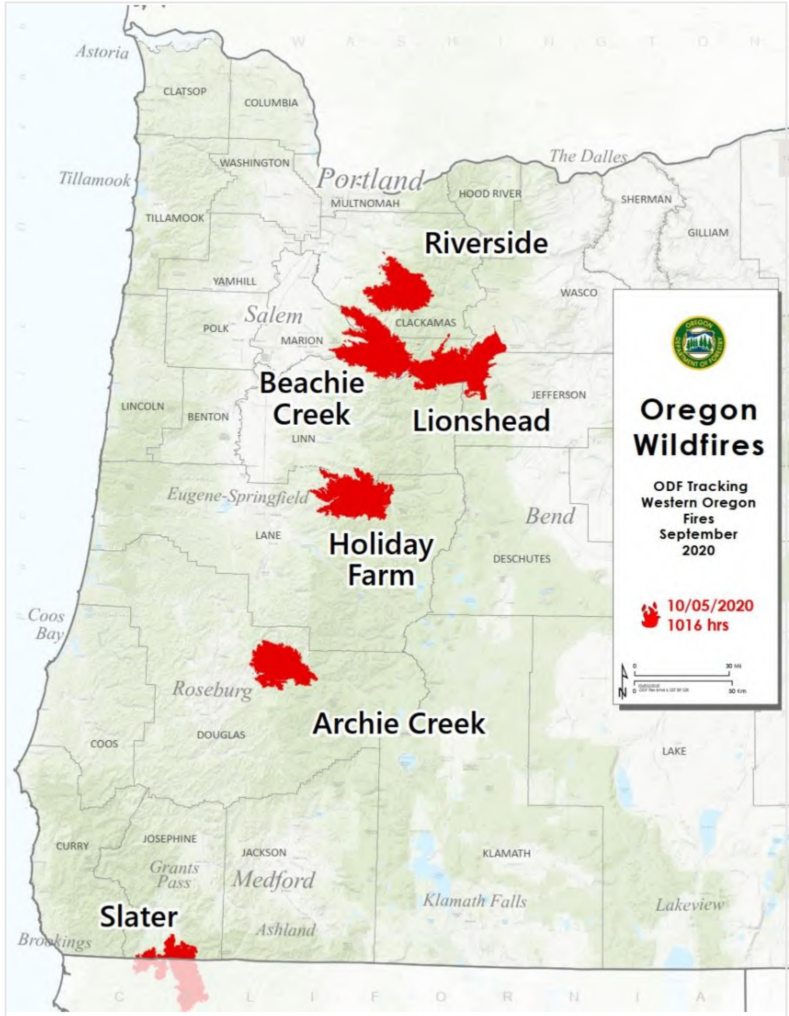
Wildfire on Highway 97 near Chiloquin, September 2020. *Photo courtesy of Oregon Department of Transportation.*

[i] Note that a full investigation of the cause(s) and impacts of the September 2020 wildfires has not yet occurred. The State Fire Marshall, law enforcement agencies, and other relevant local and state authorities will be involved in this effort.

What it Means for Oregon

While the risk of wildfire in any given year can vary significantly across different areas of the state and utility service territories, major fires can occur in almost any part of the state. The large fires in September 2020 along the west slope of the Cascade Range demonstrate this and are an example of the widespread damage that can occur from these increasingly severe wildfires in Oregon. According to data from the Oregon Department of Forestry, the total acreage burned by wildfires in Oregon has been increasing at an alarming rate in recent decades, from an average of approximately 150,000 acres annually in the 1990s, to 350,000 acres annually in the 2000s, to more than 500,000 acres annually in the last decade.[8] ODF's Final Fire Report for the 2020 fire season reported that more than 1,200,000 acres burned in the state this year, a large share of that from the fires that started in the days following Labor Day.[9] [10]

Figure 1: Map of 2020 Oregon Wildfires[10]



Total Acres Burned (as of 10/19/20)

Riverside – 138,054

Beachie Creek – 193,556

Lionshead – 204,469

Holiday Farm – 173,393

Archie Creek – 131,542

Oregon had already been anticipating an increased potential for major wildfire events driven by a changing climate. Several major wildfires in Oregon in 2017 (notably the Chetco Bar Fire that burned nearly 200,000 acres in the Coast Range of Curry County[11] and the Eagle Creek Fire that burned nearly 50,000 acres in the Columbia River Gorge[12]), and recent catastrophic fires in California, contributed to Governor Kate Brown establishing the Governor's Council on Wildfire Response in January 2019.[13] The Council—consisting of thirteen members appointed by the Governor including one representative from the electric utility sector—was charged with reviewing the state's current model for wildfire preparedness and response and developing recommendations to strengthen or improve those processes.[14] The Council reported its findings and recommendations in a report to the Governor in November 2019.[15]

The report identified a need for electric utility companies to "take additional measures to reduce the risk of transmission-related fire events."[16] It continued:

> *Due to the often remote location, power line fires have the potential to be larger than fires from other causes. Suppression of these fires during extreme weather conditions has become less effective. Reducing the risk of transmission-caused wildfire will have a direct and positive benefit to Oregon's effort to reduce human-caused wildfires.*


GOVERNOR'S COUNCIL ON WILDFIRE RESPONSE

November 2019: Report and Recommendations

Purpose

In response to increased wildfire risks affecting all Oregonians, Governor Brown signed an executive order creating the Governor's Council on Wildfire Response in January 2019.

The Council is tasked with reviewing Oregon's current model for wildfire prevention, preparedness and response, and analyzing the sustainability of the current model to provide recommendations to strengthen, improve, or replace existing systems.

To address this problem, the Council's first overall report recommendation called for the development of electric transmission system wildfire plans, which it categorized as being of the "highest" priority. The Council made the following specific recommendations:[17]

- Oregon legislature pass legislation requiring both investor- and consumer-owned utilities to prepare risk-based, wildfire standards and procedures inclusive of criteria for initiating power outages.
- The Oregon Public Utility Commission (PUC) use workshops to develop these risk-based standards and procedures.
- All utilities and transmission and distribution system owners participate in these workshops.

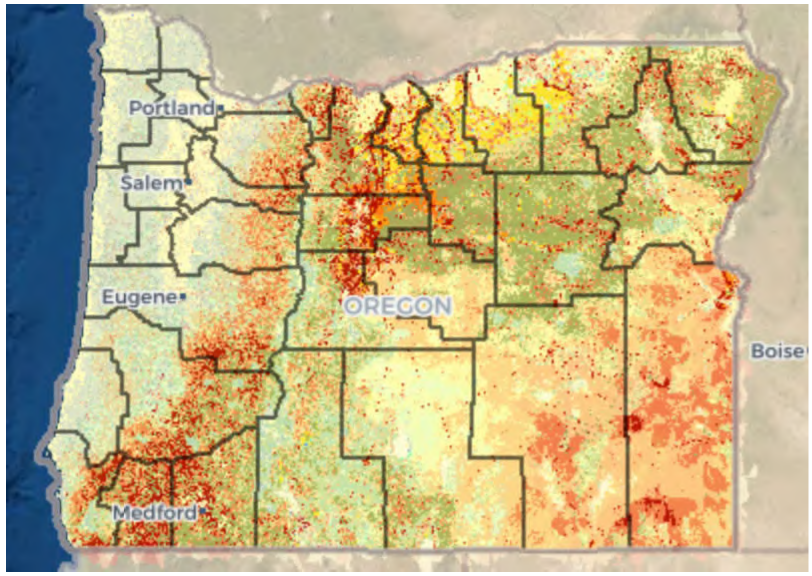
To implement these recommendations, Senate Bill 1536 (2020) was introduced at the request of Governor Brown, but did not pass during the 2020 Legislative Session.[18] Following that session, Governor Brown issued Executive Order 20-04: Directing State Agencies to Take Actions to Reduce and Regulate Greenhouse Gas Emissions, which recognized that climate change is increasing the frequency and severity of wildfires in Oregon, and identified a need for the state's utility sector to improve the resilience of the energy system in light of these increasing risks.[19] Specifically, the order's directives to the PUC requires the agency to evaluate risk-based wildfire program plans for investor-owned utilities and convene periodic workshops to develop and share best practices for mitigating wildfire risk in the utility sector.[20] The Commission initiated its implementation of these two directives with kickoff meetings in May 2020 with PacifiCorp, Portland General Electric, and Idaho Power, and by convening a conversation with operators of electric distribution systems across the state (including consumer-owned utilities).[21]

Bonneville Power Administration, the owner and operator of the most line miles of electric transmission in the state, is not subject to the jurisdiction of EO 20-04 (nor would SB 1536 have applied to them) on account of its status as a federal agency. Nevertheless, BPA is taking action to mitigate against wildfire risks and published a wildfire mitigation plan in 2020.[22] BPA staff have also been active participants in the workshops and meetings hosted by the Oregon PUC that are intended to share wildfire mitigation best practices among electricity service providers in the state.[23]

The Latest: Utility Wildfire Planning

Figure 2: Map of Oregon Showing Overall Wildfire Risk and Threat[24]

(darker colors = higher risk/threat)



Electric service in Oregon is nearly universal, which requires the electric grid to stretch over thousands of miles of terrain to reach every corner of the state. Electric service providers have a long history of managing this vast system to mitigate against a range of risks, from the potential to overload lines during hot weather, to managing encroaching vegetation, to routine repair and replacement of aging infrastructure. As the changing risks posed by climate change become better understood, utility wildfire mitigation plans are likely to continue evolving in the years ahead. ODOE is not aware of any universally accepted guidance related to the development of utility wildfire mitigation plans. Most of the actions found in these emerging plans, however, are focused on mitigating against one or both of two related risks: the potential for utility infrastructure to ignite a wildfire and the potential for a wildfire, irrespective of its source, to damage utility infrastructure.[24] (See the Climate Vulnerability Assessment Policy Brief.)

Utility presentations to the Oregon PUC in July 2020,[25] regulatory filings from PGE and PacifiCorp,[26] [27] and BPA's published wildfire mitigation plan,[28] included a number of measures that utilities can take to evolve their approach to wildfire through improved risk assessments, mitigation strategies, and operational changes.

Oregon PUC Rulemaking

The PUC recently opened a rulemaking focused on the development of risk-based wildfire mitigation plans consistent with Gov. Brown's EO 20-04 (see PUC Docket AR 638[29] for more information). For more details on the wildfire mitigation efforts currently underway by the largest electric system operators in Oregon, see the following:

- PacifiCorp's 2020 Wildfire Plan (as filed in California)
- Portland General Electric: Wildfire Planning
- BPA Wildfire Mitigation Plan

"As the climate crisis creates hotter and drier summers with longer wildfire seasons, the overall risk of climate fires is increasing." – Eugene Water and Electric Board [30]

"Past practices are not enough in an era of changing climate conditions. PGE is continuing to enhance its Wildfire Mitigation program based on learnings from peers in the energy and forestry industries." – Portland General Electric[31]

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Policy Brief: Agricultural Energy Use and Associated Greenhouse Gas Emissions in Oregon

Oregon is well-known for its agricultural diversity – and this diversity of crops, livestock, soils, climates, and production methods is reflected in how Oregon farms use energy. Oregon farmers and ranchers use energy for many purposes: to power tractors and other farm equipment in the field, to chill milk and freshly-picked produce, to provide heat and light for greenhouses, to mechanically control weeds, to pump water, and to run equipment like hop dryers, seed cleaners, and mint oil distilleries. "Indirect energy consumption" in farming includes energy used for manufacturing agricultural materials, such as fertilizers and pesticides,[1] while activities that occur off the farm such as food processing, transport, and storage also use energy. This section will focus on "direct energy consumption," or energy used directly on the farm or ranch, including the processes involved in producing crops, raising livestock, and in additional processing such as drying, cooling, and packing that happens inside the farm gate.

Figure 1: Oregon's Top 20 Agricultural Commodities (2019)

OREGON'S TOP 20 AGRICULTURAL COMMODITIES: 2019

Rank	Commodity	Value of Production
1	Greenhouse & nursery[1]	$955,166,000
2	Hay	$674,280,000
3	Cattle & calves	$625,158,000
4	Milk	$552,096,000
5	Grass seed[2]	$517,406,000
6	Wheat	$282,948,000
7	Grapes for wine[3]	$237,784,000
8	Potatoes	$198,889,000
9	Blueberries	$134,254,000
10	Pears	$108,774,000
11	Onions	$108,409,000
12	Christmas trees[1]	$104,451,000
13	Hazelnuts	$84,480,000
14	Cherries	$75,221,000
15	Hops	$71,628,000
16	Dungeness crab[4]	$67,671,967
17	Eggs	$56,798,000
18	Mint for oil	$40,536,000
19	Apples	$38,746,000
20	Sweet corn	$38,103,000

[1] Oregon Department of Agriculture estimate
[2] Oregon State University estimate
[3] Oregon Wine Board estimate
[4] Oregon Department of Fish & Wildlife estimate
All others are estimates from NASS.

Oregon farmers and ranchers use several different forms of energy: gasoline, diesel, propane, natural gas, electricity, biofuels, and biomass. Cost, suitability for the work at hand, and availability of either the energy source itself or equipment that must run on a specific source of energy are the main factors driving the choice of which form of energy to use. The Oregon Farm Bureau surveyed its members in 2018 regarding their energy usage to inform policy discussions. While the 120 responses are not a representative sample for the entire Oregon agricultural sector, the survey results demonstrate the sector's diversity and are consistent with literature and stakeholder conversations.[2]

Table 1: Oregon Farm Bureau Survey

Top 5 Uses of Electricity	Top 3 Uses of Natural Gas	Top 3 Uses of Propane
Irrigation	Greenhouses	Forklifts
Seed Cleaning	Dryers (hops, onions)	Greenhouses
Greenhouses	Shop/Farm	Shop/Farm
Shop/Farm		
Cold Storage		

Electricity is by far the largest direct energy type used in Oregon agriculture. Electricity powers irrigation pumps, lighting, HVAC, and a variety of other equipment for farm and ranch operations, as well as more specialized uses in greenhouses and for pre-market processing like seed drying. People often think of Oregon as wet, but even west of the Cascades the summers are dry, and many crops require irrigation.

While liquid fuels have traditionally been most well-suited for farm work requiring mobility, such as field operations or moving livestock and materials, propane forklifts have become commonplace on farms and electric farm vehicles like tractors and small utility vehicles are starting to become available in the marketplace. Natural gas and propane are well-suited for stationary tasks such as heating and drying, with the choice between these two fuels often driven by whether piped natural gas is available at the farm or nursery.

Oregon Nonprofits Join Forces to Introduce Electric Tractors

Oregonians across the state are embracing electric vehicles, with double the number of EVs on Oregon roads today than there were at the beginning of 2018. But some sectors, like Oregon's agricultural producers, have fewer options for embracing electric transportation at work.

Nonprofits Sustainable Northwest, Forth, Bonneville Environmental Foundation, and Wy'East Resource Conservation and Development Area Council, Inc. are joining forces to expand rural electrification with a pilot program for electric tractors. Electric tractors can bring many benefits for farmers who no longer need to purchase imported fuels. They have the potential to provide fuel savings, reduce maintenance costs, and decrease noise and particulate pollution. Similar to the very first electric vehicle buyers out there, making the switch to a nascent technology like electric tractors carries some risk for farmers. After confirming there was interest among Oregon farmers in trying electric tractors, the nonprofit group decided to form a "ride share" program to get the tech out into Oregon fields and farms for testing.

With the help of the Bonneville Environmental Foundation, U.S. Department of Agriculture, and other funding partners, the group expects to receive its first electric tractor in the fall of 2020, followed by a second in early 2021. The first two tractors will be a compact electric tractor (30 horsepower) and a small utility tractor (40 horsepower); as manufacturers come out with larger models in the next 12 to 18 months, the group hopes to take at least one on board. Both of the initial tractors will include front end loaders, hydraulics, a rear three-point hitch and 540 RPM power take off. The group expects that tractors of this size, with their ability to maneuver in small spaces, will work well for vineyards, greenhouses and nurseries, animal confinement operations, vegetable fields and orchards, as well as performing light duty tasks for farm and ranch operations and grooming rodeo and equestrian arenas in the winter months.

The tractors selected for the program will be different models, so the group can perform rigorous testing around the state, with varied farming conditions, weather, and utility territories. Wy'East, which offers technical expertise for agricultural producers, will lead the way in initial testing and lending the equipment to Oregon farms. Ideally, the tractors will travel to match production schedules so the tractors run year-round. The tractors – and the farmers who use them – will provide invaluable data to help determine how well they perform.

Similar to electric passenger vehicles, the electric tractors are expected to need less overall maintenance. The tractor batteries should last three to seven hours, depending on the work the tractors are performing – for example, just like petroleum-based fuels, plowing a field is expected to take more energy than lighter maintenance of a riding arena or stables. Each tractor will come with an extra battery pack, so farmers can swap out batteries to extend worktime.

Going forward, if the pilot is successful and farmers are interested in purchasing electric equipment of their own, the nonprofit group hopes to sort out how they could help support the market and encourage adoption, including identifying cost-share opportunities, creative leasing or lending opportunities, or other incentives to make the equipment more affordable.

While state-to-state comparisons are difficult due to variation in climate and crops or livestock produced, the percent of each major energy source used by Oregon farmers differs compared to farmers in other states. This is likely due to several factors: Oregon's crop mix and the higher percentage of irrigated crops, the prevalence of electricity versus other fuels to power irrigation pumps in Oregon,[3] and the availability of relatively low-cost electricity in the Pacific Northwest.

Each farm or ranch typically purchases energy from a few different suppliers with a variety of business models, including investor-owned electric and natural gas utilities, consumer-owned electric utilities, and private businesses supplying diesel, gasoline, and propane. For a number of rural consumer-owned electric utilities, farms are their primary customer base, and the seasonal dynamics of supplying energy to farms drives COU operations (see Table 2 below). For example, electricity for irrigation comprised 71 percent of 2018 sales for Harney Electric Cooperative,[4] which takes operational measures such as shutting down a portion of its substations during the winter when irrigation pumps are idle. Harney Electric Cooperative receives 100 percent of its energy supply from the Columbia River Power System, and the peaks and troughs of Harney's demand largely parallel the availability of hydropower from the greater system.[5]

For several rural consumer-owned utilities, farms are the primary customer base – and the seasonal dynamics of supplying energy to farms drives utility operations.

For other suppliers, such as larger consumer-owned utilities and the investor-owned utilities, farms are a smaller slice of their customer base with farm loads often eclipsed by industrial, commercial, and/or residential loads. While farm loads are important to these utilities, the seasonality of farm loads does not dramatically affect their systems. For example, according to Oregon Public Utility Commission's statistics, Umatilla Electric Cooperative has the largest volume of irrigation sales for any consumer-owned utility in Oregon, yet irrigation accounts for 12 percent of its total electricity sales[6] due to its large industrial load, in part driven by recent growth in data centers and food processing.[7]

Table 2: Irrigation as Percent of Electric Load for Selected Oregon Consumer-Owned Utilities

COU	Irrigation Customers	Sales to Irrigation Customers (kWh)	Sales to All Customers (kWh)	Percent of Sales for Irrigation
Central Electric	1,611	65,132,071	721,227,099	9%
Columbia Basin Co-op	237	33,968,286	108,960,129	31%
Columbia Power Co-op	254	5,250,077	23,377,892	22%
Columbia Rural Electric (OR/WA)	67	4,043,915	7,328,324	55%
Harney Electric Co-op	665	72,595,009	101,545,015	71%
Oregon Trail Electric Co-op	1,272	59,118,482	657,477,999	9%
Surprise Valley Electric Corp (OR/CA/NV)	268	15,065,855	37,040,981	38%
Umatilla Electric Co-op	1,488	316,295,168	2,532,516,559	12%
Wasco Electric Co-op	314	14,473,288	106,704,503	14%

Source: 2018 Oregon Utility Statistics. Oregon Public Utility Commission

Note that while the majority of irrigation sales are to farms and ranches, other types of businesses may also purchase power under a utility's irrigation rate schedules, meaning that a portion of a utility's irrigation sales may be to non-agricultural businesses.

Oregon's Agricultural Sector Energy Use

No single entity collects and compiles data on direct energy use by the agricultural sector at either the federal or state level. The U.S. Energy Information Administration aggregates agricultural energy use with industrial energy use in its data and reporting.[8] The same approach is reflected in U.S. Environmental Protection Agency greenhouse gas emissions inventory protocols, which include agricultural emissions from energy use as part of industrial energy emissions[9] (see discussion below).

At the state level, several entities collect data on a portion of energy sales to agriculture businesses, although this information is often incomplete or is aggregated with energy sales to other sectors. For example, as part of the Oregon Clean Fuels Program, the Oregon Department of Environmental Quality collects data on liquid fuel sales by fuel suppliers with sales over the compliance threshold, even though some fuels are sold for off-road agricultural use and are exempt from program compliance.[10] The Oregon Public Utility Commission collects information on electricity sales for irrigation by consumer-owned utilities. However, sales of electricity and natural gas to farms and ranches by investor-owned utilities are aggregated with industrial sales for reporting purposes, and are not easily separated because utilities sell energy to both industrial and agricultural users under the same rate schedules.[11] Farm use of biomass on site, such as burning hazelnut shells to fuel equipment that dries the nuts, is not included in reporting to any government agency. Compiling information to quantify energy use on Oregon farms and ranches is a necessary step in targeting opportunities to reduce agricultural energy use in order to save farmers and ranchers money, and in identifying the most promising and effective opportunities to reduce the state's GHG emissions.

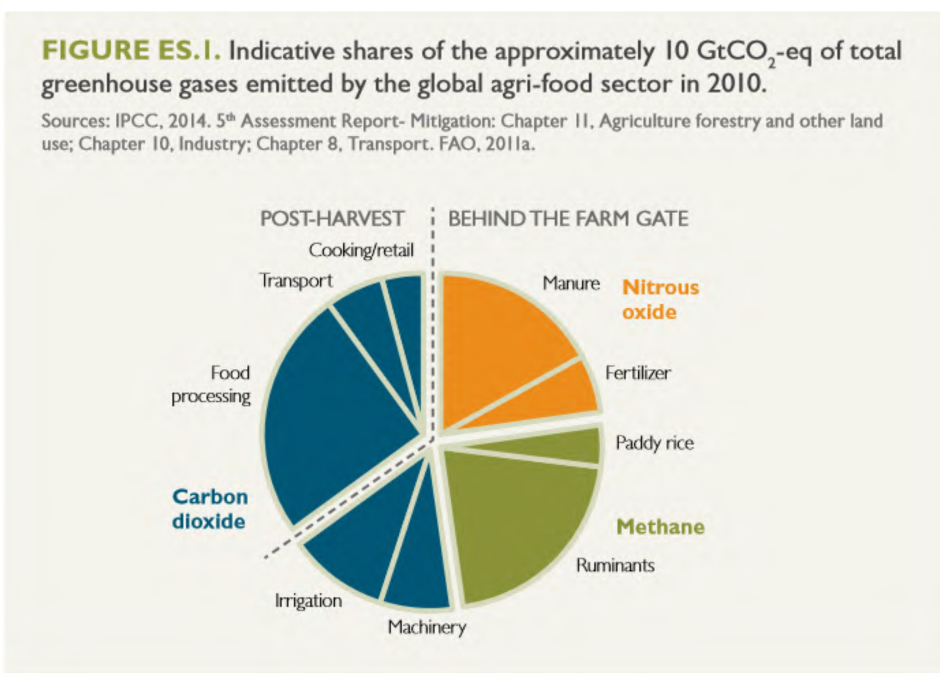
Energy is a significant – though not the largest – expense for most farmers. The U.S. Department of Agriculture's National Agricultural Statistics Service collects information on energy expenditures by farms in its agricultural census every five years. In the 2017 agricultural census, Oregon farms reported that "Gasoline, fuels, and oils purchased" accounted for 4 percent of their expenditures, while "Utilities" accounted for 3.6 percent. By contrast, labor (the sum of "Farm labor hired" plus "Contract labor") was 25.2 percent of total expenditures, materials directly related to growing crops (fertilizers, lime, chemicals, seeds, starter plants) totaled 16.0 percent, and animal feed was 12.9 percent.[12]

Greenhouse Gas Emissions from Agricultural Energy Use

Agriculture is both a source and sink of GHG emissions. While several components of the sector's GHG emissions have been well-quantified at the state level, no entity has yet quantified the portion of Oregon's agricultural emissions that are related to energy use on the farm and ranch. International and national estimates of energy-related farm emissions, paired with available data on Oregon's agricultural energy use, provide context for what we could expect from an analysis of Oregon's on-farm energy emissions. Energy-related GHG emissions are not the largest component of Oregon's agricultural emissions and a substantial portion of Oregon's agricultural electricity is from non-carbon sources. However, available information suggests that reducing energy use on the farm/ranch, paired with other emissions-reductions activities, has a role to play in reducing the sector's emissions.

On a global scale, CO2 emissions associated with on-farm energy use, mainly for irrigation pumping and farm machinery, are a smaller part of total farm emissions compared to nitrous oxide emissions and methane emissions associated with raising livestock, fertilizer use, and paddy rice agriculture (See Figure 2). However, as noted by the Food and Agriculture Organization of the United Nations, which compiled food-related emissions data from the most recent Intergovernmental Panel on Climate Change assessment report, there is

Figure 2: Shares of Greenhouse Gases Emitted by the Global Agri-Food Sector in 2010[13]

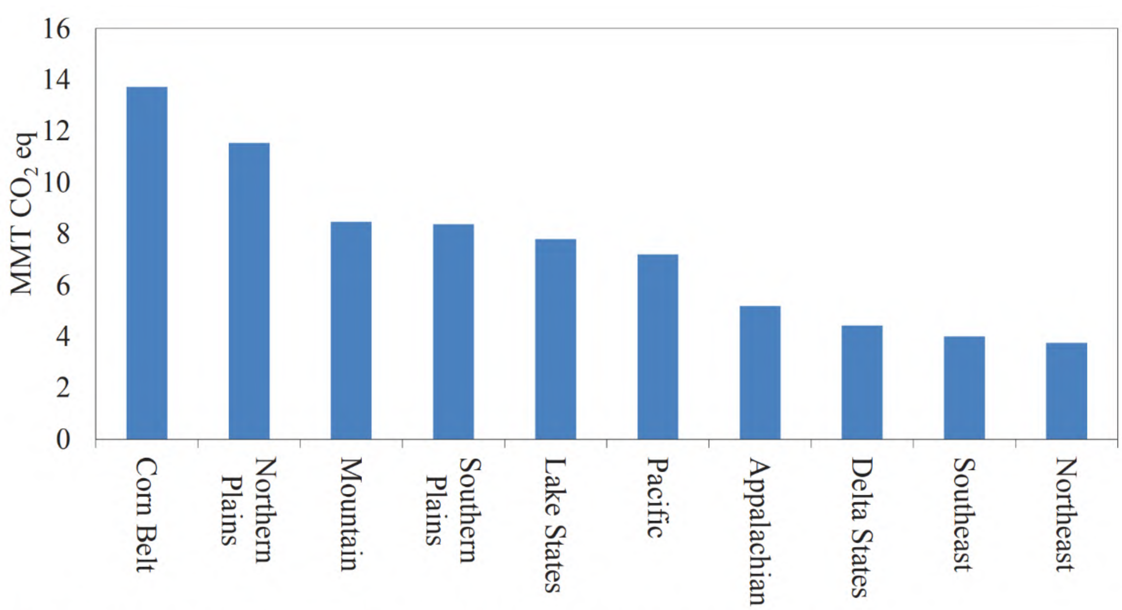


significant variation among countries and regions due to climate and production methods.[13] According to the state GHG emissions inventory compiled by the Oregon DEQ, the share of Oregon's emissions attributable to agriculture was 9.1 percent in 2017, with nitrous oxide and methane from enteric fermentation, manure management, and soil management accounting for 97 percent of agricultural emissions. The remaining 3 percent of agricultural emissions were CO2 associated with fertilizer use and liming of soils.[14] The state GHG inventory uses U.S. EPA protocols, which means emissions from agricultural energy use are included under industrial sector energy use; therefore, the often-cited figure of 9 percent for agriculture's share of Oregon's total GHG emissions does not include emissions from on-farm/ranch energy use.[15] [16]

At the federal level, the USDA has published a "U.S. Forestry and Agriculture Greenhouse Gas Inventory" roughly every five years since 2001. USDA's inventory includes agricultural energy use, while also providing perspective on long-term trends in agricultural energy use and emissions. According to the USDA, national agricultural energy use and emissions peaked in the 1960s and 1970s, then declined through the 1980s due to high fuel prices and the adoption of federal fuel efficiency standards, before rising again through the 1990s. The national trends in agricultural energy use and emissions since 2000 have been relatively steady, with year-to-year fluctuations due to weather, crop and livestock production volumes, and fuel prices.[17]

USDA's emissions estimate is based upon a straightforward methodology, dividing reported energy expenses from agricultural surveys by energy prices to get the estimated amount of energy used on the farm, then using the volume of energy to estimate emissions. For electricity, the report used regional emissions factors calculated by the EIA to account for regional differences in fuel sources to generate electricity. The most recent version of the USDA report found that energy used in agricultural production contributed 74 million metric tons of CO2 emissions nationally in 2013, which was approximately 1.4 percent of all U.S. energy-related emissions for that year.[18] The Pacific region consisting of California, Oregon, and Washington had the third highest energy use among U.S. regions in 2013, while ranking sixth in CO2 emissions, which USDA attributes to the region's reliance upon hydroelectric power.[19]

Figure 3: CO2 Emissions from Energy Use in Agriculture by Region (2013)[17]



(MMT CO_2 eq. is million metric tons of carbon dioxide equivalent)

The USDA report does not include an estimate of emissions at the state level, although regional estimates and comparisons provide insight into what we might expect from a more detailed analysis of Oregon's on-farm emissions. For instance, data on Oregon's agricultural energy use compiled by ODOE indicates that electricity accounts for a larger share of Oregon's on-farm energy use compared to national averages, with a larger-than-average share of Oregon's electricity coming from hydropower. It is not clear whether or to what degree Oregon farms and ranches use less diesel or other fossil fuels compared to farms in other parts of the country. According to data compiled from a variety of sources for 2018, 2019, and 2020, ODOE estimates on-farm energy use as 8,900 billion BTUs. Additional analysis, including the application of appropriate emissions factors by energy source, will be needed to estimate emissions from Oregon's on-farm energy use.

In addition to national and regional agricultural emissions estimates, several researchers have quantified emissions at the level of an individual food product. These studies, termed "lifecycle analyses," focus on calculating the GHG emissions associated with the consumption of an individual product regardless of where the emissions occur, encompassing all stages in the product lifecycle. Oregon DEQ produces a consumption-based GHG inventory that uses a lifecycle approach to take into account global emissions associated with all of the products consumed in Oregon, including the foods that Oregonians consume whether grown and processed in the state or elsewhere.[20] For a food product, lifecycle emissions encompass all activities from the field through the factory, grocery store, and restaurant or home kitchen, ending with disposal of food waste. Hence, lifecycle analyses for food products include emissions that would be quantified under the agricultural, industrial, transportation, commercial, and residential sectors in a sector-based GHG inventory.

Lifecycle analyses provide valuable details about energy use and emissions for specific food products; however, lifecycle analyses likely do not exist for all of Oregon's 225 agricultural products, and lifecycle analyses will differ for crops or livestock produced in Oregon compared to the same crops and livestock produced in other climates and using different methods.[21] While this section of the Biennial Energy Report takes a sector-based approach, focusing on emissions from energy use on Oregon farms and ranches that can be directly affected by Oregon's energy programs and policies, lifecycle analyses provide a rich source of data that points out where most emissions occur in a food product's lifecycle – and therefore where opportunities exist to make significant emissions reductions taking into account Oregon's crop mix, climate, and production methods.

Oregon State University Research Shows Bright Future for Agrivoltaics

Oregon is home to more than 37,000 farms across 16 million acres of the state. Our agricultural producers raise animals, supply dairy products, and grow food – and sometimes even generate renewable energy. Wind energy is a good fit in several rural areas of the state where there are strong wind resources and development is compatible with land use and agricultural requirements. While many in the agricultural community have concerns about the ability to farm around solar arrays, for some Oregon farms and ranches, solar development could fit well into their cropping or grazing operations. Such "dual-use development" is subject to rules adopted in 2018 by the Oregon Land Conservation and Development Commission.

Oregon State University researchers and students, led by Associate Professor Chad Higgins, are studying situations where Oregon farms can blend solar energy and agriculture for mutual benefit. Professor Higgins reports that they want to accomplish four things: more food, better food, less water use, and more energy. So far, the school's research is showing that marrying solar panels (photovoltaics) and agriculture – into "agrivoltaics" – has promise for some of Oregon's important crops, with potential benefits for farmers and the environment.

Plants need light to grow – but it turns out, they don't always need that light from the direct sun, and in certain cases actually thrive in low-light conditions. OSU's research shows that some plants are less stressed when they have partial shade and produce higher quality crops with less water. One OSU study of pasture grass showed that adding solar to the land quadrupled the water efficiency and doubled the production. Other studies showed that agrivoltaics increased tomato and bean yields; boosted production in restored bee habitat; and even changed sheep behavior and lamb growth patterns, with the sheep seeking out the shade provided by the solar arrays.

Solar arrays in an agrivoltaics project would likely look different from other ground-mounted solar arrays. OSU's studies showed that choosing the right orientation and spacing of the panels solely to remove "excess light" helped plants thrive. Panel installation would need to be less dense and elevated off the ground so farm machinery could get through. An unexpected bonus of agrivoltaics is how the plants can in turn help the solar panels. When plants are actively growing, they make the surrounding environment cooler – and solar panels are more efficient (and therefore produce more energy) when they are cooler. For certain Oregon crops, agrivoltaics could provide mutual benefit for the agricultural producer, the solar panels, and the plants.

OSU's team of researchers and students plan to continue experimenting with ways to help Oregon's farmers, from researching electricity-generated fertilizer to reducing evaporation to testing an electric tractor. Learn more about OSU's work and the Nexus of Energy, Water, and Agriculture Laboratory:

http://agsci-labs.oregonstate.edu/newaglab/

Increasing Energy Efficiency and Reducing Energy-Related GHGs in Agriculture

Given the wide variety of crops and livestock raised in Oregon and the multifaceted nature of agricultural GHG emissions and sinks, multiple approaches across the agricultural sector will be needed to achieve our state reduction goals. In aggregate, agriculture can make a meaningful contribution. Sequestration of CO2 in agricultural soils has perhaps the single largest potential impact of any action in the sector at 1-2 billion metric tons of CO2 globally per year (compared to 37 billion tons of CO2 equivalent global emissions in 2018), but there remain several challenges to implementation, notably financing and ensuring the permanency of CO2 sequestration in soils.[22]

While on-farm energy-related GHG emissions are not the largest share of agricultural emissions, farmers already have proven technologies and programs to save energy in agriculture. Many Oregon farmers and ranchers have already made investments in reducing their energy use through energy efficiency and renewable energy, contributing to meeting Oregon's GHG emissions reduction goals; 2,845 Oregon farms reported having renewable energy generation on-site in the 2017 USDA agricultural census, with 2,441 farms reporting solar panels, 332 reporting geothermal/geoexchange systems, and 162 reporting wind turbines.[23]

This section focuses on energy efficiency measures on Oregon farms and ranches, including technical and financial assistance available to help farmers become more efficient. Energy efficiency saves money and energy as well as reduces emissions, but replacing inefficient equipment, redesigning systems, or purchasing more efficient equipment from the start requires an upfront investment. As the Oregon Department of Agriculture found in a 2011 report on agriculture and energy in Oregon, "While covering an up-front capital cost is challenging for many businesses, it can be particularly challenging for farming and ranching businesses, which have much of their assets tied up in equipment and land."[24]

Several programs offer technical and financial assistance to Oregon farms and ranches for energy efficiency projects, with most funding coming from electric and natural gas utility ratepayer funds and a lesser amount coming from the federal Farm Bill. Many program offerings are targeted to specific technologies, with a published incentive paid for each unit purchased, often in the form of a rebate. Examples include variable frequency drives that help farmers and ranchers use only the amount of energy needed for a task like pumping water, efficient irrigation nozzles that give crops only the amount of water they need, and thermostatic controllers that shut off equipment when the ambient temperature climbs above freezing. Programs administered by Energy Trust of Oregon and Bonneville Power Administration offer a wide array of energy efficiency incentives, including incentives targeted to industrial businesses for equipment that is also frequently used by farms, and farms frequently take advantage of industrial incentives as well as those specifically targeted at agriculture.[25]

Many agricultural energy efficiency projects are eligible for financial assistance from multiple funders, including programs that fund conservation and environmental improvements with other goals, such as improving wildlife habitat or water quality; however, piecing together funding can be challenging with varying eligibility requirements and deadlines. The variety of Oregon farms means that every project is different, particularly for irrigation improvements, and farmers do not always have the time or expertise to complete required energy savings analysis in order to apply for financial assistance. The uncertainty in competitive grant programs also dissuades farmers and ranchers from committing time and effort to completing application paperwork for grants they may not get.[26]

There are multiple entry points for farmers and ranchers to learn about opportunities for technical and financial assistance for energy efficiency projects, including their local utility, Energy Trust of Oregon within the investor-owned utility territories, county-level USDA offices, and soil and water conservation districts. Consultants, universities, and nongovernmental organizations around the state have developed expertise to assist farmers in completing applications, coordinating and sequencing multi-stage projects, and identifying and targeting potential funding sources. The USDA Renewable Energy Development Assistance grant program provides funding to support entities such as universities and nongovernmental organizations that provide energy audits for agricultural producers and rural small businesses. REDA grants may also be used to provide renewable energy technical assistance and site assessments.[27] The USDA Natural Resources Conservation Service also offers funding for energy audits required to access NRCS funding for an energy-saving project.

Bonneville Power Administration Energy Efficiency Incentives
Program Description: BPA allocates ratepayer funds to utilities in its Pacific Northwest service territory that purchase public power to be used for energy efficiency programs for utility customers. Utilities receive an allocation for each rate period that may be awarded to agricultural projects, but there is not a specific amount designated for the agricultural sector. Some utilities run their own energy efficiency programs, while others join with other utilities in a "pool" to run a joint program or contract with a third-party entity to run their program. The Regional Technical Forum, a technical advisory committee to the Northwest Power and Conservation Council, maintains lists for each economic sector of "UES" or unit energy savings measures, for which energy savings are estimated on a per-unit basis, such as savings per light bulb. UES measures approved by the RTF, such as variable frequency drives, irrigation hardware, and thermostatic outlet controllers receive a fixed reimbursement per unit, while agricultural construction projects that incorporate efficient HVAC or other features can receive payments that depend on the life of the project and the energy savings. Agricultural energy efficiency measures in Oregon funded by Bonneville Power Administration in 2019 accounted for just under one average megawatt in first year energy savings, with irrigation measures making up the majority of savings.[28]
Eligible Uses of Program Funds: UES (Per unit reimbursement): freeze-resistant stock water tanks, thermostatically controlled outlets and stock tanks, transformer de-energization, irrigation system conversions, irrigation sprinkler and hardware replacement, irrigation pump testing, variable frequency drives and agricultural pumps. Custom projects include new agricultural construction and other energy saving projects.
Annual spending by Oregon utilities in BPA service territory: $1,894,837 (2019)
Program website: https://www.bpa.gov/EE/Sectors/agriculture/Pages/default.aspx

Energy Trust of Oregon Agricultural Energy Efficiency Measures
Program Description: Energy Trust of Oregon incentivizes energy efficiency savings in the agricultural sector using funds from the Public Purpose Charge paid by customers of investor-owned utilities. Energy Trust maintains a list of eligible measures, with some measures receiving rebates on a prescriptive per unit or per linear or square foot basis, and others eligible for rebate amounts based upon savings that the measure is expected to achieve through calculated savings.
Eligible Uses of Program Funds: Rebates based on unit or linear/square foot measurement: irrigation sprinklers, nozzles and gaskets; Low Energy Precision Application (LEPA) and Low Elevation Spray Application (LESA); greenhouse improvements, such as covers, controllers, condensing unit and radiant heaters, thermal curtains, pipe insulation, and greenhouse sprinkler hardware; building insulation; lighting and lighting controls; and scientific irrigation scheduling (per irrigated acre). Reimbursements based on calculated savings for specific project: irrigation pump variable frequency drives; irrigation system conversions; greenhouse glazing and boilers; custom lighting and lighting control upgrades; and insulation and dehumidifiers for licensed cannabis and hemp indoor grow facilities. Custom projects may receive a percentage of project cost.
Annual Spending by Energy Trust of Oregon for agricultural energy efficiency measures: Agricultural Equipment (2019): $364,761 non-cannabis/$1,143,677 cannabis ($1,134,801 for lighting and controls) Greenhouse upgrades (2019): $238,918 non-cannabis/$46,910 cannabis Irrigation (2019): $1,211,098 Non-cannabis/$0 cannabis
Program website: https://www.energytrust.org/programs/agriculture/

USDA Natural Resources Conservation Service Environmental Quality Improvement Program (EQIP) On-Farm Energy Initiative

Program Description: Agricultural producers planning an energy saving project may apply for EQIP grants for up to 75 percent of project costs with funding awarded as part of a competitive process.[29] Historically underserved farmer or rancher groups, including veterans, farmers or ranchers with limited resources, beginning (less than ten years of experience) farmers or ranchers, and socially disadvantaged farmers or ranchers, may qualify for up to 90 percent of project costs under the program.[30]

The Oregon USDA office received an allocation of $22.7 million in EQIP funding for 2020, with portions of the state allocation set aside for specific conservation priorities, including $100,000 for the On-Farm Energy Initiative which specifically targets energy saving projects. Energy is one of six NRCS categories of "resource concerns" that eligible projects may address, with individual projects frequently listing multiple resource concerns; other areas of resource concern include soil, water, air, plants, and animals.[31] The Oregon NRCS office maintains a payment schedules for specific equipment or improvements, including funding for an Agricultural Energy Management Plan or other qualifying energy audit, which is required of all applicants.

Note: While the EQIP On-Farm Energy Initiative specifically targets energy savings, two other NRCS conservation programs include energy on the list of "resource concerns" for which projects can receive funding: Conservation Stewardship Program and Regional Conservation Partnership Program. Oregon is one of the leading states in receiving funds under NRCS conservation programs, and Oregon irrigation modernization projects with energy savings have recently received funding under the Regional Conservation Partnership Program.[32]

Eligible Uses of Program Funds: Core energy practices: farmstead energy improvements, irrigation water management, pumping plant, lighting system improvements, and building envelope improvements.

Other eligible energy-related practices: combustion system improvements, cover crops, micro irrigation, irrigation sprinklers, mulching, residue and tillage management, waste recycling, and windbreak establishment.

Annual Awards in Oregon for USDA NRCS projects where energy was listed as one of the project's resource concerns:
Environmental Quality Improvement Program: $619, 576 (2019)
Conservation Stewardship Program: $315,438 (2020)
Regional Conservation Partnership Program: $363,631 (2019)

Program website: https://www.nrcs.usda.gov/wps/portal/nrcs/main/or/programs/financial/eqip/

USDA Rural Development Rural Energy for America Program (REAP)
Program Description: The REAP program offers 1) grants that cover up to 25 percent of total project cost, with remaining costs required to be covered by non-federal funding sources; and 2) loan guarantees that cover up to 75 percent of the total project cost, with combined grant and loan guarantee funding limited to 75 percent of total eligible project costs. REAP funding may be combined with funding from other sources, such as Energy Trust of Oregon, but federal funding from any source may not account for more than 25 percent. Funding under the REAP program may be used for either energy efficiency or renewable energy projects, although in Oregon this funding source is used almost exclusively for solar electric systems. In 2019, over 99 percent of the REAP grant funds went to solar projects, with loan guarantees almost exclusively covering loans for solar electric projects as well. REAP recipients must be either agricultural producers with at least 50 percent of gross income coming from agricultural operations or a business located in a rural area. USDA does not require applicants to identify whether they are an agricultural producer; however, information supplied on applications suggests that approximately 30 percent of 2019 grant funds awarded for renewable energy went to farms or vineyards, while one of the two 2019 grant funds awarded for energy efficiency projects went to an agricultural producer.
Eligible Uses of Program Funds: Purchase, installation, and construction of energy efficiency improvements or renewable energy systems.
Annual spending for USDA Rural Development REAP program in Oregon: 2019: $832,727 total REAP funds awarded (single funding pool for both renewable energy and energy efficiency; one energy efficiency project received grant funding in 2019)
Program website: https://www.rd.usda.gov/programs-services/rural-energy-america-program-renewable-energy-systems-energy-efficiency/or

Opportunities for Future Progress

Stakeholders working on energy issues in Oregon's agricultural sector agree that much potential remains to save energy on-farm/ranch, particularly in irrigation. The Northwest Power and Conservation Council estimates energy savings potential in the agricultural sector for the region as part of its periodic planning process. In its Seventh Power Plan, NWPCC found a total of 130 average megawatts in agricultural energy savings over the 20-year planning period ending in 2035, with the most savings potential in irrigation hardware (80 average megawatts) and irrigation water management (41 average megawatts). The remaining energy savings potential is in dairy equipment and lighting. NWPCC found that large dairies in the region, particularly new businesses, have mostly already adopted more efficient options.[33]

At the regional level, agricultural energy savings potential for the 20-year planning period is not as high as for the commercial sector (1,870 average megawatts) or the residential sector (2,300 average megawatts).[34] However, energy costs are a significant expense for farmers and ranchers, particularly for those who irrigate, and on-farm energy use is locally important for rural energy suppliers. In many instances, conservation projects that conserve water or improve water quality also produce energy savings, and money saved on energy bills helps to make conservation projects feasible. While up-front costs can be prohibitive for certain energy efficiency improvements, irrigation improvements range in size and cost from irrigation hardware switch-outs to wholesale system redesigns and the addition of precision irrigation equipment such as sensors, timers, and computer automation. Irrigation improvements often can be implemented incrementally, field-by-field, over time to reduce the initial investment and bring immediate returns to farmers through water and energy savings. Many irrigation improvements save time and labor costs, and in some cases reduce the amount of fertilizer applied, which can reduce GHG emissions.[35]

Wy’East Helps Oregon Farmers Save Water and Energy

Wy’East Resource Conservation and Development Area Council, Inc. is a nonprofit development organization that provides education, outreach, and technical assistance for energy efficiency and renewable energy projects for agricultural producers and rural small businesses in the Pacific Northwest.

One of Wy’East’s largest ongoing projects, with Rural Electric Cooperatives and People’s Utility Districts, is expanding access to Advanced Precision Irrigation 2.0 equipment for Oregon farmers.

Changing up irrigation equipment can lead to significant water and energy savings for agricultural producers. Oregonians may be familiar with some traditional agricultural sprinklers, like the large circular wheel sprinkler systems or the high-pressure gun-style sprinklers. These sprinkler types, because they are higher above crops, can mean just 80 percent of the water makes it into the soil, while the remaining 20 percent is evaporated. Making a switch to what is known as LEPA (low energy precision application) or LESA (low elevation sprinkler application) irrigation drops the sprinklers lower to the ground, so 95 to 98 percent of the water gets into the soil. This means reduced water use and less energy to pump water through the system.

In addition to water and energy savings, the advanced irrigation systems can also be part of the “Internet of Things,” where equipment and tools are connected to a computer or smartphone for better monitoring and real-time adjustments. Connected soil sensors allow farmers to make adjustments as needed and gather data to predict the best and worst times to irrigate based on energy rates, weather, or other factors. Some electric utilities even offer time-of-use programs, where customers can voluntarily reduce electricity use during peak hours (say, 2 – 6 p.m.) in exchange for a reduced kilowatt rate at a different time of day, when overall electricity use is down.

Learn more about Wy’East and its precision irrigation work: **http://wyeast-rcd.org/index.html**

Among technological advancements mentioned in conversations with stakeholders, precision agricultural applications were mentioned most often. Applications include a variety of sensor and communication technologies to fine-tune inputs of water and fertilizers to farm fields or to control temperature and lighting in greenhouses and animal barns, saving energy, water, and labor while reducing chemical application and improving performance. As noted above, reducing fertilizer use leads to indirect energy savings thanks to the energy-intensive nature of fertilizer manufacturing. Depending on local climate, no-till or reduced-till farming can reduce energy needed for field operations while improving soil health and moisture retention. Many farmers in the Columbia Basin have successfully implemented no- or reduced-till, for example. No- or reduced-till has different challenges in western Oregon where increased crop residue on the soil provides cover for slugs, but has been used in some cropping systems.[36]

Gaps and Opportunities

The wide variation among Oregon farms makes sharing knowledge among farmers and designing programs to improve energy efficiency challenging, compared to states with a limited number of crops and more uniform growing conditions. Farmers may not see examples from another part of the state or by farmers growing another crop as relevant to them and their operations. Yet there have been impressive successes in Oregon agriculture, including the widespread implementation of water-saving irrigation technologies – notably in the Umatilla basin as well as other areas of the state; the adoption of no- and reduced-till in the Columbia Basin; the continued expansion of irrigation modernization by irrigation districts across the state; and collaborative efforts like the "Climate Friendly Nurseries" campaign, a 2009-2011 partnership between the Oregon Association of Nurseries and the Oregon Environmental Council to reduce GHG emissions by saving energy, reducing chemical and materials use, and improving soil health.[37]

While there are technical and financial assistance programs for on-farm energy efficiency, accessing these programs can be challenging for farmers and ranchers and many are not aware of opportunities for assistance. USDA programs cover the whole state, but energy has not historically been the main emphasis of USDA conservation programs. Utility funding differs depending upon whether the farm is in Energy Trust of Oregon territory or is supplied by a consumer-owned utility. The programs are largely siloed from each other with little coordination or alignment, although it is possible for projects to stack funding from multiple programs within limitations. As noted above, a small number of nongovernmental organizations, consultants, and educational institutions are working to bridge this gap and have developed expertise in assisting Oregon farmers to apply for USDA and utility-funded programs, although their resources are limited. A few of these groups operate at a regional level (e.g., Klamath and Wallowa) while others such as Sustainable Northwest, Spark Northwest, and Farmers Conservation Alliance are active across the whole state or in neighboring states as well.

Learn more about conduit hydropower in the Technology Review section.

Oregon farmers could benefit from Oregon-specific research on precision agriculture strategies and no- and reduced-till agriculture to account for the specific crops grown in the state and the variety of growing climates. Field trials and demonstrations to prove and quantify results, including direct and indirect energy savings, emissions reductions, and other environmental benefits, followed by incentives and training for farmers, could accelerate adoption of advanced practices.

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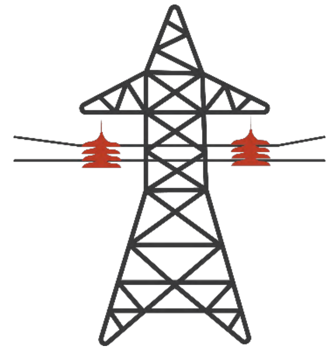
Policy Brief: Emerging Trends in Renewable and Zero-Emissions Electricity Standards



Numerous policies have been used in the United States at the state and federal level to encourage development of renewable electricity generation resources, from tax credits to tariffs – but one of the most successful has been the renewable portfolio standard, or RPS. An RPS establishes a target percentage of a jurisdiction's electricity that must come from eligible renewable resources. This target can be either a non-binding goal, as it is for a small number of states, or a binding requirement, as it is for most states with an RPS. According to Lawrence Berkeley National Laboratory, roughly half of the non-hydropower renewable energy development in the U.S. since 2000 can be attributed to RPS policies.[1]

Oregon established its RPS in 2007 with Senate Bill 838,[2] providing a requirement for the largest[i] utilities – Portland General Electric, PacifiCorp, and the Eugene Water & Electric Board – to provide 25 percent of retail sales of electricity from eligible renewable sources by 2025, with interim targets along the way. In 2016, the Oregon Clean Electricity and Coal Transition Plan (SB 1547[3]) increased the RPS requirement for the largest utilities to 50 percent by 2040. At the time, this placed Oregon in a small cohort of states with RPS targets of 50 percent or higher; since 2016, renewable energy policy has moved fast, with a number of states implementing higher RPS targets as well as 100 percent "clean" or "zero-carbon" standards.[4]

This section highlights recent trends in RPS design and targets in the U.S., describes different approaches various states have adopted in designing these programs, highlights interactions between RPS targets and clean electricity standards, and provides information on renewable energy policy actions that Oregon could consider in the future.

For more background on 100 percent renewable and zero-emissions electricity standards, see the Energy 101 section of this Biennial Energy Report.

Trends in RPS Targets and Clean Electricity Standards

As of May 2020, RPS policies are on the books in 30 states in the U.S. and in the District of Columbia. While most of these policies were enacted before 2008, there has been a flurry of activity in recent years by states making significant policy revisions to their RPS rules.

Increasing RPS Targets

Since January 2018, ten states and the District of Columbia have increased their RPS targets.[ii]

[i] Determined by the percent of Oregon's retail electricity sales the utility serves.
[ii] While some U.S. territories also have RPS and Clean Electricity Standards, they are not addressed in this paper.

Table 1: State RPS Target Increases Since January 2018

State	Previous RPS Target	New RPS Target
California	33% by 2020	60% by 2030
Connecticut	23% by 2020	44% by 2030
District of Columbia	25% by 2025	100% by 2032
Maine	40% by 2017	84% by 2030
Maryland	20% by 2022	50% by 2030
Massachusetts	1% annual increases	41.1% by 2030
New Jersey	22.5% by 2020	54.1% by 2031
New Mexico	20% by 2020	80% by 2030
Nevada	25% by 2025	50% by 2030
New York	30% by 2015	70% by 2030
Virginia	Voluntary Goal	100% by 2050

Table adapted from Barbose (2019) and Leon (2019)

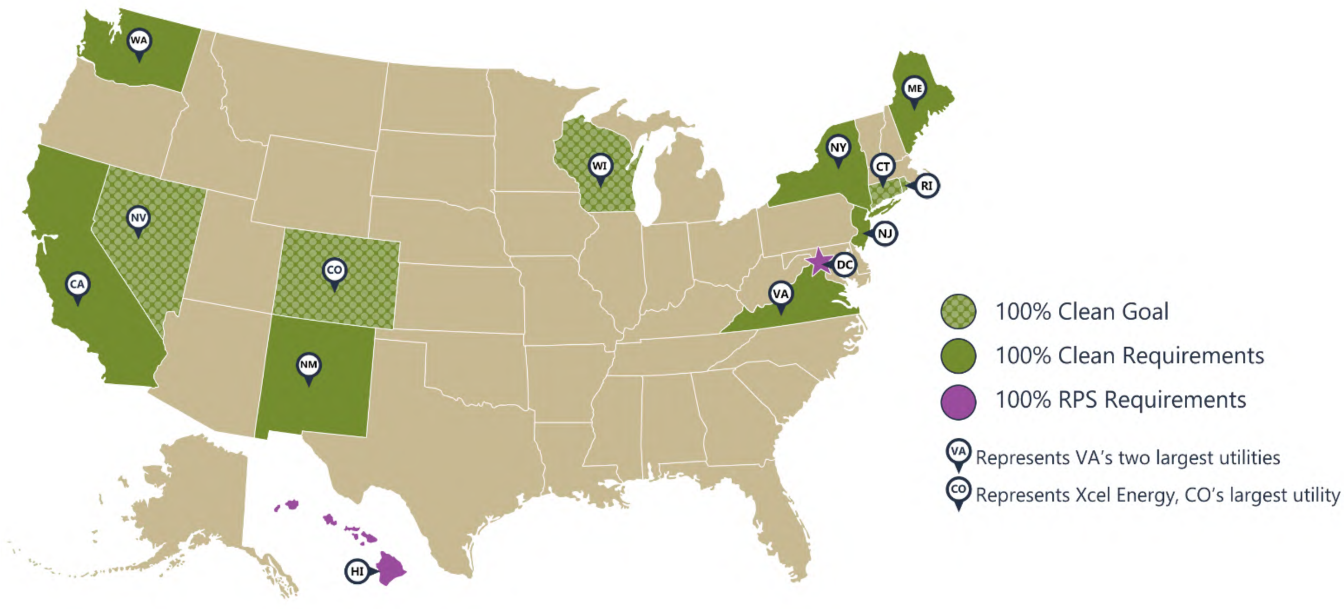
100 Percent RPS vs 100 Percent Clean Electricity Standards

One of the biggest recent trends in clean energy policies is the push for 100 percent clean electricity standards. States have gone about this via three main pathways: legislation, voluntary (non-binding) goals, and gubernatorial executive orders. Terminology indicating whether these pathways are binding or non-binding is not consistently applied across state programs. For clarity purposes, throughout this discussion, references are made to *goals* and statutory *targets*, where targets are legislatively codified and goals are either non-codified (as in the case with gubernatorial executive orders) or non-binding.

See Energy 101 section for more about renewable and zero emissions standards

While a 100 percent RPS requirement and a 100 percent clean electricity standard may seem interchangeable, there can be material differences between the implementation of the two. For example, many state RPS policies were originally enacted to incentivize the development of *new* renewable resources, which in practice left many older renewable resources ineligible, such as the Pacific Northwest's legacy hydropower. Some RPS policies have also excluded generation sources that are not traditionally considered "renewable" but that may be low-carbon or zero-carbon, such as nuclear power or fossil fuel-generated electricity with carbon capture and storage (CCS) technology. States can make legislative changes to their RPS programs to allow new generation sources, but given how mature many state's RPS policies are, and how complex they can be with carve-outs and tiers (see below for more information), some may determine it to be easier administratively to preserve the RPS policy as is and then add a complementary new clean energy standard.

Figure 1: 100% RPS and 100% Clean Electricity Goals by State (Data: EQ Research[5])



Below is a discussion of the 100 percent RPS or 100 percent clean electricity standard policies individual states have enacted, and a table summarizing the information is available below. Two jurisdictions now have 100 percent RPS targets: Hawaii and the District of Columbia.

The **District of Columbia** passed a Clean Energy Act in 2018 that established a requirement of 100 percent RPS by 2032. The district's current RPS has two tiers and allows for a small percent of annual compliance to come from Tier Two resources like hydropower (other than pumped storage), combustion of municipal solid waste, and generation from older, less efficient biomass facilities and/or those that use black liquor.

Hawaii also has a 100 percent RPS requirement by 2045. Current RPS-eligible resources include solar, wind, hydropower, biogas, geothermal, ocean energy, biomass, combustion of municipal solid waste, and hydrogen produced from renewable sources.

Other states have chosen instead to couple their RPS policies with a clean electricity standard that totals to a 100 percent clean electricity target (see Table 2). Following are details on each state with a 100 percent "clean" electricity target, including how each state chooses to define "clean" or "zero-carbon." Definitions differ across states and most states have not yet defined what resources will be eligible for the "clean" portion of the 100 percent standard. For that reason, information is provided for some states on resources eligible for the RPS.

Because it is not yet clear from the details included in the legislation or Governor's Executive Orders, some of the state targets outlined below potentially could be categorized as a 100 percent RPS policy instead of a 100 percent clean electricity standard because they will not add new resource eligibility beyond what's already allowed for RPS compliance. Those states include Maine, Nevada, Rhode Island, and Virginia.

California increased its RPS requirement to 60 percent by the end of 2030 and added a requirement that all retail electricity be from either RPS-eligible renewables or "zero-carbon" sources by the end of 2045. The legislation, SB 100 (2018), does not define "zero-carbon resources," but in planning for implementation, the state is considering two scenarios:[6]

- RPS+ scenario, where resources eligible for the RPS, plus large hydropower, nuclear, and natural gas with carbon capture and storage would be considered eligible "zero-carbon resources;" and
- No Fossil Fuel scenario, where resources eligible for the RPS plus large hydropower and nuclear would be considered eligible "zero-carbon resources."

Colorado, in 2019, codified the non-binding goal of its largest utility, Xcel Energy, to provide customers with electricity generated from 100 percent "clean energy resources" by 2050. The legislation defines clean energy resources as those that generate or store electricity without emitting carbon dioxide into the atmosphere, including those already eligible for the state's RPS: solar, wind, geothermal, biomass, small hydropower, coal mine methane,[iii] and pyrolysis (but not combustion) of municipal solid waste. Colorado has not identified what other resources, if any, beyond RPS-eligible resources, could be considered clean energy resources.

Connecticut's Governor-signed Executive Order No. 3 in 2019 requires state agencies to analyze pathways and provide recommendations for meeting a 100 percent "zero carbon" goal for the electric sector by 2040, but it does not make the goal binding, does not define "zero carbon," and does not list eligible resources. Instead, it tasks the state with analyzing pathways and strategies for reaching this non-binding goal. The state's RPS allows for resource eligibility according to tiers, with Tier 1 resources like solar, wind, geothermal, some hydropower, etc. providing the bulk of compliance. Tier II and Tier III resources may only be used for a small slice of annual compliance and include combustion of municipal solid waste and combined heat and power as eligible resources.

Maine passed legislation in 2019 requiring that 100 percent of electricity consumed in the state must come from "renewable" resources by 2050. The bill did not define renewable resources so it is not clear whether only currently RPS-eligible resources would be considered. If that's the case, this legislation would be categorized as a 100 percent RPS target instead of a 100 percent clean electricity standard. Maine's RPS-eligible resources include solar, wind, geothermal, biomass, combustion of municipal solid waste, some hydropower, and fuel cells.

Nevada's SB 358 (2019) requires the state to generate 50 percent of its electricity from renewable resources by 2030 and provides a non-binding goal of 100 percent of electricity sold by providers in the state from "zero carbon dioxide emission resources" by 2050. "Zero carbon" resources are not defined in the legislation, nor are the policies needed for compliance. Currently, the Nevada RPS allows for solar, some hydropower, wind, geothermal, biomass, and combustion of municipal waste.

New Jersey's 2018 Clean Energy Act increased its RPS requirement to 50 percent by 2030 and the Governor's 2018 Executive Order No. 28 added a 100 percent "carbon-neutral" electricity standard by 2050. The state hasn't yet codified what sources of electricity will meet the threshold of carbon neutral, but the Governor's Executive Order required that the state's 2019 Energy Master Plan provide a blueprint for meeting the 2050 target. This plan outlined the state's intent to model scenarios to inform decisions on how New Jersey can meet the 100 percent clean energy standard at the least possible cost. Currently, New Jersey's RPS allows for some hydropower and combustion of municipal solid waste to meet the Class Two requirements, which is 2.5 percent annually.

[iii] Coal mine methane and synthetic gas created from the pyrolysis of municipal solid waste are only eligible resources for the Colorado RPS if the PUC determines the resulting electricity is greenhouse gas neutral.

New Mexico passed its Energy Transition Act in 2019, which requires that 100 percent of all retail sales of electricity in the state be supplied by "zero-carbon resources" by 2045. The Act defines "zero-carbon resources" as those that "emit no carbon dioxide into the atmosphere as a result of electricity production"[7] but does not list eligible resource types.

New York, in 2019, passed legislation requiring a 70 percent RPS by 2030 and that the "statewide electrical demand system will be zero emissions"[8] by 2040. Resources that would meet the definition of "zero emissions" are not enumerated in the bill.

Rhode Island's Governor signed Executive Order 20-01 in January 2020, which requires the state's energy office to conduct analysis to develop viable pathways to meeting 100 percent of the electricity demand with "renewable energy resources" by 2030. The state energy office must submit an implementation plan to achieve the goal to the Governor by December 31, 2020, which should include initiatives that could be launched in 2021. It's not clear whether this plan will suggest expanding the state's current definition of renewable resources, which includes solar, wind, kinetic or thermal ocean energy, small hydropower, biomass, landfill gas, and fuel cells using an RPS-eligible energy source.

Virginia's Governor signed Executive Order 43 in 2019, which directed state agencies to develop a plan for producing 100 percent of the state's electricity from "carbon-free sources" by 2050. The following year, the Virginia Clean Economy Act was passed, creating the state's first RPS policy while also codifying the 100 percent "carbon-free" electricity by 2050 requirement from the Governor's 2019 Executive Order. It's difficult to categorize Virginia as having a 100 percent RPS or a 100 percent clean electricity standard as the legislation defines "zero-carbon electricity" as electricity generated by a generating unit that does not emit carbon dioxide as a by-product from the generation of electricity, but then provides for an RPS requirement of 100 percent by 2050 to be met with RPS-eligible resources that include solar, wind, some hydropower, combustion of municipal solid waste, landfill gas, or biomass.[iv]

Washington state passed a clean electricity standard in 2019 requiring all retail electricity sales be "greenhouse gas neutral" by 2030, and by 2045, 100 percent of retail sales of electricity must be from either RPS-eligible renewables or from "non-emitting" resources. The bill defines "non-emitting" resources as distinct from RPS-eligible resources but do not emit GHGs as a byproduct of electricity production. The difference between the 2030 target and the 2045 target is that, for the period between 2030 and 2045, utilities may meet up to 20 percent of their compliance with a combination of flexibility measures, including electricity produced from the combustion of municipal solid waste.

Wisconsin's Governor signed Executive Order No. 38 in 2019, creating an Office of Sustainable and Clean Energy and tasking it with achieving a goal of ensuring all electricity consumed in the state is 100 percent "carbon-free" by 2050. The Executive Order does not define "carbon-free" and the Office has not yet released any guidance. At this time, the Wisconsin RPS includes as eligible resources solar, wind, tidal or wave energy, geothermal, biomass, hydropower, fuel cells powered by renewable energy, thermal energy, and pyrolysis (but not combustion) of municipal solid waste.

[iv] Facilities that generate electricity from combustion of municipal solid waste or landfill gas must have been in operation as of January 1, 2020 and may not use waste heat from fossil fuel combustion or woody biomass as fuel to be RPS-eligible. Biomass facilities must have also been in operation as of January 1, 2020 and are limited in the amount of their qualifying annual generation.

Table 2: Select State RPS and Clean Electricity Standard Details

State	Year	Pathway	Target	Mechanism	Type	Labels Used	Eligible Resources	Notes
CA	2018	Legislation	100% by 2045	RPS + CES	Binding	carbon free	TBD	State agencies must submit plans by Jan 1, 2021 for achieving goal.
CO	2019	Legislation	100% by 2050 for Xcel Energy	RPS + 100% pledge	Non-binding	clean energy resources	TBD	Xcel service territory covers about 60% of the state's electricity load.
CT	2019	Executive Order	100% by 2040	TBD	Non-binding	zero carbon	TBD	
DC	2018	Legislation	100% by 2032	RPS	Binding	renewable	Tier 1 Resources: solar, wind, qualifying biomass, biogas, geothermal, ocean, fuel cells. Tier two resources: hydropower, waste-to-energy, less efficient biomass, black liquor.	Unclear whether Tier Two resources will be eligible after 2020.
HI	2016	Legislation	100% by 2045	RPS	Binding	renewable	Solar, wind, biogas, hydropower, biomass, geothermal, ocean energy, combustion of municipal solid waste, and hydrogen from renewable sources.	

State	Year	Pathway	Target	Mechanism	Type	Labels Used	Eligible Resources	Notes
ME	2019	Legislation	100% by 2050	RPS + CES?	Binding	renewable	Includes solar, wind, biomass, geothermal, combustion of municipal solid waste, some hydropower, fuel cells.	Unclear whether RPS will be only mechanism to implement.
NV	2019	Legislation	100% by 2050	RPS + CES?	Non-binding	zero carbon	TBD	Legislation includes non-binding goal of 100% by 2050 but no pathway to implement.
NJ	2018	Executive Order	100% by 2050	RPS + CES	Binding	carbon neutral	TBD	NJ will model scenarios for meeting the 100% target.
NM	2019	Legislation	100% by 2050	RPS + CES	Binding	zero carbon	TBD	
NY	2019	Legislation	100% by 2040	RPS + CES	Binding	zero emissions	TBD	
RI	2020	Executive Order	100% by 2030	RPS + CES?	Non-binding	renewable	TBD	State agency to provide analysis of 100% goal, but does not require entities to meet goal.
VA	2020	Legislation	100% by 2050 for two largest utilities	RPS + CES?	Binding	carbon free zero carbon	TBD	State to produce plan to implement by July 1, 2020.
WA	2019	Legislation	100% by 2045	RPS + CES	Binding	non-emitting	TBD	
WI	2019	Executive Order	100% by 2050	RPS + CES	Non-binding	carbon free	TBD	State agencies, utilities to achieve goal of 100% by 2050.

Removing RPS Carve-Outs, Adding New Ones

Carve-outs are a common design element of RPS programs and are often used to support emerging renewable electricity technologies by requiring that utilities meet a certain percent of their annual RPS compliance requirement with that technology. As technologies become commercialized, the need for support from a carve-out should lessen. This has been the case for solar, which was the technology most often supported by RPS carve-outs in earlier years. Between 2010 and 2018, the costs associated with a utility-scale one-axis PV solar installation have fallen by 80 percent;[9] since 2016, Ohio, New Jersey, and Nevada have phased out their RPS solar carve-outs.[10] Colorado shifted its solar carve-out into a broader distributed generation carve-out, which includes rooftop solar and other small, distribution system devices that provide decentralized electricity generation. Oregon's RPS does not have a solar carve-out but it does offer a credit multiplier for solar generators in operation before 2016 and between 500 kW and 5 MW so that each kilowatt hour (kWh) counts as two kWh.[11] Credit multipliers are meant to increase the value of a specific type of resource since the generation is given "extra credit" for each unit of electricity delivered.

While the costs for familiar renewable energy technologies like solar and onshore wind have fallen, technologies like wave energy and offshore wind are still very expensive as compared to other generation options and thus prime candidates for carve-outs. For example, the Energy Information Administration calculates the levelized cost of offshore wind to be nearly three times the cost of onshore wind for resources entering service in 2023 ($117/MWh versus $42.8/MWh).[12] In 2018, three states (New Jersey, New York, and Maryland) added or increased offshore wind RPS carve-outs.

Critics of carve-outs contend that the added costs associated with requiring utilities to meet the RPS with more expensive technologies will raise the overall cost of RPS compliance. This is of special concern in states with RPS cost caps, such as Oregon, and in general as the costs of compliance may increase as states reach higher levels of installed renewable energy. Additionally, multipliers can have an unintended consequence of reducing the overall amount of renewable generation built as certain generators can earn double credit for each kWh. This could potentially result in states achieving significantly fewer kWh generated from renewables (up to half as much) in the absence of the double credit. As an example, 8 percent of compliance with Michigan's RPS in 2017 was met with renewable energy certificates (RECs) associated with a credit multiplier.[13]

Clean Peak Standards

As the percent of variable renewable energy increases in a state's electricity mix, the value of renewable energy becomes increasingly tied to *when* it is available to the grid. For example, an oversupply of solar energy in the middle of the day, well beyond what's needed to meet demand, can lead to low or even negative wholesale electricity prices and/or a reduction in the amount of electricity generated over what could have been produced because of curtailment. In this scenario, every extra unit of renewable energy is worth less than the last one and its environmental benefit is lower as it's replacing other renewable energy or relatively efficient fossil fuel-generated electricity. However, renewable energy is much more valuable at times of peak demand, when relatively dirtier, less efficient fossil fuel-powered "peaker" plants are commonly used to meet that demand. Having a higher percentage of renewable electricity delivered during peak times can not only reduce GHG and other emissions but can also deliver significant savings to ratepayers.

Clean Peak Standards are an emerging policy option to address the time value of renewable energy delivery to the grid. A clean peak standard builds on an RPS by requiring that a certain percent of electricity delivered to retail customers during designated peak times must be from eligible renewable resources. This essentially turns an RPS that was a straight procurement policy into one that includes capacity requirements.

Both California and Arizona have considered adding clean peak standard policies to their RPS, but Massachusetts was the first (and so far, only) state to enact such policy, in 2018.[14] The program will function as a market mechanism with the goal of sending a price signal for investment in energy storage technologies that can address peak demand. Eligible resources will receive Clean Peak Energy Certificates for each unit of electricity delivered during the designated peak periods, which will then be used by utilities to demonstrate annual compliance with the standard.

The Massachusetts statute defines the following as eligible resources for the clean peak standard:

- *New* RPS-eligible resources;
- Existing RPS-eligible resources paired with *new* energy storage capabilities;
- New stand-alone energy storage resources that will be charged primarily by renewable resources; and
- Demand response resources.[15]

Figures 2 and 3 show how the Massachusetts clean peak standard is designed to shift more renewable resources to times of peak demand. Figure 2 shows a forecasted typical winter week in 2030 without a clean peak standard. Very little, if any, of the generation from solar (in yellow) or offshore wind (in light blue) occurs during the predicted times of peak demand on some of the days (red circles). Massachusetts would have to maintain generation from oil or gas to meet these peak loads, despite cost or decarbonization goals. However, Figure 3 shows how the clean peak standard would incentivize shifting the output from renewable resources to times of higher demand, primarily through energy storage.

Figure 2: Massachusetts Electricity Generation and Demand During a Winter Week in 2030 Without the Clean Peak Standard[16]

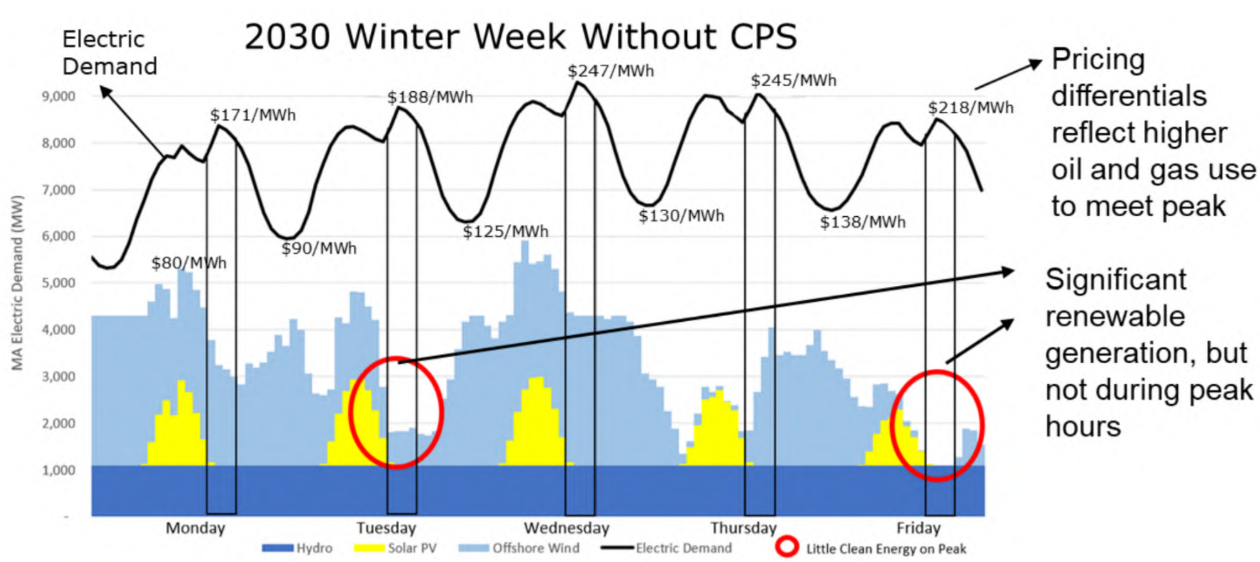
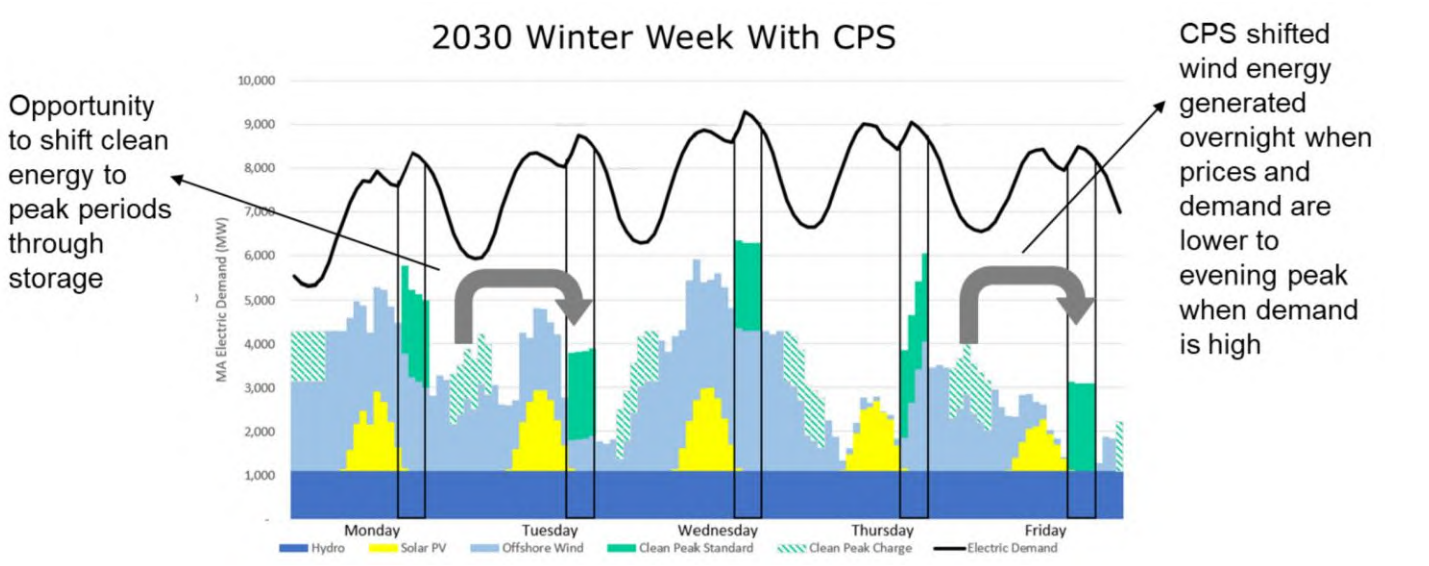


Figure 3: Massachusetts Electricity Generation and Demand During a Winter Week in 2030 With the Clean Peak Standard[17]



One consideration with a clean peak standard, and with energy storage as part of an RPS in general, is what resource is used to charge the energy storage device. These policies are meant to support renewable and zero-emission resources, which would be contradicted by providing financial benefit to fossil fueled-resources or unspecified power. The Massachusetts clean peak standard requires that eligible energy storage systems either be co-located with an RPS-eligible generating resource, have a contract to purchase electricity from an RPS-eligible generator, be charged at times when the electricity resource mix traditionally has the highest levels of renewable energy, or demonstrate an operational schedule that addresses power and flow concerns associated with variable renewable energy.

Some stakeholders have expressed concerns with the Massachusetts draft rules and suggest that in absence of stricter standards around pairing storage with renewable energy, GHG emissions during peak demand could *increase* under the clean peak standard. The state's Attorney General office provided comments on the draft rules that clean peak energy certificates should only be issued for storage charged by renewable resources, and suggested: additional metering requirements for co-located energy storage; purchase and retirement of renewable energy certificates for storage charged by contractually purchased renewable energy; and re-evaluation of the eligibility of storage based on charging at times of high renewable energy production (which may be impossible to select given market volatility) and based on provision of certain ancillary services.[18]

100 Percent RPS and 100 Percent Clean Electricity Policies – A Deeper Dive

As outlined above, state adoption of 100 percent RPS targets or clean electricity standards is a fast-growing trend. No two states have taken the same path to a 100 percent target, showing the diversity of options for implementing such policies. However, nearly all of these states have explicitly addressed the opportunities and challenges associated with meeting a 100 percent target, including reliability of electricity service, cost, and equity, among other considerations.

Opportunities with 100 Percent RPS and Clean Electricity Standards

Greenhouse Gas Emissions Reductions

As policies, 100 percent RPS and 100 percent clean electricity standards represent an opportunity to reduce greenhouse gas (GHG) emissions from the electricity sector. RPS policies have been considered implicit GHG emissions reduction policies given that the electricity required for an RPS will almost always be lower-carbon than the fossil fuel-generated electricity it replaces. However, when enacting original RPS legislation years ago, few state legislatures made GHG emissions reductions an *explicit* rationale for an RPS. It's a different story today, with legislative rationales for 100 percent RPS and clean electricity policies including not only GHG emissions reductions, but also increased air quality, reduced dependence on fossil fuels, and a transition to a more affordable and reliable energy system.

While 100 percent RPS or clean electricity standards can reduce GHG emissions as a stand-alone policy, they are especially useful as part of a larger decarbonization effort. Some studies have found that while renewable electricity is an important part of decarbonization, relying heavily or solely on an RPS or clean electricity policy could result in higher GHG emissions and higher costs than a policy that addresses carbon more comprehensibly.[19] [20] This is because an RPS or clean electricity policy requires procurement that can ignore the potential of other GHG emissions reduction contributions, like energy efficiency or electrification of thermal loads. Stand-alone policies can also introduce distortions into wholesale markets, such as negative pricing during times of high renewable output.[21] That said, some states have recognized that having an RPS policy on the books and simultaneously working on decarbonization via multiple pathways is a preferred alternative.

The "wedges" approach to decarbonization, first described in 2004,[22] looks at the total GHG emissions reductions needed to reach a specific GHG mitigation target[v] and then breaks that amount into numerous wedges that correspond to either specific policies (e.g., increasing fuel economy standards) or sectors (e.g., the electricity or transportation sector).

While Oregon does not yet have a comprehensive carbon pricing policy or a cap-and-trade program,[vi] the state established initial non-binding GHG emissions reduction goals back in 2007, with a reduction goal of at least 75 percent below 1990 levels of GHG emissions by 2050.[23] More recently, in March 2020, Governor Brown's Executive Order 20-04 established a new statewide reduction goal of 45 percent below 1990 levels by 2035 and 80 percent below by 2050.[24]

Governor Brown signed Executive Order 20-04 in March 2020, establishing a new statewide GHG emissions reduction goal of 80 percent below 1990 levels by 2050.

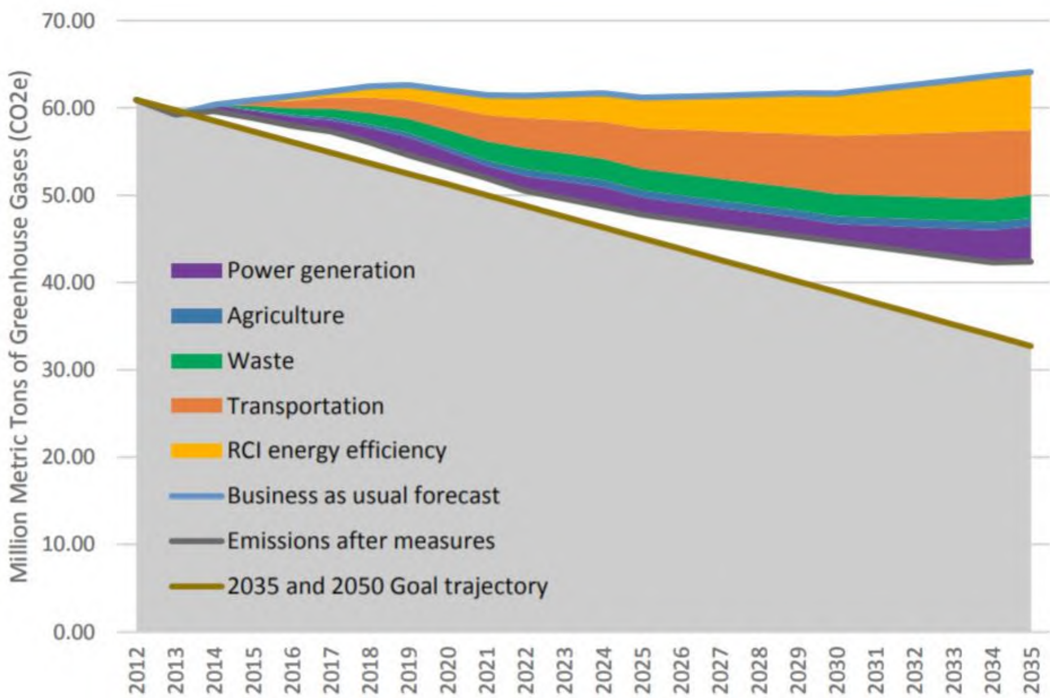
The Oregon Global Warming Commission conducted a wedges analysis for Oregon in 2015 and constructed a scenario (called Case 1) that included a number of the most cost-efficient measures that could reduce Oregon's GHG emissions and get it closer to meeting its 2035 emissions level target.[25] The combination of measures in Case 1 would result in roughly a 22 million metric tons of CO_2e

[v] Such as a target to hold the earth's atmosphere at a maximum parts per million concentration of GHGs, a target to maintain a maximum global temperature increase, etc.

[vi] Although, in 1997 Oregon became the first state to establish a price on carbon by requiring new plant's emissions to be 17% below the most efficient natural gas-fired facility operating in the country or pay for equivalent offsets.

(carbon dioxide equivalent)[vii] emissions reduction compared to business-as-usual in 2035, but would still leave Oregon about 10 million metric tons of CO2e short of achieving the 2035 GHG emissions reduction interim goal (see Figure 4). The wedge analysis was a comprehensive plan and Oregon's RPS was one of many actions and represented a big part of the "power generation" wedge reductions. While Case 1 falls short of Oregon's GHG emissions reduction goals, the analysis found that adding a gradually increasing carbon price to the Case 1 portfolio of measures would put Oregon back on track to meet the 2050 goal.

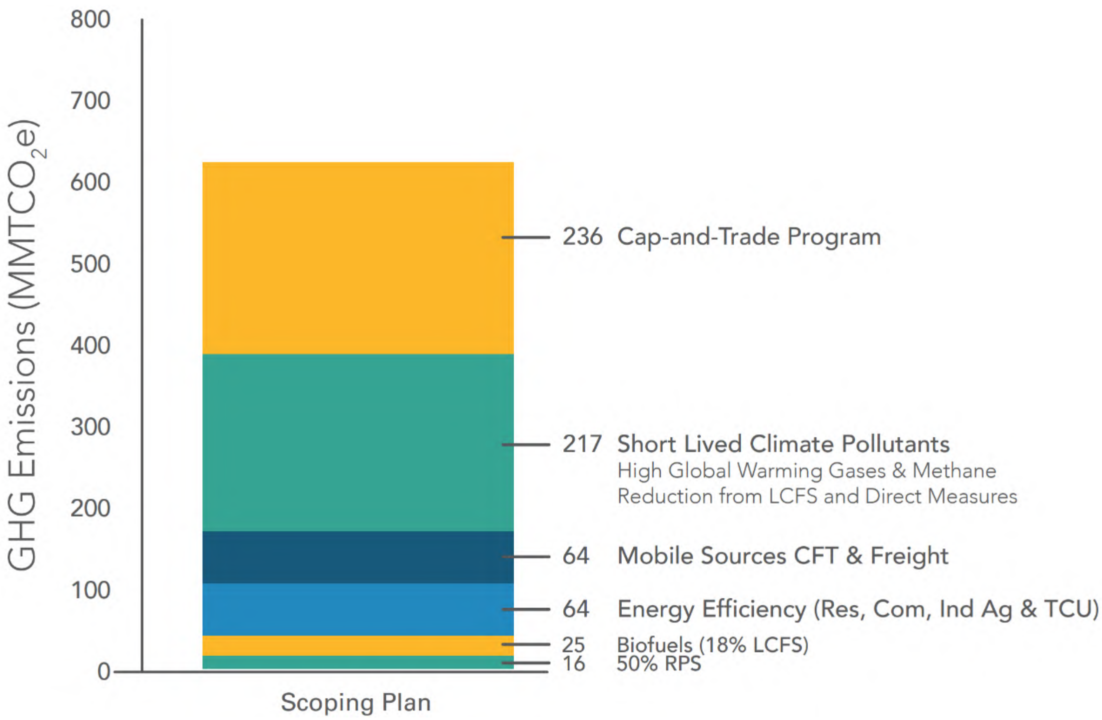
Figure 4: Case 1 Scenario for Reducing GHG Emissions in Oregon (Source: Oregon Global Warming Commission)



California launched its cap-and-trade program in 2013 and has repeatedly updated its RPS requirement in recent years, culminating in a 60 percent RPS and a 100 percent clean electricity standard, passed in 2018. In 2015, electricity generation represented 19 percent of California's annual GHG emissions and as part of its 2017 Climate Change Scoping Plan, the California Air Resources Board estimated that the then-current policy of a 50 percent RPS target would contribute 16 million metric tons of GHG emissions reductions from 2021 to 2030, but that was only a small portion of the overall GHG emission reductions needed.[26]

[vii] Each greenhouse gas has a different global warming potential, expressed over a period of years. For example, the global warming potential of methane is 21 over 100 years, as compared to 1 for carbon dioxide. This means that the emission of one million metric tons of methane is equivalent to the emission of 21 million tons of carbon dioxide over 100 years. Carbon dioxide equivalent allows discussion of greenhouse gases as a group.

Figure 5: Estimated Cumulative GHG Reductions by Policy/Program for 2021-2030 in California[27]



Valuation of "Clean" Resources Not Included in an RPS

The Pacific Northwest is blessed with abundant hydropower resources – in Oregon alone, hydropower provided over 43 percent of the electricity consumed in the state in 2018.[28] However, much of this hydropower is not eligible for the state's RPS. The goal of the Oregon RPS legislation was to promote "research and development of *new* renewable energy sources in Oregon"[29] (emphasis added). For this reason, aside from a few exceptions, only facilities that became operational on or after January 1, 1995, are eligible for participation in the RPS. The facility age requirement serves to incentivize the development of new renewable electricity sources, which is one reason why much of the existing hydropower in the region is not eligible for the RPS.

The section above enumerated the many different resources that states have deemed eligible to meet their "carbon-free" or "zero-emissions" electricity standards, such as a greater share of hydropower, nuclear, or fossil-fueled generation with carbon capture and storage. Not only does inclusion of these generating resources in a clean electricity standard provide them with additional value, but it can increase a state's likelihood of meeting the target without affecting reliability (see section below for more discussion on this topic).

Challenges with 100 Percent RPS and 100 Percent Clean Electricity Standards

When analyzing pathways to high renewable or 100 percent zero-carbon electricity systems, numerous studies have found that getting to 100 percent is technically feasible, but that the challenges (and costs) increase as one gets closer to 100 percent.[30] The reasons for this are that states need flexible zero-carbon resources to balance the grid, a major increase in the amount of regional transmission, gigawatts of energy storage, an overbuild of variable renewable resources and curtailment, or a mix of all of the above. Other challenges include building greater regionalization of infrastructure and markets, getting buy-in across stakeholder groups, and planning a long-term strategy for implementation that meets near-term goals without creating policy "lock-in," (e.g., a situation where policies that work in the near-term could also reduce the chances of long-term success).

It's important to note that, while they are not discussed here, energy efficiency and demand-side management are also two critical pillars in decarbonizing the electricity grid, especially given expected increase in electricity demand from beneficial electrification and electric vehicles.

Limited Options for Zero-Carbon Flexible Resources

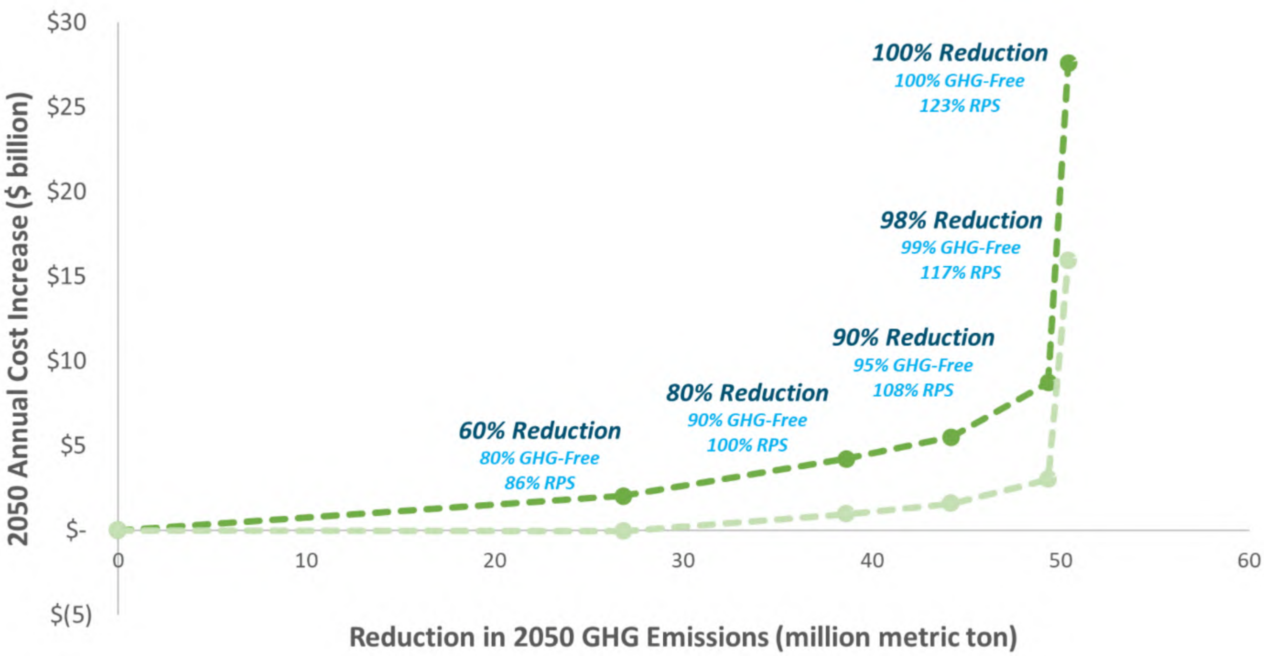
While many fossil fuel power plants take time to start up or shut down, most of them can provide electricity continuously once they are up and running and are often referred to as "baseload" generators, delivering "firm" power. "Baseload" has no industry-accepted definition but has come to mean facilities that are usually large in terms of megawatt (MW) output, designed to operate at or near capacity, and that provide some of the cheapest power when operating at high capacity. This is in contrast to many renewable electricity resources, which are more variable – solar panels only work when the sun is shining, and turbine blades only spin when there's wind.

The growing share of variable renewable resources in our electricity mix in the West has led to a discussion of "flexibility" when integrating intermittent renewables, where flexibility refers to a resource's ability to ramp generation up or down quickly to meet load requirements at all times, no matter the season or time of day. This is because the electric grid must be kept in balance at all times with respect to supply and demand; failure to maintain this balance can destabilize the grid and lead to brownouts, blackouts, and even safety threats. Unlike other forms of energy, such as liquid fuels, natural gas, or coal, it can be costly to store electricity in large quantities, at least with the technology available today. So, if electricity can't easily and/or cheaply be stored, then it must be produced it when it's needed, and that means flexible resources that can operate when variable renewable sources are not available or cannot fully meet demand are necessary.

Currently there are limited options for firm and/or flexible zero-carbon resources – namely geothermal, biomass, some hydropower, nuclear, and fossil fuel generation with carbon capture and storage (CCS) – and each has limitations. For example, geothermal generation is highly location-specific and expensive to develop; biomass can be limited by available feedstock; hydropower in the Northwest is primarily run-of-river and the amount of water available for electricity generation is dependent on a number of factors and other uses; and CCS technologies are as yet expensive and limited in deployment.

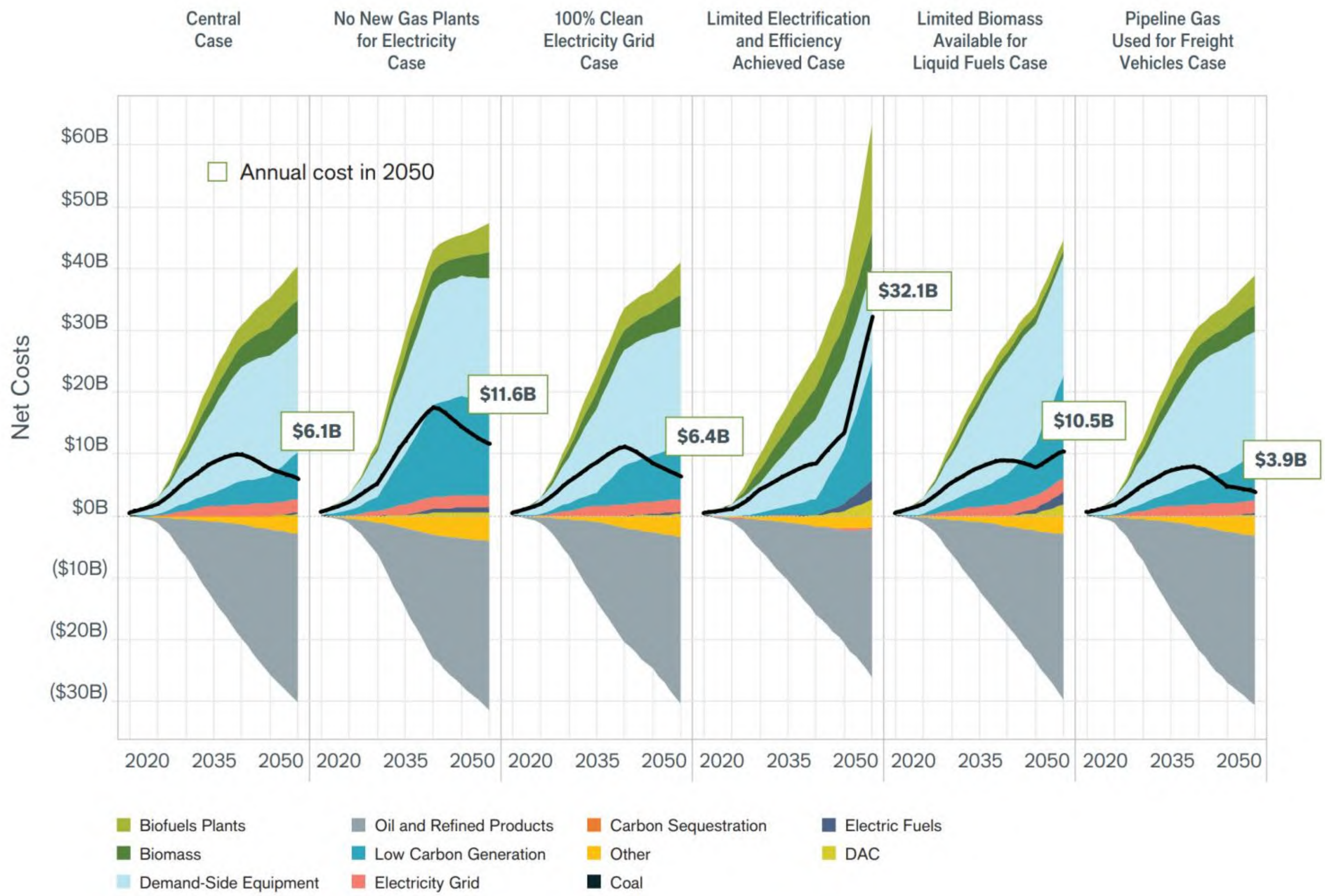
For this reason, recent decarbonization studies have recommended keeping a small percentage of existing or new natural gas generation capacity (with or without CCS) and not phasing out existing zero-carbon firm resources like hydropower or nuclear power. In its analysis of low-carbon scenarios for the Northwest, E3 found that a moratorium on new natural gas plants results in significant additional costs without a significant reduction in GHG emissions and suggested that natural gas generation may be key to meeting GHG emissions reductions goals "reliably and at least cost."[31] In another E3 study, this one looking at decarbonization pathways in the Northwest while maintaining resource adequacy, they again found that achieving 100 percent zero-carbon electricity with only wind, solar, hydropower, and energy storage to be "impractical and prohibitively expensive."[32] The study estimated the costs associated with various GHG emissions reductions, shown in Figure 6, and found that an additional $100 billion to $170 billion would be need to go from the 99 percent GHG-free electricity scenario to the 100 percent GHG-free scenario. This sharp cost curve is due to the significant renewable overbuild (and curtailment) required to ensure reliability in this scenario and the increasing amounts of energy storage needed to integrate all of that variable renewable energy.

Figure 6: Costs of Achieving Increasing Reductions of GHG Emissions in the Pacific NW (Source: E3, 2019)



Another study, this one from the Clean Energy Transition Institute, took an economy-wide look at decarbonization and found that while a "nearly" 100 percent clean grid is a critical component of decarbonization, the optimum, cost-effective electricity resource mix for the Northwest was one that retained 3.7 percent of gas-fired electricity generation (called the Central Case in the study).[33] However, the study also modeled a 100 percent clean electricity scenario, where gas-fired plants would be allowed to burn biogas and synthetic fuels, and found it was only nominally more expensive at $6.4 billion by 2050 (as compared to the Business as Usual scenario) than the Central Case scenario, which was estimated to cost $6.1 billion more by 2050 than business as usual (see Figure 7, below).[34] The difference in the costs of getting to 100 percent clean between the E3 study and the Clean Energy Transition Institute Study are due, in part, to the economy-wide focus of the latter study as opposed to just the electricity sector focus of the E3 study. The Clean Energy Transition Institute study found that "economy-wide decarbonization involving the fuel supply sectors and not just the electricity grid brings two benefits that make it easier to attain 100 percent clean electricity. First, flexible electric fuels increase load flexibility and make balancing the electricity system easier, and second, the clean synthetic gas that is produced can be used to generate electricity during challenging system-balancing conditions."[35] Here "electric fuels" refers to a process called Power-to-Gas, where electricity is used to create synthetic fuels. This is explained further in the next sub-section.

Figure 7: Annual Net Energy System Costs for Six Cases Compared to the Business as Usual Case (Source: Clean Energy Transition Institute)



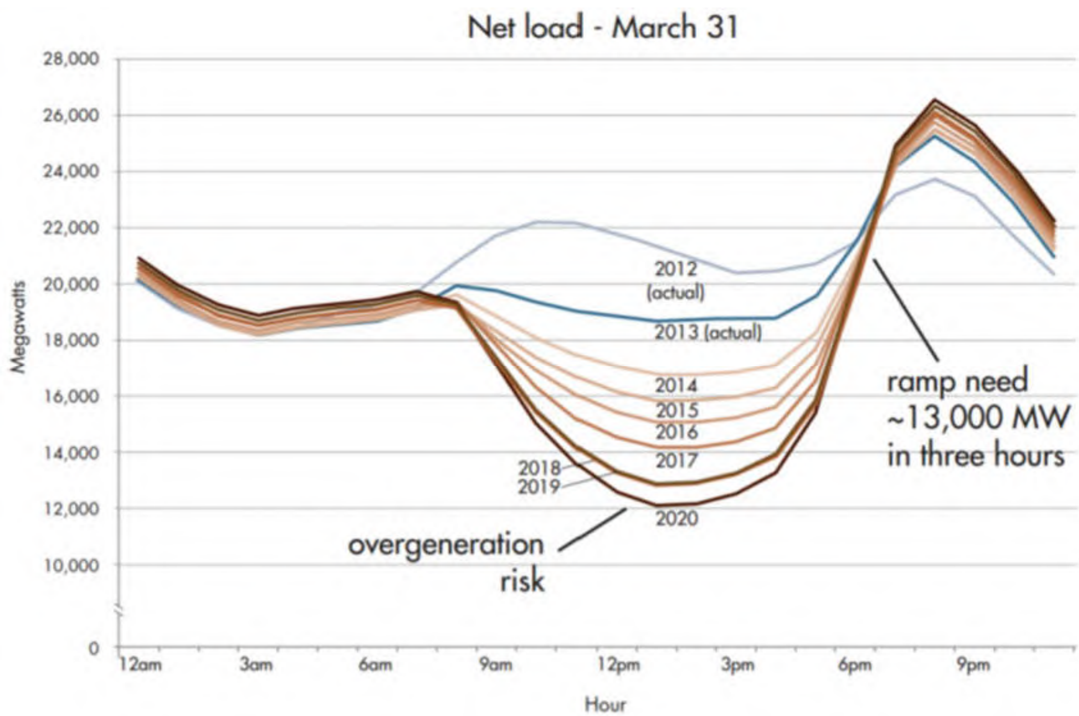
Finally, the recent 2035 study from UC Berkeley found that the U.S. can achieve a 90 percent clean grid by 2035 without coal or new natural gas plants with wholesale electricity costs about 10 percent lower that they are today.[36] The lower electricity costs in the 90 percent scenario are primarily due to the dramatically declining costs for wind and solar PV and, to a lesser extent, lithium ion battery storage, coupled with savings from no new natural gas generation facilities being built.[viii] The study's 90 percent scenario also results in significant environmental, health, and jobs benefits, but the study shows that achieving a 90 percent clean grid by 2035 is not possible without new policies to further support decarbonization. Perhaps one of the most important take-aways from the 2035 study is that existing technologies can immediately get us on the path to deep decarbonization of the electricity sector and better poised to meet future 100 percent targets.

[viii] While the study shows that wholesale electricity costs for the 90 percent scenario are lower than today's wholesale electricity costs, the costs in 2035 for the 90 percent scenario are 12 percent higher than the "no new policy" scenario in 2035 when environmental and social costs and benefits are not included.

Overbuilding and Curtailment

One option for integrating high levels of variable renewable energy is to overbuild and curtail, which refers to building more capacity than a system requires to meet peak demand and then to curtail[ix] those renewable resources at times of oversupply. The now-famous California duck curve graphically shows that the California Independent System Operator (CAISO) has a glut of solar power in the middle of spring and fall days (see Figure 8) and that as solar trails off towards evening, there is an increasingly steep ramp that must be met with flexible resources. Each line in the chart shows the net load, i.e., the demand for electricity minus wind and solar generation. The "belly" of the duck shows the period of lowest net load, where solar generation is at its highest, and that belly has grown as more solar has been added to the CAISO generation mix from 2012 to 2020 (estimated).[37]

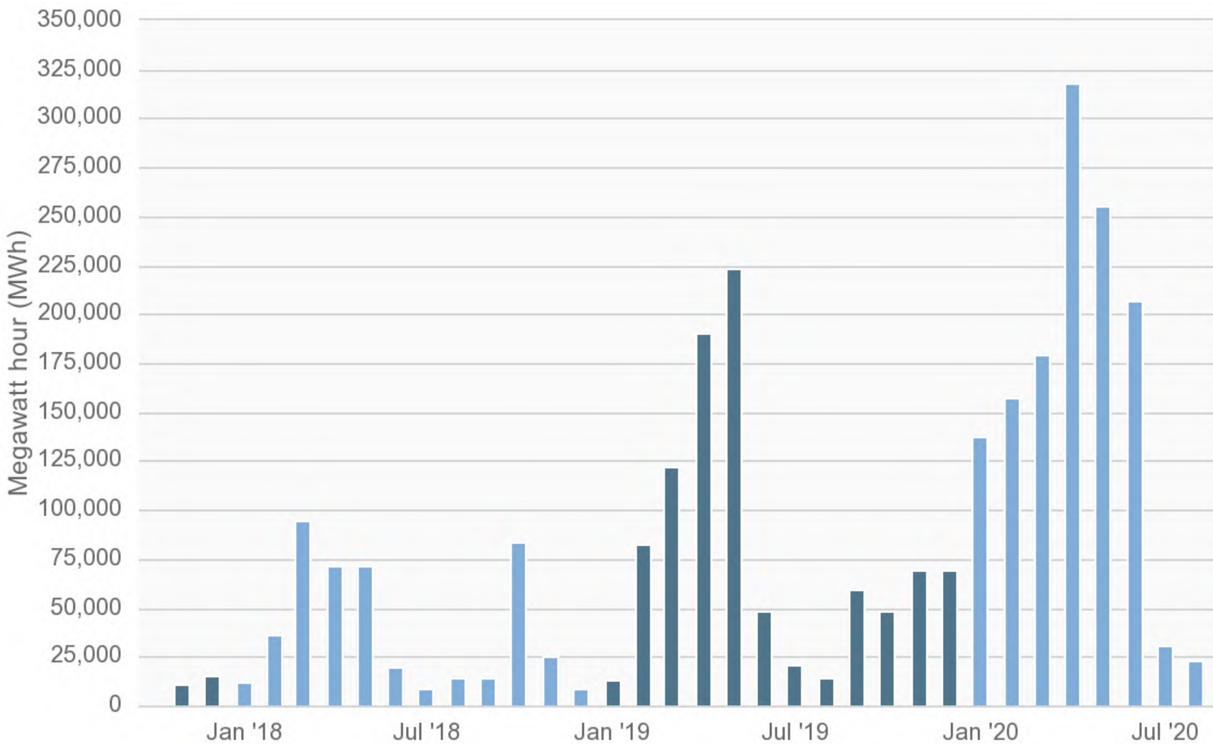
Figure 8: The CAISO Duck Curve (Source: Denholm)



The duck curve also highlights the overgeneration potential of variable renewable resources, which has increasingly resulted in curtailed electricity. When the system is in oversupply, CAISO's options are to use as much of the generation as possible, store what it can, export what it can, and then curtail the rest. Figure 9 illustrates the growing amount of energy curtailment in CAISO from 2018 to 2020.[38] In 2018, the most curtailment occurred in March – over 94,000 MWh. The highest curtailment for 2019 occurred in May and was more than double the March 2019 total at over 223,000 MWh. In 2020, curtailment was highest in April at 318,444 MWh, more than triple the highest curtailment number in 2018. As California's clean energy goals increase and the state adds more variable renewable energy to its mix, one can reasonably expect the curtailment numbers to continue to grow every year.

[ix] Curtailment refers to temporarily reducing the output of electricity from a generator from what it could have otherwise produced.

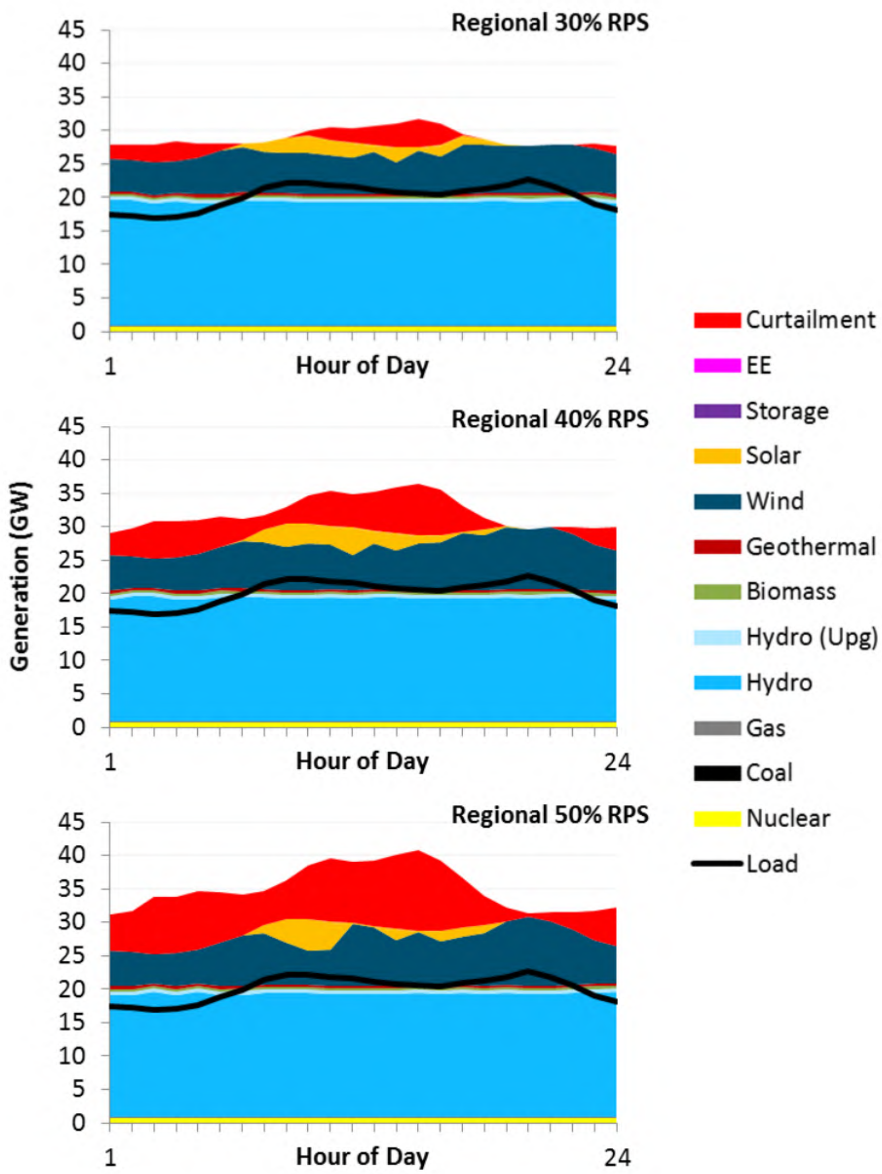
Figure 9: Wind and Solar Curtailments by Month in CAISO From November 2018 to August 2020 (Source: CAISO 2020)



Overbuilding and curtailment represent real costs, not to mention the persistent challenges associated with siting new renewable installations. While the levelized costs of solar and wind power have reached parity with fossil-fuel generation in numerous jurisdictions – and are, in some cases, cheaper – overbuilding leads to a reduction in the marginal value of each next unit of variable renewable energy. Each new MW of variable renewable energy becomes less useful and less valuable than the one before it. This is because 1) an excess of variable renewable energy at times of peak generation can lead to near-zero wholesale electricity prices given the near-zero operational costs of these units; and 2) more overbuilding necessarily leads to more curtailment.

In its analysis of low-carbon scenarios for the Northwest, E3 found that increasing regional RPS targets could lead to an increase in both the magnitude and frequency of curtailment events.[39] When looking at a day with high hydropower supply, the study found that curtailment of available renewable generation went from 4 percent to 9 percent in the 20 percent regional RPS scenario versus the 50 percent scenario (see Figure 10). Curtailment patterns in California are driven by the high penetration of solar and coincide with the highest hours of solar output, differing from those seen in the Northwest, where instead curtailment is driven by combined high output from both hydro and wind resources, with less frequent but longer-lasting incidents, depending on the hydro conditions.

Figure 10: Increasing Renewable Curtailment Observed with Increasing Regional RPS Goals[40]



Again, an option for avoiding curtailment is deployment of energy storage, but given the current costs of energy storage technologies, some states are finding its cheaper to overbuild and curtail than to invest in large amounts of storage. For example, the Minnesota Solar Potential Analysis[41] found that in scenarios investigating getting to 70 percent solar by 2050, it would be more cost-effective to overbuild and curtail variable renewable resources rather than add long-duration or seasonal storage. However, the costs for lithium-ion storage systems are rapidly declining, which is already making storage cost-effective in a number of utility-scale applications.[42]

An alternative to battery storage for soaking up excess renewable electricity that would otherwise be curtailed is Power-to-Gas, or PtG, which is the process of using electricity to create synthetic fuels that can then be stored for later use in meeting thermal loads or in generating electricity. Power-to-Methane (PtM) can create carbon-neutral methane to be used in place of natural gas if the carbon dioxide used is from direct air capture and if the electricity used to power electrolysis is renewable. Power-to-Hydrogen (PtH) can generate carbon-neutral hydrogen gas if the electricity used to power the process is renewable. Not only do these fuels act as energy storage, but when injected into a pipeline system, the entire infrastructure can be imagined as one big battery. A study by the Finnish firm Wärtsilä analyzing California's path to 100 percent renewables found that if California maximized its use of PtG technologies, it could meet its 100 percent clean goal five years early while reducing GHG and particulate emissions and saving approximately $8 billion dollars as compared to the current path.[43]

Learn more about PtG in the Technical Review and Policy Briefs sections.

Though not detailed here, another option for addressing overgeneration of renewable resources is using demand response programs to shift demand from periods of high demand to periods where demand is lower.

Increased Transmission

Transmission refers to the delivery of high-voltage electricity across long distances to move power from where it's generated to where it's consumed. This not only allows for building generation facilities where the renewable resource is best, even when it's far from load centers, but also allows for smoothing out the variability of intermittent renewable energy. This is to say that the larger the area across which you're sharing power, the greater the likelihood that the sun is shining or the wind is blowing *somewhere*.

The ability to move renewable power over greater distances is why numerous studies on decarbonization include increased transmission as a key part of a *cost-effective* transition to zero-carbon electricity, though this may seem counter-intuitive given that new transmission infrastructure isn't exactly cheap. In a 2014 report for the Western Electricity Coordinating Council, Black & Veatch estimated the costs for new transmission lines in the West to range from $959,700 to $1.6 million per mile in 2014 dollars.[44] Despite these costs, the Clean Energy Transitions Institute study found the costs of decarbonization could be reduced by an estimated $11.1 billion over the 30-year study period if the Northwest and California electric grids were expanded and better integrated.[45] The reduced cost from building fewer generating or storage resources offsets the higher costs of transmission, leading to the cost savings.

Conclusions

The renewable portfolio standard is a mature procurement policy for renewable electricity and has been widely adopted by states in the U.S. As interest in aggressive decarbonization of our electricity supply grows, many states have used the RPS policy to drive GHG emissions reductions in the electricity sector, either by adding higher RPS targets, all the way up to 100 percent, or enacting 100 percent clean electricity standards that expand the list of eligible generating resources. States are also updating RPS policies to boost emerging technologies, like offshore wind, or to address complex issues like the GHG emissions associated with peak electricity demand. Finally, instead of supplanting RPS policies, GHG emissions reduction policies are increasingly being enacted alongside existing RPS programs, and RPS policies are considered an important part of a wider electricity, and economy, decarbonization plan.

With respect to implementation of 100 percent clean electricity standards, numerous studies[x] have shown that reaching a 100 percent target is feasible. Though questions remain as to how best to cost-effectively reach the last few percentage points on the road to 100 percent, the options for meeting targets up to 80-95, depending on the region, percent are relatively straightforward.

Numerous studies show that reaching 100% clean electricity standards is feasible.

[x] See References

Oregon's RPS: Looking Ahead

Oregon policymakers can draw a number of valuable conclusions from the recent RPS and clean electricity standard trends occurring in other states. Following are some ideas for consideration:

RPS + Price on Carbon

Numerous recent studies have found that a high or 100 percent RPS or clean electricity standard alone is not the most cost-effective way to reduce emissions from the electricity sector. Pairing an RPS or clean electricity standard with a price or cap on carbon allows for greater emissions reductions at lower cost.

Considerations for 100 Percent RPS or Clean Electricity Standard

Some Oregon stakeholders have signaled an interest in a 100 percent renewable or clean standard for the state's electricity sector. If the state chooses to pursue such a policy, the following are important questions to address:

- Is a 100 percent clean electricity target the right one for Oregon? Numerous studies show that leaving just a small margin for firm natural gas generation reduces costs while minimally affecting GHG reductions. Is there a role for natural gas electricity generation to play in a future clean electricity standard?
- How should the state define terms like "clean" or "zero carbon"? What resources should be eligible? Building a diverse portfolio of electricity generation options can reduce costs and threats to reliability.
- How can the costs to consumers be made as equitable as possible? The long-term costs of doing nothing are much higher than the costs of decarbonization, but there are also real costs associated with decarbonization, which is why the state needs to pay particular attention to protecting vulnerable Oregonians.
- How will the state approach medium-term and long-term planning in such a way that reduces costs to the consumer and successfully meets medium-term goals in a way that doesn't possibly preclude meeting longer-term goals?

Regionalization

Regardless of whether Oregon enacts an increased RPS, a clean electricity standard, or a carbon pricing policy, other states in the West have already done so and their policies will affect the supply and cost of electricity available to Oregon. Greater coordination in the West of energy markets and transmission infrastructure will help Oregon and other states to cost-effectively meet their policy goals.

New RPS Carve-Out

While carve-outs can affect the cost of compliance with an RPS, they also provide vital support to emerging new technologies that will be necessary in the coming years to meet decarbonization goals. Oregon policymakers may want to consider whether there are new technologies they wish to incentivize with this mechanism. For example, an RPS carve-out for offshore wind could help commercialize this new renewable generating resource. However, as described above, the benefits of an RPS carve-out would need to be weighed against the additional costs.

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Policy Brief: Evaluating the Resource Adequacy of the Power System

Background

> **Suggested reading:**
>
> For more background on Resource Adequacy and why it's important for maintaining the long-term reliability of the power system, see the Energy 101 on Resource Adequacy.

The electric power system is unique, relative to other industry sectors, in that it has little to no capability to store electricity as an end-use fuel. As a result, the electric generation and transmission system must be built to satisfy the largest hourly requirements for electricity—called peak demands—even though consumers use less (oftentimes significantly less) during most hours of the year. This results in an electric generation and delivery system that is, by design, underutilized much of the time, especially when compared to the liquid fuels and natural gas sectors.[1] To evaluate the adequacy of the power system, utilities and grid planners must forecast customer demand for electricity and compare that to the ability of existing resources to meet that demand in real-time. If the capabilities of existing resources might fall short, then new capacity resources will need to be developed – a process that can require several years (or more) depending on the types of resources.

> **Resource Adequacy** (or RA) is the term that grid planners and utilities use to refer to the evaluation of whether adequate generating capacity will be available to meet forecasted demand over the next several years (typically from one to five years).[i]

Resource Adequacy can be evaluated for individual load-serving entities, like a utility, or for local areas within their system. It can also be evaluated for balancing authority areas, for states, or for entire regions. In any case, the following are several key technical questions that must be considered as part of an adequacy evaluation:

Table 1: Resource Adequacy Evaluation: Key Technical Questions

Demand: How much power will customers require in the future?	○ **Energy efficiency**: How much incremental energy efficiency savings will accrue? ○ **Population**: Is the population expected to increase or decline? And by how much? ○ **Economic growth**: Will the economy grow at its current rate? Will it accelerate? Will it slow down? ○ **Electrification**: To what extent are customers expected to adopt electric vehicles or switch from gas to electric furnaces?

[i] Note that **Resource Adequacy** in this context focuses on long-term resource acquisition strategies to ensure adequate future power supplies, whereas the similarly-named **Resource Sufficiency Tests** (applied by the Western EIM) focus on the short-term management of existing resources and must be met hourly in order to fully participate in the EIM's real-time markets. (see Wholesale Electricity Markets Policy Brief for more information).

	○ **Large loads**: What is the potential for large industrial customers to enter or leave the utility's service area? ○ **Extreme weather**: What is the likelihood of severe cold or hot weather that could set a new annual peak demand? ○ **Climate change**: How much is climate change expected to affect historic weather patterns, changing the likelihood of severe weather? ○ **Demand response**: To what extent can customers be incentivized to reduce demand during peak hours?
Supply: How much power can generation resources deliver in the future?	○ **Energy constraints**: Do any of the utility's supply-side resources have constraints on energy availability? (e.g., variability in renewable energy availability or potential limitations on natural gas delivery to power plants) ○ **Ramp rates:** What are the ramping capabilities of the utility's capacity resources to quickly increase or decrease output to respond to changes in net load? ○ **Retirements**: Are there any existing resources scheduled for retirement? ○ **Resources under development**: Do any utilities in the region have generation resources currently under development? Should expected future output from those resources be incorporated into the analysis? ○ **Proposed resources**: Are any utilities in the region currently proposing or planning to develop new generation resources? Should potential future output from those resources be incorporated into the analysis? ○ **In-region market resources**: Historically, how many in-region resources have been available on the market during the utility's peak demand hours? Is that market availability expected to change materially? Will those market resources become exceedingly expensive under certain conditions (e.g., heatwave across the entire western U.S.)? ○ **Out-of-region imports**: How much power from out-of-region can be expected to be available for import to meet demand? ○ **Transmission constraints**: Do in-region or out-of-region constraints on the transmission system impede the delivery of power to load centers?

- **Climate change**: To what extent is climate change expected to affect these supply-side considerations, such as the availability of hydropower due to changing precipitation patterns or market resources due to changing loads across the west (e.g., higher demand for AC during hotter summers)?

In many cases, these technical questions cannot be answered with certainty, and instead a probability must be attributed to any one of a range of possible outcomes. The answer to any one of these questions has the potential to significantly impact the overall evaluation of RA, either in terms of how much demand is expected or how much supply is available. Ultimately, these are *technical questions* that must be evaluated by utilities and grid planners. Before an evaluation of RA can address these technical questions, three key *policy questions* must first be answered to define the parameters within which that technical evaluation will occur:

Policy Question #1 – Perspective: From what perspective should we evaluate these technical questions? From the perspective of an individual utility or load-serving entity (e.g., Portland General Electric)? At the statewide level (e.g., Oregon)? The entire region (e.g., Pacific Northwest)? Or even a larger area (e.g., the entire western United States)?

Policy Question #2 – Risk: Given the uncertainty surrounding future conditions, it is cost prohibitive to build adequate power resources that can meet customer demand 100 percent of the time no matter the circumstances. Thus, this policy decision comes down to answering a basic question: how much risk is acceptable when it comes to a utility, state, or region having inadequate capacity available to meet forecasted future demand for electricity?

Policy Question #3 – Time Period: Many jurisdictions evaluate the adequacy of capacity to meet forecasted future peak demands for electricity on an annual basis, irrespective of when those peaks occur within the year. Could alternative methods evaluate capacity adequacy on a monthly or seasonal basis, with potentially significant impacts on which capacity solutions are identified?

There is no right or wrong answer to these policy questions and multiple entities—individual utilities, a collection of utilities voluntarily pooling together, a state regulator like the PUC, a regional independent system operator, or even a state legislature—might have different perspectives on what the answers should be. Thus, depending on each entity's perspective, future "reliable" power systems could be made up of different resource portfolios with vastly varied costs. These policy questions are examined in more detail below.

This section is intended to serve as a guide for a reader trying to better understand the key policy questions that underlie existing technical evaluations of RA and that must be addressed before engaging in any new evaluation of the long-term reliability of the power system.

What it Means for Oregon

Oregonians have long enjoyed a very reliable, relatively low-cost (and low carbon emitting) power system compared to many other parts of the country. As described in RA 101, the Northwest Power and Conservation Council (NWPCC) annually develops a long-term regional assessment of RA that evaluates the adequacy of the region's power supply five years in the future.[2] The goal of the NWPCC's RA assessment is to "establish a resource adequacy framework for the Pacific Northwest to provide a clear, consistent, and unambiguous means of answering the question of whether the region has adequate deliverable resources to meet its load reliably and to develop an effective implementation framework."[3] Individual utilities in Oregon often use the NWPCC analysis as an input into their own evaluation of RA for their systems, because they (and their regulators) are responsible for ensuring that they have adequate capacity to meet the demand of their customers.

Utility Resource Planning in Oregon

All electric utilities engage in some version of electricity supply planning to ensure the continued delivery of safe, reliable, and affordable power to customers across Oregon. Every several years the state's IOUs, for example, file Integrated Resource Plans (IRPs) with the PUC. These plans are developed with significant stakeholder input and focus on resource actions over an approximately 4-to-5-year time horizon. According to the PUC, the IRP is intended to present the utility's current plan to meet the future energy and capacity needs of its customers through a "least cost, least risk" combination of resources, inclusive of supply- and demand-side measures.[4] The PUC does not pre-approve proposed actions in an IRP but instead will "acknowledge" a proposed action, which serves as a factor in the PUC's later review of the prudency of individual investments.[5]

Many of the state's COUs also engage in a similar type of electricity supply planning process, subject to the review of their governing boards. A significant number of Oregon's COUs ("full requirements" customers) rely entirely on BPA for all of their power needs.[6]

It is through these types of integrated evaluations of future resources and demand that utilities in Oregon identify a need for additional capacity resources to maintain an adequate power supply. For more on the latest regarding recently filed and under development IRPs from the state's largest electric utilities, see the following:

Portland General Electric: Integrated Resource Planning

PacifiCorp: Integrated Resource Plan

EWEB: Electricity Supply Planning

Meanwhile, the Northwest Power Pool is currently developing a program that is expected to formalize a short-term regional assessment of RA for the northwest that would be contractually binding on individual participating utilities and load-serving entities.[7] Those entities would voluntarily join the program, but then would have a contractual legal obligation to procure their apportioned share of capacity resources necessary, as assessed by the NWPP, to maintain overall regional RA in the short-term (from a period of days and weeks to months).[8] The NWPCC's regional assessment would still provide complementary, valuable insight into the long-term adequacy of the power supply in the northwest.

The existing NWPCC RA assessment answers the three policy questions described above by applying its evaluation to the entire northwest, adopting a 5 percent loss of load probability risk metric (more details below), and evaluating RA on an annual basis. Any program developed by the NWPP or another jurisdiction would similarly need to address those three key policy questions before undertaking a technical analysis of the adequacy of the power system.

Regional Evaluation of Resource Adequacy

> "While utility portfolios are typically designed to meet specified resource adequacy targets, there is no single mandatory or voluntary national standard for resource adequacy. Across North America, resource adequacy standards are established by utilities, regulatory commissions, and regional transmission operators, and each uses its own conventions to do so. The North American Electric Reliability Corporation (NERC) and the Western Electric Coordinating Council (WECC) publish information about resource adequacy, but have no formal governing role."
>
> E3, *Resource Adequacy in the Northwest* (2019) [9]

There is no one size fits all approach to how regions evaluate the adequacy of the power system. The following provides an overview of some of these approaches, which will serve as a foundation for the analysis of the key policy questions that follow:

Pacific Northwest

- Regional Assessment: The Northwest Power and Conservation Council (NWPCC) conducts an annual regional assessment of RA to evaluate the adequacy of capacity resources in the region to meet forecasted future demand for electricity for the next 5 years. The goal of this assessment is to "establish a resource adequacy framework for the Pacific Northwest to provide a clear, consistent, and unambiguous means of answering the question of whether the region has adequate deliverable resources to meet its load reliably and to develop an effective implementation framework."[10]
- Utility Specific Assessment: Consumer-owned utilities, investor-owned utilities, and their regulators in the northwest look to the annual assessment from the NWPCC to inform their own capacity planning analyses. The regional analysis from the NWPCC is influential, but does not impose any legal or contractual obligations upon specific utilities to procure new capacity resources should a regional deficit be identified. Each utility, with its regulators, determines whether it needs to procure additional capacity.

California

- Statewide: The California Public Utilities Commission imposes binding RA obligations on all jurisdictional Load Serving Entities, including IOUs, Energy Service Providers (independent power producers serving direct access customers), and Community Choice Aggregators (CCAs enable local governments to procure electricity for retail customers living within their jurisdiction). The CPUC program is designed to ensure that new resources are added to the grid in the specific areas needed by the California Independent System Operator (CAISO). Each LSE is required to make annual and monthly filings to demonstrate compliance with its RA obligations.[11]

Southwest Power Pool

- Southwest Power Pool (SPP): SPP covers portions of 14 states, stretching from northern Texas to North Dakota's border with Canada.[12] SPP evaluates RA across this wide geographic region, mostly served by vertically-integrated utilities, and identifies a need for capacity across individual regions and sub-regions for the summer peak season. It then allocates a portion of the responsibility for delivering this identified capacity need to individual utilities. The utilities either supply that capacity with utility-owned resources or secure capacity via bilateral contracts, a process which is overseen by and enforced by local regulators (either Public Utility Commissions or local public power governing boards).[13]

PJM Independent System Operator

- Reliability Pricing Model: PJM covers all of New Jersey, Delaware, Pennsylvania, Maryland, Washington D.C., Virginia, West Virginia, Ohio, and portions of six other states. The PJM Independent System Operator manages a capacity market known as the Reliability Pricing Model. The RPM is designed to send forward price signals that incentivize the retention of existing capacity resources, and the development of any new capacity resources necessary to "support the reliability and stability of the electric grid" to meet consumer demand.[14]
- RPM Auctions: While PJM is considered by many to operate a capacity market, it still relies on an administrative determination of need for new capacity resources. PJM develops a capacity market demand curve in a way that is designed to procure a certain amount of capacity at each price point on the curve. Where that administratively-determined curve intersects with the supply of capacity available in the RPM auction will determine the price and the quantity of the capacity that is cleared through the market. PJM designs its capacity market demand curve such that it is intended to procure enough capacity to meet, but not substantially exceed, the region's target planning reserve margin.[15]

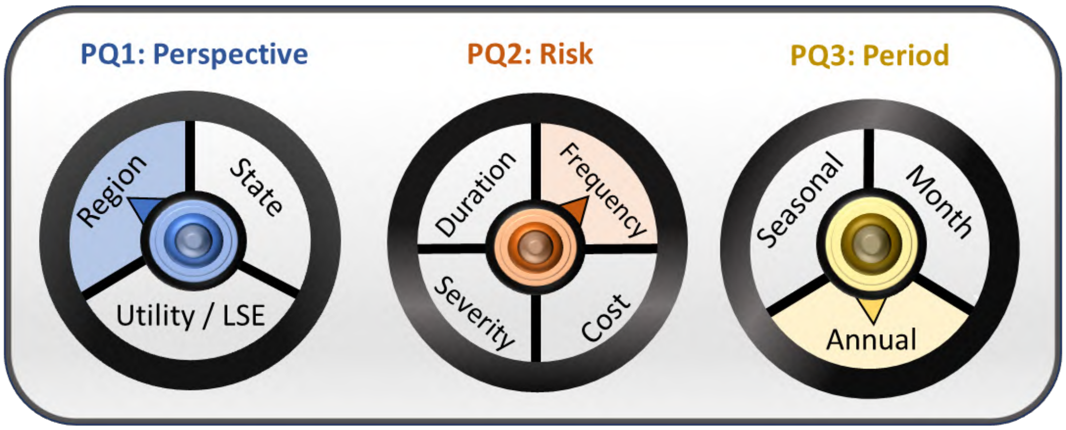
Texas

- Energy-Only Market: The Electric Reliability Council of Texas (ERCOT) manages the state's electric transmission system and operates electricity markets for 90 percent of the state.[16] Rather than having either utility-specific administrative capacity targets or a capacity market to drive the procurement of new capacity resources, ERCOT has adopted a very high cap on prices in its energy market ($9,000/MWh) instead. Developers should theoretically be willing to enter the market with new capacity resources if prices in the energy market are high enough for a sufficient number of hours.[17] ERCOT's energy-only market design, however, has failed to achieve its targeted level of reliability in five of the last ten years.[18]

Key Policy Questions

As described above, a utility or a region must evaluate several key factors (e.g., load forecast, weather conditions, supply constraints, climate impacts, etc.) to ascertain whether there is likely to exist a shortfall of capacity needed to meet forecasted future electric demand. In many respects, these are primarily *technical* considerations.

Based on a review of different approaches to RA across the country, three key policy questions (PQ) stand out as foundational to establishing a framework within which a technical evaluation of RA can occur. The graphic below represents these three policy dimensions as dials, each of which can be adjusted separately. An entity can ultimately maintain a reliable power system regardless of how these questions are answered, but how they are answered can have a substantial impact on the portfolio of resources needed to maintain an adequate system and the costs of that system. This graphic appears throughout this section to help explain the key policy questions involved in evaluating the adequacy of the power system to meet future electric demand.



Each of these three policy questions is explored in more depth below, including an identification of how different regions of the country have set these dials in establishing their respective RA programs. While some of the pros and cons of different approaches are identified, this section does not make any recommendations on specific settings for any of these policies.

Policy Question 1 – Perspective

The first key policy question involves defining the boundaries around the geographic area to be assessed for RA. Evaluating RA across multiple utilities over a larger geographic footprint can be more efficient as it allows those utilities to essentially pool their risk to benefit from a diversity of customer demand and availability of supply. On the flipside, this expanded geographic approach creates a potential hazard of overestimating the resources that utilities in other regions will actually have available to share and could result in failing to develop enough capacity resources locally. Developing mechanisms or processes to share more accurate information (e.g., around potential transmission constraints or time delineated resource and load information) across regions can help to mitigate against these types of hazards.

Historically, vertically-integrated electric utilities would develop, own, and operate adequate generating capacity to meet the future electric demand of their customers. If utility-owned resources were inadequate to meet all needs, utilities would sign contracts for additional output from other resources. This essentially remains how investor-owned utilities maintain resource adequacy in the northwest today. For example, Oregon's investor-owned utilities, with oversight from the PUC, evaluate the adequacy of their available capacity resources (including market purchases and imports) to meet forecasted future need, then secure additional resources as necessary. For the state's consumer-owned utilities, the situation is somewhat different, primarily because nearly all of them rely heavily (exclusively in many cases) on the delivery of power from BPA to meet their customer's needs.

Some states (e.g., California and New York) have developed statewide RA programs that encompass multiple utility service areas. As described above in the California example, state regulators evaluate RA statewide and identify capacity targets that each utility is responsible for meeting through capacity procurements to contribute their share to the overall RA of the state's electric system.

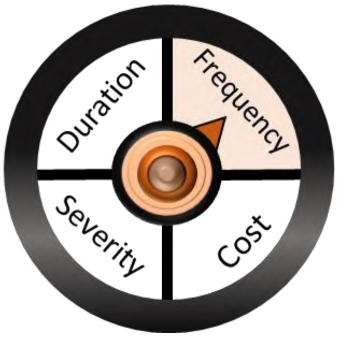
Many other regional electric systems operate within Regional Transmission Organizations (RTO) or Independent System Operators (ISO) that encompass multiple states. PJM and SPP, mentioned above, are examples of this type of an arrangement. In these cases, RA is evaluated across the multi-state regional footprint of the RTO or ISO, but also considers more local evaluations of adequacy.

There are several key considerations for policymakers when choosing the altitude or perspective at which to evaluate RA. Ultimately, a prescribed level of long-term power system reliability can be achieved under a variety of circumstances for a cost. Historically, Oregon utilities have evaluated RA across their own service territories for their cost of service retail customers (see the Resource Adequacy 101 for a discussion of the impact of customer choice programs on maintaining RA). Utilities in other areas of the United States, however, have often found engagement in a more structured RA program across a broader geographic area to be more cost-effective. Policymakers need to consider how the perspective for assessing RA can impact the cost to electric ratepayers of having a reliable power system.

- **Resource Diversity:** Some resources (such as hydropower or solar) might be more abundant in certain geographic locations than others. How much benefit can be gained by giving individual utilities access to capacity resources across a broader geographic region to benefit from the diversity of the output of different resources?
- **Load Diversity:** Similarly, some areas within a state or region might have significantly different weather from one another that results in substantive differences in the demand for electricity between those areas. Coastal areas of Oregon, for example, have milder weather and flatter demand for electricity than in areas of Eastern Oregon. How much benefit can be gained by allowing utilities to benefit from this diversity of load when evaluating resource adequacy?
- **Resilience:** Much of the electric generating capacity in Oregon today exists along the Columbia River, from the Bonneville Dam east to Hermiston. Those resources deliver power over long distance transmission lines to serve electric demand in the Willamette Valley, coastal areas, Southern Oregon, and beyond. Are there advantages to having more capacity resources

dispersed across a broader area to improve the resilience of the power supply within specific load pockets?

Policy Question 2 – Risk



How different regions of the country evaluate RA at the utility, state, or regional level was reviewed above. In each case, a specific RA standard must be applied against which the adequacy of capacity to meet future electric demand is measured. Due to the challenges associated with predicting future conditions, any RA standard will necessarily incorporate elements of uncertainty or risk.

The first development of a long-term power reliability target that's based on a probabilistic expectation of the inability to serve load a certain number of hours per year is often credited to Giuseppe Calabrese's *Generating Reserve Capacity Determined by the Probability Method*, published in 1947.[19] [20] In the decade that followed, several other technical papers were published in the industry that seemed to settle on a long-term reliability standard of "1-day-in-10-years" (or 2.4 hours per year) as being reasonable.[ii] According to a recent paper on the topic by the National Association of Regulatory Utility Commissioners,[21] those papers from the middle of the last century, while converging upon this standard, did not provide a basis of analysis for *why* this standard was appropriate. Following its formation in 1968, the North American Electric Reliability Corporation (NERC) identified this long-term reliability standard for the industry and it was subsequently adopted by most regions of the country.[22] Some variation of this standard remains a popular risk metric for evaluating RA today, although different utilities and regions apply alternative metrics which will be reviewed in more detail below.

Some variation of a "1-day-in-10-years" standard has long been established as the default long-term reliability metric for the electric industry. Several studies over the last decade, however, have called into question whether this standard is still appropriate, particularly given changes to the electric system from variable output renewables and the emergence of battery storage technologies.[23] [24] [25] [26] This standard has also been questioned due to the overall cost of maintaining the level of capacity necessary to meeting the standard. For example, the Brattle Group found that less than 1 percent of customer outages nationally are caused by inadequate generating capacity, while the remainder are primarily caused by outages on the transmission or distribution system.[27] This paper does not take a perspective on whether one risk metric or another is more appropriate for evaluating RA. The intention is to put this type of a risk metric into context, along with the other policy considerations involved in developing a comprehensive assessment of RA.

Ultimately, this policy question requires deciding: what tolerance for risk do we have when it comes to having inadequate capacity available to meet electric demand under certain future conditions? What are the key factors influencing this tolerance for risk?

[ii] This means planning the power system such that a combination of factors combine to result in inadequate generating capacity being available to meet electric demand no more than 1 day in every 10 years. Another way to state this standard would be no more than 24 hours in 10 years, or more simply, no more than 2.4 hours in 1 year.

Existing Approach in the Pacific Northwest

As described above, the NWPCC develops a regional assessment of RA in the northwest that many individual utilities use to inform their capacity procurement decisions. To develop that assessment, the NWPCC has adopted an RA standard based on a Loss of Load Probability (LOLP) metric of 5 percent. LOLP is a metric designed to approximate the acceptable probability, or the risk, of having inadequate generating capacity available to meet future electric demand.

The NWPCC's adequacy model performs a chronological hourly simulation of the northwest power system's operation thousands of times for a single future operating year, under a wide range of possible future conditions (e.g., temperature-sensitive demand, economic growth, wind and solar output, forced resource outages, and river flow conditions), and records each simulation in which at least one event occurs in which inadequate generating capacity is available to meet electric demand. To achieve the 5 percent LOLP standard requires the region to have enough modeled capacity available such that this inadequacy only occurs in 5 percent or fewer of the annual simulations. If that inadequacy occurs in more than 5 percent of simulations, the NWPCC can estimate the magnitude of the inadequacy by assessing how much additional incremental modeled capacity is necessary to return the region to 5 percent LOLP.

These model simulations are dependent on several highly uncertain inputs, such as forecasting economic growth and electric demand over a four-state region, or precipitation patterns and the impact on hydropower output. The uncertainty of these variables creates risk, which is why the NWPCC runs thousands of permutations to evaluate how the power system performs under even the worst-case combinations. The uncertainties of these key inputs, however, are not the types of risks that we consider here. Instead, we focus on the level of risk inherent in the application of the 5 percent LOLP standard itself compared to alternative metrics for evaluating RA.

Key Characteristics of Risk Metrics for Evaluating Resource Adequacy

The 5 percent annual LOLP metric used in the northwest is one among several different standards used to evaluate RA. In this instance, the metric measures the probability (or likelihood) that the region will experience at least one resource inadequacy event during the year being analyzed. The 5 percent LOLP, therefore, translates into the likelihood of at least one resource inadequacy event occurring in 1 year out of every 20.

The most commonly used risk metrics in the electric sector to evaluate RA focus on one of four key characteristics: frequency, severity, duration, or cost.

- **Frequency:** The loss of load event (LOLEV) metric measures the number of expected inadequacy events per year, where an inadequacy event is defined as a contiguous set of hours in which resources cannot meet demand. Although the NWPCC's adequacy standard is based on the annual LOLP metric, the NWPCC also calculates LOLEV along with metrics that measure the magnitude and duration of potential inadequacy events (see below). **Does our risk tolerance change based only on the potential frequency of inadequacy events across a year?**
- **Severity:** Another consideration concerns the severity of events when the region lacks adequate generating capacity to meet demand. The Expected Unserved Energy (EUE) metric measures the expected amount of unserved energy per year, in units of megawatt-hours. This

metric along with the LOLH (described below) are the adequacy metrics that NERC reports in its biannual probabilistic adequacy assessment publication.[28] NERC also reports normalized EUE, which is simply the expected unserved energy divided by the expected (weather-normalized) annual load, in megawatt-hours. The NEUE allows for the comparison of the severity of adequacy events across regions with vastly different sized loads. **Does our risk tolerance change whether a capacity inadequacy impacts delivery of energy to 1,000 residential customers for 24 hours, or 100,000 residential customers for 1 hour, or a single large customer for 4 hours?**

- **Duration:** The Loss of Load Hours (LOLH) metric measures the expected duration, in hours, of inadequacy events. NERC has standardized the definition of the adequacy metrics highlighted in this document (along with other less commonly used metrics) in a technical reference published in 2018.[29] **Does our risk tolerance change whether a capacity inadequacy lasts for 10 minutes, 10 hours, or 2 days?**
- **Cost:** Another consideration across any of these metrics involves cost. The more stringent a utility or a region makes its resource adequacy standard, the more it will need to invest in capacity resources to ensure that it minimizes the risk of inadequacy. The costs for these investments will ultimately end up recovered by utilities through customer rates. An uncommonly used metric in the United States is the Value of Lost Load (VOLL) that attempts to quantify how much customers are willing to pay to avoid having their demand for additional energy go unserved. The VOLL can be used as a measure of whether new investment in capacity resources is necessary.[iii] In other words, new capacity resources should be acquired only if their cost is *less than* the VOLL that would result from an inadequacy event. It should be noted, however, that VOLL by itself is not an adequacy metric and decision makers do not choose what the VOLL is – it is defined by customers. However, VOLL can be used to aid in adopting thresholds for other adequacy metrics. **Does our risk tolerance change depending on how much customers are willing to pay for higher levels of resource adequacy?**

Determining which of these characteristics is most important to electricity consumers is an important consideration when developing an RA program. Depending on which metric is selected, it can ultimately result in a more-or-less reliable power system, but it can also result in a more-or-less expensive power system. However, defining an adequacy standard need not be limited to using a single adequacy metric. For example, a much more robust standard would use all three metrics described above to set limits on the size, duration, and frequency of potential inadequacy events.[30]

Planning Reserve Margin

After using a probabilistic analysis—one that incorporates a distribution of possible outcomes for key variables—to identify a capacity target needed to maintain a selected RA standard, that amount of capacity can be compared to the system's historic peak demand. The *Planning Reserve Margin (PRM)* is a simple shortcut that has historically been used for this purpose in the electric sector to approximate how much capacity in excess of expected peak demand (often based on an historic evaluation of median peak demand) is needed to maintain an adequate power system:

[iii] An implied VOLL can also be derived post facto from the application of another RA standard. Irrespective of that existing standard, current levels of investment and actual occurrences of resource inadequacy can be used to calculate an implied VOLL associated with maintaining current RA levels.

$$\textbf{Planning Reserve Margin} = \frac{\textbf{Capacity (MW) Needed to Maintain RA} - \textbf{Expected Peak Demand (MW)}}{\textbf{Expected Peak Demand (MW)}}$$

An application of the various probabilistic risk metrics described above to achieve a prescribed level of RA tends to result in a PRM in the range of 12 to 20 percent, although there can be wide variations in exactly how the PRM is calculated.[31] As a rule of thumb, this margin should allow approximately enough headroom in the system to account for unplanned outages of generators and historically unprecedented load excursions. The PRM is often reported as an easy-to-understand metric of how much "excess" capacity the system requires to maintain an adequate system.

Why not just use a Planning Reserve Margin?

Given the simplicity in calculating a PRM, one might wonder why not exclusively apply a PRM metric (e.g., evaluate historic peak demand, then simply add 12 to 20 percent) to ensure the adequacy of the power system? The main argument against this practice concerns the real-world complexity of the power system and the deployment of new technologies, such as high penetrations of variable output renewables, the adoption of EVs, and more dynamic demand-side resources.

The key technical questions introduced in Table 1 above highlight this complexity, including consideration of variability in both the availability of power supply and customer demand throughout the year. Given the wide range of potential outcomes to these questions and the distribution of the likelihood of any particular outcome occurring in a given year, the use of the PRM as a deterministic planning guide has significant limitations.

The use of a more sophisticated probabilistic evaluation, on the other hand, allows policymakers to have a much more robust understanding of how the power system is likely to perform under a wide range of future conditions. This understanding gives them better insight into the risk of a future combination of events (e.g., perhaps a combination of low water flow in the rivers that reduces hydropower output, combined with unusually divergent temperatures driven by climate change and an unplanned outage of a large thermal generator) leading to an inadequate amount of generating capacity being available to meet electric demand.

Policy Question 3 – Time Period

The third key policy question to consider when determining how to assess RA across a utility or a region involves the time period evaluated. In an ideal power system, one might imagine that all capacity resources could be available to operate at full output during every hour of the year (or 8,760 consecutive hours). The reality, of course, is significantly more complicated.

> "Because it maintains an annual design, PJM effectively imposes the same reliability requirement in both the summer and winter seasons even though winter peak load is substantially lower . . . Ignoring that reality means that summer-only capacity cannot participate without being matched with an equivalent amount of winter-only capacity. This results in inefficiently little reliance on summer-only resources, and inefficiently high procurement of annual capacity."
>
> NRDC, *Opportunities to More Efficiently Meet Seasonal Capacity Needs in PJM* (2018) [32]

Many, but certainly not all, thermal plants (e.g., coal, gas, and nuclear) are capable of operating near full output for most hours of the day and months of the year. But even thermal plants require downtime for routine maintenance and are subject to unplanned outages that can take them offline for days, weeks, or longer.

Hydropower projects, which dominate the power system in the northwest, can meet a significant amount of the region's capacity need on any given day. That said, these projects are energy-constrained because of their dependence on natural water flows that fluctuate (sometimes by a large degree) based on temperature, precipitation patterns, and season. Other types of renewable energy, like wind and solar, also have variable output, but can still contribute to the region's capacity need. A common method for assessing the capacity contribution of renewables is the evaluation of the effective load carrying capability (or ELCC) of the resource, which allows for a comparison of the coincidence of the variable output of the renewable resource with the power system's net capacity need.[33] The ELCC of a particular type of resource is not static and can change over time due to changes in the net capacity need, driven either by changes in load or the capacity contributions of other existing resources on the system.

On the flipside, peak demand for electricity can also look quite different from season-to-season, and even from hour-to-hour, depending on the time of year. Increasingly, net demand can also present a significant challenge given the need for fast-ramping supply resources that can accommodate significant changes in the output of solar power on the system over the course of several hours.[iv] Power planners need to assess RA in a way that ensures adequate capacity is available despite these variations in supply and in demand across different time periods. As a result, the time period

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[iv] Net demand or net load refers to the total electric demand on the system net of what can be met by output from variable renewables like solar. As solar penetration grows, these changes in net load can become dramatic in the early morning (as solar output rises) and early evening (as solar output declines) and may require grid planners to acquire fast-ramping, flexible resources to maintain adequacy.

evaluated for purposes of maintaining adequacy could have a significant impact on the suite of capacity solutions identified.

Three different time periods for evaluating RA are:

- **Annual:** Many regions of the country evaluate resource adequacy on an annual basis. Planners will apply an RA standard (described in more detail above) to evaluate how often during a given year there is expected to be inadequate capacity available to meet demand.
- **Seasonal:** An alternative approach would be to evaluate RA on a seasonal basis. Such an assessment might find that one season is more likely than another to have the conditions present to create an RA issue. Given the ability of some resources (e.g., solar) to contribute more to capacity during some seasons than others, this has the potential to have a significant impact on the identification of capacity solutions.
- **Monthly:** A third, more granular approach would be to evaluate resource adequacy on a monthly basis. Similar to the seasonal evaluation, this could potentially narrow the time period further during which potential resource adequacy issues are most likely to occur. For example, if climate change results in reduced river flows as the summer months progress, perhaps RA issues will become more prevalent in August than in June.

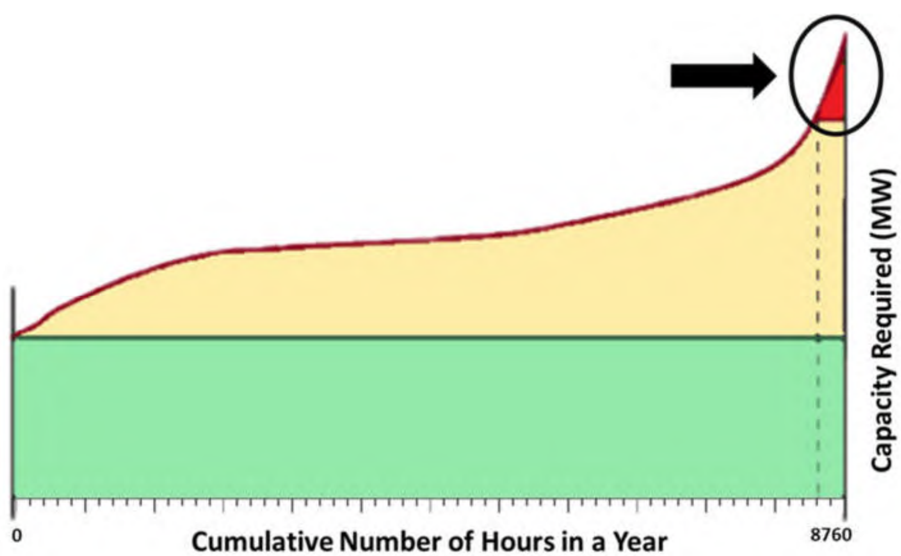
Note, however, that these time periods for evaluation can be, but need not be, mutually exclusive. The annual peak demand for a particular region may still occur in the summer months, for example, but the region may find its greatest capacity need exists in another season due to the particular characteristics of their system.

Conclusion

When Oregonians flip a light switch or plug-in an electric car, they have come to expect that the electricity they need will be there. For the vast majority of the hours in a given year, the power system can meet this need without much difficulty because the system is necessarily built to meet customer demand during those few hours (or days) of the year when peak demand occurs. What does this look like? Figure 1 depicts a graph of a hypothetical annual load duration curve that illustrates the point.

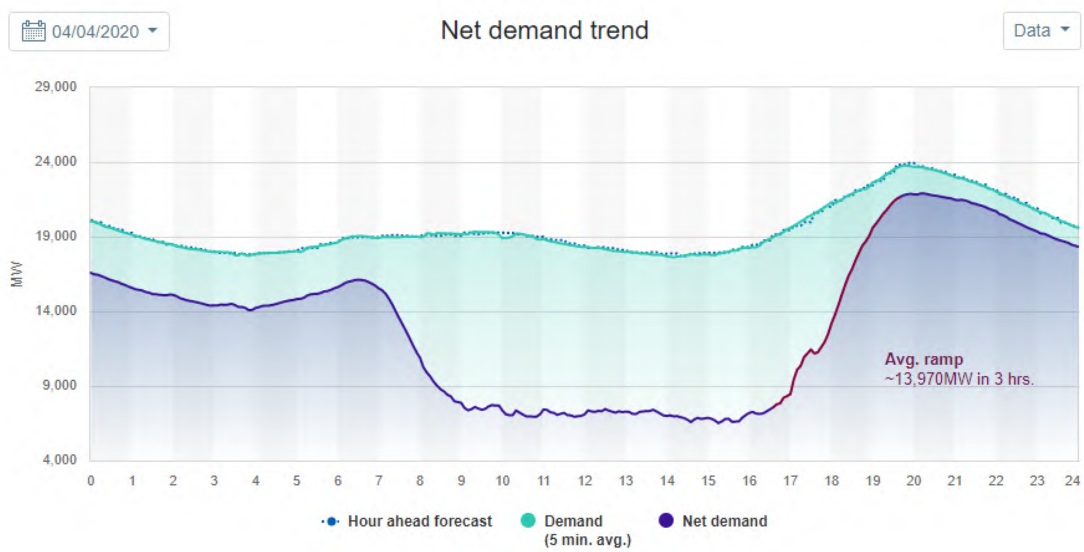
The evaluation of RA is often focused on the area circled in black here—those relatively few hours (or days) of the year when the capacity required to meet demand is the greatest. Utilities and grid planners must plan for capacity resources to be available to deliver electricity to customers when those times arrive.

Figure 1: Hypothetical Annual Load Duration Curve



Meanwhile, net demands on the system can present a related but different challenge for maintaining the adequacy of the power system. Consider the net demand load curve in Figure 2 from CAISO on April 4, 2020 which illustrates the impact of large penetrations of solar power on maintaining adequacy:[34]

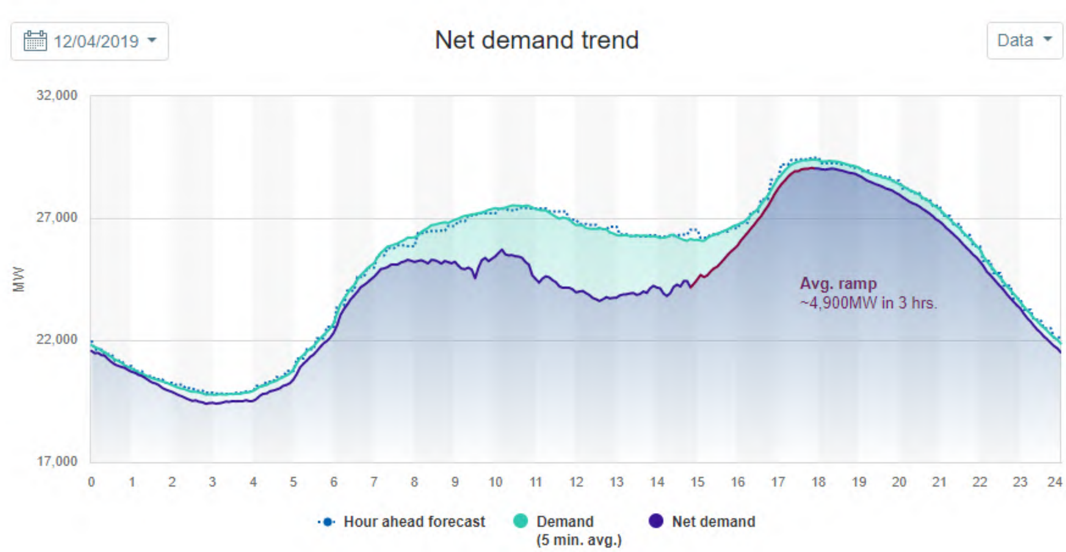
Figure 2: Net Demand Load Curve from CAISO in April 2020



On this day, the peak demand of 24,000 MW occurred around 8:00 p.m. So while grid planners needed to ensure that the system had adequate capacity to meet that 24,000 MW of peak demand (plus reserves), they also had to ensure that the system had adequate flexibility to quickly ramp up output from its non-renewable capacity resources by nearly 14,000 MW in the span of just three hours.

Now consider the same net demand curve from CAISO exactly four months earlier on December 4, 2019. Peak demand on that day was approximately 30,000 MW (or 25% higher than the day shown above) and occurred around 6:00 p.m., yet the ramp need of the system was significantly less at just under 5,000 MW in three hours (or only about 35% of the ramp needed on the day shown above):[35]

Figure 3: Net Demand Load Curve from CAISO December 2019



This section has identified several of the key technical considerations involved in evaluating the adequacy of the power system to meet these peak demands (and increasingly net demands) and explored in detail three key policy questions underlying this technical analysis. There are no right or wrong answers to these questions when evaluating RA, but as noted previously, different answers can result in different solution sets, or potentially different costs for maintaining the same level of adequacy of the power system.

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Policy Brief: Advanced Metering Infrastructure (Smart Meters)

Smart meters – also referred to as Advanced Metering Infrastructure or AMI – enable two-way communications between an electric utility and the meter at the customer's site. These meters can provide near real-time information about the customer's energy consumption and establish the capability for utilities and electric devices to communicate with each other. Information is transmitted using radio frequency waves over secure networks. While similar, AMI is not the same as automatic meter reading (also referred to as AMR), which enables radio frequency communication from the meter to the utility, but does not provide real-time consumption data or two-way communications with a utility. Electric utilities may use both types of metering, but many water and gas utilities also use AMR, including all three Oregon gas utilities.[1 2 3]

Benefits of AMI

AMI is a technology that provides sub hourly information on energy consumption and paves the way for improved management of the grid in the future. This detailed electricity consumption data not only provides information to the customer about their usage, it also provides more refined data to utilities. Utilities can use this information to manage their systems to be more resilient, reliable, and cost-effective. In Oregon, AMI is already used by utilities to communicate with some residential thermostats to control loads.

AMI is a prerequisite for "smart grid" development. Many appliances are now available that can be managed via an AMI interface, including air conditioners, dishwashers, electric car chargers, and hot water heaters. This interaction between electric devices and the utility is part of the development of a smart grid – a grid system in which utilities are able to communicate with generation equipment and electrical devices to manage electricity generation and electricity demand.

This communication with smart devices can enable utilities to optimize their operations. Wide-spread use of these smart appliances will encourage states to develop or adopt standards for smart appliances. Oregon is taking a leadership role in smart appliance standards following Governor Brown's Executive Order 20-04, through which ODOE is updating energy efficiency standards for products and adding a requirement for smart grid-ready electric water heaters.[4] Development and adoption of these standards will ensure Oregon is well positioned to realize future benefits of smart appliances and smart metering infrastructure.

Oregon is updating energy efficiency standards for some appliances and products, including smart grid-ready electric water heaters.

Many utilities already benefit from AMI they have deployed. AMI can send customer consumption information directly to the utility, eliminating the need to dispatch trucks and staff to manually read meters. These cost savings are significant and are passed onto utility customers through their rates.

Spotlight: Oregon Utilities Embrace Advanced Metering Infrastructure

Emerald People's Utility District provides electricity services to about 22,000 customers in the Eugene-Springfield area. In 2019, Emerald PUD finished installation of new smart meter/advanced metering infrastructure (AMI) technology for its customers. The smarter system benefits customers by supporting faster outage restorations, expanded payment options, and improved account management tools. The meters also help the utility prevent future outages by giving staff better insight into the performance of the electrical system with regular data transmissions.

Central Lincoln People's Utility District provides electricity services to about 55,000 customers on the central Oregon coast. Central Lincoln incorporated an AMI system that has been fundamental to improving reliability and resilience in day-to-day operations. Employees are able to view meter data on handheld devices and operators can determine system status from the substation to the customer meter.

After a disaster, having eyes on the system to the meter level means that crews can be directed to specific prioritized outages resulting in more timely repairs and reduced outage times. Central Lincoln will continue to use AMI data to optimize its systems including the communication network that it relies upon to operate. With the AMI system, Central Lincoln is in a position to integrate distributed energy resources as they come available including solar, wind, biomass, battery storage, and wave energy.

Smart meters enable additional financial and operational benefits beyond the immediate savings associated with automated meter reading. Utilities can use the detailed consumption information to better manage local grid needs, especially in planning for maintenance and upgrades. AMI also provides important information to customers about their electricity use, which customers can use to monitor and adjust their electricity consumption to reduce their overall costs.

AMI plays a valuable role in adoption of onsite energy resources, such as rooftop solar and battery storage, by improving utility operations and planning. Onsite generators can help increase the resilience of a customer's home or business and may support utility grid operations. Given the likely future adoption of more rooftop solar, home energy storage, advanced load controls (e.g., smart thermostats), and electric vehicles, it is likely that smart meters will continue to support smart grid developments and enable more benefits for customers in the years ahead.

Learn more about energy storage in the Technology Review section of this report.

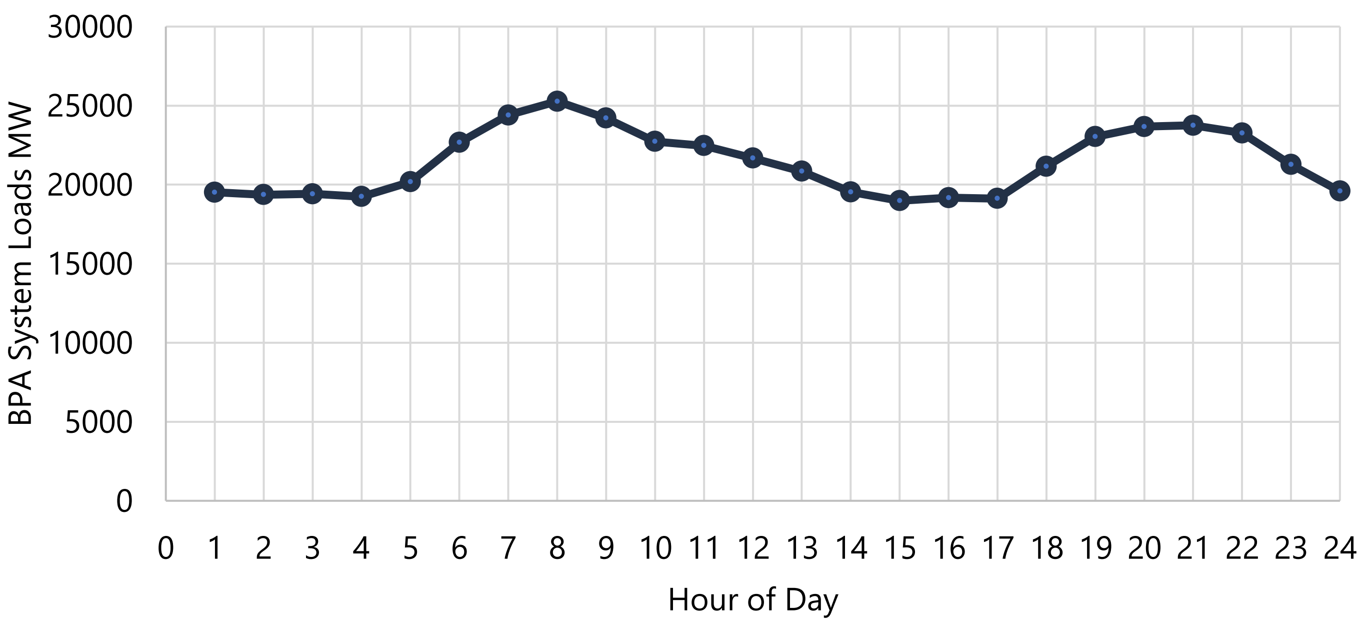
AMI in Oregon

Smart meters and smart grid advancements enable more efficient and reliable operation of grid generation, transmission, and distribution systems. Benefits include more efficient transmission of electricity, quicker restoration of electricity after power disturbances, and increased security.[5] The detailed load data provided by smart meters supports better utility planning and more responsive operation of conventional power plants.

With smart meters, utilities can not only track how much energy is consumed by a customer, but also when that energy is consumed. Two significant programs offered to customers by some utilities are time-of-use rate schedules and direct load control. Time-of-use schedules enable customers to pay different prices for their electricity depending on the time of day that it is being used. Rates are usually more expensive during peak load hours for the utility and less expensive when demand for electricity is lower. Similarly, direct load control is a demand response strategy that enables a utility to control – with that customer's express permission – the electricity used to power smart devices during periods of high demand (e.g., turning up a customer's smart thermostat by 1 or 2 degrees during a heat wave that's putting stress on the electric grid). Reductions in peak loads translate to savings in utility operations, deferred investments in new generation, and ultimately lower costs for customers.

Time-of-use rates are designed to address specific electric load profiles that change depending upon the utility. For example, Con-Edison in New York has peak pricing from 8 a.m. to midnight, when daytime loads are highest.[6] Conversely, Pacific Gas & Electric in California offers lower electricity costs throughout the middle of the day, when abundant solar electricity generation is available, and higher costs into the evening hours when solar generation declines. As a result, Pacific Gas & Electric charges peak rates from 4-9 p.m.[7] In the Northwest, a typical load profile includes both a morning and evening peak in the cooler months and single evening peak in the summer months. Figure 1 demonstrates the load profile on the Bonneville Power Administration's system in March 2020.

Figure 1: Bonneville Power Administration Total Transmission System Load (March 25, 2020)[8]



Time-of-use rates have not been used much in the Pacific NW because the region's hydropower system and other resources have traditionally provided sufficient capacity to meet peak loads. However, some Oregon utilities are using time-of-use pricing and direct load control to provide financial incentives to customers who shift electricity consumption to off-peak periods. For example, Portland General Electric offers the following optional time-of-use pricing to residential customers.[9] As shown in Table 1, the peak pricing periods coincide with the typical daily peaks demonstrated in the chart in Figure 1 above.

Table 1: PGE Residential Time-of-Use Energy Pricing

Time-of-Use	Winter (Nov. 1 – April 30)	Summer (May 1 – Oct. 31)	Energy Charge
On-Peak Period	6 – 10 a.m. M-F 5 – 8 p.m. M-F	3 – 8 p.m. M-F	12.38 cents per kWh
Mid-Peak Period	10 a.m. – 5 p.m. M-F 8 – 10 p.m. M-F 6 a.m. – 10 p.m. Sat.	6 a.m. – 3 p.m. M-F 8 – 10 p.m. M-F 6 a.m. – 10 p.m. Sat.	7.051 cents per kWh
Off-Peak Period	10 p.m. – 6 a.m. every day 6 a.m. – 10 p.m. Sun. and specified holidays		4.128 cents per kWh

The time-of-use rates in Table 1 are available to residential customers of PGE and represent an opportunity for cost savings. For example, if a customer wishes to charge an electric vehicle, they can pay 43 percent less by delaying charging until after 8 p.m. or 67 percent less by delaying charging until after 10 p.m. Customers of Idaho Power in Oregon may also realize bill savings by enrolling in the "Oregon Time of Day" plan.[10] Similarly, residential, commercial and irrigation customers of Pacific Power may save money with Oregon Time of Use pricing.[11]

PGE has also established a Direct Load Control pilot, which provides financial incentives to homeowners who participate.[12] Participants must have a smart meter and smart thermostat that can be controlled by PGE. When additional electricity resources are needed, PGE will notify program participants of an approaching load control event in advance, allowing participants to opt out of the event if they wish. If the participant does not opt out then PGE can communicate with the thermostat to adjust the temperature for the duration of the high load event, usually lasting no more than a few hours. Load control events may reduce cooling loads in the summer months or heating loads in the winter months. Though small on an individual basis, the combined electricity savings from multiple customers may be large enough to help the utility meet demand without procuring more expensive capacity resources.

Smart meters also support the addition of more distributed energy resources on the grid. For example, in Oregon there are more than 16,000 residential rooftop solar facilities totaling more than 80 MW of capacity.[13] Each one of these homes may export energy to the grid during the day and consume energy from the grid throughout the night. Smart meters can enable monitoring of homeowner consumption and onsite generation, ensuring the distributed solar resources are optimally integrated into the grid. Smart meters also support the integration of more large-scale renewable energy facilities through improved data and utility planning.

Electricity system reliability can be strengthened with smart meters through enhanced detection and management of power outages and remote control of individual customers to manage loads. Utilities can respond to power outages faster because AMI enables them to pinpoint the outage location. AMI also helps utilities ensure that power outages remain localized and do not have a domino effect across the grid by enabling utilities to isolate affected customers from the rest of the grid until the problem can be resolved.

Smart Meter Adoption

Despite the rapid widespread adoption of smart meters, and the many benefits that these types of meters enable for the utility and customers, some customers have identified potential concerns with their use. These concerns tend to fall into one of two categories:

- **Privacy:** Some customers have raised privacy concerns regarding the amount of data on their energy usage that smart meters collect and transmit. This concern includes not only the granularity of the data that utilities will be collecting, but also the potential for the data to be captured and collected by others. Utilities protect the privacy of the data by using secure networks to transmit smart meter data.
- **EMF radiation exposure:** Other customers have raised concerns about potential adverse health effects from electro-magnetic frequency (EMF) radiation emitted by smart meters. EMF radiation is common, with sources including motors, electric blankets, microwave ovens, computers, WiFi, cell phones, Bluetooth, and power lines.[14] Multiple studies have refuted meter-related EMF concerns, including Lawrence Berkeley National Laboratory's Smart Grid Technical Advisory Project, which found that "EMF radiation levels from advanced and smart meters do not pose a health hazard."[15]

To address customer concerns about privacy and EMF radiation, most utilities around the country offer customers the ability to "opt out" of smart meter service. Many utilities, including those in Oregon, are finding that very few customers choose to opt out. As of August 2018, Pacific Power had installed over 440,000 smart meters in Oregon and PGE had installed more than 775,000.[16]

Most utilities charge a fee for customers to opt out of AMI programs. The fees are designed to offset the actual cost to the utility of dispatching trucks and staff to manually read meters at these customer locations. Before the advent of smart meters, this was the only way to read meters, so the cost of this service was shared across all utility customers. If the utility were to charge less than its actual costs to provide this manual meter reading service, then the costs of that service would be subsidized by other utility ratepayers who choose not to opt out. Customers who wish to opt out of smart meter programs can contact their utility to determine the costs.

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Policy Brief: How Utilities Are Assessing and Managing Electric Cars on the Grid

Electric vehicle adoption is increasing in the light-duty passenger vehicle sector. As of July 1, 2020 there are 31,977 EVs registered in Oregon, and that number continues to grow.[1] In 2019, the Oregon Legislature passed Senate Bill 1044,[2] which established EV adoption targets for passenger vehicles, including:

- 50,000 registered EVs by the end of 2020
- 250,000 registered EVs by 2025
- 25 percent of registered vehicles and 50 percent of vehicle sales by 2030
- 90 percent of vehicle sales by 2035

Because EVs use electricity for fuel, utilities are already planning for and addressing increasing numbers of EVs on their systems. This discussion will highlight some basic information on potential impacts to the electric grid and how utilities are managing these changes.

Currently, the overall effect of EV charging is not distinguishable from normal fluctuations in electricity load, primarily because EV adoption levels are relatively low. EV growth in Oregon is expected to accelerate as prices for EVs approach those of similar petroleum-fueled vehicles, and as more vehicle platforms like SUVs and pickup trucks become available. As electric transportation fuel becomes a larger portion of the overall load, EV charging may become more obvious in daily electricity load profiles. The cumulative amount of electricity for charging is only one piece of the puzzle as utilities plan for increasing numbers of EVs on their system. Of more importance is *where* EVs are charging and *when* they are charging, which is discussed below.

Understanding customer energy use trends and planning how to serve them is one of the fundamental functions of an electric utility. In the 1930s, the relatively new electricity industry had to plan for increasing adoption of refrigerators, a significant load at the time, as adoption grew from less than 10 percent of U.S. households to over 90 percent in about 20 years.[3] Fast adoption rates of appliances and other equipment that use electricity for power has recurred many times in the last century.

Figure 1: Technology Adoption in U.S. Households, 1931-2017[3]

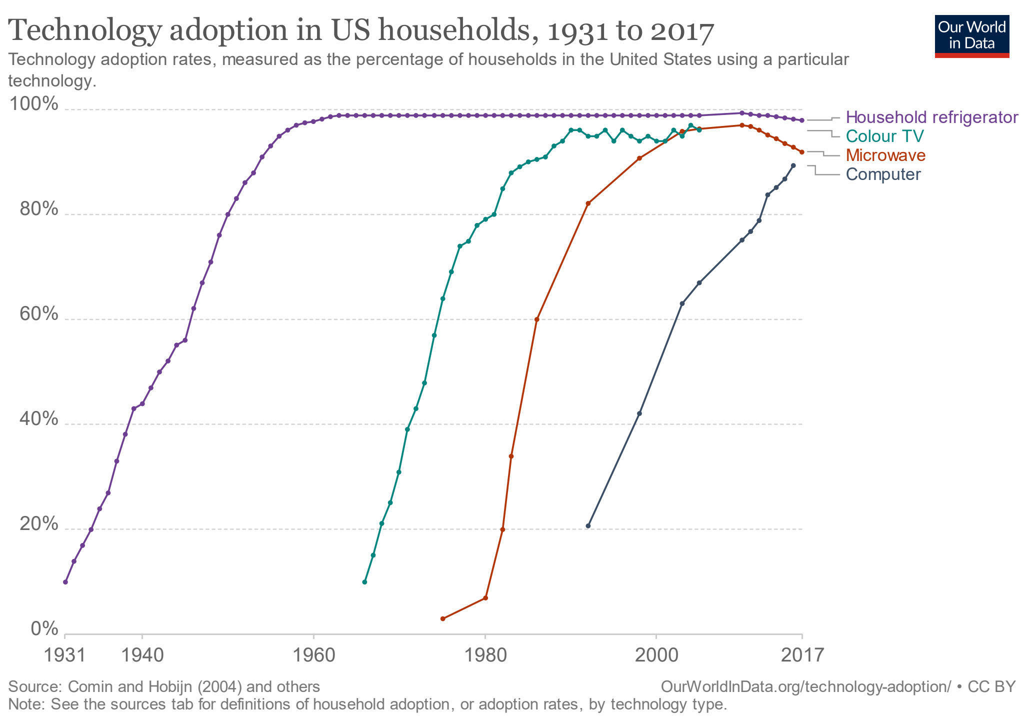
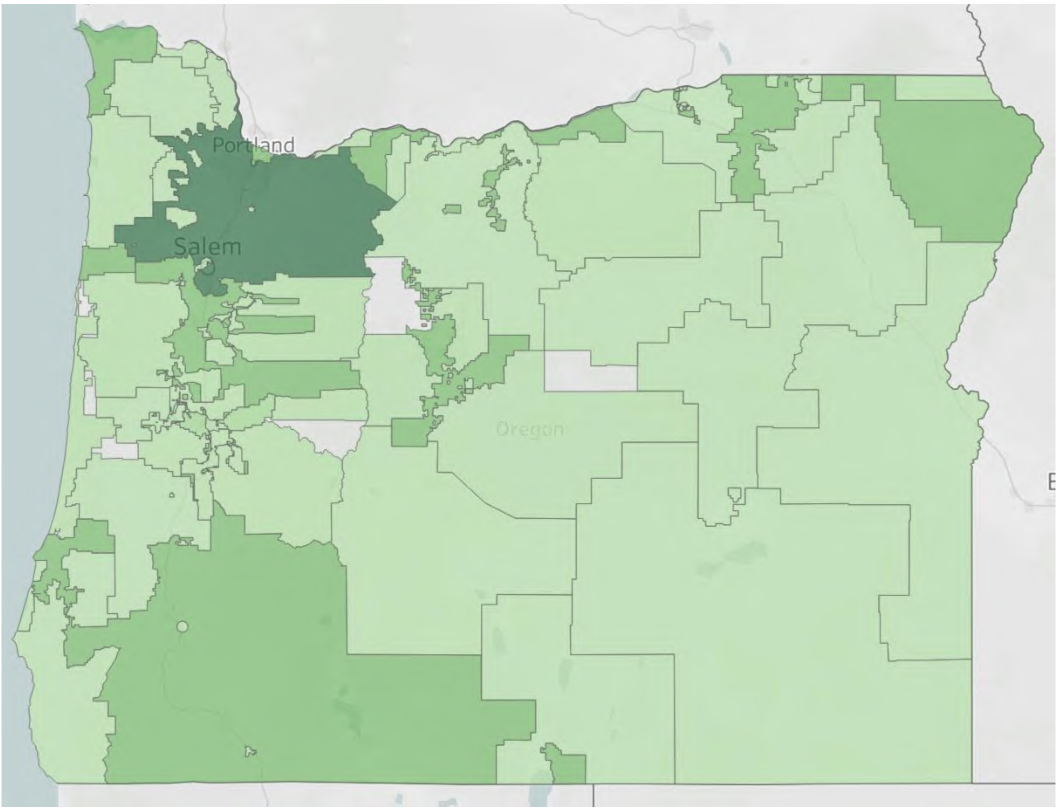


Figure 2: Registered EVs by Oregon Utility Service Territory[4]



Darker shades of green = more registered EVs

Today, Oregon's utilities are preparing for a future with more EVs charging on their systems. Nearly all utilities in Oregon now have EVs registered in their territory.[4]

As EV adoption accelerates, utilities will assess future EV loads and plan for how to accommodate these loads in a cost-effective manner that meets customer needs. As an example, Pacific Power completed an independent study on the overall impact to their systems if the EV market continued to increase at current adoption rates. They provided the results in their Transportation Electrification Plan,[i] which was approved by the Oregon Public Utility Commission in June 2020.[5]

Each utility will assess the specific EV adoption forecasts for their territory. To assess the overall energy required by EVs, ODOE reviewed statewide adoption levels and electricity needs. The estimated amount of electricity needed to charge the current Oregon fleet of EVs is approximately 116,000 MWh per year.[ii] Based on ODOT's DMV Registration Data, there are 31,977 registered EVs and the average efficiency of those EVs is 3.2 mi/kWh (the equivalent to 107.1 MPG). In comparison, utilities sold 50,213,201 MWh to Oregonians in 2019.[6] The current fleet of EVs uses less than a quarter of one percent of the state's electric load.

Using the same method as above, and the EV adoption targets from SB 1044, the state would see the portion of load to meet EV charging needs increase to 5.6 percent by 2030.[7] This oversimplification only illustrates the magnitude at the highest level. Other considerations such as time and location will be discussed later.

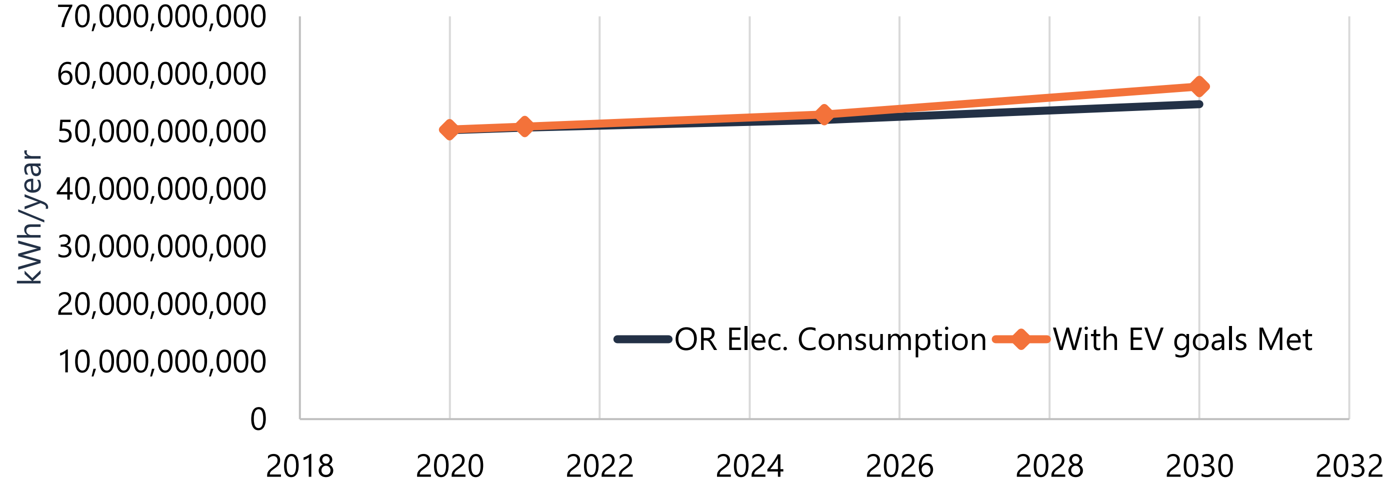
Overall, load impacts on the system are one measurement for utilities to understand the effects of increasing EV adoption. However, as utilities look at this overall load, they must also consider the times EVs are expected to be charging and the places where EV charging will occur. Timing will inform their planning activities around necessary generation resources, energy efficiency, and demand side

[i] Oregon Public Utility Commission Docket UM 2056, Order 20-200.

[ii] Based on 31,977 registered light-duty EVs with an average efficiency of 3.2 miles/kWh and 11,556 average annual miles traveled.

management to meet peak load times. Understanding where EVs will charge has implications for how utilities plan to upgrade and maintain the distribution systems that deliver electricity to consumers.

Figure 3: Electricity Load Needed to Meet EV Targets by Year[7]

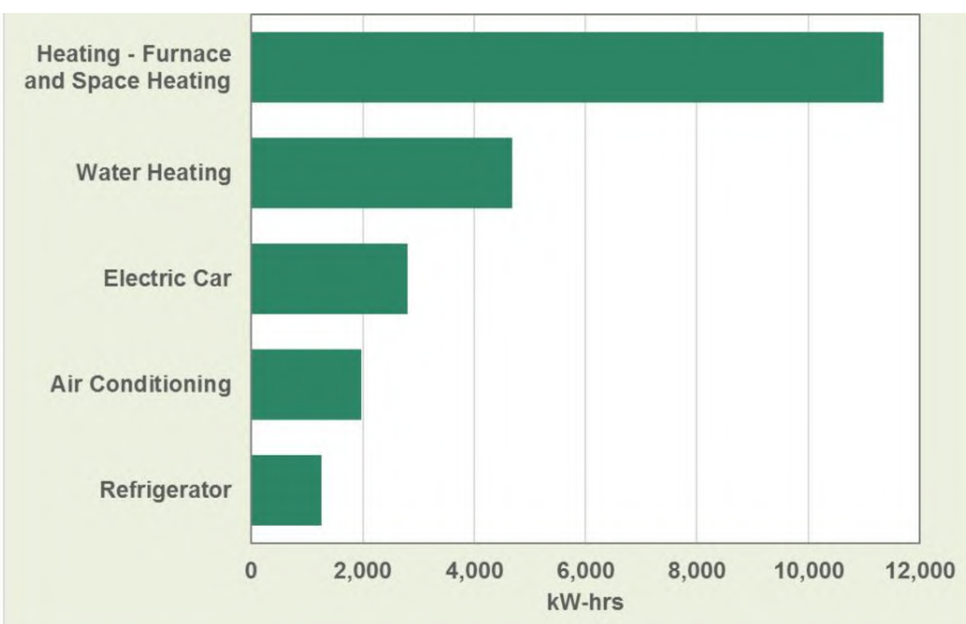


Effects of EVs on Local Distribution Systems

EV loads are not unusually large compared to other consumer loads, such as refrigerators, air conditioners, and hot tubs, in terms of total kWh of electricity consumption. As an example, a Nissan Leaf charging at a home[iii] would require only twice as much energy as a typical refrigerator, and less power than an electric water heater or furnace on an annual basis.

Utilities have built their distribution systems to be able to deliver enough energy to meet simultaneous peak customer demands for electricity, which are often far larger than average customer demands. As a result, a single EV charging on a utility's distribution system is not likely to create problems. More than one or two EVs charging simultaneously in close proximity on the grid, however, can potentially add stress to the distribution system, particularly if charging with more powerful Level 2 chargers. Distribution transformers, which connect every home and business to the distribution grid, are the most vulnerable elements of

Figure 4: Average Annual Energy Use for a Household[8]

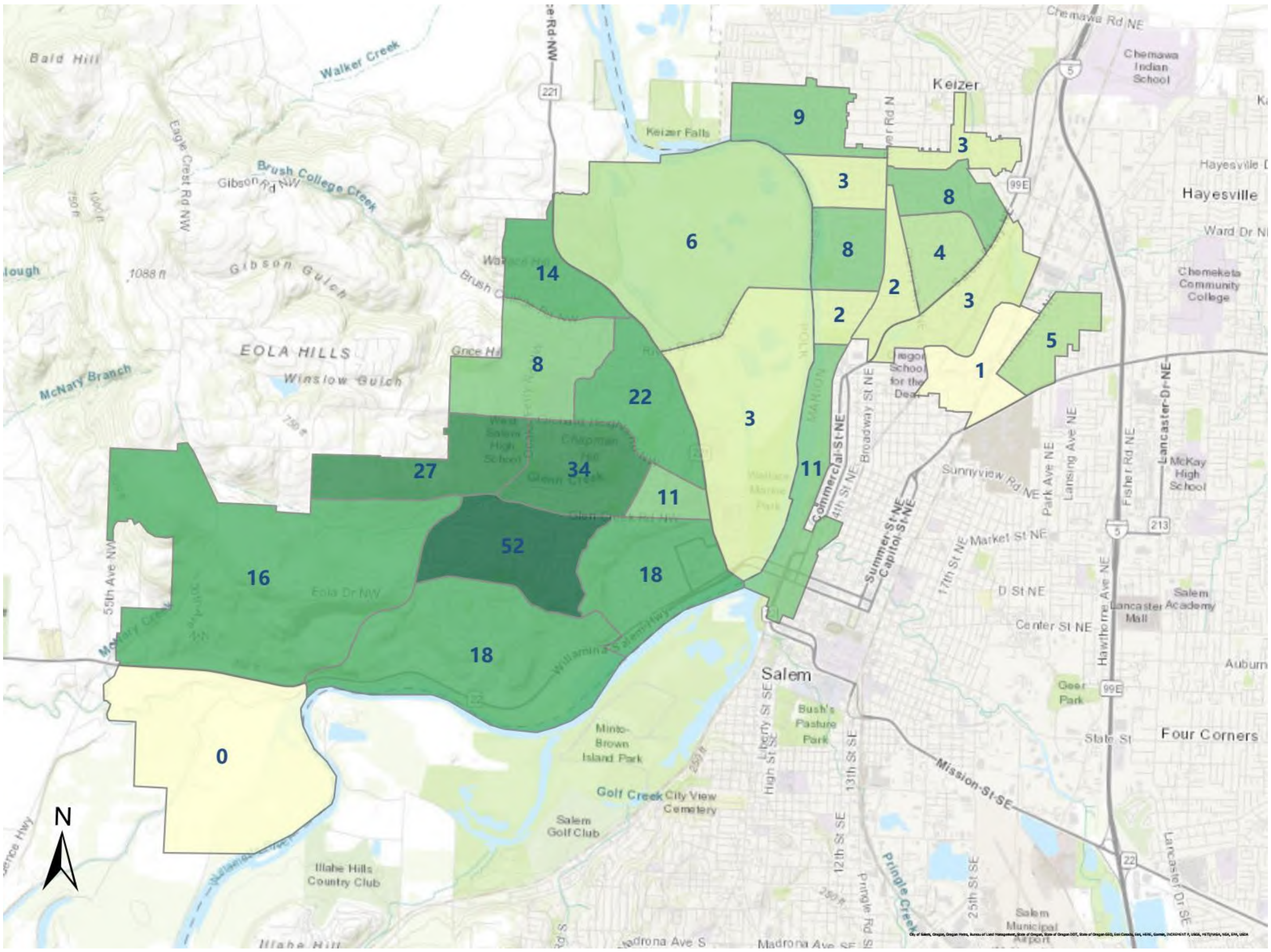


[iii] Level 1 charging (110V).

the electricity distribution system.[9] Most residential transformers serve 10 – 50 kilovolt-amperes (kVA), and an EV charging on a Level 2 system consumes about 7 kVA.[10] Multiple EVs charging on a Level 2 charger could quickly consume much of the transformer's capacity.

Electric utilities are aware of the impact that multiple EVs charging can have on distribution transformers, and often have programs in place to help identify where EVs are located on their system so that they can better plan for necessary upgrades to transformers or other components before new loads become a potential problem. In 2019 and 2020, ODOE collaborated with Salem Electric Cooperative on a pilot project that produced the map in Figure 5 of where EVs were charging in their territory to inform operational and maintenance plans for their system.

Figure 5: Electric Vehicles Charging in Salem Electric Cooperative Territory

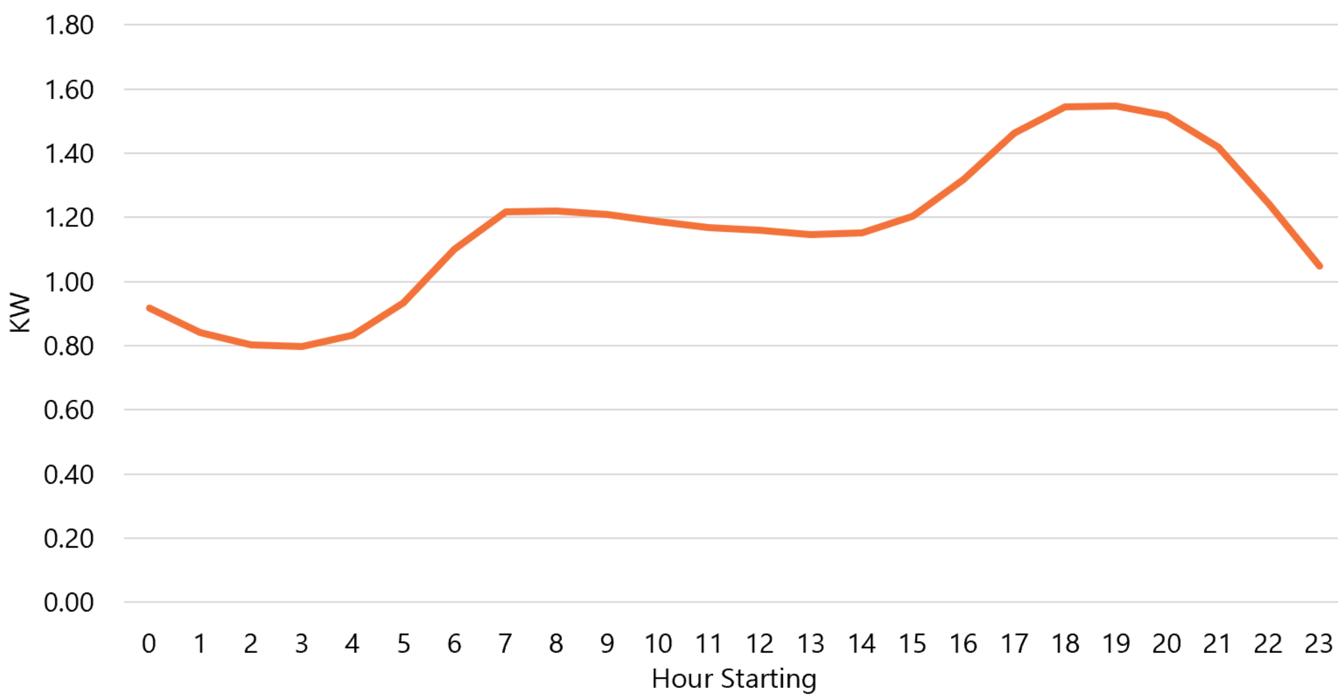


Managing Timing of EV Charging Can Enable More EVs Without the Need for More Electricity Generation

The timing of EV charging is often dependent on how much charge the customer expects to need to accommodate when the vehicle is next driven. Some vehicles may only be driven a few times each day and could potentially be charging when not in use, if chargers are available. Other vehicles, such as delivery trucks or taxis, need to be able to operate for extended periods of time and would require either fast charging while on duty or the ability to charge overnight. Vehicles used for long-distance traveling or for people or businesses that lack their own charging infrastructure may need access to publicly available charging stations, likely higher-powered DC fast chargers. This variability in charging needs provides some flexibility in when EVs are charged. This flexibility can be leveraged by utilities to accommodate the growing amount of load from electric vehicles without requiring the development of additional generation resources.

Electric utilities develop their systems to satisfy the largest requirements for electricity anticipated to occur over the planning timeframe – often from a year to 20 years. This results in an electric generation and delivery system that is, by design, underutilized much of the time. Similarly, consumer demand for electricity fluctuates daily on predictable cycles and patterns – often the most electricity is needed in the late afternoon and evening hours when people tend to return home from work, prepare meals, and engage in activities that use electricity. EV charging can occur at any time of day, but residential charging tends to occur in the evening, coinciding with the daily load peak. Figure 6 shows year-round average residential customer load for 2019.[11]

Figure 6: 2019 Annual Average Residential Hourly Profile[11]



Shifting the demand for charging to later in the evening and overnight would enable the utility to better optimize its current resources to produce the electricity needed and reduce the need for additional generation resources. Figure 7 below shows how peak demand (shown in blue) can be shifted to other hours (shown in gray), thereby accommodating the same amount of electricity demand, but at a later time.

Shifting EV charging to off-peak hours would not only allow more EVs to be added to the roads without significant investments by utilities in new generation, but would also allow utilities to get more use out of existing power plants that may be otherwise underutilized during these times.[12] There are many ways that utilities can encourage customers to shift when they charge their vehicles. For example, EWEB offers incentives for Level 2 charger installation, specifically because this equipment can be programmed to charge at certain times. They have also launched a public education campaign to encourage customers to shift discretionary energy use, like EV charging, to off-peak hours (10 p.m. to 6 a.m.).[13] The following is a review of some of these methods Oregon utilities are using.

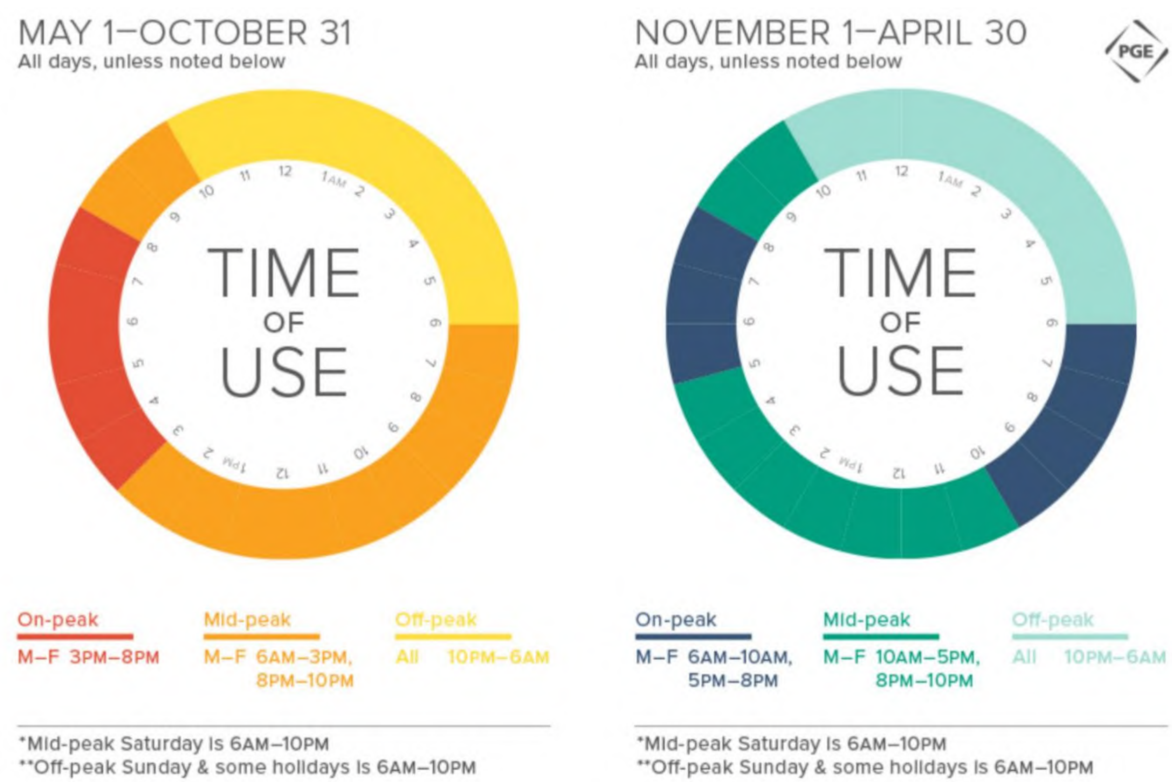
Customer Outreach

Most electricity customers are not accustomed to notifying their utility when they purchase a new electric device or technology. Instead, people simply plug items in and expect the electricity to flow. New EV owners may not be aware that simply programming their vehicle to charge later in the evening could benefit the utility. For this reason, many utilities have offered incentives for customers who purchase EVs or EV charging equipment. In addition to incentivizing EV adoption, use of the rebates establish an individual connection for utilities to inform customers about the benefits of charging in off-peak hours. For example, many Oregon utilities offer rebates on the purchase and/or installation of Level 2 chargers. This benefits customers, who save on the cost of the charger, but also benefits utilities by enabling them to provide information specifically to EV owners. In addition, utilities can better assess their distribution system for any upgrades that might be needed to accommodate the more powerful charger.

Time-of-Use and Incentives

Some utilities provide monetary incentives that encourage shifting EV charging to times when loads are lower, typically the nighttime hours. The most common of these are rate schedules known as time-of-use (TOU) rates. TOU rates offer customers a lower cost per kWh of electricity during off-peak hours, encouraging customers to delay using electricity until these times. Using TOU rates can save EV drivers money. For example, PGE's TOU residential rate for off-peak hours is about a third of the cost of electricity for on-peak hours.[14]

Figure 7: Portland General Electric's Time-of-Use Charts[14]



As more EVs are adopted, however, time-of-use rates may not be the optimal solution for the long term. If a utility sets their cheapest time-of-use rate to being at 10 p.m., it is likely that customers would program their EVs to start charging at that time, potentially leading to a load spike. This will become more pronounced as EV adoption grows. In order to manage this, utilities will need to stagger the onset of charging for the EVs that are on their system.

Managed Charging

Managed charging, often referred to as "smart charging," represents the next evolution of utility EV charging management. Conceptually, it is similar to time-of-use rates in trying to shift charging to off-peak hours, but instead of simply encouraging the EV operator to program charging start times, smart charging affords the electricity provider with limited direct control of the vehicle charging. When the grid operators can control the charging of the EV, it is referred to as Grid-to-Vehicle (G2V). The benefit of this arrangement is that the party in control of the charging has access to historical and real-time data about grid loads, allowing for greater optimization of EV charging. This would also enable the utility to stagger the onset of EV charging to reduce the potential large demand spike that might occur with time-of-use programs.

Taking the managed charging idea further is a technology called vehicle-to-grid (V2G). With two-way communications, grid operators would also have the flexibility to use the large resource of electric vehicles plugged into the grid at any given time to store excess electricity or as a resource to pull electricity when needed to meet short-lived peak demand events. PGE has stated that the company not only plans for capacity to accommodate EV load, but that PGE is also planning for how to utilize EVs to help manage the grid. In addition, PGE is involved with research on how electric vehicles can utilize two-way grid connections, though this technology is in an early stage.[15]

Under a V2G scenario, there are many logistics yet to be worked out, including contracts limiting curtailment or how low the batteries could be drawn down, the effects on an EV manufacturer's warranty, and determining value to grid operations. Utilities are currently studying the other potential applications that would help them better manage the grid.

> "Having EV loads is welcome, because it's environmentally cleaner and helps sustain revenues for utilities."
>
> – Northwest Power and Conservation Council Staff[16]
>
> *The Northwest Power and Conservation Council is responsible for developing regional power plans.*

In the future, EVs could be a beneficial resource for utilities and increase overall capacity. The flexibility of EV charging is a key component for utilities to use in managing this increasing load on their systems. The ability to shift when EVs are charging and ensure that the infrastructure to support where EVs are charging is key.

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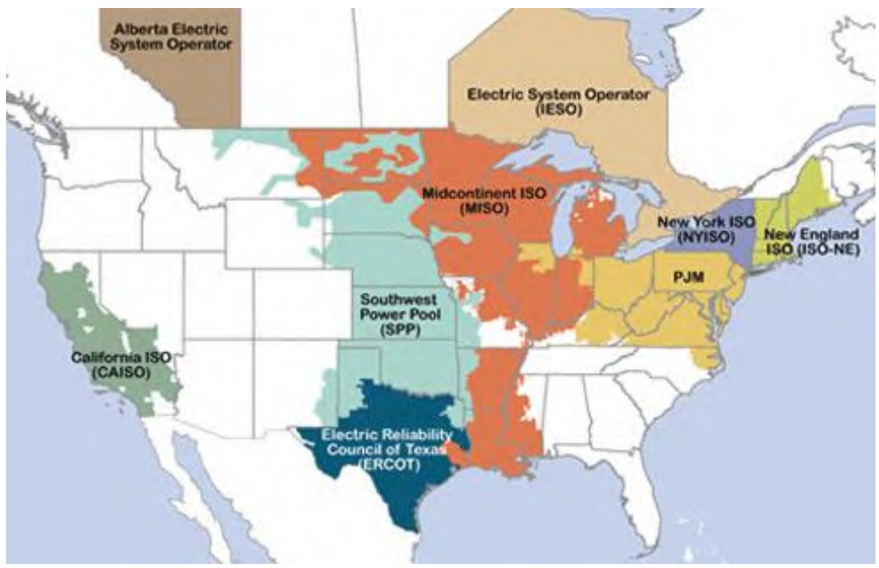
Policy Brief: Evolving Wholesale Electricity Markets

The electric sector is undergoing significant transition marked by accelerating coal plant closures; increasing pressures on the hydropower system in the northwest; rapid expansion in the deployment of variable output renewables, like solar and wind; low natural gas prices driven by new domestic discoveries in recent decades; an emergence of increasingly cost-effective grid-connected battery storage systems; and a growing awareness of and concern for equity in the sector. These changes are combining to drive interest in the evolution of wholesale electricity markets in Oregon and across the west. Utilities are exploring whether participation in broader regional markets can facilitate the integration of renewables at lower cost, help to manage the closure of coal plants and constraints on the transmission system, and support long-term capacity procurement.

Organized Energy Markets in Oregon

Figure 1: ISOs and RTOs in North America



Most wholesale transactions for electricity in the northwest occur via utility-to-utility bilateral transactions, where an entity with a surplus of electricity will sell to an entity with a deficit for a negotiated price. By contrast, most areas of the United States are served by organized energy markets, administered by Independent System Operators (ISOs), or Regional Transmission Organizations (RTOs) that centrally manage the least-cost economic dispatch of available electric generating resources on day-ahead and real-time (or intra-hour) intervals to meet energy need. While individual structures differ, these ISOs and RTOs are also often involved in some level of coordination of long-term capacity planning and procurement. The day-ahead and real-time energy markets can only optimize the dispatch of existing power plants. Capacity planning, meanwhile, dictates what power plants are built and made available for dispatch in the future by the energy markets. In the western U.S., the only ISO operating organized energy markets is the California Independent System Operator (CAISO), which started in 1997 and operates both day-ahead and real-time markets, in addition to playing a central role in long-term procurement of capacity within its footprint.[1 2]

PacifiCorp joined with the CAISO in 2014 to launch the Western Energy Imbalance Market (EIM), a real-time energy market that has generated cost savings for participants, reduced the curtailment of renewables across the west, and facilitated a reduction in GHG emissions.[3] The EIM is the first significant expansion of CAISO's energy markets beyond the state of California, and its membership has grown quickly over the past six years to 11 participating entities, including all three of the investor-owned utilities serving Oregon. Bonneville Power Administration is on schedule for entry by 2022 along with nine additional entities.[4] If all 10 entities currently scheduled to join by 2022 eventually join, 82 percent of electric load in the west will be served by utilities participating in the EIM.[5] The EIM's innovative approach allows these non-CAISO entities to participate in and benefit from the real-time dispatch afforded by the CAISO markets without having to join the CAISO.

How the EIM Works

All utilities, regardless of whether they participate in the EIM or other markets, will forecast their expected demand for energy for each hour or 15-minute increment of the next day (that is, on a day-ahead basis). Because it is impossible to predict future energy demand with precision, utilities continue to adjust those forecasts as the real-time hour approaches, and they need to deliver power to customers. Figure 3, generated by CAISO, shows how the day-ahead forecast might differ from the revised hour-ahead forecast and then ultimately the real-time, actual demand on a given day:[6]

Figure 2: Map of CAISO

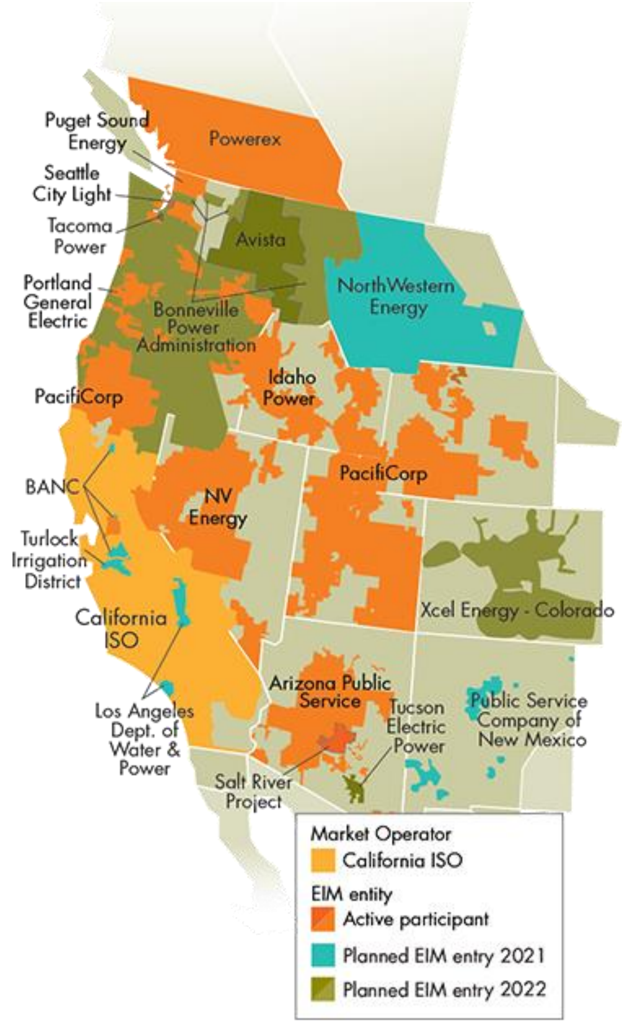
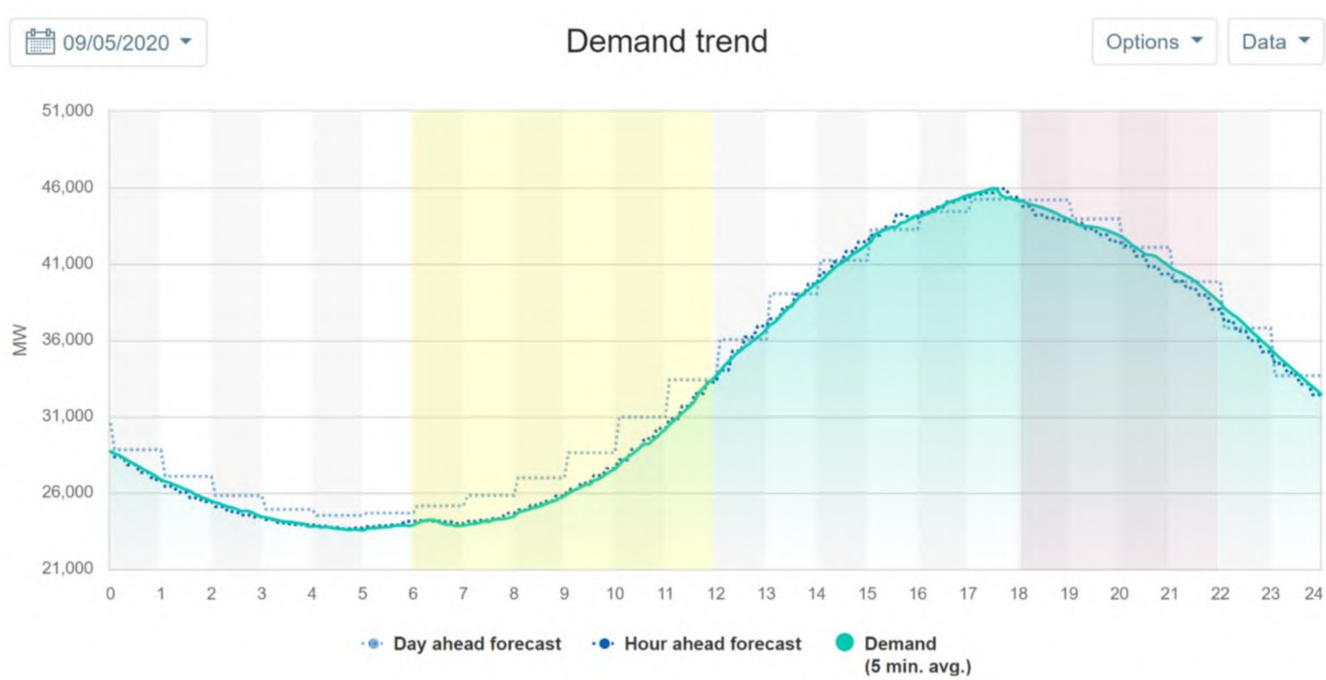


Figure 3: Day-Ahead Forecast (CAISO)



On a day-ahead basis, utilities will need to secure commitments from power plants or other resources to ensure that they can meet their expected demand the following day. Outside of an organized market, like in the northwest, these day-ahead commitments might come from utility-owned resources, long-term contracted resources, or other bilateral market purchases rather than being committed through a market mechanism (such as the case with CAISO's Day-Ahead Market). In the example shown above for CAISO, the hour-ahead forecast came in significantly lower than what had been forecasted on a day-ahead basis for the morning hours (e.g., 6 a.m. to 12 p.m., yellow shaded area). As a result, more units than expected were available to the market to serve demand, likely resulting in lower overall costs by dispatching the least-cost resources needed to meet that actual lower demand and not dispatching higher cost units that had been committed in the day-ahead market.

Slightly harder to discern from the example above, but still evident, is the divergence of real-time demand from the hour-ahead forecast in the evening hours (e.g., approximately 6 p.m. to 10 p.m., purple shaded area). This divergence, or intra-hour variation of actual demand from what had been forecast on an hour-ahead basis, is referred to as an "imbalance." A utility whose actual demand comes in slightly above its hour-ahead forecast will need to buy additional power to serve real-time load. Conversely, a utility whose actual demand comes in slightly below its hour-ahead forecast will be able to sell its additional marginal power to another participant. The EIM offers an optimized real-time market that facilitates the exchange of power in these circumstances.

CAISO manages its own Balancing Authority Area for utilities within its footprint, and in conjunction with the California PUC, ensures that those utilities maintain adequate levels of capacity to ensure a target level of resource adequacy (see the Energy 101 section for more on resource adequacy). It is self-evident that the EIM (as any other energy market) can only dispatch energy to serve load from existing capacity resources. As a result, it is critically important to a well-functioning market that market operators have confidence that there will be enough capacity participating in the markets to actually serve load while providing grid balancing services and other necessary reserves.

However, CAISO (and by extension the EIM) does not have visibility into the long-term resource adequacy of entities outside of CAISO. For this reason, the EIM requires participants to pass a series of resource sufficiency tests to participate fully in the market.[i] This manifests as a requirement for each EIM participant to demonstrate 75 minutes before the start of each hour (e.g., by 1:45 p.m. for the hour starting 3 p.m.) that it has sufficient capacity resources committed to meet its own forecasted demand for that upcoming hour. Only after meeting these sufficiency tests can an EIM participant bid a resource to fully participate in the market for an intra-hour exchange. These requirements ensure that participants with inadequate resources will not be able to "lean" on the EIM to maintain adequate power supply.[7]

The EIM leverages CAISO's real-time operation capabilities to evaluate all resources that participants voluntarily commit to the EIM within each hour to find the least-cost resources to serve load and intra-hour imbalances.[8] An EIM participant may voluntarily commit some or all of its generating

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[i] Note that Resource Adequacy focuses on long-term resource acquisition strategies to ensure adequate future power supplies, whereas the similarly-named Resource Sufficiency Tests (applied by the Western EIM) focus on the short-term management of existing resources and must be met hourly in order to fully participate in the EIM's real-time markets.

resources to be re-dispatched within the EIM (i.e., the commitment for a particular unit might be re-dispatched by EIM to serve another utility's load). This allows for the EIM's real-time optimization to match the least-cost resources with customer demand over 5-minute and 15-minute intervals across a wide region of the western United States.

How the EIM is Governed

The EIM is governed by the EIM Governing Body, an independent five-member board with its authority delegated from the CAISO Board. The current Chair and Vice Chair of the EIM Governing Body have ties to the northwest electric sector.[9] Another important component of the EIM governance structure is the Body of State Regulators (BOSR). The BOSR is an independent educational forum and advisory body to the EIM Governing Board that is composed of one state regulator from each state with a regulated utility participating in the EIM. The BOSR's primary role is to provide a forum for state regulators to learn about the EIM in addition to participating in the selection of the EIM Governing Body members and advising the EIM Governing Body.[10]

After experiencing rapid growth— in numbers, geographic scope, and composition of its participants—in its first five years of operation, an EIM Governance Review Committee (GRC) convened in 2019 to consider evolving and strengthening the EIM's governance structure. The GRC was established as a temporary advisory group to the EIM Governing Body and the CAISO Board of Governors.[11] The GRC concluded Phase 1 of its work with the development of a revised charter,[12] and is currently engaged in Phase 2 focused on substantive changes to the market based on evolutions to date and potential future expansion, such as into a day-ahead market.[13]

A straw proposal published by the GRC in July 2020 identified four key issue areas to be resolved, including: the delegation of authority to the governing body concerning market rules; the selection of governing body members; stakeholder engagement and meetings of the governing body; and other potential areas for involvement of the governing body, including policy initiatives, market monitoring and surveillance, and funding for the BOSR.[14]

Benefits of the EIM

The EIM reports quarterly the gross benefits realized by each of its participating members in the form of lower costs, which as of Q3 2020 has surpassed $1 billion across all participants since 2014:[15]

Table 1: EIM Participants and Cumulative Gross Benefits (2020)

EIM Participants	Cumulative Gross Benefits ($ Millions)
PacifiCorp (Oregon + Non-Oregon territories)	$265.02
Portland General Electric	$98.30
Idaho Power	$74.85
Non-Oregon Participants	$679.84
TOTAL EIM BENEFITS SINCE 2014:	**$1,118.01**

Source: EIM 3Q20 Update (October 29, 2020)

Next Steps

Participation in the EIM by electricity providers in Oregon marks a notable shift in recent years away from historic bilateral power transfers and toward an increased reliance on organized markets for real-time transactions. This trend may accelerate in the years ahead with the development of an Extended Day-Ahead Market (EDAM) which looks to extend CAISO's day-ahead market to EIM participants. Using a similar approach as the EIM's real-time markets, EDAM would allow entities outside of CAISO to participate in CAISO's existing day-ahead market operations without fully integrating into the CAISO.

Wholesale electricity markets in Oregon are likely to continue evolving in the years ahead, marked by three significant ongoing developments: (1) the development of EDAM; (2) BPA's commitment to join EIM; and (3) the development of a regional Resource Adequacy program by the Northwest Power Pool (NWPP).

According to CAISO, the EDAM would be designed to improve market efficiency and lower costs by integrating renewables using day-ahead unit commitment and scheduling across the entirety of the EIM's footprint.[16] There are also potential reliability benefits.[17] While the current EIM facilitates intra-hour exchanges among participants, the EDAM would facilitate transactions in the day-ahead timeframe where significantly larger volumes of electricity are likely to be exchanged. However, these larger volume transactions raise unique challenges, particularly around the evaluation of the resource sufficiency of participants; the provision of transmission capacity to facilitate EDAM transfers; and the allocation of congestion revenues. CAISO staff made initial recommendations for addressing these issues in a straw proposal published in July 2020, but more work remains to finalize the EDAM.[18] The eventual framework adopted by CAISO to reconcile these outstanding issues will affect the potential benefits (and challenges) to participation in the EDAM by electricity providers in Oregon.

As noted above, BPA is currently moving toward joining the EIM. Bonneville signed an EIM implementation agreement with the CAISO in September 2019 and continues to engage with its stakeholders on EIM-related policy issues. BPA expects to address potential implications of participating in the EIM on its transmission and power rates and identify any necessary tariff modifications by Fall 2021, in anticipation of joining the EIM in the first half of 2022.[19]

Expanding Regionalization: An ISO for the Pacific Northwest?

As described here, significant efforts have been taken in recent years to expand the regionalization of competitive wholesale energy markets across the west. How would the formation of a regional Independent System Operator (or ISO) be different?

The EIM provides some of the core functions that a regional ISO would provide, including: [20]

- Compliance with national reliability standards
- 5-minute real-time optimize market
- Centralized competitive energy market
- Optimized geographic diversity of generating resources
- Efficient access to lower cost resources
- Greater transparency in generation data (including greenhouse gas emissions)

- Independent market monitoring

The EDAM would add one key additional function to these: [21]

- 24-hour day-ahead optimized market

Participation in a regional ISO, however, would go even further by providing the following functions that, for example, CAISO provides for its members: [22]

- Independent entity provides open access to transmission system
- Integrated transmission planning by an independent entity
- Competitive solicitation for transmission development
- Lower costs from geographic load diversity

Efforts have been made in the past to explore the development of a regional ISO in the northwest, either as a separate independent entity, or as an expansion of the CAISO. Previous efforts in the 1990s and early 2000s failed due to concerns about potential unfavorable impacts to existing transmission rights in the region, and questions about the costs and benefits of regionalization of transmission systems.[23] In addition, in 2018, legislative efforts in California to pursue the expansion of the CAISO into a regional ISO to potentially include utilities in Oregon and the northwest failed because of concerns that regionalizing the CAISO could hamper California's aggressive clean energy goals or dilute the state's current control over the ISO.[24] [25]

In 2016, Governor Kate Brown expressed her belief that a well-designed regional ISO "could deliver substantial benefits" to Oregon through a more integrated electricity grid, but that it would be critically important "that governance of [the ISO] be independent and represent all the states" of participating utilities.[26] Oregon utilities can continue to accrue significant benefits from participation in the EIM, and its potential day-ahead market functionality in the years ahead, without the need to form or join a regional ISO.

The wholesale market evolutions discussion so far have been concerned solely with the provision of *energy*, but a separate effort is also underway to explore the development of a Resource Adequacy (RA) program in the northwest that would support *capacity* planning over a multi-year time horizon. Currently in Oregon, individual electricity service providers (with their boards and regulators) plan for procuring capacity resources to meet expected future demand for electricity. However, many other regions of the country operate centralized RA programs administered through an ISO or RTO that can provide a more holistic evaluation of RA across a broader geographic region and facilitate the procurement of capacity resources. The NWPP is leading an effort, joined by all three of Oregon's investor-owned utilities and BPA, to develop a regional RA program for the northwest. This effort is ongoing, but is expected to result in the development of a regional RA program framework before the end of 2020, with program implementation to begin in 2021.[27]

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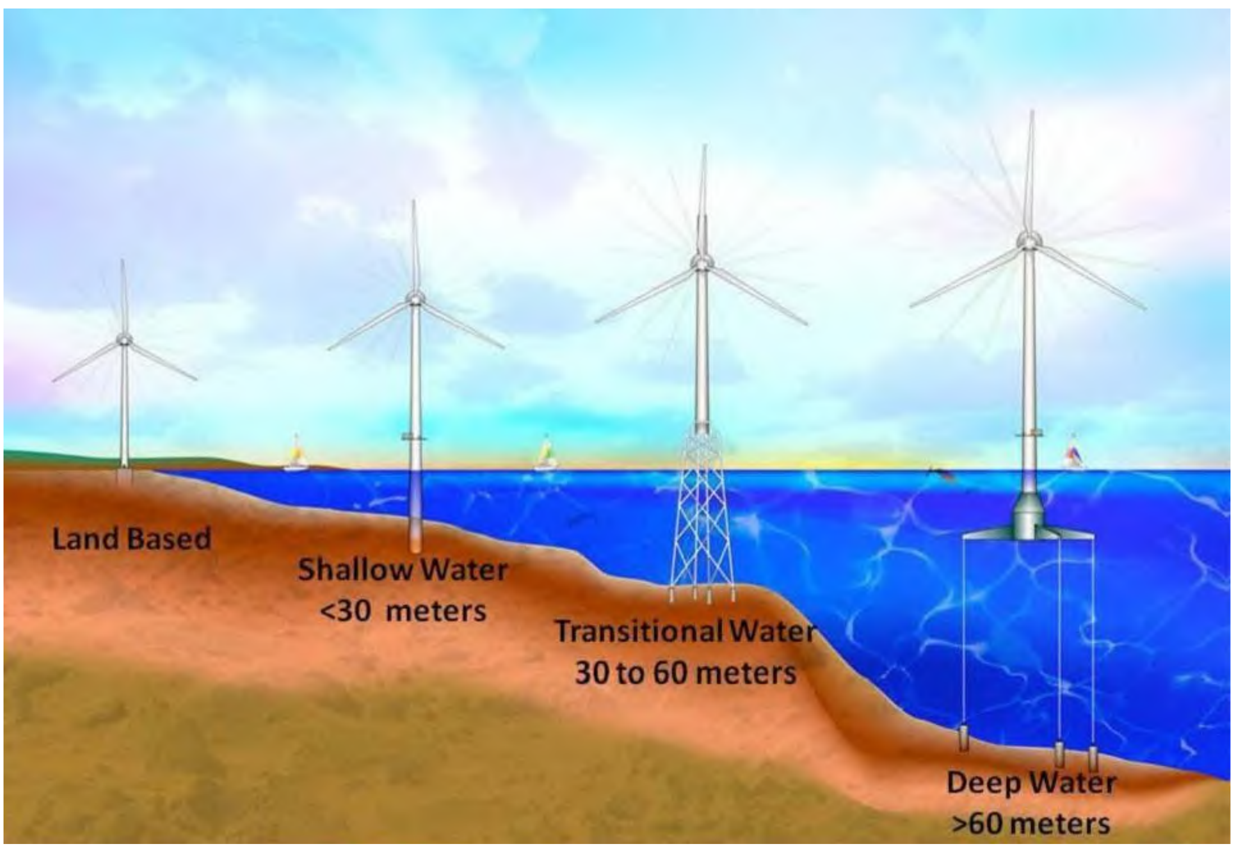
Policy Brief: **Offshore Wind**

Offshore wind is a term used to describe technologies that generate electricity from wind powered turbines located offshore and away from land. The characteristics, materials, and technologies used to construct offshore wind projects are similar to onshore (land-based) wind projects, with a few notable differences.

Costs

Currently, offshore wind is more costly than its land-based cousin. Unlike land turbines, offshore wind turbines must be anchored to the seafloor. In the case of the Oregon coastline, that anchoring is more complex and expensive due to the significant depth of the ocean floor along the coast. To date, nearly all global offshore wind development has been fixed-bottom, which is only feasible in shallower waters (depths less than 60 meters),[1] where offshore wind towers can be directly bored into underwater floors and fixed in place. Deeper waters (depths greater than 60 meters)[2] require even more complicated support systems consisting of anchored, floating platforms that indirectly fix wind towers to a targeted location, but allow for some movement.

Figure 1: Fixed-bottom Foundation versus Floating Offshore Wind[3]



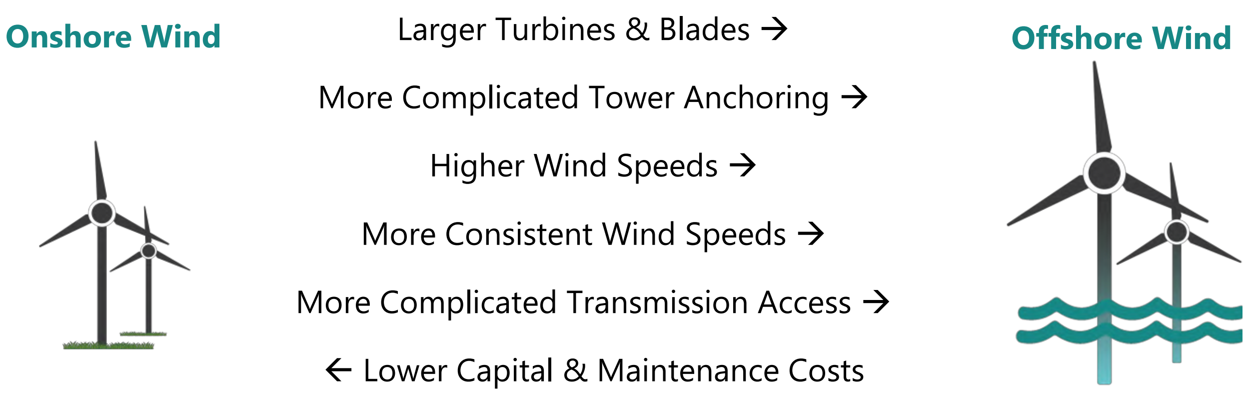
The potential need for significant local transmission upgrades can also make offshore wind more expensive than land-based wind development, which contributes to the overall economic viability of a project. However, offshore wind does have an advantage of economies of scale that can increase economic viability because turbines can be built using higher towers, larger generators, and longer blades than wind turbines built on land. As offshore wind technology matures and costs decline, these economies of scale may enable offshore wind to be more cost competitive in the coming decade. A National Renewable Energy Laboratory study forecast the levelized cost of energy for offshore wind to decline from $74 to $53 per MWh by 2032, which could be cost competitive in some market conditions described in more detail below.[4]

Benefits

Learn more in the Offshore Wind Technology Review

Despite the generally higher costs, offshore wind projects can have several advantages over onshore wind. For example, offshore wind projects can generate larger and more consistent power outputs than land-based wind because offshore wind speeds are generally stronger and more constant. Open ocean surfaces in deep waters far from shore can provide flexibilities that can promote scaling up of floating offshore wind turbines relative to fixed-bottom and land-based wind turbines.[5] In addition, to the extent offshore wind can generate electricity at different times of the day compared to land-based solar and wind resources, offshore wind can add diversity to renewable resource mixes and be used to complement onshore renewables.[6] [7] Offshore wind can also provide more localized generation to coastal communities, which can improve power quality, reliability, and resilience when coastal communities – like many in Oregon – are located at the ends of long radial transmission lines that supply power from distant, inland generation resources. Figure 2 below provides a comparison of offshore wind and onshore wind.

Figure 2: Comparing Offshore Wind and Onshore Wind

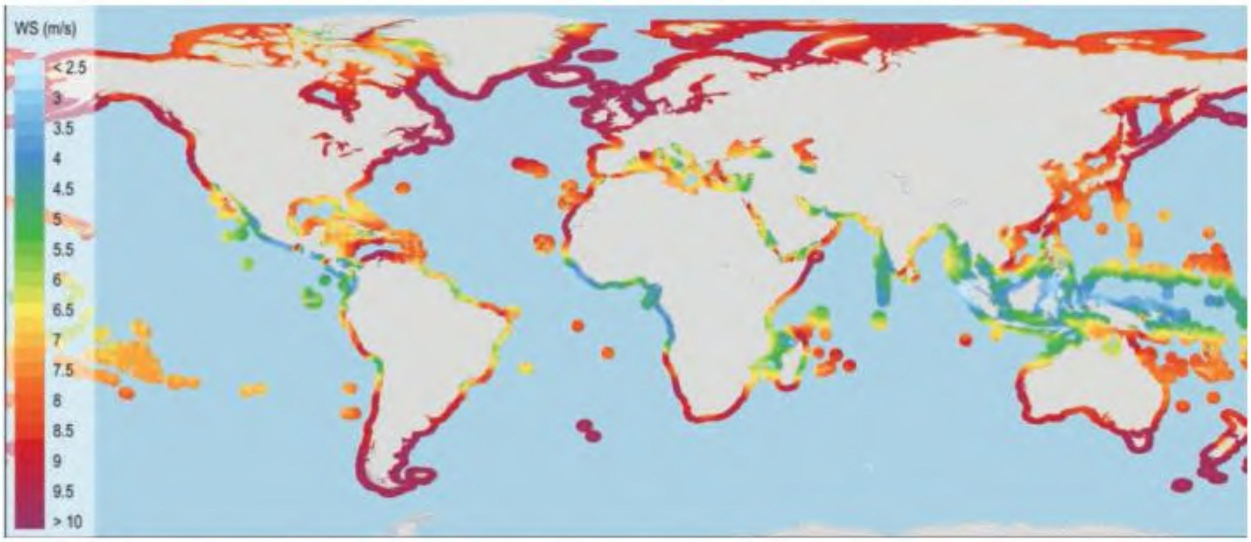


Current State of Offshore Wind

Offshore wind is still in its early days of market penetration because of its higher costs. Global development of offshore wind has largely been limited to fixed-bottom offshore wind in locations near large population centers with shallower waters.[8] As of 2018, the world has 22,546 MW of operating nameplate capacity from 168 fixed-bottom offshore wind projects, compared to only 46 MW from eight floating offshore wind projects, with 30 MW coming from a single floating project near Peterhead, Scotland.[9] As of 2018, there are 4,888 MW of floating offshore wind in the global pipeline of project development, suggesting the construction of floating offshore wind projects may increase in the years ahead.[10]

As of 2018, total offshore wind capacity (fixed-bottom plus floating) accounts for only 0.3 percent of total global electricity supply.[11] Offshore wind does, however, play a larger role in other countries – for example, 15 percent of Denmark's 2018 generation came from offshore wind.[12] A map showing the global potential for total offshore wind (fixed and floating) can be seen in Figure 3 below.

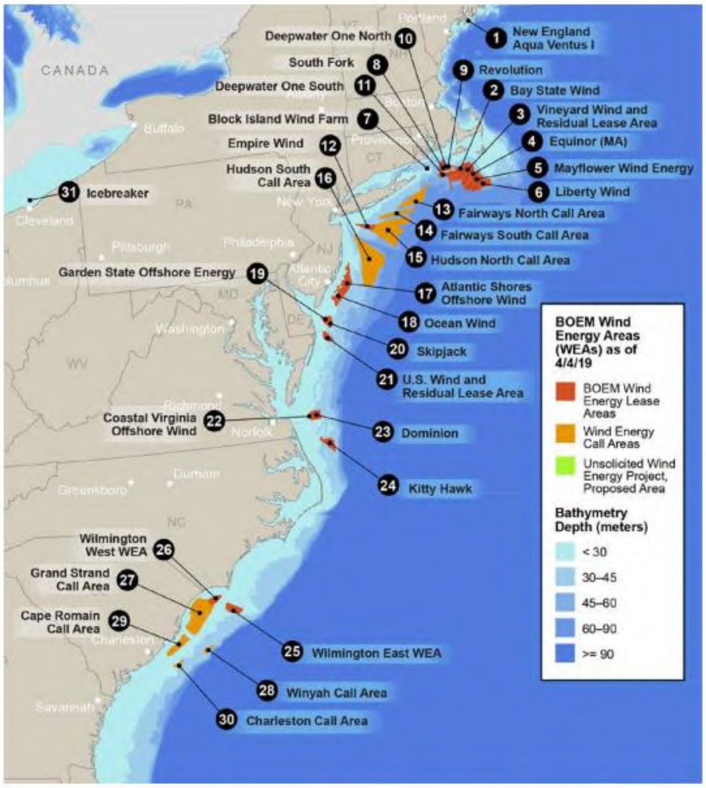
Figure 3: Global Map of Areas w/ High Offshore Wind Speeds (Fixed and Floating)[13]



Floating offshore wind costs are forecasted to fall precipitously over the next 10 years,[14] due in part to scaling up from small, single-turbine pilot projects to larger demonstrations, potential knowledge transfers from fixed offshore wind, and potential automation of the production of floating platforms – with some floating projects already being built where they are cost competitive for some localities (e.g. remote and island locations).[15] [16] As floating offshore wind costs continue to decline, new markets are likely to emerge.[17] The global potential for over 6,950 GW of floating offshore wind capacity has been identified in areas with very strong and consistent wind speeds (i.e. locations with "high energy resource values").[18] In 2015, the Carbon Trust – a leading European offshore wind consultant – forecasted that 80 percent of the entire potential for offshore wind in Europe and 60 percent of the potential for offshore wind in the United States is for floating offshore wind in deep waters.[19]

As of 2018, the U.S. had 30 MW of fixed-bottom offshore wind in the Block Island Wind Farm, the first project operating in state-controlled waters off the coast of Rhode Island.[20] The U.S. Department of Energy identified another 25,794 MW of fixed offshore wind projects in various planning and development stages in the U.S. as of 2018, indicating the U.S. could be poised for significant fixed offshore wind development in the future.[21] For example, in summer 2020, the first fixed-bottom wind turbines were installed in U.S. federal waters off Virginia Beach for the Coastal Virginia Offshore Wind Project.[22] While the U.S. has not developed any floating offshore wind projects, significant efforts to do so are already underway in windy, deep water areas offering high energy resource values (*discussed in next section*).

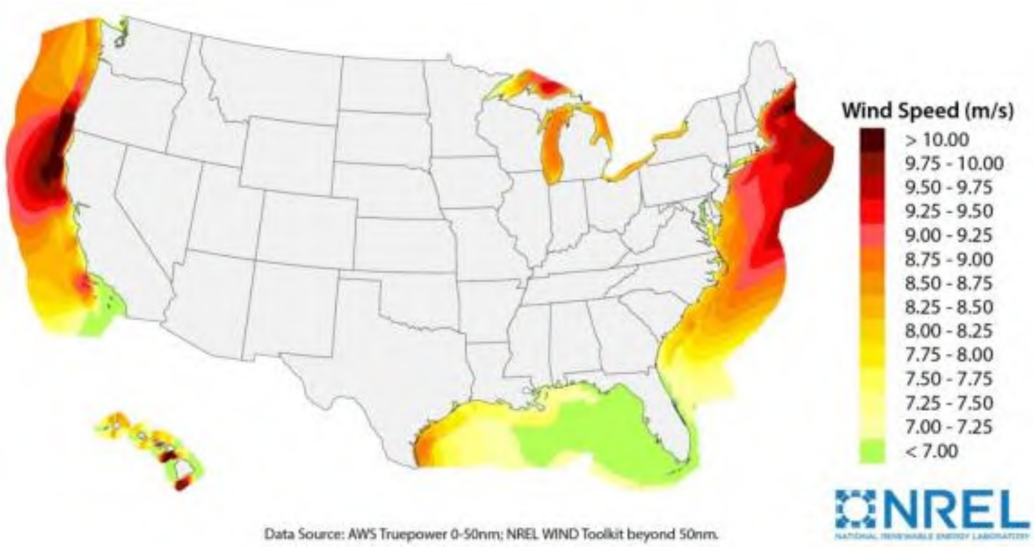
Figure 4: Map of U.S. Activity in Fixed Offshore Wind[23]



Factors Influencing Floating Offshore Wind Development on the West Coast and Oregon

Due to very strong average wind speeds, ocean locations off the California and Oregon coastlines offer the highest potential resource values for floating offshore wind in federal waters surrounding the U.S. coastline. A 2016 assessment by the National Renewable Energy Laboratory reported that ocean depths of 60 to 1,000 meters have a net technical potential for approximately 107 GW of nameplate capacity off California's coast, and 60 GW off Oregon's coast – and that these technical potentials closely correspond with distances from shore ranging from 3 to 50 nautical miles.[24]

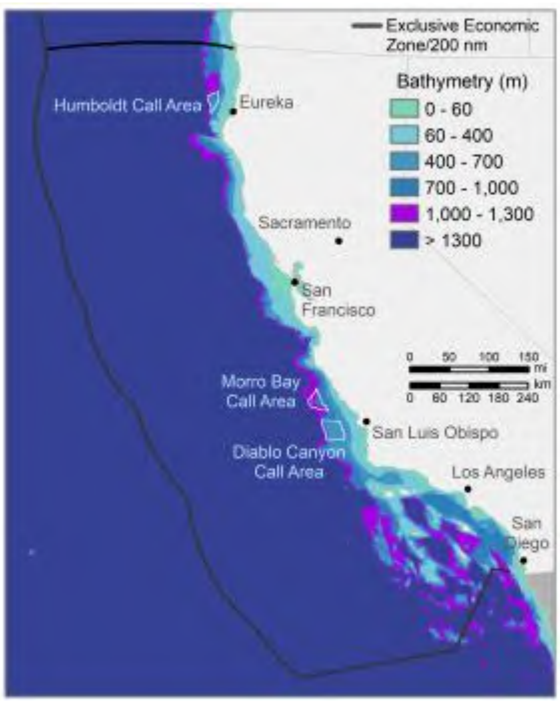
Figure 5: U.S. Wind Map of Areas w/ High Offshore Wind Resource Values[25]



Although Oregon and the most northern part of California have some of the best offshore wind resources in the U.S., as shown above, the overall populations in these coastal areas are relatively low compared to the East Coast of the U.S., where offshore wind is further along in development. Because of the lower populations, a substantial portion of the West Coast does not have a robust network of onshore transmission infrastructure close to the shoreline necessary to interconnect floating offshore wind to the grid. However, in high population load centers farther south in California, there is more transmission infrastructure.

Floating offshore wind could be a more attractive procurement option for California utilities, compared to utilities in Oregon, because they can leverage existing coastal transmission infrastructure. In locations where new transmission lines that tie generation to the bulk transmission system (gen-tie lines) can interconnect new offshore wind projects with existing coastal transmission infrastructure, the "all-in" costs to build offshore wind can be lower. For windy, deep water areas that are far from large coastal load centers, like the Humboldt area shown in Figure 6 below, the idea of sinking long underwater transmission lines to reach interconnection points with coastal infrastructure is under examination.[26] [27] [28]

Figure 6: Identified Areas of Potential for Offshore Wind Development – California[29]



Without expensive new investments in onshore transmission infrastructure in Oregon, the overall scale and location at which floating offshore wind projects could be developed is likely more limited. For example, production cost modeling in a 2020 Pacific Northwest National Laboratory study indicated up to 2-3 GW (compared to the technical potential of 58 GW) of floating offshore wind could be accommodated along the Oregon coast before running into onshore transmission constraints.[30]

This means development of more than 2-3 GW begins to overwhelm the onshore transmission infrastructure. Without additional upfront investment in transmission, this begs the question of whether the cost of developing up to 2-3 GW of floating offshore wind is competitive with land-based electricity supply resources. If not, then floating offshore wind projects would likely need to be scaled even larger to become cost competitive, which could trigger the need for expensive new investments in onshore transmission infrastructure.[31 32] This can increase the costs associated with interconnecting offshore wind to the grid even more, and can increase upfront project development costs, but could increase overall cost-effectiveness.

Studies have also shown offshore wind ramps up its power production in the evenings,[33 34] and California's need for power in evening hours (when solar generation decreases and loads increase) is larger than Oregon's need. To the extent offshore wind can generate electricity at different times than onshore wind and solar, and because offshore wind can be more consistent than onshore wind, it can complement these resources. Therefore, offshore wind can potentially be more valuable for utilities that already have large amounts of onshore wind and solar in their resource mixes.

The 2020 Pacific Northwest National Lab study showed that, because of the relatively cold and dark winters in Oregon, floating offshore wind could potentially be used to serve Oregon's evening winter loads as regional solar production diminishes in late afternoon, and could also reinforce variable regional onshore wind generation in the spring, summer, and fall.[35] To date, however, Oregon utilities have not identified offshore wind as cost-effective to meet these types of needs.[i 36 37]

Oregon's electricity costs are also among the lowest in the nation.[38] This is a benefit for ratepayers, but it makes the case for investing in more expensive, newer technologies such as floating offshore wind more challenging. California's electricity costs are among the highest in the nation,[39] with very large spikes in evening wholesale electricity prices.[40] With power costs significantly higher than those in Oregon, especially during the evening hours, and with more robust coastal transmission already in place in certain areas, floating offshore wind may be more economical for California utilities.

Permitting and Jurisdictional Authorities for Offshore Wind

Jurisdiction over ocean waters is split between state and federal authorities depending on the distance from a state's coastline. Ocean waters within three nautical miles of the coastline are covered under state jurisdiction, and areas from three nautical miles to 200 nautical miles are covered under federal jurisdiction.

Oregon Jurisdiction

At the state level, there are a broad range of governing authorities involved with the permitting of energy development projects within Oregon's three nautical mile ribbon of ocean jurisdiction (roughly 1,000 square nautical miles or 1,400 square standard miles), including state and local agencies. State agencies include the Oregon Departments of State Lands, Fish and Wildlife, Parks and Recreation, Environmental Quality, Land Conservation and Development, Water Resources, Energy, and Geology and Mineral Industries. Some state and local agencies may participate in the review and approval of the generation component of an energy project in the ocean itself, and others may engage in the review and approval of any transmission lines necessary to connect the ocean resource to land.

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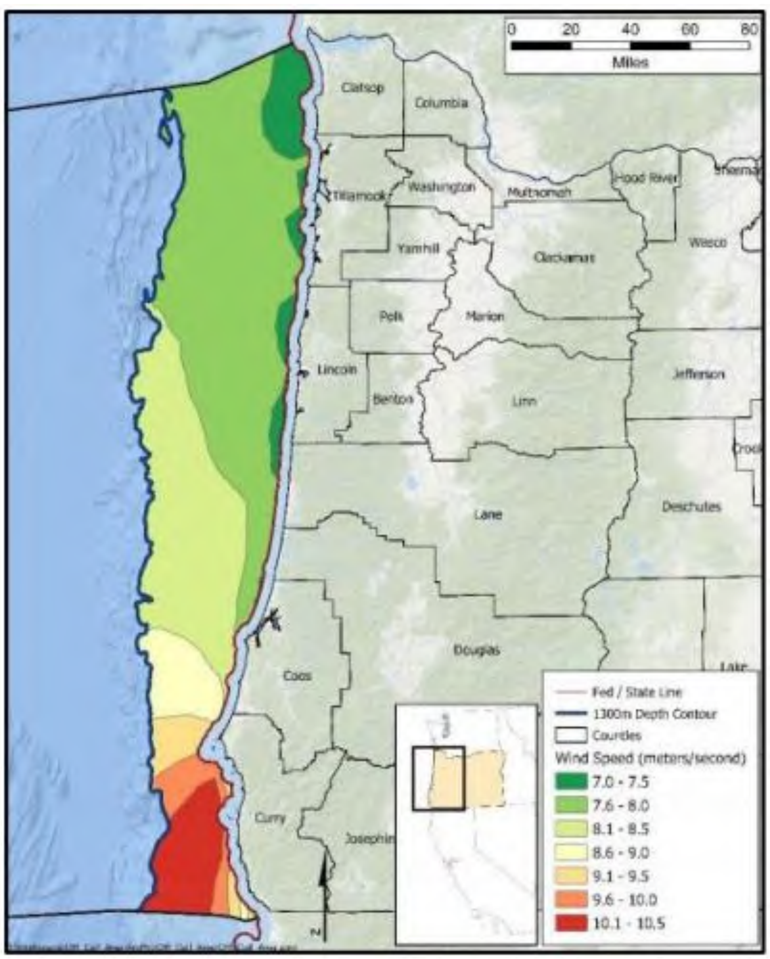
[i] Utility Integrated Resource Plans have a 20-year planning horizon. Portland General Electric's 2019 IRP has no mention of offshore wind. PacifiCorp's 2019 IRP has only a brief mention of offshore wind – "[O]ffshore wind remains expensive and requires government policy support and subsidization."

The Oregon Territorial Sea Plan, first adopted in 1994, acts as a coordinating framework for the wide range of governing authorities likely to be involved with the review and approval of any ocean energy projects located within the state's territorial ocean jurisdiction.[41] Under the Oregon Coastal Management Program, the Department of Land Conservation and Development also performs federal consistency reviews for proposed renewable energy projects that fall within an area described as the Marine Renewable Energy Geographic Location Description, which covers the areas of the outer continental shelf between the western edge of the territorial sea and the 500 fathom depth contour. [42] These reviews provide analyses of the reasonably foreseeable adverse effects that the development of marine renewable energy projects can have on important natural resources of the state.

With weaker winds and greater concerns over coastal wildlife and viewsheds in the state's shallower waters closer to shore, the potential for fixed offshore wind development off Oregon's coast has not been identified as potentially viable.[43] However, the potential for economically viable floating offshore wind projects have been identified where the winds are stronger above the deeper waters of the outer continental shelf, far from the Oregon coast, where permitting authority falls under Federal jurisdiction.[44] Floating offshore wind turbines can be located at distances far enough from shore that they are not seen or heard from land,[45] which may help address concerns about noise and visual aesthetics that the development of onshore wind has prompted.

Figure 7: High Oregon Offshore Wind Resource Values in Federal Waters[46]



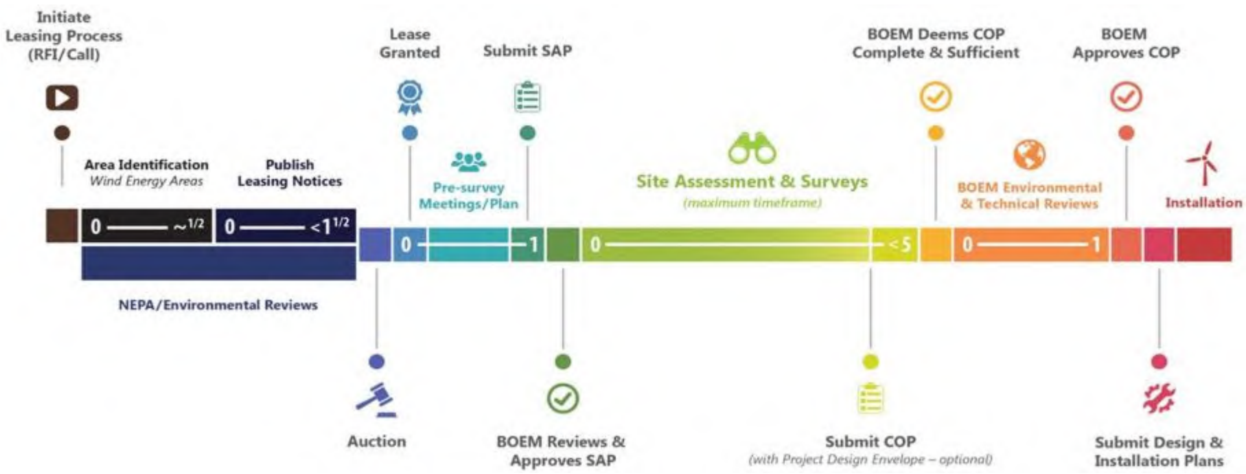
Federal Jurisdiction

Development of energy projects in federal waters (i.e. outer continental shelf) is under the jurisdiction of the Federal Bureau of Ocean Energy Management. BOEM has authority under the U.S. Department of the Interior for issuing leases, easements, and rights-of-way for renewable energy projects located on the outer continental shelf. The BOEM leasing process requires consideration of a host of factors, including interagency coordination, public comment, safety, environmental protection, competition, conservation and prevention of waste, fair return, and prevention of interference with other reasonable uses.

BOEM's planning and leasing process consists of various phases over several years and includes multiple opportunities for public input. BOEM, the State of Oregon, and other federal, tribal, and local entities – such as the Department of Defense, Coquille Indian Tribe, and Coos County Board of Commissioners – are currently coordinating through an Intergovernmental Renewable Energy Task Force (see below for more info). Specifically, BOEM and the State of Oregon are engaging in a process to gather data and conduct outreach to understand the opportunities and challenges of offshore wind, which will inform future leasing and development decisions.[ii]

Figure 8 below gives a general overview of the milestone steps and timelines (numbers indicating years) associated with BOEM's competitive leasing approval process. A deeper dive into BOEM's interagency coordination, review, and leasing processes can be found in its publication, "A Citizen's Guide" (Dec. 2016).[47]

Figure 8: BOEM's Renewable Energy Outer Continental Shelf Leasing Process (in Years)[48]



Offshore Wind Activities in Oregon

In 2011, in response to a request from former Governor Ted Kulongoski, BOEM initiated the BOEM Oregon Intergovernmental Renewable Energy Task Force with the Department of Land Conservation and Development. This Task Force provides coordination regarding potential renewable energy activities (i.e. offshore wind and wave energy) on the outer continental shelf off of Oregon. Task Force membership includes representation from federal and state agencies and Tribal and local governments. The purpose of the Task Force is to share information, coordinate project review processes, and discuss opportunities and information needs.

From 2011 to 2014, the BOEM Oregon Task Force met six times and considered intergovernmental and public comments. In 2013, Principal Power, an offshore wind developer based in Seattle, WA, submitted an unsolicited request for a commercial wind lease to BOEM. The project was proposed to be located roughly 16 nautical miles (30 km) away from Oregon's shore and adjacent to the Coos Bay area, yet far beyond Oregon's Territorial Sea.[49] In 2014, BOEM issued a Request for Interest and later determined there was no competitive interest in the area requested by Principle Power. BOEM then proceeded with the non-competitive leasing process, including issuing a Notice of Intent to prepare an Environmental Assessment for the project and holding public scoping meetings. After many months of negotiations with Oregon utilities, Principle Power could not come to a purchasing agreement for the project.[50] In short, the project was too costly and not economical for Oregon

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[ii] The Oregon Renewable Energy Siting Assessment project, funded by U.S. Department of Defense and led by the Oregon Department of Energy, is due for completion in 2021 and will provide additional insight into Oregon wind energy potential. https://www.oregon.gov/energy/energy-oregon/Pages/ORESA.aspx

ratepayers.[51] Principle Power did not submit a Construction and Operations Plan to BOEM, which was the next step in the authorization process. In September 2018, BOEM determined that Principle Power no longer retained its non-competitive interest status with the project and is no longer processing the unsolicited lease request.[52]

The cost for floating offshore wind technology has continued to decline since 2016, and forecasts as recent as 2019 have projected that floating offshore wind is becoming increasingly cost competitive with other generation technologies.[53] This has renewed the interest of some offshore wind developers to explore the viability of developing floating offshore wind on the outer continental shelf off the Oregon and California coasts.

In September 2019, based on this renewed interest, BOEM organized and initiated a re-convening of its Oregon Task Force. Its seventh public meeting (first in this renewed effort) was held on September 27, 2019, and the eighth public meeting was held on June 4, 2020.[54] Similar to its prior efforts, BOEM's Oregon Task Force continues its communication, education, collaboration, coordination, and consideration of input from a broad set of intergovernmental representation to inform BOEM's decision-making process.

The goal of the June 4 meeting was to review the "Data Gathering and Engagement Plan for Offshore Wind Energy in Oregon" created by BOEM and DLCD, and the meeting outcomes included Oregon's commitment to a planning process to determine the location(s) of a wind energy call area.[55] A cornerstone of this planning effort is how BOEM will collaborate and coordinate with DLCD. The engagement plan was finalized in October 2020 with input received from the Task Force and members of the public, and it outlines how BOEM and DLCD will: 1) engage with research organizations and potentially interested and affected parties, and 2) gather data and information to inform potential offshore wind planning and leasing decisions on the outer continental shelf adjacent to Oregon's coastline.[56] The plan includes the following goals:

1) Interested and affected parties are informed of the data and information gathering process for offshore wind planning and have meaningful opportunities to provide input.[57]
2) The best available data and information are collected to inform potential offshore wind planning and leasing decisions in Oregon.[58]
3) That BOEM and the State build partnerships and a sense of shared ownership in offshore wind planning with interested and affected parties.[59]

BOEM and Oregon have begun offshore wind planning with a data gathering and engagement process expected to run into Fall 2021.[iii]

[iii] For more information and to stay apprised of BOEM's Task Force activities, please see BOEM's Oregon's Activities website at https://www.boem.gov/Oregon

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Policy Brief: Renewable Natural Gas

As states seek to enact or strengthen decarbonization goals, renewable natural gas (RNG) is increasingly seen as a way to reduce greenhouse gas emissions from waste sectors, like landfills and agricultural manure management, while also providing a renewable fuel for other applications that lack low-carbon alternatives, such as some industrial processes, medium- and heavy-duty transportation, and building heating.

RNG is also sometimes referred to as biomethane or upgraded biogas. Biogas is generated when organic material is broken down by bacteria in an anaerobic environment (without oxygen). Common sources include landfills, wastewater treatment plants, and manure lagoons at animal operations.[1] RNG is biogas that has been cleaned up to remove contaminants and diluents so that the remaining gas is about 98 percent methane and can be used interchangeably with conventional fossil-based natural gas.[2] (For more information, see the Biogas and RNG Technology Review.)

Renewable Natural Gas Policy in Oregon

In 2017, the Oregon Legislature enacted SB 334,[3] directing the Oregon Department of Energy to develop an inventory of all the resources within the state that could be used to produce biogas and RNG. ODOE published this inventory in 2018, which looked at the potential to generate RNG across six organic material pathways – waste food, agricultural manure, landfills, wastewater treatment plants, forest residue, and agricultural residue. The inventory found that approximately 4.6 percent of Oregon's annual natural gas use could be met with RNG produced from these six resource streams, using only anaerobic digestion technology, or about 10 billion cubic feet of methane per year.[4] Adding thermal gasification technologies, which are not currently commercialized, could increase that total to almost 20 percent of Oregon's total natural gas use.

In 2019, the Oregon Legislature passed SB 98,[i] which allows natural gas utilities operating in the state to buy and sell RNG to their retail customers and to invest ratepayer funds in infrastructure for the acquisition, processing, transport, and production of biogas and RNG within Oregon. The bill stated that RNG should be supported to "ensure a smooth transition to a low carbon energy economy in Oregon," and that natural gas utilities can use RNG to reduce greenhouse gas emissions.[5] SB 98 does not require natural gas utilities to acquire RNG for their customers, but for those that do, the costs and benefits of RNG would be shared by all of their ratepayers. This is in contrast to the state's renewable portfolio standard, or RPS, which requires utilities to procure a certain amount of eligible renewable electricity each year.

Natural gas utilities are defined in the legislation as large or small according to whether they have greater or fewer than 200,000 customer accounts held in Oregon – as of October 2020, only NW Natural meets the large threshold while the other two natural gas utilities operating in Oregon, Avista and Cascade, would be considered small. Large natural gas utilities have an annual spending cap of 5 percent of their annual revenue. They also have annual volumetric targets for the amount of RNG delivered to customers, which begins at 5 percent in 2020 and increases by 5 percent every five years

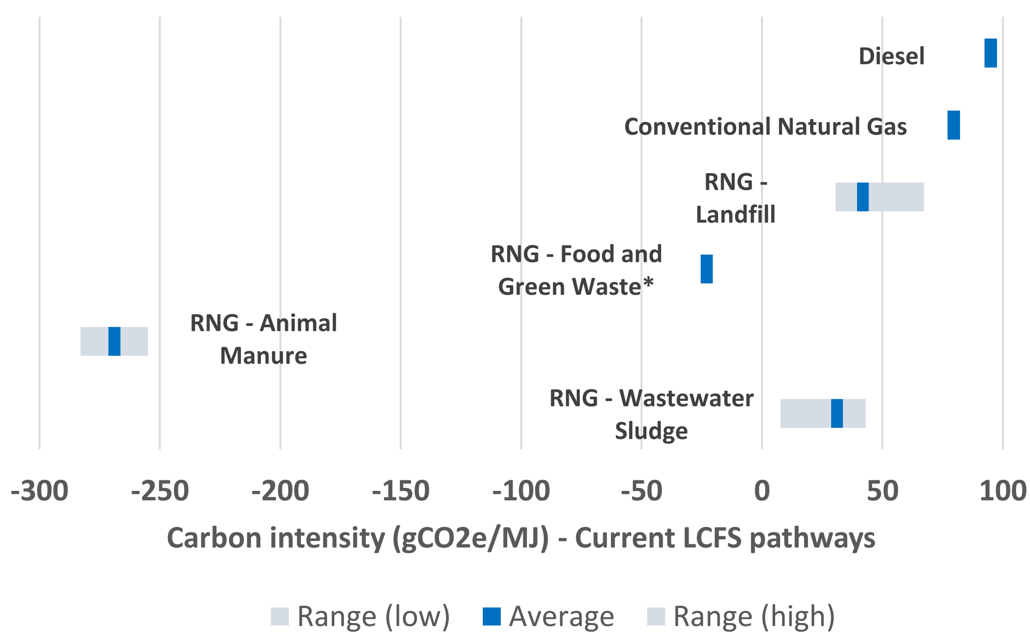
[i] SB 98 is codified in ORS 737.390 through 757.398

until reaching a maximum of 30 percent by 2050. The legislation gives the Oregon Public Utility Commission (PUC) discretion to determine the program requirements and any caps for small natural gas utilities. The bill defines renewable natural gas to include biogas that is upgraded to meet natural gas pipeline standards; hydrogen gas that is created using renewable energy resources, or methane derived from any combination of biogas, hydrogen gas or carbon oxides from renewable energy sources, or waste carbon dioxide.[6] This would allow natural gas utilities to invest in power-to-gas operations (see Power-to-Gas Technology Review).

The PUC began the rulemaking process to implement SB 98 in late 2019, which addressed questions related to defining and tracking the environmental attributes associated with RNG, utility cost-recovery mechanisms, rules for small natural gas utilities, reporting requirements, and how utility RNG programs might interact with the Oregon Clean Fuels Program and California's Low Carbon Fuel Standard, among others.[7] The rules were adopted with an effective date of June 17, 2020 and are now in Oregon Administrative Rules 860-150-0005 through 860-150-0600.

With respect to the environmental attributes associated with RNG, PUC and its stakeholders determined that defining these attributes according to the carbon intensity (the lifecycle greenhouse gas emissions) of a particular source of RNG was the most effective way to address concerns around double counting of attributes and also interactions with previously established markets for RNG, namely the California Low Carbon Fuel Standard and the Oregon Clean Fuels program.[8] Both of those programs use a carbon intensity approach. While the legislation does not require that RNG meet a certain carbon intensity threshold to be eligible for cost recovery, the different pathways for producing RNG can vary significantly (see Figure 1). As the market for RNG matures over time, utilities may wish to purchase RNG with a relatively low carbon intensity, leading to greater carbon reduction benefits for their customers.

Figure 1: Carbon Intensity of RNG Pathways Based on California's Low Carbon Fuel Standard[9]



* Range not shown for Food and Green Waste, since at the time data were collected for this report only one such project was participating in California's LCFS program. Green Waste in the above pathway refers to yard clippings, grass, leaves, and brush (e.g. from residential curbside pickup programs that is co-digested with food waste).

For each dekatherm[ii] of RNG in Oregon, the environmental attributes will be represented by a renewable thermal certificate (RTC), which will be tracked through the M-RETS electronic system[iii] in much the same way that renewable energy certificates for the Oregon RPS are tracked through the Western Renewable Energy Generation Information System (WREGIS).[iv] The RTCs will be used to track the chain of custody of the environmental benefits through a book-and-claim approach that does not physically track the RNG, similar to the accounting for both the Clean Fuels Program and the Low Carbon Fuel Standard.

Action on RNG in the U.S.

Inventories

Assessing the RNG resource potential available in any jurisdiction is an important first step in understanding the RNG market opportunities and in identifying barriers and potential policy solutions. In 2016, California was the first state in the U.S. to complete an inventory of RNG potential, followed by Oregon and Washington in 2018 and Colorado in 2019.[10] The World Resources Institute reviewed these state-level inventories and found that they all differ in terms of the feedstocks analyzed and assumptions made about resource availability, and that they focus primarily on more economical near-term opportunities, such as anaerobic digestion of so-called wet-waste resources like manure or wastewater sludge, as opposed to thermal gasification of dry feedstocks like agricultural and forestry residues. For those reasons, these state-level inventories tend to report lower potential supply than national inventories.[11]

Table 1: Summary of State-Level RNG Inventory Resource Assessments in Billion Cubic Feet per Year (BCF/yr)[12]

State	Study Name	Assessed RNG Supply from Wet-Waste Sources
California	The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute. (2016)	90.6 BCF/yr (equivalent to 7% of 2016 residential & commercial NG consumption)
Colorado	Renewable Natural Gas (RNG) in Transportation: Colorado Market Study (2019)	19 BCF/yr (equivalent to 5% of 2016 residential & commercial NG consumption)
Oregon	Biogas and Renewable Natural Gas Inventory (2018)	10.4 BCF/yr (equivalent to 8% of 2016 residential & commercial NG consumption)
Washington	Promoting Renewable Natural Gas in Washington State (2018)	14.7 BCF/yr (equivalent to 6% of 2016 residential & commercial NG consumption)

[ii] A dekatherm is equal to one million British thermal units (Btu).

[iii] A web-based system used to validate the environmental attributes of energy for power generators, utilities, marketers, and qualified reporting entities.

[iv] A web-based system used to track renewable energy certificates in the Western Interconnection territory.

For national inventories, a 2014 National Renewable Energy Laboratory study found a national resource potential for RNG to meet approximately 9 percent of residential and natural gas demand in 2018, and a 2019 study by ICF that included a more long-term focus found potential to meet between 9 and 16 percent of residential and commercial natural gas demand in the U.S.[13] [14] The ICF inventory claims to be the first to quantify RNG potential from power-to-gas operations using renewable electricity in combination with a methanation system, and it found the contributions of power-to-gas to RNG supply to be potentially significant in later years. In its low resource potential scenario, ICF estimated an annual RNG supply of roughly 1,910 trillion Btus; the high resource potential scenario yields an estimate of 4,510 trillion Btus per year by 2040.[15] Using a lifecycle accounting approach, ICF estimated greenhouse gas emissions reductions for the low potential scenario to be between 86 and 113 million metric tons and between 170 and 247 million metric tons for the high potential scenario.

State Legislation and Natural Gas Utility Programs

California

In 2016, the California Legislature passed a bill (SB 1383) aimed at reducing short-lived climate pollutants like methane, which included a requirement that the California Public Utilities Commission (CPUC) direct natural gas utilities to develop at least five dairy RNG pilot projects while allowing use of ratepayer funds for reasonable pipeline infrastructure costs.[16]

California passed two bills related to RNG and utilities in 2018. SB 1440 required the CPUC to consider adoption of RNG procurement targets or goals for investor-owned utilities, and AB 3187 required the CPUC to open a proceeding to consider allowing gas utilities to use ratepayer funds for RNG interconnection infrastructure.[17]

In 2019, SoCalGas and San Diego Gas & Electric both announced plans to offer RNG to customers in California. SoCalGas also pledged to displace 5 percent of its natural gas with RNG by 2022 and 20 percent by 2030.[18]

Washington

In 2018, the Washington Legislature passed a bill (HB 2580) requiring Washington State University and the Department of Commerce to submit recommendations to the Governor on how to promote sustainable RNG, including voluntary standards for injection of RNG into pipelines.[19] In 2019, the state passed HB 1257, which required natural gas utilities in the state to offer a voluntary RNG program to retail customers and allow utilities to include RNG in their fuel mix.[20] In 2020, Puget Sound Energy signed a contract to purchase RNG from a local Public Utility District through 2040.[21]

New York

In a 2019 rate filing, National Grid NY proposed a green gas tariff that would allow its New York customers to voluntarily purchase RNG for a residential flat rate between $5 and $50 dollars a month, according to a four-tier offering.[22] Initially, New York Public Service Commission staff were supportive of the proposal, but after another energy company raised concerns about the lack of detail in the proposal and given staff's own concerns around costs, Commission staff recommended that the Commission reject the green gas tariff in an April 2020 brief.[23] Shortly afterward, National Grid NY withdrew the green gas tariff from its pending rate case.

Other States

- In Arizona, Southwest Gas submitted an application in 2019 seeking approval to establish an RNG program to include RNG in its gas supply portfolio.[24]
- Hawaii Gas includes RNG as part of its fuel mix.[25]
- Maine utility, Summit Natural Gas, received approval in 2019 to begin offering a "voluntary renewable attribute program" where customers can match up to 100 percent of their natural gas usage with the environmental attributes derived from landfill gas.[26]
- In Michigan, DTE Energy launched its BioGreenGas program in 2013, where customers can voluntarily pay $2.50 a month to support landfill gas programs.[27]
- In 2018, CenterPoint Energy of Minnesota filed a proposal to offer a pilot voluntary RNG program to its customers, which was not approved by the state Public Utilities Commission. In 2020, the utility submitted an interconnection proposal to allow it to accept RNG into its natural gas distribution system.[28]
- Philadelphia Gas Works began offering a voluntary RNG program to its customers in Philadelphia in 2020. The cost averages about $15 a month and the RNG is sourced from landfill gas.[29]
- Utah's Dominion Energy began offering its voluntary RNG program GreenTherm to customers in 2019. Customers may purchase blocks of RNG and Dominion purchases the environmental attributes of RNG on their behalf.[30]
- Vermont Gas Systems launched its voluntary RNG program in 2017, which allows customers to meet up to 100 percent of their natural gas consumption with RNG.[31]
- In 2018, Dominion Energy Inc. and Smithfield Foods Inc. formed Align Renewable Natural Gas in 2018 to develop RNG for injection into the natural gas pipelines. Currently, Align has projects in Virginia, North Carolina, and Utah.[32]

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Policy Brief: Power-to-Gas Technology

As interest in power-to-gas (PtG) in Oregon and the U.S. grows, questions remain as to the market for and affordability of it. This piece addresses questions about the market for PtG in the sectors of electricity and transportation, the costs associated with PtG, and current developments in the deployment of the technology.

Power-to-gas (PtG) describes the process of using electricity to split water into its component parts of oxygen gas and hydrogen gas through a process known as electrolysis. The hydrogen gas generated by an electrolyzer can be converted back into electricity using a fuel cell (hydrogen) or blended with natural gas in a pipeline (up to 15 percent volume) for later combustion. When hydrogen is created with PtG using renewable electricity, the resulting hydrogen is considered renewable. Today, only about 2 percent of hydrogen is produced via electrolysis and the remaining 98 percent is produced from fossil fuels via steam reformation of natural gas or other processes.[1] Less than 1 percent of total hydrogen production is made with renewable electricity.[2] [3] Hydrogen created from fossil fuels via steam reformation or other processes is responsible for about 830 million metric tons of CO2 per year, which is roughly equivalent to the annual greenhouse gas emissions of the United Kingdom and Indonesia combined.[4]

Learn more about PtG in the Technology Review section.

The hydrogen created from PtG can be used in multiple applications, including as a form of long-duration energy storage for the electricity sector, a transportation fuel, and for industrial processes. *Renewable* hydrogen can also play a role decarbonizing non-electricity sectors as it can be used to replace conventional transportation and direct use fuels, and it can be used as an energy resource or as raw material to produce fertilizers, refine some metals, as well as other industrial end uses. Because hydrogen from PtG can be produced wherever electricity and water are present, it can also play a role in enabling local energy production and providing energy resilience benefits.

Figure 1: Potential Applications of Hydrogen from Power-to-Gas[5]

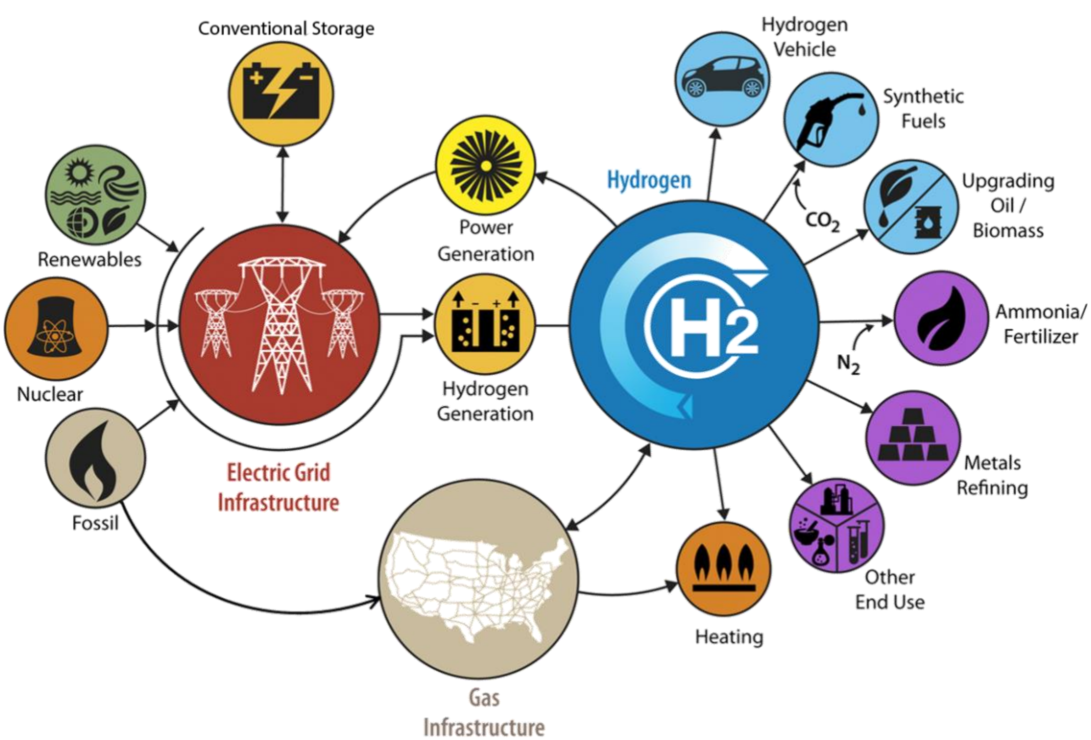

Figure 1 shows the potential applications of hydrogen in the economy, including power generation, energy storage, transportation fuels, industrial processes, and stationary uses.

While the fundamental concept of electrolysis is decades old, the combination of technologies and resources necessary to create renewable hydrogen at scale are still in their infancy. The U.S. Department of Energy Hydrogen and Fuel Cells Program was designed to address the gap between how hydrogen is produced, stored, and used today and how this resource could be used to facilitate a cleaner energy future.[6] Data on technology costs and potential energy markets vary widely across different studies. The information presented here is intended to provide a high-level overview of the market for renewable hydrogen and the associated costs. The future of PtG and renewable hydrogen is highly dependent on an evolving energy picture, and its efficacy as a technology is still being studied and analyzed.

PtG Market

Although PtG technologies have been around for decades, only a small amount of hydrogen is created using electrolysis as it is significantly more cost effective to create hydrogen through reformation (and other processes) of fossil resources, primarily natural gas. Creating *renewable* hydrogen using electrolyzers also isn't economical in most jurisdictions due to the cost of electrolyzers, the cost of renewable electricity needed to run the electrolyzer, and the efficiency losses associated with using electricity to create hydrogen and then using the hydrogen as fuel instead of just using the electricity as the fuel. However, the increased demand for lower-carbon energy coupled with increasingly cheap renewable electricity and falling costs of electrolyzers has created a renewed interest in PtG and renewable hydrogen. Europe leads the world in deployment of PtG for the production of hydrogen, while in the U.S. most projects are in early phases of development. Many experts are still evaluating the most economical end uses for hydrogen and renewable hydrogen. Fuel for medium- and heavy-duty transportation and as long-duration energy storage for the electricity grid are emerging as the best bet for near-term, cost-effective deployment of hydrogen.

Grid Energy Storage

Learn more about energy storage in the Technology Review and Policy Brief sections.

PtG can operate as storage for the electric grid. Historically lacking a cost-effective means of scalable storage, the electric grid must be kept in balance at all times with respect to supply and demand. Failure to maintain this balance can destabilize the grid and lead to brownouts, blackouts, and even safety issues. Historically, cost-effective forms of electricity storage have been very limited – mostly in the form of pumped hydropower. New opportunities for storage include batteries and PtG. Energy storage can be divided into short-duration, long-duration, and seasonal storage, which each provide different challenges and opportunities for electricity providers. Short-duration storage refers to discharging stored electricity in short bursts to provide flexible power for balancing variable renewable resources, to maintain short-term grid reliability needs, and to take advantage of arbitrage opportunities presented by changing prices for electricity based on demand. Long-duration storage refers to discharge that can last from about 10-100 hours, and seasonal storage is any storage with a discharge duration of more than 100 hours.[7]

Currently, stored hydrogen does not offer cost-effective short-duration storage capabilities for grid management. Chemical batteries, such as lithium-ion, are quickly becoming a common short-duration storage device for electricity in the U.S., with more than 922 MW of large-scale (more than one 1 MW) battery storage capacity added between 2003 and 2018, and three-quarters of that occurring between

2015 and 2018.[8] While renewable hydrogen can be stored in fuel cells and then discharged back to the grid as needed or as a compressed gas that can then be used as a fuel to generate electricity, it is not currently a candidate for many short-duration energy storage needs because of cost and the efficiency losses associated with creating and storing the hydrogen and then converting that hydrogen back to electricity.

When it comes to longer-duration storage, hydrogen becomes more cost effective. While the current chemistries of batteries (lithium-ion and others) are useful for discharging stored electricity over the course of hours, they are much less cost effective when sized to discharge for longer-duration events lasting days or weeks. The National Renewable Energy Laboratory considers hydrogen among a short list of the most promising candidate technologies that could provide future electricity systems with cost-effective long-duration and seasonal storage, along with pumped storage and compressed air.[9]

Energy Storage Beyond the Electricity Grid

Another pathway for storing hydrogen is by injecting it into the natural gas pipeline and using the pipeline infrastructure itself as the storage medium. While different from natural gas, hydrogen is also a combustible gas that can be added to the natural gas system – but due to its low density, it has less than a third of the energy content.[10] Other key differences between natural gas and hydrogen limit the proportional amount of hydrogen that can be introduced into existing pipelines and appliances to somewhere between 5 and 15 percent of hydrogen by volume.[11]

When hydrogen is "methanated," or combined with carbon dioxide, it becomes synthetic natural gas, which is freely interchangeable with natural gas and could be injected into pipelines at any volume.

Transportation

In Oregon, the transportation sector is the largest source of GHG emissions.[12] Battery electric vehicle (BEV) adoption can reduce the GHG emissions associated with transportation for many light-duty vehicles, but BEVs are not currently optimal for many medium- and heavy-duty applications due to the weight, range, charging needs, and performance of current battery technologies. Hydrogen as an alternative transportation fuel offers a number of benefits over BEVs for these applications, including fast fueling times, higher efficiency under temperature variations, and less weight needed for battery and fuel at comparable ranges.[13]

Currently the market for BEV passenger and commercial vehicles is more mature than that for fuel cell electric vehicles (FCEV), there's more charging infrastructure for BEVs, and in most applications FCEVs carry higher up-front costs. Despite the nascency of the FCEV market, the U.S. has the highest number of passenger FCEVs sold and leased in the world, with a total of 8,475 as of August 1, 2020. California is the biggest market for FCEVs and currently has 42 stations available for retail light-duty fueling, with another 15 stations currently in development.[14] A minimum of 33 percent of the hydrogen used for transportation in California must be renewable, and the California Hydrogen Business Council estimates that between 37 and 44 percent of the hydrogen for transportation in California is renewable.[15] Presently, there are no hydrogen fueling stations in Oregon, and none are anticipated for the foreseeable future.

Learn more about FCEVs and other fuel use for medium- and heavy-duty vehicles in the Energy 101, Technology Review, and Policy Brief sections.

As production of hydrogen from PtG matures as a sector, the cost of electrolyzers is expected to continue to fall, and as FCEV penetration grows, the costs of fuel cells and hydrogen refueling infrastructure are expected to drop. A recent paper by Deloitte and Ballard Power Systems Inc. estimated that, without subsidies, the total cost of ownership for FCEV buses would be lower than for BEVs or internal combustion engine (ICE) buses by 2027.[i] [16]

Costs Associated with Power-to-Gas

Figures on the costs of PtG and renewable hydrogen vary widely across the literature. The main consensus in discussions of PtG costs is that the cost of electrolyzers is expected to drop as the technology is more widely deployed. Furthermore, the cost of the electricity used to power the process has an outsized effect on overall costs. Some applications of PtG and hydrogen could be cost effective in the near term, such as long-haul commercial transportation.

Numerous studies suggest that as the market for PtG matures, polymer electrolyte membrane (PEM) electrolyzers and alkaline electrolyzers (AE) should get cheaper. BloombergNEF found that the cost of AE electrolyzers produced in North America and Europe fell 40 percent between 2014 and 2019.[17] Other studies suggest that for every doubling in installed electrolyzer capacity, total costs should decline by about 20 percent.[18]

In addition to the costs associated with the electrolyzer itself, additional infrastructure is required to move the hydrogen into natural gas pipelines, onsite storage, fueling trucks, or onsite fueling infrastructure. This could include such costs as adding pipeline to connect to the overall system, compressors to inject the gas into the pipeline or fuel truck, storage infrastructure, and the electricity to power the compressor; the compressor should be able to run on the electricity that is being generated on site. Electrolyzers also require a water source, meaning they would either need to procure water or be sited near a water resource.

Given that electricity represents a large share of the operating expenses of a PtG unit, an optimal application of PtG could be as an end use for excess renewable electricity that would otherwise be curtailed. Unlike California, the Pacific Northwest currently has limited circumstances when this type of low- or zero-cost surplus electricity is available. These situations tend to occur today in the region when three conditions are met: (1) snowmelt runoff drives high hydropower output, (2) electric loads are low in the overnight hours of mild springtime months, and (3) high wind power output. It is possible that this may occur more frequently in the future as more wind and solar power is added to the regional grid. However, PtG would have to compete for this surplus, low-cost energy against other technologies such as battery storage or demand response resources like direct load control or time-of-use pricing mechanisms.

Learn more about demand response in the Technology Review section.

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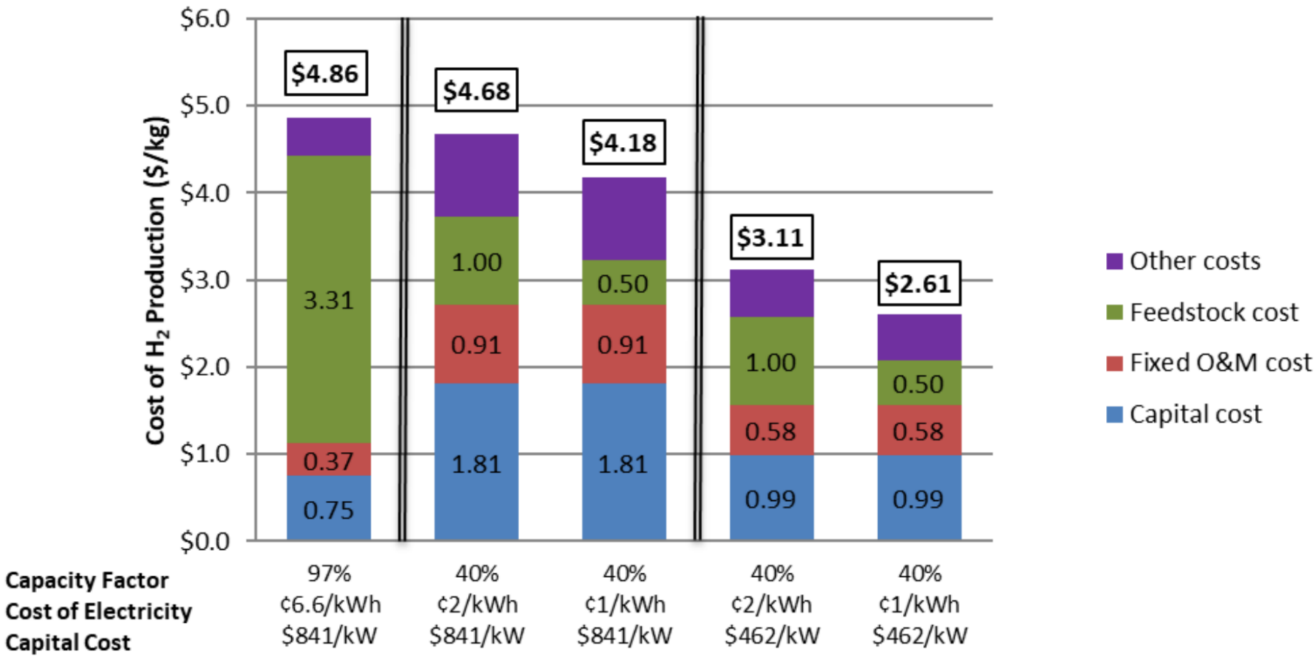
[i] The Deloitte China report analysis did not differentiate between renewable and non-renewable hydrogen in the development of hydrogen fuel cost estimates.

This means that running electrolyzers located in the Northwest only when renewable electricity that would otherwise be curtailed and would be free or nearly free is available, would result in PtG facilities with lower capacity (i.e., utilization) factors. A National Renewable Energy Laboratory (NREL) study[19] found that when running electrolyzers at lower capacity factors, presumably to take advantage of low-cost electricity, the capital cost of the electrolyzers becomes a larger share of the overall cost of the hydrogen produced. However, with low-cost electricity, even electrolyzers running at relatively low capacity factors can still produce cheaper hydrogen than facilities with high capacity factors using higher-cost electricity. Figure 2 below highlights a finding from the NREL study, which shows that an electrolyzer operating at 40 percent capacity but using electricity that costs $0.01/kWh instead of $0.066/kWh can produce hydrogen $0.68/kg (14 percent) cheaper than running the same electrolyzer at 97 percent capacity at the higher price.

Figure 2: Effect of Capital Cost, Capacity Factor, and Electricity Price on the Cost of Hydrogen Production[20]

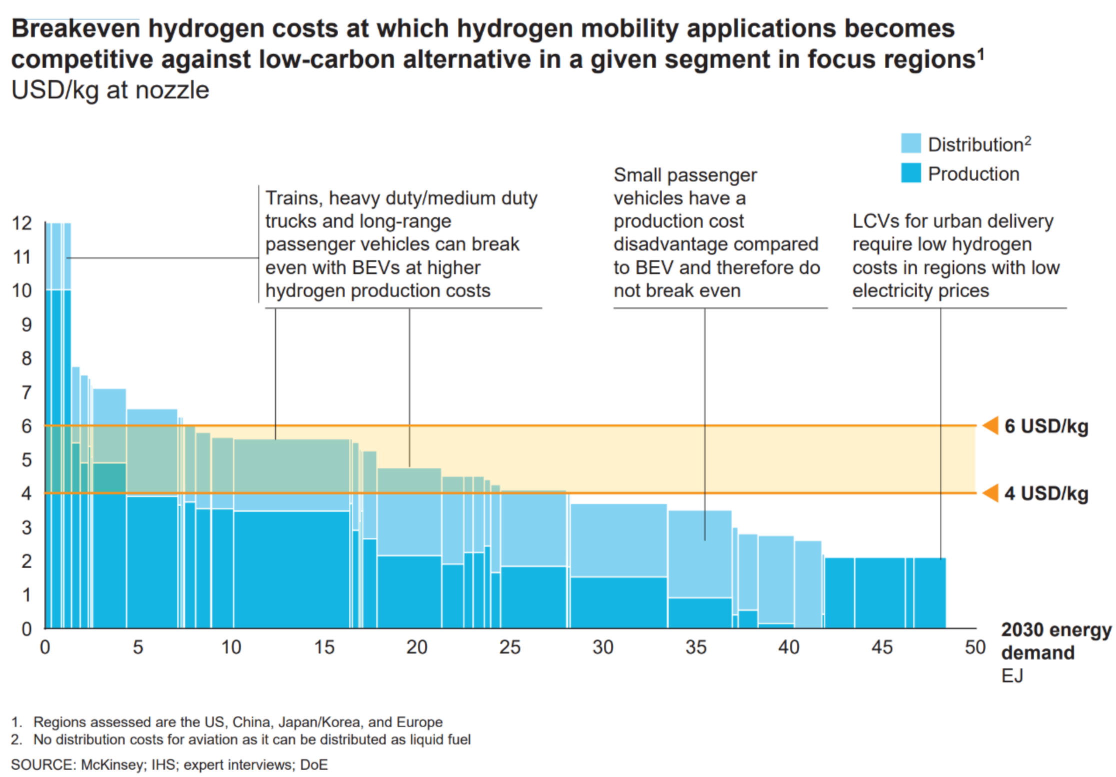


Estimates for when hydrogen might be cost competitive with other fossil fuel or renewable options for different applications vary. A recent report from the Hydrogen Council assessed the future potential for 35 different hydrogen applications and found that by 2025, hydrogen could be cost competitive with BEVs in the transportation sector (except for short-range use cases), and that by 2030, hydrogen would also be cost competitive in simple cycle turbines, boilers, and industry heating.[20] However, the report expects that hydrogen cost competitiveness will vary greatly according to location and that regions "with access to abundant low-cost clean power, biomass or CO2 capture and storage (sequestration) will present tougher conditions for hydrogen, especially where direct electrification is an option."[21] In such areas, direct electrification might be more cost effective than building out a new hydrogen pipeline network. The decarbonization study that NW Natural commissioned in 2018[22] found that use of renewable natural gas and hydrogen is of greater importance in scenarios where buildings maintain gas heating. While low-cost electricity is a necessary element to make PtG a cost-effective option, it's not the only element and for some applications, cost competitiveness may be a local calculation.

This is illustrated in the Portland General Electric 2018 deep decarbonization study.[23] In it, PGE evaluated three decarbonization scenarios based on the degree to which direct use of fossil fuels would be reduced through end-use electrification and the amount of demand response capabilities of the electric system. Only the low electrification scenario included renewable hydrogen from PtG, where it was identified as a balancing resource for excess renewable generation and to support the creation of renewable fuels for the direct use and transportation sectors. In the other two scenarios, where most end uses have been electrified or significant amounts of demand response are available, PtG was not included. In these scenarios, PtG would be competing against – and would not be as cost effective as – other demand management resources, such as battery storage, direct load control, and other demand response programs.

With respect to cost competitiveness of PtG and hydrogen for transportation, the Hydrogen Council report's cost curves show that hydrogen becomes cost competitive for long-range applications at higher prices than for shorter-range use cases, and suggests hydrogen could be viable for most regions and most long-range use cases at $6/kg (at the nozzle[ii]) by 2030.[24] Translating that into a diesel gallon equivalent without actual vehicle efficiencies is challenging, but the USDOE estimates that the fuel economy of a fuel cell truck is about 19.4 miles per gallon diesel equivalent as compared to 15.6 miles for a similarly efficient and configured diesel truck.[25] Figure 3 illustrates that even at costs of $6/kg, hydrogen could be cost competitive for about 15 percent of transport energy demand. At a cost of $4/kg, hydrogen could be cost competitive for more than 50 percent of the sector's energy demands. For comparison, the average retail price for hydrogen at a fueling station in California between 2018 and 2019 was $16.51/kg.[26]

Figure 3: Cost Curve for Hydrogen for Transportation Sector Across Segments and Regions[21]



[ii] At the nozzle pricing includes production, distribution, and retail costs.

Potential for Power-to-Gas in Oregon

While there are no PtG projects in Oregon at this time, there are a number of factors that could affect the viability of PtG in Oregon:

- **Surplus renewable electricity.** The region's abundant hydropower and wind power can create surplus renewable electricity that could provide the low-cost renewable electricity needed to make many PtG applications cost-effective. In 2018, BPA had to manage oversupply related to more than 113,000 MWh of electricity, much of it from wind, at a cost of about $4.87 million.[27] However, this source of electricity is not always available and there are increasingly more end uses in competition for that resource.
- **Utility decarbonization plans**. Electric and natural gas utilities in the west are increasingly adopting decarbonization plans and seeking more options for renewable energy and storage. In Oregon, both Portland General Electric[28] and NW Natural[29] have done decarbonization studies.
- **Existing infrastructure.** In Oregon, the natural gas pipeline system includes almost 16,000 miles of distribution main lines and over 730 miles of high-pressure transmission lines.[30] Using this existing infrastructure for storage of renewable hydrogen gas could provide Oregon with greater available supply of lower-carbon fuels. In its 2019 Future of Hydrogen report, the International Energy Agency proposes that the introduction of just 5 percent of renewable hydrogen into existing gas pipelines in many countries would help boost demand for and drive down costs of renewable hydrogen.[31]
- **Transportation decarbonization policies and programs.** As stated above, the transportation sector is the largest source of Oregon's GHG emissions. Increasing the use and availability of cleaner fuels is included in ODOT's Statewide Transportation Strategy[32] and is also the goal of the state's Clean Fuels Program.[33] Oregon is a signatory to the Multi-state Medium- and Heavy-Duty Zero Emission Vehicle MOU,[34] which creates a task force to develop a multi-state action plan to encourage adoption of medium- and heavy-duty zero-emissions vehicles, including hydrogen fuel cell vehicles.

Global Power-to-Gas Developments

Europe is actively moving toward a PtG future where hydrogen displaces fossil fuels for heating, transportation, and industrial processes. In France, the first PtG project linked to the gas transmission network came online in 2018. The facility, named Jupiter 1000, has a capacity of 1 MW for electrolysis to create renewable hydrogen. Some of the hydrogen is injected directly into the pipeline while some is methanated with carbon dioxide captured from a nearby industrial facility before injection.[35] The world's largest electrolyzer plant is planned to be built in Belgium. The 50 MW facility would be fully operational by 2025 and powered solely by excess offshore wind power.[36]

In addition to active and planned projects, the European Union (EU) and Germany have established renewable hydrogen strategies and set capacity goals for electrolyzers. In August 2020, the European Commission announced a hydrogen strategy that includes a phase one objective of installation of at least 6 GW of electrolyzer capacity to generate renewable hydrogen in the EU, and the production of at least a million metric tons of renewable hydrogen between 2020 and 2024. This would represent a major increase over the estimated 250 MW of electrolyzer capacity currently deployed globally.[37] The phase two objectives are to ensure hydrogen becomes an established part of the energy system, to install at least 40 GW of electrolyzer capacity in the EU, and to produce up to 10 million metric tons of renewable hydrogen in the EU between 2025 and 2030. A third phase is envisioned where renewable hydrogen has reached maturity and is deployed at scale to address remaining hard-to-decarbonize sectors.[38] Germany adopted a national hydrogen strategy in June 2020, which includes investment of up to €7 billion to reach a production capacity of 5 GW by 2030 and 10 GW by 2040. The strategy document stresses that renewable hydrogen will be a key element of decarbonization plans in Germany and more widely in Europe, and that the federal government expects to see European and global hydrogen markets in the next decade.[39]

Interest in PtG in the U.S. has been steadily rising given the number of potential benefits offered by the technology, though deployment is at a much lower level than in European countries. This could be in part due to the more aggressive decarbonization goals of European countries coupled with the plentiful domestic supply of low-cost natural gas in the U.S. However, the USDOE has operated the H2@Scale initiative since 2016, which was created to support innovations and R&D in the production, storage, transport, and use of hydrogen across energy sectors. Approximately $40 million was awarded to fund 29 projects in fiscal year 2019 and in July 2020, the USDOE announced $64 million in funding for 18 projects in fiscal year 2020.[40] Of the 29 projects funded in 2019, two were in Oregon – over $600,000 went to Hy-Performance Materials Testing in Bend, OR to address ways to reduce fatigue cracking in steel hydrogen storage vessels while $500,000 went to the University of Oregon in Eugene to study electrolysis membranes free of precious metals.[41]

While the U.S. does not have a national strategy for PtG, some utilities and other investors in the U.S. are developing PtG hydrogen projects. NextEra subsidiary Florida Power & Light announced in July 2020 plans to build a $65 million project featuring a 20 MW electrolyzer using surplus solar power to produce green hydrogen that would be used in the utility's Okeechobee natural gas plant.[42] The project could be operational as soon as 2023 if it receives approval from state regulators. Rocky Mountain Institute called the project a "big deal" as it represents the first voluntary, large-scale facility planned in the U.S.; and because with its substantial gas and solar infrastructure across the country, NextEra has numerous opportunities to site other electrolyzers.[43] In 2019 Mitsubishi Hitachi Power Systems and Magnum Development announced the Advanced Clean Energy Storage project in central Utah. Located near the existing Intermountain Power Plant, the project includes an electrolyzer that will create renewable hydrogen from excess, low-cost electricity and store it in naturally formed underground salt caverns.[44]

In Washington State, Douglas County Public Utility District is developing a pilot project to see if renewable hydrogen production on a larger scale could be cost effective for the utility. The PUD has contracted to purchase a 5 MW PEM electrolyzer that would use surplus electricity from the Wells Dam on the Columbia River to create renewable hydrogen and could be operational as soon as 2021.[45] The project was made possible by recent state legislation broadening the authority of PUDs to include production and wholesaling of hydrogen.[46] In Oregon, NW Natural and Eugene Water and Electric Board have teamed up with Bonneville Environmental Foundation to develop a PtG project. The project is still in the conceptual phase, but NW Natural added that current plans are for an approximately 8.5 MW electrolyzer located in Eugene, sited near industrial facilities capturing CO2, which would be used to methanate the hydrogen before injecting it into the natural gas pipeline.[47]

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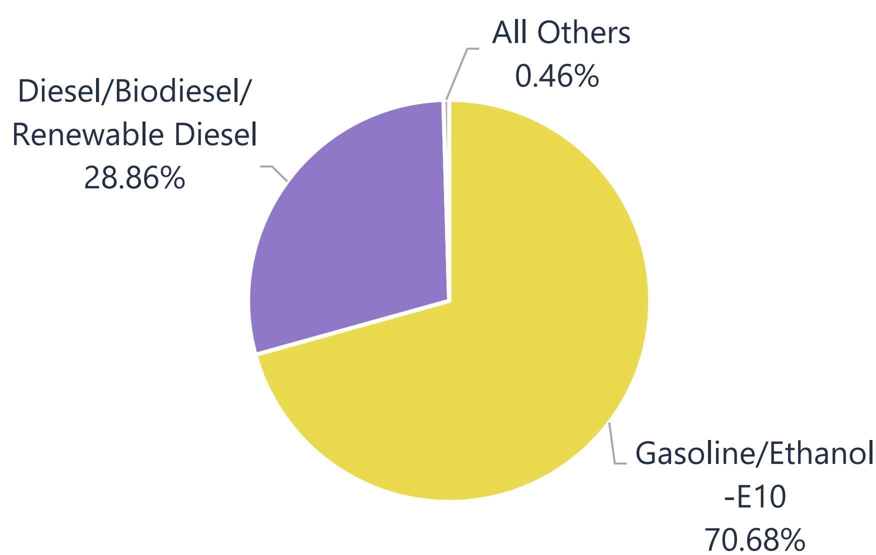
Policy Brief: Using Truck Efficiency to Reduce Fuel Consumption and Emissions

Opportunities to reduce fuel consumption and greenhouse gas (GHG) emissions in the transportation sector generally focus on three main areas: reducing vehicle miles traveled (VMT), improving the overall fuel efficiency of vehicles, and increasing use of alternative fuels. Freight trucks provide an essential service to Oregonians, delivering about 70 percent of freight goods used in the state.[1] In North America the average freight goods shipped by truck is a lower rate of 62.7 percent.[2] Unlike the passenger vehicle sector, where VMT can be reduced by increased focus on strategies like public transit, adoption of telecommuting options, and increased ride-sharing, there are fewer identified and workable solutions for delivering freight. Alternative fuels offer many opportunities for reductions in GHG emissions, and these are described in this report's section on Medium- and Heavy-Duty Alternative Fuels by Vehicle Use Case. Freight trucks, trailers, wheels, auxiliary power units, refrigeration units, and engines have been getting more efficient, leading to reductions in fuel use and GHG emissions as well as reductions in the associated fuel costs. The focus of this section is to provide information on additional efficiencies that can be added to existing vehicles that result in more efficient use of fuel and reduced emissions.

Heavy-Duty Fuel Use

Oregon's transportation sector consumes more energy and emits more GHGs than any other sector. In addition, Oregonians spent $7.7 billion on transportation fuels in 2018[3], of which about $5.4 billion goes to other states and countries where extraction, processing, and refining occurs.[4] In 2019, 70.7 percent of energy consumed on Oregon's highways was gasoline/ethanol or E10, primarily consumed by light-duty vehicles (for more information on light-duty vehicle effects on the transportation sector see the 2018 *Biennial Energy Report* Chapter 4). Diesel, biodiesel, and renewable diesel are the second most consumed on-highway transportation fuels with a 29 percent share in 2019.[5] Fossil fuel-based diesel accounts for 88 percent of diesel consumption and biodiesel and renewable diesel have an 11.7 percent share of diesel on-highway consumption.[6] All other fuels added up to only 0.46 percent of Oregon's on-highway fuel consumption.

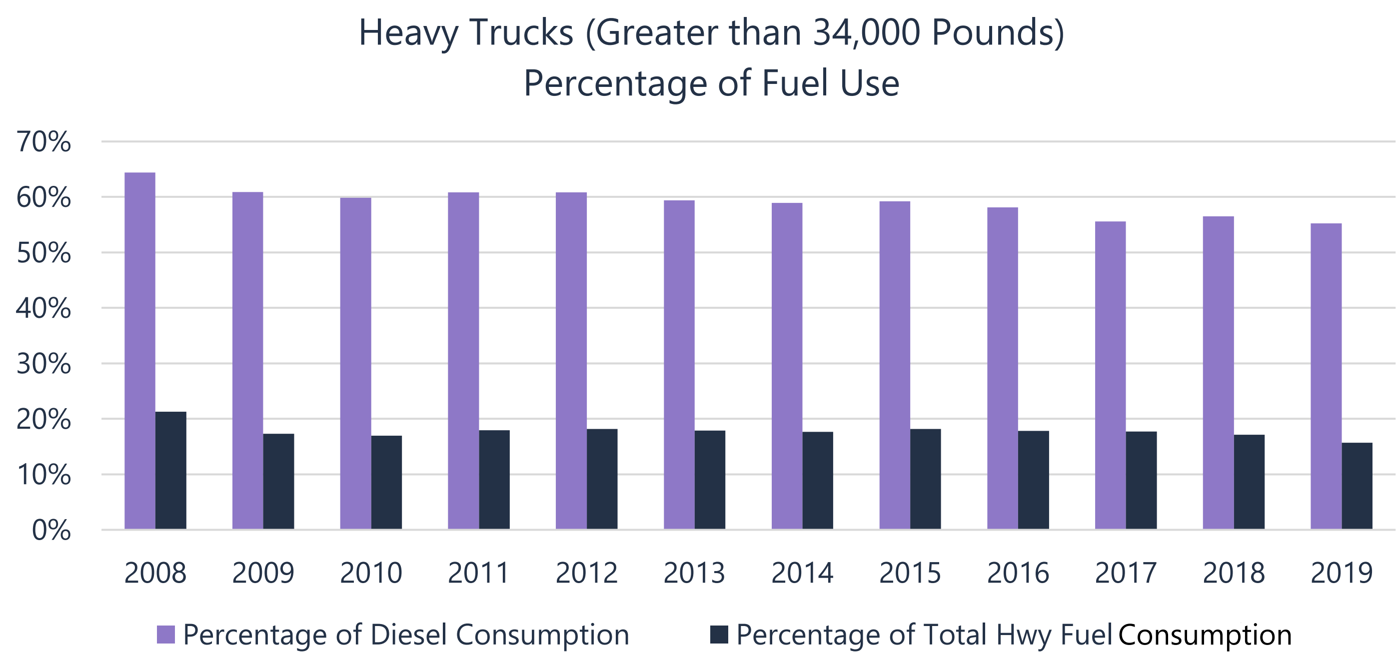
Figure 1: Oregon 2019 On-Highway Transportation Fuel Consumption[7]



Heavy-duty trucks (class 8 vehicles of 34,000 pounds gross vehicle weight or more) consumed 55 percent of diesel in the on-highway sector and 16 percent of total on-highway fuel in 2019.[8] The two weight classes of trucks that travel the most miles in Oregon are the weight classes of 78,001 to 80,000 and 104,001 to 105,500 pounds – these trucks account for a majority of the total commercial truck miles in

Oregon.[9] Tractor-trailers account for less than 2 percent of U.S. vehicles, however they represent about 20 percent of on-road transportation fuel use and GHG emissions nationally.[10] Since 2008, this segment has averaged 59 percent of the diesel and 17 percent of total on-highway fuel consumption in Oregon.[11]

Figure 2: Percent Diesel Consumption[11]



On-Highway Diesel Consumption[12] [13]

2018 U.S. Diesel consumption = 41,997,864,000 diesel gallons (EIA estimate)

2018 Oregon Diesel Consumption = 650,147,179 diesel gallons (ODOE & ODOT estimate)

Oregon percentage of U.S. consumption = 1.55%

Class 8 heavy-duty trucks have a wide range of annual VMT and typically fall between 45,000 miles per year for local haul operations up to 130,000 miles for long-distance routes. The Federal Highway Administration in 2018 estimated the average semi/trailer combination truck travelled 63,374 miles annually and had a fuel efficiency of 6.1 mpg in the U.S.[14] The figure below illustrates differences in fuel consumption and GHG emissions between diesel-fueled heavy-duty trucks and light-duty pickup trucks.

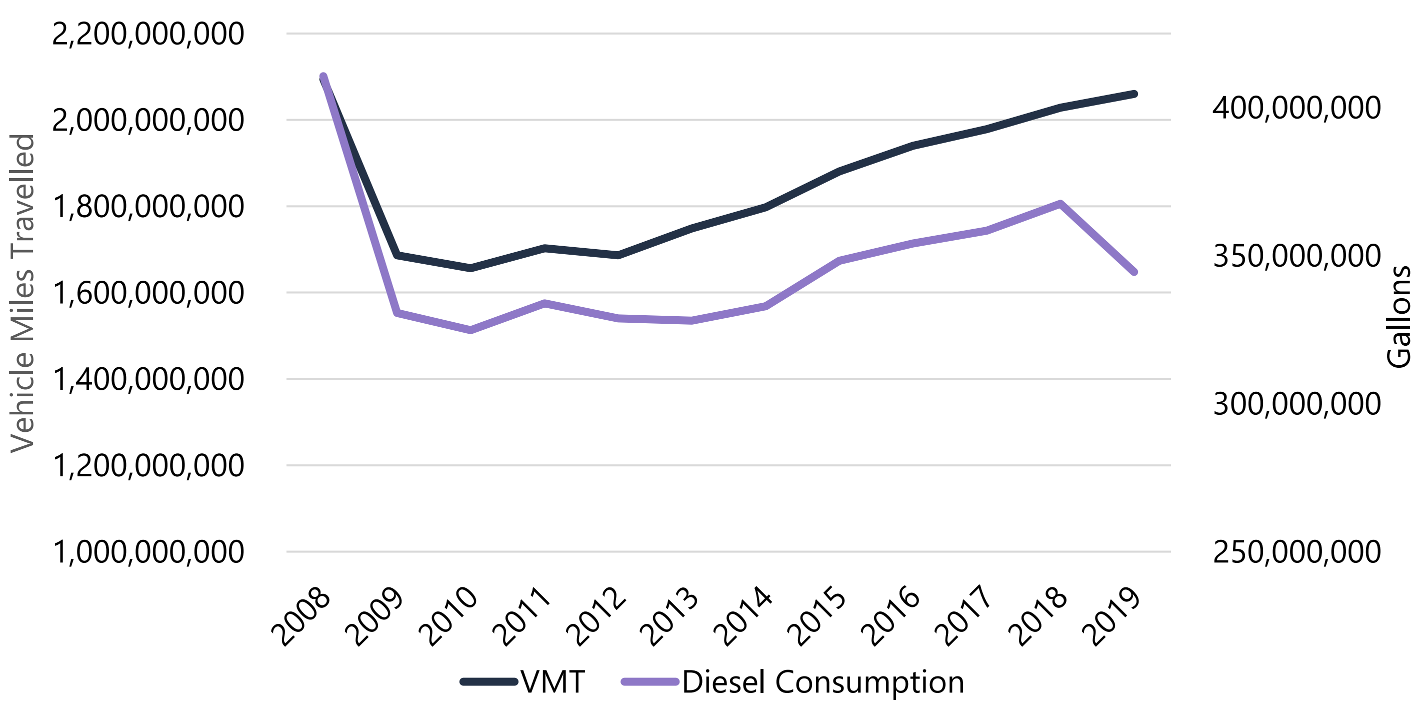
Figure 3: Comparison of a Semi and a pickup[15]

- 63,374 miles/year
- 6.1 mpg
- 10,389 gallons/year
- 137.7 MT CO2e/year

- 11,486 miles/year
- 17.9 mpg
- 642 gallons/year
- 8.5 MT CO2e/year

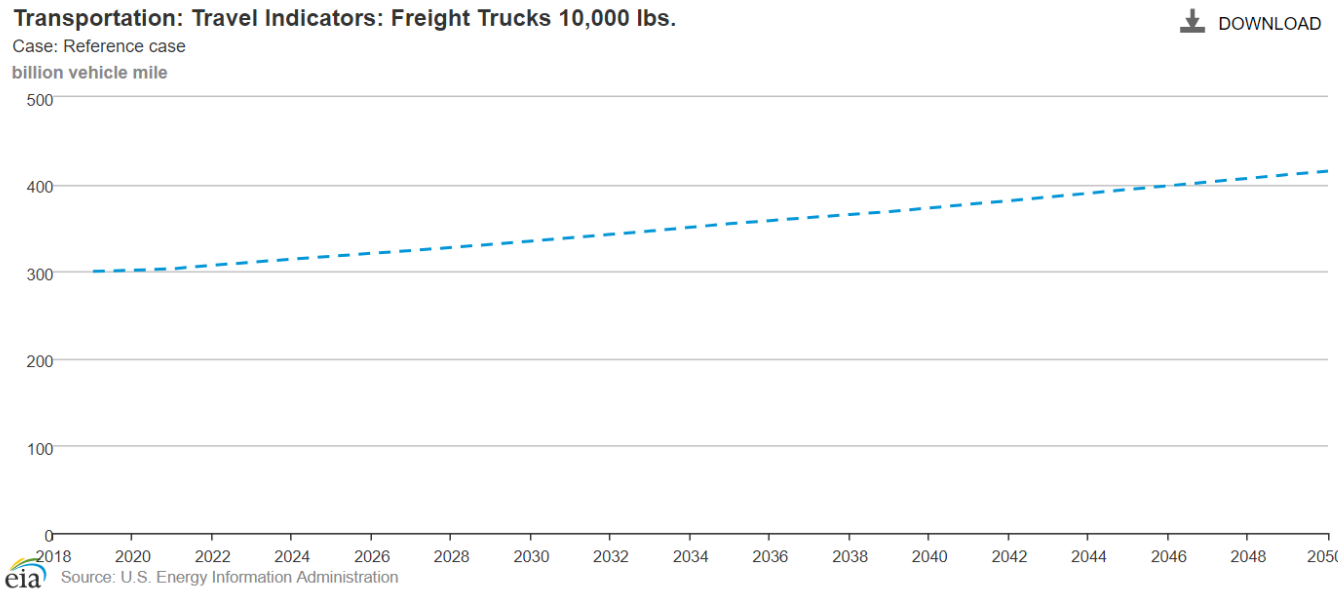
Vehicle miles traveled in Oregon for freight trucks over 34,000 pounds dropped by 19 percent from 2008 to 2009 due to the recession, but VMT has climbed steadily since then back to pre-recession levels (see chart below). It is of note that despite this increase in VMT, fuel consumption has decreased by 16 percent due to a 14.7 percent increase in truck fuel efficiency[16] over this same time period.

Figure 4: Oregon VMT and Fuel Consumption of Heavy Trucks (Greater than 34,001 Pounds)[16]



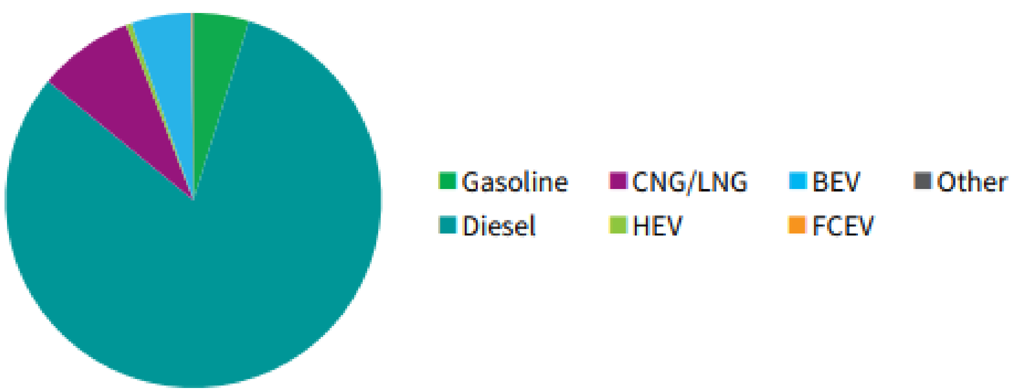
It is uncertain what potential effects the COVID-19 pandemic might have on freight VMT. However, in their 2020 Annual Energy Outlook, USDOE forecast that medium- and heavy-duty truck VMT would continue to rise due to increased freight demands and e-commerce.

Figure 5: EIA Annual Energy Outlook 2020[17]



Despite increasing adoption of alternative fuels in the medium and heavy-duty truck sector, IHS Markit forecasts that diesel-fueled trucks will still account for more than 80 percent of heavy-duty vehicles sold in 2040.[18]

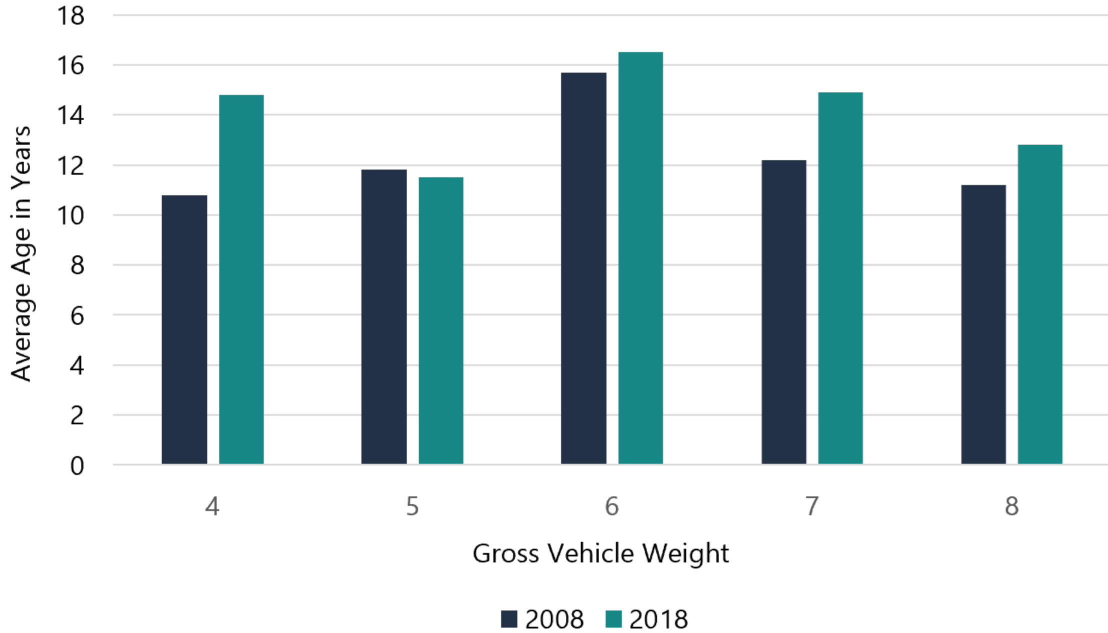
Figure 6: IHS Markit Transportation Fuel Forecast: Share of 2040 Sales by Fuel Type[18]



Diesel is expected to continue to play a large role in the medium- and heavy-duty sectors, in part because once purchased, these trucks remain in operation for over a decade. The average age of a Class 8 GVW[i] truck in the U.S. increased from 11 to nearly 13 years from 2008 to 2018, suggesting that the average age of trucks may continue to increase.

[i] Gross Vehicle Weight includes the vehicles and maximum payload weight it can carry, classified here into 5 separate weight classifications in order from lightest to heaviest.

Figure 7: IHS Markit data from NTEA-The Association for The Work Truck Industry[19]



Reducing fuel consumption, and thereby GHG emissions, can be achieved in three key ways:

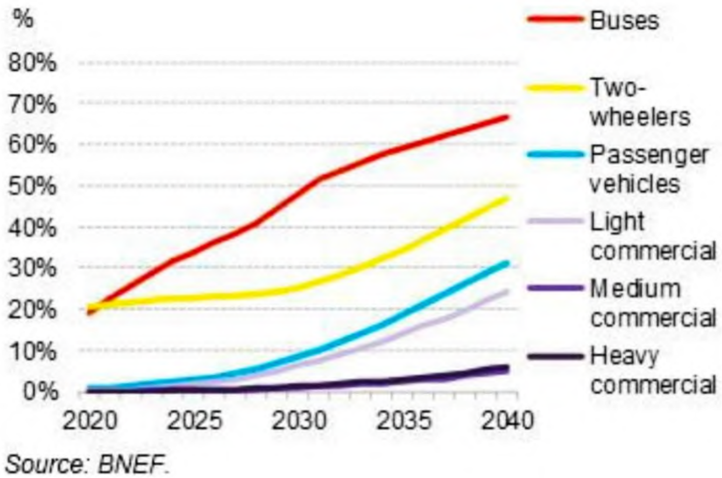
- Reducing vehicle miles traveled
- Using alternative fuels, vehicles, and modes of transportation
- Improving how efficiently vehicles consume fuel

Reducing VMT in the medium- and heavy-duty truck sectors is very limited, because there are few alternatives available to deliver freight. As Figure 5 from EIA illustrates, VMT is projected to climb in this sector. Additionally, many freight trucks consume fuel to do other work, such as refrigeration or powering equipment like hydraulic lifts, etc.

Alternative fuels such as electricity and hydrogen have great potential in the freight segment but are not commercially viable yet. Fuel cell trucks are not expected to be commercially viable until about 2027.[20] BloombergNEF forecasts that only regions with active plans for deployment of hydrogen refueling infrastructure will see some adoption, fuel cell medium-duty trucks will only have a 1.5 percent share of sales by 2040, and heavy-duty trucks are projected to have a 3.9 percent of sales.[21]

Electric vehicles use energy very efficiently, but battery weights reduce the total payload weight that the vehicle can carry. This can require more trucks to move the same amount of cargo. This would not only increase VMT but would have an effect on the economics of trucking and increase the cost to ship the same amount of cargo. As seen in the forecasts by IHS Markit and Bloomberg (see Figure 7 above and Figure 8 below), electric and fuel cell trucks are not estimated to have much market share even by 2040. There are niches where EV trucks can thrive, but many barriers remain (See Alternative Fuels for Medium-Duty/Heavy-Duty by Use Case Policy Brief). In both cases, expansive and expensive infrastructure will need to be deployed to support these technologies.

Figure 8: EV Share of Global Fleet: Bloomberg[ii] [22]



Renewable fuels such as renewable diesel and biodiesel can be used with no changes or very few changes to current fueling infrastructure and vehicles. These fuels can be used to reduce GHG emissions immediately and have seen increasing adoption levels in Oregon with a 11.7 percent share of diesel consumption in 2019.[23] Although not the focus of the discussion here, the efficiencies described in this topic combined with lower emissions fuels such as renewable diesel, may also reduce truck emissions' systems maintenance costs due to their cleaner burning benefits.

Opportunities to Reduce Fuel Consumption and GHG Emissions in Freight Trucks

Diesel trucks are anticipated to remain the largest share of freight vehicles in the next two decades, and these vehicles are increasingly being operated for longer periods of time. There are technologies that can be added to existing freight trucks and trailers that will enable trucking to operate more efficiently, by either physically improving the aerodynamic nature of the truck and trailer or through changes to accessories and auxiliary power units. In addition, training drivers to operate these vehicles in a more efficient manner can also have significant effects on fuel use. All these strategies have the effect of decreasing fuel consumption, which reduces fuel costs for owners and overall GHG emissions.

Driver Training and Vehicle Analytics

Commercial drivers can have a dramatic impact on vehicle efficiency and overall fuel consumption. A report by the American Trucking Association found a 35 percent fuel efficiency difference between drivers that used fuel efficiency techniques and those who don't.[24] This could be an extreme comparison and there is some overlap in speed and idling issues, which should be considered separately. The California Energy Commission selected a 4 percent possible benefit from driver training.[25]

Many people equate Artificial Intelligence (AI) with driverless trucks, but it is much more than that and can be used today to help drivers drive more efficiently and to avoid collisions. AI can also be used to coach a driver in real time to improve efficient use of fuel. It can also be used to determine the best route and vehicle required to maximize vehicle capacity and reduce fuel consumption. Additionally, machine learning will provide understanding of essential preventative maintenance routines to maximize fleet efficiency. Speed, braking, and steering data from drivers can help identify where a certain style of driving may correlate with mean-time-between-failure (MTBF) data to keep fleets operating in the most efficient manner.

[ii] Two-wheelers represent electric bicycles.

TITAN Freight Systems Goes Renewable and Saves

Oregon-based TITAN Freight Systems has been providing overnight transportation services in the Pacific Northwest since 1968. With 42 trucks and 124 trailers, TITAN's vehicles spend a lot of time (and miles) on the road throughout Oregon, Washington, and Idaho.

With about 40 percent of Oregon's greenhouse gas emissions coming from the transportation sector, TITAN wanted to do its part. And following the passage of HB 2007 in 2019, which set a goal to reduce diesel pollution in Oregon, TITAN turned to its own history of innovation and creativity to figure out how to reduce pollution from its fleet of trucks and trailers.

TITAN was already working on improving the fleet's miles per gallon, but even with add-ons like air deflectors, side skirts, low rolling resistant tires, and other aerodynamic improvements, the company wasn't yet reaching its MPG targets. So TITAN began to focus on achieving emissions reductions instead of looking at MPG. Converting the fleet to electricity would certainly make a difference, but the equipment and infrastructure wasn't quite there yet for heavy-duty electric vehicles.

In 2020, TITAN turned to 100 percent renewable diesel – a next-generation renewable fuel that creates fewer emissions. And because renewable diesel is ultimately indistinguishable from petroleum-based diesel once it's in the pipeline or in a vehicle, the company didn't need to make any vehicle or infrastructure modifications to begin using the fuel in its fleet.

The change has already paid off. Not only has the switch led to a 36 percent emissions reduction over the entire three-state fleet – and 67 percent in Oregon! – renewable diesel has a lower overall cost for TITAN. While the per-gallon cost of renewable diesel costs a little more than petroleum-based diesel, fleet maintenance costs are way down, with infrequent exhaust system maintenance and longer intervals between oil changes.

TITAN's model shows how innovation can make a big difference in reducing greenhouse gas emissions *and* in reducing the cost for business.

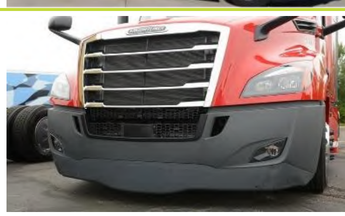
Truck and trailer add-ons for efficiency

There are several technologies that can be deployed together in different combinations that can reduce fuel consumption. At highway speeds, a class 7 or 8 tractor (the truck portion of a combination truck and trailer) will use up to 25 percent of the fuel consumption to overcome aerodynamic drag forces.[26] Significant improvements on fuel economy can be realized through small changes in the tractor and trailer aerodynamics of the vehicle.[26] Modern tractors can exceed 10 MPG fully loaded compared with their non-aerodynamic predecessors that rarely topped 6 MPG at highway speeds.[27] Regardless of the fuel being used, aerodynamic improvements can significantly reduce fuel consumption and thereby fleet costs and emissions, and many of these have payback of less than a year to 2 years.

Below are some common technologies available today and the associated fuel efficiency improvements. Not all these technologies can be applied to a single tractor trailer, and they are not additive. There are interactions that happen between devices that may reduce effectiveness. Additionally, not all tractors and trailers are the same, so devices will work differently on one vehicle than they might on another. For this reason, efficiency values are presented as a range to account for these variations. The greatest aerodynamic drag reduction can be achieved in four main areas: front, gap, underbody, and rear.

Unless otherwise noted the below estimations were taken from a California Energy Commission Report.[28]

Table 1: Tractor Upgrades

	Technology	Description	Fuel Improvement
Cab Roof Deflector		Creates smoother airflow over the cab and then onto the trailer	4% +/- 1%[28]
Trailer Gap		Decreases air turbulence between the cab and the trailer	0.7 to 3% +/- 1%[28]
Improved Air Dam Front Bumper		Smooths airflow in the front of the truck and directs it around the truck	1.5% +/- 0.3%[28]
Aero-Dynamic Mirrors		Decreases aerodynamic drag around the mirror	1.2% +/- 0.3%[28]
Under-hood Air Cleaners		Decreases aerodynamic drag by moving the air filters outside the hood to the engine compartment	1.5% +/- 0.5%[28]

Tractor Side Skirts		Reduces drag from front wheel of the tractor to rear wheel	2% +/- 1%[28]
Full Roof Fairing (with roof cap)		Reduces drag for sleeper cab and smooths air to trailer	7% +/- 2%[28]

Table 2: Wheel Technology Upgrades

Technology		Description	Fuel Improvement
Low Rolling Resistance Tires		Reduces friction between the tire and the road which reduces engine load	3.3 to 6%[28]
Aero-dynamic wheel covers		Reduces wind drag at the wheel	0.65% to 1.5% +/-1%[29]
Aero-dynamic mud flaps		Allows air flow through the flap but still hinders debris and water	1% to 10%[30]

Table 3: Trailer Upgrades

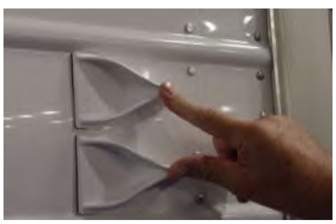
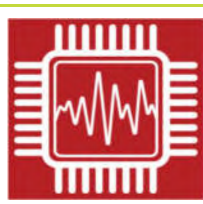
Technology		Description	Fuel Improvement
Smooth Trailer Sides		Smooth trailer sides with no posts or trailer curtains reduce drag and increases aerodynamic efficiency	2% to 4%[28]
Side Skirts		Reduces air turbulence under the trailer and to the rear axles and wheels	Up to 7%[28]
Boat Tail		Decreases turbulence at the rear of the trailer which decreases drag	3 to 5%[28]
Vortex Generators		Help maintain steady airflow to reduce aerodynamic drag	2 to 9.5%[28]
Trailer Face Fairings		Decreases the gap between the tractor and trailer reducing aerodynamic drag	1 to 3%[28]

Table 4: Additional Truck Upgrades

Technology		Description	Fuel Improvement
Speed Limiters		Travelling at 75 mph a truck consumes 27% more fuel than one travelling at 65 mph[31]	3-7%
Artificial Intelligence (AI)		A driver can be informed to maximize efficiency and safety from real time dashboard alerts	Up to 5%[32]

For additional information, the Environmental Protection Agency's SmartWay program has a list of 106 verified aerodynamic technologies that includes information on fuel savings of the device, testing method, and test protocol.[33]

Idle Reduction Technologies

Many freight tractors spend considerable amounts of time idling, whether in traffic, while refueling, or during driver rest periods. In addition to the costs incurred for the fuel use, engine idling causes excessive engine wear and increases toxic and GHG emissions that pose health risks, particularly to drivers of the vehicles.[34] Argonne National Laboratory estimates that in the U.S., "rest-period truck idling consumes up to 1 billion gallons of fuel annually."[35] Many instances of idling occur for heating and cooling of the vehicle, for driver comfort and, in some instances, are due to running auxiliary systems that might do work or keep cargo in the correct temperature range. One truck can consume 0.8 gallons of fuel per hour and typically a long-haul truck will idle about 1,800 hours a year, using about 1,500 gallons.[36] When considering all road vehicles, from passenger cars to heavy-duty trucks, Argonne National Laboratory estimates that each year more than 6 billion gallons of gasoline and diesel combined are used only for idling in the U.S.[37]

The amount of fuel consumed when idling is dependent on the size of the vehicle's engine and the systems that run off these engines. The graphic below compares different sized and fueled vehicles and shows that different types of vehicles doing different types of work can have significant differences in idling fuel consumption.

Figure 9: Fuel Consumption at Idle for Selected Gasoline and Diesel Vehicles[38]

Depending on how the vehicle is used and what activities contribute to idling time, there are idling reduction technologies that provide drivers and owners several options to fit their specific needs:

- **Automatic engine shut down/start up:** An automatic engine shut down/start up system controls the engine by stopping or starting it without operator action, based on a set time period or ambient temperature, and other parameters (e.g., battery charge).
- **Fuel-Operated Heaters:** These are small, lightweight heaters that burn fuel from the main engine fuel supply or a separate fuel reserve. They provide heat only and can be used in conjunction with cooling systems depending on comfort needs. These are primarily used to support tractor hotel functions that are needed when the driver is not on the road.
- **Auxiliary Power Units/Generator Sets:** These are small, diesel-powered engines (5 to 10 horsepower) that are installed on the truck to provide air conditioning, heat, and electrical power to run accessories like lights, on-board equipment, and appliances. These units sip fuel at 0.2 to 0.5 gallons an hour. At 0.3 gallons an hour, an APU would save 900 gallons of diesel and reduce GHG emissions by 11.88 MT annually. At $3.00 a gallon for diesel, it would also save the owner $2,700 a year.
- **Electrification:** Electrification refers to a technology that uses electricity-powered components to provide the operator with climate control and auxiliary power without having to idle the main engine. This can take the form of on-board equipment, e.g., power inverters, plugs; off-board equipment, e.g., electrified parking spaces or systems that directly provide heating, cooling, or other needs; or a combination of the two.

The systems above have an estimated payback of two to 36 months.[39]

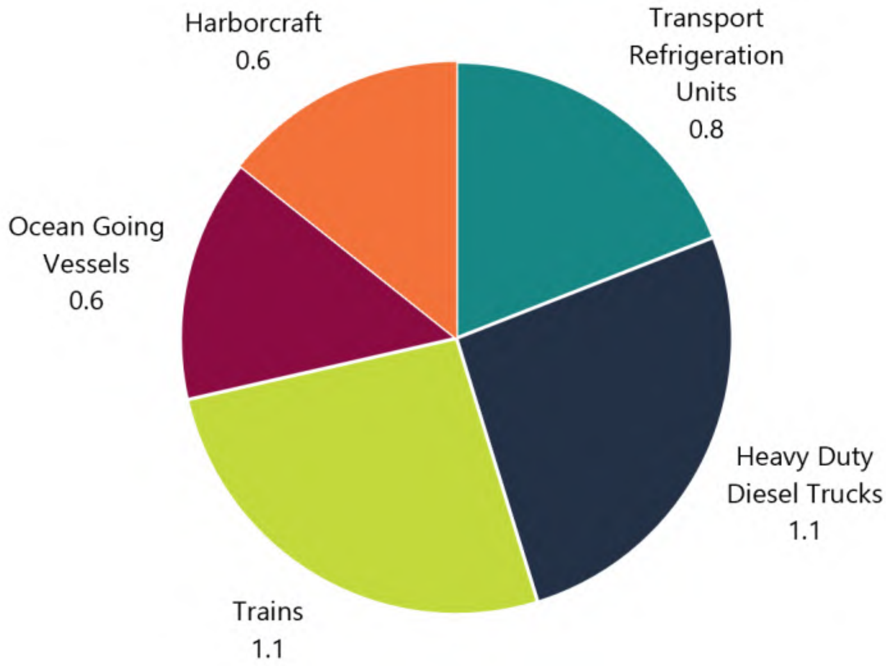
In addition to these technologies, there are opportunities to address idling emissions through driver training or through state and local policies that encourage adoption of technologies or behaviors that limit fuel use and emissions associated with vehicle idling.

Transport Refrigeration Units

Transport Refrigeration Units, sometimes called reefers, are used on vans, trucks of all sizes, rail, shipping containers, and trailers to provide temperature control for temperature sensitive freight. Historically this has been done with a refrigeration or heating unit powered by a small diesel motor within the TRU. These diesel-powered units are not only used while transporting goods but are also used at distribution centers and grocery stores to store temperature-sensitive goods, such as food, pharmaceuticals, chemicals, photographic film, and artwork. Some companies use TRUs for supplemental cold storage space, particularly in the weeks leading up to major holidays or events. Because they burn diesel, TRUs are a significant source of fuel use and associated air pollutant emissions. Often, these TRUs are congregated at large distribution centers and other cold storage facilities, which contribute to an increased health risk for nearby communities.[40] The California Air Resources Board found that TRUs accounted for nearly 20 percent of total freight PM2.5.[iii]

[iii] PM2.5 references particulate matter that is less than 2.5 microns in diameter. These particles are small enough to be inhaled deeply into the lungs where they can enter the bloodstream. Exposure to PM2.5 is associated with increased health risks, including aggravated asthma, decreased lung function, respiratory symptoms, irregular heartbeat, heart

Figure 10: Large Vehicle PM2.5 Contribution in California, 2019 (Tons Per Day (tpd))[41]



An alternative to standard diesel-powered TRUs are eTRUs, which use electricity for power either exclusively or part of the time. Fully electric eTRUs are powered by a rechargeable battery pack for shorter distances, usually daily trips. Longer haul trips often use hybrid eTRUs, which use a diesel-powered generator to power the system while in transit. Standby units, which only plug in at a distribution center or warehouse (shore power), generally use diesel when on the road. However, while away from the trucks base and when electric outlets are available, all standby eTRUs can be plugged in to run the unit.

Figure 11: TRUs on Trucks, Trailers, and Rail Cars[42]

A recent California Air Resources Board report estimated that TRU equipped trailers at truck/trailer distribution centers on average run 2,201 hours per year.[43] The following table was developed to illustrate reductions in fuel consumption, money spent on fuel, and GHG emissions at a distribution center if the center had shore power and the trailer had standby eTRUs compared to the standard diesel-equipped TRU.

attacks, and premature death in people with heart or lung disease. *Environmental Protection Agency. Particulate Matter (PM) Basics* and *Health and Environmental Effects of Particulate Matter (PM).*

Table 5: Diesel TRU Compared to eTRU[44]

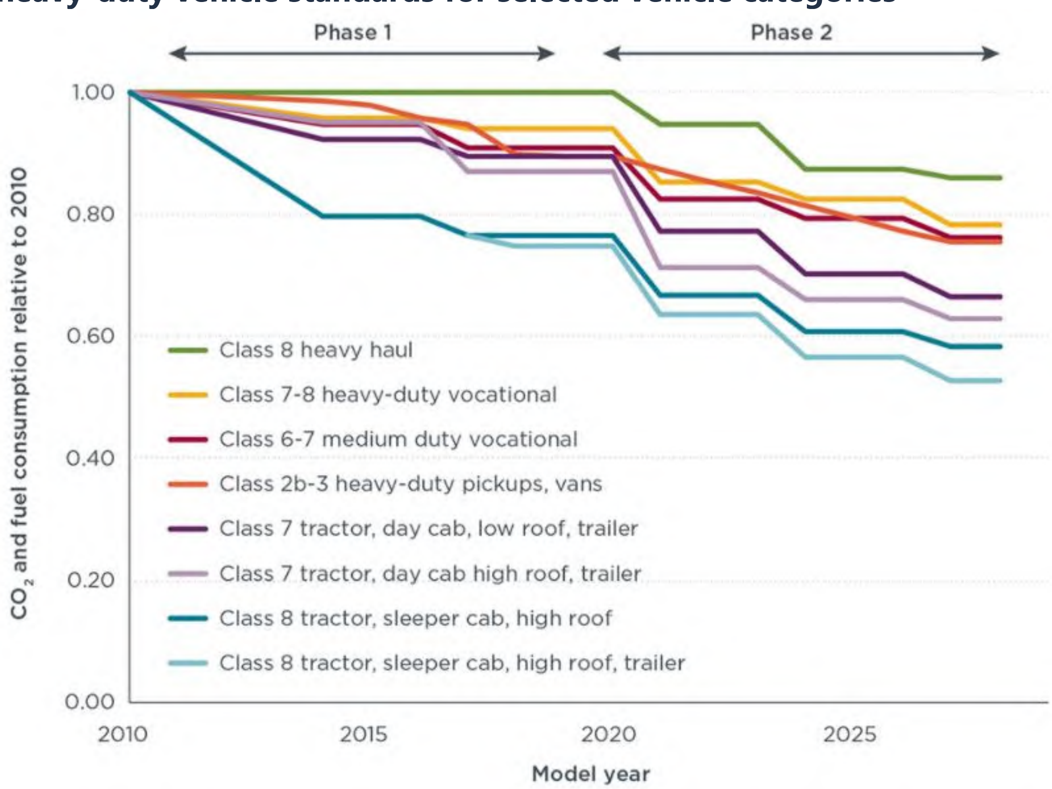
Comparing a Diesel TRU with Shore Power eTRU				GHG Emissions (MTCO2e)
	Hours	**Fuel Consumed**	**Fuel Cost**	
Diesel TRU	2,201	1,692 gallons	$5,077	22.42
eTRU	2,201	17,828 kWh	$1,605	6.95
		Reductions	$3,473	15.47

Vehicle Engine Efficiencies for New Trucks

The U.S. Environmental Protection Agency (EPA) and National Highway Traffic Safety Administration (NHTSA) coordinated to develop standards to enable the production of clean vehicles, with reduced GHG emissions and improved fuel use from on-road vehicles and engines. In 2011, they introduced fuel economy standards for medium- and heavy-duty trucks manufactured in model years 2014-2018. The agencies estimate that the combined standards will reduce CO2 emissions by about 270 million metric tons and save about 530 million barrels of oil over the life of the vehicles.[45] The agencies have now finalized Phase 2 standards for these vehicles through 2027 that will achieve up to 25 percent lower CO2 emissions and fuel consumption for combination tractors compared to phase one standards.[46] The performance-based standards provide multiple technological pathways to compliance and will begin phasing in beginning in model year 2021.

The program also includes trailers that start in Model Year (MY) 2018 and achieve 9 percent reduction in fuel consumption and CO2 emissions by MY 2027 over the 2017 baselines.[47]

Figure 12: Summary of CO2 and fuel consumption reduction from adopted Phase 1 and Phase 2 heavy-duty vehicle standards for selected vehicle categories[48]



Potential Fuel Savings and GHG Reduction Scenarios

Using the technologies described above in different combinations could significantly reduce energy use and GHG emissions in the state. The following tables represent different scenarios that include combinations of technologies and adoption levels. They were chosen to illustrate that even small measures with low adoption rates could have significant impacts. They also include high-level estimates of diesel consumption reductions and thereby GHG emissions reductions that could result from these scenarios. These estimates are on an annual basis; the total fuel savings and emissions reductions over the life of a vehicle would be much higher. These estimates are for illustrative purposes only, and use average fuel, travel, and end fuel efficiency numbers. Further analysis is needed to better understand any actual benefits and GHG reductions in freight trucks operating in Oregon.

Background data for estimates:

Table 6: 2018 Oregon Diesel Truck Baselines[49]

2018 Oregon Diesel Trucks > 34,000 Pounds	
Vehicle Miles Travelled	2,028,565,930[50]
Average MPG	5.52[51]
Registered Truck Tractors	28,165[52]
Estimated Oregon VMT/Truck	72,024 miles/year
Total Gallons of Diesel Consumed	367,493,828
Lifecycle Greenhouse Gas Emissions	4,869,091 MTCO2e

The analysis in the table below illustrates three of the technology areas discussed above: truck efficiency measures, idle reduction, and eTRUs. This could be three separate projects or one specific project; the analysis is a high-level look at potential opportunities to reduce fuel consumption and thereby save money and reduce GHG emissions.

Table 7: Single Truck and Reefer Trailer-Baseline[53]

Class 8 Long-Haul Truck-72,024 miles/year & TRU Trailer	Gallons of Diesel Consumed	GHG Emissions (MTCO2e)	Diesel Fuel Cost ($3.00/gal)
Baseline On-Highway Truck Fuel Consumption	13,048	173	$39,144
Baseline Truck Idling	1,440	19	$4,320
TRU Trailer Unit	1,692	22	$5,077
Totals	**16,180**	**214**	**$48,541**

The table below includes efficiency measures that have been added to the truck such as aerodynamics measures, low rolling resistance tires, or any mixture of measures mentioned in the Truck Efficiency section above to increase the efficiency to 6.07 mpg, an estimated 10 percent gain. An Auxiliary Power Unit (APU) to reduce idling has been added and an eTRU standby unit is on the reefer trailer to enable the trailer to be plugged into a power source when at a distribution center or warehouse. This could be achieved through one project or three separate projects. This is a high-level analysis used to illustrate potential fuel and emissions reductions as well as monetary savings.

Table 8: Efficient Truck, APU and eTRU scenarios[54]

Class 8 Long-Haul Truck-72,024 miles/year & TRU Trailer	Energy Consumed	GHG Emissions (MTCO2e)	Fuel Cost ($3/gal-.095/kWh)
Efficient Truck (10 percent efficiency gains)	11,862 gal	157.16	$35,586
Truck Idling (APU)	540 gal	7.2	$1,620
eTRU Trailer Unit (Standby) dge[iv]	17,828 kWh or 468 dge	6.95	$1,605
Totals	**12,872 dge**	**171.26**	**$38,811**

Not only do these technologies reduce fuel consumption and GHG emissions but, in the example, above, the owner or owners would save $10,770 a year in fuel costs.

What if 10 or 20 percent of combination trucks registered in Oregon were to use the same efficiencies, idle reduction technology and eTRUs? What savings could we expect? See the table below.

Table 9: Multiplied benefits of adoption of efficient trucking technologies[55]

Class 8 Long-Haul Truck-72,024 miles/year & TRU Trailer	Energy Reductions (In dge)	GHG Emissions Reductions (MTCO2e)	Fuel Cost Reductions
10% of Registered Trucks-Efficient, APUs and eTRUs	9,317,717	121,430	$27,405,261
20% of Registered Trucks-Efficient, APUs and eTRUs	18,635,435	242,860	$54,810,523

New Class 8 trucks from model years 2020-2024 are expected to see efficiency improvements of 31 percent for sleeper-cabs and 22 percent for day-cabs compared to 2010 trucks.[56] In 2010, the Federal Highway Administration estimated Class 8 combination trucks to have an efficiency of 5.9 MPG.[57] For the high-level analysis, an efficiency increase of 26.5 percent will be used. This is the difference between the sleeper-cab and the day-cab and will bring the fuel efficiency up to 7.5 MPG.

[iv] dge stands for diesel gallon equivalent. This is the amount of energy that is equivalent to a gallon of diesel.

Table 10: New Efficient Truck Reductions[58]

New 26.5 % more Efficient Class 8 Long-Haul Truck-72,024 miles/year	Energy Reductions (In dge)	GHG Emissions Reductions (MTCO2e)	Fuel Cost Reductions
10% of Registered Trucks Are New Efficient Trucks	18,392,018	243,689	$55,176,055
20% of Registered Trucks Are New Efficient Trucks	36,784,036	487,378	$110,352,109

Renewable fuels like biodiesel and renewable diesel have much lower carbon intensities than petroleum-based diesel. The table below looks at scenarios where 10 percent or 20 percent of the Class 8 combination trucks registered in Oregon run a 20 percent, 50 percent, or a 99.9 percent blend of these renewable fuels (the carbon intensities for biodiesel and renewable diesel are averaged for this exercise).[v]

Table 11: Renewable Fuel Emissions Reductions[59]

Class 8 Long-Haul Truck-72,024 miles/year & TRU Trailer	GHG Emissions Reductions (MTCO2e)
10% Trucks Use a 20% Biofuel Blend	63,300
10% Trucks Use a 50% Biofuel Blend	187,077
10% Trucks Use a 99.9% Biofuel Blend	392,961
20% Trucks Use a 20% Biofuel Blend	126,599
20% Trucks Use a 50% Biofuel Blend	374,155
20% Trucks Use a 99.9% Biofuel Blend	785,923

Table 12 below illustrates potential GHG reductions if the following measures were adopted by 10 percent of existing Oregon registered trucks:

- Increased vehicle efficiency by 10 percent by adding aerodynamics, efficient wheels and tires, and other measures mentioned in the truck efficiency section.
- Added APUs for idle reduction.
- Reefer trailers converted to eTRUs.
- Ten percent of existing trucks were replaced with new trucks as analyzed above; and
- Ten percent of trucks consumed a biofuel blend of 99.9 percent or the same amount of biofuel was consumed in varying blend rates.

[v] From those emissions reductions, the emissions reductions associated with the baseline of a 5 percent fuel blend, which is currently required in Oregon, are subtracted.

If all of these measures were adopted by 10 percent of Oregon's registered 34,000-pound-and-over older heavy-duty trucks and 10 percent new trucks were registered, the state would realize a 16 percent drop in lifecycle GHG emissions in the greater-than-34,000-pound diesel sector or 3 percent of the total on-highway transportation lifecycle emissions.

Table 12: Oregon 10 percent Registered Trucks Adopt Efficiency and Fuel Measures to Reduce GHG Emissions[60]

All Measures Added Together	GHG Emissions Reductions (MTCO2e)
10% of Registered Trucks Efficient, APUs and eTRUs	121,430
10% of Existing Trucks Replaced with New Trucks	243,689
10% Trucks use 99.9% Blend of Biofuel	392,961
Total Reduction	758,081

The next table steps this up to a 20 percent share of registered combination trucks adopting the measures outlined above. At 20 percent, GHG emissions in the greater-than-34,000-pound truck sector are reduced by 33 percent and total on-highway transportation emissions are reduced by 6 percent.

Table 13: Oregon 30 percent Registered Trucks Adopt Efficiency and Fuel Measures to Reduce GHG Emissions [61]

All Measures Added Together	GHG Emissions Reductions (MTCO2e)
20% of Registered Trucks Efficient, APUs and eTRUs	242,860
20% of Existing Trucks Replaced with New Trucks	487,378
20% Trucks use 99.9% Blend of Biofuel	785,923
Total Reduction	1,516,161

The technologies in the measures above are currently available. In the case of truck and trailer efficiencies, the costs of purchasing and installing them can typically be paid for through reduced fuel consumption over the course of one to three years.[62] [63]

Biodiesel and renewable diesel recently have been very cost competitive with diesel. It is unknown if any retail stations in Oregon offer renewable diesel, but several fleets buy it in bulk. Prices can vary depending on the amount of fuel a fleet purchases over a period and the distance from major terminals where these fuels are available. Table 14 below compares B5, an Ultra-Low Sulfur Diesel (5 percent biodiesel) blend that is required as a minimum blend in Oregon, to these fleets purchasing R99, a 99 percent blend of renewable diesel.

Table 14: Cost Difference for Four Fleets for B5 compared to R99[64]

Fleet Cost Differences When Purchasing R99		
Fleet	**Period**	**$ Difference Compared to B5**
Eugene Water & Electric Board	1/01/20 to 9/14/20	$0.11
Dept. of Administrative Services	01/30/20 to 8/14/20	($0.03)
OR Dept. Of Transportation	1/02/20 to 9/14/20	($0.13)
Titan Freight Systems	2nd Quarter 2020	$0.10

As illustrated in the chart, two of the fleets averaged reduced prices of renewable diesel compared to B5 diesel. The Oregon State fleets are some of the largest in the state, which does influence price.

Some Oregon users such as Titan Freight Systems[65] and Eugene Water and Electric Board[66] claim the added costs for the fuel is made up by a reduction in vehicle maintenance costs in areas such as emissions system maintenance, oil change intervals, and diesel emissions fluid reduction due to these fuels cleaner burning benefits.

As noted by IHS Markit and Bloomberg, clean alternatives such as fuel cells and EVs are not expected to have much market share in the 34,000-pound truck segment out to 2040 and 2050 respectively, but there are current solutions for reduction in petroleum consumption and GHGs and toxic air emissions with current technology for this heavy-duty truck sector. Not only do these technologies reduce petroleum consumption and GHG emissions, they can also save fleets money in the long run.

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Policy Brief: Alternative Fuels Assessment by Use Case for Medium-Duty and Heavy-Duty Fleets

Alternative fuel use has been increasing in Oregon over the last 15 years.[1] In 2019, nearly 9 percent of all on-highway transportation fuel consumption in Oregon came from alternative fuels. Use of these fuels can improve performance, reduce pollutants, and supports Oregon's energy independence. Support for increased adoption of cleaner fuels and cleaner vehicles is part of the Oregon Statewide Transportation Strategy, or STS.[2] The intent of this topic is to highlight considerations for fleet managers when assessing use of alternative fuels, including vehicle type and typical daily use, total cost of ownership over the life of the vehicle, and the availability of vehicles and fueling infrastructure.

Alternative Transportation Fuels

Alternative transportation fuels are generally defined as those used in place of petroleum-based fuels, namely gasoline and diesel. Three out of four trucks on the road are powered by diesel and 98 percent of the large over-the-road Class 8 trucks are diesel.[3] Alternative fuels can vary widely in their effect on vehicle performance, availability, cost, and environmental impacts, such as resultant greenhouse gas and pollutant emissions. Each of these can affect what alternative fuel is best for specific sectors or activities.

Alternative transportation fuels include the following:

- Natural gas in the form of compressed natural gas (CNG) or liquefied natural gas (LNG)
- Renewable natural gas in the form of CNG or LNG
- Propane
- Renewable propane
- Biodiesel
- Renewable diesel
- Ethanol
- Electricity in the form of batteries
- Hydrogen in the form of hydrogen fuel cells

This document focuses on natural gas (including renewable natural gas), biodiesel, renewable diesel, electricity, and hydrogen. Ethanol and propane are not included in this topic as they are not used extensively in the medium- and heavy-duty truck segment. Although gasoline engines can be used in applications where low weight and power requirements are the norm, most uses of medium- and heavy-duty trucks require the durability and power that diesel delivers. In 2019, Ford was the only manufacturer offering a gasoline version in the Class 6 and 7 work truck segments.[4] There has been some pilot work with dual-fuel propane diesel systems, where both fuels are used at the same time in different blends depending on loading, but it is not widely used.

Ethanol use in Oregon has contributed greatly to transportation emissions reductions due to its wide use in the light-duty sector, which consists of about 70 percent of the energy used in the on-highway sector.[5] Because ethanol is blended into gasoline and because propane primarily relies on gasoline technologies,[i] these fuels don't have a high penetration in the medium and heavy-duty truck segment.

Blended Fuels

Many alternative fuels can be blended with a conventional fossil "base" fuel. For example, ethanol is blended with gasoline, and renewable natural gas blended with conventional natural gas can be used for LNG and CNG. While both biodiesel and renewable diesel are blended with conventional diesel, renewable diesel[ii] is chemically identical to and can be used as a 100 percent replacement for petroleum diesel in any diesel engine and in any weather.[6] Biodiesel's performance degrades in low temperatures, and thus it is used in most diesel engines as part of a blended fuel with renewable or petroleum diesel at a ratio no more than 20 percent biodiesel. Most engine manufacturers will warranty their engines to use up to 20 percent biodiesel. Renewable diesel will always have a 0.01 percent blend of conventional diesel to qualify for the Renewable Fuel Standard's biodiesel blender tax credit,[iii] [7] though Renewable Energy Group is selling a fuel in the West that is a blend of 20 percent biodiesel and 80 percent renewable diesel.[8]

In Oregon, regulations require that all gasoline sold in the state, with some exceptions, must be blended with 10 percent ethanol and all diesel fuel sold must be blended with at least 5 percent biodiesel.[9]

Medium- and Heavy-Duty Fleet Vehicle Types and Uses

The Federal Highway Administration classifies vehicles into the categories light, medium, or heavy duty based on gross vehicle weight or the maximum weight of the vehicle as specified by the manufacturer, inclusive of fluids, passengers, and cargo. The vehicle's gross vehicle weight rating (GVWR) translates into its class categorization, with classes ranging from 1-2 for light duty, 3-6 for medium duty, and 7-8 for heavy duty (see Figure 1).

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[i] Propane is typically used in gasoline-based engines as it is difficult to ignite in a diesel engine by itself. Propane has found wide acceptance in the school bus segment of medium-duty vehicles as they are a low mileage, low weight application.

[ii] While they're both made from the same feedstocks – vegetable oils, animal fats, used cooking oils – renewable diesel and biodiesel are processed differently and are different fuels with distinct properties.

[iii] The national Renewable Fuel Standard requires U.S. transportation fuels to contain a minimum amount of renewable fuels. Compliance is achieved when a renewable fuel is blended with a petroleum-based transportation fuel or by obtaining credits called renewable identification numbers, or RINs, to achieve an EPA-specified volume of renewable fuel.

Figure 1: Federal Highway Administration Classification of Vehicles by Weight[10]

Gross Vehicle Weight Rating (lbs)	Federal Highway Administration		US Census Bureau
	Vehicle Class	GVWR Catagory	VIUS Classes
<6,000	Class 1: <6,000 lbs	Light Duty <10,000 lbs	Light Duty <10,000 lbs
10,000	Class 2: 6,001 – 10,000lbs		
14,000	Class 3: 10,001 – 14,000 lbs	Medium Duty 10,001 – 26,000 lbs	Medium Duty 10,001 – 19,500 lbs
16,000	Class 4: 14,001 – 16,000 lbs		
19,500	Class 5: 16,001 – 19,500 lbs		
26,000	Class 6: 19,501 – 26,000 lbs		Light Heavy Duty: 19,001 – 26,000 lbs
33,000	Class 7: 26,001 – 33,000 lbs	Heavy Duty >26,001 lbs	Heavy Duty >26,001 lbs
>33,000	Class 8: >33,001 lbs		

Class 1 and 2 light-duty vehicles include passenger vehicles like sedans, sport utility vehicles, minivans, utility vans, and full-size pickup trucks. Medium-duty vehicles (classes 3-6) include city delivery vehicles, walk-in trucks, bucket trucks, beverage delivery trucks, and school buses (see Figure 2), and heavy-duty vehicles include city transit buses, semis, refuse trucks, refrigerated vans, etc. (see Figure 3).

Figure 2: Example Types of Medium-Duty Vehicles According to Federal Highway Administration Classification[11]

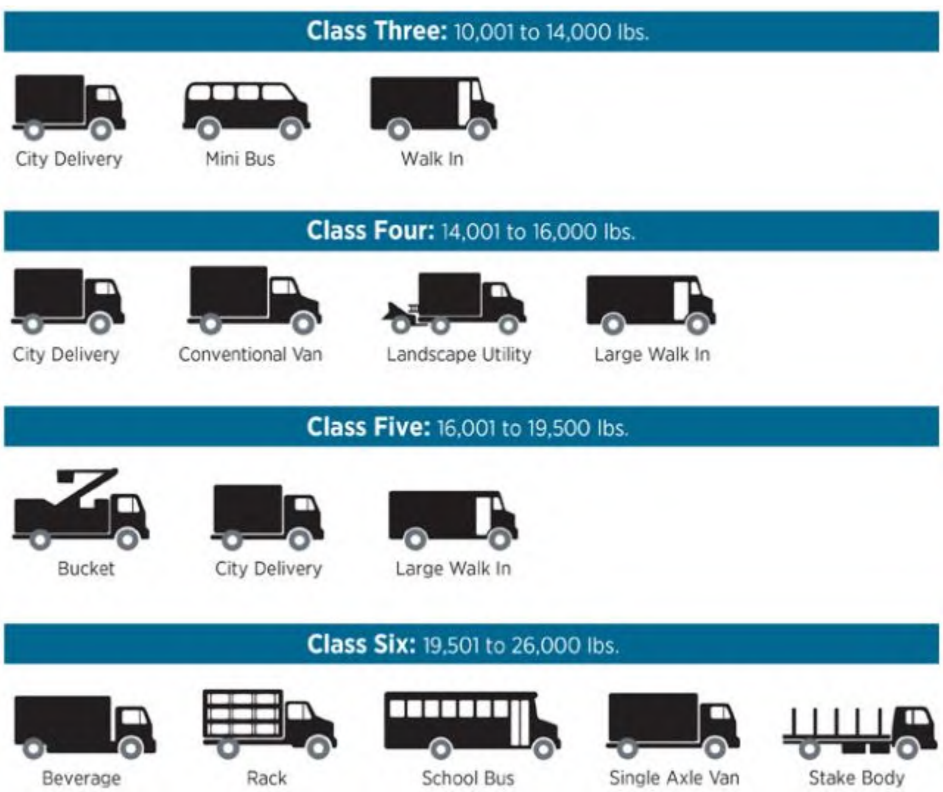
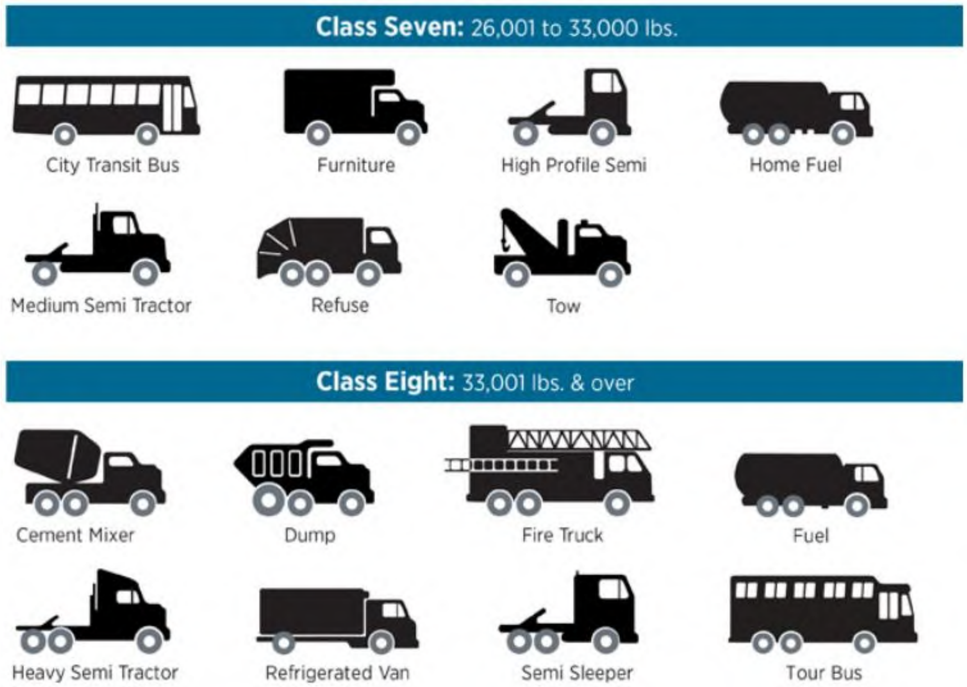


Figure 3: Example Types of Heavy-Duty Vehicles According to Federal Highway Administration Classification[12]



Determining the Optimal Alternative Fuel Vehicle Options by Use Case

When determining the best medium- and heavy-duty alternative fuel vehicles for a fleet, there are a number of factors to consider based on the operation of the vehicles, fueling timing and infrastructure needs, the climate and terrain where the vehicles will operate, existing air quality requirements and supporting clean fuels policies, cost, and the current availability of vehicles.

Duty Cycle and Drive Cycle

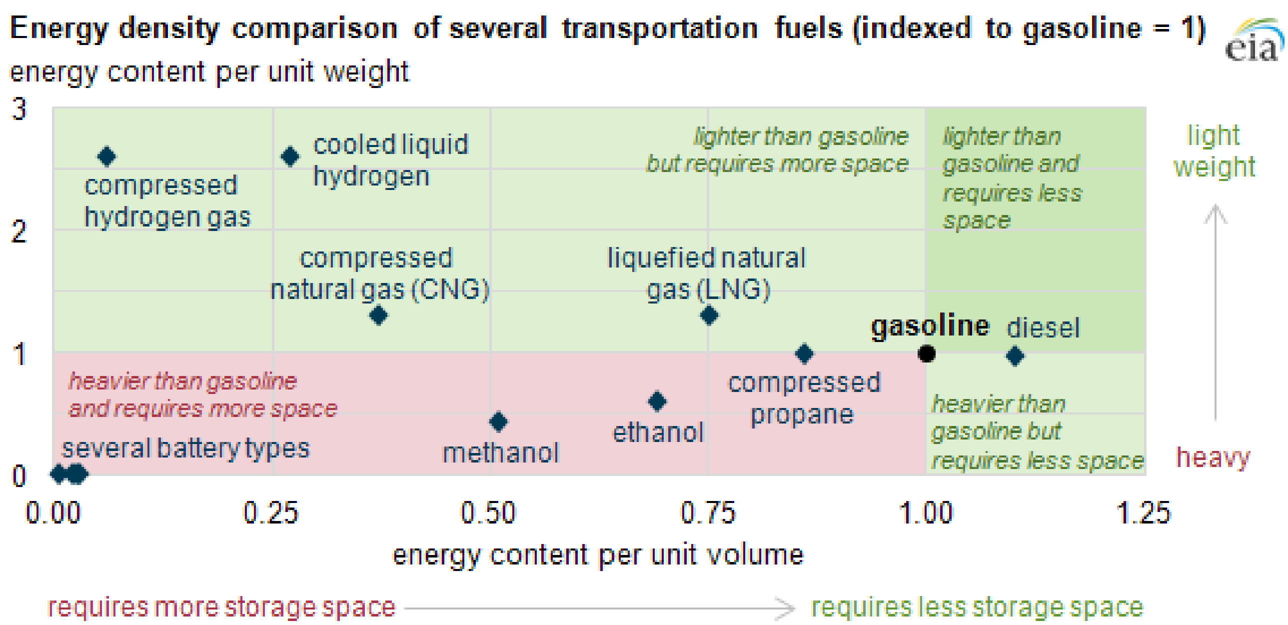
The term duty cycle refers to how much a vehicle is used with respect to hours of use per day, days of use per week, total miles driven during a single cycle, and other metrics. Duty cycle can also describe the kind of route a vehicle routinely takes, such as A-B-A or hub-and-spoke, as well as the typical route distance, such as local routes, short haul (typically between 100 and 200 miles a day), or long haul (more than 200 miles a day).[13]

Drive cycle refers to how a vehicle operates and is measured by average speed, maximum speed, idle time, etc. As an example, a city metro bus *duty cycle* would be described according to how many days the bus drove its route, total mileage the bus was driven each day, etc., whereas its *drive cycle* would be measured by the vehicle’s average speed, time spent at maximum speed, the average grade of terrain, time spent on grade, the average payload weight, the maximum payload weight, and whether the vehicle operation includes smooth, consistent braking (useful for regenerative braking in electric vehicles) or not.

Driving Range

The driving ranges of alternative fuel vehicles will vary by the energy density of the fuel used, the fuel economy of the vehicle, and the operation (drive cycle) of the vehicle. For example, natural gas-powered vehicles have similar power, acceleration, and cruising speeds as equivalent diesel-powered vehicles, but the driving range is lower because CNG and LNG have less energy content per unit than diesel.[14] This is illustrated in Figure 4, which shows the energy densities of selected transportation fuels both per unit volume and per unit weight, where gasoline is indexed as 1 for ease of comparison. Fuels such as compressed hydrogen gas, cooled liquid hydrogen, CNG, and LNG all have more energy density per unit weight than gasoline or diesel but as they are all lighter than gasoline or diesel, they require more space to approach the energy density of gasoline and diesel per unit volume. For this reason, many medium- and heavy-duty vehicles using CNG or LNG could be reconfigured to include extra fuel tanks, although any extra fuel tanks could reduce cargo space or payload.[15]

Figure 4: Energy Density Comparison of Several Transportation Fuels (Indexed to Gasoline = 1)[16]



In addition to the energy density of the fuel, vehicle efficiency (or fuel economy) will affect range. Vehicle efficiency refers to the vehicle's efficiency at converting fuel into power at the wheels.[17] As shown in Figure 4, the lithium-ion batteries used in battery electric vehicles (BEVs) have much less energy content per unit of volume than gasoline or diesel fuel. However, the BEV engines are more efficient than internal combustion engines, resulting in superior fuel economy. The U.S. Department of Energy reports that electric vehicles convert over 77 percent of the electrical energy from the grid to move a vehicle down the road, while conventional gasoline vehicles only convert between 12 and 30 percent of the energy in gasoline to move the vehicle.[18] [19]

Refueling

Both the mileage of the route and how the vehicle is operated will affect whether a vehicle can complete a single duty cycle without refueling or if it must be refueled on route. If the vehicle must be refueled on route, the availability and cost of public fueling for medium- and heavy-duty vehicles and the time to refuel are considerations. Alternatively, if a vehicle can be refueled at its base, the cost of refueling infrastructure and the wholesale cost of the fuel should be considered. Table 1 shows the number of public and private fueling stations available in Oregon by fuel type. Renewable diesel can be dispensed with existing diesel fueling infrastructure, but it is not yet available at retail stations, only in fleet scenarios. Renewable diesel consumption has been increasing, indicating access to the fuel may be increasing as well. Renewable diesel consumption data from the Oregon Clean Fuels Program is referenced in the last section, *Medium- and Heavy-Duty Alternative Fuels Vehicles in Oregon*.

Table 1: Number of Fueling Stations in Oregon for Select Alternative Fuels[20]

	Public Stations	Private Stations
Biodiesel (B20 and above)	37	0
CNG	4	11
LNG	1	1
Electricity[a]	1,801	259
Hydrogen	0	0

[a] *Does not include residential charging infrastructure*

There are more public stations available for electric charging than any of the other alternative fuels shown, but this does not mean that all, or even most, of these could accommodate a medium- or heavy-duty vehicle's charging space needs, necessary charging connection type, or enough charger power to adequately charge the vehicle in the time that is available for refueling. Additionally, the cost per kWh of public charging can vary widely. Public biodiesel (B20 and above) refueling is available at 37 stations in Oregon, most of which are located along the I-5 corridor or clustered in Multnomah County, as shown in Figure 5.[21] There is only one public LNG fueling station and four public CNG stations in Oregon, most of which are located in southern Oregon.[iv] There are no hydrogen fueling stations of any kind in Oregon at this time.

Figure 5: Location of Existing Biodiesel (B20 and above) Public Fueling Stations in Oregon

[iv] ODOT provided funding for two of the four public CNG fueling stations as part of the STS implementation work.

For fleets with vehicles on a return-to-base duty cycle, installing private refueling infrastructure onsite provides the opportunity to refuel vehicles whenever needed and, in many cases, to realize savings from wholesale fuel costs compared to retail pricing.

An LNG refueling station is structurally similar to one for gasoline and diesel, though dispensing LNG requires the use of protective gear because it is a super-cooled liquid gas. The cost to build a private LNG fueling station would depend on a number of factors. For example, a 2012 study sponsored by the American Gas Association found that the cost of an LNG station was positively correlated with the onsite storage capacity for LNG.[22] Currently, there is limited information on the costs to build fleet LNG stations, but a recent project in Sacramento, CA gives a sense of the current costs for a public station project. This 2016 project was to refurbish two existing skid-mounted LNG fueling units and to install two new units, along with related upgrades to the facility infrastructure at a cost of $1.725 million dollars.[23] This included a public station and each fueling unit had a capacity of about 5,500 U.S. gallons.

There are three types of CNG refueling stations – fast-fill, time-fill, and combination-fill – and the installation costs vary across these types based on storage capacity, compressor size, and the rate the fuel is dispensed.[24] Fast-fill stations can deliver fueling speeds similar to those for diesel or gasoline whereas time-fill stations will complete fueling over a period of hours and are commonly used for commercial fleets with return-to-base duty cycles. The combination-fill stations can do both a fast-fill and a time-fill, depending on the need. Time-fill configurations are usually the lowest cost option. In a 2014 study, NREL estimated a cost of between $250,000 and $500,000 for a small time-fill station that could serve 10-20 school buses, 5-10 refuse vehicles, or 15-20 sedans per night.[25] In a 2019 study for the California Electric Transportation Coalition (CalETC), consultant ICF estimated costs of a large fast-fill station with a capacity for 1 million diesel gallon equivalents per year to be about $2 million dollars in 2019 dollars.[26]

Estimating the cost to install EV charging for medium- and heavy-duty fleet vehicles will depend on factors such as the number and costs of chargers needed to meet the total energy requirement for the fleet, the available time to charge (the charging window), the price of electricity, smart charging software (if needed), and needed "make-ready" infrastructure, such as step-down transformers, electric service panels, conduit, mounting pads, etc.[27] ICF estimated charger and installation costs in 2019 dollars to be $25,000 for a 19 kW capacity charger up to $105,000 for a 200 kW charger (see Table 2).[28]

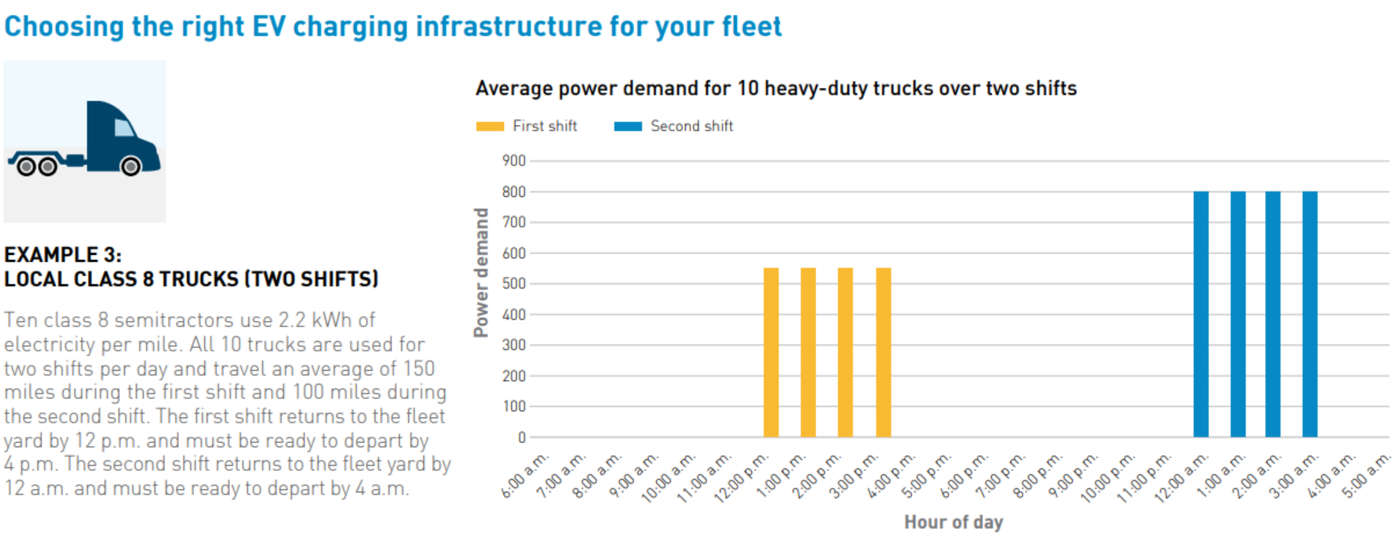
Table 2: Estimated Electric Charger and Installation Costs in 2019 Dollars (Source: ICF 2019)

Charger Capacity	Charger Cost	Installation Cost
19 kW	$5,000	$20,000
40 kW	$8,000	$20,000
100 kW	$40,000	$48,000
200 kW	$50,000	$55,000

Given that many organizations may not be familiar with the requirements of siting EV charging or have a dedicated staff member to drive the process, some utilities, including Portland General Electric

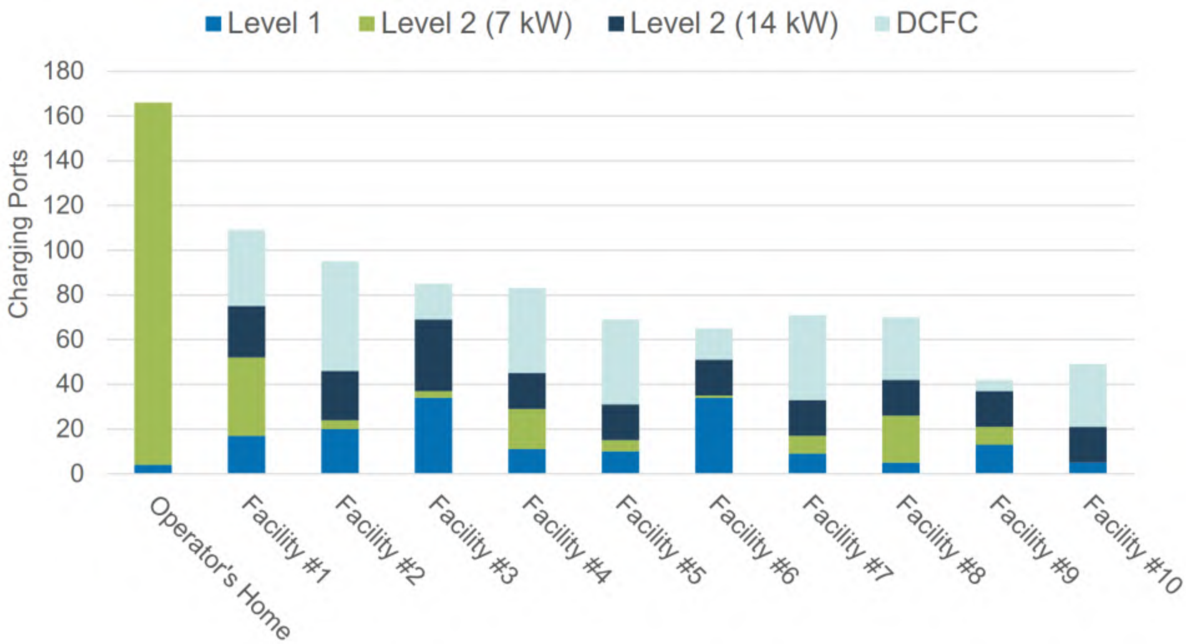
(PGE) and PacifiCorp in Oregon, and Pacific Gas and Electric in California, offer free technical assistance to their commercial customers who are interested in exploring fleet electrification. Pacific Gas and Electric's guidebook for fleet electrification demonstrates how to calculate the total charging requirement for the consumer's fleet and the average power needed to charge the vehicles during the charging window, and then provides illustrative examples (see Figure 6).[29]

Figure 6: Pacific Gas and Electric Example for Estimating a Fleet's Basic Load Profile (Source: Pacific Gas and Electric 2019)



In Oregon, PGE studied how to transition its fleet of 1,167 vehicles over 27 different facilities to electric by 2050.[30] Working with an outside consultant, PGE determined that overnight charging would be sufficient to meet most of its operational needs, but that smart charging would be necessary to reduce both infrastructure and energy costs. Smart chargers are networked to provide two-way communication, enabling remote management of the charger so that vehicles can be charged during times when electricity is inexpensive, etc.[31] With the different vehicle types and duty cycles in its fleet, PGE expects it will need a variety of chargers, as shown in Figure 7. The levels shown in this figure refer to the type of EV charger, where Level 1 is the slowest and a DC fast charger is the fastest.

Figure 7: PGE Future EV Charging Needs for Top 10 Facilities (Source: PGE 2020)



Total Cost of Ownership

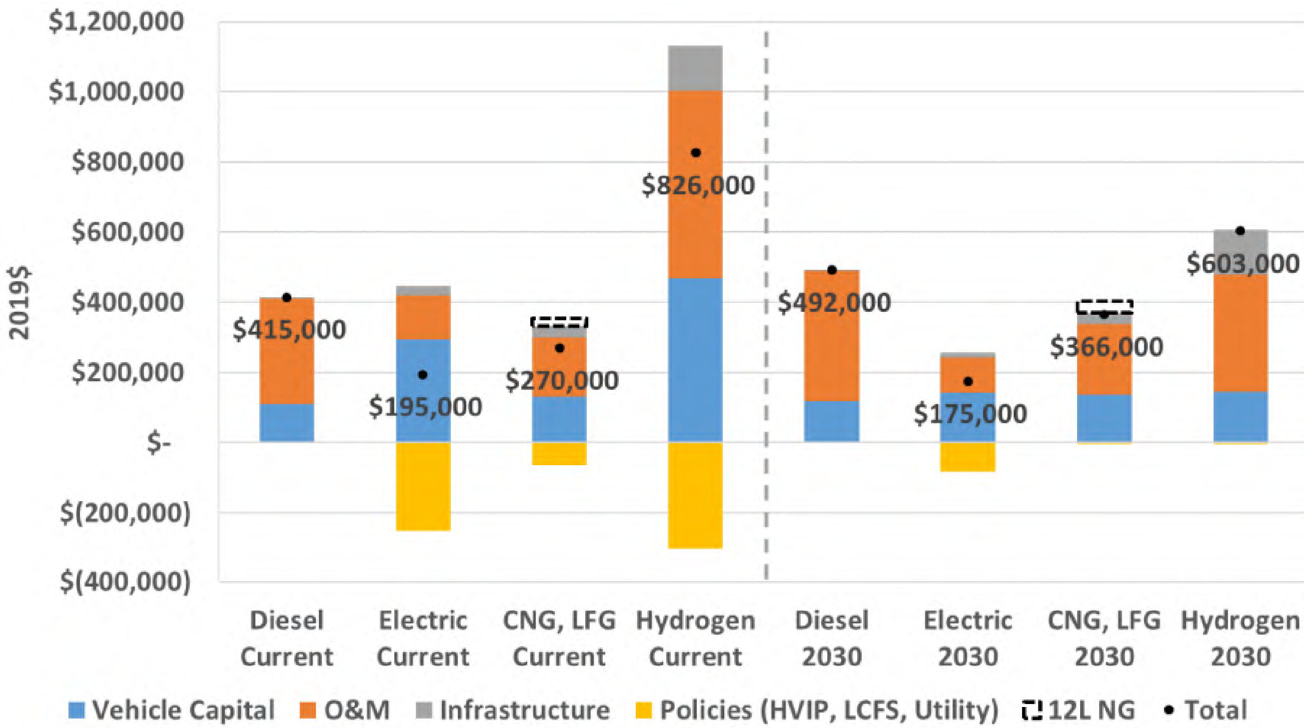
Most alternative vehicles currently have a higher purchase price than a similarly equipped gasoline or diesel vehicle, but alternative fuel vehicles can have substantially lower costs over the life of the vehicle. For this reason, vehicles are compared using a total cost of ownership, which takes into account costs related to fuel consumption, maintenance, infrastructure, incentives or disincentives,[v] and residual value of the vehicle, in addition to the upfront purchase price of the vehicle.

In its 2019 study for CalETC, ICF calculated the current total cost of ownership (TCO) and the projected 2030 TCO for a number of medium- and heavy-duty vehicles in California. For Class 8 Tractor Trailers, the TCO[vi] for a battery electric truck was $220,000 lower than for a diesel truck, driven largely by lower fuel and maintenance costs as well as benefits from California policies such as the Low Carbon Fuel Standard and utility programs (see Figure 8).[32] Natural gas trucks using landfill gas also had a TCO lower than that of a diesel truck in both the current and estimated 2030 results. TCO analyses for Class 8 short-haul and drayage trucks yielded similar results, though for Class 8 refuse trucks the TCOs across each fuel type were much closer given the duty cycle low mileage and the low baseline fuel economy.

[v] Incentives could include state or federal tax rebates or grants for a specific vehicle type or a fuel type, such as a rebate or a clean fuels program credit. Disincentives could include future costs related to emissions of air pollutants or greenhouse gases.

[vi] To calculate the TCO, ICF assumed a high-mileage duty cycle (85,000 miles/year) and a short first-owner life of five years.

Figure 8: Total Cost of Ownership Analysis Results for Class 8 Tractor Trailers in California (Source: ICF 2019)



ICF calculated the TCO for 14 different vehicle duty cycles/types and when incentives available in California were included in the TCO (the yellow bars), the electric vehicle had the lowest TCO of the fuels analyzed in 12 cases.[vii] While these results would be different for every state depending on the various incentives available, it makes clear that even with a higher upfront vehicle purchase price, an alternative fuel vehicle can prove more economical over the life of the vehicle.

Vehicle Availability

The potential cost savings for alternative fuel medium- and heavy-duty vehicles remain theoretical if there are no vehicles available for purchase. Many alternative fuels can be used in a blend with traditional fuels, such as biodiesel and ethanol, and some can be used as a "drop-in" fuel in traditional engines, such as renewable diesel, which can be used as a 100 percent replacement for petroleum diesel in any diesel engine. Diesel engines can run on biodiesel blends of more than 20 percent, but such operation would void the engine warranty for most manufacturers. Many existing vehicles can be retrofitted to run on CNG, LNG, electricity, or hydrogen.

Globally, there were 17 models of BEV medium- and heavy-duty vehicles being manufactured as BEVs (not retrofitted) in 2019, with another 10 models slated to enter regular production in 2020 or 2021.[33] There are an additional four models that have been announced without a start date for regular production. As of 2019, five models of hydrogen fuel cell medium- and heavy-duty vehicles were

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[vii] ICF used the following battery sizes for the EV trucks in their analysis: 100 kWh for Class 4-5 short-haul; 150 kWh for Class 4-5 long-haul and Class 6-7 short-haul; 250 kWh for Class 6-7 long-haul and Class 8 short-haul; and 500 kWh for Class 8 long-haul. The ranges associated with these battery types could limit some of these vehicles in completing a full duty cycle without charging, and more battery capacity would increase the upfront cost for the vehicle.

announced for future production (see Figure 9). Of these, all are currently in use in demonstration projects except for the Nikola One.[34 35 36 37]

Figure 9: Announced or In-Production Hydrogen Fuel Cell Medium- and Heavy-Duty Trucks, as of 2019 (Source: Hall 2019)

Make	Model	Range (miles)	Vehicle class	First demonstration	Start of regular production
Nikola	One	1000	8 (Tractor-trailer)		2022
Toyota	Beta	300	8 (Tractor-trailer)	2018	
Kenworth	T680	300	8 (Tractor-trailer)	2019	
Hyundai	XCient	238	8 (Straight truck)		2019
Dongfeng	Special Vehicle	205	4	2017	

Medium- and Heavy-Duty Alternative Fuels Vehicles in Oregon

The state of Oregon has a goal of increasing the availability and use of cleaner fuels in the state, which is supported both by the Oregon Department of Transportation (ODOT) Statewide Transportation Strategy[38] and the Oregon Clean Fuels Program.[39] Oregon is also a signatory to the Multi-state Medium- and Heavy-Duty Zero Emission Vehicle MOU,[40] which created a task force to develop a multi-state action plan to encourage adoption of medium and heavy-duty zero-emissions vehicles.

The **Oregon Statewide Transportation Strategy** is Oregon's guidance document to reducing greenhouse gas emissions in the transportation sector.

www.oregon.gov/odot/Planning/Pages/STS.aspx

Forthcoming Studies

The 2020 Governor's Executive Order 20-04 directs ODOT to conduct a "statewide transportation electrification infrastructure needs analysis," including reviewing use types and vehicle classes, to facilitate the state's transportation electrification goals.[41] Although the focus of the study will be to identify charging gaps and needs for the passenger vehicle sector, the study will also provide analysis for the medium- and heavy-duty sectors. This will include analysis of the market status of medium- and heavy-duty vehicle classes and types, anticipated timing on the commercial availability of these vehicles, charging infrastructure needs, and cost for that infrastructure.

Part of the interagency Every Mile Counts Effort to support implementation of the Statewide Transportation Strategy includes an alternative fuel study lead by the Department of Environmental Quality (DEQ) in collaboration with ODOT and ODOE. This study will identify the fueling and infrastructure needs for medium- and heavy-duty trucks to be powered by electricity, hydrogen, renewable natural gas, or other lower carbon biofuels, and potential approaches state agencies can take to enable a transition to alternative fuels. Anticipated outcomes include an Oregon-specific medium- and heavy-duty fleet profile as well as informed scenarios to increase alternative fuel usage.

Every Mile Counts

In Fall 2019 Governor Kate Brown directed ODOT, ODOE, DEQ, and the Department of Land Conservation and Development to collaborate on implementation of ODOT's Statewide Transportation Strategy.[42] The activities identified by the four agencies include increasing the use of cleaner alternative fuels and supporting increased transportation electrification. Efforts include:

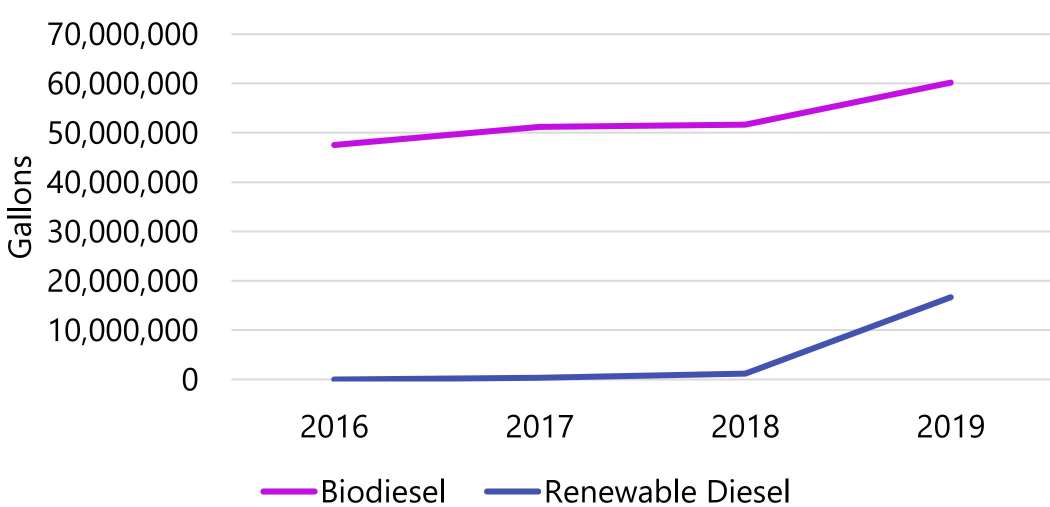
- Expansion of DEQ's market-based Clean Fuels Program.
- Development of a Zero Emissions Vehicle Action Plan – a roadmap for state agency efforts to increase Oregonians' awareness of and access to zero-emission vehicles, increasing access to charging infrastructure, and increasing state agency's use of zero emission vehicles.
- Adopting new emissions standards and zero-emission vehicle requirements for medium- and heavy-duty trucks by the Environmental Quality Commission.[43]

www.oregon.gov/odot/Programs/Pages/Every-Mile-Counts.aspx

Renewable Diesel

Data from the Clean Fuels Program shows that use of both biodiesel and renewable diesel is rising in Oregon (see Figure 10). Numerous entities in Oregon have conducted pilot programs using renewable diesel, including Eugene Water & Electric Board, City of Portland, Lane County, Deschutes County, City of Corvallis, and Lane Transit District, and some state agencies and school districts are using renewable diesel in their fleets when it is available.[44] Currently all renewable diesel is imported into Oregon, but a $1 billion facility has been proposed by NEXT Renewable Fuels at Port Westward in Columbia County and is in the permitting phase.[45] If approved, the facility would open in 2021 and start with a production capability of 37,500 barrels of renewable diesel a day, eventually growing to a full capacity of more than 50,000 barrels a day.[46] The Red Rock Biofuels facility outside of Lakeview, Oregon is slated to come online in spring 2021 and will also produce renewable diesel.[47]

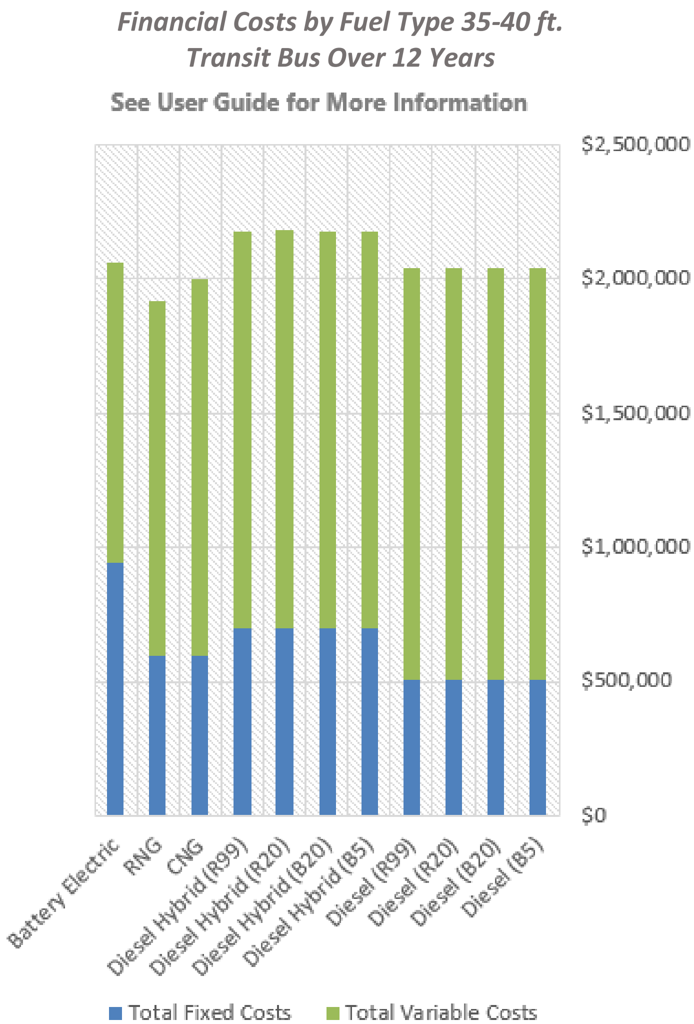
Figure 10: Total Gallons of Biodiesel and Renewable Diesel Reported to Oregon Clean Fuels Program for 2016-2019[48]



Transit and School Buses – Programs and Tools

To help entities analyze the costs associated with various alternative fuel options, ODOT, DEQ, and ODOE collaborated to develop the Electric and Alternative Fuel Transit Bus Lifecycle Cost Analysis Tool. Currently in the final stages of beta testing, the tool will provide a more complete understanding of the costs and benefits associated with available alternative fuels and alternative fuel buses (see Figure 11). In addition to a traditional cost comparison, the tool also compares the lifecycle costs, including the social costs of carbon emissions for different alternative fuel buses. ODOE and ODOT are also developing a similar comparison tool that will focus on school buses and alternative fuels.

Figure 11: Sample Output from ODOT Electric and Alternative Fuel Transit Bus Lifecycle Cost Analysis Tool



Effective January 1, 2020, school districts within PGE or PacifiCorp territories that are eligible for the Public Purpose Charge (PPC) Schools Program can use PPC funds to complete a fleet audit. Once the audit has been completed, these districts can then use PPC funds as a reimbursement for the cost of purchasing or leasing a zero-emissions vehicle, including school buses. The eligible reimbursement amount is a portion of the total cost of purchase or lease, based on the type of bus. The reimbursement may not cover the full cost of the bus but could be a significant incentive to support school districts moving towards zero-emissions vehicles.

PGE announced in May 2020 that it would provide funding to five Oregon school districts for the purchase of electric school buses and charging infrastructure. For each district, PGE will cover the difference in cost between a conventional bus and an electric bus, the total costs of charging infrastructure installation, and technical assistance.[49] The electric buses are expected to be on the road in Oregon in 2021. The funding for this program comes from the Oregon Clean Fuels Program.

Additionally, DEQ has a portfolio of grant and other programs that apply to the increased utilization of alternative fuels across Oregon.

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Policy Brief: COVID-19 Response and Effects on the Energy Sector

The COVID-19 pandemic has affected the energy sector in many ways, both around the world and in Oregon. Because of COVID-19 we saw energy consumption behavior change quickly. For example, the U.S. Energy Information Administration (EIA) reported that total national energy consumption in April 2020 was 14 percent lower than in April 2019, the lowest monthly energy consumption since 1989 and the largest year-over-year decrease since EIA began tracking this data in 1973. Trends in consumption varied substantially for different energy sources and for different sectors of the economy. U.S. petroleum consumption in April 2020 fell 27 percent compared to April 2019; and U.S. electricity consumption fell by 4 percent overall while residential electricity consumption rose by 8 percent due to more people staying home.[1]

This section will explore select impacts and trends in the energy sector in the months since March 2020, including: immediate emergency response actions; trends in energy consumption; the impacts that economic trends such as increased unemployment have had on households' energy burdens and ability to pay their utility bills; investment trends for energy efficiency, electric vehicles, and renewable energy development; and the impacts on greenhouse gas emissions of decreased fossil fuel use. And as COVID-19 persists, the overall impacts will continue to have significant effects on Oregon's energy sector and economy. COVID-19 will continue to have a significant effect on Oregon's energy sector and economy, and the full picture of its impacts will continue to be measured and analyzed after the publication of this report.

Fuels: Emergency Response Actions

On March 3, 2020, the Oregon Office of Emergency Management activated the State Emergency Coordination Center in response to COVID-19. As the state lead for emergency response to address Oregon's fuel supply, ODOE set its Oregon Fuel Action Plan into motion to monitor and respond to potential pandemic concerns in the fuel sectors. This included working closely with the fuel terminals, fuel distributors, Western States Petroleum Association (WSPA), Oregon Fuels Association (OFA), and the Pacific Propane Gas Association (PPGA) to assess impacts on the workforce, supply chain, and distribution system.[2]

Oregon's Emergency Response Framework

Oregon has 18 designated Emergency Support Functions for critical lifelines and services, the disruption of which could jeopardize the health and safety of Oregonians, the environment, and/or the economy. The state ESF structure mirrors the federal framework. The Oregon Department of Energy and the Oregon Public Utility Commission are the designated lead agencies for Emergency Support Function 12 – the energy sector. ODOE is responsible for monitoring and resolving transportation fuel and propane supply and distribution problems; PUC is responsible for ensuring utilities can effectively restore power and natural gas.

ODOE and PUC work closely with Oregon's Office of Emergency Management on planning and preparedness, response, and recovery for all-hazards events impacting the energy sectors. In the case of COVID-19, ODOE and PUC participated in daily statewide emergency response coordination calls with the Federal Emergency Management Agency (FEMA), Department of Homeland Security, Department of Defense, U.S. Coast Guard, 33 state agencies, 36 counties, and 9 federally-recognized Tribes to assess COVID-19 concerns and impacts on all critical lifelines, services, and infrastructure.

ODOE and PUC also represent the energy sector in regional and national emergency coordination. In the case of COVID-19, the U.S. Department of Energy coordinated weekly energy sector emergency response calls for FEMA's Region 10 (which includes Oregon, Washington, Idaho, and Alaska), while the National Association of State Energy Officials (NASEO) coordinated weekly calls on emergency responses for the energy sector at the national level. State agency staff represented Oregon's energy sector in both those forums.

COVID-19 revealed some unique conditions and challenges for the energy sector that are not typically experienced in other emergency response events:

Surplus Fuel Supply. The significant reduction in travel caused by COVID-19 resulted in a surplus of fuel supplies with potential impacts on all levels of supply and distribution chains (see more below on impacts to demand and supply). ODOE collaborated with the fuel industry, USDOE, NASEO, and agencies in other states to discuss possible solutions. This included: 1) reducing refinery production by 50 percent or going into idling mode to prevent shutdowns, 2) using floating storage or tanker ships to hold surplus supplies to maintain refinery and pipeline operations, and 3) storing surplus crude oil in the federal Strategic Petroleum Reserve (SPR). Between late April and early July 2020, the SPR received more than 21 million barrels of crude oil for temporary storage to assist U.S. producers with surplus supplies. Companies can now schedule the return of their oil through March 2021.[3]

Seasonal Fuel Waiver. The reduction in travel due to COVID-19 resulted in a surplus of winter grade fuels in the system, causing fuel companies to struggle to make the regulatory transition to lower volatility summer grade fuels by May 1, 2020. WSPA and the fuel terminals requested the state issue a Reed Vapor Pressure waiver to allow the industry more time to make this transition. Consistent with Oregon Fuel Action Plan procedures, ODOE facilitated the process to ensure that waivers were issued by the required Oregon entities and that Oregon waivers were consistent with the conditions of the federal RVP waiver issued by the U.S. Environmental Protection Agency on March 27, 2020.[4] ODOE worked with the Oregon Department of Agriculture on a waiver process to allow the sale of remaining winter grade fuels without penalty. The waiver process also required the Oregon Environmental Quality Commission to conduct a special hearing on Clean Air Act requirements, and the City of Portland to waive Renewable Fuels Standard enforcement.[5]

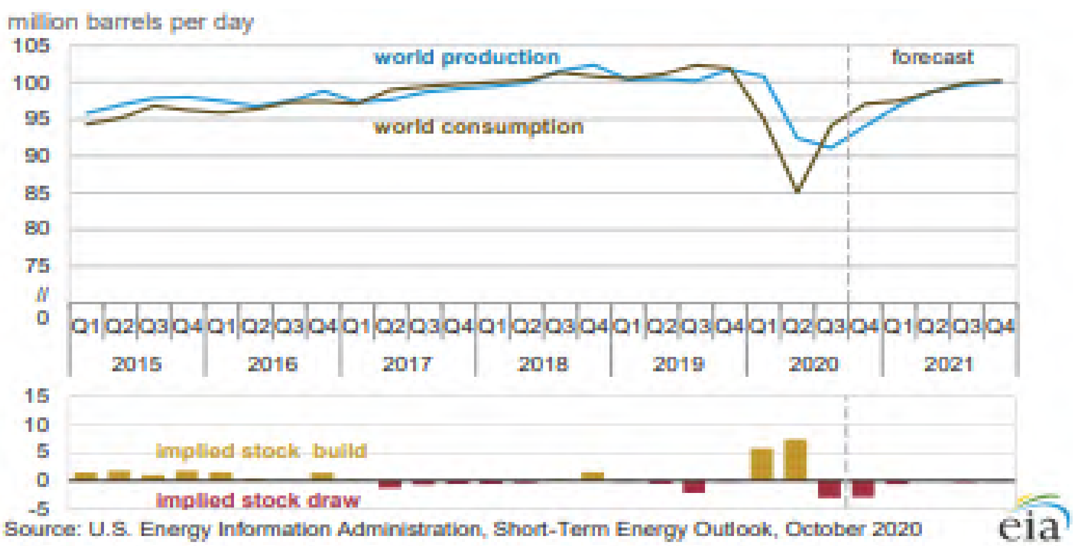
Self-Serve Gasoline. COVID-19 triggered a temporary 50 percent reduction in Oregon's gas station workforce due to illness, childcare issues, and safety concerns. The Oregon Fuels Association requested the state temporarily suspend the self-serve gas ban to allow gas station owners the option to let customers pump their own fuel, allowing gas stations to continue operations with fewer staff. The Oregon State Fire Marshal issued a temporary suspension of the self-serve gas ban in coordination with the Governor's office, ODOE, OFA, and other stakeholders on March 28. The suspension was reviewed every two weeks and ended on May 23.[6]

Ensuring Fuel Infrastructure Worker Safety. The federal government provided personal protective equipment to each state, in part to ensure the safety of critical infrastructure workers like energy providers. Oregon received reusable cloth masks, of which ODOE and PUC secured over 50,000 for energy providers. Additionally, FEMA provided Oregon with non-contact infrared thermometers, of which ODOE and PUC obtained 1,475 for energy providers.[7]

Transportation Fuels: Impacts to Demand and Supply

EIA estimates that global consumption of liquid fuels for September 2020 was down by 6.4 million barrels a day from September 2019, a 6.3 percent decrease.[8]

Figure 1: World Liquid Fuels Production and Consumption Balance



The abrupt decrease in demand due to COVID-19 caused an oversupply of fuel in global as well as local markets because supply was slow to adapt to the decrease in consumption. The market for U.S. oil futures experienced a historic event: there were so few buyers for May futures contracts for West Texas Intermediate crude for delivery at the Cushing, Oklahoma hub that prices were briefly negative ($-38/barrel) for the first time in history. Sellers were paying someone to take their oil.[9]

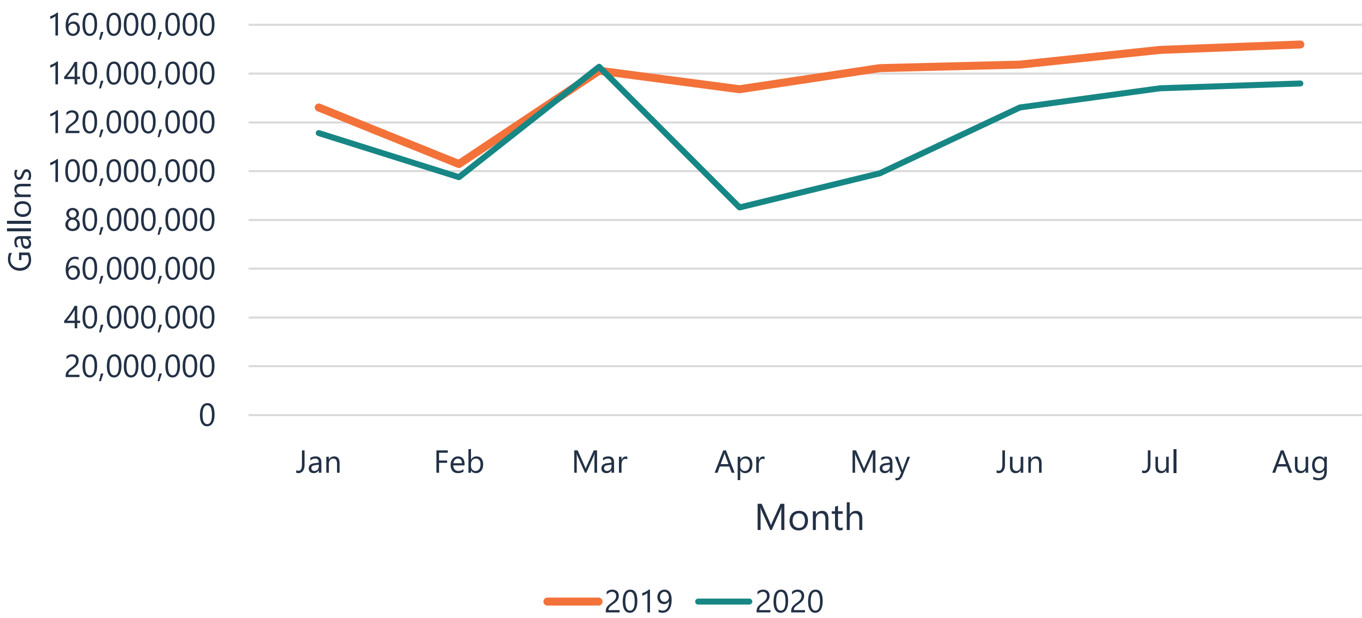
The market rebounded in October 2020 to about $40 a barrel, leaving prices still down about a third from January 2020.[10] There is still a lot of uncertainty about world demand for transportation fuels because a large portion of that demand depends on how the COVID-19 virus continues to affect the economy. There is still an oversupply of crude in storage and this may continue to put a downward pressure on price. Because some data will not be available for several months or more, analyzing impacts immediately can be difficult. In September 2020, financial market experts like Goldman Sachs projected a bullish view for oil in 2021 as prices recover alongside a possible COVID-19 vaccine.[11] On the other hand, in October 2020, OPEC, an influential oil cartel, again revised downward their projection for 2021 world oil demand, citing lower economic growth.[12]

Oregon Trends in Fuel Demand

Overall, Oregon has seen demand for transportation fuel decline in 2020 due to COVID-19, but the impacts have not been the same across all transportation fuels consumed in the state.

Gasoline. Gasoline or E10 (ten percent ethanol, 90 percent gasoline) is the most consumed fuel in the Oregon transportation sector at 60.6 percent of transportation fuels demand in 2018.[13] Consumption of gasoline in Oregon was almost identical in January through March of 2020 compared to 2019. Beginning in March 2020, Oregonians began to stay at home to reduce COVID-19 infections. Many workers started working from home and businesses and schools began closing, reducing gasoline consumption. From March to April 2020, Oregon saw a 40 percent reduction in gasoline sales that equated to a decrease in consumption of over 57 million gallons of fuel. In the months of June, July, and August 2020, sales of gasoline in the state have decreased by about 16 million gallons per month compared to 2019, approximately a 12.5 percent decrease on average.

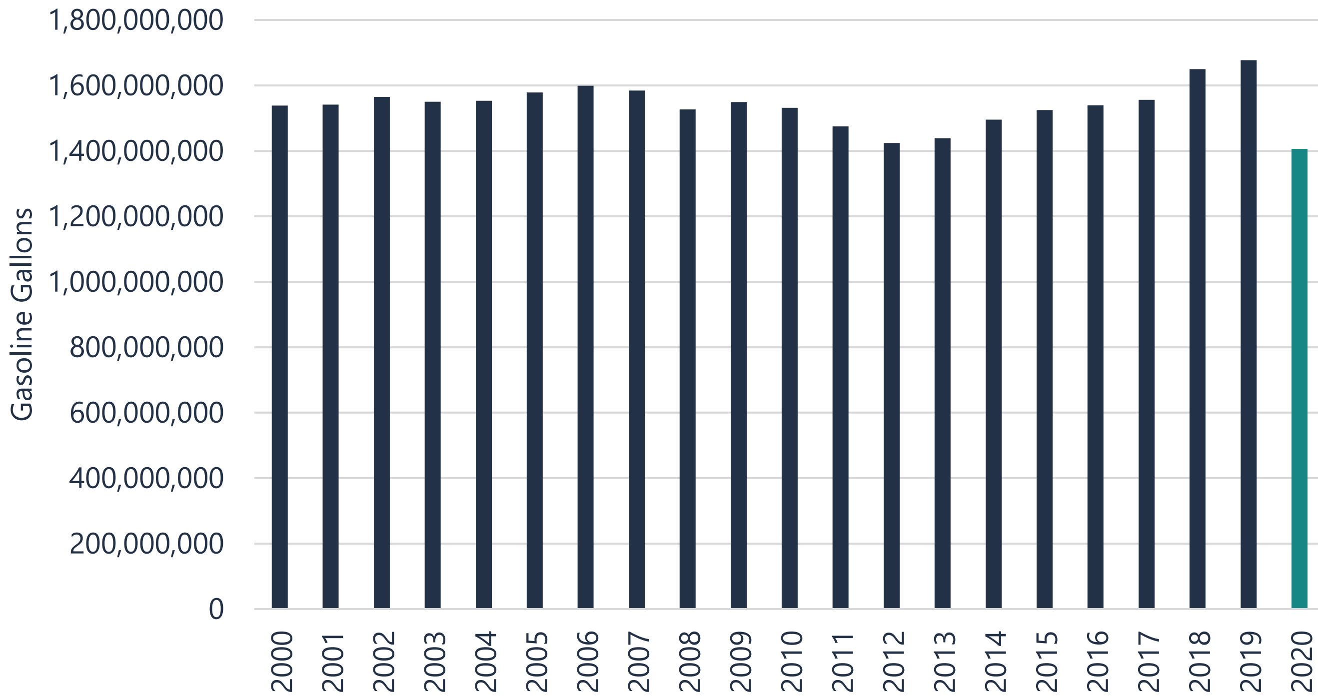
Figure 2: Oregon Gasoline Consumption (2019 Compared to 2020 January – August)[14]



The chart below presents historical gasoline consumption (E10) data for Oregon for 2000 to 2019, compiled from various sources, together with an estimate for 2020[1] calculated using Oregon Department of Transportation data for January through August 2020 to estimate a trend in gasoline consumption for the remainder of the year.[15] If Oregon stays on its current trend, gasoline consumption will be the lowest since 1992.[16]

[1] The average annual percentage reduction in demand was calculated for the months of June – August (-12.5 percent) and then multiplied by 2019 consumption for the remaining months to get an estimate for 2020.

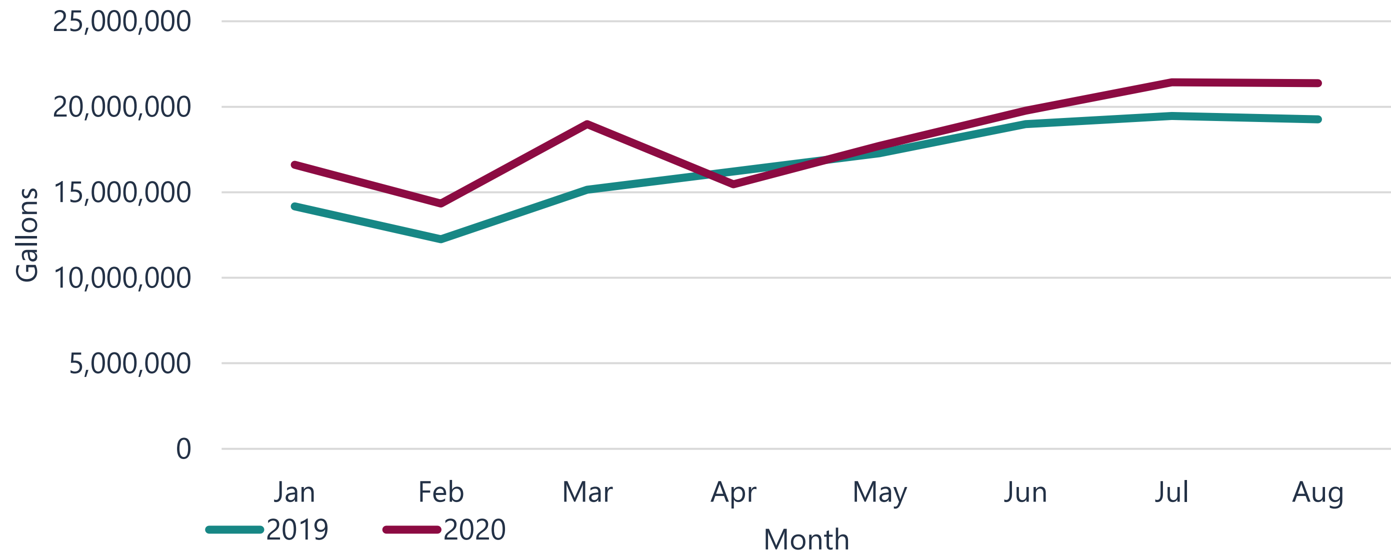
Figure 3: Oregon On-Highway Gasoline Consumption by Year (2000-2019) and 2020 Estimate[14,15]



Diesel. Diesel is the primary fuel used in trucks to deliver almost everything we need or use. COVID-19 may have slowed gasoline consumption, but diesel was needed to deliver food and goods to the marketplace and eventually to homes; in fact, truckers are deemed essential workers. Many people started ordering more items online and having them delivered to their homes to avoid visiting stores, and in some cases stores only operated on an online order and home delivery basis. Based upon data through August 2020, it appears that diesel consumption for trucks under 26,000 GVW (Gross Vehicle Weight) may be higher in 2020 than it was in 2019. (See graph below.) Currently the only data available for diesel is for taxable sales of the fuel, which applies largely to vehicles that are 26,000 pounds or less; diesel taxed by the gallon accounts for about 40 percent of the diesel market in Oregon. Complete data on diesel consumption, including diesel used in trucks over 26,000 pounds that are subject to the weight-mile tax, will not be available until mid-2021.

Diesel consumption also includes biodiesel and renewable diesel in the data presented below. In 2019, biodiesel and renewable diesel accounted for 11.7 percent of total diesel consumption in Oregon.[17] (For more information on diesel consumption, see the Freight Truck Efficiency Policy Brief.)

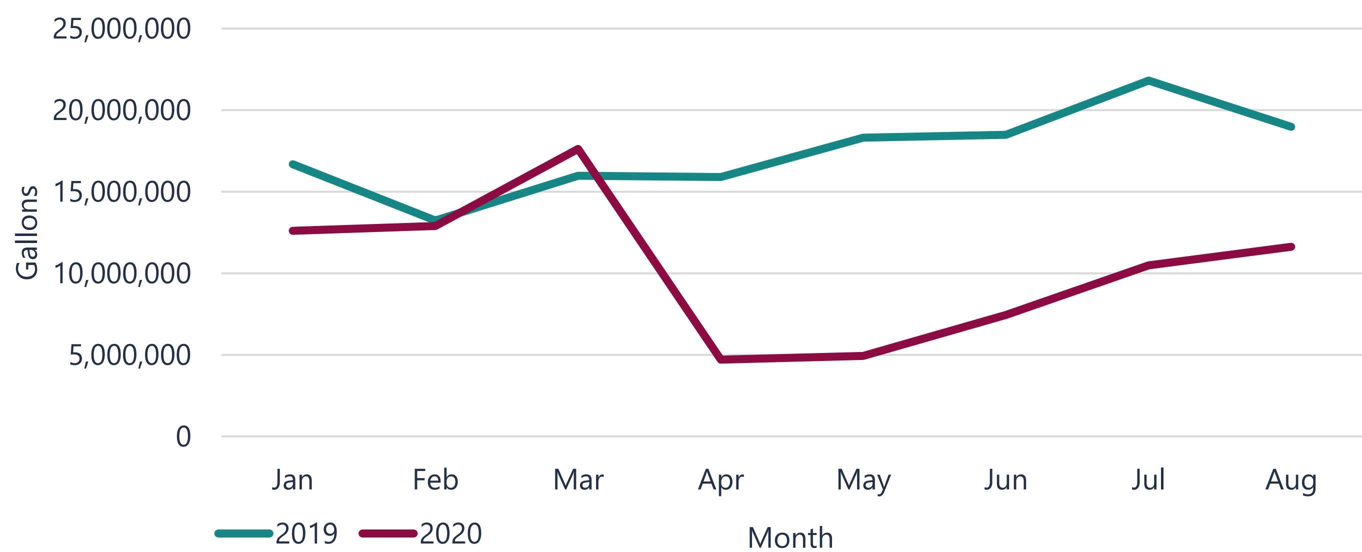
Figure 4: Oregon Sales for Diesel Taxed by the Gallon for Vehicles Less Than 26,000 Pounds (2019 Compared to 2020 January – August)[18]



Renewable Fuels and Biofuels. As of October 2020, the data is not available for these fuels, as they typically are reported separately. Ethanol is blended into gasoline so there is reason to believe that Oregon is consuming less ethanol. Biodiesel and renewable diesel are blended into diesel so Oregon could see increased volumes for these fuels in 2020, although it is uncertain at this time.

Jet Fuel. EIA estimates that global consumption of jet fuel by commercial passenger flights averaged 1.6 million barrels/day during the first two weeks of July, 69 percent less than one year ago. The largest decline in global demand for jet fuel occurred during March and April 2020, coinciding with the initial, intensified efforts to mitigate the spread of COVID-19. Globally, consumption of jet fuel grew slightly in May and June 2020; similar trends are also occurring at the regional and country levels.[19] Oregon has also seen severe reductions in jet fuel sold from March through May 2020 although the industry saw some increases in fuel use over the summer months.

Figure 5: Jet Fuel Sold in Oregon (2019 Compared to 2020 January – August)[20]



Aviation Gas. Aviation gas primarily fuels smaller propeller-driven aircraft. April 2020 saw a very large drop in sales of 167 percent compared to 2019; while this sector has seen a rebound, 2020 sales for January through August are 28 percent less than the prior year. [21]

Northwest Refinery Operations

About 90 percent of the petroleum products that Oregon consumes are processed from crude at the five refineries in Washington state (See Where Do Oregon's Petroleum Transportation Fuels Come From 101). Output data for these refineries is unavailable, but the Washington Department of Ecology releases quarterly reports on the movement of crude to Washington. As seen in the table below, when comparing second quarter reports for the years 2019 and 2020, crude by rail has been reduced by 34 percent. Almost all this crude movement by rail goes through the Columbia River Gorge, on through Portland, and then up to the refineries located in northern Washington. Overall, there was a reduction of 18 percent of total crude moved by rail, vessel, and pipeline.

Table 1: Crude Movements by Mode to Washington Refineries (2nd Quarter 2019 compared to 2020)[22]

Time Period	Rail (Barrels)	Vessel (Barrels)	Time Period	Pipeline (Barrels)	Total Crude
2019 Q2	17,445,132	17,021,377	Jan-Jun 2019	36,184,994	70,651,503
2020 Q2	11,597,752	15,463,012	Jan-Jun 2020	31,178,895	58,239,659
Percent Reduction	**34%**	**9%**		**14%**	**18%**

Oil industry infrastructure was designed and built for well-established patterns of consumption. Refineries produce gasoline, diesel, propane, and other products from a barrel of crude oil. The proportionate demand for these products in the market is relatively predictable and refineries produce a mix of products based upon market forecasts. However, due to rapid changes in the demands for different petroleum products since the inception of the pandemic in early 2020, refineries have had to quickly adjust their production mix. Gasoline production, historically the largest portion of refinery output, has stabilized at a reduced rate while other distillates – or diesel segment products – are increasing in share. For example, jet fuel is another distillate and, with tweaks, the production of this fuel can be diverted to diesel production, but the sharp fall in air traffic has created an excess of distillate.[23]

The effects of COVID-19 on the transportation energy industry and energy use in the sector are still evolving, and it is difficult to estimate long-term implications. Our historic patterns of consumption have changed, and the industry has had to adjust. Reversion to previous patterns of consumption is proceeding at different speeds for different segments. As of October 2020, it is too soon to know the long-term impacts, but the transportation sector has already seen significant, if not historic, consequences due to the COVID-19 pandemic and its associated economic slowdown.

Electric and Natural Gas Utilities

Responses to the COVID-19 pandemic in the electricity and natural gas sectors reflect the higher degree of state regulation of these services compared to other energy sectors, such as transportation fuels. Investor-owned utilities, including three electric utilities and three natural gas utilities in Oregon, are regulated by the Oregon Public Utility Commission, while consumer-owned utilities are overseen by locally elected governing boards. As noted above, PUC is designated as the lead state agency in an emergency for tracking and coordinating the state's response in the electric and natural gas sectors.

Utility Operations

Natural gas utilities in Oregon changed a number of business practices to protect both employees and customers as a result of the pandemic. Both NW Natural and Avista moved a majority of employees to remote work, closed buildings to the public, eliminated non-essential work travel, and instituted extreme social distancing for critical staff. Avista reported making changes to work crew schedules, such as staggering start times, designating pods of crew members to consistently work together, and striving for single occupancy in work vehicles when possible.[24]

Electric utilities have also altered their operations in response to COVID-19. PGE reported at the end of May 2020 to Oregon's Interim House Committee on Energy and the Environment that two-thirds of their employees were working from home, and that the company was taking special precautions for their workforce in critical operational areas.[25] At the same hearing, Oregon's consumer-owned utilities testified that their members were preparing to implement workplace practices such as plexiglass shields, sanitizing stations, masks, and social distancing protocols to keep customers and employees safe when their offices re-open to the public.[26]

Energy Sales: Electricity and Natural Gas

Available data and forecasts for 2020 show that sales of electricity and natural gas have not experienced the same level of volatility as fuel sales in the transportation sector, yet there have been discernable trends at the national and local level. For example, residential sales of electricity have generally trended higher for 2020 compared to 2019, while commercial and industrial sales have generally been level or slightly lower.

Oregon's sales of electricity and natural gas have been in line with national trends. Electric utilities report slightly higher residential loads and lower commercial loads. Because the onset of COVID-19 was in the spring and summer and not during the peak heating season, the impact on natural gas usage was not as significant as it might be this coming winter. Information about utility sales trends in Oregon is available in utility earnings reports[27] and responses to PUC workshops.[28]

At the national level, EIA forecasted in October 2020 that natural gas consumption would decline overall by 1.8 percent from 2019 to 2020, from a combination of reduced heating demand in early 2020 and reduced manufacturing activity.[29] Since April 2020, residential and commercial consumption has been relatively similar to 2019.[30] EIA forecasted that retail sales of electricity would fall nationally by 6.2 percent in the commercial sector and 5.6 percent in the industrial sector but that sales of electricity in the residential sector would increase by 3.2 percent for the year. Lower heating costs in early 2020 were offset by increased cooling costs in the summer and increased home use of electricity with people working and attending school from home.[31]

Economic Impacts to Utility Customers

The full economic impact on utility customers of the COVID-19 pandemic and the measures taken to slow the spread of infections is not yet known, although available data shows an increase in both the number of customers with past due bills and in the amounts that are owed. Investor-owned utility data reported by the Oregon PUC showed that pre-pandemic past due balances for the early months of 2020 were trending below 2019. However, by May 2020, a few months into the pandemic, the total balance of unpaid utility bills had risen above the unpaid balances for the prior year and were on a steep upward trend.[32]

Consumer-owned utilities in Oregon differ widely in their member demographics and local economic base, which was reflected in different impacts to COU customers in the early months of the pandemic. According to legislative testimony on May 28, 2020, a quarter of the state's electric cooperatives were experiencing customer past due balances that were 50 percent higher than expected for that time of year, while about one third were experiencing normal levels. People's utility districts were experiencing similarly divergent trends. Sixty-day delinquent accounts at municipal utilities were up 82 percent in April 2020 over the same period in 2019, with one municipal utility reporting an increase of 740 percent compared to 2019.[33]

Impacts on Home Energy Burden in Oregon

Home Energy burden is the percent of household income spent on electricity, natural gas, and other home energy bills. If a household is spending greater than 6 percent of their income on home energy costs, they are considered energy burdened. [34] If a household is spending 10 percent or more of their income on home energy costs, they are considered severely energy burdened.[35] Oregon Housing and Community Services' (OHCS) Affordable Housing Assessment Tool estimated 391,263 out of 1,591,835 Oregon households struggled to pay their energy bills in 2019, indicating 25 percent of Oregon households were home energy burdened.[36] Though data is not yet available for 2020, the number of energy-burdened households in Oregon likely increased due to impacts associated with the COVID-19 pandemic, such as job and income loss, unexpected increases in caretaking responsibilities, increased time at home, and, for some, illness and increased healthcare expenses.

Pre-COVID-19 energy burdens were not evenly distributed. A recent national study found that low-income households, low-income multifamily residents, and manufactured home residents had the highest energy burdens,[37] while a recent study of energy burdens in Oregon found that rural residents and communities of color were disproportionately affected. Oregon Housing and Community Services reported to the PUC in June 2020 its findings that for low-income households, defined as households with incomes below 60 percent of the area median income, Native American, Pacific Islander, multi-racial and Black low-income households were more likely to be energy-burdened than white or Asian low-income households.[38]

National data suggests that the impacts of the pandemic on energy burden also will not be evenly distributed. A Pew Research Center survey in March and April 2020 found that early economic impacts of the COVID-19 pandemic affected low-income communities and people of color more than other communities:

- 61 percent of Hispanic Americans and 44 percent of Black Americans said in April that they or someone in their household had experienced a job or wage loss due to the coronavirus outbreak, compared with 38 percent of white adults.
- Nearly three-quarters of Black (73 percent) and Hispanic adults (70 percent) said they did not have emergency funds to cover three months of expenses; around half of white adults (47 percent) said the same.
- Black (48 percent) and Hispanic adults (44 percent) were more likely than white adults (26 percent) to say they "cannot pay some bills or can only make partial payments on some of them this month."[39]

Responses to COVID-19 Impacts on Utility Customers

Energy bill payment assistance programs. OHCS administers the Low-Income Home Energy Assistance Program (LIHEAP), providing home energy assistance to low-income Oregonians, especially households with the lowest incomes and the highest home energy need (see 2018 BER Chapter 7 for more information on energy assistance programs). In 2020, OHCS received $9.5 million from the federal CARES Act to bolster LIHEAP support. The state of Oregon's Emergency Board also allocated $15 million in June 2020 to provide additional energy assistance support. To learn about how these funds were allocated to community action agencies, please visit OHCS interactive allocation map.[40]

Local community action agencies implement OHCS programs and provide support to low-income Oregonians, and these agencies have experienced challenges in connecting households to energy assistance during the pandemic. Many agencies closed their offices and staff are working remotely while engaging the communities they serve. Collecting documentation from low-income households for support has been challenging as programs require in-person presentation of documents and government offices such as the U.S. Social Security Administration are closed or have limited hours. Weatherization services provided by community action agencies including in-home energy efficiency improvements and DIY workshops were impeded by COVID-19, due to the need for in-person contact and lack of connectivity in many low-income households. This decrease in weatherization opportunities posed a particular challenge to community action agencies, as weatherization is often a "foot in the door" program that helps them connect households to other social services.[41]

Disconnections suspended. Oregon investor-owned utilities and consumer-owned utilities voluntarily suspended disconnections for nonpayment in March 2020 and stopped sending disconnection notices to customers. Investor-owned utilities continue to suspend disconnections as of October 2020, while COU disconnection policies vary by utility.

It is unknown how many disconnections would have occurred if not for the suspension by utilities. On average, investor-owned utilities made 4,475 disconnections for nonpayment each month in Oregon between August 2018 and March 2020.[42] The suspension of utility disconnections has resulted in a significant drop in investor-owned utilities' call volumes from customers who are having trouble paying their utility bills.[43] Utilities often receive calls from customers who have received a notice of an impending shutoff, at which point utilities engage these customers to develop payment plans and refer them directly to local community action agencies for help connecting with energy bill assistance programs. Participants in workshops at the PUC on COVID-19 impacts to utility customers (see below) expressed concern that many potentially eligible customers were not hearing about assistance programs, and that some customers could be accruing large unpaid balances.[44]

Other utility actions. Energy utilities in Oregon, both investor-owned and consumer-owned, have taken a mix of additional actions in response to the economic impacts to their customers.[45,46] Some of the actions taken by utilities include:

- Waiving fees for disconnections and reconnections.
- Waiving the accrual and collection of late payment fees, interest, and penalties.
- Increasing the duration and flexibility for payment arrangements to pay off past due balances.
- Creating new relief funds offering bill credits to customers who have lost income due to the pandemic.
- Assisting business customers in applying for federal COVID-19 aid.
- Relaxing eligibility conditions for equal payment plans.
- Refunding security deposits or applying them to utility bills.
- Easing paperwork requirements to qualify for energy assistance programs and medical certification.

PUC workshops on COVID-19 customer impacts. After conducting an initial special public meeting June 9, 2020 on the "Impact to Utility Customers during the COVID-19 Pandemic and Future Economic Recovery,"[47] the PUC followed up with a more in-depth discussion of the topic over a series of several workshops. Workshop participants included representatives from the investor-owned utilities, PUC staff, Energy Trust of Oregon, and representatives from community action agencies. A variety of community groups and consumer advocates, some of which have not taken part in PUC proceedings before, also participated in the workshops and offered comments. Information about these workshops is available on the PUC website: https://www.oregon.gov/puc/utilities/Pages/COVID-19-Impacts.aspx

Later workshops focused on reaching agreement among the participants on a timeline and process for the resumption of utility residential disconnections; future actions to assist and protect utility customers; and how to account for lost utility revenues from bills that may remain unpaid and waived or foregone fees. As presented in legislative testimony on September 24, 2020, the Public Utility Commissioners approved a PUC staff recommendation to convene an advisory committee to focus on "low-income customers' energy burden and related social inequities." Commissioners also approved a recommendation for PUC staff to engage with stakeholders to consider a number of low-income, social justice, and environmental justice initiatives, including policies to mitigate differential energy burdens; increase the availability of low-income energy efficiency and weatherization funding; lower the cost of Community Solar Program subscription fees for low-income customers; and streamline enrollment processes for low-income programs.[48]

Energy Efficiency Programs

Overall, demand for energy efficiency services continues to be strong during the pandemic but with some variation between economic sectors. Energy Trust has seen decreased activity for large projects, but higher interest in low-cost/small-savings projects. While energy efficiency activity was down early in the pandemic, Energy Trust now expects to achieve 91 percent of electric and 98 percent of its gas savings goals for 2020 due to their "quick pivot to conducting business remotely," bonus incentives, and new offers. Like many organizations, Energy Trust has made changes to operations like moving to virtual inspections and incorporating social distancing for solar installers.[49]

In the commercial and industrial sectors, large capital and construction projects that were already underway before March 2020 are being finished but face uncertainty and volatility in material costs and project timelines due to global supply chain disruptions, tariffs, and permitting delays. Meanwhile, the queue of new projects is smaller and certain industries that have been severely affected by COVID-19 have stopped or severely curtailed energy efficiency investments, including hospitality, small retail and restaurants, higher education, food production, and aerospace.[50]

While new residential construction has slowed down and is expected to remain slow into 2021, the pandemic has caused increased interest in energy efficiency improvements for many residential customers: some households are upgrading their homes for increased comfort, while others are taking advantage of no-cost and low-cost measures to save on their energy bills.[51] Energy Trust reported to the PUC in June that they had distributed 13,000 LED lightbulbs and seen a 35-fold increase in requests for energy savings kits in the first month of the pandemic, and were working to expand offerings under the "Savings Within Reach" initiative, which offers increased incentives for income-qualified households.[52]

Community action agencies saw a decrease in their weatherization activity in the early months of the pandemic, likely due to residents' discomfort with having contractors in their homes.

Renewable Energy Development

Despite challenges posed by the pandemic, utility-scale renewable energy development has continued at a strong pace while small-scale and residential installations have declined. At the national level, EIA forecasts that renewable energy will be the fastest-growing source of electricity generation in 2020, with the addition of 23.3 gigawatts of new wind capacity and 13.7 gigawatts of new utility-scale solar in 2020.[53] In Oregon, the Energy Facility Siting Council (EFSC) has not seen a slowdown in applications or amendments for renewable energy projects, primarily driven by utility-scale solar requests. As of October 25, 2020, Oregon had 894 MW of wind generation under construction, with 350 MW of wind and 1,233 MW of solar photovoltaic generation under review by EFSC.[54]

Some renewable energy projects under construction have experienced delays due to the pandemic. As has happened in many businesses, COVID-19 associated restrictions have made on-site inspections and in-person meetings difficult, resulting in extended project timelines. Renewable energy projects at all scales have suffered from interrupted and inhibited supply chains. Manufacturing and the movement of materials have slowed down during the pandemic, resulting in delays to project development.[55]

National trends show that residential and small-scale solar installations have seen a significant decline with the economic recession. Wood Mackenzie Power and Renewables, an energy industry research and consulting group, reported in September 2020 that "installations were down 23% quarter-over-quarter in the residential segment, and 12% quarter-over-quarter in the non-residential sector, due to restrictions and shelter-in-place orders imposed to curb the pandemic."[56] Wood Mackenzie foresees a continued high level of uncertainty in regards to the market for new solar projects which could impact development for years to come.

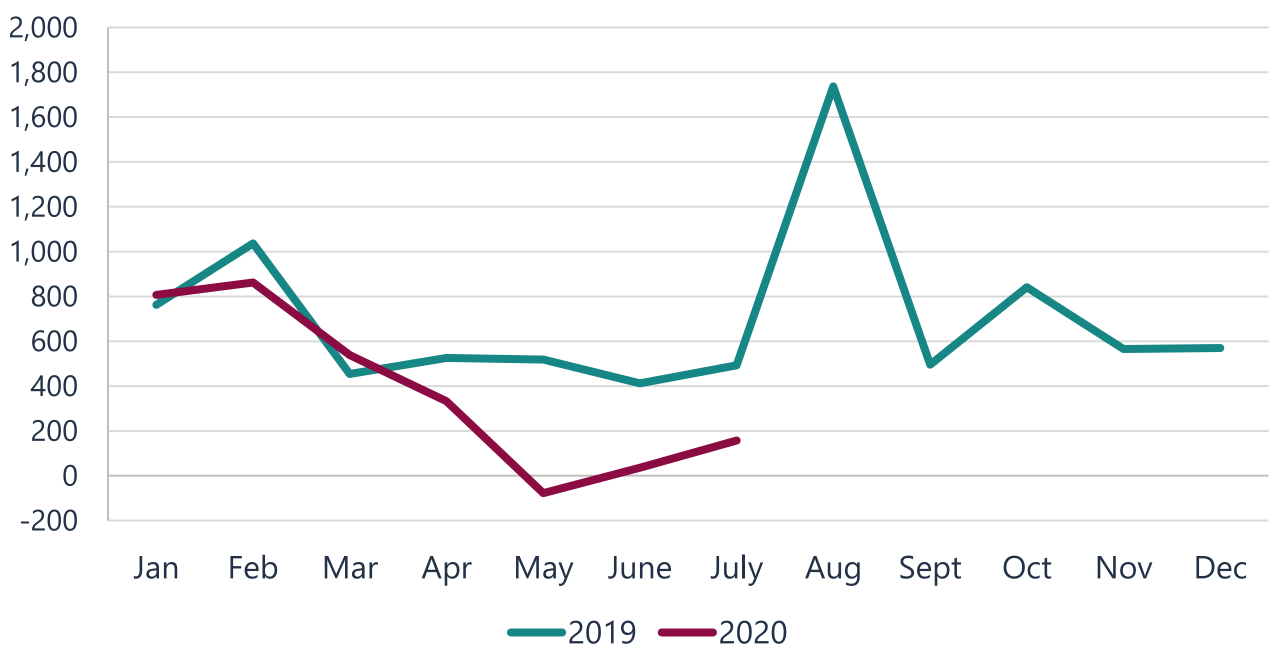
The Oregon Department of Energy's Oregon Solar + Storage Rebate program[57] saw only a minor slowdown in applications since the COVID-19 pandemic emerged. The Solar + Storage Rebate program, which first opened in January, saw a high demand for rebates in the two application periods in January 2020 and April 2020. The demand for this program continues to outpace available funds. However, associated economic repercussions from COVID-19 have made the program more challenging to implement. State budget cuts resulted in a $60,000 loss in Oregon Solar + Storage program administration funds. The program requires site inspections, which have been difficult due to COVID-19 restrictions, causing slowdowns in the development timeline for projects.

The Oregon Community Solar Program provides tools and support to customers of Portland General Electric, Pacific Power, and Idaho Power interested in developing solar projects.[58] Energy Trust of Oregon, which administers the program in partnership with Energy Solutions and Community Energy Project, reports reduced customer engagement and communication associated with COVID-19 restrictions. The program, which started receiving applications in January 2020, will deliver increased solar energy access to low-income community members who may not be able to afford a solar system without assistance. Restrictions to community outreach may impact program administrators' ability to engage hard to reach customers.[59]

Electric Vehicle Adoption

Overall electric vehicle registrations in Oregon have slowed since March 2020. EV registrations grew by 1.4 percent between March and July (from 31,941 to 32,389), down from 8.3 percent growth during the same time period in 2019 (from 23,577 to 25,252).[60]

Figure 6: Annual Oregon Electric Vehicle Registrations (2019-2020)



Impacts on GHG Emissions

As described earlier in this report, Oregon is not currently on track to meet its greenhouse gas reduction goals (see Climate Update Policy Brief). Transportation emissions have grown as a share of Oregon's statewide GHG emissions and are the primary driver of the current upward trend.

By significantly affecting human behavior and the distribution of energy consumption across Oregon and the world, COVID-19 has led to substantial reductions in GHG emissions in 2020. For example, with an unprecedented number of people working from and staying at home, the average number of commuters driving to work and other destinations has decreased. As reported above, gasoline sales in Oregon during the summer of 2020 were 12.5 percent less than in the summer of 2019. In addition, some energy consumption has shifted, for example, from commercial to residential spaces.

According to EIA, U.S. CO2 emissions from the energy sector are expected to be 10 percent lower in 2020 compared to 2019 due to reduced consumption of all fossil fuels, with emissions from coal and petroleum down 19 and 13 percent from 2019, respectively.[61] Modeling by Energy Innovations suggests an economy-wide reduction in U.S. GHG emissions of 7 to 11 percent in 2020 compared to 2019.[62]

At the global scale, the International Energy Agency estimates that economy-wide GHG emissions in 2020 may be 8 percent lower than 2019 levels due to the economic impacts of COVID-19.[63] However, they caution that **any drop in emissions due to COVID-19 will be temporary and without additional and significant actions emissions are expected to return to previous levels.** For example, the U.S. EIA forecasts that 2021 energy-related GHG emissions for the U.S. will increase by 5.4 percent above 2020 levels as the economy recovers.[64]

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Policy Brief: Equity in State Renewable Energy Programs

Oregon has been a leader in development of renewable energy for many years. Customer-owned or on-site renewables can provide individual financial benefits, societal benefits associated with clean energy production, and economic development associated with jobs to install systems. However, access and benefits of on-site renewable energy systems have not been enjoyed by all Oregonians. There are a number of ways in which Oregonians have gained access to renewable energy including customer or community sited systems, utility voluntary green power programs, and acquisition of large-scale renewables by utilities. In addition, the largest source of clean power in the state comes from hydropower. Access to renewable energy does not necessarily ensure equitable distribution of benefits as many access options require significant financial investments by consumers.

For on-site renewables, the state has historically invested in renewable energy through financial incentive programs to support the development and commercialization of renewable energy technologies such as solar photovoltaics (PV). Many of these state investments have been in the form of tax credits.[1] Early incentive programs were designed to provide access to renewables. Today we understand that access alone does not ensure an equitable distribution of benefits. One of the goals of these residential tax credits was to support market transformation by incentivizing early adopters to make investments in emerging technologies. These early investments were intended to then reduce future costs by increasing market volume. Along with the state tax credits, there were also federal tax credits and utility incentives that worked together to impact markets. While the programs were successful in making some technologies more affordable, they did not have specific goals related to equitable access to renewable energy. This policy brief examines equity considerations in accessing renewable energy, analyzes the state's investment in solar PV through Residential Energy Tax Credit program data, and describes recent renewable energy programs that are designed to incorporate equity objectives.

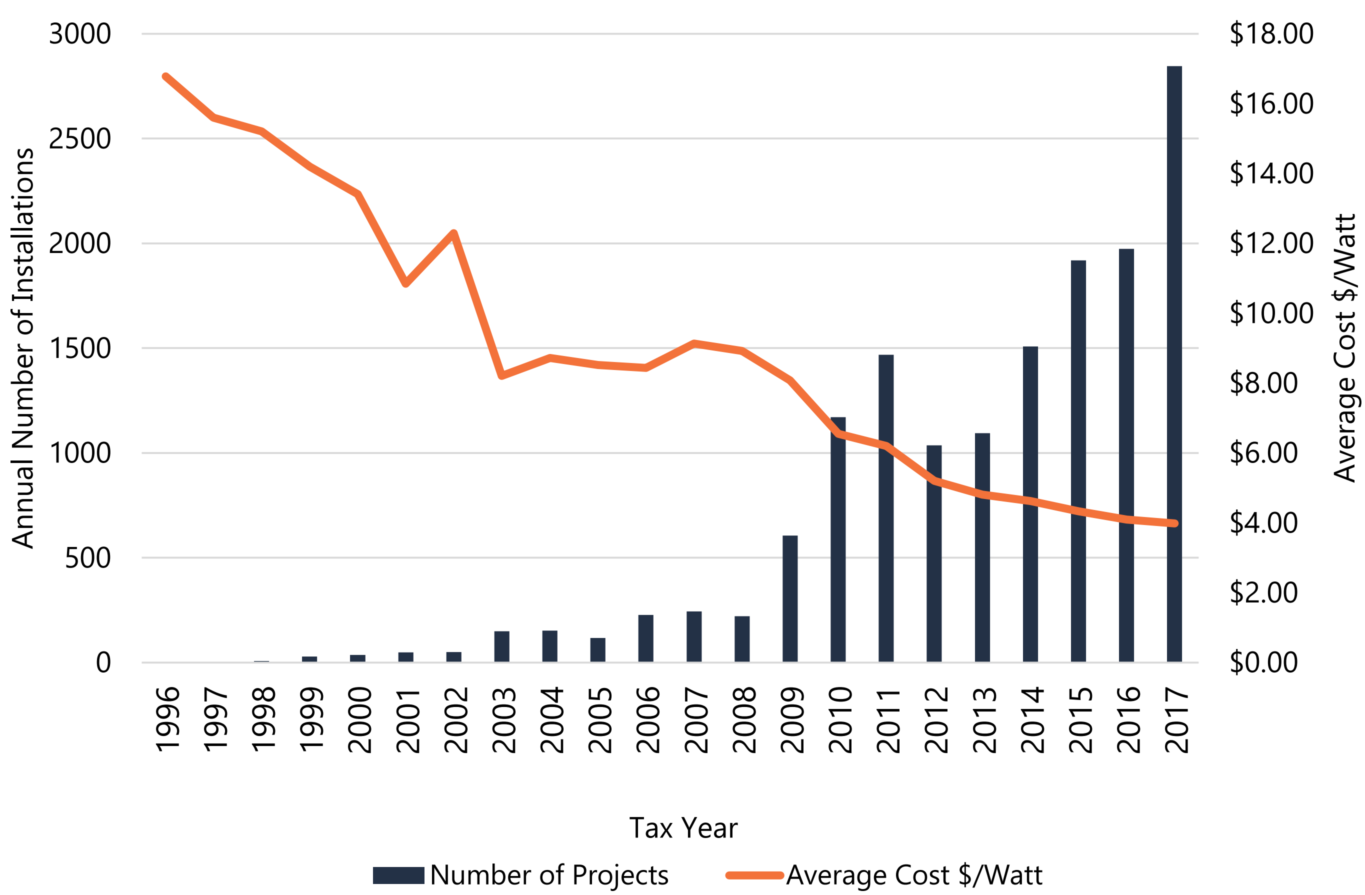
Solar PV can still be considered an emerging technology. In Oregon there are about 16,700 residential PV systems, making up about 1 percent of all households.[2] Early adopters of solar PV technologies provided a significant share of the upfront cost to build the PV systems, but they also received significant financial incentives and realized long-term benefits from cost savings on their electricity bills – savings that could continue beyond the payback of their upfront investments. These high up-front costs for the consumer are often a significant barrier to access for low-income or other historically or currently underserved communities. Lack of homeownership, lack of awareness, and lack of access to low-cost financing are also factors that create barriers to PV adoption.[3]

In 2020, recognizing these and other long-standing inequities, Governor Kate Brown's Office of Diversity, Equity and Inclusion directed state agencies to consider equity when making decisions regarding state resources through an Equity Framework.[4] While the Framework is primarily related to COVID-19 recovery efforts, it will also be used in long-term equity efforts by directing state agencies to consider equity when making decisions regarding state resources. The Framework provides a definition of equity that "acknowledges that not all people, or all communities, are starting from the same place due to historic and current systems of oppression." Equity is achieved through efforts to provide different levels of support, based on an individual's or group's needs in order to achieve fair outcomes. Equity actionably empowers communities most affected by systemic oppression and requires the redistribution of resources, power, and opportunity to those communities. Bearing this in mind, this policy brief evaluates specific investments the state has made to support market transformation of residential solar PV systems and assess what a similar monetary investment could provide for underserved communities while retaining similar environmental, societal, and economic benefits to Oregon.

Renewable Energy Programs Supporting Market Transformation

Market transformation is accomplished when emerging technologies experience increased sales volumes that allow installers and manufacturers to achieve economies of scale.[5] The result is lower prices for consumers, which in turn supports more volume. Ideally this cycle continues until the technology is affordable for all and the technology becomes widely adopted. While adoption of residential PV is still relatively low in Oregon, Figure 1 below demonstrates the increasing volumes and decreasing prices indicative of market transformation.[i]

Figure 1: Annual Count and Average Cost of PV installations in the Residential Energy Tax Credit Program



In 1977, the Oregon legislature established the RETC program to encourage adoption of new energy saving technologies. The program was designed to help offset Oregon's energy load growth needs

[i] Compiled data from Residential Energy Tax Credit program.

with conservation and renewable resources. For 40 years, the RETC program promoted residential energy savings, energy displacement, and market transformation by providing personal income tax credits to Oregonians who purchased eligible energy efficient devices and renewable energy systems for their homes.[6]

Figure 1 above demonstrates that the RETC program, in conjunction with technology improvements, manufacturing improvements, federal incentives, utility incentives, and other policies like the Renewable Portfolio Standard, supported market transformation by providing financial incentives to early adopters, increasing the volume of installations, and thereby contributing to reducing costs across the solar industry through economies of scale.[7] In 1999 there were 29 RETCs issued for solar PV systems that had an average cost of more than $14.00 per watt. In 2017, the final year of the program, the volume was 100 times higher – 2,846 PV systems installed at under $4.00 per watt, less than 30 percent of the average cost in 1999.

While the RETC program was successful in supporting market transformation, its program design did not explicitly include equity as an objective, and it did not enable equitable access to renewable energy for Oregonians of all income levels. When evaluating equity outcomes in the RETC program, the following are important considerations:

1. The RETC program design for renewable energy devices did not include a legislative objective in 1977 or subsequent amendments that involved equity.[8]
2. The RETC program did not collect data from participants on income level, race, housing types, or education level.
3. The RETC program required significant investments from early adopters who were responsible for the majority of system costs, which meant that low-income households were less likely to be able to participate in the program. From 1996-2010, RETCs covered only 17 percent of project costs.
4. The RETC program operated during the same period as federal and utility financial incentives for renewable energy devices. Many projects in the RETC program also received funding from these other sources.[6]
5. There were other energy incentive programs specifically targeted to low-income households that operated at the same time as the RETC. These programs focused on weatherization and energy efficiency measures and were primarily managed by Oregon Housing and Community Services and delivered by local Community Action Partnership agencies.[9]

Access to Renewable Energy

Financial incentive programs have supported access to on-site renewable electricity for many Oregonians. However, there are still significant barriers for low- and moderate-income households. Home ownership is almost a pre-requisite for installing PV systems on residential rooftops. Availability of an area for PV modules that is not shaded by trees, other buildings, or obstructions is also required. Renters, or those living in homes requiring structural, electrical, or roofing repairs have had less access to residential rooftop PV systems. Similarly, high up-front costs and lack of access to low-cost financing are also significant barriers to adopting on-site renewable energy for low-income households.

The majority of those who access on-site renewable energy, and thereby derive direct financial benefits, are middle-income and upper-income homeowners who can afford the up-front costs. For example, a 2018 Lawrence Berkeley National Lab study found that the median income of residential rooftop PV adopters was $32,000 higher than the general population.[10] The same study found that households with incomes in the lowest 20 percent represented only about 6 percent of the PV market in 2010.

Over the past 20 years, Oregonians have gained access to renewable energy through a variety of options. For example, residential rooftop systems, commercial on-site systems, community solar programs, utility-scale solar facilities, and green power purchase programs have all played a role in enabling access to solar. Over the same period, there were a number of financial incentive programs available in Oregon to support adoption of solar PV systems, including the State of Oregon's business energy tax credit programs, utility volumetric incentive rates, Renewable Energy Development Grants, federal tax credits, Energy Trust of Oregon programs, and various Oregon consumer-owned utility incentive programs. Following is a summary of five key renewable energy access options in Oregon over the past 20 years, including an evaluation of equity considerations.

Residential Rooftop

As of October 2020, there are more than 16,700 residential rooftop systems installed in Oregon.[11] These systems are net metered (see Net Metering 101) with the electric utility and result in reduced electric bills for the system owners.

Equity Considerations:

- **Home ownership**: The residential rooftop PV market is dominated by single-family owner-occupied dwellings.[10] Home ownership greatly simplifies residential rooftop solar investments because the homeowner has control of the dwelling's roof and can directly realize financial benefits from the supplemental electricity provided resulting in lower utility bills. A 2018 study found that Oregon households with an annual income of $100,000 or more had home ownership rates above 80 percent, while households with an income of $50,000 or less had home ownership rates below 50 percent. There are also disparities in home ownership across race and ethnicity. For example, an Oregon Housing and Community Services Department analysis shows that in 2017, 65 percent of white Oregonians owned homes compared to 35 percent of black Oregonians.[12]
- **Upfront Cost**: Residential PV systems have considerable up-front costs. State tax credits, utility rebates, and a federal tax credit help to offset system costs in Oregon, but the system owner is still responsible for a significant portion of the cost. In addition, tax credits could take up to four years to be recovered, which requires the participant to provide more of the initial costs. Further, the tax credits, which were available from the State of Oregon as well as the federal government, required the tax credit holder to have adequate tax liability to utilize the credits. The table below summarizes PV system costs for low- and moderate-income (LMI) and non-LMI participants in the new Oregon Solar + Storage Rebate program that started in 2020.[6] While the

rebates provided significant value for participants, Table 1 below shows that LMI homeowners were still responsible for a net cost of over $5,700.[ii]

Table 1: Average System Sizes and Costs for Residential Participants in the Oregon Solar + Storage Rebate Program

	Not Low- and Moderate-Income	Low- and Moderate-Income
Average System Cost	$27,512	$21,402
Average System Size (kW)	8.9	7.1
Average OSSRP Rebates	$2,040	$4,959
Average Additional Utility Incentives	$1,967	$6,964
Estimated Federal Tax Credit*	$6,642	$3,754
Net Cost to Homeowner	**$16,863**	**$5,725**

**The federal tax credit requires federal tax liability and may not be available to all individuals*

- **Cost Shifting**: Early adopters of residential PV systems made significant investments in their PV systems but also realized long-term cost savings. Residential rooftop PV systems can operate for 25 years or more.[13] Over this period, some of the system owners likely had reduced electric bills as a result of net metering agreements with their utilities, although these policies vary widely from utility to utility. Some have raised concerns that net metering participants may not cover all of the utility's fixed costs to provide service, and that those costs may be shifted to other ratepayers.[14] (see Net Metering 101). While cost shifting is a potential equity concern, it has been demonstrated that states like Oregon, with low PV adoption, have not experienced any detectable cost shifting to date.[15]

Commercial Rooftop

As of October 2020, there are more than 1,800 Commercial PV systems installed in Oregon.[16] Most of these systems are net metered (see Net Metering 101) with the electric utility and result in reduced electric bills for the system owners.

Equity Considerations

Commercial PV systems have many of the same potential equity considerations as residential rooftop systems. Upfront costs, ownership of property, tax liability, and cost shifting are all relevant to commercial PV systems. Business owners who were able to install on-site PV systems received additional federal tax benefits, in the form of accelerated depreciation, that were not available to residential customers.[17]

[ii] Values from Oregon Solar + Storage Rebate Program 2020 Program Report. Federal tax credit estimated at 26 percent of eligible cost for systems purchased in 2020. This tax credit will decrease to 22 percent of eligible costs in 2021.

Community Solar

Community solar programs typically enable participants to buy a subscription to a centrally located PV system. The subscription represents a portion of the generation from the community solar project and often translates to savings on the participant's electric bill. Because the solar installation is in a centralized location, there is no need for participants to own a home. Similarly, participants who own a home that is not appropriate for a PV system – such as a shaded location – may be interested in participating in a community solar project instead.[18] Community solar projects can also enable participants to buy a much smaller increment of a PV project than would be feasible for a residential rooftop system. For example, the Solar Pioneer II community solar project developed by Ashland Electric enabled participants to buy as little as one-quarter of a PV panel as a share. The cost for this minimum share is $1.70 per month.[19]

Equity Considerations:

- Community solar projects have the potential to address some of the equity concerns associated with residential rooftop systems. For example, home ownership and large up-front costs will not be required for a participant to access community solar. The Oregon Community Solar program established by the 2016 legislature[20] is being implemented and does not yet have a completed project to evaluate, but equity considerations are part of the program design because the legislation requires a process to ensure that at least 10 percent of allocated capacity be made available to low-income customers.[21] Program evaluation will include participation rates of traditionally underserved populations. Further analysis of equity in the community solar program will be possible once projects in this program are completed. Depending on where the project is located, and the ownership structure, there may also be community resilience benefits and local economic development benefits from community solar projects.
- Community solar projects may have higher soft costs when compared to conventional commercial or utility-scale solar developments. Soft costs are the non-hardware costs associated with solar projects – including permitting, financing, and installing solar, as well as the expenses solar companies incur to acquire new customers and cover their bottom line – that are incorporated into the overall price a customer pays for a solar energy system.[22] Community solar may also have higher soft costs associated with marketing expenses to recruit participants, developing complex financing models, administrative costs associated with enrolling in Oregon's program, and ongoing costs associated with participant communications and future recruitments. Utilities may also incur additional costs associated with administering bill credits in community solar agreements.

Utility-Scale Solar

In some states, utility-scale solar is now cheaper than conventional electricity resources. California, Arizona, Texas, and Utah have all seen utility contracts to purchase solar energy below $30 per MWh.[23] Closer to home, in 2019 Idaho Power announced a contract with a 150 MW solar facility to provide electricity at $21.75 per MWh.[24] In a submission to the Idaho Public Utilities Commission, Idaho Power Company staff conducted an analysis that indicates significant cost savings and benefits to all ratepayers from the acquisition of the solar generation.[25] The same submission referenced an Idaho Power avoided cost rate of $38.49 per MWh, or 77 percent higher than the contracted solar rate. Deployment of cost-competitive clean energy brings the benefit of decarbonization to all rate payers regardless of homeownership, income level, or demographic distinctions.

Equity Considerations

- These projects can lower costs and bring environmental benefits to all Oregonians. However, they do not enable access to the individual benefits associated with on-site net metered systems, which enable a customer to realize bill savings valued at the full retail rate of electricity.

Voluntary Green Power

Voluntary green power programs enable participants to access the environmental attributes of renewable energy through voluntary purchasing of renewable energy certificates (RECs)[iii] through their electric bills. In Oregon, electric investor-owned utilities are required by law[26] to offer a renewable electricity option to retail customers, and Portland General Electric (PGE) and PacifiCorp have two of the most popular programs in the country. In the 2019 National Renewable Energy Laboratory's annual Utility Green Pricing Programs rankings, PGE had the number one program in the country according to total green power sales in MWh, total number of green power participants, participation rate, and green power sales rates. PacifiCorp was third in green power sales and total green power customers (including its total service territory of six states).[27]

These programs enable participants to access the environmental benefits of renewable electricity from projects without the need for onsite installations, home ownership, cancellation fees, or large upfront costs, but do require participants to pay slightly higher costs through their electric bills. Participants in these programs can choose a block rate that allows them to pay a fixed cost for "blocks" of kWhs of renewable electricity or a volumetric rate that supports renewable energy equal to 100 percent of their electricity use and can vary month-to-month with any changes in the amount of electricity consumed. For example, PGE customers can pay approximately $6/month (depending on electricity consumption) in the Green Source program to cover 100 percent of their electricity with renewables purchases or they can purchase blocks from the Clean Wind project at $2.50 per kWh block.[28] These programs are available to any PGE or Pacific Power customer regardless of income or race but are not designed specifically as equity programs; other electric utilities in Oregon offer similar programs.

Equity Considerations:

- These programs are popular in Oregon. They involve voluntary higher electricity bills rather than bill savings. These additional costs may be a barrier to enrollment for those already struggling to pay utility bills.
- The programs are month-to-month and do not require participants to agree to long-term contracts or cancellation fees. This allows greater flexibility for customers who may be experiencing changes in their finances or who move frequently.
- Some programs may disqualify customers who have had a power shutoff due to non-payment in the recent past.

[iii] Renewable energy certificates, or RECs, are tradable certificates used to track renewable electricity and to determine where it is ultimately consumed. A REC can be generated for every eligible MWh of renewable electricity and the REC represents the environmental benefits associated with that MWh of renewable electricity and the ownership of those benefits.

Equity Policy Considerations

Market transformation has brought about dramatic reductions in PV costs. As a result, thousands of residential PV systems have been installed across Oregon. Investments by the State of Oregon, Oregon utilities, and early adopters have ensured that Oregon was in a position to take advantage of the transforming market.[iv] Oregon now has an established solar industry that can deliver projects at a fraction of the costs seen in the early years of the market transformation programs. This benefits all Oregonians.

Given the considerations above, it is worthwhile to evaluate how investments similar to those made to target early adopters in market transformation programs could be made today with a more equitable distribution of benefits. The following analysis considers the value of state tax credits for PV systems in the RETC program from 1996 through 2010, and how a hypothetical similar expenditure today could be targeted to provide a more equitable distribution of the benefits associated with PV systems.

The period from 1996 through 2010 represents the first 20 percent of RETC PV projects (by count).[30] 2010 was selected as the final year for this analysis because it represents a transition in the RETC program. 2011 was the first year that third-party ownership models were available for residential projects in Oregon. These innovative financing models dramatically reduced the up-front cost for a homeowner to access solar by transferring ownership of the system to a third party that could take advantage of additional federal financial incentives. The homeowners hosted the installations through a lease-to-own agreement with the third-party owner. In 2010, zero percent of RETC projects were financed through a third-party model. In 2011, 60 percent of RETC projects were financed through a third-party model. [30]

The advent of third-party financing opened up the residential PV market to more middle-income participants. This trend was seen nationally as well as in Oregon. A study conducted by Lawrence Berkeley National Laboratory, which included Oregon, evaluated the share of PV adopters based on household income.[10] Figure 3 below demonstrates that the share of the market held by the highest income households (dark blue bars) steadily decreases starting in 2011.

[iv] See Figure 1 above for cost and volume trends in residential PV systems in Oregon.

Figure 3: Income Distribution of PV Adopters by Install Year[10]

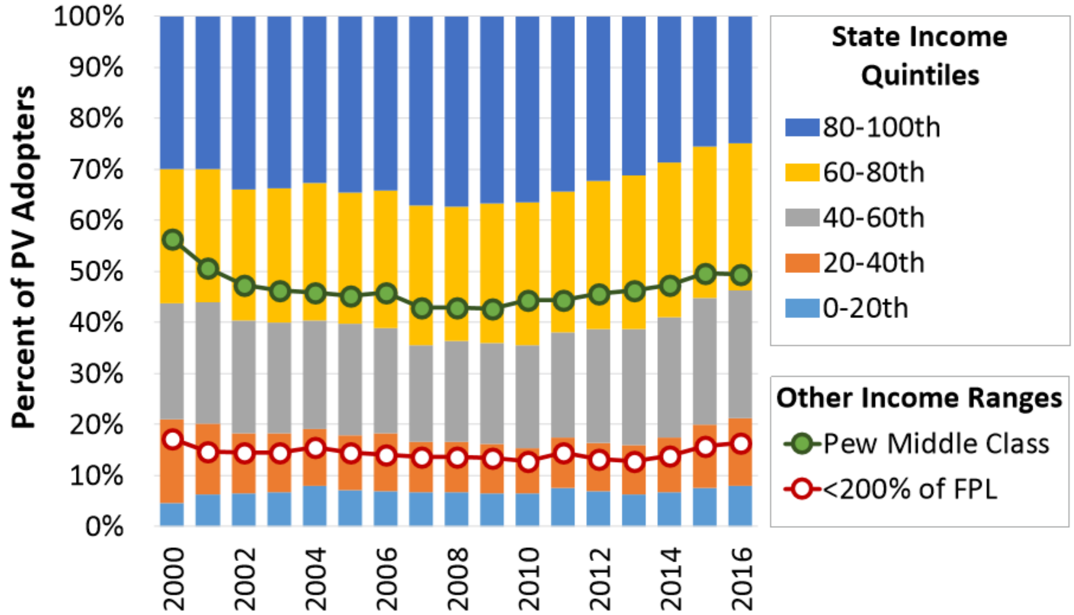
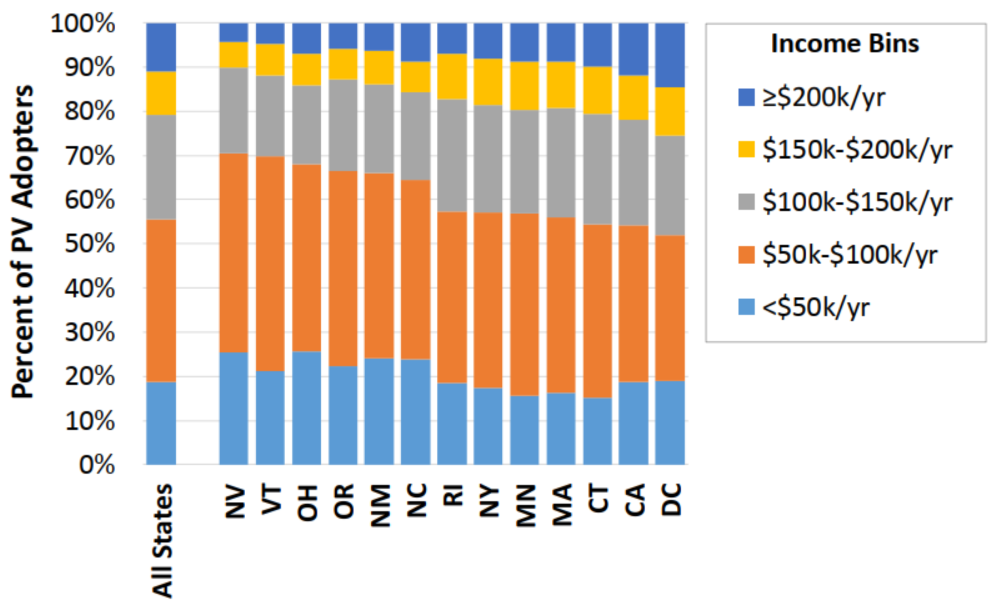


Figure 3 also demonstrates that in 2010, only about 6 percent of national PV installations were on households in the lowest income quintile while more than 35 percent of installations were in the highest income quintile.

The LBNL study demonstrates that while the share of projects held by the highest income is relatively high compared to the lowest income, there is also broad adoption of PV systems within the middle incomes. By 2016 nearly half of the residential PV systems were installed in households in the lowest three income quintiles. This is especially true in Oregon where there were nearly twice as many PV systems installed by households with an income below $100K per year compared to households above $100K per year. Figure 4 below shows the distribution of PV systems through 2016 for each state in the study.

Figure 4: Income Distribution of PV Adopters by Location[10]



To explore racial equity across the early RETC program (though 2010), ODOE compared the distribution of race in the Oregon population from the 2010 Decennial Census with the distribution of race in 2010 Decennial Census block groups with RETC installations.[29] As noted previously, information on race was not collected in the RETC program, however the program did collect address information. To complete this analysis, approximately 2,717 RETC projects were geocoded to 2010 Decennial Census block groups. Each project was assigned the racial distribution of the block group. The average distribution across all RETC project block groups was then established. It should be noted that this analysis is based on the racial makeup of census block groups and not the actual racial makeup of participants in the RETC program.

The table below shows that on average, block groups with RETC projects had a higher proportion of white residents than the Oregon population distribution. Conversely, all other racial groups were less represented in block groups with RETC projects when compared to the total population distribution.

Table 2: Race Distribution of 2010 RETC Census Blocks

	2010 Oregon Population Race Distribution	2010 RETC Block Group Race Distribution
White	78.46%	84.76%
Hispanic	11.75%	6.40%
Asian	3.64%	3.29%
Two or More Races	2.87%	2.76%
Black	1.70%	1.61%
American Indian and Alaska Native	1.14%	0.81%
Hawaiian / Other Pacific Islander	0.33%	0.22%
Other	0.14%	0.16%

Table 3 summarizes tax credit expenditures as well as the capacity and annual energy production of systems installed in the RETC program through 2010.[30]

Table 3: RETC System Installation Expenditures and System Information

Tax Year	Total RETC Incentives	Avg System Cost $/Watt	Incentive % of Project Cost	Total Capacity (KW)	Annual Production (KWh)
1996	$2,400	$16.78	6%	2	2,474
1997	$1,200	$15.60	13%	1	623
1998	$9,108	$15.21	12%	5	5,509
1999	$38,149	$14.20	11%	25	25,623
2000	$52,050	$13.41	10%	38	39,163
2001	$61,890	$10.84	16%	38	39,939
2002	$63,724	$12.29	15%	38	39,562
2003	$217,764	$8.21	11%	273	283,595
2004	$216,326	$8.72	12%	278	288,341
2005	$203,251	$8.52	13%	217	225,503
2006	$1,157,828	$8.44	27%	535	555,453
2007	$1,300,318	$9.13	24%	647	671,253
2008	$1,203,668	$8.92	24%	611	633,621
2009	$3,534,287	$8.08	24%	1,857	1,926,850
2010	$6,771,192	$6.55	30%	3,474	3,604,729
Totals	**$14,833,155**	**$11.00 Avg**	**17% Avg**	**8,040**	**8,342,237**

Tax credit expenditures from 1996 through 2010 totaled nearly $15 million dollars and resulted in about 8,000 kW of solar capacity with an estimated production of more than 8.3 million kWh per year. These tax credits covered an average of 17 percent of project costs, the rest of which was provided from other financial incentives and significant investments by the project owners. When adjusted for inflation to 2020 dollars, the value of tax credits through 2010 for residential PV systems is $24.6 million.[v] This amounts to an incentive of over $3.00 per watt based on the 8,040 kW installed in the program through 2010.

In addition to market transformation, the benefits associated with PV systems in the RETC program may be simplified into three categories: (1) individual benefits associated with lower electric bills, (2) societal benefits associated with the renewable energy production and associated greenhouse gas reductions, and (3) economic stimulus associated with job creation to install the systems. For purposes of this analysis the societal and economic stimulus benefits are based on the total installed capacity and production of PV systems, and it is assumed that solar installed today will have similar

[v] Calculation includes 4.5 percent discount rate applied through 2020.

societal benefits to the same amount of solar installed through 2010. The following analysis will demonstrate that if $24.5 million were spent today to subsidize residential PV systems – which are now much less expensive – it could be equitably distributed to enable more Oregonians to access rooftop solar and result in similar amounts of solar being installed.

The average cost of residential PV systems in Oregon dropped from $16.78 per Watt in 1996 to $6.55 per Watt in 2010.[vi] Today the average system costs is $3.55 per Watt.[31] Given the dramatic cost reductions, it would be possible to cover a larger portion of system costs with a similar amount of funds while delivering similar installed capacity and energy production as the early RETC program. For purposes of this analysis, efficiency improvements that result in increased production from today's PV systems are not assessed. Similarly, changes in hardware and installation methods that impact the amount of labor needed to install modern systems are also not assessed. Table 4 below compares the percentage of system costs covered by a financial incentive program in 2010 and 2021 to deliver similar societal and economic stimulus benefits.

Table 4: Percent of System Costs Covered by Incentives

Tax Year	Total Incentives*	Total Capacity (kW)	Estimated Annual Production (kWh)	Avg System Cost $/Watt	Incentive % of Project Cost
1996-2010	$24.57 M	8,040	8,342,237	$11.00	**17%**
2021	$24.57 M	8,040	8,342,237	$3.55	**86%**

**2020 dollars*

This table demonstrates that an investment of $24.6 million, which is equivalent to the expenditures in the RETC program from 1996 through 2010, could cover 86 percent of residential rooftop project costs today. This analysis assumes similar installed capacity and energy production. Another way to achieve more equitable distribution could involve commercial-scale projects installed on multifamily developments or as low-income community solar projects. The average cost for commercial projects in 2020 is $2.55 per Watt.[31] Given that the incentives in the early RETC program averaged over $3.00 per watt, in today's dollars it would be possible to deliver considerably higher capacity and annual energy production. Even if 100 percent of project costs were covered, it would result in over 9,600 kW of capacity installed – or 120 percent of the capacity that was installed in the RETC program through 2010.

Current Renewable Energy Programs with Equity Considerations

Equity considerations have been incorporated into some renewable energy programs in Oregon. The above hypothetical analysis demonstrates one way in which incentive funds could be applied over time to help support equity in access to renewable energy options. Other initiatives to improve equity

[vi] See Figure 1 above for average PV System Costs from 1996 through 2017.

in Oregon programs are currently under way. Following is a brief summary of select energy programs in Oregon with specific goals related to improving equitable access to renewable energy.

Energy Trust of Oregon

Energy Trust has been providing financial incentives for renewable energy systems since 2007. While the initial programs and enabling legislation did not include equity considerations for renewable energy, the Energy Trust has worked to improve equity in their programs. In 2018, Energy Trust adopted a Diversity, Equity and Inclusion Operations Plan that established 10 equity and inclusion goals for Energy Trust programs.[32] Energy Trust has also established a Diversity Advisory Council to support diversity, equity, and inclusion goals and to make recommendations to the board of directors and staff on assessing and measuring progress in this work.[33] In 2020 Energy Trust launched the "Solar Within Reach" initiative, which provides additional financial incentives for participants who meet income qualifications.[34] Energy Trust has also supported minority- and women-owned businesses within their trade ally network.[35]

Community Solar

Senate Bill 1547 (2016) directed the Oregon Public Utility Commission to "Determine a methodology by which 10 percent of the total generating capacity of the community solar projects operated under the [Community Solar] program will be made available for use by low-income residential customers of electricity."[36] In 2019, the Oregon PUC approved the Community Solar Program Implementation Manual.[37] The implementation manual includes clarification and guidance related to equity goals in the program. Specifically:

1. *The goal of the Oregon Community Solar Program is to expand access to solar energy for customers who are not able to or do not want to invest in a rooftop system, including but not limited to renters, people who live in multifamily buildings, low-income customers and small businesses in rented or leased space.*[38]
2. *For the Interim Offering, at least 10 percent of the generating capacity of each project must be subscribed by low-income residential customers at the time of Certification and throughout the commercial operation of the Project.*[39]

As of October 2020, more than 20 community solar projects have been pre-certified but none are yet operating or delivering bill credits to participants. Evaluation of the equity measure described above will be considered upon completion of the first round of community solar projects.

Oregon Solar + Storage Rebate Program

House Bill 2618 (2019) established the Oregon Solar + Storage Rebate Program.[40] The bill directed the Oregon Department of Energy to develop program rules including preferences for providing rebates that benefit low- and moderate-income residential customers and nonresidential customers that are low-income service providers. The bill also established a 25 percent budget carve-out for low-income applicants and allowed for incentives for low-income applicants to cover a higher percentage of project costs.

ODOE launched the Oregon Solar + Storage Rebate program on January 1, 2020. Of the program's $1.5 million rebate budget, the department allocated $750,000, or half of the total budget, to projects for low- and moderate-income residential customers and low-income service providers. In a report to the Oregon Legislature in September 2020, ODOE detailed 85 rebates issued so far totaling $729,408 for low- and moderate-income participants and low-income service providers.[41] As of October 2020, the Oregon Solar + Storage Rebate program is fully subscribed and expected to issue final rebates as projects are completed.

Portland Clean Energy Community Benefits Fund (PCEF)

PCEF provides dedicated funding for climate action that advances racial and social justice.[42] The fund was created by local ballot measure #26-201 in November 2018, which passed with overwhelming community support. In the face of climate change, racial injustice, economic insecurity, and COVID-19, PCEF offers a community-led vision, grounded in justice and equity, that builds citywide resilience and opportunity. Nonprofit organizations are eligible to apply for grant funds from PCEF, which are awarded on a competitive basis and can include multi-year requests.

The Fund is anticipated to bring $44 - $61 million in new revenue annually for green jobs, healthy homes, and a climate-friendly Portland. The revenue is generated from a 1 percent surcharge on the gross sales activity of large retailers, defined as those have sales of over $1 billion nationally, and over $500,000 within Portland. Sales in certain critical sectors are exempted, such as food, medicine, utilities and health care. As the nation's first-ever climate fund created and led by communities of color, PCEF is for and by the community. PCEF has guiding principles that center Black and Indigenous people, and other disadvantaged and marginalized groups in addressing the climate crisis.

Interaction between Energy Trust of Oregon and PCEF

The Portland Clean Energy Community Benefits Fund is unique because it supports community-driven clean energy solutions and jobs to help Portlanders that need them the most. It also provides resources for workforce training programs, green infrastructure and innovative projects related to reducing carbon emissions. PCEF is intended to fill funding gaps and serve people who have previously not had access to the benefits of clean energy economy. Energy Trust of Oregon provides support and market-based incentives for residential energy efficiency and solar energy to the maximum level governed by the Oregon Public Utility Commission, whose mission does not currently include climate change or social justice. Projects funded by PCEF will have the opportunity to also leverage Energy Trust incentives to broaden access to clean energy. In addition, PCEF will provide Portland a stable source of long-term funding for energy efficiency and renewable energy projects, filling a need that has been missing in past programs like the Oregon Department of Energy's Residential Energy Tax Credit (RETC) program, which expired in 2017.

PCEF Grant Committee and Principles

PCEF is guided by a nine-member Grant Committee, comprised of diverse Portland residents.[43] The Grant Committee makes funding recommendations to the Mayor and City Council and evaluates the effectiveness of the Fund achieving the goals of the initiative. Membership of this committee must reflect the racial, ethnic and economic diversity of the City of Portland; include at least two residents living east of 82nd Avenue; and possess experience in different subject areas supported by the Fund. Project staff to support the PCEF program are housed at the City's Bureau of Planning and Sustainability.

The Grant Committee developed a set of principles to guide the program. These Guiding Principles describe the values by which the PCEF program is administered and were developed with public input and engagement with frontline communities. The following Guiding Principles complement the legislative code (Portland City Code 7.07) and help ensure that decisions are being made in a way that aligns with the vision and values of the Committee and the community:[44]

- Justice driven. Advance systems change that addresses historic and current discrimination. Center all disadvantaged and marginalized groups – particularly Black and Indigenous people.
- Accountable. Implement transparent funding, oversight, and engagement processes that promote continuous learning, programmatic checks and balances, and improvement. Demonstrate achievement of equitable social, economic, and environmental benefit. Remain accountable to target beneficiaries, grantees, and all Portlanders.
- Community powered. Trust community knowledge, experience, innovation, and leadership. Honor and build on existing work and partnerships, while supporting capacity building for emerging community groups and diverse coalitions. Engage with and invest in community-driven approaches that foster community power to create meaningful change.
- Focused on climate action with multiple benefits. Invest in people, livelihoods, places, and processes that build climate resilience and community wealth, foster healthy communities, and support regenerative systems. Avoid and mitigate displacement, especially resulting from gentrification pressures.

PCEF priority populations

Providing benefits to historically marginalized populations is central to the PCEF program. These populations are called out in the legislative code and are the focus of PCEF's grant programs. It is important that organizations applying for PCEF grants understand and reflect these priority populations. The PCEF legislative code identifies two "priority populations":

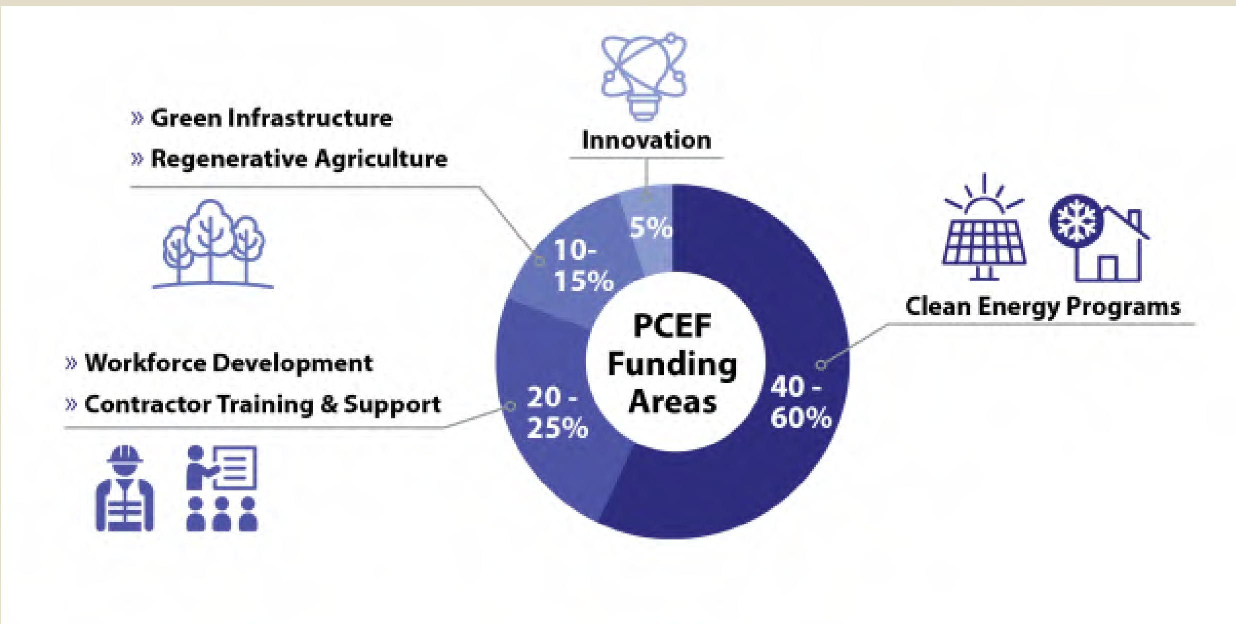
1. Priority populations for clean energy, green infrastructure, and regenerative agriculture projects: People with low income and people of color are priority populations for grants that address clean energy, green infrastructure, and regenerative agriculture. Historically, these populations have had less access to the benefits of green investments, and at the same time they are more vulnerable to extreme heat, wildfire smoke, vector borne diseases, flooding and other climate-related impacts.
2. Priority populations for workforce and contractor development projects: Women, people of color, people with disabilities, and people who are chronically underemployed are identified as priority populations for grants that address workforce and contractor development. These populations have not had equitable access to workforce and contractor opportunities associated with the clean economy. Developing a diverse and well-trained workforce and contractor pool in the clean energy field requires reaching

these populations and addressing the barriers that have prevented their full participation in this field.

Timeline, funding opportunity, and capacity-building in PCEF

PCEF released a Request for Proposals (RFP) for an initial round of $8.6 million of funding on September 16, 2020. The applications are due November 16, 2020, and PCEF staff have provided outreach, informational webinars, and grant writing trainings with organizations interested in the PCEF funding opportunities. In addition, the Grant Committee recognized that small organizations face barriers to grant development and organizational capacity, particularly those that serve Black and Indigenous people. In August 2020, the Committee made available small grants of $5,000 each to small organizations through a process that allocated a total of $200,000 in order to support capacity-building activities in these priority populations. The PCEF program intends to continue offering additional learning and organizational development opportunities for organizations interested in climate action and social justice, to complement the deployment of funding for projects. The next round of PCEF funding will be in the 2021 program year, with an expected allocation of $41-61 million.

Visit https://www.portland.gov/bps/cleanenergy to learn more.



Conclusion

Oregon has been a leader in development of renewable energy resources since the 1970s when the state legislature first established financial incentives to support adoption of renewable energy resources such as solar PV. Since that time state, federal, and utility incentives have supported market transformation for PV technologies, which are now available at a fraction of the cost seen early in the incentive programs. However, neither incentives nor market transformation have resulted in an equitable access or benefits associated with solar PV systems. As the state works to achieve more equitable outcomes, clean energy programs are increasingly being designed to ensure access to benefits for all Oregonians.

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Policy Brief: Energy Efficiency

In 2020, energy efficiency continues to be a cornerstone of Oregon's energy policy. As the least-cost and priority resource, energy efficiency is second only to hydropower in terms of meeting the region's electricity needs. As has been stated earlier in this report, the Pacific Northwest region has achieved 7000 average MW[i] of energy savings since 1978, resulting in millions of dollars in savings for Oregonians.[1] Over the past decade, energy efficiency has helped reduce Oregon's per capita energy use, making the state the most efficient of all Northwest states. Electric and natural gas efficiency programs continue to deliver consistent savings, even during an unprecedented public health event that slowed the economy.

The 2018 BER provided a summary of policies and programs that promote energy efficiency in Oregon and described how efficiency is acquired. In the 2020 BER, this section examines two trends that have developed since 2018: the region is no longer on track to meet its electricity energy efficiency goals for everything from greenhouse gas reductions to equity, and at the same time, Oregonians are recognizing and seeking co-benefits of energy efficiency. In autumn 2020, energy efficiency is at a crossroads.

Acquisition Trends

Every five years, the NW Power and Conservation Council produces a Regional Power Plan, including energy savings targets for the Northwest states of Oregon, Washington, Idaho, and Western Montana.

2021 is the final year of the Action Plan period for the 2016 Seventh Power Plan and the 2021 Plan production is underway. In September 2020, the Council received the annual Conservation Progress Report for the 2016 plan.[2] The progress report indicates that the trend of program achievements for the remaining two years of the Seventh Power Plan action plan period is downward, with 2018 and 2019 each delivering fewer savings than expected and showing overall declining expenditures for energy efficiency across the region, even though there is ample cost-effective energy efficiency still available.[3]

As seen in Figure 1, the Conservation Progress Report shows that the decline in electricity savings from efficiency programs is forecasted to continue.[ii] This is an important consideration for the 2021 Power Plan as the Council charts a course forward that will continue to deliver cost-effective energy efficiency savings to the region at a lower cost than new power generation.

Electricity and natural gas efficiency programs operated by Energy Trust of Oregon have not experienced the same concerning trend as region-wide electricity efficiency. These programs have continued to meet or exceed their savings targets.

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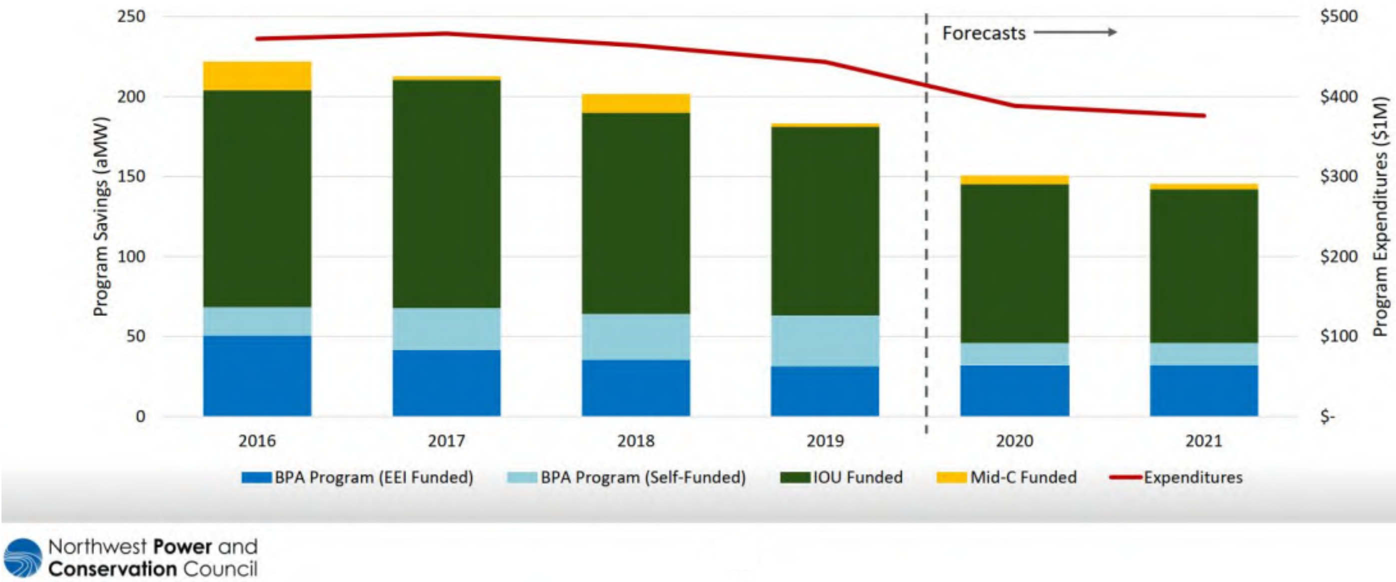
[i] An Average MW (aMW) is the metric for one megawatt of generation operating for one year. It represents 8,760,000 kWh.

[ii] Mid-Columbia is a reference to 118 miles of the Columbia River in Central Washington where five hydro projects are located. These projects are owned and operated by Chelan County PUD, Grant County PUD and Douglas County PUD https://www.chelanpud.org/my-pud-services/business-services/mid-c-services

Figure 1: Annual Program Savings and Expenditures, Including Forecasts (NWPCC)



In 2019, Oregon also saw its ranking on the ACEEE scorecard go down to ninth place – the lowest rank for Oregon since the scorecard began in 2006.[4] ACEEE's national energy efficiency review uses consistent metrics across all states and is intended to guide policymakers, utilities, regional energy efficiency organizations, and program implementers by comparing their activities to other states. Each year's score is primarily based on the previous calendar year's accomplishments, so the past achievements of legacy programs with years of ongoing savings are not counted for the annual score. Also, energy savings are not the sole criteria for the scorecard. This means that states like Oregon, with strong legacy programs may not fare as well in the scorecard as states that are creating new programs, ramping up their programs with new funding, and getting energy savings that are easier to achieve.

Electricity and natural gas efficiency programs operated by Energy Trust have not experienced the same concerning trend as region-wide electricity efficiency. These programs have continued to meet or exceed their savings targets.

Evolution of Energy Efficiency Programs

While energy efficiency continues to deliver cost savings for Oregonians, programs and policies are increasingly intersecting with new considerations in addition to resource acquisition. These programs, which were designed to deliver reductions in energy use at a lower cost than new production or generation, can also contribute to desired outcomes such as resource adequacy, public health, equity, and climate change. Co-benefits are being incorporated into program targets and goals, offering potential new value streams.

For example, energy assistance and weatherization programs can help Oregonians who have experienced unemployment or other economic hardships due to COVID. As Oregonians work to reduce the airborne spread of the virus, energy efficiency programs, codes[5], and policies can contribute to better indoor air quality. Heightened interest in ventilation for homes and business, first for pandemic response and later for wildfire smoke, are emerging in energy efficiency retrofit programs because energy efficiency upgrades often include heating, ventilation, and air conditioning (HVAC) equipment.[6] Increasing consideration is being paid to ensuring that currently and historically underserved communities are benefiting from energy efficiency programs, and equity and inclusion concerns are causing implementers of efficiency programs to evaluate and re-tool their offerings to serve a more diverse population.[7]

Savings from efficiency programs also create more opportunities for Bonneville Power Administration to market its surplus hydropower capacity to other entities in the region, as it did when it recently signed a five year agreement with PGE to supply up to 200 MW of surplus hydropower to backfill for capacity Portland General Electric is losing with the retirement of the Boardman coal plant.[8]

Finally, efficiency policies and programs are adding greenhouse gas reduction to their list of benefits, with increased efforts to reduce energy use in buildings and transportation in order to reduce greenhouse gases from direct energy use or electricity generation.[9] [10] [11] The list of things we are asking of future energy efficiency programs is growing, and the 2021 Power Plan will have to recalibrate goals and expectations.[12] New value outcomes from efficiency could translate into new value considerations for efficiency. An example would be an "adder," similar to the Total Resource Cost conservation ten percent allowance (see EE 101). A benefit from efficiency, such as reduced greenhouse gases from direct use of fuels or indirectly from electricity generation reduction, could be explicitly quantified and included in the Total Resource Cost. Climate change and its effects on energy use are being modeled for the 2021 Power Plan, which could inform an evaluation of climate value efficiency actions.[13]

The added value from co-designed and equitably deployed energy efficiency programs could be another consideration. For example, the Energy Trust "Savings Within Reach" initiative includes an income and ownership component in the overall incentive design, providing a higher level of incentive while still meeting TRC and Utility Cost Tests.[14]

Energy Trust introduced an incentive for furnaces in rental properties after determining there was an opportunity to help rental property owners – and tenants by way of energy savings – upgrade furnaces in this market segment.[15] By targeting a segment of consumers instead of the broader market, Energy Trust effectively adds more energy savings for the portfolio of programs.

Energy Efficiency as Cornerstone of Climate Change Executive Orders

A key example of increased recognition of an energy efficiency co-benefit is the emphasis put on efficiency by Governor Kate Brown in her recent climate change executive orders. In 2017, she issued Executive Order 17-20, "Accelerating efficiency in Oregon's built environment to reduce greenhouse gas emissions and address climate change" (See 2018 BER, Chapter 6, for a detailed discussion). While Oregon's energy efficiency programs have long delivered reductions, this EO was one of the first policies to identify greenhouse gas reductions as a primary benefit of energy efficiency. Like cost-effective resource acquisition, greenhouse gas reductions through energy efficiency can be structured as a cost-effective method to combat climate change.[16]

Over the past three years, ODOE completed all of the directives in EO 17-20. For more information, see ODOE's website. One of the directives in EO 17-20 is for the residential energy building code to be equivalent to USDOE's Zero Energy Ready Home by 2023. As part of the ongoing public process, the Oregon Building Codes Division is currently in the rulemaking stage for the 2020 Residential Specialty Code, expected to be in effect later in 2021 after a delay due to COVID.[17] The energy portion of the code will include several components for the Zero Energy Ready Home equivalence.[18] New efficiency requirements and options include improved ventilation, more efficient windows, air leakage reduction, and relocation of ductwork to conditioned space. After adoption of the new code, BCD and ODOE will convene with stakeholders to describe a new baseline for the 2020 code, so the progress toward 2023 and beyond can be quantified.

EO 17-20 also included a requirement for solar-ready provisions in the building code to make future installations of on-site renewables more accessible for building owners.[19] As of October 2020, this has been incorporated into the Oregon Residential Specialty Code.[20] The 2019 Oregon commercial energy code requires completion of the "2019 Oregon Zero Energy Ready Commercial Code Compliance Form"[21] that, while not specifically requiring onsite or offsite renewables in the code, includes a requirement for an estimate of building energy consumption, renewables needed to achieve net zero energy, and the on-site renewable generation potential.

This trend toward using energy efficiency as a greenhouse gas reduction strategy continued with Executive Order 20-04, issued by Governor Kate Brown in March 2020.[22] EO 20-04 directs ODOE "to pursue emissions reductions by establishing and updating energy efficiency standards for products at least to levels equivalent to the most stringent standards among West Coast jurisdictions, including grid-connected appliances that can be utilized to manage end-use flexible electrical loads. ODOE also is directed to periodically evaluate and update those standards, as practicable, to remain at least equivalent to the most stringent standards among West Coast jurisdictions." Alignment with standards in neighboring states helps manufacturers distribute their efficient products in the large west coast market.

After a public process during the spring and summer of 2020, including public meetings and a rulemaking advisory committee, ODOE issued new and updated appliance standards at the end of August 2020. Initial staff analysis found that updating and establishing standards for the products identified in the EO could, in the year 2025, result in annual savings to Oregonians of 200 GWh of electricity, 500 billion Btu of natural gas, 76,000 metric tons of $CO2$, and over $35 million in utility bills.

Executive Order 20-04 also directs the Building Codes Division (BCD) of the Oregon Department of Consumer and Business Services to work with ODOE to update Oregon's energy building codes.[23] Oregon already has one of the strongest energy codes in the country, and the EO sets savings goals to be achieved over the next three code cycles: 2023, 2026, and 2029. Both residential and commercial buildings are to achieve an overall reduction in building energy use of 60 percent when compared to a 2006 baseline.

The Commercial energy code is on a linear track to the EO 20-04 goal for 2029. By adopting ASHRAE Standard 90.1 as the basis for the code, Oregon can adopt subsequent three-year updates of the ASHRAE Standard on the regular code cycle. The ASHRAE Standard updates are expected to deliver increased efficiency along the same path as the EO requirements.

The Residential energy code is also on track to the overall reduction of 60 percent from 2006-code homes by 2029. The first milestone is USDOE Zero Energy Ready equivalence in 2023. The USDOE program is not a model code or standard, and Oregon must craft its code beyond available model codes. This has been the case for several years as Oregon has been a leading state in energy code strength. Working with a stakeholder panel designed as part of the EO 20-04 implementation plan, BCD and ODOE are mapping out the expected components for each code cycle to keep the code on track to meeting energy targets.[24]

Also as directed in the EO, BCD is developing a statewide voluntary Reach Code. In 2021, local jurisdictions that want to offer an optional path for builders in their community to build to an even higher code can promote the statewide voluntary Reach code. Utility incentive programs for energy-efficient new construction can encourage participation and align program requirements with Reach Code components. Incentives also help prepare the market for building components that may become mandatory in future building codes.

Home Energy Scores as a Climate Action

As discussed in the 2018 BER, the City of Portland chose the Oregon Home Energy Score as an action in its Climate Action Plan to reduce greenhouse gases associated with energy use. The purpose of disclosing the efficiency level and the annual estimated energy costs as part of the home sale process is to educate homeowners and home buyers and to spur retrofits that reduce energy use. To date, more than 20,000 home scores have been issued in Portland. Scores are required when a home is put on the market. Portland is preparing a program evaluation to determine the energy savings, retrofits chosen, and demographic aspects of their program in its first two years.[25]

Other Oregon cities have shown interest in adopting the Home Energy Score as part of their climate action plans. In October 2020, Milwaukie began implementation of a mandatory Home Energy Score for homes put on the market.[26]

ODOE supports the statewide voluntary Home Energy Scores through administrative rules for scoring systems, verifying training for licensed Home Energy Score Assessors, and coordination with an implementation contractor to assist cities in their adoption and implementation process. Learn more about Oregon's Home Energy Score program:

https://www.oregon.gov/energy/save-energy/Pages/HEPS.aspx

Incorporating Equity and Environmental Justice

EO 20-04 describes the disproportionate effect that climate change has "on the physical, mental, financial, and cultural wellbeing of impacted communities, such as Native American tribes, communities of color, rural communities, coastal communities, lower income households, and other communities traditionally underrepresented in the public process, who typically have fewer resources for adapting to climate change and are therefore the most vulnerable to displacement, adverse health effects, job loss, property damage, and other effects of climate change."[27]

In a time of reduced spending and unmet goals for energy efficiency, the resouce acquisition model for funding may not be adequate to meet future goals for efficiency, equity, and GHG reduction. Legacy programs and rate structures were not designed to directly address equity or climate change.

To meet these additional goals above and beyond energy savings, new considerations, evaluation methods, and targets may be needed.

Three examples highlight the challenges and opportunities associated with incorporating equity considerations into energy efficiency programs and policies.

- **Energy Trust of Oregon** has developed and is implementing a Diversity, Equity, and Inclusion (DEI) Operations Plan. They have established a Diversity Advisory Council to provide advice and resources to staff and the Board of Directors on operationalizing DEI, as well as assessing and measuring progress toward DEI goals. Programmatic goals of this plan include: increasing customer participation in energy efficiency and renewable energy programs for all underserved populations, including communities of color, lower-income Oregonians, and rural customers: increasing contracts with minority-owned and women-owned business; increasing market awareness and understanding of underserved populations through developing and deepening relationships; and developing systems to collect, track, analyze, and report demographic information.[28]

  A collaboration between **Community Energy Project** and Energy Trust is helping low-income Portland residents benefit from energy efficiency and reduced energy bills. Nonprofit Community Energy Project, which has a long history of reaching residents with low incomes and communities of color, installs heat pump water heaters in low-income homes at no cost to the participants. Sponsored by Energy Trust, the effort tests a new model of program design that taps into the networks of community-based organizations to deliver services to wider audiences. An Energy Trust cash incentive of $875 offsets the full cost of the water heater for participants, who will save an estimated $190 on annual energy bills. So far, Community Energy Project and Energy Trust have helped 82 low-income Portland residents take advantage of heat pump water heaters through this small startup effort.[29]

- **The Northwest Power and Conservation Council produced the** Northwest Underserved Energy Markets Assessment in 2018 to inform DEI efforts. Council has received input from its advisory committees indicating an interest in addressing DEI in the 2021 Power Plan. The Council is engaging its advisory committees to consider what attributes of power system resources are impacted by considerations of DEI.[30] Guidance for DEI in the Power Plan comes directly from the NW Power Act:[31]

> 4(e)(2)"The plan shall set forth a general scheme for implementing conservation measures and developing resources pursuant to Section 839d of this title to reduce or meet the Administrator's obligations with due consideration by the Council for (A) *environmental quality,* (B) compatibility with the existing regional power system, (C) protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival, and propagation of anadromous fish, and (D) *other criteria which may be set forth in the plan.*
>
> In the exercise of his authorities pursuant to this section, the [BPA] Administrator shall, consistent with the provisions of this Act and the Administrator's obligations to particular customer classes, insure that benefits under this section, including financial and technical assistance, conduct of conservation demonstrations, and experimental projects, services, and billing credits, *are distributed equitably throughout the region."*

- **The Portland Clean Energy Fund** was created by a ballot measure in November 2018. As the nation's first-ever climate-fund created and led by communities of color, PCEF is a strong example of a clean energy program with a specific focus on equity and climate change. PCEF centers Black and Indigenous people, and other disadvantaged and marginalized groups in addressing the climate crisis.[32] In November 2020, Portland Clean Energy Community Benefits Fund is seeking proposals for $8.6 million in its first round of funding for community projects. This opportunity follows a round of funding for organizations to develop their grant proposal skills. This unique skill-building round of funding helped prepare a group of local organizations for successful grant applications for community benefits projects. Examples of community benefits include solar panels and energy efficiency upgrades on multifamily housing, new workforce training programs in clean energy manufacturing and installation, shared food gardens, and increased tree canopy in under-shaded neighborhoods.

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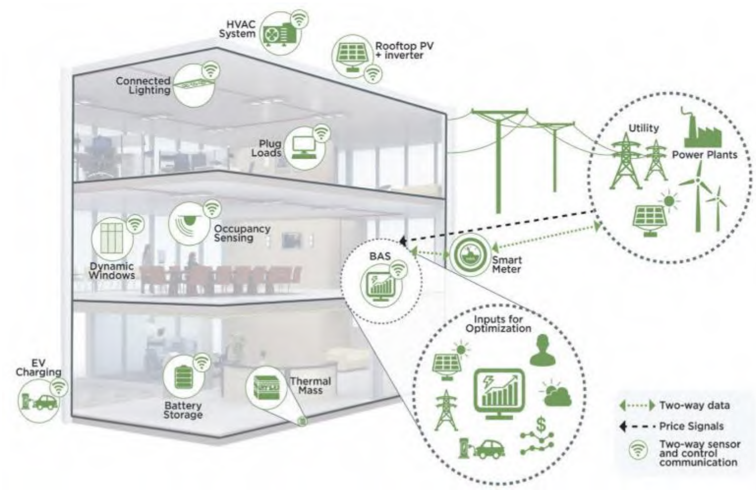
Policy Brief: Grid-interactive Efficient Buildings

The term Grid-interactive Efficient Buildings, sometimes referred to as GEB, has emerged from the application of cross-cutting strategies and advancement of interactive technologies in the built environment. While still evolving, the Grid-interactive Efficient Buildings concept envisions "energy efficient building(s) with smart technologies characterized by the active use of DERs (distributed energy resources) to optimize energy use for grid services, occupant needs and preferences, and cost reductions in a continuous and integrated way."[1]

Figure 1. Grid-interactive Efficient Buildings[2]



Suggested Reading: Grid-interactive Efficient Buildings is an intersectional topic. For more background on related topics, see: Demand Response Technology Review, Microgrid and Resiliency Technology Review, Electricity Distribution System Planning, and Net Zero Buildings.

What are Distributed Energy Resources (DERs)?

DERs refer to any resource interconnected to the distribution grid of a local utility. DERs include:

- Generation sources (e.g., rooftop solar or diesel generators)
- Technologies that modify demand on the distribution system (e.g., energy efficiency and demand response)
- Electric vehicles and associated charging infrastructure; energy storage technologies (e.g., distributed batteries)
- Hardware or software control systems used to communicate with the grid and/or to optimize the usage of other DERs

Buildings are one of many demands on the energy system, consuming approximately 40 percent of U.S. energy and 75 percent of all U.S. electricity – costing $380 billion a year.[2] In Oregon, the commercial and residential sectors accounted for 44 percent of energy consumption and 33 percent of energy expenditures in the state – costing Oregonians $4.7 billion a year. Along with these costs, energy use in buildings contributes to greenhouse gases (GHGs) emissions and can adversely affect grid resilience and reliability. Therefore, reducing and better managing building energy demand can benefit the environment, public health, consumers, and the grid.

Building energy use can now be managed more intelligently and flexibly due to the expansion of energy efficiency and demand response programs, reduced technology costs, customer adoption, and advancement of controls and integration systems - simultaneously meeting occupant needs and serving as a grid resource. Grid-interactive Efficient Buildings enable customers to provide and consume grid services that help reduce peak demand, moderate grid stresses, support power quality, and integrate more renewable generation and transportation electrification.

Grid-interactive Efficient Buildings: Deeper Dive

Characteristics and Applications

Figure 2. Grid-interactive Efficient Buildings Characteristics (adapted)[2]

Grid-interactive Efficient Buildings share four characteristics of being efficient, connected, smart, and flexible. Individual characteristics can occur across a spectrum but are all needed to capture the full potential benefits and uses of these buildings.

Energy efficiency is the first core characteristic, which is critical to reducing building energy consumption and peak demand. By reducing total energy demand, the building would need less onsite generation (e.g., PV or backup generators) and storage to achieve net-zero (see Net-Zero Buildings 101) and resilience. Specific energy efficiency features will vary by building type and commonly include more passive, structural components like insulation and high-quality windows, operational components like energy-efficient heating systems and appliances, and occupant practices that reduce energy consumption and peak demand. [3] Once a building is operating efficiently, energy loads within Grid-interactive Efficient Buildings must be **connected** and capable of operating synergistically within the building and in harmony with the grid. This connectivity requires the use of telecommunication signals that can either directly monitor and control equipment or trigger building management systems (BMS)[i] to act based on price signals and grid conditions. The BMS should be able to exchange signals with grid operators directly or via service providers that can aggregate individual grid-connected building resources.

A **smart** Grid-interactive Efficient Building uses sensors, analytics, and controls to continually assess and optimize building operations to meet occupant needs while providing grid services. Such smart buildings are not only responsive to the grid but may also provide ongoing "commissioning" services to anticipate, diagnose, and flag maintenance needs and operational improvements within the building. Finally, to maximize the value and benefits of Grid-interactive Efficient Buildings, the building must be **flexible.** What this flexibility means may vary and might be adapted for the building type and operation, but this functionally allows for optimizing building energy loads at any point in time to better align with grid needs and may also include export of generated and stored power to the grid (see Strategies below).

While these characteristics are shared across buildings, they will be tailored in commercial, residential, and community applications. Larger commercial and industrial buildings have been the primary focus for many demand-response programs that curtail electricity use in peak periods due to their large, centralized loads (see Demand Response Technology Review). Beyond this, technologies and approaches are now being piloted in homes, and in aggregate at the neighborhood[4] and community

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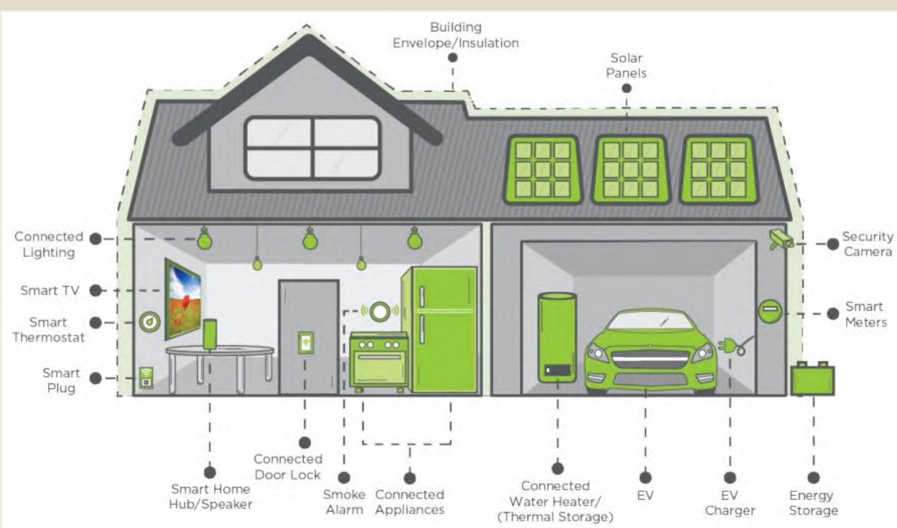
[i] A Building Management System "integrates hardware, software and communications to collect data, monitor use, predict operations, and prescribe automated responses to achieve optimum performance." Learn more at: https://www.nema.org/directory/Products/view/Building-Management-Systems

scale.[5] Pilot projects can test technologies, communication protocols, and program design in both commercial and residential structures, and in new and retrofitted buildings, to "work at scale in a real-world context."[6] For example, in Alabama a set of high performance homes are the southeast's first community-wide microgrid and are supporting community-scale power resilience.[7] Utah's Soleil Lofts development, in collaboration with PacifiCorp's Rocky Mountain Power business unit, includes all-electric and energy efficient apartments, and the largest residential battery demand response project in the U.S.[8] And in Oregon, PGE's Smart Grid Test Bed includes three distinct communities serving as a proving ground to deploy demand response resources at-scale (See more below). [9]

Spotlight: Residential Grid-interactive Efficient Buildings

Residential buildings consume more electricity and are the largest contributor to peak demand of any energy end-use sector 10 – providing real potential to participate in Grid-interactive Efficient Buildings strategies and benefits.[11] Energy efficiency is the foundational strategy for reducing energy use in any building, including homes. Smart home technologies include thermostats and appliances embedded within home entertainment and security systems - supported by growing consumer interest in distributed energy resources and adoption of solar and storage technologies (e.g., batteries and electric vehicles). [12] Integration of these resources into a central, connected platform are now emerging through customer facing apps and home energy management systems. Once deployed, a Grid-interactive efficient home must be integrated and communicate with the utility/grid operator. Employing this full range of functionality allows consumers to have more control of their homes, reduce the energy and environmental effects in the residential building sector, and unlock a new suite of grid services to help the community. To learn more, read *Residential Grid-interactive Efficient Building Technology and Policy: Harnessing the Power of Homes for a Clean, Affordable, Resilient Grid of the Future*.[13]

Figure 3. Smart, Connected Home[6]



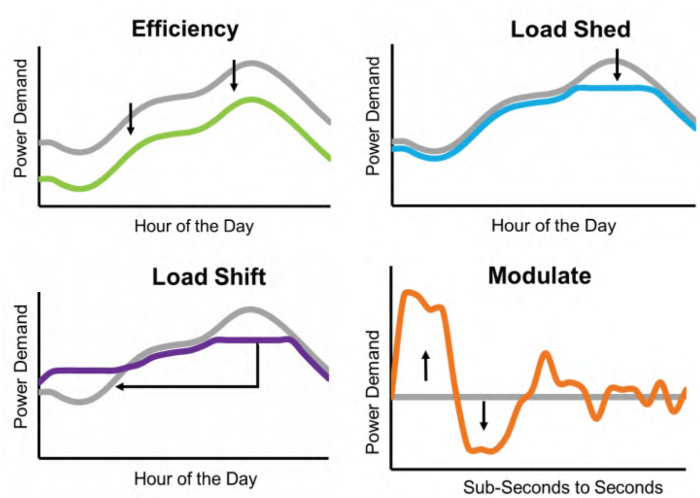
Strategies

Grid-interactive Efficient Buildings maximize and integrate on-site DERs, which in turn provide load flexibility or demand response. A primary characteristic of a Grid-interactive Efficient Building is the integration of efficiency, generation, and storage resources combined with dynamic load adjustment that responds to price and direct dispatch signals from the grid.

The U.S. Department of Energy's Building Technologies Office has defined **five demand flexibility modes**[14]:

- **Efficiency:** Reduced energy use in building equipment and functions due to installed and sustained efficiency measures
- **Load Shed:** Quickly reduces demand for short periods (often less than one-hour), which is usually needed during peak demand periods or extreme weather events (e.g., activating thermostat setpoints and reducing lighting levels), but may persist for longer durations during prolonged events
- **Load Shift:** Changes energy use to a different time (two to four hours), which is usually done intentionally during peak demand periods, during high renewable generation (i.e., help avoid curtailment), or when electricity prices are highest (e.g., activate connected water heaters, utilizing storage)
- **Modulate:** Autonomously re-balances on-site power supply/demand (or reactive power draw/supply) in real-time in response to a direct signal from the utility/grid operator (e.g., dispatching battery storage systems, modulating IT equipment and HVAC systems) to maintain power quality characteristics
- **Generate/Store:** On-site generation of electricity that can be used on-site or exported to the grid in response to a signal or dispatch request. Battery storage can increase the ability to consume or deliver generated electricity, which is helpful when needing to sustain a requested action for two to four hours, and potentially longer. Learn more in the Microgrid and Resiliency Technology Review.

Figure 4. Building load strategies and flexibility modes[1]



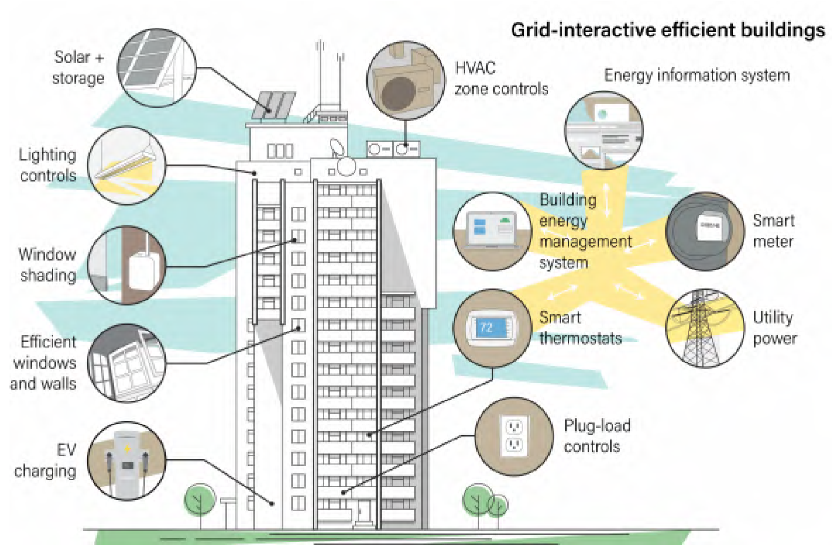
Advanced technologies include a suite of equipment, controls, sensors, and cross-cutting systems. Technologies with the highest potential [15] to provide grid services through energy efficiency and demand flexibility include:

- smart thermostats
- grid-connected water heaters
- advanced lighting sensors and controls
- advanced envelope materials
- automated window attachments
- combined heat and power (CHP)
- building automation systems
- electrochemical (battery) and thermal energy storage
- electric vehicles

Building operators can make adjustments that operate equipment at specific times or have the automated building controls change over to specific control strategies (e.g., power up or down, change output level/intensity).[16] This can be accomplished in existing buildings with demand management equipment and also in buildings that wish to add on-site generation and storage technologies.

Optimization and integration strategies meet occupant needs, while integrating disparate technologies to ensure high performance in the building. Advanced sensors and demand management controls set the parameters for high-performance operation, optimize occupancy settings, and provide ongoing detection of equipment issues. In commercial buildings it is estimated that this approach alone could lead to annual energy savings of 29 percent.[17] For example, Grid-interactive Efficient Building functionality would gather information from weather, grid operators and occupants, process that information through an intelligent energy management system responsive to grid and occupant needs, and then execute a strategy that optimizes the maximum benefit to both the occupants and the grid. This can be further optimized if other DERs, such as solar or storage, are available.[18]

Figure 5. Example of Grid-interactive Efficient Buildings features and integration points[19]

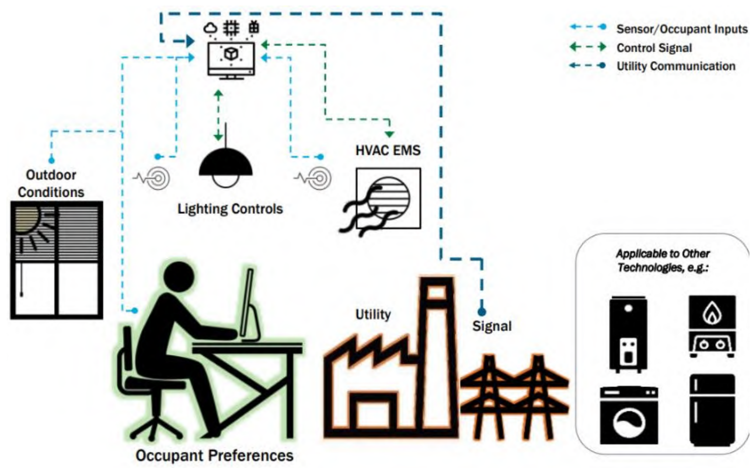


Integration points include operational use data and predicted energy consumption, utility price signals, and status of available on-site generation and storage. Integration is necessary to gauge building responsiveness potential, but is critical when occupants are interested in bringing in additional DERs that may serve in demand response or resiliency planning.[19] Grid-interactive Efficient Buildings integrate and continuously manage these DERs, and adjust building operation to co-optimize for energy costs, grid services, and occupant needs in a systematic and integrated way that provides greater value and resiliency to both consumers and the grid.[20]

Uses and Benefits

Grid services and utility-side benefits are driving analysis, valuation, and use of Grid-interactive Efficient Buildings. Widespread adoption of these types of buildings could help to flatten peak loads, moderate "ramp rates" (how quickly system demand changes), reduce "curtailment" of renewable generation, and reduce overall building demand, which can help support energy system reliability and affordability.[21] For example, there are increasing efforts by electric utilities to modernize their distribution systems (see Electricity Distribution System Planning Policy Brief). At the same time that efforts are being made to optimize electricity use in buildings, policies to decarbonize the energy sector more broadly are leading to increased electrification of end-uses within the building sector (e.g. shifting to electric heating loads and charging of electric vehicles). This may create challenges to flattening peak loads and reducing overall demand for electricity in the building sector, but these new electric loads can also be managed in ways that minimize the growth of peak demand.[22] Other challenges include increases in peak electricity demand caused by factors like population growth and climate change, integrating variable renewable electricity generation, and overcoming existing constraints on transmission and distribution infrastructure.[23] Utilities and grid managers continue to look for ways to reduce demand, increase the flexibility of demand, and activate demand-side resources in support of grid needs.

Figure 6. Interaction with building occupants. USDOE EERE, 2019.



At full potential, Grid-interactive Efficient Buildings could serve as an asset to balance and change energy use during times of peak demand, which can reduce strain on the grid, maintain grid reliability, and balance/integrate other generation sources. At scale, in which a portfolio of residential and commercial Grid-interactive Efficient Buildings are aggregated, the buildings could serve in the portfolio of "distribution grid services," which can act as "virtual power plants"[24] that may help reduce the need for supplies from bulk generation, reduce the need for transmission and distribution upgrades, optimize the use of distributed generation, and support frequency regulation.[25] For example, one estimate found that by 2030, cost-effective load flexibility potential would be three times existing demand response capability, saving consumers $15 billion annually in avoided utility system costs. Nearly 40 percent of that potential can be "achieved simply by modernizing existing conventional programs through revamped program design and customer engagement." [26]

Consumer benefits are complementary to utility and grid services - creating new opportunities for building occupants and owners. Grid-interactive Efficient Buildings can reduce overall consumption and peak demand, making building energy costs less expensive. Efficiency helps reduce operating costs due to overall lower energy use, but the biggest customer value is the reduction of demand charges through peak demand reduction and shifting. Those already subject to peak demand costs (e.g., higher electricity rates during peak load times) may be able to avoid or minimize demand charges – with an estimated 10-20 percent of commercial building peak load having the currently untapped capability to be temporarily managed or curtailed using advanced sensors and controls. [27] Building owners and occupants working with utilities may have also access to utility incentives to implement these technologies and practices.

Energy efficiency and advanced building design and construction may also help building occupants experience improved performance and comfort because advanced and integrated controls allow for continued optimization. Grid-interactive Efficient Buildings are smart; they can learn occupancy patterns and optimize operations within occupant preferences such as thermal comfort and lighting. They are also integrated such that the occupant can set priorities across a suite of operation or production activities. The optimization of energy use based on customer preferences[28] also increases consumer satisfaction, flexibility, and choice. Grid-interactive Efficient Buildings also support consumers interested in smart and adaptive technologies, in which the occupant has access, control, and configurability in their building.

Along with cost and comfort, Grid-interactive Efficient Buildings offer consumers a pathway to participate in the value and community benefits that smart, connected neighborhood and communities can provide. For example, by supporting grid modernization and utility-scale distributed asset management, communities may be able to work with utilities to meet resiliency, reliability, and sustainability goals. As part of the Portland General Electric Smart Grid Test Bed (see below), PGE is exploring customer value propositions that extend beyond just monetary incentives

External and community benefits of Grid-interactive Efficient Buildings are expanding with growing recognition that buildings can be an asset to meeting community energy, climate, and health goals. By reducing demand, especially during peak periods, grid connected buildings can increase resilience of the utility generation, transmission, and distribution supply system – not only reducing chronic system stressors but also improving capacity and assets to facilitate recovery from disruptions. Grid-interactive Efficient Buildings integration of generation and storage can supply on-site electricity during outages and help maintain shelter conditions for people and critical operations.[29] Reduced energy demand and integration of renewables also have environmental benefits by potentially reducing the carbon intensity of energy consumption and bringing more renewable energy into the system – thus reducing GHG emissions.[30] For example, the load shift function of these buildings may allow renewably generated power - that would otherwise be curtailed (wasted) due to lack of loads - to be consumed by thermal or battery storage. This can help support emissions reduction goals by increasing use of renewable energy whenever its available to meet demand. This is particularly helpful for states and communities that have set renewable energy, electric vehicle, and clean energy goals.

Spotlight: PGE Smart Grid Test Bed

The PGE Smart Grid Test Bed is working to understand different customer value propositions of Grid-interactive Efficient Buildings while assessing the technical potential of demand response resources.[31] This will test and evaluate a host of grid services beyond peak reduction and capacity replacement including balancing services and the ability of flexible loads to reduce curtailment of renewables, while also offering more control and value to customers. A cross-locational and multi-sector program, the SGTB will test residential technologies (e.g., smart thermostats, smart water heaters, EV chargers, etc.). Customers within the Testbed are automatically enrolled in a peak-time rebate program and PGE will implement an in-depth customer study to test and understand customer values, engagement, and participation. PGE will further try to understand the barriers and hurdles to customer engagement and participation by customer microsegment. This will provide greater insight into how to adjust program development to be more inclusive to all customers from low income to high earners. Commercial properties will be evaluated for direct installation of smart thermostats, building management system and strategies as-well as energy storage applications. Results will inform how utilities can engage with customers, technical achievable potential for DERs at scale, and distribution system planning. Read more in the Electricity Distribution System Planning Policy Brief.

Barriers and Limitations

While there is significant potential for Grid-interactive Efficient Buildings, a suite of barriers exist throughout program design and participation, financial structure and motivation, planning and analysis needs, and regulatory and policy issues (e.g., rate structure, business models, and legislation). The intersectional nature of these buildings also requires coordination across utility and grid operation and governance, utility commissions, state energy offices, energy service providers, and the community.

It is also critical to note that without active efforts and change, equity and access barriers that currently exist in energy programs and policies may be perpetuated. For example, low-income households may not have wi-fi access, ability to pay upfront improvement costs, or be as flexible to adjust their energy use. [32] While the integrated nature of these buildings provides new opportunities to become a system asset, they also present an important opportunity to incorporate equity considerations that recognize and address the under-quantified impacts and community benefits in the energy policy and program development spaces.

Validation and valuation methods for Grid-interactive Efficient Buildings are yet to be formalized and adopted – thus are a barrier to being able to fully quantify benefits and opportunities. Valuing flexible demand management and multiple DERs is more complex than traditional cost-effectiveness valuation of energy efficiency programs. The value of a kilowatt-hour saved or kilowatt of demand avoided varies by time and place. To address this challenge, utilities and decisionmakers will need to agree to methods that identify and quantify these values at different scales (community, state, national) and for different stakeholders, including customers and utilities. Progress is being made in assessing these values.[33] [34]

The NASEO-NARUC Grid-interactive Efficient Building Working Group (see more about this group below) is helping states to identify analytical methods and frameworks for **valuation**, including location and time-sensitive valuation.[35] Along with valuation, they are also interested in quantifying building **load potential** to provide grid services and maximize demand response capacity.[36] For example, one estimate found that by 2030, the U.S. would have nearly 200 gigawatts of cost-effective load flexibility potential, equal to 20 percent of estimated U.S. peak load.[37] There is also a need to test technologies to see if they perform as predicted and will meet grid and occupant needs. This will require methodology and verification of technology and strategies. This challenge may be overcome by pilot programs, enhanced analytical methods and practices, and coordinated action between state energy offices and utility commissions – which can increase confidence in the values Grid-interactive Efficient Buildings could provide. [38] [39]

Implementation barriers in Grid-interactive Efficient Buildings occur across a range of technology, controls, practice, and policy elements. Similar to existing efficiency and demand response programs, upfront costs and market adoption of technologies are a barrier. Once adopted, both customers and grid operators also face the challenge of analyzing and acting on the vast amount of data and information available through Grid-interactive Efficient Buildings technologies. Data gathering and analysis is further challenged by a lack of standardized technologies and protocols, cybersecurity concerns, and interoperability of proprietary systems. There are information gaps for technology and the need to learn which ones are best suited to provide solutions to specific grid needs. With more information, utilities and decision-makers can then assess and prioritize technologies based on customer performance and grid services. The NASEO-NARUC working group is interested in **end-use modeling** across the US to develop "savings profiles" for buildings and technologies.[40] They are also interested in developing open source, scalable, secure **control systems**.[41] There is also a real need for ground truthing strategies that maintain building services and customer needs while allowing for flexible and responsive building operation. This will require testing and co-development of solutions that meet grid operator and building occupant needs. Each of these challenges may be addressed by conducting technology demonstrations that evaluate technology performance, value streams, and adoption.

Customers may lack financial resources for technology and staff resources for implementation of Grid-interactive Efficient Buildings practices. This can be exacerbated by lack of motivation or knowledge of available incentives, or disincentives for energy related investments by building owners who don't pay utility bills (i.e., owner-occupied vs. tenant/landlord relationship). The value and acceptance of Grid-interactive Efficient Buildings for customers also needs more research. Customer value and priorities may change over time and traditional efficiency and demand response program propositions may not directly translate for neeeded customer participation and building owner adoption. To address this, expanded value propositions may need to include GHG emission reduction, support for renewable energy, and social values like competing with neighbors to reduce peak demand, and donating credits to charity.[42] These challenges may be addressed using pilot programs, market and product research, proper program and rate design, aligned incentive deployment.

Activities and Resources

Looking forward, the concept of Grid-interactive Efficient Buildings presents an intersectional space to expand existing conversations between energy efficiency experts, the building design community, grid operators, utility program leaders, transportation analysts, and energy policymakers. State energy offices and utility commissions can collaborate to centralize data and support new research while working with stakeholders, local governments, utilities, and frontline communities on innovative pilot projects – including leading by example in new and public buildings. Facing a complex energy future, it is likely that cross-cutting concepts like Grid-interactive Efficient Buildings will provide a valuable framework to bring together people and resources that have been siloed for too long. Breaking down these policy and programmatic barriers will be difficult, but also offers new opportunities to advance both the building sector and optimize its contribution to decarbonization of the grid. To learn more about actions states can take, see the NASEO "Grid-interactive Efficient Buildings: State Briefing Paper" listed below.

To approach these issues the National Association of State Energy Officials (NASEO) and the National Association of Regulatory Utility Commissioners (NARUC) established the NASEO-NARUC Grid-interactive Efficient Building Working Group, with the support of the U.S. Department of Energy Building Technologies Office and the Pacific Northwest National Laboratory. The NASEO-NARUC Grid-Interactive Efficient Buildings Working Group is led by NASEO and NARUC staff, along with two state co-chairs from the Oregon Department of Energy and the Minnesota Public Utility Commission. The group now consists of 18 member states including Colorado, Florida, Georgia, Hawaii, Maryland, Massachusetts, Michigan, Minnesota, Nebraska, New Jersey, New York, Oregon, South Carolina, Tennessee, Virginia, Washington, Wisconsin, and Wyoming. [43]

Working Group participants explore Grid-interactive Efficient Buildings technologies and applications and collaborate to advance GEB knowledge and strategies. This work includes meetings, webinars, and research to identify opportunities and challenges, and share best practices and pilot program findings to inform development of future policy, planning, programs, and regulations. The Working Group has conducted state interviews and produced a suite of reports and webinars with more being developed. [44]

Highlights of introductory resources include:

- NASEO: Grid-interactive Efficient Buildings: State Briefing Paper
- USDOE EERE BTO Grid-interactive Efficient Buildings: Factsheet and Grid-interactive Efficient Buildings: Overview
- SEE Action Network: Grid-interactive Efficient Buildings: An Introduction for State and Local Governments
- ACEEE: State of the Market: Grid-interactive Efficient Building Utility Programs
- Videos: One minute video from ASHRAE: "Building Research: The Importance of Grid-Interactive Buildings" and 25-minute video from Lawrence Berkeley National Laboratory: "Grid-Interactive Efficient Buildings: Potential Impacts on Regional Utility Loads"

To learn more, visit the Work Group Resources page that also includes links to other external papers, research, and presentations at https://www.naseo.org/issues/buildings/naseo-geb-resources.

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CONCLUSION

In the 2018 Biennial Energy Report, we explored what it means for Oregon to transition to a low-carbon economy. The final chapter of that report recognized that achieving Oregon's energy and climate goals while protecting consumers requires partnership and coordination among affected communities, policy makers, state and local governments, businesses, and industry leaders. The 2018 report concluded with recommendations that focused on collaboration – a critical step on which the state has made progress over the past two years. The recommendations called for increased data sharing across state agencies and fostering new relationships between public, private, and community organizations to explore and publish data that better informs stakeholders, decision-makers, and the public.

In drafting the 2020 BER, the Oregon Department of Energy was able to identify and better leverage information and the expertise of our sister agencies and community partners. Collaborative efforts to address the state's goals – such as the work that the Departments of Transportation, Environmental Quality, Land Conservation and Development, and ODOE are doing to advance the Statewide Transportation Strategy; and the coordination between ODOE and the Building Codes Division of the Department of Consumer and Business Services on building codes – have enhanced the state's informative capacity by strengthening relationships and creating efficiencies.

Another recommendation in 2018 was for energy policies to identify and address their effects on all Oregonians, both in terms of their burdens and benefits. In the 2020 report, ODOE has included more demographic data to better describe and highlight how energy programs and policies contribute (or don't contribute) to equitable outcomes. As an agency, we recognize that we still have a long way to go before we can tell the whole story, which is why one of the key initiatives in our new agency strategic plan is to improve our ability to collect and analyze demographic and other socio-economic data. Leadership from Governor Kate Brown, especially through her Equity Framework, has encouraged state agencies to design policies with all Oregonians in mind and improve engagement within Oregon communities.

Developing a report in 2020 also meant we needed to reflect on numerous concurrent challenges in our communities – from social unrest to the current effects of climate change to an economic recession and global pandemic. The scope and scale of the events in 2020 has made it more important than ever that we listen and amplify diverse voices. Transition was the theme of the agency's very first Biennial Energy Plan 45 years ago, and it remains a theme today. We recognize that not only do we need to transition to a decarbonized economy and energy system, but we need to do so in a way that addresses current and historic inequities. Energy decisions cannot be made in a vacuum; the development of energy policy is intersectional work and must be considered with climate, environment, and equity lenses. It will take Oregonians from all backgrounds and experiences to help Oregon's policy- and decision-makers get this right.

For this reason, the 2020 Biennial Energy Report does not include a specific list of recommendations. Instead, policy briefs include ideas for decarbonizing the transportation, direct fuels, and electricity sectors, and highlight innovative ways that Oregonians are moving toward a clean energy future. Oregon's farmers are investing in energy efficiency projects to save money and reduce emissions. Utilities are using smart meters and distributed resource planning to work with homeowners and business to accelerate grid modernization and increase resilience. The natural gas sector is looking to innovative technologies like renewable natural gas and power-to-gas to reduce emissions. Cleaner transportation options are emerging – not only for individual Oregon drivers but also for fleet managers. And communities around the state are making investments in clean energy projects that also increase opportunities and work in partnership with underserved Oregonians.

Instead of internally-developed recommendations, we propose that Oregonians join us in a conversation about what they want the future of our energy system to look like and how to get there. This report is intended to serve as a starting place for those conversations. We have structured it to be a resource for all Oregonians – those new to energy issues and those already steeped in policy and practice. For those who are new to energy issues, the history timeline provides context and helps readers understand the events that shaped the energy sector in our state. We created a 101 section for people who want to learn more about how the system works and are interested in understanding the background on policy discussions like clean energy standards and resource adequacy. The policy briefs offer additional analysis on the issues in front of policy makers and communities. At a high level, similar themes for recommendation discussions are emerging such as filling data gaps, addressing equity and energy burden, planning for transition, and assessing the need for state engagement and investment.

But in order to develop specific recommendations, we need to work with not only energy industry experts, but also with Tribes, community-based organizations, and especially the Oregonians who disproportionately feel the impacts of our energy choices every day. We want all Oregonians to be able to engage in a conversation about Oregon's energy future, whether they are experts or not. And we hope this report will help.

ABOUT THE REPORT

In 2017, the Oregon Department of Energy, recognizing that the energy sector and ODOE's role in it had changed, led an effort to establish a new Biennial Energy Report.

The Oregon Legislature agreed, passing HB 2343 (ORS 469.059). ODOE published its inaugural biennial report in 2018.

The primary **purpose of the report** is to inform local, state, regional and federal energy policy development, energy planning, and energy investments, and to identify opportunities to further the energy policies of the state. To do this, ODOE, the state's dedicated energy office, **collects critical energy data and information** and analyzes what they mean for Oregon.

The report **framework is built to be an evolving document** that discusses Oregonians' contemporary interests and inquiries about resources, policies, trends, and impacts across the state. The **biennial nature of the report** creates a **central "go-to" document and process** to ensure the report is timely and responsive to a diverse group of stakeholders and the public. Ultimately, the report is meant to **serve as a trusted, data-driven platform to have informed conversations** on the emerging issues and policies in our community, along with goals and strategies for the future.

2020 Development and Engagement Process

As directed by the statute, ODOE "shall seek public input and provide opportunities for public comment during the development of the report." With distribution and continued use of the 2018 report, ODOE recognized that broader and more diverse outreach was needed in subsequent reports. The drafting of the 2020 report also coincided with ODOE's strategic planning effort, which identified new strategic imperatives focused on equity and engagement.

ODOE undertook a deliberate internal planning effort to enhance our engagement efforts. Work plan objectives included:

- Meet statutory requirements while engaging with a wider range and more diverse stakeholders, including those traditionally underrepresented in energy policy discussions or who have perspectives about inequities of energy policies and programs.
- Ensure content is relevant and timely to stakeholder interests and questions.
- Ensure project work is consistent and complementary to other stakeholder engagement approaches and tools at ODOE.
- Create engagement resources and identify input opportunities during ODOE's existing work with stakeholders.
- Facilitate centralized and coordinated outreach activities using various media and customer portal submissions.

Implementation

ODOE heard from more than 100 people through a public survey, website comment portal, and staff discussions, ranging from members of the public to NGOs to energy industry experts. In 2020 and looking forward, key interests and priorities of stakeholders expressed to ODOE included:

- Greater access to clean energy resources and ensuring energy options for diverse communities across Oregon.
- Maintaining reliable and low-cost energy while the state gets closer to 100 percent clean energy.
- Interest in the status of new and emerging energy technologies in Oregon.
- Impact of the COVID-19 pandemic on the energy sector.
- Key historical energy decisions that affect energy in Oregon.
- Natural and cultural resources protection when developing new energy resources.

Website Portal

ODOE hosts a public website for the 2020 Biennial Energy Report: https://www.oregon.gov/energy/Data-and-Reports/Pages/Biennial-Energy-Report.aspx. Along with a link to sign up for email updates, ODOE provided an online comment form to receive and review public comments. As part of the scoping process, all comments received through May 2020 were compiled and reviewed by the report development team. The team completed a review and action-assessment to ensure each response was evaluated and included for consideration during the development process.

Survey

ODOE initiated a month-long survey that was promoted on ODOE communication channels and sent out directly to stakeholders. The survey collected approximately 70 responses from the general public, government, elected officials, Tribes, utilities, non-profits, and energy-related fields. Self-reported demographics show that respondents were predominantly white and located along the I-5 and I-84 corridors. In evaluating this data, the BER team discussed establishing a goal to increase and diversify future participation in the BER survey and as part of our agency's strategic plan. Respondents who read the 2018 report found many sections of the report useful, particularly Energy by the Numbers, and recommended improvements to the length/style of the report and topics chosen. For 2020, primary areas of interest included: energy burden and equity, energy efficiency, climate change, renewable energy, resilience, transportation, and the impacts of COVID-19. The steering team for the report at the agency reviewed survey results and conducted an action-assessment to ensure each response was evaluated and considered during the development and drafting process.

Direct Discussion & Equity Consideration

In the course of ODOE's existing work, staff presented and discussed scoping for the Biennial Energy Report with various stakeholder and advisory groups. This included ODOE's Energy Advisory Work Group, utilities, League of Oregon Cities, and the Government-to-Government Natural Resources Work Group. Slides, the website link, and a scoping handout were provided, along with direct follow-up with ODOE's Associate Director of Strategic Engagement & Development.

ODOE staff also completed specific outreach to stakeholders and organizations with an update on the project and list of opportunities to provide comments. Stakeholders provided direct input and ODOE completed more than 20 scoping input webinars to gather specific feedback prior to content development. The scoping input process helped identify where ODOE could address required topics through a data-driven process inclusive of equity considerations. This was an important contribution to the agency's efforts on prioritization and development of topics and priorities.

Once the topic areas were chosen, the internal steering team completed a scoping process to identify the specific objectives, information, and narrative for each topic. Initial scoping prompts included: *Are there equity considerations/discussions that can be included in this scope? Are there opportunities to lift up voices that haven't typically been heard in this space?*

In the drafting process, assignments that address key questions or policy issues included prompts for consideration including: *What challenges or barriers are being identified or addressed? What are the equity considerations for this topic, including opportunities, challenges, and how are these being addressed?*

Incorporation of an equity lens in the scoping and content development process of the report is an important step forward, but not an end point. Many topics or issues were identified but will require more time and exploration, especially with community-based organizations and underserved communities, to fully understand and bring these topics to readers. This has been identified as a lesson learned for the team and a continuous improvement objective for future iterations of the report.

Peer Review and Interagency Collaboration

In preparing this report, ODOE leveraged the knowledge and data of our sister agencies. In particular, the Oregon Department of Transportation shared information on electric vehicle registrations and fuels, Oregon Housing and Community Services and its contractor, TRC, provided county-level data used in the sector profiles and energy burden sections, Northwest Power and Conservation Council's data informed the energy efficiency and resource adequacy sections, and ODOE used Oregon Public Utility Commission data on utilities and Department Environmental Quality data for our energy and climate change analyses. ODOE deeply appreciates the many staff at our sister agencies who took the time to read sections of this report and provide input. OPUC, DEQ, ODOT, NWPCC, OHCS, and the Department of Land Conservation and Development, in particular, responded quickly to requests to review and offered expert feedback and technical assistance. Their contributions improved the quality of this report.

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