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.

OREGON DEPARTMENT OF ENERGY

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Policy Briefs

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]

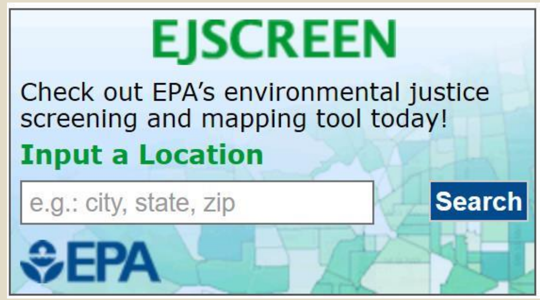
How energy is generated and used heavily affects—and is affected by—climate change. In Oregon, about 80 percent of the state's GHG emissions come from the amount and type of energy Oregonians use every day.[7] This section:

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

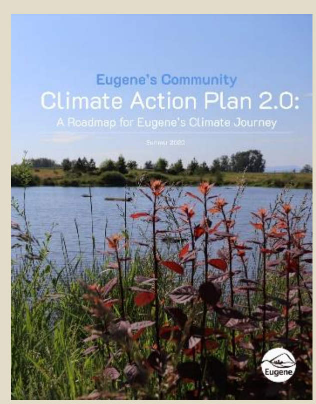
✓ = completed/included ↪ = in progress	Climate Mitigation								Climate Adaptation			
	GHG Mitigation Goal	GHG Inventory	Focus Areas: Transportation & Land Use	Renewable Energy	Buildings	Materials Management	Carbon Sequestration	Equity	Focus Areas: Vulnerability Assessment	Adaptation/Resilience Strategies	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.

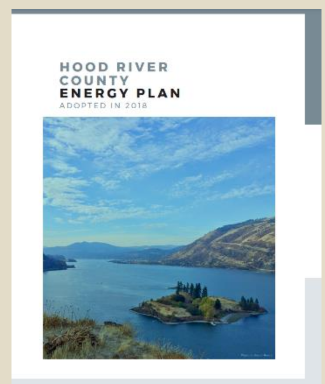
Eugene worked with the Urban Sustainability Director's Network to connect with other cities that have successfully merged climate and equity to identify what might work for Eugene. Following outreach efforts to underserved communities and an application process, the City named six representatives to 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 (2.7°F) above pre-industrial levels.[120]

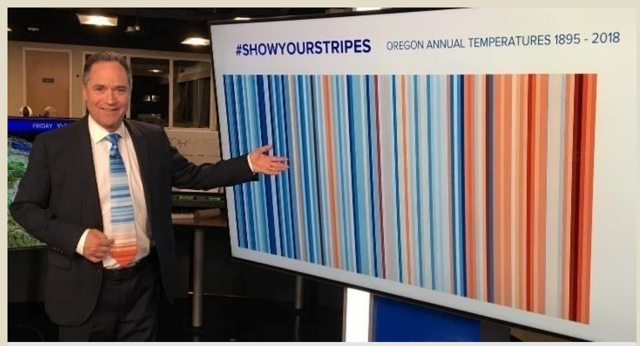
These public-private partnerships and coalitions, including Renew Oregon, the U.S. Climate Alliance, and others, have grown in recent years. In 2019, Nike, one of Oregon's largest companies in terms of revenue and number of employees, launched its "Move to Zero" initiative aiming to achieve zero carbon 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

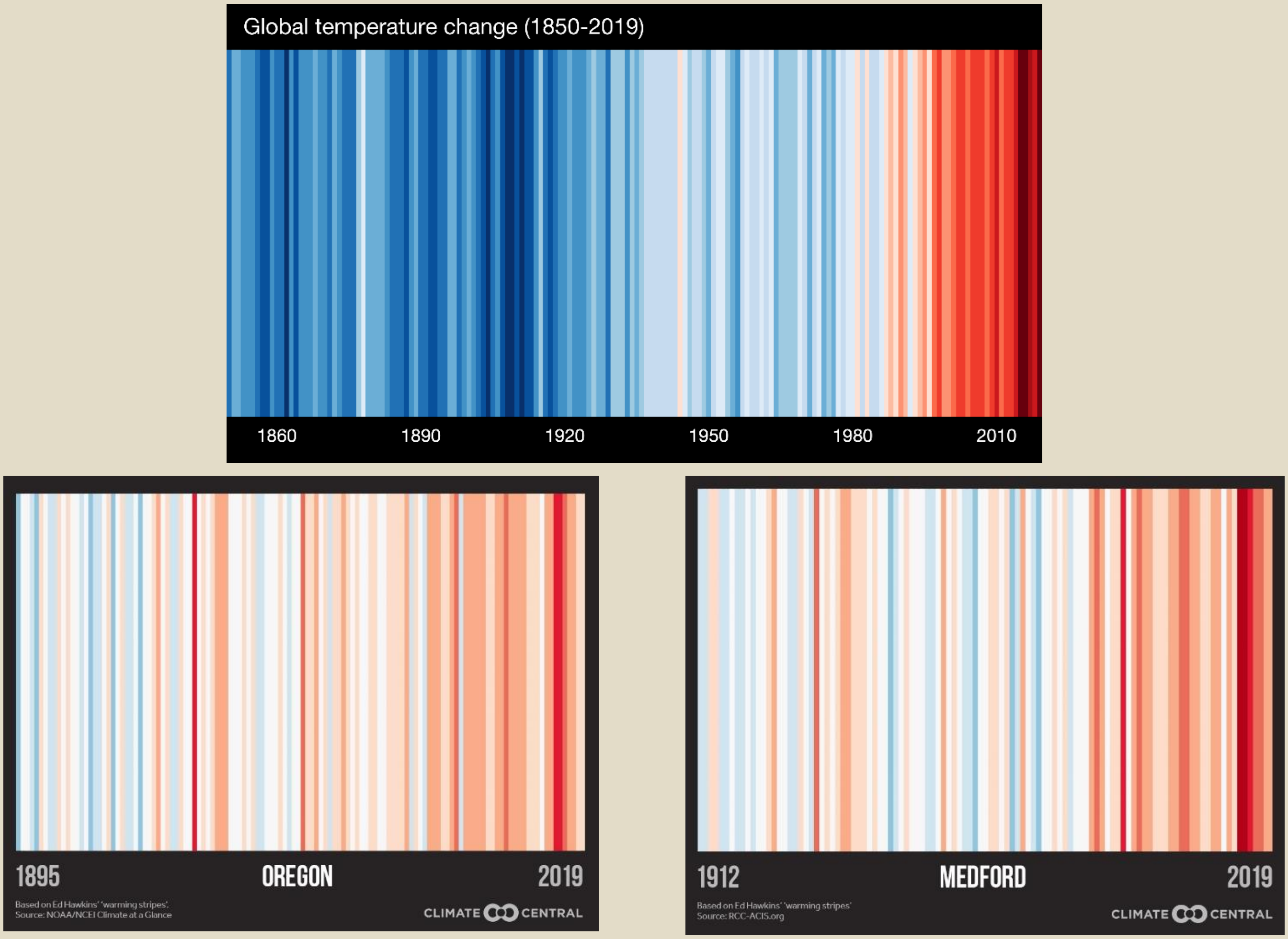
Although public awareness about climate change has increased substantially over the years, gaps remain in public understanding of the many risks posed by a warming climate. While two out of three Americans are worried about climate change, less than half think it will harm them personally.[125] Meteorologists, 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.

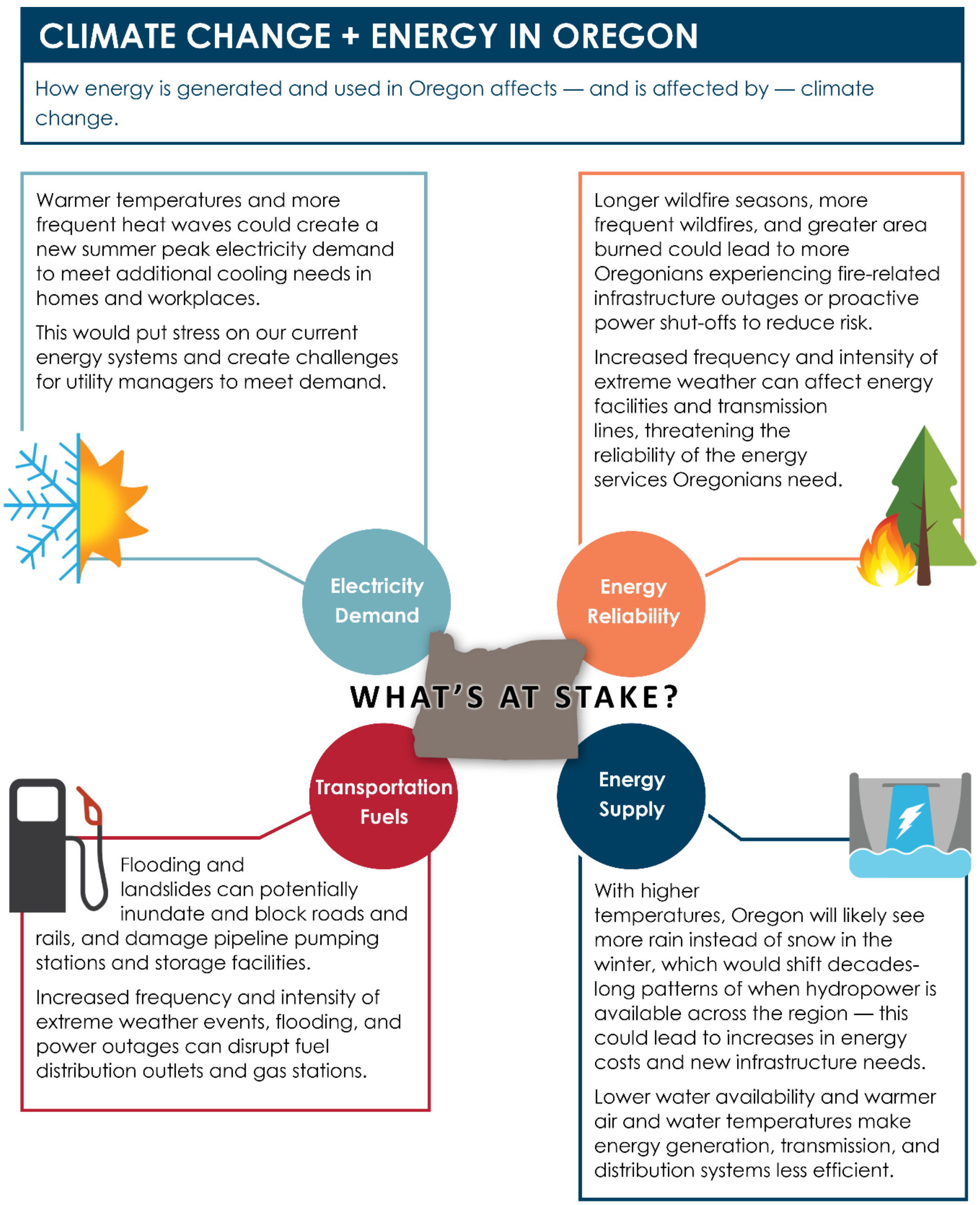
Preparing Energy Systems for Climate Change

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

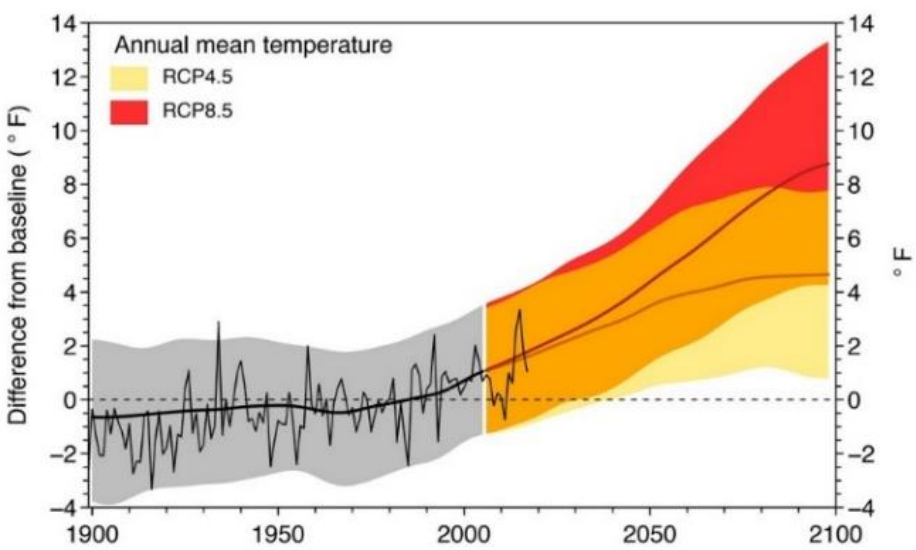
This section identifies example climate hazards, their potential impact on Oregon's energy systems, and climate outlook in the coming decades.

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 (1.1°C) 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 3.6°F (2°C) under RCP4.5 and 5.0°F (2.8°C) under RCP8.5; by 2080, the rise increases to 4.6°F (2.6°C) under RCP4.5 and 8.2°F (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 3.3°F (1.8°C) under RCP4.5 and 4.5°F (2.5°C) under RCP8.5, while average summer temperatures (in June through August) are projected to increase by 4.5°F (2.5°C) under RCP4.5 and 6.3°F (3.5°C) 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]

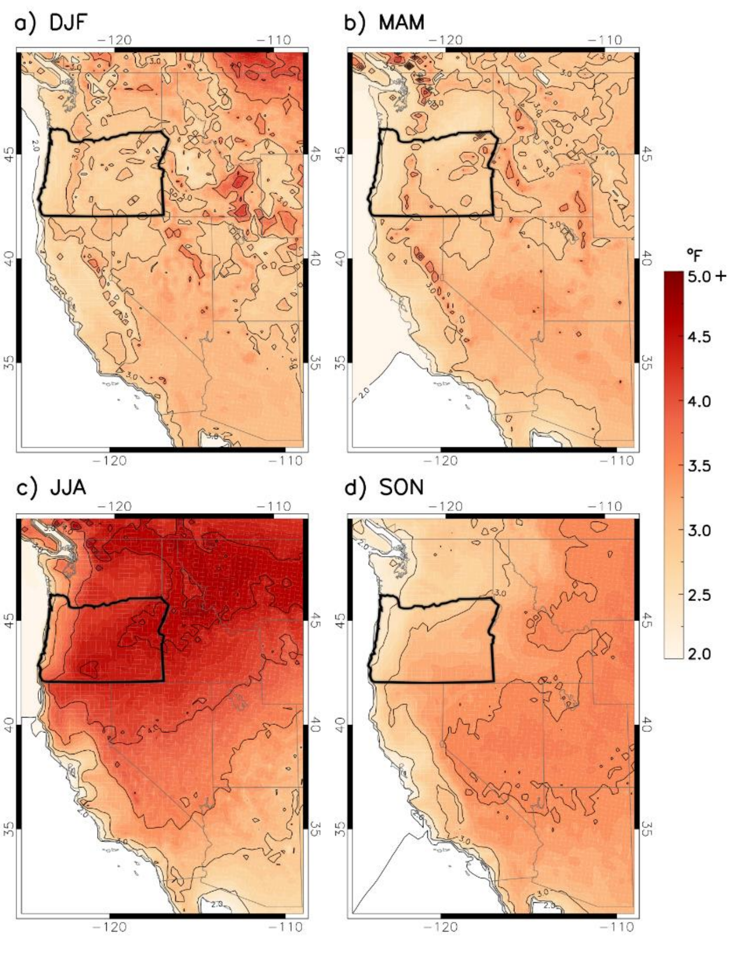
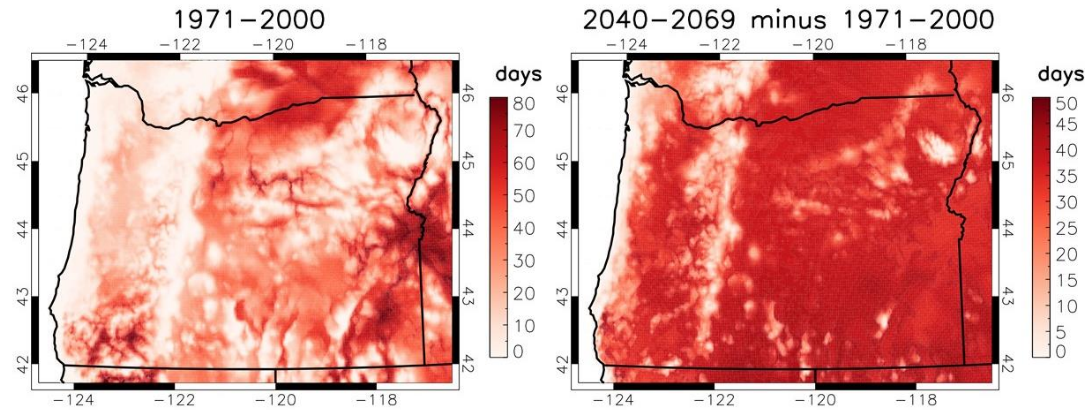
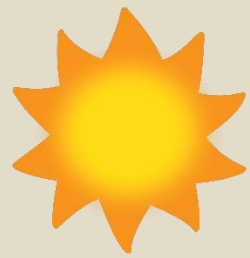


Figure 3: Number of hot days (with daily high temperatures above 86°F) observed (1971-2000; left). Additional number of hot days expected to occur by mid-century (right), under RCP8.5.[8]



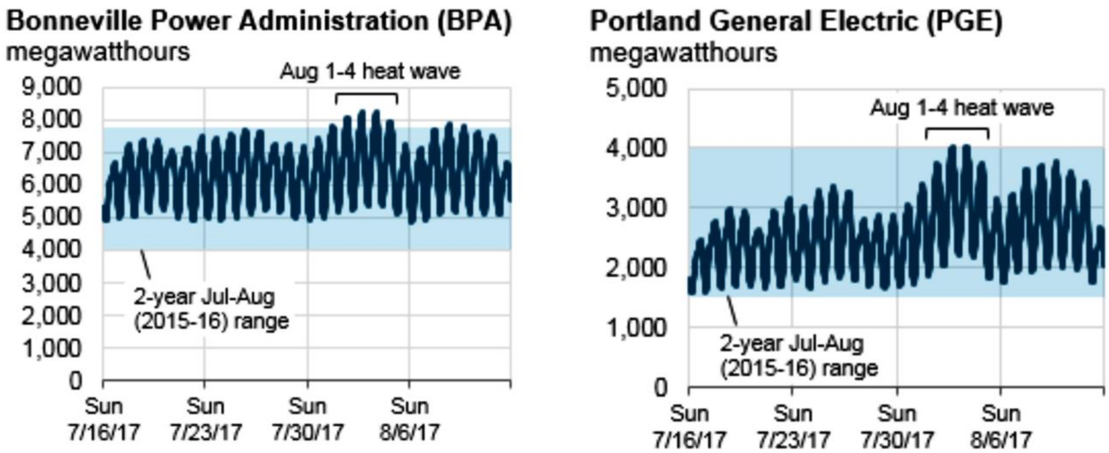
Heatwaves and Air Conditioning



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]

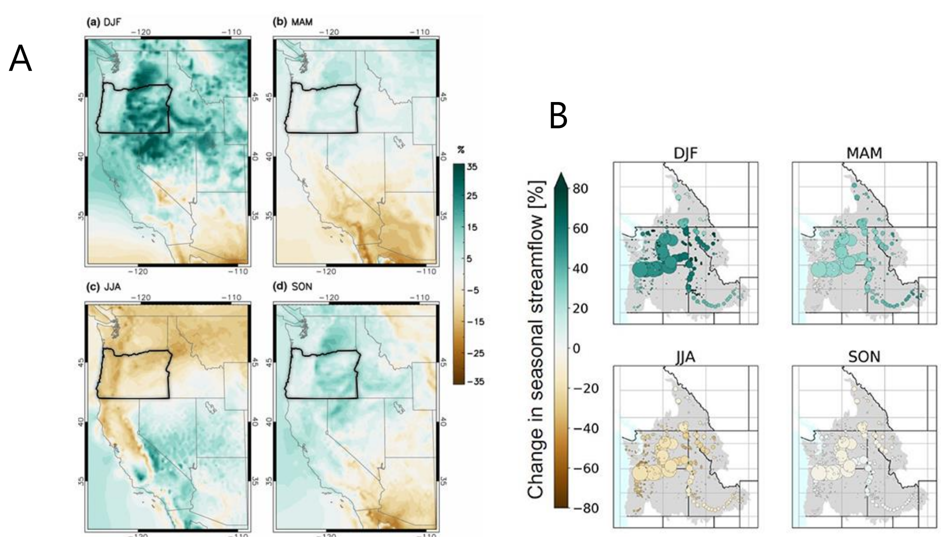
Changing precipitation patterns are also likely to increase the frequency and intensity of heavy precipitation events. By flooding and blocking roads, these events can disrupt the distribution of fuels for home-heating and transportation needs. They can also damage transmission lines, threatening the 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]



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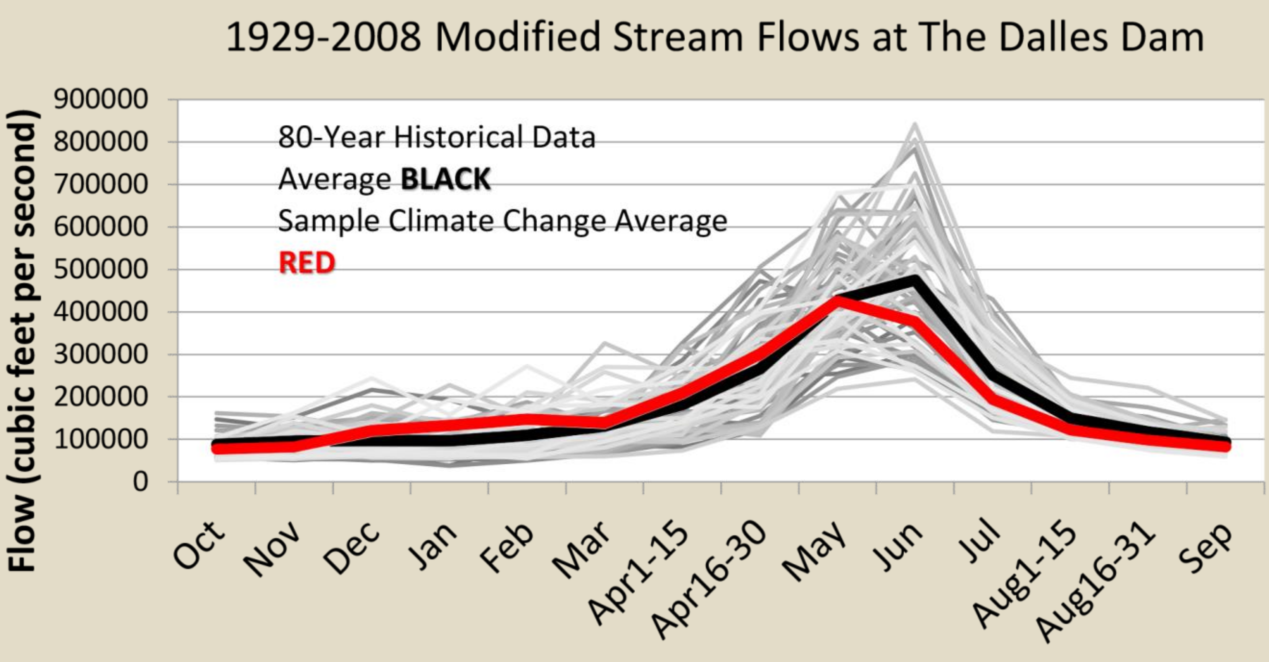
[i] Snowpack is measured by the amount of snow water equivalent on the first day of April averaged over a twenty-year timeframe.

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]

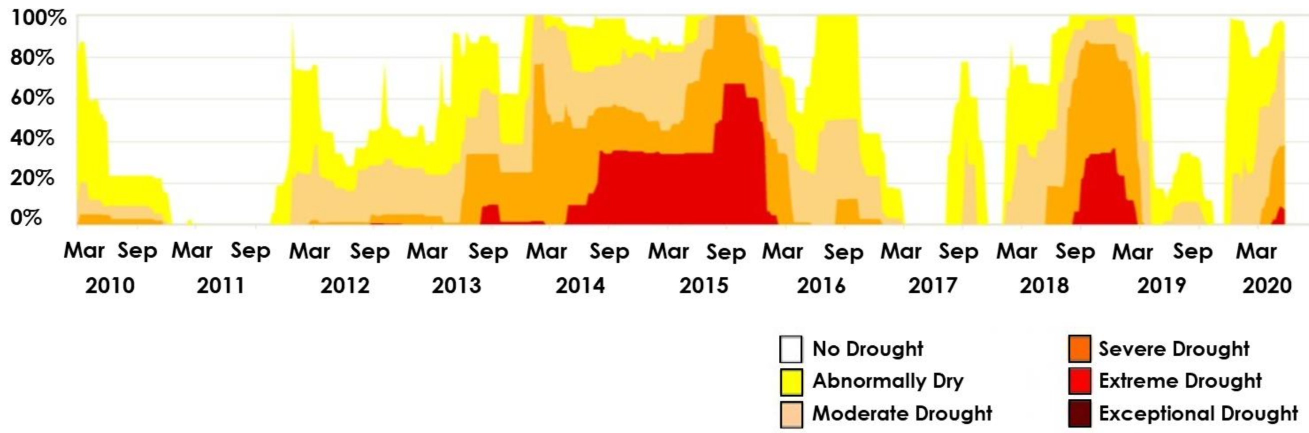


Increased Incidence of Drought

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]

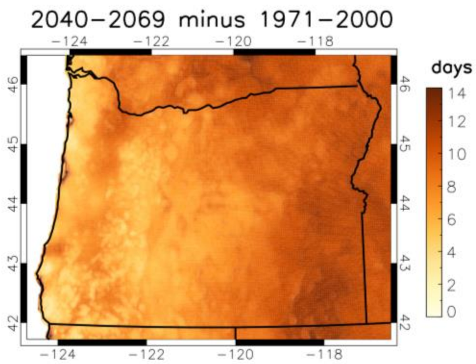
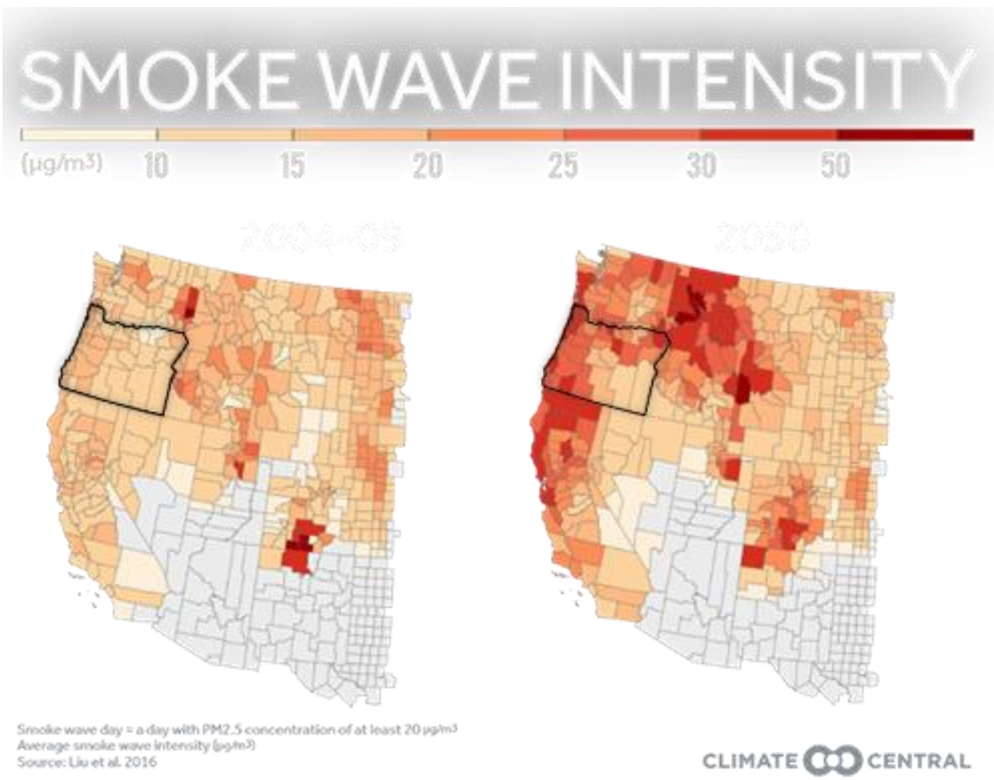


Figure 9: Average smoke wave intensity in the recent past compared to projected smoke intensity in 2050.[51] Under the Air Quality Index (AQI), an AQI less than 50 (equivalent to 12 micrograms per cubic meter, µg/m³) represents good air quality, whereas an AQI greater than100 (35.5 µg/m³) becomes unhealthy 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]

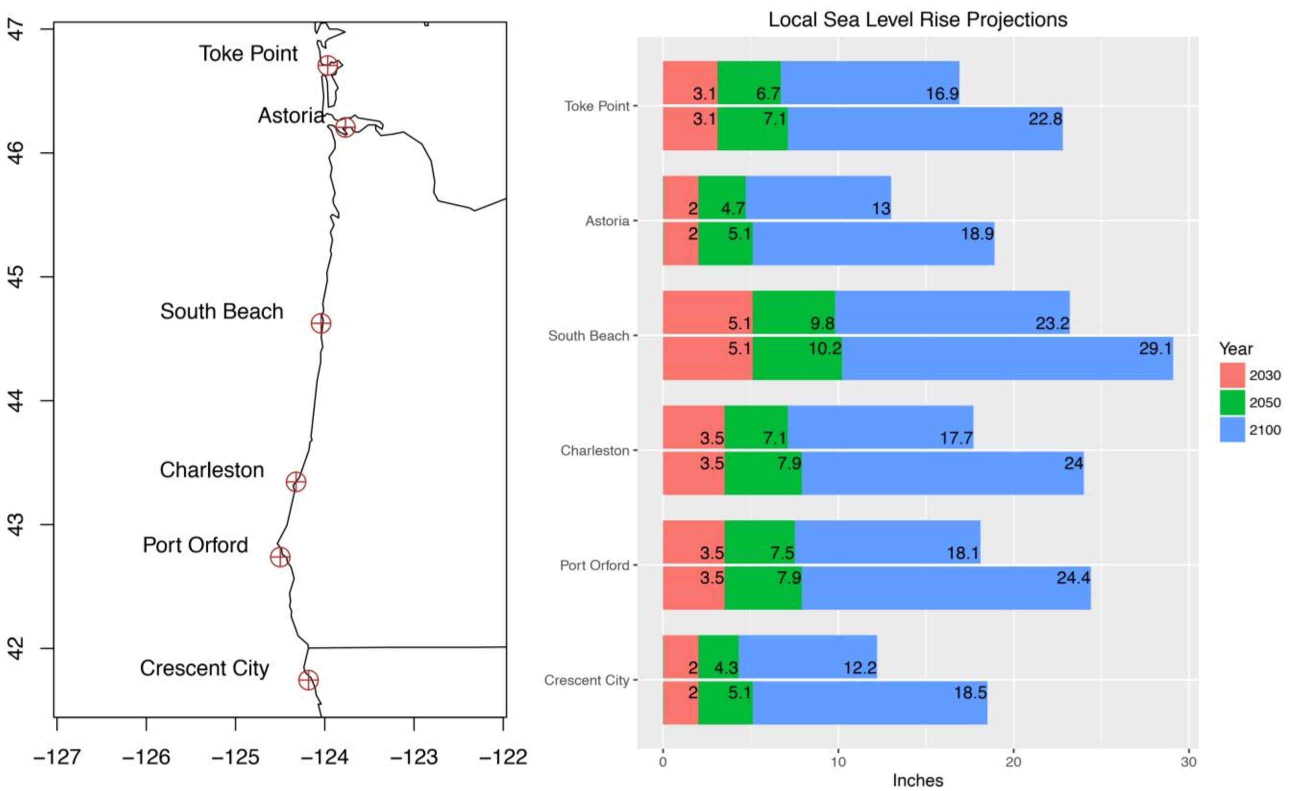


Figure 11: Wildfire in Oregon (left); tidal flooding in Nehalem, Oregon (right).

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]

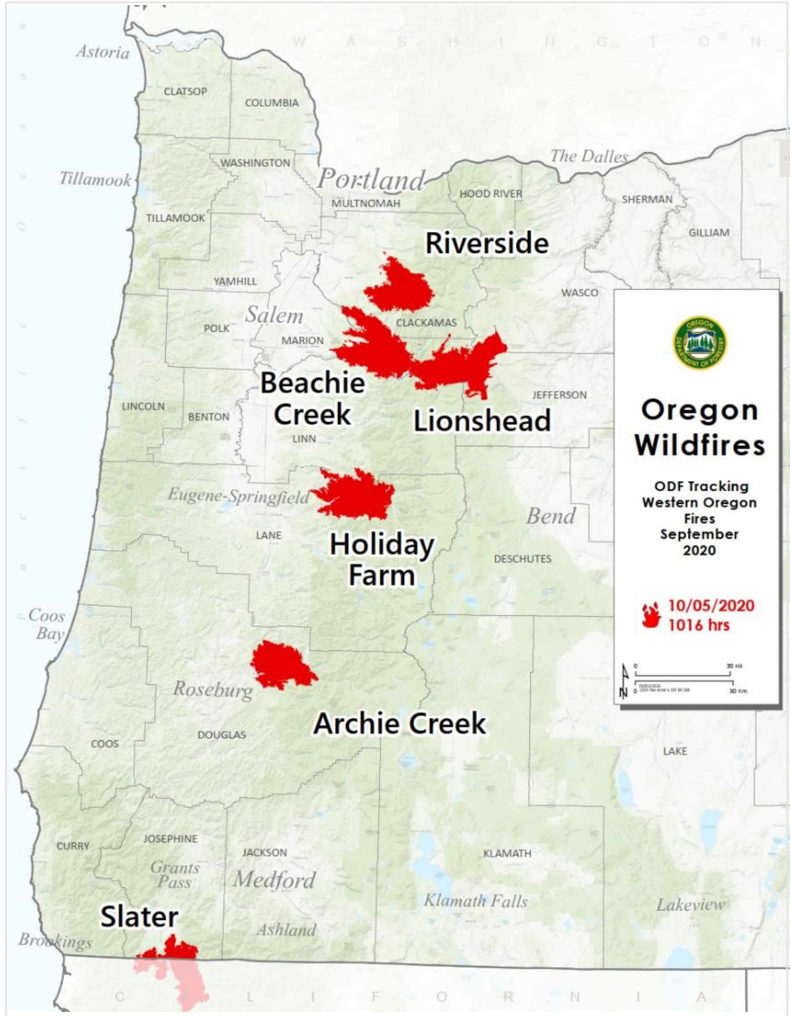
Wildfire on Highway 97 near Chiloquin, September 2020. *Photo courtesy of Oregon Department of Transportation.*

[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.

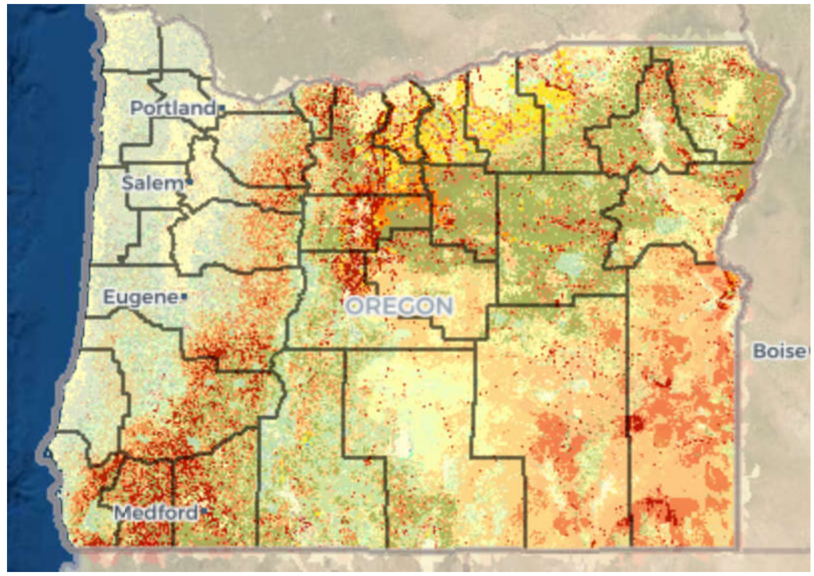
To implement these recommendations, Senate Bill 1536 (2020) was introduced at the request of Governor Brown, but did not pass during the 2020 Legislative Session.[18] Following that session, Governor Brown issued Executive Order 20-04: Directing State Agencies to Take Actions to Reduce and Regulate Greenhouse 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 stay charged 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.

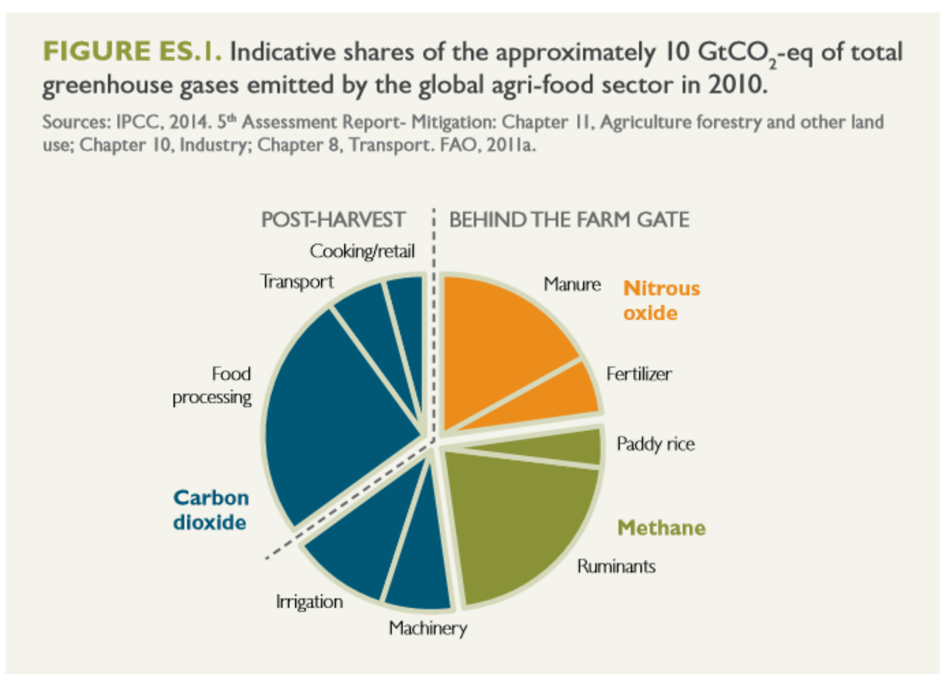
Energy is a significant – though not the largest – expense for most farmers. The U.S. Department of Agriculture's National Agricultural Statistics Service collects information on energy expenditures by farms in its agricultural census every five years. In the 2017 agricultural census, Oregon farms reported 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]

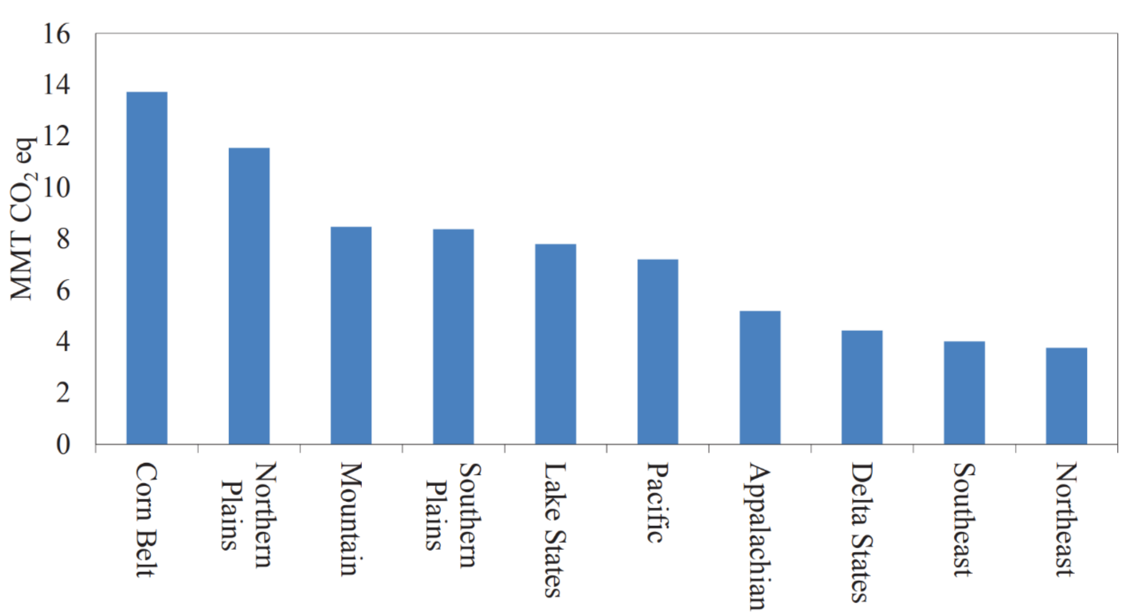


significant variation among countries and regions due to climate and production methods.[13] According to the state GHG emissions inventory compiled by the Oregon DEQ, the share of Oregon's emissions attributable to agriculture was 9.1 percent in 2017, with nitrous oxide and methane from enteric fermentation, 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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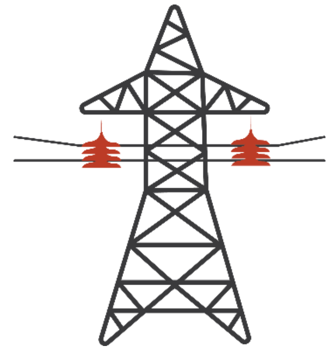
Policy Brief: Emerging Trends in Renewable and Zero-Emissions Electricity Standards



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)

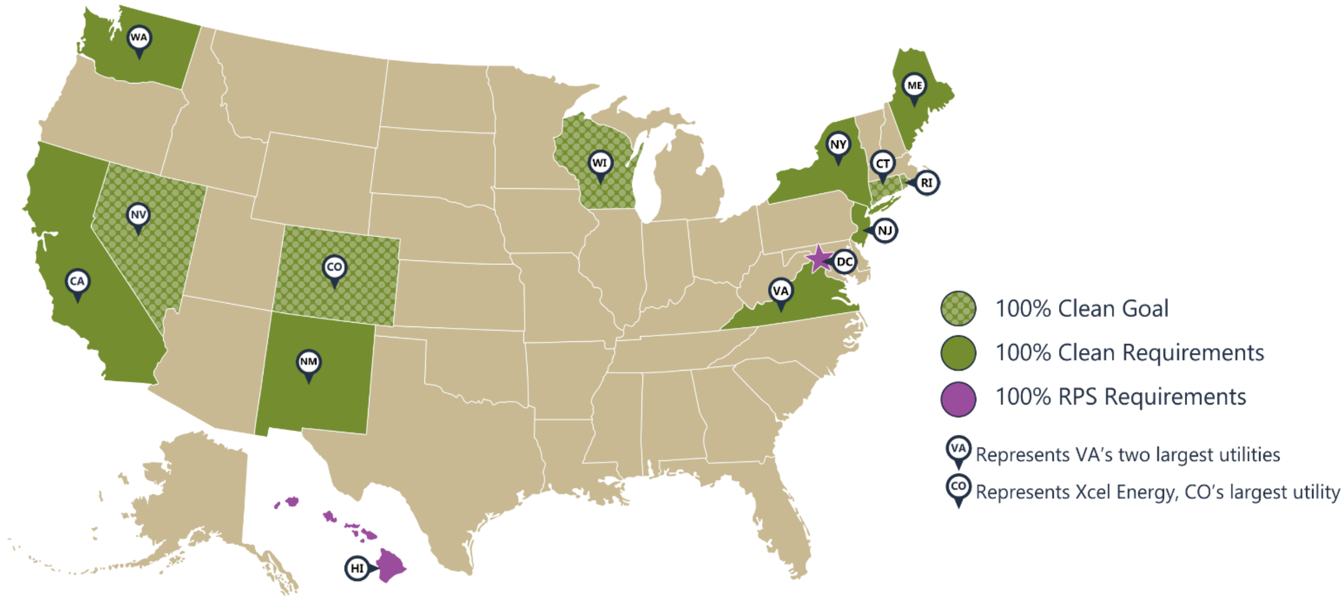
100 Percent RPS vs 100 Percent Clean Electricity Standards

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.

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.

See Energy 101 section for more about renewable and zero emissions standards

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]

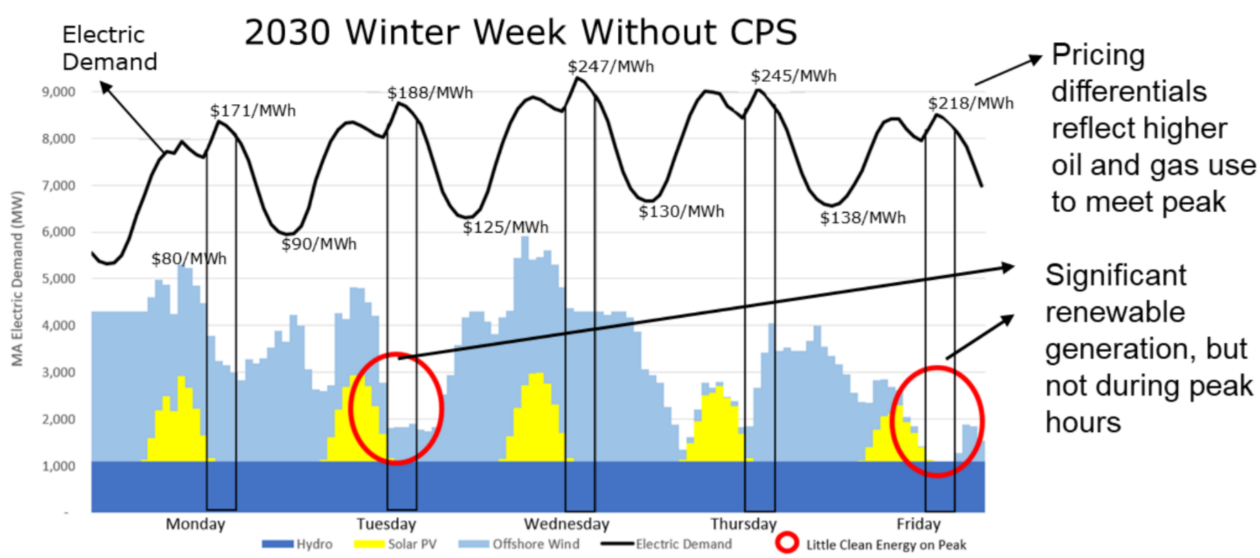
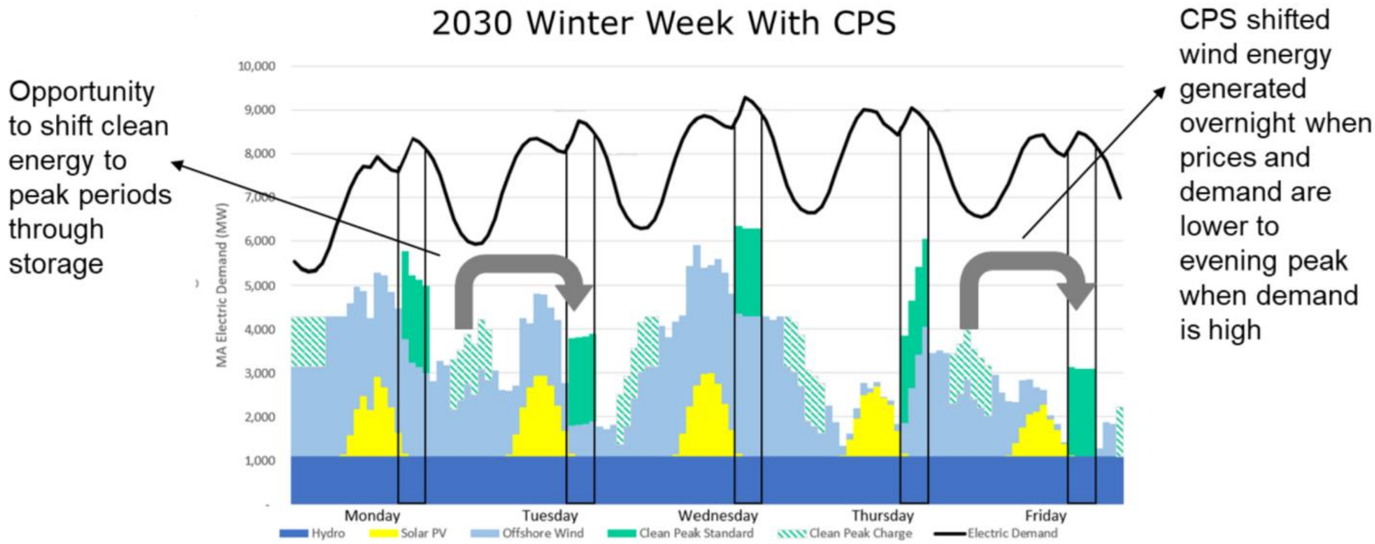


Figure 3: Massachusetts Electricity Generation and Demand During a Winter Week in 2030 With the Clean Peak Standard[17]



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.

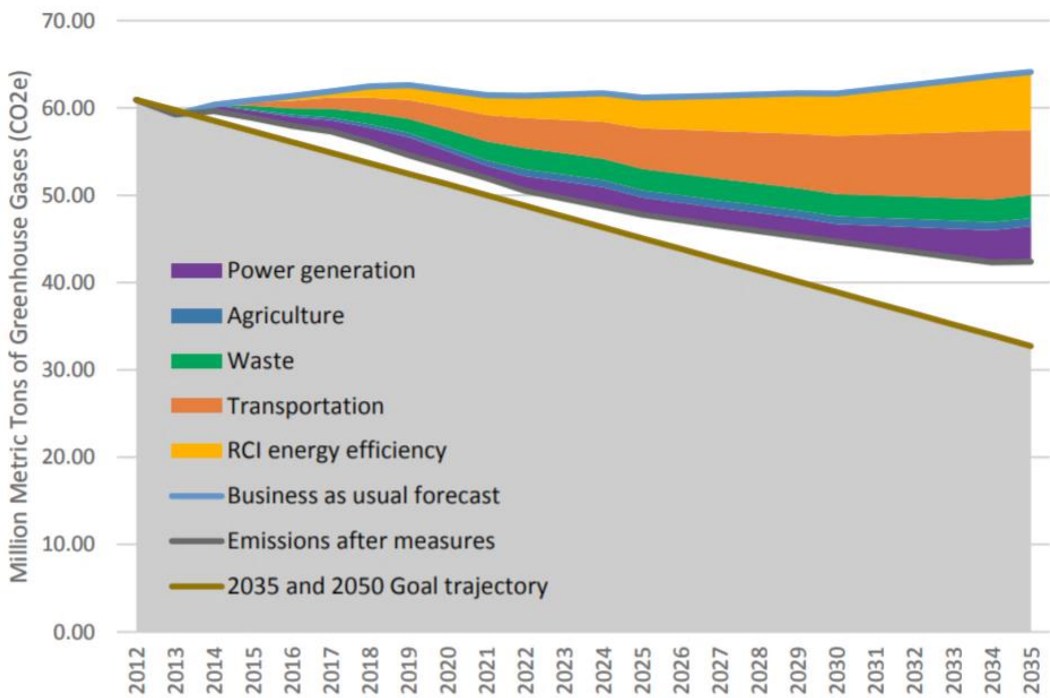
The Oregon Global Warming Commission conducted a wedges analysis for Oregon in 2015 and constructed a scenario (called Case 1) that included a number of the most cost-efficient measures that could reduce Oregon's GHG emissions and get it closer to meeting its 2035 emissions level target.[25] The combination of measures in Case 1 would result in roughly a 22 million metric tons of CO2e

[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.

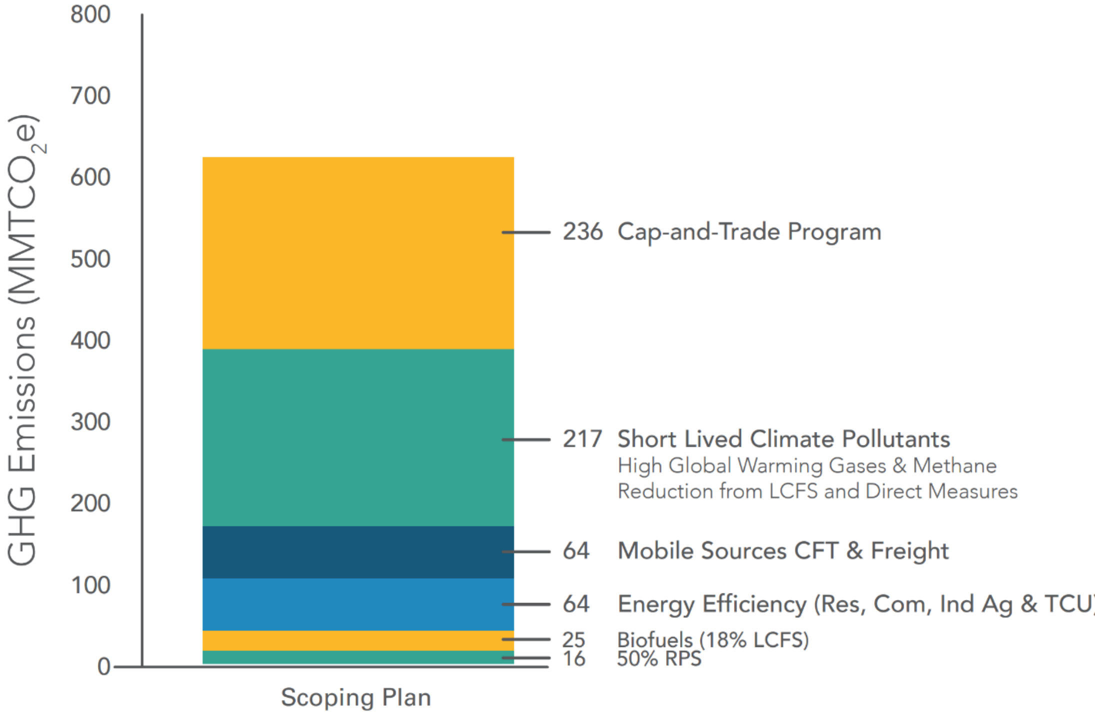
Figure 4: Case 1 Scenario for Reducing GHG Emissions in Oregon (Source: Oregon Global Warming Commission)



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

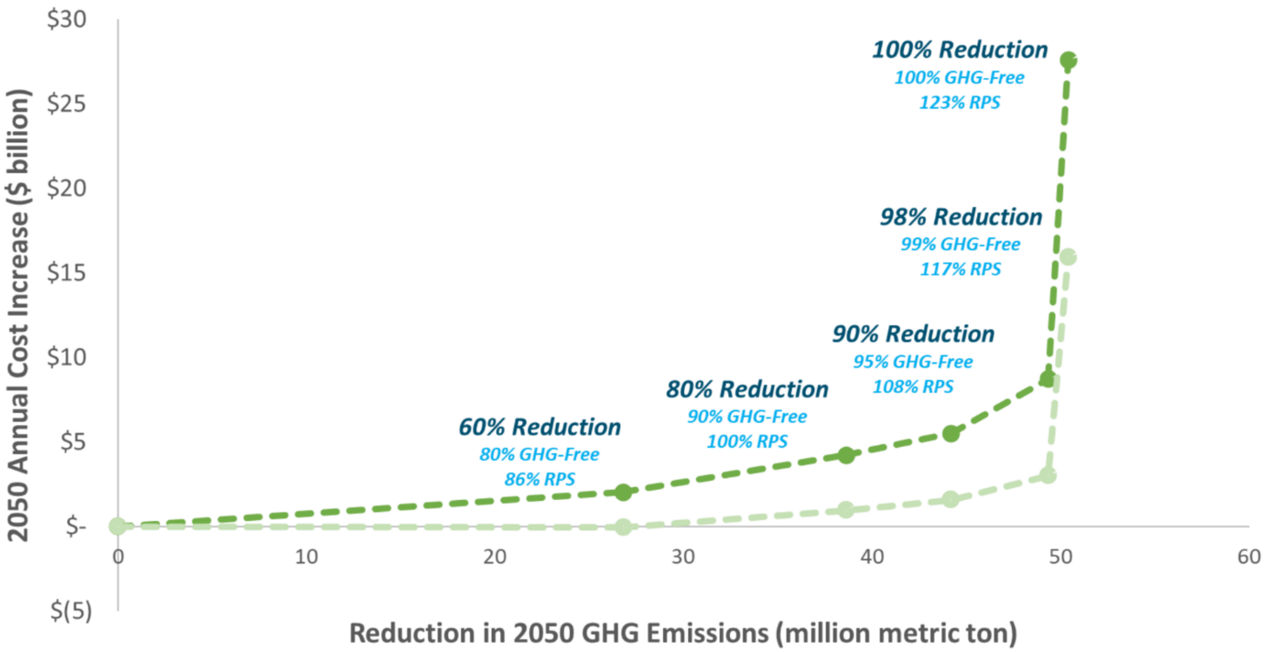
While many fossil fuel power plants take time to start up or shut down, most of them can provide electricity continuously once they are up and running and are often referred to as "baseload" generators, delivering "firm" power. "Baseload" has no industry-accepted definition but has come to mean facilities 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.

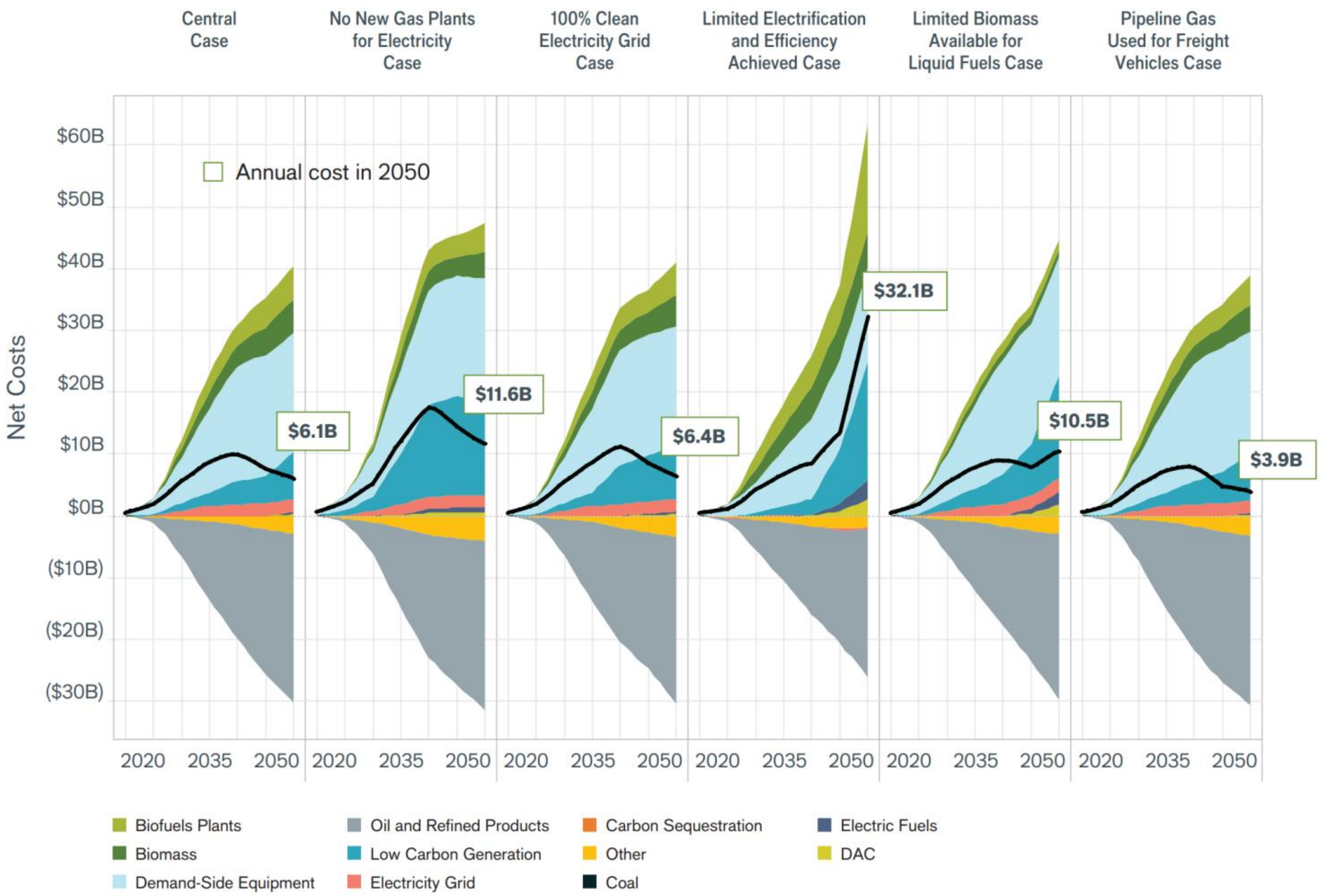
For this reason, recent decarbonization studies have recommended keeping a small percentage of existing or new natural gas generation capacity (with or without CCS) and not phasing out existing zero-carbon firm resources like hydropower or nuclear power. In its analysis of low-carbon scenarios for the 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)



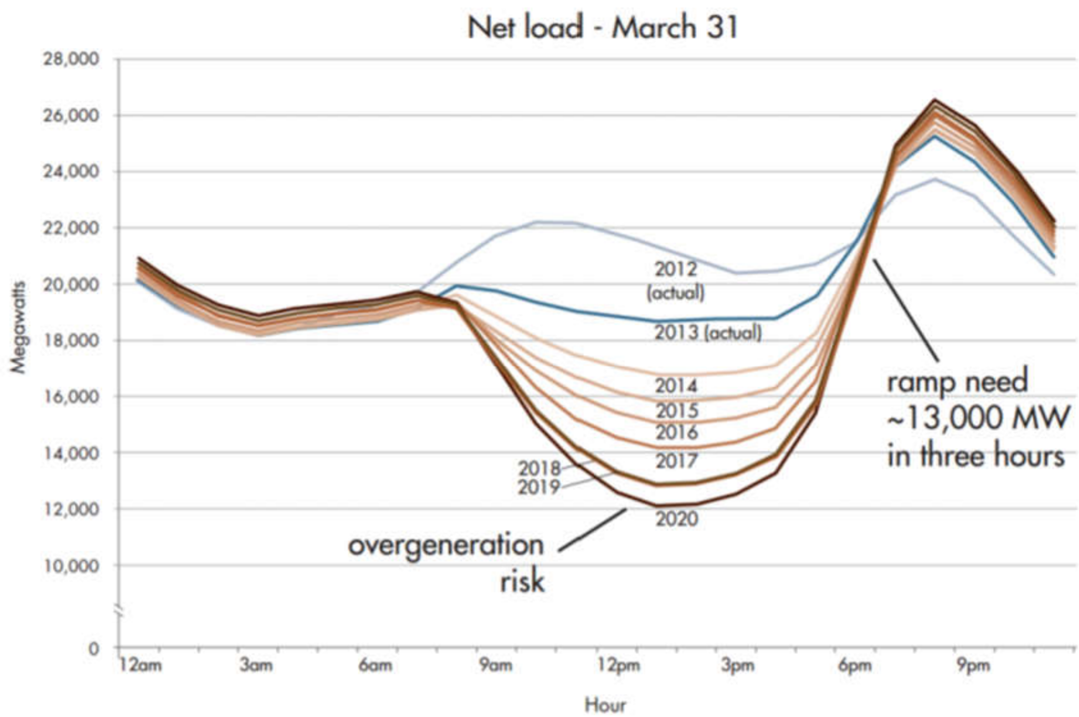
Finally, the recent 2035 study from UC Berkeley found that the U.S. can achieve a 90 percent clean grid by 2035 without coal or new natural gas plants with wholesale electricity costs about 10 percent lower that they are today.[36] The lower electricity costs in the 90 percent scenario are primarily 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]

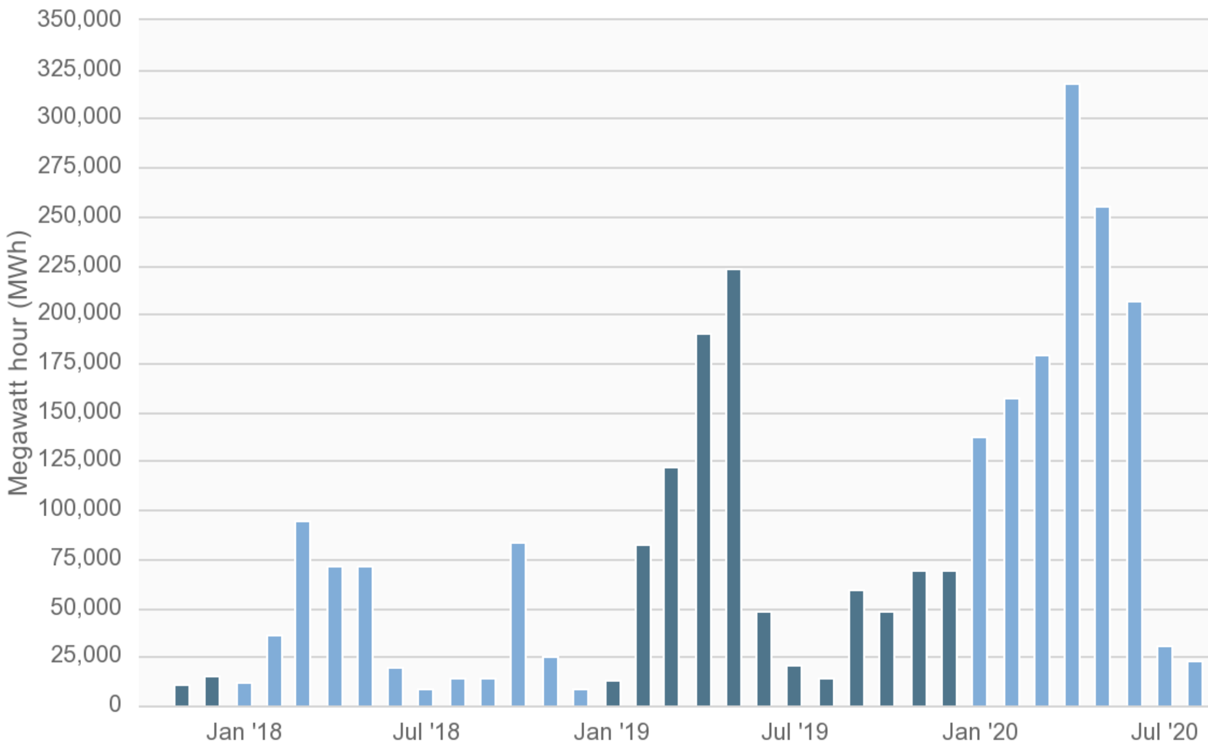
Figure 8: The CAISO Duck Curve (Source: Denholm)



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.

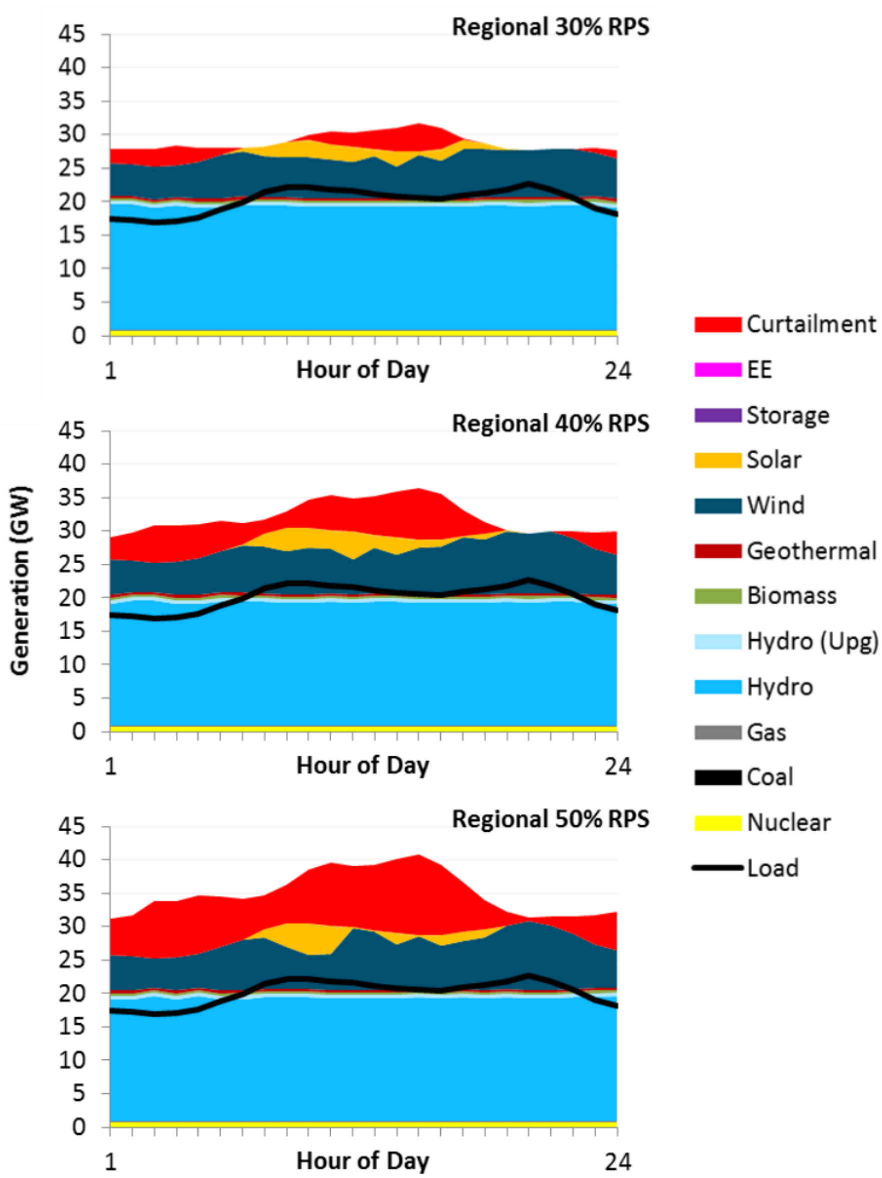
Figure 9: Wind and Solar Curtailments by Month in CAISO From November 2018 to August 2020 (Source: CAISO 2020)



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).

	○ **<u>Large loads</u>**: What is the potential for large industrial customers to enter or leave the utility's service area? ○ **<u>Extreme weather</u>**: What is the likelihood of severe cold or hot weather that could set a new annual peak demand? ○ **<u>Climate change</u>**: How much is climate change expected to affect historic weather patterns, changing the likelihood of severe weather? ○ **<u>Demand response</u>**: To what extent can customers be incentivized to reduce demand during peak hours?
Supply: How much power can generation resources deliver in the future?	○ **<u>Energy constraints</u>**: 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) ○ **<u>Ramp rates:</u>** What are the ramping capabilities of the utility's capacity resources to quickly increase or decrease output to respond to changes in net load? ○ **<u>Retirements</u>**: Are there any existing resources scheduled for retirement? ○ **<u>Resources under development</u>**: Do any utilities in the region have generation resources currently under development? Should expected future output from those resources be incorporated into the analysis? ○ **<u>Proposed resources</u>**: 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? ○ **<u>In-region market resources</u>**: 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.)? ○ **<u>Out-of-region imports</u>**: How much power from out-of-region can be expected to be available for import to meet demand? ○ **<u>Transmission constraints</u>**: 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]

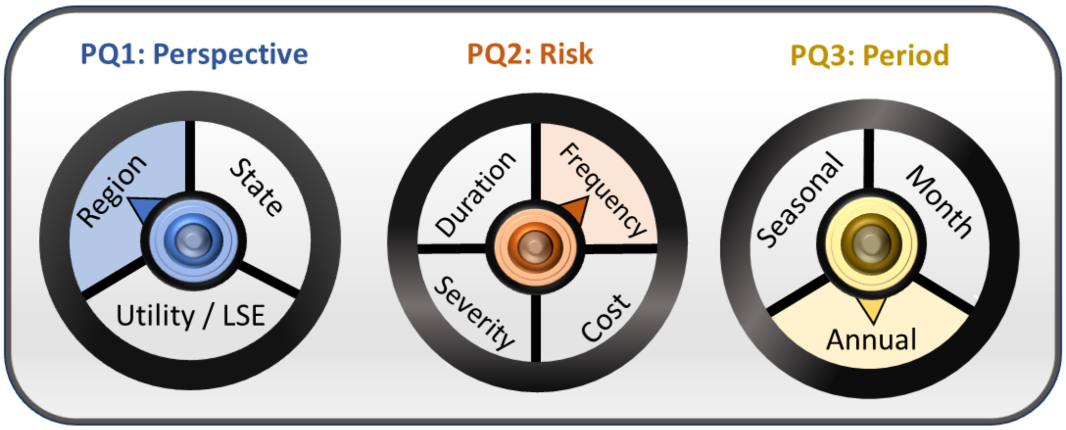
Texas

- 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.

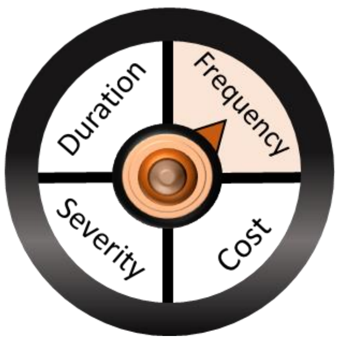
Many other regional electric systems operate within Regional Transmission Organizations (RTO) or Independent System Operators (ISO) that encompass multiple states. PJM and SPP, mentioned above, are examples of this type of an arrangement. In these cases, RA is evaluated across the multi-state regional 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

[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.

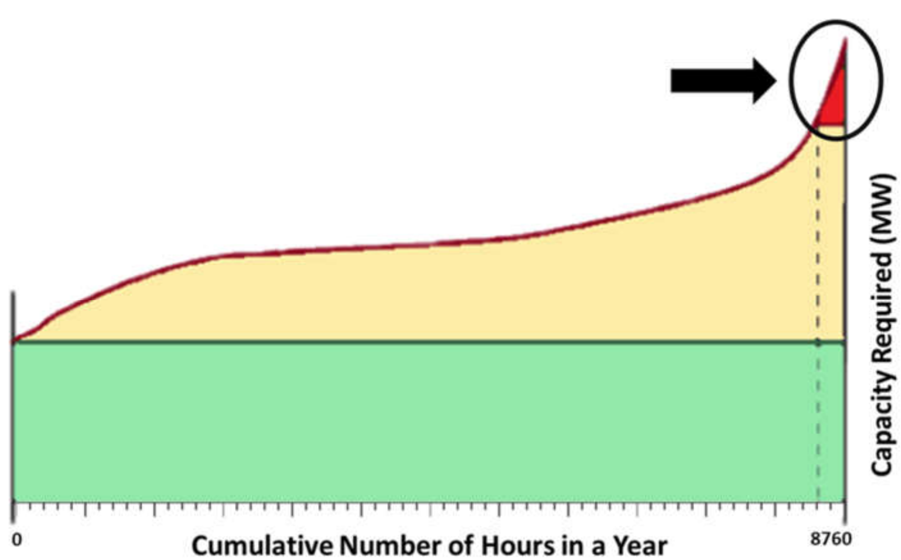
Note, however, that these time periods for evaluation can be, but need not be, mutually exclusive. The annual peak demand for a particular region may still occur in the summer months, for example, but the region may find its greatest capacity need exists in another season due to the particular characteristics 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.

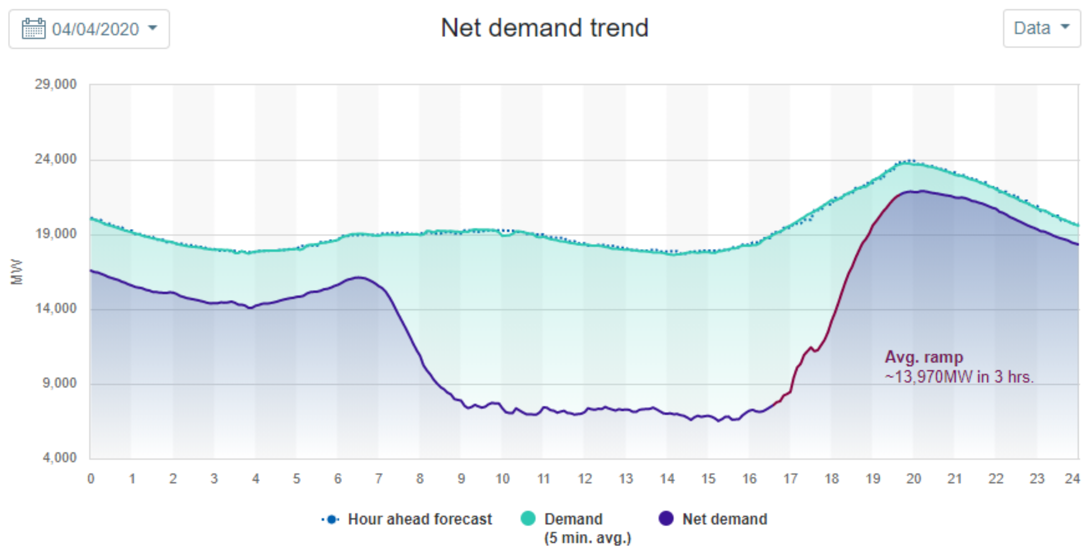
The evaluation of RA is often focused on the area circled in black here—those relatively few hours (or days) of the year when the capacity required to meet demand is the greatest. Utilities and grid planners must plan for capacity resources to be available to deliver electricity to customers when those 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]

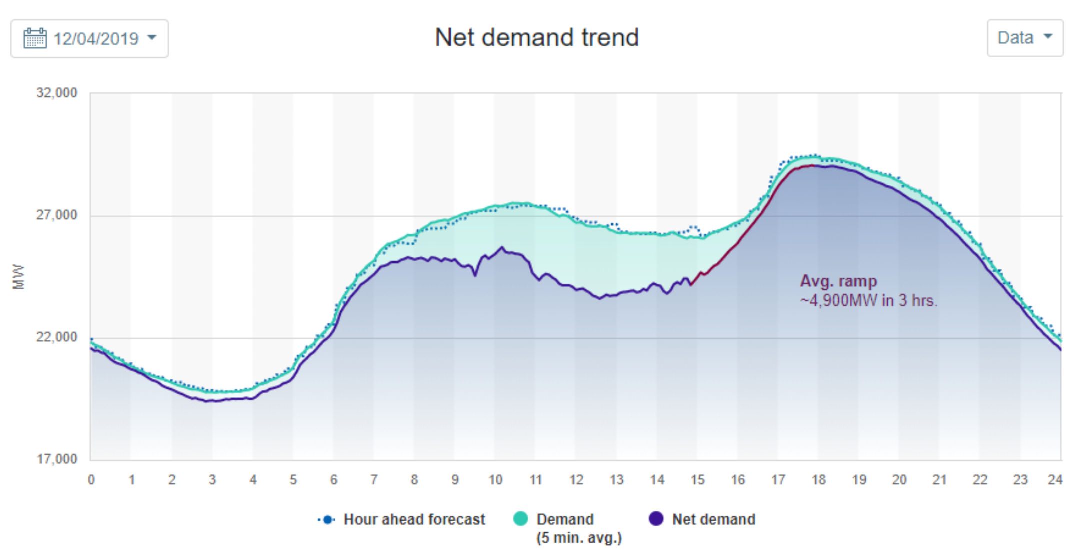
Figure 2: Net Demand Load Curve from CAISO in April 2020



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.

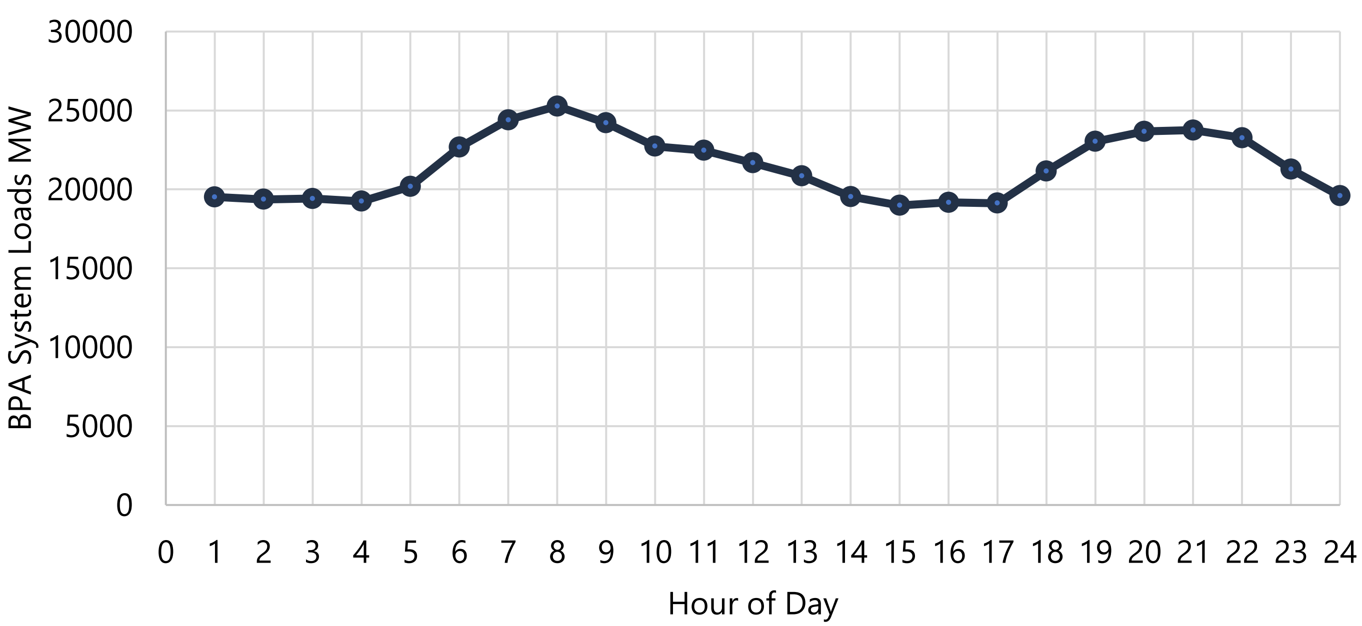
AMI in Oregon

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]

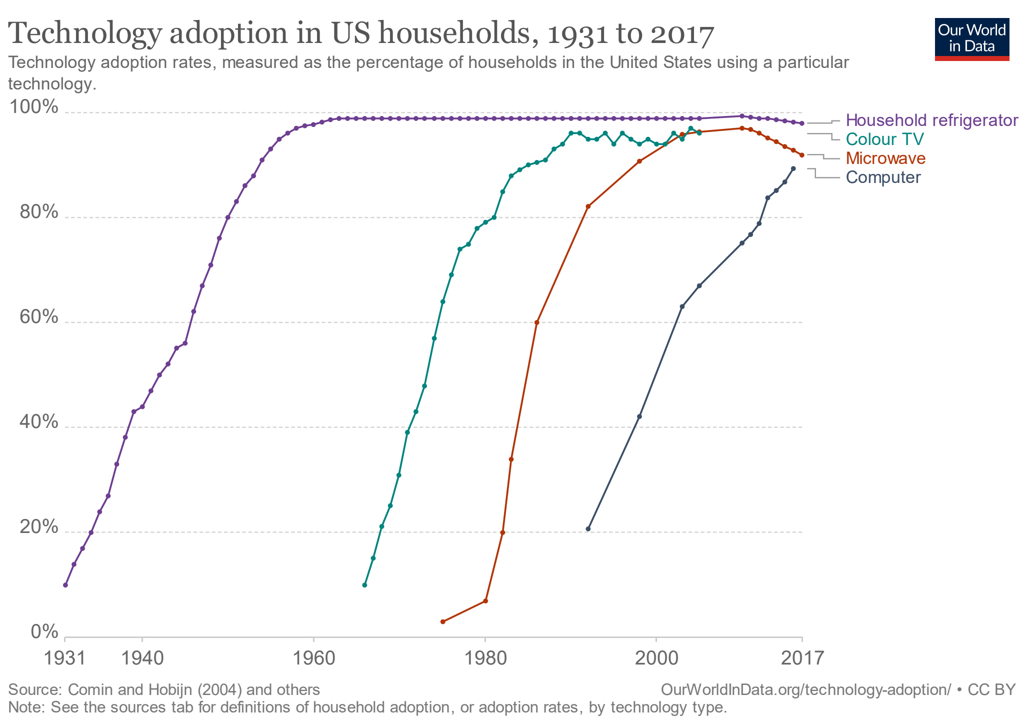
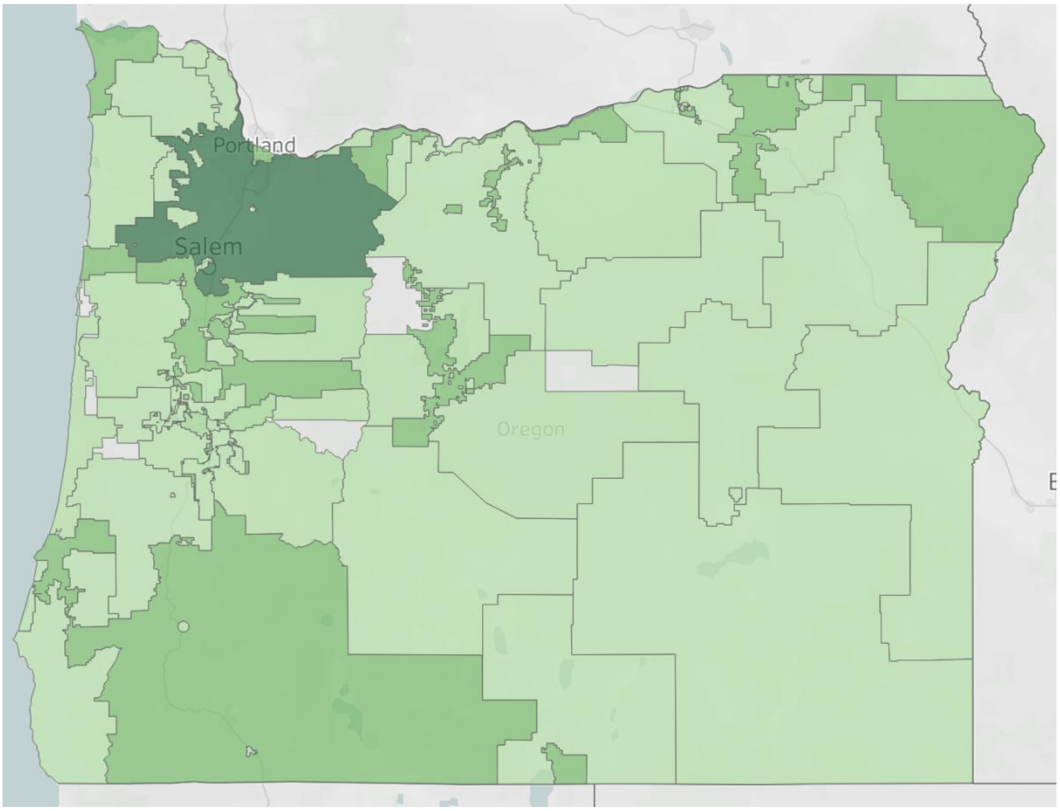


Figure 2: Registered EVs by Oregon Utility Service Territory[4]



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.

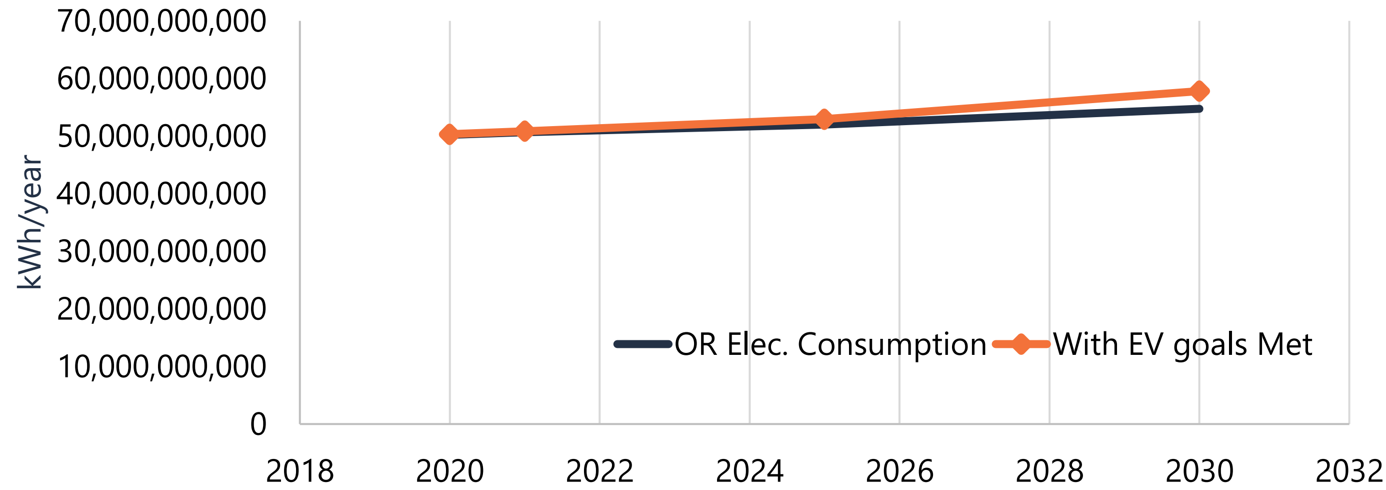
Overall, load impacts on the system are one measurement for utilities to understand the effects of increasing EV adoption. However, as utilities look at this overall load, they must also consider the times EVs are expected to be charging and the places where EV charging will occur. Timing will inform 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]

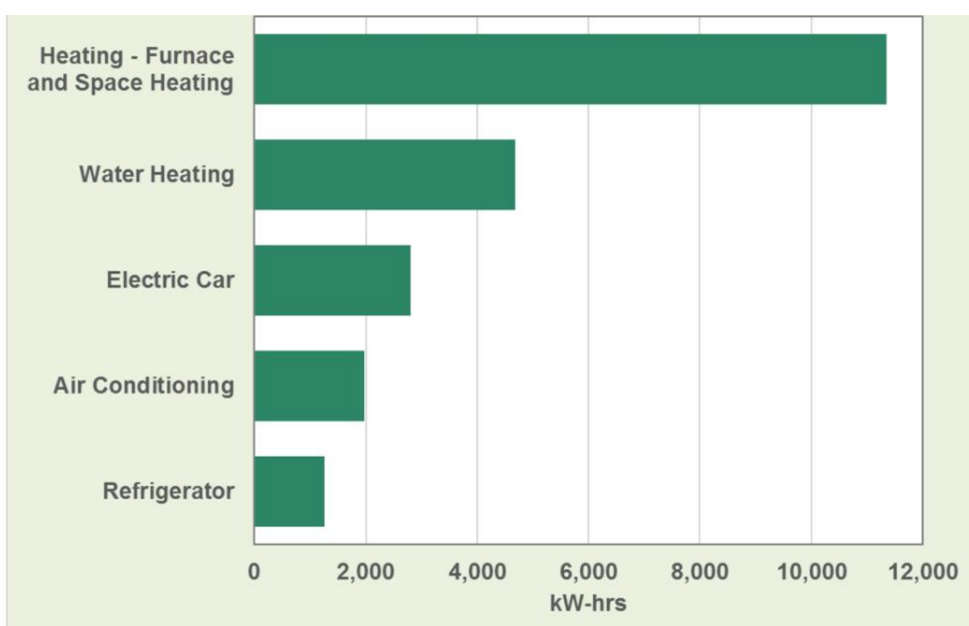


Effects of EVs on Local Distribution Systems

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]

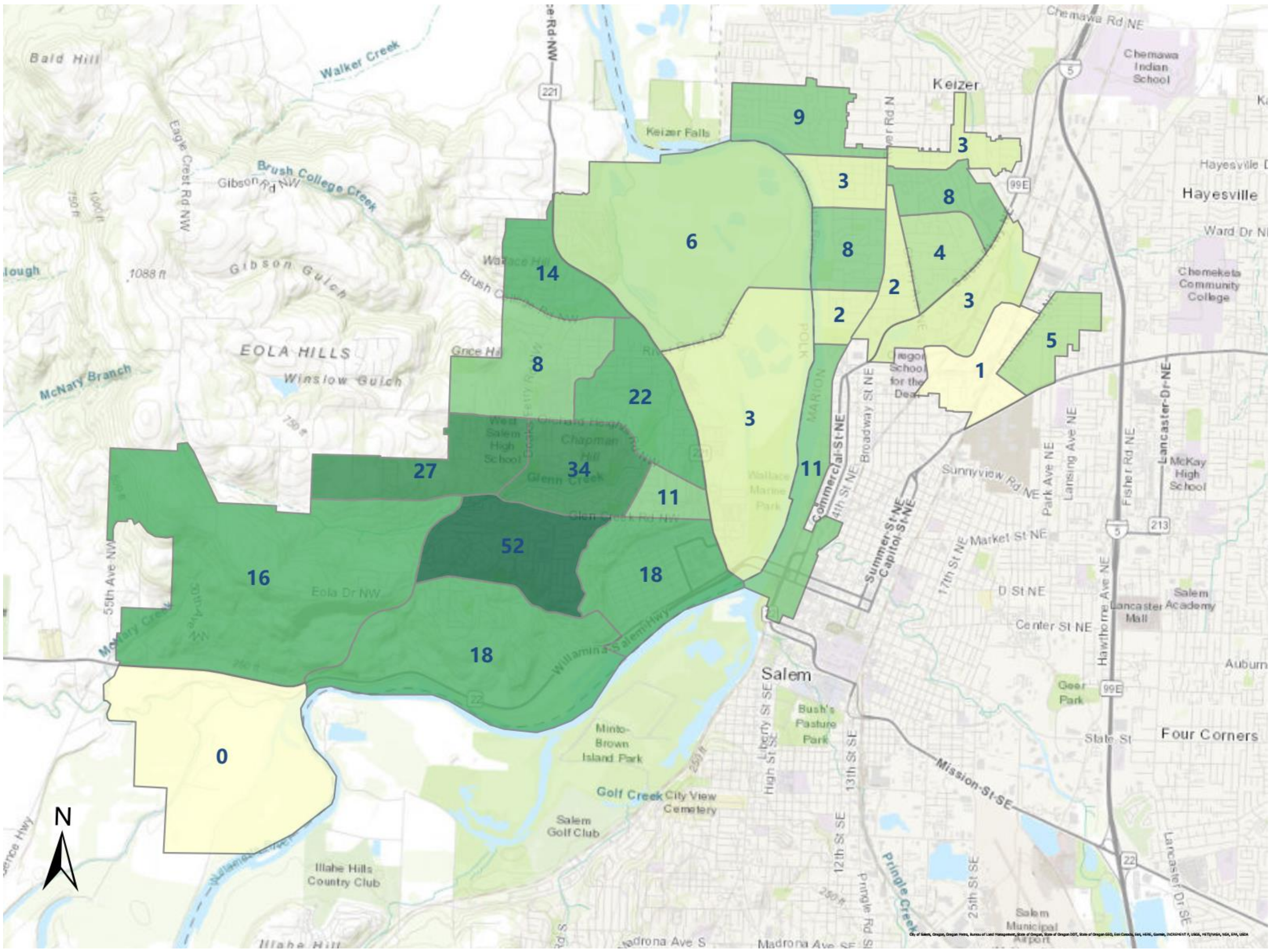


[iii] Level 1 charging (110V).

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

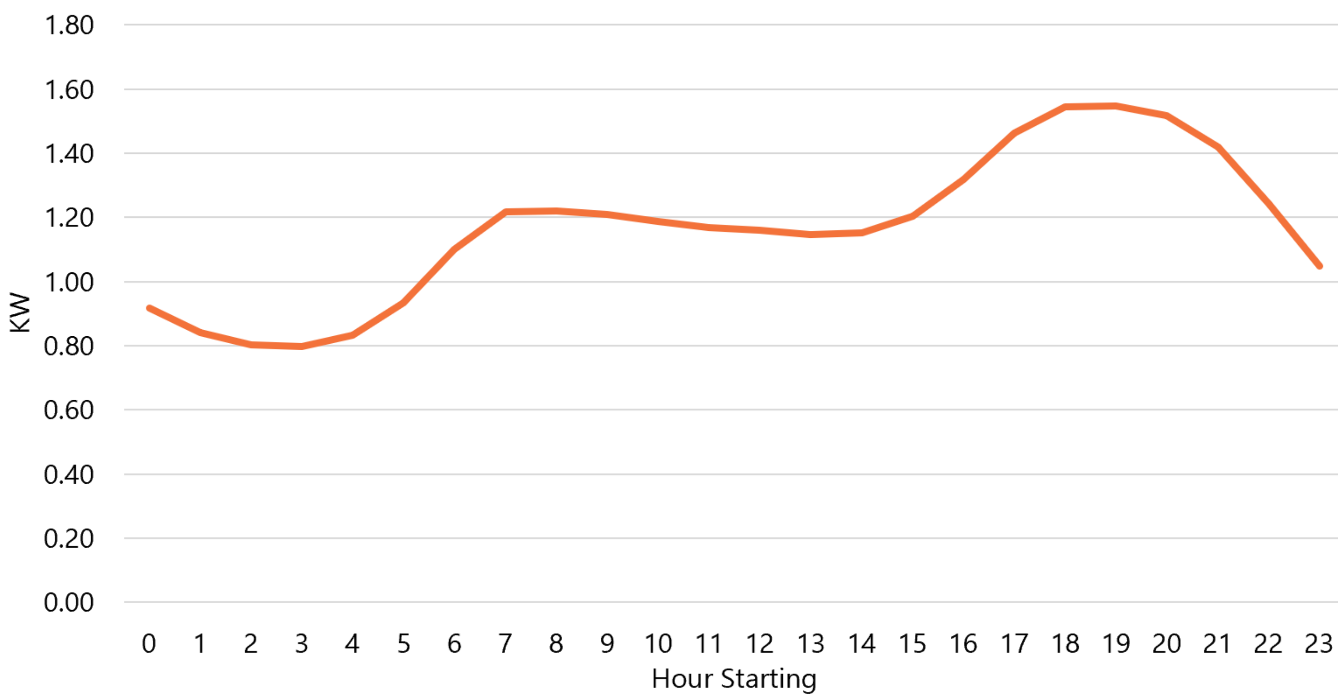


Managing Timing of EV Charging Can Enable More EVs Without the Need for More Electricity Generation

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.

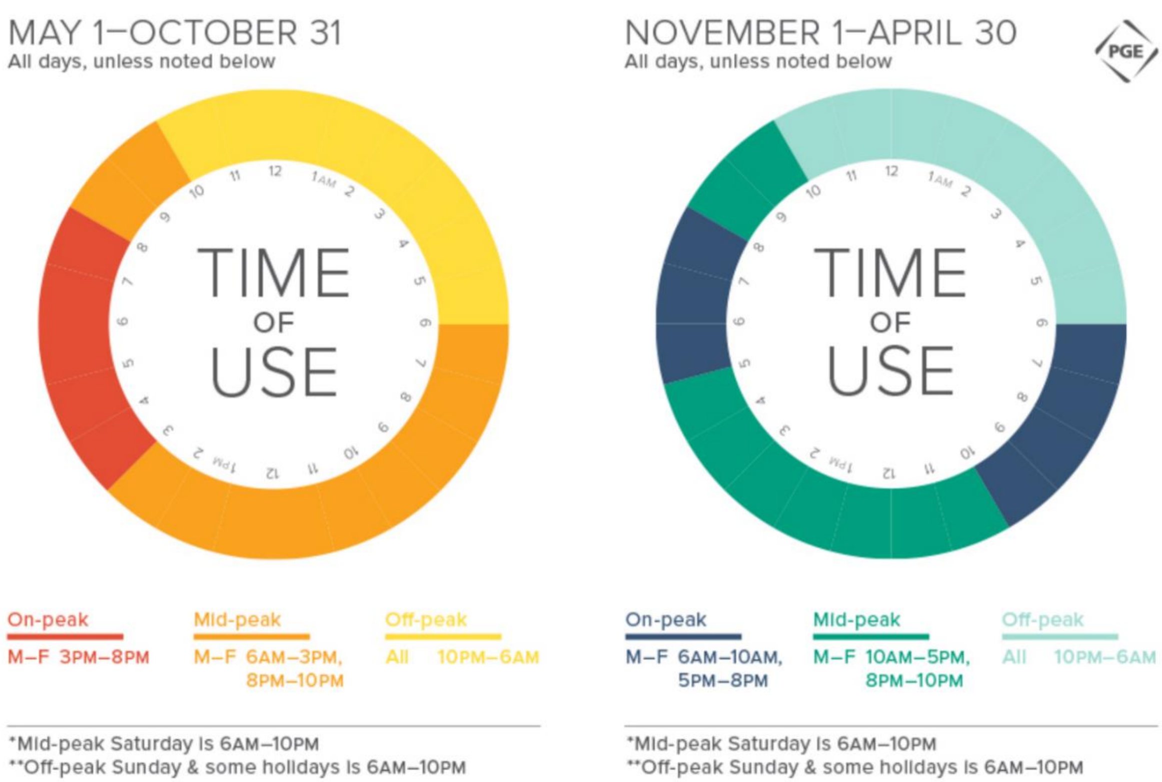
Customer Outreach

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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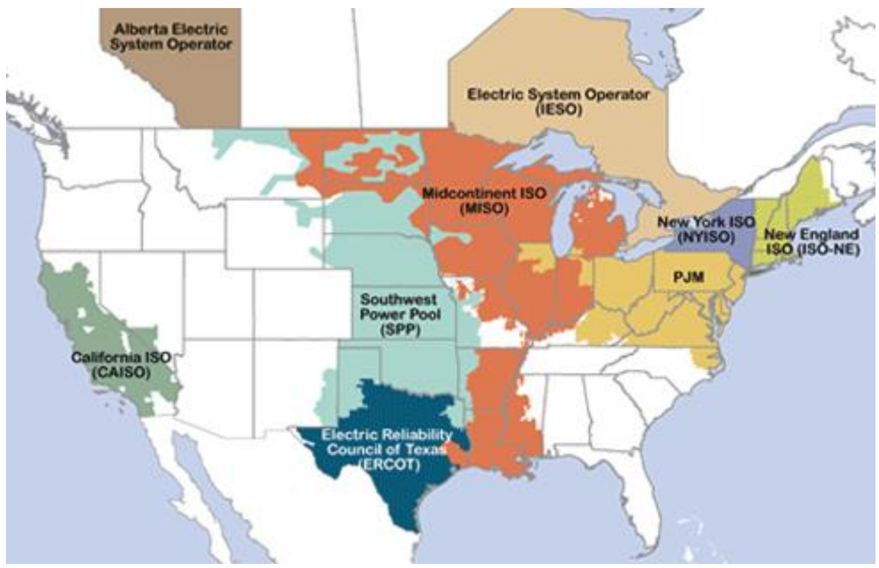
Policy Brief: Evolving Wholesale Electricity Markets

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 EIM Entities

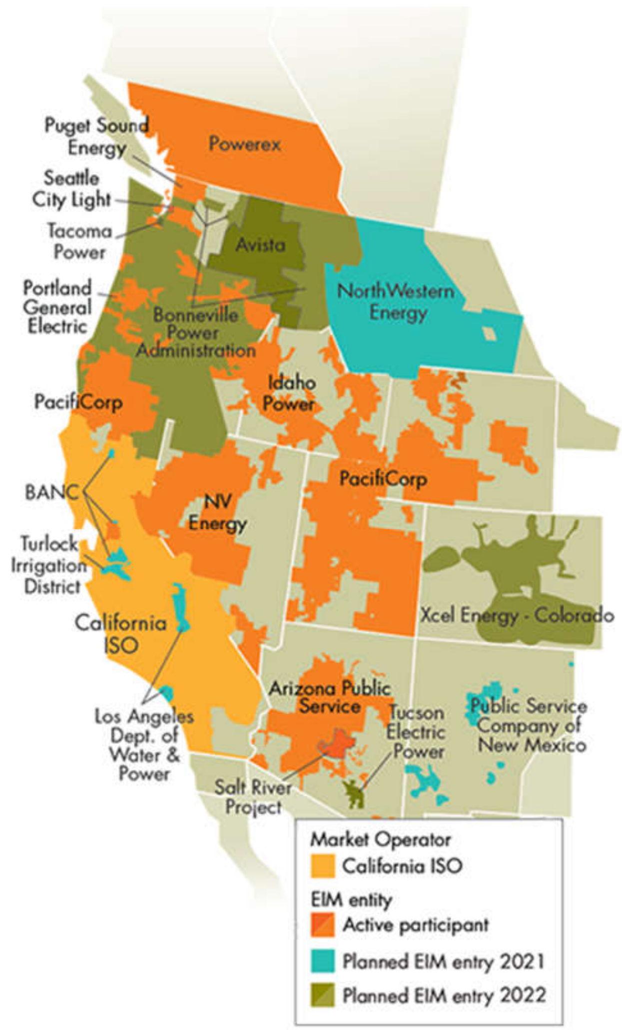
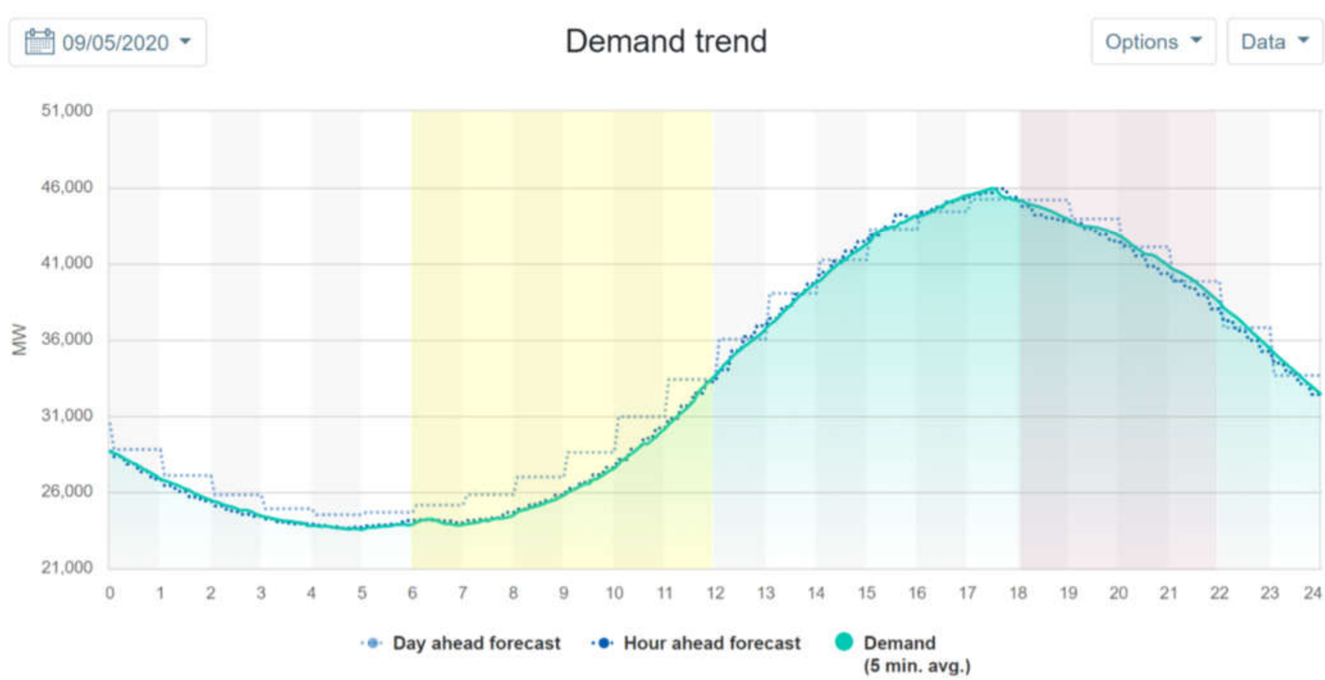


Figure 3: Day-Ahead Forecast (CAISO)



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

[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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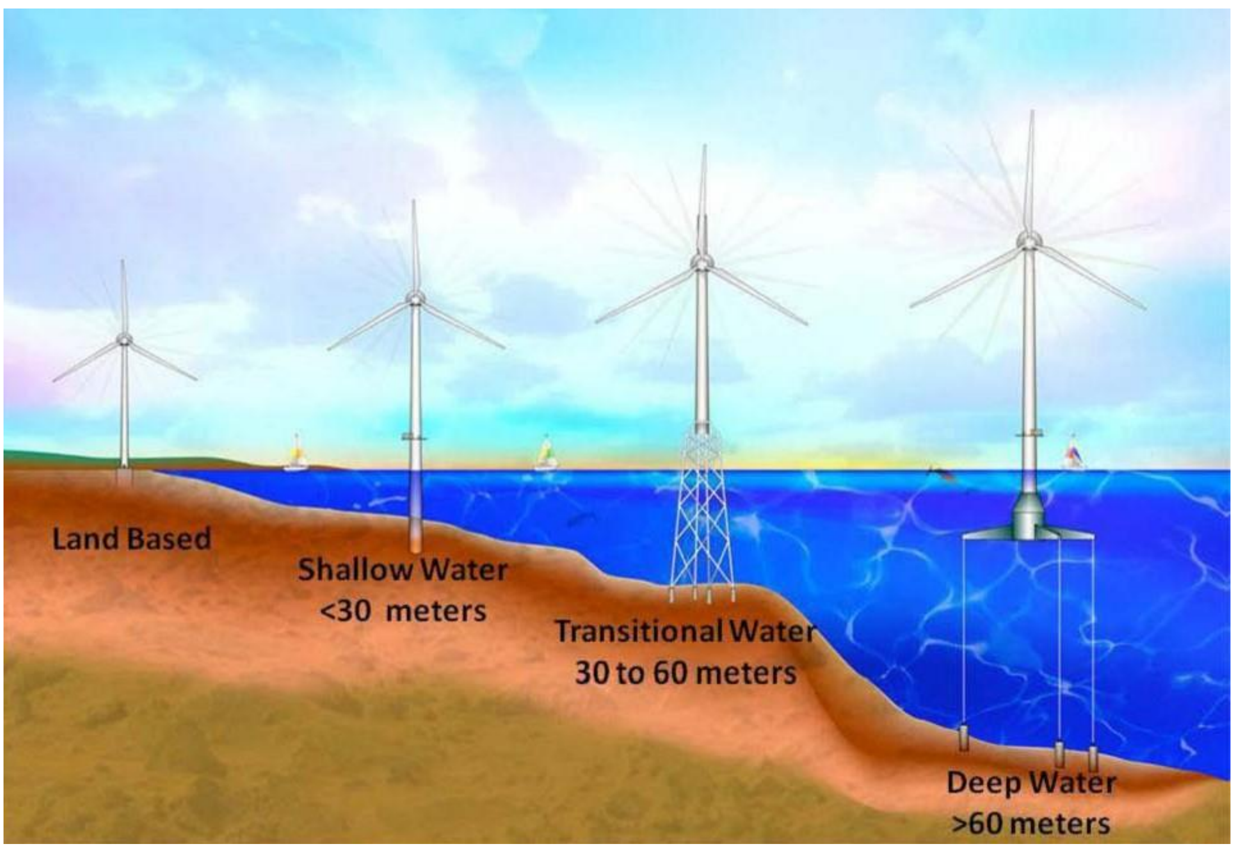
Policy Brief: **Offshore Wind**

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]



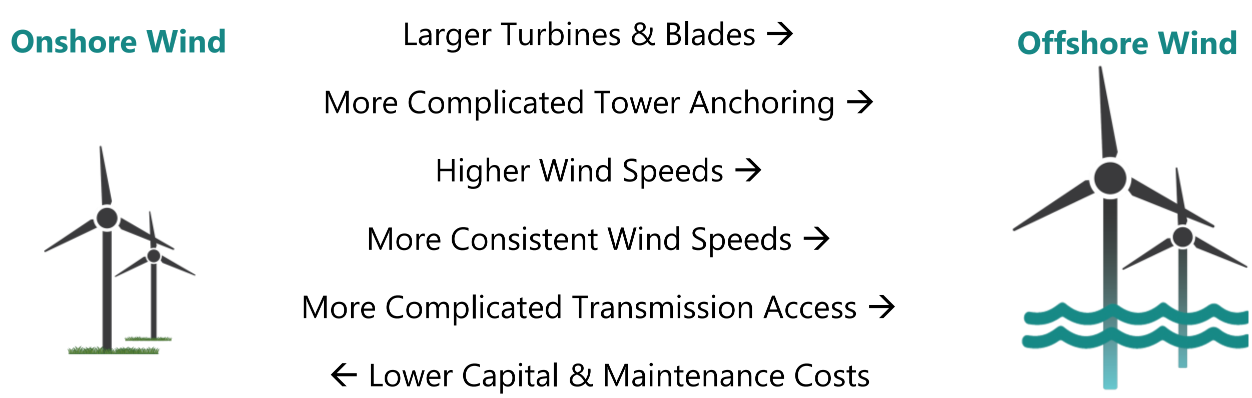
The potential need for significant local transmission upgrades can also make offshore wind more expensive than land-based wind development, which contributes to the overall economic viability of a project. However, offshore wind does have an advantage of economies of scale that can increase economic 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

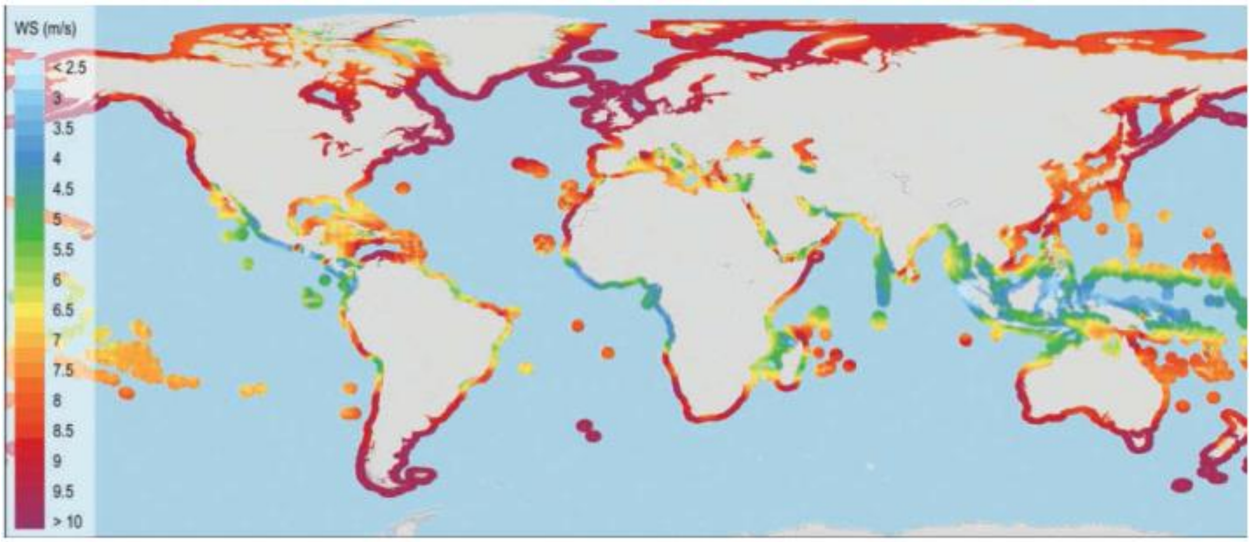


Current State of Offshore Wind

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.

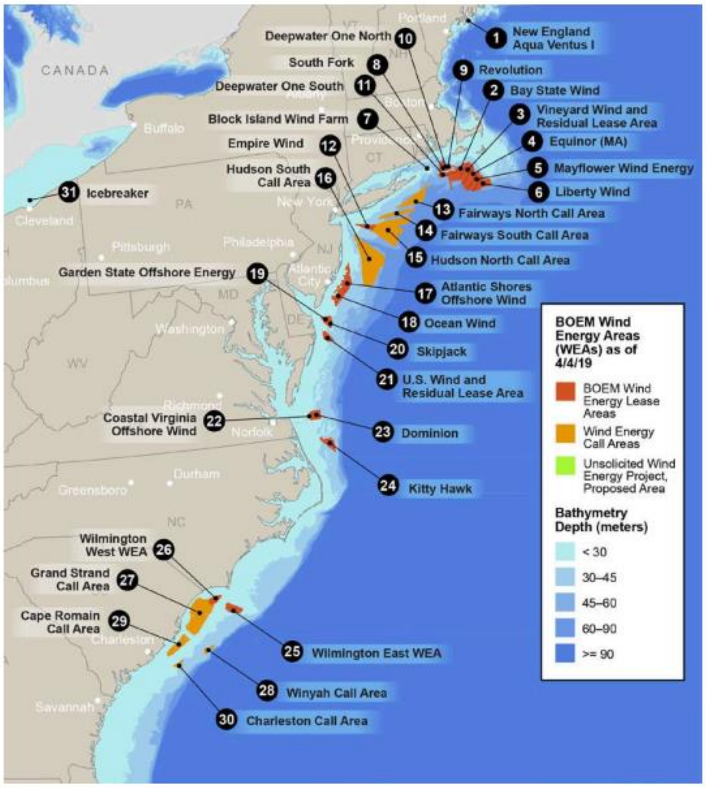
Figure 3: Global Map of Areas w/ High Offshore Wind Speeds (Fixed and Floating)[13]



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*).

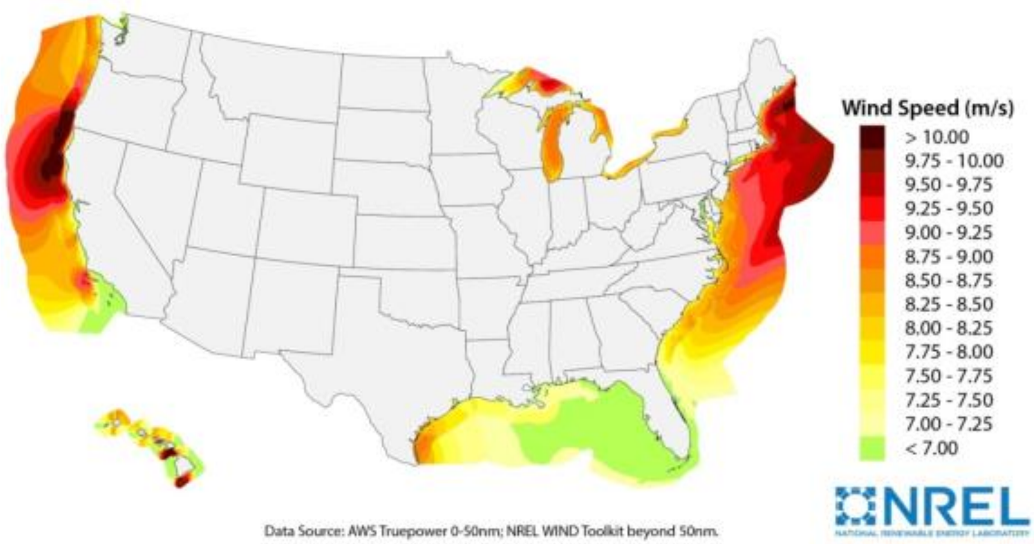
Figure 4: Map of U.S. Activity in Fixed Offshore Wind[23]



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]

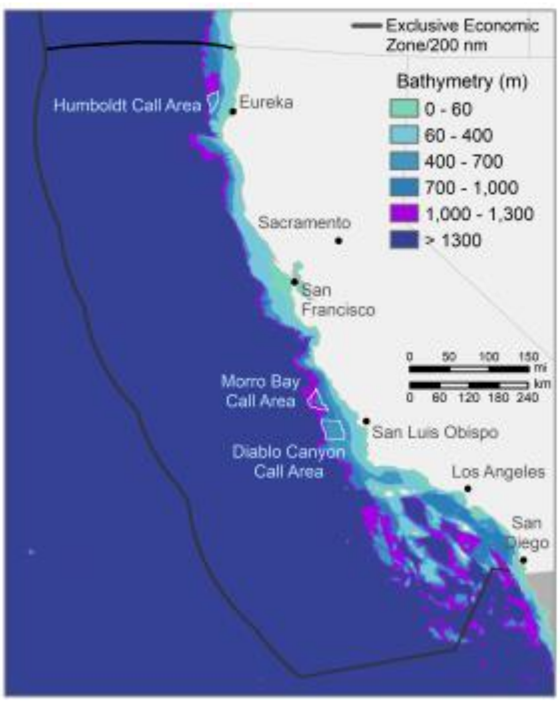
Figure 5: U.S. Wind Map of Areas w/ High Offshore Wind Resource Values[25]



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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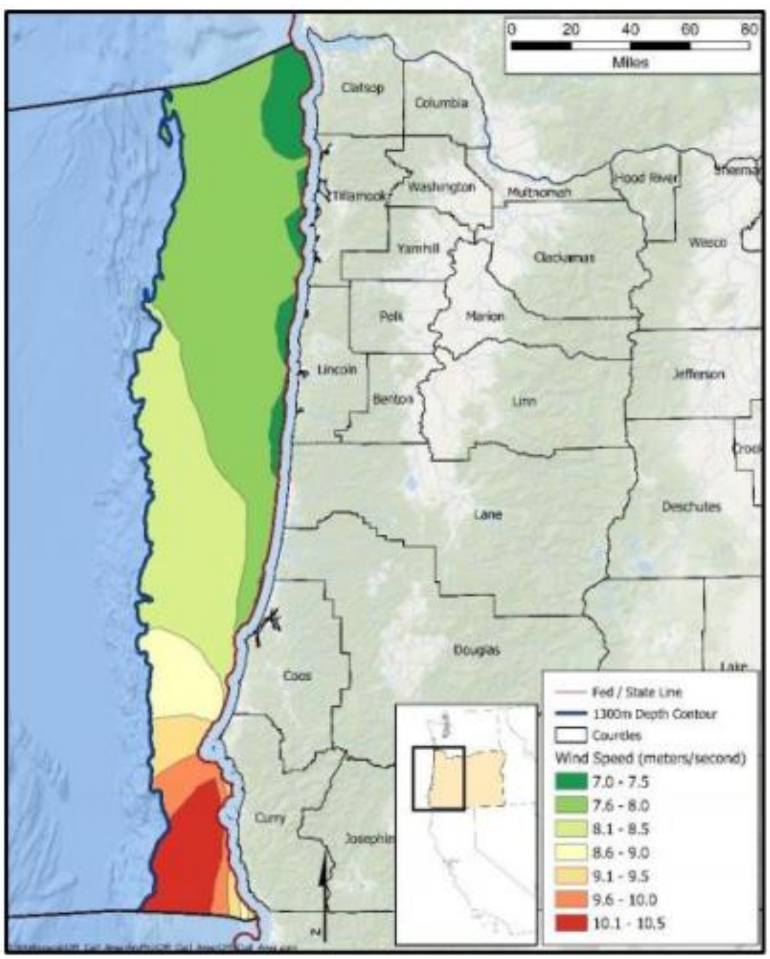
[i] Utility Integrated Resource Plans have a 20-year planning horizon. Portland General Electric's 2019 IRP has no mention of offshore wind. PacifiCorp's 2019 IRP has only a brief mention of offshore wind – "[O]ffshore wind remains expensive and requires government policy support and subsidization."

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]



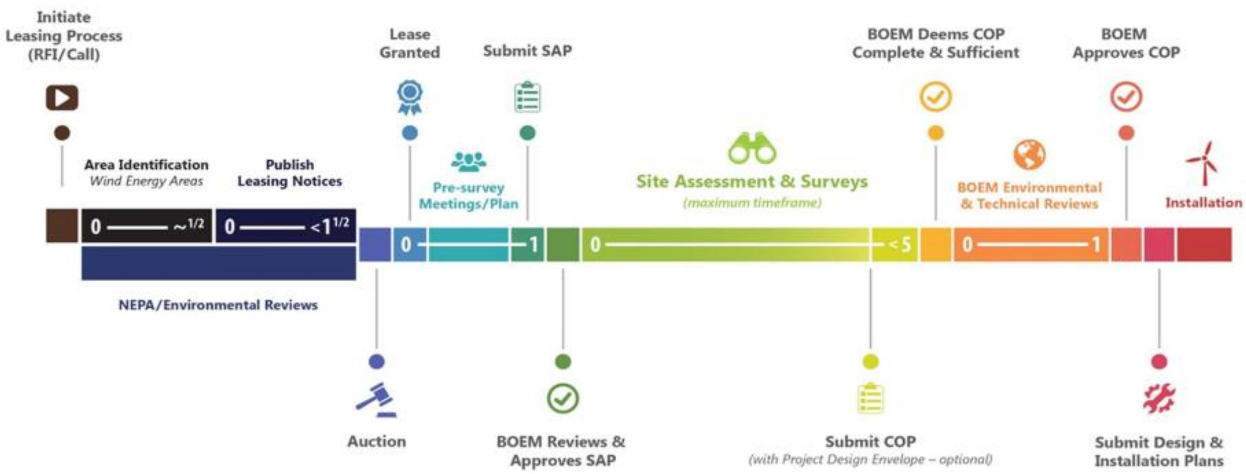
Federal Jurisdiction

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

[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

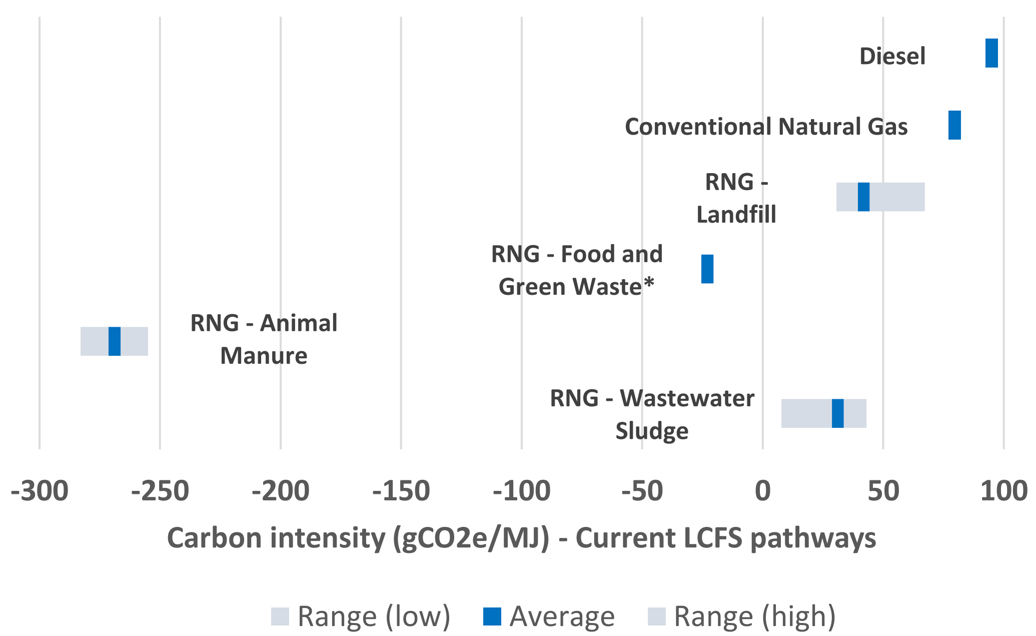
[i] SB 98 is codified in ORS 737.390 through 757.398

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]

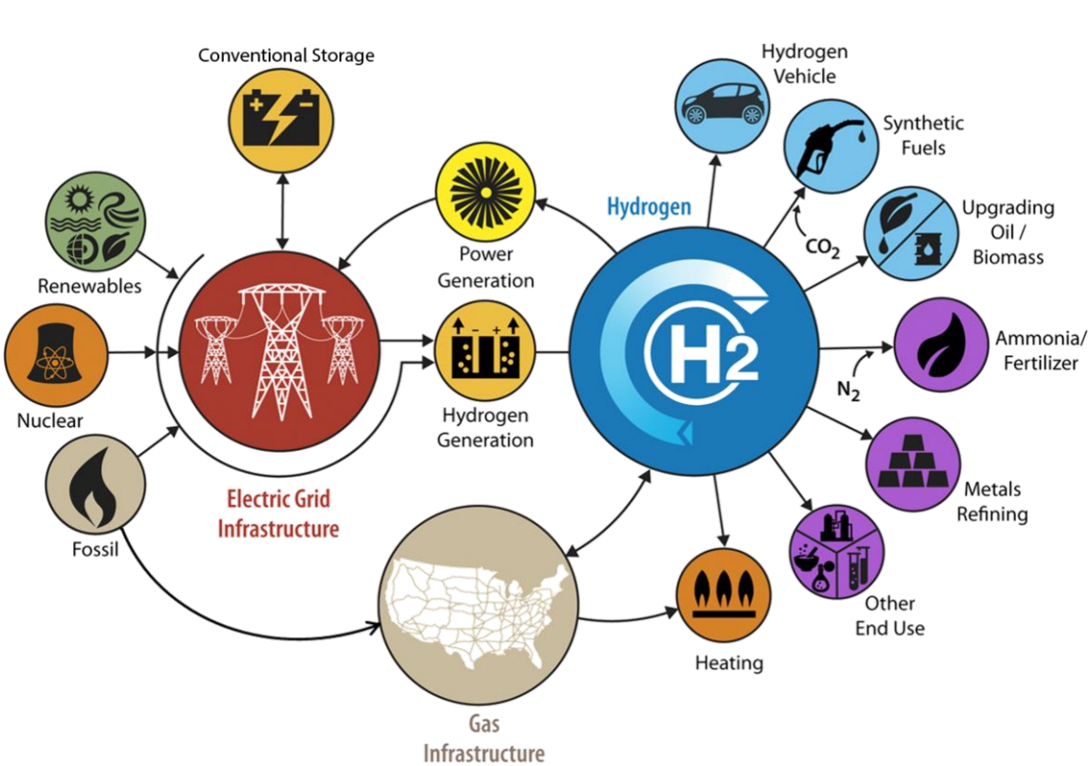


Figure 1 shows the potential applications of hydrogen in the economy, including power generation, energy storage, transportation fuels, industrial processes, and stationary uses.

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.

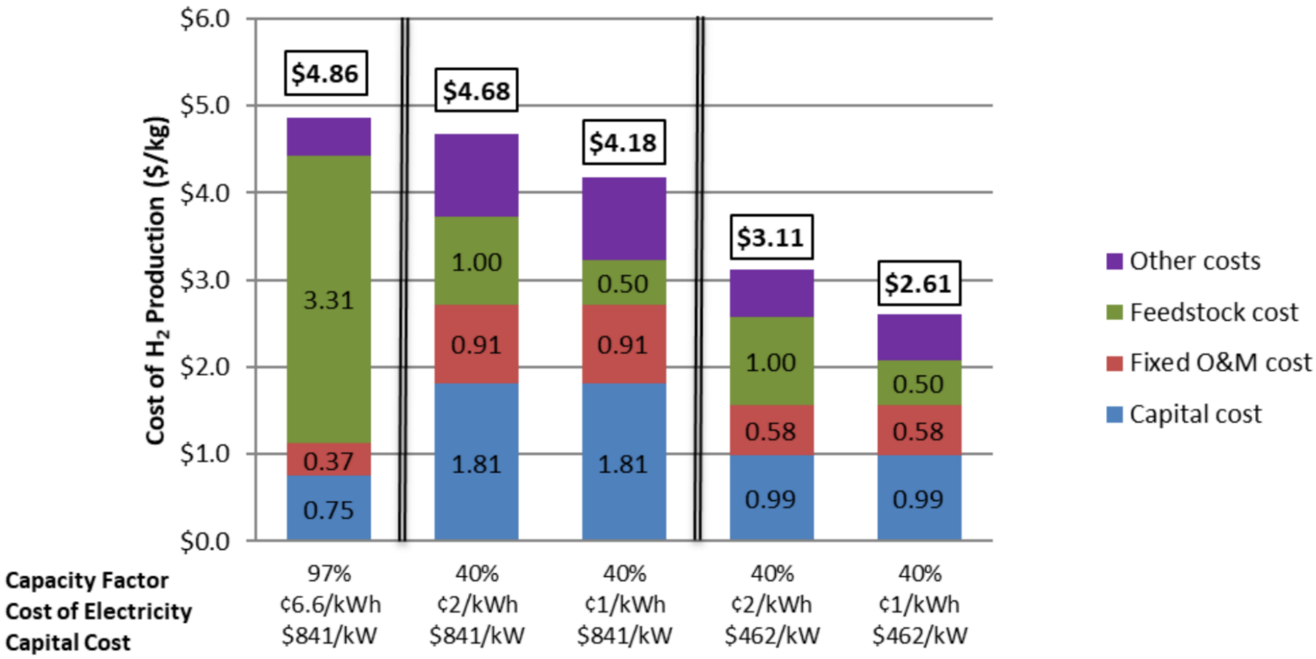
Given that electricity represents a large share of the operating expenses of a PtG unit, an optimal application of PtG could be as an end use for excess renewable electricity that would otherwise be curtailed. Unlike California, the Pacific Northwest currently has limited circumstances when this type 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.

[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]

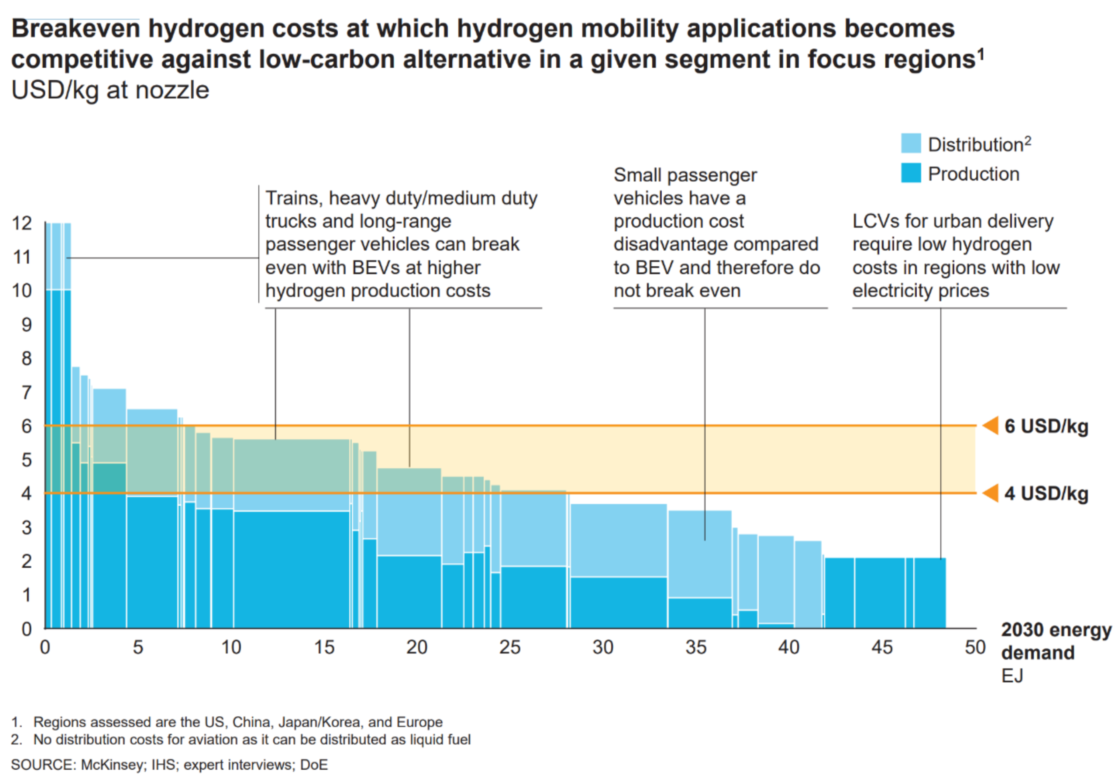


Estimates for when hydrogen might be cost competitive with other fossil fuel or renewable options for different applications vary. A recent report from the Hydrogen Council assessed the future potential for 35 different hydrogen applications and found that by 2025, hydrogen could be cost competitive 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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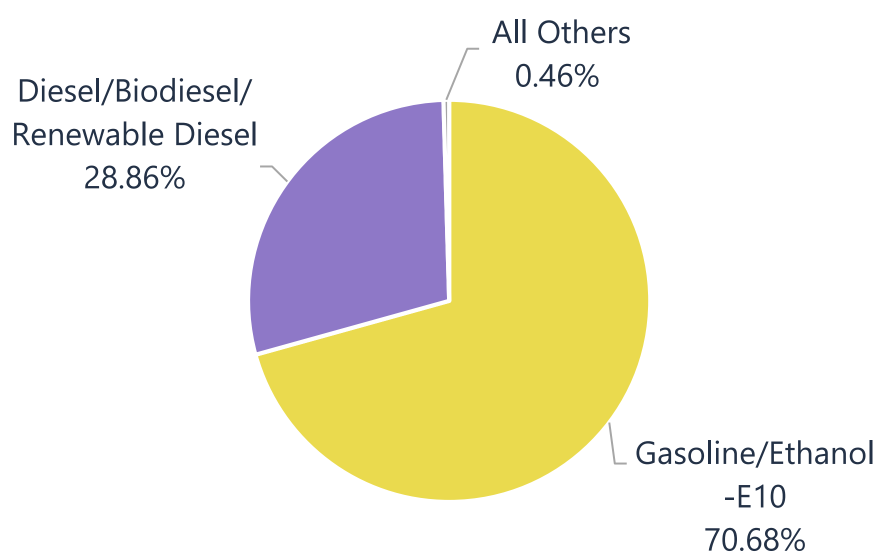
Policy Brief: Using Truck Efficiency to Reduce Fuel Consumption and Emissions

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.

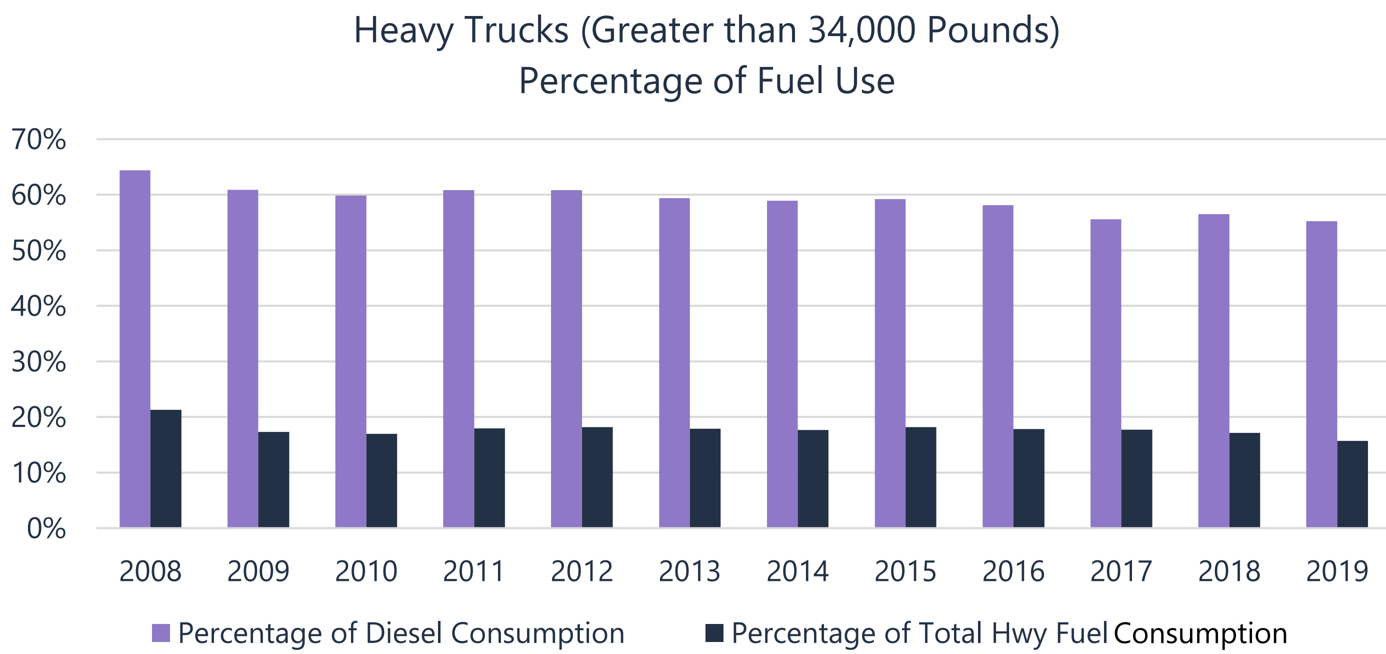
Figure 1: Oregon 2019 On-Highway Transportation Fuel Consumption[7]



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.

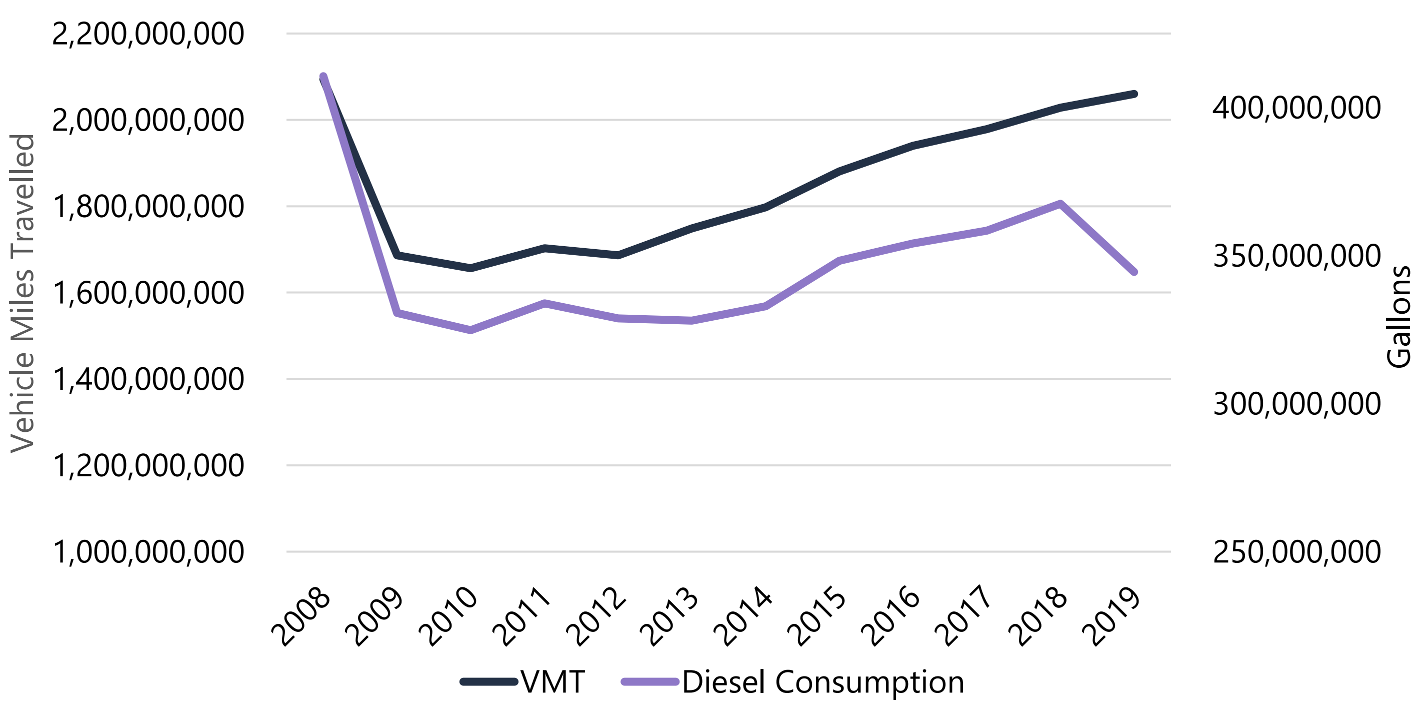
Figure 3: Comparison of a Semi and a pickup[15]

- 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

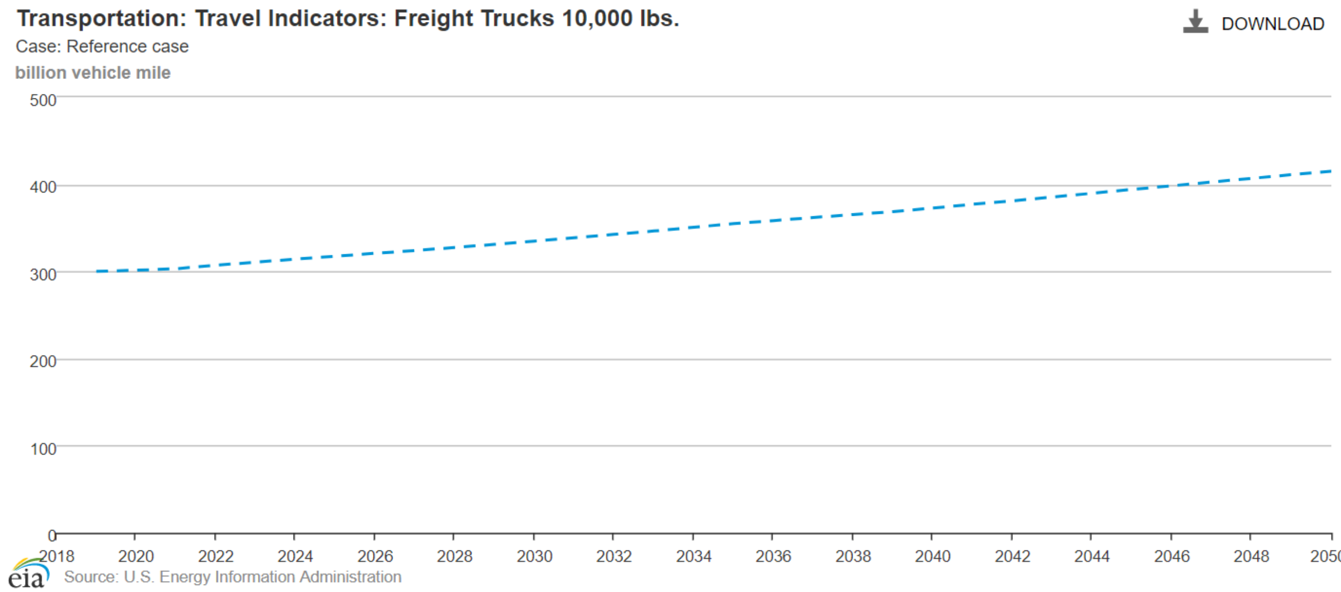
Vehicle miles traveled in Oregon for freight trucks over 34,000 pounds dropped by 19 percent from 2008 to 2009 due to the recession, but VMT has climbed steadily since then back to pre-recession levels (see chart below). It is of note that despite this increase in VMT, fuel consumption has decreased 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]



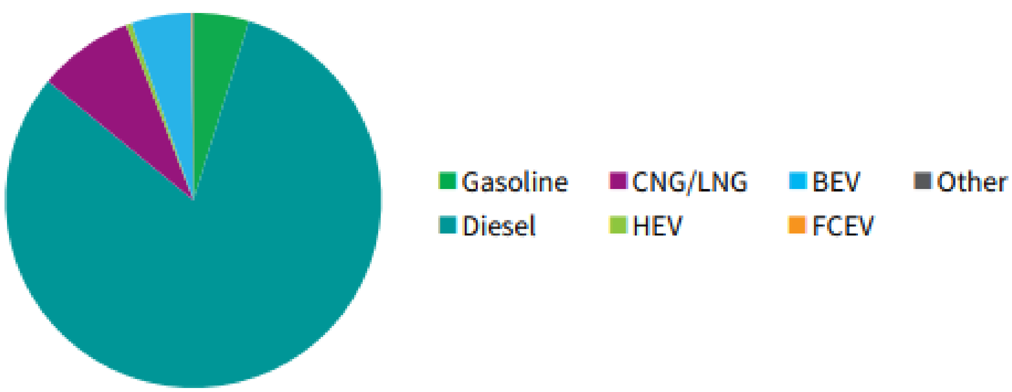
It is uncertain what potential effects the COVID-19 pandemic might have on freight VMT. However, in their 2020 Annual Energy Outlook, USDOE forecast that medium- and heavy-duty truck VMT would continue to rise due to increased freight demands and e-commerce.

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]

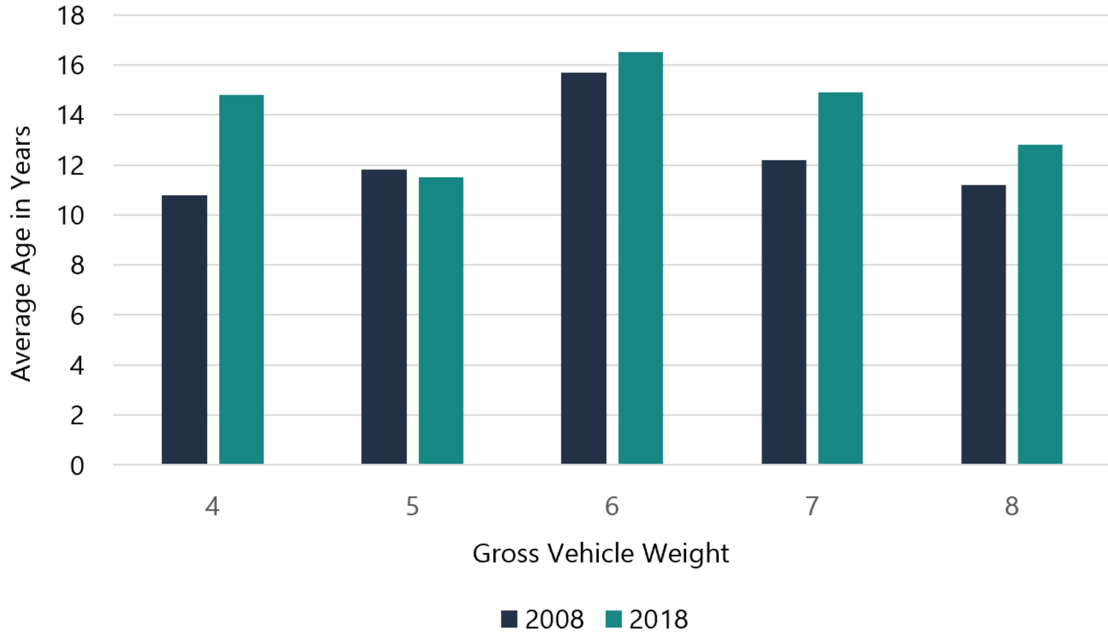
Figure 6: IHS Markit Transportation Fuel Forecast: Share of 2040 Sales by Fuel Type[18]



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:

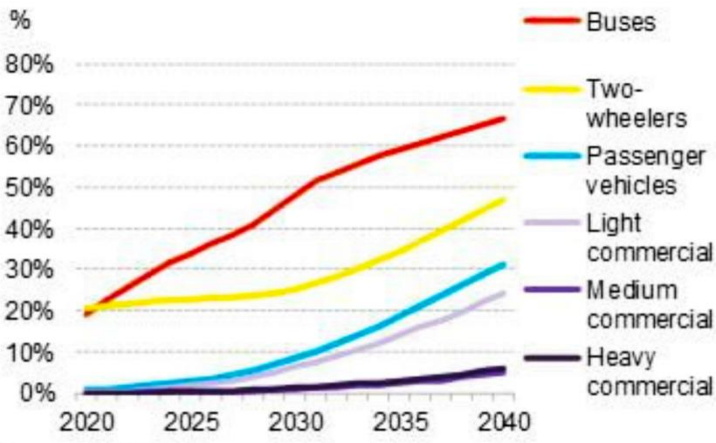
- Reducing vehicle miles traveled
- Using alternative fuels, vehicles, and modes of transportation
- Improving how efficiently vehicles consume fuel

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]



Source: BNEF.

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]

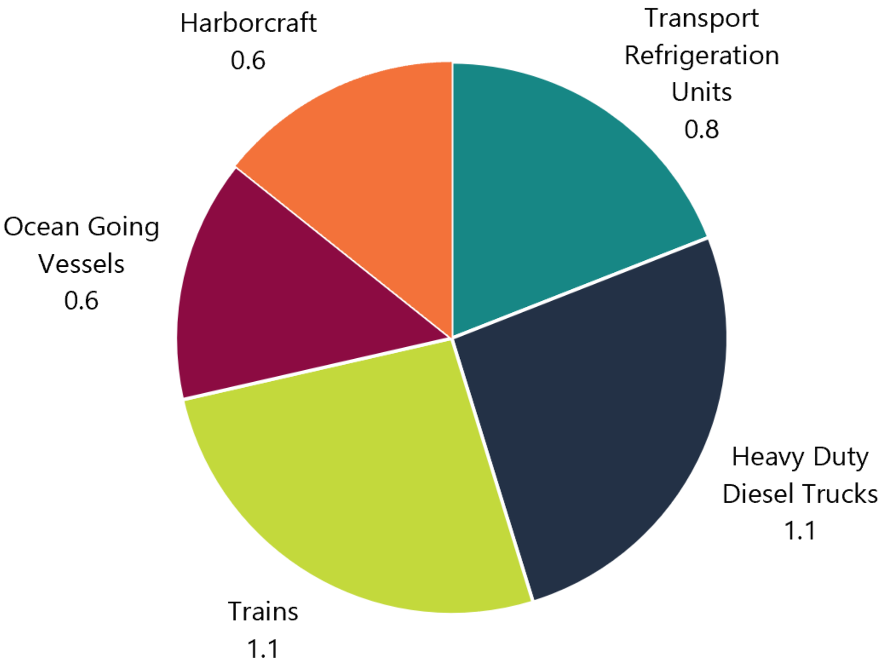
In addition to these technologies, there are opportunities to address idling emissions through driver training or through state and local policies that encourage adoption of technologies or behaviors that limit fuel use and emissions associated with vehicle idling.

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.

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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]

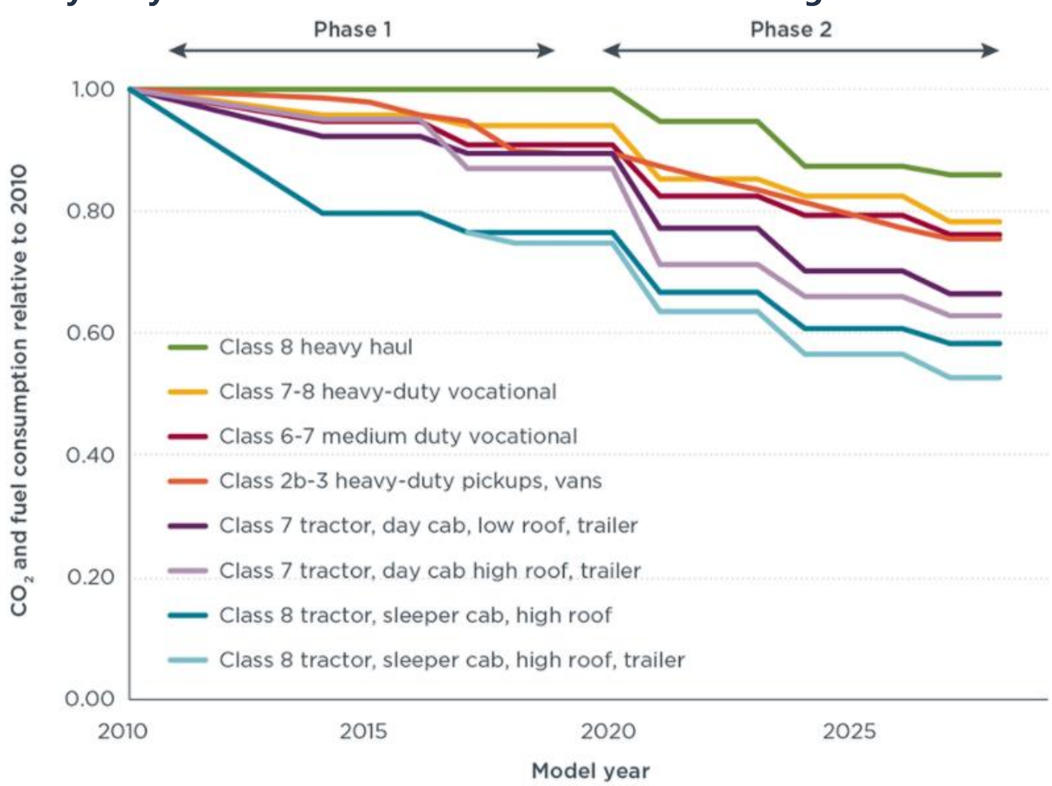
Comparing a Diesel TRU with Shore Power eTRU				GHG
	Hours	**Fuel Consumed**	**Fuel Cost**	**Emissions (MTCO2e)**
Diesel TRU	2,201	1,692 gallons	$5,077	22.42
eTRU	2,201	17,828 kWh	$1,605	6.95
		Reductions	$3,473	15.47

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).

[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]

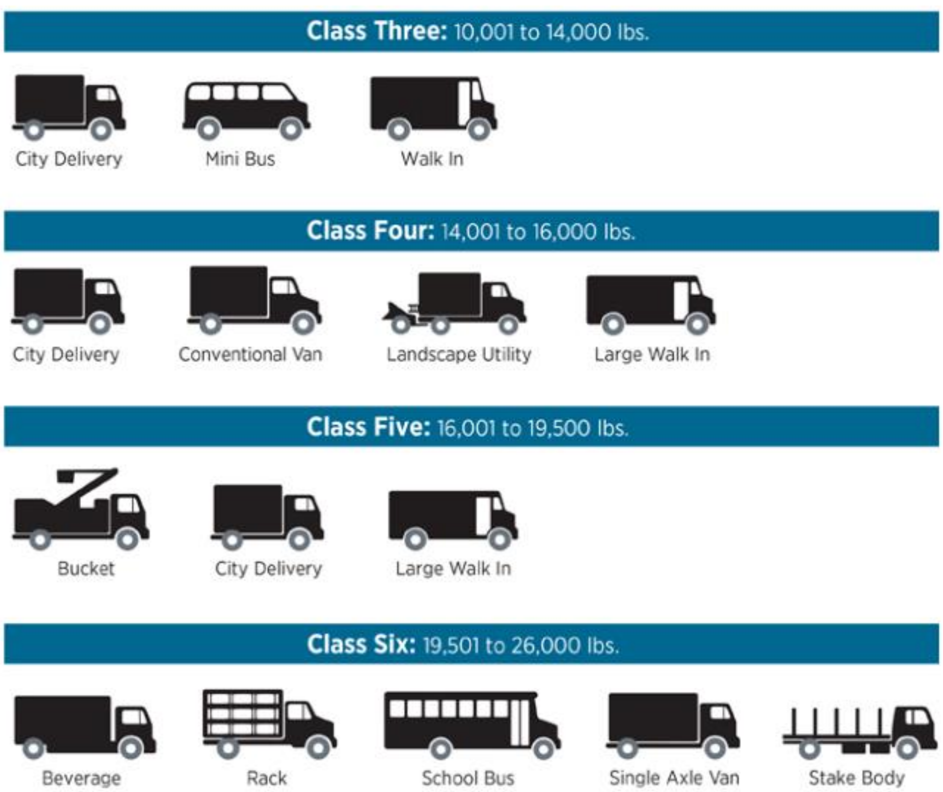
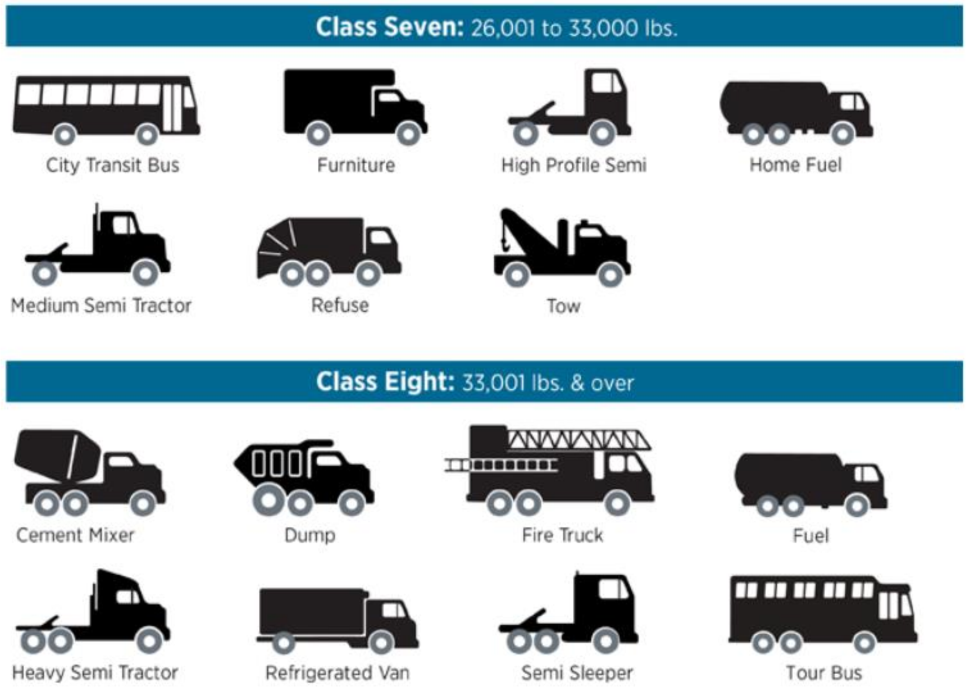


Figure 3: Example Types of Heavy-Duty Vehicles According to Federal Highway Administration Classification[12]



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

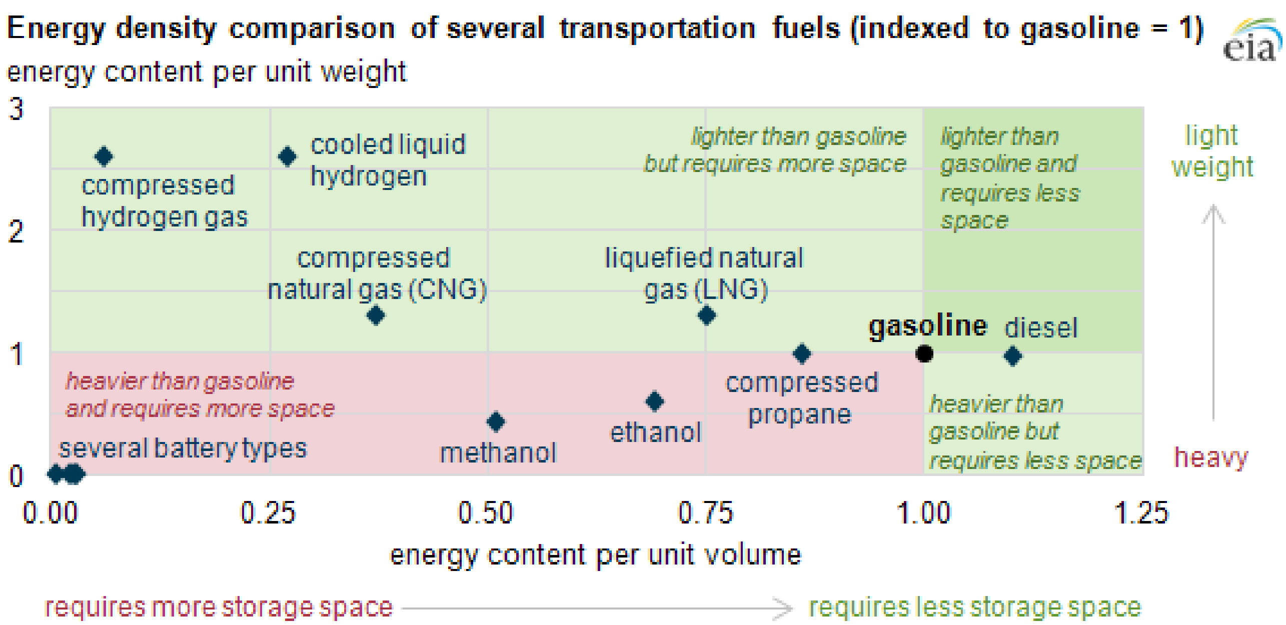
The term duty cycle refers to how much a vehicle is used with respect to hours of use per day, days of use per week, total miles driven during a single cycle, and other metrics. Duty cycle can also describe the kind of route a vehicle routinely takes, such as A-B-A or hub-and-spoke, as well as the typical 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*.

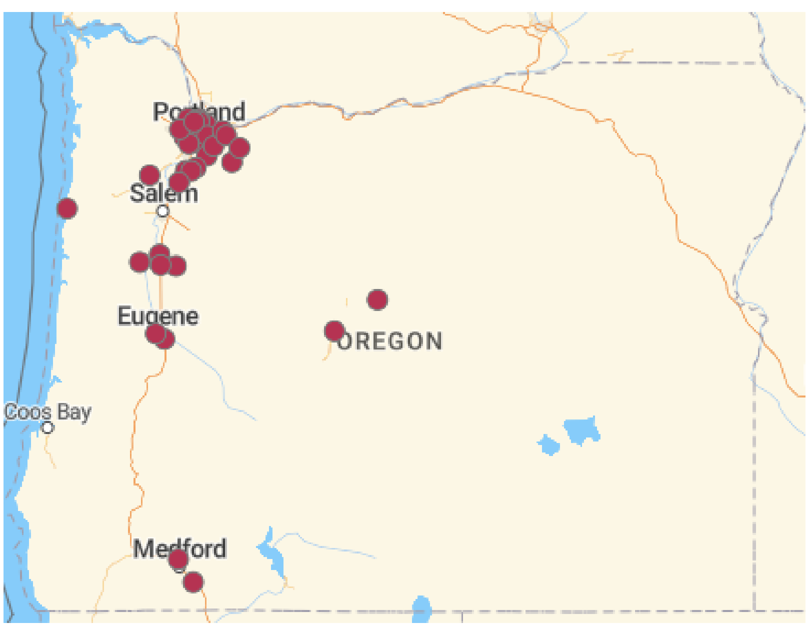
Table 1: Number of Fueling Stations in Oregon for Select Alternative Fuels[20]

	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]

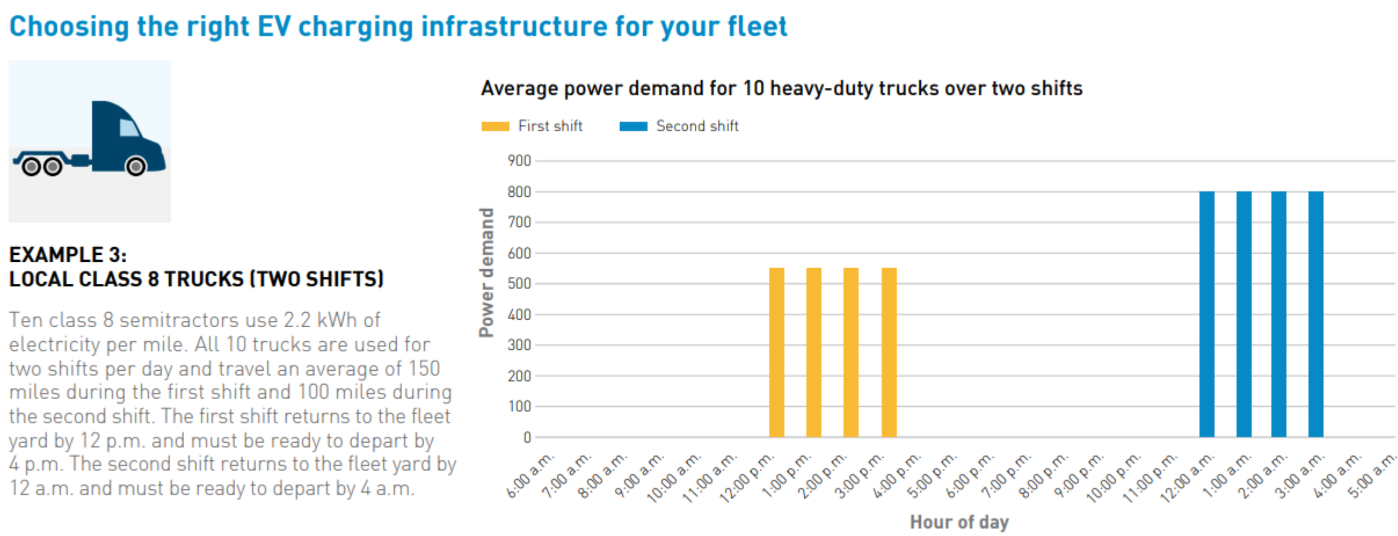
Table 2: Estimated Electric Charger and Installation Costs in 2019 Dollars (Source: ICF 2019)

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

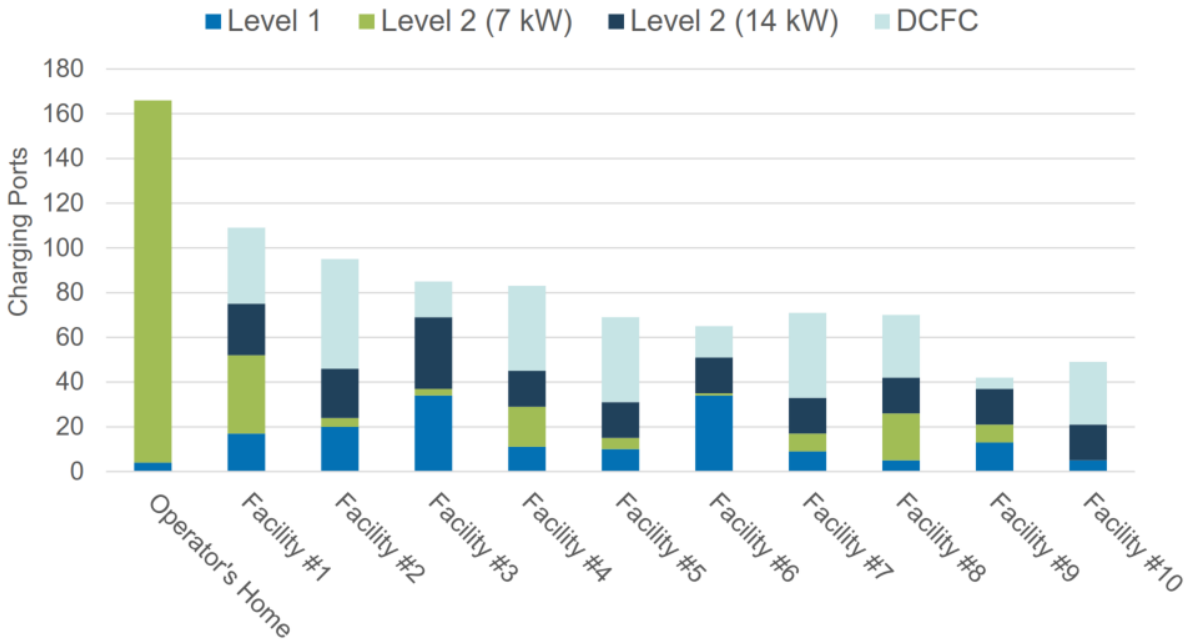
(PGE) and PacifiCorp in Oregon, and Pacific Gas and Electric in California, offer free technical assistance to their commercial customers who are interested in exploring fleet electrification. Pacific Gas and Electric's guidebook for fleet electrification demonstrates how to calculate the total charging 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.

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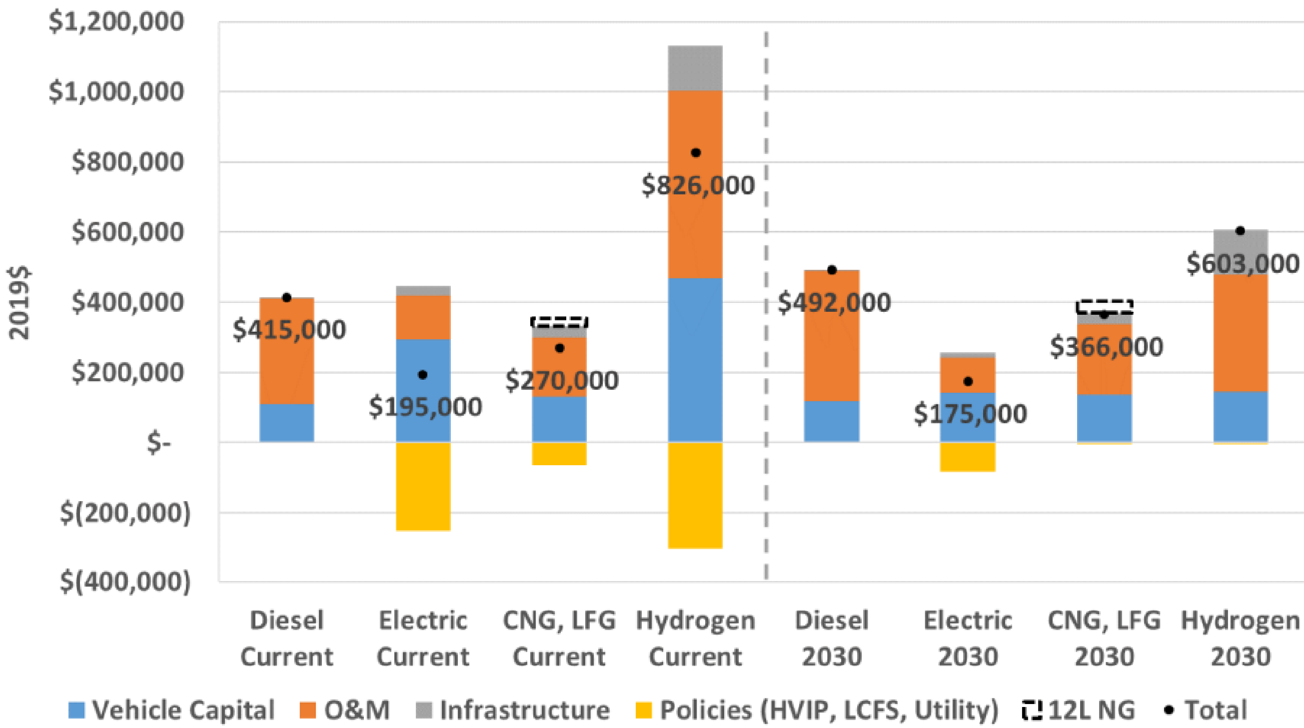
[v] Incentives could include state or federal tax rebates or grants for a specific vehicle type or a fuel type, such as a rebate or a clean fuels program credit. Disincentives could include future costs related to emissions of air pollutants or greenhouse gases.

[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

[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:

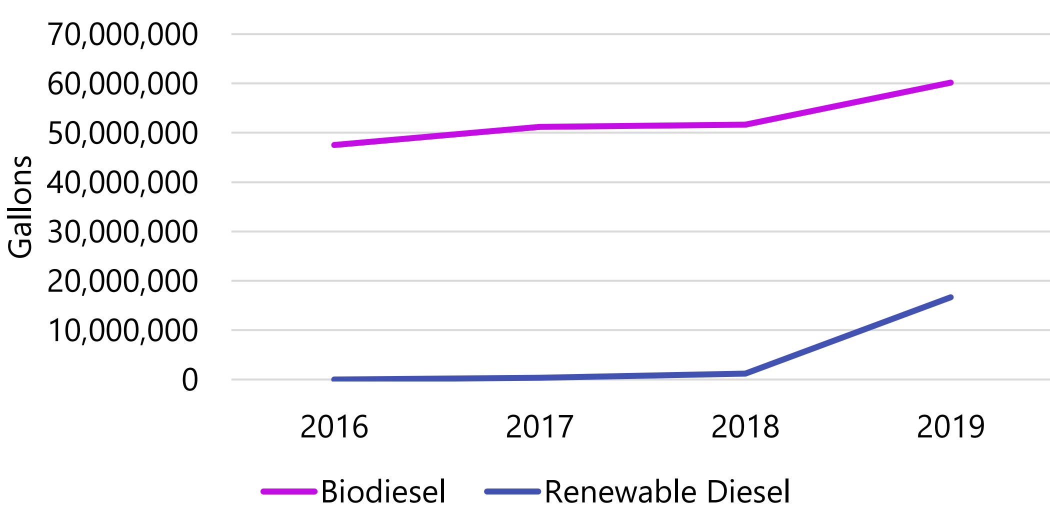
- Expansion of DEQ's market-based Clean Fuels Program.
- Development of a Zero Emissions Vehicle Action Plan – a roadmap for state agency efforts to increase Oregonians' awareness of and access to zero-emission vehicles, increasing access to charging infrastructure, and increasing state agency's use 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]

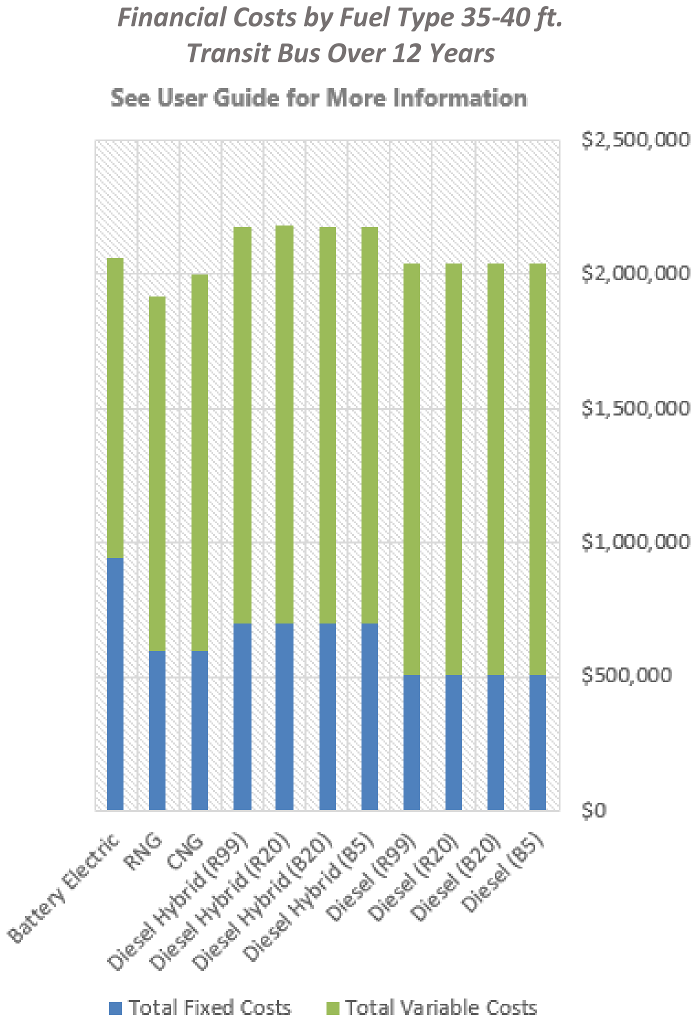
Figure 10: Total Gallons of Biodiesel and Renewable Diesel Reported to Oregon Clean Fuels Program for 2016-2019[48]



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]

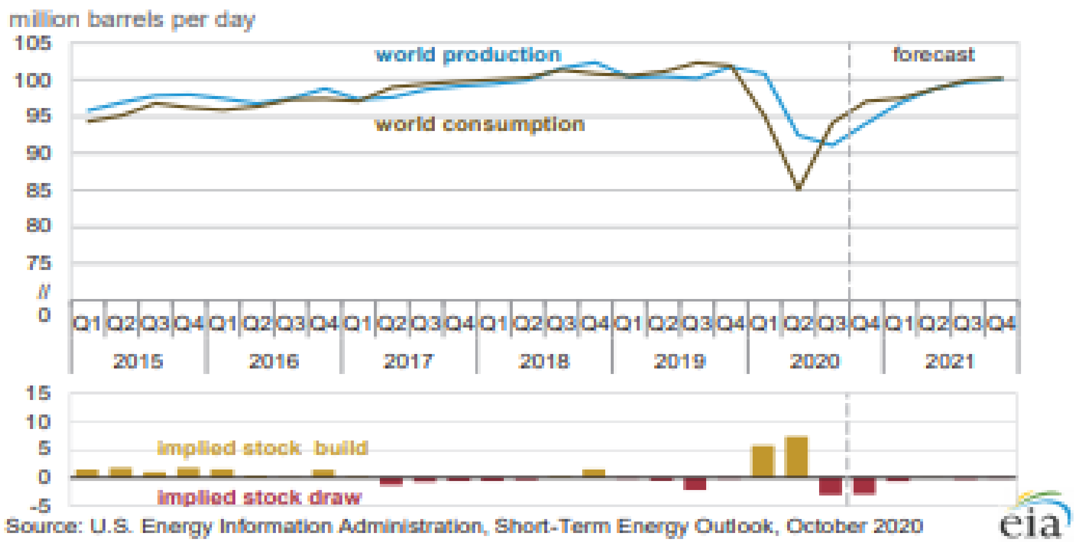
Self-Serve Gasoline. COVID-19 triggered a temporary 50 percent reduction in Oregon's gas station workforce due to illness, childcare issues, and safety concerns. The Oregon Fuels Association requested the state temporarily suspend the self-serve gas ban to allow gas station owners the option to let customers 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]

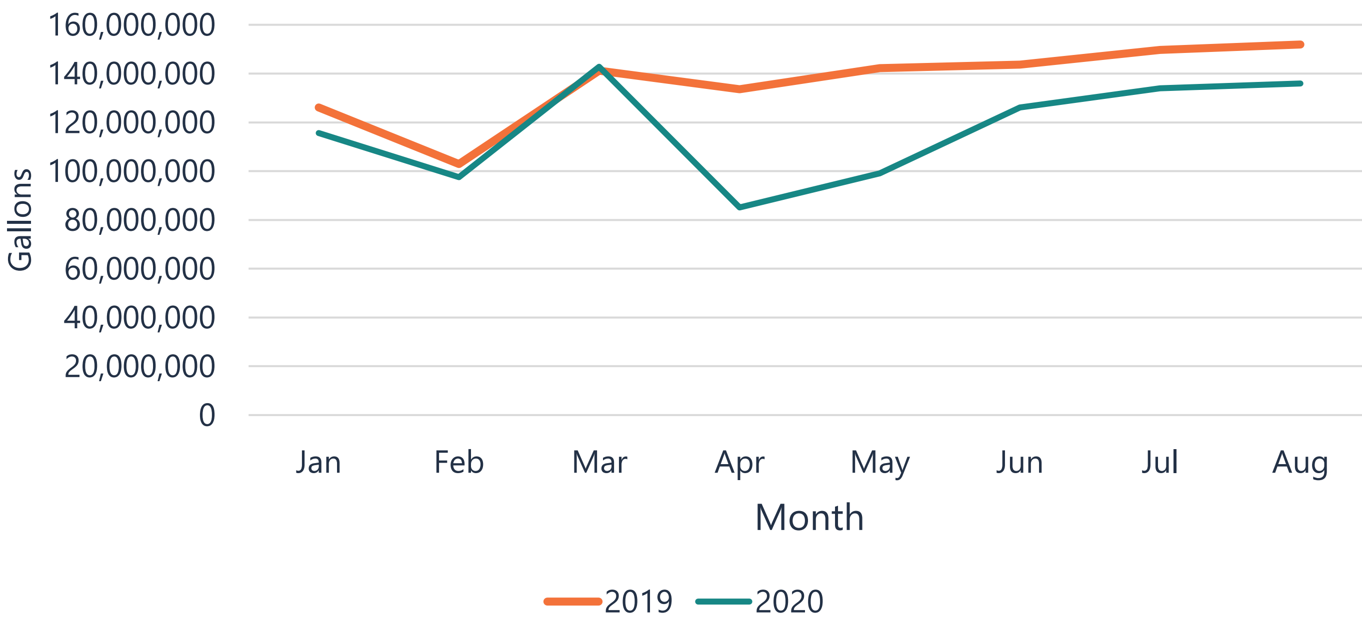
The market rebounded in October 2020 to about $40 a barrel, leaving prices still down about a third from January 2020.[10] There is still a lot of uncertainty about world demand for transportation fuels because a large portion of that demand depends on how the COVID-19 virus continues to affect the economy. 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.

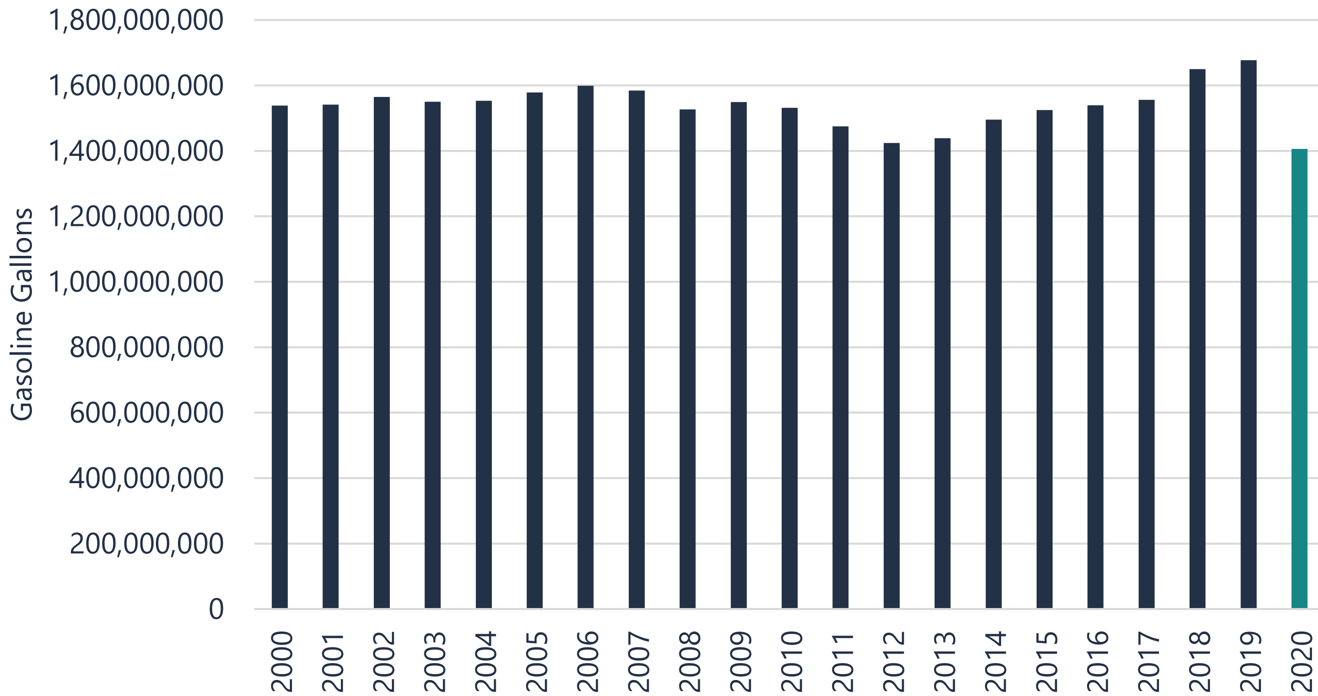
Figure 2: Oregon Gasoline Consumption (2019 Compared to 2020 January – August)[14]



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.

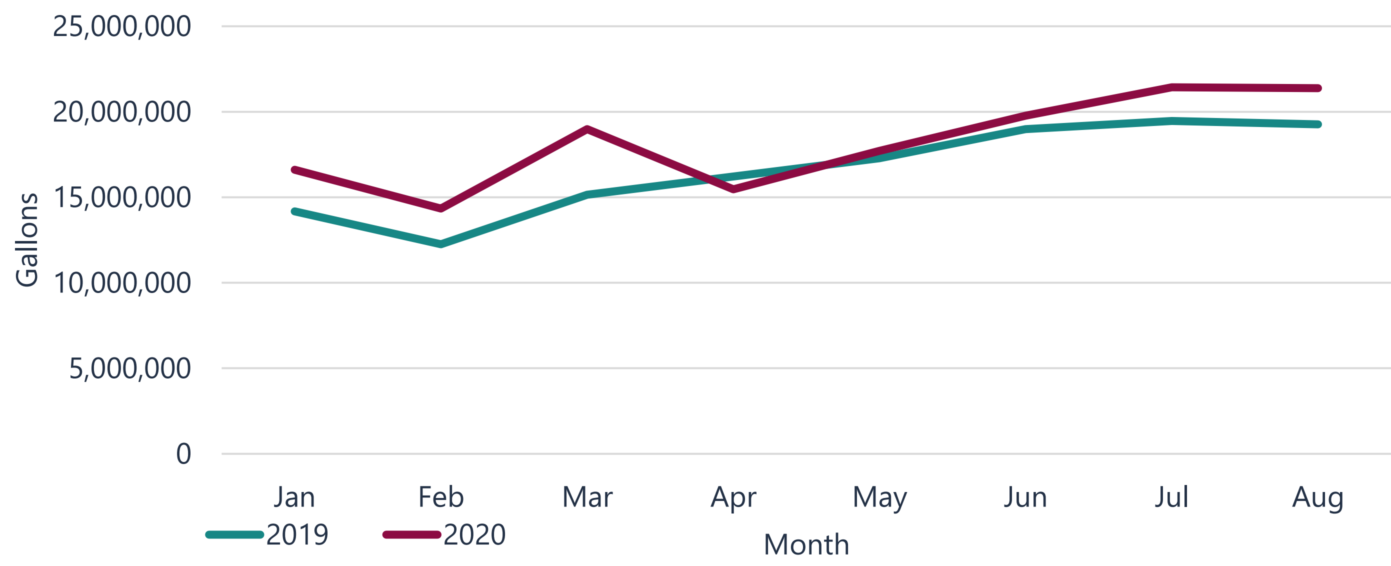
Figure 3: Oregon On-Highway Gasoline Consumption by Year (2000-2019) and 2020 Estimate[14,15]



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.)

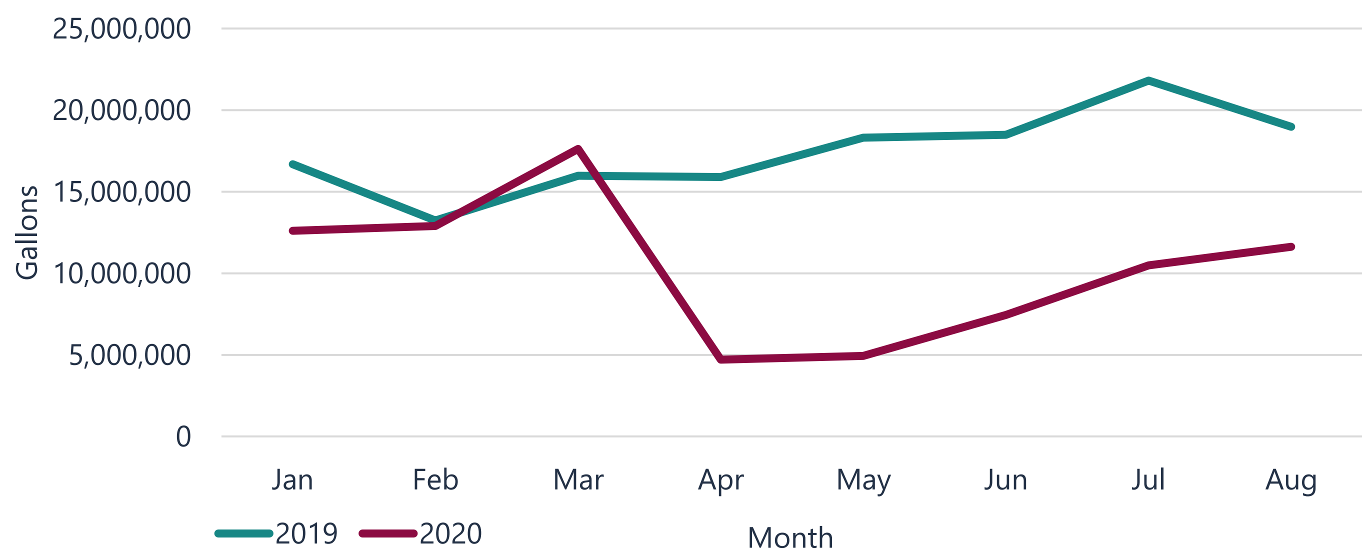
Figure 4: Oregon Sales for Diesel Taxed by the Gallon for Vehicles Less Than 26,000 Pounds (2019 Compared to 2020 January – August)[18]



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.

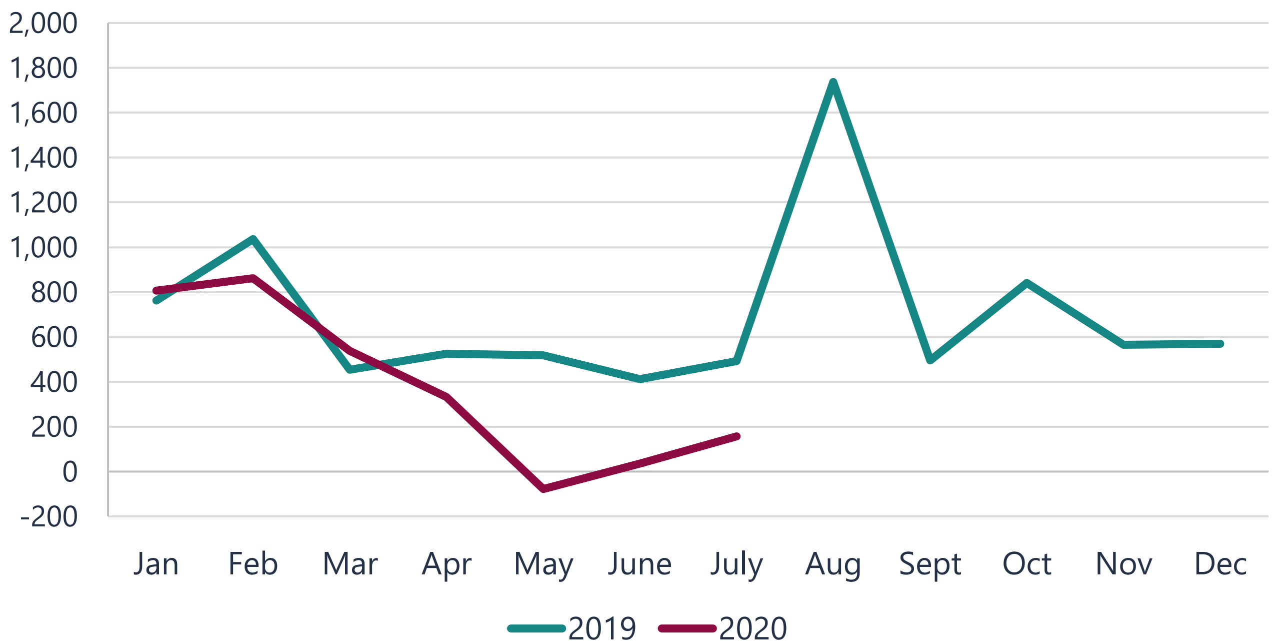
The Oregon Department of Energy's Oregon Solar + Storage Rebate program[57] saw only a minor slowdown in applications since the COVID-19 pandemic emerged. The Solar + Storage Rebate program, which first opened in January, saw a high demand for rebates in the two application periods in January 2020 and 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.

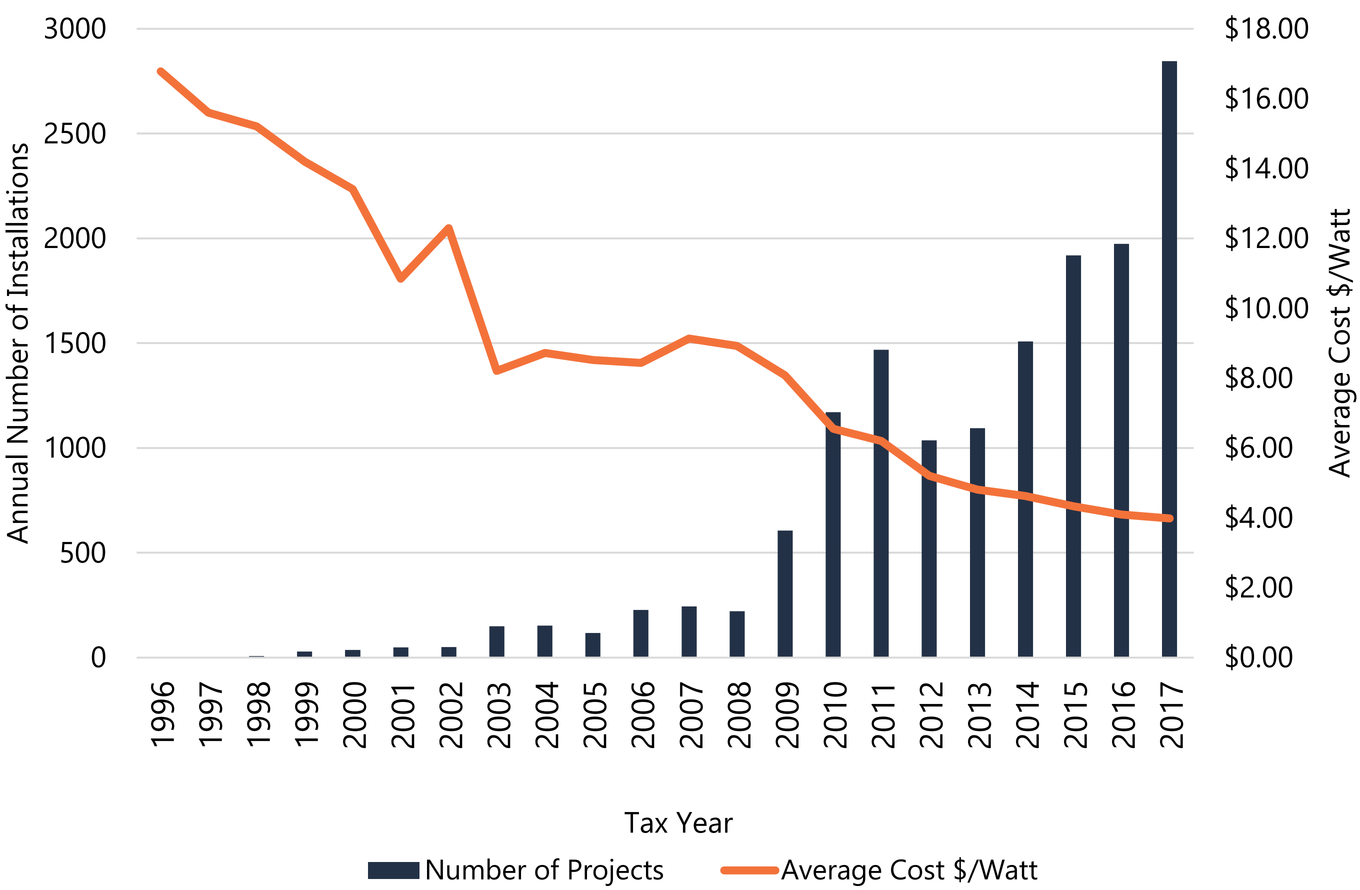
Solar PV can still be considered an emerging technology. In Oregon there are about 16,700 residential PV systems, making up about 1 percent of all households.[2] Early adopters of solar PV technologies provided a significant share of the upfront cost to build the PV systems, but they also received significant 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]

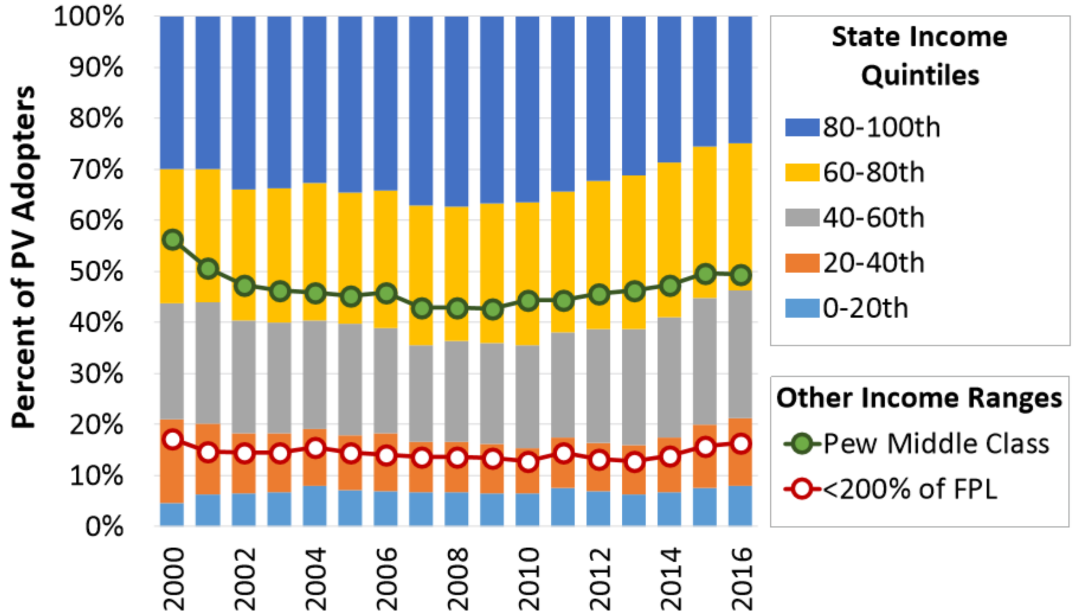
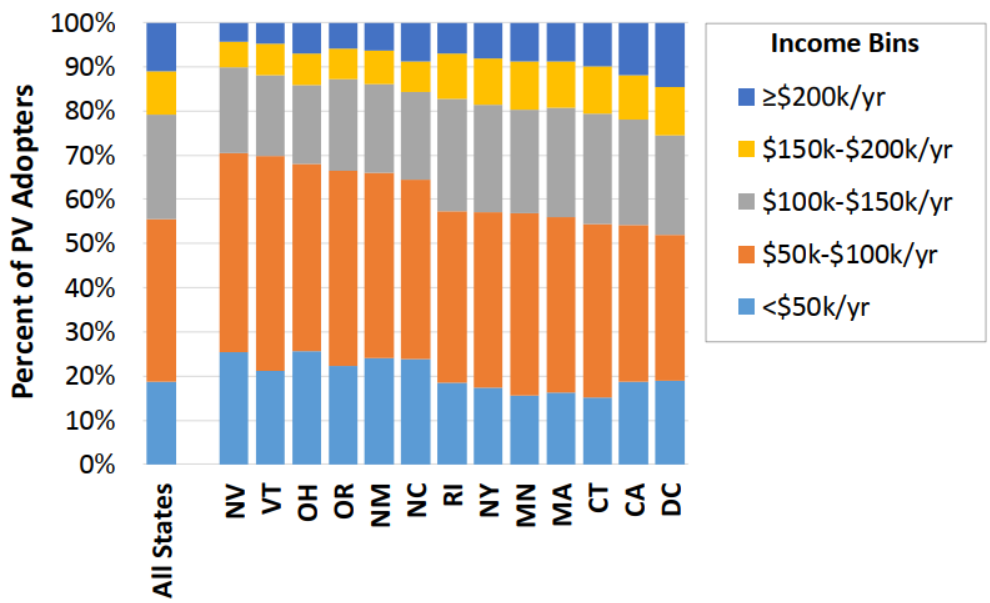


Figure 3 also demonstrates that in 2010, only about 6 percent of national PV installations were on households in the lowest income quintile while more than 35 percent of installations were in the highest income quintile.

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":

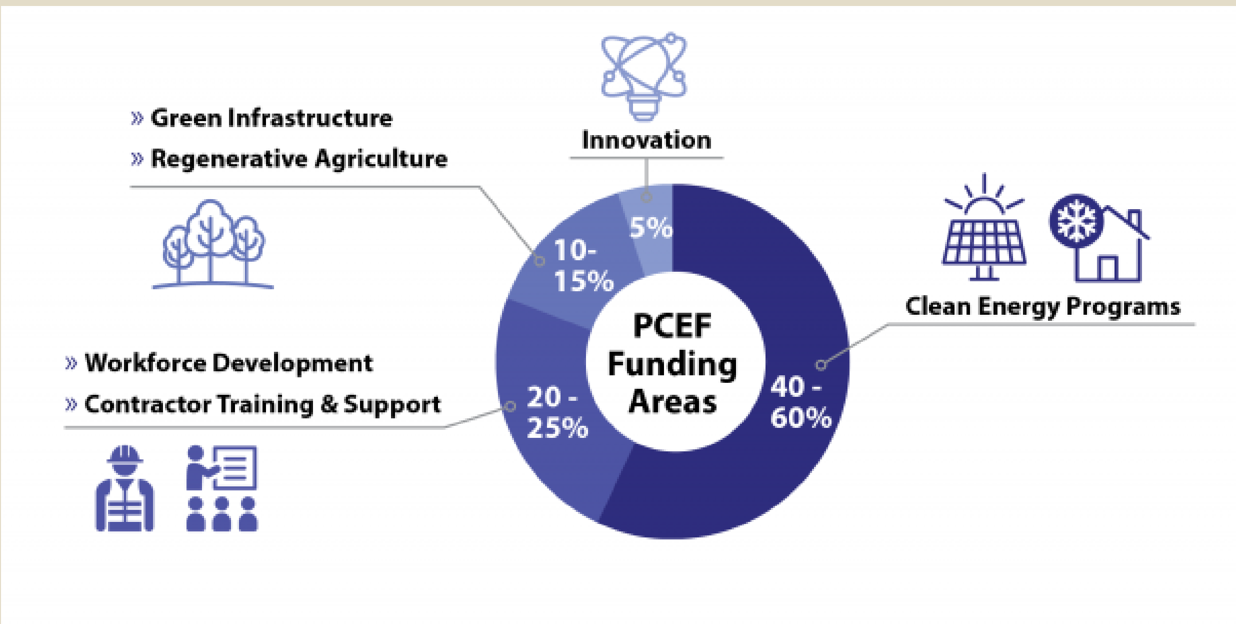
1. Priority populations for clean energy, green infrastructure, and regenerative agriculture projects: People with low income and people of color are priority populations for grants that address clean energy, green infrastructure, and regenerative agriculture. Historically, these populations have had 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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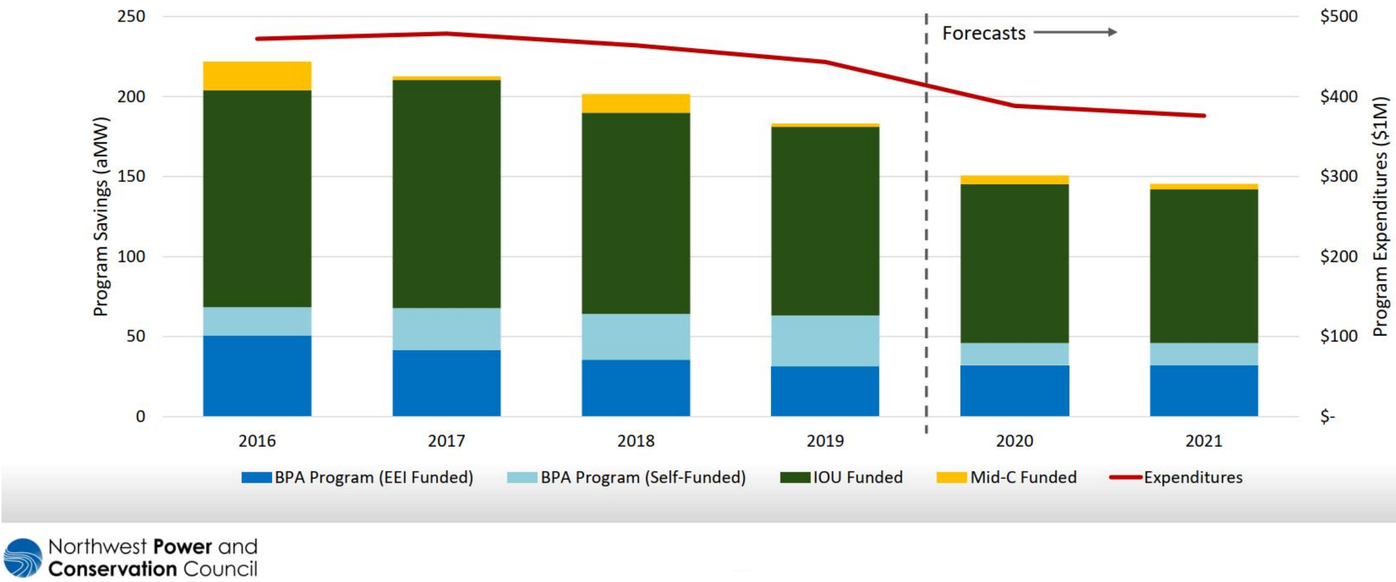
[i] An Average MW (aMW) is the metric for one megawatt of generation operating for one year. It represents 8,760,000 kWh.

[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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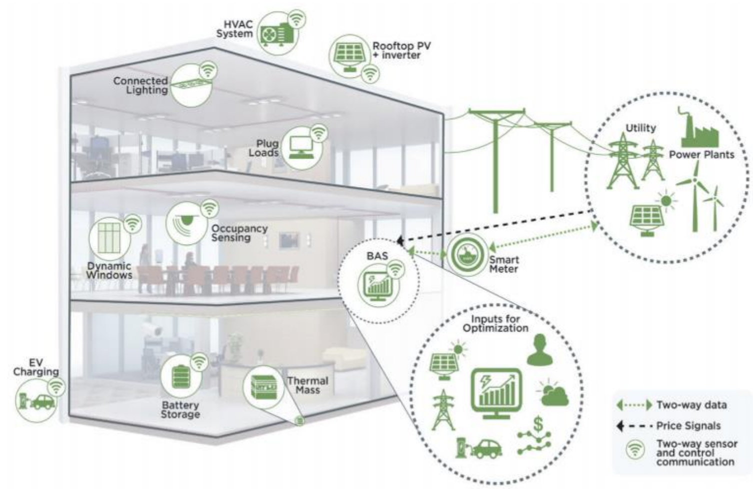
Policy Brief: Grid-interactive Efficient Buildings

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

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.

Figure 2. Grid-interactive Efficient Buildings Characteristics (adapted)[2]

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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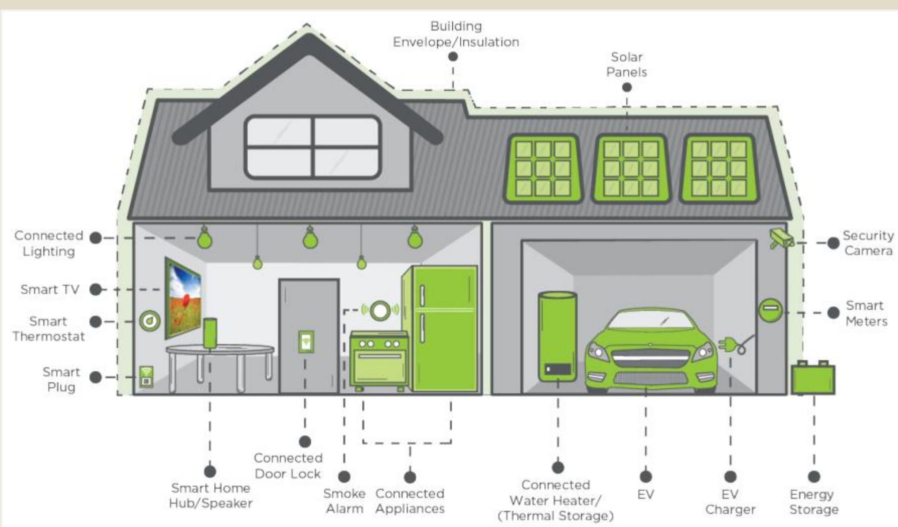
[i] A Building Management System "integrates hardware, software and communications to collect data, monitor use, predict operations, and prescribe automated responses to achieve optimum performance." Learn more at: https://www.nema.org/directory/Products/view/Building-Management-Systems

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]



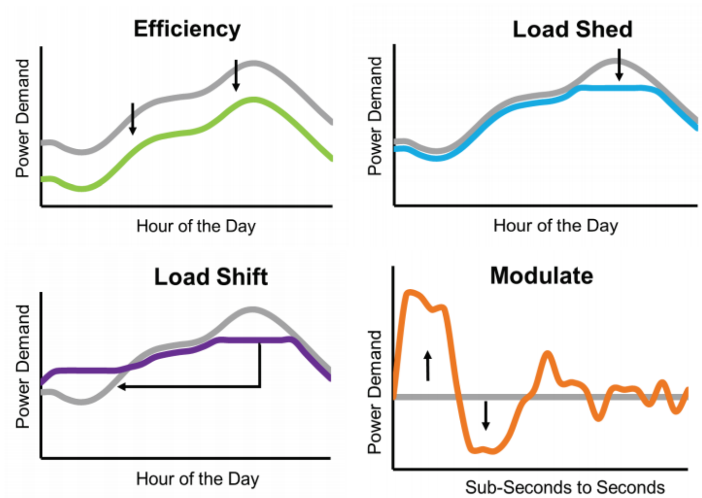
Strategies

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]



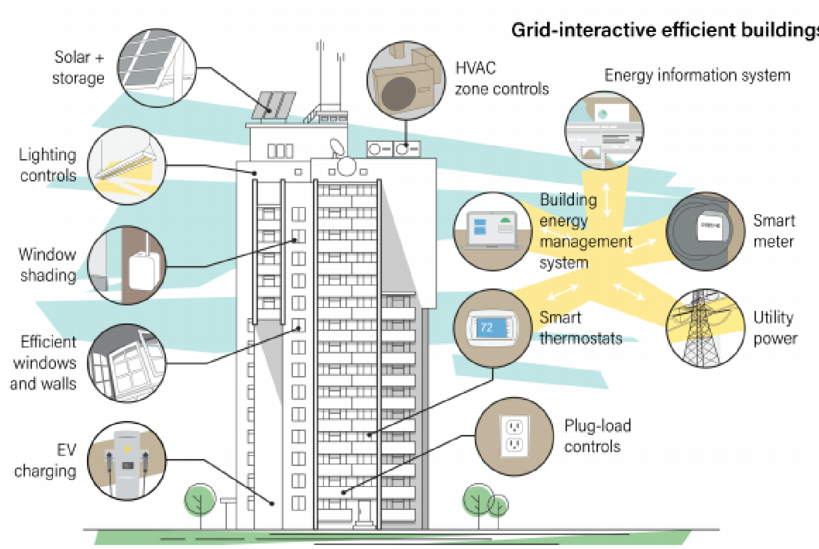
Advanced technologies include a suite of equipment, controls, sensors, and cross-cutting systems. Technologies with the highest potential [15] to provide grid services through energy efficiency and demand flexibility include:

- 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]

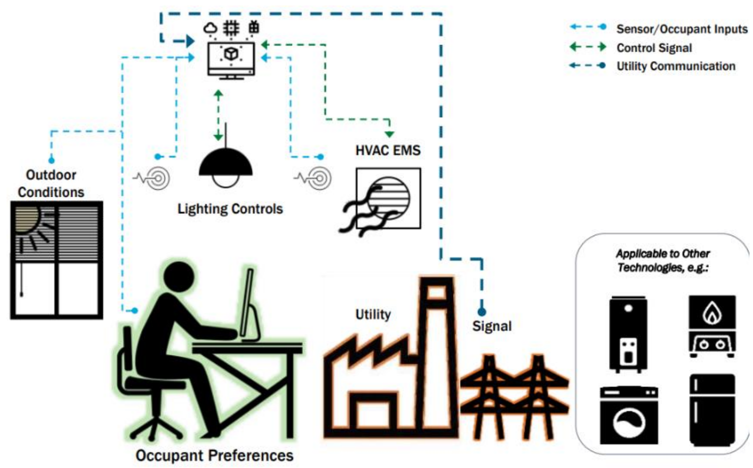


Integration points include operational use data and predicted energy consumption, utility price signals, and status of available on-site generation and storage. Integration is necessary to gauge building responsiveness potential, but is critical when occupants are interested in bringing in additional 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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