CHAPTER 3: RENEWABLE ENERGY

Oregon's renewable electricity capacity has grown over the years, thanks to some of the early supporting policies, a growing voluntary demand for cleaner electricity, substantial decreases in the costs of renewable electricity technologies, and recent policies like a strengthened Renewable Portfolio Standard.

Oregon will face a number of challenges and opportunities as we work toward a clean energy future.

KEY TAKEAWAYS

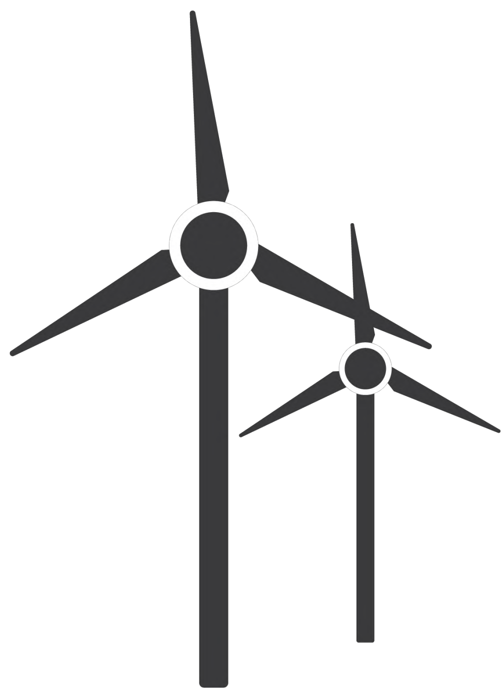
- Installed capacity and consumption of **renewable electricity in Oregon** have grown over the years, thanks to policies like the Renewable Portfolio Standard (RPS); federal and state incentives; growing interest from consumers and businesses to purchase renewable energy voluntarily; and significant decreases in the costs of renewable energy technology.

- To increase renewable energy in Oregon while maintaining reliability and low costs, the state will need to understand and address a wide web of interrelated issues and make choices on how to meet our **state energy goals**.

- To meet the challenge of efficiently and cost-effectively integrating increasing amounts of variable renewable electricity onto the grid, Oregon should investigate how to **leverage and combine flexible electricity resources** and technologies; flexible control over demand through innovative new rate structures and demand response programs; and access to more flexible markets, such as the Energy Imbalance Market.

Introduction

Oregon's renewable electricity capacity has grown over the years, thanks to some of the early supporting policies, a growing voluntary demand for cleaner electricity, substantial decreases in the costs of renewable electricity technologies, and recent policies like a strengthened Renewable Portfolio Standard. Oregon will face a number of challenges and opportunities as it works toward a goal of 50 percent renewable electricity consumption by 2040. Changes within the utility industry itself, new technologies, and changing customer demands will affect how Oregon reaches its RPS target.



While *energy* and *electricity* are not fully interchangeable terms, this chapter uses the term *energy* when discussing electricity in Oregon. Energy typically includes uses other than electricity, including transportation, industrial processes, and home heating; these types of energy are discussed in other chapters of this report.

Renewable Energy 101

Renewable energy is generally defined as energy from sources that are naturally replenishing on a relatively short time horizon, including solar, wind, geothermal, hydropower, biomass, and marine energy.* Certain renewable energy policies have a narrower definition for renewable energy that is used for compliance, such as a renewable portfolio standard.

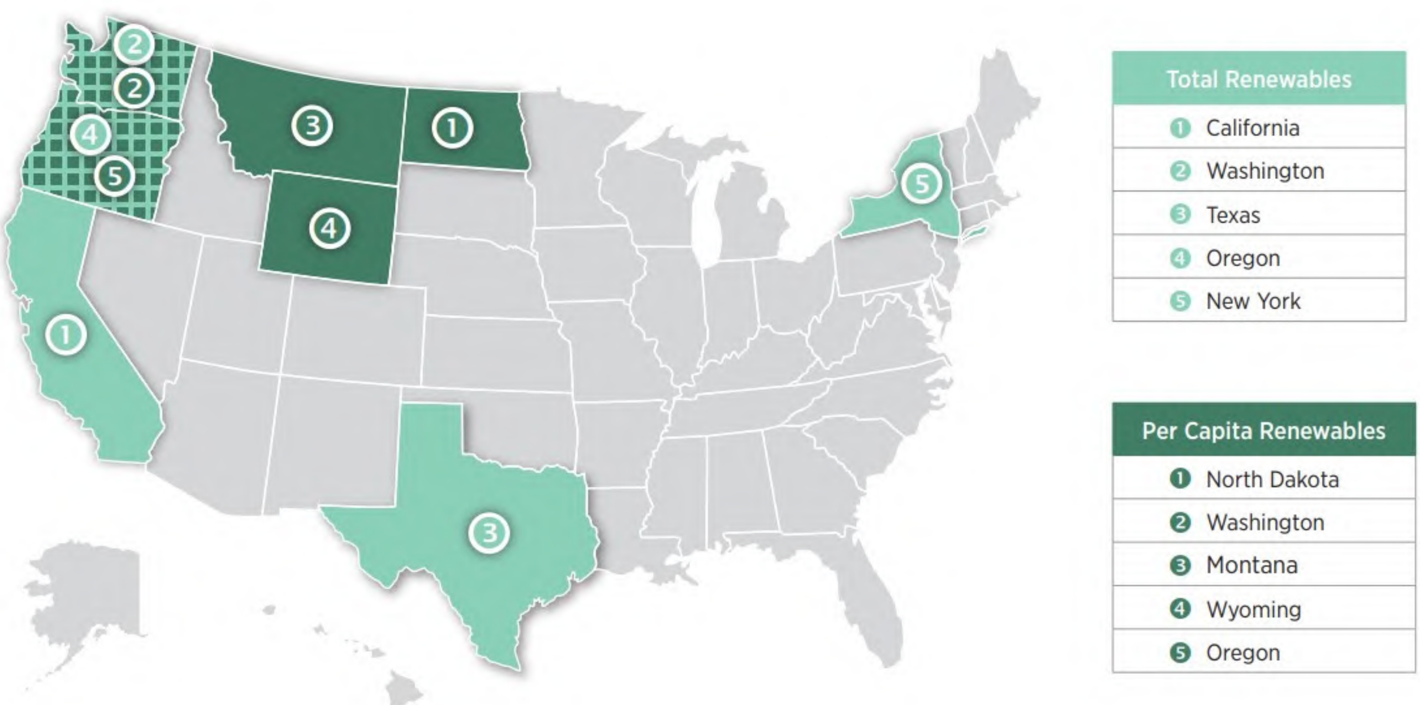
*__Marine energy__ is an emerging renewable resource, which includes wave, tidal, and current energy.

Oregon’s RPS outlines which sources are eligible and under what constraints. All of the sources listed above are eligible for Oregon’s RPS. Some of the sources — such as the direct combustion of municipal solid waste, certain categories of biomass, and hydropower — are limited in eligibility due to facility age or concerns around particulate emissions, chemical preservatives, or land management. For more information on the eligibility of various resources for the RPS, see ORS 469A.[1]

Renewable Electricity Installations in Oregon

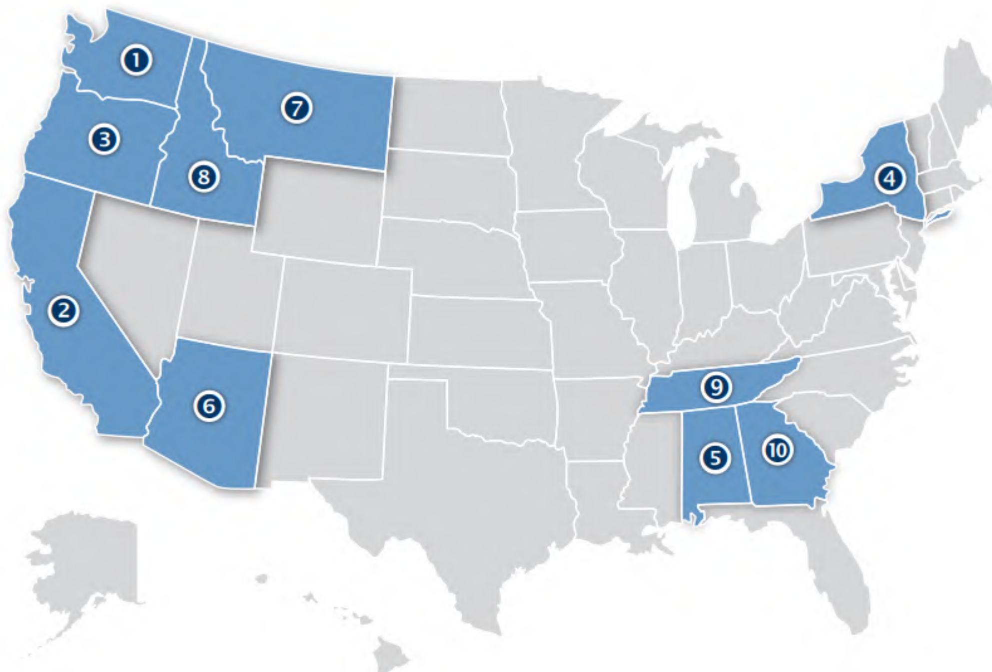
Beginning in 1977 with the creation of the Residential Energy Tax Credit (RETC) program, the Oregon legislature passed a series of bills promoting renewable energy resources, including the public purpose charge, net metering, the RPS, funding for wave energy, zoning measures, and requirements for public buildings. This legislative momentum, as well as the region’s hydropower, has helped place Oregon as one of the leading states for renewable energy installations. As of 2016, Oregon was fourth in the nation for cumulative renewable electricity installed capacity, and fifth in terms of per capita installed capacity.[2]

Figure 3.1: Top States for Cumulative Renewable Electricity Installed Capacity for 2016[2]



With approximately 12,211 MW of installed renewable capacity in 2016, Oregon also ranked high for installed capacity of both hydropower (third) and geothermal generation (fifth).[2]

Figure 3.2: States Leading Hydropower Electricity Installed Capacity in 2016[2]



Total Installed Capacity (MW)[1]	
1 Washington	21,106
2 California	10,051
3 Oregon	8,446
4 New York	4,672
5 Alabama	3,319
6 Arizona	2,718
7 Montana	2,628
8 Idaho	2,541
9 Tennessee	2,499
10 Georgia	1,965

Renewable Energy Drivers in Oregon

Many factors have driven the increase in renewable energy generation and consumption in Oregon, such as state and federal policies, increased customer demand, and sharply declining costs of technology. This section will explore these drivers:

- **Required Procurement:** Policies requiring renewable procurement;
- **Voluntary Procurement:** Programs and market opportunities that meet consumers' voluntary renewable energy demand;
- **Financial Incentives:** Incentives for renewable energy; and
- **Falling Costs:** Falling costs associated with renewable energy technology and project development.

Required Procurement

Oregon has a number of policies that require entities to procure and consume renewable energy. While there has been no comprehensive assessment of the impact of these policies on the development of renewable energy, the three policies described below – PURPA, RPS, and the Green Energy Technology program – have required utilities and public entities in Oregon to develop renewable energy.

PURPA

One of the original drivers of renewable energy development in Oregon was the federal Public Utility Regulatory Policies Act of 1978, or PURPA,* which obligates utilities to buy output from qualifying small

*PURPA is codified in numerous sections of 16 U.S.C., including, § 796, § 824a-3 and §§ 2601, et seq.

renewable generators and cogeneration facilities ("qualifying facilities") at the utility's "avoided cost"* of procuring that energy elsewhere. PURPA removed barriers to development of renewable generating resources and created a fair and open market for independent (non-utility) electricity producers. PURPA has been a major driver for renewable energy project development in the West, including Oregon, and analysts expect it to be one of the main drivers for utility-scale solar development in the U.S. in 2018 and beyond.[3]

The Oregon Renewable Portfolio Standard

A renewable portfolio standard is a policy requiring retail electricity providers to meet a certain percentage of their annual electricity sales with eligible renewable energy generating resources. Nationally, state RPS policies have been responsible for approximately 50 percent of the growth in non-hydro renewable energy generation since 2000. In the West, between 70 and 90 percent of renewable energy additions were built to meet RPS requirements.[4]

Oregon established its RPS in 2007 with Senate Bill 838 (Oregon Laws 2007, Chapter 301), providing a requirement for the largest utilities[1] – Portland General Electric, PacifiCorp, and the Eugene Water & Electric Board – to provide 25 percent of retail sales from eligible renewable sources by 2025, with interim goals along the way. The state's many smaller consumer-owned utilities (COUs) were given lower targets, depending on the percent share of the state's total retail electricity load supplied by the COU. Other than EWEB, only Umatilla Electric Cooperative has had enough sales to trigger the large utility RPS threshold, which is three percent or more of total statewide retail electricity sales in any three consecutive years.

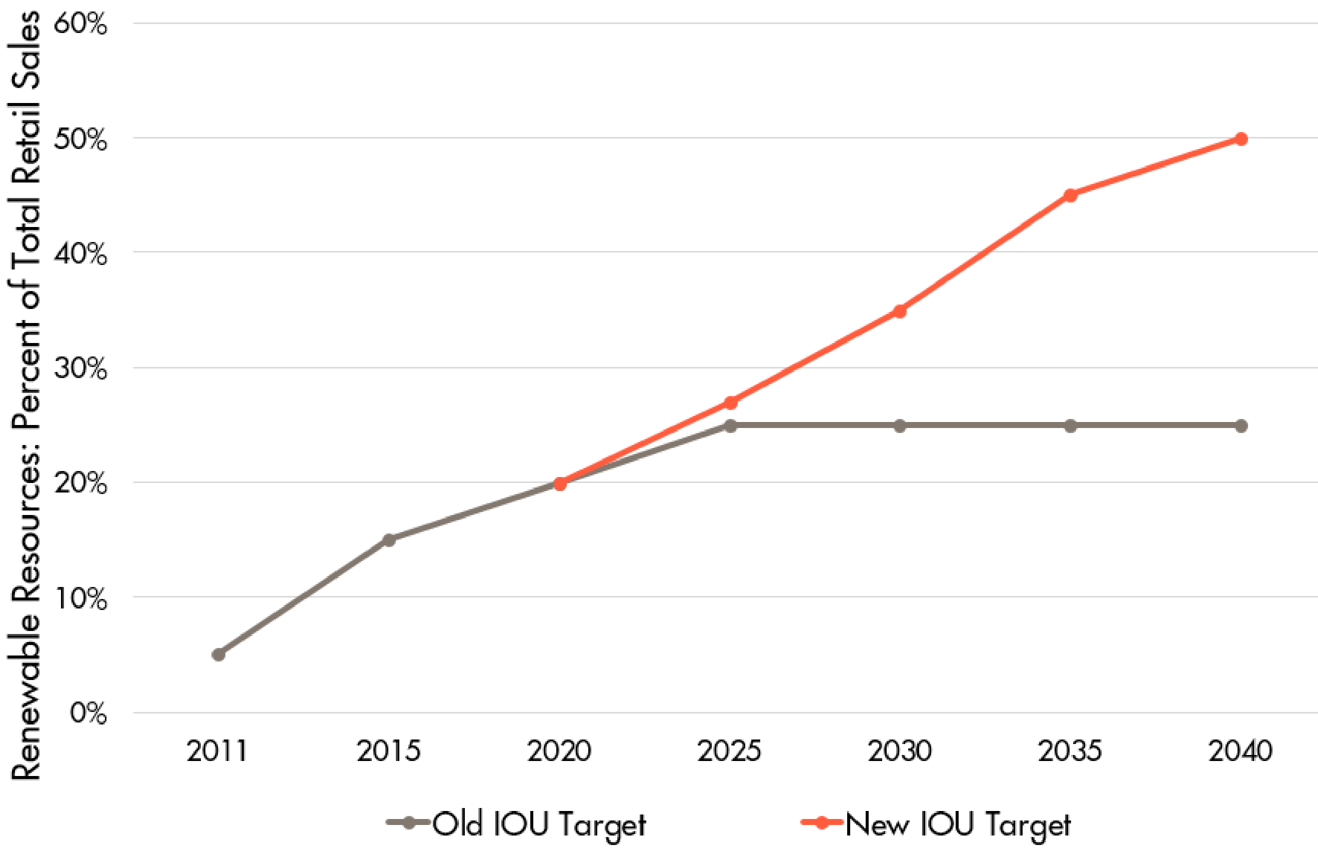
Table 3.1: Annual Percent Share of Total Retail Electricity Sales in Oregon for the Largest Utilities for 2015-2017[5,6,7]

Entity	Utility Type	Percent Share of Oregon Retail Sales		
		2015	2016	2017
PGE	Investor-owned	37.50	36.60	35.80
PacifiCorp	Investor-owned	27.20	27.30	26.60
EWEB	Municipal-owned	4.88	4.85	4.95
Umatilla	Cooperative	3.35	3.80	4.29
Central Lincoln	People's Utility District	2.63	2.68	2.73
Clatskanie	People's Utility District	1.92	1.91	2.24
Springfield	Municipal-owned	1.55	1.57	1.50

The Oregon Clean Electricity and Coal Transition Plan increased Oregon's RPS target in 2016 through Senate Bill 1547 (Oregon Laws 2016, Chapter 28).[92] Also known as the "Coal to Clean" legislation, SB 1547 increased the RPS from 25 percent by 2025 to 50 percent by 2040. This 50 percent target applies to the large investor-owned utilities (IOUs) that provide three percent or more of total state retail electricity sales. COUs' compliance is capped at 25 percent by 2025.

*In Oregon, utilities establish different avoided costs rates based on the technology. Learn more about avoided costs later in this chapter.

Figure 3.3: Original Oregon IOU RPS Targets and New Targets after 2025



Eligibility

Eligibility of resources for the Oregon RPS is based on two factors: the source of the renewable energy and the age of the generating facility (also referred to as the commercial operation date). Generation sources eligible for the Oregon RPS include solar, wind, geothermal, certain biomass sources, some hydropower, and a handful of others. SB 1547 provided an additional eligible RPS generating resource: thermal energy generated at a facility that also generates electricity using RPS-eligible biomass sources. As of fall 2018, four facilities in Oregon have applied for RPS certification for thermal energy. The Gresham Wastewater Treatment Plant is the first facility to be certified.

Gresham Wastewater Treatment Plant

The goal of the RPS legislation was to promote "research and development of new renewable energy sources in Oregon" and to "increase their [utilities] use of renewable energy sources."[8] 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. However, the importance of the region's existing hydropower resources was realized by two exemptions for pre-1995 hydropower facilities: any incremental generation attributable to efficiency upgrades made at existing hydropower facilities after 1995 would be eligible, as would generation from an existing facility if it became certified as a low-impact hydroelectric facility* after 1995. Additionally, new hydropower projects could qualify for the RPS if they are certified as low impact or if they are located outside certain protected areas.

RPS Exemptions

Oregon's RPS allows for four exemptions to a portion of a utility's RPS compliance requirement, two of which further acknowledge the value of zero-emissions hydropower:

- **Cost cap:** An entity is not required to comply with the RPS to the extent that the costs of compliance exceeds four percent of the entity's annual revenue requirement for the compliance year.
- **Excess load:** An entity need not comply to the extent that it would have to acquire electricity in excess of its load requirement.
- **BPA Tier 1 power:** COUs are not required to comply with the RPS to a point where they would be required to reduce their consumption of non-RPS eligible BPA Tier 1** hydropower.
- **Older renewables:** An entity is not required to comply to the extent that it would have to substitute newer renewable electricity for electricity from older, non-RPS sources that are not fossil-fueled, such as legacy hydropower.

RPS Tracking – Renewable Energy Certificates

As electrons from, for example, a natural gas plant become indistinguishable from those from a wind farm once they stream onto the grid, renewable energy certificates, or RECs, are used to track renewable energy and to determine where it is ultimately consumed. At the simplest level, a REC is a tradeable certificate that represents the renewable attributes of one-megawatt hour (1 MWh) of qualifying renewable electricity delivered to the grid.

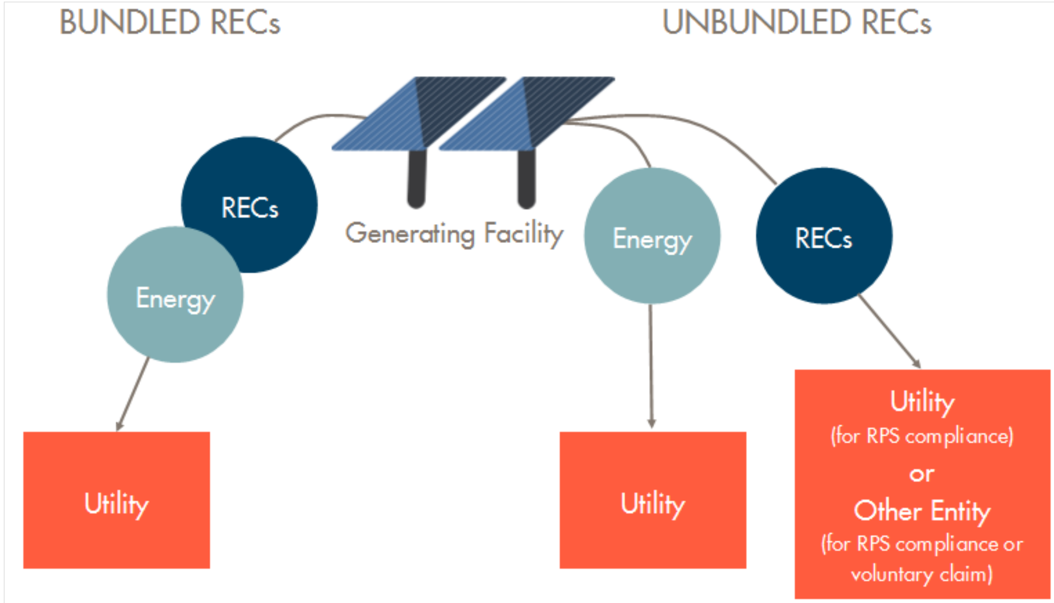
A majority of jurisdictions define RECs to include environmental attributes associated with the renewable energy generated, but there are some differences across jurisdictions in how those attributes are defined. Oregon defines a REC as including the "environmental, economic, and social benefits" associated with renewable energy.[9] If the renewable electricity and its corresponding RECs are sold together to the same customer, the RECs are considered to be "bundled" and to include all of the attributes of the renewable generation. Simply put, bundled means that 1 MWh of renewable electricity *and* the REC created for that

*The Oregon RPS requires a certification from the Low Impact Hydropower Institute (LIHI) for a facility to be considered low impact. LIHI certification is awarded to facilities according to eight dimensions related to environmentally sound hydropower generation, such as water quality, fish passage, watershed protection, endangered species protection, and avoidance of impacts on cultural and historic resources.[89]

**BPA has a two-tiered power rate design for public power customers. Tier 1 is the base rate for the agency's low cost resources. Tier 2 represents incremental power BPA must purchase to meet the power needs of any BPA customers beyond what is covered by Tier 1 rates. The tiered approach is meant to not only provide an incentive for utilities to practice energy efficiency but also to provide a price signal should a public utility wish to build its own resources in place of purchasing Tier 2 power from BPA.

1 MWh are delivered together to a single entity. However, if the REC is "unbundled" (i.e. sold separately) from its corresponding 1 MWh of electricity generated, the attributes of renewable generation stay with the REC and the remaining electricity is no longer counted as "renewable" – sometimes referred to as "system power." Whoever purchases the unbundled REC may make a claim of consuming renewable electricity while the buyer of the MWh of electricity – now without its corresponding REC – cannot make any renewable claims about the consumption of that unit of electricity.

Figure 3.4: Flow of Bundled and Unbundled RECs



Oregon entities may comply with the RPS using bundled RECs, unbundled RECs, or Alternative Compliance Payments (ACP). ACPs are a cost-containment mechanism to protect Oregon ratepayers. The Oregon Public Utility Commission sets the ACP rate for IOUs and Electricity Service Suppliers (ESSes) each compliance year at a level that is high enough to incentivize compliance using RECs rather than ACPs but that provides for a compliance cost ceiling should the costs of procuring renewable energy rise considerably. So far, no Oregon IOUs or ESSes have used ACPs to comply with the RPS. The 2018-2019 ACP rate for IOUs and ESSes is $90/ MWh.[93] For COUs, individual COU boards sets the ACP rate.

Unbundled RECs may only be used for up to 20 percent of an IOU's annual compliance obligation; COUs may use up to 50 percent unbundled RECs for annual compliance. Starting in 2021, ESSes, entities that may sell electricity services through the Direct Access program, may only use unbundled RECs for up to 20 percent of their annual RPS compliance requirement. Learn more about Direct Access later in this chapter.

RPS Compliance

Oregon's two biggest IOUs – PacifiCorp and PGE – report to the Oregon Public Utility Commission annually on what resources they used to comply with the RPS and at what cost.

Both PGE and PacifiCorp have met their RPS requirements every year since the first compliance year of 2011 without exceeding the cost cap or using the ACP mechanism. While PacifiCorp has primarily met its RPS compliance obligations with wind resources, especially in earlier RPS years, PGE has relied on both hydropower and wind resources. Some of the hydropower PGE uses for compliance each year is from generation attributable to efficiency upgrades at older hydropower facilities.

Both utilities' compliance portfolios have also included some solar, geothermal, biogas, and biomass resources. Solar resources did not provide much of the early RPS compliance for either utility, but both PGE and PacifiCorp have been adding solar to their compliance portfolios.

Figure 3.5: PacifiCorp RPS Compliance Resources 2011-2016

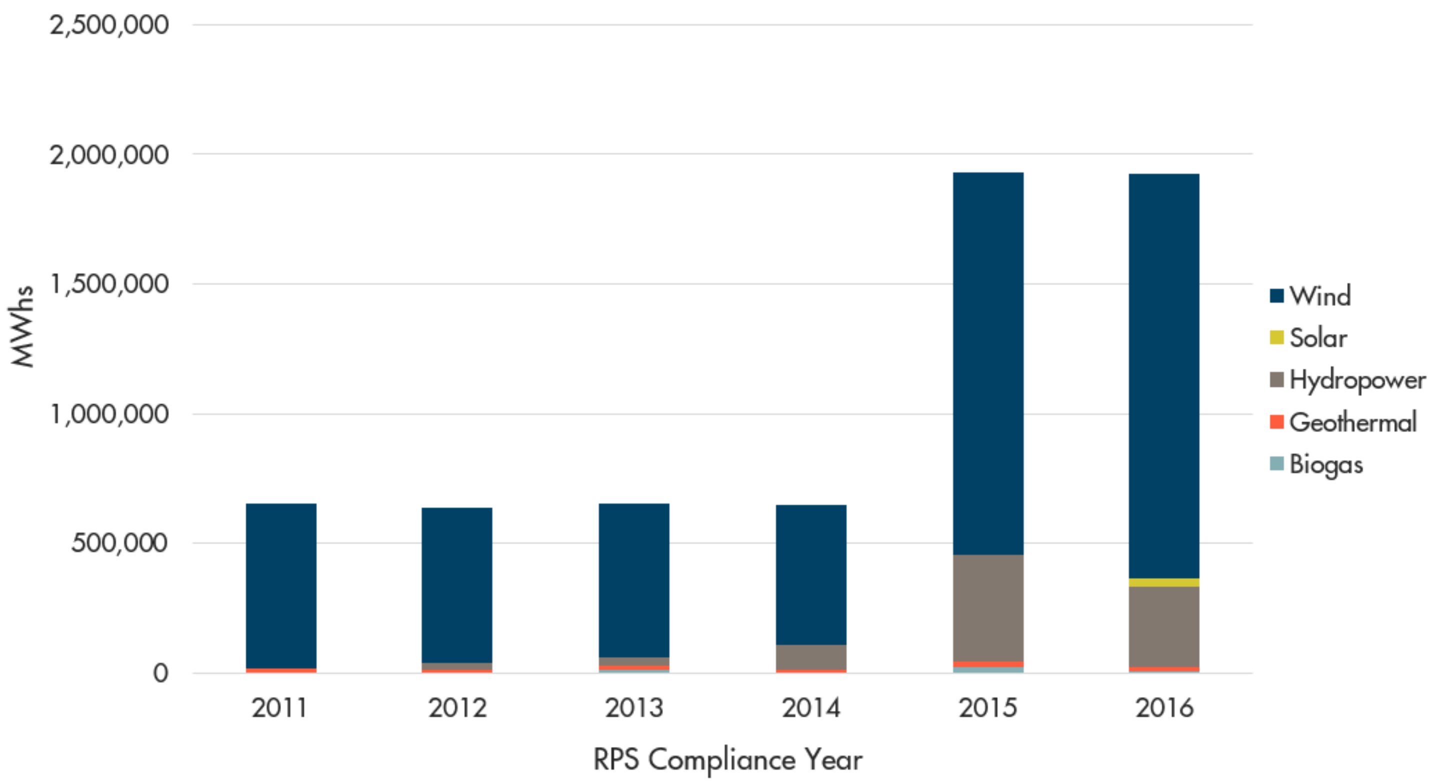
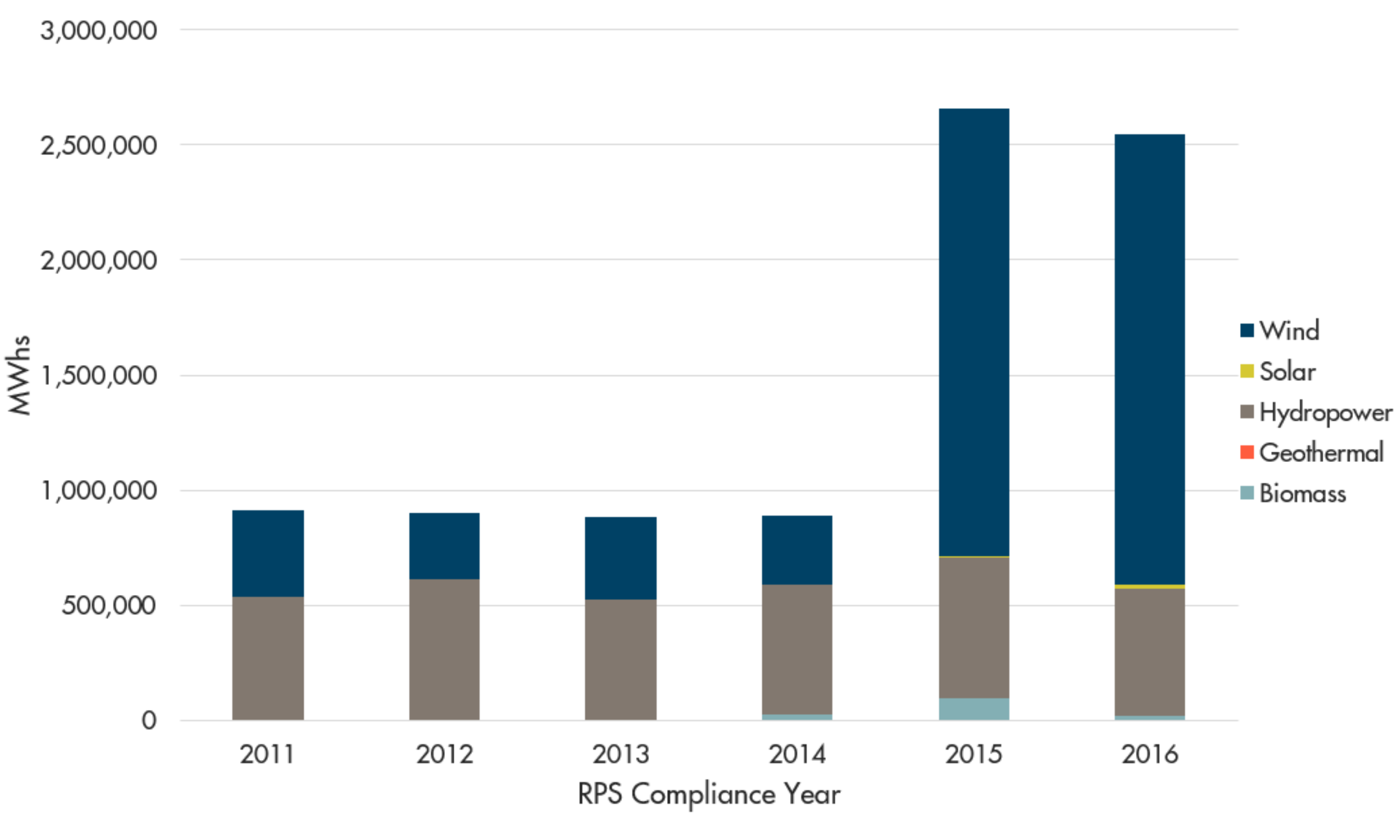


Figure 3.6: PGE RPS Compliance Resources 2011-2016



In 2015, the RPS target took its first big jump from five to 15 percent, and both PGE and PacifiCorp met this higher interim target with a mix of renewable resources located in Oregon and within the region. The next RPS target increase is from 15 to 20 percent in 2020.

While IOUs must demonstrate RPS compliance to the OPUC, COUs must report their compliance to their respective members or customers, usually through the COU's board. As noted above, EWEB is the only COU that currently has an RPS requirement, and it reports directly to its Board of Commissioners on its RPS compliance each year. However, due to some of the RPS compliance exemptions listed above, EWEB has not yet had an RPS compliance requirement above zero. EWEB purchases a quantity of Tier 1 electricity from BPA, and also meets a portion of its load with legacy hydropower generation from non-BPA sources. For example, in 2017 EWEB had total retail sales of 2,526,200 MWh, with a resultant 15 percent RPS requirement of 378,900 MWh. However, because all of its retail sales were from exempt sources (BPA Tier 1 and legacy hydropower), EWEB was left with a 2017 RPS compliance requirement of zero.[10]

The Small-Scale Community-Based Renewables Target

ORS 469A.210[94] states "by the year 2025, at least eight percent of the aggregate electrical capacity of all electric companies that make sales of electricity to 25,000 or more retail electricity consumers in this state must be composed of electricity generated by one or both of the following sources:

a) Small-scale renewable energy projects with a generating capacity of 20 megawatts or less **that generate electricity utilizing a type of energy described in ORS 469A.025**; or

b) Facilities that generate electricity using biomass that also generate thermal energy for a secondary purpose."

The law applies to PGE and PacifiCorp.

While the statute defines facility types that are eligible for the RPS as well as a clear target, there are a number of terms and provisions within the statutory language that lack formal definitions. For example, the term "aggregate electrical capacity" does not have a statutory definition. As a result, a facility database was developed with analysis tools to consider different compliance scenarios. In addition, the term "community-based renewable energy project" is also not defined in statute and does not have a broadly accepted definition.

To understand different ways utilities might meet the eight percent target, ODOE staff developed a database of renewable energy facilities serving PGE and PacifiCorp, along with scenario analysis tools to consider different compliance options. For the purposes of the analysis, it was agreed that utility peak load could serve as a proxy for aggregate electrical capacity.

The five types of facilities included in the database:

1. **Net metered facilities:** facilities that are installed on the customer side of the electric meter and serving onsite loads.

2. **Non-RPS compliant facilities:** facilities constructed before 1995 that do not meet the definition of renewable energy projects established under ORS 469A.025[94] but that may meet the qualifications described in the small-scale community-based renewable energy facilities target.

3. **Out-of-state facilities:** renewable energy facilities located outside of Oregon that contribute to Oregon's load. When included, these facilities are considered based on the estimated share of their output serving the Oregon market.

4. **Contracted facilities:** the utilities provided data on projects that are under contract but not yet online by February of 2018.

5. **Interconnection applications:** the utilities provided data on projects that have submitted an application for interconnection but are not yet contracted. Historically many facilities in the interconnection application queues have not been built. Conversely, by 2025, many facilities may be built that are not currently in the interconnection application queues.

Using utility peak load assumptions as a proxy for "Net Aggregate Capacity," the tables below show the facilities that could contribute towards the eight percent target for PGE and PacifiCorp.

Table 3.2 shows facilities reported by PGE. Each row represents a facility classification and the relative contribution of those facilities towards the eight percent target.

Table 3.2: PGE Facilities Potentially Contributing to Eight Percent Target

PGE Facilities		2016	2025
Peak Load Assumptions		3,652 MW	3,800 MW
Facility Scenarios	**Facilities Capacity (MW)**	**% of Peak Load**	**% of Peak Load**
Baseline Contributing	75	2.1%	2.0%
Net Metered	48	1.3%	1.3%
Non RPS Compliant	18	0.5%	0.5%
Out of State	5	0.1%	0.1%
Contracted Facilities	513	14.0%	13.5%
Interconnection Applications	1013	27.7%	26.6%

Table 3.3 shows facilities reported by PacifiCorp. Each row represents a facility classification and the relative contribution of those facilities towards the eight percent target.

Table 3.3: PacifiCorp Facilities Potentially Contributing to Eight Percent Target

PacifiCorp Facilities (De-rated Capacity)		2016	2025
Peak Load Assumptions		2,267 MW	2,400 MW
Facility Scenarios	Facilities Capacity (MW)	% of Peak Load	% of Peak Load
Baseline Contributing	83	3.7%	3.5%
Net Metered	34	1.5%	1.4%
Non RPS Compliant	104	4.6%	4.3%
Out of State	51	2.2%	2.1%
Interconnection Applications	47	2.1%	2.0%

Table 3.3 includes capacity values based on PacifiCorp's allocation of resources over its entire western service territory. As a result, all facilities, including in-state facilities, are de-rated to about 25 percent of their nameplate ratings. If the PacifiCorp facilities that are located in Oregon are counted at their full nameplate capacity, they have a significant impact on progress toward the target. Table 3.4 below describes the existing projects and interconnection applications for PacifiCorp facilities located in Oregon.

Table 3.4: Existing Projects and Interconnection Applications for PacifiCorp Facilities

PacifiCorp Facilities (Full Capacity)		2016	2025
Peak Load Assumptions		2,267 MW	2,400 MW
Facility Scenarios	Facilities Capacity (MW)	% of Peak Load	% of Peak Load
Existing Facilities in State	471	20.8%	19.6%
Interconnection Applications in State	119	5.3%	5.0%

Figures 3.7 and 3.8 describe the nature of the small-scale renewable energy projects by facility type reported by PGE and PacifiCorp. The charts report all projects in the database regardless of the eligibility scenario analysis. As can be seen, solar facilities make up the majority of planned capacity.

Figure 3.7: Cumulative Capacity (MW) of Existing Facilities Reported in the Small Scale Renewable Energy Facilities Database; Reported Online as of February 2018

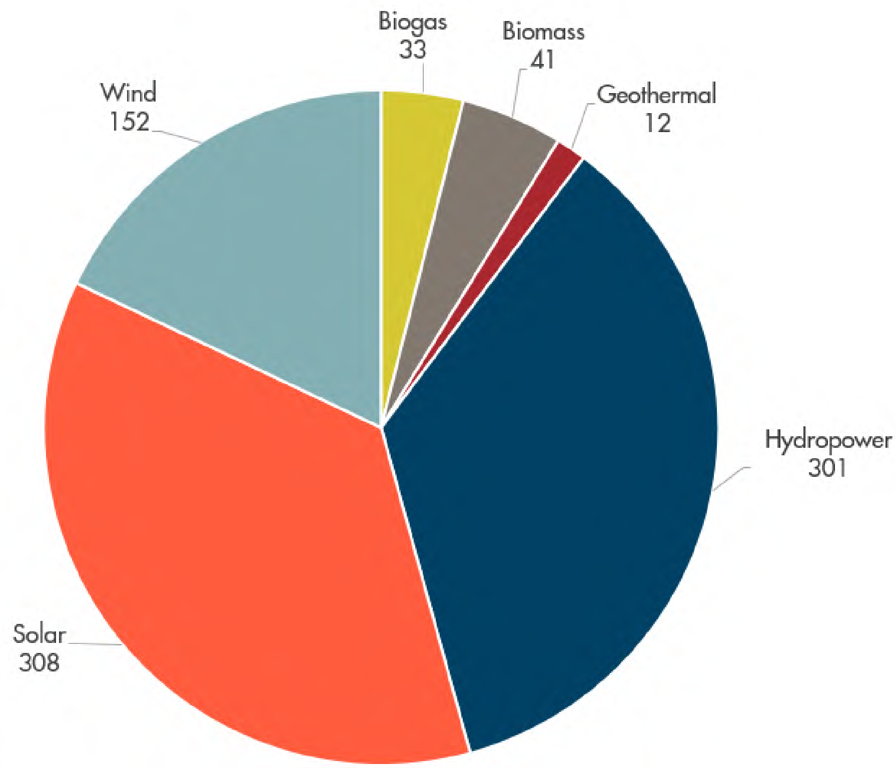
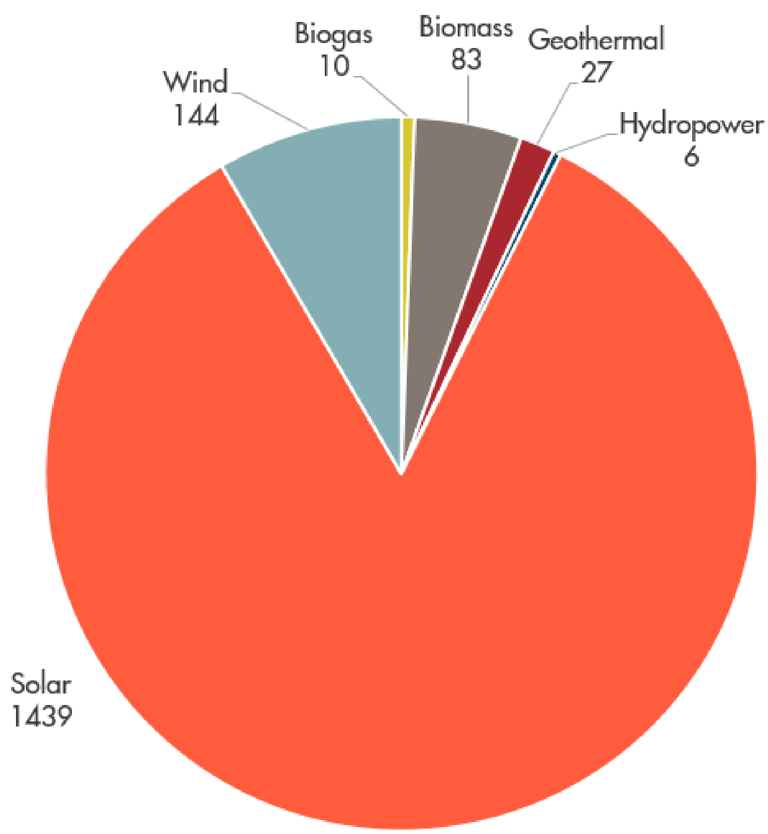


Figure 3.8: Capacity (MW) of Planned Facilities Reported in the Small Scale Renewable Energy Facilities Database; Reported as of February 2018



In 2018, the OPUC began a rulemaking (Docket AR 622[95]) to clarify terms and create implementation rules. This docket is ongoing and tentatively scheduled to be completed by the end of 2018.

The Oregon Youth Authority's New Bridge High School installed solar as part of its GET program re-

1.5 Percent for Green Energy Technology

Oregon requires public bodies to spend 1.5 percent of public improvement construction costs on green energy technology or woody biomass energy technology (WBET). The requirement is for new public buildings with construction costs exceeding $1 million or building renovations with construction costs exceeding $1 million and 50 percent of the insured value of the building.[96]

Eligible green energy technologies include solar PV, solar hot water, passive solar, day lighting, and geothermal systems. As of January 1, 2018, public bodies may choose woody biomass energy technology as an alternative to green energy technology. WBET technologies must use certain types of woody biomass as a feedstock in boilers with a combustion efficiency of at least 80 percent.[11] As of January 1, 2018, 81 public projects were reported, with 75 percent of those being photovoltaic projects. Few projects attempt the passive solar path as the passive elements must reduce whole building energy use by 20 percent. One geothermal project has been completed. As of the date of this report, no woody biomass projects have been reported.

Voluntary Procurement

Another clear driver of renewable energy development in Oregon and the West has been voluntary demand from residential customers and corporate and industrial entities, which has been increasing alongside growing concern about climate change and also decreasing costs of renewable technologies. Voluntary renewable energy purchases are those where the buyer was not required to purchase renewable energy but chose to, usually for reasons related to cost-savings, risk management, corporate social responsibility, or corporate marketing.

COMMUNITY CLEAN ENERGY GOALS

In 2017, the City of Portland and Multnomah County committed to 100 percent renewable electricity by 2035, and **100 percent renewable energy** – across sectors – by 2050.

"Cities that invest in renewable energy are making the responsible choice for our global future and bringing our significant purchasing power to bear in the transition to a clean energy economy. I am a firm believer in the power of local government to lead the change we want to see in the world. After all – this is an issue that our very life depends on. The world is looking to states and cities to be bold and resourceful with policy and action at the local level." — *Portland Mayor Ted Wheeler*

VOLUNTARY GREEN POWER PROGRAMS IN OREGON

As part of the electric power industry restructuring required in Oregon by SB 1149 (1999),[97] Oregon's electric IOUs are required to offer customers a portfolio of rate options, including renewable energy options since October 2001. While PacifiCorp and PGE's programs were not the first to launch in the U.S., they quickly became two of the most successful programs nationwide, according to annual ratings from NREL.

There are a few program options in Oregon for PGE and PacifiCorp customers, but most customers participate in one of two options:

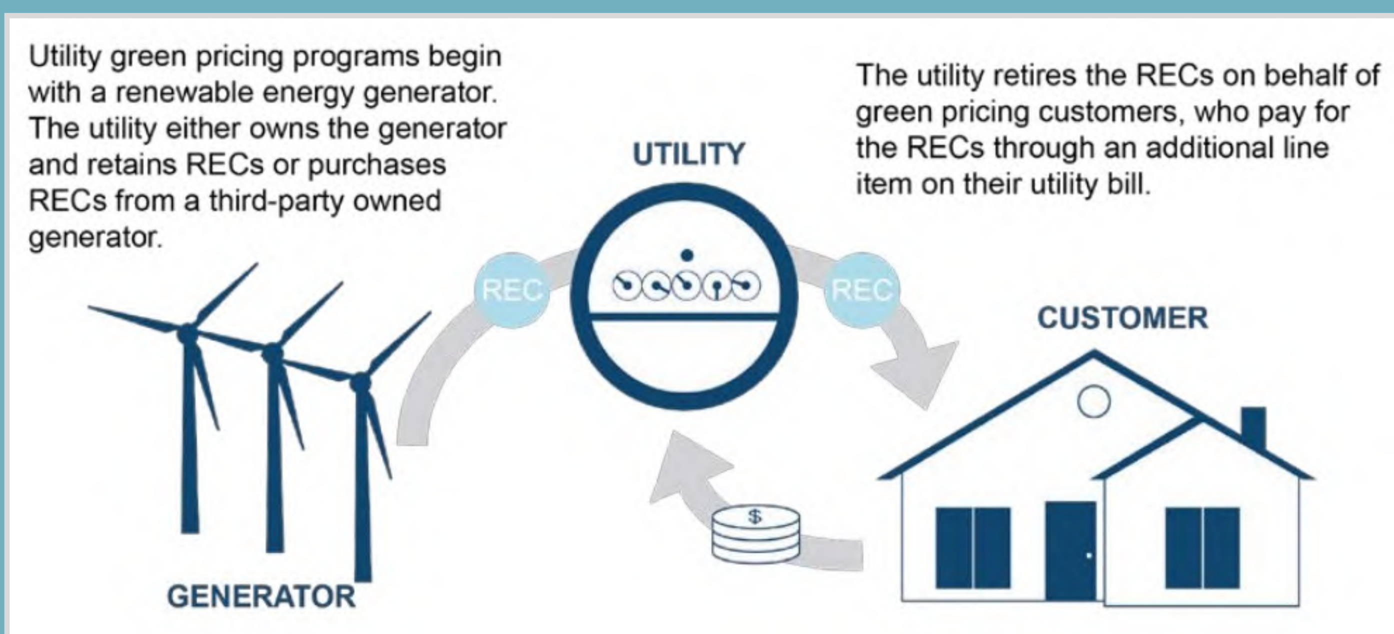
1. A block rate that allows participants to pay a fixed cost for a "block" of kWhs of electricity; or
2. A volumetric rate where participants fund the purchase of RECs equal to 100 percent of their electricity consumption.

Additionally, customers participating in voluntary green power programs may elect to pay a small monthly fee to support native fish habitat.

In 2017, PGE's voluntary green power program was ranked first in the country, and yielded the highest total number of participants (173,856), the highest rate of participation (almost 20 percent of all eligible customers), and the highest total sales of MWh of green power (over 1.8 million MWhs).

2017 marked the ninth consecutive year that PGE topped the NREL rankings for total program participants and the sixth consecutive year for most MWhs sold through the programs. PacifiCorp has followed close behind PGE in the rankings, and in early years of the programs (2004-06), its programs outranked PGE's in terms of total participants. Since 2009, PacifiCorp has consistently ranked second in the country in terms of total program participants (NREL did not collect data in 2011) and second or third in total sales of MWh of green power.

Figure 3.9: How Oregon's Utility Green Power Programs Work[13]



Green Power Programs – Residential and Small Commercial Customers

Oregon's largest electric IOUs – PGE and PacifiCorp – have two of the most successful voluntary green power programs in the country, as tracked and ranked annually by the National Renewable Energy Laboratory.[12] In Oregon in 2016, over 200,000 voluntary green power program participants were responsible for purchasing more than two million MWhs of green power.[13]

One of PGE's voluntary green power programs, *Green Future Solar*, allows customers to buy blocks of solar energy, like the energy generated from this array near Willamina, OR.

Voluntary green power programs allow residential and small commercial consumers in Oregon to opt in and pay a premium on their electricity bills for the purchase of renewable energy certificates, and to contribute toward the above-market costs of various renewable energy projects in Oregon and in the West.

Though COUs predominantly get their electricity from BPA hydropower and are not required to provide green power programs, some choose to offer such programs to their customers. For example, EWEB's Greenpower program allows customers who purchase green electricity to support local incentives for residential and commercial solar projects, and grants for renewable energy projects at local nonprofit, government, or academic organizations.

Large Customer Options

Large commercial and industrial customers are also driving renewable energy development in Oregon and in the Northwest. Corporate social responsibility and sustainability-related targets at companies have driven the quickly-growing trend of corporate renewable energy procurement, as have reductions in the costs of renewable energy and new, easier ways of purchasing off-site renewable energy.[14] The result has been contracting for over 10 GW of off-site renewable energy development for corporate customers nationwide since 2015.[15] A number of companies with operations in Oregon have signed onto pledges such as the RE100 Pledge, a global campaign to get some of the largest companies in the world to commit to using 100 percent renewable energy, including Apple, Facebook, Google, Nike, and Salesforce.[16] Separately, Intel has committed to powering all of its U.S. operations with 100 percent renewable energy,[17] and a number of other Oregon-based companies, including Adidas, Columbia Sportswear, Keen, and PGE, have committed to reducing GHG emissions, which will include greater use of renewable energy sources.[18]

In Oregon, these large customers have had two primary pathways for procuring voluntary renewable energy:

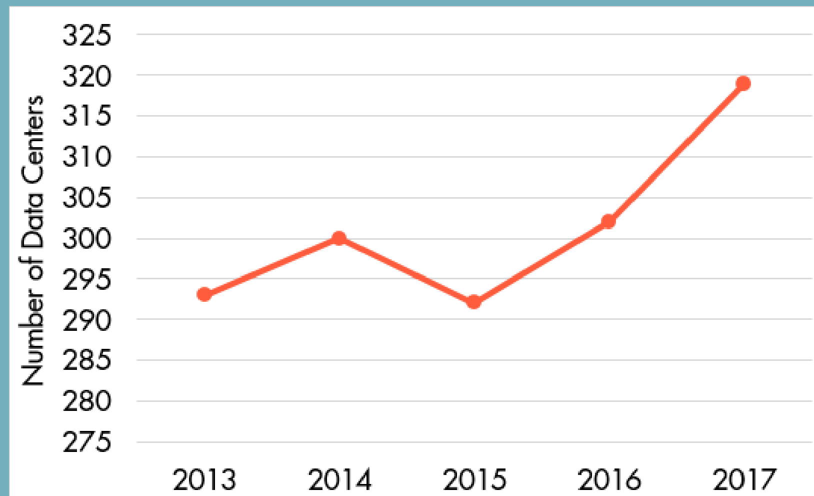
1. The state's Direct Access program; and
2. Utility green power programs for large customers.

A third option, a green tariff, has been discussed in Oregon, and in 2018 PGE filed with OPUC for approval of its proposed green tariff option for large customers.[98]

CORPORATE RENEWABLE ENERGY PROCUREMENT

The number of data processing, hosting, and related services, known here collectively as data centers, grew nearly six percent in the last year. Since 2013, the segment as a whole grew just over eight percent. These facilities house thousands of computers in the form of servers and are linked together via thousands of miles of wiring.

Figure 3.10: Growth of Data Center Industry in Oregon (2013-2017)[43]



The largest issue facing developers of data centers? Cooling their facilities. For this task, they require energy – and lots of it! According to the Northwest Power and Conservation Council, data centers could become the region's largest consumers of electricity since the aluminum industry of the 1980s.[40] More specifically, companies developing these facilities are in search of Oregon's plethora of clean, low-carbon and low-cost energy. Companies such as Facebook, Apple Inc., Google, Amazon, and others have populated Central and Eastern Oregon with their facilities. With these facilities, many procure nearly 100 percent clean energy from separate energy projects or nearby utilities. Google recently opened a facility in The Dalles without relying directly on fossil fuels, while Facebook will power its next Prineville facility with 437 MW of solar power.[40,41] The company already has three datacenters in Prineville with two more on the way.[41] Some companies cannot find enough renewable energy, such as Microsoft. After some disagreement, the software giant reached a settlement with its electric utility, Puget Sound Energy, which uses fossil fuels for nearly 60 percent of its generation, to create a new tariff for large industrial or commercial customers if the customers opt-out of buying electricity from the utility.[42]

Through **Direct Access**, commercial and industrial entities that are customers of the state's largest IOUs may choose a retail provider of electricity other than their incumbent utility. This allows firms to seek out a new electricity supplier that can address their needs related to price or generation source. Direct Access was conceived as a way to allow for a more competitive electricity marketplace by allowing independent providers of electricity, called Electricity Service Suppliers (ESSes), to compete directly with vertically-integrated IOUs. ESSes have historically provided electricity from natural gas resources, but recently some ESSes have added more renewable energy to their portfolio. Both PGE and PacifiCorp have experienced recent growth in the percentage of their load attributable to the Direct Access program, with PGE at over 17 percent and PacifiCorp at almost five percent for 2017. While there is no indication that the majority of Direct Access customers have historically chosen to procure renewable resources, there are a few noteworthy new entrants to the program for whom sourcing renewable energy has been one of the main motivations.

Apple Inc. is one company that has chosen to purchase electricity for its Prineville data centers through the Direct Access program instead of from its incumbent utility, PacifiCorp. Apple has committed to powering its corporate facilities with renewable energy, and the company's preference is to own the renewable energy generation sources whenever feasible. Apple seeks to enter into long-term power purchase agreements for renewable energy when ownership is not feasible.[19] While Oregon customers do not currently have a pathway long-term contracting of this sort, PGE is in the process of launching such a pathway with its green tariff (see below).

To power its Prineville facilities, Apple entered into long-term agreements to purchase renewable electricity from two Avangrid Renewables projects in Oregon: 200 MW from the Montague Wind Project in Gilliam County and 56 MW from the Solar Star Oregon PV project in Prineville.[19] The Montague wind project is expected to ramp up construction in 2019 and the Solar Star project is operational.

The PUC is required to ensure that the provision of direct access service "not cause the unwarranted shifting of costs"[20] from direct access participants to the utility's other customers. As a result, non-residential customers accepting direct access service must pay transition charges (sometimes referred to as an "exit fee") for a period of time not to exceed 10 years. This charge is designed to compensate the utility for costs it reasonably incurred in the past to serve that customer and that it must continue to reasonably incur to maintain the capability to provide the customer with default electric service in the event that its direct access arrangement fails for any reason.

Like residential customers who can take advantage of voluntary green power programs, **large customers can elect to pay more through green power programs**, generally through the purchase of unbundled RECs. While both PGE and PacifiCorp offer large commercial and industrial customers programs that are Green-e Energy certified,* the way these programs are structured, customers typically cannot specify the projects from which they will receive RECs. The utility picks the renewable projects and aggregates them into a single green energy product.

PacifiCorp has offered its Schedule 272 to large non-residential customers as a way to purchase unbundled RECs since 2004. Before 2016, under a Schedule 272 agreement, the customer pays the base rate for its electricity consumption to PacifiCorp and then also pays the cost of unbundled RECs. However, the customer would not necessarily know in advance the generation resource, location, or facility age associated with the unbundled RECs. In 2016, PacifiCorp amended its existing Schedule 272 tariff to allow customers the ability to purchase unbundled RECs from a specific facility or facilities, allowing customers greater control over how to "green" their energy supply and addressing concerns over additionality.

In 2018, Facebook entered into an agreement under Schedule 272 to purchase unbundled RECs from PacifiCorp. Under its agreement with PacifiCorp, Facebook will pay the base rate in addition to the cost of unbundled RECs associated with specific new renewable projects. Because Facebook is purchasing RECs from new projects, it can make a defensible claim that it is supporting new renewable energy development. PacifiCorp will purchase the power and the RECs from generating facilities, which were identified as least-cost, least-risk for customers and use the energy towards fulfilling its system capacity needs, then sell the unbundled RECs to Facebook. The electricity purchases will not count toward PacifiCorp's RPS requirements, as Facebook will own the RECs and therefore the property right to the renewable attributes of the electricity.

*Green-e Energy is an independent consumer protection program providing certification and verification for renewable electricity and renewable energy certificates (RECs) sold to households and organizations.

Utility **green tariff programs** differ from green power programs in that they allow commercial and industrial customers to voluntarily purchase RECs bundled with the corresponding renewable energy from specified projects within a utility's service territory. In this way, large customers receive the financial benefits of renewable energy and long-term contracting, as opposed to paying a premium for an unbundled REC as they would in a voluntary green power program, or paying large exit fees to participate in the Direct Access program. As of February 2018, 21 green tariffs in 15 states have been approved by their respective PUCs.[21]

A green tariff, commonly referred to as a voluntary renewable energy tariff, or VRET, is not currently an option in Oregon. However, both PacifiCorp and PGE have worked with the OPUC to develop a program since 2014 and PGE has an open docket at the OPUC for a Green Tariff Program, where stakeholder discussions are ongoing.

In 2014, the Oregon Legislature passed a law[22] requiring the OPUC to investigate the potential for a VRET in Oregon that would balance policy factors such as further development of renewable energy, effects on the competitive retail market, and potential cost-shifting. After two years of evaluation and discussion amongst stakeholders, a VRET was not adopted.[23] In April 2018, PGE petitioned OPUC to reopen the process, citing pledges the utility had made to continue action toward meeting the United States' Paris Agreement commitments and to support the climate and renewable energy goals of cities in its service territory, including Portland, Milwaukie, Hillsboro, Salem, Gresham, and Beaverton.[24]

At the same time, PGE filed a VRET proposal whereby PGE would execute long-term PPAs of 10 or 20 years with renewable energy generators, and then allow VRET customers to participate by paying, on top of their cost of service, the energy and capacity costs associated with the power purchase agreement (PPA).* Program participants would need to have an annual peak demand of at least 30 kW, though entities like municipalities could aggregate smaller loads to meet the threshold, and commit to a contract length of 5, 10, 15, or 20 years. PGE's proposal suggested that there would be no cost-shifting to non-participants, nor risk-shifting.[24] As mentioned above, OPUC has opened a new docket (UM 1953) to address PGE's proposal to offer a VRET and stakeholder discussions are ongoing.[98]

Financial Incentives for Renewable Energy Development

A number of state and federal incentive programs available over the years have supported renewable energy development in Oregon. While these programs served to reduce the costs associated with development and operation, it is not known to what extent development was driven by these incentives, especially since many of them could be combined.

Oregon Incentives

Oregon's Business Energy Tax Credit Program (BETC) began in 1979 and sunset on July 1, 2014. The program, which grew and evolved over time, was used to help Oregon businesses, governments, nonprofits, and other entities invest in energy conservation, renewable energy resources, rental weatherization, and cleaner

*"Customers receiving service under the VRET will pay the cost of service rate, plus the difference between the QF rate and the PPA cost. PGE shareholders will pay the VRET rate for the unsubscribed portion of the PPA. VRET customers may also pay a risk premium depending on the commitment length and PPA subscription rate." Testimony from OPUC Staff. Staff/100 Response Testimony. OPUC Docket UM 1953 (July 18, 2018).

transportation fuels. In the 35 years of the program's operation, ODOE certified 24,738 BETC projects that helped save energy, displace conventional energy sources, or generate renewable energy. Of those, 1,724 renewable projects received over $653 million in tax credits. The program provided tax credits to qualifying projects not to exceed 35 percent of the eligible project costs. In 2007, the Oregon Legislature (HB 3201)[99] increased the incentive percentage for renewable projects from 35 percent to 50 percent through the sunset of the program.

The Residential Energy Tax Credit Program (RETC) was also administered by ODOE until it sunset in 2017. ODOE received the first RETC applications in 1978 and issued more than 630,000 tax credits totaling more than $258 million to help residential consumers power their homes with renewable energy, charge alternative fuel vehicles, and reduce the energy use of their homes through conservation measures and energy efficient appliances. Eligible renewable energy devices under the RETC program included solar electric (PV), geothermal energy, solar water heating, solar space heating, and wind. In 2017, the program's final year, ODOE issued 3,946 solar electric credits, 102 for geothermal devices, 128 for solar water heating, and five for solar space heating. Over the lifetime of the program, more than 15,000 solar projects were approved, with a production estimate of about 75 million kWh/year.

The Renewable Energy Development (RED) Grant program, a current program administered by ODOE, promotes investment in renewable energy by awarding grants to Oregon individuals, businesses, nonprofits, tribes, or other organizations that install and operate a renewable energy system.[101] Grants are awarded through a competitive selection process and can total up to $250,000, not to exceed 35 percent of eligible project costs. Eligible RED Grant projects include systems that use biomass, solar, geothermal, hydroelectric, wind, landfill gas, biogas, or wave, tidal, or ocean thermal energy to produce electricity. In 2018, 18 renewable energy projects, predominantly solar projects, were selected for grant awards totaling approximately $2 million. Projects that have been completed through the RED program have a combined capacity of 28 million kWh/year.

The Bend Area Habitat for Humanity ReStore received a RED Grant in 2015.

Energy Trust of Oregon provides financial incentives to customers of PGE and PacifiCorp in the form of cash rebates for solar, hydro, bio power, wind, and geothermal electricity generators. The incentives help to buy down the above-market costs associated with renewable energy projects and are funded through the public purpose charge described in ORS 757.612.[100] Standardized incentives are offered for residential and commercial solar projects. Incentives for large solar facilities and non-solar technologies are based on projects costs compared to the market value of the energy produced. Large incentives may be offered on a competitive basis.

Business Oregon oversees the Solar Development Incentive (SDI), a cash incentive paid to solar project developers for each kWh of electricity generated at a solar project in Oregon with a nameplate capacity between two and 10 MWs. Each project can receive $0.005 per kWh of electricity generated for a period up to five years. This program was created by Oregon Laws 2016, Chapter 63[25] with enrollment for eligible projects closing on January 2, 2017. Business Oregon selected 19 utility-scale solar projects to receive the SDI, representing over 146.5 MWs of projects valued at upwards of $362 million and located primarily in central, southern, and eastern Oregon.[26]

SOLAR DEVELOPMENT INCENTIVE PROGRAM

In 2016 the Oregon legislature passed HB 4037 creating a program to encourage the development of utility-scale solar energy projects.[25] The program, known as the Solar Development Incentive and administered by Business Oregon, provides a cash incentive of a half a cent per kWh of electricity generated for a period of five years. Business Oregon awarded the incentive to 19 projects totaling 146.5 MW and representing seven different facility owners in eight Oregon counties. To put this into perspective 146.5MW is about twice as much capacity as the entire residential solar sector in Oregon and nearly four times the solar capacity that was installed under the Oregon Business Energy Tax Credit program.

The solar development incentive has provided valuable information regarding the economic impact and geographical distribution of utility-scale solar projects in Oregon. Projects supported by the SDI program are anticipated to bring at least $361 million in private investment to the state, as well as $115 million of federal tax credits through the Solar Investment Tax Credit program. To date, these projects have resulted in at least 1,514 construction jobs and more than 23 operations and maintenance jobs. More than 90 percent of the capacity in the program is located east of the Cascades, demonstrating the financial benefits associated with the higher solar resources and lower valued land in central and eastern Oregon.

Table 3.5: Business Oregon Solar Development Incentive-funded Projects

County(ies)	Number of Projects	Number of Construction Jobs	Number of Operations & Maintenance FTE	Payments to Date	Estimated Investment	Estimated 2016 Property Taxes	Capacity (MW)
Deschutes/Jefferson	4	261	4	$305.4 K	$93.7 M	$140.8 K	39.9
Klamath/Jackson	6	447	6	$244 K	$121.5 M	$218.3 K	49
Lake	3	255	1.55	$240 K	$66.7 M	$140.5 K	28
Malheur	3	316	6	$407 K	$64.4 M	$12.7 K	23
Yamhill/Marion	3	105	6	$36.3 K	$15.4 M	$1,229	6.6
Totals	**19**	**1384**	**23.55**	**$1.2 M**	**$361.7 M**	**$513.5 K**	**146.5**

Information provided by Business Oregon.

The Strategic Investment Program in ORS 285C.600 – 635[102] offered a 15-year property tax exemption on a portion of certain large capital investments. The program was created in the 1990s to induce large, capital-intensive facilities to locate in Oregon. More than 20 wind farms qualified for the program, resulting in upwards of 2,117 MW of capacity and $4.27 billion in project investment by the end of the 2015.[27]

Federal Incentives

In addition to drops in the capital costs associated with renewable electricity installations, numerous federal incentives have also helped spur greater renewable energy development. The two main federal incentives have been the Investment Tax Credit and the Renewable Energy Production Tax Credit. The ITC provides a one-time tax credit based on the investment costs to develop a new solar energy project. It originally provided a tax credit of up to 30 percent of eligible project costs, but recent federal legislation initiated a reduction of the ITC over time for certain solar and geothermal technologies, and a phase-out for all other technologies. For residential and commercial solar PV projects, the ITC stays at 30 percent for projects that have started construction by 2019, and steps down to 26 percent for projects begun in 2020 and then to 22 percent for those begun in 2021. The residential ITC sunsets after 2021 while the commercial ITC drops to 10 percent and continues at that level.[28]

The PTC provides a tax credit for each kWh generated and sold in a year, though it too has been reduced and sunset at the end of 2017 for all non-wind technologies, and sunsets for wind at the end of 2019. The PTC has been a big driver for new wind power projects across the U.S., and the importance of it to project development can be seen in the precipitous dip in new projects coming online every time there is uncertainty about whether the tax credit will be renewed by Congress. This policy uncertainty, coupled with the long ramp-up period needed to get a wind project moving forward, leads to a boom-and-bust cycle of wind power development.

Falling Technology Costs

In the past eight years, the costs of renewable energy project development nationally have fallen precipitously. Between 2010 and 2017, the costs associated with a utility-scale one-axis PV solar installation in the U.S. dropped by 77 percent.[29] About 71 percent of that drop in costs can be attributed to reductions in the costs of hardware, with another 10 percent due to labor cost reductions and 19 percent due to lower soft costs, such as legal fees and sales taxes (Figure 3.11).

Single-axis solar tracking systems have solar panels that can rotate on one access, which increases energy output by 25 percent or more over fixed-tilt installations (where the panels are mounted at a fixed angle and do not move to track the sun).[30]

Figure 3.11: NREL PV System Cost Benchmark Study (inflation adjusted) for 2010-2017[31]

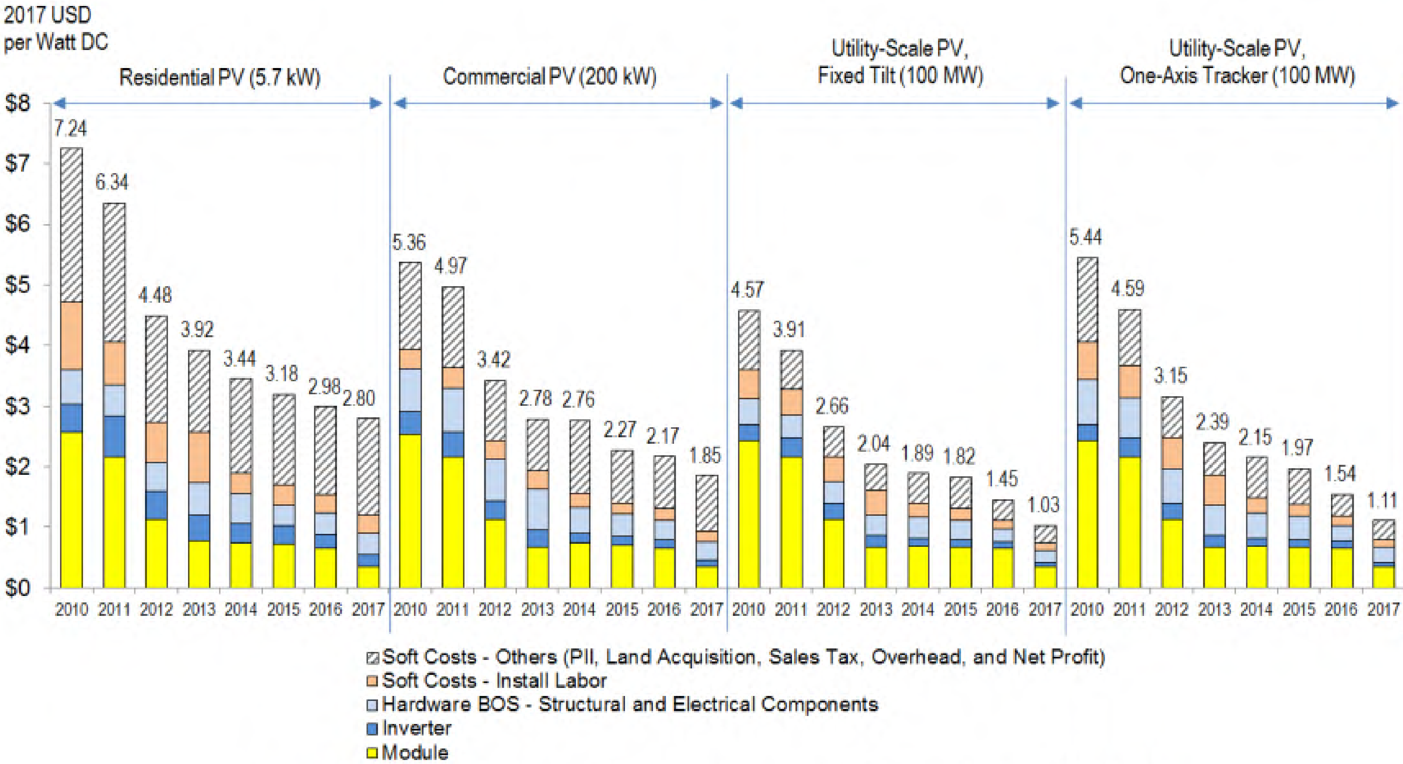
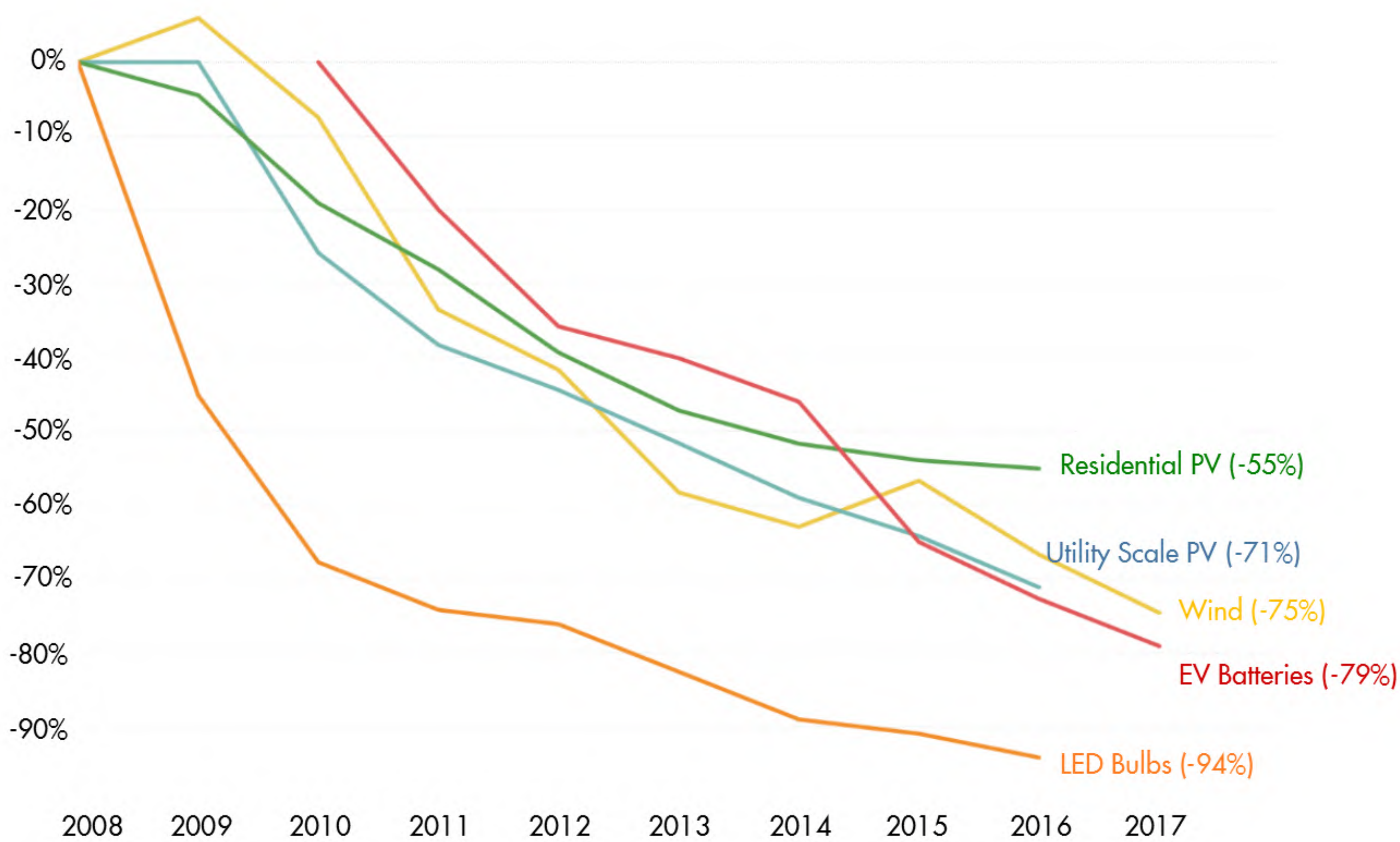


Figure ES-1. NREL PV system cost benchmark summary (inflation adjusted), 2010–2017

Between 2008 and 2017, the average levelized cost of wind energy dropped by 75 percent (See Figure 3.12). A levelized cost of energy is an accepted way of comparing the costs of various technologies, and includes the costs of building and operating a generation facility over its assumed financial life, expressed in a dollars per megawatt hour (MWh) cost in discounted real dollars. While these costs fell, installed wind and solar PV capacity in the U.S. surged, with wind representing over 40 percent of all new installed electricity capacity in 2015, and with the total installed capacity of utility-scale solar PV growing by 43 percent from 2014 to 2015.[32] Costs are expected to continue to decline, especially as energy storage options become more technically mature, which can reduce the intermittency of variable renewable energy resources. For example, in late 2017 Xcel Energy received what were then unprecedentedly low bids for renewable energy and storage resources for Colorado: just over $18/MWh for wind ($0.018/kWh) and $21/MWh for wind plus battery storage ($0.021/kWh).[33] These prices are well below the unsubsidized levelized cost of energy range of $30 to $60/MWh for wind power as estimated by Lazard in 2017.[34]

Figure 3.12: Cost Reductions in Major Clean Energy Technologies[35]



While costs have dropped for renewable energy technologies, some traditional fossil fuel generating facilities have not experienced the same reductions, like coal. These facilities' costs are closely linked to the commodity price of their input fuel (i.e. coal, natural gas, etc.) as well as the rising costs associated with pollution mitigation. However, given the current low price for natural gas as an input fuel, the upcoming reduction of federal incentives for renewable generation (the ITC and PTC), and other drivers related to the integration of variable renewable energy, much of the aging electricity generation sources in the U.S. are being replaced with natural gas generation and numerous studies predict that new natural gas plants will replace a great deal of this aging electricity generation in the future as well.[36,37] Whether aging and retiring resources are replaced with natural gas resources or renewable resources will depend on factors such as the commodity price for natural gas as a fuel and to what degree the costs of renewable generation and energy storage continue to fall.

What's Next for Renewable Energy in Oregon

The electricity industry is in flux. Required procurement policies, voluntary renewable purchases responding to consumer demand, and falling technology costs are likely to continue driving renewable energy development in the near future. Policymakers in the state will determine to what extent state-level financial incentives and further policies to level the playing field for renewables, such as a price on carbon, will play a role. As Oregon seeks to meet its renewable energy and greenhouse gas reduction targets in the most flexible, affordable, and equitable way, a number of challenges emerge. After examining trends in renewable energy, this section focuses on three challenges in particular: the integration of new policies with the existing energy policy landscape, balancing competing goals for land and resources, and the integration of a growing amount of variable renewable energy into the existing electricity grid.

Integrating New Policies into the Oregon Energy Policy Landscape

As Oregonians discuss the development of a carbon policy framework for the state, there have been questions about how a cap-and-trade program would integrate with existing policies that affect greenhouse gas emissions, including the RPS. More information about cap-and-trade programs can be found in Chapter 2.

Integrating a Potential Cap-and-Trade Program with the Oregon RPS

While there are similarities in the broader goals of RPS and cap-and-trade programs, they each have distinct objectives – the purpose of the RPS is to increase deployment of renewable electricity generation and the purpose of a cap-and-trade program is to leverage market mechanisms to reduce greenhouse gas emissions. Jurisdictions that have both RPS and cap-and-trade can increase the likelihood of meeting each of these goals.

An RPS creates a competitive market for renewable energy, which in turn leads to reductions in the costs of renewable energy technologies. Additionally, it provides certainty to developers of renewable energy projects that they will receive benefits from investing in renewable energy. Alternatively, by putting a price on GHG emissions, cap-and-trade increases the cost-competitiveness of renewable energy development as compared to fossil fuel energy development. All ten states in the U.S. that have implemented various types of cap-and-trade programs have also kept existing RPS programs in place.

Table 3.6: Goals, Expected Outcomes, and Compliance Pathways for RPS Policies Compared to Cap-and-Trade Policies

	RPS	Cap & Trade
Primary Goal	Increases the share of new renewable electricity consumed in a state. Oregon's goal is 50 percent by the year 2040.	Reduces a state's annual GHG emissions to reach a long-term target level of emissions.
Primary Outcome	Leads to development of new renewable energy projects and a decrease in the carbon intensity of the state's resource mix, but not for an exact quantity of emissions.	Produces a quantity of emissions reductions but does not set sectoral targets – encourages least-cost reductions wherever they may be found.
How to Comply	Renewable energy certificates (RECs).	Emissions reductions, allowances, offsets.

Separate Compliance Instruments

RECs, which Oregon uses to track RPS compliance, are used to track renewable energy and to determine where it is ultimately consumed.

Allowances represent the authorization to emit a unit of GHGs measured in a common unit known as carbon dioxide equivalent, or CO2e, and are the primary compliance instruments of a cap-and-trade program. Every entity regulated under the cap-and-trade program would have to acquire and then surrender a set number of allowances each compliance period as determined by the program to cover its emissions.

An offset represents a reduction in emissions equal to one metric ton of CO2e. Offsets are generated from sectors of the economy not covered by a cap-and-trade program and can be used to meet a portion of a regulated entity's compliance with cap-and-trade.

Separate Programs

Integrating a cap-and-trade program with Oregon's RPS would be relatively straightforward. The main area of program overlap is how to account for renewable electricity imports from neighboring states. As discussions on the design of potential cap-and trade legislation continue in Oregon, this will be an area needing further clarification.

Integrating a Potential Cap-and-Trade Program with Oregon's Voluntary Renewable Energy Programs

Though not a part of the RPS, the voluntary renewable energy market would likewise be affected by cap-and-trade legislation. To qualify for the voluntary market, renewable energy must be what is called "surplus to regulation," which means it was not generated to comply with any regulatory requirement, such as an RPS. There are a handful of standards for voluntary RECs, one of the most stringent being Green-e, and many of the REC tracking programs used for RPS compliance RECs are also used to track voluntary market RECs. Both PGE and PacifiCorp's voluntary green power programs are certified by Green-e, as was recommended by the Portfolio Options Committee for purposes of quality control and consumer protection.[38]

Other jurisdictions with cap-and-trade programs have protected the voluntary market by setting aside allowances and retiring them according to how much voluntary renewable energy is produced in a given period. Such a set-aside effectively removes this renewable energy from being considered by the cap and it can again be considered "surplus to regulation." California and eight of the nine states (excluding Delaware) currently in the Regional Greenhouse Gas Initiative (a cap-and-trade-program across nine states in the Northeast and Mid-Atlantic) have included set-asides for voluntary renewable energy in their programs.[39]

Balancing State Land Use and Natural Resource Demands

Renewable energy development is one of many potential uses for Oregon's landscape and natural resources. The state has a number of energy, environmental, land use, and economic development policies, statutes, and goals, which interact in complex ways and are sometimes in conflict. As renewable energy development increases, these conflicts can be exacerbated and tradeoffs may be necessary. Two examples of the need for balancing competing demands highlighted in this chapter are the intersection of renewable energy project development and other uses of the land and the operation of the Federal Columbia River Power System (FCRPS). Siting of solar facilities and the interactions with Oregon's land use laws are covered further in the case study on solar, below.

Renewable Energy Project Development and Land Use

Oregon's goals and values are reflected in numerous ways within statute. When it comes to energy facility siting, Oregon's energy goals must be considered alongside a broad set of 19 statewide land use goals, which cover a host of issues, from air and water quality to protection of natural resources and open spaces. The land use goals include specific mandates related to citizen involvement, economic development, transportation, recreation, and energy conservation.

These goals are designed to help implement the mission of the statewide land use planning program, which is to conserve farm land, forest land, coastal resources, and other important natural resources; encourage efficient development; coordinate the planning activities of local governments and state and federal agencies; enhance the state's economy; and reduce the public costs that result from poorly planned development.[44] All city and county land use and development ordinances and comprehensive plan provisions that are used to evaluate local jurisdictional energy projects must align with these state level land use goals.

Smaller scale renewable energy projects are approved at the county level. Oregon's Energy Facility Siting Council (EFSC) is responsible for overseeing the siting of most large-scale energy facilities and infrastructure in Oregon.[45] State-level oversight of energy facilities helps ensure a comprehensive, coordinated review that results in projects that are sited, constructed, and operated consistent with the protection of public health and safety, and that are in compliance with energy policy and environmental protection policies of the state.[46] (More information on EFSC can be found on ODOE's website.[47])

State jurisdictional energy facilities must meet 14 general standards in order to receive approval for construction, which includes Oregon's land use goals. There are specific standards for non-generating facilities and for wind. The general standards also cover a range of issues, such as fish and wildlife habitat, historic and cultural resources, recreation, and scenic resources.

Energy facilities use land in different ways, depending primarily on the type of energy generation resource. Fossil-fueled electricity generating facilities often have smaller land-use footprints than some renewable energy generating facilities, but only if the calculations do not take into account the footprint needed for resource extraction, processing, and transportation.[48] For example, the Hermiston Generating Project, a natural gas-fueled electric generating facility with a generating capacity of 474 MW, takes up approximately 10 acres. In contrast, a solar facility typically uses land at a rate of 6 to 10 acres per megawatt of capacity; the recently approved Boardman Solar Energy Facility has a generating capacity of 75 MW and has a site boundary of 798 acres. Additional land may be needed for transmission or preserving cultural or environmental aspects of the site. Wind facilities may have a large project boundary, though much of the land may still be used for farming or grazing, enabling multiple land uses to continue and thereby reducing conflict.

Both Oregon's land use laws and the siting process, established in the early 1970s, ensure that important natural, historic, or cultural resources are not negatively affected, and that impacts are minimized if they cannot be avoided. However, at times these programs come into conflict with the state's efforts to increase renewable energy development. For example, it can take significant time and resources for project developers to demonstrate that their projects are consistent with the state's goals and standards, and this can have a dampening effect on development. In designing and implementing land use and energy policy, state policymakers and regulators must balance competing demands of environmental protection and energy development.

RENEWABLE ENERGY: COMMUNITY EFFECTS

The Economy

Like many places in Oregon, Sherman County is largely defined by its geography and weather. For decades, the county in north-central Oregon had its economic wagon tied to dryland wheat and barley, and cattle. When the rains came at the right time, times were good. But the rains didn't always come.

Much more dependable than rain on the Columbia Plateau is the wind, which regularly blows between the Cascade Mountains to the west and the rolling desert to the east. The wind industry noticed this about 20 years ago and came knocking on doors in Sherman, Gilliam, and Morrow counties. At the time, Sherman County was second-to-last in Oregon's per capita personal income. Since that time, a host of large and small wind farms have cropped up in Sherman; the big ones sited through the state (Biglow Canyon and Klondike III) and the smaller ones going through the county (Biglow I & II, Pa'Tu, Hay Canyon and Star Point).

Gary Thompson, Sherman County Judge for the past 18 years, saw it all coming and was convinced the nascent industry would help diversify the agriculture-dominated region. It did, and Thompson looks back with great pride at what the industry and County put together for the residents. "Since wind energy projects came to Sherman County, the County has received more than $25 million in property taxes, over $14 million in community service fees, and in excess of $57 million in Strategic Investment Program fees," he said.[49]

The taxes and fees have allowed the County to fund two dozen buildings or projects, including a new school and library, a Residential Incentive Program, two scholarships, fiber for 911 emergency services, a new weed district building, a courthouse addition and renovation, and the Rufus Industrial Park. The Residential Incentive Program awards $590 each year to the head of a household that has proven a year's residency. Since the program began in 2009, it has distributed $3.66 million.[49]

RENEWABLE ENERGY: COMMUNITY EFFECTS

The View

While renewable energy has been touted for its many benefits – mainly no carbon dioxide emissions and free fuel – there are some drawbacks. Just ask Barry Beyeler, chair of Oregon's Energy Facility Siting Council, who testified as much to an Oregon legislative committee in 2016.[50]

Beyeler, who lives in the northeastern Oregon town of Boardman and has been on EFSC since 2010, regularly hears from Oregonians about the hundreds of wind turbines that pepper the high desert landscape southwest of his town. The average wind turbine in the United States is taller than the Statue of Liberty, and they are on track to get larger. This can pose a significant visual impact to both the communities in which they are sited and those traveling through.

When EFSC was created in the 1970s, the Council was largely evaluating baseload electricity generating plants fueled by natural gas and coal. "Where baseload energy facilities are measured in acres, wind farms are measured in square miles," Beyeler told the legislative committee. Moreover, Oregon's standards by which EFSC evaluates the large facilities allow for each project to be judged on its own merit and not by the cumulative effects of others nearby.

While many of the state's natural gas plants are located in industrial areas, the same cannot be said for wind and solar farms, which are permitted in agricultural zones and on rangeland. Both wind and solar have large land footprints and must be located near large transmission lines. That's why the sunny and windy farms and ranches on the Columbia Plateau near the Bonneville Power Administration's transmission grid became a prime target for the industry.

"Over the past 20 years, the vast majority of large-scale energy projects have been sited in rural portions of the state," Beyeler told the committee. "We, those living in rural areas, see every day the impacts. We see the good, the bad, and the ugly."

"The Willamette Valley, where the energy demand lies, has no utility-scale generation, so the majority of Oregonians might not be familiar with the day-to-day impacts of either baseload or renewable energy."

Balancing Interests: the Many Uses of the Columbia River Basin

As noted in Chapter 1, hydroelectric power is the single largest source of electricity in Oregon, with the majority of that power coming from the Federal Columbia River Power System (FCRPS).

The Columbia River existed long before construction of the first hydroelectric project, and the operation of the FCRPS is still evolving today to accommodate its many uses. Important among historic uses are those of the 13 Native American tribes whose ancestral homelands are located within the Columbia River Basin – many of these uses continue to be protected today under tribal treaty rights. The Federal Action Agencies (BPA, the Army Corps of Engineers, and the Bureau of Reclamation) have a trust responsibility established in law that provides the foundation of their government-to-government relationship with these federally recognized tribes.

The Federal Action Agencies operate the FCRPS to meet core purposes like flood control, fish and wildlife habitat, and power generation as shown Figure 3.13.[51] These different uses can come into conflict, as they often call for different ways of operating the river. One particular conflict, with implications for energy prices and for hydropower's ability to integrate variable renewable energy in the region, involves dams and the threatened and endangered fish species.

Figure 3.13: Columbia River Uses[52]

The restoration of endangered and threatened fish species and the protection of habitat within the Columbia River basin have been priorities for Oregon and the other states surrounding the FCRPS. While there are numerous threats to fish species in the Columbia River Basin, from habitat loss to predation by sea lions to climate change, this section focuses on the conflict with dams and the modifications made to hydropower in an effort to improve fish survival.

A LITTLE MORE ABOUT FISH...

The interactions of native fish species and the FCRPS are complex. The following provides a brief overview of some key terms and concepts:[53,54]

Fish ladder at the Bonneville Lock and Dam. *Photo: U.S. Army Corps of Engineers,*

Adult Fish: Many adult fish species navigate upstream to spawn, and the construction of dams in the early twentieth century impeded this passage. The installation of fish ladders and the way that water flows are managed at particular dams can improve adult passage upstream.

Juvenile Fish: The construction of dams also created significant new challenges for the downstream navigation of juvenile fish. Juveniles can be killed passing through hydroelectric turbines, and the creation of reservoirs behind dams can create greater risks of predation.

Fish Ladders: Fish ladders are gradual stair-step systems with pools of water at different elevations to allow fish migrating upstream to climb from lower to higher elevation to navigate past dams.

Spill: Spill is a term used to describe spilling water over a dam's spillways, rather than running the water through the powerhouse to generate electricity. Increasing the amount of water spilled at a dam reduces the percentage of juvenile fish that pass through the dam's hydroelectric turbines by diverting more approaching juvenile fish over the spillways, but can also result in increased total dissolved gas levels (see below) and decreased power generation.

Total Dissolved Gas (TDG): TDG is an important measurement of water quality that assesses the concentration of total dissolved gas saturation in the water relative to atmospheric pressure. High levels of TDG can negatively affect water quality and wildlife health. TDG levels can increase at the bottom of the dam's spillway as spill levels are increased at that dam. State water quality agencies, including the Oregon Department of Environmental Quality, have established maximum TDG levels to protect water quality and the health of fish.

Fish Passage Plan (FPP): The U.S. Army Corps of Engineers, in coordination with BPA and other partners, develops the FPP annually. The FPP describes specific year-round operations at each of the four dams on the main stem of the Columbia River and the four lower Snake River dams to provide for fish passage and protection consistent with the Biological Opinion issued by the National Marine Fisheries Service, an office within the National Oceanic and Atmospheric Administration (also known as NOAA Fisheries).

Biological Opinion (BiOp): Pursuant to the Endangered Species Act (ESA), NOAA Fisheries develops and publishes a BiOp that evaluates the effects of operating the FCRPS on ESA-listed threatened and endangered species. The BiOp also includes a table of recommended actions and strategies designed to avoid jeopardizing ESA-listed species.

In 1995, NOAA Fisheries released a biological opinion (1995 BiOp) describing new operations for the FCRPS designed to improve fish passage. Over the next two decades, NOAA Fisheries developed several supplements to the BiOp, along with entirely new BiOps in 2000 and 2008. Through these BiOps, actions were taken to help support fish, including: habitat restoration; establishing additional hatcheries; and articulating research, monitoring, and evaluation objectives. These BiOps also included new juvenile fish passage objectives resulting in increased spill in spring and summer months to help juvenile salmon migrate safely back to the ocean. More recently, new, safer fishways that align with the migratory paths of Columbia River salmon have been constructed:[55]

- Spillway weirs that allow fish to pass smoothly over a dam in the surface water;
- A corner collector at the Bonneville Dam;
- A spillwall guide at The Dalles Dam that guides fish to the deepest, safest part of the river; and
- Fish screens and bypass systems to divert fish away from the hydroelectric turbines.

Despite these improvements, 13 fish species within the Columbia River Basin are listed as either threatened or endangered under the Endangered Species Act.[56] The State of Oregon, along with a number of conservation organizations and the Nez Perce Tribe, have been engaged in litigation with the Federal Action Agencies since 2001 over their management of the FCRPS and specifically over whether that management has been sufficient to avoid jeopardizing the survival of the fish species listed pursuant to the ESA.[56] The Courts have ruled in the plaintiffs' favor, finding that NOAA Fisheries violated the ESA when it concluded that the operation of the FCRPS, described in the 2014 supplement to the 2008 BiOp, would *not* jeopardize the fish species listed as threatened or endangered.

One mitigation effort called for by the plaintiffs has been to increase the level of water "spilled" over the dams to increase the safe passage of juvenile fish species over the dams. In April 2017, the District Court granted the plaintiffs' request for more spill and ordered it to begin in the 2018 "spill season" – the time of year that fish biologists have identified as being when the greatest number of fish migrate back to the ocean through the FCRPS. To comply with the court order, the federal defendants were required to spill water up to the maximum TDG levels ("gas caps") allowable by state law at the dams on the main stem of the Columbia River and the lower Snake River.

Looking to the Future: The Role of the FCRPS and a Low-Carbon Regional Grid

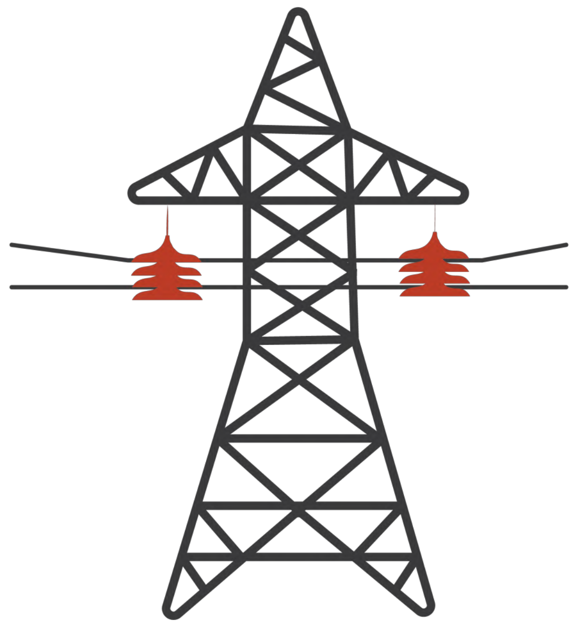
As the state and the region take more aggressive action to address climate change, the ability of the Federal Action Agencies to flexibly operate the FCRPS' 22,458 MW of carbon-free hydroelectric power will become increasingly valuable.

Regionally, as more variable-output renewable sources of energy come online, more flexibility will be needed in the electric sector—both in terms of demand for electricity that can shift to better align with the availability of renewable output, and in terms of other sources of electricity supply that can be re-dispatched to complement the variable output of renewables like solar and wind. While many fossil fuel power plants have the ability to operate flexibly to complement and integrate renewables, hydroelectric power plants are able to do the same without emitting greenhouse gasses.

Through the summer and into the fall of 2018, interested parties in the region have been exploring opportunities to increase the flexibility that BPA has to dispatch the FCRPS, while also doing more to restore threatened and endangered fish populations. Historically, BPA has relied upon selling a significant amount of its surplus power to utilities across the West. The revenue from these so-called "secondary sales" has been utilized by BPA to help maintain lower long-term power rates for their customers in Oregon and across the Northwest. To the extent that a new paradigm can be developed that allows BPA to better monetize its flexible, carbon-free surplus power, the more it will be able to continue to maintain low long-term power rates for its customers in Oregon.

Integration Challenges: Adding More Variable Renewable Resources to the Grid

As Oregon and other states consider various GHG emissions reduction programs and RPS targets, and as renewable energy technologies become increasingly cost-competitive with traditional resources, the conversation has turned to how to integrate increasingly higher percentages of variable renewable energy onto the grid at least cost and in a way that provides the most value.



Historically, utilities have designed and built the electric system to accommodate variability in customer demand by building transmission and distribution systems capable of carrying enough electricity from generators to customers to meet the highest level of demand expected, even if that level of demand only occurs a few hours of the year. This also required building out complementary resources, such as natural gas peaking facilities, that could deliver enough supply to meet variability in customer demand throughout the day and during different times of the year.

While the deployment of renewables presents new challenges, they are not dissimilar from the types of challenges faced by the industry in the past. The word often used when discussing solutions for integrating renewables is flexibility. Unlike conventional generators that utilities could dispatch to match variability in customer demand, the output of renewable generators is variable, requiring other electric generators to operate with more flexibility to complement the variability of renewables. Technology advancements are also making it increasingly possible to harness the variability of customer demand and better align that demand with the availability of renewable output. Meanwhile, energy storage technologies can provide flexibility of either supply or demand, as required, to complement the availability of renewable output. Finally, participation in larger electricity markets (such as the Western Energy Imbalance Market (EIM)) provides flexibility to utilities by giving them access to more liquid markets to buy and sell electricity to complement the variable output of renewables. Ultimately, the cost-effectiveness of any one of these solutions will need to be evaluated against the others to determine the least-cost pathways to integrating renewables. And with each potential solution, new policy mechanisms may be required to ensure that the value of the integration benefits are being appropriately compensated with the right price signals.

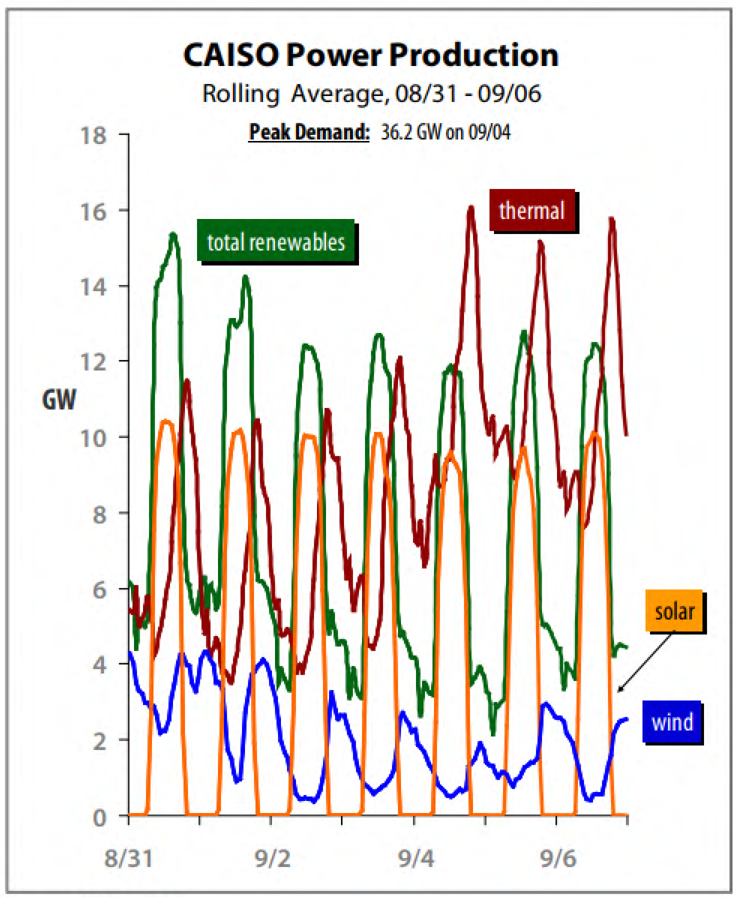
Flexible Supply

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 (as can hydroelectric facilities). Such plants have traditionally also been relied upon for providing ancillary services such as frequency support, voltage control, and reserves, and are often referred to as "baseload" generators. "Baseload" has no industry-accepted definition but has come to be understood as facilities that are usually large, designed to operate at or near capacity, and provide the cheapest power when operating at high capacity.[57]

The round-the-clock output of baseload facilities is in contrast to the variability of renewable resources like solar and wind power. Figure 3.14 demonstrates how fossil fuel generators (also known as thermal generators) are ramping up and down during hot summer days to integrate massive levels of solar generation. These thermal plants have several important physical limitations that should be noted. Each thermal plant will have a "ramp rate" that indicates how much it can increase or decrease output over a specific time horizon (e.g., 50 MW per hour). Pairing battery storage with these thermal plants can help to supplement these ramp rates. Additionally, these plants also have minimum output levels below which the plants would need to cycle off completely before restarting, a process that could take many hours or days, depending on the plant.

Oversupply is a term used to describe situations when the availability of variable output generation from sources such as wind or solar is greater than the net demand for that generation after accounting for the ability of other resources to ramp down to minimum levels of output. This has occurred in the Northwest in recent years during certain hours in the springtime when there is very low demand coupled with high output from hydropower and wind generators. Oversupply has become a much more significant issue in places with more renewable energy generation, such as Germany and California. As California continues to add more renewables to its electricity mix, the California Independent System Operator (CAISO) expects oversupply conditions to occur more frequently during certain times of year.[58] This is already becoming especially common during the day in the spring and fall, for example, due to the combination of a high level of output from the state's solar PV, with relatively low heating and cooling energy demands.

Figure 3.14: Rolling Average of Electricity Production by Source in CAISO for 8/31/18 – 9/06/18



Sources: CAISO and BPA

The most commonly used strategy to address renewable oversupply has been curtailment, or temporarily reducing the output of electricity from a generator from what it could have otherwise produced. While California has curtailed significant amounts of solar generation, most often during the spring and fall, Oregon does not yet have the same problem with solar. Most of the curtailment in Oregon occurs due to high wind output during the spring in the overnight hours between midnight and 4 a.m. – the spring runoff leads to more water in the hydropower system, winds are also strongest during overnight hours, and consumer consumption is at its lowest at those times.[59]

There are alternatives to curtailment when addressing renewable oversupply. One alternative is to re-dispatch other types of generation resources to complement the variability in output of renewables. For example, having a dispatchable generator that can quickly ramp down output as renewables come online can help to mitigate the need to curtail renewable oversupply. On the flipside, there will also be a commensurate need to have that same generator (or another) able to just as quickly ramp up output as the renewables stop generating. This type of quick-ramping capability has typically been provided by natural gas plants or hydropower in the past. Increasingly, new technologies like battery storage, pumped hydro storage, or more flexible renewables like geothermal, bioenergy, and wave energy can help provide this type of ramping capability.

At this point, the development of more flexible renewable resources involves significant costs and uncertainties to overcome technical, financial, legal, and regulatory barriers. Non-variable renewable resources (e.g. geothermal power) and less variable/more predictable renewable resources (e.g. off-shore wind and wave power) have fewer integration challenges than variable renewable resources but face significant technical and financial hurdles to achieve commercial development. Additionally, established variable renewable technologies (e.g. wind and solar) may be combined with emerging storage technologies, demand response programs, and related demand-side management strategies to be able to more closely resemble conventional, dispatchable resources.

Flexible Demand

Electricity demand has *always* been highly variable – the demand for electricity on a utility's system can be twice as large during the peak hour of demand in a day as it is during the lowest hour of demand on the very same day. Similarly, the peak demand over an entire year can be several times greater than the lowest point of demand in the same year. As noted above, the electric system has been designed, by and large, to meet these types of large swings in demand for electricity over different hours of the day and times of the year.

One method in the electric industry for minimizing the peaks is demand response. The Demand Response Advisory Committee at the Northwest Power Council* defines demand response as "a non-persistent intentional change in net electricity usage by end-use customers from normal consumptive patterns in response to a request on behalf of, or by, a power and/or distribution/transmission system operator. This change is driven by an agreement, potentially financial, or tariff between two or more participating parties."[60] Ideally, demand response programs allow retail customers to know when system costs are high,

*The NWPCC formed the Demand Response Advisory Committee in 2016 to develop and implement the NWPCC's recommendation in its 7th Power Plan to develop 600 MW of demand response in the region by the early 2020s.

typically due to high demand, and then shift their demand to lower-cost times when demand is lower. Utility time-of-use (TOU) rates are one example of a demand response mechanism that accomplishes this by charging higher or lower rates at different times of the day or year based on system conditions. Alternatively, customers may opt in to allow a utility (or a third-party aggregator) to have direct control over their demand for electricity from some processes or appliances, especially those related to heating and cooling, based on market signals or grid conditions. Demand response resources can be gathered at the moment of need or scheduled ahead of time. By reducing the magnitude of peak demands on the system, demand response assets can postpone, reduce, or even eliminate the need for costly upgrades or even for new generating resources to provide additional peak capacity. Flexible demand allows for the easier and more cost effective integration of variable renewable resources – demand can be dynamically increased or decreased in alignment with the availability of renewables. Increasingly, new technologies are creating opportunities for customers to automate these types of demand response activities, including the use of so-called “smart” thermostats or water heaters that can be optimized based on signals from the grid.

Many parts of the country already have significant amounts of demand response capacity deployed. For example, the PJM Interconnection in the mid-Atlantic region of the U.S.—the largest regional transmission organization in the country with peak summer loads near 150,000 MW—has more than 9,000 MW of demand response deployed throughout its territory.[61] In Oregon, the capacity provided by the region’s hydroelectric system has historically dampened the need for demand response. A variety of factors working in combination are beginning to change this, including continued (albeit slowed) regional load growth, retirement of fossil fuel resources, increasing penetration of variable renewables, additional constraints on the hydro system, and a growing summer peak load during a time of the year when output from the hydro system is lower. As a result, utilities in Oregon and across the region have been actively evaluating and deploying a variety of demand response pilot projects.

Many utilities across the region (including PGE, PacifiCorp, and BPA, among others) were participants in the Pacific Northwest Smart Grid Demonstration Project, a five-year, $178 million project co-funded by the U.S. Department of Energy through the American Recovery and Reinvestment Act of 2009.[62] The project concluded in 2015 and resulted in the deployment of dozens of innovative grid modernization and smart grid pilot projects, many of which incorporated demand response and load control functions. More recently, PGE has been actively developing a proposal, in response to guidance given in OPUC Order 17-386,[90] to develop a demand response test bed. The Smart Grid Test Bed, as envisioned, would result in PGE deploying demand response assets at scale, downstream of three different substations across its service territory. The goals of the project for PGE include: identify compelling and sustainable value propositions that demand response can provide to customers; determine the maximum amount of demand response capacity achievable; develop a plan to replicate demand response deployments beyond the test bed; and improve internal understanding of operational control of demand response assets to meet utility needs.

In Between Supply and Demand: Energy Storage and DERs

Depending on the circumstances, energy storage and other distributed energy resources (DERs) may exhibit the characteristics of either supply or demand. Learn more about DERs in Chapter 5.

Energy 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 threats. Unlike other forms of energy, such as liquid fuels, natural gas, or coal, it can be difficult and costly to store electricity in large quantities. That said, storage technologies are becoming more cost effective, and will likely prove critical to integrating higher levels of variable renewable energy and addressing peak loads.[63]

The most common residential and commercial energy storage systems use batteries. Utility-scale facilities may use batteries or other storage technologies, such as pumped hydro storage systems, mechanical systems such as flywheels or compressed air, or thermal storage systems that store heated materials for winter heating or ice for summer cooling. Storage systems may be designed to charge and discharge over a short-term daily basis, or over the long-term to balance seasonal energy cycles or for use during emergencies or outages.

In 2015, the Oregon Legislature established an energy storage mandate through HB 2193,[91] requiring PGE and PacifiCorp to procure a minimum of 5 MWh of energy storage by 2020, not to exceed battery capacity equal to one percent of the utility's peak load from 2014. With significant stakeholder engagement, the utilities developed an evaluation of the potential to site energy storage on their systems, as well as proposals for the procurement of energy storage projects consistent with the requirements of HB 2193.

In August 2018, the OPUC approved PGE's proposal to develop up to 39 MW of energy storage. PGE's proposal includes five separate projects:

1. **A 17 to 20 MW battery system located at one of its distribution substations;**
2. **A 2 MW battery system co-located with an existing solar project;**
3. **A 4 to 6 MW battery system interconnected to the transmission system and co-located at a utility-scale natural gas plant;**
4. **Multiple microgrid projects at customer sites, including up to 12.5 MW of battery systems; and**
5. **Up to 500 behind-the-meter, but grid-connected, battery systems at residential customer sites.**[64]

Meanwhile, in September 2018, the OPUC approved PacifiCorp's proposal to develop two separate energy storage projects: (1) a 2 MW / 6 MWh battery system located at a single customer site to evaluate energy storage alongside a blend of renewable and conventional generation; and (2) provide financial and technical assistance for the development of up to four energy storage projects intended to enhance community resiliency.[65]

Energy Markets

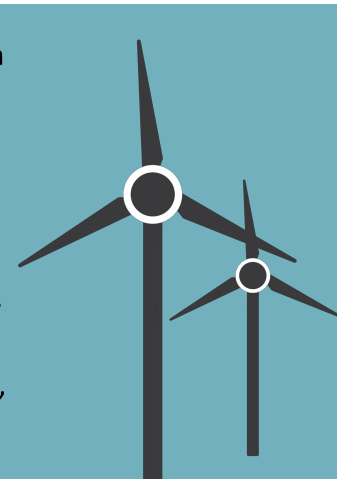
Energy markets provide a fourth type of flexibility for integrating renewable energy. Electric utilities must balance the availability of generating resources with loads on the electric grid. To do this, utilities commit generating resources over a variety of time horizons to meet expected future demands. With dispatchable resources, like fossil fuel plants, utilities can be assured of the level of generation output that the plant can deliver at a specific point in time in the future. The variable nature of renewable output, however, makes it more difficult for the utility to anticipate exactly how much output can be expected at a specific point in time in the future.

If a utility is attempting to secure commitments from generators to meet expected demands the next day, it may underestimate the output expected from variable renewable generators to avoid having insufficient resources committed to meet load. For the same reason, that utility may also overcommit its dispatchable resources because of the certainty of the output that those resources can deliver. Continual improvement in the industry's forecasting of the output of variable renewable generators helps utilities to be more accurate when making these types of commitments in advance. But having the ability to re-dispatch renewable generators over shorter time intervals provides another valuable tool for utilities to more efficiently utilize the output of renewable generators when their output varies from the advanced forecast.

Participation in the Western Energy Imbalance Market (EIM) provides participants (including PGE and PacifiCorp in Oregon) with access to real-time markets that can re-dispatch generators across a wide area of the western United States over five-minute time intervals. Allowing for optimization over such near-term time intervals allows participants to utilize more variable renewable output and lowers overall system costs.

CONCLUSIONS

While Oregon has a long history of supporting renewable energy, with this history comes a need to **update and align programs and associated policies** to meet the evolving energy needs of this state.



Meeting the new RPS requirements while also addressing increased demand for voluntary renewable electricity means addressing a number of interrelated challenges and opportunities, including efforts to increase system flexibility, integration of variable renewable resources, energy storage, demand response, smart grid technologies, greenhouse gas mitigation policies, changing energy imbalance markets, and nascent renewable energy technologies.

To address these challenges the Oregon Department of Energy recommends **exploring new strategies for energy planning**, a review and analysis of the role of incentives to determine whether phase outs will materially affect project development, and continued evaluation of regional market opportunities.

Advances in Solar Energy

Case Study of Renewable Energy Market Transformation

Technology Overview

Solar photovoltaic (PV) systems generate electricity from sunlight. They are unique in the renewable energy sector because of the wide distribution of the resource. Unlike wind, geothermal, or hydropower facilities, which are dependent upon specific sites, a solar energy project may be located on any unshaded site across Oregon. PV systems range from remote off-grid cattle watering stations in Eastern Oregon to grid-tied facilities connected to utility distribution systems in the rainiest locations on the coast.

Grid-tied solar energy facilities may be categorized as residential, commercial, or utility-scale systems. While these categories do not have strict definitions, residential systems are typically net metered and less than 25 kW in size. Commercial systems are also net metered and may be up to 2 MW in size, though most of them are considerably smaller. Utility-scale systems are not net metered and instead sell energy directly to a utility; these systems are typically 2 MW or larger.

Net metered systems are typically interconnected to an electric service panel and offset some of the electricity used on-site during certain hours of the day and year. With net metering arrangements, excess solar energy production (i.e., output that's in excess of what the customer consumes on-site) is exported back to the utility and generates a credit on the host customer's electric bill. In Oregon, all electric utilities are required to offer net metering to their customers, though the terms of net metering agreements differ widely, particularly between IOUs and COUs. Oregon's IOUs are required to offer "annualized" net metering, where a monthly surplus of energy may be carried forward to future months, and the customers are compensated for any excess exported to the utility with a bill credit equivalent to their full retail rate had they purchased the same amount of electricity from the utility. This is especially valuable in Western Oregon, where a summer surplus may be carried into the less sunny winter months to continue offsetting their utility bills during those months. The state's COUs, meanwhile, are mandated to offer net metering, however the treatment of surplus production differs by utility. Some offer "monthly" net metering where surplus energy is not carried forward to future billing periods. COUs may offer annualized net metering on a voluntary basis. Additionally, while each COU implements net metering differently, COUs are not required to offer bill credits equivalent to the customer's full retail rate.

Utility-scale solar facilities are either owned by a utility, sell energy to a utility or sell energy directly to a corporate partner through a direct access agreement. These facilities are typically interconnected on a utility distribution or transmission system. The energy payments from utilities to project owners for most projects are based on the utility's avoided cost for energy or negotiated power purchase agreements. The avoided cost is a value representing what the utility would pay for energy under their standard energy procurement contracts.

Global Trends in Solar

Increasing Capacity and Investments

Solar energy has become a global leader in new added capacity and new financial investments. In 2017, more than $160 billion was invested in solar energy development – more than the investments in coal, natural gas, and nuclear combined.[66]

PacifiCorp's 2-megawatt Black Cap Solar facility in Lakeview, OR.

While the pace of solar development has skyrocketed, solar still makes up a relatively small share of our energy mix nationally. In 2017, solar generation accounted for 1.9 percent of total U.S. generation.[67] As the price to develop solar projects continues to decline, it is expected that solar projects will increasingly be developed to replace retiring coal and natural gas plants.

Cost Reductions

A number of factors are working together to increase the deployment of solar energy facilities. The primary factor has been cost reductions. As discussed earlier in this chapter, the cost of PV modules, the primary component of a PV facility, has dropped by more than 85 percent since 2010. Other hardware components have also seen significant price reductions during the same time period.

In some parts of the country, cost reductions have led to PV facilities competing with conventional coal and natural gas plants on price for as-available energy in some instances. Recent examples include the Xcel Energy bid in Colorado, announced in January 2018, where solar plus battery storage was bid at a median price of $36 per MWh, or 3.6 cents per kWh.[33] In June 2018, NV Energy in Nevada received bids for solar energy below 2.3 cents per kWh.[68] An RFP from the Central Arizona Project solicited bids from a 30 megawatt solar facility to provide energy at $2.499 per kWh.[69] The Arizona project was proposed to replace energy delivered by the coal-fired Navajo Generating Station. In this case the energy supplied by the coal facility cost around 5.0 cents per kilowatt-hour, or twice as much as the proposed solar contract. While these solar facilities are competing in the market based on their cost of as-available energy, they are not designed to completely replace thermal power plants which are still providing additional grid services and are capable of operating at much higher capacity factors.

PV Module Efficiency

In addition to cost reductions, PV modules have also become more efficient over time. PV modules are measured in Direct Current (DC) Watts based on their power output under standard test conditions. In 2010, SolarWorld in Hillsboro, which was recently purchased by Sunpower, produced one of the most efficient PV modules in the world, generating 220 to 235 watts of power. Today, the same-sized SolarWorld module will generate 300 watts of power, representing an increase of more than 25 percent.[70]

Efficiency improvements affect several factors in deployment and pricing of PV projects:

1. **Reduced system footprint / land use: As the efficiency of PV modules increases, the amount of roof space or land necessary for a given system capacity decreases. Just as PV modules are measured in DC Watts, PV facilities are measured in units of 1000 Watts (Kilowatt or kWdc). A 100 kWdc system installed in 2010 would have required about 7,700 square feet of PV modules. The same 100 kWdc system installed in 2018 will require about 6,000 square feet.**

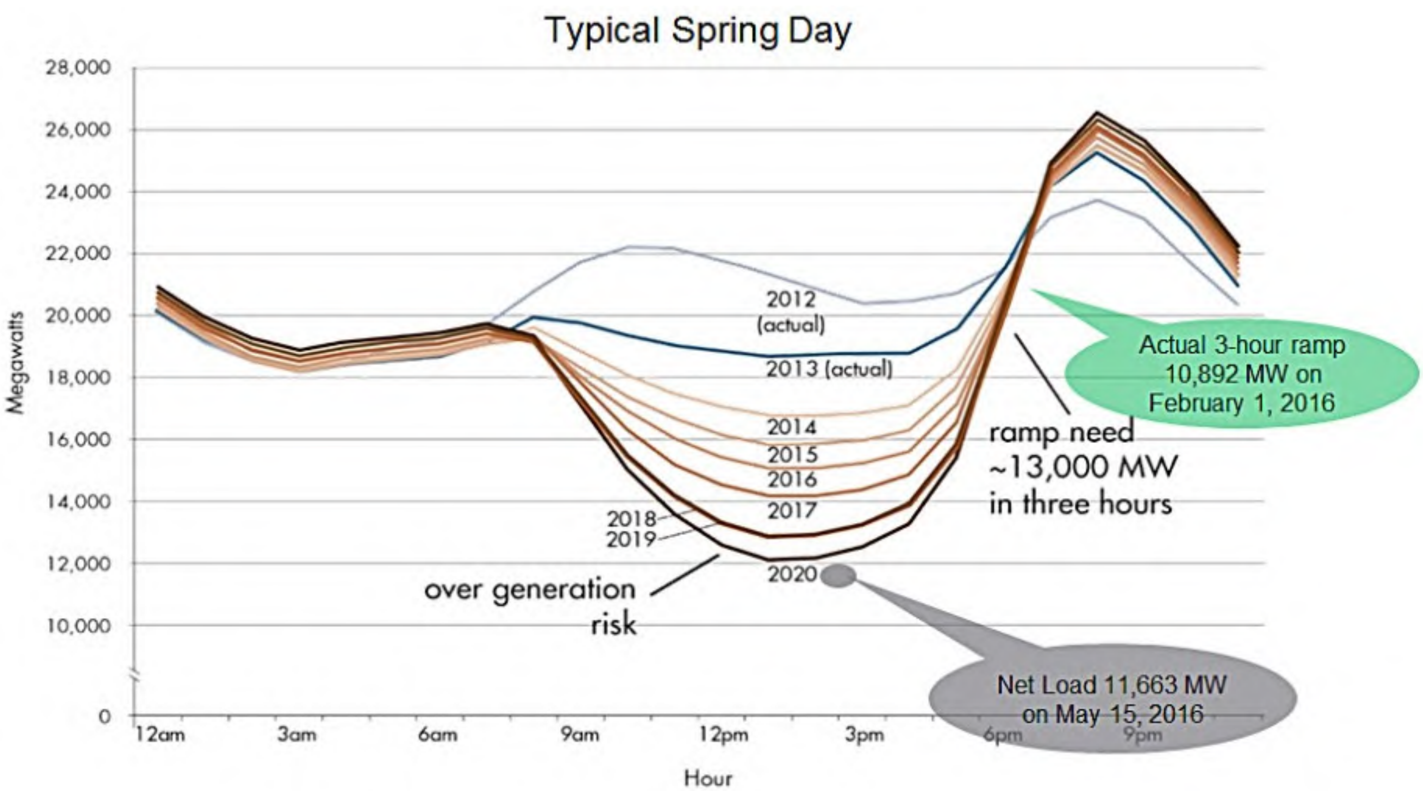
2. **Reduced labor costs: The labor associated with handling and installing PV modules is a major component of overall system pricing. Increased efficiencies results in fewer PV modules and a reduction in labor costs for a project with the same generation capacity.**

3. **Reduction in balance of system equipment: Similar to labor reductions, increased module efficiency reduces the balance of system equipment necessary to install a PV system. Balance of system equipment refers to racking, mounting hardware, wires, and other materials but does not include the PV modules or inverters.**

Integration Challenges

Solar PV facilities are variable generators that only produce energy during daylight hours. Solar generation ramps up quickly in the morning, provides peak generation during the middle of the day, and ramps down quickly in the evening. This pattern has proven to be a challenge for grid operators to integrate with system loads. As solar output is declining in the early evening, customer energy demand on the grid tends to be increasing. Net load or net demand is a term used to describe system energy demand, less the demand that is met by solar output on the grid. In areas with high solar penetration, the resulting net demand curve can drop steeply in the morning as solar output increases rapidly, and then climb steeply in the evening as solar output declines. When plotted over the hours of the day, the net demand curve resembles the profile of a duck and so has been colloquially named “the duck curve.” The “belly” of the duck represents low net power demand on the grid due to peak solar output on the grid. The “neck” of the duck represents the steep ramp up of net power demand as people come home from work and turn on lights and appliances at the same time the sun is going down and solar output declines. This neck of the duck requires a large amount of non-solar capacity to be dispatched on the grid over a relatively short timeframe. This phenomenon occurs when two factors are present: (1) significant solar output, and (2) comparatively low net load during mid-day hours. As a result, to date the duck curve has occurred in markets with large amounts of solar, especially California and Hawaii, during springtime months when mild weather results in low mid-day net loads.

Figure 3.15: The Duck Curve on California's Grid



The challenges associated with solar integration can be mitigated with four primary and interactive strategies:

1. **Change the shape of the load profile:** Late afternoon and evening loads are primarily attributed to increasing residential demands that naturally occur at the end of the work day. Some of these loads, such as water heating, dish washing, laundry, and air conditioning could be shifted to earlier or later in the day.

2. **Change the shape of the solar production profile:** While the output from PV modules will always correspond with the amount of sunlight, the output of the overall PV facility may be changed with energy storage. Adding batteries to a solar facility can shape the production profile to match the load profile.

3. **Increase flexible capacity resources:** Flexible capacity resources are able to ramp up and down to serve the variable loads on the grid. Battery storage systems, natural gas "peaker" plants, pumped storage hydro systems and the existing BPA hydro system are all able to provide flexible capacity in the Northwest.

4. **Export, curtail, or transform excess solar generation.** Curtailment is currently being implemented in California during periods of excess solar generation. Regional energy markets may be able to provide an export option. Transforming excess generation could be accomplished by using solar energy to create hydrogen or liquid fuels. This is also known as power-to-gas.

Where does Oregon Stand?

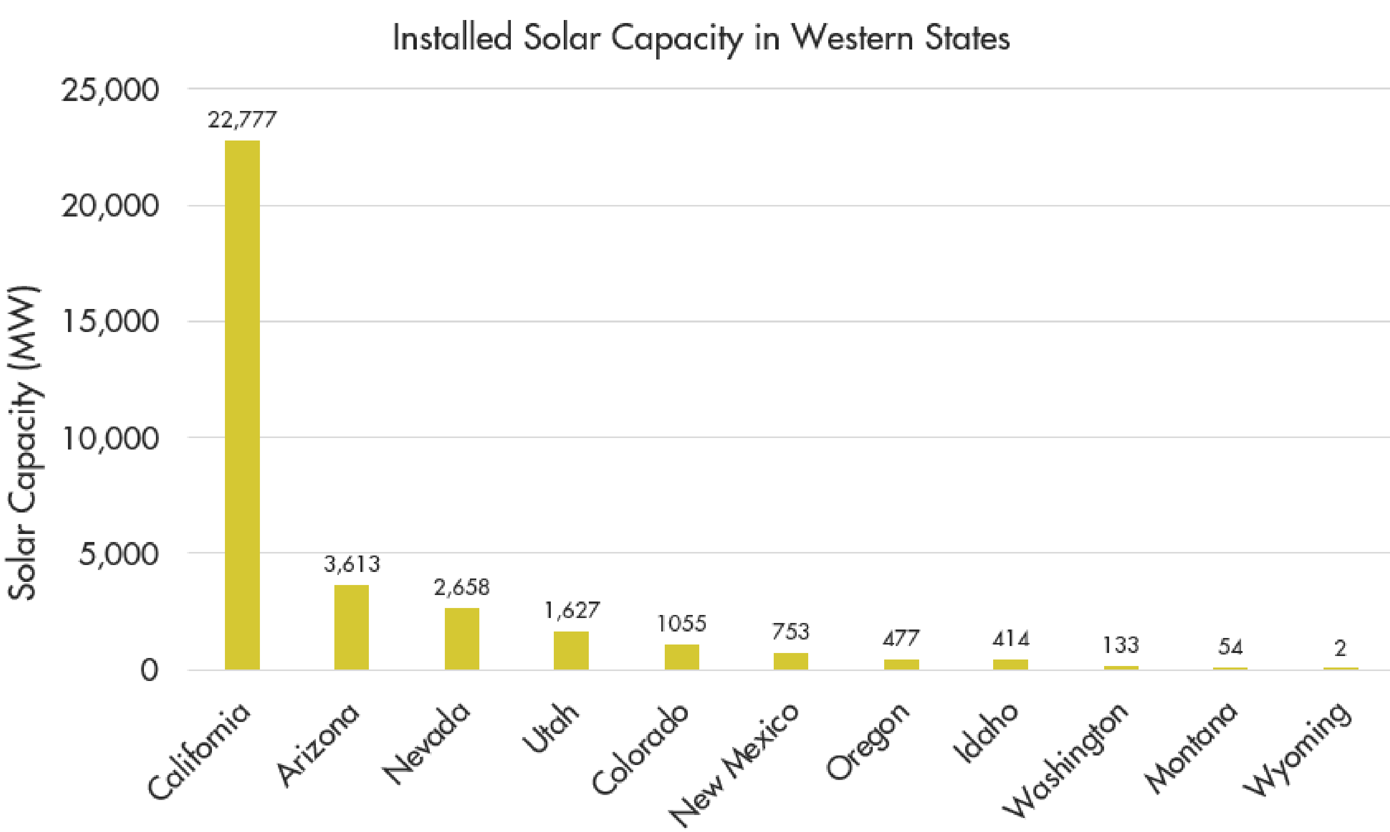
Despite being known for its rainy climate, Oregon has significant solar potential. For example, a residential PV system installed in Astoria will generate only about six percent less energy than the same system in Portland. The same system installed in Newport will generate three percent more energy than the Portland system.[71] Despite the wide differences in resource potential around the state, nearly half of the residential PV capacity in the state is installed in Multnomah, Clackamas, and Washington counties.[72]

Oregon's coastal solar resource, in fact, outperforms much of Europe where a significant amount of solar capacity has been installed. A PV system in Astoria will generate about 5 percent more energy than the same system in Munich, Germany. Germany has installed more than 44 GW of solar, or about 100 times as much as Oregon and Munich is located in the part of the country with the best solar resource.[73]

As of Q2 2018, there was at least 477 MW of total solar capacity installed in Oregon. More than 70 percent of the total solar capacity in Oregon was installed since the beginning of 2017,[74] and there has been an increase in the size of projects. For example, the 56 MW Gala Solar project installed in Prineville in 2017 will generate more energy in 2018 than all of the residential systems in the state combined.

According to the Solar Energy Industries Association (SEIA), Oregon ranks 20th in the U.S. for total installed solar capacity.[74] Figure 3.16 shows installed PV capacity in western states, as of Q2 2018. It is difficult to track the exact cumulative capacity of solar installed in Oregon in real time, as many projects come online before utility data reports are updated.

Figure 3.16: Installed Solar Capacity in the Western States[75]

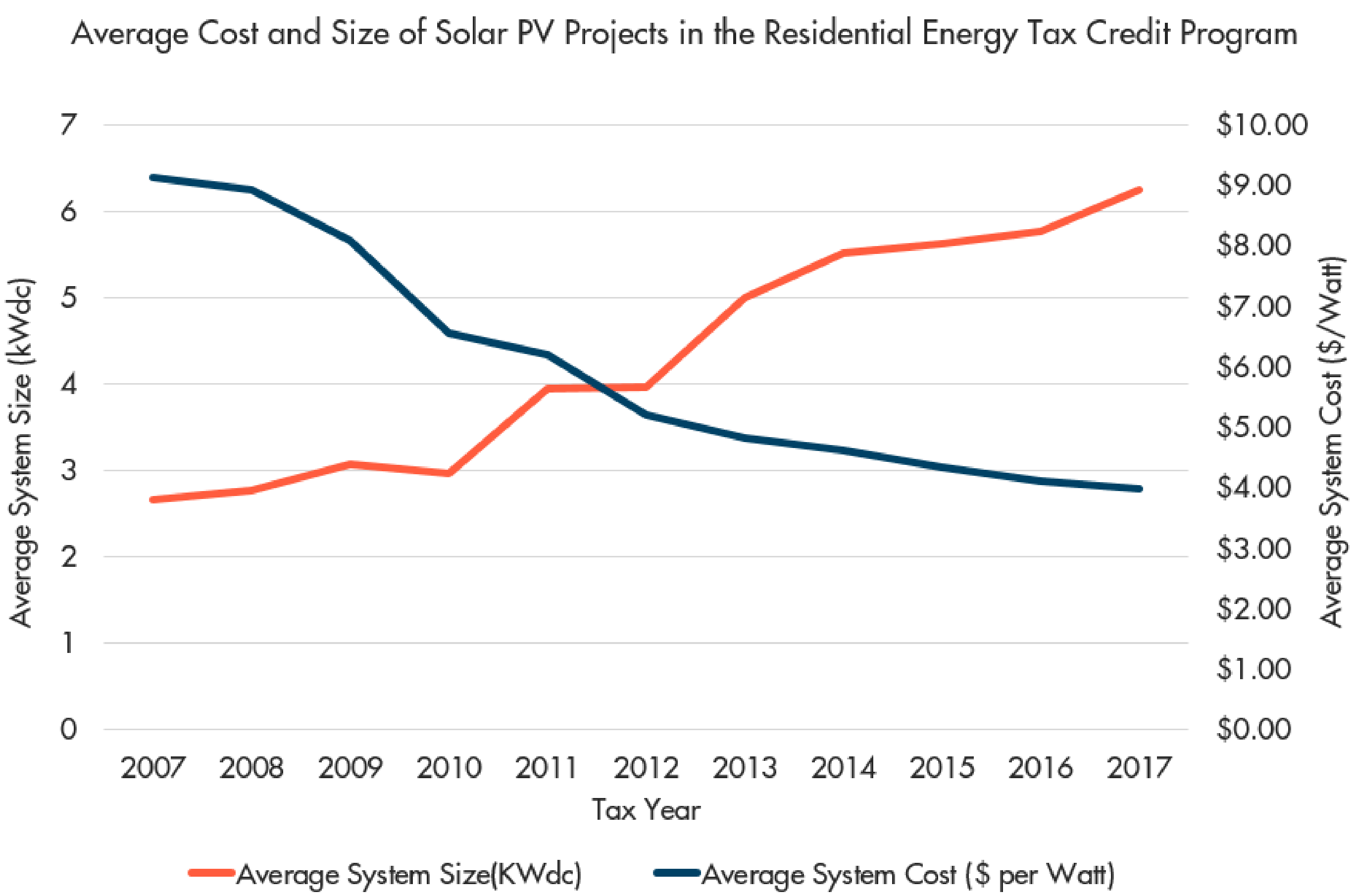


Oregon's solar capacity is divided between residential, commercial, and utility-scale projects. Approximately

85 percent of the residential capacity is west of the Cascades while about 90 percent of the utility-scale projects are east of the Cascades.

Reduced costs for PV equipment have resulted in larger systems being installed. As figure 3.17 demonstrates, in the Oregon residential market, the average PV system size has increased from 2.5 kWdc in 2007 to more than 6 kWdc in 2017. Over the same period, the cost of these systems has decreased from over $9.00 per watt to about $4.00 per watt. Over the same period the number of systems installed per year increased from less than 250 in 2007 to more than 2,800 in 2017.

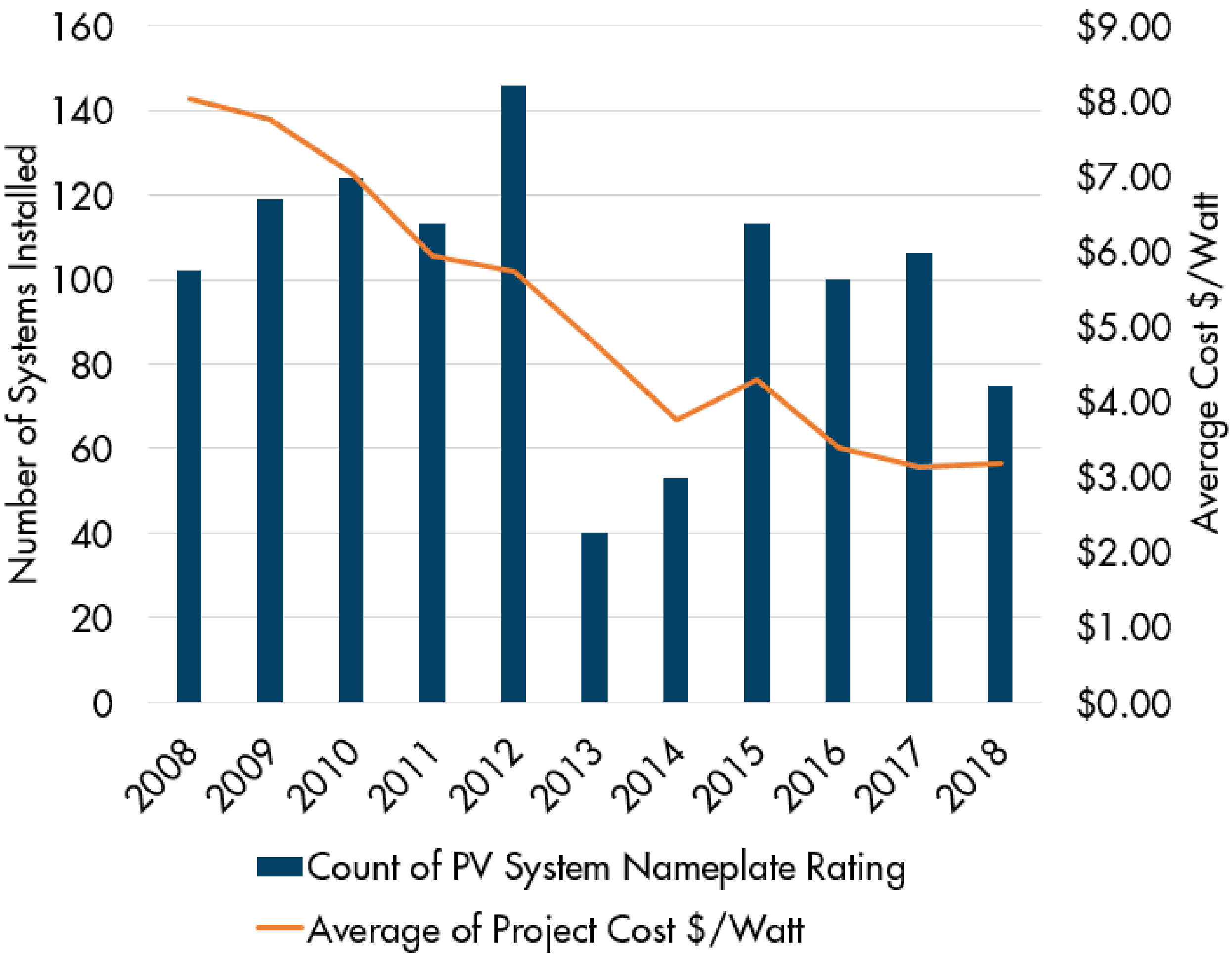
Figure 3.17: Average Cost and Size of Solar PV Projects in the RETC Program[72]



While the cost of residential solar energy projects in Oregon has declined, the rate of decline has not kept up with the national average pricing of $2.80 per watt in 2017 demonstrated in the NREL 2017 benchmark study,[31] due in part to the relatively small solar market in Oregon compared to some other states. In 2017 there was a total of 20 MW of residential solar installed in Oregon, which makes up less than one percent of the 2,227 MW installed nationwide.[72,76]

Oregon's commercial PV sector has also seen significant cost reductions. The average cost for commercial PV systems in the Energy Trust of Oregon incentive programs was about $8.00 per watt in 2008 compared to about $3.00 per watt today. The sharp drop in projects seen in the figure below is a result of changes to the Business Energy Tax Credit program.

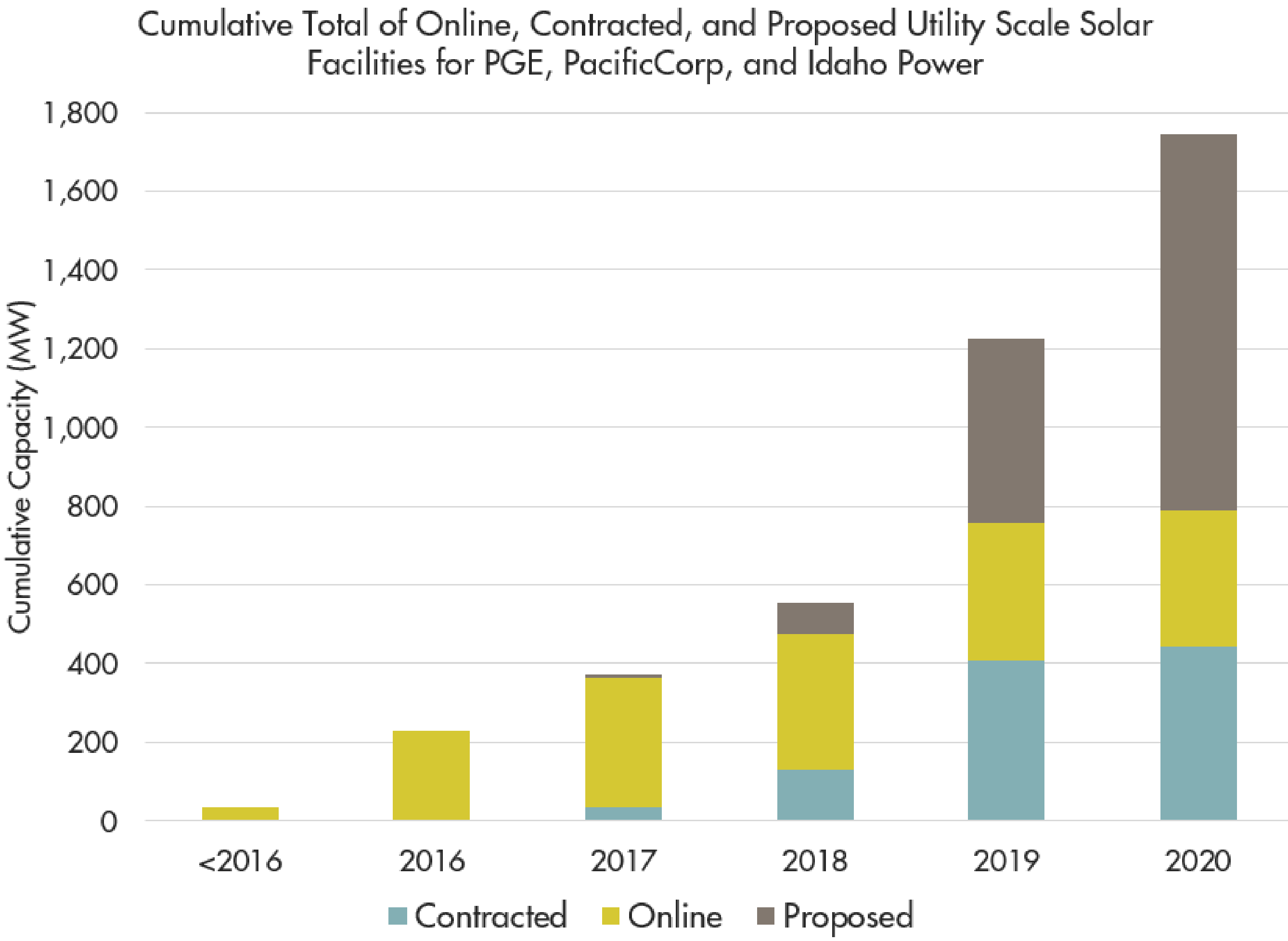
Figure 3.18: Average Cost and Number of Solar PV Projects in the Energy Trust of Oregon Commercial Incentive Programs[77]



Utility-scale projects have also grown in size. In 2013, the Outback Solar facility in Christmas Valley was, at 5.2 MW, the largest single solar project in Oregon.[78] By the end of 2016, there were an additional 22 facilities exceeding 5 MW and totaling more than 180 MW of combined capacity. In 2017, the Gala solar project in Prineville became the state's largest at 56 MW. The Boardman Solar project is the first solar facility to be approved for a Site Certificate through Oregon's Energy Facility Siting Council, and is proposed to be 75 MW. In California there are many facilities between 100 and 500 MW in size. Globally, PV facilities exceeding 1,000 MW in capacity have been installed in India and China.

Development of utility-scale solar facilities has rapidly increased in Oregon since 2016. More than 50 percent of Oregon's total solar capacity (260 MW) is in utility-scale facilities installed or scheduled for operation in 2017 and 2018. Nearly 1,000 MW of additional capacity is currently proposed for development by the end of 2020. These proposed projects are reported in utility interconnection queues which have traditionally had a high attrition rate. As solar project costs continue to fall, more facilities will be constructed in Oregon.

Figure 3.19: Cumulative Existing Capacity and Interconnection Applications for Utility Scale Solar Capacity Reported by PGE and PacifiCorp



Federal Tariffs

In January 2018, the Trump Administration established tariffs on imported solar modules. The tariff is initially set at 30 percent, reducing 5 percent each year, and ending in 2022. As most of the solar modules used in Oregon and the U.S. as a whole are imported, these tariffs could significantly increase the cost of solar projects. In addition, tariffs on steel and aluminum products also threaten to reverse the downward cost trends seen in the solar industry. Cypress Creek Renewables, a solar developer active in Oregon, announced the cancellation of 1,500 MW of new solar projects across the country as a result of the tariffs.[79] Nationally, more than $2.5 billion in new solar investments have been cancelled.[80] Some domestic manufacturers, including Hillsboro's Solar World, advocated for the tariffs in order to provide a boost for U.S. solar manufacturers. The overall impact in Oregon from these tariffs is not yet known.

In June 2018, the IRS issued a ruling regarding treatment of the federal Solar Investment Tax Credit (ITC) ramp-down. The ruling allows the 30 percent ITC to be taken by project owners who commit at least five percent of the budget by the end of 2019. These projects then have until 2023 to complete construction. This means that 2022 and 2023 will be years where projects can avoid tariffs and still claim the full 30 percent ITC.

Policies Affecting Solar in Oregon

There are a number of new solar programs and policies under development in Oregon that have the potential to significantly alter local solar markets. The Oregon Legislature passed SB 1547[92] in 2016, which established the state's first legislative mandate for a community solar program and development of a resource value of solar.

Community Solar

Community solar projects have been installed in 42 states, 19 of which have implemented community solar programs. By Q1 of 2018, there were more than 1,000 MW of community solar projects nationwide.[81] These community solar projects typically differ from conventional solar facilities in a couple of ways. First, ownership of community facilities may include a cooperative of participants, a utility, or private developers and investors. Second, the output of a community solar project is typically allocated among participants. This allocation may be accomplished with or without involvement from a utility partner. Projects installed with a utility partner may utilize virtual net metering where the output from a central solar facility will be allocated to each participant in the form of a credit on their existing utility bills.

Oregon Laws 2016, Chapter 28 (SB 1547)[92] directs the OPUC to establish a program that enables owners and subscribers of a community solar project to share in the costs and benefits of the project. The program applies to customers of PGE, PacifiCorp, and Idaho Power, and enables subscribers to realize electric bill savings associated with a share of a community solar facility. The program is still in development at OPUC and has not yet resulted in any projects.

Community solar projects have been built in Oregon outside of the OPUC community solar program. In 2007, the City of Ashland installed a 63 kW community solar system known as Solar Pioneer II at the City of Ashland Service Center. Shares of the project were made available to any Ashland Utility customer. In 2016, Central Electric Cooperative completed installation of the 200 kW Shared Solar community solar project in Bend. Similarly, Emerald People's Utility District launched their Sharing Sun community solar project in 2017.

Community solar projects present numerous opportunities for utilities, home owners, renters, low-income communities, solar contractors, and program delivery contractors:

- Increased access to solar for Oregonians who cannot or have not installed individual solar facilities of their own. A 2015 report from NREL indicates that 49 percent of American households and businesses lack adequate solar resources for an onsite solar installation.[82]
- Increased solar market activity for Oregon solar contractors. Community solar projects may help to offset market losses associated with the end of the RETC program in 2017, described in more detail below.
- Utilities will be given the opportunity to provide additional services to their customers. While there may also be an increase in utility administrative costs, this may be offset by increasing customer choice and satisfaction among customers.
- Increased access to solar by low-income Oregonians. For many Oregonians, conventional solar

installations are not affordable, so community solar could provide options for participation with minimal financial burden. Oregon's community solar program has a provision to make 10 percent of the program available to low-income communities. While implementation of the low-income provisions has yet to be defined, it is expected to increase the equitable distribution of solar in Oregon.

- Centralized community solar projects are able to leverage economies of scale compared to an equivalent capacity of distributed solar facilities.
- Centralized community solar projects are more likely to be optimized for annual solar energy production. This may be accomplished through strategic site selection to minimize shading obstructions and through the use of solar trackers for ground mounted systems.

There are also a number of challenges specific to community solar projects:

- Administrative burden for utilities to implement programs, including development of virtual net metering protocols.
- Additional administrative costs associated with ownership and membership of the projects. Administrative costs make up one component of "soft costs" associated with all solar projects. Community solar projects may have additional costs associated with marketing to participants, legal fees associated with ownership models, and ongoing bookkeeping costs associated with allocating facility production among members.

Resource Value of Solar

Oregon Laws 2016, Chapter 28[92] directs the OPUC to establish a resource value of solar (RVOS). The RVOS is an analysis to determine the net costs and benefits that distributed solar facilities bring to the ratepayers of Oregon's investor-owned utilities. The OPUC currently has four dockets dedicated to examining the RVOS. They are:

- UM 1716 (Investigation to Determine Resource Value of Solar)
- UM 1910 (PacifiCorp Resource Value of Solar)
- UM 1911 (Idaho Power Resource Value of Solar)
- UM 1912 (Portland General Electric Resource Value of Solar)[83]

UM 1716 determined the methodology for calculating the RVOS. The docket started with a scoping task to determine which elements to include in the RVOS calculation. The OPUC determined that only elements directly attributable to utility electric ratepayers should be included, and that any additional societal benefits associated with distributed solar should not. Table 3.6 includes the 11 elements identified in UM 1716 to be included in the RVOS. Positive values are described as a benefit while negative values are described as costs.

Table 3.7: Elements Considered in the Oregon Resource Value of Solar Calculations

Benefits	Costs
• Avoided Energy Cost	• Administration
• Avoid generation capacity	• Integration
• Avoided transmission and distribution capacity	
• Avoided line losses	
• Market price response	
• Avoided hedge value	
• Avoided environmental compliance	
• Avoided RPS compliance	
• Grid services	
Total Resource Value of Solar: Net Benefit	

Distributed solar cost/benefit analyses have been completed in more than 20 states with a variety of results. Some states, such as Pennsylvania and New Jersey, have included societal benefits in the analysis.[84] Societal benefits included elements such as local economic development, health and environmental benefits associated with reduced fossil fuel combustion, water and land savings, and other environmental benefits. The Oregon PUC decision to not include societal benefits is consistent with the HB 2941 solar incentives report published by the PUC in 2016.[85] In that report the PUC recommended, "If the Legislature sees value in promoting the development of solar PV in Oregon for social and economic development reasons, it should consider adopting incentives available to all Oregonians."

Once established, the RVOS in Oregon will be used as the reimbursement rate for utilities to credit community solar participants. In an effort to enable community solar projects to proceed as RVOS is developed, the Oregon PUC has established an interim RVOS rate equal to residential retail rates. This value will be revisited upon completion of RVOS proceedings. While community solar reimbursements are the only statutorily directed use for the RVOS, the 2016 report from the OPUC recommended alignment of community solar and net metering reimbursements rates. The report also indicates that following the RVOS valuation proceedings, the OPUC will open future dockets to determine additional applications for the RVOS.[85]

Incentives for Residential PV Systems

Oregon's low energy rates affect the cost-effectiveness of solar energy projects in the state, and policymakers have created financial incentive programs to support development. While the cost of PV systems has decreased, residential and commercial PV projects still have considerable above-market costs in Oregon. Above-market costs are the difference between the market value of a project's energy production compared to the actual costs to produce the energy. Figure 3.20 shows how much a residential PGE customer could anticipate paying for a solar system in 2018 and how long it would take to pay off with estimated bill savings. The analysis does not account for escalating energy prices or the time value of money.

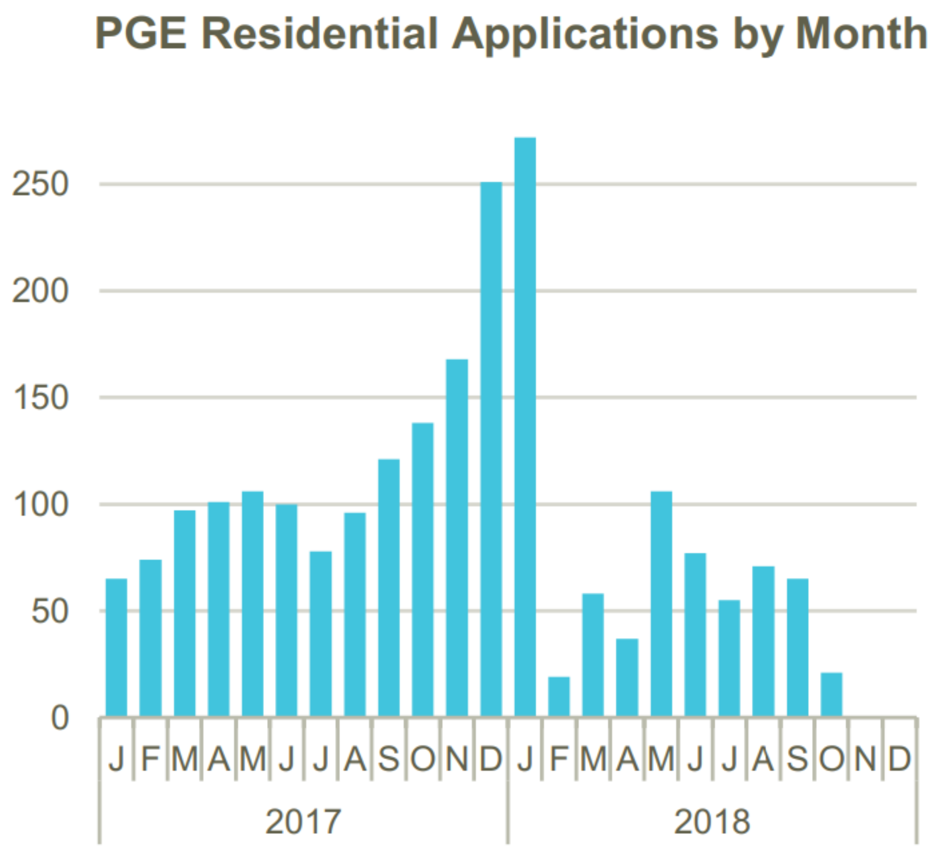
Figure 3.20: Typical Solar Cost for PGE Residential Customer

System Size:	6 kWdc
Cost:	$22,500 ($3.75/watt)
Energy Trust of Oregon incentive:	-$2,700
Federal Tax Credit	-$5,940
Net Cost to Owner	**$13,860**
Estimated Annual Energy Production	7,200 kWh
Estimated Annual Bill Savings:	$800 ($0.11/kWh)
Simple Payback:	17 years

The Oregon Legislature has created a variety of incentive programs through the years, including tax credits, cash rebates, volumetric incentive rates, production payments, and property tax abatements. The Energy Trust of Oregon offers incentives for solar installations for consumers in PGE and Pacific Power service territories and some consumer-owned utilities offer incentives to their customers. While these incentives have successfully supported the development of a solar industry in the state, they have also contributed to periods of volatility, especially in the residential market. In 2012, about 1,500 residential solar projects were installed in Oregon; one year later, less than 900 systems were installed. The decline was primarily attributed to reductions in Energy Trust of Oregon incentives. During the 2017 tax year, ODOE's Residential Energy Tax Credit program processed applications for more than 2,800 systems. System installations are expected to drop by nearly half in 2018, due to the sunset of the RETC program on December 31, 2017.

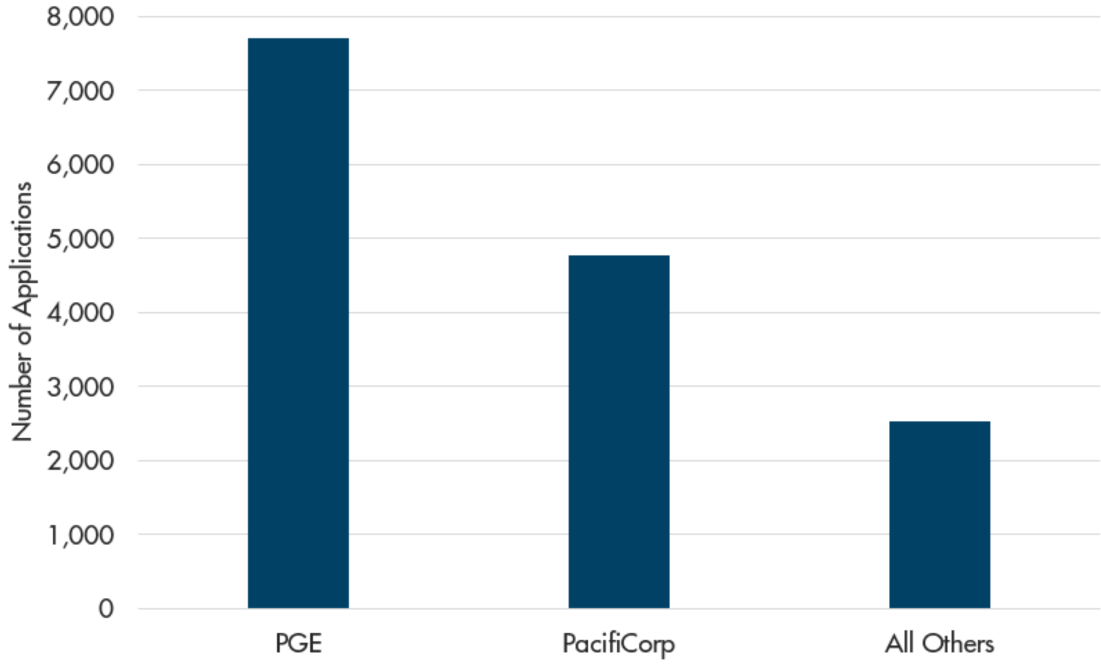
The RETC program provided up to $6,000 in tax credits taken over four years, and reduced the simple payback period to around 10 years for the sample system in PGE territory described above. A reduction in residential PV applications at Energy Trust of Oregon provides an indication of the impact associated with the sunset of the RETC. Prior to 2018, participants in the Energy Trust of Oregon PV incentive program were also eligible for the RETC. The RETC sunset resulted in increased program activity in 2017 followed by a decrease in activity in 2018. Figure 3.21 demonstrates the number of applications received by Energy Trust of Oregon in 2018 compared to 2017, following the sunset of the RETC program. In the first six months of 2017, Energy Trust received 1,040 applications compared to 545 over the same period in 2018. The second half of 2017 saw a spike in applications from homeowners racing to take advantage of the RETC. Energy Trust increased residential solar financial incentives to correspond with the RETC sunset. The Energy Trust residential PV incentive in December 2017 in PGE territory was $0.25 per watt, up to $1,500. In January 2018, the incentive rate more than doubled to $0.60 per watt, and the incentive cap more than tripled to $4,800. Even with Energy Trust's higher incentive for residential PV, out-of-pocket costs for customers went up when RETC ended.

Figure 3.21: Residential Solar Applications from PGE Customers Received by Energy Trust in 2017 and 2018 (Energy Trust of Oregon Solar Status Update 9/7/2018)[103]



Systems installed under the Energy Trust incentive program still receive a financial incentive and are easy to track. In 2017, there were 2,800 residential PV systems that received a RETC. Of those, 500, or about 18 percent, were outside of Energy Trust territory, which only includes customers of PGE and PacifiCorp. The effect of the loss of the RETC incentive is expected to be higher outside Energy Trust territory. Complete 2018 data from these markets is not yet available. Figure 3.22 demonstrates how projects have been distributed across utility service territories in the RETC program.

Figure 3.22: RETC Project Distribution Across Utility Service Territories



As solar costs continue to come down, financial incentives will play a smaller role in market adoption. Financial incentives aimed at solar market transformation are meant to serve as a bridge to a future market where solar is cost-competitive or at parity with conventional grid electricity. This can be seen in the design of the federal investment tax credit which begins a ramp down in 2020, and drops to zero in 2022. In a 2012 report, NREL determined that Oregon would be among the last states to reach grid parity due primarily to low energy costs and lower solar resources than many other U.S. states.[86] While many of the market conditions have changed in the last six years, it is true that Oregon still has larger financial hurdles than many other states.

Land Use

Solar land use laws in Oregon primarily affect utility-scale systems, and vary by the system size and the classification of soils on the site. While the rise of utility-scale projects in Oregon is relatively new, farmers have been installing solar energy systems to support on-site energy loads for years. Many of these systems used barn roofs or uncultivated land adjacent to irrigated fields, and were interconnected to electrical services for farm operations and irrigation pumps.

In 2012, Outback Solar, the state's first utility-scale project, was installed on 50 acres of rangeland in Christmas Valley (right).

Permitting authority for utility-scale solar projects is dependent on the proposed size and location of the projects. Smaller projects are subject to county (or city) jurisdiction, and larger projects are subject to EFSC jurisdiction. The majority of these projects are proposed on farmland that is zoned as "Exclusive Farm Use." "Goal 3" of the Oregon statewide land use planning goals[44] protects farmland, and the Land Conservation and Development Commission has issued rules implementing Goal 3 protections. Projects that permanently remove farmland from production over certain thresholds must receive a Goal exception as part of their approval in order to construct these projects. Those thresholds are tied to agricultural productivity and include the following:

- Facilities that occupy more than 12 acres of high-value farm land;
- Facilities that occupy more than 20 acres of arable lands; or
- Facilities that occupy more than 320 acres of non-arable lands.

Like all energy generation projects, for solar projects to be as financially viable as possible, they are sited near transmission lines to minimize the cost of creating inter-tie transmission lines, which are very expensive. This limits the locations in Oregon where energy generation development, including solar energy development, can occur.

Future site of the approved Boardman Solar Facility.

There is a lot of variation in the size of utility-scale solar facilities. The vast majority of these projects are between 12 and 100 acres. However, there are several larger projects of note. The largest operating is the 320-acre Gala Solar project located in Crook County. The largest approved but not yet constructed project is the Boardman Solar project in Morrow County, which is proposed to be 545 acres when completed. Finally, the Oregon Department of Energy just received the Obsidian Solar Center project application in north Lake County which is proposed to be 3,921 acres.

Locations in Oregon that can support such large-scale industrial development, and that are located in close proximity to transmission lines with capacity, tend to be either farmland, rangeland, or undeveloped native habitat. Effects from solar development on farmland or native habitat have caused considerable interest and concern from many parties. As a response to solar development proposals on Willamette Valley farmland, both Marion County and Yamhill County have passed ordinances restricting future solar development until additional assessment, land use rules, and protection measures can be developed, and the effects of solar on farmland can be further considered by the counties.

Similar opposition has come from other groups concerned about solar development on native habitat, particularly in central, southern, and eastern Oregon's high desert regions. Solar projects in these areas functionally remove habitat from use by native species, and, at a very large scale, can disturb movement by larger species, including big game. Solar projects under EFSC jurisdiction must comply with the EFSC Fish and

Wildlife Habitat standard, which is connected to the ODFW Fish and Wildlife Mitigation Policy, and which includes requirements to attempt to avoid and minimize effects, and provide compensatory mitigation commensurate with the affected habitat in accordance with the policy. Solar projects under local jurisdiction, however, do not have to meet the same requirement unless county governments enforce such a requirement.

There are many areas in Oregon that are good locations to site a solar project – areas with minimal or no effect on native habitat or farmland, and areas with access to transmission. To date, approximately 90 percent of utility-scale solar projects have been installed east of the Cascades due, in part, to better solar resources and lower cost of land. As communities consider local energy resiliency initiatives, there may be additional value recognized in developing more distributed energy facilities in close proximity to loads and population centers.

Net Metering

ORS 757.300[100] describes Oregon's net metering laws, including the treatment of surplus generation and a cap on aggregated net metering capacity. Figure 3.22 above demonstrates that 85 percent of the residential solar capacity in Oregon has been installed in PGE or PacifiCorp territories.

The aggregate capacity cap described in ORS 757.300 establishes a limit of how much solar can be installed within a utility service territory before the utility is no longer mandated to offer net metering. In Oregon the cap is set at 0.5 percent of the utilities' peak hourly load. Once the cumulative capacity of net metered systems reach this cap, the utility is no longer required to offer net metering. PGE and Pacific Power have exceeded the 0.5 percent cap but have so far continued to offer net metering on a voluntary basis. Other western states have aggregate capacity limits ranging from 0.5 percent on the low end (Oregon and Washington) to 20 percent on the high end (Utah). Many states do not specify a limit.

PURPA Contracts

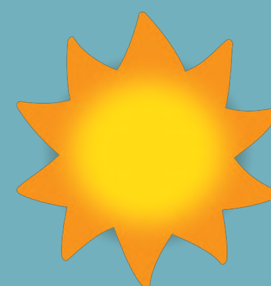
As described earlier in this chapter, Oregon utilities must contract with renewable energy facilities to purchase energy at the utilities' scheduled avoided costs rates. In Oregon, utilities establish different avoided costs rates based on the technology installed on their system. Solar facilities provide intermittent power which is valued less than "baseload" facilities that provide constant, steady power. For example, PGE developed Schedule 201, establishing different fixed avoided cost rates for baseload, wind, and solar facilities. Under PGE's Schedule 201,[87] a baseload facility has an average monthly fixed price of $58.95 per MWh for energy delivered during on-peak periods in 2025. A solar facility under the same time period would get an average fixed price of $38.62, about 35 percent lower than the baseload facility. As battery storage systems become more affordable, it will be possible for solar facilities to provide many of the services currently provided by baseload facilities, and this may raise questions about whether the existing avoided rate methodology is appropriate. The issue is already under discussion in Idaho, where Idaho Power and the Idaho Public Utility Commission are in a dispute with a solar developer about whether two proposed solar plus battery storage projects should be eligible for contract terms associated with "Other Projects," which are preferable to the contract terms associated with solar projects.[88]

Property Taxes

Local jurisdictions currently have two options for levying property taxes on utility-scale solar facilities. The first is known as a centralized assessment, which aims to establish a property value in a manner similar to other power plants in Oregon. The second option is to levy a fee in lieu of property taxes, currently valued at $7,000 per megawatt of capacity per year. The fee in lieu of taxes was established in Section 1, Chapter 571, Oregon Laws 2015[104] as a simplified approach to property tax evaluation. As solar costs continue to decrease, the value of future facilities will also decrease, which will decrease property taxes calculated under a centralized assessment. This may result in the $7,000 per MW fee falling out of line with the market. Some solar industry stakeholders may wish to revisit the $7,000 per megawatt value of the fee in future years.

CONCLUSIONS

Solar energy has experienced significant technological advancements and dramatic cost reductions in the past decade. The result is that solar energy facilities now represent a significant share of new energy acquisitions globally and in some markets are **cost competitive** with conventional resources such as coal and natural gas.



Oregon has traditionally had a small share of the national solar market, but has been a **leader in solar energy policies**. Some sectors still struggle in Oregon to achieve consistent market growth. 2018 is proving to be a challenging year in the residential sector with the sunset of the RETC program. Commercial projects have seen similar volatility year over year. Oregon’s utility-scale solar sector is poised for rapid growth based on the number of interconnection applications to Oregon utilities however challenges such as low avoided cost rates and federal trade tariffs may jeopardize many of those projects.

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