2021 PSE Integrated Resource Plan

D

Electrical Resources and Alternatives

This appendix describes PSE's existing electric resources; current electric resource alternatives and the viability and availability of each; and estimated ranges for capital and operating costs.[1]

1 / *Operating costs are defined as operation and maintenance costs, insurance and property taxes. Capital costs are defined as depreciation and carrying costs on capital expenditures.*

Contents

1. RESOURCE TYPES

The following overview summarizes some of the distinctions used to classify electric resources.

Supply-side and Demand-side

Both of these types of resources are capable of enabling PSE to meet customer loads. Supply-side resources provide electricity to meet load, and these resources originate on the utility side of the meter. Demand-side resources contribute to meeting need by reducing demand. An "integrated" resource plan includes both supply- and demand-side resources.

SUPPLY-SIDE RESOURCES for PSE include:

- Generating plants, including combustion turbines (baseload and peakers), coal, hydro, solar and wind plants
- Long-term contracts with independent producers to supply electricity to PSE (these have a variety of fuel sources)
- Transmission contracts with Bonneville Power Administration (BPA) to carry electricity from short-term wholesale market purchases to PSE's service territory

DEMAND-SIDE RESOURCES for PSE include:

- Energy efficiency
- Distribution efficiency
- Generation efficiency
- Distributed generation
- Demand response

The contribution that demand-side programs make to meeting resource need is accounted for as a reduction in demand for the IRP analysis.

Thermal and Renewable

These supply-side resources are distinguished by the type of fuel they use.

THERMAL RESOURCES use fossil fuel (natural gas, oil, coal) or alternative fuels (biodiesel, hydrogen, renewable natural gas) to generate electricity. PSE's combustion turbines and coal-fired generating facilities are thermal resources.

RENEWABLE RESOURCES use renewable fuels such as water, wind, sunlight and biomass to generate electricity. Hydroelectricity and wind generation are PSE's primary renewable resources.

Baseload, Peaking, Intermittent and Storage

These distinctions refer to how the resource functions within the system.

BASELOAD RESOURCES produce energy at a constant rate over long periods at a lower cost relative to other production facilities available to the system. They are typically used to meet some or all of a region's continuous energy demand. Baseload resources usually have a high fixed cost but low marginal cost and thus could be characterized as the most efficient units of the fleet.

For PSE, baseload resources can be divided into two categories: thermal and hydro. These have different dispatching capabilities. Thermal baseload plants can take up to several hours to start and have limited ability to ramp up and down quickly, so they are not very flexible. Hydro plants, on the other hand, are very flexible and are typically the preferred resource to balance the system.

PSE's three sources of baseload energy are combined-cycle combustion turbines (CCCTs), hydroelectric generation and coal-fired generation.

PEAKING RESOURCES are quick-starting units that can ramp up and down quickly in order to meet short-term spikes in need. They also provide flexibility needed for load following, wind integration and spinning reserves. Peaking resources generally have a lower fixed cost but are less efficient than baseload plants. Historically, peaking units have low capacity factors because they are often not economical to operate compared to market purchases.

The flexibility of peaking resources will become more important in the future as new renewable resources are added to the system and as PSE continues to participate in the Energy Imbalance Market (EIM).

PSE's peaking resources include simple-cycle combustion turbines (SCCTs) and hydroelectric plants that can perform peaking functions in addition to baseload functions.

INTERMITTENT RESOURCES, also commonly referred to as Variable Energy Resources (VERs), provide power that offers limited discretion in the timing of delivery. Renewable resources like wind and solar are intermittent resources because their generating patterns vary as a result of uncontrollable environmental factors, so the timing of delivery from these resources doesn't necessarily align with customer demand. As a result, additional resources are required to back up intermittent resources in case the wind dies down or clouds cover the sun.

PSE's largest intermittent resources are utility-scale wind generation and solar generation. Other intermittent resources include small-scale power production from customer generation (including rooftop solar), and the 10 aMW of energy PSE is required to take from co-generation.

ENERGY STORAGE has the potential to provide multiple services to the system, including efficiency, reliability, capacity arbitrage, ancillary services and backup power for intermittent renewable generation. It is capable of benefiting all parts of the system – generation, transmission, distribution and end-use customers; however, these benefits vary by location and the specific application of the technology or resource. For instance, storage in one location could be installed to relieve transmission congestion and thereby defer the cost of transmission upgrades, while storage at another location might be used to back up intermittent wind generation and reduce integration costs.

PSE's energy storage resources include hydro reservoirs behind dams, oil backup for the peaking plants and batteries. Battery and pumped hydro energy storage operate with a limited duration and require generation from other sources. Detailed modeling is required to fully evaluate the value of energy storage at the sub-hourly level.

Capacity Values

The tables on the following pages describe PSE's existing electric resources using the net maximum capacity of each plant in megawatts (MW). Net maximum capacity is the capacity a unit can sustain over a specified period of time – in this case 60 minutes – when not restricted by ambient conditions or de-ratings, less the losses associated with auxiliary loads and before the losses incurred in transmitting energy over transmission and distribution lines. This is consistent with the way plant capacities are described in the annual 10K report[2] that PSE files with the U.S. Securities and Exchange Commission and the Form 1 report filed with the Federal Energy Regulatory Commission (FERC).

Different plant capacity values are referenced in other PSE publications because plant output varies depending upon a variety of factors, among them ambient temperature, fuel supply, whether a natural gas plant is using duct firing, whether a combined-cycle facility is delivering steam to a steam host, outages, upgrades and expansions. To describe the relative size of resources, it is necessary to select a single reference point based on a consistent set of assumptions. Depending on the nature and timing of the discussion, these assumptions – and therefore the expected capacity value – may vary.

2 / PSE's most recent 10K report was filed with the U.S. Securities and Exchange Commission in February 2020 for the year ending December 31, 2019. See http://www.pugetenergy.com/pages/filings.html.

2. EXISTING RESOURCES INVENTORY

Supply-side Thermal Resources

Baseload Combustion Turbines (CCCTs)

PSE's six baseload combined-cycle combustion turbine plants have a combined net maximum capacity of 1,293 MW and supply 15 to 16 percent of PSE's baseload energy needs, depending on market heat rates and plant availabilities. In a CCCT, the heat that a simple-cycle combustion turbine produces when it generates power is captured and used to create additional energy. This makes it a more efficient means of generating power than the peakers (simple-cycle turbines) described below. PSE's fleet of baseload CCCTs includes the following.

- **MINT FARM** is located in Cowlitz County, Wash.
- **FREDERICKSON 1** is located in Pierce County, Wash. (PSE owns 49.85 percent of this plant; the remainder of the plant is owned by Atlantic Power Corporation.)
- **GOLDENDALE** is located in Klickitat County, Wash.
- **ENCOGEN, FERNDALE** and **SUMAS** are located in Whatcom County, Wash.

Coal

The Colstrip generating plant currently supplies 16 to 17 percent of PSE's baseload energy needs.

THE COLSTRIP GENERATING PLANT. Located in eastern Montana about 120 miles southeast of Billings, the plant consists of four coal-fired steam electric plant units. PSE owns 25 percent each of Units 3 & 4. PSE's total ownership in Colstrip contributes 370 MW net maximum capacity to the existing portfolio.

The Colstrip Generating Plant Retirement/Shutdown Plan: After a request in June 2019 by PSE's Unit 1 & 2 co-owner and plant operator, Talen Montana LLC, PSE agreed to retire the units. The decision was based on economic considerations. In early January 2020, the facility ceased to generate electricity and work commenced to place it in a secure and safe condition. Environmental remediation of impacted water is currently under way and will continue, in compliance with all local, state and federal regulations, as the retirement of the physical structures occurs. In the future, when Units 3 & 4 have also been retired, the main structures of Units 1 & 2 will be further addressed.

Units 3 & 4 are owned by six separate entities with different interests. PSE is limited in its ability to act unilaterally since operational decisions are dictated by the rules governing the ownership agreement. The Clean Energy Transformation Act (CETA) restricts PSE from serving load from Colstrip without penalty after 2025 and as a result this IRP only includes generation from Colstrip 3 & 4 through to 2025.

Figure D-1: PSE's Owned Baseload Thermal Resources

POWER TYPE	UNITS	PSE OWNERSHIP	NET MAXIMUM CAPACITY (MW)[1]
Coal	Colstrip 3 & 4[1]	25%	370
Total Coal			**370**
CCCT	Encogen	100%	165
CCCT	Ferndale[2]	100%	253
CCCT	Frederickson 1[2,3]	49.85%	136
CCCT	Goldendale[2]	100%	315
CCCT	Mint Farm[2]	100%	297
CCCT	Sumas	100%	127
Total CCCT			**1,293**

NOTES
1. Net maximum capacity reflects PSE's share only.
2. Maximum capacity of Ferndale, Frederickson 1, Goldendale and Mint Farm includes duct firing capacity.
3. Frederickson 1 CCCT unit is co-owned with Atlantic Power Corporation - USA.

Peakers (SCCTs)

These simple-cycle combustion turbines provide important peaking capability and help PSE meet operating reserve requirements. The company displaces these resources when their energy is not needed to serve load or when lower-cost energy is available for purchase. PSE's three peaker plants (eight units total) contribute a net maximum capacity of 612 MW. When pipeline capacity is not available to supply them with natural gas fuel, these units are capable of operating on distillate fuel oil.

- **FREDONIA** Units 1, 2, 3 and 4 are located near Mount Vernon, Wash., in Skagit County.
- **WHITEHORN** Units 2 and 3 are located in northwestern Whatcom County, Wash.
- **FREDERICKSON** Units 1 and 2 are located south of Seattle in east Pierce County, Wash.

Ownership and net maximum capacity are shown in Figure D-2 below.

Figure D-2: PSE's Owned Peaking Resources (Simple-cycle Combustion Turbines)

NAME	PSE OWNERSHIP	NET MAXIMUM CAPACITY (MW)
Fredonia 1 & 2	100%	207
Fredonia 3 & 4	100%	107
Whitehorn 2 & 3	100%	149
Frederickson 1 & 2	100%	149
Total SCCT		**612**

Supply-side Renewable Resources

Hydroelectricity

Hydroelectricity supplies approximately 14 percent of PSE's baseload energy needs. Even though restrictions to protect endangered species limit the operational flexibility of hydroelectric resources, these generating assets are valuable because of their ability to instantly follow customer load and because of their low cost relative to other power resources. High precipitation and snowpack levels generally allow more power to be generated, while low-water years produce less power. During low-water years, the utility must rely on other, more expensive, self-generated power or market resources to meet load. The analysis conducted for this IRP accounts for both seasonality and year-to-year variations in hydroelectric generation. PSE owns hydroelectric projects in western Washington and has long-term power purchase contracts with three public utility districts (PUDs) that own and operate large dams on the Columbia River in central Washington. In addition, we contract with smaller hydroelectric generators located within PSE's service territory.

BAKER RIVER HYDROELECTRIC PROJECT. This facility is located in Washington's north Cascade Mountains. It consists of two dams and is the largest of PSE's hydroelectric power facilities. The project contains modern fish-enhancement systems including a "floating surface collector" (FSC) to safely capture juvenile salmon in Baker Lake for downstream transport around both dams, and a second, newer FSC on Lake Shannon for moving young salmon around Lower Baker Dam. In addition to generating electricity, the project provides public access for recreation and significant flood-control storage for people and property in the Skagit Valley. Hydroelectric projects require a license from FERC for construction and operation. These licenses normally are for periods of 30 to 50 years; then they must be renewed to continue operations. In October 2008, after a lengthy renewal process, FERC issued a 50-year license allowing PSE to generate approximately 710,000 MWh per year (average annual output) from the Baker River project. PSE also completed construction of a new powerhouse and 30 MW generating unit at Lower Baker dam in July 2013. The replacement unit improves river flows for fish downstream of the dam while producing more than 100,000 additional MWh of energy from the facility each year. This incremental energy qualifies as a renewable resource under the State of Washington Energy Independence Act, RCW 19.285.

SNOQUALMIE FALLS HYDROELECTRIC PROJECT. Located east of Seattle on the Cascade Mountains' western slope, the Snoqualmie Falls Hydroelectric Project consists of a small diversion dam just upstream from Snoqualmie Falls and two powerhouses. The first powerhouse, which is encased in bedrock 270 feet beneath the surface, was the world's first completely underground power plant. Built in 1898-99, it was also the Northwest's first large hydroelectric power plant. FERC issued PSE a 40-year license for the Snoqualmie Falls Hydroelectric Project in 2004. The terms and conditions of the license allow PSE to generate an estimated 275,000 MWh per year (average annual output). The facility underwent a major redevelopment project between 2010 and 2015, which included substantial upgrades and enhancements to the power-generating infrastructure and public recreational facilities. Efficiency improvements completed as part of the redevelopment increase annual output by over 22,000 MWh. This incremental energy qualifies as a renewable resource under the State of Washington Energy Independence Act, RCW 19.285.

MID-COLUMBIA LONG-TERM PURCHASED POWER CONTRACTS. Under long-term power purchase agreements with three PUDs, PSE purchases a percentage of the output of five hydroelectric projects located on the Columbia River in central Washington. PSE pays the PUDs a proportionate share of the cost of operating these hydroelectric projects. In March 2017, PSE entered into a new power sales agreement with Douglas County PUD that began on August 31, 2018 and continues through September 30, 2028. Under this new agreement, PSE will continue to take a percentage of the output from the Wells project. The actual percentage available to PSE will be calculated annually and based primarily on Douglas PUD’s retail load requirements – as Douglas PUD’s retail load grows (or declines), they will reserve a greater (or lesser) share of Wells project output for their customers and the percentage PSE purchases will decline (or increase) as a result. PSE has a 20-year agreement with Chelan County PUD for the purchase of 25 percent of the output of the Rocky Reach and Rock Island projects that extends through October 2031. PSE has an agreement with Grant County PUD for a 0.64 percent share of the combined output of the Wanapum and Priest Rapids developments. The agreement with Grant County PUD will continue through the term of the project’s FERC license, which ends March 31, 2052.

Figure D-3: PSE Owned and Contracted Hydroelectric Resources

PLANT	OWNER	PSE SHARE %	NET MAXIMUM CAPACITY (MW)[1]	CONTRACT EXPIRATION DATE
Upper Baker River	PSE	100	91	None
Lower Baker River	PSE	100	105	None
Snoqualmie Falls	PSE	100	48[2]	None
Total PSE-owned			**244**	
Wells	Douglas Co. PUD	27.1	228[3]	9/30/28[3]
Rocky Reach	Chelan Co. PUD	25.0	325	10/31/31
Rock Island I & II	Chelan Co. PUD	25.0	156	10/31/31
Wanapum	Grant Co. PUD	0.6	7	03/31/52
Priest Rapids	Grant Co. PUD	0.6	6	03/31/52
Contracted Total			**706**	
Total Hydro			**950**	

NOTES
1. Net maximum capacity reflects PSE's share only.
2. The FERC license authorizes the full 54.4 MW; however, the project's water right, issued by the state Department of Ecology, limits flow to 2,500 cfs, and therefore output, to 47.7 MW.
3. In March 2017, PSE entered a new PPA with Douglas County PUD for Wells Project output that began on August 31, 2018 and continues through September 30, 2028. PSE also entered into an agreement in June 2018 to purchase an additional 5.5 percent of the Wells project through September 2021.

Wind Energy

PSE is the largest utility owner and operator of wind-power facilities in the Pacific Northwest. Combined, the maximum capacity of the company's three wind farms is 773 MW. They produce more than 2 million MWhs of power per year on average, which is about 8 percent of PSE's energy needs. These resources are integral to meeting renewable resource commitments.

HOPKINS RIDGE. Located in Columbia County, Wash., Hopkins Ridge has an approximate maximum capacity of 157 MW. It began commercial operation in November 2005.

WILD HORSE. Located in Kittitas County near Ellensburg, Wash., Wild Horse has an approximate maximum capacity of 273 MW. It came online in December 2006 at 229 MW and was expanded by 44 MW in 2010.

LOWER SNAKE RIVER. PSE brought online its third and largest wind farm in February 2012. The 343 MW facility is located in Garfield County, Wash.

Solar Energy

The Wild Horse facility contains 2,723 photovoltaic solar panels, including the first made-in-Washington solar panels.[3] The array can produce up to 0.5 MW of electricity with full sun. Panels can also produce power under cloudy skies – 50 to 70 percent of peak output with bright overcast and 5 to 10 percent with dark overcast. The site receives approximately 300 days of sunshine per year, roughly the same as Houston, Tex. On average this site generates 780 MWhs of power per year.

Battery Energy Storage System (BESS)

The Glacier Battery Demonstration Project was installed in early 2017. The 2 MW / 4.4 MWh lithium-ion battery storage system is located adjacent to the existing substation in Glacier, Wash., in Whatcom County. The Glacier battery serves as a short-term backup power source (up to 2.2 hours at capacity with a full charge) to a core "island" of businesses and residences during outages, reduces system load during periods of high demand, and helps balance energy supply and demand. The project was funded in part by a $3.8 million Smart Grid Grant from the State of Washington Department of Commerce. Between January and June, 2018, Pacific Northwest National Laboratory (PNNL) performed two use test cases. Since then, PSE has continued to test the battery's capabilities under planned outage scenarios – working toward the goal of successfully responding to unplanned outages.

Figure D-4 presents details about the company's wind, solar and battery storage resources.

3 / Outback Power Systems (now Silicon Energy) in Arlington produced the first solar panels in Washington. The Wild Horse Facility was Outback Power Systems' launch facility, utilizing 315 of their panels. The remaining panels were produced by Sharp Electronics in Tennessee.

Figure D-4: PSE's Owned Wind, Solar and Battery Storage Resources

POWER TYPE	UNITS	PSE OWNERSHIP	NET MAXIMUM CAPACITY (MW)
Wind	Hopkins Ridge	100%	157
Wind	Lower Snake River, Phase 1	100%	343
Wind	Wild Horse	100%	273
Total Wind			**773**
Solar	Wild Horse Solar Demonstration Project	100%	0.5
Energy Storage	Glacier Battery Demonstration Project	100%	2.0
Total Solar and Storage			**2.5**
Total Wind, Solar and Battery Storage			**775.5**

Supply-side Contract Resources

Long-term contracts consist of agreements with independent producers and other utilities to supply electricity to PSE. Fuel sources include hydropower, wind, solar, natural gas, coal, waste products and system deliveries without a designated supply resource. These contracts are summarized in Figure D-5. Short-term wholesale market purchases negotiated by PSE's energy trading group are not included in this listing.

POINT ROBERTS PPA. This contract provides for power deliveries to PSE's retail customers in Point Roberts, Wash. The Point Roberts load, which is physically isolated from PSE's transmission system, connects to British Columbia Hydro's electric distribution facilities. PSE pays a fixed price for the energy during the term of the contract.

BAKER REPLACEMENT. Under a 20-year agreement signed with the U.S. Army Corps of Engineers (USACE) PSE provides flood control for the Skagit River Valley. Early in the flood control period, PSE drafts water from the Upper Baker reservoir at the request of the USACE. Then, during periods of high precipitation and runoff between October 15 and March 1, PSE stores water in the Upper Baker reservoir and releases it in a controlled manner to reduce downstream flooding. In return, PSE receives a total of 7,000 MWhs of power and 7 MW of net maximum capacity from BPA in equal increments per month for the months of November through February to compensate for the lower generating capability caused by reduced head due to the early drafting at the plant during the flood control months.

PACIFIC GAS & ELECTRIC COMPANY (PG&E) SEASONAL EXCHANGE. Under this system-delivery power exchange contract, each calendar year PSE exchanges with PG&E 300 MW of seasonal capacity, together with 413,000 MWh of energy, on a one-for-one basis. PSE is a winter-peaking utility and PG&E is a summer-peaking utility, so PG&E has the right to call for the power in the months of June through September, and PSE has the right to call for the power in the months of November through February.

CANADIAN ENTITLEMENT RETURN. Under a treaty between the United States and Canada, one-half of the firm power benefits produced by additional storage capability on the Columbia River in Canada accrue to Canada. PSE's benefits and obligations from this storage are based on the percentage of our participation in the Columbia River projects. Agreements with the Mid-Columbia PUDs specify PSE's share of the obligation is to return one-half of the firm power benefits to Canada during peak hours until the expiration of the PUD contracts or expiration of the Columbia River Treaty, whichever occurs first. This is energy that PSE provides rather than receives, so it is a negative number. The energy returned during 2018 was approximately 18 aMW with a peak capacity return of 32.5 MW. The Columbia River Treaty has no end date but can be terminated after 2024 with 10 years' notice. The United States and Canada recently concluded the ninth round of negotiations to modernize the treaty to ensure the effective management of flood risk, provide a reliable and economical power supply, and improve the ecosystem.

COAL TRANSITION PPA. Under the terms of this agreement, PSE began to purchase 180 MW of firm, baseload coal transition power from TransAlta's Centralia coal plant in December 2014. On December 1, 2015, the contract increased to 280 MW. From December 2016 to December 2024 the contract is for 380 MW, and in the last year of the contract, 2025, volume drops to 300 MW. This contract conforms to a separate TransAlta agreement with state government and the environmental community to phase out coal-fired power generation in Washington by 2025. In 2011, the state Legislature passed a bill codifying a collaborative agreement between TransAlta, lawmakers, environmental advocacy groups and labor representatives. The timelines agreed to by the parties enable the state to make the transition to cleaner fuels, while preserving the family-wage jobs and economic benefits associated with the low-cost, reliable power provided by the Centralia plant. The legislation allows long-term contracts, through 2025, for sales of coal transition power associated with the 1,340 MW Centralia facility, Washington's only coal-fired plant.

KLONDIKE III PPA. PSE's wind portfolio includes a power purchase agreement with Avangrid Renewables[4] for a 50 MW share of electricity generated at the Klondike III wind farm in Sherman County, Ore. The wind farm has 125 turbines with a project capacity of nearly 224 MW. This agreement remains in effect until November 2027.

4 / Formerly Iberdrola

LUND HILL SOLAR PPA. PSE has executed a 20-year power purchase agreement with Avangrid Renewables (through the project company Lund Hill Solar, LLC) to purchase the output from the Lund Hill Solar Project, to be located in Klickitat County, Wash. The project has an expected online date in March 2021. The output from the facility will be used to serve subscribers to PSE's new Green Direct program (Schedule 139), which is described in the Demand-side Resources section of this appendix.

SKOOKUMCHUCK WIND PPA. PSE has executed a 20-year power purchase agreement with Renewable Energy Systems (RES) to purchase the output from the Skookumchuck Wind Project.[5] The wind project is currently in development in Thurston and Lewis counties and is scheduled to be operational by the end of 2020.[6] Along with the output from Lund Hill Solar facility, the Skookumchuck facility output will be used to serve subscribers to PSE's Green Direct program (Schedule 139), which is described in the Demand-side Resources section of this appendix.

ENERGY KEEPERS PPA. PSE has entered into an agreement with Energy Keepers, Inc., the tribally owned corporation of the Confederated Salish and Kootenai Tribes, to purchase 40 MW of zero carbon energy produced by the Selis Ksanka Qlispe hydroelectric project through July of 2035.

SPI BIOMASS PPA. PSE has entered into a 17-year contract with Sierra Pacific Industries (SPI) to purchase 17 MW of renewable energy from SPI's Mt. Vernon Mill starting in 2021. SPI's cogeneration facility is an operational plant that uses wood byproducts from its lumber manufacturing process to generate steam used to make electricity and heat kilns to dry lumber. An air pollution control device filters out fine particles and other emissions from the burning wood so that what is released into the atmosphere comes out clean.

BPA CAPACITY PRODUCT. Under a five-year agreement beginning in January 2022, the Bonneville Power Administration will offer to sell PSE up to 100 MW of surplus power generated from the Federal Columbia River Power System. Hydroelectricity can quickly increase and decrease to meet power demand, and help the region achieve its renewable goals by dovetailing with more variable output resources such as wind and solar.

---

5 / PSE was notified on 10/24/2019 that Southern Power Company had purchased the project.
6 / The estimated in service COD is November 2, 2020.

MSCG SYSTEM PPA. PSE has entered into a Western System Power Pool (WSPP) agreement with the Morgan Stanley Commodities Group (MSCG) for a 4-year, 363-day, system PPA to deliver 100 MW of firm heavy load hour (HLH) energy in Q1 and Q4 only, commencing in January 2022.

GOLDEN HILLS WIND PPA. PSE has executed a 20-year power purchase agreement with Avangrid Renewables for the output of a 200 MW wind farm to be built in Sherman County, Ore. Avangrid expects to complete the project by late 2021. The project will help PSE meet its goals to reduce carbon dioxide emissions while providing additional capacity to serve customers, particularly during winter periods of high electricity demand.

RFP RESOURCE PPA. PSE expects to complete execution of a 20-year power purchase agreement in early 2021. For the purposes of this IRP, which files in April, it is labeled as a generic RFP resource.

HYDROELECTRIC PPAs. Among PSE's power purchase agreements are several long-term contracts for the output of production from hydroelectric projects within its balancing area. These contracts are shown in Figure D-5 below and have the designator "Hydro – QF" for qualifying facility. The projects are run-of-river and do not provide any flexible capacity.

SCHEDULE 91 CONTRACTS. PSE's portfolio includes a number of electric power contracts with small power producers in PSE's electric service area (see Figure D-5). These qualifying facilities offer output pursuant to WAC chapter 480-106. WAC 480-106-020 states: "A utility must purchase, in accordance with WAC 480-106-050 Rates for purchases from qualifying facilities, any energy and capacity that is made available from a qualifying facility: (a) Directly to the utility; or (b) Indirectly to the utility in accordance with subsection (4) of this section." A qualifying facility is defined in WAC 480-106-007 as a "cogeneration facility or small power production facility that is a qualifying facility under 18 C.F.R. Part 292 Subpart B."

Figure D-5: Long-term Contracts for Electric Power Generation (continued next page)

NAME	POWER TYPE	CONTRACT START	CONTRACT EXPIRATION	CONTRACT CAPACITY (MW)
Pt. Roberts[1]	System	10/1/2019	9/30/2022	8
Baker Replacement	Hydro	10/1/2019	9/30/2029	7
PG&E Seasonal Exchange-PSE	System	10/11/1991	Ongoing	300
Canadian Entitlement Return	Hydro	1/1/2004	09/15/2024	(32.5)
Coal Transition PPA	Transition Coal	12/1/2014	12/31/2025	380 [2]
Klondike III PPA	Wind	12/1/2007	11/30/2027	50
Energy Keepers PPA	Hydro	3/1/2020	7/31/2035	40
SPI Biomass PPA	Biomass	1/1/2021	12/31/2037	17
BPA Capacity Product PPA	Hydro	1/1/2022	12/31/2026	100
MSCG System PPA	System	1/3/2022	12/31/2026	100
Golden Hills Wind PPA	Wind	7/1/2022	6/30/2042 [3]	200
RFP Resource	Wind	TBD	TBD	350
Lund Hill Solar	Schedule 139 – Solar	3/1/2021	7/01/2041[4]	150
Skookumchuck Wind	Schedule 139 - Wind	6/30/2020	12/31/2039 [5]	136.8
Twin Falls PPA	Hydro-QF	12/1/1989	3/018/2025	20
Koma Kulshan PPA	Hydro-QF	12/1/1990	3/31/2037	13.3
Weeks Falls PPA	Hydro-QF	12/1/1987	12/01/2022	4.6
Farm Power Rexville	Schedule 91 - Biogas	8/28/2009	12/31/2023	0.75
Farm Power Lynden	Schedule 91 - Biogas	12/1/2010	12/31/2023	0.75
Rainier Biogas	Schedule 91 – Biogas	11/30/2012	12/31/2023	1.0
Vanderhaak Dairy	Schedule 91 – Biogas	11/5/2004	12/31/2023	0.60 [6]
Edaleen Dairy	Schedule 91 – Biogas	8/21/2012	12/31/2023	0.75
Van Dyk - Holsteins Dairy	Schedule 91 – Biogas	6/1/2011	12/31/2023	0.47
Blocks Evergreen Dairy	Schedule 91 – Biogas	6/1/2017	12/31/2031	0.19
Emerald City Renewables [7]	Schedule 91 – Biogas	11/6/2013	12/31/2029	4.50
Emerald City Renewables 2	Schedule 91 – Biogas	12/31/2018	12/31/2031	4.50
Skookumchuck Hydro	Schedule 91 – Hydro	2/25/2011	1/31/2024	1.0
Black Creek	Schedule 91 – Hydro	3/26/2021	3/25/2031	4.2
Nooksack Hydro	Schedule 91 – Hydro	1/1/2014	12/31/2023	3.5
Sygitowicz – Kingdom Energy [8]	Schedule 91 – Hydro	3/25/2016	12/31/2030	0.448

NAME	POWER TYPE	CONTRACT START	CONTRACT EXPIRATION	CONTRACT CAPACITY (MW)
Island Solar [9]	Schedule 91 – Solar	6/22/2011	12/31/2023	0.075
Finn Hill Solar (Lake Wash SD)	Schedule 91 – Solar	7/16/2012	12/31/2023	0.355
CC Solar #1, LLC and CC Solar #2, LLC (combined)	Schedule 91 – Solar	9/28/2012	1/1/2026	0.026
IKEA	Schedule 91 – Solar	1/1/2017	12/31/2031	0.828
TE – Fumeria	Schedule 91 – Solar	1/1/2020	12/31/2031	4.99
TE – Penstemon	Schedule 91 – Solar	1/1/2020	12/31/2031	4.99
TE – Typha	Schedule 91 – Solar	1/1/2020	12/31/2031	4.99
TE – Urtica	Schedule 91 – Solar	8/1/2018	12/31/2031	4.99
TE – Camas	Schedule 91 – Solar	8/1/2018	12/31/2031	4.99
Iron Horse Solar	Schedule 91 – Solar	6/1/2018	12/31/2030	4.5
Osprey	Schedule 91 – Solar	6/1/2018	12/31/2030	0.95
Heelstone Energy – Westside Solar	Schedule 91 – Solar	10/1/2019	12/31/2031	4.99
Heelstone Energy – Dry Creek Solar	Schedule 91 – Solar	10/1/2019	12/31/2031	4.99
Cypress Renewables – Gholson Solar	Schedule 91 – Solar	1/1/2020	12/31/2032	4.99
GCSD PSE3 LLC	Schedule 91 – Solar	7/1/2018	12/31/2031	4.0
Knudson Wind	Schedule 91 – Wind	6/16/2011	12/31/2023	0.108
3 Bar-G Wind	Schedule 91 – Wind	8/31/2011	12/31/2023	0.120 [10]
Swauk Wind	Schedule 91 – Wind	12/14/2012	12/31/2023	4.25
Total				**1,923**

NOTES

1. The contract to provide power to PSE's Point Roberts customers expired on 9/30/2019 and the new contract with a three-year term was negotiated between PSE and PowerEx, commencing October 1, 2019. Point Roberts is not physically interconnected to PSE's system, and relies on power from a single intertie point on BC Hydro's distribution grid.

2. The capacity of the TransAlta Centralia PPA is designed to ramp up over time to help meet PSE's resource needs. According to the contract, PSE will receive 280 MW from 12/1/2015 to 11/30/2016, 380 MW from 12/1/2016 to 12/31/2024 and 300 MW from 1/1/2025 to 12/31/2025.

3. A 1-year system PPA for interim capacity has also been signed in the event that COD is pushed past December 2021, but no later than June 20, 2022.

4. 20-year term subject to final COD date, now anticipated in Q1, 2021.

5. 20-year term subject to final COD date.

6. VanderHaak has two generators with a combined capacity of .60 MW. However, VanderHaak primarily runs only the larger generator, which has a capacity of .45 MW.

7. Emerald City Renewables was formerly known as BioFuels Washington.

8. The site was purchased on May 1, 2020 by Hillside Clean Energy with PSE's consent.
9. Ownership was transferred to the Port of Coupeville on July 1, 2020 with PSE's consent.
10. Agreement originally for 1.395 MW but only 0.120 MW was constructed and the contract was amended to reflect this change.

Supply-side Transmission Resources

Mid-C Transmission Resources

Transmission capacity to the Mid-Columbia (Mid-C) market hub gives PSE access to the principal electricity market hub in the Northwest, which is one of the major trading hubs in the Western Electricity Coordinating Council (WECC). It is the central market for northwest hydroelectric generation. PSE has 2,481 MW of transmission capacity to the Mid-C market; of that, 2,031 MW is contracted from BPA on a long-term basis and 450 MW is owned by PSE.[7] The BPA transmission rights are owned by PSE Merchant. The 450 MW of transmission is sold by PSE Transmission as the Transmission Provider. Currently, PSE's 449 customers hold the rights to the 450 MW of transmission; however, when these rights are not fully utilized by the 449 customers, these transmission rights are allocated to PSE Merchant or sold on OASIS. PSE's Mid-C transmission capacity is detailed in Figure D-6 below; approximately 1,500 MW of this transmission capacity to the Mid-C wholesale market is utilized for short-term market purchases to meet PSE's peak need.[8]

7 / PSE also owns transmission and transmission contracts to other markets in addition to the Mid-C market transmission detailed here.
8 / See Chapter 8, Electric Analysis, for a more detailed discussion of PSE reliance on wholesale market capacity to meet peak need.

Figure D-6: Mid-C Hub Transmission Resources

NAME	EFFECTIVE DATE	TERMINATION DATE	TRANSMISSION DEMAND (MW)
BPA Mid-C Transmission			
Midway	11/1/2017	11/1/2022	100
Midway	4/1/2008	11/1/2035	5
Rock Island	7/1/2007	7/1/2037	400
Rocky Reach[9]	11/1/2017	11/1/2022	100
Rocky Reach	11/1/2017	11/1/2022	100
Rocky Reach	11/1/2019	11/1/2024	40
Rocky Reach	11/1/2019	11/1/2024	40
Rocky Reach	11/1/2019	11/1/2024	40
Rocky Reach	11/1/2019	11/1/2024	5
Rocky Reach	11/1/2019	11/1/2024	55
Rocky Reach	9/1/2014	11/1/2031	160
Vantage	11/1/2017	11/1/2022	100
Vantage	12/1/2019	12/1/2024	169
Vantage	10/1/2013	3/1/2025	3
Vantage	11/1/2019	11/1/2024	27
Vantage	11/1/2019	11/1/2024	27
Vantage	11/1/2019	11/1/2024	27
Vantage	11/1/2019	11/1/2024	3
Vantage	11/1/2019	11/1/2024	36
Vantage	11/1/2019	11/1/2024	5
Wells	9/1/2018	9/1/2023	266
Vantage	3/1/2016	2/28/2021	23
Midway	10/1/2018	10/1/2023	115
Midway	3/1/2019	3/1/2024	35
Wells/Sickler	11/1/2018	11/1/2023	50
Vantage	11/1/2018	11/1/2023	50
Vantage	12/1/2019	11/1/2022	50
Total BPA Mid-C Transmission			**2,031**
PSE Owned Mid-C Transmission			
McKenzie to Beverly	-	-	50
Rocky Reach to White River	-	-	400
Total PSE Mid-C Transmission			**450**
Total Mid-C Transmission			**2,335**

9 / *Contract split between Mid-C and EIM Imports below*

EIM Transmission Resources

When PSE joined the Energy Imbalance Market (EIM) in October 2016, it redirected 300 MW of Mid-C transmission capacity contracted from BPA on an annual basis for EIM trades. Starting in June 2020, Mid-C transmission redirected for use in the EIM was reduced to 150 MW in order to align with PSE's market-based rate authority. This is a required amount to maintain market-based authority and still gives PSE the capability to redirect beyond this amount for use in the EIM. Although these redirects reduce transmission capacity available to support PSE's peak need, PSE still maintains sufficient capacity to meet the winter peak. The amount of redirected Mid-C transmission will need to be renewed on an ongoing basis, and this will allow PSE to reevaluate its EIM transfer capacity needs in light of future winter peak needs. Figure D-7 details the transmission capacity currently redirected for EIM.

An additional 300 MW reserved under the PG&E Seasonal Exchange contract is redirected for EIM during certain months of the year on an as-feasible basis. When PSE's obligations to PG&E during summer months prevent this redirect, PSE instead redirects its existing Mid-C transmission, bringing total redirected Mid-C transmission for EIM during summer months up to 450 MW.

Figure D-7: Mid-C Hub Transmission Resources Redirected for EIM as of 1/1/2021

NAME	EFFECTIVE DATE	TERMINATION DATE	TRANSMISSION DEMAND (MW)
BPA Mid-C Transmission Redirected for EIM			
Rocky Reach	11/1/2017	11/1/2022	150
Total BPA Mid-C Transmission Redirected for EIM			**150**

Demand-side Resources

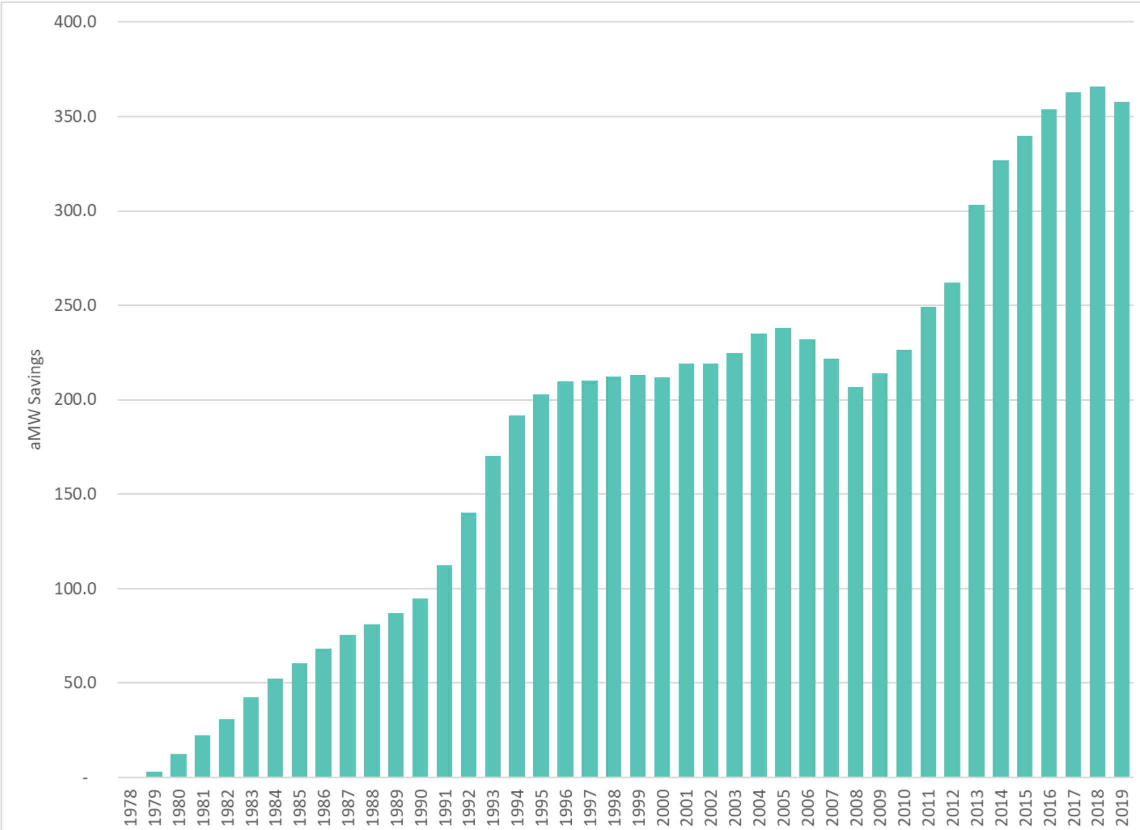
Energy reduction and energy production programs that contribute to meeting need by reducing demand are called demand-side resources (DSR). These are often implemented on the customer side of the meter. DSR programs currently offered through PSE include:

- **ENERGY EFFICIENCY**, implemented by PSE's Customer Energy Management group
- **DISTRIBUTION EFFICIENCY**, managed by PSE's System Planning group
- **GENERATION EFFICIENCY**, evaluated by PSE's Customer Energy Management group (This represents energy efficiency opportunities at PSE generating facilities.)
- **DISTRIBUTED GENERATION**, overseen by PSE's Customer Energy Management group (with the exception of distributed solar photovoltaics, which is overseen by the Customer Renewable Energy Programs group)
- **DEMAND RESPONSE** pilots, currently overseen by PSE's Customer Energy Management group

PSE has been a leader in the Pacific Northwest when it comes to implementation of demand-side energy efficiency resource programs. Since 1978, annual first-year savings (as reported at the customer meter) have grown by more than 300 percent, from 9 aMW in 1978 to 27.6 aMW in 2019. On a cumulative basis, these savings reached a total of 358 aMW by 2019. (Savings are adjusted for measure life and then retired so they no longer count towards the cumulative savings.[10]) To achieve these savings over the 1978 to 2019 period, the company spent a total of approximately $1.57 billion in incentives to customers and for program administration.

10 / For the purposes of the IRP analysis, measure life is assumed to be 10 years.

Figure D-8: Cumulative Electric Energy Efficiency Savings from DSR, 1978 through 2019



Energy Efficiency

Energy efficiency is by far PSE's largest electric demand-side resource. It consists of measures and programs that replace existing building components and systems such as lighting, heating, water heating, insulation, appliances, etc. with more energy efficient ones. There are two types of measures: "retrofit measures" (when replacement is cost effective before the equipment reaches its end of life); and lost opportunity measures (when replacement is not cost effective until existing equipment burnout).

PSE energy efficiency programs serve all types of customers – residential (including low income), commercial and industrial. Program savings targets are established every two years in collaboration with key external stakeholders represented by the Conservation Resource Advisory Group (CRAG) and the IRP public participation process. The majority of electric energy efficiency programs are funded using electric "conservation rider" funds collected from all customer classes.[11]

11 / See Electric Schedule 120, Electricity Conservation Service Rider, for more information.

In the most recently completed program cycle, the 2018-19 tariff period, energy efficiency achieved a total savings of 61.4 aMW; the target for the current 2020-21 program cycle is 60.0 aMW. Some of the changes in the 2020-21 program cycle are noted below.[12]

- HB1444 made high efficiency LED lighting the baseline technology, so the general service LED lighting savings, which a huge part of the residential program savings will no longer be offered and will be replaced with other program offerings. The home energy assessment program which relied on LED savings will be repurposed to focus on hard to reach customers only.
- Expanded distribution channels for high efficiency space heating and water heating heat pump products for residential customers.
- Expanded home energy reports program to enroll more customers.
- Target moderate income residences that are not qualified under the low income category for space, water and weatherization measures.
- Increased incentives for lighting and non-lighting measures in the commercial and industrial sectors.
- Expanded distribution channels for delivery of heat pumps in commercial and industrial sectors.

The 2020-2021 electric energy efficiency programs are targeted to save 60.05 aMW of electricity at a cost of just under $194 million.

12 / See 2020-21 Biennium Conservation Plan Overview for more details on efficiency programs, especially low-income weatherization programs.

Distribution Efficiency

The Production and Distribution Efficiency program includes implementing energy conservation measures within PSE's own distribution facilities that prove cost-effective, reliable and feasible.

For transmission and distribution (T&D) efficiency, improvements are implemented at PSE's electric substations. These improvements focus on measures like phase balancing and conservation voltage reduction (CVR). The methodology used to determine CVR savings is the Simplified Voltage Optimization Measurement and Verification Protocol provided by the Northwest Power and Conservation Council Regional Technical Forum.[13]

Figure D-9 below lists the CVR-related projects completed to date and planned for the 2020-21 period. In future years, a significant expansion in CVR project implementation is planned, tied to the implementation of the Advanced Metering Infrastructure (AMI) project and substation automation project. These two projects will enable Volt-Var optimization (VVO), an improved CVR method that allows for deeper levels of savings compared to PSE's current CVR implementation method of line drop compensation (LDC).

Savings associated with CVR are affected by several variables, including but not limited to the increasing penetration of distributed energy resources (DERs) that is expected in the future. Therefore, the savings from these projects can vary significantly. PSE is currently investigating the need for a study that provides an updated energy savings methodology for Volt-Var CVR projects. Currently, the first Volt-Var CVR project is expected to launch in 2023.

13 / *rtf.nwcouncil.org*

Figure D-9: Energy Savings from Conservation Voltage Reduction, Cumulative Savings to Date, kWh

Substation	Year of Execution	Date of Completion	Date of QC of Non-payment Request	kWh Savings / YEAR	Savings as % of Baseline kWh
South Mercer	2013	11/1/2013	12/18/2013	607,569	1.3%
Mercerwood	2013	12/8/2013	12/18/2013	357,240	0.9%
Mercer Island	2014	8/8/2014	9/22/2014	859,586	1.3%
Britton	2014	12/5/2014	12/24/2014	636,197	5.6%
Panther Lake	2015/2016	8/27/2015	6/23/2016	804,326	1.3%
Hazelwood	2015/2016	9/18/2015	6/23/2016	1,352,149	1.4%
Pine Lakes	2015/2016	9/17/2015	6/23/2016	1,163,150	1.3%
Fairwood	2017/2018	5/1/2018	11/13/2018	768,367	1.2%
Rhode Lakes	2017/2018	5/23/2018	11/13/2018	1,639,803	1.6%
Rolling Hills	2017/2018	5/24/2018	11/2/2018	1,359,515	1.5%
Phantom Lake	2018/2019	12/19/2018	4/16/2019	343,748	0.8%
Overlake	2018/2019	12/6/2019	12/27/2019	326,644	1.0%
Lake McDonald	2020	5/26/2020		404,699	1.0%
Maplewood	2020	In progress		1,534,573	estimate
Cambridge	2021	In progress		956,084	estimate
Marine View	2021	In progress		1,600,000	estimate
Klahanie	2021	In progress		1,072,000	estimate
Norway Hills	2021	In progress		1,356,225	estimate
Average to Date				**952,326**	**1.6%**
Total to Date		**11/19/2020**		**10,218,294**	

Generation Efficiency

In 2014, PSE worked with the CRAG to refine the boundaries of what to include as savings under generation efficiency. It was determined that only parasitic loads[14] served directly by a generator would be included in the savings calculations as available for generation efficiency upgrades; generators whose parasitic loads are served externally – from the grid – would not be included. Using this definition, PSE completed site assessments in 2015 and the assessments did not yield any cost-effective measures. Most of the opportunities were in lighting, and very low operating hours made these opportunities not cost effective.

14 / Electric generation units need power to operate the unit, including auxiliary pumps, fans, electric motors and pollution control equipment. Some generating plants may receive this power externally, from the grid; however, many use a portion of the gross electric energy generated by the unit for operations – this is referred to as the "parasitic load."

Analyses performed during 2020-2021 planning revealed that there are no cost-effective measures available for PSE generation facilities. Program staff will continue examination of these facilities in 2020 and adjust PSE's 2021 Annual Conservation Plan, should conservation opportunities in generating facilities become cost effective.[15]

Distributed Generation

PSE offers cogeneration/combined heat and power incentives under its commercial and industrial programs. However, to date no project has been implemented.

Renewable distributed generation programs are discussed under "Customer Renewable Energy Programs" in the next section.

Demand Response

PSE will file an All-Source RFP and a Demand Response RFP with the WUTC in 2021.

In the meantime, PSE's Customer Energy Management group plans to operate geographically targeted pilots in both a natural gas (Duvall) and an electric (Bainbridge Island) program in 2021.

15 / *2021 Annual Conservation Plan*

Demand-side Customer Programs

Customer Renewable Energy Programs

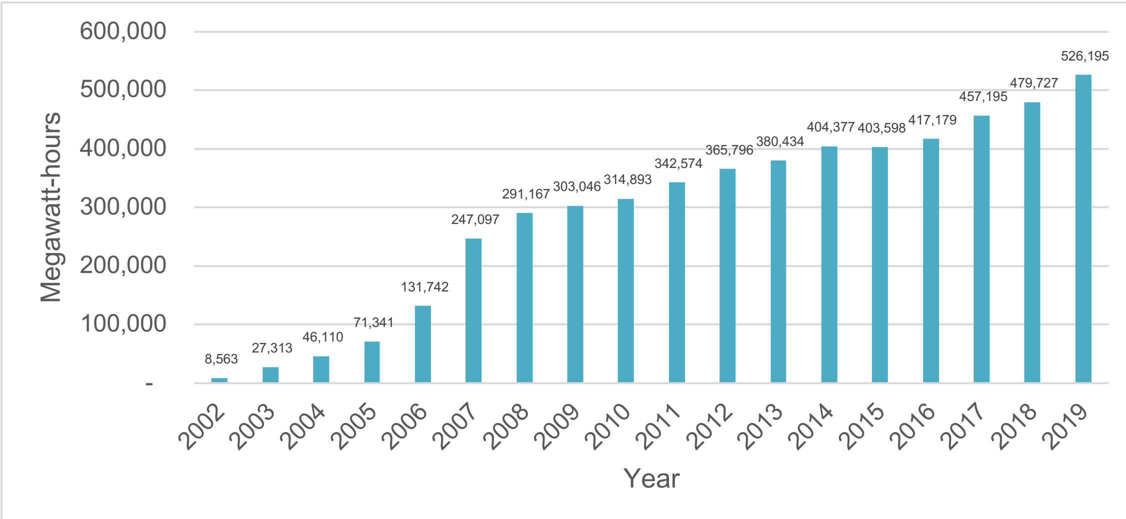
PSE's customer renewable energy programs remain popular options. The Green Power Program serves customers who want to purchase additional renewable energy, and Net Metering and Local Energy Development programs serve customers who generate renewable energy on a small scale. Our customers find value as well as social benefits in these programs, and PSE embraces and encourages their use.

GREEN POWER PROGRAM. Launched in 2001, PSE's Green Power Program allows customers to voluntarily purchase retail electric energy from qualified renewable energy resources. In 2009, PSE began working to increase participation in the program with 3Degrees, a third-party renewable energy credits (REC) broker that has developed and refined education and outreach techniques while working with other utility partners across the country. Since then, the program has grown to over 60,000 participants by the end of 2019. In addition, the number of megawatt-hours purchased increased by approximately 5 percent from 2017 to 2018 and 9.6 percent from 2018 to 2019, ending the period with sales amounting to 526,195 MWhs in 2019.

Top 10

PSE has been recognized as one of the country's top 10 utilities for Renewable Energy Sales and Total Number of Green Power Participants by the National Renewable Energy Laboratory since 2005.

Figure D-10: Green Power Megawatt-hours Sold, 2002-2019



The Green Power Program has built a portfolio of RECs generated from a wide variety of technologies. In 2017, PSE issued an RFQ that resulted in competitively awarding multi-year REC contracts to Bonneville Environmental Foundation and 3Degrees to help supply the balance of our Green Power program portfolio needs for up to three years, beginning in 2018 and expiring at the end of 2020. These suppliers provide the program with RECs primarily from Pacific Northwest renewable energy facilities. In mid-2020, PSE issued an RFQ seeking RECs to supply the Green Power program for the years 2021-2023. In addition, the Green Power Program directly purchases RECs from small, local and regional producers in order to support the development of small-scale renewable resources. These have included FPE Renewables, Farm Power Rexville, Edaleen Cow Power, Van Dyk-S Holsteins, Rainier Biogas, 3Bar G Community Wind, First Up! Knudson Community Wind, Ellensburg Community Solar, Swauk Wind and LRI Landfill Gas. Some of our small-scale solar contracts such as Skagit Community Solar, APSB Community Solar, Maple Hall Community Solar, Anacortes Library Community Solar and Greenbank Community Solar expired at the end of 2020. Many of these entities also provide power to PSE under the Schedule 91 contracts discussed above.

The increase in the number of utility-scale solar projects in Idaho and Oregon has allowed PSE to dramatically increase the number of RECs sourced from solar projects. PSE's preference is to source RECs first from projects located in Washington, and then from Oregon and Idaho. However, the supply of Pacific Northwest RECs continues to tighten as voluntary program sales have grown, and more resources are dedicated to serving compliance targets. This has made it more difficult to source all of our supply from this region. In an effort to maintain current program pricing, we have begun sourcing from other locations in the WECC, including Montana, Utah, Colorado, California and British Columbia. We believe this trend will continue as CETA compliance increases demand for renewable energy in the region.

GREEN POWER COMMUNITY GRANTS. Over the past 13 years, the Green Power Program has also committed over $1,850,000 in grant funding to 15 cities, 6 community service organizations and 10 low income multi-family housing agencies for solar demonstration projects. For example, in 2019, PSE awarded solar grants to 10 non-profit organizations specializing in low income or transitional multi-family housing. Anacortes Housing Authority, Community Youth Services, Family Support Center of South Sound, Homes First, King County Housing Authority, Kulshan Community Land Trust, Lummi Nation Housing Authority, Muckleshoot Housing Authority, Lydia Place and Opportunity Council received over $575,000 that resulted in more than 219 new kW of installed solar. In 2020, PSE issued a solicitation to award up to $1,000,000 in grant funding for solar installations to non-profits, public housing authorities or tribal entities serving low income or Black, Indigenous and People of Color (BIPOC) community members in PSE's electric service area. Projects are expected to be installed in 2021.

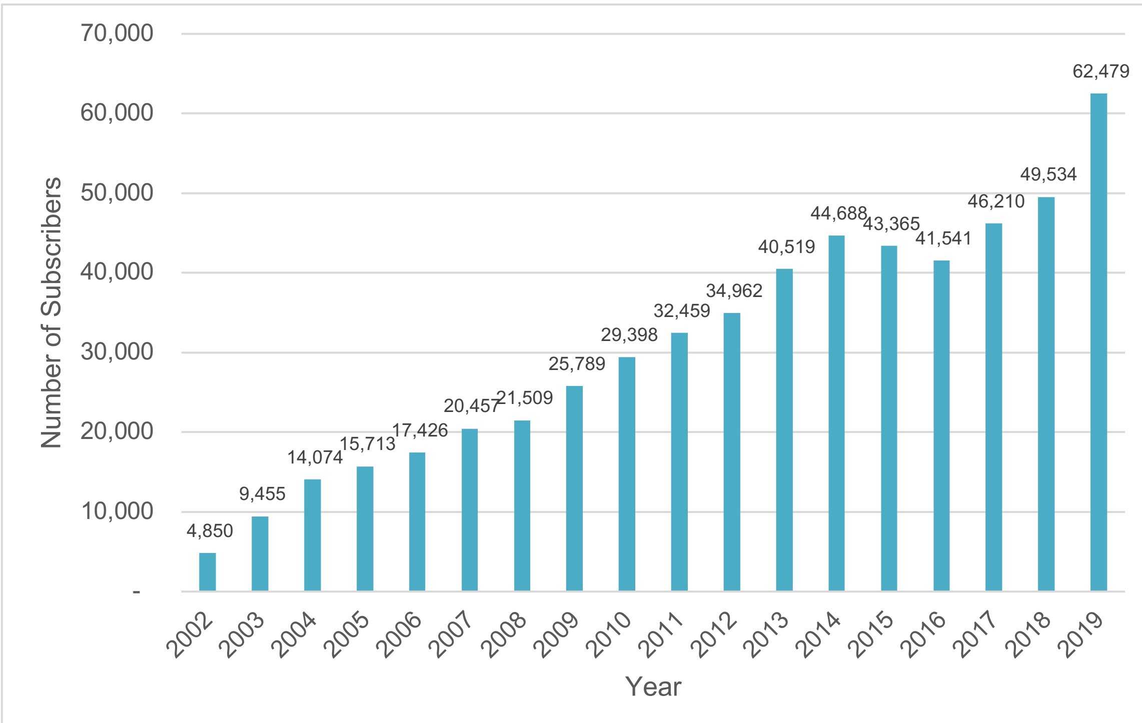
GREEN POWER RATES. In September 2016, PSE received approval from the WUTC to reduce Green Power rates. The standard rate for green power dropped from $0.0125 per kWh to $0.01 per kWh. Customers can purchase 200 kWh blocks for $2.00 per block with a two-block minimum or choose to participate in the "100% Green Power Option" introduced in 2007. This option adjusts the amount of the customer's monthly green power purchase to match their monthly electric usage. The large-volume green power rate dropped from $0.006 per kWh to $0.0035 per kWh for customers who purchase more than 1,000,000 kWh annually. This product has attracted approximately 30 customers since it was introduced in 2005.

In 2019, the average residential customer purchase was 718 kWh per month, and the average commercial customer purchase was 1,957 kWh. The average 2019 large-volume purchase under Schedule 136, by account, was 31,260 kWh per month.

SOLAR CHOICE. In September 2016, the WUTC approved PSE's Solar Choice program, a renewable energy product offering for residential and small to mid-size commercial customers. Similar to the Green Power program, Solar Choice allows customers to voluntarily purchase retail electric energy from qualified renewable energy resources; but in this case, all of the resources supplied are solar energy facilities located in Washington, Oregon and Idaho. Customers can elect to purchase solar in $5.00 blocks for 150 kilowatt-hours. The purchase is added to their monthly bill. The program was officially launched to customers in April 2017, and current participation stands at 7,654 participants. Collectively, these customers purchased 18,563 megawatt-hours of solar energy in 2019, a 112 percent increase from 2018 to 2019.
Figure D-11 illustrates the number of subscribers in our Green Power and Solar Choice offerings by year. Of our 62,479 Green Power and Solar Choice subscribers at the end of 2019, 61,554

were residential customers, 856 were commercial accounts, and 79 accounts were assigned under the large-volume commercial agreement. Cities with the most residential and commercial participants include Bellingham with 7,350, Olympia with 6,909 and Kirkland with 4,564.

Figure D-11: Green Power and Solar Choice Subscribers, 2002-2019



GREEN DIRECT. The Green Direct program launched on September 30, 2016 after WUTC approval. Like the Green Power program and Solar Choice, Green Direct falls under the rules governing utility green pricing options found in Washington RCW 19.29A, Voluntary Option to Purchase Qualified Alternative Energy Resources. Green Direct is a product that allows the utility to procure and sell fully bundled renewable energy to large commercial (10,000 MWh per year or more of load in PSE's service area) and government customers from specified wind and solar resources.

For Phase I, PSE signed a 20-year power purchase agreement for the output from the 137 MW Skookumchuck Wind project in Lewis County. Customers could elect to enroll for terms of 10, 15 or 20 years. The customer continues to receive and pay for all of the standard utility services for safety and reliability. Customers are charged for the total cost of the energy from the new plant, but receive a credit for the energy-related power costs from the company.

Phase I of Green Direct held its first open enrollment period in November and December 2016, followed by a second open enrollment period that opened on May 1, 2017. By the end of June 2017, less than two months later, the wind facility was fully-subscribed with 21 customers. Enrollees include companies like Starbucks, Target Corporation and REI, and government entities like King County and the City of Olympia.

For Phase II, PSE issued a Request for Proposals to identify a new resource (or resources) in August 2017. In early 2018, PSE selected a 120 MW solar project to be built in south-central Washington that is expected to begin operations in 2021. Following selection, PSE proposed a blended rate of the Phase I wind project and Phase II solar project, which the WUTC approved in July 2018. Phase II enrollment opened on August 31 at 1:00 pm, and was completely subscribed by 16 customers; four were wait listed. PSE subsequently requested an expansion of the project size from 120 MW to 150 MW, which the WUTC approved. The expansion allowed all 20 customers to participate. Phase II customers include T-Mobile, Amazon, Walmart, UW Bothell, Bellevue College, six Washington State agencies, the Issaquah School District, Providence Health & Services, Kaiser Permanente, Port of Bellingham, the cities of Kent and Redmond, and several customers from Phase I requesting additional supply.

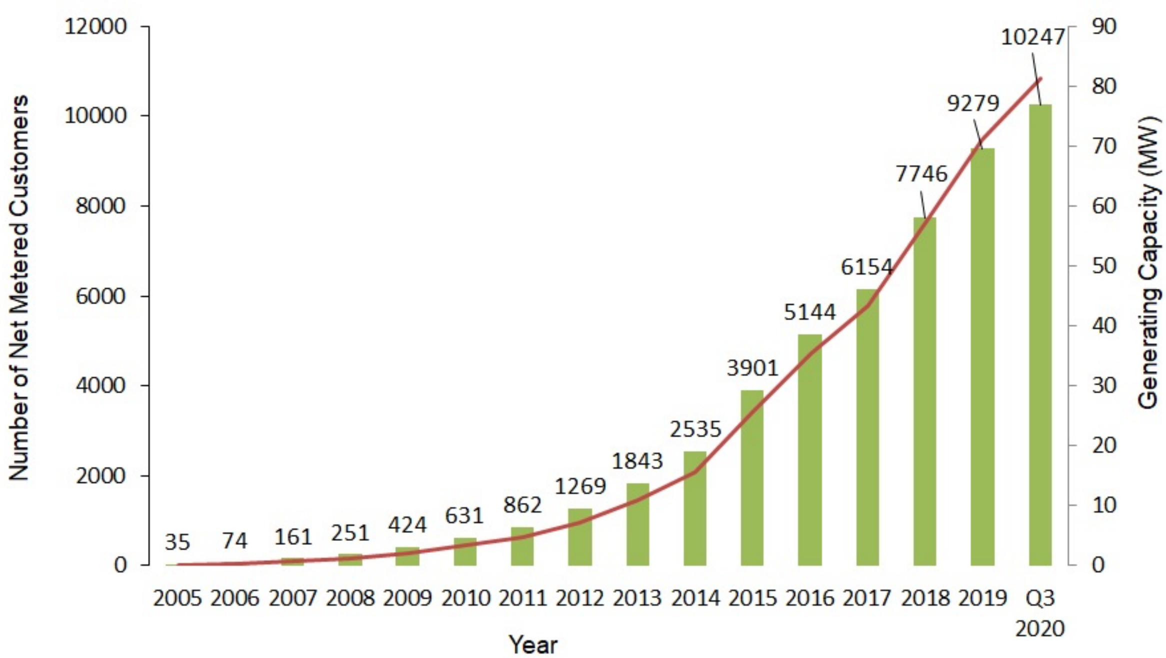
Customer Connected Renewables Programs

PSE offers two customer programs for customers who install their own small-scale generation, a net metering program and the Washington State Renewable Energy Production Incentive Program. These are not mutually exclusive, and the majority of customer-generators were enrolled in both programs until the Production Incentive Program closed to new participants in 2019.

The **NET METERING PROGRAM**, defined in Rate Schedule 150 and governed by RCW 80.60, began in 1999, and was most recently updated by Washington State Senate bill ESSB 5223 on July 28, 2019. Net metering provides a way for customers who generate their own renewable electricity to offset the electricity provided by PSE. The amount of electricity that the customer generates and sends back to the grid is subtracted from the amount of electricity provided by PSE, and the net difference is what the customer pays for on a monthly basis. A kWh credit is carried over to the next month if the customer generates more electricity than PSE supplies over the course of a month. The “banked” energy can be carried over until March 31, when the account is annually reset to zero according to state law. The interconnection capacity allowed under net metering is 100 kW AC.

Customer interest in small-scale renewables has increased significantly over the past 20 years, as Figure D-12 shows. The program has doubled the number of participating customers in the last four years, with strong growth continuing even after the closure of the State Production Incentive Program. In August of 2020, PSE celebrated its 10,000th net metered customer.

Figure D-12: Net Metered Customers, 1999-2020



The vast majority of customer systems (99 percent) are solar photovoltaic (PV) installations with an average generating capacity of 8 kW, but there are also small-scale hydroelectric generators and wind turbines. These small-scale renewable systems are distributed over a wide area of PSE's service territory. By mid-2020, PSE was net metering more than 80 MW (AC) of generating capacity.

Customer preference along with declining prices and federal tax incentives continues to drive customer solar PV adoption. Residential customers were 95 percent of all solar PV by number and 87 percent by nameplate capacity. In 2019, PSE revised Schedule 150 and streamlined the interconnection and net metering application process. PSE continues to examine our processes to allow for customer generation to scale up.

Figure D-13: Interconnected System Capacity by Type of System, as of Q3 2020

SYSTEM TYPE	NUMBER OF SYSTEMS	AVERAGE CAPACITY PER SYSTEM TYPE (kW [MW])	SUM OF ALL SYSTEMS BY TYPE (kW [MW])
Hybrid: solar/wind	16	9.3 [0.0093]	184 [0.184]
Micro hydro	6	15.7 [0.0177]	101 [0.101]
Solar array	10,196	8.0 [0.008]	80,993 [81]
Wind turbine	29	2.7 [0.0027]	80 [0.08]
Total	**10,247**	**8.0 [0.008]**	**81,359 [81.359]**

Figure D-14: Net Metered Systems by County

COUNTY	NUMBER OF NET METERS
Whatcom	2,126
King	3,342
Skagit	954
Island	485
Kitsap	1,031
Thurston	1,189
Kittitas	576
Pierce	536
Total	**10,247**

RENEWABLE ENERGY PRODUCTION INCENTIVE PAYMENT PROGRAM. The Washington State Renewable Energy Production Incentive Program is a production-based financial incentive for customers with solar, wind and bio-digester generating systems. PSE has voluntarily administered this state incentive to qualified customers under Schedule 151 since 2005.

In order for a PSE customer-generator to participate in Schedule 151, they must:

- Be a PSE customer with a valid interconnection agreement with PSE for the operation of their grid-connected renewable energy system.
- Have a system that includes production metering capable of measuring the energy output of the renewable energy system.
- Be certified (as named on the PSE account) by the Washington State Program Administrator as eligible for annual incentive payments.

In June 2019, the Washington State Program Administrator issued notice that this program's budget was fully obligated and PSE formally withdrew our voluntary participation effective December 12, 2019. PSE continues to administer annual incentive payments to all certified program participants, but customers installing new solar systems after December 12, 2019 are not eligible to participate in this program. Thus, the State Production Incentive Program is no longer a driver of solar energy adoption.

Annual Production Reporting and Payments: Annually, PSE measures and reports the kilowatt hours generated by participants' renewable energy systems and makes incentive payments to eligible customers as determined by the Washington State Program Administrator.

Legacy participants (those certified to participate by the Department of Revenue prior to October 1, 2017) with valid certifications will continue to receive payments of up to $5,000 per year for electricity produced through June 30, 2020 at rates ranging from $0.14 to $0.504 per kWh. Participants who obtained state certification on or after October 1, 2017 and who maintain ongoing eligibility requirements are eligible for up to eight years of annual incentive payments on kilowatt-hours generated from July 1, 2017 through June 30, 2029. The incentive rate for these participants ranges from $0.02 to $0.21 per kWh based on system size, technology and the date of certification.

Participant eligibility, rates, terms, payment limits and incentive payment amounts are determined by the Washington State Program Administrator.

Through 2019, PSE had administered to our customers over $72 million in production incentive payments. These payments are recovered through state tax credits. PSE expected to issue another $19 million in payments to approximately 8,000 participating customers. 2020 was the final payment year for 5,300 legacy program participants.

3. ELECTRIC RESOURCE ALTERNATIVES

This overview of alternatives for electric power generation describes both mature technologies and new methods of power generation, including those with near- and mid-term commercial viability. Within each section, resources are listed alphabetically.

COST ASSUMPTIONS. The generic resource costs for renewable, energy storage and thermal resources described in the following pages were aggregated from publicly available data sources including the National Renewable Energy Laboratory (NREL), the U.S. Energy Information Administration, Lazard, the Northwest Power and Conservation Council, various other National Laboratories and regional Integrated Resource Plans. Aggregated costs were then informed and adjusted through the stakeholder feedback process. Generic resource cost assumptions, including all data sources and averaging assumptions are available for review on the PSE IRP website.[16]

OPERATING CHARACTERISTICS. Generic resource operating characteristics were informed by PSE's experience, solar and wind data published by the NREL, and the Generic Resource Costs for Integrated Resource Planning report completed by consultant HDR for PSE in 2018, available for review on the PSE IRP website.[17]

16 / https://oohpseirp.blob.core.windows.net/media/Default/documents/Generic_Resource_Cost_Summary_PSE%202021%20IRP_post-feedback_v5.xlsx
17 / https://oohpseirp.blob.core.windows.net/media/Default/PDFs/HDR_Report_10111615-0ZR-P0001_PSE%20IRP_Rev4%20-%2020190123).pdf

Demand-side Resource Costs and Technologies

Demand-side resource (DSR) alternatives are analyzed in a Conservation Potential Assessment and Demand Response Assessment (CPA) to develop a supply curve that is used as an input to the portfolio analysis. The portfolio analysis then determines the maximum amount of energy savings that can be captured without raising the overall electric or natural gas portfolio cost. This identifies the cost-effective level of DSR to include in the portfolio.

PSE included the following demand-side resource alternatives in the CPA that was performed by The Cadmus Group for this IRP.

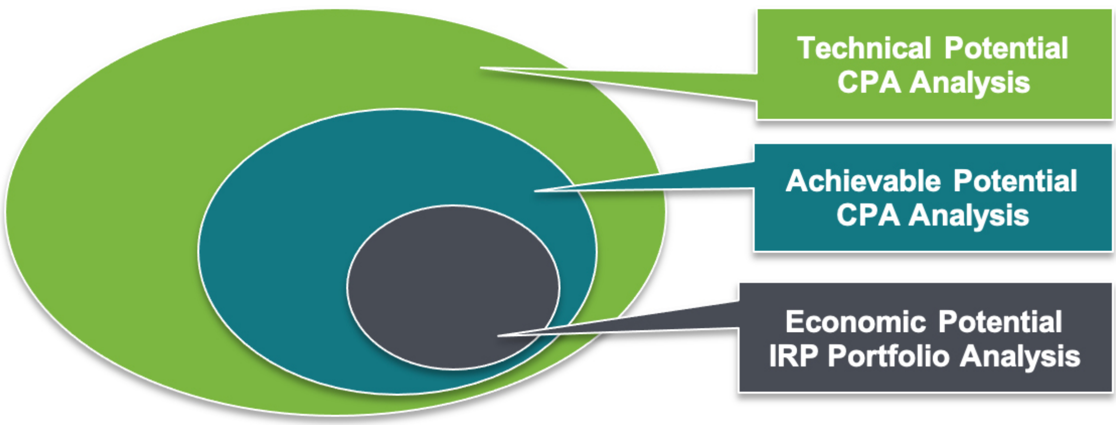
- **ENERGY EFFICIENCY MEASURES.** This label is used for a wide variety of measures that result in a smaller amount of energy being used to do a given amount of work. These include retrofitting programs such as heating, ventilation and air conditioning (HVAC) improvements, building shell weatherization, lighting upgrades and appliance upgrades.
- **DEMAND RESPONSE (DR).** Demand response resources are comprised of flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost.
- **DISTRIBUTED GENERATION.** Distributed generation refers to small-scale electricity generators located close to the source of the customer's load on customer's side of the utility meter. This includes combined heat and power (CHP) and rooftop solar.[18]
- **DISTRIBUTION EFFICIENCY (DE).** This involves conservation voltage reduction (CVR) and phase balancing. Voltage reduction is the practice of reducing the voltage on distribution circuits to reduce energy consumption, as many appliances and motors can perform properly while consuming less energy. Phase balancing eliminates total current flow energy losses.
- **GENERATION EFFICIENCY.** This involves energy efficiency improvements at the facilities that house PSE generating plant equipment, and where the loads that serve the facility itself are drawn directly from the generator and not the grid. These loads are also called parasitic loads. Typical measures target HVAC, lighting, plug loads and building envelope end-uses.
- **CODES AND STANDARDS (C&S).** These are no-cost energy efficiency measures that work their way to the market via new efficiency standards set by federal and state codes and standards. Only those that are in place at the time of the CPA study are included.

18 / In this IRP distributed solar PV is not included in the demand-side resources. Instead, it is handled as a direct no-cost reduction to the customer load. Solar PV subsidies are driving implementation and the subsidies are not fully captured with by the Total Resource Cost (TRC) approach that is used to determine the cost-effectiveness of DSR measures. Under the TRC approach, distributed solar PV is not cost effective and so is not selected in the portfolio analysis. Treating solar as a no-cost load reduction captures the adoption of this distributed generation resource by customers and its impact on loads more accurately.

Treatment of Demand-side Resource Alternatives

The conservation potential assessment and demand response assessment (CPA) performed for PSE by The Cadmus Group develops two levels of demand-side resource potential: technical potential and achievable technical potential. The IRP portfolio analysis then identifies the third level, economic potential. Figure D-15 shows the relationship between the technical, achievable and economic conservation potentials.

Figure D-15: Relationship between Technical, Achievable and Economic Potential



First, the CPA screened each measure for technical potential. This screen assumed all energy- and demand-saving opportunities could be captured regardless of cost or market barriers, which ensured the full spectrum of technologies, load impacts and markets were surveyed.

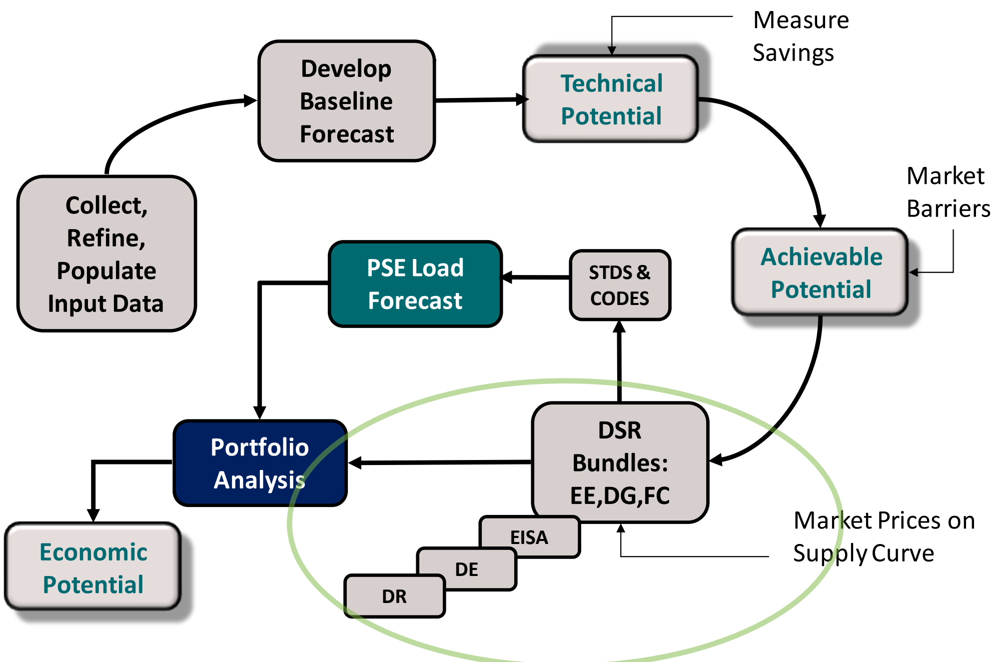
Second, market constraints were applied to estimate the achievable potential. To gauge achievability, Cadmus relied on customer response to past PSE energy programs, the experience of other utilities offering similar programs, and the Northwest Power and Conservation Council's most recent energy efficiency potential assessment. For this IRP, PSE assumed achievable electric energy efficiency potentials of 85 percent in existing buildings and 65 percent in new construction.

In the third step, the measures were combined into bundles based on levelized cost. This produces a conservation supply cost curve that is included in the IRP portfolio optimization analysis to identify the economic potential (cost-effectiveness) of the bundles.

Figure D-16 illustrates the methodology PSE used to assess demand-side resource potential in the IRP.

>>> See Appendix E, Conservation Potential Assessment and Demand Response Assessment, to access the Cadmus report.

Figure D-16: General Methodology for Assessing Demand-side Resource Potential

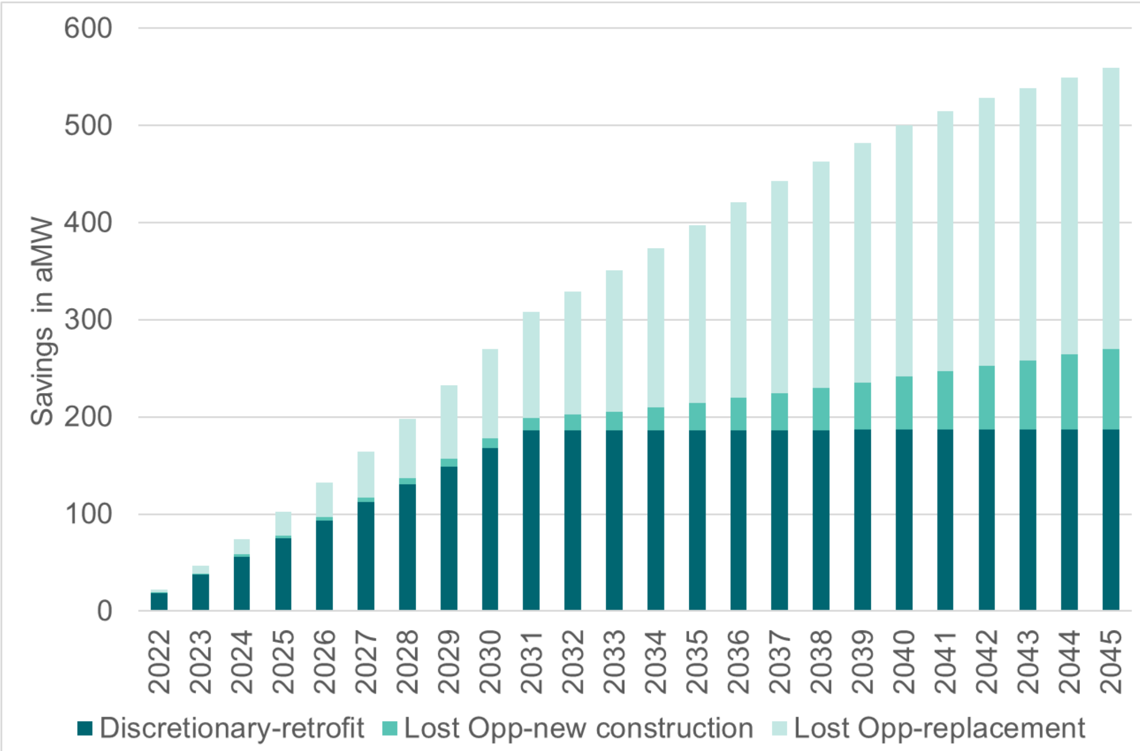


The tables and charts that follow summarize the results of the Cadmus Group's analysis of demand-side resources. Bundles 1 through 13 include energy efficiency and distributed generation. Each bundle adds measures to the bundle that preceded it. For a discussion of distribution efficiency (DE) bundles, see the section below. For the discussion of the Codes and Standards (C&S) bundles, see Appendix E, Conservation Potential Assessment report.

The savings potential for Bundles 1 through 13 consists of both retrofit and lost opportunity measures.[19] Figure D-17 shows the proportion of discretionary versus lost opportunity measures in the bundles.

19 |According to the Regional Technical Form: Lost opportunity measures are those that are available only during a specific window of time at a cost specific to the circumstances surrounding that instance of implementation, for example the replacement of equipment on failure of equipment or the addition of new equipment or facilities. Similarly, retrofit measures, also known as discretionary measures, are improvements to or replacements of systems that do not need to occur at the time of actual improvement or replacement.

Figure D-17: Discretionary versus Lost Opportunity Measures in Bundles 1 to 13



Distribution Efficiency

Plans for distribution efficiency have been updated in this IRP to reflect the changes in technology required to maintain power quality and stability as the role of distribution efficiency grows, while at the same time increasing amounts of distributed generation are entering the delivery system.

The original conservation voltage reduction (CVR) program PSE implemented in 2012-2013 utilized AMI meters that are now outdated and incompatible with the company-wide rollout of upgraded AMI technology that began in 2018. That rollout is expected to be completed in 2023. In the meantime, selected substations that have received the AMI upgrade will be able to participate in the current CVR program.

A second technology upgrade is planned as well. The current CVR program is a static form of CVR that cannot react to compensate for changes on the distribution system produced by distributed resources such as battery storage, solar generation and DR schemes. Because the static system cannot react and adjust to changing conditions on the distribution system, PSE is therefore investing in Automated Distribution Management System (ADMS) technology that can be programmed to automatically detect and anticipate changing conditions on the system. This will enable the system to react fast enough to prevent putting customers' power quality at risk.

Once the AMI and ADMS technologies are fully implemented, PSE will also have the operational control system necessary to transition the CVR program to full Volt-Var Optimization (VVO). ADMS will leverage AMI data at the end of line, with its own analytics and control intelligence to dynamically optimize power delivery within the distribution network, minimize losses and conserve energy. This builds upon dynamic voltage control by sensing and managing switched capacitors to optimize the power factor. VVO is a more sophisticated and extensive process than CVR, but relies on similar principles.

Completion of the AMI rollout is expected in 2023, and the ADMS software platform is expected to be completed in 2021. PSE expects to begin piloting VVO in 2021. From 2019-2021, we will continue implementing the current, static line drop compensation (LDC) CVR, but we expect we may continue to encounter complications and risks due to changes on the distribution system that are already occurring.

Eligible Substations: The current CVR program was put into place based on a study completed in 2007. According to that study, approximately 150 substations with at least 50 percent residential customers were identified as having the potential for energy savings using LDC CVR, based on typical customer usage patterns and the customer composition of the substations. Those 150 substations represented 52 percent of PSE's total 297 distribution substations and affected 67 percent of the PSE's customers.

An updated study is needed to confirm the number of substations which have the potential for cost-effective energy saving VVO. The implementation schedule and associated energy savings in Figures D-18 and D-19 below outline a projected number of substations to be completed each year and the cumulative savings expected.

Figure D-18: Implementation Schedule for Eligible Substations

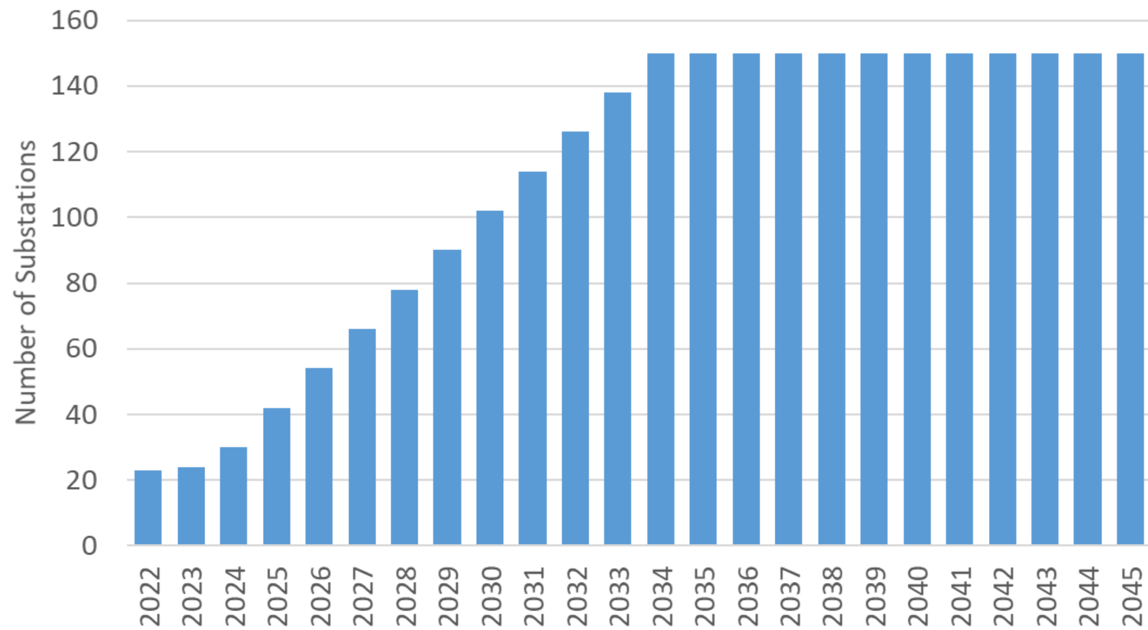


Figure D-19: Cumulative Savings in aMW from Distribution Efficiency (CVR+VVO)

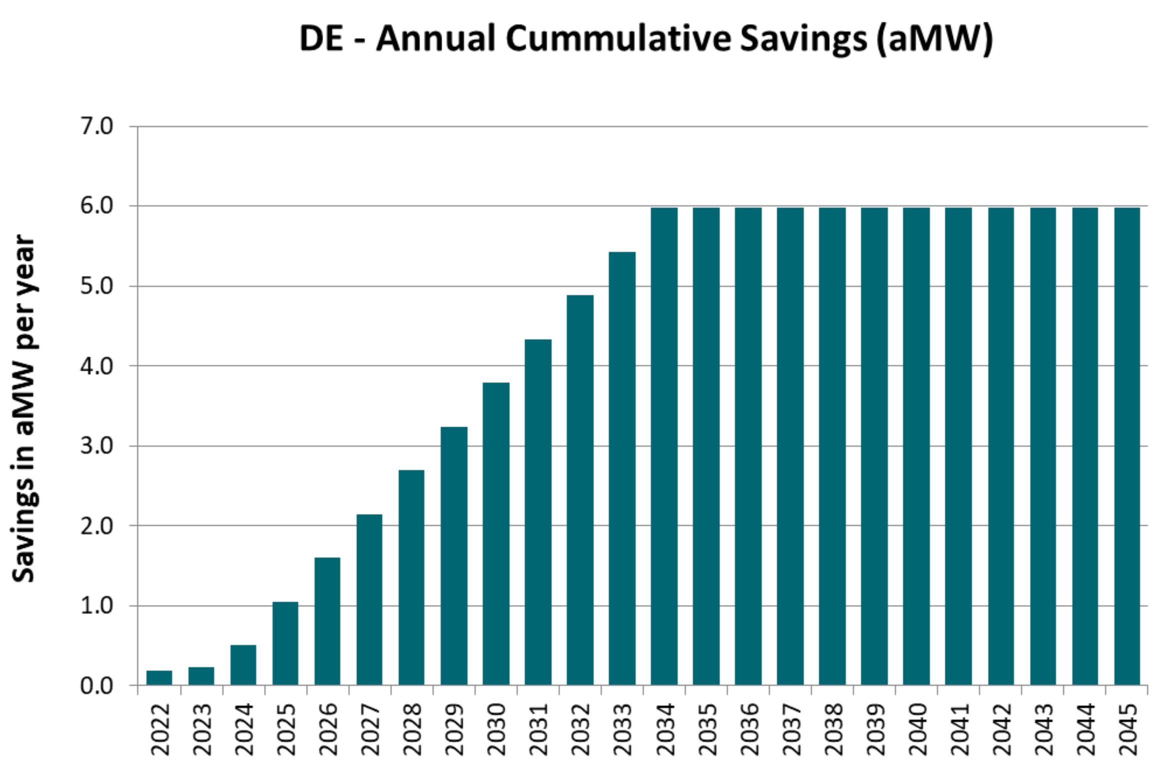


Figure D-20: Annual Energy Savings (aMW)

	Bundles (aMW)														
	1	2	3	4	5	6	7	8	9	10	11	12	13	DE	C&S
2022	3.7	1.8	1.2	0.2	0.5	0.2	0.6	0.5	1.2	0.2	0.1	0.1	1.3	0.5	21.8
2023	11.8	5.8	3.6	0.8	1.6	0.6	2.1	1.6	3.8	0.7	0.4	0.3	4.1	1.1	33.1
2024	20.4	10.0	6.2	1.4	2.7	1.0	3.8	3.1	6.9	1.4	0.7	0.5	7.2	1.7	44.8
2025	29.2	14.4	8.7	2.3	3.8	1.4	5.7	4.6	10.2	2.3	1.0	0.8	10.6	3.0	53.3
2026	38.3	18.8	11.2	3.3	4.9	1.7	7.9	6.2	13.7	3.4	1.5	1.0	14.4	4.3	60.5
2027	47.7	23.5	13.7	4.5	6.1	2.1	10.4	8.0	17.3	4.7	2.0	1.3	18.5	5.7	67.4
2028	57.6	28.6	16.2	6.0	7.4	2.5	13.2	10.0	21.0	6.3	2.7	1.6	23.2	7.0	73.9
2029	67.3	33.5	18.7	7.7	8.7	2.9	16.2	11.9	24.7	8.1	3.4	1.8	28.1	8.3	80.1
2030	77.2	38.6	21.2	9.6	10.0	3.3	19.3	13.9	28.4	10.3	4.2	2.2	33.5	9.6	86.5
2031	87.5	43.8	23.7	11.8	11.4	3.7	22.7	16.2	32.2	12.9	5.2	2.5	39.3	10.9	93.4
2032	95.0	47.5	25.2	14.0	12.4	4.0	25.9	18.3	35.4	15.8	6.1	2.8	44.4	12.2	99.1
2033	98.6	49.1	25.2	16.2	12.8	4.0	28.3	19.8	37.6	18.9	6.9	3.0	48.2	13.5	104.2
2034	102.6	50.8	25.3	18.5	13.3	4.1	31.0	21.5	39.9	22.3	7.8	3.3	52.4	14.8	110.3
2035	106.7	52.7	25.4	20.7	13.9	4.1	33.7	23.5	42.3	26.0	8.7	3.5	56.7	14.8	117.1
2036	111.0	54.7	25.6	23.0	14.5	4.2	36.7	25.6	44.8	30.0	9.7	3.8	61.2	14.8	123.0
2037	114.7	56.2	25.6	25.2	15.0	4.3	39.3	27.3	46.9	34.0	10.6	4.1	65.4	14.8	128.7
2038	118.7	57.6	25.7	27.4	15.6	4.3	42.0	28.6	48.1	37.9	11.5	4.3	69.4	14.8	134.4
2039	122.8	59.0	25.7	29.6	16.2	4.4	44.7	29.6	48.6	41.8	12.3	4.6	73.1	14.8	140.3
2040	126.9	60.5	25.8	31.6	16.8	4.5	47.3	30.8	49.2	45.8	13.2	4.9	76.8	14.8	145.9
2041	129.6	61.6	25.8	32.4	17.3	4.5	49.1	31.7	49.4	49.5	14.0	5.1	79.9	14.8	151.7
2042	132.6	62.8	25.9	32.6	17.9	4.6	50.5	32.7	49.7	53.2	14.7	5.4	82.8	14.8	157.4
2043	135.6	64.1	25.9	32.7	18.5	4.6	51.7	33.7	49.9	56.3	15.0	5.6	84.5	14.8	163.0
2044	139.1	65.6	26.0	32.9	19.1	4.7	53.1	34.9	50.3	59.1	15.1	5.9	85.8	14.8	168.4
2045	141.7	66.6	25.9	32.9	19.6	4.8	54.1	35.9	50.4	61.4	15.1	6.1	86.4	14.8	174.1

Figure D-21: Total December Peak Reduction (MW)

	Bundles (MW)														
	1	2	3	4	5	6	7	8	9	10	11	12	13	DE	C&S
2022	12.1	7.2	3.7	0.7	2.7	0.9	2.7	1.3	4.1	0.6	0.5	0.3	5.3	1.2	37.0
2023	24.8	14.7	7.3	1.5	5.4	1.7	5.7	3.0	8.6	1.6	1.1	0.7	11.2	1.5	61.4
2024	38.0	22.5	11.0	2.6	8.1	2.6	9.1	4.8	13.4	2.9	2.0	1.0	17.6	2.2	80.2
2025	51.6	30.4	14.7	4.0	10.9	3.4	12.7	6.7	18.4	4.7	3.0	1.4	24.9	3.9	92.1
2026	65.6	38.5	18.4	5.6	13.7	4.2	16.7	8.7	23.5	6.8	4.2	1.7	32.9	5.1	107.0
2027	80.2	47.0	22.1	7.5	16.7	5.1	21.2	10.8	28.7	9.6	5.7	2.1	42.0	6.4	120.9
2028	95.2	55.8	25.8	9.8	19.7	6.0	26.0	13.2	34.0	13.0	7.4	2.5	52.0	7.7	145.6
2029	110.3	64.5	29.5	12.4	22.7	6.8	31.0	15.4	39.3	17.1	9.4	2.9	62.8	8.9	158.9
2030	126.0	73.5	33.2	15.4	25.8	7.6	36.3	17.9	44.7	22.0	11.7	3.3	74.7	10.2	163.0
2031	142.1	82.6	36.9	18.6	29.1	8.5	41.9	20.5	50.1	27.6	14.1	3.7	87.4	11.5	168.7
2032	147.8	85.3	37.0	21.8	29.9	8.5	45.5	22.3	52.5	33.6	16.5	3.9	96.2	12.8	180.6
2033	153.9	87.7	37.1	25.0	30.6	8.6	48.9	23.8	54.8	40.4	18.9	4.2	105.4	14.1	199.0
2034	160.5	90.6	37.3	28.4	31.5	8.6	52.7	25.8	57.2	47.7	21.3	4.5	115.0	15.4	222.2
2035	166.8	93.3	37.5	31.5	32.3	8.7	56.5	27.9	59.6	55.4	23.8	4.8	124.5	14.6	236.9
2036	173.0	95.8	37.7	34.7	33.2	8.7	60.2	30.0	62.0	63.5	26.2	5.0	134.1	14.6	224.7
2037	179.3	98.1	37.7	37.9	34.1	8.8	63.8	31.6	64.1	71.7	28.7	5.3	143.8	14.6	236.9
2038	185.8	100.3	37.7	41.2	35.1	8.9	67.6	32.8	64.8	79.8	31.2	5.6	153.0	14.6	248.3
2039	192.5	102.4	37.8	44.4	36.1	8.9	71.2	34.0	65.5	88.1	33.5	5.8	161.6	14.6	271.2
2040	198.1	104.3	37.9	46.7	36.9	9.0	74.4	35.3	66.1	96.3	35.8	6.1	169.9	14.6	296.2
2041	203.3	106.2	37.9	47.2	37.9	9.0	76.6	36.4	66.5	104.7	38.2	6.4	177.8	14.6	292.8
2042	208.3	108.1	37.9	47.5	38.8	9.1	78.5	37.6	66.8	112.2	40.0	6.6	183.7	14.6	290.3
2043	213.3	110.1	38.0	47.6	39.5	9.2	80.1	38.8	67.2	116.6	40.0	6.9	184.9	14.6	302.1
2044	218.7	112.3	38.0	47.8	40.4	9.3	81.9	40.2	67.7	121.2	40.2	7.2	186.7	14.6	325.8
2045	223.7	114.1	38.0	47.9	41.2	9.3	83.5	41.4	68.1	125.6	40.2	7.4	188.0	14.6	354.1

The DSR December peak reduction is based on the average of the very heavy load hours (VHLH). The VHLH method takes the average of the five-hour morning peak from hour ending 7 a.m. to hour ending 11 a.m. and the five-hour evening peak from hour ending 6 p.m. to hour ending 10 p.m. Monday through Friday. The system demand peaked during the evening hours and correspondingly the demand-side resource peaks were chosen to be coincident with those evening system peak hours.

Figure D-22: Annual Costs (dollars in thousands)

(Codes and Standards has no cost and is considered a must-take bundle.)

	Bundles ($'000)													
	1	2	3	4	5	6	7	8	9	10	11	12	13	DE
2022	$3,892	$14,579	$13,849	$2,855	$7,341	$2,949	$12,265	$11,739	$32,508	$6,044	$3,789	$4,260	$253,744	$2,450
2023	$4,456	$16,015	$13,875	$3,744	$7,573	$3,032	$15,121	$15,469	$38,664	$8,988	$4,867	$4,436	$263,266	$2,700
2024	$4,313	$16,818	$13,891	$4,603	$7,797	$3,034	$17,609	$17,750	$42,756	$11,803	$5,940	$4,623	$272,897	$3,270
2025	$4,449	$16,870	$13,892	$5,673	$7,969	$2,921	$19,528	$17,875	$45,311	$14,627	$7,317	$4,771	$283,391	$5,490
2026	$4,718	$17,775	$13,905	$6,779	$8,263	$2,966	$22,357	$19,702	$47,244	$17,658	$8,691	$5,024	$295,726	$6,090
2027	$5,052	$18,637	$13,918	$8,148	$8,610	$3,014	$25,215	$21,434	$48,468	$21,677	$10,355	$5,327	$310,353	$6,690
2028	$5,404	$19,548	$13,925	$9,661	$8,995	$3,093	$27,962	$23,623	$49,350	$25,827	$12,128	$5,696	$325,699	$7,290
2029	$5,570	$19,178	$13,911	$11,033	$9,180	$2,961	$28,866	$21,403	$49,538	$30,455	$13,887	$5,822	$337,674	$7,890
2030	$6,054	$20,295	$13,913	$12,570	$9,649	$3,094	$31,667	$24,708	$50,292	$35,746	$15,620	$6,271	$354,541	$8,490
2031	$6,483	$20,106	$13,902	$13,799	$10,025	$3,160	$33,625	$26,678	$50,788	$40,908	$17,023	$6,612	$368,456	$9,090
2032	$3,187	$6,840	$629	$13,117	$3,267	$418	$24,695	$19,903	$31,880	$44,259	$15,151	$4,948	$137,645	$9,690
2033	$3,260	$5,999	$630	$13,595	$3,207	$247	$23,882	$15,919	$31,569	$48,716	$15,828	$4,703	$140,718	$10,290
2034	$3,968	$7,510	$674	$13,933	$3,733	$493	$26,666	$22,065	$32,414	$53,435	$16,284	$5,210	$153,873	$10,890
2035	$4,333	$7,471	$692	$13,489	$3,971	$576	$27,421	$24,135	$32,703	$56,968	$16,418	$5,341	$159,132	$7,650
2036	$4,490	$6,827	$693	$13,401	$3,958	$513	$27,007	$22,734	$32,506	$59,827	$16,407	$5,190	$159,094	$7,650
2037	$4,409	$6,042	$303	$13,237	$3,778	$367	$25,713	$17,088	$27,103	$60,962	$16,381	$4,885	$155,776	$7,650
2038	$4,682	$5,429	$214	$13,290	$3,956	$461	$26,376	$10,793	$6,096	$56,491	$15,508	$5,043	$134,395	$7,650
2039	$4,830	$5,239	$213	$13,288	$4,049	$505	$25,532	$11,995	$6,279	$57,191	$15,145	$5,105	$126,308	$7,650
2040	$4,919	$5,414	$212	$9,910	$4,104	$534	$22,761	$12,723	$6,389	$57,704	$15,116	$5,139	$127,299	$7,650
2041	$4,776	$4,822	$199	$1,270	$3,952	$433	$15,285	$10,004	$3,298	$57,974	$15,083	$4,918	$119,554	$7,650
2042	$4,865	$5,146	$207	$1,102	$4,033	$495	$13,272	$11,597	$3,173	$54,249	$11,749	$5,014	$102,142	$7,650
2043	$4,858	$5,030	$208	$449	$3,628	$503	$12,019	$11,816	$3,190	$37,667	$228	$5,007	$53,941	$7,650
2044	$4,955	$5,283	$217	$511	$3,676	$571	$12,613	$13,565	$3,394	$36,919	$39	$5,116	$55,811	$7,650
2045	$4,745	$4,650	$202	$421	$3,508	$473	$11,623	$11,040	$3,079	$36,600	$36	$4,901	$51,404	$7,650

Demand Response

Demand response (DR) is a strategy designed to decrease load on the grid during times of peak use. It involves modifying the way customers use energy – particularly when they use it. For instance, businesses might work with PSE to voluntarily adjust their operations during a specified time range. Residential customers might automate their usage with smart thermostats or water heaters. While there are often financial incentives to participate in DR pilots and programs, it is also a way for both PSE and customers to increase efficiency and reduce their carbon footprints.

Demand response programs are voluntary, and once enrolled, customers usually receive notifications in advance of forecasted peak usage times. Depending on the program, this might mean that their thermostat automatically warms their home or building earlier than usual. Because of the remote function of demand response, no action is required from customers to initiate their reduction in load, and they can always choose to opt out of an event.

Demand response programs are organized into four categories. These include:

- Direct Load Control (DLC)
- Commercial and Industrial (C&I) Curtailment
- Dynamic Pricing or Critical Peak Pricing (CPP)
- Behavioral DR

Figures D-23a and 23b provide the total winter and summer peak reduction potential for each program, and Figures D-24a and 24b show the costs for each of those programs. In these tables, the numbers across the top represent the 16 different DR programs analyzed, as follows:

1. Residential CPP-No Enablement
2. Residential CPP-With Enablement
3. Residential DLC Heat-Switch
4. Residential DLC Heat-BYOT
5. Residential DLC ERWH-Switch
6. Residential DLC ERWH-Grid-Enabled
7. Residential DLC HPWH-Switch
8. Residential DLC HPWH-Grid-Enabled
9. Small Commercial DLC Heat-Switch
10. Medium Commercial DLC Heat-Switch
11. Commercial & Industrial Curtailment-Manual
12. Commercial & Industrial Curtailment-AutoDR
13. Commercial CPP-No Enablement
14. Commercial CPP-With Enablement

Figure D-23a: Demand Response Programs, Total Winter Peak Reduction (MW)

	DR Winter Programs (MW)															
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	4	0	5	1	0	0	1	0	0	0	0	0	0	1
2024	0	0	8	0	9	2	0	0	1	1	0	0	0	0	0	3
2025	5	0	16	0	18	5	0	0	2	2	1	1	0	0	1	4
2026	10	0	25	1	25	10	0	0	3	3	1	1	1	0	1	5
2027	20	1	34	1	31	16	0	0	5	3	2	2	1	1	2	7
2028	30	1	42	1	35	24	1	0	6	4	2	2	1	1	2	7
2029	41	1	43	2	32	27	0	0	6	4	2	2	1	1	2	7
2030	52	2	43	2	29	31	0	0	6	4	2	3	1	1	3	7
2031	53	2	44	2	25	35	0	1	6	5	2	3	1	1	3	7
2032	54	2	44	3	22	39	0	1	6	5	3	3	1	1	3	7
2033	54	2	45	3	18	43	0	1	6	5	3	3	1	1	4	7
2034	55	2	45	3	15	47	0	1	6	5	3	3	1	1	4	7
2035	56	2	46	3	11	51	0	1	6	5	3	3	1	1	4	8
2036	57	2	46	3	10	53	0	1	6	5	3	3	1	1	5	8
2037	58	2	47	3	10	54	0	1	6	5	3	3	1	1	5	8
2038	59	2	47	3	10	54	0	1	6	5	3	3	1	1	6	8
2039	60	2	48	3	10	55	0	1	6	5	3	3	1	1	6	8
2040	60	2	48	3	10	55	0	1	6	5	3	3	1	1	6	8
2041	61	2	48	3	10	56	0	1	6	5	3	3	1	1	7	8
2042	62	2	49	3	10	56	0	1	6	5	3	3	1	1	7	8
2043	63	2	49	3	10	57	0	1	7	5	3	3	1	1	8	9
2044	64	2	50	3	11	57	0	1	7	5	3	3	1	1	8	9
2045	64	2	50	3	11	58	0	1	7	5	3	3	1	1	9	9

Figure D-23b: Demand Response Programs, Total Summer Peak Reduction (MW)

	DR Summer Programs (MW)															
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	2	0	5	1	0	0	1	1	0	0	0	0	0	1
2024	0	0	4	2	9	2	0	0	1	3	1	1	0	0	0	2
2025	3	0	8	3	18	5	0	0	3	6	1	1	1	1	1	2
2026	6	0	12	6	25	10	0	0	4	9	2	2	1	1	1	3
2027	12	0	16	11	31	16	0	0	6	12	2	3	1	2	2	4
2028	19	0	20	14	35	24	1	0	8	16	3	3	1	3	2	4
2029	25	1	20	17	32	27	0	0	8	16	3	3	1	3	2	4
2030	32	1	21	20	29	31	0	0	8	16	3	3	1	3	3	4
2031	32	1	21	22	25	35	0	1	8	16	3	3	1	3	3	4
2032	33	1	21	24	22	39	0	1	8	16	3	3	1	3	3	4
2033	33	1	21	26	18	43	0	1	8	16	3	3	1	3	4	5
2034	34	1	22	27	15	47	0	1	8	17	3	3	2	3	4	5
2035	34	1	22	28	11	51	0	1	8	17	3	3	2	3	4	5
2036	35	1	22	28	10	53	0	1	8	17	3	3	2	3	5	5
2037	35	1	22	29	10	54	0	1	8	17	3	4	2	3	5	5
2038	36	1	22	29	10	54	0	1	8	17	3	4	2	3	6	5
2039	36	1	23	29	10	55	0	1	8	17	4	4	2	3	6	5
2040	37	1	23	30	10	55	0	1	8	18	4	4	2	3	6	5
2041	37	1	23	30	10	56	0	1	8	18	4	4	2	3	7	5
2042	38	1	23	30	10	56	0	1	9	18	4	4	2	3	7	5
2043	38	1	24	31	10	57	0	1	9	18	4	4	2	3	8	5
2044	39	1	24	31	11	57	0	1	9	18	4	4	2	3	8	5
2045	39	1	24	31	11	58	0	1	9	18	4	4	2	3	9	5

Figure D-24a: Winter Demand Response Annual Costs (dollars in thousands)

	DR Winter Bundles ($'000)															
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
2022	$219	$6	$141	$9	$23	$125	$0	$2	$85	$65	$74	$76	$131	$94	$300	$150
2023	$75	$2	$1,016	$4	$3,379	$103	$127	$4	$155	$65	$19	$95	$74	$49	$336	$88
2024	$77	$2	$1,273	$12	$3,504	$261	$132	$10	$185	$78	$39	$119	$77	$51	$454	$183
2025	$515	$9	$2,641	$26	$6,715	$706	$252	$27	$382	$160	$81	$245	$111	$70	$613	$285
2026	$539	$9	$3,210	$47	$6,758	$1,198	$254	$45	$448	$188	$125	$297	$115	$73	$804	$396
2027	$1,032	$16	$3,816	$78	$6,648	$1,817	$250	$68	$517	$217	$173	$353	$119	$75	$1,041	$514
2028	$1,080	$17	$4,460	$95	$6,372	$2,576	$239	$97	$590	$248	$223	$414	$123	$78	$789	$534
2029	$1,129	$18	$2,621	$117	$2,027	$2,393	$76	$90	$287	$121	$231	$245	$55	$39	$864	$555
2030	$1,181	$19	$2,715	$139	$1,863	$2,737	$70	$103	$297	$126	$239	$257	$57	$40	$972	$576
2031	$150	$3	$2,813	$159	$1,684	$3,102	$63	$117	$308	$130	$249	$271	$58	$41	$1,053	$600
2032	$154	$4	$2,913	$176	$1,490	$3,489	$56	$131	$318	$135	$258	$272	$60	$42	$1,137	$624
2033	$157	$4	$3,015	$190	$1,279	$3,900	$48	$147	$329	$139	$265	$278	$61	$43	$1,225	$648
2034	$161	$4	$3,122	$201	$1,050	$4,334	$39	$163	$340	$144	$276	$298	$63	$44	$1,319	$673
2035	$165	$4	$3,231	$210	$804	$4,794	$30	$180	$351	$149	$288	$315	$64	$46	$1,420	$701
2036	$168	$4	$3,343	$218	$735	$4,684	$28	$176	$363	$154	$298	$319	$66	$47	$1,529	$730
2037	$171	$4	$3,457	$226	$1,252	$4,648	$47	$175	$375	$159	$309	$329	$67	$48	$1,645	$760
2038	$175	$4	$3,575	$234	$1,294	$4,809	$49	$181	$388	$164	$320	$343	$69	$49	$1,767	$790
2039	$179	$4	$3,697	$243	$1,337	$4,974	$50	$187	$401	$169	$333	$359	$71	$50	$1,894	$822
2040	$183	$4	$3,823	$251	$1,382	$5,145	$52	$193	$414	$175	$345	$370	$72	$52	$2,065	$854
2041	$187	$4	$3,952	$260	$1,428	$5,321	$54	$200	$428	$181	$358	$386	$74	$53	$2,201	$889
2042	$191	$4	$4,086	$269	$1,476	$5,502	$55	$207	$442	$187	$372	$400	$76	$54	$2,337	$924
2043	$195	$5	$4,223	$279	$1,525	$5,689	$57	$214	$456	$193	$386	$416	$78	$55	$2,473	$959
2044	$200	$5	$4,364	$289	$1,575	$5,881	$59	$221	$471	$199	$401	$432	$80	$57	$2,606	$994
2045	$204	$5	$4,510	$299	$1,628	$6,079	$61	$228	$487	$206	$417	$451	$82	$58	$2,737	$1,032

Figure D-24b: Summer Demand Response Annual Costs (dollars in thousands)

	DR Summer Bundles ($'000)															
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
2022	$220	$5	$65	$85	$23	$125	$0	$2	$48	$102	$74	$76	$81	$144	$300	$150
2023	$75	$2	$984	$37	$3,379	$103	$127	$4	$347	$173	$24	$122	$57	$88	$336	$54
2024	$77	$2	$1,233	$117	$3,504	$261	$132	$10	$414	$207	$50	$153	$59	$91	$454	$111
2025	$516	$8	$2,557	$251	$6,715	$706	$252	$27	$857	$428	$104	$316	$93	$136	$613	$174
2026	$539	$8	$3,108	$456	$6,758	$1,198	$254	$45	$1,003	$501	$161	$382	$96	$141	$804	$241
2027	$1,033	$16	$3,695	$756	$6,648	$1,817	$250	$68	$1,159	$579	$222	$455	$100	$146	$1,041	$314
2028	$1,081	$16	$4,319	$912	$6,372	$2,576	$239	$97	$1,323	$662	$288	$533	$104	$151	$789	$326
2029	$1,130	$17	$2,537	$1,129	$2,027	$2,393	$76	$90	$644	$324	$297	$315	$36	$62	$864	$338
2030	$1,181	$18	$2,629	$1,342	$1,863	$2,737	$70	$103	$666	$335	$309	$332	$36	$63	$972	$352
2031	$151	$3	$2,723	$1,537	$1,684	$3,102	$63	$117	$690	$347	$321	$349	$37	$65	$1,053	$366
2032	$154	$3	$2,820	$1,702	$1,490	$3,489	$56	$131	$713	$359	$332	$351	$38	$66	$1,137	$381
2033	$158	$3	$2,920	$1,835	$1,279	$3,900	$48	$147	$737	$371	$342	$358	$39	$68	$1,225	$395
2034	$162	$3	$3,023	$1,940	$1,050	$4,334	$39	$163	$762	$383	$355	$384	$40	$70	$1,319	$411
2035	$165	$3	$3,129	$2,027	$804	$4,794	$30	$180	$788	$396	$371	$406	$41	$72	$1,420	$428
2036	$169	$3	$3,237	$2,106	$735	$4,684	$28	$176	$814	$410	$384	$412	$42	$73	$1,529	$445
2037	$172	$3	$3,348	$2,183	$1,252	$4,648	$47	$175	$841	$423	$398	$425	$43	$75	$1,645	$464
2038	$176	$3	$3,462	$2,262	$1,294	$4,809	$49	$181	$869	$437	$413	$443	$44	$77	$1,767	$482
2039	$179	$3	$3,580	$2,344	$1,337	$4,974	$50	$187	$898	$452	$429	$463	$45	$79	$1,894	$501
2040	$183	$3	$3,701	$2,428	$1,382	$5,145	$52	$193	$928	$467	$445	$477	$47	$81	$2,065	$521
2041	$188	$3	$3,827	$2,515	$1,428	$5,321	$54	$200	$959	$483	$462	$498	$48	$83	$2,201	$542
2042	$192	$4	$3,956	$2,605	$1,476	$5,502	$55	$207	$991	$498	$479	$516	$49	$85	$2,337	$563
2043	$196	$4	$4,089	$2,697	$1,525	$5,689	$57	$214	$1,023	$515	$498	$536	$50	$87	$2,473	$585
2044	$200	$4	$4,226	$2,792	$1,575	$5,881	$59	$221	$1,057	$532	$517	$557	$51	$89	$2,606	$607
2045	$205	$4	$4,367	$2,890	$1,628	$6,079	$61	$228	$1,091	$549	$537	$582	$53	$91	$2,737	$629

Supply-side Renewable Resource Costs and Technologies

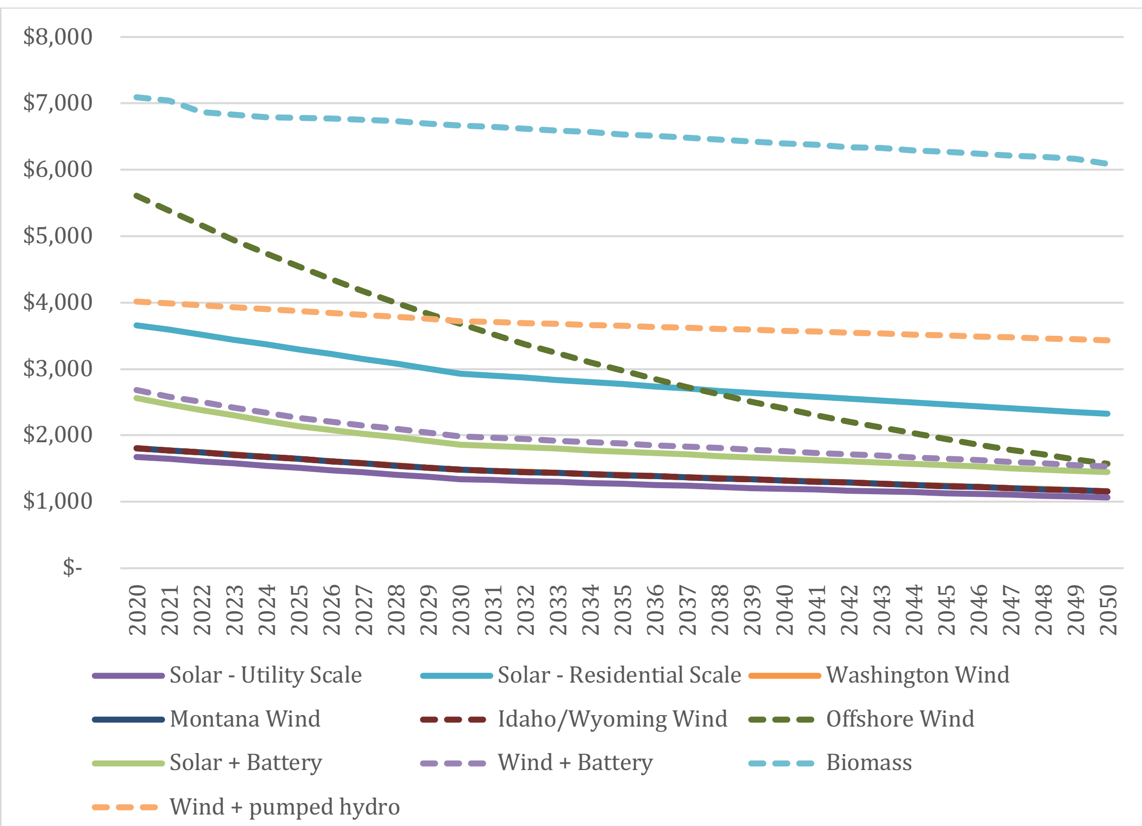
PSE modeled the following supply-side renewable resources in the 2021 IRP:

- biomass
- solar
- wind
- energy storage
- hybrid resources (renewable plus energy storage)

CAPITAL COST CURVE. Capital costs assumptions start in current the current year, but for future years, the cost curve from the NREL Annual Technology Baseline (ATB) 2019 was applied to the current costs.

Figure D-25 below shows the capital cost curves for the renewable resources modeled in the 2021 IRP.

Figure D-25: Capital Cost Curve for Renewable Resources



Biomass Characteristics

Biomass in this context refers to the burning of woody biomass in boilers. Most existing biomass in the Northwest is tied to steam hosts (also known as “cogeneration” or “combined heat and power”). It is found mostly in the timber, pulp and paper industries. This dynamic has limited the amount of power available to date. The typical plant size observed is 10 MW to 50 MW. One major advantage of biomass plants is that they can operate as a baseload resource, since they do not impose generation variability on the grid, unlike wind and solar. Municipal solid waste, landfill and wastewater treatment plant gas are discussed in the section on waste-to-energy technologies, titled Renewable Resources Not Modeled.

Biomass is modeled in the IRP as a 15 MW, wood-fired facility with a heat rate of 14,599 BTU per kWh. These parameters are intended to reflect a cogeneration facility within proximity to a timber mill.

Commercial Availability: This technology is commercially available. Greenfield development of a new biomass facility requires approximately four years.

Figure D-26: Biomass Generic Resource Assumptions

2020 $	UNITS	BIOMASS
ISO Capacity Primary	MW	15
Capacity Credit	%	0%
Operating Reserves	%	3%
Capacity Factor	%	85%
Capital Cost	$/KW	$7,093
O&M Fixed	$/KW-yr	$207
O&M Variable	$/MWh	$6
Land Area	acres/MW	6 – 8
Degradation	%/year	N/A
Fixed Transmission	$/KW-yr	$22.20
Variable Transmission	$/MWh	$0.00
Loss Factor to PSE	%	1.9%
Heat Rate – Baseload (HHV)	Btu/KWh	14,599
EMISSIONS		
NOx	lbs/MMBtu	0.03
SO2	lbs/MMBtu	0.03
CO2	lbs/MMBtu	213
DEVELOPMENT PARAMETERS		
First Year Available		2024
Economic Life	years	30
Greenfield Dev. & Const. Lead Time	years	3.3

Solar Modeling in the IRP

Solar energy uses electromagnetic radiation from the sun to directly generate electricity with photovoltaic (PV) technology, or to capture the heat energy of the sun for either heating water or for creating steam to drive electric generating turbines. This IRP models two solar PV applications, a utility-scale, single-axis tracking PV technology and a residential-scale fixed-tilt, rooftop or ground-mounted PV technology.

For the 2021 IRP, PSE has evaluated six solar resources: utility-scale solar PV in eastern Washington, western Washington, eastern Wyoming, western Wyoming, Idaho and residential-scale rooftop or ground-mounted PV solar in western Washington.

Specific solar generation profiles, or shapes, were derived for each of these solar resource types using irradiance data queries from the NREL's National Solar Radiation Database (NSRDB).[20] The NSRDB irradiance data was then processed with NREL's System Advisory Model (SAM)[21] to create realistic generation profiles for each location. SAM inputs were varied depending on the specific solar resource modeled:

- All solar resources were modeled with SAM's implementation of the NREL PVWatts v7.
- All solar resources were modeled with the "premium" module type to estimate solar panel efficiencies of 18 to 20 percent.
- All solar resources were modeled with a DC to AC ratio of 1.2.
- All solar resources assumed an inverter efficiency of 96 percent.
- Residential-scale solar resources were modeled as fixed-tilt, rooftop or ground-mounted panels.
- Utility-scale solar resources were modeled as ground-mounted, single-axis tracking panels.

Figure D-27 provides a summary of the solar resources modeled. All capacity factors are provided as AC (alternating current), where the capacity of the inverter is taken as the nameplate of the solar facility. This differs from the DC (direct current) capacity, which measures the capacity based on the capacity of the solar modules installed. The AC capacity is typically higher, because most solar facilities undersize the inverter as defined by the DC to AC ratio; in the case of PSE generic resources, the DC to AC ratio is 1.2.

After all profiles were processed by SAM, 250 representative draws are selected from the complete list based on nearness to the annual average production of all the solar profiles sampled. Finally a single, most-representative draw is selected from the 250 draws using the

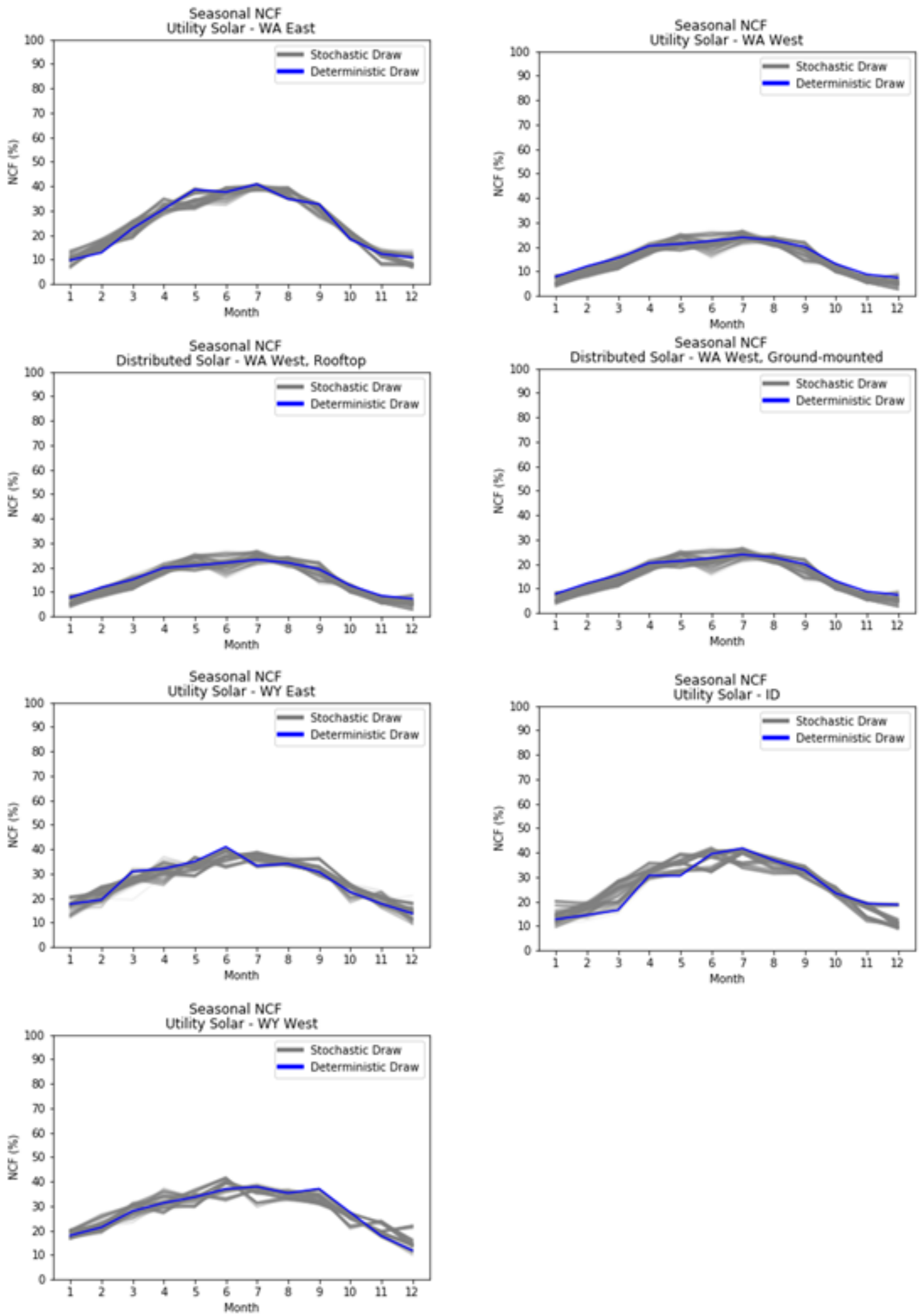
20 / https://nsrdb.nrel.gov/
21 / https://sam.nrel.gov/

same selection process. Figure D-28 provides a summary of the seasonal solar shapes used in the 2021 IRP, the grey lines represent each of the 250 stochastic draws and the blue line represents the draw selected as most-representative.

Figure D-27: Solar Generic Resource Assumptions

2020 $	Units	Utility Solar WA East	Utility Solar WA West	Utility Solar WY West	Utility Solar WY East	Utility Solar ID	Distributed Solar WA West, Rooftop	Distributed Solar WA West, Ground-mounted
ISO Capacity Primary	MW	100	50	400	400	400	300	50
Capacity Credit (2027)	%	4.0%	1.2%	6.0%	6.3%	3.4%	1.6%	1.2%
Operating Reserves	%	3%	3%	3%	3%	3%	3%	3%
Capacity Factor	%	24.2%	16.0%	28.0%	27.3%	26.4%	15.7%	16.0%
Capital Cost	$/KW	$1,675	$1,675	$1,675	$1,675	$1,675	$4,389	$3,568
O&M Fixed	$/KW-yr	$22	$22	$22	$22	$22	$0	$0
O&M Variable	$/MWh	$0	$0	$0	$0	$0	$0	$0
Land Area	acres/MW	5 - 7	5 - 7	5 - 7	5 - 7	5 - 7	N/A	5 - 7
Degradation	%/year	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Fixed Transmission	$/KW-yr	$30.48	$8.28	$207.80	$227.90	$154.78	$0.00	$0.00
Variable Transmission	$/MWh	$9.53	$9.53	$9.53	$9.53	$9.53	$0.00	$0.00
Loss Factor to PSE	%	1.9%	N/A	4.6%	4.6%	4.6%	N/A	N/A
DEVELOPMENT PARAMETERS								
First Year Available		2024	2024	2026	2026	2026	2024	2024
Economic Life	Years	30	30	30	30	30	30	30
Greenfield Dev. & Const. Lead Time	Years	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Figure D-28: Seasonal Solar Shapes



Solar Technologies

Photovoltaics are semiconductors that generate direct electric currents. The current then typically runs through an inverter to create alternating current, which can be tied into the grid. Most photovoltaic solar cells are made from silicon imprinted with electric contacts; however, other technologies, notably several chemistries of thin-film photovoltaics, have gained substantial market share. Significant ongoing research efforts continue for all photovoltaic technologies, which has helped to increase conversion efficiencies and decrease costs. Photovoltaics are installed in arrays that range from a few watts for sensor or communication applications, up to hundreds of megawatts for utility-scale power generation. PV systems can be installed on a stationary frame at a tilt to best capture the sun (fixed-tilt) or on a frame than can track the sun from sunrise to sunset.

DISTRIBUTED SOLAR uses similar technologies to utility-scale photovoltaic systems, but at a smaller scale. The defining characteristic of distributed solar systems is that the power is generated at, or near, the point where the power will be used. This means that distributed solar systems do not have the same costly transmission requirements of utility-scale systems. Distributed solar may include rooftop or ground-mounted systems (such as parking lot canopies).

CONCENTRATING PHOTOVOLTAICS use lenses to focus the sun's light onto special, high-efficiency photovoltaics, which creates higher amounts of generation for the given photovoltaic cell size. The use of concentrating lenses requires that these technologies be precisely oriented towards the sun, so they typically require active tracking systems.

BIFACIAL PHOTOVOLTAIC modules collect light on both sides of the panel, instead of just on the side facing the sun (as in typical PV installations). Bifacial modules can achieve greater efficiencies per unit of land, reducing the land use requirements. Efficiency gains made by bifacial module are highly dependent on the amount of light reflected by the ground surface, or albedo.

SOLAR THERMAL PLANTS focus the direct irradiance of the sun to generate heat to produce steam, which in turn drives a conventional turbine generator. Two general types are in use or development today, trough-based plants and tower-based plants. Trough plants use horizontally mounted parabolic mirrors or Fresnel mirrors to focus the sun onto a horizontal pipe that carries water or a heat transfer fluid. Tower plants use a field of mirrors that focus sunlight onto a central receiver. A heat transfer fluid is used to collect the heat and transfer it to make steam.

Commercial Availability: Currently, renewable portfolio standards (RPS), falling prices and tax incentives drive most utility-scale solar development in the United States. The Solar Electric Industries Association (SEIA) reports that as of Q3 2020, the U.S. has installed over 85 GW of total solar capacity, with an average annual growth rate of 59 percent over the last ten years.

According to SEIA, solar has ranked first or second in new electric capacity additions in each of the last 7 years. Through Q4 in 2020, 43 percent of all new electric capacity added to the grid came from solar.[22]

With less sunlight than other areas of the country and incentive structures that limit development to smaller systems, photovoltaic development has been relatively slow in the Northwest, and there are no customer or utility-scale concentrating solar thermal installations in Washington state. California continues to be the U.S. leader with nearly 28,000 MW of combined residential, non-residential and utility-scale solar installations as of Q3 2020. While PV installations make up the majority of the installed capacity, the total also includes thermal solar systems, which have been operating successfully in California since the 1980s.[23]

Cost and Performance Assumptions: Since PSE built the Wild Horse Solar Demonstration Project in 2007, installed costs for PV solar systems have declined considerably. SEIA reports that the installed cost of solar has dropped more than 70 percent since 2010, and prices as of Q2 2020 are at or near their lowest historical level across all market segments despite tariffs on modules, inverters, aluminum and steel. According to SEIA's U.S. Solar Market Insight report, by Q3 2020 costs for utility fixed-tilt and tracking projects averaged \$0.80 and \$0.94 per Watt_{dc}, respectively; costs for residential systems had reached approximately \$2.84 per Watt_{dc}; and costs for commercial systems had reached \$1.37 per Watt_{dc}.[24]

Wind Modeling in the IRP

Wind energy is the primary renewable resource for meeting RPS and CETA requirements in our region due to wind's technical maturity, reasonable life cycle cost, acceptance in various regulatory jurisdictions and large "utility" scale compared to other technologies. However, it also poses challenges. Because of its variability, wind's daily and hourly power generation shapes don't necessarily correlate with customer demand; therefore, more flexible thermal and hydroelectric resources must be standing by to fill the gaps. This variability also makes wind power challenging to integrate into transmission systems. Finally, because wind projects are often located in remote areas, they frequently require long-haul transmission on a system that is already congested.

ONSHORE AND OFFSHORE WIND. For this IRP, wind was modeled in the following locations: eastern Washington, central and eastern Montana, western and eastern Wyoming, eastern Idaho and Washington offshore. Figure D-29 summarizes the assumptions for generic wind resources.

22 / Solar Electric Industries Association (SEIA)/Wood Mackenzie Power & Renewables U.S, Solar Market Insight Report, Q4 2020: https://www.seia.org/research-resources/solar-market-insight-report-2020-q4
23 / Solar Electric Industries Association (SEIA), Solar Spotlight – California for Q3 2018, December 2018: https://www.seia.org/sites/default/files/2018-12/Federal_2018Q3_California_1.pdf
24 / Solar Electric Industries Association (SEIA), Solar Market Insight Report, Q4 2020: https://www.seia.org/research-resources/solar-market-insight-report-2020-q4

Eastern Washington wind is located in BPA's balancing authority, so this wind requires only one transmission wheel through BPA to PSE. Montana wind, however, is outside BPA's balancing authority and will require four transmission wheels plus various system upgrades to deliver the power to PSE's service territory. Similarly, the Wyoming and Idaho wind sites are well outside PSE's service territory and will require multiple transmission wheels to deliver the power. PSE is investigating potential ownership of transmission on the Boardman to Hemingway[25] and Gateway West[26] transmission projects currently under construction by Idaho Power and Rocky Mountain Power.

PSE is modeling offshore wind located 3 miles off the coast of Grays Harbor County, Wash. Offshore wind would require a marine cable to interconnect all of the turbines and bring the power back to land. Once on land, it would require a transmission wheel through BPA to PSE.

Specific shapes were derived for each generic wind resource. Wind speed at 100 meters above ground level was obtained from the NREL Wind Toolkit database.[27] For each wind resource location, the database was queried to return all wind profiles within a 50 to 75 mile radius of the point of interest. All of these wind speed profiles, typically 1,000 to 2,000 unique profiles, are then processed with a heuristic wind production model. The wind production model performs the following steps:

- A power curve for a modern, 3 MW, 140 meter rotor diameter turbine is adjusted for site specific air density.
- The wind speed data is processed through the power curve to calculate gross power production.
- A heuristic loss estimation model is used to apply loss factors to the gross production value to obtain net production. Losses include:
    - Turbine interaction effects (waking and blockage)
    - Availability (estimated as a stochastic loss)
    - Temperature loss (based on power curve information)
    - Icing losses (estimated using the International Energy Agency [IEA] Icing Class[28] and applied as a stochastic loss)
    - Degradation, performance and other losses

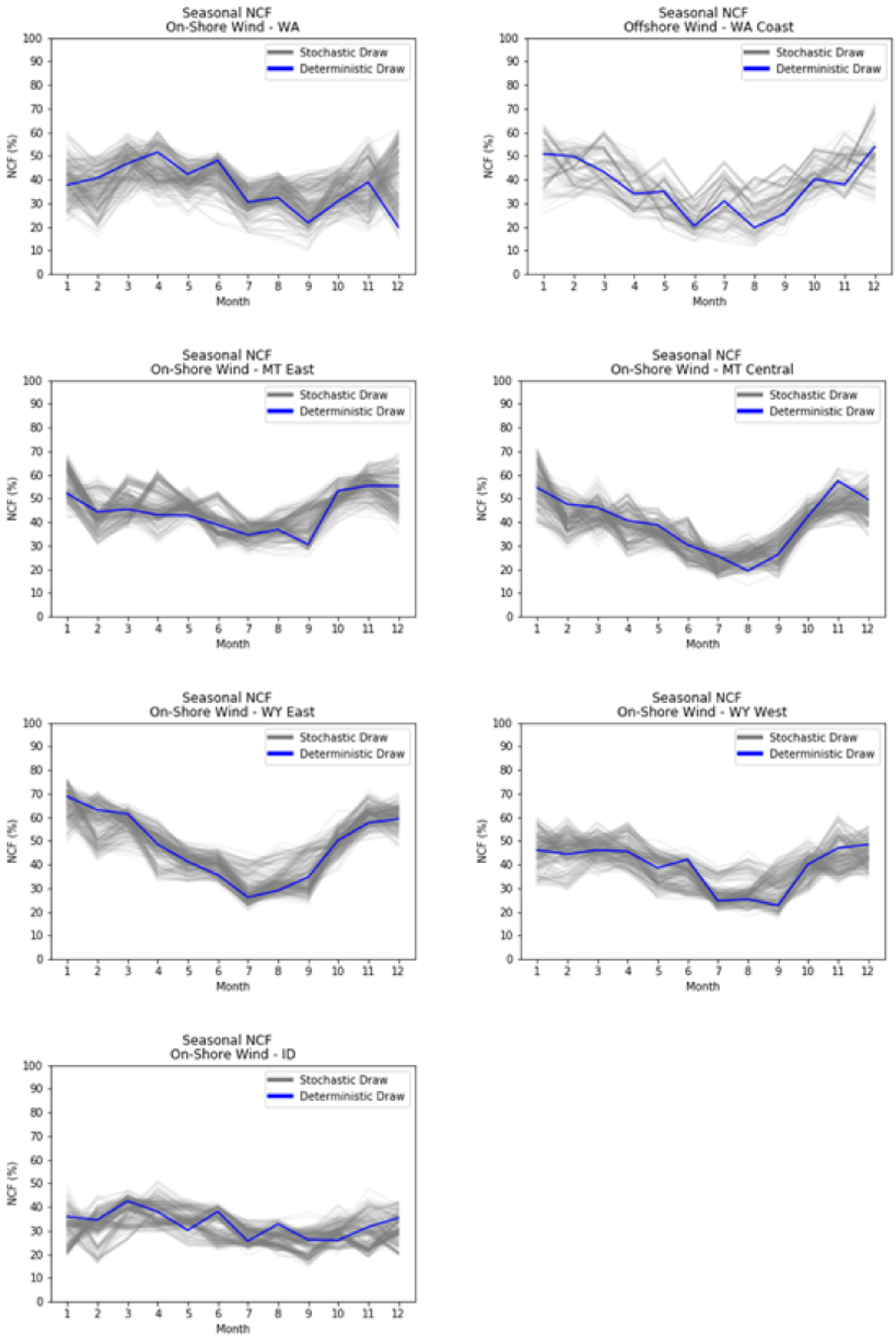
25 / https://www.boardmantohemingway.com/
26 / http://www.gatewaywestproject.com/
27 / https://www.nrel.gov/grid/wind-toolkit.html
28 / http://virtual.vtt.fi/virtual/wiceatla/

After all profiles were processed by the wind production model, 250 representative draws are selected from the complete list. Representative draws are selected based on a least-squares regression to the seasonal average production of all the wind profiles sampled. Finally a single, most-representative draw is selected from the 250 draws using the same selection process. Figure D-30 provides a summary of the seasonal wind shapes used in the 2021 IRP; the grey lines represent each of the 250 stochastic draws and the blue line represents the draw selected as most-representative.

Figure D-29: Wind Generic Resource Assumptions

2020 $	Units	On-Shore Wind MT East	On-Shore Wind MT Central	On-Shore Wind SE Wash.	Off-shore Wind WA Coast	On-Shore Wind WY West	On-Shore Wind WY East	On-Shore Wind ID
ISO Capacity Primary	MW	200	200	100	100	400	400	400
Capacity Credit (2027)	%	21.8%	30.1%	17.8%	48.4%	27.6%	40.0%	24.2%
Operating Reserves	%	3%	3%	3%	3%	3%	3%	3%
Capacity Factor	%	44.3%	39.8%	36.7%	34.8%	39.2%	47.9%	33.0%
Capital Cost	$/KW	$1,806	$1,806	$1,806	$5,609	$1,806	$1,806	$1,806
O&M Fixed	$/KW-yr	$41	$41	$41	$110	$41	$41	$41
O&M Variable	$/MWh	$0	$0	$0	$0	$0	$110	$0
Land Area	acres/MW	48.2	48.2	48.2	N/A	48.2	48.2	48.2
Degradation	%/year	0%	0%	0%	0%	0%	0%	0%
Fixed Transmission	$/KW-yr	$49.65	$49.65	$33.36	$33.36	$210.68	$230.78	$157.66
Variable Transmission	$/MWh	$9.53	$9.53	$9.53	$9.53	$9.53	$9.53	$9.53
Loss Factor to PSE	%	4.6%	4.6%	1.9%	1.9%	4.6%	4.6%	4.6%
DEVELOPMENT PARAMETERS								
First Year Available		2024	2024	2024	2030	2026	2026	2026
Economic Life	years	30	30	30	30	30	30	30
Greenfield Dev. & Const. Lead Time	years	2.0	2.0	2.0	3.2	2.0	2.0	2.0

Figure D-30: Seasonal Wind Shapes



Land-based Wind Technology

Land-based wind turbine generator technology is mature and the dominant form of new renewable energy generation in the Pacific Northwest. While the basic concept of a wind turbine has remained generally constant over the last several decades, the technology continues to evolve, yielding higher towers, wider rotor diameters, greater nameplate capacity and increased wind capture (efficiency). Commercially available turbines are in the 2.0 to 4.0 MW range with hub heights of 80 to 130[29] meters and blade diameters up to160 meters. These changes have come about largely because development of premium high-wind sites has pushed new development into less-energetic wind sites. The current generation of turbines is pushing the physical limits of existing transportation infrastructure. In addition, if nameplate capacity and turbine size continue to increase, the industry must explore creative solutions for ever taller towers, such as concrete tower sections poured or stacked on site and segmented blades for final assembly on site.

Commercial Availability: Declining and expiring tax incentives will likely drive demand in the short term. Greenfield development of a new wind facility requires approximately two to three years and consists of the following activities at a minimum: one to two years for development, permitting and major equipment lead time, and one year for construction.

Cost and Performance Assumptions: The cost for installing a wind turbine includes the turbine, foundation, roads and electrical infrastructure. Installed cost for a typical facility in the Northwest region is approximately $1,319 per kW. The levelized cost of energy for wind power is a function of the installed cost and the performance of the equipment at a specific site, as measured by the capacity factor. The all-in levelized cost of energy ranges from $28.79 to $55.32 per MWh (in 2019 U.S. dollars), which is very dependent on the capacity factor of wind at the location.[30]

Offshore Wind Technology

Offshore winds tend to blow harder and more uniformly than on land. The potential energy produced from wind is directly proportional to the cube of the wind speed. As a result, increased wind speeds of only a few miles per hour can produce a significantly larger amount of electricity. For instance, a turbine at a site with an average wind speed of 16 mph would produce 50 percent more electricity than at a site with the same turbine and average wind speeds of 14 mph.

Wind turbine generators used in offshore environments include durability modifications to prevent corrosion and operate reliably in the harsh marine environment. Their foundations must be

29 / One hundred meters is equivalent to 328 feet which is equivalent to a 30-story building.
30 / U.S. Energy Information Administration (EIA), Annual Energy Outlook 2020, January 2021: https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf. Levelized cost of energy assumes tax credits available for plants entering service in 2022.

designed to withstand storm waves, hurricane-force winds and even ice floes. The engineering and design of offshore wind facilities depends on site-specific conditions, particularly water depth, geology of the seabed, and expected wind and wave loading. Foundations for offshore wind fall into two major categories, fixed and floating, with a variety styles for each category. The fixed foundation is a proven technology that is used throughout Europe. Monopiles are the preferred foundation type, which are steel piles driven into the seabed to support the tower and shell. Fixed foundations can be installed to a depth of 60 meters.

Roughly 90 percent of the offshore U.S. wind energy resource occurs in waters too deep for current fixed foundation technology, particularly on the West Coast. The wind industry is developing new technologies, such as floating wind turbines, that will allow wind construction in the harsher conditions associated with deeper waters.

All power generated by offshore wind turbines must be transmitted to shore and connected to the power grid. Each turbine is connected to an electric service platform (ESP) by a power cable. High voltage cables, typically buried beneath the sea bed, transmit the power collected from wind turbines from the ESP to an onshore substation where the power is integrated into the grid.

Cost and Performance Assumptions: Offshore wind installations have higher capital and operational costs than land-based installations per unit of generating capacity, largely because of turbine upgrades required for operation at sea and increased costs related to turbine foundations, balance of system infrastructure, interconnection and installation, and the difficulty of maintenance access. In addition, one-time costs are associated with the development of infrastructure to support offshore construction, such as vessels for foundation erection and turbine installation and related port facilities.

The United States currently has one operational offshore wind project – the 30 MW Block Island Wind Farm off the coast of Rhode Island which began operation in December 2016. The American Wind Energy Association (AWEA) notes that the two-turbine 12 MW Coastal Virginia Offshore Wind pilot project completed construction in June of 2020 and will start commercial operation later in the year. As a result, reliable capital cost estimates for large-scale U.S. installations are not available. Offshore wind would benefit from a continuation of federal and state government mandates, renewable portfolio standards, subsidies and tax incentives to help innovate and solidify the market. According to AWEA, project developers currently expect 14 offshore wind projects totaling 9,112 MW to be operational by 2026. As the market develops, costs should decrease as experience is gained. Based on the current design trajectory of wind turbine development, bigger units will be able to capture more wind and achieve greater economies of scale in the years ahead.[31]

Commercial Availability: In Europe, offshore wind is a proven technology in shallow coastal waters. Some 14.5 GW have been installed since 1991 with a total installed capacity of 22.1 GW as of 2019, and costs continue to stabilize. The U.S. is just beginning the process of developing offshore wind; however, thousands of megawatts of future development are currently in the planning stages, mostly in the Northeast and Mid-Atlantic regions. Projects are also being considered along the Great Lakes, the Gulf of Mexico and the Pacific Coast. The floating platforms required for deep water offshore wind are yet not commercially mature.

Hybrid Resources

Hybrid resources combine two or more resources at one location to take advantage of synergies created through co-location of the resources. Hybrid resources may combine two generating resources such as solar and wind, or one generating and one storage resource such as solar and a battery energy storage system. Benefits of hybrid resources include reduced land use needs, shared interconnection and transmission costs, improved frequency regulation, backup power potential and operational balancing potential, among others. From 2017 to 2020, the number of installed hybrid systems in the U.S. has more than doubled from less than 30 to 80 facilities.[32]

PSE is evaluating three hybrid systems, each of which pairs a generating resource with a storage resource. These hybrid resources include Washington wind plus 2-hour Lithium-ion battery storage, Washington utility solar plus 2-hour Lithium-ion battery storage, and eastern Montana wind plus pumped hydroelectricity storage. PSE configured the hybrid resources in the model so the storage resource can only charge using the energy from the renewable resource to which it is connected. This is different than co-located resources, which allow the storage resource to be independent of the renewable resource; this is an important distinction for federal tax incentive programs such the Investment Tax Credit (ITC).

31 / https://www.energy.gov/eere/wind/offshore-wind-research-and-development
32 / https://www.eia.gov/todayinenergy/detail.php?id=43775

Figure D-31: Hybrid Generic Resource Assumptions

2020 $	UNITS	MT Wind + Pumped Hydro	Wind + Battery	Solar + Battery
ISO Capacity Primary	MW	300	125	125
Capacity Credit (2027)	%	54.3%	23.6%	14.4%
Operating Reserves	%	3%	3%	3%
Capacity Factor	%	44.3%	36.7%	24.2%
Capital Cost	$/KW	$4,016	$2,680	$2,563
O&M Fixed	$/KW-yr	$57	$64	$46
O&M Variable	$/MWh	$0	$0	$0
Land Area	acres/MW	48.2	48.2	5 - 7
Degradation	%/year	0.0%	0.5%	0.5%
Fixed Transmission	$/KW-yr	$49.65	$33.36	$30.48
Variable Transmission	$/MWh	$9.53	$9.53	$9.53
Loss Factor to PSE	%	4.6%	1.9%	1.9%
First Year Available		2028	2024	2024
Economic Life	years	30	30	30
Greenfield Dev. & Const. Lead Time	years	5 - 8	2.0	1.0
Operating Range	%	147-500 MW	2.0%	2.0%
R/T Efficiency	%	80.0%	82.0%	82.0%
Discharge at Nominal Power	hours	8.0	2.0	2.0

Renewable Resources Not Modeled

FUEL CELLS. Fuel cells combine fuel and oxygen to create electricity, heat, water and other by-products through a chemical process. Fuel cells have high conversion efficiencies from fuel to electricity compared to many traditional combustion technologies, on the order of 25 to 60 percent. In some cases, conversion rates can be boosted using heat recovery and reuse. Fuel cells operate and are being developed at sizes that range from watts to megawatts. Smaller fuel cells power items like portable electric equipment, and larger ones can be used to power equipment, buildings or provide backup power. Fuel cells differ in the membrane materials used to separate fuels, the electrode and electrolyte materials used, operating temperatures and scale (size). Reducing cost and improving durability are the two most significant challenges to fuel cell commercialization. To be economical, fuel cell systems must be cost-competitive with, and perform as well as, traditional power technologies over the life of the system.[33]

Provided that feedstocks are kept clean of impurities, fuel cell performance can be very reliable. They are often used as backup power sources for telecommunications and data centers, which require very high reliability. In addition, fuel cells are starting to be used for commercial combined heat and power applications, though mostly in states with significant subsidies or incentives for fuel cell deployment.

Commercial Availability: Fuel cells have been growing in both number and scale, but they do not yet operate at large scale. According to the Department of Energy's report *State of the States: Fuel Cells in America 2017*,[34] there are fuel cell installations in 43 states, and more than 235 MW of large stationary (100 kW to multi-megawatt) fuel cells are currently operating in the U.S. The report further states that California remains the leader with the greatest number of stationary fuel cells. In some states, incentives are driving fuel cell pricing economics to be competitive with retail electric prices, especially where additional value can be captured from waste heat. Currently, Washington State offers no incentives specific to stationary fuel cells. The EIA, estimates fuel cell capital costs to be approximately $6,700 per kW.[35]

GEOTHERMAL. Geothermal generation technologies use the natural heat under the surface of the earth to provide energy to drive turbine generators for electric power production. Geothermal energy production falls into four major types.

Dry Steam Plants use hydrothermal steam from the earth to power turbines directly. This was the first type of geothermal power generation technology developed.[36]

33 / U.S. Department of Energy, Energy Efficiency and Renewable Energy, Fuel Cell Technologies Program.
34 / U.S. Department of Energy's report, "State of the States: Fuel Cells in America 2017," dated January 2018, https://www.energy.gov/sites/prod/files/2018/06/f53/fcto_state_of_states_2017_0.pdf
35 / U.S. Energy Information Agency Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies, February 2020
36 / http://energy.gov/eere/geothermal/electricity-generation

Flash Steam Plants operate similarly to dry steam plants, but they use low-pressure tanks to vaporize hydrothermal liquids into steam. Like dry steam plants, this technology is best suited to high-temperature geothermal sources (greater than 182 degrees Celsius).[37]

Binary-cycle Power Plants can use lower temperature hydrothermal fluids to transfer energy through a heat exchanger to a fluid with a lower boiling point. This system is completely closed-loop, no steam emissions from the hydrothermal fluids are released at all. The majority of new geothermal installations are likely to be binary-cycle systems due to the limited emissions and the greater number of potential sites with lower temperatures.[38]

Enhanced Geothermal or "hot dry rock" technologies involve drilling deep wells into hot dry or nearly dry rock formations and injecting water to develop the hydrothermal working fluid. The heated water is then extracted and used for generation.[39]

Geothermal plants typically run with high uptime, often exceeding 85 percent. However, plants sometimes do not reach their full output capacity due to lower than anticipated production from the geothermal resource.

Commercial Availability: In 2019, there were geothermal power plants in seven states, which produced about 16 GWh, equal to 0.4% of total U.S. utility-scale electricity generation.[40] As of November 2019, 2.5 GW of geothermal generating capacity was online in the United States.[41] Operating geothermal plants in the Northwest include the 28.5 MW Neal Hot Springs plant and the 15.8 MW Raft River plant in Idaho.

The EIA estimates capital costs for geothermal resources to be approximately $2,521/MW.[42] Because geothermal cost and performance characteristics are specific for each site, this represents the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located. Overall, site-specific factors including resource size, depth and temperature can significantly affect costs.

37 / Ibid
38 / Ibid
39 / http://energy.gov/sites/prod/files/2014/02/f7/egs_factsheet.pdf
40 U.S. Energy Information Administration, https://www.eia.gov/energyexplained/geothermal/use-of-geothermal-energy.php
41 / U.S. Energy Information Administration, https://www.eia.gov/todayinenergy/detail.php?id=42036
42 / U.S. Energy Information Administration, Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies, February 2020

WASTE-TO-ENERGY TECHNOLOGIES. Converting wastes to energy is a means of capturing the inherent energy locked into wastes. Generally, these plants take one of the following forms.

Waste Combustion Facilities: These facilities combust waste in a boiler and use the heat to generate steam to power a turbine that generates electricity. This is a well-established technology, with 86 plants operating in the United States, representing 2,720 MW in generating capacity. According to the U.S. EPA's web site, no new facilities have opened since 1995, although some existing facilities have expanded their capacity to convert more waste into electricity.[43]

Waste Thermal Processing Facilities: This includes gasification, pyrolysis and reverse polymerization. These facilities add heat energy to waste and control the oxygen available to break down the waste into components without combusting it. Typically, a syngas is generated, which can be combusted for heat or to produce electricity. A number of pilot facilities once operated in the United States, but only a few remain today.

Landfill Gas and Municipal Wastewater Treatment Facilities: Most landfills in the United States collect methane from the decomposition of wastes in the landfill. Many larger municipal wastewater plants also operate anaerobic systems to produce gas from their organic solids. Both of these processes produce a low-quality gas with approximately half the methane content of natural gas. This low-quality gas can be collected and scrubbed to remove impurities or improve the heat quality of the gas. The gas can then be used to fuel a boiler for heat recovery, or a turbine or reciprocating engine to generate electricity. According to the U.S. EPA's web site, as of August 2020, there are 565 operational landfill gas energy projects in the United States.[44]

43 / U.S. Environmental Protection Agency website. Retrieved from https://www.epa.gov/smm/energy-recovery-combustion-municipal-solid-waste-msw#01, January 2019.
44 / U.S. Environmental Protection Agency website. Retrieved from https://www.epa.gov/lmop/basic-information-about-landfill-gas, August 2020.

Commercial Availability: Washington's RPS initially included landfill gas as a qualifying renewable energy resource, but excluded municipal solid waste. The passage of Washington State Senate bill ESSB 5575 later expanded the definitions of wastes and biomass to allow some new wastes, such as food and yard wastes, to qualify as renewable energy sources.

Currently, several waste-to-energy facilities are operating in or near PSE's electric service area. Three waste facilities – the H.W. Hill Landfill Gas Project, the Spokane Waste-to-Energy Plant and the Emerald City facility – use landfill gas for electric generation in Washington state; combined, they produce up to 67 MW of electrical output. The H.W. Hill facility in Klickitat County is fed from the Roosevelt Regional Landfill and capable of producing a maximum capacity of 36.5 MW.[45] The Spokane Waste-to-Energy Plant processes up to 800 tons per day of municipal solid waste from Spokane County and is capable of producing up to 22 MW of electric capacity.[46] Emerald City uses landfill gas produced at the LRI Landfill in Pierce County to generate up to 4.8 MW of electricity. The facility became commercially operational in December 2013.[47] PSE purchases the electricity produced by the facility through a power purchase agreement under a Schedule 91 contract, which is discussed above.

The largest landfill in PSE's service territory, the Cedar Hills landfill, currently purifies its gas to meet pipeline natural gas quality; the gas is sold to PSE rather than using it to generate electricity.

Cost and Performance Assumptions: Relatively few new waste combustion and landfill gas-to-energy facilities have been built since 2010, making it difficult to obtain reliable cost data. The EIA's *Annual Energy Outlook 2018* estimates municipal solid waste-to-energy costs to be approximately $8,742 per kW.

In general, waste-to-energy facilities are highly reliable. They have used proven generation technologies and gained considerable operating experience for more than 30 years. Some variation of output from landfill gas facilities and municipal wastewater plants is expected due to uncontrollable variations in gas production. For waste combustion facilities, output is typically more stable, as the amount of input waste and heat content can be more easily controlled.

45 / Phase 1 of the H.W. Hill facility consists of five reciprocating engines, which combined produce 10.5 MW. Phase 2, completed in 2011, adds two 10 MW combustion turbines, and a heat recovery steam generator and steam turbine for an additional 6 MW. Source: Klickitat PUD website. Retrieved from http://www.klickitatpud.com/topicalMenu/about/powerResources/hwHillGasProject.aspx, January 2019.
46 / Spokane Waste to Energy website. Retrieved from https://my.spokanecity.org/solidwaste/waste-to-energy/, January 2019.
47 / BioFuels Washington, LLC landfill gas to energy facility (later sold to Emerald City Renewables, LLC and renamed Emerald LFGTE Facility). Retrieved from https://energyneeringsolutions.com/wp-content/uploads/2018/02/ESI_CaseStudy_Emerald.pdf, January 2019.

WAVE AND TIDAL. The natural movement of water can be used to generate energy through the flow of tides or the rise and fall of waves.

Tidal Generation technology uses tidal flow to spin rotors that turn a generator. Two major plant layouts exist: barrages, which use artificial or natural dam structures to accelerate flow through a small area, and in-stream turbines, which are placed in natural channels. The Rance Tidal Power barrage system in France was the world's first large-scale tidal power plant. It became operational in 1966 and has a generating capacity of approximately 240 MW. The Sihwa Lake Tidal Power Station in South Korea is currently the world's largest tidal power facility. The plant was opened in late 2011 and has a generating capacity of approximately 254 MW. The 20 MW Annapolis Royal Generating Station in Nova Scotia, Canada, is the world's next-largest operating tidal generation facility. China, Russia and South Korea have smaller tidal power installations.[48] Also worth noting is the planned 400 MW Mey Gen Tidal Energy Project in Scotland, which if completed, would be the largest tidal generation facility in the world. The project is designed to be constructed in multiple phases with final deployment targeted for 2021. A 6 MW portion of the first phase began operating in April 2018.[49]

Wave Generation technology uses the rise and fall of waves to drive hydraulic systems, which in turn fuel generators. Technologies tested include floating devices such as the Pelamis and bottom-mounted devices such as the Oyster. The largest wave power plant in the world was the 2.25 MW Agucadoura Wave Farm off the coast of Portugal, which opened in 2008.[50] It has since been shut down because of the developer's financial difficulties.

In 2015, a prototype wave energy device developed by Northwest Energy Innovations was successfully launched and installed for grid-connected, open-sea pilot testing at the Navy's Wave Energy Test Site in Kaneohe Bay on the island of Oahu, Hawaii. According to the U.S. Department of Energy's web site, the 20 kW Azura device is the nation's first grid-connected wave energy converter device.[51]

48 / U.S. Energy Information Administration website. Retrieved from https://www.eia.gov/energyexplained/index.php?page=hydropower_tidal, January 2019.
49 / Wikipedia website. Retrieved from https://en.wikipedia.org/wiki/MeyGen, January 2019.
50 / CNN website. Retrieved from http://www.cnn.com/2010/TECH/02/24/wave.power.buoys/index.html, February 2010.
51 / The U.S. Department of Energy website. Retrieved from https://www.energy.gov/eere/articles/innovative-wave-power-device-starts-producing-clean-power-hawaii, July 2015.

Commercial Availability: Since mid-2013, a number of significant wave and tidal projects and programs have slowed, stalled or shut down altogether. In general, wave and tidal resource development in the U.S. continues to face limiting factors such as funding constraints, long and complex permitting process timelines, relatively little experience with siting and the early stage of the technology's development. FERC oversees permitting processes for tidal power projects, but state and local stakeholders can also be involved. After permits are obtained, studies of the site's water resource and aquatic habitat must be made prior to installation of test equipment.

There are three demonstration tidal projects in various stages of development of the United States, located in Roosevelt Island (New York), Western Passage (Maine) and Cobscook Bay (Maine). Currently, there are no operating tidal or wave energy projects on the West Coast. In late 2014, Snohomish PUD abandoned plans to develop a 1 MW tidal energy installation at the Admiralty Inlet.[52] Several years ago, Tacoma Power considered and later abandoned plans to pursue a project in the Tacoma Narrows.

Tidal and wave generation technologies are very early in development, making cost estimates difficult. Most developers have not produced more than one full-scale device, and many have not even reached that point. Few wave and tidal technologies have been in operation for more than a few years and their production volumes are limited, so costs remain high and the durability of the equipment over time is uncertain.

Energy Storage Resource Costs and Technologies

PSE modeled three energy storage alternatives in the 2021 IRP: lithium-ion batteries, flow batteries and pumped hydro energy storage (PHES).

GENERIC ENERGY STORAGE RESOURCE COST ASSUMPTIONS. Figure D-32 summarizes the generic costs assumptions used in the analysis for energy storage resources. All costs are in 2020 dollars.

52 / The Seattle Times website. Retrieved from http://www.seattletimes.com/seattle-news/snohomish-county-pud-drops-tidal-energy-project/, October 2014.

Figure D-32: Generic Energy Storage Assumptions

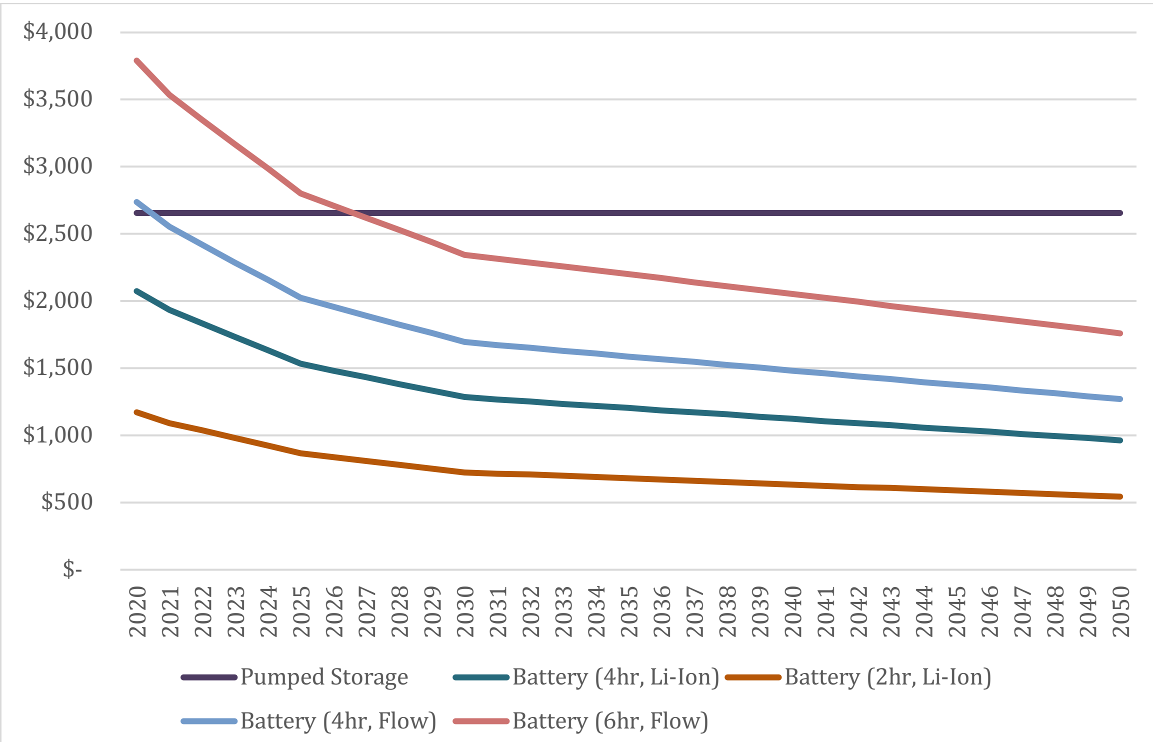
2020 $	UNITS	Pumped Hydroelectric Storage	Battery Energy Storage System (BESS)			
		Closed Loop (8 Hour)	Li-Ion 2-hr (2 Cycles Daily)	Li-Ion 4-hr (2 Cycles Daily)	Flow 4-hr (2 Cycles Daily)	Flow 6-hr (2 Cycles Daily)
Nameplate Capacity	MW	25	25	25	25	25
Capacity Credit (2027)	%	37.2%	12.4%	24.8%	22.2%	29.8%
Operating Reserves	%	3%	3%	3%	3%	3%
Capital Cost	$/KW	$2,656	$1,172	$2,074	$2,738	$3,791
O&M Fixed (c)	$/KW-yr	$16	$23	$32	$22	$38
O&M Variable	$/MWh	$0	$0	$0	$0	$0
Degradation	%/year	(a)	(d)	(d)	(d)	(d)
Operating Range	%	147-500 MW (b)	2.0%	2.0%	2.0%	2.0%
R/T Efficiency	%	80%	82%	87%	73%	73%
Discharge at Nominal Power	Hours	8	2	4	4	6
Maximum Storage	MWh	200	50	100	100	150
Fixed Transmission	$/KW-yr	$22.20	$0.00	$0.00	$0.00	$0.00
Variable Transmission	$/MWh	$0.00	$0.00	$0.00	$0.00	$0.00
First Year Available		2028	2023	2023	2023	2023
Economic Life	years	30	30	30	30	30
Greenfield Dev. & Const. Lead time	years	5 - 8	1	1	1	1

NOTES
Pumped Hydroelectric Storage (PHES) - assumed to represent a slice of a larger project.
a - PHES degradation close to zero
b - The operating range minimum is the average of the minimum at max (111 MW) and min head (183 MW).
c - Fixed O&M costs for Lithium-ion batteries include augmentation by OEM ensuring MW and MWh rating for project life.
d - Battery can discharge up to the indicated percent of nameplate.

CAPITAL COST CURVE. Capital costs assumptions start in the current year, but for future years, the cost curve from the NREL Annual Technology Baseline (ATB) 2019 was applied to the current costs.

Figure D-33 below shows the capital cost curves for the energy storage resources modeled in the 2021 IRP.

Figure D-33: Capital Cost Curve for Energy Storage



Energy Storage Characteristics

Energy storage encompasses a wide range of technologies that are capable of shifting energy usage from one time period to another. These technologies could deliver important benefits to electric utilities and their customers, since the electric system currently operates on "just-in-time" delivery. Generation and load must be perfectly balanced at all times to ensure power quality and reliability. Strategically placed energy storage resources have the potential to increase efficiency and reliability, to balance supply and demand, to provide backup power when primary sources are interrupted and to assist with the integration of intermittent renewable generation. Energy storage technologies are rapidly improving and are capable of benefiting all parts of the system – generation, transmission and distribution – as well as customers. The drawbacks to energy storage are that it operates with a limited duration and requires generation from other sources.

Battery Storage Technologies

Unlike conventional generation resources such as combustion turbines, battery storage resources are modular, scalable and expandable. They can be sized from 20 kW to 1,000 MW and sited at a customer's location or interconnected to the transmission system. It is possible to build the infrastructure for a large storage system and install storage capacity in increments over time as needs grow. This flexibility is a valuable feature of the technology.

Within the battery category, there are many promising chemistries, each with its own performance characteristics, commercial availability and costs. PSE chose to model lithium-ion and flow batteries as the generic battery resources in this IRP because both technologies are commercially available, there are successful projects in operation, and cost estimates and data are available on a spectrum of system configurations and sizes. Other advantages are described below.[53]

LITHIUM-ION BATTERIES have emerged as the leader in utility-scale applications because they offer the best mix of performance specifications for most energy storage applications. Advantages include high energy density, high power, high efficiency, low self-discharge, lack of cell "memory" and fast response time. Challenges include short cycle life, high cost, heat management issues, flammability and narrow operating temperatures. Battery degradation is dependent on the number of cycles and state of the battery's charge. Deep discharge will hasten the degradation of a lithium-ion battery. Lithium-ion batteries can be configured for varying durations (i.e., 0.5 to 6 hours), but the longer the duration, the more expensive the battery. Lithium-ion storage is ideally suited for ancillary applications benefitted by high power (MW), low energy solutions (MWh), and to a lesser extent, for supplying capacity.

53 / In an actual RFP solicitation, PSE would evaluate all proposed technologies based on least-cost and best-fit criteria, including technical and commercial considerations such as warranties, performance guarantees and counterparty credit, etc.

In late 2015, PSE started construction on a 2-megawatt (MW), 4.4 megawatt-hour (MWh) lithium-ion battery system adjacent to the existing substation in the Whatcom County town of Glacier. The project is funded in part by a $3.8 million Smart Grid grant from the Washington State Department of Commerce, in addition to a $7.4 million investment by PSE. The battery was energized in 2016, and in January, 2017, achieved its first successful islanding attempt. Between January, 2018 and June, 2018, Pacific Northwest National Laboratory (PNNL) performed two use test cases. Since then, PSE has continued to test the battery's capabilities under planned outage scenarios – working toward the goal of successfully responding to unplanned outages. As of August, 2019, PSE has successfully powered Glacier's town core through more than six planned outages. The Glacier battery's first successful unplanned response occurred on February 4, 2019, when the battery remotely responded to an outage and provided power for approximately 4 hours until repairs were made to the transmission line.

FLOW BATTERIES are a type of rechargeable battery in which recharge ability is provided by two chemical components dissolved in liquids contained within the system. The two components are separated by a membrane, and ion exchange occurs through the membrane while both liquids circulate in their respective spaces. The ion exchange provides the flow of electric current. Flow batteries can provide the same services as lithium-ion batteries, but they can be used with more flexibility because they do not degrade over time. Flow batteries have limited market penetration at this time, but are an emerging battery storage technology. In 2016, Avista Utilities installed the first large-scale U.S.[54] flow battery storage system in Washington, and in 2017 two additional flow battery facilities were installed by electric utilities in Washington and California. Approximately 70 MW and 250 MWh of flow batteries, almost all in medium- to large-scale projects, have been deployed worldwide.[55]

Commercial Availability: At the end of 2018, the U.S. had 869 MW of large-scale battery energy storage resources in operation. Lithium-ion batteries continued to dominate the energy storage market, representing more than 90 percent of operating large-scale battery storage capacity. In 2018, U.S. utilities also reported 234 MW of existing small-scale storage capacity.[56] Just over 50 percent of this capacity was installed in the commercial sector, 31 percent in the residential sector and 15 percent in the industrial sector, with the remaining 3 percent directly connected to the distribution grid.

54 / Large-scale refers to a facility that is typically grid connected and greater than 1 MW in capacity. Small-scale refers to systems typically connected to a distribution system that are less than 1 MW in power capacity.
55 / IDTechEx Research, Batteries for Stationary Energy Storage 2019-2029
56 / U.S. Energy Information Administration, U.S. Battery Storage Market Trends, July 2020: https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf

Pumped Hydroelectric Storage Technology

Pumped hydroelectric storage (“pumped storage” or “pumped hydro”) plants provide the bulk of utility-scale energy storage in the United States. These facilities store energy in the form of water, which is pumped to an upper reservoir from a second reservoir at a lower elevation. During periods of high electricity demand, the stored water is released through turbines to generate power in the same manner as a conventional hydropower station. Load shifting over a number of hours requires a large volume of energy storage capacity, and a storage device like pumped hydro is well suited for this type of application. During periods of low demand (usually nights or weekends when electricity costs less), the upper reservoir is “recharged” by using lower-cost electricity from the grid to pump the water back to the upper reservoir.

Reversible pump-turbine and motor-generator assemblies can act as both pumps and turbines. Pumped storage facilities can be very economical due to peak and off-peak price differentials and because they can provide critical ancillary grid services. Pumped storage projects are traditionally large, at 300 MW or more. Due to environmental impacts, permitting for these projects can take many years. Pumped storage can be designed to provide 6 to 20 hours of storage with 80 percent roundtrip efficiency.

Commercial Availability: According to the Department of Energy’s most recent *Hydropower Market Report*, there are 43 plants with a capacity of 21.9 GW, which represent 93 percent of utility-scale electrical energy storage in the U.S. Most of this capacity was installed between 1960 and 1990, and almost 94 percent of these storage facilities are larger than 500 MW. No new pumped storage projects have come online in the United States since 2012.[57] At the end of 2019, there were 67 pumped storage projects with a potential capacity of 52.48 GW in the development pipeline. The median project size in the development pipeline is 480 MW, but projects span a wide range of sizes from large projects greater than 3,000 MW to small closed-loop systems of less than 100 MW.[58]

57 / U.S. Energy Information Agency, Annual Electric Generator Report
58 / https://www.energy.gov/sites/prod/files/2021/01/f82/us-hydropower-market-report-full-2021.pdf

Energy Storage Not Modeled

LIQUID AIR ENERGY STORAGE (LAES). LAES converts energy from a variety of sources, such as natural gas or wind, and stores it as thermal energy. To charge the energy, air is cooled and compressed into a liquid state using electricity (i.e., liquefied air or liquefied nitrogen) and stored in tanks. To dispatch electrical energy back to the grid, the liquid air is heated and pressurized, bringing it back to a gaseous state. The gas is used to turn a turbine to generate electricity.

Potential benefits include the technology's suitability to deliver large-scale power for utility and distributed power applications; its suitability for long-duration energy storage; and its ability to use waste heat and cold from its own processes to enhance its efficiency. Also, LAES systems can be large in scale without requiring a large footprint, giving them greater geographical flexibility.

Commercial Availability: LAES systems combine three existing technologies: industrial gas production, cryogenic liquid storage and expansion of pressurized gasses. While the components are based on proven technology currently used in industrial processes and available from large Original Equipment Manufacturers (OEMs), no commercial LAES systems are currently in operation in the U.S. However, in June 2018, Highview Power Storage, a small U.K. company partnering with GE to develop utility-scale LAES systems, launched the world's first grid-scale LAES plant at a landfill gas site near Manchester. The pilot plant is capable of producing 5 MW/15MWh of storage capacity. According to Highview Power Storage, the technology can be scaled up to hundreds of megawatts to better align with the needs of cities and towns.[59]

HYDROGEN ENERGY STORAGE. Hydrogen energy storage systems use surplus renewable electricity to power a process of electrolysis, in which current is passed through a chemical solution to separate and create hydrogen. This renewable hydrogen is then stored for later conversion back into electricity, as well as for other applications such as fuel for transport. Hydrogen does not degrade over time and can be stored for long periods in large quantities, most notably in underground salt caverns. This pure hydrogen can be used for re-electrification in a fuel cell or combusted in a gas turbine.

59 / Forbes website. Retrieved from https://www.forbes.com/sites/mikescott/2018/06/08/liquid-air-technology-offers-prospect-of-storing-energy-for-the-long-term/#3137f759622f, January, 2019.

Commercial Availability: In 2018, Enbridge Gas Distribution and Hydrogenics opened North America's first multi-megawatt power-to-gas facility using renewably sourced hydrogen, the 2.5 MW Markham Energy Storage Facility in Ontario, Canada. In the United States, SoCalGas has partnered with the National Fuel Cell Research Center to install an electrolyzer powered by the University of California at Irvine on-campus solar electric system, which generates renewable hydrogen to be fed into the campus power plant. SoCalGas has also partnered with NREL to install the nation’s first biomethanation reactor system located at their Energy Systems Integration Facility (ESIF) in Golden, Colo. Full-scale hydrogen energy projects are also in development, most notably a 1,000 MW Advanced Clean Energy Storage (ACES) facility in Utah through a partnership of Mitsubishi Hitachi Power Systems and Magnum Development, which owns large salt caverns to store the hydrogen. Xcel Energy is partnering with the NREL to create a 110 kW wind-to-hydrogen project using the site’s hydrogen fueling station for storage, to be converted back to electricity and fed to the grid during peak demand hours.[60]

Supply-side Thermal Resource Costs and Technologies

PSE modeled two types of thermal resources in the 2019 IRP, baseload combustion turbine plants and peaking capacity plants.

Generic Combustion Turbine Resource Cost Assumptions

Figure D-34 summarizes the cost assumptions used in the analysis for baseload combustion turbine plants and peaking capacity plants. All costs are in 2020 dollars.

60 / Sources: Fuel Cell & Hydrogen Energy Association, Energy Storage Association, Utility Dive

Figure D-34: Generic Combustion Turbine Resource Assumptions

2020 $	UNITS	FRAME PEAKER 1x0 F-Class Dual Fuel CT (NG)	CCCT 1x1 F-Class CC (NG Only)	RECIP PEAKER 12x0 18 MW RICE (NG Only)
ISO Capacity Primary	MW	225	336	219
Winter Capacity Primary (23º F)	MW	237	348	219
Incremental Capacity DF (23º F)	MW	N/A	19	N/A
Capital Cost + Duct Fire*	$/KW	$947.53	$1,254.53	$1,671.27
O&M Fixed	$/KW-yr	$7.68	$12.87	$6.40
O&M Fixed	$MW-week	$147.63	$247.45	$123.15
O&M Variable	$/MWh	$7.86	$3.32	$7.05
Start-up Costs	$/Start	$6,831.16	N/A	N/A
Operating Reserves	%	3%	3%	3%
Forced Outage Rate	%	2.38%	3.88%	3.30%
Heat Rate – Baseload (HHV)	Btu/KWh	9,904	6,624	8,445
Heat Rate – Turndown (HHV)	Btu/KWh	15,794	7,988	11,288
Heat Rate – DF	Btu/KWh	N/A	8,867	N/A
Minimum Capacity	%	30%	38%	30%
Start Time (hot)	minutes	21	45	5
Start Time (warm)	minutes	21	60	5
Start Time (cold)	minutes	21	150	5
Start-up fuel (hot)	mmBtu	366	839	69
Start-up fuel (warm)	mmBtu	366	1,119	69
mmBtu/MW/Start (warm)		1.544	3.214	0.317
Staru-up fuel (cold)	mmBtu	366	2,797	69
Ramp Rate	MW/min	40	40	16

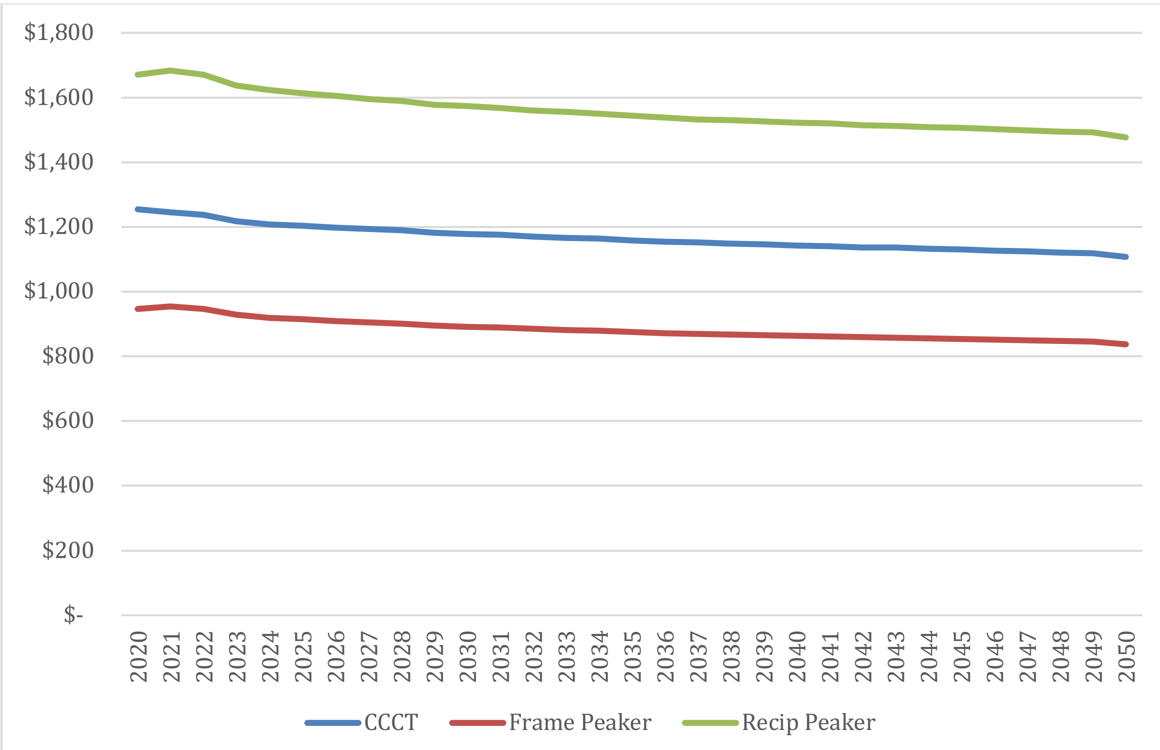
Fixed Gas Transport	$/Dth/Day	$0.00	$0.25	$0.25
Fixed Gas Transport	$/KW-yr	$0.00	$14.67	$18.70
Variable Gas Transport	$/MMBtu	$0.04	$0.06	$0.06
Fixed Transmission	$/KW-yr	$0.00	$0.00	$0.00
Variable Transmission	$/MWh	$0.00	$0.00	$0.00
EMISSIONS				
CO2 - Natural Gas	lbs/MMBtu	118	118	118
NOx - Natural Gas	lbs/MMBtu	0.004	0.008	0.029
DEVELOPMENT PARAMETERS				
First Year Available		2025	2025	2025
Economic Life	years	30	30	30
Greenfield Dev. & Const. Lead Time	years	1.8	2.7	2.3

NOTES
1. For recip peaker, the ramp rate indicated is for a single reciprocating internal combustion engine (RICE) unit; operations and maintenance costs include oil backup.
2. For frame peaker, operations and maintenance costs include oil backup. Variable Operations and Maintenance (VOM) is variable operations only. Major maintenance is included in start-up costs.

CAPITAL COST CURVE. Capital costs assumptions start in current the current year, but for future years, the cost curve from the NREL Annual Technology Baseline (ATB) 2019 was applied to the current costs.

Figure D-35 below shows the capital cost curves for the thermal plants modeled in the 2021 IRP.

Figure D-35: Capital Cost Curve for Thermal Plants



NATURAL GAS TRANSPORTATION COSTS MODELED. Fixed and variable natural gas transportation costs for the combustion turbine plants assume that natural gas is purchased at the Sumas Hub. Natural gas transportation costs for resources without oil backup assume the need for 100 percent firm gas pipeline transportation capacity plus firm storage withdrawal rights equal to 20 percent of the plant's full fuel requirements. This applies to the baseload CCCT and reciprocating engine without oil. The analysis assumes that the gas transportation needs for these resources will be met with 100 percent firm gas transportation on a Northwest Pipeline (NWP) expansion to Sumas plus 100 percent firm gas transportation on the Westcoast Pipeline[61] expansion to Station 2. The plants are dispatched to Sumas prices, so a basis differential gain between Sumas and Station 2 mitigates the gas transportation costs. For frame peaker resources, we assume oil backup with no firm gas transportation.

61 / Westcoast Pipeline is operated by Westcoast Energy, a subsidiary of Enbridge, Inc.

Figure D-36 below shows the natural gas transport assumptions for resources without oil backup.

Figure D-36: Natural Gas Transportation Costs for Western Washington CCCT and Reciprocating Engine Peakers without Oil Backup – 100% Sumas on NWP + 100% Station 2 on Westcoast

PIPELINE/RESOURCE	FIXED DEMAND ($/DTH/DAY)	VARIABLE COMMODITY ($/DTH)	ACA CHARGE ($/DTH)	FUEL USE (%)	UTILITY TAXES (%)
NWP Expansion[1]	0.6900	0.0083	0.0013	1.41%	3.85%
Westcoast Expansion[2]	0.7476	0.0551	-	-	-
Basis Gain[3]	(0.8139)	-	-	2.71%	3.85%
Gas Storage[4]	0.0767	-	-	2.00%	3.85%
Total	***0.7004***	***0.0634***	***0.0013***	***6.12%***	***3.85%***

NOTES
1. Estimated NWP Sumas to PSE Expansion
2. Estimated Westcoast Expansion Fixed Demand
3. Basis gain represents the average of the Station 2 to Sumas price spread, net of fuel losses and variable costs over the 20-year forecast period. Variable Commodity Charge includes B.C. carbon tax and motor fuel tax of $0.0551 per Dth per day and fuel losses are 2.71 percent per Dth. A state utility tax of 3.852% applies to the natural gas price.
4. Storage requirements are based on current storage withdrawal capacity to peak plant demand for the natural gas for power portfolio (approximately 20 percent).

Figure D-37: Natural Gas Transportation Costs for Western Washington Frame Peakers with Oil Backup – No Firm Gas Pipeline

PIPELINE/ RESOURCE	FIXED DEMAND ($/DTH/DAY)	WEIGHTED AVERAGE "VARIABLE" DEMAND ($/DTH)	VARIABLE COMMODITY ($/DTH)	ACA CHARGE ($/DTH)	FUEL USE (%)	UTILITY TAXES (%)
NWP Demand	0.0000	0.0300	0.0083	0.0013	1.41%	3.82%
Total	**0.0000**	**0.0300**	**0.0083**	**0.0013**	**1.41%**	**3.82%**

Combustion Turbine (CT) Characteristics

Combustion turbines still play an important role in the portfolio given their versatility and reliability. PSE is exploring fuel alternatives to natural gas fuel, such as RNG, hydrogen and biodiesel as we move toward CETA goals. For this IRP, PSE analyzed the use of biodiesel. The following characteristics make combustion turbines an important tool.

- **Proximity:** Combustion turbines located within or adjacent to PSE's service area avoid costly transmission investments required for long-distance resources like wind.
- **Timeliness:** Combustion turbines are dispatchable, meaning they can be turned on when needed to meet loads, unlike "intermittent" resources that generate power sporadically such as wind, solar and run-of-the-river hydropower.
- **Versatility:** Combustion turbine generators have varying degrees of ability to ramp up and down quickly in response to variations in load and/or wind generation.

When relying on natural gas fuel, storage and fuel supply are important considerations, so the analysis also includes gas storage for some resources. The baseload and peaking resources modeled in this analysis are described below.

Baseload Combustion Turbine (CT) Technologies

Baseload CT plants – combined-cycle combustion turbines or CCCTs – produce energy at a constant rate over long periods at a lower cost relative to other production facilities available to the system. They are typically used to meet some or all of a region's continuous energy demand.

COMBINED-CYCLE COMBUSTION TURBINES (CCCTs). These baseload plants consist of one or more combustion turbine generators equipped with heat recovery steam generators that capture heat from the combustion turbine (CT) exhaust. This otherwise wasted heat is then used to produce additional electricity via a steam turbine generator. The baseload heat rate for the CCCTs modeled for this IRP is 6,624 BTU per kWh. Many plants also feature "duct firing." Duct firing can produce additional capacity from the steam turbine generator, although with less efficiency than the primary unit. CCCTs have been a popular source of baseload electric power and process steam generation since the 1960s because of their high thermal efficiency and reliability, relatively low initial cost and relatively low air emissions.

In this analysis, natural gas supply is assumed to be firm year-round at projected incremental gas pipeline firm rates. This analysis assumes 20 percent of gas storage is available to the baseload CCCT plants modeled to accommodate mid-day start-ups or shutdowns. The unit is assumed to be connected to the PSE transmission system and as such does not incur any direct transmission cost.

This technology is commercially available. Greenfield development requires approximately three years.

Peaker Technologies

Peakers are quick-starting single-cycle combustion turbines that can ramp up and down rapidly in order to meet spikes in need. They also provide flexibility needed for load following, wind integration and spinning reserves. PSE modeled two types of peakers; each brings particular strengths to the overall portfolio.

FRAME PEAKERS. Frame CT peakers are also known as “industrial” or “heavy-duty” CTs; these are generally larger in capacity and feature frames, bearings and blading of heavier construction. Conventional frame CTs are a mature technology. They can be fueled by natural gas, distillate oil or a combination of fuels (dual fuel). PSE is exploring fuel alternatives to natural gas fuel, such as RNG, hydrogen and biodiesel as we move toward CETA goals. In this IRP, PSE evaluated the use of biodiesel. The turndown capability of the units is 30 percent. The assumed heat rate for frame peakers in this IRP is 9,904 BTU per kWh. They also have slower ramp rates than other peakers, on the order of 40 MW per minute for 237 MW facilities, and some can achieve full load in twenty-one minutes.

Frame CT peakers are commercially available. Greenfield development requires approximately two years.

RECIP PEAKERS (RECIPROCATING INTERNAL COMBUSTION ENGINE - RICE). The reciprocating engine technology evaluated is based on a four-stroke, spark-ignited gas engine which uses a lean burn method to generate power. The lean burn technology uses a relatively higher ratio of oxygen to fuel, which allows the reciprocating engine to generate power more efficiently. Ramp rates are 16 MW per minute for an 18 MW facility. The heat rate is 8,445 BTU per kWh. However, reciprocating engines are constrained by their size. The largest commercially available reciprocating engine for electric power generation produces 18 MW, which is less than the typical frame peaker. Larger-sized generation projects would require a greater number of reciprocating units compared to an equivalent-sized project implementing a frame turbine, reducing economies of scale. A greater number of generating units increases the overall project availability and reduces the impact of a single unit out of service for maintenance. Reciprocating engines are more efficient than simple-cycle combustion turbines, but have a higher capital cost. Their small size allows a better match with peak loads, thus increasing operating flexibility relative to simple-cycle combustion turbine peakers.

This technology is commercially available. Greenfield development requires approximately three years.

Oil Backup: For frame peakers with oil backup, natural gas supply is assumed to be available on an interruptible basis at projected gas pipeline seasonal interruptible rates for much of the year. The oil backup is assumed to provide fuel during peak periods. For units without oil backup, natural gas supply is assumed to be firm year-round at projected incremental gas pipeline firm rates. In either case, the analysis assumes 20 percent of gas storage is available to the peaking gas plants modeled to accommodate mid-day start-ups or shutdowns. The peaker unit is assumed to be connected to the PSE transmission system and as such does not incur any direct transmission cost.

Thermal Resources Not Modeled

As discussed below, other potential thermal resource alternatives are constrained by law, practical obstacles and cost. Long-term coal-fired generation is not a resource alternative because RCW 80.80 precludes utilities in Washington from entering into new long-term agreements for coal. The Clean Energy Transformation Act (CETA) also requires utilities to eliminate coal-fired generation from their state portfolios by 2025. New nuclear generation is neither practical nor feasible.

COAL. Coal fuels a significant portion of the electricity generated in the United States. Most coal-fired electric generating plants combust the coal in a boiler to produce steam that drives a turbine-generator. A small number of plants gasify coal to produce a synthetic gas that fuels a combustion turbine. Of the fuels commonly used to produce electricity, coal produces the most greenhouse gases (GHGs) per MWh of electricity. Technologies for reducing or capturing some of the GHGs produced are currently in the research and development phase.

Commercial Availability: New coal-fired generation is not a resource alternative for PSE, because RCW 80.80 sets a generation performance standard for electric generating plants that prohibits Washington utilities from building plants or entering into long-term electricity purchase contracts from units that emit more than 970 pounds of GHGs per MWh.[62] With currently available technology, coal-fired generating plants produce GHGs (primarily carbon dioxide) at a level two or more times greater than the performance standard, and carbon capture and sequestration technology is not yet effective or affordable enough to significantly reduce those levels. Furthermore, CETA, passed on May 7, 2010, explicitly requires Washington state utilities to eliminate coal-fired electricity generation from their state portfolios by 2025.

There are no new coal-fired power plants under construction or development in the Pacific Northwest.

62 / To support a long-term plan to shut down the only coal-fired generating plant in Washington state, state government has made an exception for transition contracts with the Centralia generating plant through 2025.

NUCLEAR. Capital and operating costs for nuclear power plants are significantly higher than most conventional and renewable technologies such that only a handful of the largest capitalized utilities can realistically consider this option. In addition, nuclear power carries significant technology, credit, permitting, policy and waste disposal risks.

Cost Assumptions: There is little reliable data on recent U.S. nuclear developments from which reasonable and supportable cost estimates can be made. The construction cost and schedule track record for nuclear plants built in the U.S. during the 1980s, 1990s and 2000s has been poor at best. Actual costs have been far higher than projected, construction schedules have been subject to long delays, and interest rate increases have resulted in high financing charges. The Fukushima incident in 2011 also motivated changing technical and regulatory requirements and public controversy that have contributed to project cost increases.

With many other energy options to choose from, the demonstrated high cost, poor completion track record, lack of a comprehensive waste storage/disposal solution and the bankruptcy of a major nuclear supplier all create significant uncertainty, making nuclear energy an unwise and unnecessary risk for PSE at this time.

AERO PEAKERS (Aeroderivative Combustion Turbines). Aeroderivative combustion turbines are a mature technology, however, new aeroderivative features and designs are continually being introduced. They can be fueled by natural gas, oil, RNG, hydrogen, biodiesel or a combination of fuels (dual fuel). A typical heat rate is 8,810 BTU per kWh. Aero units are typically more flexible than their frame counterparts, and many can reduce output to nearly 25 percent. Most can start and achieve full output in less than eight minutes and start multiple times per day without maintenance penalties. Ramp rates are 50 MW per minute for a 227 MW facility. Another key difference between aero and frame units is size. Aero CTs are typically smaller in size, from 5 to 100 MW each. This small scale allows for modularity, but it also tends to reduce economies of scale.

This technology is commercially available. Greenfield development requires approximately three years.