2 Clean Energy Action Plan

This chapter describes the 10-year Clean Energy Action Plan for implementing the Clean Energy Transformation Standards.

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1. OVERVIEW

The Clean Energy Transformation Act (CETA) introduced the CEAP as a new aspect of the IRP designed to identify likely action over the next 10 years to meet the goals of CETA. The content of the Clean Energy Action Plan (CEAP) is specifically defined in WAC 480-100-620 subsection 12. This chapter follows the structure defined in subsection 12 and short-term actions are outlined in Chapter 1. This is the first IRP to include a CEAP, and as with any new requirement or assessment, the CEAP will evolve over time, and future IRPs will benefit from the lessons learned in this first implementation of the new planning process.

PSE is committed to achieving the goals of the Clean Energy Transformation Act (CETA) and achieving carbon neutrality by 2030 and carbon free electric energy supply by 2045, and CEAP presented here reflects these changes and goals. Specifically, the CEAP provides a 10-year outlook that refines the IRP preferred portfolio. In turn, the CEAP informs the Clean Energy Implementation Plan (CEIP), which develops specific targets, interim targets and actions over a 4-year period per RCW 19.405.060.

2. EQUITABLE TRANSITION TO CLEAN ENERGY

Assessment of Current Conditions

CETA sets out important new planning standards that require utility resource plans to ensure that all customers benefit from the transition to clean energy. To achieve this goal, PSE performed an Economic, Health and Environmental Benefits (EHEB) Assessment (or "the Assessment") to provide guidance for development of the utility's CEAP and CEIP. The purpose of the Assessment is two-fold: first, to identify highly impacted communities and vulnerable populations within PSE's service territory; and second, to measure disparate impacts to these communities using specific customer benefit indicators.

At the November 2020 IRP meeting, PSE outlined the methodology and proposed customer benefit indicators to be used in the Assessment and solicited stakeholder feedback. This feedback was incorporated into the development of the Assessment, as well as insights gained from the WUTC's December 2020 final rulemaking language and associated adoption order and the February 2021 Cumulative Impact Analysis completed by the Washington Department of Health. A full description of the methods, results and future plans for the Assessment are available in Appendix K.

PSE recognizes the importance of developing a process in which all voices are included and heard, and acknowledges that the IRP public participation process is only the first incremental step in seeking stakeholder feedback on the Assessment. Many populations and communities are not represented in the IRP public participation process. This will be an important part of the evolution of the resource planning process, and PSE anticipates additional engagement through the CEIP public participation process and in future IRP cycles.

The initial qualitative and quantitative customer benefit indicators developed through the Assessment provide a snapshot in time of the economic, health, environmental, and energy security and resiliency impacts of resource planning on highly impacted communities and vulnerable populations within PSE's service territory. Due to the timing of the IRP process and the new CETA regulations, the initial customer benefit indicators included in the CEAP should be viewed as preliminary and likely to change through public participation and input from PSE's Equity Advisory Group. The initial customer benefit indicators will be modified and evaluated over time to measure progress towards achieving an equitable distribution of benefits and reduction of burdens.

Role of the Equity Advisory Group

As part of the CEIP public participation process, PSE is establishing an Equity Advisory Group to provide specific input on the first CEIP, due in October of 2021, as well as on the implementation of that plan. In future planning cycles, the Equity Advisory Group's input will be important to incorporate starting with the planning for the IRP process. This will be an important area of learning and improvement through the entire planning cycle from the IRP through to the CEIP.

Customer Benefit Indicators

A key component to ensuring the equitable distribution of burdens and benefits in the transition to a clean energy future is to include customer benefit indicators in the preferred portfolio development process. For this IRP, due to the timing of the rulemaking and establishment of the Equity Advisory Group, PSE was only able to incorporate feedback during the IRP public process. Future IRPs will have the benefit of input from the Equity Advisory Group and the CEIP public participation process.

To reflect customer benefit indicators in the development of the preferred portfolio, the customer benefit indicators were first linked to specific portfolio modeling outputs. These outputs were then combined into broader customer benefit indicator areas which provided a context for interpreting the portfolio outputs. Each portfolio from the sensitivity analyses was ranked on how well it performed in each of the customer benefit indicator areas to get an understanding of which benefits or burdens it may confer upon PSE's customers. Portfolios had to score well in several customer benefit indicator areas to be considered a preferred portfolio. The customer benefit indicator framework is described in more detail in Chapters 3 and 8.

In summary, PSE is taking several preliminary actions to ensure that all customers benefit from the transition to clean energy:

1. Establishing the Equity Advisory Group
2. Developing a public participation plan for the CEIP to obtain input on equitable distribution of benefit and burdens
3. Refining customer benefit indicators and metrics with the EAG and the CEIP public participation process
4. Updating the Customer Benefits Analysis to incorporate the customer benefit indicators and related metrics in the CEIP and future IRPs

3. 10-YEAR CLEAN RESOURCE ADDITIONS

10-Year Clean Resource Summary

In alignment with the IRP 24-year outlook, Figure 2-1 below summarizes the 10-year outlook for the resource mix in the preferred portfolio. The customer benefit indicators informed the final selection of resources while also ensuring the preferred portfolio met PSE's peak capacity, energy and renewable needs and addressed market risk.

Figure 2-1: 10-year Annual Resource Additions Preferred Portfolio

Resource Type	Incremental Nameplate Resource Additions (MW)										Total (MW)
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
Distributed Energy Resources											
Demand-side Resources											
Energy Efficiency	36	39	41	42	44	47	50	50	54	56	458
Distributed Generation – Solar PV	0.2	0.4	0.7	1.2	2.1	3.6	6.1	10	16	18	58
Distribution Efficiency	1.2	0.3	0.7	1.8	1.2	1.3	1.3	1.3	1.3	1.3	12
Codes & Standards	37	24	19	12	15	14	25	13	4	6	169
Total Demand-side Resources	74	64	61	57	63	66	82	75	75	81	696
Battery Energy Storage	-	-	-	25	25	25	25	25	50	25	200
Solar - ground and rooftop	-	-	-	80	30	30	30	30	30	30	260
Demand Response	-	5	6	18	27	34	40	27	26	13	196
DSP Non-wire Alternatives	3	6	9	4	3	5	6	5	4	4	50
Total Distributed Energy Resources	78	75	75	184	148	160	183	161	185	153	1,402
Renewable Resources											
Wind	-	-	-	400	200	400	-	200	200	100	1,500
Solar	-	-	-	-	-	100	-	100	198	0	398
Total Renewable Resources	-	-	-	400	200	500	-	300	398	100	1,898
Peaking Capacity with Biodiesel	-	-	-	-	255	-	-	-	-	-	255
Firm Resource Adequacy Qualifying Capacity Contracts	-	185	187	202	202	203	-	-	-	-	979

Conservation Potential Assessment

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 IRP portfolio analysis. Then the portfolio analysis determines the maximum amount of energy savings that can potentially be captured without raising the overall electric portfolio cost. This identifies the cost-effective level of DSR to include in the portfolio. The full assessment is included in Appendix E.

PSE included the following demand-side resource alternatives in the CPA that was performed by The Cadmus Group for this IRP. While the IRP evaluates demand-side resources through the CPA process, the CEIP will establish the specific targets for renewable energy, energy efficiency and demand response, and may evaluate programs aligned with those targets.

- **ENERGY EFFICIENCY MEASURES.** This includes 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. The achievable technical potential for demand response was assessed through the CPA, and the cost-effective demand response programs identified in this IRP are described in a separate section below.
- **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. The CPA identifies combined heat and power (CHP) and customer-owned rooftop solar as distributed generation. Other distributed energy resources are also evaluated in this IRP and described in a separate section below.
- **DISTRIBUTION EFFICIENCY (DE).** Distribution efficiency addresses conservation voltage reduction (CVR), which is the practice of reducing the voltage on distribution circuits to reduce energy consumption, since many appliances and motors can perform properly while consuming less energy. Phase balancing is required for CVR to eliminate total current flow energy losses.
- **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 in place at the time of the CPA study are included.

Figure 2-2 shows the achievable technical potential of demand-side resource savings in PSE's service territory. The year 2031 savings represent the 10-year potential starting in 2022.

Figure 2-2: 10-year Achievable Technical Potential Demand Side Resource Savings

Demand-Side Resources	Nameplate 2031	Energy Savings 2031	Peak Capacity Savings 2031
Energy Efficiency	458 MW	263 aMW	458 MW
Distributed Generation: Solar PV	58 MW	7 aMW	0 MW
Distribution Efficiency	12 MW	11 aMW	12 MW
Codes and Standards	169 MW	93 aMW	177 MW
Total Achievable Technical Potential	696 MW	374 aMW	646 MW

NOTES
1. Demand response is not included in the cost-effective DSR. It is included separately below.
2. Customer solar PV is the only distributed resource modeled as a separate measure, CHP is included in energy efficiency.
3. Given the nature of the IRP, assumptions for the models need to be set months before the IRP is finalized. This is simply of forecast of best known information at the time. Some of these forecast may have changed since the IRP inputs were finalized.

The IRP analysis evaluates the amount of demand-side resources (conservation) that is cost effective to meet the portfolio's capacity and energy needs, optimizing lowest cost and considering both distributed and centralized resources. The final analysis indicates that although current market power prices are low, accelerating the acquisition of DSR continues to be a least-cost strategy to meet renewable requirements. CETA renewable requirements result in significant increases in avoided cost, and this impacts the amount of cost-effective DSR. The large amounts of renewable resources needed to meet CETA move higher cost demand-side resources into the portfolio because conservation reduces load, thereby reducing the amount of renewable resources needed to meet requirements. Figure 2-3 shows the cost-effective amount of demand-side resources identified in the IRP by category (energy efficiency, customer solar PV forecast, distribution efficiency and codes and standards).

Figure 2-3: Cost-effective Demand-side Resources Incremental Nameplate Additions

Demand-Side Resources	Incremental Nameplate Additions		10-year Total
	2022-2025	2026-2031	
Energy Efficiency	157 MW	301 MW	458 MW
Distributed Generation: Solar PV	2 MW	56 MW	58 MW
Distribution Efficiency	4 MW	8 MW	12 MW
Codes and Standards	92 MW	77 MW	169 MW
Total Demand-side Resources	256 MW	440 MW	696 MW

NOTES
1. Demand Response is not included in the cost-effective DSR. It is included separately below.
2. Customer solar PV is the only distributed resource modeled as a separate measure, CHP is included in energy efficiency. Additional distributed energy resources were evaluated in this IRP and are described below.

Resource Adequacy

PSE has established a 5 percent loss of load probability (LOLP) resource adequacy metric to assess physical resource adequacy risk. LOLP measures the *likelihood* of a load curtailment event occurring in any given simulation regardless of the frequency, duration and magnitude of the curtailment(s). Therefore, the likelihood of capacity being lower than the load, occurring anytime in the year, cannot exceed 5 percent.

Assessing the amount of peak capacity each resource can reliably provide is an important part of resource adequacy analysis. To quantify the peak capacity contribution of renewable resources (wind, hydro and solar), PSE calculates the effective load carrying capacity, or ELCC, for each of those resources. The ELCC of a resource is unique to each utility and dependent on load shapes and supply availability, so it is hard to compare the ELCC of PSE's resources with those of other entities. Some of the ELCCs are higher and some are lower, depending on PSE's needs, demand shapes and the availability of supply-side resources. A full description of the peak capacity and ELCC values is in Chapter 7.

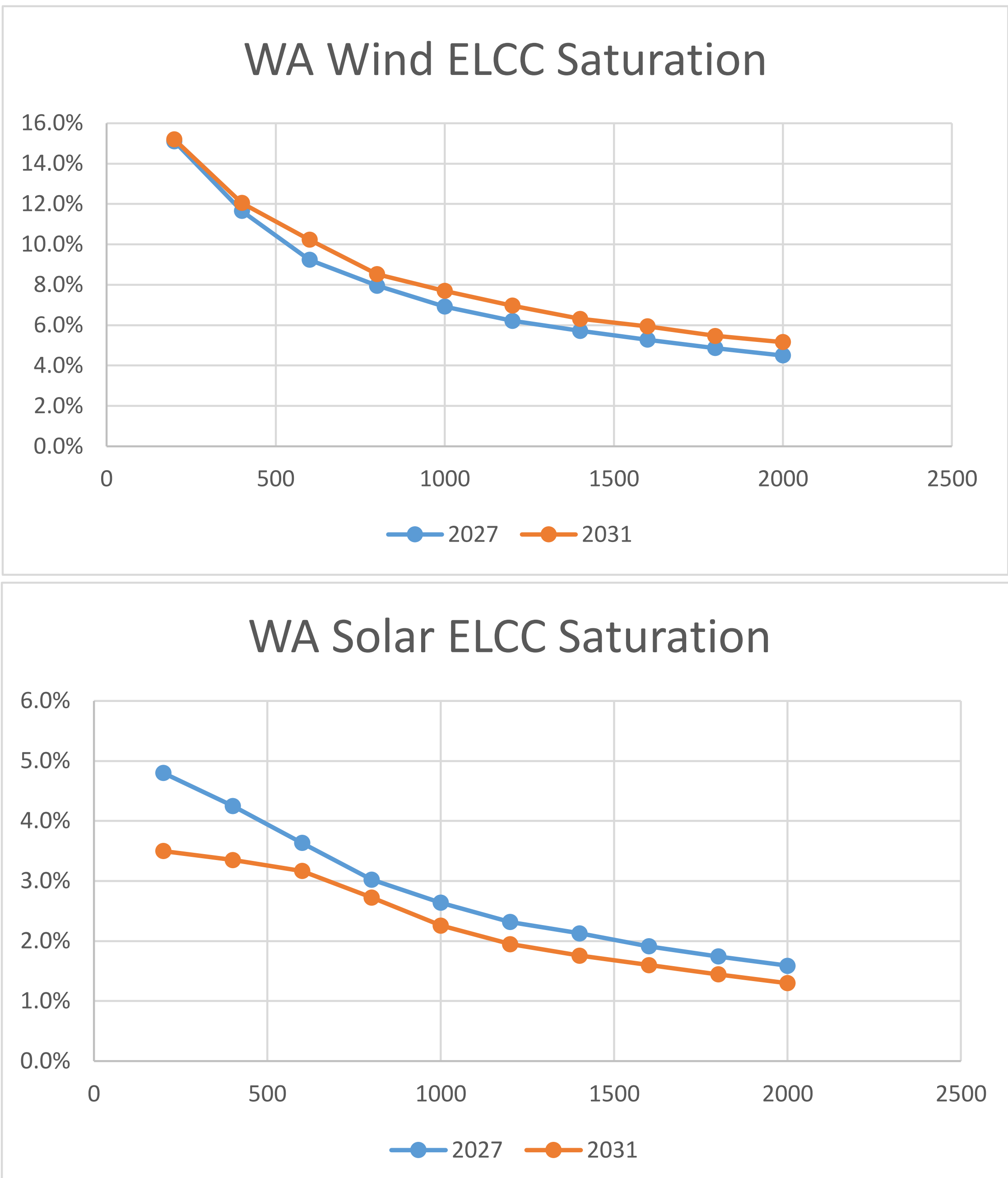
Figure 2-4 shows the estimated peak capacity credit or ELCC of the wind and solar resources included in this IRP. The order in which the existing and prospective projects were added in the model follows the timeline of when these projects are acquired or about to be acquired. The concept of resource saturation is also important to the ELCC calculation. Each incremental resource added in the same geographical area provides less effective peak capacity because it provides more of the same resource profile rather than increasing the diversity of the resource profile. The ELCC calculation for the first 100 MW of the resource is shown below in Figure 2-4, and the full saturation curve for up to 2,000 MW of Washington wind and solar is shown in Figure 2-5.

Figure 2-4: Peak Capacity Credit for Wind and Solar Resources

WIND AND SOLAR RESOURCES	Capacity (MW)	ELCC Year 2027	ELCC Year 2031
Existing Wind	823	9.6%	11.2%
Skookumchuck Wind	131	29.9%	32.8%
Lund Hill Solar	150	8.3%	7.5%
Golden Hills Wind	200	60.5%	56.3%
Generic MT East Wind1	350	41.4%	45.8%
Generic MT East Wind2	200	21.8%	23.9%
Generic MT Central Wind	200	30.1%	31.3%
Generic WY East Wind	400	40.0%	41.1%
Generic WY West Wind	400	27.6%	29.4%
Generic ID Wind	400	24.2%	27.4%
Generic Offshore Wind	100	48.4%	46.6%
Generic WA East Wind[1]	100	17.8%	15.4%
Generic WY East Solar	400	6.3%	5.4%
Generic WY West Solar	400	6.0%	5.8%
Generic ID Solar	400	3.4%	4.3%
Generic WA East Solar	100	4.0%	3.6%
Generic WA West Solar – Utility scale	100	1.2%	1.8%
Generic WA West Solar – DER Roof	100	1.6%	2.4%
Generic WA West Solar – DER Ground	100	1.2%	1.8%

ELCC SATURATION CURVES. The table above shows the peak capacity credit for the first 100 MW of installed nameplate capacity for Washington state wind and solar. Below, Figure 2-5 plots the peak capacity credit for the next 200 MW and then the next 200 MW after that and so on, showing how the peak capacity credit decreases as more wind or solar is added in the same region. Wind or solar nameplate capacity is shown in MW on the horizontal axis, and peak capacity credit as a percent of nameplate capacity is shown on the vertical axis.

Figure 2-5: Saturation curves for Washington Wind and Solar



STORAGE CAPACITY CREDIT. The estimated peak capacity credit of two types of batteries were modeled as well as pumped storage hydro. The lithium-ion and flow batteries modeled can be charged or discharged at a maximum of 100 MW per hour up to two, four or six hours duration when the battery is fully charged. For example, a four-hour duration, 100 MW battery can produce 400 MWh of energy continuously over four hours. Thus, the battery is energy limited. Figure 2-6 shows the peak capacity credit of the types of storage resources modeled in the IRP. The peak capacity credit for battery storage is low because batteries are relatively short-duration resources. Unlike generating resources, battery storage resources have to recharge; therefore, when long-duration needs for energy occur as in winter peaks, batteries provide little contribution compared to generating resources. Longer duration storage resources provide higher peak capacity credits.

Figure 2-6: Peak Capacity Credit for Energy Storage

BATTERY STORAGE	Capacity (MW)	Peak Capacity Credit Year 2027	Peak Capacity Credit Year 2031
Lithium-ion, 2-hr, 82% RT efficiency	100	12.4%	15.8%
Lithium-ion, 4-hr, 87% RT efficiency	100	24.8%	29.8%
Flow, 4-hr, 73% RT efficiency	100	22.2%	27.4%
Flow, 6-hr, 73% RT efficiency	100	29.8%	35.6%
Pumped Storage, 8-hr, 80% RT efficiency	100	37.2%	43.8%

DEMAND RESPONSE CAPACITY CREDIT. The estimated peak capacity credit of demand response is shown in Figure 2-7.

Figure 2-7: Peak Capacity Credit for Demand Response

DEMAND RESPONSE	Capacity (MW)	Peak Capacity Credit Year 2027	Peak Capacity Credit Year 2031
Demand Response, 3-hr duration, 6-hr delay, 10 calls per year	100	26.0%	31.6%
Demand Response, 4-hr duration, 6-hr delay, 10 calls per year	100	32.0%	37.4%

Wholesale Electric Market Risk

The wholesale electric market has changed significantly in recent years and is now experiencing tighter supply and increasing price volatility. As a result, regional power suppliers, including PSE, are making changes to how they plan with regard to resource adequacy. Addressing resource adequacy issues on a regional basis, rather than utility-by-utility, has the potential to increase reliability for all providers in the region, and as a result, numerous regional entities, including PSE, are collectively developing a regional resource adequacy program. At this time, the program has not been included in the IRP analysis because sufficient details are not yet known. However, it is important that PSE takes appropriate steps in its resource planning to allow for future participation in a regional resource adequacy program once established.

For this IRP, PSE conducted a market risk assessment to evaluate the use of its 1,500 MW of firm transmission to the Mid-Columbia market hub with short-term energy purchase agreements. . The assessment resulted in a recommendation that part of PSE's Mid-C transmission be dedicated to firm resource adequacy qualifying capacity contracts to ensure reliable service. The recommendation includes limiting the amount of real-time, day-ahead and term market purchases and replacing a portion of those energy contracts with firm resource adequacy qualifying capacity contractual arrangements to meet PSE's resource adequacy requirements as well as those of a future regional resource adequacy program. PSE has a strong preference for clean resources and contractual arrangements.

Ensuring Resource Adequacy

PSE must meet capacity need over the planning horizon with firm capacity resources or contractual arrangements to maintain reliability. All resources, including renewable resources, distributed energy resources and demand response, contribute to meeting the capacity needs of PSE's customers, but they make different kinds of contributions. This IRP determined that the limited-run use of simple-cycle combustion turbines (peakers) operated on biodiesel (a CETA complaint fuel) is the most cost effective means of ensuring resource adequacy. Chapters 3, 5 and 8 describe the numerous clean resource combinations PSE analyzed as an alternative to the biodiesel peaker solution and the significant increases in portfolio costs that resulted. Figure 2-8 summarizes the capacity needed to meet reliability requirements across the first ten years of the planning horizon. The recommended approach from the market risk assessment is also included and shown as firm resource adequacy qualifying capacity contracts.

Figure 2-8: Capacity Additions to meet Reliability

Resource Type	Incremental Resource Additions		10-year Total
	2022-2025	2026-2031	
Peaking Capacity with Biodiesel	0 MW	255 MW	255 MW
Firm Resource Adequacy Qualifying Capacity Contracts	574 MW	405 MW	979 MW

Demand Response

Demand response programs are voluntary, and once enrolled, customers usually receive notifications in advance of forecasted peak usage times requesting them to reduce their energy use. Some program types require action by the customer, others can be largely automated. For example, an automated program might warm a customer's home or building earlier than usual with no action required. In a program that requires customer action, a wastewater plant may be asked to curtail pumping during certain peak energy need hours if they can operationally do so. Because customers can always opt out of an event, demand response programs include some risk. If PSE is relying on a certain amount of load reduction from demand response to handle a peak event but customers opt out, then PSE must use generating resources to fill the customer's needs.

Demand response programs modeled for this IRP 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 Demand Response

Figure 2-9 lists the estimated achievable technical potential for all winter demand response programs modeled for the residential, commercial and industrial sectors in this IRP. The table shows the achievable potential of each demand response program in MW and the percentage of winter peak need it fills to illustrate the total potential impact of demand response on system peak. The winter percent of system peak load was calculated as the average of PSE's hourly loads during the 20 highest-load hours in the winter of 2019. The total demand response nameplate achievable potential is 228 MW. The peak capacity credit of demand response programs is shown above in Figure 2-7. Further details about demand response programs modeled in this IRP can be found in Appendix D and E. The program costs shown include a transmission and distribution (T&D) benefit that reflects the value of the program to the distribution system non-wires alternatives. Some programs have a negative cost because the benefits they deliver are greater than their cost to the system.

Figure 2-9: Demand Response Achievable Potential and Levelized Cost by Product Option

Program	Product Option	Winter Achievable Potential (MW)	Winter Percent of System Peak	Levelized Cost ($/kW-year)
Residential CPP	Res CPP-No Enablement	64	1.28%	-$3
	Res CPP-With Enablement	2	0.04%	-$8
Residential DLC Space Heat	Res DLC Heat-Switch	50	1.00%	$71
	Res DLC Heat-BYOT	3	0.06%	$61
Residential DLC Water Heat	Res DLC ERWH-Switch	11	0.21%	$126
	Res DLC ERWH-Grid-Enabled	58	1.15%	$81
	Res DLC HPWH-Switch	< 1	< 0.1%	$329
	Res DLC HPWH-Grid-Enabled	1	0.02%	$218
Commercial CPP	C&I CPP-No Enablement	1	0.03%	$86
	C&I CPP-With Enablement	1	0.02%	$81
Commercial DLC Space Heat	Small Com DLC Heat-Switch	7	0.13%	$64
	Medium Com DLC Heat-Switch	5	0.10%	$29
Commercial and Industrial Curtailment	C&I Curtailment-Manual	3	0.06%	$95
	C&I Curtailment-Auto DR	3	0.06%	$127
Residential EVSE	Res EV DLC	9	0.17%	$361
Residential Behavioral	Res Behavior DR	9	0.17%	$76

This IRP evaluated 16 different demand response programs and 14 of those were found to be cost effective. Demand response takes a couple of years to set up before savings are achieved, so with five programs starting in 2023, the total nameplate capacity by 2025 is 29 MW due to the time it takes to establish the programs and enroll customers; by 2031, this grows to 196 MW. Figure 2-9 summarizes the cost-effective demand response nameplate capacity.

Figure 2-9: Cost-effective Demand Response Incremental Nameplate Capacity

Resource Type	Incremental Resource Additions		10-year Total
	2022-2025	2026-2031	
Demand Response	29 MW	167 MW	196 MW

Renewable Resources

For this IRP, wind was modeled in seven locations throughout the northwest United States, including eastern Washington, central Montana, eastern Montana, Idaho, eastern Wyoming, western Wyoming and off the coast of Washington. Solar was modeled as a centralized, utility-scale resource at several locations throughout the northwest United States.

Energy storage resources were modeled separately and in combination with the renewable resources. Two battery storage technology systems were analyzed, lithium-ion and flow technology. These systems are modular and made up of individual units that are generally small. Batteries provide both peak capacity and sub-hourly flexibility value. Pumped storage hydro resources were also analyzed. These are generally large, on the order of 250 to 3,000 MW, and the analysis assumes PSE would split the output of a pumped storage hydro project with other interested parties. PSE analyzed an 8-hour pumped storage hydro resource and modeled the project in 25 MW increments. In addition to standalone generation and energy storage resources, PSE modeled hybrid resources that combine two or more resources at the same location to take advantage of synergies between the resources. Three types of hybrid resources were modeled: eastern Washington solar plus 2-hour lithium-ion battery, eastern Washington wind plus 2-hour lithium-ion battery and Montana wind plus pumped storage hydro.

This IRP found that Montana and Wyoming wind power is expected to be more cost effective than wind and solar from the Pacific Northwest. Given transmission constraints, resources from the Pacific Northwest region may be limited. The timing of renewable resource additions is driven by CETA renewable requirements and is shown in Figure 2-10 below. Hybrid resources were shown to be cost effective later in the planning horizon so they are not shown in the first ten years.

Figure 2-10: Renewable Resources Incremental Nameplate Capacity

Resource Type	Incremental Resource Additions		10-year Total
	2022-2025	2026-2031	
Wind Resources	400 MW	1,100 MW	1,500 MW
Solar Resources	-	398 MW	398 MW
Total Renewable Resources	400 MW	1,498 MW	1,898 MW

Distributed Energy Resources

While the adoption of distributed energy resources (DER) is still low in PSE's service territory, about 1 percent of PSE customers are participating in net-metered solar, with an installed capacity of approximately 85 MW. As DER technology evolves and prices decline, customer adoption will likely increase. DERs will play an important role in balancing utility-scale renewable investments and transmission constraints while also meeting local distribution system needs. To accomplish this, PSE will file a draft targeted RFP with the WUTC no later than November 15, 2021 for both distributed energy resources and demand response resources, consistent with Order 05 in Docket UE-200413.

In this IRP, PSE specifically included several different types of distributed energy resources. In addition, demand response, which is considered a distributed energy resource, was also modeled in this IRP as discussed above.

BATTERY ENERGY STORAGE. Two distributed battery storage technology systems were analyzed: lithium-ion and flow technology. These battery storage systems are modular and made up of individual units that are generally small. Batteries provide both peak capacity and sub-hourly flexibility value. In addition, since they are small enough to be installed at substations or on the distribution system, they can potentially defer local transmission or distribution system investments. PSE analyzed 2-hour and 4-hour lithium-ion batteries and 4-hour and 6-hour flow battery systems.

DISTRIBUTED SOLAR GENERATION. Distributed solar generation refers to small-scale rooftop and ground-mounted solar panels located close to the source of the customer's load. Distributed solar was modeled as a residential-scale resource in western Washington.

NON-WIRES ALTERNATIVES. The role of DERs in meeting delivery system needs is changing and the planning process is evolving to reflect that change. Non-wires alternatives are being considered when developing solutions to specific, long-term needs identified on the transmission and distribution systems. The resources under study have the benefit of being able to address system deficiencies while simultaneously supporting resource needs, and they can be deployed across both the transmission and distribution systems, providing some flexibility in how system deficiencies are addressed. The non-wires alternatives considered during the planning process include energy storage systems and solar generation.

Figure 2-11 shows the battery energy storage, solar and non-wire alternatives distributed energy resources.

Figure 2-11: Distributed Energy Resources Incremental Nameplate Capacity

Resource Type	Incremental Resource Additions		10-year Total
	2022-2025	2026-2031	
Battery Energy Storage	25 MW	175 MW	200 MW
Solar	80 MW	180 MW	260 MW
Non-Wire Alternatives	22 MW	28 MW	50 MW
Total Distributed Energy Resources	127 MW	383 MW	510 MW

4. DELIVERABILITY OF RESOURCES

PSE will work to optimize use of its existing regional transmission portfolio to meet our growing need for renewable resources in the near term, but in the long term, the Pacific Northwest transmission system may need significant expansion, optimization and possible upgrades to keep pace. The main areas of high-potential renewable development are east of the Cascades (Washington and Oregon), in the Rocky Mountains (Montana, Wyoming), in the desert southwest (Nevada, Arizona) and in California. The specific opportunities for expanding transmission capabilities and regional efforts to coordinate transmission planning and investment are described in detail in Appendix J. The 10-year delivery system plan is described in Appendix M.

Investments in the delivery system are needed to deliver energy to PSE's customers from the edge of PSE's territory and to support DERs within the delivery grid. The delivery system 10-year plan described in Appendix M identifies work that is needed to ensure safe, reliable, resilient, smart and flexible energy delivery to customers, irrespective of resource fuel source. These include specific upgrades to the transmission system to meet NERC compliance requirements and other evolving regulations related to DER integration and markets and to the distribution system to enable higher DER penetration. Specific delivery system investments will become known when energy resources, whether centralized or DERs, begin siting through the established interconnection processes. The readiness of the grid and customers for DER integration will decrease the cost for interconnection and increase the number of viable locations. Proactive investments in grid modernization are also critical to support the clean energy transition and maximize benefits. The key investment areas are summarized below.

Visibility, Analysis, and Control

Data availability, integrity and granularity are critical aspects to planning for and operating DERs. Through PSE's ongoing investment in Advanced Metering Infrastructure (AMI) and SCADA at distribution substations, PSE will have new data and visibility that can be utilized for delivery system planning, customer program planning and operational analytics. AMI is an integrated system of smart meters, communications networks and data management systems that enables two-way communication between utilities and customers. AMI meters will serve to provide significant enhancements to the types and granularity of data PSE can collect to proactively plan for growth, integrate new technologies, offer services to customers, respond more quickly to system needs and operate the system safely. PSE is currently implementing an Advanced Distribution Management System (ADMS). ADMS is a computer-based, integrated platform that provides the tools to monitor and control our distribution network in real time. The implementation of ADMS will ultimately lead to advanced operational capabilities for DERs including an integrated Distributed Energy Resource Management System (DERMS). Prior to implementation of a fully integrated DERMS, PSE anticipates the need for a virtual power plant (VPP). Virtual power plants forecast and aggregate different types of DERs in order to coordinate dispatch to meet system resource needs. VPPs can aggregate DERs including demand response, EV charging management, CHP, solar PV (smart inverters) and distributed storage. Some VPPs can also manage alternative pricing programs such as Peak Time Rebates. In order to realize the dispatchable capacity benefits of the DER additions expected over the next 5 years, PSE needs a VPP to manage DER customer acquisition, forecasting, dispatch and settlement. needs a VPP to manage DER customer acquisition, forecasting, dispatch and settlement. PSE will develop the technical and operational requirements for a VPP platform in mid-2021. In addition to AMI and ADMS, SCADA provides real-time visibility and remote control of distribution equipment to reduce duration of outages, improve operational flexibility and enhance overall reliability of the distribution system.

PSE also recognizes the importance of maintaining and augmenting the data that we already have, particularly the asset data within our Geographic Information System (GIS). PSE is working to evolve GIS processes so that changes in the field can be quickly incorporated and so that data such as DER asset information is collected and displayed. GIS connects with many enterprise systems, and GIS data will be increasingly central to the ability to plan for and operate DERs. Finally, data analytics programs will support optimization of customer service and system operations including predicting asset replacement needs before failure as DERs are added to the grid.

PSE also plans to implement a geospatial load forecasting tool that includes DER forecasting capabilities as well as end-use forecasting information that supports our energy efficiency and demand response programs. With this tool we can understand not only the anticipated growth of DERs, but also the specific feeder locations. This will enable proactive system investments and potentially uncover targeted demand-side management options and support non-wires alternatives. PSE will continue to enhance its modeling tools and capabilities to ensure grid stability.

Reliability and Resiliency

To avoid reactive investments due to unanticipated DER adoption and integration and in addition to the work already described, PSE will pursue targeted, proactive asset management and system upgrades to enable DER integration and transportation electrification through ensuring a healthy system, managing load and DERs, and ensuring reliable operation. Grid modernization investments will improve the reliability of PSE systems, improve their ability to withstand and recover from extreme events, and enable smart and flexible grid capabilities. Ongoing and site-specific asset investments are needed such as pole replacement, tree-wire conductor and cable remediation programmatic transformer replacements as DERs and electric vehicles propagate, and substation and circuit enhancements that ensure or expand DER effectiveness.
Managing increasing loads will be intentional with advanced capabilities such as Volt-Var Optimization (VVO) and enabling faster system outage restoration through use of Fault Location, Isolation Service Restoration (FLISR), all enabled through the ADMS platform and additional investments in reclosers, switches, voltage regulators, capacitors banks and network communications infrastructure. FLISR will support grid reliability to enable battery energy storage charging and transportation electrification. VVO will manage voltage and reactive power as loads shift due to DER implementation.

PSE will also pursue energy security and resiliency investments such as microgrids or infrastructure hardening where specific locations require increased resilience. These locations could include highly impacted communities, transportation hubs, emergency shelters and areas at risk for isolation during significant weather events or wildfires.

DER Integration Processes

In addition to the enabling technologies, analytical capabilities and system component upgrades, PSE is investigating options and requirements for an enhanced web-based interconnection portal that would streamline the interconnection process for both customers and developers by prescreening applications. Additional customer tools, such as modifications to billing systems and program administration and design, may be needed as PSE’s operating model moves from traditional one-way power flow to two-way energy flow and delivery. PSE continues to integrate non-wire alternative analysis in developing investment plans to meet various energy needs of our customers.

Security, Cybersecurity and Privacy

While pursuing our grid modernization strategy, PSE will continue to put a strong focus on cyber-security. PSE applies the same level of due diligence across the enterprise to ensure risks are consistently addressed and mitigated in alignment with the rapidly changing security landscape. PSE utilizes a variety of industry standards to measure maturity as each standard approaches security from a different perspective. As critical infrastructure technology becomes more complex, it is even more crucial for PSE to adapt and mature cyber-security practices and programs allowing the business to take advantage of new technical opportunities such as Internet of Things (IoT) devices. In addition, we continue to foster strong working relationships with technology vendors to ensure their approach to cyber-security matches PSE's expectations and needs.

Backbone Infrastructure Projects

Finally, PSE will continue to upgrade its local transmission system in order to meet NERC compliance requirements and evolving regulations related to DER integration and markets and meet peak demand reliably. PSE will deploy identified, project-specific non-wires solutions to support the near-term integration of DERs and continue to validate the DER forecast to realize predicted solutions to meet resource needs.

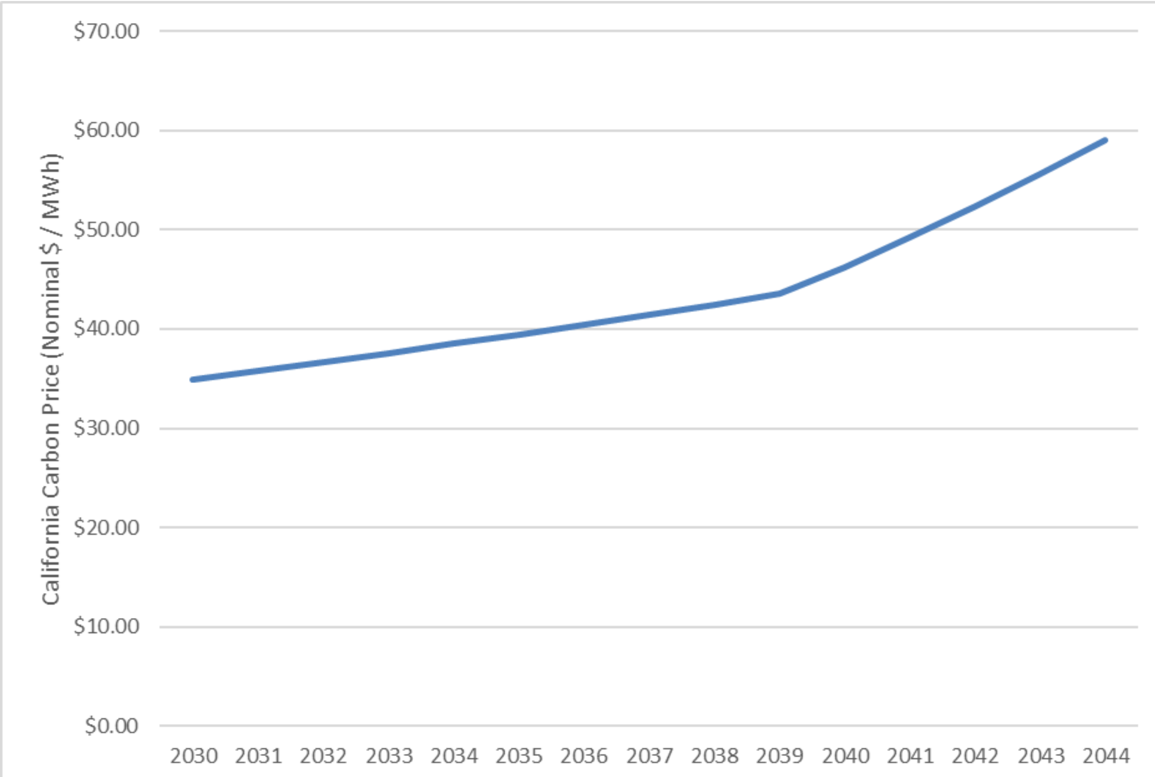
5. ALTERNATIVE COMPLIANCE OPTIONS

Under CETA, up to 20 percent of the 2030 greenhouse gas neutral standard can be met with an alternative compliance option. These alternative compliance options can be used beginning January 1, 2030 and ending December 31, 2044. An alternative compliance option includes any combination of the following:

- making an alternative compliance payment in an amount equal to the administrative penalty
- purchasing unbundled renewable energy credits
- investing in energy transformation projects that meet criteria and quality standards developed by the Department of Ecology, in consultation with the Department of Commerce and the Commission

In this IRP, PSE evaluated two alternative compliance options. For the first option, PSE assumed that unbundled renewable energy credits would be purchased for 20 percent of load not met by renewable generation starting in 2030 and decreasing linearly to zero in 2045. Because there is no a transparent forecast of the future price of unbundled renewable energy credits, PSE used the California carbon price as a proxy, as this may align with the requirement for greenhouse gas neutral electricity. The forecasted prices start at over $34 per MWh in 2030 and increase to $59 per MWh in 2044 as shown on Figure 2-12. The costs are included in all the portfolios as part of meeting the 2030 standard and in the preferred portfolio.

Figure 2-12: California Carbon Price Forecast (nominal $ per MWh)



In addition to using carbon prices as a proxy price for unbundled renewable energy credits, PSE also wanted to understand the impact of meeting the 20 percent of load with renewable resources such that 100 percent of PSE's load is met with renewable resources by 2030. PSE modeled two ways of meeting this requirement; with battery energy storage and with pumped storage hydro. The total 24-year NPV of this compliance option is $32 billion with batteries and $66 billion with pumped storage hydro. The costs of these two portfolios are between $16 billion and $50 billion higher than the preferred portfolio. Chapter 8 describes these portfolios in detail in Sensitivity N.

Actual compliance may be met through other mechanisms that are still under development and will be determined in the first CEIP that includes 2030, the year the greenhouse gas neutral standard takes effect. PSE will analyze these mechanisms as the Department of Ecology develops guidance on methods for assigning greenhouse gas emission factors for electricity, establishes a process for determining what types of projects qualify as energy transformation projects, and includes other options such as transportation electrification.

6. SOCIAL COST OF GREENHOUSE GASES

The social cost of greenhouse gases (SCGHG) is applied as a cost adder in the development of the electric price forecast and in the portfolio modeling process when considering resource additions. The SCGHG is not included in the final dispatch of resources because it is not a direct cost paid by customers. CETA explicitly instructs utilities to use the SCGHG as a cost adder when evaluating conservation efforts, developing electric IRPs and CEAPs, and evaluating resources options. The SCGHG cost adder is included in planning decisions as part of the fixed operations and maintenance costs of that resource, but not in the actual cost and dispatch of any resource. A SCGHG adder is also applied to the unspecified market purchases.

The SCGHG in CETA comes from the Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document, August 2016 update. It projects a 2.5 percent discount rate, starting with $62 per metric ton (in 2007 dollars) in 2020. The document lists CO_2 prices in real dollars and metric tons. PSE has adjusted the prices for inflation (nominal dollars) and converted to U.S. tons (short tons). This cost ranges from $69 per ton in 2020 to $189 per ton in 2045. Further details can be found in Chapter 5.