2021 PSE Integrated Resource Plan

4 Planning Environment

This chapter reviews the conditions that defined the planning context for the 2021 IRP. This chapter will be updated for the final IRP due in April 2021.

Contents

1. CLEAN ENERGY TRANSFORMATION ACT RULEMAKINGS

Since the passage of the Clean Energy Transformation Act (CETA) in 2019, several state agencies have been engaged in rulemakings to implement key provisions of the statute. These include the following.

1. The Washington Utilities and Transportation Commission (WUTC) – multiple topics, including the IRP, Clean Energy Implementation Plan (CEIP), and Purchase of Electricity rulemakings
2. The Department of Commerce (Commerce) – CETA rulemaking primarily for consumer-owned utilities
3. The Department of Health (DOH) – cumulative impact analysis
4. The Department of Ecology – unspecified emissions rate and energy transformation projects.

Each of these rulemaking efforts is summarized below. At the time of this writing, some topics remain unresolved in rulemaking and await further discussion and development in 2021.

WUTC CETA Rulemakings

The WUTC anticipates completing three rulemakings at the end of 2020 to implement CETA: the Energy Independence Act (EIA) Rulemaking, the IRP/CEIP Rulemaking, and the Purchase of Electricity Rulemaking. At this time of this writing, these rules are not final or in effect yet.

EIA RULEMAKING. The EIA rulemaking revises certain provisions of existing EIA rules to align with CETA and defines key terms related to the low-income provisions of CETA in RCW 19.405.120, including “low income,” “energy assistance need” and “energy burden.”

IRP/CEIP RULEMAKING. The IRP/CEIP Rulemaking outlines the timing and processes associated with filing an IRP, a Clean Energy Action Plan (CEAP) and Clean Energy Implementation Plan (CEIP). Utilities are directed to established equity advisory groups to advise utilities on equity issues, including vulnerable population designation, equity customer benefit indicator development and recommended approaches for compliance with RCW 19.405.040(8) as codified in the rule.

PURCHASE OF ELECTRICITY RULEMAKING. The Purchase of Electricity Rulemaking outlines the timing and expectations for utilities when acquiring resources that are identified as a resource need in the IRP.

In addition, the WUTC anticipates further discussions and policy development in 2021 regarding the following issues through a subsequent Markets Work Group rulemaking as required in RCW 19.405.130 or other rulemakings or policy statements.

- Non-energy benefits and the cost-effectiveness test
- No-coal attestation under CETA
- Natural gas IRP rulemaking per HB 1257
- Policy guidance for implementing Section 12 low-income provisions of CETA
- Interpreting a utility's "use" of electricity to serve customers
- Incorporating DOH's CIA into utility planning processes

Department of Commerce CETA Rulemaking

The Department of Commerce (Commerce) is charged with developing rules for implementation of CETA for consumer-owned utilities. Additionally, Commerce is responsible for developing reporting procedures for all utilities, investor-owned and consumer-owned. Commerce expects to file final rule language by the end of December 2020.

Department of Commerce CETA Low-income Draft Guidelines and WUTC Low-income Policy Development

In early 2020, the Department of Commerce released draft guidelines to support the low-income reporting requirements that utilities must meet under RCW 19.405.120 (Section 12 of CETA). Utilities provided data related to energy assistance to Commerce pursuant to the guidelines issued on November 13, 2020.

Beginning July 31, 2021, utilities must provide to Commerce a biennial assessment of the following.

- Programs and mechanisms to reduce energy burden, including the effectiveness of those programs and mechanisms for both short-term and sustained energy burden reduction
- Outreach strategies used to encourage participation of eligible households

- A cumulative assessment of previous funding levels for energy assistance compared to funding levels needed to meet 60 percent of the current energy assistance need, or increasing energy assistance by 15 percent over the amount provided in 2018, whichever is greater, by 2030; and 90 percent of the current energy assistance need by 2050.

This assessment also must include a plan to improve the effectiveness of the assessment mechanisms and strategies towards meeting the energy assistance need.

PSE anticipates that this biennial low-income energy assistance report to Commerce will be used to inform any energy assistance potential assessment that may be required in future IRP cycles.[1]

Department of Health Cumulative Impact Analysis

CETA directs the Department of Health (DOH) to develop a cumulative impact analysis (CIA) of the impacts of both climate change and fossil fuels on population health, in order to designate highly impacted communities. The results of the CIA will be used to inform power utilities' planning in the transition towards cleaner energy. While DOH set out to carry out this work collaboratively with robust input from stakeholders through work group meetings and subcommittees, DOH's plans for stakeholder engagement were scaled back in 2020 after the onset of the COVID-19 pandemic. DOH anticipated having a draft tool available by the end of November 2020 and a final CIA tool available in December 2020, but, at the time of this writing, stakeholders have not seen the tool.

Under CETA, the CIA is an important tool for informing a utility's equity-related assessment in its IRP, as well as informing its Clean Energy Implementation Plans.

Department of Ecology Rulemaking

The Department of Ecology (Ecology) is responsible for adopting rules that provide methods for assigning greenhouse gas emission factors for electricity and establishing a process for determining what types of projects may be eligible as "energy transformation projects" under CETA.

1 / See Draft WAC 480-100-620(3)(b)(iii), included as part of the UTC's IRP/CEIP Final Proposed Draft Rules published on December 4, 2020.

While Ecology's rules are not final yet, the near-final set of rules indicates that Ecology intends to adopt in its rulemaking: (1) the default unspecified emissions factor in CETA; and (2) a general process for determining eligible energy transformation projects. Ecology intends to finalize its rules at the end of 2020.

2. TECHNOLOGY CHANGES

Convergence of Delivery System Planning and Resource Planning

Traditionally, the focus of an integrated resource planning process has been to determine the lowest reasonable cost mix of demand- and supply-side resources needed to meet the total projected load and peak needs of its customers with an adequate reserve margin. For 33 states, the planning process is prepared under rules or requirements for an IRP and reviewed by state utility commissions. This is the case in Washington.

The IRP's resource planning process includes the cost of transmission and distribution infrastructure needed to connect and transmit the power from potential new generation sources; however, planning for the transmission and distribution delivery systems that ensure power can be delivered to end-use customers has traditionally been separate from the IRP process.

A variety of economic, technological and societal factors are changing the electric utility planning process and blurring the historical division between delivery system planning (DSP) and integrated resource planning. These include the increasing affordability of solar generation (including rooftop solar), the maturing of battery storage technology, electric vehicle adoption, advancements in customer management and information about electricity use, and advancements in the management and data systems used to integrate and control distributed energy technologies.

In the future, continued growth of customer solar generation and other distributed energy resources will contribute to meeting the overall resource need but will also lead to power being pushed back to a distribution feeder that was not designed for two-way power flows. This will require PSE to plan and build a grid that is different than today to capture the resource benefit effectively. The grid of the future needs to be safe, reliable, resilient, smart, clean and flexible.

Washington State's Clean Energy Transformation Act is also driving change.
It recognizes that transforming the state's energy supply requires the modernization of its electricity system and that clean energy action planning must include any need to develop new, or expand or upgrade existing, bulk transmission and distribution facilities. Additionally RCW 19.280.100, resulting from House Bill 1126, furthers this connection as energy supply

needs are met through distributed energy resources (DERs). It established a policy that guides how distributed energy resource planning processes are to occur in order to illuminate the interdependencies among customer-sited energy and capacity resources.

With this backdrop, PSE is in the process of increasing the coordination of delivery system planning with resource planning as it provides benefits by bringing together solutions to address delivery system challenges while meeting resource needs.
With the increasing maturity and feasibility of DERs, delivery system needs may be solved using these non-traditional solutions at local points or in certain areas of the delivery system. If these non-traditional resources decrease load (such as demand response programs) or provide a generation source (such as rooftop solar), they may also provide benefit to the overall energy supply resource portfolio. This creates a natural connection between DSP and energy supply resource planning.

Historically, the two planning processes have occurred on separate timelines. However, DERs installed in sufficient quantity to solve delivery system needs may change the results in the resource planning process, so coordinating the two benefits both processes and analyses. The confluence of technology, customer adoption, grid integration capability and solution effectiveness will drive the pace of interconnecting the DSP and IRP processes.

Distributed Energy Resources Planning Process

HB1126 was passed by the Washington legislature and became effective July 28, 2019. This Act relates to enabling electric utilities to prepare for the distributed energy future, adding a new section to chapter 19.280 RCW.[2] RCW 19.280.100 codified the legislation verbatim. No further rules, as defined by the Washington Administrative Code, have been developed by the WUTC at this time.

RCW 19.280.100 states that it is the policy of the state of Washington that any distributed energy resources planning process engaged in by an electric utility in the state should accomplish specified activities and considerations.[3]

Through PSE's Smart Grid Technology reporting that was required by WUTC,[4] PSE has been progressing toward planning for and integrating distributed energy resources. The following provides a highlight of how PSE has integrated this policy into its IRP and delivery system planning, recognizing that greater maturity will develop through the next planning cycle.

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2 / http://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/Session%20Laws/House/1126.SL.pdf?cite=2019 c 205 § 1
3 / https://app.leg.wa.gov/RCW/default.aspx?cite=19.280.100
4 / https://apps.leg.wa.gov/wac/default.aspx?cite=480-100-505

Statutory or Regulatory Requirement	Discussion
RCW 19.280.100. (2) (a) Identify the data gaps that impede a robust planning process as well as any upgrades, such as but not limited to advanced metering and grid monitoring equipment, enhanced planning simulation tools, and potential cooperative efforts with other utilities in developing tools needed to obtain data that would allow the electric utility to quantify the locational and temporal value of resources on the distribution system;	Appendix M describes PSE's vision including preliminary data gaps and upgrades that include investments or enhancements such as AMI, SCADA and GIS along with planning tools such as geospatial load forecasting. PSE is working with EPRI and peer utilities in the Washington Utility Symposium described in Appendix A. There will be more to learn as larger quantities of DERs are integrated.
RCW 19.280.100. (2) (b) Propose monitoring, control, and metering upgrades that are supported by a business case identifying how those upgrades will be leveraged to provide net benefits for customers;	Appendix M describes monitoring, control and metering upgrades including AMI and ADMS.
RCW 19.280.100. (2) (c) Identify potential programs that are cost-effective and tariffs to fairly compensate customers for the actual monetizable value of their distributed energy resources, including benefits and any related implementation and integration costs of distributed energy resources, and enable their optimal usage while also ensuring reliability of electricity service, such as programs benefiting low-income customers;	Programs will be identified through the CEIP process and through engagement with the equity advisory group. PSE is pursuing an Alternative Pricing pilot.
RCW 19.280.100. (2) (d) Forecast, using probabilistic models if available, the growth of distributed energy resources on the utility's distribution system;	Appendix E, Conservation Potential Assessment and Demand Response Assessment, includes a forecast of DERs

Statutory or Regulatory Requirement	Discussion
RCW 19.280.100. (2) (e) Provide, at a minimum, a ten-year plan for distribution system investments and an analysis of nonwires alternatives for major transmission and distribution investments as deemed necessary by the governing body, in the case of a consumer-owned utility, or the commission, in the case of an investor-owned utility. This plan should include a process whereby near-term assumptions, any pilots or procurements initiated in accordance with subsection (3) of this section or data gathered via current market research into a similar type of utility or other cost/benefit studies, regularly inform and adjust the long-term projections of the plan. The goal of the plan should be to provide the most affordable investments for all customers and avoid reactive expenditures to accommodate unanticipated growth in distributed energy resources. An analysis that fairly considers wire-based and nonwires alternatives on equal terms is foundational to achieving this goal. The electric utility should be financially indifferent to the technology that is used to meet a particular resource need. The distribution system investment planning process should utilize a transparent approach that involves opportunities for stakeholder input and feedback. The electric utility must identify in the plan the sources of information it relied upon, including peer-reviewed science. Any cost-benefit analysis conducted as part of the plan must also include at least one pessimistic scenario constructed from reasonable assumptions and modeling choices that would produce comparatively high probable costs and comparatively low probable benefits, and at least one optimistic scenario constructed from reasonable assumptions and modeling choices that would produce comparatively low probable costs and comparatively high probable benefits;	Appendix M, Delivery System 10-Year Plan includes major electric transmission work highlighting non-wires analysis performed for four areas to date. It also discusses pilots in the near term. Further elaboration regarding data gathered, market research, source information and peer reviewed science, will be added as this 10-year plan matures to fully support this RCW subsection. Appendix A, Public Participation, describes the stakeholder work thus far and future plans and coordination with other stakeholder requirements. PSE included a range of costs for integrating distributed energy resources as initial way to consider pessimistic and optimistic scenarios. More work will be done to build out this process.

Statutory or Regulatory Requirement	Discussion
RCW 19.280.100. (2) (f) Include the distributed energy resources identified in the plan in the electric utility's integrated resource plan developed under this chapter. Distribution system plans should be used as inputs to the integrated resource planning process. Distributed energy resources may be used to meet system needs when they are not needed to meet a local distribution need. Including select distributed energy resources in the integrated resource planning process allows those resources to displace or delay system resources in the integrated resource plan;	Chapter 5, Key Analytic Assumptions describes the DER forecast derived from a non-wires analysis that is included in the IRP which provides resource and delivery system value. Chapter 2, Clean Energy Action Plan, includes DERs from the non-wire analysis. Appendix M, Delivery System 10-Year Plan, describes the investments that will be needed to support and enable DERs identified in the IRP.
RCW 19.280.100. (2) (g) Include a high level discussion of how the electric utility is adapting cybersecurity and data privacy practices to the changing distribution system and the internet of things, including an assessment of the costs associated with ensuring customer privacy; and	Chapter 2, Clean Energy Action Plan, describes PSE's focus on cyber-security with grid modernization.
RCW 19.280.100. (2) (h) Include a discussion of lessons learned from the planning cycle and identify process and data improvements planned for the next cycle.	Lessons learned from this planning cycle will be discussed in future IRPs. Appendix M, Delivery System 10-Year Plan, discusses current data gaps that are actively being addressed.
RCW 19.280.100. (3) To ensure that procurement decisions are based on current cost and performance data for distributed energy resources, a utility may procure cost-effective distributed energy resource needs as identified in any distributed energy resources plan through a process that is price-based and technology neutral. Electric utilities should consider using competitive procurements tailored to meet a specific need, which may increase the utility's ability to identify the lowest cost and most efficient means of meeting distribution system needs. If the projected cost of a procurement is more than the calculated system net benefit of the identified distributed energy resources, the governing body, in the case of a consumer-owned utility, or the commission, in the case of an investor-owned utility, may approve a pilot process by which the electric utility will gain a better understanding of the costs and benefits of a distributed energy resource or resources.	Further work will be done through the Clean Energy Implementation Plan

New Fuel Technologies

Renewable Natural Gas

Renewable natural gas (RNG) is pipeline quality biogas that can be used as a substitute for conventional natural gas streams. Renewable natural gas is gas captured from sources like dairy waste, wastewater treatment facilities and landfills. The American Biogas Council ranks Washington 22nd in the nation for methane production potential from biogas sources, with the potential to develop 128 new biogas projects within the state. RNG is significantly higher cost than conventional natural gas; however, it provides greenhouse gas benefits in two ways: 1) by reducing CO_2e emissions that might otherwise occur if the methane and/or CO_2 is not captured and brought to market, and 2) by avoiding the upstream emissions related to the production of the conventional natural gas that it replaces.

RNG usage in both simple- and combined-cycle plants will be explored as a means of providing capacity support, in a less carbon intensive manner, to support the renewable generation required under CETA.

RNG is not yet produced at utility-scale in this region and will require developing both supply sources and an infrastructure to deliver that supply to utilities. RNG will most likely be directed toward natural gas utilities before being used as a generation fuel. The electric sector has access to a more mature set of renewable options than the natural gas sector, which include hydro, wind, solar, geothermal and energy storage systems that can capture surplus energy. Gas utilities have very few options to decarbonize, so as gas utilities begin decarbonizing their systems in earnest, markets will probably pull RNG to gas utilities before it is used broadly as generation fuel. Costs remain high to upgrade RNG to gas pipeline specifications and bring it to market. Another obstacle is that RNG currently generated in the U.S. is mostly used as a transportation fuel because of federal and state programs such as the EPA’s Renewable Fuel Standard (RFS) and California’s Low Carbon Fuel Standard (LCFS), which provide more value through generating credits than when it is used for end-use consumption or to generate electricity. However, the existing natural gas distribution network can be used to deliver renewable fuel.

HB 1257 became effective in July, 2019, and PSE is working with the WUTC and other stakeholders to develop guidelines to implement its requirements. However, recognizing the competitive nature of the existing RNG market, PSE concluded that there would be an advantage to be a first-mover. To that end, PSE conducted a RFP to determine availability and pricing of RNG supplies. After analysis and negotiation, PSE acquired a long-term supply of RNG from a recently completed and operational landfill project in Washington at a competitive price. PSE is in final design of Tariff provisions and IT enhancements to facilitate availability of a voluntary RNG program for PSE customers to take effect in the first half of 2021. RNG supply not utilized in PSE's voluntary RNG program(s) will be incorporated into PSE's supply portfolio, displacing natural gas purchases as provided for in HB 1257.

This IRP does not analyze hypothetical RNG projects that would connect to NWP or to PSE's system and displace conventional natural gas that would otherwise flow on NWP pipeline capacity. Because of RNG's significantly higher cost, the very limited availability of sources and the unique nature of each individual project, RNG is not suitable for hypothetical analysis. The benefits of RNG are measured primarily in its carbon reduction benefits, which are unique to each project. The incremental costs of new pipeline infrastructure to connect the RNG projects to the NWP or PSE system are also unique to each project. Due to the very competitive RNG development market, PSE is not prepared to analyze specific RNG projects in a public environment. Individual projects will be analyzed and documented as opportunities arise and there is further clarity of the guidelines for incorporation of RNG into PSE's supply portfolio.

In addition, PSE has a current offering called Carbon Balance which provides residential natural gas customers the choice to purchase blocks of carbon offsets for $3 each per month. The program provides customers with a way to reduce their carbon footprint through the purchase of third-party verified carbon offsets from local projects that work to reduce or capture greenhouse gases.

Biodiesel

Biodiesel is defined as a renewable resource under section 2 (34) of CETA. To be considered renewable, biodiesel must not be derived from crops raised on land cleared from old growth or first-growth forests. Biodiesel is chemically similar to petroleum diesel but is derived from waste cooking oil or from dedicated crops. According to Western Washington Clean Cities, there are two facilities in Washington state that make biodiesel, which together can manufacture 100 million gallons of biodiesel a year.[5] Biodiesel may become crucial in the future as a fuel supply for combustion turbines. These units would be the same basic generator as a natural gas combustion turbine, but instead of burning natural gas with petroleum diesel as a backup fuel, the generator would burn renewable natural gas with biodiesel as the backup fuel. This technology may be crucial to maintaining a reliable, renewable electric system during low hydro conditions.

Two primary challenges will need to be addressed for PSE to be able to use these types of combustion turbines. One is the supply-chain limit for biodiesel. Just one 229 MW renewable peaker would require 85 percent of the current estimated production capacity. Clearly, the supply chain would need to be expanded – probably by adding new production lines to existing refineries

2 / See: https://www.pscleanair.org/284/Biodiesel and using dedicated crops. The other challenge is the engineering and design of these peaking units. Biodiesel tends to burn hotter than petroleum diesel and may have higher particulate emissions. Hawaii Electric has reported thermal stress and emission rate challenges with burning biodiesel in existing units designed for conventional diesel. PSE will need to pursue research and development into how combustion turbines can efficiently burn biodiesel as a backup.

Hydrogen

Renewable hydrogen, also known as power-to-gas, is a process by which excess renewable electricity can be transformed (by splitting hydrogen from water) into hydrogen or, if combined with carbon, synthetic natural gas. These fuels can then be stored utilizing existing natural gas pipeline infrastructure to more cost effectively shift seasonal supply when mismatched with demand.

PSE is a founding member of the Renewable Hydrogen Alliance (RHA). The RHA promotes using renewable electricity to produce climate-neutral hydrogen and other energy-intensive products to supplant fossil fuel consumption. This group is instrumental in keeping PSE up to date on industry happenings.

Hydrogen, or its derivatives, can be used to reduce the GHG content of gas for gas utilities. Renewable hydrogen can be injected into the existing pipeline infrastructure. The amount of hydrogen that can be blended into the pipeline system with natural gas is limited, because hydrogen is less energy dense than current standards for pipeline quality gas. That means a cubic foot of hydrogen has less energy than a cubic foot of natural gas. Pipeline systems are required to maintain heat content within predetermined ranges for safety reasons. Gas-consuming equipment and appliances are designed to use a certain amount of gas per unit of time, so the gas feeding that equipment needs to maintain these standards. Currently, it appears the ratio of hydrogen that could be injected into the system is about 20 percent.

Hydrogen can also be used a fuel in gas combustion turbines – both simple-cycle and combined-cycle plants. The hydrogen can be blended into the upstream natural gas supply and delivered on existing infrastructure, based on the physical safety limits described above for gas utilities. Hydrogen can also be injected directly into combustion turbines or blended in higher ratios than 20 percent, if the hydrogen manufacturing, storage and delivery infrastructure is built out in the future.

A significant challenge for hydrogen is cost. Today, gray hydrogen (hydrogen manufactured with fossil fuel energy) sells for about $2 per kilogram delivered to a few key chemical market hubs, which translates to about $17.6 per MMBtu for natural gas.[6] While green hydrogen may use surplus renewable electricity that may cost less on a dollars per MWh basis, the output of a hydrogen manufacturing facility using only surplus renewable energy will be less, which will drive up the average cost per unit. That is, the region is not expected to have a surplus of baseload renewable energy any time soon, so the manufacturing process cannot be a baseload operation.

6 / See S&P Global at: https://www.spglobal.com/ratings/en/research/articles/201119-how-hydrogen-can-fuel-the-energy-transition-11740867#:~:text=S%26P%20Global%20Ratings%20believes%20hydrogen,and%20massive%20growth%20of%20renewables.&text=A%20Hydrogen%20Council%20report%20suggests,primary%20energy%20supply%20by%202050

3. WHOLESALE MARKET CHANGES

Prices, Volatility and Liquidity / August 2020 Supply Event

Wholesale electricity prices in the Pacific Northwest remain, on average, relatively low. In recent years, however, these relatively low prices have been punctuated by periods of high volatility and limited market liquidity.

On August 17, 2020, in the middle of a heat wave affecting the western U.S., the region's reliability coordinator declared an Energy Emergency Alert for PSE and four other grid operators in the WECC, indicating these entities risked not having sufficient energy supply to meet their load and reliability obligations. Wholesale market dynamics and reliance on energy transfers from neighboring entities were key factors in how this event developed in the northwest. In the day-ahead market, power prices at the Mid C hub spiked to more than five times what they were just days earlier. Offers to sell power at Mid C disappeared as available supply flowed to even higher priced delivery points in California and the desert southwest. By Monday August 17, 2020, forecasted load had increased with higher temperatures, but additional supply in the Mid C real-time market was extremely scarce. For the highest load hours of the day PSE was unable to procure power at any price. In California, the situation was even more severe, and in the days leading up to August 17, 2020, CAISO implemented rolling black-outs in order to maintain grid stability.

In its report on the August 2020 event, CAISO identifies extreme heat resulting from climate change and the evolving mix of generation resources as primary factors leading to insufficient supply conditions. As extreme temperatures become more common and traditional thermal resources continue to be replaced with variable renewable resources, high price volatility and the risk of unavailable supply are likely to be more prevalent in western U.S. wholesale power markets.

Market Developments / CAISO EDAM

In late 2018, CAISO engaged stakeholders to examine the feasibility of extending participation in its day-ahead market to entities already participating in the energy imbalance market (EIM). Potential benefits of an extended day-ahead market (EDAM) include production cost savings through more efficient use of available transmission, more efficient day-ahead unit commitment, and the creation of day-ahead base schedules at hourly granularity; diversity of imbalance reserves; and environmental benefits including reduced curtailment of renewable resources. EDAM would operate in a framework similar to EIM's approach to the real-time market, which does not require full integration into the California ISO balancing area. Participating entities and their regulatory authorities would remain responsible for transmission planning, resource adequacy and balancing area control performance.

A feasibility assessment completed near the end of 2019 identified significant benefits associated with the EDAM proposal, and stakeholder entities have since started work on more specific market design criteria. Evaluation of topics including governance, resource sufficiency requirements and the distribution of market benefits has been ongoing throughout 2020, and a final market design proposal is expected in late 2021.

4. REGIONAL RESOURCE ADEQUACY

Utilities in the Northwest Power Pool (NWPP) footprint, including PSE, are accelerating retirements of firm generating resources. Firm generators are expected to be replaced by variable renewable energy resources as a result of Washington State's Clean Energy Transformation Act and other states' and utilities' own goals and commitments focused on reducing greenhouse gas emissions. As the resource mix changes, a key challenge will be to ensure that the region maintains adequate levels of firm capacity to reliably serve load. This will require utilities to accurately assess how resources like renewables and energy storage can help maintain system reliability and what other firm generation may be needed to maintain system reliability. Resource planning in the Northwest is currently done on a utility-by-utility basis, typically through integrated resource planning processes. This utility-by-utility planning framework has worked well for the region during times when the region was surplus capacity. As large amounts of firm generators retire and several regional studies point to a capacity deficit in the next decade, utilities have growing concerns about whether the new capacity needed to maintain regional reliability can be procured in a timely manner.

As a result, utilities across the Northwest have partnered to explore a potential regional resource adequacy program. A Northwest resource adequacy program would offer two key benefits: reliability and cost savings. First, a regional resource adequacy program would ensure that sufficient generation is available to reliably serve demand during periods of grid stress. Resource adequacy programs do this by establishing transparent processes to assess, allocate and procure a region's resource needs. Second, a regional resource adequacy program would enable cost savings. By planning for the peak demand of the entire region (the coincident peak demand) instead of each utility's individual (non-coincident) peak demand, a regional approach would produce an overall lower capacity need and therefore a reduced level of investment. Furthermore, larger systems tend to require lower reserve margins because they are less vulnerable to single contingencies and variation in supply and demand.

Resource adequacy programs deliver these benefits by establishing transparent, coordinated calculations of required capacity and offering mechanisms for sharing resources among participants. A resource adequacy program in the Northwest would help the region navigate reliability and cost challenges given its evolving resource mix.

In late 2019, Northwest Power Pool (NWPP) members initiated a resource adequacy program design development process. In mid-2020, the NWPP Resource Adequacy Program Conceptual Design was completed and Southwest Power Pool (SPP) was hired to lead, in partnership with the NWPP members, the detailed design. At the time of this writing, the detailed design is underway. The detailed design process is expected to conclude in mid-2021. The timeline for the overall resource adequacy program implementation is estimated to be in 2024. PSE is actively involved in the design development process and looks to leverage program benefits.

5. FUTURE DEMAND UNCERTAINTY FACTORS

Electric Vehicles

Electric vehicles (EV) are rapidly gaining a presence in PSE's service territory and taking hold in every vehicle market. These EVs include light-duty vehicles (LDV), medium-duty vehicles (MDV), or heavy-duty behicles (HDV), both cars and trucks, and they are operated by individuals and as members of fleets. With EVs comes new electric load, which PSE is preparing for by having an EV sales and load forecast performed on its behalf, which was then incorporated into the 2021 IRP Demand Forecast. This load forecast revealed new opportunities to manage this load and improve customer experience, which PSE is investigating through a suite of EV pilot programs.

The 2021 IRP Base Demand Forecast incorporates GuideHouse's incremental EV energy forecast by excluding demand from existing vehicles. See Chapter 6, Demand Forecasts, for a discussion of base energy demand and peak impacts.

Demand Impacts

The Electric Vehicle Charger Incentive (EVCI) Pilot Program, which went into effect on May 1, 2014, allowed PSE to offer a $500 rebate to customers who purchase their own Level 2 electric vehicle charger.[7] Using data gathered through this pilot, PSE created an "Electric Vehicle Household and Charger Load Profiling" study with a study period set for 12 months ending June 2017. At the time, there were an estimated 13,140 EVs registered in PSE's electric service territory, of which 9,480 were 100 percent battery-operated (BEV) and 3,660 were plug-in hybrid vehicles (PHEV).[8]

The key findings of the study were as follows:

- On a typical weekday, hourly load per Level 2 EV charger varied between 0.1 kW and 0.9 kW while hourly load per Level 1 charger ranged between 0.06 kW and 0.6 kW.[9]
- On a typical weekend day, hourly load per Level 2 charger ranged between 0.08 kW and 0.6 kW while the range of hourly load per Level 1 charger was 0.04 kW to 0.5 kW.

7 / Docket UE-131585
8 / A list of EV's registered through the end of June 2017 was provided by Washington State Department of Licensing.
9 / The average hourly load per EV charger should not be interpreted as the hourly energy use by a typical EV charger. For example, a typical Level 2 charger uses between 1.1 kW and 2.6 kW while in use and close to zero while not in use. An individual L2 charger load shape would be characterized by a flat load at nearly zero kW for most of the day interrupted by one or more charging events which last a few hours or so per event.

- Daily peak of EV charger load occurred mostly in the early evening hours of 6:00PM to 8:00 PM, as does monthly system peak demand.
- Monthly load factor and system coincidence factor of EV charger loads are fairly low for most months. During the study period, all of the monthly load factors were below 0.29 while 8 of 12 monthly system coincidence factors were lower than 0.40. However, the system coincidence factor will become very high if monthly system peak and EV charger peak loads occur on the same day, as happened in March 2017 when the system coincidence factor was 0.91.
- Although the total load of residential EV chargers represents less than 0.7 percent of the residential class load now, it will grow rapidly to take up a significant portion of the residential class load during the next 10 to 15 years. With 250,000 EV's driven by PSE residential customers, the annual peak load of their EV chargers is estimated to be 371 MW, or over 10 percent of the residential class peak.

EVs represent a significant and unpredictable load that can be added anywhere in the system and can be coincident with peak. This presents a problem for distribution at the circuit level as unexpected demand can be rapidly added with no notice.

Influencing the Load

PSE is uniquely situated to design programs that can manage customer charging patterns in a way that mitigates this peak load increase while still maintaining a positive customer experience. In 2017, PSE surveyed customers who had received a rebate for a Level 2 charger as part of PSE's EVCI program. The survey asked – among other things – about the customer's willingness to shift their charging behavior. The results of the survey indicated that the average surveyed EV driver does not schedule a time to charge their vehicle and instead charges that vehicle during peak hours but would be willing to change that if incentivized.

While customers are willing to shift their charging behavior, the question remains as to what exactly the incentive should be. Many factors about the vehicle and its operator's current charging behavior influence the best solution to providing customers a positive experience while successfully managing the EV load. These factors include the vehicle class (LDV, MDV or HDV), the ownership type (individual or fleet), the vehicle type (BEV or PHEV), the level of charging technology used (L1, L2 or DC Fast), and the location of the charger (workplace, single family residential, multifamily residential, and public charging). Right now, PSE is gaining knowledge about each of these factors through a comprehensive suite of pilot programs so that we can devise and implement the best solutions for managing the charging load. These programs are developing electric vehicle infrastructure across PSE's service area, with targeted charging pilots for single family residential, workplace and fleet, multifamily residential and public. In addition, PSE is also operating programs to educate customers on EVs and to improve access to EVs for low income customers. While these programs, except for the single family residential program outlined below, do not have specific load management features, they are helping PSE to understand the type of charging behavior that exists in these use cases so that we can devise tailored solutions that best fit that behavior.

While most of the programs currently operated by PSE are designed to understand charging load, the single family residential pilot program also has a load-shifting component. PSE covered a significant portion of the installation cost for a smart L2 charger in 500 single family homes, then randomly sorted participants into a control group or one of four treatment groups, all of which experiment with different methods of encouraging customers to charge outside of peak hours. The degree to which participants in each group charge off peak will be compared to the control group to identify which method is the most effective in encouraging customers to shift their EV load to times that are more desirable to the utility while still maintaining a positive customer experience. PSE expects to have preliminary results of the load-shifting study in early 2021.

PSE is continuing to explore different mechanisms to manage EV charging and the associated loads through incentives and rates. These efforts will continue with future LDV EV programs and anticipated programs for fleet and commercial customers (MDV and HDV).

Codes and Standards, Energy Efficiency Technology and Electrification

This section will be completed for the final IRP in April 2021.

Distributed Energy Resources

DER-based generation, such as rooftop solar panels, has seen price declines and increases in customer adoption. DER technology is still evolving as is its rate of adoption, and therefore future demand can be significantly impacted by policy, including incentives, and technological advances, including price declines.

While PSE adoption of DER is low when compared to states like California and Hawaii, PSE residential solar is increasing by about 2,000 customers annually. Additionally, the average capacity of residential solar is increasing. In 2009, the average residential capacity was 4.7 kW while the current average system generating capacity is 10 kW. As of the end of 2020, PSE's system hosted 85 MW of net metered solar, with over 10,100, or about 1 percent, of customers participating. In comparison, for Hawaii, solar represents about 25 percent of its generation capacity and over 10 percent of its residential customers have solar generation.

Adding increasing volumes of DERs to the distribution system, whether they are generating technologies such as solar, storage technologies such as batteries, or load management tools, requires rethinking how the distribution system operates and what standards and controls are needed to maintain the safety and reliability of the system. Demand will be impacted by when and how these technologies operate, whether dependably and reliably decreasing load or intentionally increasing load if charging is allowed during peak hours.

Additionally, most customers pursing DER solutions today do not self-consume all of the energy they generate on-site in real time, making demand and power flow more variable on the local distribution system and resource management overall. Storage and control systems promise improvement to assist in managing DERs' benefits and impacts on demand, and over 4 percent of PSE's net metered solar installations include battery storage today. These emerging capabilities are maturing, and as monitoring, control, communications, delivery infrastructure and energy storage systems are modernized, opportunities to understand real demand impacts will increase.

5. GAS SUPPLY AND PIPELINE TRANSPORTATION

Risks to Gas Supply

Natural gas is imported to the Pacific Northwest, primarily from British Columbia and the Rocky Mountain region. Disruptions to natural gas transportation infrastructure, therefore, present a risk to reliable gas supply in the region.

In October 2018 the Westcoast Pipeline, a major pipeline that brings gas from British Columbia south to the U.S. border, ruptured, severely limiting the supply of natural gas to the Pacific Northwest. Through a combination of immediate conservation efforts, the shutdown of natural gas fired power plants, and curtailment of service to select industrial customers, the region only narrowly avoided destabilization of the gas transportation system and curtailment of service to large swaths of natural gas customers.

Capacity restrictions on the Westcoast Pipeline continued well into 2019 causing a dramatic increase to wholesale natural gas prices in the region. By late 2019, the pipeline had been restored to normal full capacity, and while average gas prices have generally returned to pre-event levels, prices remain significantly more volatile compared to recent historical periods.

6. PURCHASING VERSUS OWNING ELECTRIC RESOURCES

The IRP determines the supply-side capacity, renewable energy and energy need which set the supply-side targets for future detailed planning in the Clean Energy Implementation Plan, as well as the acquisition process. The formal Request for Proposal (RFP) processes for demand-side and supply-side resources are just one source of information for making acquisition decisions. Market opportunities outside the RFP and build decisions should also be considered when making prudent resource acquisition decisions.

In Build versus Buy, “Build” refers to resource acquisitions that involve PSE ownership of an asset. Ownership could occur anywhere along the development life cycle of a project. PSE could complete development activities from the beginning or buy the asset anywhere from early stage development to Commercial Operation Date (COD) or after. “Buy” refers to purchase of the output of a project through Power Purchase Agreement (PPA).

In general, quantitative and qualitative evaluations for Build and Buy proposals are conducted similarly in an RFP, consistent with WAC 480-107, solving for the lowest cost options for customers. Qualitative project risks are evaluated in the same way for both kinds of acquisitions. Quantitative evaluations for Build options include costs of ownership such as operating expenses and depreciation. These are typically embedded in the MWh price for PPAs. Build proposals include the allowable rate of return on capital assets as a cost to customers, while Buy proposals include a return on the PPA costs as allowed by the Clean Energy Transformation Act. Project designs also need to be more carefully scrutinized for projects that PSE would own and operate. Equipment selection and design specifications must meet PSE standards for ownership.

In the 2018 RFP, PSE received a large number of ownership proposals. These proposals included offers for PSE to take ownership of projects before COD, at COD and after COD. Primarily because of the fact that PSE cannot monetize federal tax incentives for renewable projects, these proposals were not competitive relative to PPAs.