Puget Sound Energy

2021 IRP Progress Report

November 15, 2019

Contents

Overview

On November 7, 2019, the Washington Utilities and Transportation Commission (WUTC) issued an order, Docket UE-180607 and Docket UG-180608 Order 2, granting a temporary exemption from the requirements of WAC 480-100-238(4)-(5) and WAC 480-90-238(4)-(5). In accordance with the order, PSE files this progress report and plans to file the next draft Integrated Resource Plan (IRP) by January 4, 2021 and the next final IRP by April 1, 2021.

This progress report reviews key updates developed during the work on PSE's 2019 IRP. It includes:

- An update on the 2017 IRP electric and natural gas action plans
- An updated electric needs analysis for capacity and renewable/non-emitting energy
- An updated power price forecast modeled with renewable portfolio standards and clean energy policies passed in 2019
- An updated natural gas needs analysis
- A summary of the public participation and consultation PSE conducted during the 2019 IRP cycle
- An update on open action items developed during the development of the 2019 IRP

The energy industry is in a state of transition as major clean energy policies are being implemented in most states, significant amounts of firm generation is being retired, new intermittent renewable generation is being constructed, and Western energy prices have become more volatile. These changes will cause PSE to make changes in how we plan, especially with regard to resource adequacy, exposure to the Mid-C bilateral spot market and the acquisition of new resources.

During the past eight months, PSE has worked diligently with WUTC staff and stakeholders to solicit public input on the model inputs, assumptions, methodology and modeling needed to ensure that PSE's IRP complies with the requirements of the Clean Energy Transformation Act (CETA). PSE appreciates the time, expertise and input of the Technical Advisory Group (TAG) and the IRP Advisory Group (IRPAG) during the 2019 IRP process. Many recommendations made by TAG members were incorporated in the 2019 effort. We will work with care and deliberation to ensure that the applicable contributions and feedback of TAG members in the 2019 process is included in the 2021 IRP.

PSE remains committed to removing coal-fired generation from its portfolio of generating resources by 2025 and transitioning PSE's electric supply portfolio to be 100 percent carbon-free by 2045. We are committed to delivering safe, dependable, reliable power to meet our customer's needs with a resource planning and acquisition strategy focused on the following key elements:

- target increased levels of conservation;
- acquire firm, dispatchable, flexible replacement capacity to meet peak capacity need, using

resources that comply with CETA;

- reduce reliance on the Mid-C bilateral spot market to meet physical peak capacity;
- acquire renewable and non-emitting resources for RPS and CETA compliance;
- explore options for energy storage, pumped hydro and battery investments as technology improves and costs decline; and
- build integrated organized regional wholesale power systems that facilitate integration of variable energy resources, optimize generation assets across a broad footprint, and reduce power costs while increasing reliability.

We look forward to working with stakeholders to develop the 2021 IRP.

Report on 2017 IRP Action Plans

Each IRP reports on the action plans developed in the previous IRP. Below are the progress reports prepared on the 2017 IRP action plans for the 2019 IRP.

2017 Electric Action Plan

Per WAC 480-100-238 (3) (h), each item from the 2017 IRP electric resources action plan is listed below, followed by the progress made in implementing those recommendations.

1. Acquire Energy Efficiency

Develop two-year targets and implement programs that will put us on a path to achieve an additional 374 MW of energy efficiency by 2023 through program savings combined with savings from codes and standards.

PROGRESS: PSE collaborated with its Conservation Resource Advisory Group (CRAG) to develop its 2018-2019 total electric conservation program savings target of 59.41aMW and is on-track to exceed that savings target. As directed by the Commission, PSE used data from its 2017 IRP to set the energy efficiency target for its 2020-2021 Biennial Conservation Plan that was filed on November 1, 2019.

2. Demand Response

Clarify the acquisition, prudence criteria and cost recovery process for demand response programs. Issue a demand response RFP based on those findings. Re-examine the peak capacity value of demand response programs in the 2019 IRP to include day-ahead demand response programs, and use the sub-hourly flexibility modeling capability developed in this IRP to value sub-hourly demand response programs.

PROGRESS: PSE is continuing to evaluate the best use cases for demand response, including its potential as a non-wires alternative for transmission and distribution investments. PSE filed a Demand Response RFP on June 11, 2018. The RFP called for demand response program offers to help meet capacity needs in program years 2019 to 2023. The RFP process is ongoing. Additional information about the RFP can be found online at www.pse.com/rfp.

3. Energy Storage

Install a small-scale flow battery to gain experience with the operation of this energy storage system in anticipation of greater reliance on flow batteries in the future.

PROGRESS: PSE installed a flow battery at the Wild Horse Wind Facility's operations and maintenance building in April 2018. Technology and performance issues resulted in less than satisfactory operation; however, this test provided PSE with opportunities to learn about flow battery technology. Ultimately, the flow battery was removed from the site after a year of trial and errors due to poor performance and physical leaks.

4. Supply-side Resources: Issue an All-source RFP

Issue an all-source RFP in the first quarter of 2018 that includes updated resource needs and avoided cost information.

PROGRESS: PSE filed an all-resource RFP on June 8, 2018. The RFP called for resources sufficient to meet PSE's need for additional capacity and renewable resources beginning in 2022 and 2023, respectively. The RFP process is ongoing. Additional information about the RFP can be found online at www.pse.com/rfp.

5. Develop Options to Mitigate Risk of Market Reliance

Develop strategies to mitigate the risk of redirecting transmission and increasing market reliance. The strategies may include:

- *Maintaining options to build capacity resources quickly;*
- *Re-examining PSE policies with regard to how much of its market reliance should managed via short-term purchases versus long-term contracts; and*
- *Working with others in the region on options for PSE to join or to help develop functioning wholesale markets that incorporate energy, capacity and flexibility services.*

PROGRESS on redirecting transmission: The strategy to redirect transmission was not selected in the all-resource RFP as part of the lowest reasonable cost solution to meet PSE's peak capacity need.

PROGRESS on building capacity resources quickly: The idea of maintaining quick-build options has been abandoned. The "shelf life" of project permits is too short to justify the expense of obtaining them for a project that is merely an option.

PROGRESS on managing short-term market risk to meet peak capacity: PSE continues to participate in the Mid-C bilateral market to make transactions to supply its energy and capacity needs. The ability to rely on a liquid Mid-C market with low price volatility has been an important part of meeting the capacity and short-term energy needs of our customers. However, short-term energy markets have become more volatile as western state policies have driven changes in the resource mix across the western interconnect.

PSE is focused on three key efforts:

1. Increase confidence that PSE and the region is resource adequate by designing and adopting uniform resource adequacy standards and methods for all balancing authorities and designated load serving entities in the region.
2. Integrate with well-designed, monitored, and regulated wholesale power markets that facilitate decarbonization in state policies, reduce power costs through production cost and investment savings, and increase system reliability.
3. Execute commercial strategies that deliver asset portfolios that meet policy objectives while maintaining system reliability for the benefit of our customers.

Resource adequacy of the region is very important to maintain physical reliability. To maintain confidence in the wholesale market and ensure that sufficient resources are installed and committed, PSE, along with Northwest Power Pool members, is designing and implementing a regional resource adequacy program. In other parts of the country, resource adequacy programs function effectively and deliver benefits by establishing transparent, coordinated calculations of required capacity and by offering mechanisms for participants to share resources. In the Northwest, a resource adequacy program would help the region navigate the challenges resulting from the region's evolving resource mix and offer two key benefits: reliability and cost savings. With regard to reliability, a regional resource adequacy program would ensure that sufficient generation is available to reliably serve demand during periods of grid stress by establishing transparent processes to assess, allocate and procure the region's resource needs. With regard to cost savings, planning for the peak demand of the entire region instead of each utility's individual peak demand would produce an overall lower capacity need and therefore a reduced level of investment. In addition, larger systems tend to require lower reserve margins because they are less vulnerable to single contingencies and variation in supply and demand. The initial design phase of the resource adequacy program is under way, with an implementation goal of 2022.

Currently, PSE utilizes approximately 1,500 MW of transmission to the Mid-C to import energy and meet its peak capacity from the wholesale market through bilateral short-term transactions. Relying on the wholesale market in this way has been a reasonable strategy, because the Pacific Northwest has historically been surplus in both energy and capacity. However, with a significant amount of firm generation announced for retirement in the next decade, PSE needs to secure firm capacity in a planned manner to maintain the resource adequacy of its system.

6. Energy Imbalance Market

Continue to participate in the California Energy Imbalance Market for the benefit of our customers.

PROGRESS: The Western Energy Imbalance Market (EIM) is a voluntary, within-hour energy market that provides Balancing Authorities another tool to reliably and economically maintain balance between electric demand (i.e., load) and supply (i.e., generating resources). It is operated by a central market operator that optimizes the generation resources of the Balancing Authorities within the EIM footprint every 15 and five minutes. The California Independent System Operator (CAISO) serves as the market operator for the EIM in which PSE operates. The EIM enables Balancing Authorities to transact with other Balancing Authorities to utilize lower-cost resources to balance load and resources. As of 2019, there are nine active participants and nine pending participants.

Active (newest to oldest)

- Balancing Authority of Northern California (Phase1) – entered 2019
- Idaho Power Company – entered 2018
- Powerex – entered 2018
- Portland General Electric – entered 2017
- Puget Sound Energy– entered 2016
- Arizona Public Service – entered 2016
- NV Energy – entered 2015
- PacifiCorp – entered 2014
- California ISO – entered 2014

Pending

- Salt River Project – entry 2020
- Seattle City Light – entry 2020
- Los Angeles Department of Water & Power – entry 2021
- Public Service Company of New Mexico – entry 2021
- Balancing Authority of Northern California (Phase 2) – entry 2021
- Avista – entry 2022
- Tucson Electric Power – entry 2022
- Tacoma Power – entry 2022
- Bonneville Power Administration – entry 2022

Participation has resulted in enhanced system reliability, more cost effective integration of variable energy resources, geographic diversity of electricity demand and generation resources, and cost savings for PSE customers. Benefits can take the form of cost savings or revenues or a combination of both. Benefits include:

- transfer revenues, which are the net of payments received or paid by PSE for the transfer of energy between EIM participants;
- dispatch benefits, which are the difference between PSE's cost to dispatch resources to meet load on its own and PSE's cost to dispatch resources according to EIM instructions;
- greenhouse gas (GHG) revenues, which are payments from CAISO to offset California GHG cost obligations; and
- flexible ramping revenues, which are payments for transfer of flexible ramping capacity between EIM participants.

CAISO reports that since 2014, the EIM has generated system-wide gross economic benefits of $736.26 million.[1] The benefits of the EIM are driven primarily by increased efficiency with respect to "inter- and intra-regional dispatch in the Fifteen-Minute Market (FMM) and Real-Time Dispatch (RTD)."[2]

PSE is also evaluating further participation in the Extended Day-Ahead Market (EDAM). EDAM is a voluntary initiative on the part of CAISO and other EIM participants to extend participation in the day-ahead market to EIM entities in a framework similar to the existing EIM approach for the real-time market.[3] The goal of the EDAM is to "improve market efficiency by integrating renewable resources using day-ahead unit commitments and scheduling across a larger area."[4]

EIM entities contracted with The Brattle Group and Energy+Environmental Economics (E3) to conduct an Extended Day-Ahead Market Feasibility Assessment, which estimates system-wide production costs savings in the range of $119 to $227 million per year.[5] In October 2019, CAISO initiated a stakeholder process to develop an approach to extend participation in CAISO's day-ahead

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[1] CAISO EIM Benefits Report, Q2 2019, p. 3.

[2] Ibid., p. 3.

[3] California ISO: Extended day-ahead market. (2019). Retrieved October 7, 2019, from http://www.caiso.com/informed/Pages/StakeholderProcesses/ExtendedDay-AheadMarket.aspx. ("CAISO Extended Day-Ahead Market").

[4] CAISO Extended Day-Ahead Market.

[5] Extended Day-Ahead Market: Feasibility Assessment Update from EIM Entities (2019). Retrieved October 7, 2019, from https://www.caiso.com/Documents/Presentation-ExtendedDay-AheadMarketFeasibilityAssessmentUpdate-EIMEntities-Oct3-2019.pdf.

market to EIM entities.[6] CAISO is planning to begin implementation in the fall of 2021 and onboard market participants in 2022.

7. Regional Transmission

Examine regional transmission needs in the 2019 IRP in light of efforts to reduce the region's carbon footprint.

PROGRESS: Regional transmission strategies are being evaluated in light of the Clean Energy Transformation Act.

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[6] California ISO. (2019). *Extending the Day-Ahead Market to EIM Entities*. *Extending the Day-Ahead Market to EIM Entities* (p. 3); Rothleder, M. (2019, September 18). California ISO: Briefing on extended day-ahead market initiative. Retrieved October 7, 2019, from http://www.caiso.com/Documents/Briefing-ExtendedDay-AheadMarketInitiative-Presentation-Sep2019.pdf.

2017 Natural Gas Action Plan

Per WAC 480-90-238 (3) (i), each item from the 2017 IRP natural gas resources action plan is listed below, along with the progress that has been made in implementing those recommendations.

1. Acquire Energy Efficiency

Develop two-year targets and implement programs to acquire conservation, using the IRP as a starting point for goal-setting. This includes 14 MDth per day of capacity by 2022 through program savings and savings from codes and standards.

PROGRESS: PSE collaborated with its Conservation Resource Advisory Group (CRAG) to develop a 2018-2019 total gas conservation program savings target of 619.5 MDth per year and is on-track to exceed that target. As directed by the Commission, PSE used data from its 2017 Integrated Resource Plan to set the energy efficiency target for its 2020-2021 Biennial Conservation Plan that was filed on November 1, 2019.

2. LNG Peaking Plant

Complete the PSE LNG peaking project located near Tacoma.

PROGRESS: Construction of the facility is under way.

3. Option to Upgrade Swarr

Maintain the ability upgrade the Swarr propane-air injection system in Renton, which the plan forecasts will be needed by the 2024/25 heating season.

PROGRESS: PSE maintains the option to upgrade the Swarr facility by the heating season studied.

Electric Resource Need

The electric resource needs that PSE analyzed for the 2019 IRP and discussed with IRP stakeholder groups are reviewed below, and include peak capacity need and renewable energy need. The resource adequacy analysis and demand forecasts on which they are based will be updated for the 2021 IRP.

Peak Capacity Need

Peak capacity need refers to the resources required to ensure reliable operation of the energy supply system. It starts with a projection of customer demand, which is then adjusted to add planning margins and operating reserve obligations. The planning margin and operating reserves are amounts of capacity over and above customer demand that are required to ensure the system has enough resources to provide the flexibility to handle balancing needs and unexpected events such as variations in temperature, hydro and wind generation; equipment failure; or transmission interruption with minimal interruption of service.

For the 2019 IRP, mid, low and high demand forecasts were developed for the planning horizon using national, regional and local economic and population data. These forecasts were then adjusted to add planning margin and operating reserves. These forecasts were presented to the IRP Technical Advisory Group at its January 2019 meeting and are available online at www.pse.com/irp. Demand forecasts are updated for every IRP and will be updated in 2020 for the 2021 IRP.[7]

Figure 1 shows the peak capacity need graph PSE discussed with the Technical Advisory Group at its September 2019 meeting. The graph shows the difference between the forecast peak load (with planning margin) and the peak capacity contribution of existing PSE resources plus any short-term bilateral market transactions for the three demand forecasts. It does not include demand-side (conservation) resources, because one of the major tasks of the IRP analysis is to identify the cost-effective amount of conservation. To do this, it is necessary to start with demand forecasts that do not include forward projections of conservation savings. Once calculated, the cost-effective conservation reduces the demand forecast and therefore the peak capacity need. At the time of this update, the cost-effective amount of conservation is not yet available for publication, so it has not been included in the graph and table below.

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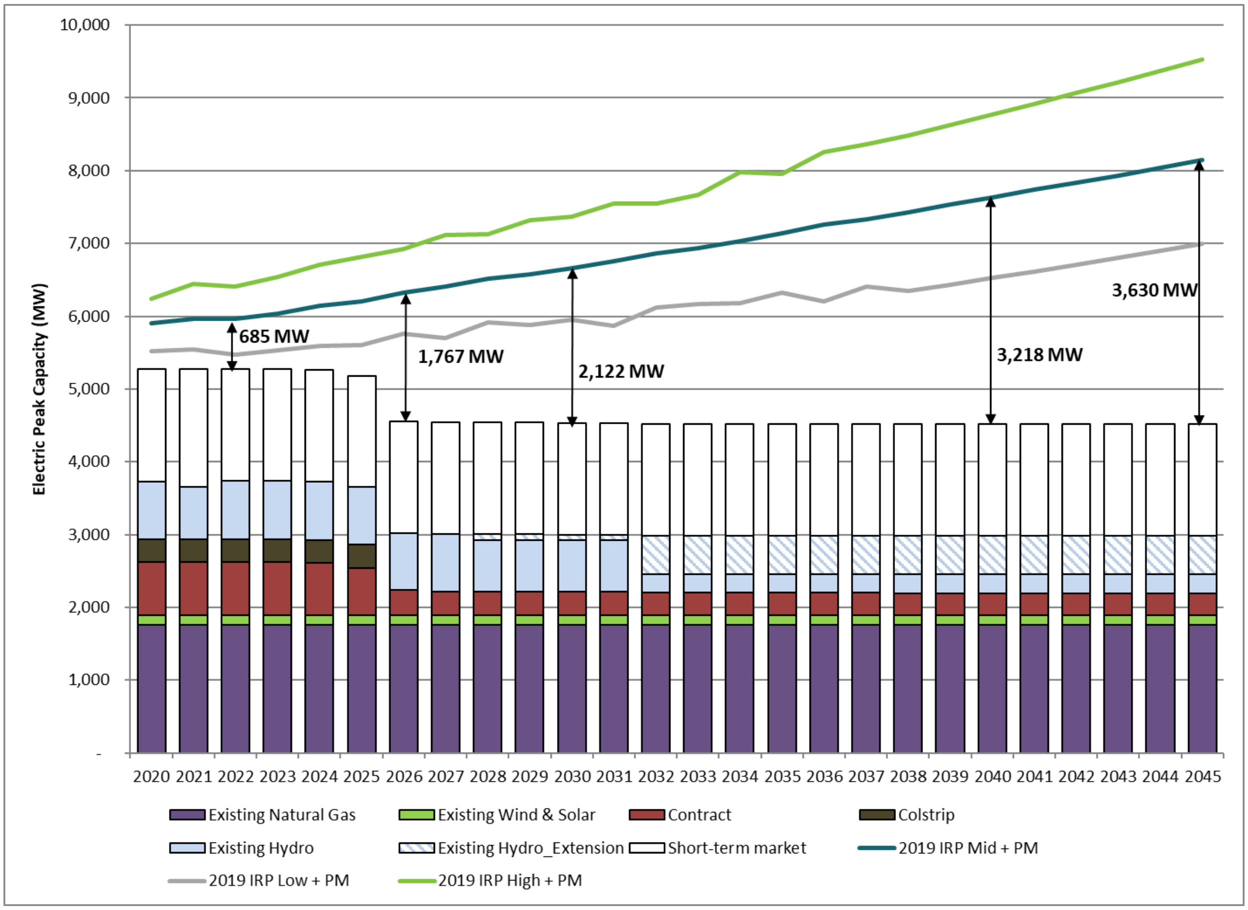
[7] When PSE issues an all-source RFP to meet capacity and/or renewable deficits, PSE updates the demand forecast and any known resource changes with the latest available information. Due to the long lead time necessary to complete the IRP analyses, it is not always possible for the IRP to use the same assumptions and inputs used in the resource acquisition process.

The graph shows that PSE's energy supply portfolio will undergo significant changes as coal resources retire. Colstrip Units 1 and 2 (approximately 300 MW) are scheduled to retire at the end of 2019. PSE's 380 MW transition contract with TransAlta will expire upon retirement of the Centralia plant at the end of 2025, and Colstrip Units 3 and 4 (approximately 370 MW) will also be removed from PSE's resource portfolio in 2025. These significant reductions in firm capacity create a peak capacity deficit in the first ten years of the planning horizon. Figure 1 does not include demand-side resources and new resources or contracts that may be acquired through the ongoing All-source RFP.

Figure 1: Electric Peak Capacity Need before Conservation



Select years are included in Figure 2 below consistent with the graph shown above.

Figure 2: Select Years of Peak Capacity Need before Conservation

	December 2022	December 2026	December 2030
Normal Peak Load	5,064 MW	5,345 MW	5,627 MW
Peak Load with Planning Margin	5,965[1] MW	6,323[2] MW	6,657 MW
Total Resources Peak Capacity Contribution	3,737 MW	3,024 MW	2,999 MW
Short-term Market Purchases	1,541 MW	1,532 MW	1,536 MW
Peak Capacity Need before Conservation	685 MW	1,767 MW	2,122 MW

NOTES

1. *The planning margin is 17.8% and includes operating reserves.*
2. *The planning margin increases to 18.3% in 2026 after Colstrip Units 3 and 4 are removed from the energy supply portfolio.*

In addition to energy and capacity, existing resources provide various attributes that supply ancillary services that help to meet system reliability needs. As PSE retires and replaces existing resources, it will be important to ensure that the new resources either provide these same attributes or other mechanisms will need to be put in place. A summary of these attributes is presented below.

Figure 3: Attributes of Existing Generating Resources

	Essential Reliability Services (Frequency, Voltage, Ramp Capability)				Fuel Assurance			Flexibility				Other	
			Ramp										
Resource Type	Frequency Response (Inertia & Primary)	Voltage Control	Regulation/Load Following	Contingency Reserve	Not Fuel Limited (> 72 hours at Eco. Max Output)	On-site Fuel Inventory	Dual Fuel	Cycle	Short Min Run Time (<2 hrs)/ Multiple Starts Per Day	Dispatchability	Startup/Notification Time < 30 Minutes	Black Start Capable	No Environment Restrictions (That Would Limit Run Hours)
Hydro - PSE Owned	●	●	◓	●	◓	◓	○	●	●	●	●	◓	○
Hydro - MidC	●	●	●	●	◓	◓	○	●	●	●	●	○	○
Natural Gas - Combined Cycle Combustion Turbine	◓	●	●	◓	●	◓	◓	●	○	●	○	○	○
Natural Gas - Simple Cycle Combustion Turbine	●	●	●	●	●	●	●	●	●	●	●	◓	○
Coal - Steam	●	●	○	●	●	●	○	◓	○	●	○	○	○
Wind	◓	◓	◓	○	○	○	○	●	●	○	●	○	●
Battery/Storage	◓	◓	○	○	○	○	○	●	●	●	●	○	●
Solar	○	○	○	○	○	○	○	●	●	○	●	○	●
Purchases	●	○	○	○	○	○	○	○	○	◓	○	○	○

Planning Margin

PSE performs a capacity planning standard analysis is to determine the appropriate level of planning margin for the utility. Planning margin for capacity is defined as the level of generating resource capacity reserves required to provide a minimum acceptable level of service reliability to customers under peak load conditions. PSE incorporates a planning margin that achieves a 5 percent loss of load probability (LOLP) in its description of resource need. The 5 percent LOLP is an accepted standard resource adequacy metric used to evaluate the ability of a utility to serve its load.

Using the 5 percent LOLP metric, we determined that PSE needs 685 MW of firm capacity by 2022. The 685 MW need in December 2022 was calculated with Colstrip Units 1 & 2 retired.

The following figure summarizes the winter peak capacity forecast for PSE's existing supply-side resources for December 2022. It includes a total of 2,075 MW of BPA and PSE-owned transmission capacity available. A portion of this capacity, 516 MW, is allocated to long-term contracts and existing resources such as PSE's portion of the Mid-C hydro projects. This leaves 1,541 MW of capacity available for short-term Mid-C bilateral market transactions.

Figure 4: Existing Supply-side Resources

Type of Generation	Nameplate Capacity	2022 Winter Peak Capacity
Hydro	950 MW	800 MW
Colstrip	370 MW	314 MW
Natural Gas	1,905 MW	1,761 MW
Renewable Resources	1112 MW	131 MW
Contracts	817 MW	731 MW
Total Supply-side Resources	5,154 MW	3,737 MW
Short-term Market Purchases	2,075 MW	1,541 MW
Total Supply-side Resources	7,229 MW	5,278 MW

The 685 MW capacity need translates to a 17.8 percent planning margin, including operating reserves. A summary of the calculation is shown in the table below. In the 2017 IRP, the planning margin to maintain a 5 percent LOLP was 13.5 percent, but did not include operating reserves. The planning margin increases to 18.3 percent in 2026 after Colstrip Units 3 and 4 are removed from the energy supply portfolio.

The planning margin (expressed as percent) is determined as:

Planning Margin = (Peak Need – Normal Peak Load) / Normal Peak Load,

Where Peak Need (in MW) is the resource capacity that meets the reliability standard established in a probabilistic resource adequacy model (Peak Capacity Need from LOLP) in addition to the peak capacity contribution from existing resources (Total Resources) and short-term Mid-C bilateral market purchases.

Figure 5: Planning Margin Calculation

	Winter Peak Without Colstrip 1 & 2	Winter Peak Without Colstrip 1 - 4
Peak Capacity Need to meet 5% LOLP	685 MW	1,026 MW
Total Resources Peak Capacity Contribution[1]	3,737 MW	3,423 MW
Short-term Market Purchases	1,541 MW	1,541 MW
Peak Need	5,963 MW	5,990 MW
Normal Peak Load	5,064 MW	5,064[2] MW
Planning Margin	17.8%	18.3%

NOTES

1. *Does not include demand-side resources.*
2. *Colstrip Units 3 and 4 are expected to be removed from PSE's portfolio in 2026 however the resource adequacy analysis was conducted for 2022-2023 and therefore uses the 2022 normal peak load to maintain the 5% LOLP.*

Renewable Energy Need

Washington State has two renewable energy requirements. The first is a renewable portfolio standard (RPS) which requires PSE to meet specific percentages of our load with renewable resources or renewable energy credits (RECs) by specific dates. Under the statute (RCW 19.285), PSE must meet 15 percent of retail sales with renewable resources by 2020. PSE has sufficient qualifying renewable resources to meet RPS requirements until 2023, including the ability to bank RECs. Existing hydroelectric resources may not be counted towards RPS goals except under certain circumstances for new run of river plants and efficiency upgrades to existing hydro plants.

The second renewable energy requirement is Washington State's Clean Energy Transformation Act (CETA). CETA requires that at least 80 percent of electric sales (delivered load) in Washington state must be met by non-emitting/renewable resources by 2030 and 100 percent by 2045. The difference between CETA and RCW 19.285 is that hydro resources are qualifying renewable resources for compliance with CETA, and other non-emitting resources can be used to meet the requirements. Under normal hydro conditions, PSE will meet 31 percent of sales with renewal resources in 2020.

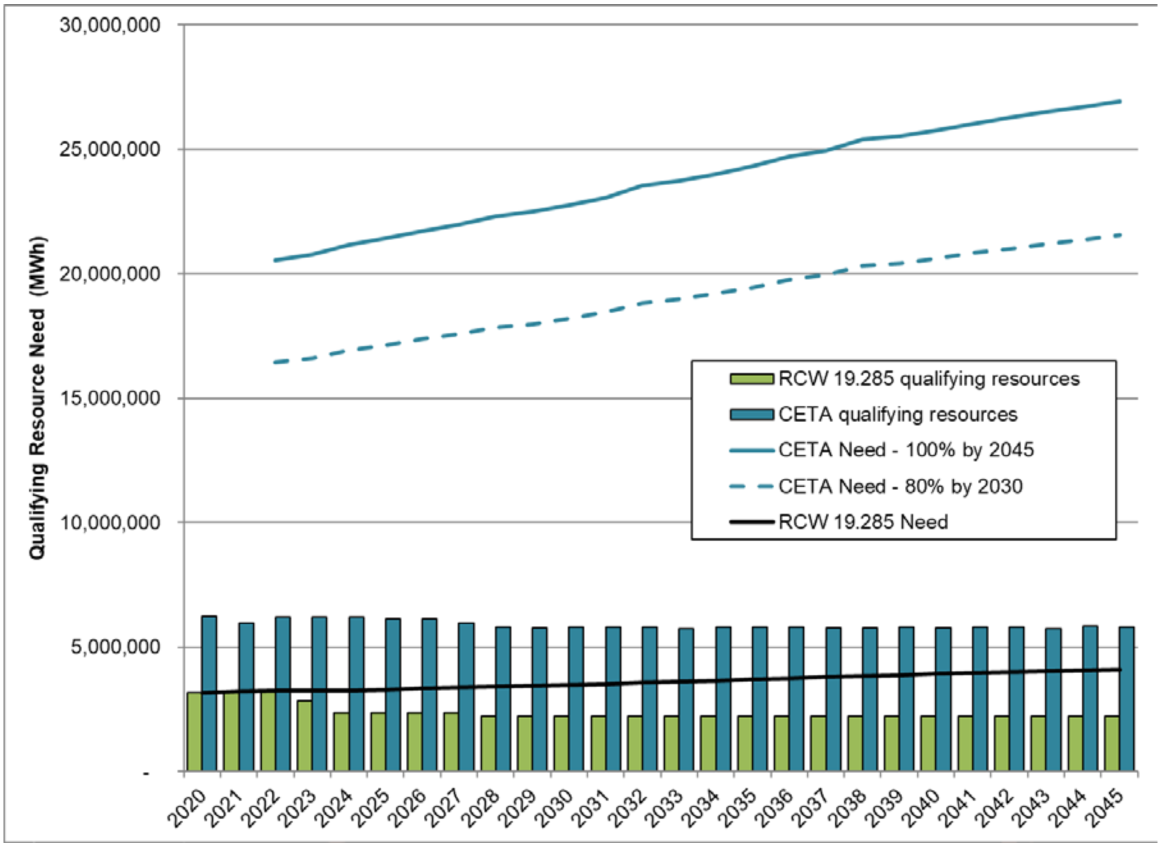
Washington State's RPS and renewable energy requirements calculate the required amount of renewable resources as a percentage of megawatt hour (MWh) sales; therefore, when MWh sales decrease, so does the amount of renewables we need. Achieving demand-side resources targets has precisely this effect. Demand-side resources decrease sales volumes, which then decreases the amount of renewable resources needed.

Figure 6 below illustrates the renewable energy need for both RCW 19.285 and CETA. The need is based on the mid demand forecast produced for the 2019 IRP. Any future conservation efforts and demand-side resources that may decrease the demand forecast are not included for the reasons explained previously.

In the chart, the green bars represent the existing renewable resources that qualify for RCW 19.285 and the black horizontal line shows the RPS need. With the existing resources and REC banking, PSE has a deficit of 398,053 RECs by 2023 and 885,700 RECs by 2024. The teal bars represent the existing renewable resources that qualify for CETA. The teal dashed line is PSE's load, before conservation, and represents the CETA requirement that 80 percent of electric sales (delivered load) must be met with non-emitting/renewable resources by 2030. The teal solid line represents the CETA requirement that 100 percent of electric sales must be met with non-emitting/renewable resources by 2045.[8] The CETA "need" will change with changes in delivered load, conservation, voluntary renewable energy programs, and other programs. Actual compliance requirements are not yet known and the graph is included for illustration only. Nevertheless, PSE will have a significant renewable resource need to meet CETA requirements.

[8] In calculating CETA need, the 2019 IRP mid demand forecast is adjusted for customer programs.

Figure 6: Qualifying Energy Need to Meet RCW 19.285 and CETA Requirements

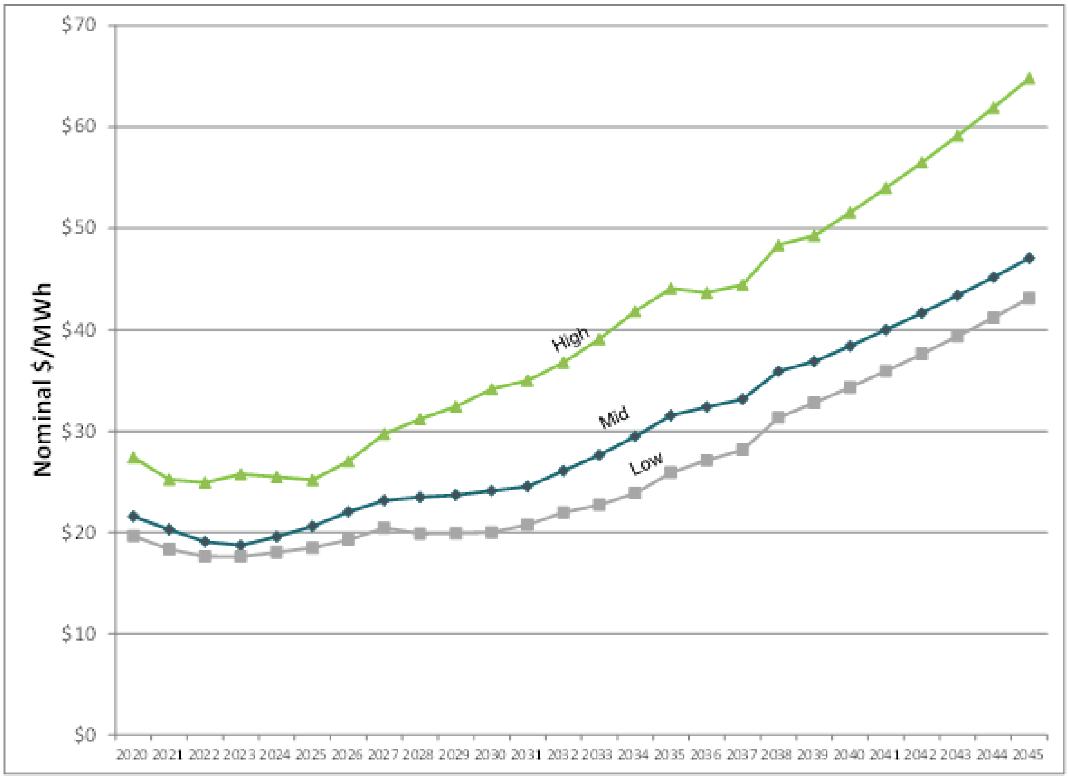


Power Price Forecast

PSE created wholesale power prices for three scenarios to capture the different sets of economic assumptions and future power market conditions. The power price forecast represents the price to PSE of purchasing (or selling) one megawatt of power on the wholesale market, given the economic conditions that prevail in that scenario. The IRP Technical Advisory Group provided input on the development of wholesale power prices through the public participation process.

PSE models wholesale power prices using the WECC-wide AURORA model and includes updates to regional demand, natural gas prices, gas pipeline adders, variable operations and maintenance costs, CO_2 prices, renewable portfolio standards requirements, and resource retirements and builds. The figure below shows the three power price forecasts produced. PSE incorporated renewable portfolio and clean energy standards passed in 2019 including California Senate Bill 100, New Mexico Senate Bill 489, Nevada Senate Bill 358 and Washington Senate Bill 5116. The social of cost of carbon planning adder defined by the CETA was used when making decisions to add or retire resources. The low, mid and high power price forecasts represent low, mid and high regional demand and gas price assumptions. PSE provided the power price forecast results to the IRP stakeholders at the September 2019 Technical Advisory Group meeting. The full presentation and meeting summary are available at www.pse.com/irp.

Figure 7: Annual Average Mid-C Power Price Forecast



Natural Gas Resource Need

PSE's natural gas sales need is driven by peak day demand, which occurs in the winter when temperatures are lowest and heating needs are highest. The current design standard ensures that supply is planned to meet firm loads on a 13-degree design peak day, which corresponds to a 52 Heating Degree Day (HDD).[9] Two primary factors influence demand, peak day demand per customer and the number of customers. The heating season and number of lowest-temperature days in the year remain constant and use per customer is growing slowly, if at all. The biggest factor in determining load growth at this time is the increase in customer count.[10]

The IRP analysis tested three customer demand forecasts over the 20-year planning horizon: mid, high and low demand forecasts.

- In the low demand forecast, we have sufficient firm resources to meet peak day need throughout the study period.
- In the mid (base) demand forecast, the first resource need occurs in the winter of 2022-2023.
- In the high demand forecast, the first resource need occurs immediately.

Mid, low and high demand forecasts were developed for the 2019 IRP planning horizon using national, regional and local economic and population data. These forecasts were presented to the IRP Technical Advisory Group at its September 2019 meeting and are available online at www.pse.com/irp. Demand forecasts are updated for every IRP and will be updated in 2020 for the 2021 IRP.

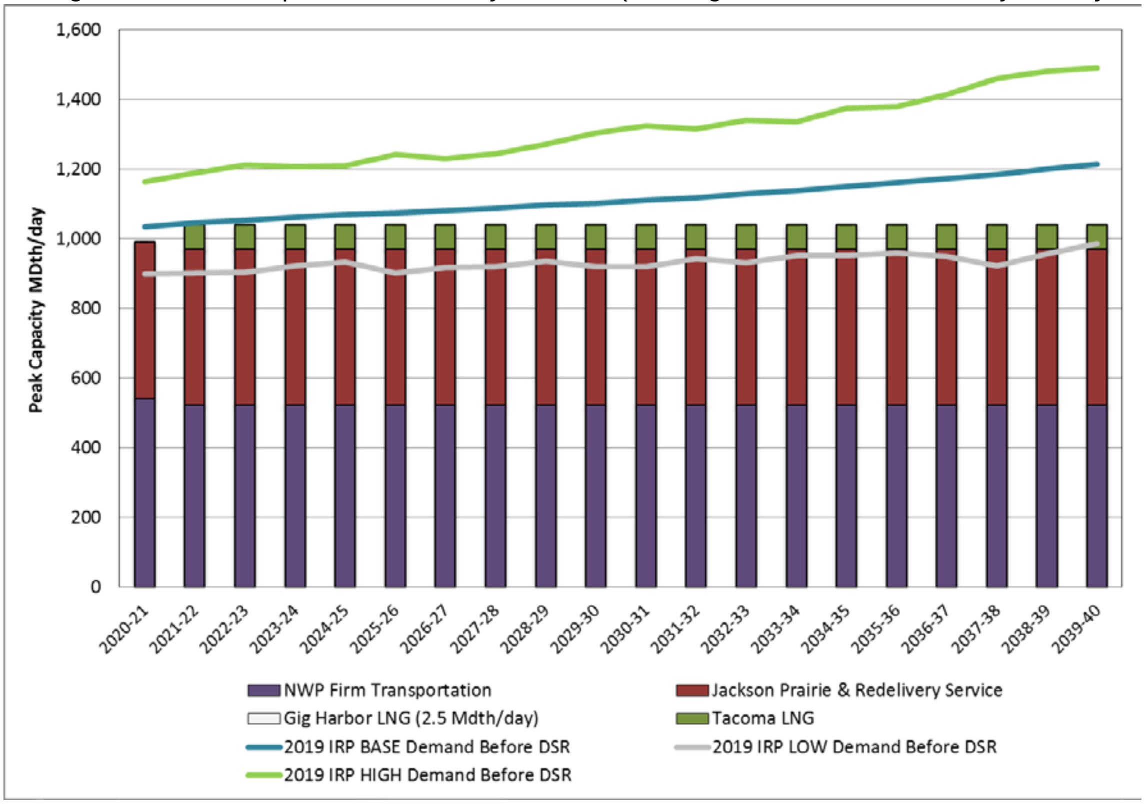
Figure 8 illustrates natural gas sales peak resource need over the 20-year planning horizon for the three demand forecasts modeled in this IRP. Figure 9 shows the resource need surplus/deficit for the base (mid) demand forecast.

9 / Heating Degree Days (HDDs) are defined as the number of degrees relative to the base temperature of 65 degrees Fahrenheit. A 52 HDD is calculated as 65° less the 13° design peak day temperature.

10 / The 2019 IRP demand forecast projects the addition of approximately 12,000 natural gas sales customers annually on average.

In Figure 8, the lines rising toward the right indicate peak day customer demand before additional demand-side resources (DSR),[11] and the bars represent existing resources for delivering gas supply to our customers. These resources include contracts for transporting natural gas on interstate pipelines from production fields, storage projects and on-system peaking resources.[12] The gap between demand and existing resources represents the resource need.

Figure 8: Gas Sales Peak Resource Need before DSR,
Existing Resources Compared to Peak Day Demand (Meeting need on the coldest day of the year)



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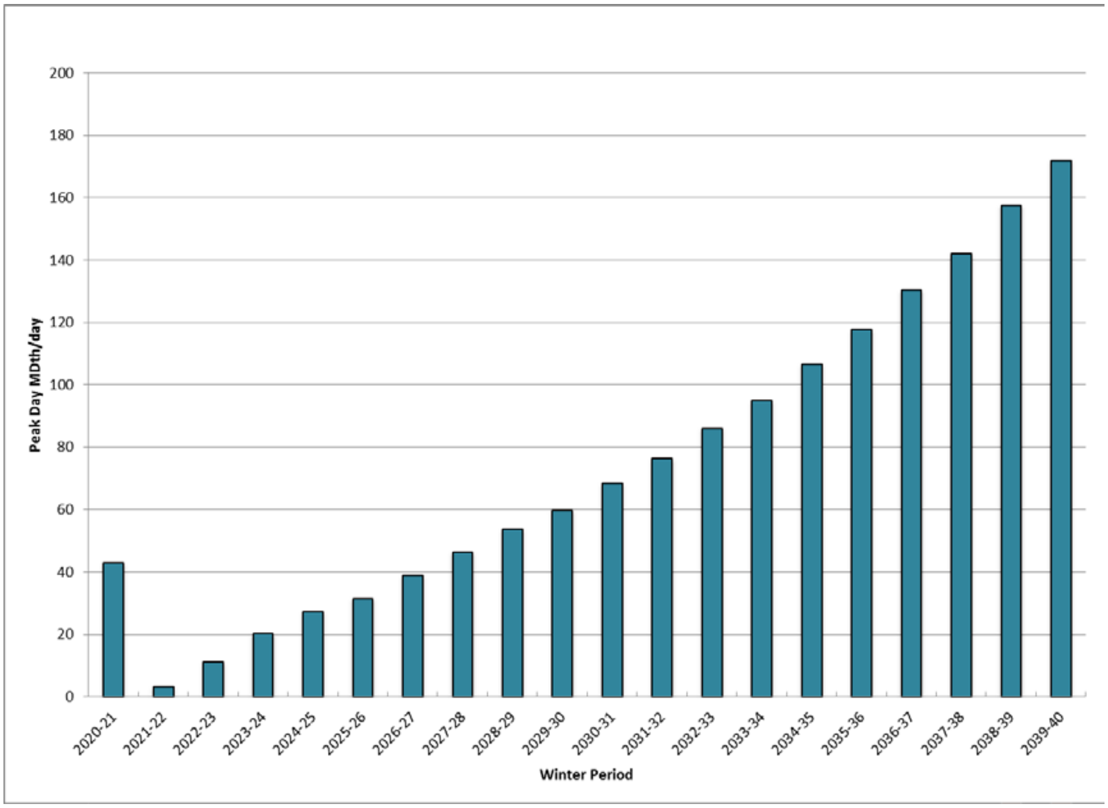
11 / One of the major tasks of the IRP analysis is to identify the most cost-effective amount of conservation to include in the resource plan. To accomplish this, it is necessary to start with demand forecasts that do not already include forward projections of additional conservation savings. Therefore the IRP gas demand forecasts include only demand-side resources (DSR) measures implemented **before** the study period begins in 2020. These charts and tables are labeled “before DSR.”

12 / Tacoma LNG is shown as an existing resource, as the facility is currently under construction and anticipated to be in service and available by the winter of 2021-2022.

Figure 9: Gas Sales Peak Resource Deficit in Mid (Base) Demand Forecast before DSR



Public Participation

To date, the development of PSE's Integrated Resource Plan was informed by participation and input from more than 30 stakeholder groups, plus interested members of the public and customers.

Two chartered groups in particular were integral to the public participation process: the Integrated Resource Plan Advisory Group (IRPAG), which was designed for non-technical stakeholders to learn about, provide input on and contribute to the IRP, and the Technical Advisory Group (TAG), which was created specifically to address more technical aspects of the IRP and assist PSE staff in the development of the analysis. TAG members applied and were nominated by IRPAG stakeholders and PSE with input from the WUTC, and they brought technical expertise in energy resourcing, transmission, utilities, conservation and economics.

Between May 2018 and November 2019, 10 formal meetings will have been held, as well as dozens of informal meetings, phone and email communications. These meetings and exchanges generated valuable constructive feedback, and the suggestions and practical information received from organizations and individuals helped to guide both the public participation process and the development of the plan. We thank those who took part for both the time and energy they invested, and we encourage their continued participation.

To support the 2019 TAG and IRPAG groups, external stakeholder engagement specialists helped set up the charters for the 2019 TAG and IRPAG groups, provided independent meeting facilitation, developed meeting and public comment guidelines, assisted with the documentation of meeting notes, and suggested adjustments to the meetings to promote communication and stakeholder engagement.

In response to input from these groups, PSE made improvements throughout the process to enhance communication, transparency and accountability. These improvements included:

- A listening session with PSE senior leadership was added.
- Presentation materials were distributed via email and posted to www.pse.com/irp one week prior to each meeting.
- Draft meeting summaries were distributed to TAG members within two weeks of each meeting. TAG members were provided a week for review, comment and clarification, and the project team posted final meeting summaries to www.pse.com/irp within four weeks of each meeting.
- Each meeting included dedicated time for public comment. Comment guidelines were adhered to at each meeting.
- Progress on action items was reviewed and tracked throughout the process.

- Public observation of TAG meetings was encouraged, and TAG members also participated in IRPAG meetings.
- Time for discussion between TAG members and the PSE team was added at the start of TAG meetings.
- All meeting schedules, agendas, materials, communications and summaries are posted online at www.pse.com/irp.
- A public comment portal was added to PSE's IRP website and all comments were posted to the site. PSE posts responses to comments in a monthly report.
- IRPAG meetings were moved to evening hours to make participation easier.
- Call-in numbers were provided for those who could not attend meetings in person.

Public input is valuable in the development of the IRP and PSE will continue to implement improvements in its stakeholder engagement process.

IRPAG Meetings

The IRPAG is a forum for non-technical stakeholders to learn about, provide input on and contribute to the IRP. It is open to all members of the public and represents a wide range of community, environmental and faith-based organizations. Participants included parents, grandparents, community activists, concerned citizens, outdoors people, naturalists, doctors, teachers and many other professions. Many were PSE customers, and some were non-customers who were interested in Pacific Northwest and global energy issues. The IRPAG provided input related to demand, public interest in conservation and other IRP-related topics.

The IRPAG met three times during the development of the 2019 IRP. Participation ranged from about 30 individuals at the smallest meeting to about 150 individuals at the largest. IRPAG meetings lasted between three and four hours.

Because the meetings were intended to promote education and understanding of the Integrated Resource Plan and planning process as well as to receive input, IRPAG presentations were less technical than TAG presentations. However, topics and developments in the IRPAG meetings informed the TAG meetings. TAG members often attended IRPAG meetings, and IRPAG members were welcome to attend TAG meetings.

Listening Session

The May 22, 2019, IRPAG meeting included a PSE executive listening session to provide customers and interested community members with an opportunity to present concerns about PSE's business and environmental practices. Before the listening session, David Mills, Senior Vice President, Energy Policy and Energy Supply, presented an overview of the Clean Energy Transformation Act and expressed support for and excitement about CETA and what it means for PSE and PSE's customers. PSE is grateful for the participation of the community and the thoughtful feedback that was provided over the course of four hours. Approximately 150 people attended the meeting. Sixty-seven individuals spoke, 15 provided comment via the comment portal on the website and 48 provided written comment during the meeting. All comments are recorded in the 108-page meeting summary.

TAG Meetings

The TAG was created specifically to address more technical aspects of the IRP, to provide input to PSE staff on the development of the IRP analysis, and to help address ways to improve the public meeting process. This group is new to the 2019 process. PSE, IRPAG stakeholders and groups who applied to PSE for membership nominated up to two representatives to the TAG. Fifty individuals representing 33 organizations and one individual contributor comprised PSE's 2019 TAG. These members represented a balance of industry and conservation expertise, and brought technical expertise in energy resourcing, transmission, utilities, conservation and economics. The TAG was also charged with considering other stakeholder input and other information sources in providing recommendations to PSE.

TAG meetings focused in technical detail on specific topics key to the development of the IRP. These topics appear in the meeting descriptions that follow. Attendance ranged from 23 to 36 members (not including observers), and meetings lasted from 6 hours to 8 hours.

TAG input helped shape the technical analysis of the 2019 IRP, including the inputs and assumptions used in the scenarios and sensitivities, the modeling of the Clean Energy Transformation Act and inputs to other parts of the analysis.

In late June 2018, PSE wrote to 31 Washington tribes inviting tribal participation in the 2019 IRP process. The invitations were extended to Tribal directors of economic development and Tribal Council Chairs from Irena Netik, Director Energy Supply Planning and Analytics, and Dom Amor, PSE Tribal Relations Manager. (For Tribes without economic development divisions, letters were sent to the Tribal Council Chairs.) The letters included background regulatory information concerning the IRP and invitations to participate in the IRPAG meetings and join the TAG. Relevant meeting dates were provided, along with links to PSE's online IRP documents. Of the 31 tribes invited, the Tulalip Tribe responded and was added to the TAG membership roster. PSE continued to provide the Tulalip Tribe meeting invitations and meeting materials throughout the process.

Meeting Schedule and Topics

Agendas, presentation, meeting summaries, public comments and action items are available online at www.pse.com/irp.

IRPAG 1, May 30, 2018, *South Evergreen Park Drive, Olympia, WA*

Explanation of the IRP process, discussion of IRPAG meeting expectations, and initial discussion of charter development. Overview of system planning. Public comments. Attendance: 72 participants attended in person or by phone in addition to the PSE project team. Five people spoke. All comments are recorded in the meeting summary. A record of the meeting is contained within the 13-page meeting summary.

TAG 1, July 26, 2018, *Bellevue College, Bellevue, WA*

Presentation of generic electric resource costs developed for the IRP analysis by HDR Engineering; discussion of the stakeholder participation process and charter development. Attendance: 32 TAG members and 10 observers participated in person or by phone in addition to the PSE project team. A record of the meeting is contained within the 15-page meeting summary.

IRPAG 2, August 28, 2018, *Meydenbauer Center, Bellevue, WA*

Updates to the stakeholder process and review of the IRP planning process. Presentation of load forecasts, planning standards, resource needs and electric resource costs. Attendance: 25 IRPAG and TAG members participated in person or by phone in addition to the PSE project team. Twenty-three individuals spoke during the public comment period. All comments were recorded in the meeting summary. A record of the meeting is contained within the 45-page meeting summary.

TAG 2, October 11, 2018, *Meydenbauer Center, Bellevue, WA*

Overview of analysis models; presentation of scenarios (including carbon prices, gas prices and power prices); presentation of sensitivities; discussion of gas sales resource alternatives. Attendance: 28 TAG members and 10 observers participated in person or by phone in addition to the PSE project team. Nine people spoke during the public comment period. All comments are recorded in the meeting summary. A record of the meeting is contained within the 20-page meeting summary.

TAG 3, December 6, 2018, *Hilton Bellevue, Bellevue, WA.*

Overview of demand-side resources for both electric and gas sales planning, including initial findings of the Conservation Potential Assessment (CPA) prepared by Cadmus Consulting for the IRP. Explanation of how the CPA is used in the IRP analysis. Attendance: 23 TAG members and 10 observers participated in person or by phone in addition to the PSE project team. Four people spoke during the IRP public comment period. All comments, plus two email comments, are recorded in the meeting summary. A record of the meeting is contained within the 10-page meeting summary.

TAG 4, January 9, 2019, *Hilton Bellevue, Bellevue, WA*

Discussion of delivery system planning status and progress on changes being made to incorporate non-wire alternatives and distributed energy resources. Discussion of proposed portfolio sensitivities. Presentation of the electric and gas sales demand forecasts. Attendance: 24 TAG members and six observers participated in person or by phone in addition to the PSE project team. Six people spoke during the public comment period. All comments and email comments are recorded in the meeting summary. A record of the meeting is contained within the 11-page meeting summary.

TAG 5, February 7, 2019, *Hilton Bellevue, Bellevue, WA*

Discussion of resource adequacy including: The Northwest Power and Conservation Council's regional power supply adequacy assessment; PSE electric capacity need and planning margin; effective load carrying capacity; and consultant Energy+Environmental Economics' (E3's) Pacific Northwest resource adequacy study. Presentation of the gas sales planning standard. Attendance: 36 TAG members and six observers participated in person or by phone, in addition to the PSE project team. Three people spoke during the public comment period. All comments, plus seven email comments, are recorded in the meeting summary. A record of the meeting is contained within the 21-page meeting summary.

IRPAG 3, May 22, 2019, *Hilton Bellevue, Bellevue, WA*

Executive listening session with David Mills, PSE Senior Vice President, Energy Policy and Energy Supply. Mr. Mills presented an overview of the Clean Energy Transportation Act, and the PSE team reviewed the updates being made to the IRP as a result of the Act before the listening session. Approximately 150 people attended. Sixty-seven individuals spoke, 15 provided comment via the website and 48 provided written comment during the meeting. All comments are recorded in the meeting summary. A record of the meeting is contained within the 108-page meeting summary.

TAG 6, May 29, 2019, *Hilton Bellevue, Bellevue, WA*

Review of the Clean Energy Transformation Act. Presentation of the revised IRP scenarios and sensitivities (adjusted to align with CETA goals and requirements), including carbon prices, gas prices and power prices. Discussion of upstream gas emission methodology. Brief review of progress on action items from previous TAG and IRPAG meetings. Attendance: 36 TAG members and nine observers participated in person or by phone in addition to the PSE project team. Two people spoke during the public comment period. All comments are recorded in the meeting summary. A record of the meeting is contained within the 18-page meeting summary.

TAG 7, August 6, 2019 – Canceled

Scheduled topic: discussion of Energize Eastside project and energy efficiency. This meeting was canceled due to pending appeals of the Energize Eastside South Conditional Use Permit, which was approved in June 2019. The appeal parties include TAG members, and PSE cannot give presentations or engage with appellants outside of the legal process.

TAG 8, September 19, 2019, *Hilton Bellevue, Bellevue, WA*

Overview of gas and electric modeling processes and presentation of the electric power price scenario results. Review of progress on action items from previous TAG and IRPAG meetings. Presentation of PSE's approach to addressing the social cost of carbon. Attendance: 31 TAG members and seven observers participated in person or by phone in addition to the PSE project team. No participants elected to speak during the public comment period, but TAG emails sent immediately before and following the meeting are included in the meeting record. A record of the meeting is contained within the 25-page meeting summary.

PSE cancelled the IRPAG 4 meeting scheduled for November 26, 2019 and the TAG 9 meeting scheduled for December 11, 2019. The meetings were cancelled in anticipation of a WUTC order temporarily granting an exemption from WAC 480-100-238(4) and (5) and WAC 480-90-238(4) and (5) which require electric and natural gas utilities to file IRPs every two years. The purpose of these meetings was to share the draft 2019 IRP resource plan and scenario results. PSE is not prepared to publish a resource plan that may not meet new statutory requirements and Commission's new rules currently under development.

Outstanding Action Items from the 2019 IRP

Although PSE will not file the 2019 IRP, we continue to advance the modeling in preparation for the 2021 IRP and are grateful for the valuable input the TAG members provided during the process. The following updates will be made available on our website to close out the 2019 process:

1. **Social cost of carbon webinar**: PSE plans to share the details of the social cost of carbon methodology and related results for scenarios comparing the social cost of carbon cost adder to a tax. The webinar is scheduled for the afternoon of December 11. The details of the webinar, along with all related materials, will be available at www.pse.com/irp.
2. **Listening session response**: The 108 pages of comments received during the May 2019 listening session will be categorically addressed in a separate report and published on our website.

Throughout the development of 2019 IRP, PSE tracked the action items developed by its stakeholder groups. In support of our commitment to transparency, here we report on PSE's progress in responding to the items that the TAG and the IRPAG asked us to include in the 2019 IRP filing. The list below includes a reference to the meeting when the action item was created and is followed by a progress report on each item.

1. Include carbon impact in scenarios or sensitivities. (IRPAG #1, May 30, 2018 and TAG #2, October 11, 2018).
2. Investigate converting the gas emission rate to a percentage. (TAG #2, October 11, 2018 and TAG #3, December 6, 2018, and January 9, 2019).
3. Add line miles and project status to the planned major projects list and include cost ranges. (TAG #4, January 9, 2019).
4. Include several previous IRP load forecasts in the IRP and compare those forecasts to actuals for multiple years. (TAG #4, January 9, 2019).
5. Verify the calculation used to develop the EV load as a percentage of load in 2035. (TAG #4, January 9, 2019).
6. Add a recommendation for time-of-day rate analysis to the 2019 IRP action plan. (TAG #4, January 9, 2019).

1. Include carbon impact in scenarios or sensitivities.

PROGRESS: Prior to the Clean Energy Transformation Act, TAG members discussed the range of possible of scenarios and sensitivities for capturing carbon impacts of PSE's energy supply portfolio. CETA provides requirements for PSE to use the social cost carbon when evaluating resources. PSE plans to comply with CETA and use the guidance provided in the law and by the WUTC. PSE will re-assess the range of scenarios and sensitivities for the 2021 IRP and solicit stakeholder input during the public process.

2. Investigate converting the gas emission rate to a percentage.

PROGRESS: PSE presented details of this analysis at the October 2018 and May 2019 TAG meetings and answered additional questions at the September 2019 TAG meeting. Discussion on this topic is included in the meeting notes. During the course of the development of the 2019 IRP, PSE also responded to various questions on this topic, provided subject matter experts and followed up with interested TAG members. Related correspondence on this topic and meeting notes are available at www.pse.com/irp. PSE developed the following description for expressing gas emission rates in response to this request and prepared the content below for the 2019 IRP.

UPSTREAM CO_2 EMISSION FOR NATURAL GAS

The upstream emission rate represents the carbon dioxide, methane and nitrous oxide releases associated with the extraction, processing and transport of natural gas along the supply chain. These gases were converted to carbon dioxide equivalents (CO_2e) using the Intergovernmental Panel on Climate Change Fourth Assessment (AR4) 100-year global warming potentials (GWP) protocols.[1]

For the cost of upstream CO_2 emissions, PSE used emission rates published by the Puget Sound Clean Air Agency[2] (PSCAA). PSCAA used two models to determine these rates, GHGenius[3] and GREET,[4] Emission rates developed in the GHGenius model apply to gas produced and delivered from British Columbia and Alberta, Canada. The GREET model uses U.S.-based emission attributes and applies to gas produced and delivered from the Rockies basin.

__[1]__ / Both the EPA and the Washington Department of Ecology direct reporting entities to use the AR4 100-year GWPs in their annual compliance reports, as specified in table A-1 at 40 CFR 98 and WAC 173-441-040.

__[2]__ / Proposed Tacoma Liquefied Natural Gas Project, Final Supplemental Environmental Impact Statement, Ecology and Environment, Inc., March 29, 2019

__[3]__ / GHGenius. (2016). GHGenius Model v4.03. Retrieved from http://www.ghgenius.ca/

__[4]__ / GREET. (2018). Greenhouse gases, Regulated Emissions and Energy use in Transportation; Argonne National Laboratory.

Figure 10: Upstream Natural Gas Emissions Rates

	Upstream Segment	End-use Segment (Combustion)	Emission Rate Total	Upstream Segment CO2e (%)
GHGenius	10,803 g/MMBtu	+ 54,400 g/MMbtu	= 65,203 g/MMBtu	19.9%
GREET	12,121 g/MMBtu	+ 54,400 g/MMbtu	= 66,521 g/MMBtu	22.3%

NOTE: End-use Combustion Emission Factor: EPA Subpart NN

The upstream segment of 10,803 g/MMBtu is converted to 23 lb/mmBtu and then applied to the emission rate of gas plants.

3. Add line miles and project status to the planned major projects list and include cost ranges.

PROGRESS: PSE developed the following figure in response to this request. Line miles and cost ranges are included if publicly available and the final design is complete. Projects in the planning phase do not yet have an identified solution.

Figure 11: PSE Planned Electric Major Projects

Project Name	Est in Svc.	Phase	Costs	Line Miles
White River – Electron Heights 115 kV Line Re-route to Alderton (Phase 2)	2018	Implementation/ Closeout	$8,755,773	7.2
Pierce County Transformer Addition	2018		$53,141,963	8.5
Talbot 230 kV Bus Improvements (Phase 2)	2018		$6,226,299	N/A
Bellingham 115 kV Substation Rebuild	2019		$27,678,066	N/A
Lake Hills – Phantom Lake New 115 kV Line	2019		$13,843,696	2.5
Talbot 230 kV Bus Improvements (Phase 3)	2020		$5,500,000	N/A
Sammamish – Juanita New 115 kV Line	2020		--	4.5
Energize Eastside	2020		--	32
Electron Heights – Enumclaw 55-115 kV Conversion	2020		--	21
Sedro Woolley - Bellingham #4 115 kV Rebuild and Re-conductor	2021		--	24
Bainbridge Island Transmission Project	2021		--	8
Lynden Substation Rebuild and Install Circuit Breaker	2023	Planning	--	--
Kent / Tukwila New Substation	2023		--	--
Black Diamond Area New Substation	2023		--	--
Issaquah Area New Substation	2023		--	--
West Kitsap Transmission Project	2023		--	--
Bellevue Area New Substation	2024		--	--
Spurgeon Creek Transmission Substation Development (Phase 2)	2024		--	--
Electron Heights - Yelm Transmission Project	2024		--	--
Inglewood – Juanita Capacity Project	2025		--	--

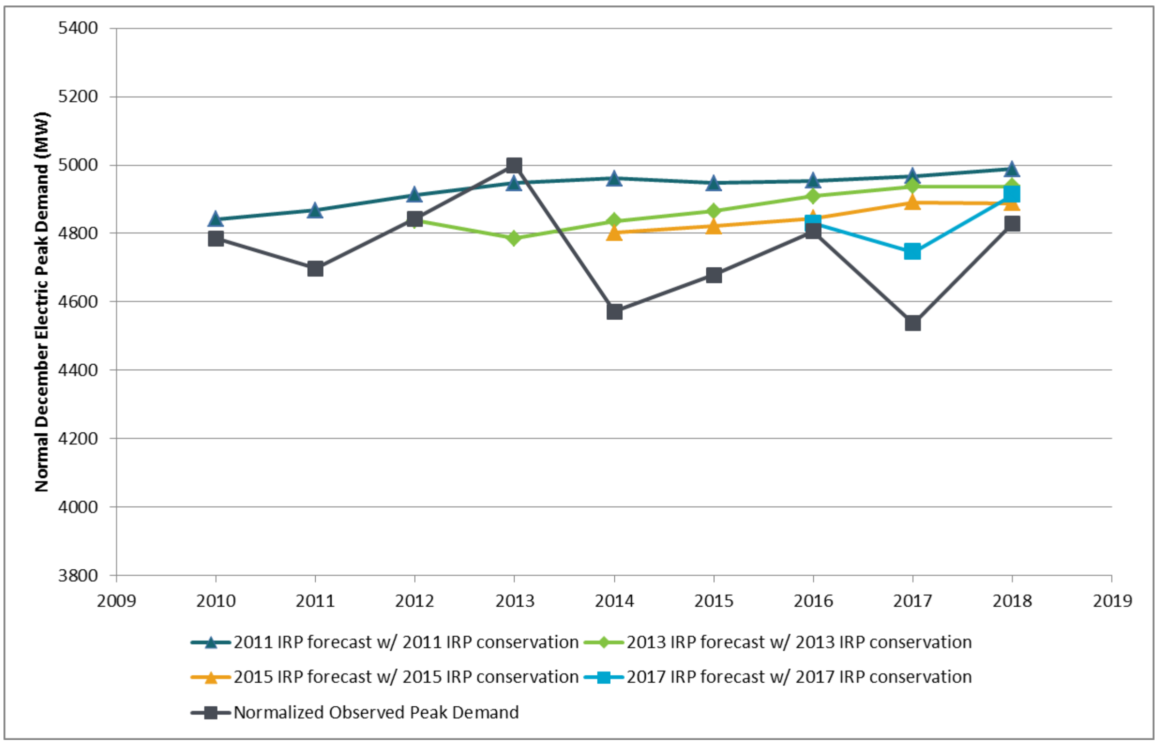
4. Include several previous IRP load forecasts in the IRP and compare those forecasts to actuals for multiple years.

PROGRESS: PSE developed the following retrospective of previous demand forecasts for the 2019 IRP in response to this request.

IRP PEAK DEMAND FORECASTS COMPARED TO ACTUAL PEAKS

Figure 12 compares the 2011, 2013, 2015 and 2017 IRP electric Base Scenario peak demand forecasts after DSR with normalized[13] actual observations. The normalized actual observations account for peak hourly temperature, monthly HDDs, and the day of week and time of day the actual peak was observed. The percent difference of normalized actual values compared to each IRP forecast is presented for each year in Figure 13.

Figure 12: Observed Normalized Electric December Peak Demand Compared to Previous IRP Forecasts



[13] / Given that the forecasts are for peaks at a design temperature, observed actual peaks are adjusted to reflect what would have been the peak if the design peak temperatures had been achieved.

Figure 13: Observed Electric Peak Demand and Difference from Previous IRP Forecasts

ELECTRIC DECEMBER PEAK DEMAND % DIFFERENCE OF IRP FORECAST VERSUS WEATHER NORMALIZED ACTUAL OBSERVATION				
Year	**2011 IRP**	**2013 IRP**	**2015 IRP**	**2017 IRP**
2010	1.2%			
2011	3.6%			
2012	1.5%	-0.1%		
2013	-1.0%	-4.3%		
2014	8.5%	5.8%	5.1%	
2015	5.7%	4.0%	3.0%	
2016	3.1%	2.1%	0.8%	0.5%
2017	9.5%	8.8%	7.8%	4.6%
2018	3.3%	2.3%	1.2%	1.7%

Similarly, weather normalized actual gas peak demand is compared to the gas peak forecasts after conservation from the 2011, 2013, 2015 and 2017 IRPs in Figures 14 and 15.

Figure 14: Observed Weather Normalized Gas Peak Demand
Compared to Previous IRP Forecasts of Gas Peak Demand

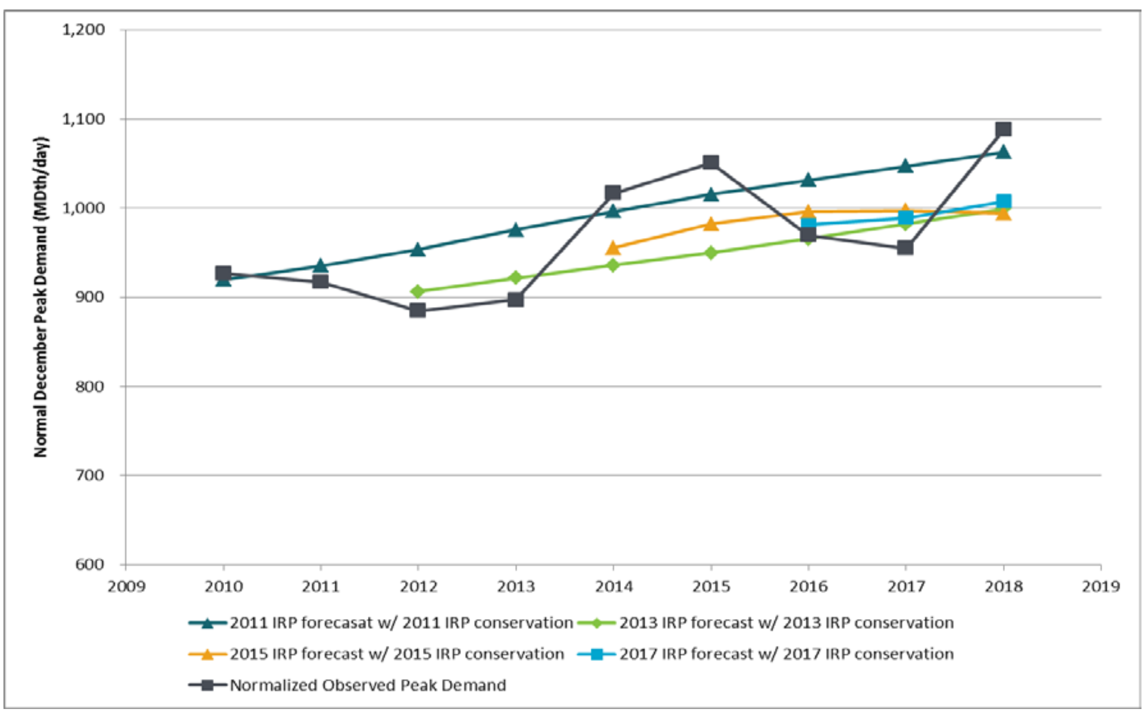


Figure 15: Observed Gas Peak Demand and Difference from Previous IRP Forecasts

GAS DECEMBER PEAK DEMAND % DIFFERENCE OF IRP FORECAST VERSUS WEATHER NORMALIZED ACTUAL OBSERVATION				
Year	**2011 IRP**	**2013 IRP**	**2015 IRP**	**2017 IRP**
2010	-0.7%			
2011	2.0%			
2012	7.8%	2.4%		
2013	8.8%	2.7%		
2014	-2.0%	-7.9%	-5.6%	
2015	-3.4%	-9.6%	-6.1%	
2016	6.4%	-0.4%	3.2%	1.2%
2017	9.7%	2.8%	5.0%	3.6%
2018	-2.3%	-8.2%	-8.2%	-7.4%

REASONS FOR FORECAST VARIANCE

The IRP peak demand forecasts are based on forecasts of key demand drivers that include expected economic and demographic behavior, conservation, customer usage and weather. When these forecasts diverge from observed actual behavior, so does the IRP forecast. These differences are explained below.

Economic and Demographic Forecasts

Economic and demographic factors are key drivers for the IRP peak demand forecast. After the 2008 recession hit the US economy, many economists, including Moody's Analytics, assumed that the economy would recover sooner than it did. A full recovery was pushed out with each successive forecast as the U.S. economy failed to bounce back to its previous state year after year. The charts below compare the Moody's forecasts of U.S. housing starts and population growth incorporated in the last five IRP forecasts (including 2019) with actual U.S. housing starts and population growth. Moody's too-optimistic forecasts of housing starts and population growth during the recession led to overestimated forecasts of customer counts.

Figure 16: Moody's Forecasts of U.S. Housing Starts Compared to Actual Housing Starts

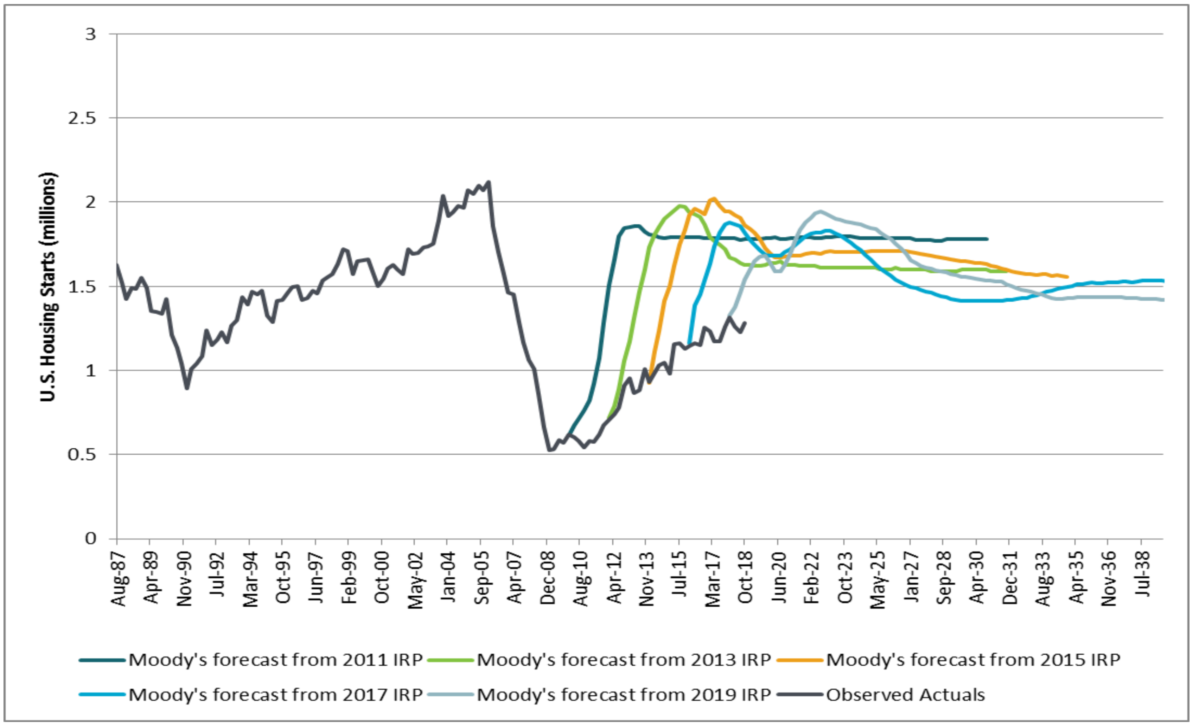
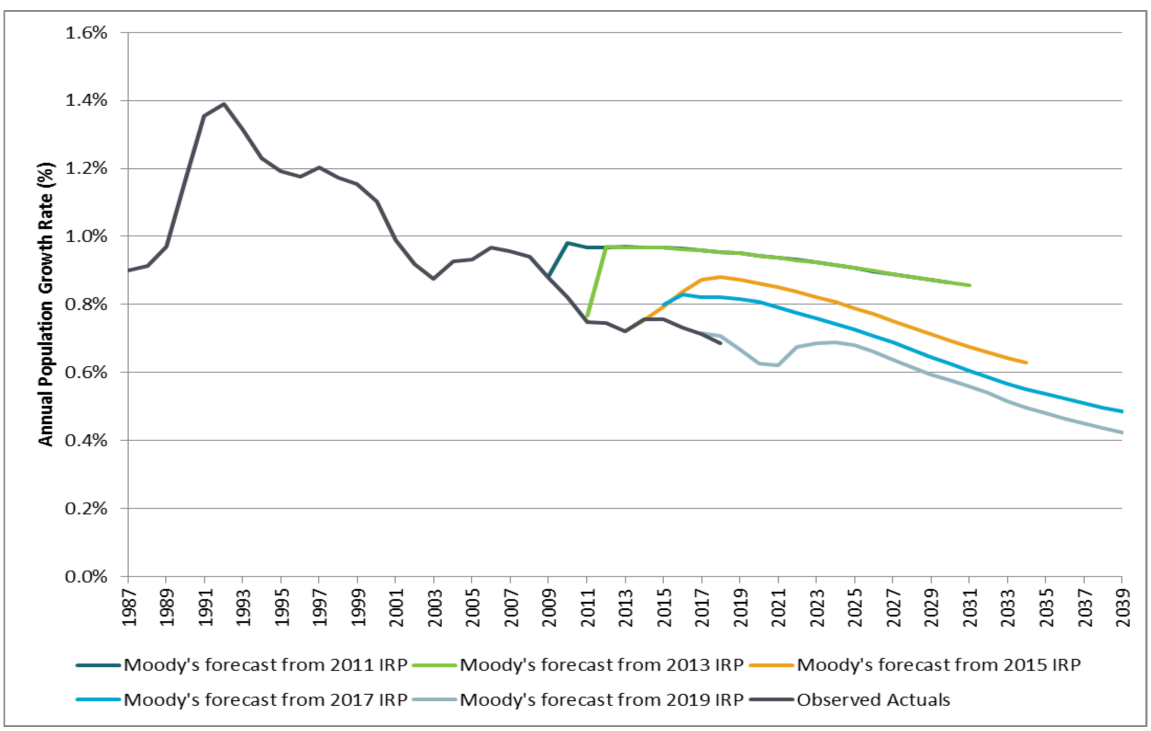


Figure 17: Moody's Forecasts of U.S. Population Growth Compared to Actual Population Growth



Conservation and Customer Usage

The comparison in Figure 12 of weather normalized peak observations to the IRP peak demand forecasts after conservation assumes that the forecasted conservation will be implemented. However, consumers can adopt energy efficient technologies that are above and beyond what is incentivized by utility-sponsored conservation programs and building codes and standards. This leads to more actual conservation taking place than forecasted. Additionally, conservation programs can change over time. Programs that were not cost effective in the past, and therefore not included in the optimal bundle, can be chosen in a later IRP as cost effective. This can make an older forecast out of date, making the forecast of conservation too low and therefore the load forecast after conservation too high.

Also, the Global Settlement from the 2013 General Rate Case (GRC) PSE accelerates electric conservation by 5 percent each year. This was taken into account in the 2015 IRP forecast and subsequent forecasts, but it was not included in conservation estimates for the 2011 or 2013 IRP forecasts after conservation.

Normal Weather Changes

Normal weather assumptions change from forecast to forecast. For each IRP, the normal weather assumption is updated by rolling off two older years of data and incorporating two new years of weather data into the 30-year average. Over time normal heating degree days have been declining and normal cooling degree days have been increasing. As temperatures change over time, the forecast of demand with normal weather changes. Additionally, over time our customers' weather sensitivity has been changing. As energy efficiency measures have been implemented, customers use less energy at a given temperature, including at peak temperatures. More recent forecasts reflect this change in weather sensitivity better than older forecasts.

Non-design Conditions during Observed Peaks

Peak values are weather normalized using the peak forecasting model. This model uses peak values from each month to create a relationship between peak demand, monthly demand and peak temperature. However, some of the observed December peaks shown above occurred on atypical days rather than typical days. For example, gas peaks in 2010, 2013, 2016, and 2017 fell on weekends, and gas peaks in 2010, 2012, and 2015 fell on New Year's Eve. Additionally, in 2014, the electric peak fell on the Monday morning after Thanksgiving weekend, and in 2015 it fell on New Year's Eve. Usage on these days is likely to be different than usage on a typical non-holiday weekday peak. Therefore, when these dates are weather normalized, they may not line up with the forecasted values since the usage patterns are atypical.

Service Area Changes

In March 2013, Jefferson County left the PSE service area. Jefferson County usage was included in the electric peak demand forecast in the 2011 IRP, therefore, when comparing that forecast to today's actuals, we would expect those forecasts to be higher than the actual peak demand.

5. Verify the calculation used to develop the EV load as a percentage of load in 2035.

PROGRESS: PSE presented the electric vehicle forecast created by E3 in 2017 during the January 2019 TAG meeting. The forecast assumes almost 22,000 light duty EVs on the road in PSE's service territory in 2020, increasing to 177,000 EVs in 2039. Annual energy usage by the additional electric vehicles adds 33,000 MWh in 2020 and 944,000 MWh in 2039. Seventy-nine percent of this charging is assumed to occur on residential accounts, while the remaining 21 percent is assumed to occur through commercial accounts. The additional energy demand by electric vehicles grows to a 3.1 percent share of total peak demand by 2035.

6. Add a recommendation for time-of-day rate analysis to the 2019 IRP action plan.

PROGRESS: PSE will add this recommendation to the 2021 IRP action plan.