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*2017 PSE Integrated Resource Plan*

## Wholesale Market Risk

*This appendix updates the original wholesale market risk study presented in the 2015 PSE IRP.*

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## 1. EXECUTIVE SUMMARY

Because PSE relies on more than 1,600 MW of wholesale market purchases to meet its current and forecasted energy and peak demand obligations, we must monitor regional resource adequacy issues closely and be prepared to modify our purchase strategy accordingly should changing conditions warrant.

For more than a decade, the Pacific Northwest region's large capacity surplus has kept wholesale power prices relatively low and made these existing resources a lower cost alternative to filling PSE's peak capacity need than building new generation. However, the long-term load/resource studies developed by the region's major energy organizations, NPCC, PNUCC and BPA,<sup>1</sup> while they differ in some details, generally point in the same direction: The current Pacific Northwest (PNW) energy and capacity surplus is expected to cross over to deficit at some point in the next decade unless new supply-side and/or demand-side resources are developed. Those studies are summarized in this chapter. Based upon current information, and assuming that all independently owned generation located within the PNW will be available to serve PNW peak loads, the region is forecast to transition from having a winter season capacity surplus of approximately 3,911 MW in 2017 to having a winter capacity deficit of approximately 2,014 MW in 2026.<sup>2</sup>

In response to the changing regional outlook, PSE presented its first analysis of wholesale market purchase risk in the 2015 IRP.<sup>3</sup> For the 2017 IRP, we refine that analysis based on the updated long-term regional resource adequacy studies performed by NPCC, PNUCC and BPA.

Fortunately, recent evidence, particularly the updated 2017 NPCC *Pacific Northwest Power Supply Adequacy Assessment for 2021 and 2022* (which was not available in time for this analysis) suggests that the region is in the process of adding new resources – mainly in the form of additional investments in conservation – to fill this forecasted resource gap. In addition, regional utility load forecast growth rates are continuing to trend downwards, thereby also closing some of the projected gap. Also, the amount of power that can be reliably imported into the region

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1 / *The Northwest Power and Conservation Council (NPCC or the Council), the Pacific Northwest Utilities Conference Committee (PNUCC) and the Bonneville Power Administration (BPA). These studies are included in Appendix F, Regional Resource Adequacy Studies.*

2 / *Based on information provided in BPA's 2016 Pacific Northwest Loads and Resources Study. The cited figures include 425 MW of long-term firm imports from California that are incorporated into the BPA Study plus an additional 3,400 MW of short-term imports from California that are assumed to be available to meet PNW winter peak loads.*

3 / *Prior to 2015, PSE IRP analyses assumed that wholesale market purchases were 100 percent reliable under all load/resource conditions. Although adequacy analyses conducted prior to 2015 had demonstrated that technically, regional capacity would be insufficient to meet firm loads in all circumstances, the region continued to pass capacity adequacy planning standards, so refining this wholesale purchase reliability assumption was not a high priority at the time.*



during winter and summer peak load events may be higher than the figures currently being used in the NPCC’s resource adequacy model. Finally, PSE’s shift to a 5 percent LOLP metric in this IRP for its capacity planning standard (as opposed to the Value of Lost Load approach used in the 2015 IRP) has resulted in a higher level of reliability being assigned to wholesale market purchases.

While uncertainties remain, there are also reasons for increased confidence. So, while there is still some level of risk to PSE in relying on wholesale market purchases in order to meet resource need, this risk appears to be significantly reduced from the level presented in the 2015 IRP due to the reasons discussed above.

Figure G-1, summarizes the findings of PSE’S 2017 wholesale market risk analysis. It shows the peak capacity contribution of wholesale market purchases to PSE’s portfolio starting in 2021.<sup>4</sup> An important finding is that while wholesale market purchases are not 100 percent reliable, they are still expected to be highly reliable given current projected regional load/resource conditions for the winter of 2020-2021.

*Figure G-1: Capacity Contribution of Wholesale Market Purchases*

Capacity Contribution of Wholesale Market Purchases	2021	
Market Reliance Capacity (MW)	1,580	
Effective Capacity Contribution	1,568	
Reduction in Capacity Contribution with Risk in Market Reliance	12	
Effective Load Carrying Capability (ELCC)	99%	(= 1,568/1,580)

It should be noted, however, that the reliability of wholesale market purchases would be expected to change as the PNW transitions from having large winter season capacity surpluses to potentially experiencing capacity deficits by 2026. Also, uncertainties remain, such as whether the region’s forecasted conservation targets will actually be achieved and the specific timing of the early retirements of some of the region’s coal-fired generating plants. Thus, it is important that PSE continue to closely monitor region’s projected winter season load/resource balance and to update its assessment of the reliability of wholesale market purchases as conditions warrant.

<sup>4</sup> / Additional details regarding the peak capacity contribution of wholesale market purchases are contained in Appendix N.



**DESCRIPTION OF THE ANALYSIS.** This analysis is designed to quantify the capacity value of wholesale market purchases in light of: 1) the 2015 & 2016 regional load/resource forecasts published by BPA and PNUCC, and 2) the 2016 regional resource adequacy assessment published by the NPCC. The goal is to better understand the physical and financial risk to PSE customers of reliance on wholesale market purchases to meet peak load needs under these forecasted regional conditions.

To accomplish this analysis, PSE aligned its Resource Adequacy Model (RAM) and Wholesale Market Curtailment Model (WCPM) with other regional reliability models in order to translate the regional load curtailment forecasts made by the NPCC's GENESYS model to PSE-level impacts. We then evaluated the capacity contribution of wholesale market purchases using the same methodology used to calculate capacity value for all other resources in this IRP, Expected Load Carrying Capacity (ELCC).<sup>5</sup> Section 3 of this appendix explains the analysis in detail.

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<sup>5</sup> / ELCC refers to the peak capacity contribution of a resource relative to that of a gas-fired peaking plant. It is calculated as the change in capacity of a generic natural gas peaking plant that results from adding a different resource with any given energy production characteristics to the system while keeping the target reliability metric constant.



## 2. REGIONAL LOAD/RESOURCE FORECASTS

### Overview

For a decade starting in the mid-2000s, the Pacific Northwest region experienced large energy and capacity surpluses. These surpluses were the result of a rush to build new generating capacity after the 2000-2001 west coast energy crisis, coupled with low natural gas prices, and followed by the subsequent slow-down of utility load growth. The resulting surpluses enabled many utilities, including PSE, to use wholesale market purchases to meet firm load obligations with a high degree of confidence in the reliability of both physical supply and reasonable prices.

Today, a different combination of forecasted circumstances could produce a capacity deficit in the region within the next 10 years. The primary factors contributing to this trend include the increasing need for balancing capacity as additional intermittent resources are added to the grid and planned generating plant retirements.

**GROWTH IN INTERMITTENT RESOURCES.** Renewable wind and solar plants have been the focus of most new construction in the region, primarily due to state-mandated renewable energy portfolio targets. The variability of these intermittent resources has substantially increased the region's need for balancing capacity.

**COAL PLANT RETIREMENTS.** Between 2019 and 2025, the Pacific Northwest will lose 2,489 MW of generating capacity and approximately 2,127 aMW of annual energy production as six coal-fired units are shut down: Valmy Unit 1 (137 MW Capacity)<sup>6</sup>, Boardman (585 MW capacity) and Centralia Unit 1 (730 MW capacity) in 2020; Colstrip Units 1 & 2 (307 MW combined capacity)<sup>7</sup> in 2022; and Centralia Unit 2 in 2025 (730 MW capacity).

In particular, the region's ability to reliably meet firm winter season peak loads and operating reserve obligations could be a concern even after including all long-term and short-term imports available from California, as will be discussed below. This situation is especially critical for PSE since PSE is a winter season peaking utility.

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<sup>6</sup> / Idaho Power's 50 percent ownership of Valmy Unit 1 (137 MW) is dedicated to serving loads located in the PNW region while NV Energy's remaining 50 percent share is dedicated to serving loads outside the region.

<sup>7</sup> / PSE's 50 percent ownership share of Colstrip Units 1 & 2 (307 MW) is dedicated to serving loads located in the PNW region while Talen Energy's remaining 50 percent share is dedicated to serving loads outside the region.



The long-term load/resource studies developed by NPCC, PNUCC and BPA differ in some details, but all of the forecasts point in the same direction: The current Pacific Northwest capacity surplus is projected to cross over to deficit at some point in the next decade unless new supply-side and/or demand-side resources are developed. These studies are summarized below, and copies or web links to the reports are included in Appendix F, Regional Resource Adequacy.

### NPCC Regional Adequacy Studies for 2021

On September 27, 2016, the NPCC published its *Pacific Northwest Power Supply Adequacy Assessment for 2021*. This study focused on the region's ability to meet the peak load planning criteria adopted by the Council, which is a 5 percent loss of load probability (LOLP). These LOLP studies incorporated complex modeling of the region's hydroelectric resources and included IPP (independent power producer) plants located in the PNW, long-term and short-term power imports from California, and existing and announced demand-side management programs. Rather than producing traditional load/resource tables, the NPCC studies produced a series of regional PNW load-curtailement events that occur under different scenarios in 2021. These scenarios model varying levels of hydro and wind generation, regional loads and thermal plant forced outages.

***The 2016 NPCC 2021 Base Case study indicates that in order for the PNW to meet the 5 percent LOLP planning standard, the region would need to add slightly over 1,000 MW of new firm, dispatchable generating capacity.***

The NPCC's 2021 Base Case assumes the following conditions.

- That approximately 700 MW of "emergency" generating resources could be used (on an annual energy-limited basis) to help meet regional peak loads, including 300 MW of backup diesel generators owned by Portland General Electric (PGE) and 300 MW at the John Keys pumped storage plant.
- That the 650 MW Grays Harbor baseload CCCT plant located in the Puget Sound area could be fully utilized to meet regional peak load needs.
- That spot market power amounting to 2,500 MW could be imported from California during winter-season on-peak hours and 3,000 MW could be imported during winter season off-peak hours.



In addition to the Base Case, the 2016 NPCC 2021 adequacy analysis also includes a Colstrip Sensitivity study that incorporates the impacts of shutting down Colstrip Units 1 & 2 in 2021. Although these units will probably not be retired until mid-2022, advance knowledge of how this change will impact the region's need for new sources of firm capacity under the current NPCC planning standard will be useful to regional resource planners.

***The 2016 NPCC 2021 Colstrip Sensitivity study indicates that in order for the PNW to meet the 5 percent LOLP planning standard, the region would need to add approximately 1,400 MW of new firm, dispatchable generating capacity.***

### 2017 NPCC UPDATE

On July 11, 2017, the NPCC published its updated *Pacific Northwest Power Supply Adequacy Assessment for 2021 and 2022*, which shows an improved outlook relative to the 2016 assessment. In the 2017 NPCC study, the 2021 Base Case indicates that in order for the PNW to meet the 5 percent LOLP planning standard, the region would need to add 400 MW of new firm, dispatchable generating capacity. The reduction in the projected 2021 regional capacity deficit from the NPCC's previous 2016 assessment is due to several factors, including lower forecasted utility winter peak load forecasts and increased regional investments in conservation. This gives us increased confidence in the reliability of wholesale market purchases. However, the NPCC also cautions that normal variations in the loads and resource forecasts incorporated into the 2017 Adequacy Assessment could change the 400 MW of new generating capacity needed in 2021 to between 0 and 1,000 MW.

This IRP wholesale market risk study was based on the NPCC's 2016 assessment because the 2017 Assessment was not available in time to be used; therefore, the IRP analysis should be considered a conservative approach to assessing the peak capacity value of market purchases.



## PNUCC Northwest Regional Forecast for 2017– 2026

PNUCC's annual *Northwest Regional Forecast of Power Loads and Resources* (the NRF) was published in April 2016 and covers the period 2017 – 2026. This analysis aggregates data from the region's electric utilities to produce region-wide load/resource projections over a 10-year time frame (net of conservation), with particular focus on annual energy and winter season capacity surpluses and/or deficits. The NRF also provides information on the amount of IPP generation located in the region that *may* be available to serve PNW firm loads.

There are several ways to look at the results of the 2016 NRF.

- The NRF 2021 forecast is based upon the utility-owned or controlled resources located within the PNW region that are known to be dedicated to serving firm PNW loads, plus 425 MW of long-term, firm purchased power agreement (PPA) imports from California; this results in a 4,800 MW deficit in 2021.
- When all IPP-owned generation located within the region is assumed to be available to serve PNW winter peak loads, the PNUCC 2021 winter capacity deficit is reduced to approximately 1,700 MW.
- When the NRF's 2021 winter capacity forecast is adjusted to include 3,400 MW of potentially available short-term imports – which PSE assumed in the Wholesale Purchase Containment Model (WPCM) – the 1,700 MW capacity deficit noted above changes to a 1,700 MW surplus.

While looking at surplus/deficit figures for the year 2021 is useful, it is even more important to recognize the long-term trend. Looking forward – based upon current information and assuming that all IPP generation will be available to serve PNW peak loads – the NRF forecasts that the region will transition from a 2017 winter season peak load surplus of approximately 2,010 MW to a peak load deficit of approximately 5,425 MW in 2026. When the NRF capacity forecast is adjusted to include 3,400 MW of short-term imports from California, the region would transition from a 2017 winter capacity surplus of 5,410 MW to a peak load deficit of approximately 2,025 MW in 2026.



## BPA Loads and Resources Study for 2017– 2026

BPA published its *2015 Pacific Northwest Loads and Resources Study* in January 2016. This study provided detailed information on BPA's forecasted loads and resources as well as overall loads and resources for the entire region. The BPA study is similar to the PNUCC study, but there are some differences, particularly in the modeling of the PNW hydroelectric system and the inclusion of non-utility owned generation located in the PNW region.

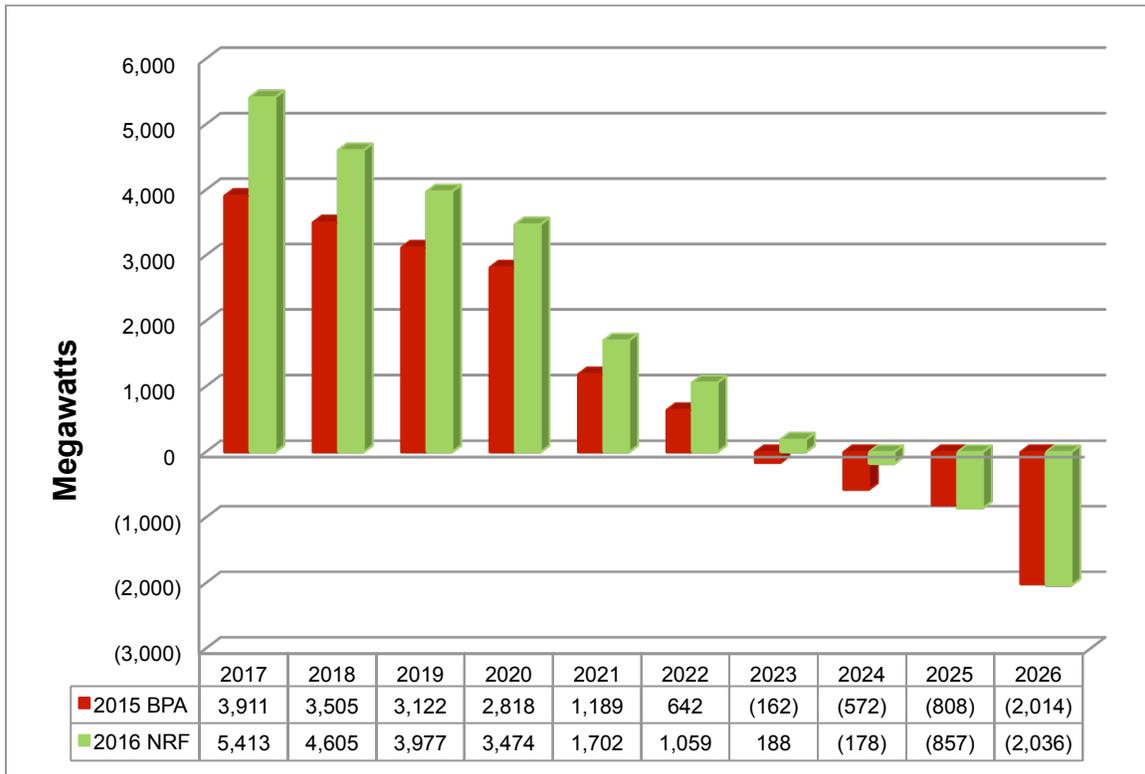
The BPA forecast used a 120-hour sustained hydro peaking methodology and assumed that all IPP generation located within the PNW is available to serve PNW peak loads. This figure includes 425 MW of long-term firm PPA imports from California, but it does not include any potentially available spot market imports.

- For 2021, the BPA study forecasts an overall regional winter peak load deficiency of 2,211 MW.
- When BPA's 2021 winter capacity forecast is adjusted to include 3,400 MW of potentially available short-term imports, the 2,211 MW capacity deficit noted above would change to a 1,189 MW surplus.
- Looking forward to 2026 – based upon current information and assuming that all IPP generation will be available to serve PNW peak loads – BPA's forecast shows that the region will transition from a 2017 winter season peak load surplus of approximately 511 MW to a peak load deficit of approximately 5,414 MW in 2026.
- When BPA's 2026 capacity forecasts are adjusted to include 3,400 MW of short-term imports from California – which PSE assumed in the WPCM – the region would transition from a 2017 winter capacity surplus of 3,911 MW to a peak load deficit of approximately 2,014 MW.

Again, the long-term winter capacity trend is perhaps more important than the exact surplus or deficit forecasted for 2021. The BPA forecast indicates, as does the PNUCC study, that the PNW is may experience larger winter capacity deficits over time. This long-term trend is illustrated in Figure G-2.



Figure G-2: 2016 PNUCC NRF Study/2015 BPA Study,  
Pacific Northwest Winter Capacity Surplus/(Deficiency), 2017-2026  
(Colstrip Units 1 & 2 retire in mid-2022.)



NOTES

1. The 2016 NRF winter capacity surplus/deficiency figures have been adjusted to include 3,400 MW of short-term imports from California and all available PNW IPP capacity.
2. The 2015 BPA winter capacity surplus/deficiency figures have been adjusted to include 3,400 MW of short-term imports from California.



### 3. WHOLESALE MARKET RELIABILITY ANALYSIS

#### PSE's Wholesale Purchase Strategy

PSE currently relies on up to approximately 1,722 MW of wholesale market purchases to meet its firm peak load obligations in the winter season. Figure G-3 compares the amount of wholesale market purchases that five PNW investor-owned utilities (IOUs) planned to use to meet forecasted 2021 peak loads (including reserve margins), according to their 2015 IRPs.

*Figure G-3: Forecasted 2021 Seasonal Peak Wholesale Market Purchases  
by PNW Investor-owned Utilities*

Investor-owned Utility	Wholesale Purchases to Meet 2021 Seasonal Peak Load (MW)
Puget Sound Energy <sup>4</sup>	1,722
Avista <sup>1,4</sup>	0 - 260
Idaho Power <sup>6</sup>	102
PacifiCorp (East and West Systems) <sup>3</sup>	1,670
Portland General Electric <sup>2,4</sup>	819

#### NOTES

1. Avista's loss of load analysis indicated that Avista could rely upon up to 260 MW of wholesale market purchases during some extreme peaking events.
2. PGE indicated that they intend to limit the amount of required winter peak spot purchases in 2021 to only 200 MW.
3. The PacifiCorp data includes both the PacifiCorp East (PACE) and PacifiCorp West (PACW) systems.
4. Puget, Portland General Electric and Avista are winter peaking utilities. In addition, the PacifiCorp West System is a winter-peaking Balancing Authority Area although the combined PacifiCorp West and East systems are summer peaking.
5. The figure cited for PacifiCorp is for the combined PACE and PACW systems for the summer of 2021. PacifiCorp's 2015 IRP Update did not provide winter 2021 peak information for the PACW System.
6. Idaho Power is a summer peaking utility. Idaho Power's wholesale purchases to meet peak load figure assumes that 390 MW of demand response is deployed.



When the regional surplus of energy and capacity began in the mid-2000s, PSE strategically positioned itself as “a buyer in a buyer’s market.” Instead of constructing new generating plants to meet load growth and replace the loss of long-term legacy PPAs, the company pursued an aggressive program of purchasing relatively lower cost energy and capacity in the wholesale marketplace. Again taking advantage of this position, the company acquired two baseload CCCT plants (Goldendale and Mint Farm) from their original owners at significant discounts from their original construction costs.

For many years, this strategy has been successful at achieving the lowest reasonable cost means of fulfilling customers’ energy needs. While PSE has long acknowledged that relying upon wholesale market purchases to meet a portion of its firm load obligations is not entirely a risk-free strategy, the region’s large (and relatively steady) capacity surplus acted to significantly mitigate this risk. However, the PNW energy markets are now in a state of transition due to many factors. These include: 1) a steady decline in the region’s forecasted capacity surplus across the next decade, 2) lower projected utility energy and peak load growth rates, 3) future greenhouse gas emission policies, 4) the impacts of new technology, and 5) shifting individual customer preferences. These factors combine to create a significant amount of uncertainty for PSE (and other regional utilities) regarding the preferred mix of supply-side and demand-side resources to economically and reliably meet its customers’ needs in the future.

### Quantifying Wholesale Market Purchase Risk

Due to the changing landscape in the regional utility industry, PSE identified a need in the 2015 IRP to develop a new analytical tool to objectively quantify wholesale market purchase risk so that the company could continue to prudently monitor its wholesale purchase strategy and incorporate physical wholesale purchase risk into its IRP planning models. In response to this need, PSE developed the Wholesale Purchase Curtailment Model (WPCM) in the 2015 IRP using the following design criteria:

- Use existing analytical modeling tools whenever possible, including PSE’s LOLP/RAM and financial portfolio cost models.
- Use the results of publically available, region-wide load/resource studies as inputs to PSE’s IRP models when possible, primarily the NPCC and BPA LOLP studies for Operating Year 2021.
- “Sync up” the inputs and outputs of GENESYS, the NPCC and BPA LOLP model, with PSE’s LOLP model, the Resource Adequacy Model (RAM).



- Develop a methodology for translating the regional load curtailments forecast by the NPCC and BPA models into PSE-level impacts. (The result is the Wholesale Purchase Curtailment Model.)
- Incorporate regional load curtailments into PSE's RAM model by reducing the amount of wholesale market purchases PSE is able to import into its system.
- Include forced outage events at PSE-owned or jointly owned thermal plants shown in the NPCC and BPA LOLP models in PSE's RAM model in a consistent manner.
- Include the impact of scarcity in the wholesale power price forecasts used in PSE IRP financial models.

In 2015, this was new territory for both PSE and the Washington Utilities and Transportation Commission (WUTC or the Commission); none of the utilities under the Commission's jurisdiction had previously attempted to quantify physical wholesale market purchase risk in their IRP planning processes. In its review of PSE's 2015 IRP, the WUTC recognized PSE's model as "fundamentally sound" and a "reasonable means of modeling a difficult challenge." We have therefore continued to refine the WPCM for use in the 2017 IRP.

The following sections describe how PSE has integrated physical and financial wholesale market risks into its 2017 IRP modeling process.

### Modeling Physical Supply Risk

Since PSE is a winter-peaking utility, winter peak load and winter resource capacity are its primary focus with regard to evaluating physical power supply risks. The company's main analytical tool for evaluating the reliability of power supply is its Resource Adequacy Model. To identify the frequency of potential outages under varying conditions, RAM performs a multi-simulation analysis that includes the impacts of variable loads, hydro generation, wind generation, generating plant forced outages (and repair times), and available short-term wholesale market imports. The RAM calculates several reliability metrics, including LOLP, EUE (expected unserved energy) and LOLH/LOLE (loss of load hours or loss of load expectation).

For the 2017 analysis, the following key refinements were incorporated into PSE's IRP models.

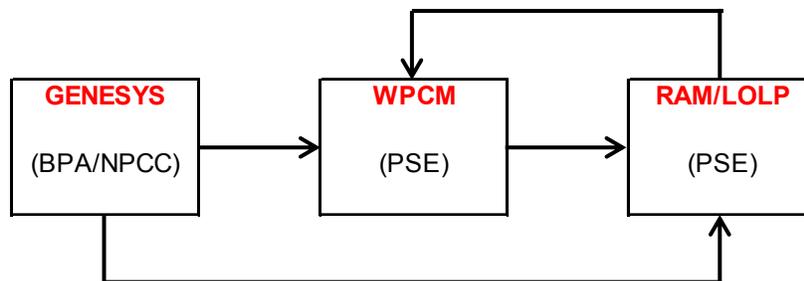
- A return to the 5 percent LOLP planning standard, as recommended by the Commission.
- Under some conditions, the amount of wholesale power available for PSE to purchase is limited to less than its maximum available Mid-C transmission capability of 1,722 MW.



- Limitations on PSE’s available supply of wholesale peaking capacity are tied to the regional load/resource conditions in the NPCC and BPA regional resource adequacy analyses using their GENESYS model.
- Specific hourly reductions to PSE’s wholesale market purchases are determined by PSE’s WPCM.

To accomplish this analysis, PSE modified its RAM model to incorporate the 2021 forecasts from the 2016 NPCC Resource Adequacy Study,<sup>8</sup> the 2016 PNUCC Regional Forecast and the BPA 2015 Northwest Loads and Resources Study. As in 2015, PSE introduced into its RAM model the equivalent of forced outage events for PSE’s wholesale market purchases when regional deficit conditions are forecast. Figure G-4 illustrates the individual modeling tools utilized by PSE in this IRP to evaluate physical supply risk and how the inputs and outputs of these models are linked:

Figure G-4: Market Reliability Analysis Modeling Tools



The modeling steps illustrated in Figure G-5 are discussed in more detail in the following pages.

## The GENESYS Model

The GENESYS model was developed by the NPCC and BPA to perform regional-level load and resource studies. GENESYS is a multi-scenario model that incorporates 80 different years of hydro conditions and 77 years of temperature conditions. When combined with thermal plant forced outages, mean time to repair those units, variable wind plant generation and available imports of power from outside the region, the model determines the PNW’s overall hourly capacity surplus or deficiency in each of 6,160 multi-scenario “simulations.” Since the GENESYS model includes all potentially available supplies of energy and capacity that could be utilized to

<sup>8</sup> / The 2017 NPCC assessment was not published in time to use for this analysis.



meet PNW firm loads regardless of cost, a regional load-curtailement event will occur on any hour that has a capacity deficit.<sup>9</sup>

Since the PNW relies heavily upon hydroelectric generating resources to meet its winter peak load needs, GENESYS incorporates sophisticated modeling logic that attempts to minimize potential load curtailments by shaping the region's hydro resources to the maximum extent possible within a defined set of operational constraints. GENESYS also attempts to maximize the region's purchase of energy and capacity from California (subject to transmission import limits) utilizing both "purchase ahead" (i.e., forward purchases) and short-term purchases. GENESYS also incorporates a set of approximately 700 MW of energy-limited "emergency standby resources" that may be called upon to attempt to minimize PNW load-curtailement events; these resources include approximately 300 MW of backup diesel generation on PGE's system and 300 MW at the Bureau of Reclamation John W. Keys hydroelectric pumped storage plant.<sup>10</sup>

## Regional Curtailment Events

PSE utilized the GENESYS model run from the 2016 NPCC Colstrip Sensitivity study to evaluate physical supply risk in this IRP.<sup>11</sup>

The GENESYS Colstrip Sensitivity study incorporated the following key assumptions:

- PSE's 307 MW share of Colstrip Units 1 & 2 are removed in operating year 2021 (October 31, 2020 – September 30, 2021) before evaluating PNW load and resource conditions.
- Imports of short-term wholesale power from California during the winter season (November – February) were limited to 2,500 MW for on-peak hours and 3,000 MW for off-peak hours.
- The 650 MW Grays Harbor gas-fired CCCT plant was included as a firm resource in all months.<sup>12</sup>
- PGE's proposed 440 MW Carty 2 CCCT plant was not included in the analysis.<sup>13</sup>

9 / Operating reserve obligations (which include unit contingency reserves and intermittent resource balancing reserves) are included in the GENESYS model. A PNW load-curtailement event will occur if the total amount of all available resources (including imports) is less than the sum of firm loads plus operating reserves.

10 / The Bureau of Reclamation is currently limiting pump/generation operations at the Keys hydroelectric pumped storage plant to avoid excessive wear on the units and to meet its irrigation water delivery obligations.

11 / Support from NPCC staff was essential for this analysis – PSE is grateful for the assistance they provided and for help from the staff of PNUCC.

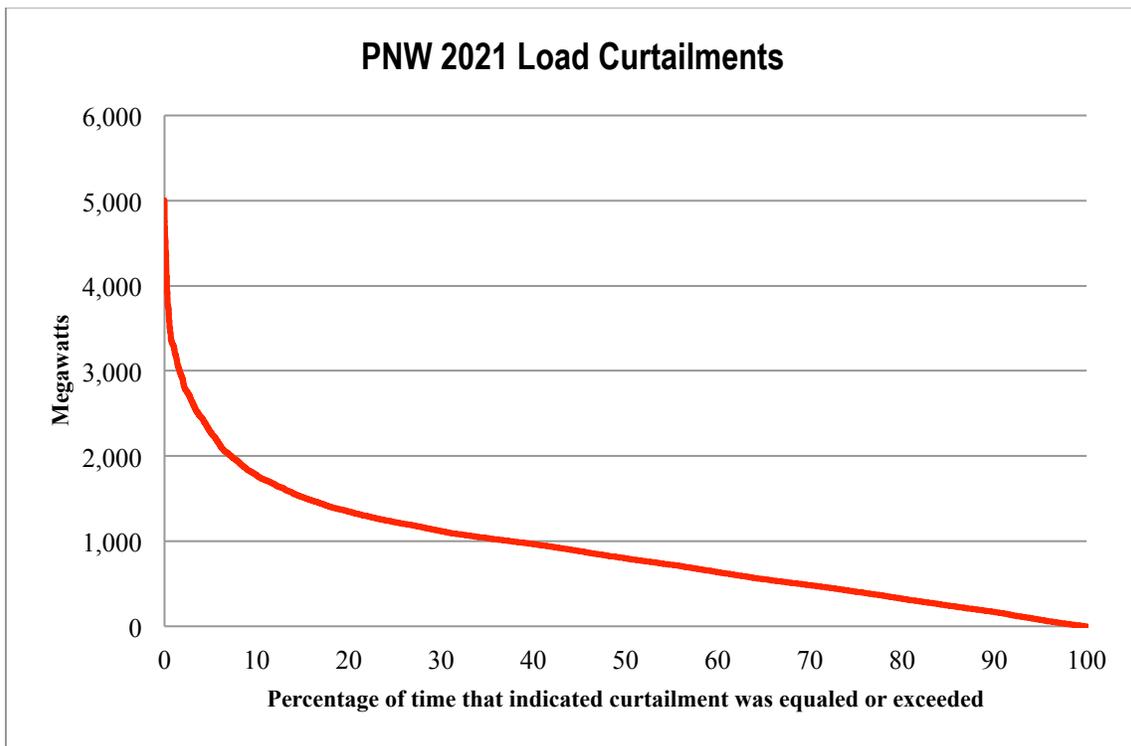
12 / The firmness of the natural gas supply for the Grays Harbor baseload CCCT plant has been an issue of concern for regional power supply planners, especially during the winter season. However, in November 2016, the owner/operator of the plant (Invenergy) indicated that it had secured an option on firm natural gas supplies for the plant for 2021; given this updated information, PSE's 2017 IRP analysis assumes that the plant would be available to provide firm capacity during all months of the year.

13 / At the present time, PGE's proposed Carty 2 plant does not meet the criteria established by the NPCC for inclusion in its long-term resource adequacy studies. (Proposed new plants must be both sited and licensed to be included in the adequacy analysis.)



One of the outputs from this study is a set of all simulations in which there is a PNW-wide load-curtailment event of any magnitude on any given hour. The GENESYS Colstrip Sensitivity study output contained 35,937 hourly load curtailments for the PNW; these occurred in 1,039 of the 6,160 total simulations and ranged from 0.2 MW to 5,003 MW. This produced a region-wide LOLP of 16.9 percent (not including the emergency standby resources).<sup>14</sup> When the 700 MW of emergency standby resources are included, the LOLP drops to slightly more than 13 percent. Figure G-5 illustrates the magnitude of PNW load curtailment events across the 35,937 hours that had curtailments greater than 0 MW.

*Figure G-5: 2021 Pacific Northwest Load Curtailments  
2016 NPCC Study, Colstrip Sensitivity Case*



No adjustments were needed to the initial set of hourly PNW curtailments derived by GENESYS for use in this IRP, thanks to enhancements made since 2015 by NPCC and BPA staff to the hydro generation shaping logic incorporated into the GENESYS model.

<sup>14</sup> / The impacts of PGE's backup generation and the Keys pumped storage plant are incorporated into the IRP analysis via the PGE and BPA peaking resources that are included in PSE's Wholesale Purchase Curtailment Model.



### PSE Wholesale Market Reliability Scenarios

Using the hourly PNW load curtailments from the GENESYS study, PSE developed four Wholesale Market Reliability Scenarios to evaluate physical supply and financial risks. Scenario 1 assumes there is no wholesale market risk while Scenarios 2 through 4 incorporate market reliability – or the risk of interruption – consistent with the base assumptions for the resource additions, and fuel supply availability as used in the NPCC’s 2016 Resource Adequacy Assessment for the winter of 2021. For all scenarios, PSE increased spot market imports to 3,400 MW, which is greater than the NPCC assumption of 2,500 MW for on-peak hours and 3,000 MW for off-peak hours. The four scenarios are described below.

**SCENARIO 1:** No wholesale market risk. This scenario assumes unlimited wholesale market supplies are available with no risk of interruption under any condition.

**SCENARIO 2:** NPCC 2016 assumptions, Colstrip sensitivity study

**SCENARIO 3:** NPCC 2016 assumptions, Colstrip sensitivity study + a new 227.5 MW peaker (with the output assigned to PSE).

**SCENARIO 4:** NPCC 2016 assumptions, Colstrip sensitivity study + 100 MW of new Columbia Gorge wind generation (with the output assigned to PSE).

PSE chose Wholesale Market Reliability Scenario 2 to evaluate resource adequacy impacts in the 2017 IRP.

### The Wholesale Purchase Curtailment Model (WPCM)

As described earlier, the GENESYS model is configured to analyze conditions for the region as a whole, but it cannot determine which specific load-serving utility or utilities will bear all or a portion of a regional load-curtailment event. PSE developed the WPCM to link those regional events to their specific impacts on PSE’s system and on PSE’s ability to make wholesale market purchases to meet firm peak load and operating reserve obligations.

In essence, on an hourly basis, the WPCM translates a regional load-curtailment event into a reduction in PSE’s wholesale market purchases (both measured in MW). In some cases, reductions in PSE’s initial desired volume of wholesale market purchases could trigger a load-curtailment event in the PSE RAM.



## The WPCM Computational Methodology

During a PNW-wide load-curtailement event, there is not enough physical power supply available in the region (including available imports from California) for all of the region's load-serving utilities to fully meet their firm loads plus operating reserve obligations. To mimic how the PNW wholesale markets would likely operate in such a situation, the WPCM uses a multi-step approach to "allocate" the regional capacity deficiency among the region's individual utilities. These individual capacity shortages are reflected via a reduction in each utility's forecasted level of wholesale market purchases.

The WPCM assumes that under PNW capacity shortage conditions:

1. all entities that need to purchase capacity in order to meet their own native load-serving obligations will be willing to purchase power up to the same threshold price,
2. all entities that need to purchase capacity in the PNW wholesale marketplace to meet their native load-serving obligations have equal opportunity and ability to locate and purchase needed capacity,<sup>15</sup> and
3. any load-serving entity that manages to purchase more capacity than it needs to meet its load-serving obligations will re-sell the surplus capacity to other, still-deficient load-serving utilities.<sup>16</sup>

It should be noted that in actual operations, no central entity in the PNW is charged with allocating scarce supplies of energy and capacity to individual utilities during regional load-curtailement events (although Peak Reliability, as the Security Coordinator for the region, would be actively working with the region's utilities to maintain transmission system stability during such events). The PNW wholesale marketplace would, in effect, be the allocating mechanism as multiple parties attempt to enter into purchase and sale transactions under abnormal conditions. It is likely that forward market wholesale transactions would be partially curtailed or fully unwound to the extent allowed under the governing purchase/sale contracts. Furthermore the Western Systems Power Pool (WSPP) Agreement used for most wholesale power transactions in the PNW markets explicitly allows load-serving utilities to curtail or terminate firm Schedule C sales transactions to meet their own load-serving obligations.

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<sup>15</sup> / The WPCM does not incorporate potential transmission limitations that in practice might restrict one or more PNW load-serving utilities from purchasing some available capacity supplies.

<sup>16</sup> / The WPCM assumes that the PNW wholesale power markets are perfectly efficient; i.e. that sellers are always able to sell 100 percent of their available capacity supplies and that no surplus capacity is left unsold due to the inability of purchasers and sellers to initiate purchase/sale transactions due to timing, credit or communication issues.



(Appendix G of the 2015 IRP describes in detail how the Pacific Northwest wholesale power markets work and the impacts these processes could have during deficit conditions. It reviews the general PNW market structure, spot and forward wholesale power markets, key market characteristics, the WSP Agreement and FERC price caps.)

The computational methodology incorporated into 2017 version of the WPCM is largely unchanged from the 2015 IRP version. The only logic modification made in the model was to address a situation where removals of large amounts of capacity from PSE's own resource portfolio (such as the early retirement of Colstrip Units 1 & 2) tended to understate the curtailments to PSE's Mid-C wholesale purchases as compared to the removal of the same amount of non-PSE capacity. This situation was addressed by allowing PSE to attempt to purchase wholesale power in quantities larger than its hourly Mid-C transmission import right; this additional PSE capacity need is termed the "PSE Excess Deficiency" in the WPCM.

The impact of this modification is to recognize that reductions in PSE's firm resource portfolio (such as the removal of Colstrip Units 1 & 2) increases PSE's wholesale purchase need while at the same time reducing the overall amount of capacity available for purchase in the PNW wholesale markets (in an amount equal to the PSE resource reduction). This, in turn, creates slightly increased PSE hourly wholesale purchase curtailments due to the increased competition among PNW utilities to make wholesale purchases from a smaller regional pool of available capacity.<sup>17</sup>

### Regional Utility Load and Resource Inputs

Because the amounts of capacity that other load-serving entities in the region need to purchase in the wholesale marketplace has a direct impact on the amount of capacity that PSE would be able to purchase, it was necessary to assemble load and resource data for both the region as a whole and for many of its individual utilities, especially those that would be expected to purchase relatively large amounts of energy and capacity during winter peaking events.

For this analysis, PSE chose to use the capacity data contained in BPA's *2015 Pacific Northwest Loads and Resources Study* as an initial point of reference, because it contained useful differentiation at the regional level and because it treated individual utility data more consistently than other available sources. BPA's study tabulates forecasted loads and resources of non-BPA entities by class (IOUs, PUDs, municipalities, etc.), and it generally applies the same forecasting assumptions and methodologies to all regional utilities. In contrast, the computational methodologies used in individual utility IRPs can vary significantly.

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<sup>17</sup> / It should be noted that the reverse is also true; if PSE adds new firm resources to its portfolio, this would increase the overall supply of capacity in the PNW markets and thereby reduce the curtailments to PSE's wholesale purchases due to less competition for scarce capacity.



Using the 2020-2021 capacity data contained in the 2015 BPA study and applying some general assumptions, PSE constructed winter 2021 load/resource tables for eight classes of market participants:

- |                              |                             |
|------------------------------|-----------------------------|
| 1. federal entities          | 5. marketers                |
| 2. cooperatives              | 6. municipalities           |
| 3. direct service industries | 7. public utility districts |
| 4. investor-owned utilities  | 8. other                    |

From this data, PSE computed the surplus/deficiency positions for each of the eight entity classes under 2021 winter peaking conditions using BPA's 120-hour sustained hydro peaking case.

To create winter peak load/resource tables for the region's investor-owned utilities (several of which are large purchasers of wholesale energy and capacity), PSE assembled load and resource data from 2015 and 2016 IRPs to create winter 2021 peak load/resource tables for each utility. Forecasted winter 2021 peaking surplus/deficiencies were then determined for each of the following IOUs: PacifiCorp, PGE, Avista and Idaho Power.

PSE then tried up the 2021 winter peaking surplus/deficiencies between the 2015 BPA study, the IRPs of the above utilities and PSE's own 2017 IRP load/resource data to create a simplified model of the PNW wholesale market for use in the WPCM.<sup>18</sup> Additional information and computational steps were required to incorporate PacifiCorp load/resource information into the model since PacifiCorp East (PACE) is a summer-peaking system and PacifiCorp West (PACW) is a winter-peaking system.<sup>19</sup>

The WPCM's input data also includes information regarding the IPP plants located within the region. For these plants, 100 percent of net winter season capacity was assumed to be available to meet PNW loads, as is the case in the BPA study. Idaho's surplus was also assumed to be available to meet PNW winter peak loads, since Idaho Power is a summer-peaking utility and its IRP indicated that it expects to have a moderate winter-season capacity surplus for 2021.

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*18 / In the 2015 IRP, PSE performed a series of preliminary sensitivity studies using varying amounts of PSE and other PNW utility winter surpluses and deficiencies to gauge the sensitivity of the WPCM's outcomes to the relative size and number of surplus and deficient utilities in the PNW region. The results of these studies indicated that utilities with small surpluses or deficiencies relative to PSE's average of approximately 1,600 MW, 2021 winter peak deficiency had very little (or no) impact on the level of PSE's computed wholesale purchase curtailments. It was therefore possible to significantly simplify the WPCM by aggregating the smaller utility capacity surpluses and deficits into one proxy "other" utility system. The 2017 version of the WPCM utilizes this same approach.*

*19 / Deriving winter 2020/21 load and resource information for the PACW system proved challenging given the fact that PacifiCorp overall is a summer-peaking system and PacifiCorp's 2015 IRP did not contain separate PACW and PACE load/resource tables under winter-peaking conditions. PSE therefore estimated PACW's winter 2021 peak load using a combination of the limited information contained in PacifiCorp's 2015 IRP and publically available historical load data from multiple FERC reports/filings including PacifiCorp's 2016 Triennial Market-Based Rate filing.*



In addition to deriving base winter 2021 surplus and deficiency values, PSE also computed a set of “sensitivity ratios” for PSE, PGE, BPA, PACW, other utilities, and the combination of the PNW IPPs and Idaho Power. The purpose of the sensitivity ratios is to scale each entity’s base surplus/deficiency (which was computed on a single-point deterministic basis) up or down to match the varying hourly PNW load-curtailed values from the GENESYS model. The sensitivity ratios are a measure of the relative size of each PNW entity and were computed as follows:

$$\text{Entity SR} = (\text{Entity ABS PK LD} + \text{Entity PK Res}) / (\text{PNW ABS PK LD} + \text{PNW PK Res})$$

Where:

Entity SR = Each Entity’s Sensitivity Ratio

Entity ABS PK LD = The Absolute Value of Each Entity’s 2021 Peak Load

Entity PK Res = Each Entity’s Total 2021 Peak Resources

PNW ABS PK LD = The Absolute Value of Total PNW 2021 Peak Loads

PNW PK Res = Total PNW 2021 Peak Resources

The sensitivity ratios were computed as a function of both load and resources since the multi-scenario GENESYS model varies both load and generation quantities; therefore, a regional PNW load-curtailed event could be the result of either a load-driven event, a generation-driven event or both.

The above computations yielded the base set of winter season surpluses and deficiencies and associated sensitivity ratios shown in Figure G-6 below:



Figure G-6: WPCM Regional Utility Surplus/Deficiencies and Sensitivity Ratios for Winter 2021

Scenario 2 – 2016 NPCC Assumptions, Colstrip Sensitivity Study

PNW Entity	Winter 2021 Peak Load(MW)	Winter 2021 Peak Resources (MW)	Net Peak Sur/(Def) (MW)	Sensitivity Ratio Absolute Value of Peak Load + Peak Resources
PSE	(6,334.0)	4,050.0	(2,284.0)	0.147
PGE	(4,126.0)	3,307.0	(819.0)	0.106
PACW	(4,032.6)	3,095.0	(937.6)	0.102
BPA	(10,861.0)	9,841.0	(1,020.0)	0.295
Other PNW Utilities	(8,309.4)	8,044.0	(265.4)	0.233
PNW IPPs + IPC	(2,704.0)	5,512.0	2,808.0	0.117
PNW IPPs	(265.0)	2,445.0	2,180.0	
Idaho Power	(2,439.0)	3,067.0	628.0	
<b>Total</b>	<b>(36,367.0)</b>	<b>33,849.0</b>	<b>(2,518.0)</b>	<b>1.00</b>

NOTE: The PacifiCorp winter-season deficiency is for the PACW system only.

## Allocation Methodology

For each hour that there is a PNW load-curtailement, the WPCM simulates how the five largest purchasers of winter season capacity in the PNW wholesale markets – PSE, PACW, PGE, BPA and all other utilities – would compete to purchase scarce supplies of capacity.

**FORWARD MARKET ALLOCATIONS.** The model assumes that each of the five large buyers purchases a portion of their base capacity deficit, as shown in Figure G-7, in the forward wholesale markets. Under most scenarios, each utility is able to purchase their target amount of capacity in these markets. This reduces the amount of remaining capacity available for purchase in the spot markets. If the wholesale market does not have enough capacity to satisfy all of the forward purchase targets, those purchases are reduced on a pro-rata basis based upon each utility's initial target purchase amount.



**SPOT MARKET ALLOCATIONS.** For spot market capacity allocation, each of the five large utility purchasers is assumed to have equal access to the PNW wholesale spot markets, including available imports from California. The spot market capacity allocation *is not* based on a straight pro-rata allocation, because in actual operations the largest purchaser (which is usually PSE) would not be guaranteed automatic access to a fixed percentage of its capacity need. Instead, all of the large purchasers would be aggressively attempting to locate and purchase scarce capacity from the exact same sources. Under deficit conditions, the largest of the purchasers would tend to experience the biggest MW shortfalls between what they need to buy and what they can actually buy. This situation is particularly true for small to mid-sized regional curtailments where the smaller purchasers may be able to fill 100 percent of their capacity needs but the larger purchasers cannot.

### WPCM Outputs

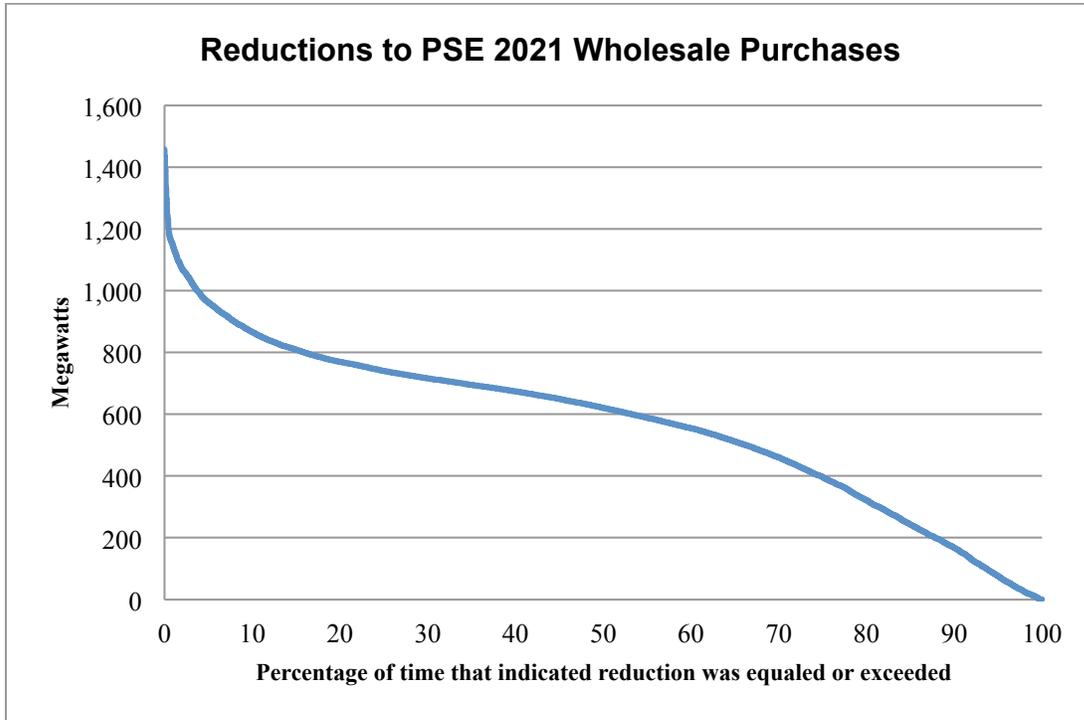
For each simulation and hour in which the NPCC GENESYS model determines there is PNW load-curtailment event, the WPCM model outputs the following PSE-specific information:

- PSE's initial wholesale market purchase amount (in MW), limited only by PSE's overall Mid-C transmission rights.
- The curtailment to PSE's market purchase amount (in MW) due to the PNW regional capacity shortage.
- PSE's final wholesale market purchase amount (in MW) after incorporating PNW regional capacity shortage conditions.



Figure G-7 illustrates the magnitude of the reductions in PSE’s wholesale market purchases across the 35,937 hours with PNW load curtailments greater than 0 MW in the NPCC’s 2016 Study (Colstrip Sensitivity Study).

*Figure G-7: 2021 Reductions to PSE 2021 Wholesale Purchases due to PNW Load Curtailment Events*



As discussed above, the amount of PSE’s wholesale purchase reductions is not a straight pro-rata calculation; rather, PSE’s percentage reduction in its initial target wholesale purchase amount varies depending upon

1. the magnitude of the PNW regional load-curtailment event, and
2. the capacity deficits of PSE and the other large capacity purchasers under each specific PNW load-curtailment event.



Figure G-8 illustrates this point for several different magnitudes of hourly load-curtailment events from the same simulation of the NPCC's GENESYS model, for the Colstrip Sensitivity Study.

*Figure G-8: Hourly Load-curtailment Events  
from the NPCC's GENESYS Model, Colstrip Sensitivity Study*

Initial Hourly PSE Wholesale Purchase (MW)	PNW Load Curtailment Amount (MW)	Final Hourly PSE Wholesale Purchase (MW)	PSE Hourly Purchase Reduction (Percent)	PSE Share of PNW Load Curtailment (Percent)
1,658.0	(171.2)	1,486.8	10.3%	100.0%
1,527.0	(901.1)	979.4	35.9%	60.8%
1,671.0	(2,050.5)	737.2	55.9%	45.5%
1,671.0	(3,284.5)	517.8	69.0%	35.1%
1,669.0	(4,135.5)	365.6	78.1%	31.5%
1,668.0	(5,002.6)	211.0	87.4%	29.1%



## Summary of WPCM Results

Before incorporating wholesale purchase availability risk, PSE's average 2021 wholesale purchase amount was 1,587 MW during the 35,937 hours in the GENESYS Colstrip Sensitivity where there were PNW load curtailments. After incorporating wholesale purchase availability risk via the WPCM, PSE's average wholesale market purchases were reduced to only 1,016 MW – a 36 percent reduction in the average hourly amount of energy and capacity available for PSE to meet its firm winter peak load and reserve obligations. Furthermore, on some hours, PSE's wholesale purchases were reduced by as much as 88 percent from their original amounts; these large PSE wholesale purchase reductions tend to occur during the very large PNW load-curtailment events.

Summary results from the WPCM for each of the four Wholesale Market Reliability Scenarios are shown in Figure G-9.

*Figure G-9: PSE Wholesale Market Purchases by Scenario*

Reliability Scenario	Initial Average PSE Wholesale Purchase (MW)	Final Average PSE Wholesale Purchase (MW)	Average Purchase Reduction (MW)	Average Purchase Reduction (Percent)
1. No Market Risk	1,586.9	1,586.9	0.0	0
2. NPCC 2016 Colstrip Sensitivity	1,586.9	1,016.4	(570.5)	36.0%
3. NPCC 2016 + 227.5 new peaker	1,589.4	1,040.2	(549.2)	34.6%
4. NPCC 2016 + 100 MW new wind	1,587.1	1,021.2	(566.0)	35.7%



### Linking the WPCM and RAM Models

PSE's RAM operates much like the GENESYS model, except that it is designed to analyze load/resource conditions for PSE's power system rather than the entire PNW region.<sup>20</sup> Like GENESYS, PSE's RAM is a multi-scenario model that varies a set of input parameters across 6,160 individual simulations, and the result of each simulation is PSE's hourly capacity surplus or deficiency. The loss of load probability (LOLP), expected unserved energy (EUE) and loss of load hours/expectations (LOLH/LOLE) for the PSE system is then computed across the 6,160 simulations.

One of the RAM input variables is the hourly wholesale market purchases that PSE imports into its system using its long-term Mid-C transmission rights. The initial set of hourly imports is computed as the difference between PSE's maximum import rights (which total approximately 2,300 MW in 2021) less the amount of transmission capability required to import generation from PSE's Wild Horse wind plant and PSE's contracted shares of the Mid-C hydro plants. To reflect regional deficit conditions, this initial set of hourly wholesale market imports is reduced on the hours when a PNW load-curtailement event is identified by the WCPM. The final set of hourly PSE wholesale imports from the WPCM is then used as a data input into the PSE RAM, and PSE's loss of load probability, expected unserved energy, and loss of load expectation are then determined. In this fashion, the LOLP, EUE and LOLH metrics determined in the RAM incorporate PSE's wholesale market reliance risk.

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<sup>20</sup> / PSE's RAM is described in detail in Appendix N.



## Calculating the Capacity Contribution of Wholesale Market Purchases

With the reliability of wholesale market purchases now reflected in PSE's RAM, we applied the same analytical process that we use for other resources to estimate the capacity value of wholesale market purchases. That is, just as PSE cannot count on the full nameplate capacity of a wind plant to meet peak capacity needs because the wind doesn't blow all the time, we cannot always count on the full amount of wholesale market purchases to meet our peak need, because the wholesale market is not perfectly reliable. To make this capacity value assessment, the 2017 IRP uses an effective load carrying capacity (ELCC) analysis.<sup>21</sup> The results of this analysis are summarized in Figure G-10 for Scenario 2, the NPCC 2016 assumptions, Colstrip Sensitivity Study. The reason why the average purchase reduction of 36 percent in the WCPM model translates to a 99 percent ELCC is that those purchase reductions do not necessarily result in a PSE load curtailment in the RAM model when using a 5 percent LOLP planning standard. Under the LOLP metric, multiple PSE load curtailments that occur on different hours within the same simulation in the RAM only count as one failure. Therefore, a large number of curtailments to PSE's wholesale purchases that occur across many different hours in the same simulation can still result in a relatively high ELCC for wholesale purchases even though the average wholesale purchase curtailment percentage (36 percent in this case) is relatively large. The PNCC's updated 2017 regional adequacy study, which reflects larger regional investments in conservation and slowing regional load growth, increases our confidence in this result.

*Figure G-10: Capacity Value of PSE's Wholesale Market Purchases*

For Scenario 2: NPCC 2016 Assumptions, Colstrip Sensitivity Study	Capacity	Capacity Needed to Maintain 5% LOLP	Effective Load Carrying Capacity
PSE Wholesale Market Purchases (Using Available Mid-C Transmission Rights)	1,580 MW	12 MW	99%

<sup>21</sup> / The ELCC analysis for PSE's wholesale market purchases and other resource types are discussed in Appendix N.



## 4. MONITORING WHOLESALE MARKET RISK

As has been previously discussed, the PNW utility industry is in a state of transition on many fronts. Some of the key issues that are currently impacting long-term utility load/resource planning efforts include: 1) a steady decline in the region's forecasted capacity surplus across the next decade, 2) lower projected utility energy and peak load growth rates, 3) potential future greenhouse gas emission policies, 4) the impacts of new technology, and 5) shifting individual customer preferences. These factors combine to create a significant amount of uncertainty for PSE (and other regional utilities) regarding the preferred mix of supply-side and demand-side resources to economically and reliably meet customers' needs in the future.

For many years, PSE has relied upon a strategy of purchasing relatively large amounts of power in the regional wholesale markets in order to achieve the lowest reasonable cost means of fulfilling customers' energy needs. However, as conditions continue to change, PSE must proactively monitor how these changes could impact its wholesale power purchase strategy and be prepared to modify this strategy in order to maintain a balance between the associated risks and benefits when compared against other supply-side and demand-side resource alternatives.

The following sections discuss several important issues that PSE will continue to actively monitor and/or discuss with other regional long-term planners so that we can reassess our wholesale power purchase strategy as changing conditions warrant.

### Do additional reliability metrics need to be considered?

The NPCC's 2016 Resource Adequacy Assessment analyzed PNW regional electric reliability from the perspective of the LOLP planning metric developed by the Council and adopted by some utilities – including PSE. This planning standard requires utilities to have sufficient peaking resources available to fully meet their firm peak load and operating reserve obligations in 95 percent of simulated market conditions.

The LOLP metric measures the likelihood of having one or more regional load-curtailement events in a sample year, but it provides no information about the *frequency* of events within a simulation or the *magnitude* or *duration* of those events. The current LOLP metric does not take into account the size of regional load curtailments; i.e., a 1 MW curtailment and a 1,000 MW curtailment are treated equally when computing loss of load probability. In addition, the LOLP metric tends to understate reliability-related impacts associated with energy-limited resources such as hydro and demand response.



Several PNW utilities (including PSE) and NPCC staff have expressed interest in evaluating and potentially adopting additional metrics to provide regional resource planning stakeholders with a more complete picture of the region's ability to reliably meet peak load and reserve obligations.<sup>22</sup>

- The Expected Unserved Energy (EUE) metric is a quantitative measure of the *magnitude* of load curtailments.
- The Loss of Load Expectation (LOLE) metric, also called the Loss of Load Hours (LOLH), provides information about the *duration* of the curtailment events.

PSE believes that the concept of supplementing and/or replacing the LOLP metric as a capacity planning standard deserves further attention; the company will therefore continue to pursue those discussions at the regional level before bringing the issue to the Commission.

## Changes to Regional Load/Resource Forecasts

The amounts of energy and capacity that are forecast to be available for purchase in the future by PSE are closely related to the load/resource projections made by PSE and other regional utilities as part of their long-term planning processes. As utilities continue to refine their long-term load/resource studies – for example to incorporate new greenhouse gas emissions policies or the deployment of emerging technologies such as energy storage – assessments of the region's resource adequacy will change; this could either increase or decrease the region's need for new firm, dispatchable resources. Also, the potential range of new investments in conservation and demand response will continue to be updated (and hopefully narrowed) over time as well.

In addition, actions taken by regional entities other than PSE can have an indirect effect on PSE and its wholesale purchase strategy; for example, the decision by another PNW utility to develop new generation resources (to meet its own needs) may benefit PSE as well by increasing the supply and reliability of capacity available for purchase by PSE in the short-term wholesale markets.

PSE will continue to take a leadership role in PNW long-term planning forums in order to: 1) stay abreast of current trends, 2) actively work with the NPCC, BPA, PNUCC and other regional stakeholders to improve the accuracy of regional resource reliability assessments, and 3) maintain a safe, reliable and economic power system for the benefit of our customers and the region.

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<sup>22</sup> / The Council has initiated a process to review its current 5 percent LOLP adequacy standard. This review is expected to consider similar efforts going on in other parts of the United States, namely through the IEEE Loss-of-Load-Expectation Working Group and the North American Electric Reliability Corporation (NERC).



## Energy and Capacity Imports from California

The high-voltage AC and DC interties that connect the Pacific Northwest with California were designed to facilitate large transfers of energy and capacity between the two regions. Imports and exports on these interties allow load-serving utilities to take advantage of seasonal load diversity, since California peaks in the summer and the Pacific Northwest (overall) peaks in the winter.

How much power from California will be available to import for meeting PNW winter peak loads in the future? This is a topic of great interest to the region's resource planners. Determining the amount of power that can reliably be imported from California under winter peak conditions is a complex exercise that involves modeling all of the loads and resources within the Western Electricity Coordinating Council (WECC) and all of the associated transmission line transfer path ratings. Recent BPA studies that have been vetted by several regional stakeholders (including the NPCC's Resource Adequacy Advisory Committee) have determined that up to 3,825 MW of energy and capacity could be imported from California under winter peaking conditions during on-peak hours.

Currently only 425 MW of imports from California are contracted for under long-term firm PPAs for the on-peak hours of the winter of 2020-2021. Of that amount, 300 MW is associated with PSE's power exchange agreement with PG&E. The remaining 3,400 MW of south-to-north intertie capability during the winter season is assumed to be available to import short-term supplies of wholesale power from California in order to help PNW load-serving utilities meet their winter peak load obligations.<sup>23</sup> Regional resource planners are continuing to assess the amounts of capacity that could reliably be imported from California to help meet PNW winter peak loads and will modify this conservative estimate if conditions warrant.

In addition, regional load/resource models may not fully incorporate the potential for outages and/or derates on the interties that interconnect the PNW with California. This is an especially important issue for PSE, since it relies upon 300 MW of firm imports from California to meet winter peak loads under the long-term PSE/PG&E Exchange Agreement. PSE will continue to assess whether we need to develop a forced outage rate for the PSE/PG&E Exchange Agreement in order to address this potential risk.

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*23 / It should be noted that the assumed volume of short-term wholesale power imports from California during the summer season is 0 MW since: 1) California is a summer-peaking region, and 2) many load-serving entities in California typically purchase energy and capacity from the PNW to meet their summer peak load obligations.*



## Market Friction

The various PNW-level load/resource models used by the NPCC, PNUCC and BPA, as well as PSE's own RAM and WPCM models, assume that the wholesale markets always operate in an optimally efficient fashion. However, many real-world uncertainties and behaviors are difficult to incorporate into the models. For instance, during a severe winter cold weather event, the region's load-serving utilities would be expected to be very conservative with regard to meeting their statutory native load obligations. This could lead some utilities to forego making wholesale power sales in advance of the delivery hour, even though, after the fact, some surplus capacity may have been available. In addition, utilities operating energy-limited hydroelectric-based systems may not be willing to sell "surplus" water today if they think they may need that same increment of water at a future time to meet their own load-serving obligations. Incorporating this "market friction" impact could therefore result in more frequent and/or severe PNW load-curtailement events than the current set of models indicate.

## CAISO Energy Imbalance Market

In late 2014, the California Independent System Operator (CAISO) expanded its centrally operated wholesale power markets to include a within-the-hour Energy Imbalance Market (EIM). The CAISO EIM is a voluntary, centrally-dispatched energy imbalance market that allows for the participation of loads and generating resources that are located in Balancing Authority Areas (BAAs) outside of the CAISO's own BAA.

PSE's application to join the CAISO EIM was approved by the FERC on September 30, 2016, and PSE commenced operations in the EIM on October 1, 2016. Currently, the EIM "footprint" is comprised of the following six BAAs: 1) CAISO, 2) PacifiCorp East, 3) PacifiCorp West, 4) Nevada Energy, 5) Arizona Public Service, and 6) PSE. In addition, PGE, Idaho Power and Seattle City Light are expected to join the EIM in late 2017, early 2018 and early 2019 respectively.

The primary focus of the EIM is to reduce the within-the-hour **energy-related** generation dispatch costs associated with the participants balancing load and resources in their respective BAAs; this is achieved by creating a larger "pool" of generating plants available to be re-dispatched within each hour based upon the combined energy imbalance need of all of the participants.

The CAISO EIM is currently not designed to be a **capacity balancing** market since each participating BAA operator must demonstrate that it has sufficient resources available to meet all



of its forecasted capacity obligations (including operating reserves) prior to the start of each delivery hour. However, should the EIM decide to form a capacity balancing market in the future, this may present new alternatives for PSE from a long-term capacity planning perspective.

### Balancing Reserves for Intermittent Resources

The GENESYS model used to produce PNW-level load/resource studies now incorporates forecasts of the real-time balancing reserves for wind plants located within multiple PNW Balancing Authority Areas.<sup>24</sup> This is a significant enhancement from previous model versions; however, as additional wind and solar generating projects are developed within the region, these balancing capacity forecasts may need to be further refined, especially with regard to solar PV plants since little historical data currently exists for these types of facilities located in the PNW.

### Fuel Supplies for Generating Plants

The firmness of generating plant fuel supplies are a concern for regional load/resource planners. Since the PNW is a heating-load-driven, winter-peaking region, demand for natural gas supplies tends to peak at the same time as the demand for electricity. A shortage of gas supply or limitations on gas pipeline capacity could lead to natural gas deliveries being curtailed to some gas-fired baseload and peaking plants. While many PNW gas-fired generating plants have backup fuel supplies (generally oil), at least one major plant – the 650 MW Grays Harbor CCCT plant – does not have an on-site backup fuel supply. As an independent power producer, the status of this plant's fuel supply is first and foremost a contractual issue between the plant's owner (Invenergy) and the entities that are purchasing power from the plant. However, since the NPCC's adequacy studies assume that all PNW IPP generating capacity will be available to meet regional peak loads, the firmness of the plant's fuel supply is a regional-level issue as well.

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<sup>24</sup> / Earlier version of GENESYS, including the version utilized in PSE's 2015 IRP, only incorporated balancing capacity reserves for wind plants located within BPA's BAA.