

FUTURE NORTHWEST CAPACITY SHORTAGES¹

By Randy Hardy and Larry Kitchen

I. Recent Events Affecting the Mid-Term Pacific Northwest (PNW) Capacity Outlook

Several developments which have occurred, or become apparent, in the last few months will significantly impact the PNW resource capacity outlook in the 2020-2030 timeframe. Such recent developments are described below. To provide some context for this issue, a short history of PNW capacity development is included as Appendix A.

A. E3 Study on PNW Resource Adequacy

E3, the consulting/analytical firm which has studied numerous West Coast power issues, completed a comprehensive analysis of PNW capacity issues in January 2019. Among that study's conclusions was that, due to load growth and announced coal plant retirements, the PNW faces a potential eight-gigawatt (GW) capacity deficit by 2030 unless new dispatchable capacity is constructed. Absent such construction, regional loss of load probability (LOLP) will grow to 48 percent by that date (five percent LOLP is the normal reliability standard used by WECC utilities). The Northwest Power and Conservation Council (NPCC) in its draft mid-term assessment of its Seventh Power Plan has also noted the PNW faces resource adequacy issues absent new construction.

B. Washington (WA) State Zero Carbon Legislation

In addition to PNW capacity deficits projected by E3 absent new construction, the WA state legislature has enacted legislation mandating that WA utilities achieve zero fossil fuels in their resource base by 2045. This legislation is modelled after California's zero carbon legislation passed in 2018. Its major near/mid-term provisions include a directive that no WA utility is supplied by coal by 2025. This provision will impact Puget Sound Energy (PSE), Avista and PacifiCorp (PAC), all of whom own shares of Colstrip 3 and 4, possibly causing those plants to close in 2025 rather than their current planned retirement in 2035.

Next, by 2030, all WA utilities must be 80 percent carbon free in terms of the power resources used to supply their load. This provision will not only require substantial renewable acquisition by PSE and others over the next ten years, but will also mean that those utilities, after 2030, will need to offset any carbon emissions associated with use of their existing gas-fired resources with purchase of RECs or other approved non-carbon measures.

¹ The views in this paper are strictly our own, and do not necessarily reflect those of our clients.

Finally, the loss of Colstrip 3 and 4 will add another 1.5 GW to E3's projected 8 GW capacity deficit in 2030.

C. No New Gas Sentiment

Besides these developments, the current political climate in both WA and Oregon (OR) is strongly against development of any new gas-fired resources (e.g., combustion or combined cycle turbines – CTs/CCTs) to fill the projected 8 GW PNW capacity deficit. Not surprisingly, this posture in the PNW closely parallels the no new gas/retire existing gas sentiment which has existed in CA in recent years.

II. Consequences of These Developments

Taken together, these actions, along with already projected PNW coal plant retirements, will create a substantially different set of resource acquisition and operating procedures in the Northwest.

A. Renewables Only

From 2020 on, the most likely energy resources which can be acquired in the PNW will be wind and solar. In WA such resources will need to bring each utility's non-carbon emitting resource portfolio to 80 percent of load by 2030. Operationally, coal resources can still be used until 2025 and CTs/CCTs until 2030 (with limited use after 2030), but the WA renewables mandate will be a significant challenge for PSE and other in-state investor owned utilities (IOUs) to meet. Oregon's present 50 percent RPS will provide similar renewable dominant incentives but with more flexibility than WA mandates.

B. Capacity Needs – Batteries/Pumped Storage (PS)

As a result of these dynamics, the most likely capacity resources PNW entities will be able to develop are batteries and PS. There may be some limited carbon-free capacity from existing hydro providers (e.g., BPA, Seattle City Light, Powerex) but it is likely to be limited in both quantity and duration. With only batteries and PS available (in lieu of CTs), and an 8 GW projected capacity deficit by 2030, capacity acquisitions will be different and significantly more challenging than during the last 20 plus years. In addition, battery/PS resources will be needed, not just to meet cold snap winter reliability needs, but also to provide most of the renewable resource firming requirements as the region approaches 2030. The contrasts between these two types of capacity resources are notable: batteries can be installed quickly at points near load centers or other optimal locations; batteries, however, in aggregate are still quite expensive (e.g., probably two to three times cost of a CT) and have yet to have their performance characteristics (e.g., four-hour discharge cycle, 10-year life) tested at magnitudes needed to effectively help utilities manage the grid (e.g., greater than 50 MW capacity). While costs are decreasing and performance data will eventually be forthcoming, utilities will be taking significant operational risks that are inherent with any new technology (at least on the scale required here).

On the other hand, PS is a proven technology which has successfully operated in utility systems around the world for decades. It is capital intensive and has long lead times to become operational, but performance characteristics and costs for individual projects are well known. In addition, there are several PS sites, both in the PNW and CA, which are potentially viable.

Given the magnitude of the PNW's 2030 capacity deficit, it is likely that both substantial battery and PS installations will be needed. Other potential capacity resources that might be viable include small modular nuclear resources, cogeneration, biomass and geothermal resources and demand side management, depending on future technical developments and availability.

C. Impact on California (CA)

The magnitude of future PNW capacity requirements will also likely decrease capacity and energy available for export to CAISO/CA entities between 2020-2030. Specifically, significant PNW surplus capacity and energy has been readily available to CA since 2002, and, since the capacity has typically been embedded in energy deliveries, it has essentially been free to CA purchasers. Given the PNW's changing resource mix, such imported capacity will likely decrease substantially, unless the CAISO provides sufficient financial payments and associated market structure changes for existing surplus capacity to continue flowing south.

D. Low Water

Another major uncertainty which further complicates this situation is the variation in generation in the PNW due to water availability. Low water conditions typically occur every five (25th percentile) to ten (10th percentile) years depending on severity. Severe PNW drought conditions such as 2001 removed 3500 to 7000 MW of supply during the months of January through August from the average year West Coast power supply. If we were to experience such low water in, for example, 2024-25, it would dramatically add to both energy and capacity problems in CA and the PNW with possibly severe reliability consequences.

E. Recent Scarcity Events – Wake-Up Call

During July through September 2018, the Peak net load of the CAISO was 7% lower (46,000 to 50,000) than the peak load in 2017. Nevertheless, system marginal energy prices in the day-ahead market reached record highs on July 24, 2018, peaking at almost \$980/MWh in hour ending 20. The frequency of high day-ahead prices increased significantly during the third quarter, largely concentrated between July 23 and August 10, driven by extreme temperatures across the western region and limited natural gas availability.

On March 1, 2019, the Midc index price for day ahead bilateral trades exceeded \$900/MWh for heavy load hour energy and \$160/MMBtu for natural gas. These prices were driven by a number of factors including cold temperatures, a pro-longed cold period prior to March 1 resulting in depletion of hydro generation and natural gas in storage, an inability of Los Angeles Department of Water and Power (LADWP) gas resources to support exports on the DC Intertie due to various system constraints, and limitations in supplies of Canadian natural gas impacting the ability of some U.S. natural gas generation to operate.

These high prices, and the capacity shortage that they reflected, occurred despite nearly all the soon-to-be retired PNW coal plants operating at maximum capacity. This occurrence should serve as a wake-up call to PNW entities.

III. Possible Actions to Alleviate Capacity Shortfalls

Policy should address the problems likely to be caused by the changing PNW resource mix unless developing integrated resource plans (IRPs) direct the construction of more CTs/CCTs, which seems impossible given current West Coast political sentiment. Policy development needs to conscientiously assess the role of ratepayers taking risk through resources selected in IRPs and independent power producers (IPPs) taking risk based on their assessment of the competence of government plans. Some potential policies include:

A. Ensure Robust Day Ahead Resource Sufficiency in the CAISO Expansion of its Day Ahead Market (EDAM) to EIM Entities

CAISO plans to launch EDAM in the near future. If successful, it would require resource sufficiency (as opposed to resource adequacy) demonstrations from all EDAM participants. The resource sufficiency metrics would be designed to ensure each EIM Entity has developed or purchased enough capacity to meet its own load without relying on neighboring EIM Entities beyond agreed estimates of resource sharing.

B. Acquisition of Batteries/Pumped Storage

As mentioned earlier, batteries or PS appear to be the only new capacity resources currently able to be procured by West Coast utilities, either for reliability needs or renewables firming, in the foreseeable future. Both resources have their strengths and weaknesses, but WECC utilities will need to test their performance viability post-2020. Developing products that pay resources for offering ramping capability will assist in the construction of such resources.

C. Demand Response

The NPCC has identified demand response (DR) as the primary capacity resource on a planning basis and proposed 600 MW of demand response by 2023 in its 2017 plan. Utilities have proposed programs that would meet that target in the summer but not the winter. Successful implementation of DR requires wholesale prices or regulatory requirements that incentivize utilities and load serving entities to develop programs providing retail incentives or retail price signals to encourage consumers to participate. Consumers need financial incentives to change their consumption patterns or make necessary investments to control or modify their energy use. Complicating the economics of these investments are the seasonal nature of different uses of energy, frequency of use if program implementation creates consumer impacts, and the amount of notice required to implement temporary changes in consumption. These complications will likely slow DR implementation so achieving significant regional penetration occurs more in the post-2025-2030 period.

D. Review Fossil Fuel Era Planning and Operating Metrics

The changing PNW resource mix calls into question a number of habits that have become common wisdom over the last 15 years. Many PNW utilities have relied on short term 96 hour per week energy purchases from the bilateral wholesale market. These purchases were enabled by the ability to produce energy on demand from fossil fuel capacity resources and the surplus energy from hydroelectric resources. The 3-4.5 GW of retiring coal plants (and possibly the additional 5 GW of capacity due to 2020-2030 load growth) will likely be replaced/served in IRPs with energy limited capacity, not capacity capable of baseload or heavy load hour operation. IRPs will need to develop assessments of the necessary energy duration of the capacity needed for resource adequacy and should not rely on the metrics of the fossil fuel era.

Development of wide area markets was predicated on diversity inherent from planning reserve margins for individual utilities based on the development of fossil fuel resources for capacity. Policy makers should be cautious in relying on further diversity benefits from wide area markets to cover upcoming capacity shortfalls. Assuming that energy limited resources will be available on the hour that capacity is needed requires additional study and will inject additional risk into the system during the upcoming rapid transition period. While the planning reserve margins of individual utilities may have been inefficient, they also covered the unplanned events that occur beyond the 95% thresholds commonly used for long term planning. These individual planning margins captured the diversity among utilities by reliance on short term capacity purchases for resource planning in the areas with surplus generation.

E. Explore Development of PNW Resource Adequacy Agreement

Resource adequacy is a policy construct designed to ensure enough generation or demand side resources have been developed or procured to meet day ahead resource sufficiency and real time load and reserve requirements in a given area. All the resource adequacy programs developed in North America (other than plans of individual entities) have been developed by organized wholesale power markets run by independent system operators or regional transmission organizations. Absent creation of an organized wholesale market for energy and reserves in a given area, development of a resource adequacy program for a given area requires the voluntary agreement of the utilities and other load serving entities in such area or an agreement of the States served in such area on a common set of metrics to measure resource adequacy and an enforcement mechanism. Given the complexity of the metrics involved in such an agreement, an organization would be needed to design and administer such program and such agreement would need to address the governance of such organization.

The PNW has attempted to develop an organized wholesale market several times over the last 25 years and has failed to reach agreement. The rapid transition of the PNW electric industry may provide the impetus to reach agreement on metrics for ensuring the reliability of PNW electricity markets.

F. Possible Transmission (Tx) Solutions

As these capacity driven trends emerge, it is possible that a variety of tx solutions will also develop. For example, PNW utilities (in addition to PAC and Idaho Power) may decide to participate in PAC's Gateway West tx project. Such participation could enable PNW utilities both to acquire Wyoming wind (with its complementary load shape and higher capacity factor to Columbia Gorge wind) to meet their RPS goals and even access Wyoming/Utah thermal capacity for reliability emergencies. Somewhat similar dynamics might also exist for tx access to Montana wind.

IV. Or Not

A. Pray for Rain and Mild Weather

Murphy's law predicts that the next low water year in the PNW will arrive in 2025 as peak coal plant retirement occurs and the PNW IRPs defer decisions on construction of new resources waiting for the next cost reduction in carbon free capacity.

Appendix A

Short History of PNW Capacity Resource Development

I. Development of the Federal Columbia River Power System (FCRPS)

Following initial development of hydroelectric generation on local rivers by PNW utilities, the Federal government began development of the Columbia River in the 1930s with the construction of Bonneville and Grand Coulee dams. Development of the Columbia River involved a reshaping of the natural hydrograph to better match the pattern of electric loads in the PNW. The hydroelectric system that developed only has the capability to store about a third of the annual runoff. Due to the large difference in hydroelectric power production between wet and dry years, it was economic to install turbines in the dams with capability far in excess of dry year energy production – installed turbine nameplate ratings are roughly three times dry year average energy production. The Bonneville Power Administration (BPA) was established to develop the transmission and market the power produced by the hydroelectric system,

The FCRPS as developed was able to move energy production to periods where it was most needed or most valuable. The system was planned and operated for a 42 ½ month period where energy was shaped not only day to day and month to month but over a 42 ½ month period based on the driest 42 ½ month period in the historical record. This planning construct allowed BPA to “borrow” as much as 1500MW from expected water availability in future years to serve loads in the current year.

II. Development of the Columbia River Treaty (Treaty)

In the early 1960’s, the United States and Canada negotiated a Treaty regarding flood control and development of storage reservoirs on the Columbia River. Among many aspects of the Treaty was a requirement to agree on a set of metrics measuring dry year assured hydroelectric production and a sharing of the increased production resulting from new storage reservoirs in Canada. As the Treaty approaches the end of its 60-year initial minimum term, the United States and Canada are now engaged in a process examining renegotiation of the Treaty including the metrics for determining benefits of the Treaty and how those benefits should be shared.

Development of the Treaty created a surplus of hydroelectric generation in the mid-60s that provided the impetus for development of the Pacific Northwest-Pacific Southwest Intertie transmission facilities (Intertie). These transmission facilities allowed PNW utilities to trade surplus PNW summer capacity needed by California utilities for surplus California winter capacity and energy needed by PNW utilities (i.e. seasonal exchanges).

III. Development of the Hydro-Thermal Power Program

Continued growth of electric loads in the PNW during the 1960s led to development of the Hydro-Thermal Power program. Under this joint initiative of PNW utilities, the FCRPS would continue the installation of additional turbines at existing FCRPS dams while the utilities would

construct coal and nuclear plants to meet growing energy loads in the PNW. Many of the coal plants scheduled for retirement were a result of this program.

IV. Impacts of the Fish Measures on Energy Metrics

Congress passed the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act) in 1980 establishing the Northwest Power Planning Council (Council) tasked with creating a long-term regional resource plan and a fish and wildlife program. The fish and wildlife program and biological opinions established under the Endangered Species Act have resulted in changes to the operations of the FCRPS. These changes in operations reversed a portion of the change in the hydrograph caused by development of the FCRPS. The metrics used for dry year energy planning changed from a 42 ½ month period to an eight-month period. This change in metrics eliminated the ability to borrow from expected water availability in future years to serve the load in the current year and measured energy availability on an annual basis instead of a monthly basis. In response, planners assumed that surplus energy from PNW and California thermal plants could be purchased and stored or purchased as necessary to serve a portion of electric loads in the summer and winter of a dry year. These changes in operations to mitigate impacts on salmon have also reduced the FCRPS capability to move energy production in shorter timeframes.

V. Northwest Power Plan

Resource plans of the Council have primarily relied on several thousand MWs of conservation as described by the Regional Act to serve Pacific Northwest load growth over the last 40 years. The current power plan relies on conservation and increased development of demand response to serve PNW loads with the potential for a modest amount of natural gas resource development in the early 2020s. This plan was developed prior to the current legislative initiatives around carbon in the current Washington and Oregon legislatures.

VI. Loss of Industrial Electric Load

Another factor impacting the need for capacity in the PNW has been the change in industrial loads over the last 30 years. The PNW has seen a significant reduction of the PNW aluminum industry resulting in the loss of several thousand MWs of electric load. Global competition in pulp and paper, steel, and other industries has also resulted in the closing of industrial facilities that once used several thousand MWs of electricity in the PNW.

VII. Impact of the California Independent System Operator (CAISO) and the California Air Resources Board (CARB) on Seasonal Exchanges

Development of an organized market in California and the creation of the CAISO as well as the implementation of carbon cap and trade legislation by CARB has impacted the long-term marketing of surplus capacity over the Intertie.

Federal legislation passed prior to construction of the Intertie ensured that PNW energy in a dry year was reserved for use by PNW energy loads. This legislation enabled both short-term exchanges and long-term exchanges of energy that allowed the PNW to provide surplus capacity

to serve peak loads in California if the California entity committed to return the energy in a specified timeframe.

Creation of the CAISO created a new method of charging California loads for transmission on a per use basis instead of a fixed annual fee. The California cap and trade legislation includes a requirement to pay CARB a fee for each amount of energy generated by a fossil fuel resource and exported from California.

The current market prices for capacity will not support either long term or short-term exchanges of energy due to the impact of these two fees or charges.

VIII. Planning for Capacity

Most utility systems have historically planned to ensure they have generation capacity available to serve a few peak hours during the year leaving significant amounts of surplus energy during other periods. As the FCRPS faced reduced flexibility, BPA has reduced the amount of surplus capacity it sold long term and focused more of its sales in day to day and monthly markets. These PNW utilities, losing access to long-term surplus capacity sales from BPA, made the switch to capacity planning, however, many of them still rely on wholesale market purchases from other utilities in their planning.

BPA has primarily planned to ensure there was enough energy during a dry year. BPA has relied on planned amounts of purchases of wholesale energy during dry years instead of developing additional resources.

Development of renewable resources has created a new component of uncertainty in the system in addition to uncertainty in loads, resource outages, and availability of water. The metrics of planning for this uncertainty are still being developed.

IX. Implications of this History

The first three items of this history – development of the FCRPS, negotiation of the Columbia River Treaty and implementation of the Hydro-Thermal program – are key to understanding why capacity was never an issue in PNW power planning until now. **Because the PNW initially developed a hydro baseload system with hydro generators sized at three times the critical period Columbia River runoff, the region always had sufficient capacity to handle winter peaks.**

Subsequent developments, such as loss of aluminum load and PNW conservation efforts, basically enabled the region to continue to meet growing loads with only modest generating resource additions (primarily combustion/combined cycle turbines) until today. While fish mitigation measures lessened this capacity cushion, the real “crunch” did not come until this year, when a combination of substantial renewable resource acquisitions, scheduled retirement of existing coal plants and a political environment which probably prevents construction of new gas-fired resources will likely create substantial capacity shortfalls for the first time in the region’s 80-year electric power history.