FUTURE NORTHWEST CAPACITY SHORTAGES

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 have significant impacts on the PNW resource capacity outlook in the 2020-2030 timeframe. Such developments include:

A. E3 Study on PNW Resource Adequacy

E3, the consulting/analytical firm which has studied numerous West Coast power issues over the last several years, 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, the 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 Planning Council 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 the PNW capacity deficits projected by E3 absent new construction, the WA state legislature is considering, and probably will pass, 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 only be able to use their <u>existing</u> gas-fired resources for reliability emergencies (as opposed to economy energy transactions or normal load service).

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 only 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 and pending cap and trade system 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 only 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 very expensive (e.g., probably three to four times cost of a CT) and have yet to have their performance characteristics (e.g., four-hour discharge cycle, 20-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.

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 (25^{th} percentile) to ten (10^{th} 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, a maintenance outage on the DC intertie, and limitations in supplies of natural gas impacting the ability of some natural gas generation to operate.

These high prices, and the capacity shortage that they reflected, occurred despite 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 by 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 could incentivize development of capacity located in or deliverable on transmission to the loads of EIM Entities through increased local energy price volatility resulting from power balance failures. Depending on the design features, such expansion might provide greater marketing opportunities to resources not owned by EIM Entities (for both renewables and even CTs) if such design requires external resource participation. Such market expansion, for capacity resources, however, would be largely a by-product of that effort, unless the CAISO Board and WEIM Board develop incentives for capacity while expanding their energy-only market.

B. Prioritize Incentives for Ramping Capability Delivered to Load – 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. 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 the diversity inherent on planning reserve margins for individual utilities resulting from 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.

D. 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.