Pacific Northwest Power Supply Adequacy Assessment for 2017

Final Report

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Executive Summary

In 2010, as a part of its Sixth Power Plan, the Northwest Power and Conservation Council reported that the region's power supply was on the cusp of becoming inadequate by 2015. Based on an assessment prepared by the Resource Adequacy Forum, the plan noted that relying only on existing resources and targeted energy efficiency savings would result in a 5 percent likelihood of a shortfall, which is right at the limit the Council adopted in 2008. This result is consistent with the plan's finding that energy efficiency could meet most but not all forecasted load growth.

In this updated assessment, the forum concludes that the likelihood of a shortfall in 2017 has increased to 6.6 percent. This means that the region will have to acquire additional resources in order to maintain an adequate power supply, a finding that supports acquisition actions currently being taken by regional utilities.

Between 2015 and 2017, regional electricity demands, net of planned energy efficiency savings, are expected to grow by about 300 average megawatts. Since the last assessment, 114 megawatts of new thermal capacity, about 1,200 megawatts of new wind capacity and about 250 megawatts of small hydro and hydro upgrades have been added to the analysis. Also, a Northwest utility has contracted to purchase 380 megawatts of capacity from an independent power producer, which shifts this in-region generation from the market supply to firm resource status. Meanwhile, availability of the winter California market is assumed to decrease from 3,200 to 1,700 megawatts, mainly due to the retirement of coastal water-cooled thermal power plants.

The majority of potential future problems are short-term capacity shortfalls. The most critical months are January and February and, to a lesser extent, August. This is a different result from the 2015 assessment, which indicated that August was the most critical month. The major reason for this shift is the use of an updated streamflow record, which contains 10 more years of historical flows, new irrigation withdrawal amounts and various updates to reservoir operations both in the U.S. and Canada. The net result yields a higher average streamflow in August, thus improving summer adequacy.

The forum analyzed two different approaches to lowering the likelihood of a shortfall in 2017 back down to the 5 percent limit. Results show that adding 350 megawatts of additional dispatchable generation capacity or lowering the 2017 annual load by 300 average megawatts would bring the likelihood of a shortfall back down to the 5 percent limit. Demand response may also be a viable option but was not analyzed.

It should be noted that this assessment is not a substitute for a comprehensive resource acquisition plan. The optimal amount and mix of new resources needed to provide an adequate, efficient, economic and reliable regional power system is determined by the Council's power plan. This assessment also does not fully reflect constraints and needs of individual utilities within the region. Thus, these results should be viewed as a conservatively lower bound on regional needs for new resource capacity.

The Resource Adequacy Standard and What it Means

In 2008, the Northwest Power and Conservation Council adopted a regional power supply adequacy standard to “provide an early warning should resource development fail to keep pace with demand growth.” The standard, developed by the Northwest Resource Adequacy Forum, deems the power supply to be inadequate should the likelihood of curtailment five years in the future be higher than 5 percent. The forum uses probabilistic analysis to assess that likelihood, most often referred to as the loss of load probability.

The assessment only counts existing resources and those expected to be operational. It also includes targeted energy efficiency savings from the Council’s Sixth Power Plan. When the likelihood of curtailment exceeds the 5 percent limit, a separate analysis is made to quantify the minimum amount of new generation capacity or load reduction needed to bring the loss of load probability back down to 5 percent.

2017 Resource Adequacy Assessment

The last official adequacy assessment was adopted as part of the Sixth power plan. That assessment indicated the region’s power supply for 2015 was on the cusp of becoming inadequate -- the implied loss of load probability was 5 percent.

Between 2015 and 2017, the region’s electricity loads, net of planned energy efficiency savings, are expected to grow by about 300 average megawatts or about a 0.7 percent annual rate. Since the last assessment, 114 megawatts of new thermal capacity and about 1,200 megawatts of new wind capacity have been added along with about 250 megawatts of small hydro and hydro upgrades. The recent acquisition of 380 megawatts of a regional independent power resource has been included and the in-region market supply has correspondingly decreased.

California is expected to retire a substantial amount of its coastal water-cooled thermal power plants. It is also uncertain whether two units at the San Onofre Nuclear Generating Station will be operational in 2017. As a result, the forum reduced its assumption for the availability of California winter on-peak market supply from 3,200 to 1,700 megawatts.

Taking all of these changes into account, the expected loss of load probability for the 2017 power supply is 6.6 percent, indicating an inadequate supply if no additional resources are acquired. Types of potential problems the region could face range from energy shortfalls that could last for several days to peak curtailments that last several hours. Results show that the majority of simulated shortfalls are four hours or less in duration and over 40 percent are two hours or less.

To minimize cost and risk, new resource additions should be tailored to specifically address the expected types of shortfalls, that is, peak-hour shortages. This suggests that capacity resources such as simple-cycle combustion turbines or demand response programs or winter-peaking energy efficiency measures should be considered. It should be noted again, however, that the scope of this assessment is only to provide a gauge of the relative adequacy of the power supply. The determination of the quantity and mix of new resource capacity needed make the power supply adequate is left to more comprehensive integrated resource planning processes.

With that being said, the forum analyzed two different approaches to lowering the likelihood of a shortfall in 2017 back down to the 5 percent limit. First it examined how much additional dispatchable generating capacity would be needed to reduce the likelihood to 5 percent and secondly, it examined how much of an annual load reduction would accomplish the same objective. The results show that adding 350 megawatts of new dispatchable generation capacity would lower the 6.6 percent likelihood down to 5 percent. The same level of adequacy can be achieved by lowering the 2017 annual load by 300 average megawatts. Demand response is another alternative but the forum did not examine how much would be needed.

The findings for 2017 are consistent with assessments made by regional utilities indicating a need for new resources. It is also consistent with the plan, which concluded that energy efficiency alone will not be sufficient to offset all future load growth. In aggregate, utility planned resources far exceed the 350 megawatt gap.

In the analysis for 2017, the most critical months are January and February and, to a lesser extent, August. This is a different result from the last official assessment, which indicated that August was the most critical month. The major reason for this shift is the use of an updated streamflow record. The new record contains;

- 80 years of historical streamflow data (the old record had 70 years)
- New irrigation withdrawal amounts
- More current Canadian system operation (both for treaty and non-treaty storage)
- Updated operating requirements at Grand Coulee
- More accurate representation of the operation of Snake River Basin dams
- Other miscellaneous adjustments at various hydroelectric projects

These changes, in aggregate, result in an overall shift in streamflows across the months of the year. In particular, the average August streamflow is expected to increase by about 10,000 cubic feet per second, which translates into about 650 megawatts of additional power for the regional system.

Dependence on the Market

The methodology used to assess the adequacy of the Northwest power supply assumes a certain amount of reliance on market power supplies, both from within the region and from California. A significant part of the Northwest market is made up of independent power producer resources. The full capability of these resources, about 3,450 megawatts, is assumed to be available for Northwest use during winter months. However, during summer months, due to competition with

California utilities, the Northwest market availability for Northwest use is limited to 1,000 megawatts.

The California market is broken into on-peak and off-peak availabilities. The off-peak availability is assumed to be 3,000 megawatts year round. Energy from the off-peak market is purchased during light-load hours prior to periods of potential shortfalls and is often referred to as a purchase-ahead resource. The on-peak availability is assumed to be 1,700 megawatts during winter and not available at all during summer.

Northwest utilities routinely rely on market resources to maintain an adequate power supply. The amount of market resources used depends on a number of conditions, with the biggest factors being stream flow levels, outages of utility-owned resources, and temperature-driven load variations. For 2017, assuming only existing resources and targeted energy efficiency, the analysis shows the region would purchase an average of 1,170 megawatt-months of market supplied energy in December representing about 18 percent of the total available energy (6,450 megawatts-months). In August the region is would purchase an average of 400 megawatt-months of market supplied energy or approximately 10 percent of the total available energy (4,000 megawatts-months).

However, averages can be misleading and a more important statistic is how much market supplied energy is needed during extreme events when the regional load-resource balance tightens. Ten percent of the time, market purchases would exceed 2,200 megawatt-months in December (34 percent of the total) and 820 megawatt-months in August (21 percent of the total). The full amount of market supplied energy would be needed in less than 1 percent of all hours.

Uncertainties

The forum's analytical tools account for uncertainties in stream flows, wind generation, temperature-driven demand variations, and generating resource availability. However, there are additional uncertainties that are not explicitly modeled. Two of the more significant uncertainties are economic load growth and the availability of the California energy market. The expected 6.6 percent loss of load probability assumes the Council's medium load forecast and 1,700 megawatts of expected California on-peak winter market supply.

To investigate the potential impacts of different combinations of economic load growth and California market availability, scenario analyses were performed. In the worst case, with high load growth and no California market, the loss of load probability would be 16.8 percent. The good news is that this scenario is very unlikely. In the best case, with low load growth and 3,200 megawatts of California market, the loss of load probability drops to 2.8 percent, well within the Council's limit.

While the current assessment provides the best estimate for the probability of a power supply shortage, the loss of load probability could be larger or smaller depending on load and market conditions in 2017. And, because the uncertainty surrounding these particular variables is not well defined, it is difficult to develop a range of likely loss of load probability values. What is clear is that there is a relatively high chance that the region will need some level of new resource development by 2017 in order to maintain an adequate supply.

Future Assessments

The Resource Adequacy Forum will continue to annually assess the adequacy of the power supply. However, this task is becoming more difficult because the power supply has become more complex in recent years. The increase in variable generation resources, combined with changing patterns for electricity demand, is forcing utility planners and operators to more carefully assess what resources are needed in reserve to ensure that demand can be met minute to minute. The current adequacy assessment incorporates a certain amount of minute-to-minute reserves, but it is not certain that they will be sufficient. Regional planners are evaluating various methods to quantify and plan for these flexibility needs.

Another emerging concern is the lack of access for some utilities to market supplies due to insufficient transmission or other factors. For the current adequacy assessment, the Northwest region is split into two subsections and only the major East-West transmission lines are modeled. Similarly, only the major Canadian-US and Northwest-Southwest interties are modeled. It may be necessary to divide the Northwest region into more subsections to better address the effects of transmission congestion on power supply adequacy.

Resource adequacy continues to be a concern in the Northwest. The forum's results are consistent with regional utility integrated resource planning, which supports the need for additional capacity. The Council and forum will continue to improve methods used to assess the power supply adequacy.

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