CHAPTER 11: SYSTEM NEEDS ASSESSMENT

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KEY FINDINGS

Comparing forecasted load to existing resource capability for the 2035 operating year indicates that the annual energy supply will be 1,000 average megawatts surplus under the low load forecast but 2,600 average megawatts deficit under the high forecast. The projections for capacity needs are more pessimistic. By 2035, the winter peaking capability is projected to be 1,275 megawatts short of expected peak load for the low load forecast and over 6,000 megawatts short for the high forecast.

However, this deterministic comparison of loads and resources is not an accurate assessment of resource needs because it does not take into account the effects of future uncertainties and the availability of market supplies. A better way to assess resource needs is to determine how much additional energy and capacity are required to ensure that the power supply satisfies the Council's adequacy standard of a 5-percent loss-of-load probability (LOLP).

Using a more sophisticated probabilistic method shows a relatively small energy need of 55 to 800 average megawatts by 2035 – much lower than the needs calculated using the deterministic approach. This is because the deterministic approach does not account for the substantial amount of in-region and out-of-region market supplies and it assumes critical water conditions – a very low likelihood event. The region's capacity needs in 2035, however, are much greater than those calculated using a deterministic approach. They range from about 4,300 megawatts under the low forecast to about 10,600 megawatts under the high forecast. This is because the deterministic approach does not capture combinations of water conditions, temperature, wind generation and forced outages that produce very large gaps between available resources and demand.

It is important to highlight that acquiring resources based strictly on a deterministic approach will lead to an over built system with respect to energy needs and to an under built system with respect to capacity needs.

In the near term, the power supply remains adequate until 2021, when the Boardman and Centralia 1 coal plants are expected to retire, but this assumes that the region will continue to implement cost-effective energy efficiency measures. If energy efficiency targets are not achieved, or if loads grow unexpectedly fast or if market supplies drop sharply, the region could face an inadequate supply much sooner.

One of the key enhancements to the analysis in this power plan is the improved linkage between the Council's adequacy model (GENESYS) and the Regional Portfolio Model (RPM). Using GENESYS, the Council's 5-percent adequacy standard is converted into Adequacy Reserve Margins (ARMs), which are fed into the RPM as minimum build requirements to maintain adequacy.

Another key enhancement in the linkage between the GENESYS and RPM models is the use of the associated system capacity contribution (ASCC) for all new resources in the RPM. The ASCC represents the effective capacity of a resource when it is added to the existing system. Because, unlike GENESYS, the RPM does not model the dynamic interaction between the hydroelectric system and non-hydro resources, the benefits of storage are not accurately captured. In many cases, this interaction results in an effective system capacity that is greater than the resource's nameplate capacity.

Implementing the ARM and ASCC parameters into the RPM is a way of ensuring that resulting resource strategies will produce adequate power supplies and more realistically reflect the interaction of new resources with the existing power system. To test this, projected power supplies for the 2026 and 2035 operating years from various RPM futures were tested for adequacy using the GENESYS model. However, because of the wide range of future uncertainties modeled in the RPM and because of unit size and other limitations, it is unrealistic to expect that every year's loss-of-load probability will be exactly 5 percent (the Council's standard). A specific year's power supply extracted from an RPM analysis is deemed to be acceptably adequate if its LOLP ranges between 2 and 5 percent. Supplies with zero LOLP values are over built and those with LOLP values greater than 5 percent are under built (inadequate). Adequacy tests show that LOLP values for futures with medium to high load growth fall within the acceptable range. For futures with low load growth, LOLP values tended to be near zero, meaning that those supplies are over built – likely because the RPM is acquiring resources (energy efficiency and demand response) for economic reasons and not for adequacy.

REGIONAL LOAD-RESOURCE BALANCE

A quick way to estimate the need for future resources is to compare existing regional generating capability to projected future load. This type of calculation is often referred to as a load-resource balance[1] and is usually made for both energy and capacity needs. Energy needs refer to having sufficient generating capability and fuel (water for the hydroelectric system) to match the annual average load, in units of megawatt-hours (or average megawatts). Capacity needs refer to having sufficient machine capability to match the highest load hour in the year, in units of megawatts. Using this approach, the implied target for resource acquisition is to have sufficient energy and capacity generating capability to serve the expected annual average load and the year's highest peak load, with a little extra to cover unexpected resource outages and extreme temperature fluctuations.
For the energy load-resource balance, weather-normalized annual average load is used. Only existing rate-based resources and those that are expected to be operational in the year in question are counted. For each thermal resource, the annual generating capability is equal to its single-hour winter capacity (not always the same as the nameplate capacity) adjusted by its average forced outage rate and its average down time for maintenance. Wind energy generation is assumed to be 30 percent of its nameplate capacity. Hydroelectric generation is based on the critical water year (1937) and includes all reservoir operating constraints for fish survival as detailed in the Council's current Fish and Wildlife Program. Only the savings from current energy efficiency programs and their effect on future loads are included. No load reductions from future energy efficiency programs are counted. This type of load forecast is commonly referred to as a "frozen efficiency" forecast. Market resources, such as in-region Independent Power Producer (IPP) plants and imports from out-of-region suppliers are also not included in this calculation.

Figure 11 - 1 below illustrates the forecast annual average energy load for both low and high-growth economic futures. This figure also shows the existing resource annual energy generating capability.

[1] Load-resource balances are also estimated and published in both the PNUCC NRF and the BPA White Book.

Between 2015 and 2020 the region is expected to add 440 megawatts of new capacity from the Carty gas-fired plant and 220 megawatts of capacity from the Port Westward 2 project. In 2021, the Boardman (530 megawatt) and Centralia 1 (670 megawatt) coal plants are scheduled to be retired. By 2026 both the Centralia 2 (670 megawatts) and North Valmy (260 megawatts) coal plants are also expected to be retired. Centralia 2 and 290 megawatts of Centralia 1 are IPP resources, thus their retirements will not appear in Figure 11 - 1. Table 11 - 1 provides the corresponding load-resource energy balances for the specific years examined.

Figure 11 - 1: Annual Average Energy – Frozen Efficiency Load vs. Generating Capability

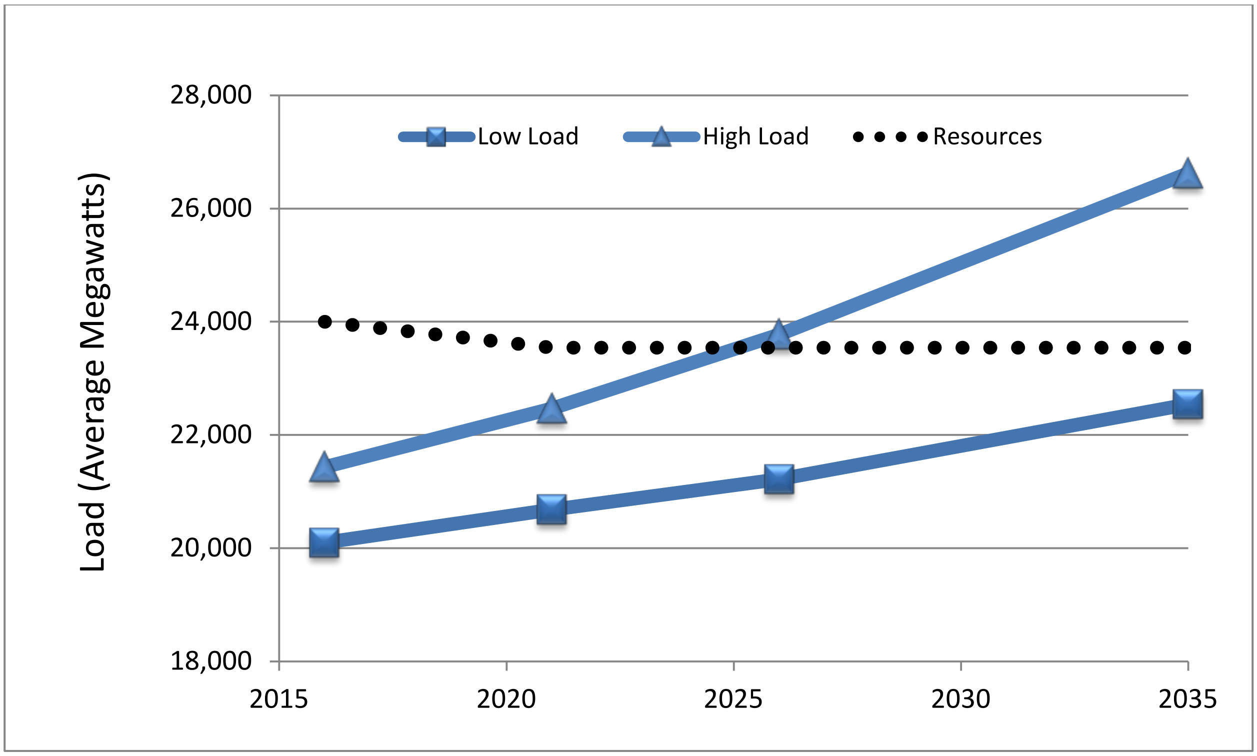


Table 11 - 1: Energy Load-resource Balance

Forecast	2016	2021	2026	2035
Low	3,903	2,859	2,322	999
High	3,248	1,510	200	-2,644

For the capacity load-resource balance, the load is the expected quarterly single-hour peak load. That value is determined by extracting the highest single-hour load for every quarter from each of the 80 different temperature profiles modeled (based on 1929-2008 historical temperatures) and then averaging those 80 peak-hour loads for each quarter. Thermal resource capacity is adjusted by the average forced-outage rate. For hydroelectric capacity, the 2.5 percentile[2] 10-hour sustained peak capability for each quarter is used. This is the maximum amount of generation that the hydroelectric system can sustain over a 10-hour period using water conditions that represent the lowest 2.5 percent for the quarter across the 80-year record. That is, there is a 97.5 percent probability that hydroelectric system capacity will be greater than this.

The single-hour peak load is used because the Council's long-term load forecasting model, which provides the loads for the RPM, does not forecast a sustained-peak load. On the resource side, the 10-hour sustained hydroelectric capacity is used because using a single-hour value greatly overestimates the capability of the hydroelectric system. Because of the relatively low storage-to-river-flow-volume ratio (about 0.16) the hydroelectric system cannot sustain the single-hour peak generation for even a two-hour period. Using the 10-hour sustained capacity with the single-hour peak load leads to a conservative assessment for the load-resource balance. Using these two parameters to define the adequacy reserve margins (as will be discussed later in this chapter) is perfectly acceptable, as long as the same parameters are used when adequacy is tested.

Figure 11 - 2 below illustrates the forecast winter peak-hour capacity load for both low and high economic futures. This figure also shows the amount of existing resource generating capacity. Table 11 - 2 provides the corresponding capacity load-resource balances for the specific years examined.

[2] The 2.5 percentile 10-hour sustained peak represents a minimum hydroelectric system peaking capability that can be achieved 97.5 percent of the time. In other words, in only 2.5 percent of the time is this peaking capability not achievable.

Figure 11 - 2: Winter Peak – Frozen Efficiency Load vs. Peaking Capacity

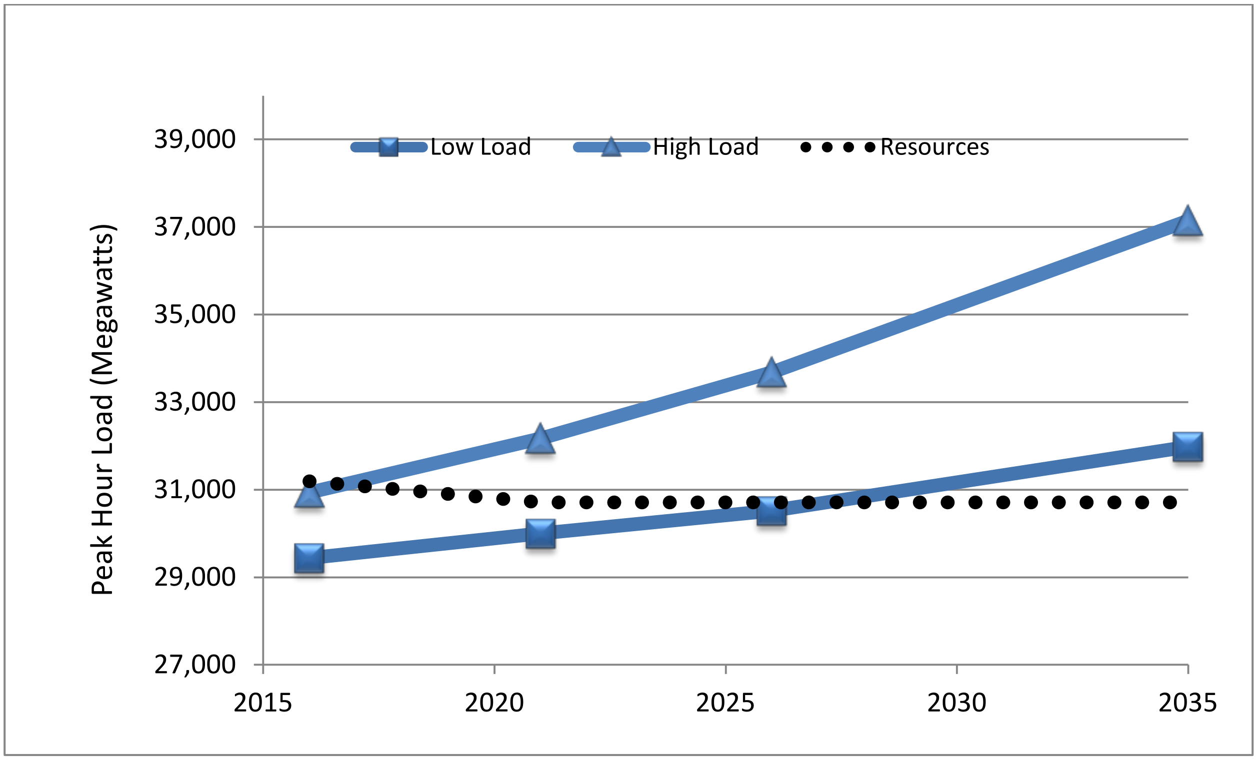


Table 11 - 2: Capacity Load-resource Balance

Forecast	2016	2021	2026	2035
Low	1,759	708	190	-1,275
High	943	-1,026	-2,538	-6,000

ENERGY AND CAPACITY NEEDS

The simple load-resource balance calculations done above provide a general idea of future resource needs. However, more accurate and appropriate methods have been developed to better assess future needs. The load-resource balance planning approach originated when the region was essentially isolated from the rest of the Western system by limited transmission. However, even after the North-South interties were built, this method continued to be used in regional load and resources summary publications.[3]

Planners generally knew, however, that a better method of assessing resource need was necessary. The reasons are twofold. First, in almost all years, hydroelectric generation will exceed production under critical-water conditions, which are used to calculate the load-resource balance. Second, Southwest markets (California, Arizona and New Mexico) should always have surplus energy and capacity to export in winter, when Northwest loads have historically been highest. Thus, planning for new resources in the Northwest based on the conservative load-resource balance criterion does not necessarily produce the least cost and least risk resource strategy and, in fact, can lead to overbuilding.

In addition, the Northwest power system has become more complex, with greater non-power constraints placed on the operation of the hydroelectric system, increased development of variable and distributed resources, and the growth of a west-wide electricity market. The Council recognized this need, and in its Fifth Power Plan recommended developing a resource adequacy standard to better assess future resource needs. Supporting this decision was federal legislation, passed in 2005, requiring an Electric Reliability Organization to develop a standard method of assessing the adequacy of the North American bulk power supply. That role is filled by the North American Electric Reliability Corporation (NERC).

Changes in the Bonneville Power Administration's role as a power provider mean that load-serving entities will bear more of the cost for their own load growth, making regional coordination to ensure adequacy especially important. Bonneville still bears the overall responsibility as the balancing authority for most of the region's public utilities.

The Council created the Northwest Resource Adequacy Advisory Committee to aid in developing a standard, and to annually assess the adequacy of the power supply. The committee, which is open to the public, includes utility planners, state utility commission staff, and other interested parties. In December of 2011, the Council adopted the advisory committee's recommendations for a northwest regional resource adequacy standard.

The Council's Adequacy Standard

The Council's overarching goal for its adequacy standard is to *"establish a resource adequacy framework for the Pacific Northwest to provide a clear, consistent, and unambiguous means of answering the question of whether the region has adequate deliverable resources to meet its load reliably and to develop an effective implementation framework."*

This standard has been designed to assess whether the region has sufficient resources to meet growing demand for electricity in future years. This is important, because it takes time – usually years – to acquire or construct the necessary infrastructure for an adequate electricity supply.

[3] The Bonneville Power Administration White Book and the PNUCC Northwest Regional Forecast of Loads and Resources.

Power supply adequacy is assessed five years into the future, assuming rate-based generating resources and a specified level of reliance on imported and within-region market supply. Resources include existing plants and planned resources that are sited and licensed and are expected to be operational during the year being assessed. Load assumptions are based on the Council's Short-term Load Model's medium forecast and are adjusted to include the expected conservation savings from the Council's latest power plan.

The adequacy of the Northwest's power supply is assessed as the likelihood of the occurrence of a supply shortfall by using probabilistic simulation methods. This approach differs from historical deterministic methods, which simply tally expected resource capability and expected regional load (i.e. load-resource balance approach). Probabilistic methods are commonly used around the country and the world because they offer a better assessment of adequacy by taking future uncertainties into account.

The metric used to assess the adequacy of the Northwest's power supply is the loss-of-load probability (LOLP). The LOLP is measured by performing a chronological hourly simulation of the power system's operation over a large set of variant conditions[4]. More specifically, the operation is simulated hourly over many different combinations of water supply, temperature (load variation), wind generation and resource forced outages. Any hour in which load cannot be served is recorded as a shortfall.

The resulting simulated shortfalls (periods when resources fail to meet load) are screened against the aggregate peaking and energy capability of standby resources. Standby resources are generating resources and demand-side management actions, contractually available to Northwest utilities, which can be accessed quickly, if needed, during periods of stress. These resources are intended to be used infrequently and are generally not modeled explicitly.

Shortfalls that exceed the aggregate capability of standby resources are considered curtailment events.[5] LOLP is assessed by dividing the number of simulations (years) with at least one curtailment event by the total number of simulations. In other words, it is the likelihood that a future year will experience a shortfall sometime during the year.

The power supply is deemed adequate if its LOLP, five years into the future, is 5 percent or less. This means that the likelihood of at least one shortfall event occurring sometime during that year must be 5 percent or less.

The GENESYS Model

The Council's GENESYS model is primarily used to assess resource adequacy. It is a Monte Carlo computer program that simulates the operation of the Northwest power system. It performs an economic dispatch of resources to serve regional load on an hourly basis. It assumes that all

[4] This type of simulation is often referred to as a Monte-Carlo analysis.

[5] It should be noted that these simulated curtailment events do not necessarily translate into real curtailments because utilities often have other, more extreme, actions that they can take. However, for assessing adequacy, the threshold is set at the capability of standby resources.

available resources will be used to serve firm load. Those resources include merchant generation within the region and limited imports from out of region.

The model splits the Northwest region into eastern and western zones to capture the possible effects of cross-Cascade transmission limits. East-west transmission capacity is a function of line loading. The Southwest-to-Northwest intertie capacity is limited to 3,400 megawatts based on historical capacity assessments (but due to market inefficiencies and other potential constraints, peak-hour imports are limited to 2,500 megawatts during winter months only). Outages on the cross-Cascade and inter-regional transmission lines are not modeled.

The important stochastic variables (future uncertainties) that are modeled are river flows, temperatures (as they affect electricity loads), wind generation and forced outages on thermal generating units. The model typically runs thousands of simulations for a single fiscal year, choosing future uncertainties at random.

Non-hydro resources and contractual commitments for imports and exports are part of the GENESYS input database, as are forecasted electricity prices.

GENESYS dispatches all available regional resources and imported energy from out-of-region suppliers in order to serve firm loads in each zone. In the event that resources are not sufficient to meet firm loads, the model will draft the hydroelectric system below the “firm drafting rights” rule curve elevations. This “borrowed” hydro energy is used for short periods of time during cold snaps and heat waves or because of the loss of a major generator. Once the emergency has passed, reservoir levels are restored by running regional non-hydro resources or by importing out-of-region energy.

The model keeps track of periods when firm loads cannot be met or when required contingency reserves cannot be maintained. The LOLP is simply the percentage of simulations that result in a shortfall divided by the total number of simulations. The output also provides the frequency and magnitude of curtailments, along with other adequacy metrics.

GENESYS does not currently model long-term load uncertainty (unrelated to temperature variations in load) nor does it incorporate any mechanism to add new resources should load grow more rapidly than expected. It performs its calculations for a known system configuration and a known long-term load forecast. In order to assess the adequacy of the system over different long-term load scenarios, the model must be rerun using new load and resource additions.

The probabilistic assessment of adequacy in GENESYS provides much more useful information to decision-makers than a simple deterministic (static) comparison between resources and load. Besides the expected values for hydroelectric generation and dispatched hours for thermal resources, the model also provides the distribution (or range) of operations for each resource. It also highlights situations when the power supply is not able to meet all of its obligations. These situations are informative because they identify the conditions under which the power supply is inadequate. The frequency, duration, and magnitude of these curtailment events are recorded so that the overall probability of not being able to fully serve load is calculated.

It should be noted that in determining the LOLP, an assumption is made in GENESYS that all available resources will be dispatched in economic order to “keep the lights on,” regardless of cost.

Assumptions

Table 11 - 3 below summarizes assumptions used to assess the adequacy of the region's power supply. In general, they define what resources and loads are counted. As can be seen in the table, an adequacy assessment considers all sources of generation and demand control that are reasonably likely to be available.

Power supply adequacy is very sensitive to the following key assumptions:

Reserves – a certain amount of resource (or load management control) is set aside to cover unexpected changes in load and in variable resource generation. The purpose of operating reserves is to ensure that load is matched exactly with generation at all times. Chapter 10 summarizes reserves and ancillary services that the power system provides. Chapter 16 and Appendix K provide more detail regarding how reserve needs are assessed and how they can be best provided.

Merchant supplies – the Council assumes that all Independent Power Producer (IPP) capability will be available for regional use during winter months. During summer, however, when California experiences its peak loads, only 1,000 megawatts of IPP capability are assumed to be available for regional needs. This amount comes from an estimate of the amount of IPP generation that does not have direct transmission to California markets.

Imports – based on a report by Energy GPS[6], California's surplus capability should exceed the South-to-North intertie transfer capability in most months. Thus, the key assumption related to imports is the availability of the transmission interties. Based on historical assessments of South-to-North transfer capability, the Council has set the intertie limit to 3,400 megawatts (this was the recommendation of the Resource Adequacy Advisory Committee). Historical data show that availability of the transmission intertie should be 3,400 megawatts or greater 95 percent of the time. However, because of market inefficiencies and other physical or operational constraints, the advisory committee suggested limiting peak-hour imports to 2,500 megawatts during winter and to zero for summer.

Standby resources – these include small generating resources (too small to model), demand-side measures not already accounted for in the load forecast, pumped storage (at Banks Lake) and other miscellaneous measures.

Borrowed hydro – this represents hydroelectric generation derived from drafting certain reservoirs below their drafting-rights rule curve elevations for short periods of time. The drafting rights elevations are determined through a complicated analysis (based on the Pacific Northwest Coordination Agreement) that optimizes hydroelectric generation for the regional load shape during critical year (river flow) conditions. This analysis effectively determines the hydroelectric system's firm energy load carrying capability, which is contractually available to all participants in every year. Drafting below the drafting-rights elevations is done as a practical matter all the time for short periods of time, such as over a few hours or a few days. The critical factor with borrowed hydro is that it must be replaced as soon as possible so that the end-of-month elevation is not affected. The amount of borrowed hydro assumed for this analysis was derived by estimating how much the

[6] Belden, Tim and Turkheimer, Joel, "Southwest Import Capacity," EnergyGPS, March 3, 2014, http://www.nwcouncil.org/media/7149574/southwest_import_capacity_20140611.pdf

system could be drafted below the drafting-rights elevations without affecting the April and June reservoir refill requirements in the Council's current Fish and Wildlife Program.

Table 11 - 3: Assumptions for Resource Adequacy/Needs Assessment

Element	Assumption
New thermal resources	Must be sited and licensed
New wind and solar	Must be sited and licensed
Existing demand response	In load forecast
New demand response	In standby resources
Standby resources energy limit	40,800 MW-hours
Standby resources capacity	623 MW winter / 833 MW summer
EE for adequacy assessment	Council Sixth Power Plan targets[7]
EE for needs assessment	No new EE (i.e. use frozen efficiency load forecast)
Energy efficiency shape	Same as load but will match RPM shape in future analyses
In-Region market (IPP)	3,000 MW winter / 1,000 MW summer
On-peak imports	2,500 MW winter / 0 MW summer
Off-peak purchase-ahead imports	3,000 MW
South-to-North intertie limit	3,400 MW
Balancing reserves	Region-wide INC/DEC requirements, which include BPA's 400 MW INC/300 MW DEC April, May and June 900 MW INC and DEC all other months
Borrowed hydro	1,000 MW-periods

Adequacy Assessment vs. System Needs

The Council's adequacy assessment is used as a check on resource development. It assesses whether the regional power supply has sufficient resources to limit the LOLP to no more than 5 percent, assuming only existing resources and the targeted level of energy efficiency savings.

[7] Future energy efficiency savings are estimated by the Council's Short-Term Load Forecasting Model. This is an econometric model that projects future savings based on past trends. The projected savings are very close to the target values derived in the Council's 6th power plan.

The Council's needs assessment differs from an adequacy assessment in that it does not include targeted energy efficiency savings and it generally spans a longer time period (20 years). The needs assessment determines the expected magnitude of energy and capacity shortfalls during key years of the study horizon, which for the Seventh Power Plan are 2021, 2026 and 2035. This provides a general gauge of the magnitude of energy and capacity needs without explicitly trying to develop a resource mix to fill those needs. That task is left for the Council's Regional Portfolio Model.

Figures 11 - 3 and 11 - 4 below are similar to Figures 11 - 1 and 11 - 2 but additionally show the load uncertainty range used in the Regional Portfolio Model. These figures illustrate the differences in load forecasts used for adequacy assessments (two individual dots) and resource needs assessment (solid lines) and system expansion (dashed lines). The loads used for adequacy assessments are generally between the low and high range of forecasted loads because they are not designed to take into account the full range of future loads examined in the needs assessment and in the RPM analyses. The frozen efficiency load forecasts assume no new energy efficiency savings but do include the effects of anticipated savings from efficiency standards that are expected to be implemented and are weather normalized. The RPM range of loads across the 20-year study horizon is wider than the Council's frozen efficiency load forecast because the RPM incorporates a wider range of uncertainty surrounding future economic conditions.

It should be noted that even though the most recent adequacy assessment[8] concluded that the 2020 power supply is expected to be adequate, there remains a significant likelihood that it may not be, depending on how loads turn out and how the availability of imports changes.

[8] The Council's latest resource adequacy assessment can be found at http://www.nwcouncil.org/media/7149624/2020_21-adequacy-assessment-final-050615.pdf

Figure 11 - 3: Annual Energy Loads and Resources

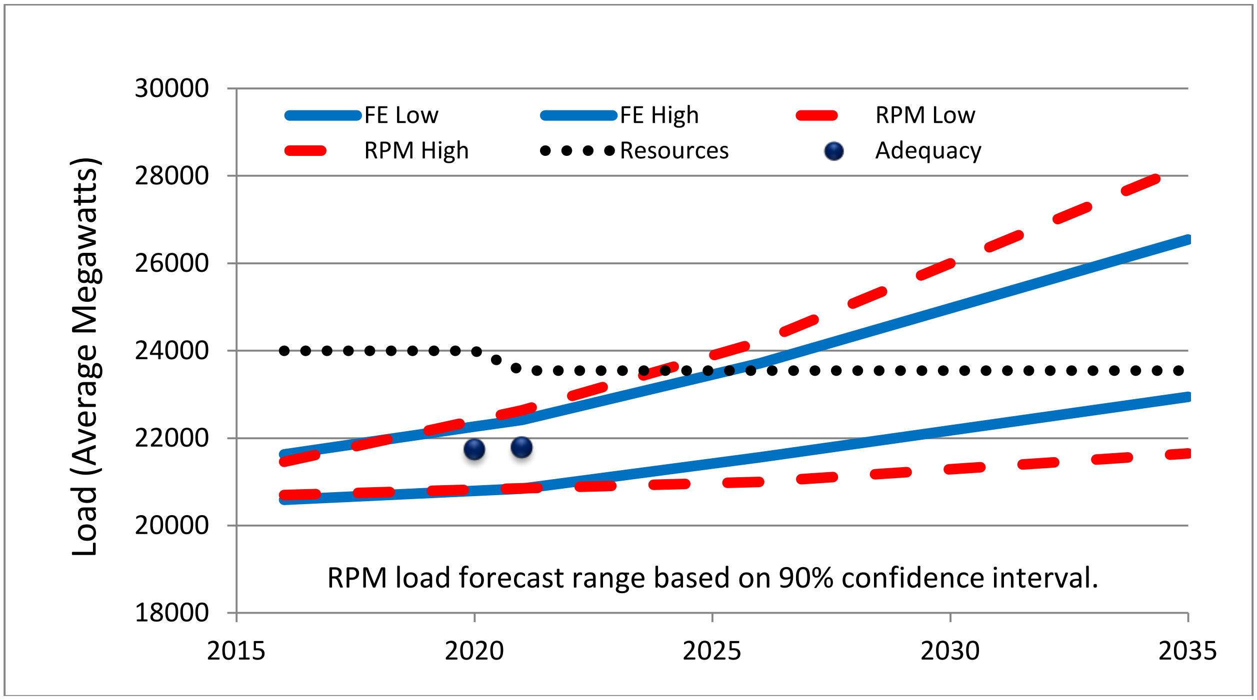
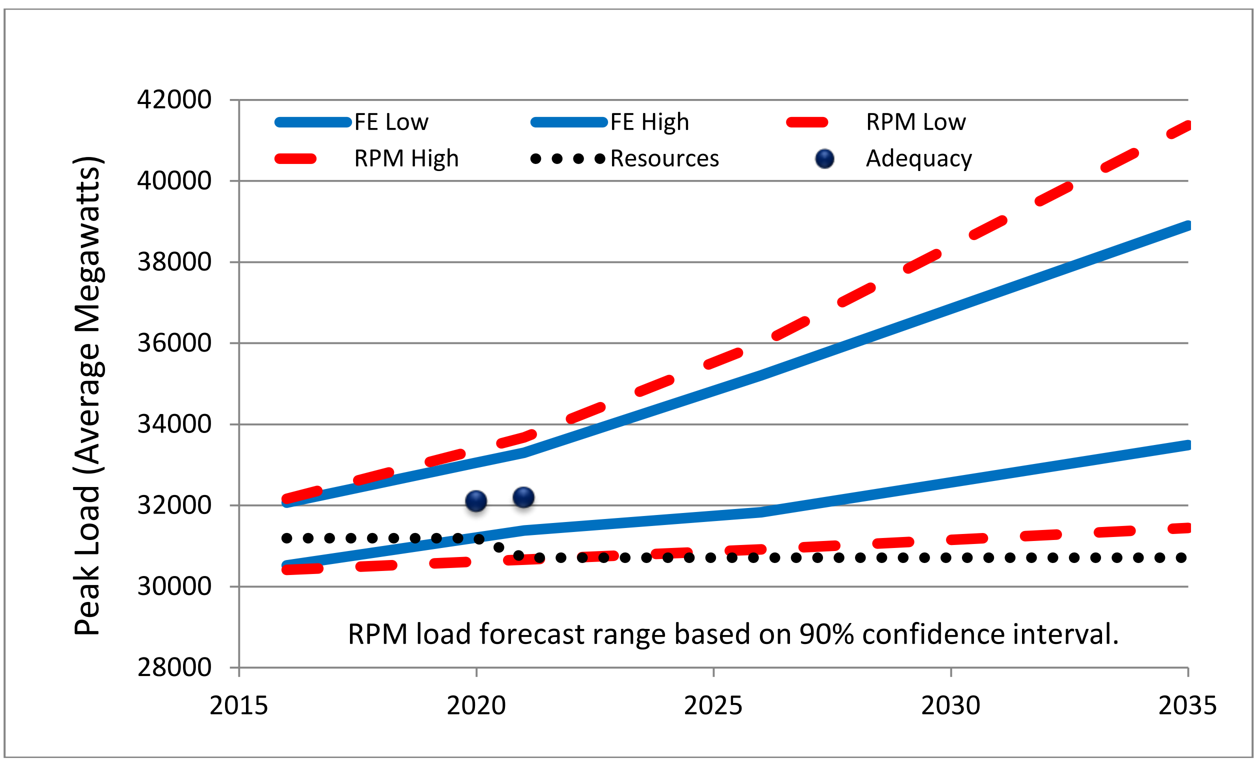


Figure 11 - 4: Winter Peak Loads and Resources



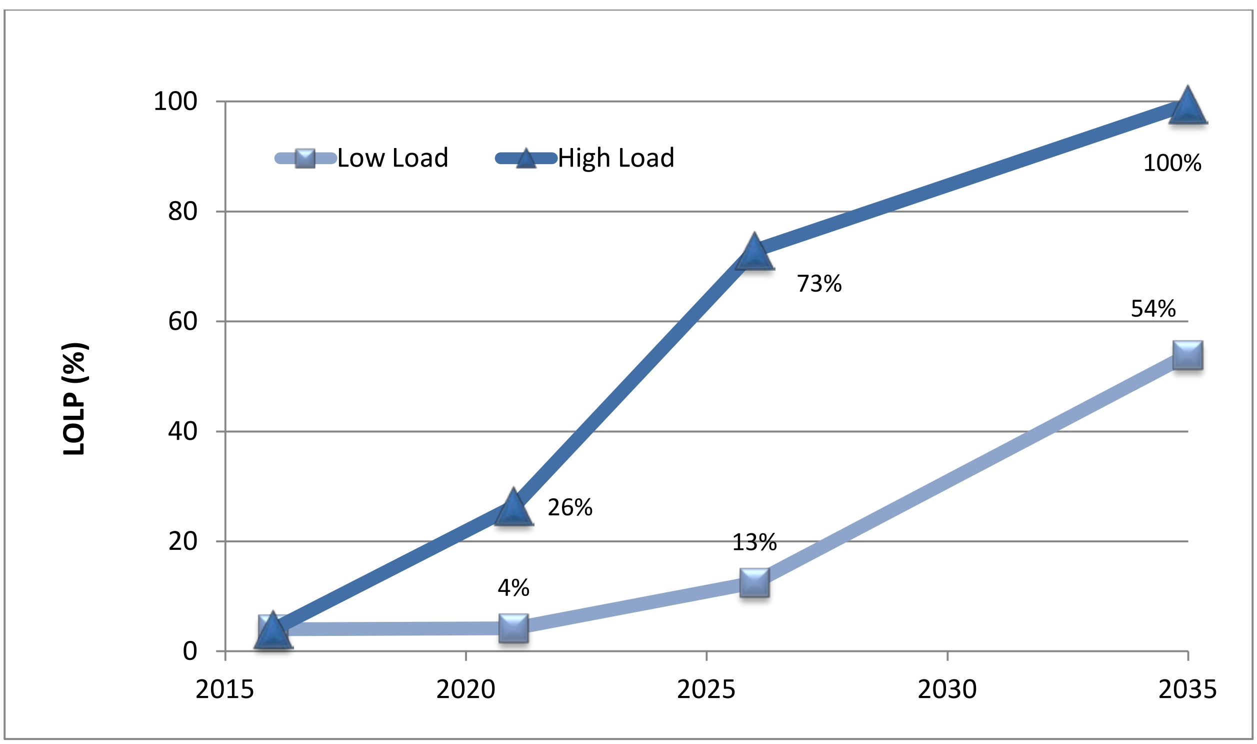
Projected Resource Shortfalls through 2035

The Council's resource needs assessment examines the loss-of-load probability for both the low and high load growth scenarios for 2021, 2026 and 2035. Those years are significant because they represent times with key resource retirements. The Boardman and Centralia 1 coal plants are scheduled to retire at the end of 2020. The second unit at Centralia and the North Valmy coal plants are expected to retire at the end of 2025. And, of course, 2035 is the end of the study horizon for the Council's Seventh Power Plan.

As illustrated in Figure 11 - 5, in every case except the 2021 low-load-growth scenario, the LOLP is greater than 5 percent (the Council's adequacy threshold). The LOLP grows to staggeringly high values over time because these analyses do not include any new generating resource additions or energy efficiency savings. In the extreme case, for 2035 under a high load growth scenario, there were very few simulations that did not have some kind of shortfall (the LOLP was just under 100 percent). This should not be a surprise since these studies, in effect, tell us what would happen if no resource actions were taken over the next 20 years.

But these results alone are not sufficient to inform resource planning. Based on these analyses, both the energy and capacity needed to get every point in Figure 11 - 5 down to a 5 percent LOLP can be determined. This information, in a slightly modified form is fed to the Regional Portfolio Model to ensure that the resulting resource strategy will provide an adequate supply.

Figure 11 - 5: Loss-of-Load Probability for the Needs Assessment (no new resources)



Resource Adequacy vs. Seventh Power Plan

The Council's latest resource adequacy assessment for the 2020 and 2021 operating years was released in May of 2015. Results indicate that the regional power supply is expected to remain adequate through 2020, assuming that the region continues to acquire the targeted Sixth Power Plan energy efficiency savings. In 2021, however, with the retirement of the Boardman and Centralia-1 coal plants[9] (1,330 megawatts of combined nameplate capacity), the report shows that the likelihood of a shortfall rises to a little over 8 percent, which is above the Council's 5-percent standard. Adding 1,150 megawatts of gas-fired generation would bring the 2021 loss-of-load probability back down to the 5-percent limit.

However, any comparison of the results of the Council's annual adequacy assessments with results from the multitude of scenarios examined while developing a power plan should be done with extreme caution. The adequacy assessment is intended to be a single-year spot check to indicate whether resource development is on track to maintain adequacy. Power plan analyses examine the operation and cost of thousands of different resource plans over a 20-year horizon, with many more future uncertainties than are accounted for in the adequacy assessment. However, in spite of these difficulties, certain specific years, with specific conditions can be compared so long as the differences in the purpose of these two analyses are understood.

One of the major differences between these two approaches is that power plan analyses use the Council's frozen efficiency load forecasts, which do not include any new energy efficiency measures but do incorporate the effects of standards and codes. In contrast, the loads forecast used to assess resource adequacy come from the Council's short-term model, which does include trends for future energy efficiency but does not account for standards and codes. Also, the frozen efficiency loads are weather normalized whereas loads used for the adequacy assessment are temperature dependent.

On the resource side of the equation, for the Seventh Power Plan the Council has amended the hydroelectric system capability to reflect a greater allocation of that resource to carry regional within-hour balancing reserves. This reduces hydroelectric system peaking capability to serve firm on-peak loads by about 1,000 megawatts[10] compared to the capability used for the May 2015 adequacy assessment, which only assumed the Bonneville Power Administration's balancing reserves.

The 2021 resource adequacy assessment loss-of-load probability was reported as about 8 percent and included about 1,700 average megawatts of expected new energy efficiency. The 2021 power plan frozen efficiency loss-of-load probability is on the order of 15 percent (for the medium load forecast) and includes no new energy efficiency but does incorporate savings from standards and

[9] Boardman and Centralia 1 coal plants are scheduled to retire in December of 2020. However, because the Council's operating year runs from October 2020 through September 2021, these two plants would be available for use during the first three months of the 2021 operating year. For this scenario, the LOLP is 7.6 percent. The Council must take into account the long term effects of these retirements and, therefore, uses the more generic study that has both plants out for the entire operating year.

[10] Actual reduction in peaking capability depends on a number of different parameters and can fluctuate from near zero in some periods to over 1,000 megawatts in others.

codes. It also assumed the reduced hydroelectric system capability, adjusted to reflect regional balancing reserves.

To get the 2021 resource adequacy assessment LOLP down to the 5-percent standard, 1,150 megawatts of gas-fired generation were added to the expected 1,700 average megawatts of new energy efficiency savings. To get the 2021 power plan LOLP down to the 5-percent standard, the Council's Regional Portfolio Model shows an average addition of 2,380 average megawatts of new energy efficiency and about 1,300 megawatts of demand response, which for modeling purposes is equivalent to the addition of about 1,100 megawatts of gas-fired generation. Thus, in spite of the vastly different assumptions between these two cases, the overall conclusions are very similar. In both cases, the 2021 power supply would be inadequate under medium loads with no new resources or energy efficiency savings.

Assessing System Needs

The results described in the load-resource balance section above take a deterministic approach to assessing future resource gaps by simply comparing the expected low and high growth scenarios with expected resource availability and firm hydroelectric generation. To make this accounting a bit more useful, planners generally add a reserve margin to the load forecast, to account for various future uncertainties. The implied target for resource acquisition using this method is to exactly match resource capability with load plus reserves. However, this target does not guarantee that the resulting resource mix will be adequate, that is, that its loss-of-load probability will be 5 percent (or less).

A more precise and sophisticated approach to assessing resource needs is to calculate the LOLP for various years along the study horizon for both the low and high load forecasts, as was illustrated in the previous section. Then by examining the resulting record of potential shortfalls, the amount of peaking need (capacity) and annual generation need (energy) can be calculated.

For energy needs, the total amount of annual energy curtailment is tallied for every simulation. Every combination of water condition (80) and temperature profile (77) was examined, making the total number of simulations 6,160. Assuming the likelihood of each simulation to be the same, the resulting curtailment records are sorted from highest to lowest. Figure 11 - 6 shows the resulting curve, with annual energy curtailment on the vertical axis and probability of occurrence on the horizontal axis. The highest point on that curve represents the annual curtailment under the worst conditions across all simulated futures. The likelihood of that occurring is one in 6,160 – a very small percentage. The point at which the curve hits zero is close to the LOLP for this case.[11] A line drawn vertically up from the 5-percent mark on the horizontal axis crosses the curve at about 27 average megawatts on the vertical axis. This means that if we were to add 27 average megawatts of energy to the power system, the entire curve would shift down and cross zero at the 5 percent mark – yielding close to a 5 percent LOLP.

[11] These curtailment values have not been adjusted for standby resource offsets.

Figure 11 - 7 provides an example for capacity needs. Each point on that curve represents the highest single-hour curtailment for each simulation. Again there are 6,160 simulations. Using the same method as above, that figure shows that adding 6,000 megawatts of capacity would drop the curve so that it crosses zero at the 5 percent mark. So, for our simple example, it would take 6,000 megawatts of capacity combined with only 27 average megawatts of energy to get us close to a 5 percent LOLP.

Of the 6,000 megawatts of capacity that would be added to this system, some of that additional capacity would only be used about 40 hours per year. This describes a system that is capacity short. By providing the RPM with specific and separate energy and capacity needs, it can pick and choose from a variety of resources (each of which has defined energy and capacity components) to determine the most cost-effective solution to best fill the capacity and energy needs, while minimizing the likelihood of overbuilding.

Results of this analysis indicate that the region's power supply is capacity short and energy long – a similar conclusion drawn from the load-resource balance calculations. By 2035, under the low-load-growth forecast, the region will need only about 50 average megawatts of energy but about 4,300 megawatts of capacity to maintain a 5 percent LOLP. Under the high-load-growth forecast, the region will need about 800 average megawatts of energy and about 10,600 megawatts of capacity.

Figures 11 - 8 and 11 - 9 show the actual model output duration curves[12] for energy and peak curtailment for the years examined in this analysis. Tables 11 - 4 and 11 - 5 summarize the energy and capacity needs.

[12] These figures show the curtailment duration curves from the GENESYS analysis prior to being adjusted for standby resources.

Figure 11 - 6: Annual Energy Curtailment Duration Curve

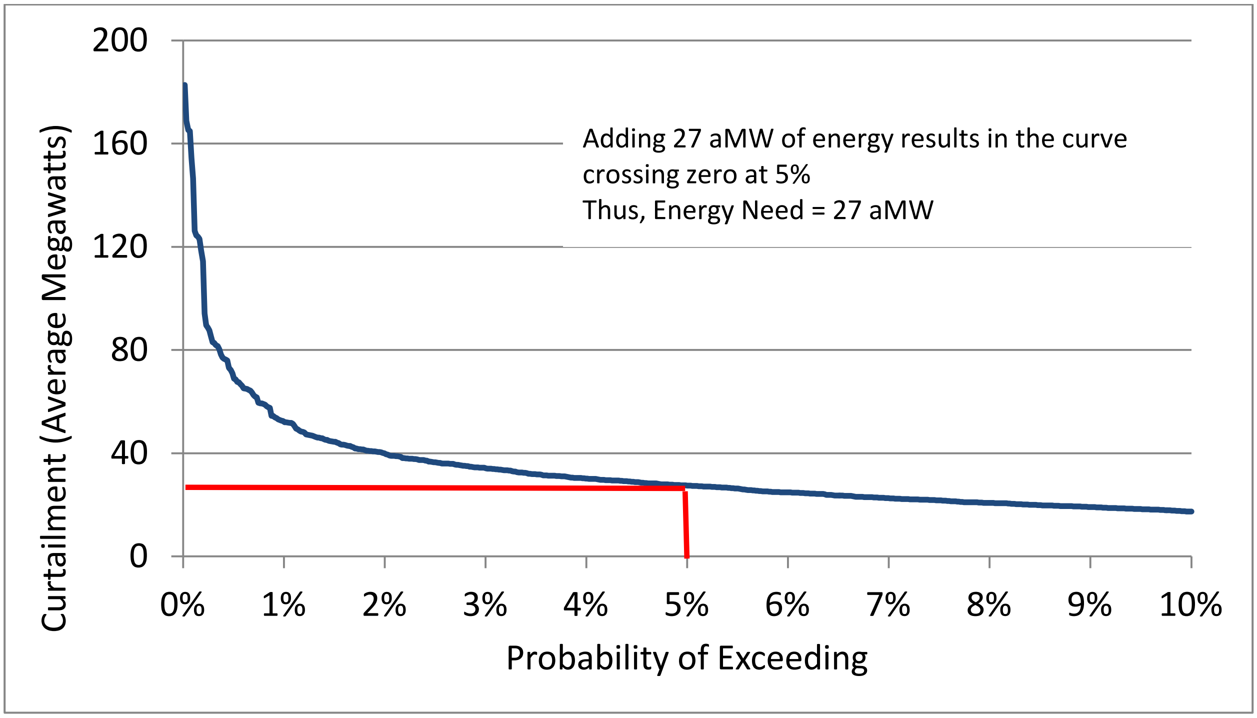


Figure 11 - 7: Peak-Hour Curtailment Duration Curve

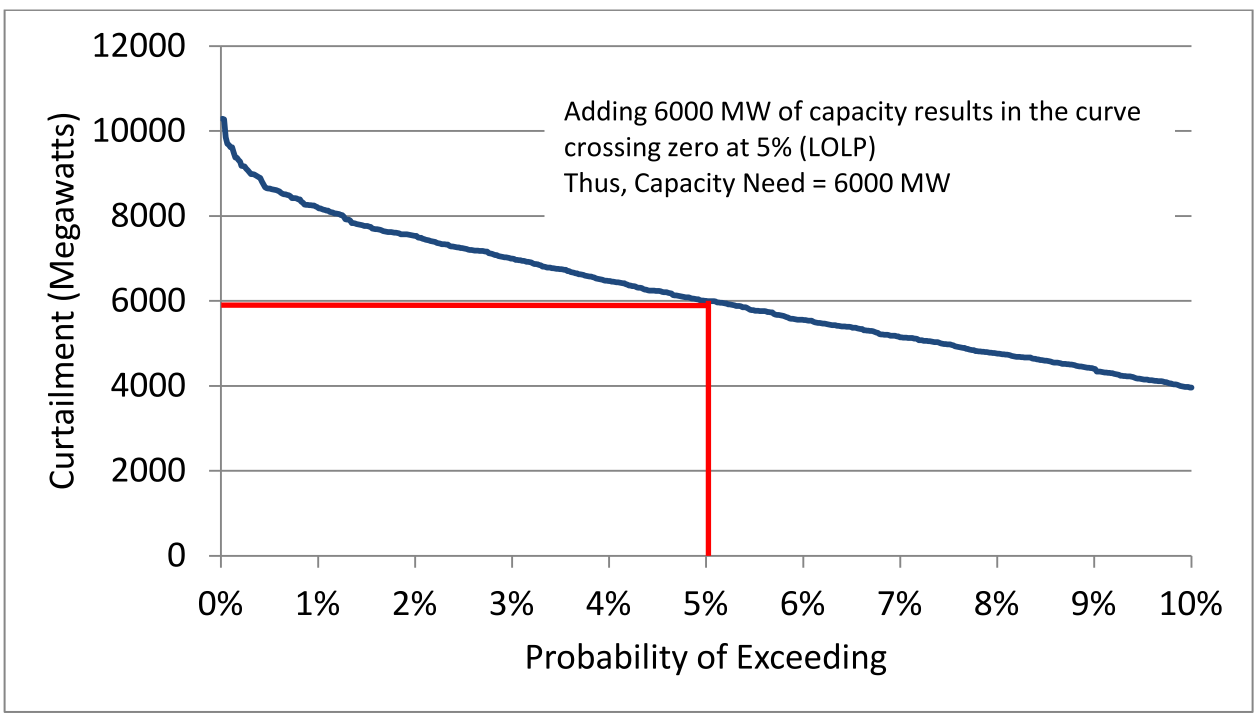


Figure 11 - 8: Annual Energy Curtailment Duration Curve

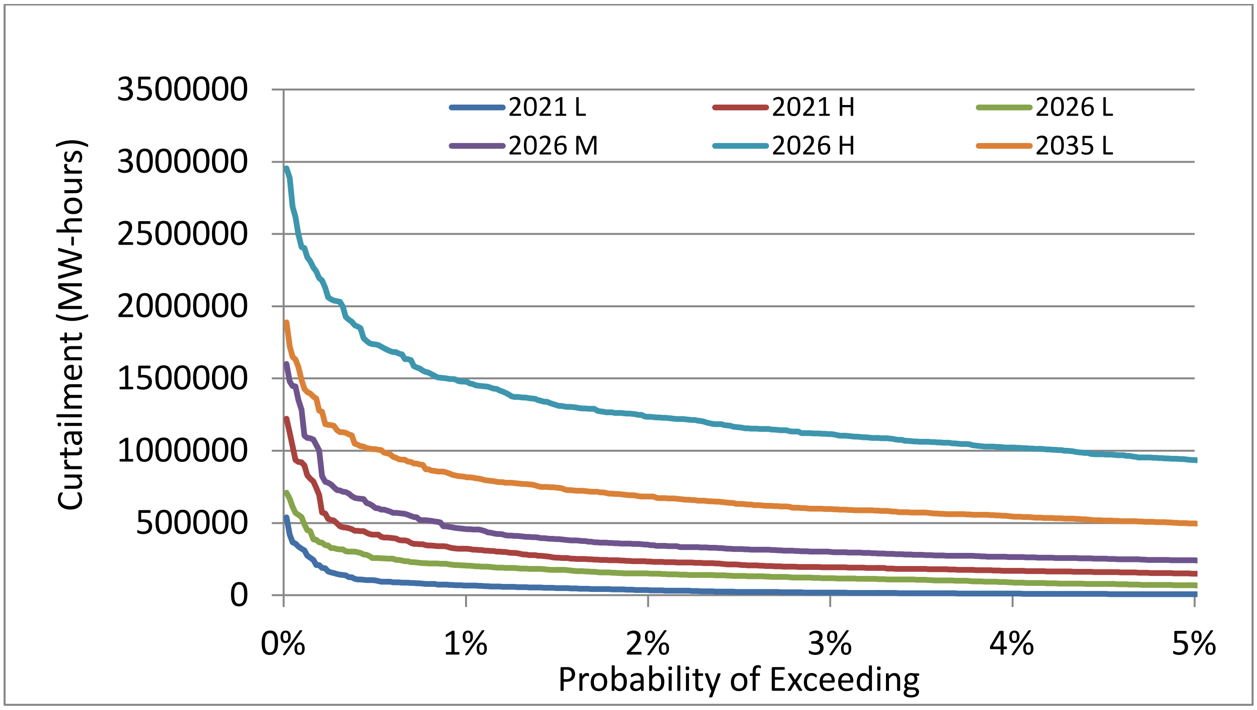


Figure 11 - 9: Peak-Hour Curtailment Duration Curve

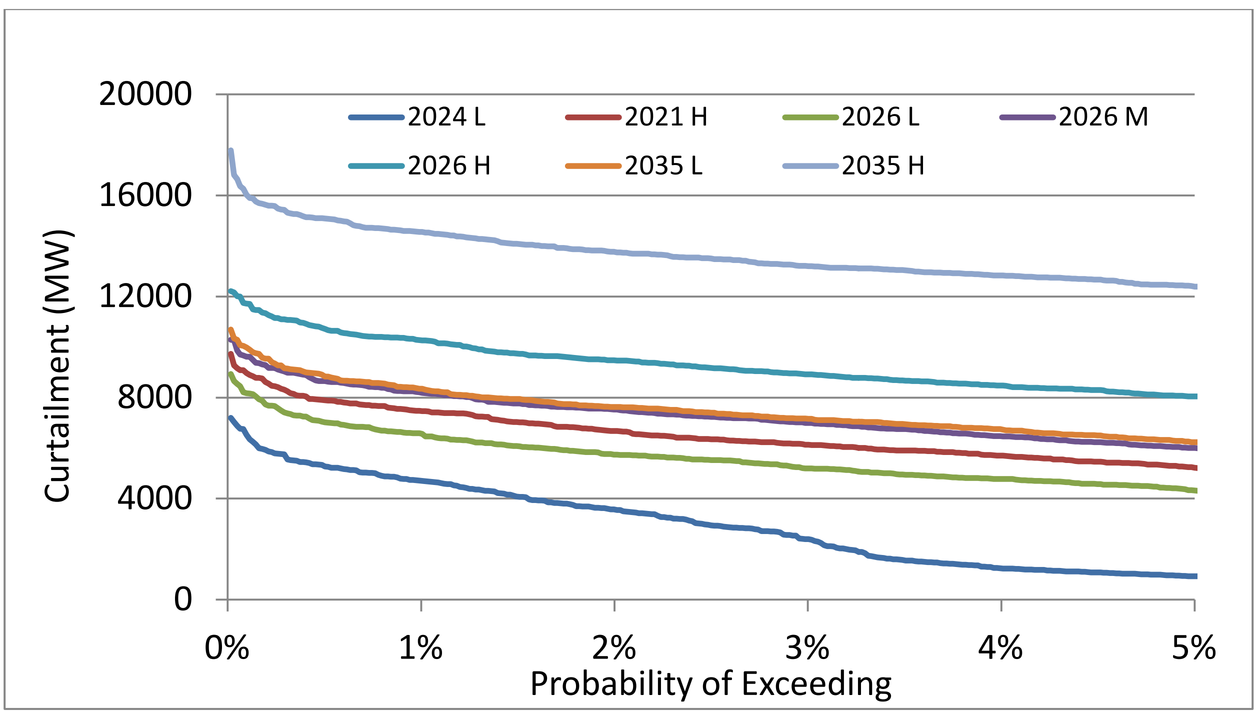


Table 11 - 4: Energy Needs (average megawatts)

Load Forecast	2021	2026	2035
Low	0	5	55
High	15	105	800

Table 11 - 5: Capacity Needs (megawatts)

Load Forecast	2021	2026	2035
Low	0	1,945	4,315
High	3,010	5,850	10,570

INCORPORATING ADEQUACY INTO THE PLAN

The resource needs assessment is valuable because it gives planners an indication of the range of potential energy and capacity needs the region may need over the next 20 years. Of course, the Council's resource strategy, which is developed with the aid of the Regional Portfolio Model, is a much more robust and adaptable plan that covers a wider range of future uncertainties. To better ensure that the RPM will produce a resource strategy that does not violate the Council's 5 percent LOLP adequacy standard and also does not significantly overbuild, the energy and capacity needs identified in the GENESYS model are converted into adequacy reserve margins, which are used in the RPM as minimum resource build requirements.

Adequacy Reserve Margin

The Adequacy Reserve Margin (ARM) is a factor that permits the adequacy standard as tested in the GENESYS model, to be incorporated in the Regional Portfolio Model's resource development logic. In simple terms, is the amount of additional capacity and energy, relative to expected load, required to maintain an adequate power supply. It is similar to the planning reserve margin that utilities often use for long-term resource planning, except that the ARM is based on a probabilistic calculation of potential curtailments under uncertain future conditions. The ARM is measured in units of percent and is defined as the difference between the generating capability of rate-based resources and expected load divided by the load, for a system that just meets the Council's adequacy standard.

Table 11 - 6 provides the details of the ARM calculation for both energy and capacity for the 2026 medium load forecast case. Resources are aggregated by similar types. The line item for thermal

resources, for both energy and capacity ARM calculations, includes whatever additional amount of capacity and energy is needed for the power supply to comply with the Council's adequacy standard. ARMs are calculated for each season (quarter) of the year except for spring, when they are assumed to be zero due to the generally surplus conditions. The ARMs are listed beginning with the fourth quarter (October through December) because both the GENESYS model and the RPM work on an operating year basis, which begins in October. ARM values are affected by resource mix and by load shape, which means that different ARM values could be assessed for every year of the study horizon and for every load path assumed (low, medium and high). However, it has not been demonstrated that this level of detail is warranted. For the final RPM analyses, the Council chose to use the mid-study-horizon ARM values (2026), averaged over the three basic load forecasts. Table 11 - 7 provides the ARM values used in the final RPM analyses.

Table 11 - 6: Example of an ARM Calculation (2026 Medium Case)

Capacity – Adequacy Reserve Margin				
Resource Type	**ARMc Calculation**	**Q4**	**Q1**	**Q3**
Thermal	Winter Capacity * (1 – FOR)	15344	16013	15251
Wind	5% of Nameplate[13]	227	227	227
Hydro	P2.5% 10-hour Sustained Peak	16715	17790	15404
Firm contracts	1-Hour Peak	-225	-167	-631
Total Resource		**32060**	**33863**	**30250**
Load	1-Hour Expected Peak	32494	33521	28142
L/R Balance	Resource – Load	-434	342	2109
ARMc	**(Resource – Load)/Load**	**-1.3%**	**1.0%**	**7.5%**

Energy – Adequacy Reserve Margin				
Resource Type	**ARMe Calculation**	**Q4**	**Q1**	**Q3**
Thermal	Winter Capacity*(1 – FOR)*(1 – Maint)	10992	10990	11012
Wind	30% of Nameplate	1360	1360	1360
Hydro	Critical Year Hydro (FELCC)	11827	10642	10569
Firm contracts	Period Average	-325	-200	-802
Total Resource		**23853**	**22790**	**22138**
Load	Period Average (weather normalized)	23319	23536	22262
L/R Balance	Resource – Load	534	-745	-124
ARMe	**(Resource – Load)/Load**	**2.3%**	**-3.2%**	**-0.6%**

[13] The ARM calculation is based on the existing power supply. The peaking contribution for existing wind resources is assumed to be 5 percent, which is the same assumption used in the RPM. The associated system capacity contribution values for wind, which are not 5 percent, only apply to new wind resources.

The ARMs shown in Table 11 - 7 range from negative to positive values. Negative ARM values can be interpreted to mean that the load-resource balance in that quarter can be deficit (based on how resources are counted) and still provide an adequate supply. Positive values mean that surplus resources are needed to maintain adequacy. These values should not be confused with planning reserve margins, which are always positive. And, while ARM values may not be intuitive, the decisive observation is that they work, that is, when used in the RPM, resulting resource acquisitions are neither under built nor over built.

Part of the reason that ARM values are not intuitive is because they do not account for the nearly 3,000 megawatts of in-region IPP capability or the 2,500 megawatts of winter import capability. They also do not include the effects of using borrowed hydroelectric generation. The ARMs for both energy and capacity are fed into the RPM model as minimum build requirements for adequacy. In other words, as the RPM steps through the study horizon years, it will build sufficient resources to ensure that the minimum ARM requirements for both energy and capacity are met. Resulting resource mixes have proven to be adequate.

Table 11 - 7: 2026 Average Energy and Capacity ARM Values used in the RPM

2026	Q4	Q1	Q3
Capacity	-0.51%	0.65%	7.52%
Energy	1.97%	-3.09%	-0.37%

Associated System Capacity Contribution

As discussed earlier in this chapter, the Council has developed a new method to better assess the specific energy and capacity needs for inadequate future power supplies. The new method uses the projected likelihood and magnitude of future curtailments, simulated by the Council's GENESYS model, to calculate how much new capacity and new energy is required to keep future power supplies adequate.

In past plans, the Council estimated future <u>energy</u> needs[14] by determining how much of a load reduction (in percent) was required to satisfy the Council's adequacy standard and, for <u>capacity</u> needs, how much new generating resource (combined-cycle combustion turbine capability) was needed to do the same. However, load reductions and new generating resource additions both provide different amounts of energy and capacity components. So, while these analyses are useful in assessing the general magnitude of inadequacy, they do not provide a precise estimate of the specific amount of energy <u>and</u> capacity needed to bring the power supply into adequacy compliance. The Council's new method provides specific amounts of capacity and energy needed for adequacy.

[14] This is not to be confused with developing a resource acquisition strategy. It is simply an estimate of potential future needs, which is useful when evaluating various resource strategies.

And, as was discussed earlier, these values are used to calculate the adequacy reserve margins used by the Regional Portfolio Model.

It was discovered, however, that using the ARMs as the adequacy thresholds in the RPM led to overbuilt supplies. This is because the RPM does not explicitly model the effects of hydro-thermal interactions (or more specifically the effects of system storage). As an example, suppose that the capacity need for a particular scenario is 5,850 megawatts (the amount of additional capacity needed to get to a 5-percent LOLP assessed by using the Council's new method). A simple solution is to add 5,850 megawatts of combined cycle combustion turbine capability to the mix. However, when that study is analyzed, the resulting LOLP is zero, meaning that the supply is overbuilt. This occurs because the added turbine capacity provides more energy generating capability than is needed for adequacy. This additional combustion turbine energy is sometimes dispatched instead of hydroelectric generation, which can be saved to be used during hours when the need is greater. The additional energy component of the combustion turbine gives it a greater effective system capacity than its nameplate value. This effect occurs for all resources that can interact with system storage.

In the example above, a separate GENESYS analysis indicated that only 4,400 megawatts of new turbine capacity was needed to bring the LOLP down to the 5 percent standard. Thus, 4,400 megawatts of new combined-cycle turbine capacity provides the equivalent of 5,850 megawatts of effective system capacity (a ratio of about 1.3). To compensate for the lack of a dynamic hydroelectric algorithm in the RPM, capacity contributions for all new resources are adjusted to account for their effective system capacity. This multiplier referred to as the Associated System Capacity Contribution (ASCC) can be greater than one or less than one. For example, the ASCC for a gas-fired turbine is 1.28 for winter months whereas the ASCC for wind during the same period is only 0.03 (3 percent). When the RPM assesses whether the power supply meets the Council's adequacy standard (i.e. meets the minimum ARM build requirement), it uses the ASCC values for all new resources. Adding the ASCC multipliers has shown that resulting resource acquisitions out of various RPM futures neither over nor under builds for adequacy. Table 11 - 8 shows the current ASCC values for new resources used in the RPM.[15]

[15] It should be noted, that like the ARM values, ASCC values are factors that enhance the communication between the GENESYS and RPM models. As such, while the ASCC convey a sense of each resource's contribution to system peak, they are not equivalent to Firm Energy Load Carrying Capability (FELCC) and Effective Load Carrying Capability (ELCC) that are sometimes used estimate intermittent resource contribution to firm energy and dependable capacity respectively.

Table 11 - 8: ASCC Values

Resource	Q1	Q2	Q3	Q4
Solar PV	0.26	0.81	0.81	0.42
Energy Efficiency	1.24	1.01	1.14	1.16
Wind	0.03	0.11	0.11	0.08
Gas-Fired Turbine	1.28	1.00	1.02	1.20
Geothermal	1.28	1.00	1.02	1.20

Confirming that the RPM Produces Adequate Supplies

Ensuring that the Council's long-term resource strategy will lead to adequate supplies is a separate issue from assessing the adequacy of the existing power system. This section describes how those analyses differ and how the Council's resource adequacy standard is incorporated into its planning models to ensure the adequacy of future power supplies.

The Northwest resource adequacy standard is based on a probabilistic metric defined by the Council that indicates whether existing resource capability is sufficient to meet firm loads through the next five years. That assessment takes into account only existing resources, targeted energy efficiency savings and new resources that are expected to be completed and operational during that time period. If a deficiency is identified, then specific actions are initiated. Those actions include reporting the problem, validating load and resource data and identifying potential solutions. This process is intended to be an early-warning for the region that indicates whether the capability of the existing power system sufficiently keeps up with load.

Although similar, an adequacy assessment for a resource strategy differs in significant ways. First, a resource strategy spans a much longer time period, namely 20 years. Second, a strategy implies that resource development will be dynamic, in other words, resource development depends on what future conditions are encountered. The adequacy of a single resource plan (i.e. the resource construction dates for a specific future) can be assessed, but that is not the same as assessing the adequacy of the strategy itself.

To ensure that the power plan's resource strategy will provide an adequate supply, adequacy reserve margins have been added to the portfolio model as minimum resource acquisition limits. In other words, if the model's economic resource acquisition does not measure up to the energy or capacity ARM thresholds; new resources will be added until ARM conditions are satisfied. When checking to see if the capacity ARM is satisfied, the associated system capacity contributions for all new resources are used.

In order to test that the ARM requirement produces an adequate supply, the LOLP for specific years, out of specific futures from the RPM analysis can be assessed. The test is considered successful if the LOLP is close to the Council's 5 percent standard. In practice, however, due to the "lumpiness" of resource size and due to lead-time considerations and uncertainty in load, a test would be considered successful if the resulting LOLP falls within a range of about 2 to 5 percent. These tests have been done for various load forecasts over various time periods and the results show that for cases when the loads are equal to or greater than the medium forecast, resulting LOLP values tend to fall between the 2 and 5 percent acceptable margin. For low load cases, resulting LOLP values are commonly close to zero because in these cases the RPM builds for economy and not for adequacy.

ARM vs. Planning Reserve Margin

As previously mentioned, the ARM is very similar to the more common planning reserve margin (PRM) used by most utilities for long-term resource planning. The PRM defines the amount of surplus capacity needed (above expected peak-hour load) to cover variations in loads and resources due to uncertain future conditions. Theoretically, building sufficient resources to meet the PRM should provide an adequate supply.

In practice the PRM has generally been developed using a "building block" approach. That is, additional reserves are added to the operating reserve to cover extreme temperatures and other future uncertainties.

For example, the Northwest Power Pool starts with an operating reserve of 7 to 8 percent (to cover contingencies and regulation). It then adds another 3 to 10 percent to cover prolonged resource outages. To that, it adds 1 to 10 percent to cover variations in weather, economics, general growth and new plant delays. The final planning reserve margin ranges from 11 to 28 percent for all future years.

The Western Electric Coordinating Council (WECC) also has used a building block approach to developing its PRM. The WECC begins with a 6 percent contingency reserve and adds to that 5 percent for regulation, 4 percent for additional outages and 3 percent for temperature variation. Their final PRM is 18 percent.

Figure 11 - 10 illustrates other planning reserve margins for various areas around the United States. The PRMs range from a low of about 12 percent to a high of over 50 percent. It is difficult to compare PRMs across utilities, however, because different utilities face different future uncertainties. To make matters more difficult, some areas do not even account for all future uncertainties when they calculate their PRMs. It should be noted that in recent years, a number of utilities in different areas in the country have begun to use probabilistic methods, similar to the Council's, to develop planning reserve margins.

Figure 11 - 10: Example of Planning Reserve Margins from around the United States