CHAPTER 11:
SYSTEM NEEDS ASSESSMENT

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KEY FINDINGS

Comparing forecasted load to resource capability for 2035 indicates that the annual energy supply will be slightly surplus under the low load forecast but 3,000 average megawatts deficit under the high forecast. The projections for peak-hour resource needs are more pessimistic. By 2035, the winter peaking capability will be 2,800 megawatts short of expected peak load for the low forecast and over 8,000 megawatts short for the high forecast.

However, this simple comparison of loads and resources is not an accurate assessment of resource need because it does not take into account the effects of future uncertainties and the availability of imports. A better way to assess resource need is to determine how much new energy and new capacity are required for each future year to ensure that it satisfies the Council's adequacy standard of no more than a five percent loss of load probability (LOLP).

In the long term, using this method shows a relatively small energy need of 55 to 800 average megawatts by 2035. The capacity needs are much greater, ranging from a little over 4,000 megawatts under the low forecast to about 10,600 megawatts under the high forecast. These results support the view that the region's needs over the past several decades have shifted from a focus on energy to one on capacity.

In the near term, the power supply remains adequate until 2021 when the Centralia 1 coal plant is expected to retire. However, if the load growth rate increases unexpectedly or if imports from California drop off over the next few years, the region could face an inadequate supply much sooner.

One of the key enhancements to the Council's analysis for the development this power plan is the improved linkage between the Council's adequacy model (GENESYS) and the Regional Portfolio Model (RPM). The Council's five percent adequacy standard from GENESYS is converted into adequacy reserve margins (ARM) for energy and capacity, which are then fed into the RPM as minimum build requirements.

Also from the GENESYS model, the effective capacity contributions for combined-cycle turbines and for energy efficiency programs are calculated. These values, referred to as the Associated System Capacity Contributions, are 1.3 for turbines and 1.2 for energy efficiency. For example, the effective system capacity of a turbine is 1.3 times its nameplate capacity. This phenomenon occurs because these resources are added to the regional power supply, which has a significant amount of storage. The interaction between these resources and the hydroelectric system storage results in a net gain in system capacity.

GENESYS feeds the adequacy reserve margins and the associated system capacity contributions to the RPM, which builds sufficient resources to meet the ARM requirement. In theory, every simulated future power supply that satisfies the ARM requirement should also satisfy the Council's adequacy standard. This was tested by assessing the adequacy of the projected power supply for 2026 from one of the 800 futures simulated in the RPM. The resulting LOLP of 4.4 percent falls within the range of acceptable results.

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. 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 hydro 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 are included. Market resources, such as in-region Independent Power Producer (IPP) plants and imports from out-of-region suppliers are 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. 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 (a 500 megawatt plant of which 260 megawatts serve regional loads) 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.

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

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

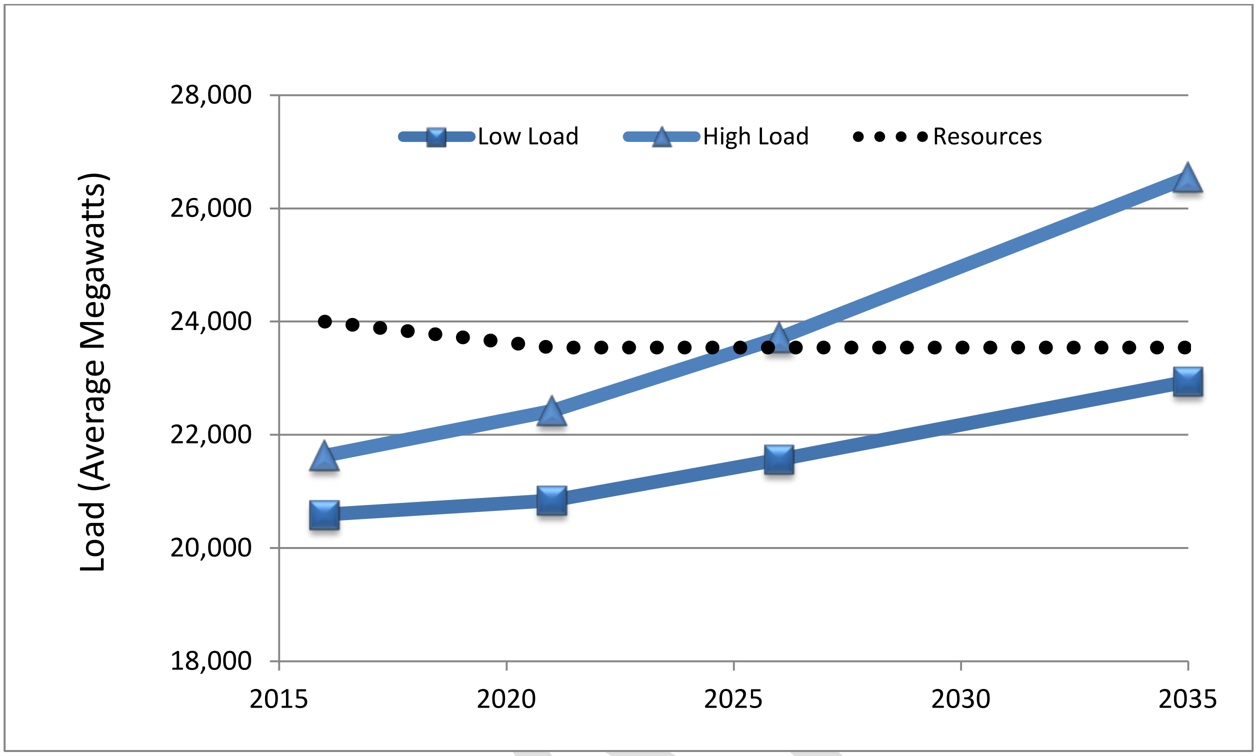

Table 11 - 1: Energy Load-resource Balance

Forecast	2016	2021	2026	2035
Low	3411	2699	1976	598
High	2369	1121	-173	-3003

For the capacity load-resource balance, the load is the expected winter single-hour peak load. That value is determined by extracting the highest winter single-hour load from each of the 80 different temperature profiles modeled (based on 1929-2008 historical temperatures) and then averaging those 80 peak-hour loads. Thermal resource capacity is adjusted by the average forced-outage rate. For hydroelectric capacity, the critical-year 10-hour sustained peak capability is used. This is the maximum amount of generation that the hydroelectric system can sustain over a 10-hour period. This value is used instead of the single-hour hydroelectric peaking capacity because supply shortfalls for the Northwest are generally expected to last from four to 10 hours.

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.

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

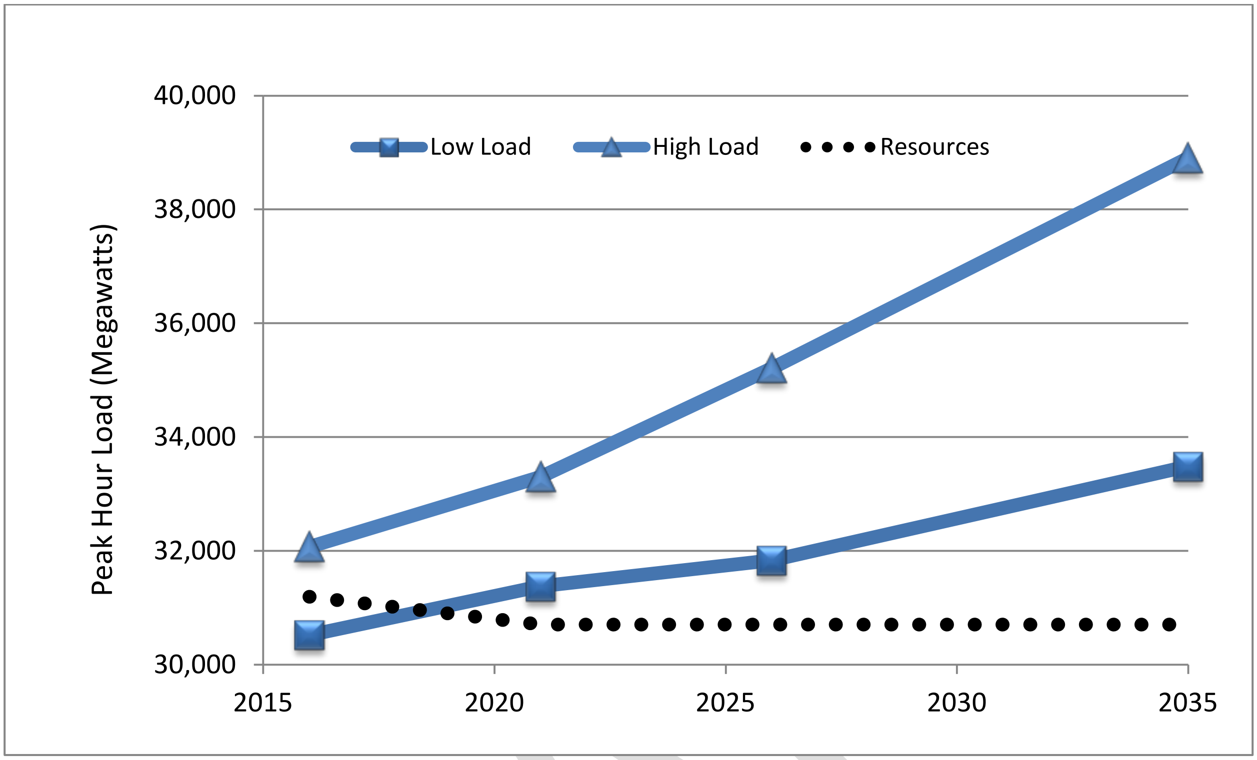

Table 11 - 2: Capacity Load-resource Balance

Forecast	2016	2021	2026	2035
Low	671	-673	-1126	-2778
High	-875	-2594	-4504	-8196

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.[2]

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. Second, Southwest markets (California, Arizona and New Mexico) should always have surplus energy and capacity to export in winter, when Northwest loads are 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 constraints placed on the operation of the hydroelectric system, increasing 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 be used 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 also mean that load-serving entities will bear more of the cost for their 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 used the Advisory Committee's recommendations as the basis for a resource adequacy standard it adopted for the Northwest power supply.

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*

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

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.

Power supply adequacy is assessed five years into the future, assuming rate-based generating resources and a specified level of reliance on imported supply. Resources include existing plants and planned projects 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 by computing the likelihood of the occurrence of a supply shortfall 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 the adequacy of the power supply 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[3]. 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.[4] 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 curtailment sometime during the year.

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

[4] 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.

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

Assumptions

Table 11 - 3 below summarizes assumptions used to assess the adequacy of the region's power supply. In general, they pertain to what resources and loads to count. As can be seen in the table, an adequacy assessment should consider 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 (IPP) 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, and then only during low load hours. 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[5], 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 set the intertie limit to 3,400 megawatts based on the recommendation of the Resource Adequacy Advisory Committee. Historical data shows that availability on the transmission intertie should be 3,400 megawatts or greater 95 percent of the time.

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 assuming critical hydro runoff 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

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[5] Reference here.

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 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.

Difference between Adequacy Assessments and System Needs

An adequacy assessment is intended as a check on resource development. It assesses whether the power supply five years out has sufficient resources to comply with the Council's adequacy standard of no more than a five percent loss of load probability. For these assessments, expected new resources are counted, including new energy efficiency savings as targeted in the Council's Sixth Power Plan.

A needs assessment differs from an adequacy assessment in that it does not include expected new energy efficiency savings or new generating resource additions and it spans a longer time period (20 years). A needs assessment determines the expected amount of energy and capacity shortfalls during key years of the study horizon. For the Seventh Power Plan, the needs assessment examines the range of energy and capacity needs for 2021, 2026 and 2035. The needs assessment gives us a general idea 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 also show the load uncertainty range used in the Regional Portfolio Model. These figures illustrate the differences in load forecasts used for adequacy assessments (dots); resource needs assessment and system expansion. The loads used for adequacy assessments are generally in the middle of 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 will be implemented within the next few years. 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[6] 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. Table 11 - 3 shows the assumptions used in GENESYS for these studies.

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[6] The Council's latest resource adequacy assessment can be found at http://www.nwcouncil.org/energy/powersupply/2014-04/

Figure 11 - 3: Annual Energy Loads and Resources

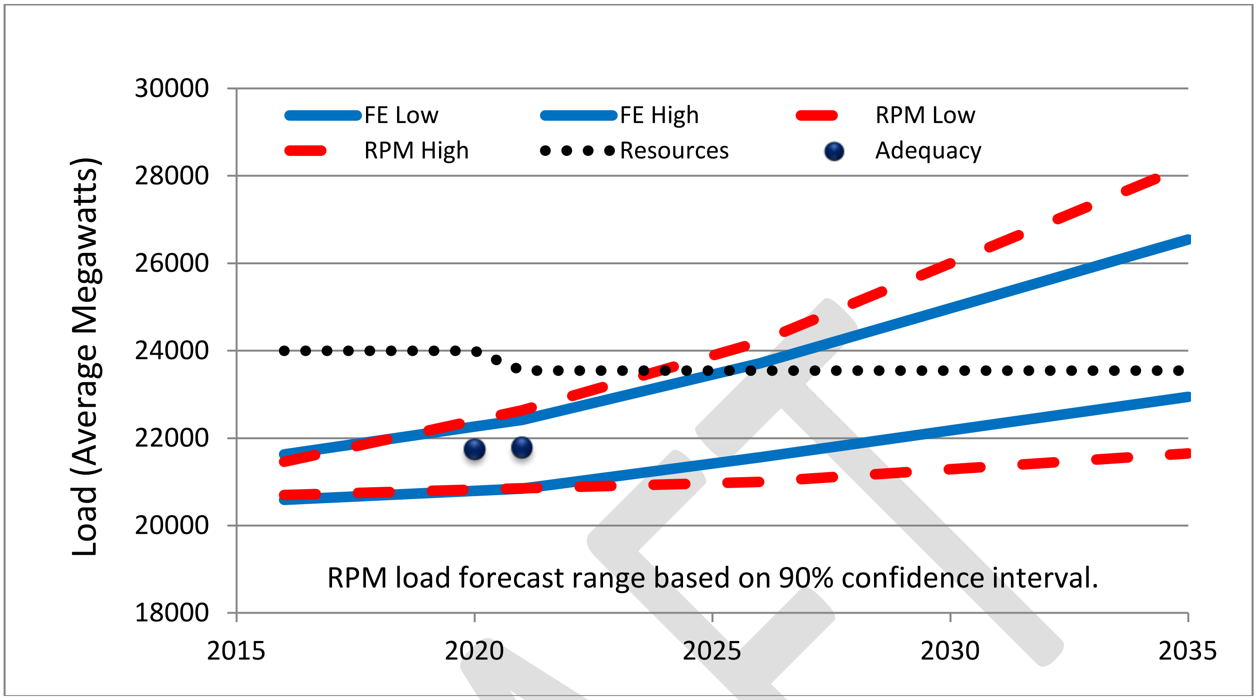

Figure 11 - 4: Winter Peak Loads and Resources

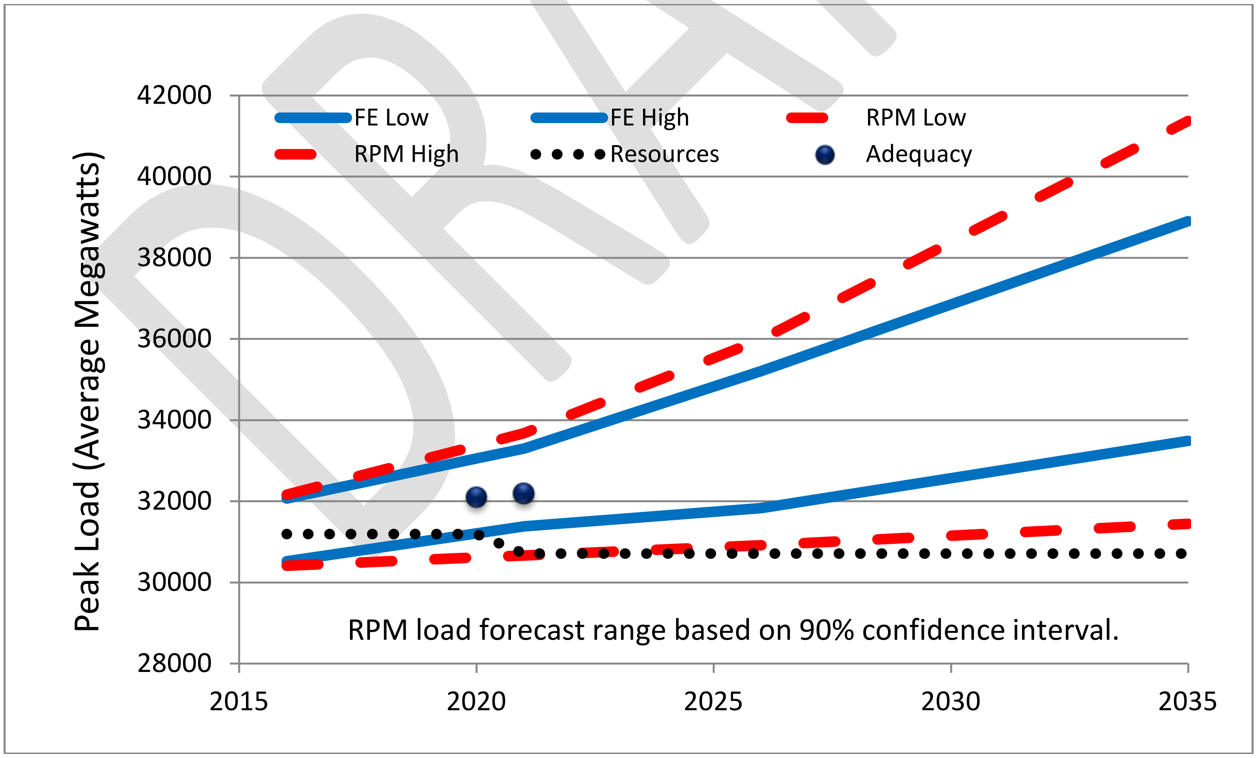

Table 11 - 3: Assumptions for Resource Adequacy/Needs Assessment

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	900 MW INC /1100 MW DEC
Borrowed hydro	1,000 MW-periods

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

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[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 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. Outages on the cross-Cascade and inter-regional transmission lines are not modeled.

The important stochastic variables (future uncertainties) that are modeled are river runoff volumes, 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 includes 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.

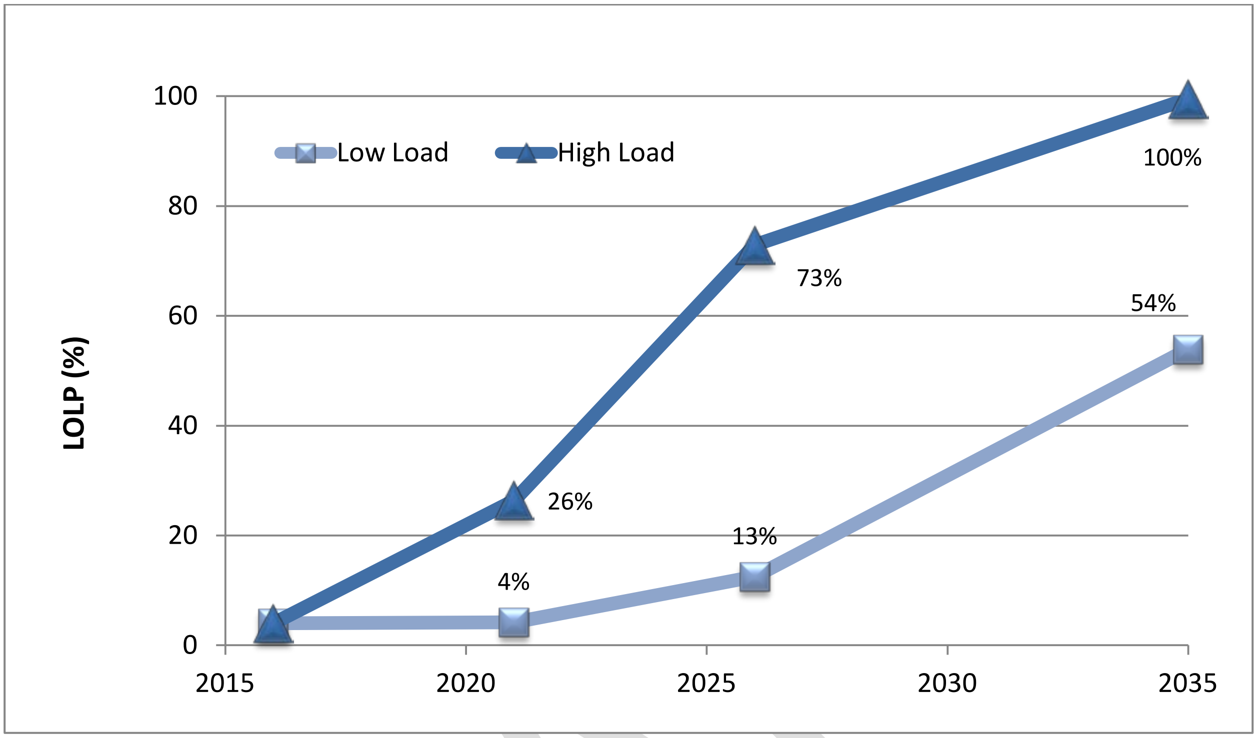
Projected Resource Shortfalls through 2035

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 five percent (the Council's adequacy threshold). The LOLP grows to staggeringly high values over time because these analyses do not include any new resources 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 to anyone 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 five 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 with No New Resources



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 (LOLP) will be five 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) were examined, making the total number of simulations 6,160. Assuming the likelihood of each simulation to be the same, these 6,160 annual curtailment values 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.[8] A line drawn vertically up from the five 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 five percent mark – yielding close to a five percent LOLP.

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, the figure shows that adding 6,000 megawatts of capacity would drop the curve so that it crosses zero at the five 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 five percent LOLP.

If 6,000 megawatts of capacity were added to this system, some amount of that 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.

Draft results 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 five 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 model output duration curves[9] for energy and peak curtailment for the years examined in this analysis. Tables 11 - 4 and 11-5 summarize the energy and capacity needs.

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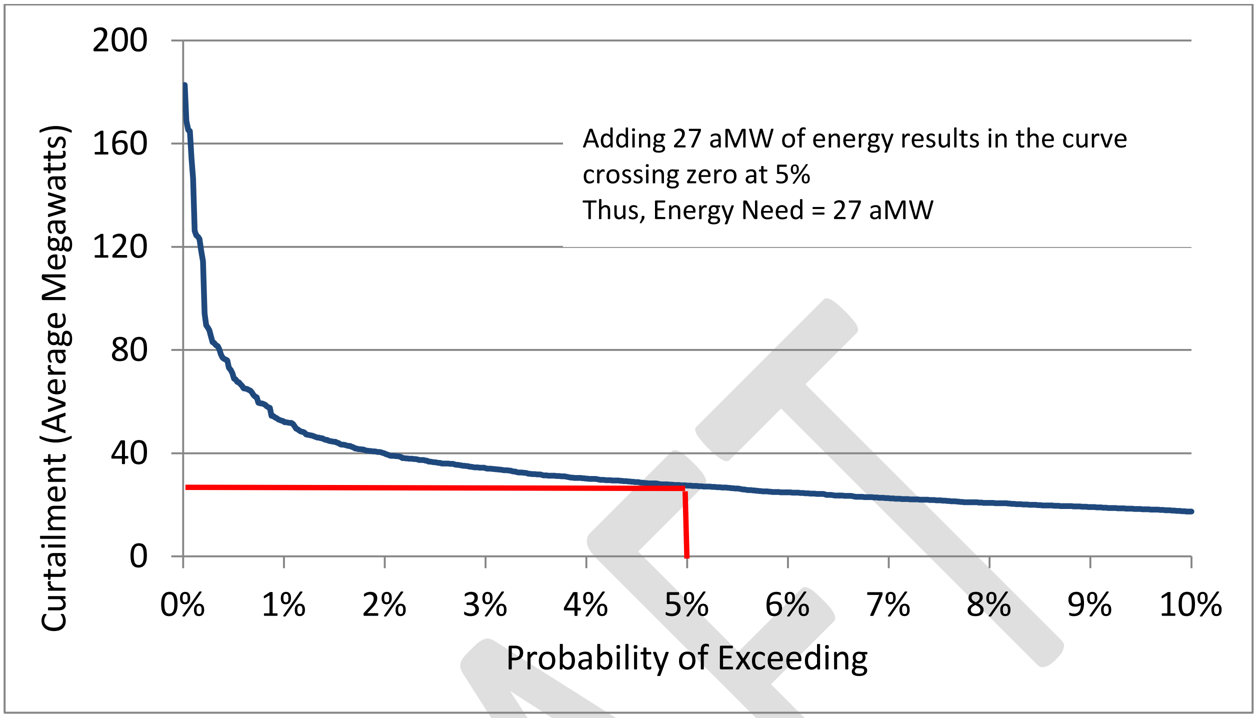
[8] These curtailment values have not been adjusted for standby resource offsets.

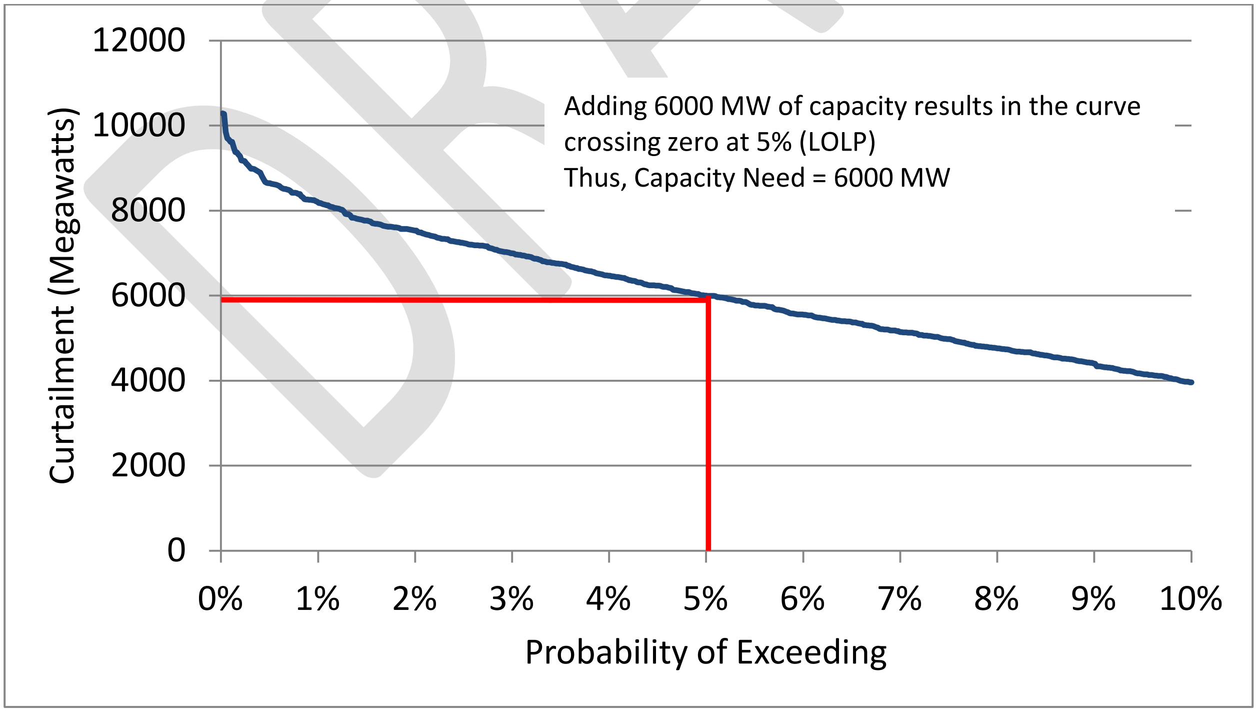
[9] These figures show the curtailment duration curves from the GENESYS analysis prior to being adjusted for standby resources.

Figure 11 - 6: Annual Energy Curtailment Duration Curve



Adding 27 aMW of energy results in the curve crossing zero at 5%
Thus, Energy Need = 27 aMW

Figure 11 - 7: Peak-Hour Curtailment Duration Curve



Adding 6000 MW of capacity results in the curve crossing zero at 5% (LOLP)
Thus, Capacity Need = 6000 MW

Figure 11 - 8: Annual Energy Curtailment Duration Curve

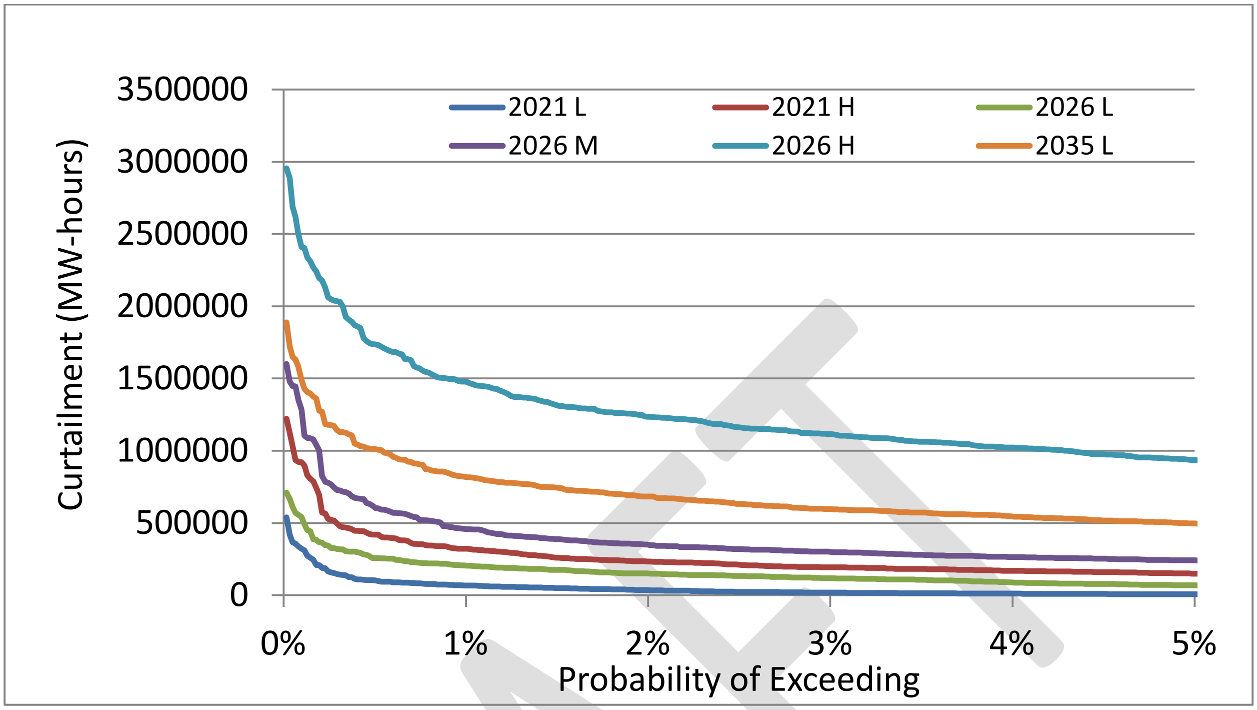


Figure 11 - 9: Peak-Hour Curtailment Duration Curve

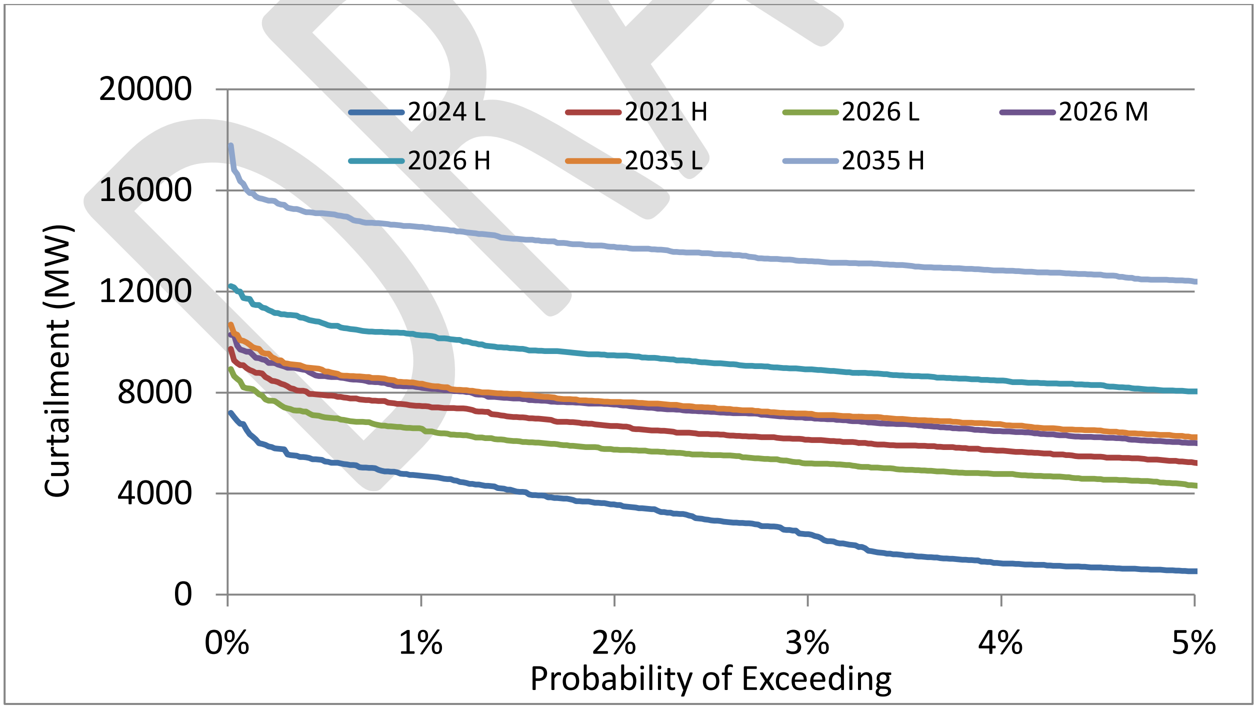


Table 11 - 4: Energy Needs

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

Table 11 - 5: Capacity Needs

Load Forecast	2021	2026	2035
Low	0	1945	4315
High	3010	5850	10570

INCORPORATING SYSTEM NEEDS 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 five percent LOLP adequacy standard and but 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 (ARM)

The Adequacy Reserve Margin, 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 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 (including the amount of new capacity and energy needed for adequacy) and expected load divided by the load. Table 11 - 6 provides an example of the ARM calculation for both energy and capacity.

In that table, resources are aggregated by similar types. The additional amount of capacity and energy needed to comply with the Council's adequacy standard are listed as separate line items. For the 2026 medium load growth forecast, an additional 1,000 megawatts of capacity is required, making the resulting ARM 2.7 percent. This means that the adequacy standard requires the peaking capability of resources in 2026 to be102.7 percent of the expected peak load in that year.

The energy adequacy reserve margin, as shown in Table 11 - 6, is negative, meaning that on an annual average basis, the energy supply can be deficit and still meet the adequacy requirement. Although this may seem strange, this result is similar to results from simple load-resource balance calculations. Because the ARM only counts firm resources, it does not account for the nearly 3,000 megawatts of in-region IPP capability or the 2,500 megawatts of winter import capability. It also does not include the effects of using borrowed hydro. The 2026 power supply requires only about 50 average megawatts of additional energy to meet the five percent LOLP standard, which results in a negative 3.1 percent value for the energy ARM. This means that the adequacy standard requires the energy capability of resource in 2026 to be 96.9 percent of the expected load in that year.

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. In theory, resulting resource mixes should prove to be adequate.

Tables 11 - 7 and 11-8 show the ARM for energy (ARM_E) and capacity (ARM_C) values for various future years and for specific load growth paths. As evident from those tables, the ARMs are not constant through time. A second interesting observation is that while the capacity ARM increases over time, the energy ARM decreases.

It is yet to be determined why the ARM values are not constant but the hypothesis is that they are related to the magnitude of load or perhaps to the load-resource balance. To test this hypothesis, ARMs were plotted as a function of load. Figure 11 - 10 shows the relationship between the energy ARM and the first quarter average energy load. Figure 11 - 11 shows the relationship between the capacity ARM and the first quarter single-hour peak load. It appears from Figure 11 - 10 that the energy ARM's relationship with energy load is quite robust, with an R-squared value of about 0.98. The relationship between the capacity ARM and the single-hour peak load in Figure 11 - 11 is not as robust, with an R-squared value of only about 0.6. Figure 11 - 12 shows the relationship between the capacity ARM and the capacity load-resource balance. Unfortunately, this relationship does not improve the predictability of the ARM based on a measurable parameter.

If a robust relationship could be found between the ARM and some easy to calculate parameter, that relationship could be incorporated into the RPM to provide a dynamic value for both the energy and capacity ARMs. Because that relationship has not yet been found and vetted, the Council chose to use the mid-study-horizon (2026) ARM value, averaged over the high, medium and load forecasts for that year.

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

Capacity - Adequacy Reserve Margin (ARM$_C$)		
Resource	**ARM$_C$ Calculation**	**Jan-Mar**
Thermal	Winter Capacity * (1 – Forced outage rate)	11594
Wind	5% of Nameplate	227
Hydro	10-hr Sustained Peak (1937)	18785
Firm contracts	1-Hour Peak	-167
Capacity Need		4,000
Total Resource		**34438**
Load	1-Hour Expected Peak	33521
L/R Balance	Resource - Load	917
ARM$_C$	**(Resource - Load)/Load**	**2.7%**

Energy - Adequacy Reserve Margin (ARM$_E$)		
Resource	**ARM$_E$ Calculation**	**Jan-Mar**
Thermal	Winter Capacity * (1 – Forced outage rate * (1 - Maintenance))	10963
Wind	30% of Nameplate	1360
Hydro	Critical Year Hydro (1937 FELCC)	10642
Firm contracts	Period Average	-200
Energy Need		50
Total Resource		**22813**
Load	Period Average (weather normalized)	23536
L/R Balance	Resource - Load	-722
ARM$_E$	**(Resource - Load)/Load**	**-3.1%**

Table 11 - 7: Energy ARM (%)

Energy ARM (%)	**2021**	**2026**	**2035**
Low	3.2	1.6	-3.6
Medium		-3.1	
High	-2.7	-7.3	-14.0

Table 11 - 8: Capacity ARM (%)

Capacity ARM (%)	**2021**	**2026**	**2035**
Low	-2.1	2.6	4.6
Medium		2.7	
High	1.3	3.8	6.1

Figure 11 - 10: Energy ARM vs. First Quarter Energy Load

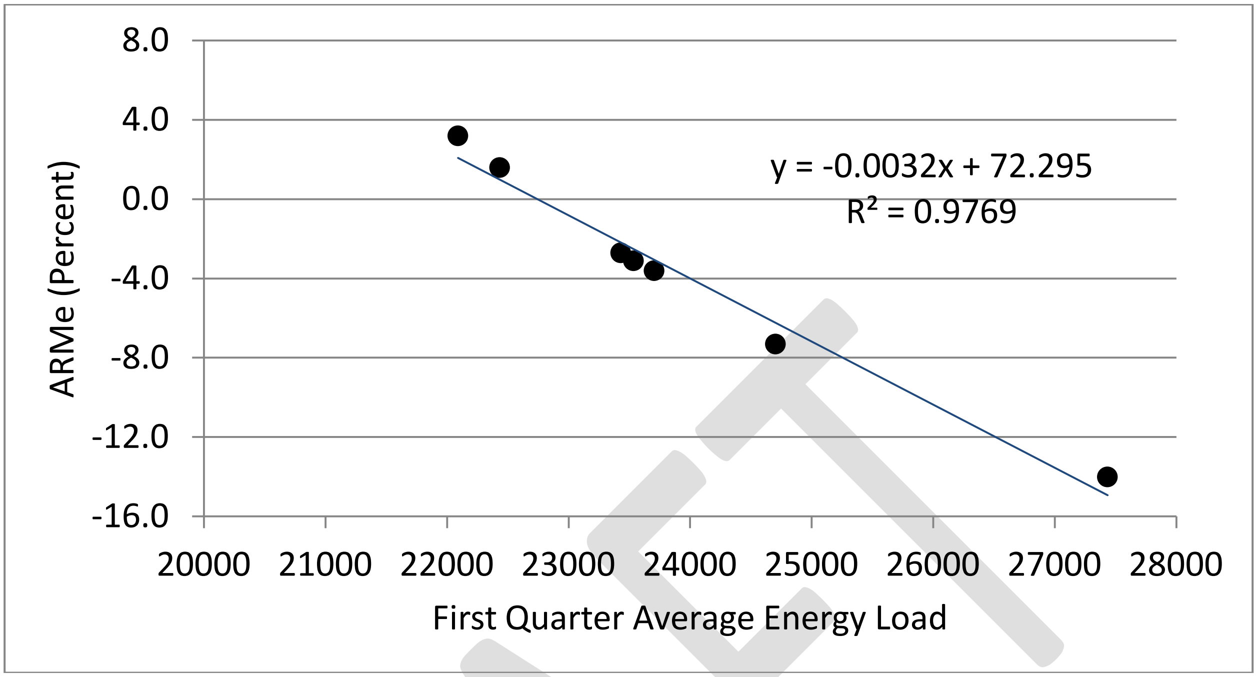


Figure 11 - 11: Capacity ARM vs. First Quarter Single-Hour Peak Load

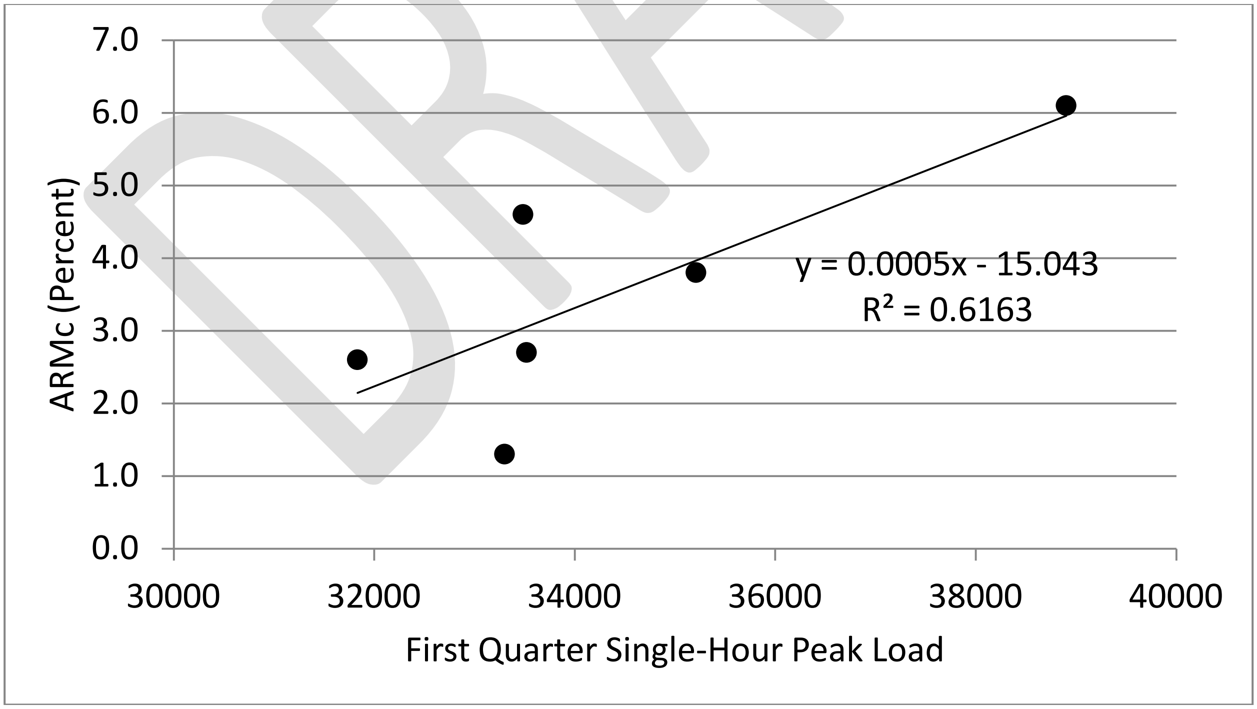
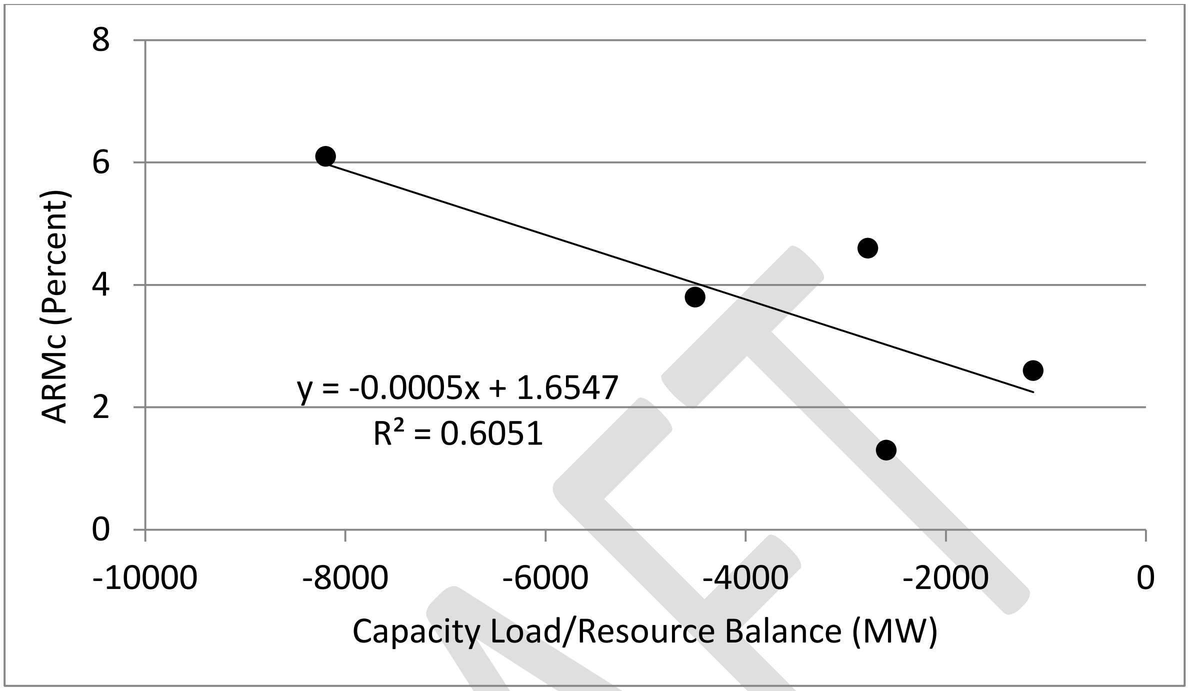


Figure 11 - 12: Capacity ARM vs. Load-resource Balance



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 of 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 the power supply adequate.

In past plans, the Council estimated future needs[10] by determining how much of a load reduction (in percent) was required to satisfy the Council's adequacy standard and, in parallel studies, how much new generating resource (combined-cycle combustion turbine) 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 and 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. And, as was discussed earlier, these values are used to calculate the adequacy reserve margins used by the Regional Portfolio Model.

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[10] 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.

It was discovered, however, that using the ARMs as the only adequacy threshold 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). For example, suppose that the capacity need for a particular scenario is 5,850 megawatts (as derived by the Council's new methodology). GENESYS, which does explicitly model hydro-thermal interactions, shows that adding 5,850 megawatts of new combined-cycle turbine capacity leads to an LOLP of almost zero – meaning that the supply is overbuilt. This occurs because the turbines add more energy generating capability to the system than needed for adequacy. This additional energy capability allows the hydroelectric system to shift some of its generation into the hours of greatest need, thereby increasing the system's ability to provide more capacity.

Running iterative studies using GENESYS indicates that only 4,400 megawatts of new turbine capacity is needed to bring the LOLP down to the five percent standard. Thus, 4,400 megawatts of new combined-cycle turbine capacity provides the equivalent of 5,850 megawatts of new system capacity – a ratio of about 1.3. To compensate for the lack of a dynamic hydro algorithm in the RPM, capacity contributions for combined-cycle turbines and for energy efficiency are increased to account for their added system capacity benefits. This capacity multiplier is referred to as the Associated System Capacity Component. The ASCC for a combined-cycle turbine is 1.3 times its nameplate capacity and the ASCC for energy efficiency is 1.2 times it peak savings. Thus, when the RPM assesses whether the power supply meets the Council's adequacy standard (i.e. meets the minimum ARM build requirement), it knows that turbines and energy efficiency capacity contributions are higher than their nameplate values.

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 combined-cycle turbines and for energy efficiency savings 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 five 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 three to five percent.

To date, one test has been run. The adequacy of the 2026 power supply from the RPM's 781st iteration (simulation) was tested. The resulting LOLP was 4.4 percent, very close to the Council's standard of five percent, implying an adequate supply.

A second test was performed to evaluate the effects of the associated system capacity contribution parameter. This second test was identical to the one above except that the ASCC values were left off. The resulting LOLP (for 2026 of the RPM's 781st iteration) was 0.3 percent – out of the success range. This means that the RPM was overbuilding and provides confirmation that the ASCC values must be included in the ARM test for adequacy in the RPM.

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.

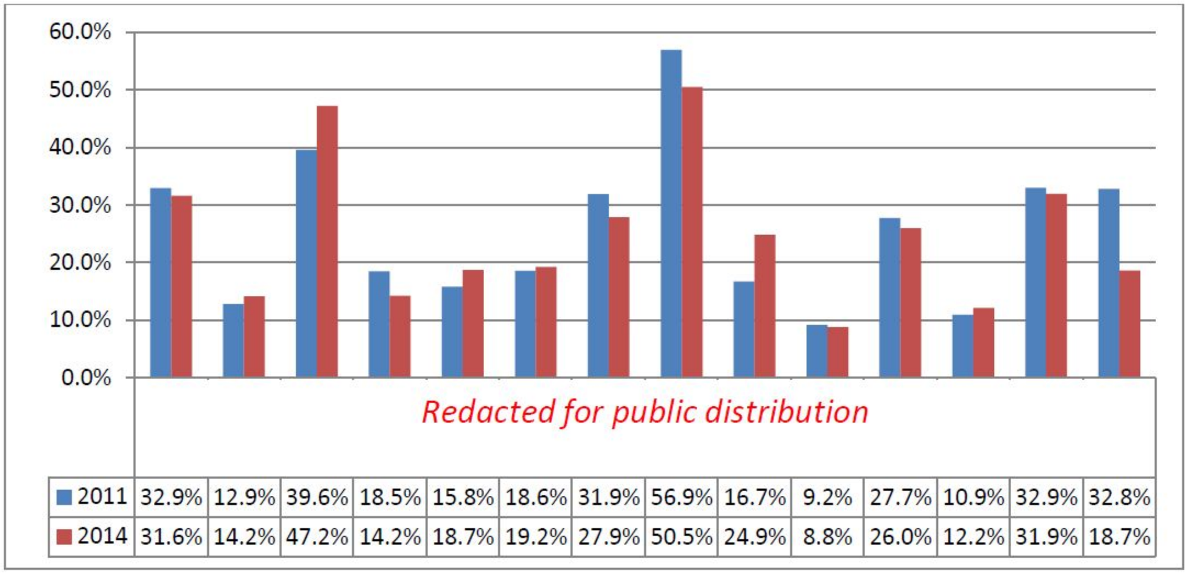
For example, the Northwest Power Pool starts with an operating reserve of 7 to 8 percent (to cover contingencies and regulation). It then adds another 3 to 10 percent to cover prolonged resource outages. To that, it adds 1 to 10 percent to cover variations in weather, economics, general growth and new 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 five percent for regulation, four percent for additional outages and three percent for temperature variation. Their final PRM is 18 percent.

Figure 11 - 13 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.

The Council's approximately three percent ARM_C for 2026 seems low relative to the Power Pool and WECC PRMs and relative to all the other areas illustrated in Figure 11 - 13. However, if in-region market supplies were added to the resources, the three percent ARM becomes 12 percent. Further, if available imports were added, the ARM grows to 19 percent.

Figure 11 - 13: Example of Planning Reserve Margins from around the United States



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🟦 2011	32.9%	12.9%	39.6%	18.5%	15.8%	18.6%	31.9%	56.9%	16.7%	9.2%	27.7%	10.9%	32.9%	32.8%
🟥 2014	31.6%	14.2%	47.2%	14.2%	18.7%	19.2%	27.9%	50.5%	24.9%	8.8%	26.0%	12.2%	31.9%	18.7%