Chapter 13: Regional Adequacy Standards

SUMMARY OF KEY FINDINGS

The 1990s saw little new resource development in the Northwest due, in part, to the emergence of an electricity market and the anticipation of deregulation. As load continued to grow, supply remained stagnant, and utility planners became concerned about the adequacy of the power system. In 2001, the second driest year on record in the Northwest coupled with a failed market in California meant the region faced a serious threat of blackouts. Actions were taken to avoid forced curtailments, but those actions were costly and resulted in soaring electricity prices.

It was becoming obvious that a new method of assessing resource adequacy was necessary. The power system was becoming more complex, with greater constraints placed on the operation of the hydroelectric system, increasing development of intermittent and dispersed resources, and the growth of a Westwide electricity market. The Council recognized this need, and in its Fifth Power Plan recommended developing a resource adequacy standard. Supporting this decision was federal legislation, passed in 2005, requiring an Electric Reliability Organization (the role now filled by the North American Electric Reliability Corporation, or NERC) to assess the adequacy of the North American bulk power supply.

In 2005, the Council and the Bonneville Power Administration created the Northwest Resource Adequacy Forum to aid the Council in developing a standard, and to periodically assess the adequacy of the power supply. The forum, which is open to the public, includes utility planners, state utility commission staff, and other interested parties. After nearly three years of coordinated effort, it reached consensus on a proposed resource adequacy standard, which the Council subsequently adopted in April 2008.

The standard helps to assess whether the electricity supply is sufficient to meet the region's needs now and in the future. It provides a minimum threshold that serves as an early warning should resource development fall dangerously short. It also suggests a higher threshold that encourages greater resource development to offset electricity price volatility. It does not mandate compliance or enforcement. It does not directly apply to individual utilities – because every utility's circumstances differ. Individual utilities must assess their own needs and risk factors and determine their own planning targets, which are screened by public utility commissions or by their boards of directors. It would be a misapplication of the adequacy standard to infer that utilities should slow their resource acquisition activity simply because the adequacy standard is being met. The Pacific Northwest Resource Adequacy Standard can be found at: http://www.nwcouncil.org/library/2008/2008-07.pdf.

Over the next five-year period, the region's resources, in aggregate, exceed the standard's minimum threshold. However, the minimum threshold should not be mistaken as a resource planning target or acquisition strategy. The Council's Power Plan, developed through an integrated resource planning process, provides a blueprint for the types and amounts of resources the Northwest should acquire to assure that the region has an "adequate, efficient, economical, and reliable power supply." In this sense, the Power Plan includes resources beyond minimum need.

BACKGROUND

Motivation for Developing a New Standard

Economic growth depends on an adequate electricity supply, and the resource adequacy standard was developed to ensure that the region's energy needs will be met well into the future. In the worst case scenario, an inadequate electricity supply can affect public health and safety, as in a blackout. Fortunately, such events are rare, and when they do happen, they are most often caused by a disruption in the delivery of electricity, not the supply. However, there have been times – during extreme cold spells or heat waves – when supply has been tenuous. The fact that most of the region's electricity comes from the hydroelectric system presents unique challenges to the energy supply, too, since periods of drought that limit hydroelectric power production are unpredictable.

While most disruptions in supply have been short term, the Western United States did experience an extended energy crisis in 2000-01. At its root, the crisis was precipitated by an imbalance of electricity supply and demand centered in California and the Pacific Northwest, where for years, development of new energy resources had lagged behind energy demand. Ripple effects from that crisis were felt throughout the West as electricity prices and consumer rates soared to historic highs.

Adding to the issue of power supply adequacy are changes in the energy environment that have made ensuring the region's power supply more challenging. Greater constraints on the operation of the hydroelectric system, increasing development of intermittent and dispersed resources, and the growth of a Westside electricity market have all contributed to creating a much more complex and interconnected power system. Changes in the Bonneville Power Administration's role as a power provider also mean that load-serving entities will bear more responsibility for their load growth, making regional coordination to ensure adequacy especially important.

Historical Approach

Historically, the Northwest has planned to a critical-water standard, which implies that Northwest resources, including hydroelectric generation produced under the driest water condition, should at least match the forecast load on an annual basis. This standard originated when the region was essentially isolated from the rest of the Western system by limited transmission links. Even after cross-regional interties were built, this policy continued because high oil and gas prices dominated generation markets in the rest of the West. However, since the collapse of oil and gas prices in the mid-1980s, the region has not had to balance in-region resources and demand under critical water conditions in order to maintain a physically adequate power supply. The reasons for this are twofold. In almost all years, hydroelectric generation will exceed production under critical water conditions; and the Southwest should always have surplus winter energy to export (the Southwest is a summer-peaking region and the Northwest is a winter-peaking region).

In practice, however, the region has strayed from strict critical period planning. Generally, reservoirs behind the dams were drafted in the fall and early winter under the assumption that the region would realize better than critical water conditions. Should a dry year ensue, the region could import surplus energy from the Southwest or interrupt a portion of the direct service industry load (DSI). These kinds of contractual agreements with the remaining DSIs no longer exist, but the Northwest is still connected to the Southwest. Both regions should be able to benefit from their different peak-demand seasons. A strict assessment of adequacy, therefore, should consider the ability to import power from outside the region. For resource acquisition purposes, however, reliance on market resources will depend on impacts to overall cost and customer rates.

Adequacy Assessment Efforts Outside of the Northwest

In order for a regional adequacy standard to be effective, it must be compatible with actions in the rest of the West. Therefore, working with the Western Electricity Coordinating Council (WECC) and other Westwide organizations is necessary. Most of the discussions in the region and the rest of the West have been directed toward developing some sort of adequacy standard that would apply to load-serving entities. The Federal Energy Regulatory Commission (FERC) proposed an adequacy standard as part of its standard market design. However, that standard was inappropriate for an energy-constrained, hydro-dominated system like the Northwest's. The FERC has subsequently deferred to the states, but in the absence of state or regional action, it might attempt to reassert authority in this area. In addition, the North American Electric Reliability Corporation (NERC) has begun developing a power supply adequacy assessment standard that would apply to the WECC.

The NERC Resource and Transmission Adequacy Task Force prepared a report with recommendations for both resource and transmission adequacy. The NERC adopted the report in 2004, and subsequently drafted a standard authorization request for a resource adequacy assessment incorporating the task force's recommendations. This proposed new standard requires regional reliability councils, such as the WECC, to establish resource adequacy assessment frameworks that the NERC will review to ensure compliance.

The WECC has since established a new framework that has been implemented in the annual Power Supply Assessments for the last two years. Northwest planners continue to refine the characterization of the Columbia River hydroelectric system, both for the regional assessment, and to improve the accuracy of its adequacy assessment for the Western Interconnection.

Some states, through their public utility commissions (PUC), have the ability to implement adequacy standards for the utilities they regulate. For example, the California PUC adopted an adequacy standard requiring investor-owned utilities to have a 15-17 percent reserve margin over their peak load. This planning reserve includes the approximately 7 percent operating reserves required by the WECC. The California PUC order also requires load-serving entities to forward contract to cover 90 percent of their summer (May through September) requirements, which would include their peak load, plus the 15 percent reserve one year in advance. Some believe this standard goes beyond what is required to assure adequacy in a purely physical sense, as it is intended to limit California’s exposure to the risk of extreme prices.

THE PACIFIC NORTHWEST ADEQUACY STANDARD

In 2005, the Council and the Bonneville Power Administration initiated the Pacific Northwest Resource Adequacy Forum. The forum includes representatives from the region’s electric utilities and utility organizations, public utility commissions and public interest groups, as well as from BPA and the Council. It is made up of a steering committee and a technical committee.

The forum’s overarching goal 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.”*

To that end, the forum has forged a voluntary, consensus-based standard for the region to address both energy (annual) and capacity (hourly) needs. This standard has been designed to assess whether the region has sufficient resources to meet growing demand for electricity well into the future. This is important, because it takes time – usually years – to acquire or construct the necessary infrastructure for an adequate electricity supply.

While some interests may wish to see an enforceable adequacy standard, currently, there are no institutions in the Northwest that could enforce such a standard for all the region’s load-serving entities.

Physical Adequacy, Economic Adequacy, or Both

Is the purpose of an adequacy standard to ensure that the “lights stay on” with an acceptably high probability (physical adequacy); or is it to protect against the economic and social costs of an energy shortage (economic adequacy)? The adequacy standard addresses the first level by providing a minimum threshold that serves as an early warning should resource development fall dangerously short. The standard also suggests a higher threshold that encourages greater resource development to offset electricity price volatility--or economic adequacy. The economic threshold is defined through the development of the Council's power plan.

Different adequacy standards could be applied at different levels. For instance, a physical standard might be most appropriately applied at the WECC level. At this level, it would provide a baseline for physical reliability and actions by load-serving entities and their regulators to address. Economic adequacy might be better addressed at the individual (or perhaps state policy) level, where different mechanisms for mitigating price risk could be put in place.

Unlike past adequacy assessments, this assessment considers the question of reliance on market supply. Physical adequacy is determined by forecast load, existing firm resources, and assessing available market supply, cost notwithstanding. Economic adequacy is determined in a similar manner, except that the region (or utility) uses an economic analysis or makes a policy decision to determine how much power to buy from the market. Utilities may want to limit their exposure to market resources for a number of reasons, price volatility being only one.

The Council's portfolio analysis results suggest maintaining a higher level of in-region resources than the adequacy standard's minimum threshold. These additional resources reduce the likelihood of having to purchase high-priced electricity. At the same time, however, the analysis also indicates that if the overall level of regional resources is sufficient, overbuilding is a riskier and more expensive alternative than some level of reliance on the market. This is true regardless of the ownership of the resources.[1] The challenge is to find the right balance.

Defining the Resource Adequacy Standard

The Northwest resource adequacy standard[2] is based on a sophisticated hourly assessment of load and resources and how they might be affected by temperature (load deviations), precipitation (water supply), forced outages to generating resources, and other factors.

Historically, the region's tolerance for a significant power supply shortage has been assumed to be 5 percent – that is, the region would tolerate a significant power shortage no more than once in 20 years. This type of metric is commonly referred to as a loss-of-load probability (LOLP) and requires a complicated computer model to assess. However, not all utilities or other planning entities are willing or able to use such a tool. Therefore, the LOLP threshold is translated into a simpler and more familiar load/resource balance measurement that regional planners can more easily use. These simpler measurements are provided both for annual energy needs and peak hourly capacity needs.

Annual Needs (Energy Standard)

Energy in this context refers to the annual electricity needs of the region. The measure for this is the annual average load/resource balance in units of average megawatts. The threshold for this measure is set so that the resulting LOLP assessment yields a 5 percent value. In determining resource generating capability, the standard includes hydroelectric generation available under

[1] Ownership refers to either utility ownership or ownership by independent power producers.

[2] The Northwest resource adequacy standard can be found at: http://www.nwcouncil.org/energy/resource/Default.asp.

critical water conditions, available annual output of regionally committed thermal generators and renewable resources, and a portion of the uncommitted independent power producer generation. The standard also includes a small amount of non-firm resources such as out-of-region market supplies and non-firm hydroelectric generation. The amount of non-firm resources the region should rely on is determined by the 5 percent LOLP analysis. In determining load, the standard uses the region's average annual firm load based on normal temperatures, and adjusted for firm out-of-region energy contract sales and purchases and savings from conservation programs.

Peak Hourly Needs (Capacity Standard)

Capacity in this context refers to the peak electricity needs of the region. The measure for this is the planning reserve margin, or the surplus sustained-peaking capacity, in units of percent. It represents the surplus generating capability above the sustained-peak period demand. In determining the planning reserve margin, the standard includes the same firm and non-firm resources used to assess the energy standard for the region. The planning reserve margin is assessed over the six highest load hours of the day for three consecutive days (sustained-peak period). This is intended to simulate a cold snap or heat wave – periods of the year when the Northwest requires the most capacity. The planning reserve margin is computed relative to normal weather sustained-peak load. The threshold for this measure is determined by the 5 percent LOLP analysis and should be sufficient to cover load deviations due to extreme temperatures and the loss of some generating capability.

Implementing the Standard

The forum wanted to ensure it did not overstep the jurisdiction of states or the prerogatives of individual utilities in planning and acquiring resources to meet load. Because each utility's circumstances differ, it is difficult to translate a regional standard into a utility-specific standard. The forum has provided some guidance for utilities, but ultimately, they and their regulators are the decision makers for resource acquisition. The implementation plan depends on regional sharing of information, transparency of assessment methodologies, and regional coordination. The forum believes that a voluntary approach will work because utilities and their governing bodies have a strong incentive to develop adequate resources to meet retail load.

Working with Other Entities

The Council, in conjunction with the forum, will assess the adequacy of the region's power supply on an annual basis. Demand forecast and resource assumptions will be compared to those in other regional reports, such as the Bonneville Power Administration's White Book and the Pacific Northwest Utilities Conference Committee's Northwest Regional Forecast. This sharing of information in a public forum should provide a favorable environment for addressing inconsistencies in data and reporting standards.

The Northwest is not alone in focusing on ensuring an adequate power supply. The NERC is expected to pick up its previously delayed work on the development of a resource adequacy assessment standard in 2009, which is expected to require the WECC to develop an adequacy assessment framework. The WECC has spent the past several years developing a framework for the West's power supply, which is currently in place. The WECC's framework is not intended to override any state or regional assessments, including regional adequacy measures or their thresholds. In fact, the WECC has solicited help from regional entities to aid in its assessment of Westwide resource adequacy. The Council and the forum will continue to participate in the WECC's efforts.

THE ADEQUACY OF THE NORTHWEST POWER SUPPLY

The adequacy standard calls for the average annual energy capability to at least equal the average annual demand. It also calls for the system's peaking capability to be able to meet expected peak-hour demand and to have sufficient surplus to cover operating reserves,[3] prolonged generator forced outages, and demand deviations due to extreme temperatures. Key findings of the current assessment are:

- Based only on existing resources (and those under construction), the region's power supply may fail to provide sufficient summer peaking capability by 2013.
- This puts the region in a "yellow alert" situation, which triggers specific actions that include a review of all load and resource data and a review of the methodology used to assess adequacy.
- The Council and regional utilities are actively developing resource acquisition strategies, which take economic risk, carbon emission policies and other factors into account.
- Adding the plan's expected resource additions keeps the power supply adequate until about 2029.

Assessment

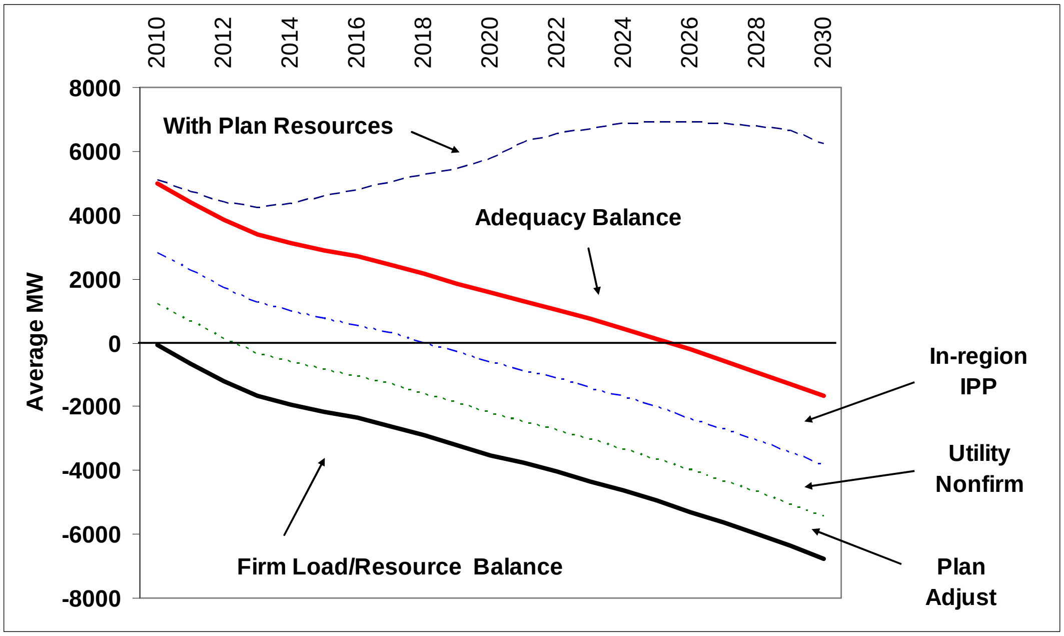
The Northwest Adequacy Standard, developed by the Resource Adequacy Forum and adopted by the Council in 2008, specifies minimum thresholds for annual energy load/resource balance and for winter and summer surplus capacity margins. Normally the adequacy assessment is targeted for 3 and 5 years out, but because this year the Council is releasing its 20-year power plan, it seems appropriate to make the assessment throughout the study period. Figures 13-1 through 13-3 show the assessed annual load/resource balance and capacity reserve margins through the year 2030.

As apparent in Figure 13-1, only counting existing firm resources, the region is in about load/resource balance today, which (without any new resources) grows to a large deficit by 2030 (black line). The standard, however, includes some non-firm resources in its definition of the load/resource balance for adequacy purposes. A planning adjustment of 1,300 average megawatts is included to account for out-of-region market supplies and some amount of non-firm hydroelectric generation. Regional utilities also own non-firm resources in that some of their resources are not fully declared as firm. These resources amount to about 1,600 average megawatts. Finally, there is a substantial amount of within-region but uncommitted generation, namely the independent power producer resources, which add about 2,150 average megawatts to

[3] Operating reserves currently do not include additional regulating or load-following reserves anticipated to be needed to integrate large amounts of new wind generation into the regional power grid, primarily because these reserves have not yet been quantified. In addition, this assessment only includes existing wind facilities and those currently under construction.

the balance. Adding the non-firm resources to the calculation yields the solid red line in Figure 13-1, which shows the region well above the adequacy threshold until about 2025 (red line). Adding new resources suggested by the power plan increases the surplus relative to a physical adequacy need (but are needed for economic and risk aversion needs).

Figure 13-1: Energy Adequacy Assessment



In a similar fashion, the winter and summer surplus sustained peaking reserve margins can be calculated and compared to their adequacy thresholds. Figures 13-2 and 13-3 show that assessment for January and July, respectively. The sustained peak reserve margin represents the amount of surplus generating capacity over the expected demand averaged over the sustained peak period, in terms of percent. The sustained peak period is defined to be the 6 highest load hours per day over 3 consecutive days (to reflect the duration of a typical cold snap or heat wave). As with the energy assessment, counting only existing firm resources, shows the region below the January minimum capacity threshold for the entire planning horizon (black line). Adding non-firm resources, as defined in the standard, raises the reserve margin above the threshold until about 2030. Again, adding the plan resources makes the reserve margin even higher.

The story is a little different for July. Looking at Figure 13-3, the reserve margin, including defined non-firm resources, only keeps the region above the minimum threshold through about 2013. According to the standard, this puts the region in a “yellow alert” situation, triggering specific regional actions, which are currently underway. First, regional planners are reviewing all load and resource data. Second, the methodology used to assess the minimum thresholds is in the process of being reviewed. Third, the Council and regional utilities are actively developing resource acquisition strategies to offset this projected need. Adding plan resources to the reserve margin in Figure 13-3 puts it above the minimum threshold through nearly the entire study horizon.

Figure 13-2: January Capacity Adequacy Assessment

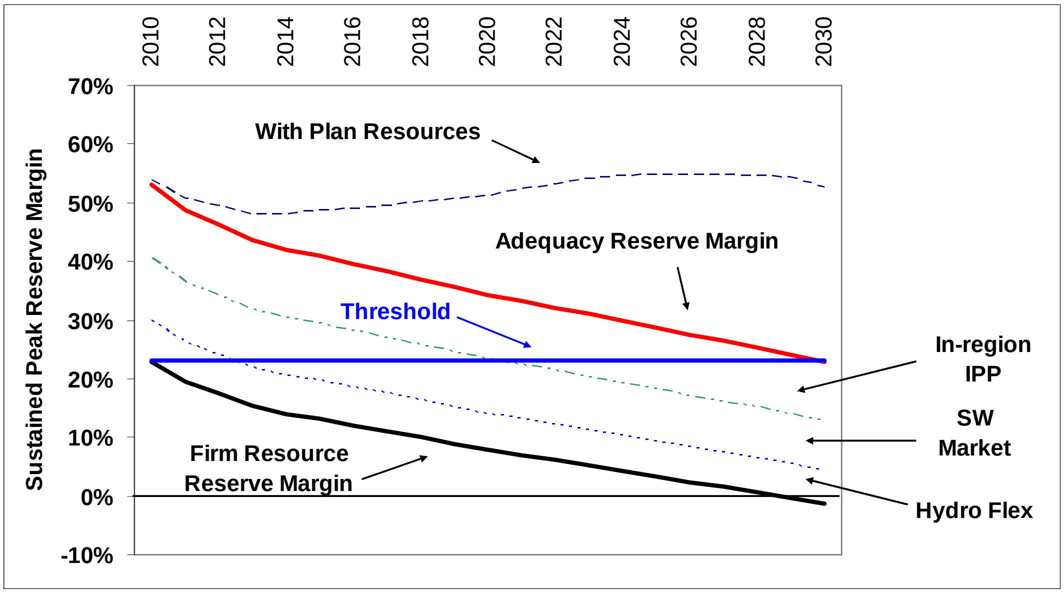
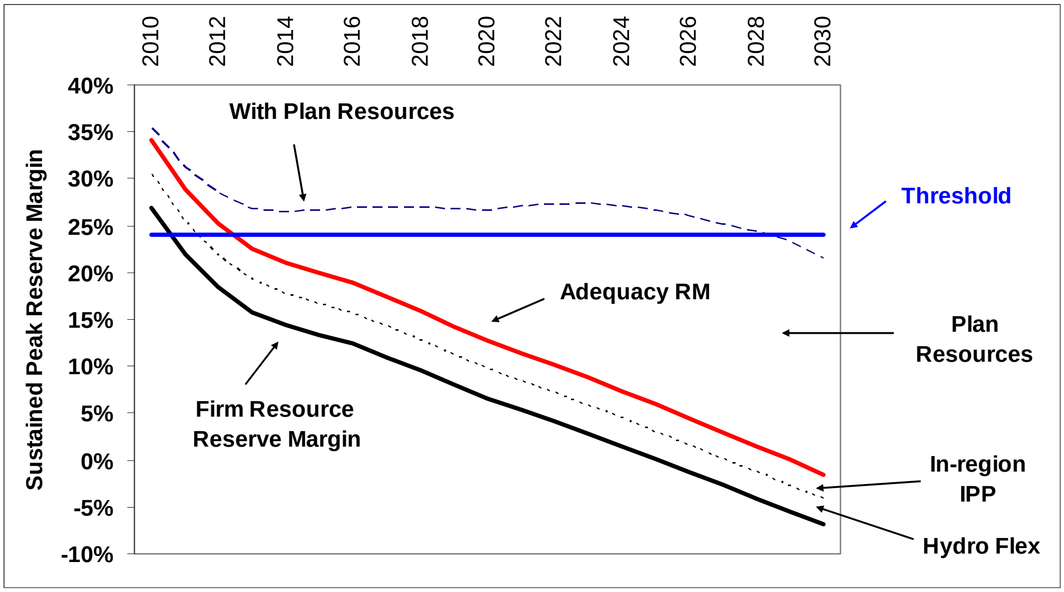


Figure 13-3: July Capacity Adequacy Assessment



Adequate vs. Optimal Power Supply

There has been considerable confusion about the relationship between the resource recommendations in the Council's power plan and the results of the Council's resource adequacy analysis using procedures developed by the Resource Adequacy Forum. The adequacy assessment implies that by acquiring the resources proposed in the power plan, the region will create a large energy surplus by the end of the study horizon (see Figure 13-1). Utility planners have questioned the need for such a surplus.

The adequacy assessment is meant to be an early warning system to alert the region if and when resource development falls dangerously short -- it is not intended to be a resource planning target. Unlike the adequacy assessment, the power plan is intended to provide guidance to regional utilities regarding the types and amounts of resources to acquire. The Council uses sophisticated analytical tools to develop its resource strategy, which is designed to keep costs low and to minimize economic risk. Plan analysis indicates that relying too much on market supplies is not in the best interest of the region. Thus, the plan suggests acquiring firm resources for economic reasons and also as a hedge against potential future carbon polices. Removing non-firm and market supplies from the load/resource balance shown in Figure 13-1 paints a different story, as described below.

Interpreting Load/Resource Balance in the Power Plan

Regional utilities have consistently used the annual average load/resource balance as a quick and simple metric to get an indication of their resource needs. For the region, the load/resource balance reported in PNUCC's NRF provides an aggregate look at utility resource needs. That calculation assumes firm loads and resources, which include critical hydro generation but no market resources. The general takeaway from this simple metric is that when the average annual load is greater than the firm supply, additional resources are likely needed. For a resource "needs" assessment this assumption makes sense. However, once a need is identified, the decision regarding how to fill that need requires a more sophisticated analysis.

While the power plan provides a general indication of the types and quantities of cost effective resources for the region, each utility's situation is unique and may require a different solution. For example, some may not have full access to market supplies (i.e. transmission limitations); others may want to limit their exposure to volatile market prices or may want more control over the resources they rely on. A full integrated resource plan assessment must be made to determine the operational reliability and cost of different resource combinations, to help lay out strategies to mitigate major risks that utilities face (such as dealing with carbon emissions) and to detail the types and quantities of required resources.

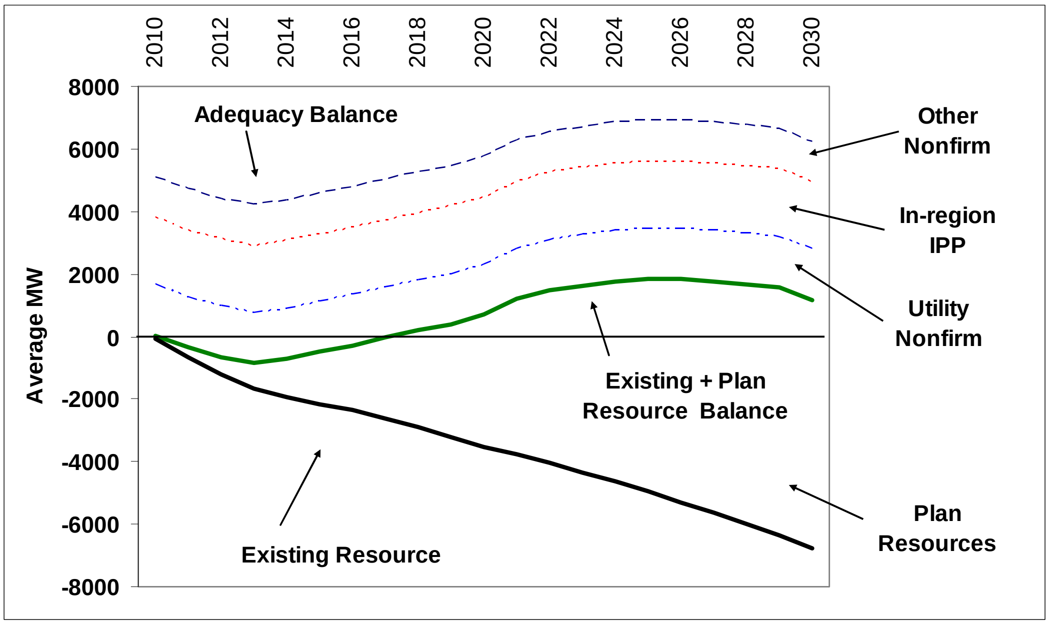
Nonetheless, the load/resource balance still provides a useful guide in assessing the status of the power supply. Figure 13-4 shows the same annual average load/resource balance as in Figure 13-1 but slightly rearranged. In this figure, we begin by counting only firm loads and existing firm resources. That assessment, illustrated in Figure 13-4 as the curve labeled "Firm Balance," indicates that the region currently is in approximate firm load/resource balance and becomes quite deficit by 2030 -- thus indicating a resource need. Adding new resources derived from the Council's plan raises the balance to positive values in later years but leaves the region somewhat deficit during the first 5 year period (solid green line). This small deficit in the near term is acceptable from an adequacy point of view because the amount of non-firm resources required to fill gap in the first 5 years is a fraction of the available market supply.

One source of non-firm generation comes from existing regional firm resources that are not expected to be fully dispatched. For example, a utility may have a simple cycle combustion turbine that it intends to use for peaking purposes only. The firm part of this resource may only be 5 percent of its availability but the other 95 percent should be available during periods of unexpectedly high demand. The area in Figure 13-4 labeled "Utility Nonfirm" represents the amount of this type of non-firm regional resource (dashed blue line). On average this value is about 1,600 average megawatts.

Another source of non-firm generation comes from uncommitted independent power producers in the region, which is labeled in Figure 13-4 as "In-region IPP" (red dashed line). All uncommitted IPP generation is assumed to be available for Northwest use during winter but only 1,000 average megawatts is assumed to be available in the summer (because of competition with the Southwest). On an annual average basis this amounts to 2,156 average megawatts.

Finally, there remains the out-of-region market supply and availability of non-firm hydroelectric generation. A loss-of-load probability analysis is used to assess how much the region should rely on these resources. That amount is reflected in the area labeled "Other Nonfirm" in Figure 13-4 and on average is 1,300 average megawatts. Putting all these pieces together yields the load/resource balance used for an adequacy assessment, which is labeled "Adequacy Balance" in Figure 13-4 (top line).

Figure 13-4: Energy Load/Resource Balance



The adequacy load/resource balance in Figure 13-4 is 5,180 average megawatts (MWa) in 2010. Subtracting the non-firm contributions results in a near zero load/resource balance for the needs assessment, which is consistent with the NRF value. Looking toward the future, the Council's power plan and utility plans (in aggregate) all indicate a need for new resources. The Council's planning approach, which is similar to methods used by many utilities, indicates that adding lost-opportunity and discretionary conservation is very effective in reducing both long-term cost and economic risk. In addition, the Council's plan includes renewable resources that would be acquired under the renewable resource portfolio standards that have been adopted in three of the four Northwest states.

The resource strategy outlined in the plan can be a useful starting point for utilities in terms of identifying the types and amount of new resources that may be cost effective for them. Of course, each utility's situation is different and may require more or different types of resource to address their own particular needs. For example, the Bonneville Power Administration, which is a balancing authority, must provide reserves to accommodate within-hour balancing operations. This may require that Bonneville acquire additional resources to provide this service.

Assessing Hourly Needs

Although not used as often in the past, capacity load/resource balances (usually computed as reserve margins) are becoming more important for assessing the need for new resources. The combination of rapidly growing summer loads and decreasing summer hydroelectric capability is pushing the region to consider more carefully its peaking needs in summer months. Figure 13-5 and Figure 13-6 show the same sustained peak reserve margin calculations for January and July as in Figures 13-2 and 13-3 but again slightly rearranged. Based on existing firm resources only, the 2010 reserve margins are 23 percent for January and 27 percent for July. Without counting any new or non-firm resources, these reserve margins decline rapidly over the 20-year study horizon. It has not yet been clearly defined what the minimum reserve requirement should be for a firm sustained peak reserve margin calculation. In other regions, a 15 to 17 percent reserve margin is typically used but that is based on a single hour peak requirement in mostly thermal systems.

For adequacy assessments, minimum sustained peak reserve margin thresholds have been estimated using a loss-of-load probability analysis. Those thresholds are 23 percent for January and 24 percent for July. However, these minimum thresholds cannot be compared to the firm reserve margin values because they include contributions from non-firm resources, which are illustrated in Figures 13-5 and 13-6. For winter months, in-region IPP generation is assumed to be fully available at 3,550 megawatts but for summer months that availability is reduced to 1,000 megawatts. Additional hydroelectric generation, in excess of critical period generation, is assumed to be 2,000 megawatts in winter and 1,000 megawatts in summer. Finally, a maximum of 3,000 megawatts of out-of-region supply is assumed for winter but none for summer. Adding the non-firm components and the plan's new resource additions to the firm reserve margin calculation yields 54 percent for January and 35 percent for July, both above the minimum thresholds required for system adequacy.

Figure 13-5: January Sustained Peaking Reserve Margin

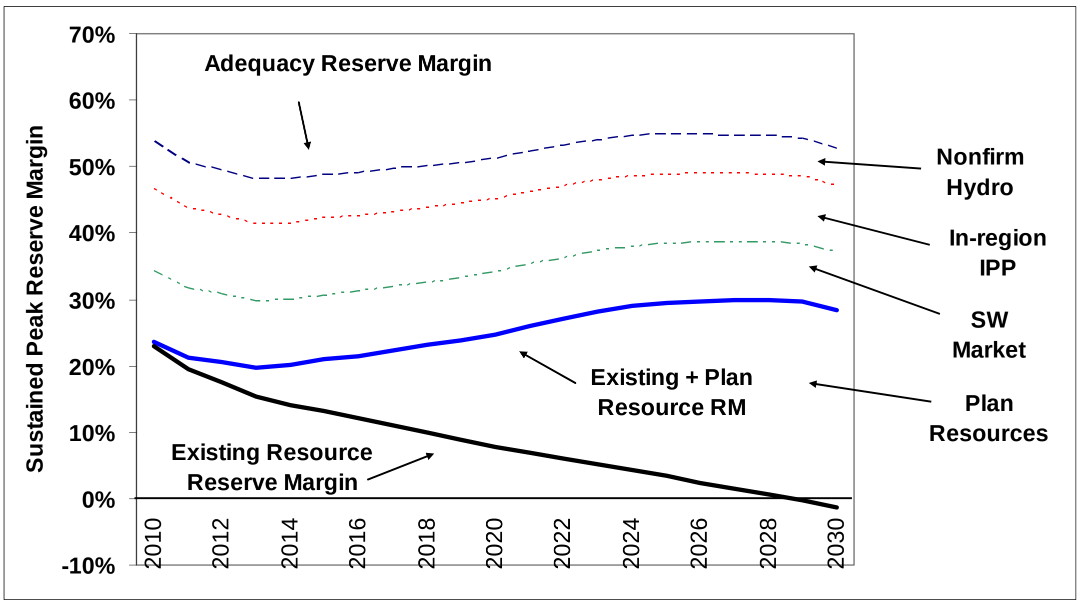
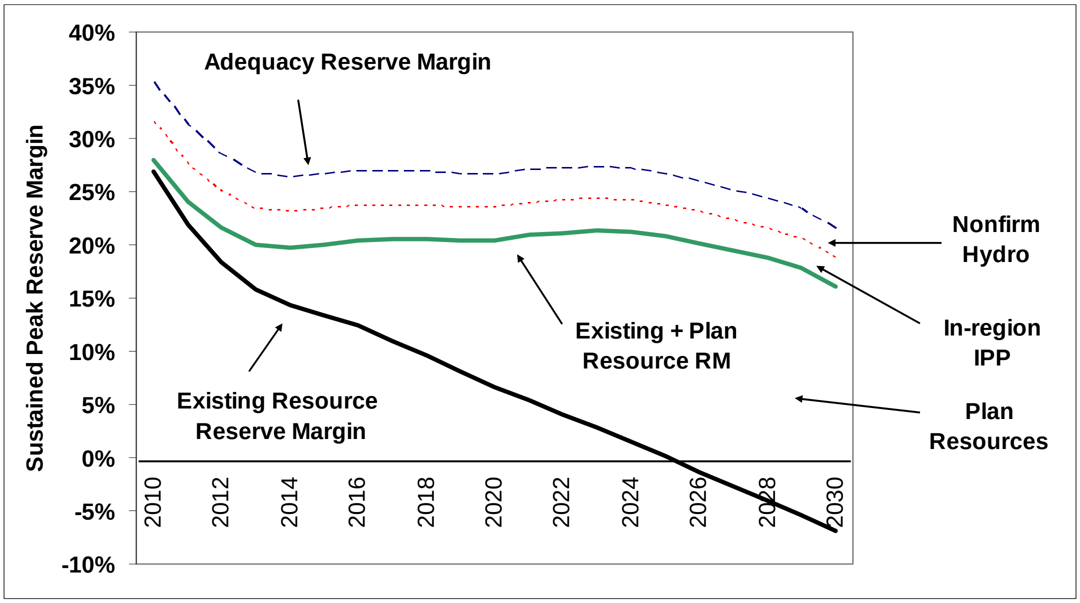


Figure 13-6: July Sustained Peaking Reserve Margin



METHODOLOGY

Analytical Tools

The Council used two complementary analyses to develop the adequacy standard. One addresses physical adequacy – the ability to meet load. The other addresses economic adequacy – avoiding extremely high costs that can result from tight supply conditions. The first analysis uses the GENESYS model, which performs a detailed simulation of the Northwest power system to assess the ability of the system to meet load with variations in future conditions. The second analysis uses the portfolio model, described in Chapter 8, to explore the cost/risk tradeoff over a large number of possible futures.

The GENESYS model was developed in 1999 to assess the adequacy of the regional power supply.[4] One of its most important features is that it is a probabilistic model, that is, it incorporates future uncertainties into its analysis. Each GENESYS study involves hundreds of simulations of the operation of the power system. Each simulation is performed using different values for uncertain future variables, such as precipitation (which affects the amount of water for hydroelectric generation) and temperature (which affects the demand for electricity).

More precisely, the random (or uncertain) variables modeled in GENESYS are Pacific Northwest streamflows, Pacific Northwest demand, generating-unit forced outages, and variability in wind generation. The variation in streamflow is captured by incorporating the 70-year (1929–1998) Pacific Northwest streamflow record. Uncertainty in demand is captured by using the Council's short-term (temperature-driven) demand model.

GENESYS does not model long-term demand uncertainty (unrelated to temperature variations in demand) nor does it incorporate any mechanism to add new resources should demand grow more

[4] *Northwest Power Supply Adequacy/Reliability Study Phase 1 Report,* Council Document 2000-4, March, 2000. http://www.nwcouncil.org/library/2000/2000-4.pdf

rapidly than expected. It performs its calculations for a known system configuration and a known long-term demand forecast, which can change over time. In order to assess the physical adequacy of the system over different long-term demand scenarios, the model must be rerun using the new demand and the corresponding new resource additions. The portfolio model deals with long-term demand uncertainty explicitly, as well as with other long-term uncertainties.

Another important feature of GENESYS is that it captures the effects of "hydro flexibility," that is, the ability to draft reservoirs below normal drafting limits during emergencies. Hydro flexibility can be particularly important in helping address potential supply problems during extended periods of high demand from extreme cold events (or heat waves). In order for GENESYS to properly assess the use of this emergency generation, a very detailed hydroelectric-operation simulation algorithm was incorporated into the model. This logic simulates the operation of the hydroelectric system on an hourly basis. The portfolio model has a much more simplistic representation of the hydroelectric system and simulates resource dispatch on a seasonal basis.

The probabilistic assessment of adequacy in GENESYS provides much more useful information to decision makers than a simple deterministic (static) comparison between resources and demand. 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. This probability, commonly referred to as the loss-of-load probability (LOLP), is the figure of merit provided by GENESYS.

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," no matter what the cost. As such, the LOLP is a physical, rather than economic, metric.

For the Northwest, the Council has defined an adequate system to have an LOLP no greater than 5 percent. This means that of all the simulations run, with uncertain water conditions, temperatures, forced outages, and variable wind, no more than 5 percent had significant curtailments. Such a system faces a maximum 5 percent likelihood that some demand will not be served due to inadequacies in the generation system (not counting potential problems in the transmission network).

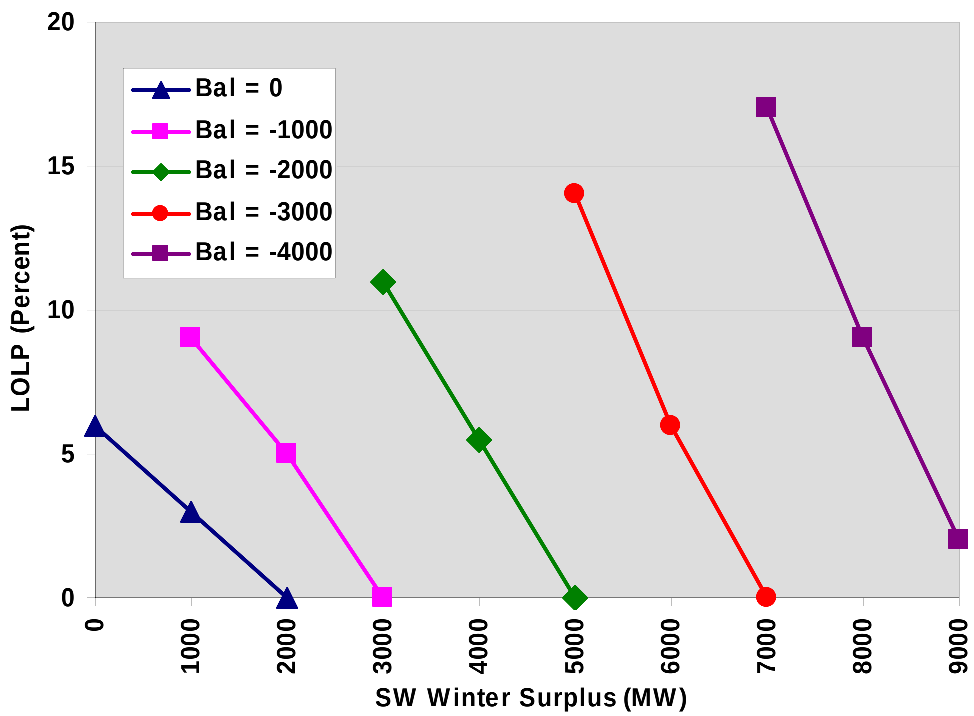
But what constitutes a significant curtailment event? Since the GENESYS model cannot possibly simulate all potentially varying parameters or know precisely every single resource that is available, a threshold is used to screen out inconsequential curtailment events. This threshold is commonly referred to as a "contingency" resource and depicts the amount and characteristics of additional generation available to utilities during emergencies.

Reliance on Market Resources

Assessing power supply adequacy is very sensitive to assumptions regarding market supplies, whether they come from within or outside the region. But how much of the market supply should the region rely on for adequacy? Assuming that no supply is available is probably too conservative, as it will result in greater resource acquisition and be more costly in the long run. And although relying more on market supplies could lower long-term costs, price volatility from year-to-year could be extreme. Therefore, some level in between, calculated with the tradeoff between risk and cost in mind, is more appropriate for planning purposes.

Figure 13-1 illustrates the relationship between the LOLP and available market supply (presented in units of capacity), for different levels of Northwest firm load/resource balance. Generally speaking, the more the market supply, the lower the LOLP will be. For example, consider the case where the region is 2,000 average megawatts deficit on a firm basis (the curve with the diamond-shaped points in Figure 13-1). Assuming that a 5 percent LOLP represents an adequate power supply, the Northwest would be adequate (even though the load/resource balance is negative) if at least 4,000 megawatts of market supply were available. If no market supply were available, the projected LOLP would be on the order of 25 percent -- well over the minimum threshold of 5 percent. Even if the Northwest were in load/resource balance (the far left curve with the circular points), the LOLP would be over 5 percent with no available market supply.

Figure 13-1: Illustrative Example: LOLP as a Function of Available SW Capacity for Different Load/Resource Balance Conditions

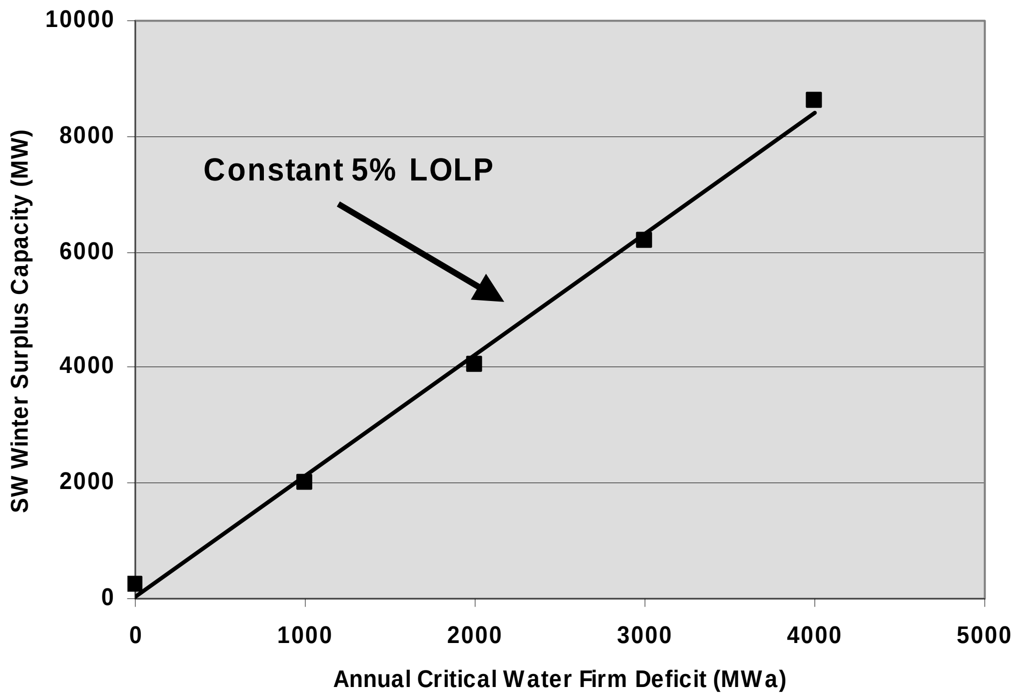


Translating the Adequacy Standard into a Simpler Measure

To make the relationship between the LOLP and market supply a little easier to see, the values in Figure 13-1 for all the points that cross the 5 percent LOLP level are plotted in Figure 13-2. In that figure, every point on the plotted curve represents the same adequacy, namely a 5 percent LOLP. Given a particular load/resource balance in the Northwest (horizontal axis), this graph shows how much market supply (vertical axis) is required to maintain an adequate system.

Again, using the same example, if the region was deficit by 2,000 average megawatts (on a firm basis), it would require about 4,000 megawatts of market supply from the SW surplus in order for the Northwest to maintain a 5 percent LOLP. This does not mean that the region would import 4,000 megawatts, but it does mean that in some hours the full 4,000 megawatts could be imported.

Figure 13-2: Illustrative Example Relationship between SW Surplus Capacity and Load/Resource Balance



The question of how much out-of-region surplus the Northwest should rely on for planning purposes, however, ends up being a policy question. If California goes forward with aggressive adequacy standards, it should mean that California will have ample winter surplus for years to come. However, current and potentially new air quality concerns may limit the operation of surplus resources in California. In addition, the potential of a future carbon tax may diminish their availability to the Northwest. Based on recent analysis, the current (arguably conservative) analysis assumes a 3,000 megawatt supply of out-of-region surplus capacity during winter months and no surplus capacity during summer months.

The in-region market supply is composed of independent power producer (IPP) resources, which sell their output to the highest bidder, whether inside or outside the region. Current estimates show about 3,550 megawatts of such resources in the Northwest. During winter months, assuming that the Southwest region is surplus, all of the IPP market supply should be available for Northwest use. However, during summer months, when Northwest utilities must compete with Southwest utilities for access to IPP generation, only a portion of their generation is assumed to be available for adequacy assessments. An estimate of available summer IPP generation for Northwest use is determined by their access to interregional transmission. IPP resources that have no direct access to interregional transmission are assumed to be available for

Northwest use. Current adequacy assessments assume that 1,000 megawatts of IPP generation is available for summer use. Thus, for capacity assessments, 3,550 megawatts of IPP generation is assumed for winter and 1,000 megawatts are assumed for summer. For energy assessments, 2,200 average megawatts of IPP annual average generation is assumed.

By using the relationship in Figure 13-2 and assuming that 3,000 megawatts of out-of-region surplus capacity is available, regional planners can assess the minimum balance between resources and loads that will yield an adequate supply (5 percent LOLP). Based on current analysis, that minimum for annual energy needs is a 1,300 average-megawatt deficit. In other words, counting only Northwest firm and IPP resources, the region's power supply can be no lower than 1,300 average megawatts less than firm loads in order to maintain an adequate supply. This means that, on average, the region can depend on 1,300 average megawatts from non-firm hydroelectric power and out-of-region supplies. A similar analysis and relationship is used to assess the minimum threshold for hourly needs.