CHAPTER 16: ANALYSIS OF COST EFFECTIVE RESERVES AND RELIABILITY

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KEY FINDINGS

This analysis shows that the existing regional power system, supplemented by actions recommended in the Seventh Power Plan's resource strategy, has sufficient capability to provide all required reserves. However, individual balancing authorities may be in a different position than the region as a whole. Further, the cost and availability of reserves varies depending on water conditions. To minimize the cost of providing reserves the region should continue to explore methods to better coordinate resource dispatch.

INTRODUCTION

This chapter focuses on the general category of reserves commonly referred to as balancing reserves.[1] While the term "balancing reserves" is most often associated with actions that are used to match generation and demand within an hour, the discussion in this chapter extends the definition to cover balancing across longer periods of time. Balancing reserves can be provided by generating resources or by demand side management measures.

For a resource to provide balancing reserves, it must be able to respond very quickly. For a generating resource this would correspond to being able to change its generation level very quickly. For a demand side management program this would correspond to being able to change load requirements from the grid within a short time frame. Balancing reserves that require additional generation or decreased load are referred to as incremental (INC) reserves and those that require reduced generation or increased load are referred to as decremental (DEC) reserves.

Within-hour balancing reserves are most commonly called upon to fill in the gaps due to short-term load variation or due to fluctuations in variable generation resources like wind or solar generation. For example, during peak load hours of the day, should expected wind generation not materialize, INC reserves are called upon to fill in the need. During light load hours, usually during the night, if wind generation exceeds expectations, DEC reserve resources will cut back their generation or alternatively, load is increased to absorb the additional and unexpected generation. Generally, some level of fast acting INC and DEC reserves must be held at all times to respond to forecast and scheduling error in the power system.

This chapter addresses the two main issues surrounding these reserves; 1) how much does the region's power system need and 2) what is the best and most cost-effective means of providing these reserves.

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[1] For more information on reserves and ancillary services see Chapter 10.

RESERVES IN THE POWER ACT

The Power Act directs the Power Plan to include an analysis of reserve and reliability requirements and cost-effective methods of providing reserves designed to ensure adequate electric power at the lowest possible cost.[2] With the expansion of variable generation resources, the requirement for reserves to balance that generation has steadily increased. The operation of the system has evolved in such a manner that many different entities, called Balancing Authorities (BAs), have the responsibility to provide reserves for the region and the larger western electric grid.

While there are requirements[3] on how far each BA can deviate from its scheduled interchange of power with other BAs in an operational time-frame, there is no formal requirement on how a BA plans for future reserves. Further, there are limited and differing levels of detail available as public information on how each BA provides or plans for reserves. The Seventh Power Plan recommends that utilities and Bonneville provide more public information on how they plan for operating reserves as part of the Action Plan.[4] Given the current lack of public information, it is not possible to quantify the lowest possible cost for providing reserves in the models used for developing this plan. However, qualitative assessment is possible and actions that will help move toward more quantitative methods are recommended in this plan.

Reliability

Reliability is defined as having two distinct parts, adequacy and security. A power system is reliable if it is:

- Adequate - the electric system can supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
- Secure - the electric system can withstand sudden disturbances, such as electric short circuits or unanticipated loss of system elements.

“Adequacy” refers to having sufficient resources – generation, efficiency and transmission – to serve loads. To be adequate, the power supply must have sufficient energy across all months, sufficient capacity to protect against the coldest periods in winter and the hottest periods in summer, and sufficient flexibility to balance loads and resources within each hour. In determining adequacy, the Council uses a sophisticated computer model that simulates the operation of the power system over many different futures. Each future is simulated with a different set of uncertainties, such as varying water supply, temperature, wind generation and thermal resource performance. The adequacy standard used by the Council deems the power supply inadequate if the likelihood of needing to take

[2] Northwest Power Act, §4(e)(3)(E), 94 Stat. 2706
[3] NERC Resource and Demand Balancing standards
[4] See Action Item REG-4

emergency action to avoid curtailment five years in the future is higher than 5 percent.[5] The Council uses probabilistic analysis to assess that likelihood, most often referred to as the “loss of load probability.”

“Security” of the regional power supply is achieved largely by having reserves that can be brought on line quickly in the event of a system disruption and through controls on the transmission system. These reserves can be in the form of generation or demand side curtailment that can take load off the system quickly. The North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC) establish reserve requirements, frequently expressed in terms of a percentage of load or largest single contingency. An additional resource requirement for the region is maintaining the reserves required for security and thus for a reliable power system.

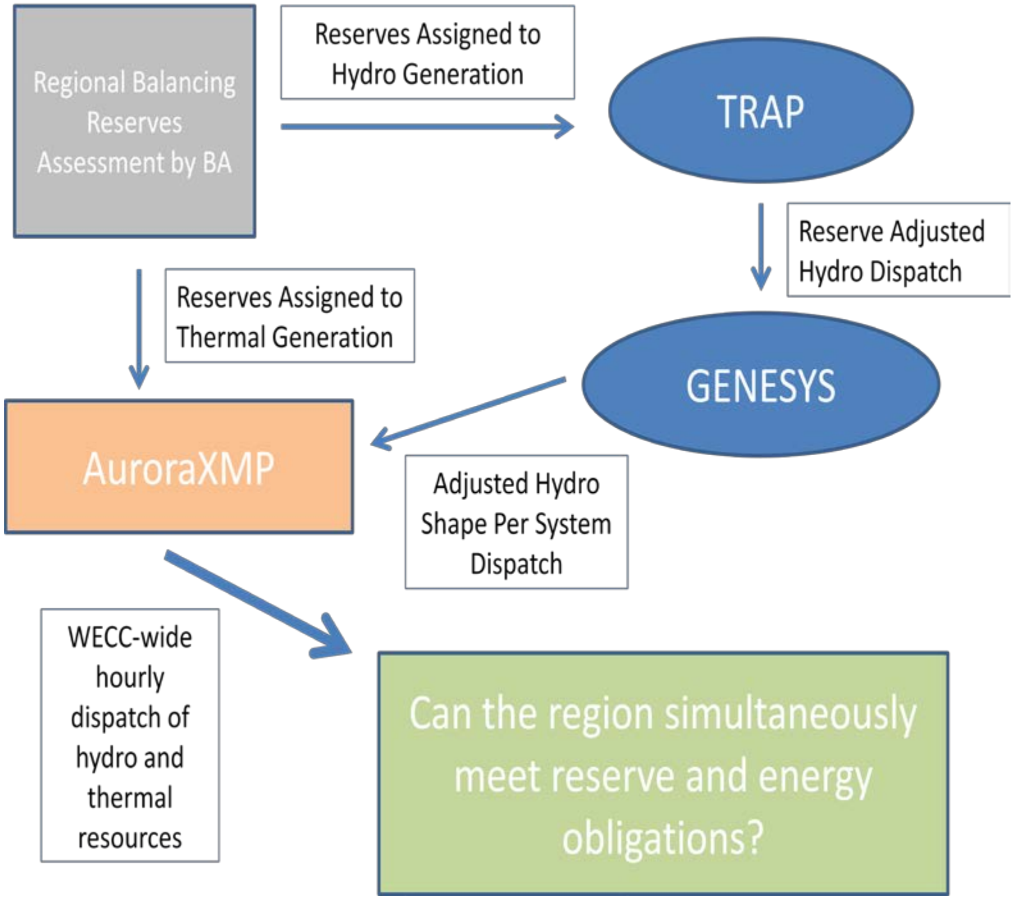
Provision of Cost-Effective Reserves

Determining how to allocate cost-effective reserves in an individual utility’s portfolio, when the balancing authority requires it to self-supply its own reserves, is a challenging prospect that requires a systems operations model for each BA. Determining a methodology to assign cost-effective reserves for the region over the length of the plan period is even more problematic considering the uncertainty related to known market structures and transmission congestion. The future of market structures in the region (energy imbalance markets and Independent System Operators or ISOs) is currently in flux with issues including: geographic footprint, market participants, scheduling, and available products. These issues alone make modeling future regional reserve sufficiency challenging. Determining the most economic reserve assignment within the regional portfolio is virtually impossible. However, considering that difficulty, the Council has attempted to assign reserves to regional hydro and thermal generation resources to best determine if there are sufficient reserves, while simultaneously attempting to acknowledge some fundamental principles of power economics in the region.

[5] For information on the adequacy standard used by the Council see Chapter 11.

The Council's methodology is represented by the flow diagram in Figure 16 - 1, and summarized in more detail in the sections below.

Figure 16 - 1: Methodology Testing Regional Balancing Reserve Capability



Were there a liquid reserve market, reserves would be assigned to the marginal unit within the system constraints. However, since there is neither a liquid reserve market nor even a price signal for those reserve products in the region, the Council assigns the reserves proportionally among reserve-providing units. The majority of reserves in the region have traditionally been provided by hydro generation resources with some sort of storage capability due to abundant, cheap and flexible fuel supply and the ramping capability of the hydro generation units. Thermal units have been used to provide reserves during periods when the hydroelectric system was heavily constrained or for utility portfolios that did not have enough hydroelectric capability to provide all reserves. Using similar reasoning, the Council's methodology assigns a majority of the regional reserve requirements to the hydroelectric system, and the remaining reserve requirements to capable thermal units.

Imbalance Markets

One possible method for reducing the need for or cost of reserves is to create new market structures that allow for the scheduled exchange of power to happen on a more frequent basis. An example of this type of market is the California ISO and PacifiCorp Energy Imbalance Market. Several studies on the cost and benefits of these markets have been completed and have shown that it is likely the benefits of these types of markets exceed the cost. In concept, these markets are formed to solve for the least system cost for providing reserves, and thus should be considered as part of a lowest possible cost provision of reserves.

ASSESSING THE NEED FOR RESERVES

The first step in testing whether the region has sufficient balancing reserves is to determine the need for balancing reserves in the region. The need for reserves is driven by short-term uncertainty in load and variable generation levels. A recent study from the Pacific Northwest National Lab[6] estimated the need for reserves by Balancing Authority. One element of this study took the intra-hour load and variable generation imbalance and assumed that 95 percent of the deviations from a baseline schedule as a level for establishing reserve needs.[7] The maximum reserve requirement for each BA by month was extracted from these data and assigned to thermal and hydro generation resources, per Table 16 - 1. The resulting reserve requirements were used as inputs into the Council's analysis. The Council assumed that if the maximum reserve level can be provided by regional resources, then the system has sufficient reserves.

Note that the total INC and DEC reserve requirements from Table 16 – 1 should not be summed to determine the maximum regional reserve requirement. This is because the maximum within-hour reserve requirement for individual BAs are not necessarily coincident with other BAs in the region. The maximum coincident INC reserve requirement for the region is 2,645 megawatts in January, while the maximum coincident DEC reserve requirement for the 3,063 MW in November.

[6] Analysis of Benefits of an Energy Imbalance Market in the NWPP

[7] Per the description of balancing reserves in Chapter 10, deviations from schedule are inevitable for load and generation due to forecast error and uncertainty. Thus, the balancing reserves held out by a BA ensure enough resources can be provided to the system to keep the system's Area Control Error within allowable limits. Note that the scenario using reserve requirements calculated to cover 95% deviations from the baseline schedule was used as the base case in the PNNL study.

Table 16 - 1: Maximum Within-Hour Reserve Requirement Assumptions for Regional BA's Under Periods of Hydro System Stress[8]

Balancing Authority	Hydro Reserve Level (MW)[9]		Thermal Reserve Level (MW)	
	INC	DEC	INC	DEC
BPA[10]	900	900	0	0
Avista	153	160	52	54
Idaho Power	187	228	80	98
Mid-Columbia	98	101	0	0
Northwestern	90	0	106	153
Pacificorp[11]	102	0	269	295
Portland General	219	258	384	452
Puget Sound Energy	167	205	269	324
Seattle City Light	148	156	0	0

ESTIMATING RESERVES PROVIDED BY RESOURCES

The second step in testing whether the region has sufficient balancing reserves is to determine the supply for balancing reserves in the region. There are two primary types of resources that provide balancing reserves: hydroelectric and thermal. Other types of resources such as demand response have also been used to provide balancing reserves in some BAs but for the Council's analysis these have been excluded[12].

Hydro Resources

Providing INC reserves with hydroelectric resources requires decreasing their maximum allowed generation. Providing DEC reserves requires increasing their minimum allowed generation, leaving the remaining range available for shaping energy. The Council's hourly hydroelectric simulation model (TRAP) was used to calculate the maximum and minimum generation available from the

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8 Note that there are other BA's in the region that were not part of the PNNL dataset. Since generally, their reserves are held on BPA's system, it is assumed for this study that BPA reserves assigned would be a proxy for the reserves on the rest of the BA's in the region.
9 Reserves assigned to hydro resources are based on regulated hydro resources owned by a particular utility. For
10 BPA Reserve requirements used are per current status, not the PNNL study.
11 Pacificorp and Northwestern Hydro resources showed flow restrictions during certain times of the year that did not allow hydro reserve requirements as assigned to be held on those resources. Since both Pacificorp and Northwestern had available thermal capability, reserves were shifted to thermal units during those times.
12 However, new and existing demand response resources are dispatched in AuroraXMP to offset total system peak needs during periods of system stress.

hydroelectric system[13]. To analyze the effects of carrying reserves using the hydroelectric system, the maximum and minimum allowed generation was reduced and increased, respectively, on groups of hydro resources that correspond to balancing authority resources.

Table 16 - 2 shows the amount of reserve requirements served within BAs with hydro generation. Note that these amounts do not necessarily correspond to hydro reserve requirements in Table 16 - 1, since some of the BAs (utilities) listed have contracts on the Mid-Columbia generating resources. Thus, the difference between reserve levels for a particular BA, in Table 16 - 1 and Table 16 – 2, represents the amount of reserves requirements assigned to the Mid-Columbia hydro generating resources.

The maximum and minimum hydroelectric generation limits from the TRAP model are then used in the Council's adequacy model (GENESYS) to determine the overall dispatch of the hydroelectric system under differing water conditions. When the hydroelectric system dispatches at a level that is not at either the minimum or maximum allowed generation, it has remaining upward or downward flexibility. This remaining flexibility on the hydro system is then considered with the remaining upward or downward flexibility on the thermal resources described below[14].

Table 16 - 2: Reserve Requirements Assigned to be Served By Hydro Resources Within BA

BA	Reserve Requirements Assigned (MW)[15]	
	INC	DEC
BPA[16]	900	900
Avista	137	143
Idaho Power	187	228
Mid-Columbia	326	329
Northwestern	90	0
Pacificorp	95	0
Portland General	128	151
Puget Sound	0	0
Seattle City Light	148	156

[13] See Appendix K for more information on the TRAP model.
[14] Note that during a limited amount of extreme hydro conditions in the 80 years of hydro conditions simulated in TRAP, the additional constraints on the hydro system imposed by the INC/DEC reserve requirements for some regulated hydro projects had to be relaxed so the other hydro constraints could be met. The amount of reserve requirements that were unable to be met on the hydro system for all 80 hydro years were assigned as additional reserve requirements on the appropriate thermal resources. See Appendix K for more details on the TRAP model.
[15] Reserves assigned to hydro resources are based on regulated hydro resources owned by a particular utility.

Thermal Resources

Similarly to method used to assign reserves to hydroelectric resources, reserves were assigned by modifying the operating range of thermal resources: decreasing their maximum allowed generation and increasing their minimum allowed generation for INC and DEC reserve assignment respectively. When allocating the reserve obligations, the maximum and minimum allowed generation was reduced on groups of thermal resources that correspond to specific balancing authority thermal resources. Using the modified thermal plant ranges and remaining hydro generation flexibility, the AuroraXMP model was used to dispatch thermal resources within the new maximum and minimum generation levels. See Appendix K for additional information on the AuroraXMP model methodology.

RESULTS

Within-Hour Balancing Reserve Requirements

The regional power system was tested to assess whether it could meet the adequacy criteria for within-hour load following and regulation requirements with and without the implementation of the Seventh Power Plan Action Plan's resource strategy using AuroraXMP to dispatch all the resources in the entire Western Electric Coordinating Council (WECC)[17]. Based on the Council's methodology, and assuming the region implements the Seventh Power Plan Action Plan's resource strategy, the regional power system met the adequacy criteria for within-hour load following and regulation requirements in the test period (October 2020 through September 2021) when evaluated under 80 different water year conditions.[18] Without developing the energy efficiency and demand response resources called for in the Seventh Power Plan's resource strategy, AuroraXMP cannot dispatch or import enough generation to meet the region's within-hour load following and regulation requirements.

Table 16 – 3 reports the number of hydro years tested with a curtailment[19] assuming the region's portfolio contains existing resources and the resources developed under the Seventh Power Plan's resource strategy. As can be seen from Table 16-3, the region cannot dispatch or import enough generation to meet the region's within-hour load following and regulation requirements in 37 out of the 80 water years tested, or just over 46 percent, with the existing system's resources. When it was

[17] The WECC is dispatched on a zonal basis with market import and export limits representing transmission constraints between geographic areas (zones). The Pacific Northwest load is represented by multiple zones in the current topology.
[18] Seventh Power Plan's resource strategy calls upon the region to develop 1400 average megawatts of energy efficiency and at least 600 megawatts of demand response by end of 2021. For this analysis the median value of 1360 MW of demand response developed over all 800 futures tested in the RPM was assumed.
[19] Note that because this is referred to as a curtailment does not necessarily mean that power would be curtailed. These "curtailment" situations are indicative of having to take some emergency action like violating flow constraints to meet load. The AuroraXMP model defines these situations as curtailments and so they are referred to as curtailments in the text. For more on this see the definition of the adequacy standard used by the Council in Chapter 11.

assumed that the region would develop 1400 average megawatts of energy efficiency and deploy 1360 megawatts of demand response per the Seventh Power Plan's resource strategy, the number of water years where curtailments occurred dropped to three out of 80, or just under four percent.

Table 16 - 3: Number of Water Year Conditions with Curtailments

Name of Scenario	Hydro Years (Out of 80)	Percent of Hydro Years
Existing System	37	46.25%
Existing System +1400 aMW EE + 1360 MW DR[20]	3	3.75%

The Existing System scenario in Table 16 – 3 is meant to be used as baseline against which the Seventh Power Plan's resource strategy could be compared. The resource strategy in the Seventh Power Plan Action Plan time period (i.e., through 2021), is further discussed below by exploring monthly unused capability distributions.

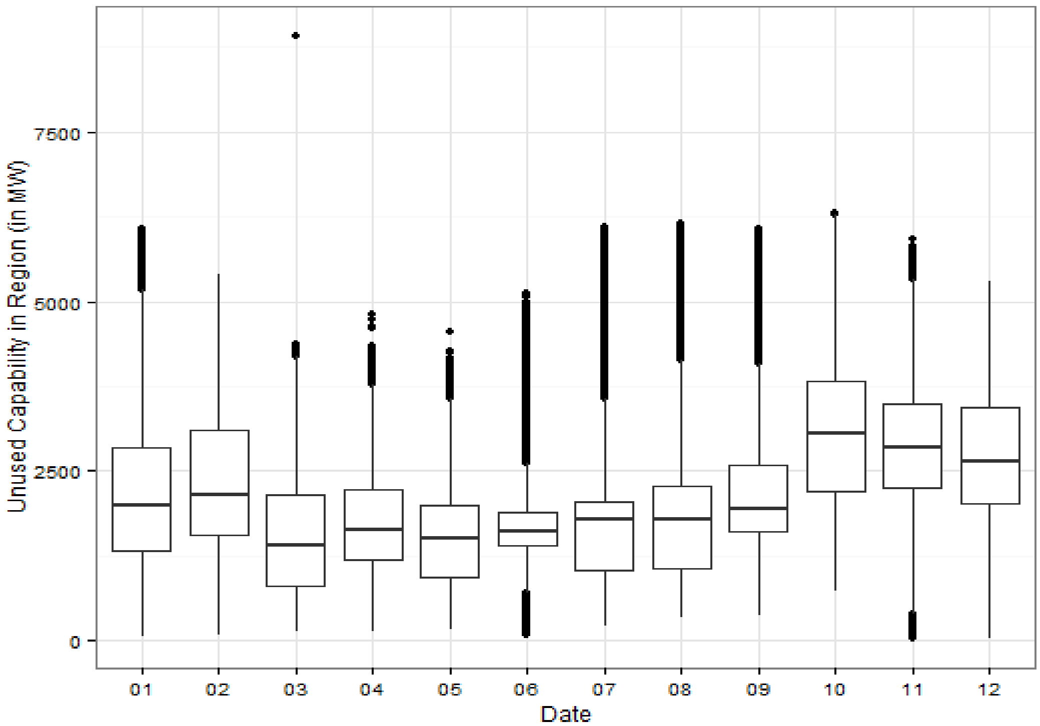
In the hours where there were not curtailments, the unused capability of the system was always greater than zero. Unused capability of the system in this context is defined as the difference between the capability of hydroelectric and thermal generation resources and the amount that those resources were dedicated to meeting system load, contingency reserve requirements, and within-hour balancing reserve requirements (load following and regulation). While unused capability is not a perfect metric for when the region could be close to or in a curtailment situation, low unused capability is often indicative of periods of greater system stress.

Since more generation is dispatched during heavy load hours than during light load hours the Council tested whether heavy load hours and light load hours had significantly different unused capability. In addition, during the morning and evening ramp periods, system loads and resource dispatch often changes dramatically, so distributions of unused capability were analyzed. The benefit in considering distributions of unused capability is the ability to consider seasonal trends of both average and minimum unused capability. The average unused capability gives a general sense of how much room the system has to change dispatch in all hydro conditions whereas the minimum unused capability gives insight on the least amount of system flexibility left under the worst conditions.

Figure 16 - 2, Figure 16 - 3, Figure 16 - 4, Figure 16 - 5 and Figure 16 - 6 show the average unused capability remaining on the system for each month of the study period for all hours, light load hours[21], heavy load hours[22], morning[23] and evening[24] ramp hours of the month, respectively.[25]

[20] Note that the 1360 MW of acquired DR is equivalent to 1117 MW during winter peak hours and 1054 MW during summer peak hours.

Figure 16 - 2: Average Unused Capability All Hours



In Figure 16 - 2, the minimum unused capability of the system is below 50 megawatts in late fall and early winter. In general, these results show the system having slightly more unused capability on average during late fall months and winter months, but the unused capability during those months is highly dependent on water conditions. During late winter and early spring months, the unused capability varies less with water conditions, but the unused capability is lower on average. This shows that in general, the risk of adverse hydro conditions increasing system stress in late fall and early winter may be less than at other times of year, but with more severe result.

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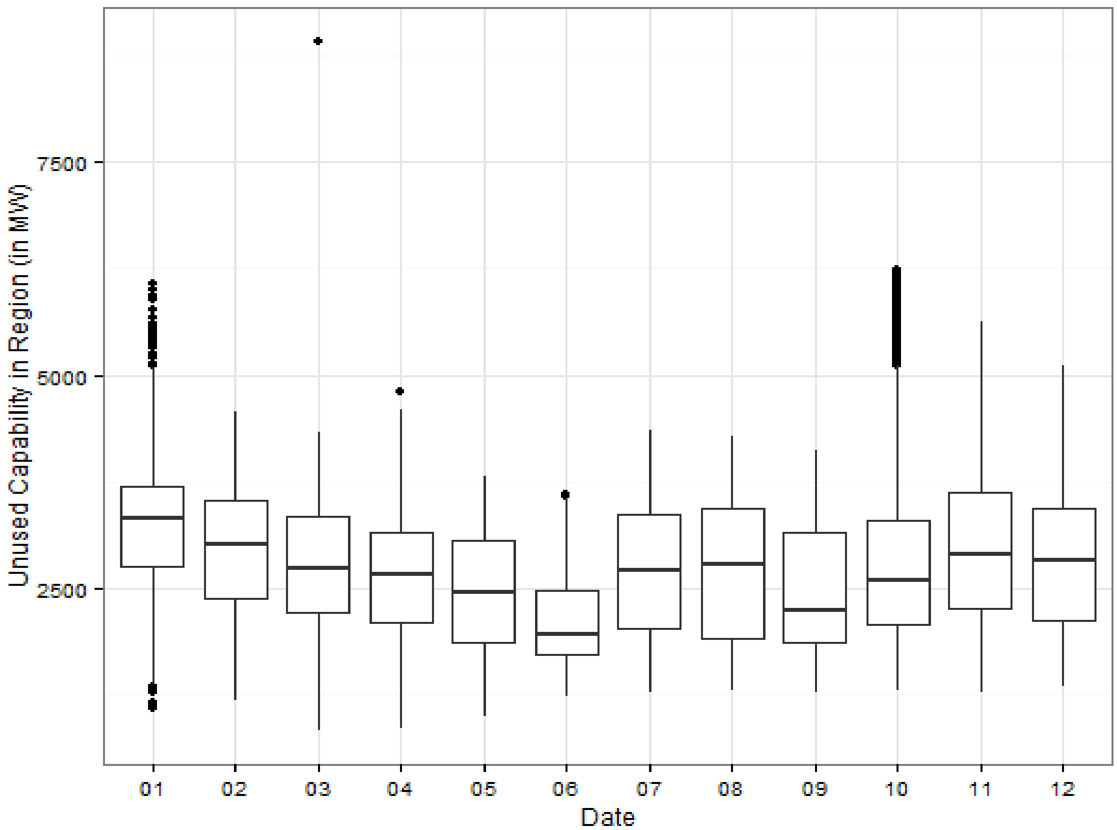
[21]Light load hours are defined as hours ending 100 to 500.
[22] Heavy load hours are defined as hours ending 900 to 2100.
[23] Morning ramp hours are defined as hours ending 600 to 800.
[24] Evening ramp hours are defined as hours ending 2200 to 2400.
[25] In the Box and Whiskers plot style, the dark line inside the "box" indicates the median (2nd quartile), the vertical "box" boundaries are indicative of the 1st and 3rd quartiles (25th and 75th percentiles), the "whiskers" indicate 1.5 times the interquartile range of all the 80 simulations, and the dots are outliers which can contain the maximum or minimum values of the sampled data.

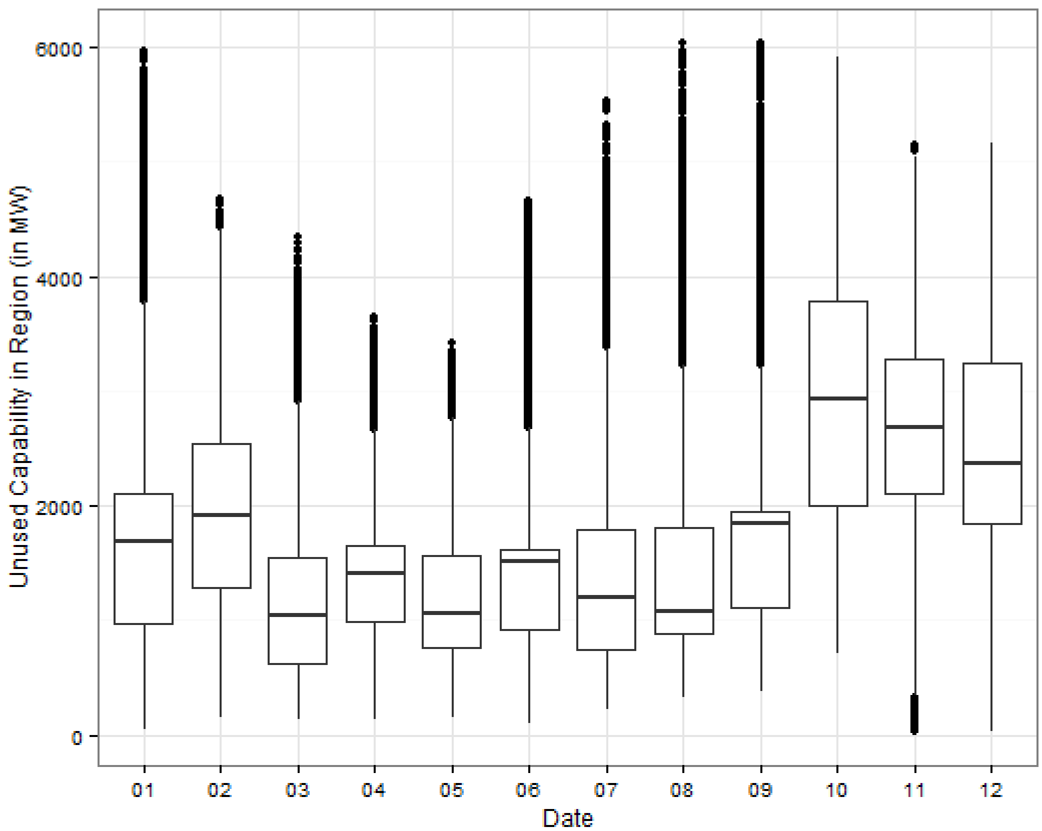
Figure 16 – 3 shows the unused capability only drops below 1,000 megawatts rarely in March and April for light load hours and does not drop below 2,000 megawatts on average during any month. This, perhaps not surprisingly, shows that there are likely to very few incidents of system stress in any water conditions in light load hours.

Figure 16 - 3: Average Light Load Hours Unused Capability



In Figure 16 - 4, like in Figure 16 – 2 the minimum unused capability of the system is below 50 megawatts in late fall and early winter. In general, also like in figure 16 – 2 these results show the system having slightly more unused capability on average during late fall months and winter months, but the unused capability during those months is highly dependent on water conditions. During late winter and early spring months, the unused capability varies less with water conditions, but the unused capability is lower on average. This mirrors the analysis for the unused capability in all hours that in general, the risk of adverse hydro conditions increasing system stress in late fall and early winter may be less than at other times of year, but with more severe result. Notice there is approximately 1,000 megawatts less unused capability on average during heavy load hours than in light load hours.

Figure 16 - 4: Average Heavy Load Hours Unused Capability



In Figure 16 - 5, also like in Figure 16 – 2, the minimum unused capability of the system during the morning ramp period occurs in late fall and winter dropping to under 100 megawatts in February. In general, also like in figure 16 – 2 these results show the system having slightly more unused capability on average during fall and early winter months, but the unused capability during those months is highly dependent on water conditions. During late winter, spring and summer months, the unused capability varies less with water conditions, but the unused capability is lower on average.

In Figure 16 – 6, describing evening ramp period, the minimum unused capability of the system is under 300 megawatts from late fall through spring. The average unused capability does not ever get under 1,700 megawatts. While there is more variability in system flexibility in these hours, the evening ramp period seems to be similarly dependent on hydro conditions to the morning ramp and heavy load hour periods but overall the system is under less stress.

Figure 16 - 5: Average Morning Ramp Hours Unused Capability

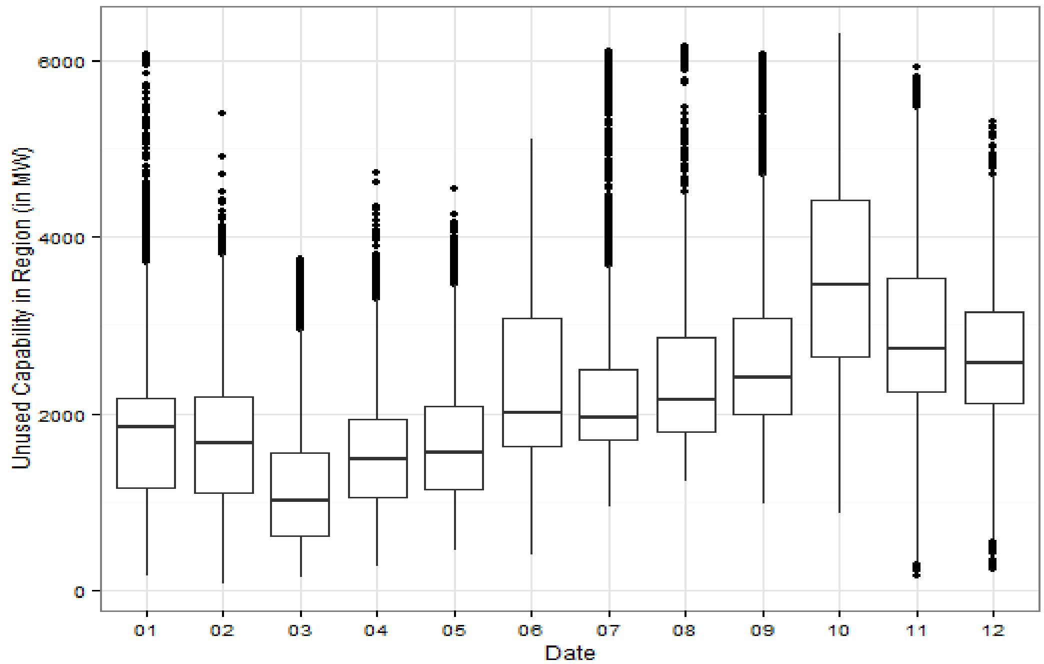
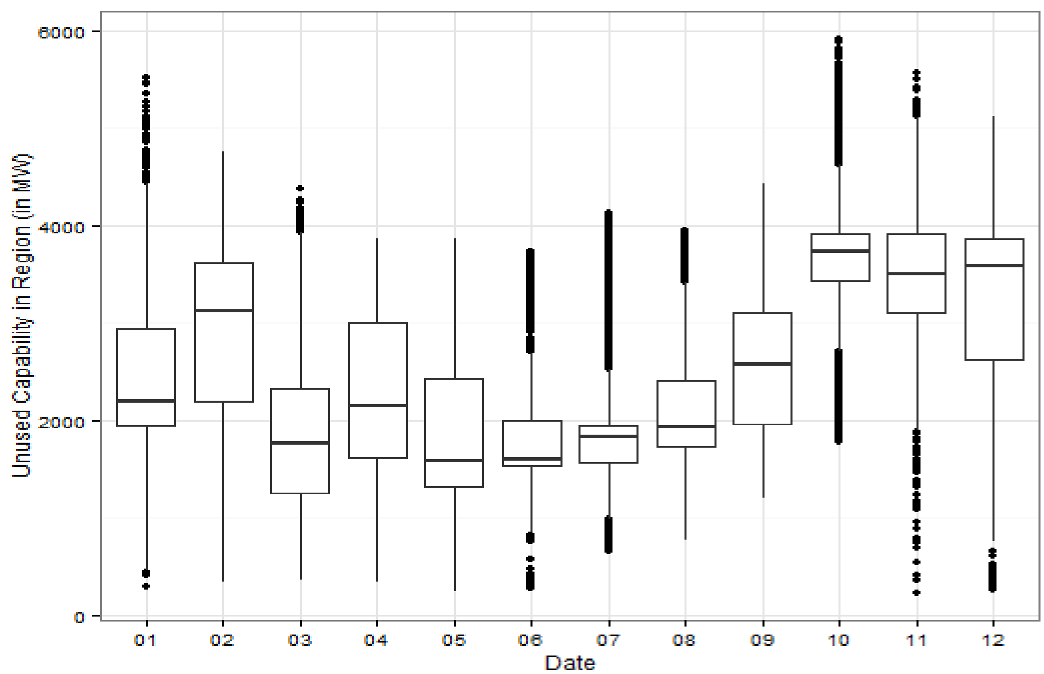


Figure 16 - 6: Average Evening Ramp Hours Unused Capability



In general, these results show that morning ramp and heavy load hours seem to be more effected by adverse hydro conditions than during the evening ramp and light load hours. This result indicates that the capability of the hydroelectric system is being used slightly more in heavy load and morning ramp hours and than in light load and evening ramp hours. The differences between heavy and light load hydropower utilization, in general, corresponds to the traditional operation of hydroelectric plants by shifting generation with limited fuel into the higher priced heavy load hours. This operation can be seen more clearly in Table 16 - 4 and Table 16 - 5 below, by comparing the monthly unused hydro capability over 80 water conditions.[26]

Table 16 - 4: Unused Hydropower Capability (MW) in Light Load and Evening Ramp Hours

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average	-	-	0.2497	0.2660	7.0716	6.7896	0.0275	0.0006	0.0002	0.0138	0.0001	-
Max	-	-	4,953	1,102	66	116	6	2	1	4	1	-
Min	-	-	-	-	-	-	-	-	-	-	-	-

Table 16 - 5: Unused Hydropower Capability (MW) in Heavy Load and Morning Ramp Hours

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average	-	-	-	0.009	0.594	0.907	0.001	-	-	-	-	-
Max	-	-	-	6	47	64	3	-	-	-	-	-
Min	-	-	-	-	-	-	-	-	-	-	-	-

Perhaps more importantly, for a large part of the year, there is not much remaining unused capability on the hydroelectric system. Therefore, during summer, fall and winter, thermal resources must be used if there is a need for additional shaping during the heavy load and morning ramp hours in almost all but the most abundant hydro years. However, as can be seen in Figure 16 - 4, the regional thermal resources still have the capability to provide these services in almost every hydro condition.

Inter-hour Balancing Reserve Requirements

While regional inter-hour balancing reserve requirements were not considered explicitly in the Council's analysis, some conclusions can be drawn from the observed inter-hour ramping requirements. Operationally, ramping requirements between multiple hours in conjunction with within-hour reserve requirements can sometimes be problematic. These coordination issues are

[26] Note that in Tables 16 – 4 and 16 – 5 when unused hydro capability is marked 0 it indicates that it is non-zero

amplified by uncertainty in load and variable generation forecasts, limited ramping capability in the regional system's resource portfolio, and limited extra-regional market availability. For this analysis, the region's inter-hour operating constraints were adhered to for both hydroelectric and thermal resources. This was modeled by ensuring that the multi-hour sustained peaking requirements of TRAP and GENESYS, and operating constraints of AuroraXMP were met.

In the modeling, when the region experienced curtailment situations, they occurred during late fall and early winter periods, which is consistent with the analysis on unused capability in the region. Analysis of the curtailment record shown in Table 16 – 6 revealed that curtailments had certain characteristics in common. These included large hour-to-hour regional load changes, no available regional hydropower flexibility and minimal regional thermal flexibility coupled with significant changes in hour to hour extra-regional market availability.[27] In addition, analysis of the curtailment record shown in Table 16 – 6, indicates that during periods of system stress, peak hour system stresses were more of an issue than ramping and light load hours.

Further analysis of different load and variable generation combinations in conjunction with the 80 hydro conditions might yield more robust results, and will be an area for further study by the Council.

Table 16 - 6: Curtailment Periods

Name of Scenario	Total Events	Morning Ramp Hours	Evening Ramp Hours	Heavy Load Hours	Light Load Hours
Existing System	260	95	7	748	2
Existing System +1400 aMW EE + 1360 MW DR[20]	8	1	0	13	2 [28]

[27] In this case, significant changes in market availability are characterized by two main phenomena: most of the resource capability in the region being on the east side and the most of the load served on the west side; in conjunction with significant load resource balance swings in California affecting the market availability in the entire WECC.

[28] Note that the two light load hour curtailments are just before the morning ramp, so it could be that the effect of the load ramp started earlier in those instances.