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2017 PSE Integrated Resource Plan

Regional Resource Adequacy Studies

The results and data from these three studies of regional load/resource balance were used in the preparation of the 2017 PSE IRP.

Contents

1. NORTHWEST POWER AND CONSERVATION COUNCIL (NPCC)

Pacific Northwest Power Supply Adequacy Assessment for 2021

Published September 27, 2016

(attached)

2. PACIFIC NORTHWEST UTILITIES CONFERENCE COMMITTEE (PNUCC)

Northwest Regional Forecast of Power Loads and Resources 2017-2026

Published April 2016

(attached)

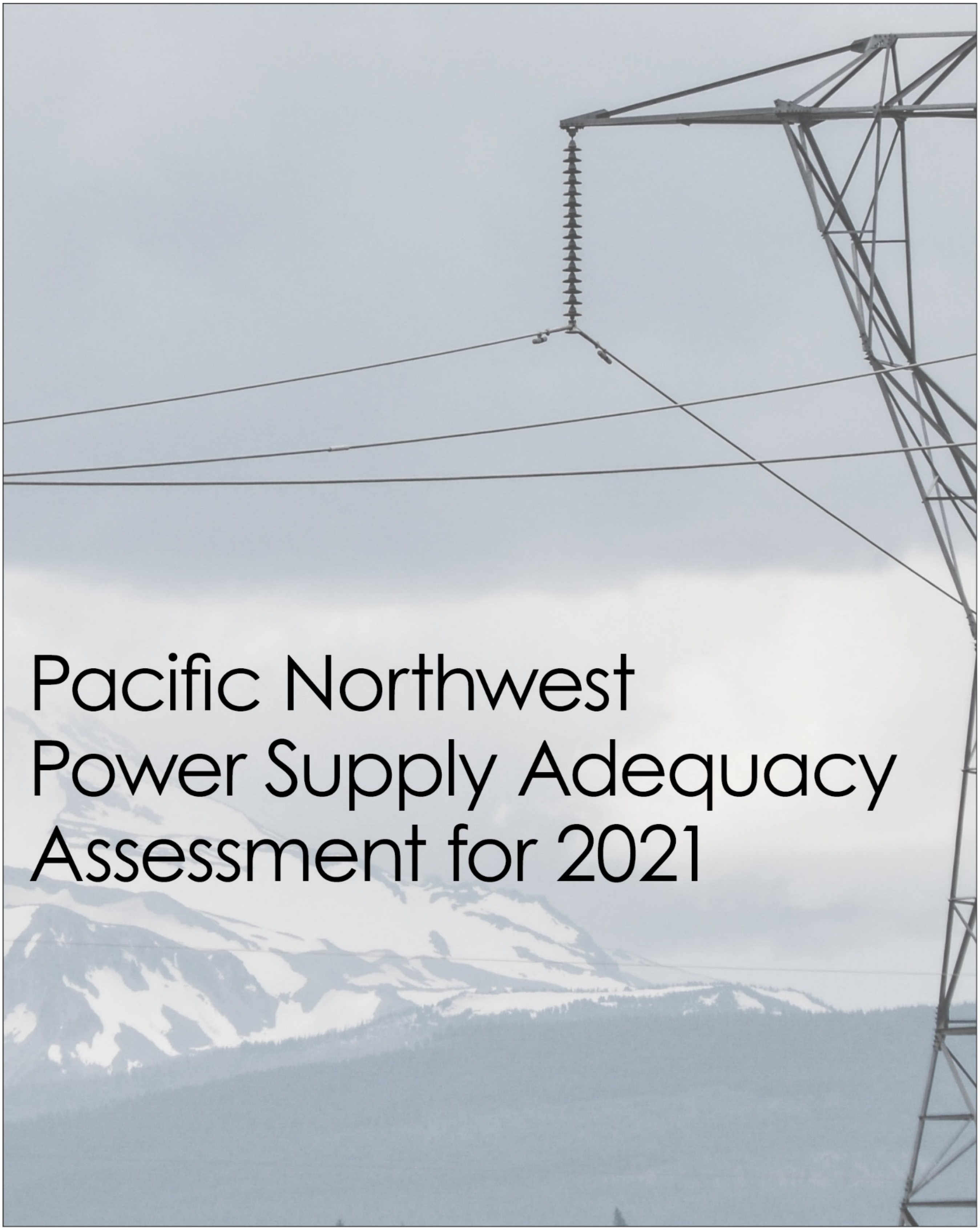
3. BONNEVILLE POWER ADMINISTRATION (BPA)

2016 Pacific Northwest Loads and Resources Study

Published December 22, 2016

Access this document at the following links:

- *Summary*
  https://www.bpa.gov/power/pgp/whitebook/2016/2016-WBK-Loads-and-Resources-Summary-20161222.pdf
- *Energy Analysis*
  https://www.bpa.gov/power/pgp/whitebook/2016/2016-WBK-Technical-Appendix-Volume-1-Energy-Analysis-20161222.pdf
- *Capacity Analysis*
  https://www.bpa.gov/power/pgp/whitebook/2016/2016-WBK-Technical-Appendix-Volume%20-2-Capacity-Analysis-20161222.pdf



Pacific Northwest Power Supply Adequacy Assessment for 2021

September 27, 2016
Document 2016-10

Northwest **Power** and **Conservation** Council

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FORWARD

This document summarizes the Northwest Power and Conservation Council's assessment of the adequacy of the power supply for the 2021 operating year (October through September). In 2011, the Council adopted the annual loss-of-load probability (LOLP) as the measure for power supply adequacy and set the maximum value at 5 percent. For a power supply to be deemed adequate, the likelihood (LOLP) of a shortfall (not necessarily an outage) occurring anytime in the year being examined cannot exceed 5 percent.

Other adequacy metrics that measure the size of potential shortages, how often they occur and how long they last, also provide valuable information to planners as they consider resource expansion strategies. This report provides that information along with other statistical data derived from Council analyses. The Council, with the help of the Resource Adequacy Advisory Committee, produced the data in the charts and tables.

The format and content of this report continue to be under development. We would like to know how useful this report is for you. For example, is the format appropriate? Would you like to see different types of output? Please send your comments, suggestions and questions to John Fazio at (jfazio@nwcouncil.org).

The Council is improving its adequacy model (GENESYS), in particular the hourly hydroelectric system dispatch simulation, and expects to complete the work by 2018. In addition, the Council has initiated a process to review its current adequacy standard. Staff and RAAC members have been asked to review the viability of the current metric (LOLP) and threshold (5 percent). This review should consider similar efforts going on in other parts of the United States, namely through the IEEE Loss-of-Load-Expectation Working Group and the North American Electric Reliability Corporation (NERC).

Cover photo courtesy of SOAR Oregon.

EXECUTIVE SUMMARY

The Pacific Northwest's power supply should be adequate through 2020. However, with the planned retirements of four Northwest coal plants[1] by July of 2022, the system will no longer meet the Council's adequacy standard and will have to acquire nearly 1,400 megawatts of new capacity in order to maintain that standard. This result assumes that the region will meet the Council's energy efficiency targets, as identified in the Seventh Power Plan. Thus, it is imperative that we continue to implement cost-effective energy efficiency programs. Beyond energy efficiency, Northwest utilities have been steadily working to develop replacement resource strategies and have reported about 550 megawatts of planned generating capacity by 2021.[2] These strategies will include the next most cost-effective and implementable resources, which may include additional energy efficiency, demand response or new generating resources. The Council will reassess the adequacy of the power supply next year to monitor the region's progress in maintaining resource adequacy.

In 2011, the Northwest Power and Conservation Council adopted a regional adequacy standard to "provide an early warning should resource development fail to keep pace with demand growth." The standard deems the power supply to be inadequate if the likelihood of a power supply shortfall (referred to as the loss-of-load probability or LOLP) is higher than 5 percent. The LOLP for the region's power supply should stay under the 5 percent limit through 2020. In 2021, with the loss of 1,330 megawatts of capacity from the Boardman and Centralia 1 coal plants (slated to retire in December of 2020), the LOLP rises to 10 percent.[3] In this scenario, the region will need a little over 1,000 megawatts of new capacity to maintain adequacy. Should the Colstrip 1 and 2 coal plants (307 megawatts committed to serve regional demand) also retire before 2021,[4] the LOLP grows to just over 13 percent and the region's adequacy need grows to about 1,400 megawatts of new capacity.

These results are based on a stochastic analysis that simulates the operation of the power supply over thousands of different combinations of river flow, wind generation, forced outages, and temperatures. Since last year's assessment for 2021, which resulted in an 8 percent LOLP,

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[1] Centralia 1 (670 megawatts) and Boardman (522 megawatts) are scheduled to retire by December 2020, Colstrip 1 and 2 (154 megawatts each) are to be retired no later than July of 2022 and Centralia 2 (670 megawatts) is expected to retire by 2025.

[2] From the Pacific Northwest Utility Conference Committee's 2016 Northwest Regional Forecast (NRF).

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

[4] Currently there is no indication that Colstrip plants 3 and 4 will be retired earlier than expected.

the region's load forecast has slightly decreased[5] and no new resources have been added. This year's LOLP assessment for 2021 has grown to 10 percent because it included all regional balancing reserve requirements instead of only the federal system reserves assumed in last year's analysis.

The conclusions made above assume that future demand will stay on the Council's medium load forecast path and that only a fixed amount of imported generation from the Southwest is available. If demand growth were to increase rapidly and if the availability of imports were to drop, the LOLP could grow as high as 30 percent and the region's adequacy needs could grow to 2,600 megawatts or more. But these extreme cases are not very likely to occur.

Resource acquisition plans to bring the 2021 power supply into compliance with the Council's standard will vary depending on the types of new generating resources or demand reduction programs that are considered. In all likelihood, utilities will use some combination of new generation and load reduction programs to bridge the gap.

This analysis does not provide a strategy to maintain an adequate, efficient, economical, and reliable power supply. The Council's Seventh Power Plan outlines a resource strategy to ensure an adequate power supply for 2021.

Northwest utilities, as reported in the Pacific Northwest Utilities Conference Committee's 2016 Northwest Regional Forecast, show about 550 megawatts of planned generating capacity for 2021. However, these planned resources are not sited and licensed and are therefore not included in the 2021 adequacy assessment. As conditions change over the next few years, we expect utilities to revise their resource acquisition strategies to invest in new resources, which include energy efficiency and demand response.

[5] This year's assessment included a hybrid load forecasting method that is different from past forecasts. This was done to insure that the load forecast used for the adequacy assessment was consistent with the one used for the development of the Council's Seventh Power Plan. The RAAC will evaluate this new load forecast in detail prior to next year's assessment for 2022.

THE COUNCIL'S RESOURCE ADEQUACY STANDARD

In 2011, the Northwest Power and Conservation Council adopted a regional adequacy standard to "provide an early warning should resource development fail to keep pace with demand growth." The standard deems the power supply to be inadequate if the likelihood of a power supply shortfall five years in the future is higher than 5 percent.

The Council assesses adequacy using a stochastic analysis to compute the likelihood of a supply shortfall. It uses a chronological hourly simulation of the region's power supply over many different future combinations of stream flows, temperatures, wind generation patterns and forced generator outages. We only count existing generating resources, and those expected to be operational in the study year, along with targeted energy efficiency savings. The simulation also assumes a fixed amount of market resource availability, both from inside and outside of the region.

The power supply is deemed to be adequate if the likelihood of a shortfall (referred to as the loss of load probability or LOLP) is less than or equal to 5 percent. If the supply is deemed inadequate, the Council estimates how much additional capacity and energy generating capability is required to bring the system's LOLP back down to 5 percent. However, the standard is not intended to provide a resource-planning target because it assesses only one of the Council's criteria for developing a power plan. The Council's mandate is to develop a resource strategy that provides an adequate, efficient, economic and reliable power supply. There is no guarantee that a power supply that satisfies the adequacy standard will also be the most economical or efficient. Thus, the adequacy standard should be thought of as simply an early warning to test for sufficient resource development.

Because the computer model used to assess adequacy (GENESYS) cannot possibly take into account all contingency actions that utilities have at their disposal to avert an actual loss of service, a non-zero LOLP should not be interpreted to mean that real curtailments will occur. Rather, it means that the likelihood of utilities having to take extraordinary and costly measures to provide continuous service exceeds the tolerance for such events. Some emergency utility actions are captured in the LOLP assessment through a post-processing program that simulates the use of what the Council has termed "standby resources."

Standby resources are demand-side actions and small generators that are not explicitly modeled in the adequacy analysis. They are mainly composed of demand response measures, load curtailment agreements and small thermal resources.

Demand response measures are typically expected to be used to help lower peak-hour demand during extreme conditions (e.g. high summer or low winter temperatures). These resources only have a capacity component and provide only a very limited amount of energy (i.e. they cannot be dispatched for more than a few hours at a time). The effects of demand response measures that <u>have already been implemented</u> are assumed to be reflected in the Council's load forecast.

New demand response measures that have no operating history and are therefore not accounted for in the load forecast are classified as part of the set of standby resources.

Load curtailment actions, which are contractually available to utilities to help reduce peak hour load, and small generating resources may also provide some energy assistance. However, they are not intended to be used often and are, therefore not modeled explicitly in the simulations. The energy and capacity capabilities of these non-modeled resources are aggregated along with the demand response measures mentioned above to define the total capability of standby resources. A post-processing program uses these capabilities to adjust the simulated curtailment record and calculate the final LOLP.

RECENT ADEQUACY ASSESSMENTS

Table 1 below illustrates the evolving nature of the effort to better quantify power supply adequacy. Since 1998, when the Council began using stochastic methods to assess adequacy, the power supply and, to some extent the methodology, have changed significantly, sometimes making it difficult to compare annual assessments. And, while this evolution is likely to continue, the Council believes that the current standard and methodology will be sufficiently stable to create a history of adequacy evaluations that can be used to record trends over time.

The Council recognizes that the power system of today is very different from that of 1980, when the Council was created by Congress. In particular, the ever increasing generation from variable energy resources, such as solar and wind, have added a greater band of uncertainty with regard to providing an adequate supply. This has led to a greater need in the ability to model hourly operations, especially for the hydroelectric system. Toward this end, the Council is currently in the process of redeveloping its adequacy model (GENESYS) to add more precision to the simulation of hydroelectric generation. The thrust of this effort is to improve the hourly operation simulation by adding a better representation of unit commitment, balancing reserve allocation and moving to a plant-specific hourly hydroelectric simulation (the current model simulates hourly hydroelectric generation in aggregate for the region). These enhancements, expected to be completed by 2018, could likely change the results in a significant way. It will require an extensive vetting effort to ensure that the results of the redeveloped model are a better representation of real-life operations. It will be important to identify the effects of the model enhancements to the resulting adequacy assessments and separate them from the effects of real load and resource changes.

Table 1: History of Adequacy Assessment

Year Analyzed	Operating Year	LOLP	Observations
2010	2015	5%	Was part of the Council's 6th Power Plan
2012	2017	7%	Imports decreased from 3,200 to 1,700 MW, load growth 150 aMW per year, only 114 MW of new thermal capacity
2014	2019	6%	Load growth 120 aMW per year, over 600 MW new generating capacity, increased imports by 800 MW
2015	2020	5%	Lower load forecast, 350 aMW of additional EE savings
2015	2021	8%	*Early estimate (BPA INC/DEC only)* Loss of Boardman and Centralia 1 (~1,330 MW)
2016	2021	10%	2021 loads lower than last year's forecast regional INC/DEC reduces hydro peaking
2016	2021	13%	Same as above but with Colstrip coal plants 1 and 2 retired (307 MW assigned to serve the region)

2021 RESOURCE ADEQUACY ASSESSMENT

The Pacific Northwest's power supply is expected to be adequate through 2020. However, with the planned retirements of four Northwest coal plants by July of 2022, the system will no longer meet the Council's adequacy standard (LOLP at 13 percent) and will have to acquire nearly 1,400 megawatts of new capacity in order to reduce the LOLP to the 5 percent standard. This result assumes that the Council's energy efficiency targets, as identified in the Seventh Power Plan, will be achieved.

In 2021, with the loss of 1,330 megawatts of capacity from the Boardman and Centralia 1 coal plants (slated to retire in December of 2020), the LOLP rises to 10 percent.[6] In this scenario, the region will need a little over 1,000 megawatts of new capacity to maintain adequacy. Should the Colstrip 1 and 2 coal plants (307 megawatts committed to serve regional demand) also retire

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

before 2021, the LOLP grows to just over 13 percent and the region's adequacy need grows to about 1,400 megawatts of new capacity.

The conclusions made above assume that future demand will stay on the Council's medium load forecast path and that only a fixed amount of imported generation from the Southwest is available. If demand growth were to increase rapidly and if the availability of imports were to drop, the LOLP could grow as high as 26 percent and the region's adequacy needs could grow to 2,600 megawatts or more. But this extreme case is not very likely to occur.

Two future uncertainties not modeled explicitly in GENESYS are long-term (economic) load growth and variability of the out-of-region market supply. Long-term load growth is bounded by the Council's high and low load forecasts, which cover roughly 85 percent of the expected load range. Variation in SW market supply is influenced by future resource development in California and by the ability to transfer surplus energy into the Northwest.

By 2021, California is scheduled to retire 2,641 megawatts of its coastal water-cooled thermal power plants, and nearly 10,000 megawatts will either be retired or replaced over the next 10 years. In addition, in 2012 California lost 2,200 megawatts of San Onofre Nuclear Generating Station capacity.[7] However, according to an Energy GPS report, California surplus is expected to greatly exceed the south-to-north intertie transfer capability during Northwest winter peak-load hours. Based on a look at historical monthly south-to-north transfer availability (BPA data), it appears that the maximum transfer capability hovers around 4,500 megawatts with a 95 percent chance of being at least 3,400 megawatts. The Council chose to set the maximum transfer capability from California into the Northwest to the 3,400 megawatt value.

In spite of the results of the Energy GPS survey of available California surplus, and supported by the Resource Adequacy Advisory Committee, the Council chose to limit California import availability to no more than 2,500 megawatts during peak hours in the winter and to 3,000 megawatts during off-peak hours year round. The on-peak imports are defined as a "spot market" resource, which can be acquired during the hour of need. The off-peak imports are defined as a "purchase ahead" resource, which can be acquired during the light-loads hours prior to an anticipated peak-hour shortfall.

To investigate the potential impacts of different combinations of economic load growth and California import availability, scenario analyses were performed. In one extreme case, with high load growth and no California import, the loss of load probability would be 26 percent. Fortunately, this scenario is not very likely. At the other end of extreme cases, with low load growth and maximum winter import availability, the loss of load probability drops to about 2 percent. Table 2 illustrates how LOLP changes as both long-term load growth and SW imports vary.

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[7] By 2025 the Diablo Canyon nuclear plant (2,200 megawatts) is expected to close.

Table 2: Load and SW Market Impacts to LOLP (121 MW new DR)

Import	3400 MW	2500 MW	1700 MW
High Load	22.1	24.2	26.2
Med Load	7.8	9.9	12.0
Low Load	1.9	3.7	5.6

Sensitivity Analysis

Sensitivity analyses are useful in helping to understand how results may change as particular input assumptions vary. We have already seen, in the section above, how LOLP changes as economic load growth and SW market assumptions vary. In this section, the sensitivity of LOLP to additional demand response and to a loss of gas supply is investigated.

Tables 3 and 4 show how LOLP changes as more demand response is added to the power supply.[8] Studies run to produce the results in these tables are identical to those run to produce the results in Table 2, with the exception that more demand response was added to each. In Table 3, an additional 379 megawatts of demand response was added to all the studies (for a total of 500 megawatts of new demand response). In Table 4 an additional 1,136 megawatts (or a total of 1,257 megawatts) of new demand response was added. As evident in the results summarized in these tables, demand response can be a very effective resource toward maintaining an adequate supply. Studies using the Council's Regional Portfolio Model, during the development of the Seventh Power Plan, indicated that up to about 1,300 megawatts of new demand response resource could be cost effective relative to other options to maintain adequacy. Unfortunately, the infrastructure and experience needed to acquire that much new demand response is not as well developed as for energy efficiency programs, thus there remains uncertainty whether this level of new demand response would actually be implementable by 2021. The Council has encouraged utilities to continue to investigate and develop means to more easily acquire cost-effective demand response resources both for winter and summer needs.

[8] It should be emphasized that demand response is exclusively a capacity provider with very limited energy contributions. As such, it may not be the best solution to offset longer-term curtailments (e.g. those that last over the 16 peak load hours of the day).

Table 3: Load and SW Market Uncertainty LOLP Map Existing (500 MW new DR)

Import	3400 MW	2500 MW	1700 MW
High Load	15.9	18.5	20.4
Med Load	5.5	7.7	9.5
Low Load	1.4	3.0	5.0

Table 4: Load and SW Market Uncertainty LOLP Map Existing (1,257 MW new DR)

Import	3400 MW	2500 MW	1700 MW
High Load	7.6	10.0	12.5
Med Load	2.6	4.7	6.7
Low Load	0.4	1.9	3.5

Table 5: Sensitivity – Loss of Gas Supply/Market Friction
(Loss of 650 MW IPP Resource)

Import	Base Case	IPP Loss + 121 MW DR	IPP Loss + 500 MW DR	IPP Loss + 1257 MW DR
High Load	24.2	30.0	23.1	13.3
Med Load	9.9	13.2	9.6	6.1
Low Load	3.7	5.4	4.5	2.9

Table 5 summarizes the sensitivity of LOLP to a loss of Northwest market supply due to a shortage of fuel (gas). The Northwest has about 3,000 megawatts (nameplate) of independent power producer (IPP) generating capability. Council adequacy assessments assume that all of that capability is available for Northwest use during winter months but only 1,000 megawatts is available during summer months (due to competition with SW utilities). These sensitivity studies examined how much the LOLP increases due to a loss of 650 megawatts of IPP generation during winter and about a 220 megawatt loss of IPP generation during summer.

As is evident in that table, a loss of Northwest market has a similar effect on LOLP (making it bigger) as does the loss of SW market supply. This type of analysis could also be thought of as a surrogate for a “market friction” sensitivity analysis. Market friction is commonly thought of as a decrease in market access due to transmission limitations or due to more conservative operations by utilities during periods of short supply (e.g. utilities may hold more generating capability in reserve during certain conditions) or a combination of both. This type of analysis will be important to investigate further for future adequacy assessments.

Monthly Analysis

Currently, the Council's adequacy standard sets a 5 percent maximum threshold for annual loss of load probability. This standard has been very useful in the past, especially compared to older deterministic methods, to aid the region in maintaining an adequate power supply. However, with the addition of more and more variable energy generation resources, such as wind and solar, and with the anticipated large increase in solar rooftop development, an annual metric may no longer be the best measure for adequacy. Figure 1 below shows the monthly LOLP values for both the reference case and the case with Colstrip 1 and 2 also retired. It is clear from this figure that the region has both winter and summer adequacy issues. For the reference case, the highest monthly LOLP values still appear mostly in winter but when the two Colstrip plants are also removed, the late summer LOLP value exceeds the winter month values.

It is important to differentiate by month (or at least by season) in order to find optimum resource acquisition strategies. For example, some demand response programs are only available in winter or in summer. It should be noted that the sum of monthly LOLP values will not equal the annual value because the annual value counts simulations with at least one curtailment event regardless of when it occurs. A simulation with multiple events, say one in January and one in August, would count the same for the annual LOLP value as a simulation with only a January event or only an August event. Monthly values for other adequacy metrics are summarized in that section of this report.

Figure 1: LOLP by Month

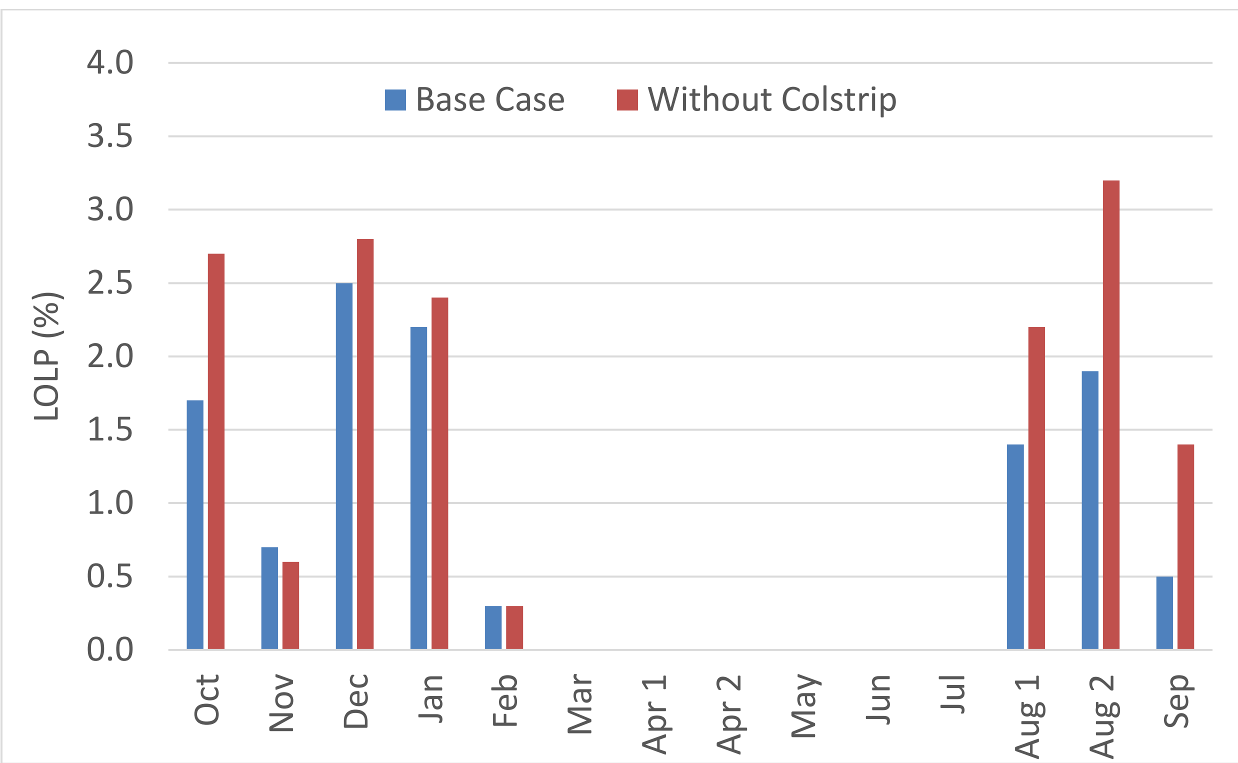

Table 6 summarizes the average monthly dispatch for groups of resources, namely wind, coal, gas, nuclear and SW market. This table shows the monthly dispatch for the reference case and for the case with the Colstrip 1 and 2 coal plant retirement and the difference. With the added loss of Colstrip 1 and 2, as expected, gas generation and SW market purchases go up to cover, as best they can, the loss of the coal generating capability. Obviously, the shift in the dispatch for these resources is not sufficient to offset the loss of the Colstrip plants as evident in the increase in curtailment events and the increase in the LOLP.

Table 6: Expected Resource Dispatch for 2021[9]

2021 Base Case	OCT	NOV	DEC	JAN	FEB	MAR	AP1	AP2	MAY	JUN	JUL	AU1	AU2	SEP
Wind	1203	1248	1201	1312	1296	1560	1767	1862	1751	1704	1571	1454	1342	1150
Coal	3254	2754	2861	2225	1828	1484	1557	801	467	670	1784	2862	3259	3533
Gas	2710	1184	1310	1356	1043	752	776	563	494	560	847	1596	2048	2439
Nuclear	1034	1039	1070	1075	1128	1076	1071	1066	1076	1053	1077	1067	1110	1055
SW Market	487	505	603	593	343	174	211	55	9	24	88	249	338	403

2021 No Colstrip	OCT	NOV	DEC	JAN	FEB	MAR	AP1	AP2	MAY	JUN	JUL	AU1	AU2	SEP
Wind	1203	1248	1201	1312	1296	1560	1767	1862	1751	1704	1571	1454	1342	1150
Coal	3027	2561	2672	2054	1718	1410	1474	777	466	649	1679	2700	2986	3224
Gas	2895	1271	1409	1425	1093	785	819	574	495	571	898	1711	2197	2625
Nuclear	1034	1039	1070	1075	1128	1076	1071	1066	1076	1053	1077	1067	1110	1055
SW Market	524	569	674	648	383	202	240	64	10	28	99	277	375	440

No Colstrip - Base	OCT	NOV	DEC	JAN	FEB	MAR	AP1	AP2	MAY	JUN	JUL	AU1	AU2	SEP
Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal	-227	-193	-189	-171	-110	-74	-83	-24	-1	-21	-105	-162	-273	-309
Gas	185	87	99	69	50	33	43	11	1	11	51	115	149	186
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SW Market	37	64	71	55	40	28	29	9	1	4	11	28	37	37

Curtailment Statistics

[9] These studies for the 2021 operating year included no maintenance for the region's sole nuclear plant, which is in error. The 2-year maintenance schedule for the Columbia Generating Station has that plant out of service for about a 2 month period during odd years. So, these studies should have shown zero capability for nuclear during May and June. Since no curtailments are expected during these months, even with the shutdown of the nuclear plant, the resulting LOLP values would remain unchanged.

Sometimes, simply looking at simulation results can provide insight into the behavior of the power system. Table 7 below summarizes a few statistics for the curtailment events reported in our analysis. All adequacy studies were run with 6,160 simulations.

Besides looking at curtailment statistics, it may also be of great use to examine what conditions existed during the time of each shortfall. Thus, a record of all curtailment events along with the values for the four random variables used in the analysis will be provided in a separate spreadsheet (available on the Council's website). The four random variables displayed in the spreadsheet are;

- Water supply, as a percentage of monthly runoff volume
- Temperature, as a percentage of that day's historical temperature range
- Wind generation, based on historical wind capacity factors from BPA's wind fleet
- Forced outage conditions

Some attempts have been made to correlate shortfall events with the occurrence of certain temperatures, water conditions, wind generation patterns and forced outages, but unfortunately without much success. This is an area of study that is being explored further and may produce better results once the GENESYS model has been enhanced to model plant-specific hourly hydroelectric operations.

Table 7: 2021 Simulated Curtailment Statistics

Statistic		**Units**
Number of simulations	6,160	Number
Simulations with a curtailment	610	Number
Loss of load probability (LOLP)	10	Percent
Number of curtailment events	2,374	Number
Number of events per year	0.4	Events/year
Average event duration	11	Hours
Average event magnitude	12,700	MW-hours
Average event peak curtailment	1,200	MW
Expected curtailed hours per year (LOLH)	2.4	Hours
Expected un-served energy (EUE)	2,500	MW-hours
Events with duration of 1 to 2 hours	11	Percent
Duration of 1 to 4 hours	20	Percent
Duration of 1 to 6 hours	28	Percent
Duration of 1 to 12 hours	49	Percent
Duration of 1 to 14 hours	56	Percent
Duration of 1 to 16 hours	86	Percent
Duration greater than 16 hours	14	Percent
Highest likely duration (15 to 16 hours)	30	Percent

Figure 2 can be used to examine the likelihood for particular duration curtailment events. In that figure, the y-axis represents the duration for an event and the x-axis represents the probability of an event with that duration (or greater) of occurring. For example, in Figure 2 the 50th percentile duration (median value) is about 13 hours.[10] This means that we expect a 50 percent chance of observing a curtailment event of 13 hours or more.

Figure 2: Curtailment Event Duration Probability

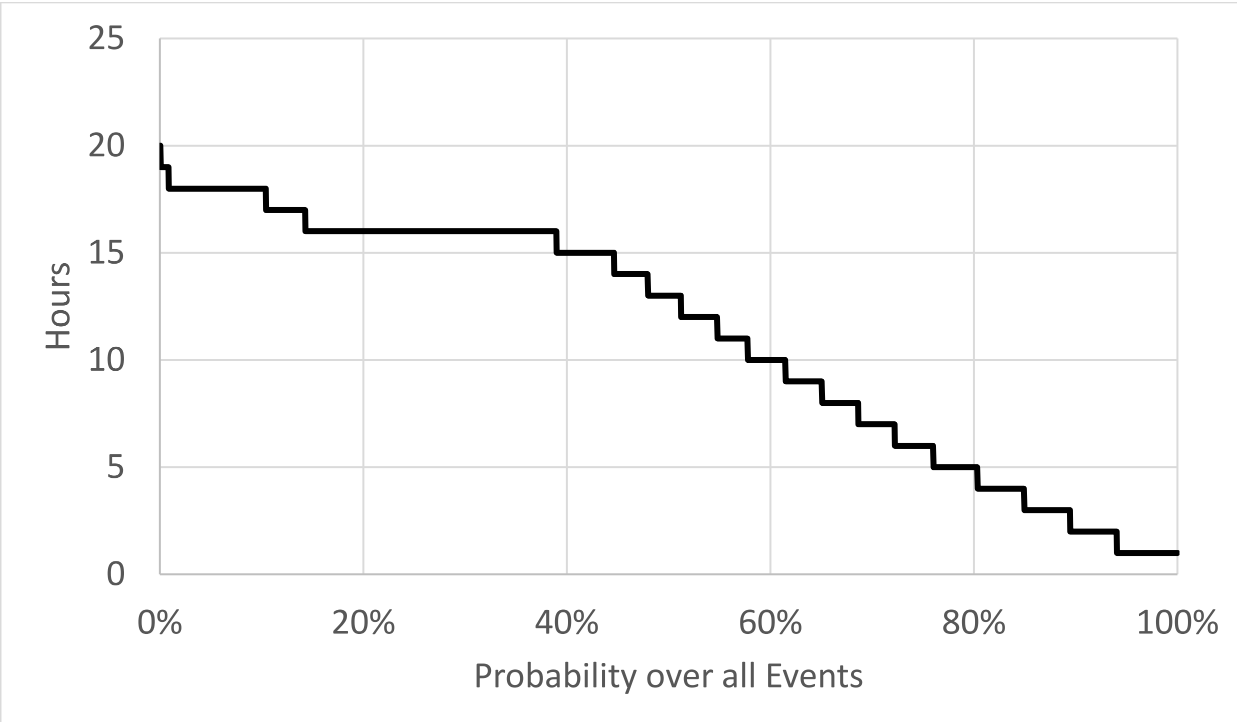

Figure 3 shows the same information in a different way. In that figure, the y-axis represents the percent of times that an event of particular duration occurs in the study. This is commonly referred to as a frequency distribution chart. For example, the most likely duration for an event is 16 hours. From Figure 3 a 16-hour duration event has about a 25 percent chance of occurring. The second most likely duration for an event is 18 hours. This result is not surprising since GENESYS will attempt to uniform any shortfall it sees across all the high-load hours of the day. Figure 4 shows the same information but the curtailment durations have been combined into 2-hour bins (as opposed to single hour bins in Figure 3). Figure 4 simply highlights the result that most event durations are between 15 and 18 hours. And, finally, Figure 5 provides more of a cumulative probability for event duration.

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[10] Note that the median duration is 13 hours while the average duration is 11 hours. This is because the distribution of event durations is not symmetric.

Figure 3: Event Duration Frequency (1-hour block incremental)

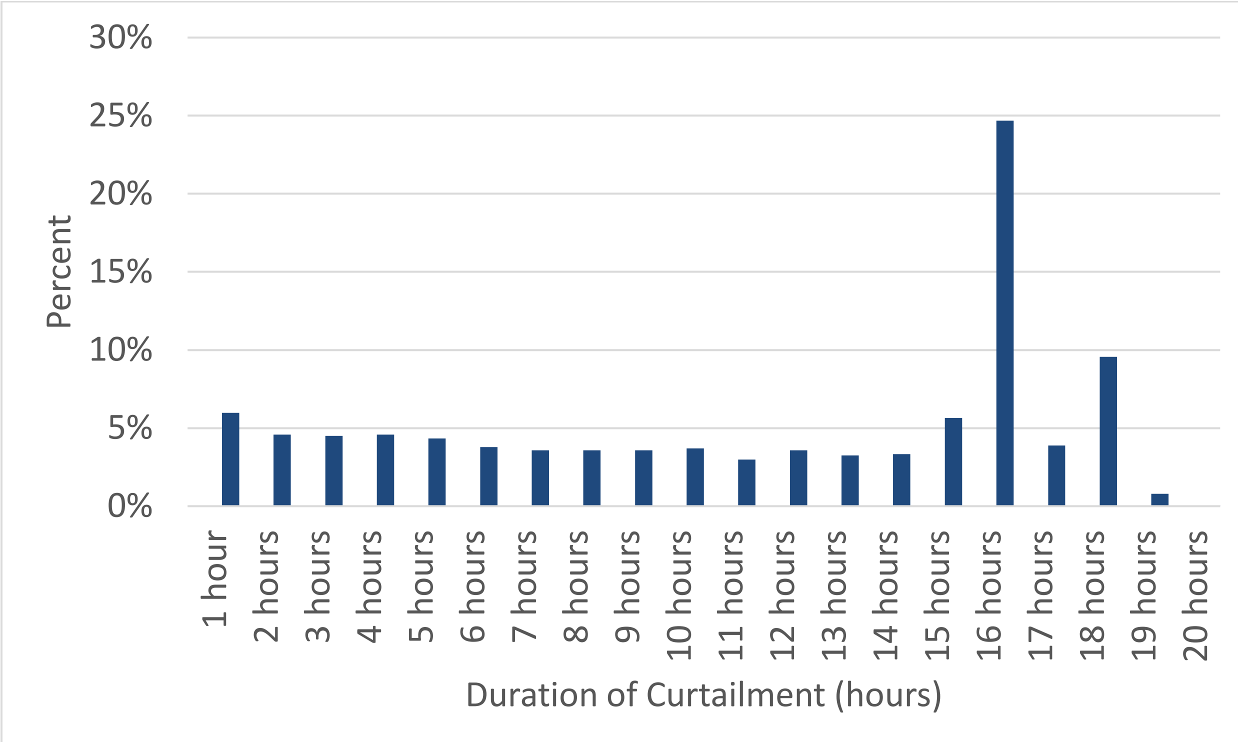


Figure 4: Event Duration Frequency (2-hour block incremental)

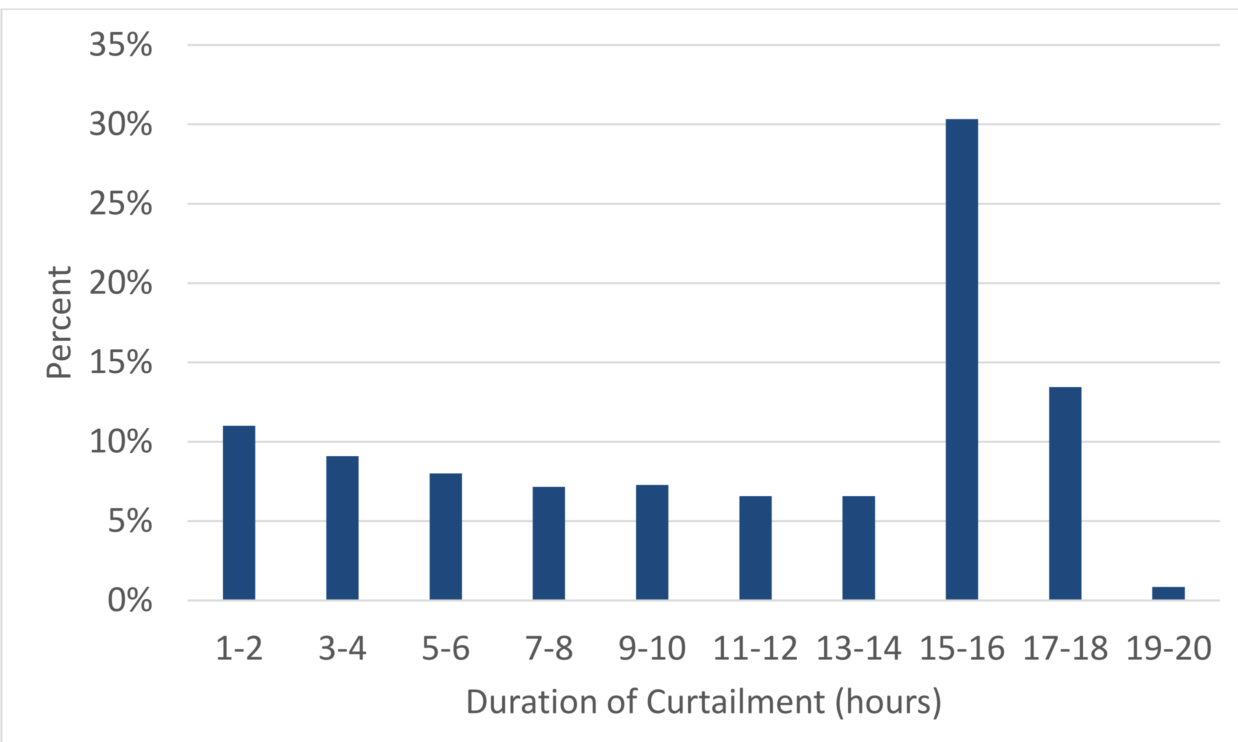
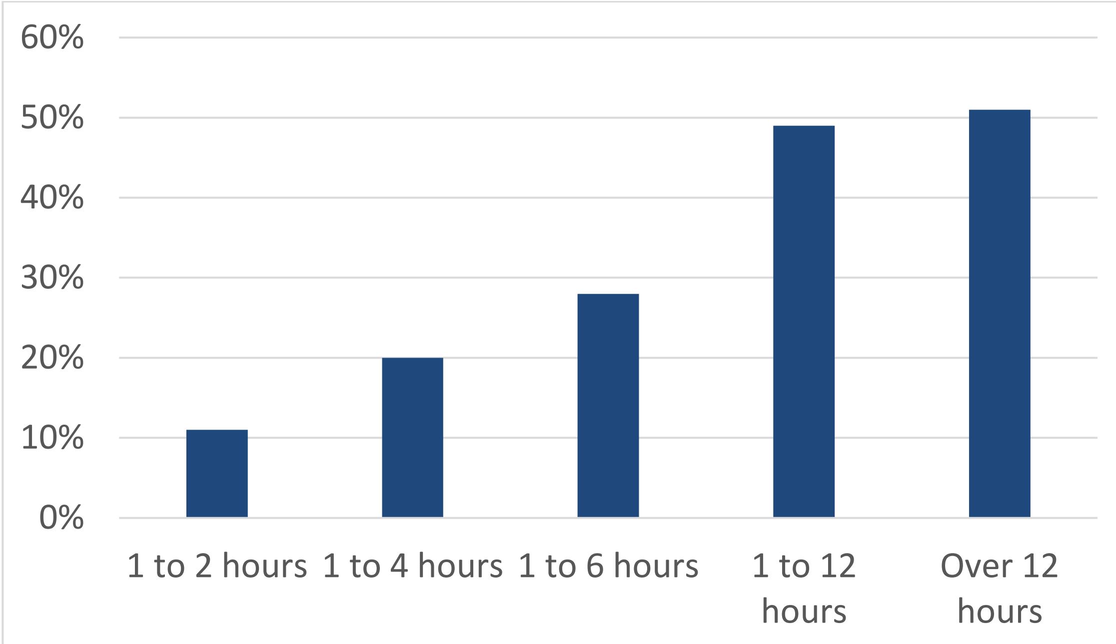


Figure 5: Event Duration Frequency (various time blocks)



The point at which these curves cross the horizontal axis would represent the LOLP except that these data were plotted prior to the implementation of standby resources.[11] By applying the effects of standby resources to the reference case results, the LOLP drops from a little over 13 percent down to the final value of 9.9 percent. In other words, if we could modify the curtailment record for that case to shows the effects of standby resources, the resulting probability curve would shift down and cross the horizontal axis at 9.9 percent. Doing the same for the Colstrip retirement case drops the LOLP to a little over 13 percent.

Figure 6 displays the annual unserved energy probability over all games for both the reference case and the Colstrip retirement case. The total unserved energy for each of the 6,160 games is summed up and then sorted from highest to lowest. Those results are then graphed in Figure 6. The vertical axis represents the amount of annual unserved energy and the horizontal axis represents the likelihood of observing a particular amount of annual unserved energy or more. From Figure 6, without the effects of standby resources, it appears that there is about a 13 percent[12] chance of observing a game with at least one curtailment (this is where the curve in Figure 6 crosses the horizontal axis). The probability curve for the Colstrip retirement case crosses the horizontal axis at about 17.7 percent.

[11] This is a simplification of the actual process, which takes into account monthly results.

[12] Remember this result is prior to adding the effects of standby resources.

Figure 6: Annual Unserved Energy Probability

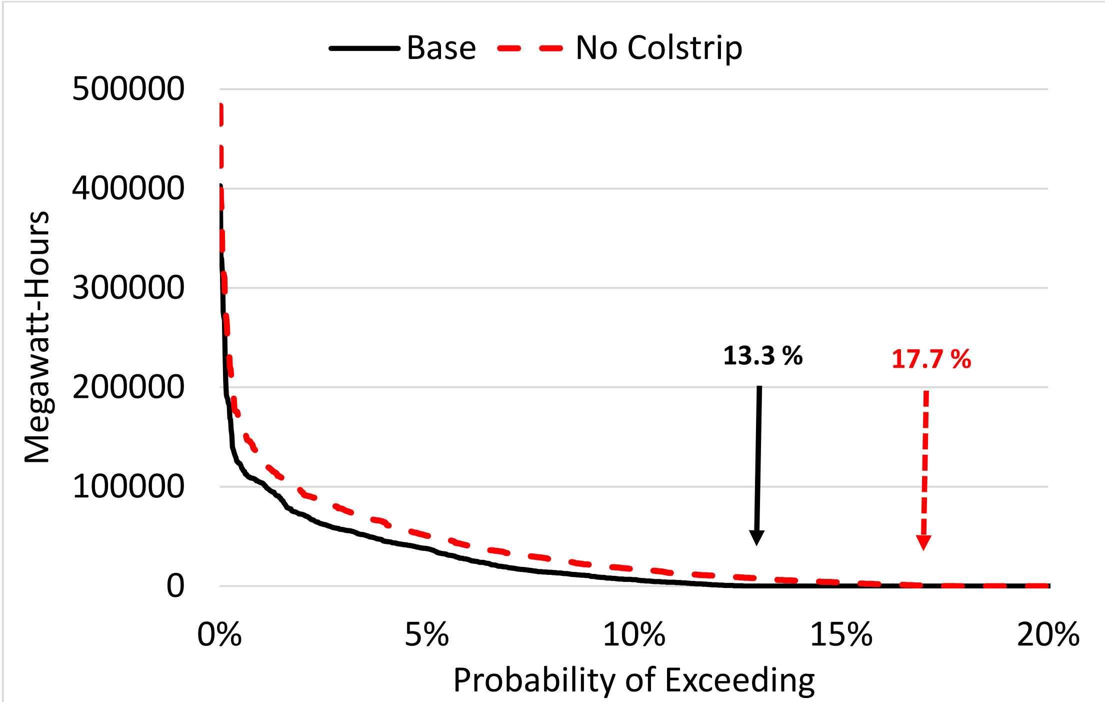


Figure 7a displays the worst-hour unserved energy probability for all games for both the reference case and the Colstrip retirement case. This figure is similar to Figure 6 but plots the worst (highest) single-hour unserved energy for each game, instead of the annual unserved energy. As expected, the probability curves in this figure cross the horizontal axis at the same percentage values as the curves in the annual unserved energy chart (Figure 6).

The curves in this figure can be used to estimate the amount of additional capacity needed to make the power supply adequate (not including the effects of standby resources). By looking at a blown-up section of Figure 7a, shown in Figure 7b, it becomes easier to see how much new capacity is required to shift the entire curve down so that it crosses the horizontal axis at the 5 percent Council adequacy limit. For the reference case, it requires a little over 1,800 megawatts of new capacity (simply draw a straight line up from the 5 percent point on the horizontal axis to the curve and then draw a straight line to the left to see where it would cross the vertical axis). Recall that these data have not been adjusted for standby resources, which contribute a little over 600 megawatts of capacity in winter. Thus, the estimate for required new capacity – in addition to the standby resource contribution – to maintain adequacy is about 1,200 megawatts. For the Colstrip retirement case, the needed amount of new capacity is about 1,500 megawatts. These values, however, are only estimates because they lump the curtailment events from all months together. Results from the more accurate analytical approach (which also include the effects of standby resources) show a need of about 1,040 megawatts and 1,400 megawatts of new capacity to maintain adequacy for the reference case and Colstrip retirement case, respectively.

It should be noted that it requires both new capacity and energy additions to move the 2021 LOLP down to the Council's 5 percent standard. Analysis indicates that the greatest need for the 2021 supply is addition of capacity, however, simply adding capacity with no energy will not result in an adequate supply. Each new resource has at least some energy providing capability, some more than others. For example, demand response programs can provide a lot of capacity but cannot be dispatched for long periods of time and therefore, provide only a very limited amount of energy. Wind resources, on the other hand, can provide a great deal of energy but can only be counted on to provide about 5 percent of their nameplate capacity toward peaking needs. This is why the Council uses its Regional Portfolio Model, which knows the energy and capacity contributions of all new resources, to develop a resource strategy that will lead to an adequate supply.

Figure 7a: Worst-Hour Unserved Energy Probability

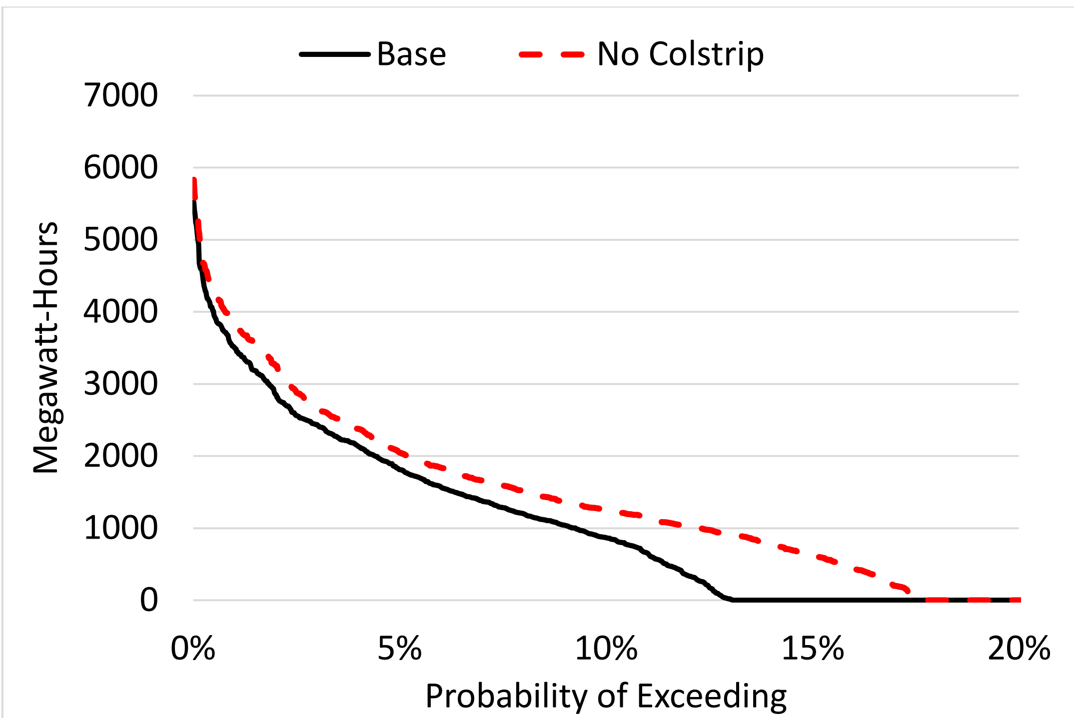
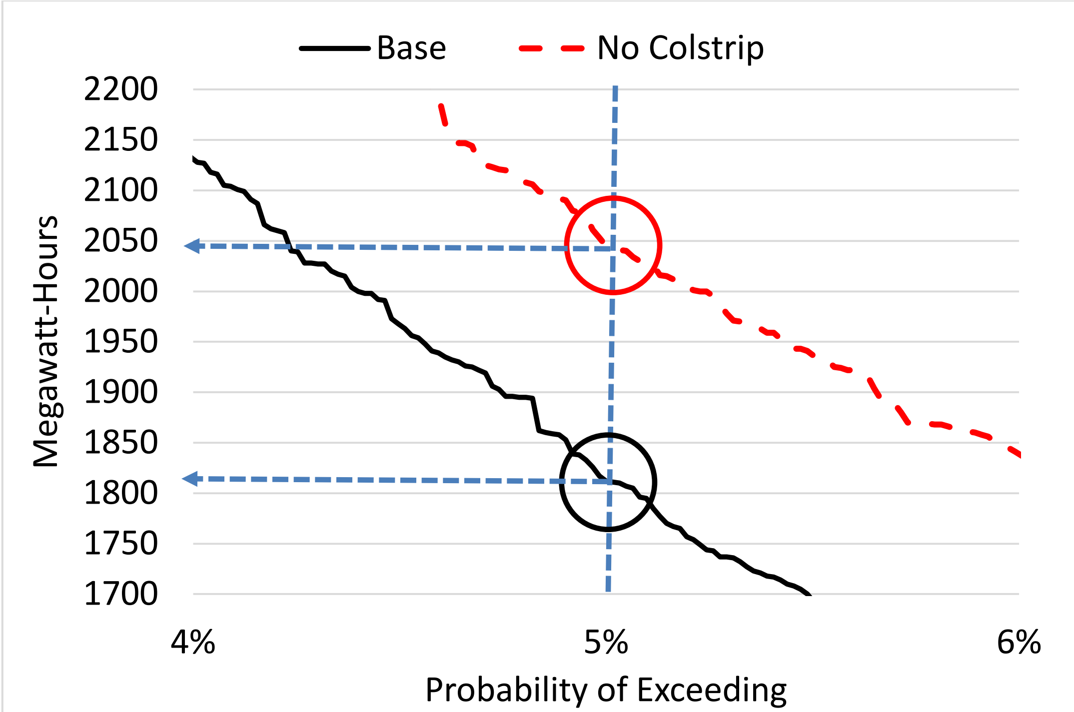


Figure 7b: Worst-Hour Unserved Energy Probability (Blow Up)



Other Adequacy Metrics

Other adequacy metrics help planners better understand the magnitude, frequency and duration of curtailments. These other metrics provide valuable information to planners as they consider resource expansion strategies. Table 8 below defines some of the more commonly used probabilistic metrics used to examine power supply adequacy and Table 9 provides the regional assessments of these metrics for 2017, 2019, 2020 and 2021.

While the Council has been using an annual LOLP metric to assess adequacy for nearly a decade, it became evident during the development of the Seventh Power Plan that monthly (or at least quarterly) values are essential to ensure a truly adequate supply. This is because resources can provide different energy and capacity contributions over each quarter. Also, the characteristics of potential shortfalls can vary by season. Thus, the Council's Regional Portfolio Model required quarterly adequacy reserve margins to develop more cost effective resource expansion strategies. The calculation of quarterly adequacy reserve margins requires quarterly adequacy targets. Recognizing this, the Council added an action item to reevaluate and amend its existing adequacy standard. Table 10 provides monthly values for LOLP and other adequacy metrics.

The North American Electric Reliability Corporation (NERC) instigated an adequacy assessment pilot program in 2012. It asked that each sub-region in the United States provide three adequacy measures; 1) expected loss of load hours, 2) expected unserved energy and 3) normalized expected unserved energy (EUE divided by load). This effort is a good first step toward standardizing how adequacy is assessed across the United States but it falls far short of establishing adequacy thresholds for these metrics. It may, in fact, be impossible to set thresholds because power supplies can vary so drastically across regions.

Table 8: Adequacy Metric Definitions

Metric	Description
LOLP (%)	Loss of load probability = number of games with a problem divided by the total number of games
CVaR – Energy (MW-hours)	Conditional value at risk, energy = average annual curtailment for 5% worst games
CVaR – Peak (MW)	Conditional value at risk, peak = average single-hour curtailment for worst 5% of games
EUE (MW-hours)	Expected unserved energy = total curtailment divided by the total number of games
LOLH (Hours)	Loss of load hours = total number of hours of curtailment divided by total number of games
PGC (%)	Percent of games with curtailment prior to implementing standby resources

Table 9: Annual Adequacy Metrics (Base Case)

Metric	2017	2019	2020	2021	Units
LOLP	6.6	5.9	4.7	9.9	Percent
CVaR - Energy	99,000	59,200	50,589	46,378	MW-hours
CVaR - Peak	4,000	3,337	2,949	2,185	MW
EUE	5,000	3,000	2,536	2,482	MW-hours
LOLH	2.7	1.7	1.5	2.4	Hours/year
PGC	9.7	8.3	6.4	13.6	Percent

Table 10: Monthly Adequacy Metrics (Base Case)

Month	LOLP Peak %	LOLP Energy %	Overall LOLP %	EUE MW-Hours	LOLH Hours
Annual	**9.9**	**1.8**	**9.9**	**2,482**	**2.4**
Oct	1.7	0.3	1.7	240	0.5
Nov	0.7	0.1	0.7	170	0.1
Dec	2.5	0.5	2.5	768	0.6
Jan	2.2	0.6	2.2	930	0.6
Feb	0.3	0.2	0.3	105	0.1
Jul	0	0	0	1	0
Au1	1.4	0.2	1.4	102	0.2
Au2	1.9	0.4	2	146	0.3
Sep	0.5	0.1	0.6	21	0.1

Assumptions

The methodology used to assess the adequacy of the Northwest power supply assumes a certain amount of reliance on non-utility supplies within the region and imports from California. The Northwest electricity market includes independent power producer (IPP) resources. The full capability of these resources, 2,943 megawatts, is assumed to be available for Northwest use during winter months. However, during summer months, due to competition with California utilities, the Northwest market availability is limited to 1,000 megawatts.

Other assumptions used for the 2021 adequacy assessment are shown in Table 11 through Table 15. Table 11 summarizes assumptions for load, energy efficiency savings and out-of-region market availability. Tables 12 and 13 provide the energy and capacity contributions for standby resources. Tables 14 and 15 provide the monthly incremental and decremental balancing reserves that were assumed. To the extent possible, the hydroelectric system was used to carry these reserves. Using the Council’s hourly hydroelectric optimization program (TRAP model), a portion of the peaking capability and minimum generation at specific hydroelectric projects was reserved to support the within-hour balancing needs. Unfortunately, not all balancing reserves could be assigned to the hydroelectric system. The remaining reserves should be assigned to other resources but the current adequacy model does not have that capability. This is one of the major enhancements targeted in the GENESYS redevelopment process.

Table 11: Assumptions used for the 2021 Adequacy Assessment

Item	Quarter 4	Quarter 1	Quarter 2	Quarter 3
Mean Load (aMW)	21,234	20,975	18,813	19,987
Peak Load (MW)	33,768	33,848	26,504	28,302
DSI Load (aMW)	338	338	338	338
Mean EE (aMW)	1,545	1,574	1,274	1,208
Peak EE (MW)	2,660	2,660	1,680	1,680
Spot Imports (MW)	2,500	2,500	0	0
Purchase Ahead (MW)	3,000	3,000	3,000	3,000

Table 12: Standby Resource Assumptions – Peak (MW)

Item	Quarter 4	Quarter 1	Quarter 2	Quarter 3
Exist DR	220	220	781	781
Exist Emergency Gen	266	266	266	266
Total Existing	**486**	**486**	**1047**	**1047**
Planned DR	121	121	0	0
Total Exist + Planned	**607**	**607**	**1047**	**1047**
Min DR (from the RPM)	379	379	468	468[13]
Total Exist + Plan + Min	**986**	**986**	**1515**	**1515**
Expected DR (from RPM)	1,136	1,136	1,178	1,178
Total Exist + Plan + Expect	**1,743**	**1,743**	**2,225**	**2,225**

[13] These are existing summer demand response programs.

Table 13: Standby Resource Assumptions – Energy (MW-hours)

Item	Quarter 4	Quarter 1	Quarter 2	Quarter 3
Exist DR	37,250	37,250	69,542	69,542
Exist Emergency Gen	5,800	5,800	5,800	5,800
Total Existing	**43,050**	**43,050**	**75,342**	**75,342**
Planned DR	6,050	6,050	0	0
Total Exist + Planned	**49,100**	**49,100**	**75,342**	**75,342**
Min DR (from the RPM)	18,950	18,950	23,400	23,400
Total Exist + Plan + Min	**68,050**	**68,050**	**98,742**	**98,742**
Expected DR (from RPM)	56,800	56,800	58,900	58,900
Total Exist + Plan + Expect	**105,900**	**105,900**	**134,242**	**134,242**

Table 14: Within-hour Balancing Reserves – Incremental (MW)

Period	BPA Hydro	Non-BPA Hydro	Non-BPA Thermal[14]
October	900	584	562
November	900	748	711
December	900	782	768
January	900	929	816
February	900	763	702
March	900	797	738
April 1-15	400	719	672
April 16-30	400	719	672
May	400	912	910
June	400	810	799
July	900[15]	750	958
August 1-15	900	797	640
August 16-31	900	797	640
September	900	716	662

[14] These balancing reserves were not assigned for this analysis.

[15] BPA's DEC reserve requirements of 400 megawatts extend through the end of July but the analysis in this report incorrectly assumed that the July reserve requirement was 900 megawatts. It was determined that rerunning all of the studies to include this correction was not warranted.

Table 15: Within-hour Balancing Reserves – Decremental (MW)

Period	BPA Hydro	Non-BPA Hydro	Non-BPA Thermal
October	900	662	786
November	900	899	1,264
December	900	687	1,073
January	900	751	908
February	900	728	955
March	900	690	899
April 1-15	900	713	942
April 16-30	900	713	942
May	900	748	1,044
June	900	723	898
July	900	629	811
August 1-15	900	609	872
August 16-31	900	609	872
September	900	746	910

FUTURE ASSESSMENTS

The Council will continue to assess the adequacy of the region's power supply. This task is becoming more challenging because planners must now focus on satisfying not only winter energy needs but also summer energy needs and capacity needs year round. Continued development of variable generation resources, combined with changing patterns of electricity demand have added complexity to the task of successfully maintaining an adequate power supply. For example, regional planners have had to reevaluate methods to quantify and plan for balancing reserve needs. In light of these changes, the Council is in the process of enhancing its adequacy model to reflect real life operations and to address capacity issues.

Another emerging concern is the lack of access to supplies for some utilities due to insufficient transmission or due to other factors. For the current adequacy assessment, the Northwest region is split into two subsections[16] in which only the major east-to-west transmission lines are modeled. Similarly, only the major Canadian-U.S. and Northwest-to-Southwest interties are modeled. The Council is hoping to address these issues in future adequacy assessments.

Also, at some point, uncertainties surrounding the change in Canadian flood control operations in 2024 and the effects of a potentially renegotiated Columbia River Treaty will have to be addressed. But besides these issues, the Council's latest power plan identifies the following action items related to adequacy assessments:

RES-8	Adaptive Management – Annual Resource Adequacy Assessments
COUN-3	Review the regional resource adequacy standard
COUN-4	Review the RAAC assumptions regarding availability of imports
COUN-5	Review the methodology used to calculate the adequacy reserve margins used in the Regional Portfolio Model
COUN-6	Review the methodology used to calculate the associated system capacity contribution values used in the Regional Portfolio Model
COUN-8	Participate in and track WECC [adequacy] activities
COUN-11	Participate in efforts to update and model climate change data
ANLYS-4	Review and enhancement of peak load forecasting
ANLYS-22	GENESYS Model Redevelopment
ANLYS-23	Enhance the GENESYS model to improve the simulation of hourly hydroelectric system operations

Issues identified in 2016 by the Council's Resource Adequacy Advisory Committee to consider for next year's assessment include those listed below:

Rec-1	Review methodology of the hybrid load forecast used for the 2021 adequacy assessment, in particular how peak loads are forecast
Rec-2	Provide an hourly forecast for energy efficiency savings.
Rec-3	Investigate how to incorporate uncertainty in EE savings into the adequacy assessments

[16] The dividing line between the east and west areas of the region (for modeling purposes) is roughly the Cascade mountain range.

Rec-4 Investigate availability of regional and extra-regional market supplies during periods of stress (supply shortages)

Rec-5 Investigate the availability of fuel during periods of stress, especially for resources without firm fuel contracts.

Rec-6 Investigate the availability of the interties that connect the NW with regions that may provide market supplies. Consider adding maintenance schedules and forced outages.

Rec-7 Explore ways to incorporate the effects of climate change into the adequacy assessments. Should assessments only include the effects of recent temperature years or is there a way to adjust historic temperature profiles to account for climate change?

Rec-8 Explore how an energy imbalance market might affect adequacy assessments. Investigate ways to incorporate an EIM into the analysis.

Rec-9 Review the use of standby resources in the adequacy assessments, in particular how demand response is modeled. The algorithms in the standby resource post processor should be incorporated into the GENESYS model. DR should be dispatched based on price. How do we deal with existing DR, assuming that its impacts have been captured (somewhat) in the load forecast?

Not all of the action items and recommendations listed above will be addressed and resolved before the next adequacy assessment, which is tentatively scheduled for release in May of 2017. However, any enhancements that can be made and tested in time for the next assessment will be implemented. Thus, it continues to be important to isolate the effects of modeling changes on the LOLP from the effects of changes in loads and resources.

Northwest Regional Forecast

of Power Loads and Resources

2017 through 2026

PNUCC

April 2016

Special thanks to PNUCC System Planning Committee members and utility staff that provided us with this information.

Electronic copies of this report are available on the

PNUCC website

www.PNUCC.org

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2016 Northwest Regional Forecast
Executive Summary

The *Northwest Regional Forecast* (*Forecast*) is a compilation of Northwest utilities' expected loads and resources through 2026. This annual supply and demand snapshot serves as a barometer for the region's electric power system. Modest load growth expectations, PURPA renewables coming online, and aggressive energy efficiency acquisitions continue to be the theme for the Northwest power sector.

The *Forecast* examines the Northwest utilities' power picture at an aggregate level. Individual utilities have different load profiles, risk tolerance and challenges than the region as a whole. Still, looking at the big picture reveals trends in the Northwest energy world. And while winter peak continues to show the largest deficit using the *Forecast's* planning criteria, summer peak is a growing concern, especially if fewer non-firm resources are available in the summer as compared to winter.

Expected load growth remains low

Idled smelters keep loads down

In 2015 the Northwest's last aluminum giant, Alcoa, announced that it would be idling its regional smelters. The smelters operation is largely hinged on the global price of aluminum. Increased supply in China has pushed the commodity price to low levels in recent years.

This lost load has pulled down regional demand expectations for winter peak and annual energy. Summer forecasted loads start in-line with last year's forecast and then grow slightly faster. [1]

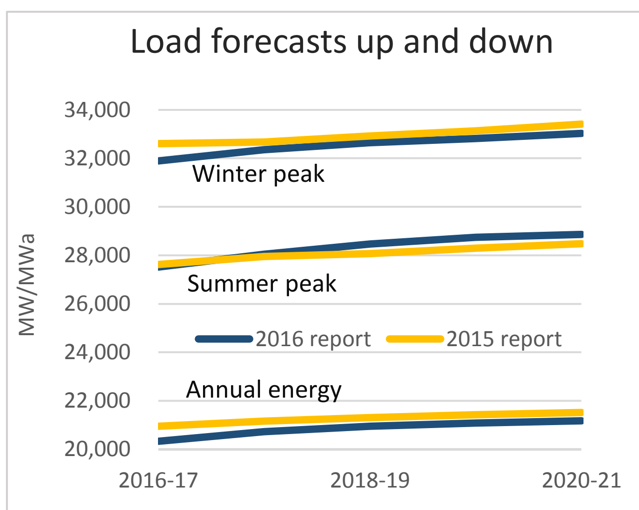

Figure 1

[1] The forecasted loads reflect expected (1-in-2) weather conditions and savings from projected energy efficiency efforts.

Varying degrees of growth across region

On average, regional annual energy load growth is projected at 0.7% per year through 2021. Winter peak load is also forecast at 0.7% while summer peak is 1%.

A look at annual energy load growth for individual utilities shows some of them forecasting growth in excess of 1% per year, whereas others are forecasting load decay. Utilities growing faster than 1% are typically a smaller utility expecting a significant new load.

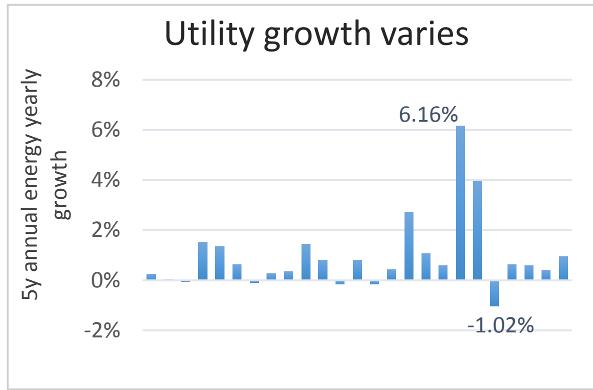

Figure 2

Reset on annual energy and winter peak

Looking at past reports, firm annual energy and winter peak requirement forecasts (load + contracted exports) have continued to start from a lower point than the previous year, implying decreasing need for annual energy and winter peak supply.

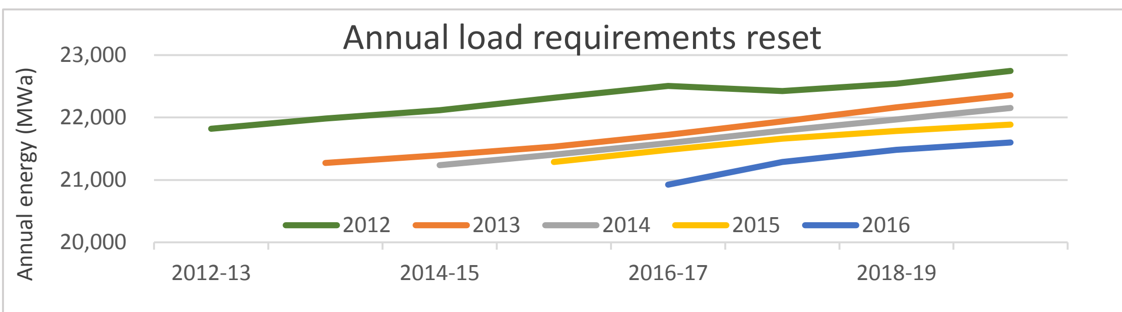

Figure 3

The starting point for the 2016 annual energy requirements forecast is down nearly 1,000 MWa from the 2012 *Forecast*. This trend is not found in the summer peak forecasts which continue to trend as expected.

Resource mix in transition

The firm power supply in the *Forecast* includes hydro at critical water levels, existing utility owned/contracted generating facilities, long-term imports and committed future resources. The *Forecast's* planning metrics do not include non-firm resources.

Wealth of carbon free resources

Largely thanks to the hydropower system, the Northwest has a wealth of CO_2 free power resources. The *Forecast* assumes critical water conditions for planning purposes, but in any given year the hydro system can generate significantly more power.

When the region has more precipitation and generates more hydropower, it relies less on other dispatchable resources, which are largely thermal. This in turn leads to lower CO_2 emissions. The hydro system's generation output under various water conditions, along with other firm carbon free resources stacked on top, are shown below.

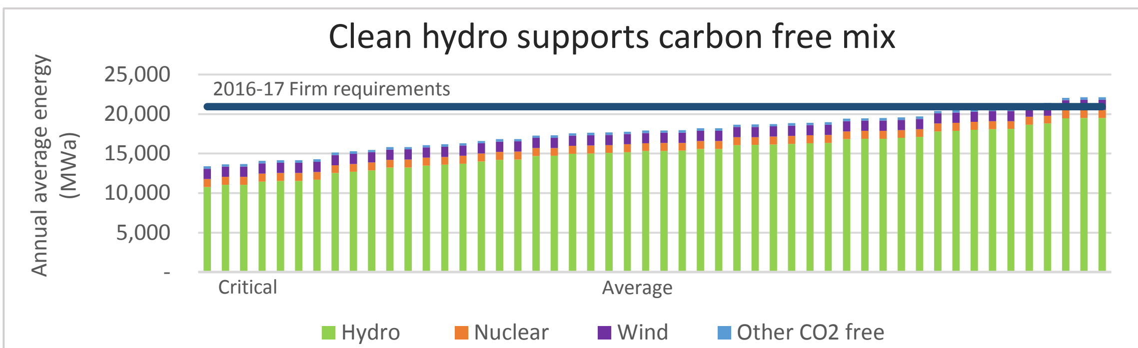

Figure 4

Hydro and thermal resources work together

Although the region's power system provides significant amounts of carbon free power, due to variations in hydro, wind and other CO_2 free resource generation, dispatchable thermal resources are relied upon to fill the gap, even during the highest of water years.

The shape of Northwest hydro generation and energy load varies month by month. During higher water years the extra hydro generation is largely found in the winter, spring and early summer months. In the late summer and early fall the difference in generation between critical and average water is less appreciable. This is largely due to the lack of storage on the Northwest's hydro system and the natural snowpack-driven, runoff pattern.

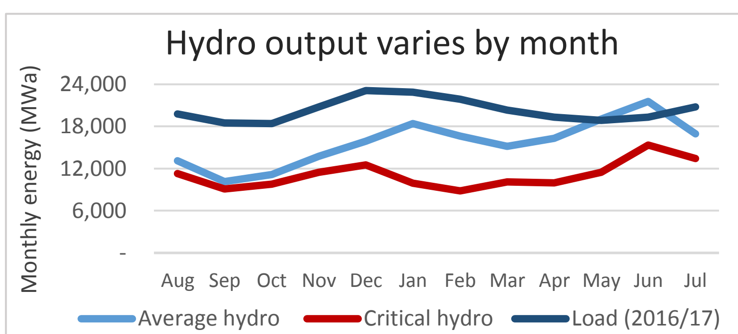

Figure 5

There are yearly and seasonal variations with wind in the Northwest as well. Wind production tends to be at its highest in the spring/early summer, which combined with hydro, can create a regional energy surplus in those months.

Region aggressively acquiring energy efficiency

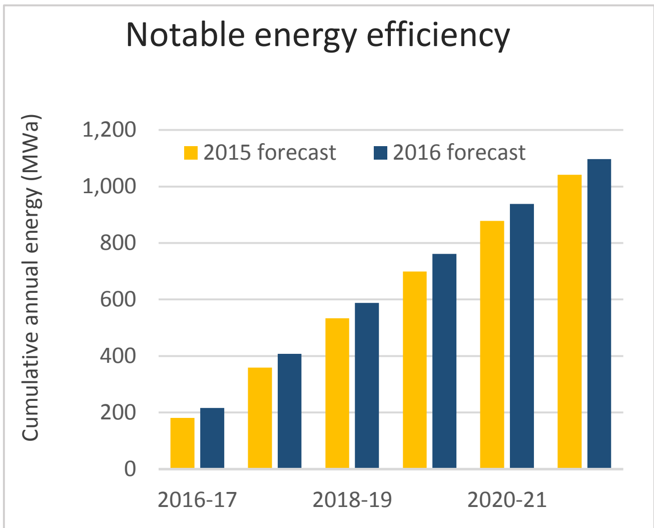

Figure 6

The *Forecast's* numbers show a region actively pursuing energy efficiency savings as a resource. One reason Northwest load growth has slowed is the thousands of megawatts of energy efficiency savings utilities and others have captured. Utilities expect to achieve additional annual electric energy savings of nearly 1,100 MWa in the next six years, slightly more than last year's *Forecast.* Once market transformation and codes and standards are accounted for this number will grow.

The sun also rises in the Northwest

Looking at committed resources, Idaho Power expects nearly 400 MW of nameplate capacity solar within the year via PURPA, and Portland General Electric's natural gas unit Carty is scheduled to be online in 2016. Some hydro system upgrades and PURPA wind in the next few years round out the picture.

In addition, around 2,000 MW of planned resources are identified by utilities to meet future demand. These projects have not been sited or licensed and thus, not included in the *Forecast's* load/resource tabulations. More details can be found in *Tables 8 and 9 Planned Resources* of the report.

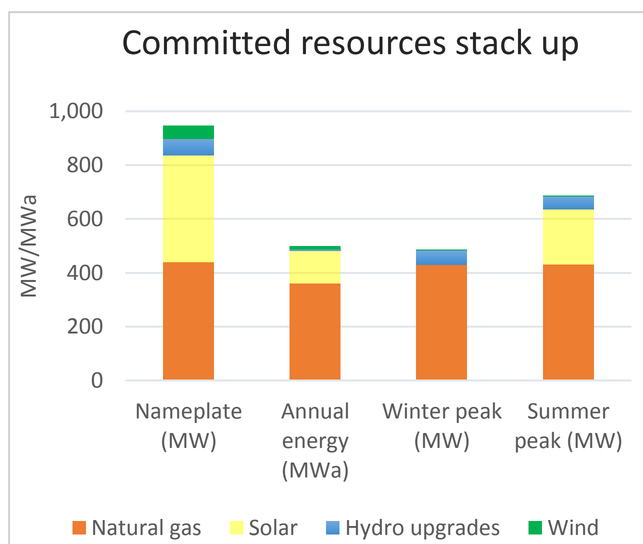

Figure 7

Demand response growing to meet peaks

Today, the Northwest has hundreds of megawatts of demand response on call. This resource is largely found in the eastern part of the region in the form of irrigation interruption. On the west side, utilities are eyeing this capacity resource as well, with nearly 150 MW of new winter programs scheduled to come on line in the next few years.

Resource retirements ahead

In the next decade over 2,000 MW of dispatchable capacity, in the form of coal units, are slated to retire. Up first are the planned retirements of Boardman and Centralia Unit 1, scheduled for the end of 2020. Further down the road Centralia Unit 2 is slated to go offline at the end of 2025, and Valmy has been dropped from Idaho Power's preferred portfolio at the end of 2025 (although its retirement is not certain).

These retirements occur within the *Forecast's* horizon. Resource availability for meeting peak capacity and energy needs could be impacted if these dispatchable units are not replaced with resources of similar operating characteristics.

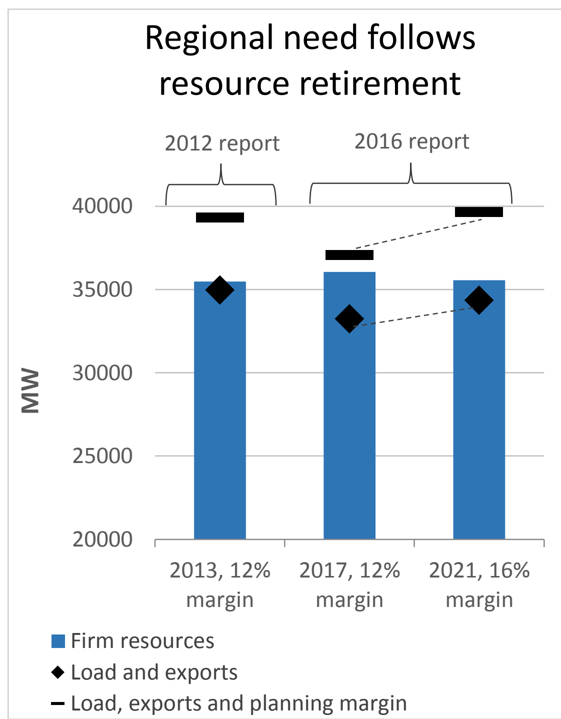

Figure 8

Attention on peak needs

Winter peak is focus

Although winter peak need has been trending down the past five years, it remains the most acute need in this year's *Forecast*. In 2012 the estimated one-hour peak need for January 2013 was about 3,000 MW. Today that gap is closer to 1,000 MW for January 2017 and grows to over 4,000 in 2021 based the *Forecast's* planning criteria.[2] This 3,000 MW increase by 2021 is in part due to increased planning margins, expected load growth and the retirement of the Boardman power plant.

It is worth noting that the 2,000 MW decrease in need from 2013 to 2017 is due to a roughly 1,300 MW drop in firm obligations and a 700 MW increase in firm resources.[3]

[2] 1-in-2 load, critical water, utility firm resources and contracts, and 12% planning margin growing 1% a year.
[3] Power plant Carty (440 MW) and Port Westward 2 (220 MW) along with a reshuffling of a few contracts.

Assumptions can drive seasonal adequacy concerns

The assumptions for non-firm resources vary between organizations and can drive which season is of greatest concern.[4] To help shed light on the potential for utilizing non-firm resources, this year's *Forecast* provides a bookend that shows how the firm power supply can be augmented if generation from independent power producers (IPPs), spot market imports, and additional hydropower (when water supply exceeds critical condition levels), are available.

A snapshot of the load/resource picture for winter and summer peak with a potential set of non-firm resources layered on is shown below. Firm resources come from the *Forecast,* assumptions for available generation from Northwest IPPs and market imports are from the Council's *2015 Resource Adequacy Assessment*, and the estimate of additional hydro generation from average water conditions is derived from the *2015 BPA White Book*.[5] As noted, the season of greatest concern could be winter or summer depending on non-firm resource assumptions.

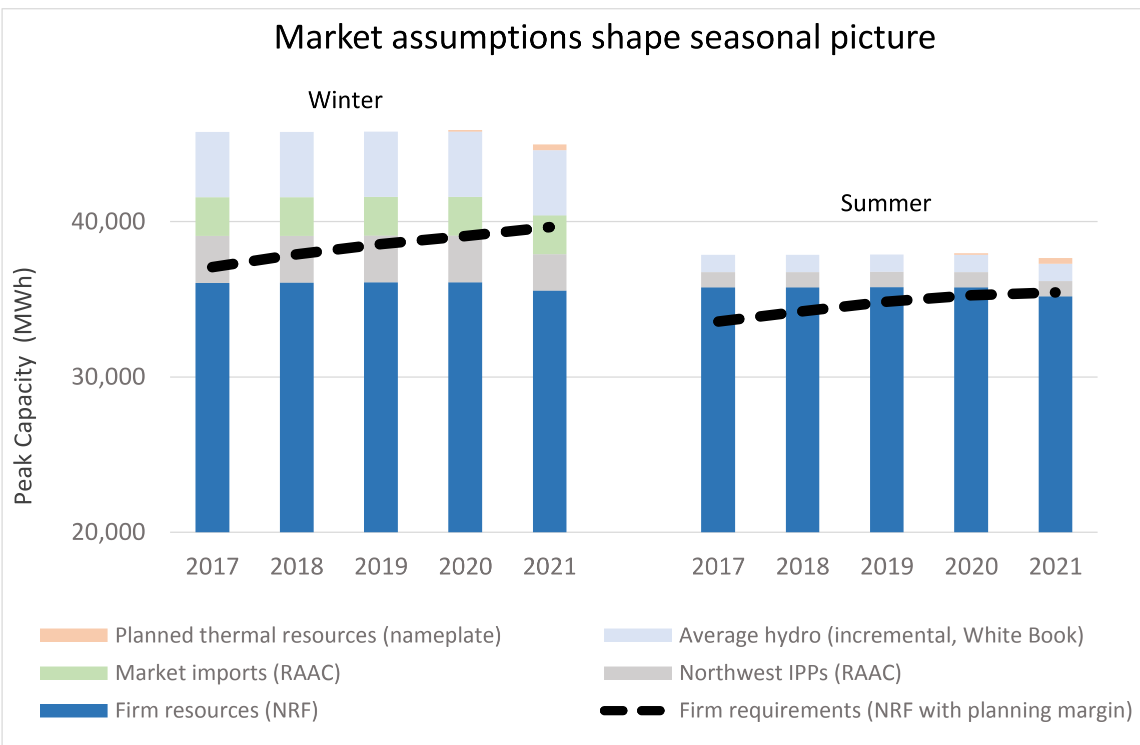

Figure 9

[4] For example, BPA assumes full IPP availability year round, whereas the Council de-rates IPP's in the summer
[5] Firm requirements include contracted exports and a planning margin that starts at 12% and grows 1% per year

Future is a little foggy

Load may not be business as usual

Although this report predicts slow load growth, there are a number of possible new loads that could increase the use of electricity in the Northwest. While some of these possible loads are already baked into the *Forecast's* figures, specific sectors could see greater than predicted growth. Additionally, the possibility of methanol plants in the Northwest could bring large scale industrial load growth to the region.

On the other hand, there are a number of programs that could pull load forecasts down further. These are factored into the report to some extent, but there is a chance they have been underestimated.

Public policy changing the power supply landscape

Although adequacy has been the driver behind some recent power plant builds in the Northwest, public policy, has played a large role as well. This will likely continue into the future with implementation of existing and new policies, and could change the needs of the power system.

State renewable portfolio standards have brought thousands of megawatts of variable energy resources to the Northwest and greater Western Interconnection. This has led to greater concerns regarding system flexibility. In addition, the retirement of Boardman and Centralia power plants, which are due in part to carbon driven public policy, may result in the construction of replacement resources.

Beyond existing policies there are additional rules and regulations on the drawing board on both a state and federal level. With each new policy there is a level of uncertainty until the policy is finalized and implements. Going forward PNUCC will continue to keep an eye on new policy developments and ensure members are aware of how they may impact the power system and need for power.

Reading the tea leaves

PNUCC is not the only organization that examines projected need for power. The Bonneville Power Administration and the Northwest Power & Conservation Council also conduct regular Northwest supply and demand studies. At a high level they both peg winter capacity as the area of chief concern.

BPA's 2015 White Book Regional Picture

The *BPA White Book* uses various methods to assess regional need for power, including critical water planning similar to the *Forecast*. One major difference between the White Book and the *Forecast* is the treatment of power supply from Northwest Independent Power Producers – the White Book "assumes that 100 percent of PNW regional uncommitted IPP generation is available to serve regional loads."[6]

The *White Book* found the region to be constrained regarding January 120 hour capacity need starting in 2019, even with the inclusion of IPP resources.[7] The *Forecast* does not have a 120 hour metric to compare. Looking at 1 hour capacity need, with all IPP resources available, the White Book sees a deficit starting in 2021.[8] One key driver of the 2021 deficit is the retirement of Boardman and Centralia Unit 1.

Council's Resource Adequacy Advisory Committee *2015 Assessment*

Each year the Council conducts a regional probabilistic five year out loss-of-load study with the goal of having a less than 5% annual chance of a supply based power outage. The *Assessmen*t for year 2020 also featured a six year outlook to examine the region after the coal unit retirements. They found a region that was adequate in year 2020, but inadequate in 2021, with the chief concern being winter capacity.[9]

[6] Bonneville Power Administration, 2015 White Book Summary Document, Jan 2016, p. 37. IPPs are ~ 3,100 MW
[7] Bonneville Power Administration, 2015 White Book Summary Document, p. 42
[8] Bonneville Power Administration, 2015 White Book Technical Appendix – Volume 2, Capacity Analysis, p. 352
[9] Northwest Power and Conservation Council, Pacific Northwest Power Supply Adequacy Assessment and State of the System Report, May 2015, p 11

Overview

Each year the *Northwest Regional Forecast* compiles utilities' 10-year projections of electric loads and resources which provide information about the region's need to acquire new power supply. The Forecast is a comprehensive look at the capability of existing and new electric generation resources, long-term firm contracts, expected savings from demand side management programs and other components of electric demand for the Northwest.

This report presents estimates of annual average energy, seasonal energy and winter and summer peak capability in Tables 1 through 4 of the *Northwest Region Requirements and Resources* section. These metrics provide a multi-dimensional look at the Northwest's need for power and underscore the growing complexity of the power system.

Northwest generating resources are shown by fuel type. Existing resources include those resources listed in Tables 5, 6, 10 and 11. *Table 5, Recently Acquired Resources* highlights projects and supply that became available most recently. *Table 6, Committed New Supply* lists those generating projects where construction has started, as well as contractual arrangements that have been made for providing power at a future time. *Table 10, Northwest Utility Generating Resources* is a comprehensive list of generating resources that make up the electric power supply for the Pacific Northwest that are utility-owned or utility contracted. *Table 11, Independent Owned Generating Resources* lists generating projects owned by independent power producers and located in the Northwest.

In addition, utilities have demand side management programs in place to reduce the need for generating resources. *Table 7, Demand Side Management Programs* provides a snapshot of utilities' expected savings from these programs for the next ten years. *Table 8, Planned Resources* is a compilation of what utilities have reported in their individual integrated resource plans to meet future need.

Planning Area

The Northwest Regional Planning Area is the area defined by the *Pacific Northwest Electric Power Planning and Conservation Act*. It includes: the states of Oregon, Washington and Idaho; Montana west of the Continental Divide; portions of Nevada, Utah, and Wyoming that lie within the Columbia River drainage basin; and any rural electric cooperative customer not in the geographic area described above, but served by BPA on the effective date of the *Act*.

Northwest Region Requirements and Resources

Table 1. ***Northwest Region Requirements and Resources – Annual Energy*** shows the sum of the individual utilities' requirements and firm resources for each of the next 10 years. Expected firm load and exports make up the total firm regional requirements.

Average Megawatts	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Firm Requirements										
Load [1/]	20,332	20,733	20,951	21,077	21,171	21,319	21,437	21,575	21,695	21,835
Exports	590	555	531	524	519	468	463	459	450	445
Total	**20,922**	**21,288**	**21,482**	**21,601**	**21,690**	**21,786**	**21,900**	**22,034**	**22,144**	**22,280**
Firm Resources										
Hydro [2/]	11,118	11,118	11,114	11,114	11,114	11,114	11,114	11,114	11,114	11,114
Natural Gas	4,238	4,267	4,304	4,277	4,254	4,226	4,250	4,243	4,248	4,242
Renewables-Other	214	213	213	212	210	206	204	204	204	203
Solar	94	129	129	129	129	129	129	129	129	123
Wind	1,294	1,294	1,294	1,294	1,291	1,221	1,204	1,191	1,178	932
Cogeneration	49	49	49	35	28	11	11	11	11	2
Imports	788	788	791	794	797	800	803	805	761	555
Nuclear	916	1,075	916	1,075	916	1,075	916	1,075	916	1,075
Coal	3,532	3,659	3,646	3,634	3,390	3,135	3,112	2,943	2,801	2,809
Total	**22,244**	**22,591**	**22,455**	**22,563**	**22,128**	**21,917**	**21,742**	**21,715**	**21,361**	**21,055**
Surplus (Deficit)	**1,322**	**1,304**	**974**	**962**	**437**	**131**	**(158)**	**(319)**	**(783)**	**(1,225)**

[1/] Loads net of energy efficiency

[2/] Firm hydro for energy is the generation expected assuming 1936-37 water conditions

Table 2. ***Northwest Region Requirements and Resources – 2016-2017 Monthly Energy*** shows the monthly energy values for the 2016-2017 operating year.

Average Megawatts	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul
Firm Requirements												
Load [1/]	19,754	18,518	18,408	20,773	23,110	22,885	21,895	20,323	19,339	18,857	19,337	20,801
Exports	851	716	530	516	518	518	518	516	515	527	615	738
Total	20,605	19,233	18,938	21,289	23,628	23,403	22,412	20,839	19,854	19,384	19,953	21,539
Firm Resources												
Hydro [2/]	11,300	9,093	9,779	11,476	12,526	9,922	8,819	10,102	9,954	11,456	15,371	13,419
Natural Gas	4,447	4,302	4,029	4,244	4,694	4,638	4,222	4,042	3,559	3,594	4,155	4,364
Renewables-Other	221	222	215	216	214	201	211	213	203	204	206	212
Solar	33	32	23	22	59	45	64	97	125	148	165	177
Wind	1,297	1,205	1,198	1,114	1,189	1,194	1,159	1,482	1,421	1,400	1,504	1,359
Cogeneration	47	42	52	52	58	58	54	59	46	38	33	47
Imports	730	688	618	853	1,058	935	867	811	717	712	731	760
Nuclear	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	347	-	971
Coal	3,844	3,394	3,323	3,599	3,783	3,730	3,770	3,555	2,965	2,696	3,408	3,777
Total	22,994	20,051	20,312	22,650	24,656	21,798	20,240	21,436	20,065	20,596	25,573	25,086
Surplus (Deficit)	**2,389**	**818**	**1,375**	**1,361**	**1,028**	**(1,606)**	**(2,172)**	**597**	**211**	**1,211**	**5,620**	**3,547**

[1/] Loads net of energy efficiency

[2/] Firm hydro for energy is the generation expected assuming 1936-37 water conditions

Table 3. *Northwest Region Requirements and Resources – Winter Peak*

The sum of the individual utilities' firm requirements and resources for the peak hour in January for each of the next 10 years are shown in this table. Firm peak requirements include a planning margin to account for planning uncertainties.

Megawatts	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Firm Requirements										
Load [1/]	31,890	32,356	32,650	32,822	33,034	33,267	33,486	33,523	33,760	33,921
Exports	1,362	1,331	1,325	1,325	1,325	1,325	1,325	1,325	1,325	1,324
Planning Margin [2/]	3,827	4,206	4,571	4,923	5,285	5,655	6,028	6,369	6,752	6,784
Total	**37,080**	**37,893**	**38,547**	**39,071**	**39,645**	**40,248**	**40,839**	**41,218**	**41,837**	**42,029**
Firm Resources										
Hydro [3/]	21,791	21,791	21,783	21,783	21,783	21,783	21,783	21,783	21,783	21,783
Demand Response	87	101	161	176	212	219	234	236	249	251
Small Thermal & Misc.	3	3	3	3	3	3	3	3	3	3
Natural Gas	6,694	6,694	6,694	6,694	6,694	6,694	6,694	6,694	6,694	6,694
Renewables-Other	244	244	244	242	240	234	234	234	234	233
Solar	3	3	3	3	3	3	3	3	3	3
Wind	222	222	222	222	222	203	205	204	201	186
Cogeneration	65	65	65	43	43	14	14	14	14	5
Imports	1,542	1,535	1,501	1,512	1,524	1,536	1,547	1,559	1,490	1,195
Nuclear	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120
Coal	4,287	4,287	4,287	4,287	3,715	3,711	3,709	3,709	3,709	3,709
Total	**36,057**	**36,064**	**36,082**	**36,084**	**35,557**	**35,517**	**35,544**	**35,556**	**35,498**	**35,180**
Surplus (Need)	**(1,022)**	**(1,830)**	**(2,465)**	**(2,986)**	**(4,088)**	**(4,731)**	**(5,295)**	**(5,661)**	**(6,340)**	**(6,849)**

Potential Non-Firm Resources	MW	Source
Northwest IPPs	3,000	Council RAAC
Out of Region Imports	2,500	Council RAAC
Average Hydro	4,200	White Book est.

[1/] Expected (1-in-2) loads net of energy efficiency

[2/] Planning margin is 12% in first year then grows 1% per year until reaching 20%

[3/] Firm hydro for capacity is the generation expected assuming critical (8%) water condition

Table 4. *Northwest Region Requirements and Resources – Summer Peak*

This table shows the sum of the individual utilities' firm requirements and resources for a peak hour in August for each of the next 10 years. Firm peak requirements include a planning margin to account for planning uncertainties.

Megawatts	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Firm Requirements										
Load [1/]	27,521	28,040	28,466	28,747	28,858	29,039	29,168	29,394	29,633	29,891
Exports	1,876	1,878	1,783	1,777	1,777	1,477	1,477	1,477	1,470	1,461
Planning Margin [2/]	3,303	3,645	3,985	4,312	4,617	4,937	5,250	5,585	5,927	5,978
Total	**32,700**	**33,563**	**34,234**	**34,836**	**35,252**	**35,452**	**35,895**	**36,456**	**37,029**	**37,331**
Firm Resources										
Hydro [3/]	21,896	21,896	21,888	21,888	21,888	21,888	21,888	21,888	21,888	21,888
Demand Response	405	407	408	410	410	410	416	428	428	428
Small Thermal & Misc.	3	3	3	3	3	3	3	3	3	3
Natural Gas	6,148	6,148	6,148	6,148	6,148	6,148	6,148	6,148	6,148	6,148
Renewables-Other	245	245	245	245	244	242	236	236	236	235
Solar	38	202	202	202	202	202	202	202	202	202
Wind	224	224	224	224	223	223	205	205	203	185
Cogeneration	51	51	51	51	29	5	5	5	5	5
Imports	1,165	1,170	1,183	1,196	1,209	1,222	1,235	1,248	1,262	1,188
Nuclear	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120
Coal	4,290	4,287	4,287	4,287	4,287	3,715	3,711	3,709	3,709	3,709
Total	**35,584**	**35,752**	**35,758**	**35,773**	**35,762**	**35,177**	**35,167**	**35,190**	**35,201**	**35,109**
Surplus (Need)	**2,884**	**2,189**	**1,525**	**937**	**509**	**(276)**	**(729)**	**(1,266)**	**(1,828)**	**(2,222)**

Potential Non-Firm Resources	MW	Source
Northwest IPPs	1,000	Council RAAC
Out of Region Imports	0	Council RAAC
Average Hydro	1,100	White Book est.

[1/] Expected (1-in-2) loads net of energy efficiency

[2/] Planning margin is 12% in first year then grows 1% per year until reaching 20%

[3/] Firm hydro for capacity is the generation expected assuming critical (8%) water condition

Northwest New and Existing Resources

Table 5. *Recently Acquired Resources* highlights projects that have most recently become available.

Project	Fuel/Tech	Name plate (MW)	Winter Peak (MW)	Summer Peak (MW)	Energy (MWa)	Utility
W10 Transformer E Replacement	Hydro	21	21	21		Grant County PUD
W09 Transformer E Replacement	Hydro	23	23	23		Grant County PUD
W09 Generator E Replacement	Hydro	21	21	21		Grant County PUD
Coffin Butte Resource Project	Landfill Gas	6	6	6	5	PGE via PURPA
Total		**71**	**71**	**71**	**5**	

Table 6. ***Committed New Supply*** lists contracts and generating projects where construction has started and that utilities are counting on to meet need. All supply listed in these tables are included in the regional analysis of power needs.

Project	Date	Fuel/Tech	Name plate (MW)	Winter Peak (MW)	Summer Peak (MW)	Energy (MWa)	Utility
Calligan Creek	Q1-2017	Hydro	6	6	2	2	Snohomish County PUD
Clark Canyon Dam	Jun-17	Hydro	8	0	1		Idaho Power via PURPA
Hancock Creek	Q1-2018	Hydro	6	6	3	2	Snohomish County PUD
North Gooding Main Hydro	May-17	Hydro	1	0	1	1	Idaho Power via PURPA
W06 Generator Replacement	Jun-16	Hydro	9	9	9		Grant County PUD
W07 Transformer D Replacement	Nov-15	Hydro	21	21	21		Grant County PUD
W08 Transformer D Replacement	Nov-15	Hydro	12	12	12		Grant County PUD
Carty	Jul-16	Natural Gas	440	430	430	360	Portland General Electric
American Falls Solar	Jan-16	Solar	20	0	11	5	Idaho Power via PURPA
American Falls Solar II	Jan-16	Solar	20	0	11	5	Idaho Power via PURPA
Arcadia Solar	Dec-16	Solar	5	0	3	3	Idaho Power via PURPA
Boise City	Jul-16	Solar	40	0	21	12	Idaho Power via PURPA
Evergreen Solar	Dec-16	Solar	10	0	5	5	Idaho Power via PURPA
Fairway Solar	Dec-16	Solar	10	0	5	5	Idaho Power via PURPA
Grand View Solar	Jul-16	Solar	80	0	42	22	Idaho Power via PURPA
Grove Solar	Dec-16	Solar	10	0	5	2	Idaho Power via PURPA
Hyline Solar	Dec-16	Solar	10	0	5	2	Idaho Power via PURPA
Jamieson Solar	Dec-16	Solar	4	0	2	2	Idaho Power via PURPA
John Day Solar	Dec-16	Solar	5	0	3	3	Idaho Power via PURPA
Little Valley Solar	Dec-16	Solar	10	0	5	5	Idaho Power via PURPA
Malheur River Solar	Dec-16	Solar	10	0	5	5	Idaho Power via PURPA
Moores Hallow Solar	Dec-16	Solar	10	0	5	5	Idaho Power via PURPA
Mountain Home Solar	Dec-16	Solar	20	0	11	7	Idaho Power via PURPA
Murphy Flat Power	Dec-16	Solar	20	0	11	5	Idaho Power via PURPA
Old Ferry Solar	Dec-16	Solar	5	0	3	3	Idaho Power via PURPA
Open Range Solar	Dec-16	Solar	10	0	5	2	Idaho Power via PURPA
Orchard Ranch Solar	Dec-16	Solar	20	0	11	5	Idaho Power via PURPA
Pocatello Solar I	Dec-16	Solar	20	0	10	6	Idaho Power via PURPA
Railroad Solar	Dec-16	Solar	10	0	5	2	Idaho Power via PURPA
RPS Solar		Solar	7				PacifiCorp
Simco Solar	Dec-16	Solar	20	0	11	5	Idaho Power via PURPA
Thunderegg Solar	Dec-16	Solar	10	0	5	2	Idaho Power via PURPA
Vale Solar	Dec-16	Solar	10	0	5	2	Idaho Power via PURPA
Benson Creek Wind	Dec-16	Wind	10	1	1	2	Idaho Power via PURPA
Durbin Creek Wind	Dec-16	Wind	10	1	1	2	Idaho Power via PURPA
Jett Creek Wind	Dec-16	Wind	10	1	1	2	Idaho Power via PURPA
Prospector Wind	Dec-16	Wind	10	1	1	3	Idaho Power via PURPA
Willow Springs Wind Farm	Dec-16	Wind	10	1	1	2	Idaho Power via PURPA
Total			**948**	**486**	**687**	**500**	

Table 7. *Demand Side Management Programs* is a snapshot of the regional utilities' efforts to manage demand. The majority of the reported conservation savings are from utility programs. This table also shows cumulative existing plus new demand response programs reported by utilities.[1]

	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Energy Efficiency (MWa)										
Incremental	216	193	179	174	177	159	159	154	149	141
Cumulative	216	408	588	762	939	1,097	1,256	1,410	1,560	1,700
Demand Response (MW)										
Winter (existing + new)	87	101	161	176	212	219	234	236	249	251
Summer (existing + new)	405	405	405	405	405	405	405	405	405	405

[1] Does not include any demand response in the Rocky Mountain Power territory

Table 8. ***Planned Resources*** captures resources utilities have identified to meet their own needs. The table shows planned generating projects that are being counted on to meet the growing demand. This information is a compilation of what utilities have reported in their individual integrated resources plans. These resources are not included in the regional analysis of power needs.

Project	Schedule	Fuel/Tech	Nameplate (MW)	Winter Peak (MW)	Summer peak (MW)	Energy (MWa)	Utility
Nine Mile 1 & 2	2016	Hydro		16	13		Avista Corp.
Shoshone Falls Upgrade	2019	Hydro	49	2	9		Idaho Power
W03 Generator Replacement	2016	Hydro	9	9	9		Grant County PUD
W04 Generator Replacement	2017	Hydro	9	9	9		Grant County PUD
W 06 Generator Replacement	2016	Hydro	9	9	9		Grant County PUD
W08 Generator Replacement	2018	Hydro	9	9	9		Grant County PUD
Gas Peaker	2020	Natural Gas	96	102	96	89	Avista Corp.
Landfill Gas	2020	Methane/gas	9			8	Seattle City Light
Landfill Gas PPA	2026	Methane/gas	10	9	9	9	Snohomish County PUD
Peakers CT	2021	Natural Gas	277	277	277		Puget Sound Energy
Peakers CT	2025	Natural Gas	126	126	126		Puget Sound Energy
Gas CCCT	2026	Natural Gas	286	286	306	265	Avista Corp.
Gas CCCT	2026	Natural Gas	577	577	577	476	Puget Sound Energy
Thermal Plant Upgrades	2021-25	Natural Gas		38	38	35	Avista Corp.
Winter Capacity PPA	2021	PPA	75	75	0	25	Snohomish County PUD
Community Solar Project	2016	Solar	0	0	0	164	Cowlitz PUD
Solar Project	2017	Solar	3	3	3	1	PNGC
Wind	2023	Wind	206	16	16	71	Puget Sound Energy
Wind	2023	Wind	63			20	Seattle City Light
Wind	2024	Wind	220			70	Seattle City Light
Wind	2025	Wind	31			10	Seattle City Light
Wind	2026	Wind	78			25	Seattle City Light
Biomass	2023	Wood waste/ cogen	44			40	Seattle City Light
Total			**2,185**	**1,562**	**1,505**	**1,307**	

Table 9. ***Planned Resources Schedule*** (Cumulative Nameplate MW)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Hydro	18	27	36	85	85	85	85	85	85	85	85
Methane/gas	0	0	0	0	9	9	9	9	9	9	19
Natural Gas	0	0	0	0	96	373	373	373	373	499	1,362
PPA	0	0	0	0	0	75	75	75	75	75	75
Solar	1	4	4	4	4	4	4	4	4	4	4
Wind	0	0	0	0	0	0	0	269	489	520	598
Wood waste	0	0	0	0	0	0	0	44	44	44	44
Total	**19**	**31**	**40**	**89**	**194**	**546**	**546**	**859**	**1,079**	**1,236**	**2,185**

Table 10. ***Northwest Utility Generating Resources*** is a comprehensive list of utility-owned and utility contracted generating resources that make up those utilities electric power supply.

Project	Owner	NW Utility	Nameplate (MW)
HYDRO			**33,128**
Albeni Falls	US Corps of Engineers	Federal System (BPA)	43
Alder	Tacoma Power	Tacoma Power	50
American Falls	Idaho Power	Idaho Power	92
Anderson Ranch	US Bureau of Reclamation	Federal System (BPA)	40
Arena Drop		Idaho Power	0
Arrowrock Dam	Clatskanie PUD/Irr Dist	Clatskanie PUD	18
B. Smith	PacifiCorp	PacifiCorp	0
Barber Dam	Enel North America	Idaho Power	4
Bell Mountain	PacifiCorp	PacifiCorp	1
Big Cliff	US Corps of Engineers	Federal System (BPA)	18
Big Sheep Creek	Everand Jensen	Avista Corp.	0
Birch Creek	Everand Jensen	Idaho Power	0
Birch Creek	PacifiCorp	PacifiCorp	3
Black Canyon Bliss Dam	PURPA	Idaho Power	0
Black Canyon	US Bureau of Reclamation	Federal System (BPA)	10
Black Canyon # 3	Big Wood Canal Co.	Idaho Power	0
Black Creek Hydro	Black Creek Hydro, Inc.	Puget Sound Energy	4
Blind Canyon	Blind Canyon Hydro	Idaho Power	2
Bliss	Idaho Power	Idaho Power	75
Boise River Diversion	US Bureau of Reclamation	Federal System (BPA)	2
Bonneville	US Corps of Engineers	Federal System (BPA)	1,102
Boston Power		PacifiCorp	
Boundary	Seattle City Light	Seattle City Light	1,040
Box Canyon	Pend Oreille County PUD	Pend Oreille County PUD	70
Box Canyon-Idaho	Richard Kaster	Idaho Power	0
Briggs Creek	Richard Kaster	Idaho Power	1
Brownlee	Idaho Power	Idaho Power	585
Burnside Hydro		Other Public (BPA)	
Bypass	Bypass, Ltd.	Idaho Power	10
Cabinet Gorge	Avista Corp.	Avista Corp.	265
Calligan Creek	Snohomish County PUD	Snohomish County PUD	6
Calispel Creek	Pend Oreille County PUD	Pend Oreille County PUD	1
Canyon Springs	J.D. McCollum	Idaho Power	0
Carmen-Smith	Eugene Water & Electric Board	Eugene Water & Electric Board	105
Cascade	US Bureau of Reclamation	Idaho Power	12
CDM Hydro	PacifiCorp	PacifiCorp	6
Cedar Draw Creek	Crys. Sprgs. Hydro	Idaho Power	2
Cedar Falls, Newhalem	Seattle City Light	Seattle City Light	20

Project	Owner	NW Utility	Nameplate (MW)
Central Oregon Siphon		PacifiCorp	5
Chandler	US Bureau of Reclamation	Federal System (BPA)	12
Chelan	Chelan County PUD	Chelan County PUD	59
Chief Joseph	US Corps of Engineers	Federal System (BPA)	2,457
C. J. Strike	Idaho Power	Idaho Power	83
Clark Canyon Dam	PURPA	Idaho Power	8
Clear Lake	Idaho Power	Idaho Power	3
Clear Springs Trout	Clear Springs Trout	Idaho Power	1
Clearwater #1	PacifiCorp	PacifiCorp	15
Clearwater #2	PacifiCorp	PacifiCorp	26
Cline Falls	COID	PacifiCorp	1
COID	PacifiCorp	PacifiCorp	7
Copco #1	PacifiCorp	PacifiCorp	20
Copco #2	PacifiCorp	PacifiCorp	27
Cougar	US Corps of Engineers	Federal System (BPA)	25
Cove Hydro		Other Public (BPA)	
Cowlitz Falls	Lewis County PUD	Federal (BPA)	70
Crystal Springs	Crystal Springs Hydro	Idaho Power	2
Curry Cattle Company	Curry Cattle Co.	Idaho Power	0
Curtis Livestock	PacifiCorp	PacifiCorp	0
Cushman 1	Tacoma Power	Tacoma Power	43
Cushman 2	Tacoma Power	Tacoma Power	81
Deep Creek	Gordon Foster	Avista Corp.	0
Derr Creek	Jim White	Avista Corp.	0
Detroit	US Corps of Engineers	Federal System (BPA)	100
Dexter	US Corps of Engineers	Federal System (BPA)	15
Diablo Canyon	Seattle City Light	Seattle City Light	182
Dietrich Drop	Enel North America	Idaho Power	5
Dry Creek		PacifiCorp	4
D. Wiggins		PacifiCorp	
Dworshak	US Corps of Engineers	Federal System (BPA)	400
Dworshak/ Clearwater		Federal System (BPA)	
Eagle Point	PacifiCorp	PacifiCorp	3
East Side	PacifiCorp	PacifiCorp	3
Eight Mile Hydro	Eightmile Hydro Corporation	Idaho Power	0
Electron	Puget Sound Energy	Puget Sound Energy	23
Elk Creek	El Dorado Hydro	Idaho Power	2
Eltopia Branch Canal	SEQCBID	Muliple Utilities	2
Esquatzel Small Hydro	Green Energy Today, LLC	Franklin County PUD	1
Fall Creek	PacifiCorp	PacifiCorp	3
Falls Creek		Other Public (BPA)	
Falls River	Marysville Hydro Partner	Idaho Power	9
Faraday	Portland General Electric	Portland General Electric	37

Project	Owner	NW Utility	Nameplate (MW)
Fargo Drop Hydro	Riverside Investments, LLC	Idaho Power	1
Farmers Irrigation	PacifiCorp	PacifiCorp	3
Faulkner Ranch	Faulkner Brothers Hydro Inc.	Idaho Power	1
Fish Creek	PacifiCorp	PacifiCorp	11
Fisheries Development Co.	Fisheries Devel.	Idaho Power	0
Foster	US Corps of Engineers	Federal System (BPA)	20
Frontier Technologies	PacifiCorp	PacifiCorp	4
Galesville Dam	PacifiCorp	PacifiCorp	2
Gem State Hydro		Other Publics (BPA)	23
Geo-Bon No 2	Enel North America, Inc.	Idaho Power	1
Georgetown Power	PacifiCorp	PacifiCorp	0
Gorge	Seattle City Light	Seattle City Light	207
Grand Coulee	US Bureau of Reclamation	Federal System (BPA)	6,494
Green Peter	US Corps of Engineers	Federal System(BPA)	80
Green Springs	US Bureau of Reclamation	Federal System (BPA)	16
Hailey CSPP	City of Hailey	Idaho Power	0
Hancock Creek	Snohomish County PUD	Snohomish County PUD	6
Hazelton A	SE Hazelton ALP	Idaho Power	8
Hazelton B	Hazelton Power Co.	Idaho Power	8
Head of U Canal	PURPA	Idaho Power	1
Hells Canyon	Idaho Power	Idaho Power	392
Hills Creek	US Corps of Engineers	Federal System (BPA)	30
Hood Street Reservoir	Tacoma Power	Tacoma Power	1
Horseshoe Bend	Horseshoe Bend Hydro	Idaho Power	10
Hungry Horse	US Bureau of Reclamation	Federal System (BPA)	428
Hutchinson Creek	STS Hydro	Puget Sound Energy	1
Ice Harbor	US Corps of Engineers	Federal System(BPA)	603
Idaho Falls - City Plant		Federal System (BPA)	
Idaho Falls - Lower Plant		Federal System (BPA)	
Idaho Falls - Upper Plant		Federal System (BPA)	
Ingram Warm Springs	PacifiCorp	PacifiCorp	1
Iron Gate	PacifiCorp	PacifiCorp	18
Island Park		Fall River REC	5
Jackson (Sultan)	Snohomish County PUD	Snohomish County PUD	112
James Boyd		PacifiCorp	
Jim Ford Creek	Ford Hydro	Avista Corp.	2
Jim Knight	Big Wood Canal Co.	Idaho Power	0
John C. Boyle	PacifiCorp	PacifiCorp	90
John Day	US Corps of Engineers	Federal System(BPA)	2,160
John Day Creek	Dave Cereghino	Avista Corp.	1
John H Koyle	John H Koyle	Idaho Power	1
Joseph Hydro		PacifiCorp	
Kasel-Witherspoon	Kasel & Witherspoon	Idaho Power	1

Project	Owner	NW Utility	Nameplate (MW)
Kerr	NorthWestern Corporation	NorthWestern Energy	194
Koma Kulshan	Koma Kulshan Associates	Puget Sound Energy	11
La Grande	Tacoma Power	Tacoma Power	64
Lacomb Irrigation	PacifiCorp	PacifiCorp	1
Lake Creek		Other Publics (BPA)	
Lake Oswego Corp.		Portland General Electric	1
Lateral No. 10	Lateral 10 Ventures	Idaho Power	2
Leaburg	Eugene Water & Electric Board	Eugene Water & Electric Board	16
Lemolo #1	PacifiCorp	PacifiCorp	32
Lemolo #2	PacifiCorp	PacifiCorp	33
Lemoyne	John Lemoyne	Idaho Power	0
Libby	US Corps of Engineers	Federal System(BPA)	525
Lilliwaup Falls		Other Public (BPA)	1
Little Falls	Avista Corp.	Avista Corp.	32
Little Goose	US Corps of Engineers	Federal System(BPA)	810
Little Wood	Little Wood Irr District	Idaho Power	3
Little Wood/Arkoosh	William Arkoosh	Idaho Power	1
Little Wood River Ranch II	PURPA	Idaho Power	1
Lloyd Fery	PacifiCorp	PacifiCorp	0
Long Lake	Avista Corp.	Avista Corp.	70
Lookout Point	US Corps of Engineers	Federal System (BPA)	120
Lost Creek	US Corps of Engineers	Federal System (BPA)	49
Lower Baker	Puget Sound Energy	Puget Sound Energy	115
Lower Granite	US Corps of Engineers	Federal System(BPA)	810
Lower Malad	Idaho Power	Idaho Power	14
Lower Monumental	US Corps of Engineers	Federal System(BPA)	810
Lower Salmon	Idaho Power	Idaho Power	60
Lowline #2	Enel North America, Inc.	Idaho Power	3
Lowline Canal	S. Forks	Idaho Power	3
Lowline Midway	Idaho Power	Idaho Power	8
Lucky Peak	US Corps of Engineers	Seattle City Light	113
Magic Reservoir	Magic Reservoir Hydro	Idaho Power	9
Main Canal Headworks	SEQCBID	Multiple Utilities	26
Malad River	V. Ravenscroft	Idaho Power	1
Mayfield	Tacoma Power	Tacoma Power	162
McNary	US Corps of Engineers	Federal System(BPA)	980
McNary Fishway	US Corps of Engineers	Other Publics (BPA)	
Merwin	PacifiCorp	PacifiCorp	136
Meyers Falls	Hydro Technology Systems	Avista Corp.	1
Middlefork Irrigation	PacifiCorp	PacifiCorp	3
Mile 28	Contractors Power Group Inc.	Idaho Power	2
Mill Creek (Cove)	City of Cove, OR	Idaho Power	1
Mill Creek		Other Publics (BPA)	1

Project	Owner	NW Utility	Nameplate (MW)
Milner	Idaho Power	Idaho Power	59
Minidoka	US Bureau of Reclamation	Federal System (BPA)	28
Mink Creek	PacifiCorp	PacifiCorp	3
Mitchell Butte	Owyhee Irrigation District	Idaho Power	2
Monroe Street	Avista	Avista Corp.	15
Mora Drop	Riverside LLC	Idaho Power	2
Morse Creek		Port Angeles	1
Mossyrock	Tacoma Power	Tacoma Power	300
Mountain Energy	PacifiCorp	PacifiCorp	0
Mount Tabor	City of Portland	Portland General Electric	0
Moyie Springs		Other Publics (BPA)	
Mud Creek/S&S	H.K. Hydro	Idaho Power	1
Mud Creek/White	Mud Creek Hydro	Idaho Power	0
N-32 Canal	Ranchers Irrig., Inc.	Idaho Power	1
Nicols Gap	PacifiCorp	PacifiCorp	1
Nicolson SunnyBar	PacifiCorp	PacifiCorp	0
Nine Mile	Avista Corp.	Avista Corp.	26
Nooksack	Puget Sound Hydro, LLC	Puget Sound Energy	3
North Fork	Portland General Electric	Portland General Electric	41
North Fork Sprague	PacifiCorp	PacifiCorp	1
Noxon Rapids	Avista Corp.	Avista Corp.	466
N.R. Rousch	PacifiCorp	PacifiCorp	0
Oak Grove	Portland General Electric	Portland General Electric	51
Odell Creek	PacifiCorp	PacifiCorp	0
O.J. Power	PacifiCorp	PacifiCorp	0
Opal Springs	PacifiCorp	PacifiCorp	5
Ormsby		PacifiCorp	
Owyhee Dam	Owyhee Irrigation District	Idaho Power	5
Oxbow	Idaho Power	Idaho Power	190
Packwood	Energy Northwest	Multiple Utilities	26
Palisades	US Bureau of Reclamation	Federal System (BPA)	177
PEC Headworks	SEQCBID	Grant County PUD	7
Pelton	Portland General Electric	Multiple Utilities	110
Pelton Reregulation	Warm Springs Tribe	Portland General Electric	19
Phillips Ranch	Glen Phillips	Avista Corp.	0
Pigeon Cove	Pigeon Cove Power	Idaho Power	2
Portland Hydro-Project	City of Portland	Portland General Electric	36
Portneuf River		PacifiCorp	1
Post Falls	Avista Corp.	Avista Corp.	15
Potholes East Canal 66	SEQCBID	Multiple Utilities	5
Powerdale	PacifiCorp	PacifiCorp	6
Preston City	PacifiCorp	PacifiCorp	0
Priest Rapids	Grant County PUD	Multiple Utilities	956

Project	Owner	NW Utility	Nameplate (MW)
Pristine Springs	Pristine Springs, Inc	Idaho Power	0
Pristine Springs #3	Pristine Springs, Inc	Idaho Power	0
Prospect #1	PacifiCorp	PacifiCorp	4
Prospect #2	PacifiCorp	PacifiCorp	32
Prospect #3	PacifiCorp	PacifiCorp	7
Prospect #4	PacifiCorp	PacifiCorp	1
Quincy Chute	SEQCBID	Grant County PUD	9
R.D. Smith	SEQCBID	Multiple Utilities	6
Reeder Gulch		Other Publics (BPA)	0
Reynolds Irrigation	Reynolds Irrigation	Idaho Power	0
Rim View	Rim View Trout Co.	Idaho Power	0
River Mill	Portland General Electric	Portland General Electric	19
Rock Creek No. 1	Rock Creek Joint	Idaho Power	2
Rock Creek No. 2	Enel North America	Idaho Power	2
Rocky Brook	Mason County PUD #3	Other Public (BPA)	2
Rock Island	Chelan County PUD	Multiple Utilities	629
Rocky Reach	Chelan County PUD	Multiple Utilities	1,300
Ross	Seattle City Light	Seattle City Light	360
Round Butte	Portland General Electric	Multiple Utilities	247
Roza	US Bureau of Reclamation	Federal System (BPA)	13
Sagebrush	Big Wood Canal Co.	Idaho Power	0
Sahko	Sahko	Idaho Power	1
Santiam	PacifiCorp	PacifiCorp	0
Schaffner	Lemhi Hydro Co.	Idaho Power	1
Sheep Creek	Glen Phillips	Avista Corp.	2
Shingle Creek	Willis D Deveny	Idaho Power	0
Shoshone II	Shorock Hydro	Idaho Power	1
Shoshone CSPP	Shorock Hydro, Inc.	Idaho Power	0
Shoshone Falls	Idaho Power	Idaho Power	13
Slide Creek	PacifiCorp	PacifiCorp	18
Smith Creek	Eugene Water & Electric Board	Eugene Water & Electric Board	38
Snake River Pottery	Snake River Pottery	Idaho Power	0
Snedigar Ranch	David Snedigar	Idaho Power	1
Snoqualmie Falls	Puget Sound Energy	Puget Sound Energy	54
Soda Creek		Other Publics (BPA)	
Soda Springs	PacifiCorp	PacifiCorp	11
South Fork Tolt	Seattle City Light	Seattle City Light	17
Spokane Upriver	City of Spokane	Avista Corp.	16
Stauffer Dry Creek		PacifiCorp	
Steffen Hydro		Snohomish County PUD	
Stone Creek	Eugene Water & Electric Board	Eugene Water & Electric Board	12
Strawberry Creek	South Idaho Public Agency	Other Publics (BPA)	
Summer Falls	SEQCBID	Multiple Utilities	92

Project	Owner	NW Utility	Nameplate (MW)
Swan Falls	Idaho Power	Idaho Power	25
Swift 1	PacifiCorp	Multiple Utilities	219
Swift 2	Cowlitz County PUD	Multiple Utilities	0
Sygitowicz	Cascade Clean Energy	Puget Sound Energy	0
TGS/Briggs		PacifiCorp	
The Dalles	US Corps of Engineers	Federal System(BPA)	1,807
The Dalles Fishway	Northern Wasco Co. PUD	Northern Wasco Co. PUD	5
Thompson Falls	NorthWestern Corporation	NorthWestern Energy	94
Thousand Springs	Idaho Power	Idaho Power	9
Tiber Dam	Tiber Montana, LLC	Idaho Power	8
Toketee	PacifiCorp	PacifiCorp	43
Trail Bridge	Eugene Water & Electric Board	Eugene Water & Electric Board	10
Trout Company	Branch Flower Co.	Idaho Power	0
Tunnel #1	Owyhee Irrig. Dist.	Idaho Power	7
Twin Falls	Idaho Power	Idaho Power	53
Twin Falls	Twin Falls Hydro Association LP	Puget Sound Energy	20
TW Sullivan	Portland General Electric	Portland General Electric	15
Upper Baker	Puget Sound Energy	Puget Sound Energy	105
Upper Falls	Avista Corp.	Avista Corp.	10
Upper Malad	Idaho Power	Idaho Power	8
Upper Salmon 1 & 2	Idaho Power	Idaho Power	18
Upper Salmon 3 & 4	Idaho Power	Idaho Power	17
Walla Walla	PacifiCorp	PacifiCorp	2
Wallowa Falls	PacifiCorp	PacifiCorp	1
Walterville	Eugene Water & Electric Board	Eugene Water & Electric Board	8
Wanapum	Grant County PUD	Multiple Utilities	934
Weeks Falls	So. Fork II Assoc. LP	Puget Sound Energy	5
Wells	Douglas County PUD	Multiple Utilities	774
West Side	PacifiCorp	PacifiCorp	1
White Water Ranch	White Water Ranch	Idaho Power	0
Wilson Lake Hydro	Wilson Pwr. Co.	Idaho Power	8
Woods Creek	Snohomish County PUD	Snohomish County PUD	1
Wynoochee	Tacoma Power	Tacoma Power	13
Yale	PacifiCorp	PacifiCorp	134
Yelm		Other Publics (BPA)	12
Yakima-Tieton	PacifiCorp	PacifiCorp	3
Young's Creek	Snohomish County PUD	Snohomish County PUD	8

Project	Owner	NW Utility	Nameplate (MW)
COAL			**5,496**
Boardman	Portland General Electric	Multiple Utilities	642
Colstrip #1	PP&L Montana, LLC	Multiple Utilities	330
Colstrip #2	PP&L Montana, LLC	Multiple Utilities	330
Colstrip #3	PP&L Montana, LLC	Multiple Utilities	740
Colstrip #4	NorthWestern Energy	Multiple Utilities	805
Jim Bridger #1	PacifiCorp / Idaho Power	Multiple Utilities	540
Jim Bridger #2	PacifiCorp / Idaho Power	Multiple Utilities	540
Jim Bridger #3	PacifiCorp / Idaho Power	Multiple Utilities	540
Jim Bridger #4	PacifiCorp / Idaho Power	Multiple Utilities	508
Valmy #1	NV Energy / Idaho Power	Multiple Utilities	254
Valmy #2	NV Energy / Idaho Power	Multiple Utilities	267
NUCLEAR			**1,230**
Columbia Generating Station	Energy Northwest	Federal System (BPA)	1,230
NATURAL GAS			**6,828**
Alden Bailey	Clatskanie PUD	Clatskanie PUD	11
Beaver	Portland General Electric	Portland General Electric	516
Beaver 8	Portland General Electric	Portland General Electric	25
Bennett Mountain	Idaho Power	Idaho Power	173
Boulder Park	Avista Corp.	Avista Corp.	25
Carty	Portland General Electric	Portland General Electric	440
Chehalis Generating Facility	PacifiCorp	PacifiCorp	517
Coyote Springs I	Portland General Electric	Portland General Electric	266
Coyote Springs II	Avista Corp.	Avista Corp.	287
Danskin	Idaho Power	Idaho Power	92
Danskin 1	Idaho Power	Idaho Power	179
Dave Gates	NorthWestern Energy	NorthWestern Energy	150
Encogen	Puget Sound Energy	Puget Sound Energy	159
Ferndale Cogen Station	Puget Sound Energy	Puget Sound Energy	245
Frederickson	EPCOR Power L.P./PSE	Multiple Utilities	258
Fredonia 1 & 2	Puget Sound Energy	Puget Sound Energy	208
Fredonia 3 & 4	Puget Sound Energy	Puget Sound Energy	108
Fredrickson 1 & 2	Puget Sound Energy	Puget Sound Energy	149
Goldendale	Puget Sound Energy	Puget Sound Energy	261
Hermiston Generating P.	PacifiCorp/Hermiston Gen. Comp.	PacifiCorp	469
Kettle Falls CT	Avista Corp.	Avista Corp.	7
Lancaster Power Project	Avista Corp.	Avista Corp.	270
Langley Gulch	Idaho Power	Idaho Power	319

Project	Owner	NW Utility	Nameplate (MW)
Mint Farm Energy Center	Puget Sound Energy	Puget Sound Energy	305
Northeast A&B	Avista Corp.	Avista Corp.	62
Port Westward	Portland General Electric	Portland General Electric	415
Port Westward Unit 2	Portland General Electric	Portland General Electric	220
Rathdrum 1 & 2	Avista Corp.	Avista Corp.	167
River Road	Clark Public Utilities	Clark Public Utilities	248
Rupert (Magic Valley)	Rupert Illinois Holdings	Idaho Power	10
Sumas Energy	Puget Sound Energy	Puget Sound Energy	121
Whitehorn #2 & 3	Puget Sound Energy	Puget Sound Energy	149
COGENERATION			**199**
Billings Cogeneration	Billings Generation, Inc.	NorthWestern Energy	64
Hampton Lumber		Snohomish County PUD	5
International Paper Energy	Eugene Water & Electric Board	Eugene Water & Electric Board	26
James River - Camas	PacifiCorp	PacifiCorp	52
Simplot-Pocatello	PURPA	Idaho Power	12
Tasco-Nampa	Tasco	Idaho Power	2
Tasco-Twin Falls	Tasco	Idaho Power	3
Wauna (James River)	Western Generation Agency	Multiple Utilities	36
RENEWABLES-OTHER			**346**
Bettencourt B6	Cargill	Idaho Power	2
Bettencourt Dry Creek	Cargill	Idaho Power	2
Big Sky West Dairy	Dean Foods Co. & AgPower Partners	Idaho Power	2
Bio Energy		Puget Sound Energy	1
Bio Fuels, WA		Puget Sound Energy	5
Biomass One	PacifiCorp	PacifiCorp	25
City of Spokane Waste	City of Spokane	Avista Corp.	26
Coffin Butte	Power Resources Cooperative	PNGC Power	6
Cogen Company	Prairie Wood Products Co-Gen Co.	Oregon Trail Coop	8
DR Johnson Lumber	PacifiCorp	PacifiCorp	8
Columbia Ridge Landfill Gas	Waste Management	Seattle City Light	13
Convanta Marion	Portland General Electric	Portland General Electric	16
Double A Digester	PURPA-Andgar Corp	Idaho Power	5
Dry Creek Landfill	Dry Creek Landfill Inc.	PacifiCorp	3
Edaleen Dairy		Puget Sound Energy	1
Farm Power Tillamook	Tillamook PUD	Tillamook PUD	1
Fighting Creek	Kootenai Electric Co-op	Idaho Power	3
Flathead County Landfill	Flathead Electric Cooperative	Flathead Electric Cooperative	2
Four Mile Hill Geothermal	Calpine	Federal System (BPA)	50
Hidden Hollow Landfill	G2 Energy	Idaho Power	3

Project	Owner	NW Utility	Nameplate (MW)
Hooley Digester	Tillamook PUD	Tillamook PUD	1
H. W. Hill Landfill	Allied Waste Companies	Multiple Utilities	11
Interfor Pacific-Gilchrist	Midstate Electric Co-op	Midstate Electric Co-op	
Kettle Falls	Avista Corp.	Avista Corp.	51
Lynden	Farm Power	Puget Sound Energy	1
Mill Creek (Cove)		Idaho Power	1
Neal Hot Springs	U.S Geothermal	Idaho Power	23
Olympic View 1&2	Mason County PUD #3	Mason County PUD #3	5
Pine Products	PacifiCorp	PacifiCorp	6
Plum Creek NLSL	Plum Creek MDF	Flathead Electric Cooperative	6
Pocatello Wastewater	Idaho Power	Idaho Power	0
Portland Wastewater	City of Portland	Portland General Electric	2
Raft River 1	US Geothermal	Idaho Power	16
Rainier Biogas		Puget Sound Energy	1
Rexville	Farm Power	Puget Sound Energy	1
River Bend Landfill	McMinnville Water & Light	McMinnville Water & Light	0
Rock Creek Dairy	PURPA	Idaho Power	4
Seneca	Seneca Sustainable Energy, LLC	Eugene Water & Electric Board	20
Short Mountain		Emerald PUD	3
Skookumchuck		Puget Sound Energy	1
Smith Creek		Puget Sound Energy	0
Stimson Lumber	Stimson Lumber	Avista Corp.	7
Stoltze Biomass	F.H. Stoltze Land & Lumber	Flathead Electric Coop	3
Tamarack	Idaho Power	Idaho Power	5
Van Dyke		Puget Sound Energy	0
VanderHaak Dairy	VanderHaak Dairy, LLC	Puget Sound Energy	0
Whitefish Hydro	City of Whitefish	Ftathead Electric Cooperative	0
SOLAR			**392**
Ashland Solar Project		BPA	-
American Falls Solar	PURPA	Idaho Power	20
American Falls Solar II	PURPA	Idaho Power	20
Arcadia Solar	PURPA	Idaho Power	5
Bellevue Solar	EDF Renewable Energy	Portland General Electric	2
Boise City Solar	PURPA	Idaho Power	40
Evergreen Solar	PURPA	Idaho Power	10
Fairway Solar	PURPA	Idaho Power	10
Finn Hill Solar		Puget Sound Energy	0
Grand View Solar	PURPA	Idaho Power	80
Grove Solar	PURPA	Idaho Power	10
Hyline Solar Center	PURPA	Idaho Power	10
Island Solar		Puget Sound Energy	0

Project	Owner	NW Utility	Nameplate (MW)
Jamieson Solar	PURPA	Idaho Power	4
John Day Solar	PURPA	Idaho Power	5
King Estate Solar	Lane County Electric Coop	Lane County Electric Coop	-
Little Valley Solar	PURPA	Idaho Power	10
Malhuer River Solar	PURPA	Idaho Power	10
Moores Hallow Solar	PURPA	Idaho Power	10
Mountain Home Solar	PURPA	Idaho Power	20
Murphy Flat Power	PURPA	Idaho Power	20
Olds Ferry Solar	PURPA	Idaho Power	5
Open Range Solor Center	PURPA	Idaho Power	10
Orchard Ranch Solar	PURPA	Idaho Power	10
Pocatello Solar I	PURPA	Idaho Power	20
PacifiCorp RPS Solar		PacifiCorp	9
PGE QF Solar Bundle		Portland General Electric	
Railroad Solar Center	PURPA	Idaho Power	10
Simco Solar	PURPA	Idaho Power	20
Thunderegg Solar Center	PURPA	Idaho Power	10
Vale Air Solar Center	PURPA	Idaho Power	10
Wild Horse Solar Project	Puget Sound Energy	Puget Sound Energy	1
Yamhill Solar	EDF Renewable Energy	Portland General Electric	1
WIND			**4,491**
3Bar-G Wind		Puget Sound Energy	1
Bennet Creek	Bennet Creek	Idaho Power	21
Benson Creek Wind	PURPA	Idaho Power	10
Big Top	Big Top LLC (QF)	PacifiCorp	2
Biglow Canyon - 1	Portland General Electric	Portland General Electric	125
Biglow Canyon - 2	Portland General Electric	Portland General Electric	150
Biglow Canyon - 3	Portland General Electric	Portland General Electric	174
Burley Butte Wind Farm	PURPA	Idaho Power	21
Butter Creek Power	Butter Creek Power LLC	PacifiCorp	5
Camp Reed Wind Park	PURPA	Idaho Power	23
Cassia Wind Farm	Cassia Wind Farm	Idaho Power	11
Coastal Energy	CCAP	Grays Harbor PUD	6
Cold Springs	PURPA	Idaho Power	23
Combine Hills I	Eurus Energy of America	PacifiCorp	41
Combine Hills II	Eurus Energy of America	Clark Public Utilities	63
Condon Wind	Goldman Sachs & SeaWest NW	Federal System (BPA)	25
Desert Meadow Windfarm	PURPA	Idaho Power	23
Durbin Creek	PURPA	Idaho Power	10
Elkhorn Wind	Telocaset Wind Power Partners	Idaho Power	101
Foote Creek Rim 1	PacifiCorp & EWEB	Multiple Utilities	41

Project	Owner	NW Utility	Nameplate (MW)
Foote Creek Rim 2	PPM Energy	Federal System (BPA)	2
Foote Creek Rim 4	PPM Energy	Federal System (BPA)	17
Fossil Gulch Wind	Idaho Power Company	Idaho Power	11
Four Corners Windfarm	Four Corners Windfarm LLC	PacifiCorp	10
Four Mile Canyon Windfarm	Four Mile Canyon Windfarm LLC	PacifiCorp	10
Golden Valley Wind Farm	PURPA	Idaho Power	12
Goodnoe Hills	PacifiCorp	PacifiCorp	94
Hammett Hill Windfarm	PURPA	Idaho Power	23
Harvest Wind	Summit Power	Multiple Utilities	99
Hay Canyon Wind	Hay Canyon Wind Project LLC	Snohomish County PUD	101
High Mesa Wind	PURPA	Idaho Power	40
Hopkins Ridge	Puget Sound Energy	Puget Sound Energy	157
Horseshoe Bend	Horseshoe Bend Wind Park LLC	Idaho Power	9
Hot Springs Wind	Hot Springs Wind	Idaho Power	21
Jett Creek	PURPA	Idaho Power	10
Judith Gap	Invenergy Wind, LLC	NorthWestern Energy	135
Klondike I	PPM Energy	Federal System (BPA)	24
Klondike II	PPM Energy	Portland General Electric	75
Klondike III	PPM Energy	Multiple Utilities	221
Knudson Wind		Puget Sound Energy	0
Leaning Juniper 1	PPM Energy	PacifiCorp	101
Lime Wind Energy	PURPA	Idaho Power	3
Lower Snake River 1	Puget Sound Energy	Puget Sound Energy	342
Mainline Windfarm	PURPA	Idaho Power	23
Marengo	Renewable Energy America	PacifiCorp	140
Marengo II	PacifiCorp	PacifiCorp	70
Milner Dam Wind Farm	PURPA	Idaho Power	20
Moe Wind	Two Dot Wind	NorthWestern Energy	1
Nine Canyon	Energy Northwest	Multiple Utilities	96
Oregon Trail Windfarm	Oregon Trail Windfarm LLC	PacifiCorp	10
Oregon Trails Wind Farm	PURPA	Idaho Power	14
Pa Tu Wind Farm	Pa Tu Wind Farm, LLC	Portland General Electric	9
Pacific Canyon Windfarm	Pacific Canyon Windfarm LLC	PacifiCorp	8
Palouse Wind	Palouse Wind, LLC	Avista Corp.	105
Paynes Ferry Wind Park	PURPA	Idaho Power	21
Pilgrim Stage Station Wind Farm	PURPA	Idaho Power	11
Prospector Wind	PURPA	Idaho Power	10
Rockland Wind	PURPA	Idaho Power	80
Ryegrass Windfarm	PURPA	Idaho Power	23
Salmon Falls Wind Farm	PURPA	Idaho Power	22
Sand Ranch Windfarm	Sand Ranch Windfarm LLC	PacifiCorp	10
Sawtooth Wind	PURPA	Idaho Power	21

Project	Owner	NW Utility	Nameplate (MW)
Sheep Valley Ranch	Two Dot Wind	NorthWestern Energy	1
Spion Kop		NorthWestern Energy	40
Stateline Wind	NextEra	Multiple Utilities	300
Swauk Wind		Puget Sound Energy	4
Thousand Springs Wind	PURPA	Idaho Power	12
Three Mile Canyon	Momentum RE	PacifiCorp	10
Tuana Gulch Wind Farm	PURPA	Idaho Power	11
Tuana Springs Expansion	Cassia Gulch Wind Park	Idaho Power	36
Tucannon	Portland General Electric	Portland General Electric	267
Two Ponds Windfarm	PURPA	Idaho Power	23
Vansycle Ridge	ESI Vansycle Partners	Portland General Electric	25
Wagon Trail Windfarm	Wagon Trail Windfarm LLC	PacifiCorp	3
Ward Butte Windfarm	Ward Butte Windfarm LLC	PacifiCorp	7
Wheat Field Wind Project	Wheat Field Wind LLC	Snohomish County PUD	97
White Creek	White Creek Wind I LLC	Multiple Utilities	205
Wild Horse	Puget Sound Energy	Puget Sound Energy	273
Willow Springs Wind Farm	PURPA	Idaho Power	10
Wolverine Creek	Invenergy	PacifiCorp	65
Yahoo Creek Wind Park	PURPA	Idaho Power	21
SMALL THERMAL AND MISCELLANEOUS			**3**
Crystal Mountain	Puget Sound Energy	Puget Sound Energy	3
	Total		**52,112**

Table 11. ***Independent Owned Generating Resources*** is a comprehensive list of independently owned electric power supply located in the region. The nameplate values listed below show full availability. Some of these units have partial contracts (reflected in the load/resource tables) with Northwest utilities.

Project	Owner	Nameplate (MW)
COAL		**1,340**
Centralia #1	TransAlta	670
Centralia #2	TransAlta	670
NATURAL GAS		**2,125**
Grays Harbor (Satsop)	Invenergy	650
Hermiston Power Project	Hermiston Power Partners (Calpine)	689
Klamath Cogen Plant	Iberdrola Renewables	502
Klamath Peaking Units 1-4	Iberdrola Renewables	100
March Point 1	March Point Cogen	80
March Point 2	March Point Cogen	60
COGENERATION		**28**
Boise Cascade		9
Freres Lumber	Evergreen BioPower	10
Rough & Ready Lumber	Rough & Ready	1
Warm Springs Forest Products		8
RENEWABLES-OTHER		**26**
Spokane MSW	City of Spokane	23
Treasure Valley		3
WIND		**3,403**
Big Horn	Iberdrola Renewables	199
Big Horn-Phase 2	Iberdrola Renewables	50
Cassia Gulch	John Deere	21
Glacier Wind - Phase 1	Naturener	107
Glacier Wind - Phase 2	Naturener	104
Goshen North	Ridgeline Energy	125
Juniper Canyon - Phase 1	Iberdrola Renewables	151
Horse Butte		58
Kittitas Valley	Horizon	101

Project	Owner	Nameplate (MW)
Klondike IIIa	Iberdrola Renewables	77
Lava Beds Wind	PURPA	18
Leaning Juniper II-North	Iberdrola Renewables	90
Leaning Juniper II-South	Iberdrola Renewables	109
Linden Ranch	NW Wind Partners	50
Magic Wind Park	PURPA	20
Martinsdale Colony North	Two Dot Wind	1
Martinsdale Colony South	Two Dot Wind	2
Notch Butte Wind	PURPA	18
Pebble Springs Wind	Iberdrola Renewables	99
Rattlesnake Rd Wind (aka Arlington)	Horizon Wind	103
Shepards Flat Central	Caithness Energy	290
Shepards Flat North	Caithness Energy	265
Shepards Flat South	Caithness Energy	290
Star Point	Iberdrola Renewables	99
Stateline Wind	NextEra	300
Vancycle II (Stateline III)	NextEra	99
Vantage Wind	Invenergy	90
Willow Creek	Invenergy	72
Windy Flats	Cannon Power Group	262
Windy Point	Tuolumne Wind Project Authority	137
SMALL THERMAL AND MISCELLANEOUS		**44**
Colstrip Energy LP Coal	Colstrip Energy Limited Partnership	44
Total		**6,966**

Report Procedures

This report provides an estimate of regional 'need to acquire' generating resources (Tables 1 - 4) using annual energy (August through July), monthly energy, winter peak-hour and summer peak-hour metrics. The peak need reflects information for January and August, as they present the greatest need for their respective seasons. These metrics provide a multi-dimensional look at the Northwest's need for power and underscore the growing complexity of the power system.

This regional report reflects the summation of individual utilities' forecasts. The larger utilities, in most cases, prepared their own projections. BPA provides much of the information for its smaller customers. Load (i.e. electricity demand), and resource information is included for the utilities listed in Table 12 at the end of this section. Procedures employed in preparing the regional load-resource comparisons of winter and summer peak and energy are described here. A list of definitions is included at the end of this section.

Load Estimate

Regional loads are the sum of loads estimated by the Northwest utilities and BPA for its federal agency customers, certain non-generating public utilities, and direct service industrial customers (DSI). Estimates are made for system peak and system energy loads. Load projections reflect network transmission and distribution losses, reductions in demand due to rising electricity prices, and the effects of appliance efficiency standards and energy building codes. Savings from demand-side management programs, such as energy efficiency, are also reflected in the regional load forecasts.

Energy Loads

A ten-year forecast of monthly firm energy loads is provided. This forecast reflects normal (1-in-2) weather conditions. The tabulated information includes the annual average load for the year forecast period as well as the monthly load for the first year of the report.

Peak Loads

Northwest regional peak loads are provided for each month of the ten year forecast period. The tabulated loads for winter and summer peak are the highest estimated 60-minute clock-hour average demand for that month, assuming normal (1-in-2) weather conditions. The regional firm peak load is the sum of the individual utility peak loads, and does not account for the fact that each utility may experience its peak load at a different hour than other Northwest utilities. Hence the regional peak load is considered non-coincident. The federal system (BPA) firm peak load is adjusted to reflect a federal coincident peak among its many utility customers.

Federal System Transmission Losses

Federal System (BPA) transmission losses for both firm loads and contractual obligations are embedded in federal load. These losses represent the difference between energy generated by the federal system (or delivered to a system interchange point) and the amount of energy sold to customers. System transmission losses are calculated by BPA for firm loads utilizing the federal transmission system.

Planning Margin

In the derivation of regional requirements, a planning margin has been added to the load. This regional planning margin is equal to 12 percent of the total peak load for the first year of the planning horizon, increasing one percent per year to 20 percent and remaining at 20 percent thereafter. They are intended to cover, for planning purposes, operating reserves and all elements of uncertainty not specifically accounted for in determining loads and resources. These include forced-outage reserves, unanticipated load growth, temperature variations, hydro maintenance and project construction delays. An increasing reserve requirement reflects greater uncertainty about load levels and of achieving construction schedules in the future.

Demand-Side Management Programs

Savings from demand-side management efforts are reported in *Table 7. Demand Side Management Programs*. These estimates are the savings for the ten year study period and include expected future energy savings from existing and new programs in the areas of energy efficiency, distribution efficiency, some market transformation, fuel conversion, fuel switching, energy storage and other efforts that reduce the demand for electricity. These estimates reflect savings from programs that utilities fund directly, or through a third-party, such as the Northwest Energy Efficiency Alliance and Energy Trust of Oregon.

Demand response activity is reported in *Table 7* as well. The total load reduction reported is the cumulative sum of different utilities' agreements with their customers. Each program has its own characteristics and limitations.

Generating Resources

This report considers existing resources, committed new supply (including resources under construction), as well as planned resources. For the assessment of need only the existing and committed resources are reflected in the regional tabulations. In addition, only those generating resources (or shares) that are firmly committed to meeting Northwest loads are included in the regional analysis.

Hydro

Major hydro resource capabilities are estimated from a regional analysis using a computer model that simulates reservoir operation of past hydrologic conditions. The historical stream flow record used covers the 80-year period from August 1928 through July 2008.

Energy

The firm energy capability of hydro plants is the amount of energy produced during the operating year with the lowest 12-month average generation. The lowest generation occurred in 1936-37 given today's river operating criteria. The firm energy capability is the average of 12 months, August 1936 to July 1937. Generation for projects that are influenced by downstream reservoirs reflects the reduction due to encroachment.

Peak Capability

For this report the peak capability of the hydro system represents the maximum sustained hourly generation available to meet peak demand during the period of heavy load. Historically, a 50 hour sustained peak (10 hours/day for 5 days) has been reported.

The peaking capability of the hydro system maximizes available energy and capacity associated with the monthly distribution of streamflow. The peaking capability is the hydro system's ability to continuously produce power for a specific time period by utilizing the limited water supply while meeting power and non-power requirements, scheduled maintenance, and operating reserves (including wind reserves).

Computer models are used to estimate the operational hydro peaking capability of the major projects, based on their monthly average energy for 70 or 80 water conditions depending on the source of information. The peaking capability used for this report is the 8th percentile of the resulting hourly peak capabilities for January and August to indicate winter and summer peak capability respectively. These models shape the monthly hydro energy to maximize generation in the heavy load hours.

Columbia River Treaty

Since 1961 the United States has had a treaty with Canada that outlines the operation of U.S. and Canadian storage projects to increase the total combined generation. Hydropower generation in this analysis reflects the firm power generated by coordinating operation of three Canadian reservoirs, Duncan, Arrow and Mica with the Libby reservoir and other power facilities in the region. Canada's share of the coordinated operation benefits is called Canadian Entitlement. BPA and each of the non-Federal mid-Columbia project owners are obligated to return their share of the downstream power benefits owed to Canada. The delivery of the Entitlement is reflected in this analysis.

Downstream Fish Migration

Another requirement incorporated in the computer simulations is modified river operations to provide for the downstream migration of anadromous fish. These modifications include adhering to specific flow limits at some projects, spilling water at several projects, and augmenting flows in the spring and summer on the Columbia, Snake and Kootenai rivers. Specific requirements are defined by various federal, regional and state mandates, such as project licenses, biological opinions and state regulations.

Thermal and Other Renewable Resources

Thermal resources are reported in a variety of categories. Coal, cogeneration, nuclear, and natural gas projects are each totaled and reported as individual categories.

Renewable resources other than hydropower are categorized as solar, wind and other renewables and are each totaled and reported separately. Other renewables includes energy from biomass, geothermal, municipal solid waste projects and other miscellaneous projects.

All existing generating plants, regardless of size, are included in amounts submitted by each utility that owns or is purchasing the generation. The energy capabilities of plants are computed on annual planning equivalent availability factors submitted by the sponsors of the projects. The factors include allowance for scheduled maintenance (including refueling), forced outages and other expected operating constraints. Some small fossil-fuel plants and combustion turbines are included as peaking resources and their reported energy capabilities are only the amounts necessary for peaking operations. Additional energy potentially may be available from these peaking resources but is not included in the regional load/resource balance.

New and Future Resources

The latest activity with new and future resource developments, including expected savings from demand-side management are tabulated in this report. These resources are reported as *Recently Acquired, Committed New Supply* and *Planned Resources* to reflect the different stages of development.

Recently Acquired Resources

The *Recently Acquired Resources* reported in Table 5 have been acquired in the past year and are serving Northwest utility loads as of December 31, 2015. They are reflected as part of the regional firm needs assessment.

Committed New Supply

Committed New Supply reported in Table 6 includes those projects under construction or committed resources and supply to meet Northwest load that are not delivering power as of December 31, 2015. In this report, resources being built by utilities or resources where their output is firmly committed to utilities are included in the regional load-resource analysis. Future savings from committed demand-side management programs are reported in Table 7.

Planned Resources

Planned Resources presented in Table 8 include specific resources and/or blocks of generic resources identified in utilities' most current integrated resource plans. Projects specifically named in *Planned Resources* are not yet under construction as of December 31, 2015, but a firm commitment to construct or acquire the power has been made. These resources are <u>not</u> part of the regional analysis.

Contracts

Imports and exports include firm arrangements for interchanges with systems outside the region, as well as with third-party developers/owners within the region. These arrangements comprise firm contracts with utilities to the East, the Pacific Southwest and Canada. Contracts to and from these areas are amounts delivered at the area border and include any transmission losses associated with deliveries.

Short term purchases from Northwest independent power producers and other spot market purchases are considered non-firm contracts and not reflected in the tables that present the firm load/resource comparisons.

Table 12 Utilities included in the Northwest Regional Forecast

Albion, City of
Alder Mutual
Ashland, City of
Asotin County PUD #1
Avista Corp.
Bandon, City of
Benton PUD
Benton REA
Big Bend Electric Co-op
Blachly-Lane Electric Cooperative
Blaine, City of
Bonners Ferry, City of
Bonneville Power Administration
Burley, City of
Canby Utility
Cascade Locks, City of
Central Electric
Central Lincoln PUD
Centralia, City of
Chelan County PUD
Cheney, City of
Chewelah, City of
City of Port Angeles
Clallam County PUD #1
Clark Public Utilities
Clatskanie PUD
Clearwater Power Company
Columbia Basin Elec. Co-op
Columbia Power Co-op
Columbia REA
Columbia River PUD
Consolidated Irrigation Dist. #19
Consumers Power Inc.
Coos-Curry Electric Cooperative
Coulee Dam, City of
Cowlitz County PUD
Declo, City of
Douglas County PUD
Douglas Electric Cooperative
Drain, City of
East End Mutual Electric
Eatonville, City of
Ellensburg, City of
Elmhurst Mutual P & L
Emerald PUD
Energy Northwest
Eugene Water & Electric Board
Fall River Rural Electric Cooperative
Farmers Electric Co-op
Ferry County PUD #1
Fircrest, Town of
Flathead Electric Cooperative
Forest Grove Light & Power
Franklin County PUD
Glacier Electric
Grant County PUD
Grays Harbor PUD
Harney Electric
Hermiston, City of
Heyburn, City of
Hood River Electric
Idaho County L & P
Idaho Falls Power
Idaho Power
Inland Power & Light
Kittitas County PUD
Klickitat County PUD
Kootenai Electric Co-op
Lakeview L & P (WA)
Lane Electric Cooperative
Lewis County PUD
Lincoln Electric Cooperative
Lost River Electric Cooperative
Lower Valley Energy
Mason County PUD #1
Mason County PUD #3
McCleary, City of
McMinnville Water & Light
Midstate Electric Co-op
Milton, Town of
Milton-Freewater, City of
Minidoka, City of
Missoula Electric Co-op
Modern Electric Co-op
Monmouth, City of
Nespelem Valley Elec.Co-op
Northern Lights Inc.
Northern Wasco Co. PUD
NorthWestern Energy
Ohop Mutual Light Company
Okanogan Co. Electric Cooperative
Okanogan County PUD #1
Orcas Power & Light
Oregon Trail Co-op
Pacific County PUD #2
PacifiCorp
Parkland Light & Water
Pend Oreille County PUD
Peninsula Light Company
Plummer, City of
PNGC Power
Port of Seattle – SEATAC
Portland General Electric
Puget Sound Energy
Raft River Rural Electric
Ravalli Co. Electric Co-op
Richland, City of
Riverside Electric Co-op
Rupert, City of
Salem Electric Co-op
Salmon River Electric Cooperative
Seattle City Light
Skamania County PUD
Snohomish County PUD
Soda Springs, City of
Southside Electric Lines
Springfield Utility Board
Steilacoom, Town of
Sumas, City of
Surprise Valley Elec. Co-op
Tacoma Power
Tanner Electric Co-op
Tillamook PUD
Troy, City of
Umatilla Electric Cooperative
Umpqua Indian Utility Co-op
United Electric Cooperative
US Corps of Engineers
US Bureau of Reclamation
Vera Water & Power
Vigilante Electric Co-op
Wahkiakum County PUD #1
Wasco Electric Co-op
Weiser, City of
Wells Rural Electric Co.
West Oregon Electric Cooperative
Whatcom County PUD
Yakama Power

Definitions

Annual Energy

Energy value in megawatts that represents the average of monthly values in a given year.

Average Megawatts

(MWa) Unit of energy for either load or generation that is the ratio of energy (in megawatt-hours) expected to be consumed or generated during a period of time to the number of hours in the period.

Biomass

Any organic matter which is available on a renewable basis, including forest residues, agricultural crops and waste, wood and wood wastes, animal wastes, livestock operation residue, aquatic plants, and municipal wastes.

Canadian Entitlement

Canada is entitled to one-half the downstream power benefits resulting from Canadian storage as defined by the Columbia River Treaty. Canadian entitlement returns estimated by Bonneville Power Administration.

Coal

This category of generating resources includes the region's coal-fired plants.

Cogeneration

Cogeneration is the technology of producing electric energy and other forms of useful energy (thermal or mechanical) for industrial and commercial heating or cooling purposes through sequential use of an energy source.

Combustion Turbines

These are plants with combined-cycle or simple-cycle natural gas-fired combustion turbine technology for producing electricity.

Committed Resources

This includes under construction projects and long-term power supply agreements that are committed but not yet producing power to meet Northwest load at the time of publication. This generation is included in the resources for calculating the regional load/resource balance.

Conservation

Any reduction in electrical power consumption as a result of increases in the efficiency of energy use, production, or distribution. For the purposes of this report used synonymously with energy efficiency.

Demand Response

Control of load through customer/utility agreements that result in a temporary change in consumers' use of electricity in times of system stress.

Demand-side Management

Peak and energy savings from conservation/energy efficiency measures, distribution efficiency, market transformation, demand response, fuel conversion, fuel switching, energy storage and other efforts that that serve to reduce electricity demand.

Dispatchable Resource

A term referring to controllable generating resources that are able to be dispatched for a specific time and need.

Distribution Efficiency

Infrastructure upgrades to utilities' transmission and distribution systems that save energy by minimizing losses.

Encroachment

A term used to describe a situation where the operation of a hydroelectric project causes an increase in the level of the tailwater of the project that is directly upstream.

Energy Efficiency

Any reduction in electrical power consumption as a result of increases in the efficiency of energy use, production, or distribution. For the purposes of this report used synonymously with conservation.

Energy Load

The demand for power averaged over a specified period of time.

Energy Storage

Technologies for storing energy in a form that is convenient for use at a later time when a specific energy demand is greater.

Exports

Firm interchange arrangements where power flows from regional utilities to utilities outside the region or to non-specific, third-party purchasers within the region.

Federal System (BPA)

The federal system is a combination of BPA's customer loads and contractual obligations, and resources from which BPA acquires the power it sells. The resources include plants operated by the U.S. Army Corps of Engineers (COE), U.S. Bureau of Reclamation (USBR) and Energy Northwest. BPA markets the thermal generation from Columbia Generating Station, operated by Energy Northwest.

Federal Columbia River Power System (FCRPS)

Thirty federal hydroelectric projects constructed and operated by the Corps of Engineers and the Bureau of Reclamation, and the Bonneville Power Administration transmission facilities.

Firm Energy

Electric energy intended to have assured availability to customers over a defined period.

Firm Load

The sum of the estimated firm loads of private utility and public agency systems, federal agencies and BPA industrial customers.

Firm Losses

Losses incurred on the transmission system of the Northwest region.

Fuel Conversion

Consumers' efforts to make a permanent change from electricity to natural-gas or other fuel source to meet a specific energy need, such as heating.

Fuel Switching

Consumers' efforts to make a temporary change from electricity to another fuel source to meet a specific energy need.

Historical Streamflow Record

A database of unregulated streamflows for 80 years (July 1928 to June 2008). Data is modified to take into account adjustments due to irrigation depletions, evaporations, etc. for the particular operating year being studied.

Hydro Maintenance

The amount of energy lost due to the estimated maintenance required during the critical period. Peak hydro maintenance is included in the peak planning margin calculations.

Hydro Regulation

A study that utilizes a computer model to simulate the operation of the Pacific Northwest hydroelectric power system using the historical streamflows, monthly loads, thermal and other non-hydro resources, and other hydroelectric plant data for each project.

Imports

Firm interchange arrangements where power flows to regional utilities from utilities outside the region or third-party developer/owners of generation within the region.

Independent Power Producers (IPPs)

Non-utility entities owning generation that may be contracted (fully or partially) to meet regional load.

Intermittent Resource (a.k.a. Variable Energy Resource)

An electric generating source with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements. Intermittent output usually results from the direct, non-stored conversion of naturally occurring energy fluxes such as solar and wind energy.

Investor-Owned Utility (IOU)

A privately owned utility organized under state law as a corporation to provide electric power service and earn a profit for its stockholders.

Market Transformation

A strategic process of intervening in a market to accelerate the adoption of cost-effective energy efficiency.

Megawatt (MW)

A unit of electrical power equal to 1 million watts or 1,000 kilowatts.

Nameplate Capacity

A measure of the approximate generating capability of a project or unit as designated by the manufacturer.

Natural Gas-Fired Resources

This category of resources includes the region's natural gas-fired plants, mostly single-cycle and combined-cycle combustion turbines. It may include projects that are considered cogeneration plants.

Non-Firm Resources

Electric energy acquired through short term purchases of resources not committed as firm resources. This includes generation from hydropower in better than critical water conditions, independent power producers and imports from outside the region.

Non-Utility Generation

Facilities that generate power whose percent of ownership by a sponsoring utility is 50 percent or less. These include PURPA-qualified facilities (QFs) or non-qualified facilities of independent power producers (IPPs).

Nuclear Resources

The region's only nuclear plant, the Columbia Generating Station, is included in this category.

Operating Year

Twelve-month period beginning on August 1 of any year and ending on July 31 of the following year. For example, operating year 2017 is August 1, 2016 through July 31, 2017.

Other Publics (BPA)

Refers to the smaller, non-generating public utility customers whose load requirements are estimated and served by Bonneville Power Administration.

Peak Load

In this report the peak load is defined as one-hour maximum demand for power.

Planned Resources

Planned resources include generic, as well as specific projects, measures, and transactions that utilities have made some commitment to acquire and are in some stage of state site certification process. However, either not all licenses have been obtained, no commercial operation data has been specified, or the specifics of the transaction have not been finalized.

Planning Margin

A component of regional requirements that is included in the peak needs assessment to account for various planning uncertainties.

Private Utilities

Same as investor-owned utilities.

Publicly-Owned Utilities

One of several types of not-for-profit utilities created by a group of voters and can be a municipal utility, a public utility district, or an electric cooperative.

PURPA

Public Utility Regulatory Policies Act of 1978. The first federal legislation requiring utilities to buy power from qualifying independent power producers.

Renewables - Other

A category of resources that includes projects that produce power from such fuel sources as geothermal, biomass (includes wood, municipal solid-waste facilities), and pilot level projects including tidal and wave energy.

Requirements

For each year, a utility's projected loads, exports, and contracts out. Peak requirements also include the planning margin.

Small Thermal & Miscellaneous Resources

This category of resources includes small thermal generating resources such as diesel generators used to meet peak and/or emergency loads.

Solar Resources

Resources that produce power from solar exposure. This includes utility scale solar photovoltaic systems and other utility scale solar projects. This category does not include customer side distributed solar generation.

Thermal Resources

Resources that burn coal, natural gas, oil, diesel or use nuclear fission to create heat which is converted into electricity.

Variable Energy Resource (a.k.a. Intermittent Resource)

An electric generating source with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements. Intermittent output usually results from the direct, non-stored conversion of naturally occurring energy fluxes such as solar and wind energy.

Wind Resources

This category of resources includes the region’s wind powered projects.