Pacific Northwest Power Supply Adequacy Assessment and State of the System Report for 2020/21

Completed in May 2015

851 S.W. Sixth Avenue, Suite 1100
Portland, Oregon 97204-1348
www.nwcouncil.org

Steve Crow
Executive Director

503-222-5161
800-452-5161
Fax: 503-820-2370

Contents

Forward ... 3
Executive Summary ... 4
The Council's Resource Adequacy Standard ... 5
Previous Adequacy Assessments ... 6
2020 Resource Adequacy Assessment ... 9
  Other Adequacy Metrics ... 9
  Addressing Other Uncertainties ... 12
  Conclusions for 2020 ... 13
2021 Resource Adequacy Results ... 13
  Gas Turbine Scenario ... 16
  Wind Scenario ... 17
  Conclusions for 2021 ... 19
Future Assessments ... 21

Table 1- History of Adequacy Assessment ... 7
Table 2: Assumptions used for Adequacy Assessment ... 7
Table 3 - Adequacy Metric Definitions ... 10
Table 4 - Adequacy Measures ... 11
Table 5 - Summary of All Adequacy Metrics by Month ... 11
Table 6 - Load and SW Market Uncertainty LOLP Map ... 13
Figure 1: CVaR and LOLP by Month (2021 Reference Case) ... 15
Table 7: Expected Resource Dispatch for 2021 ... 15
Figure 2: CVaR and LOLP by Month (2021 Gas Replacement Case) ... 16
Table 8: Expected Resource Dispatch (2021 Gas Replacement Case) ... 17
Figure 3: CVaR and LOLP by Month (Wind Replacement Case) ... 17
Table 9: Expected Resource Dispatch (Wind Replacement Case) ... 18
Figure 4: CVaR and LOLP by Month (Solar Replacement Case) ... 19
Table 10: Expected Resource Dispatch (Solar Replacement Case) ... 19
Figure 5: Expected Oversupply Energy by Month ... 20
Table 11: Reduction in Thermal Dispatch for Wind and Solar Cases ... 21

FORWARD

This *State of the System* report is a technical addendum to the Northwest Power and Conservation Council's Resource Adequacy Assessment for 2020/21, which was approved and released in May of 2015. This report provides more information regarding the assessed adequacy of the Northwest's power supply for operating years 2020 and 2021.

In 2011, the Council adopted the loss of load probability (LOLP) as the measure for power supply adequacy and set the maximum allowable value at 5 percent. This means that the likelihood of a shortfall (not necessarily an outage) occurring 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 the Council's analyses. The data in the charts and tables below are derived from official studies and analyses that the Council and BPA did to produce the 2020/21 adequacy report.

The format and content of this report are still under development. As such, we chose not to include extensive discussion or interpretation of results. In fact, many sections in this report simply provide charts and tables without specific details. We would like to know how useful this report is for you. For example, is the format appropriate? Would you like more interpretation of results? Would you like to see different types of output? Please send your comments, suggestions and questions to John Fazio at (jfazio@nwcouncil.org).

It should also be noted that work to improve the model, in particular, the hourly hydro dispatch, is ongoing. Thus, as results change for future analyses, we will attempt to separate impacts due to model improvements from those due to changes in the power system.

EXECUTIVE SUMMARY

The Pacific Northwest's power supply is expected to be adequate through 2020. The Council estimates that the likelihood of a power supply shortage in that year is just under the 5-percent standard set by the Council in 2011. By 2021, however, after the planned retirements of the Boardman and Centralia-1 coal plants (1,330 MW nameplate), the likelihood of a shortfall (also referred to as the Loss-of-load Probability or LOLP) rises to a little over 8 percent[1] and would lead to an inadequate supply without intermediate actions.

These results are based on a probabilistic analysis that examines the operation of the power supply over thousands of different combinations of river runoff volume, wind generation, forced outage and temperature for the 2020/21 operating years. However, in each case, the underlying demand was set to the Council's medium forecast and the availability of imports from the southwest was also set to a fixed value. If demand growth were to vary from the medium forecast or if the availability of imports were to change, the LOLP could drop as low as one percent or rise as high as 17 percent. The availability of imports depends not only on surplus generating capability in the southwest but also on the south-to-north transmission capacity. Currently, the limiting factor during winter months is the transmission capacity. Resource adequacy is assessed every year because the power supply is dynamic, in the sense that factors such as demand and import availability can change unexpectedly.

The results above assume that the region will continue to acquire energy efficiency savings as targeted in the Council's Sixth Power Plan, which amount to about 1,700 average megawatts through 2020. While no other resource acquisitions are required to maintain adequacy through 2020, the region will likely have to plan for additional resources before 2021 when the two coal plants are retired. Actions 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. For example, adding 1,150 megawatts of gas-fired generation would bring the LOLP back to 5 percent.

In all likelihood, some combination of new generation and load reduction programs will be used to bridge the gap. It should be noted that developing a strategy to provide the region with an adequate, efficient, economical and reliable power supply is beyond the scope of this analysis. Designing such a strategy is more appropriately done in the Council's Power Plan, which is due out later this year.

This analysis only counts existing resources and those that are sited and licensed. Northwest utilities, as reported in the Pacific Northwest Utilities Conference Committee's 2015 Northwest Regional Forecast show a combined 900 megawatts of planned generating capacity over the

---

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

next 10 years. But as conditions change over the next few years, it is expected that utilities will amend their resource acquisition strategies to ensure that sufficient investments in new resources will be made to maintain an adequate supply.

THE COUNCIL'S RESOURCE ADEQUACY STANDARD

In 2011, the Northwest Power and Conservation Council adopted a regional power supply 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.

Adequacy is assessed by using a probabilistic analysis to compute the likelihood of a supply shortfall. The analysis is based on 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. Only existing generating resources and those that are expected to be operational in the study year are counted 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. In cases when the supply is deemed to be inadequate, the Council estimates how much new dispatchable resource generating capacity 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. This is why the adequacy assessment is performed each year whereas the power plan is updated every 5 years.

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 measures to provide continuous service exceeds the tolerance for such events. Nonetheless, some contingency actions are captured in the final assessment of the LOLP through a post-processing program that simulates the use of standby resources.

Standby resources are made up of 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 or low temperatures). These resources only have a capacity component and are not intended to provide extended energy relief. The effects of demand response measures that have already been implemented 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 and small generating resources that are contractually available to utilities help reduce peak hour load may also provide some energy assistance. However, they are not intended to be used often and are therefore not 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 algorithm uses these capabilities to adjust the simulated curtailment record and calculate the final LOLP.

PREVIOUS 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 probabilistic methods to assess adequacy, the power supply and, to some extent the methodology, have changed significantly, 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.

Assumptions used for this year's assessment are summarized in Table 2.

Table 1- History of Adequacy Assessment

Year	Milestone
1998	Large load/resource balance deficit is a concern to planners
1999	Ad-hoc committee recommends using LOLP, GENESYS model created
2000	**2003 Assessment**: 24 percent LOLP
2001	West Coast energy crisis
2005	Resource Adequacy Forum created
2007	Unofficial assessment for 2013 indicates an adequate supply
2008	Preliminary standard adopted, converts 5% LOLP into deterministic metrics
2009-10	Adequacy methodology is peer reviewed
2010	**2015 Assessment**: 5 percent LOLP (documented in the Sixth Power Plan)
2011	Council revises its adequacy standard, uses 5% annual LOLP
2012	**2017 Assessment**: 7 percent LOLP = inadequate supply
2014	**2019 Assessment**: 6 percent LOLP = inadequate supply

Table 2: Assumptions used for Adequacy Assessment

Table A1Item	2019	2020
Operating Year	Oct 2018 to Sep 2019	Oct 2019 to Sep 2020
Number of Games	6160 (all combinations of water and temp years)	6160
Random Thermal Outage	On	On
Water year selection	Sequential	Sequential
Water year range	80 years historic 1929-2008	80 years historic 1929-2008
Temperature year selection	Exhaustive pairing w/water	Exhaustive pairing w/water
Temperature year range	77 years 29-05 (to match wind)	77 years 29-05 (to match wind)
Wind year selection	Correlated to temp year	Correlated to temp year
Wind year range	77 years synthetic 1929-2005	77 years synthetic 1929-2005

Table A1Item	2019	2020
Wind/temp uncertainty	Random, 20 sets per temp year	Random, 20 sets per temp year
Thermal	Sited and licensed	Sited and licensed
Installed Wind Capacity	4,846 MW (sited and licensed)	4,532 MW
Demand response	In standby resources	In standby resources
Load call back provisions	In standby resources	In standby resources
Standby energy	40,800 MW-hours	40,800 MW-hours
Standby capacity (Oct-Apr)	623 MW	623 MW
Standby capacity (May-Sep)	833 MW	833 MW
Energy Efficiency magnitude	Council's 6th plan targets	Council's 6th plan targets
Energy Efficiency shape	Same as load	Same as load
NW market (Oct-Apr)	3,467 MW (full IPP)	3,021 MW (full IPP)
NW market (May-Sep)	1,000 MW	1,000 MW
BC market	0 MW	0 MW
Southern Idaho market	Not in model	Not in model
SW market winter on-peak	2,500 MW	2,500 MW
SW market winter off-peak	3,000 MW (purchase ahead)	3,000 MW (purchase ahead)
SW market summer on-peak	0 MW	0 MW
SW market summer off-peak	3,000 MW (purchase ahead)	3,000 MW (purchase ahead)
Maximum SW import limit	3,200 MW	3,400 MW
Fed Hydro balancing reserves	900 INC and 1100 DEC	900 INC and 1100 DEC
Additional balancing reserves	Not modeled	Not modeled
Energy Imbalance Market	Not modeled	Not modeled
Borrowed hydro	1000 MW-periods	1000 MW-periods
Hydro constraints	Draft 2019 regulation	Final 2020 regulation

2020 RESOURCE ADEQUACY ASSESSMENT

The Pacific Northwest's power supply is expected to be adequate through 2020. The Council estimates that the likelihood of a power supply shortage that year is 4.7 percent, with the most critical months being January and February (discussed in more detail below). The previous two assessments (see Table 1) projected the power supply to be slightly inadequate. This year's assessment projects an adequate supply primarily because regional loads have not grown as rapidly as expected and additional energy efficiency savings have been acquired.

Since the last adequacy assessment, annual average regional loads are forecast to be 310 average megawatts lower than what was forecast for 2019. During the same period, the region should see an additional 350 average megawatts of energy efficiency savings. Those two changes more than compensate for the removal of the Big Hanaford plant (250 megawatt nameplate capacity).

Other Adequacy Metrics

Other adequacy metrics help planners better understand how large curtailments can be, how often they occur and how long they last. These other metrics provide valuable information to planners as they consider resource expansion strategies. Table 3 below defines some of the more commonly used probabilistic metrics used to examine power supply adequacy and Table 4 provides the results for 2017, 2019 and 2020.

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 3 - Adequacy Metric Definitions

Metric	Description
LOLP (%)	Loss of load probability = number of games with a problem divided by the total number of games
EUSRP (%)	Use of standby resource probability = Number of games that dispatch standby resources at least once divided by total 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 = Same as EUSRP

Table 4 - Adequacy Measures

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

Table 5 - Summary of All Adequacy Metrics by Month

Month	LOLP Peak %	LOLP Energy %	Overall LOLP %	EUSR %	CVaR Energy MW-Hrs	CVaR Peak MW	EUE MW-Hrs	LOLH Hours
Annual	**4.7**	**1.7**	**4.7**	**6.4**	**50,589**	**2,949**	**2,536**	**1.5**
Oct				0.1	108	16	5	
Dec	1.0		1.0	1.3	4926	528	246	0.2
Jan	3.1	0.1	3.1	3.5	38469	2155	1923	1.0
Feb	0.7		0.7	0.8	6326	416	316	0.2
Jun				0.1	37	4	1	
Jul					7	2		
Au1				0.2	164	16	8	
Au2	0.1		0.1	0.7	547	64	27	0.1
Sep	0.1		0.1	0.2	136	25	6	

Addressing Other Uncertainties

Two future uncertainties not modeled explicitly in GENESYS are long-term (economic) load growth and variability in out-of-region market supply. This section describes a series of sensitivity studies that were done to assess the impacts of these variables on the LOLP. Long-term load growth is bounded by the Council's high and low load forecasts, which are roughly equivalent to a 2.5 percent increase and decrease from the medium load forecast. Variation in SW market supply is influenced by future resource development in California and by the ability to transfer surplus energy into the Northwest.

For the 2020 assessment, 2,500 megawatts was assumed to be available during all winter peak-load hours. By 2019, 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, California has lost 2,200 megawatts of San Onofre Nuclear Generating Station capacity. 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.

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, 3,021 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.

California import availability is divided into on-peak and off-peak availabilities. The off-peak availability is assumed to be 3,000 megawatts year round. Energy from the off-peak market is purchased during light-load hours before periods of potential shortfalls and is often referred to as a purchase-ahead resource. The on-peak availability is assumed to be 2,500 megawatts during winter and is not available at all during summer.

The expected 4.7 percent loss of load probability assumes the Council's medium load forecast and 2,500 megawatts of California on-peak winter import availability. To investigate the potential impacts of different combinations of economic load growth and California import availability, scenario analyses were performed. In the conservative case, with high load growth and no California import, the loss of load probability would be 17 percent. Fortunately, this scenario is not very likely. In the least conservative case with low load growth and maximum winter import availability (2,500 MW), the loss of load probability drops to about 1 percent. Table 6 illustrates how LOLP could change as both long-term load growth and SW imports vary.

Table 6 - Load and SW Market Uncertainty LOLP Map

Load → / Import ↓	-2.50%	-1.50%	0%	1.50%	2.50%
0 (MW)	10.1	10.2	13.3	14.2	17.5
1,500	4.4	5.0	6.2	7.3	8.3
2,500	3.2	3.8	4.7	5.9	6.9
3,000	3.2	3.8	4.5	5.6	6.2
3,400	1.4	1.9	2.7	3.4	3.9

Conclusions for 2020

While the expected loss-of-load probability for the 2020 operating year is less than 5 percent, that does not mean that the power supply is expected to be adequate under all future conditions. Depending on the availability of imports and the rate of economic load growth, the LOLP can range from 1 percent to 17 percent. A better way to summarize this is to say that the 2020 power supply is expected to be adequate but has a slightly less than 50 percent chance of becoming inadequate depending on how the future unfolds.

2021 RESOURCE ADEQUACY RESULTS

The official 2021 Resource Adequacy Assessment will be released in 2016 as the regular annual 5-year look-ahead adequacy assessment. However, because some large generating resources will retire by the end of 2020, the Council decided that a preliminary assessment of 2021 could be useful to regional planners.

Resource retirements and added conservation are the two major changes going from 2020 to 2021. By the end of December 2020, both the Centralia Unit 1 (730 MW nameplate) and Boardman (600 MW nameplate) coal plants are slated to retire[2]. In addition to the retirements of

---

[2] The GENESYS model's 2021 assessment covers the fiscal operating year from October 2020 through September 2021. Technically these plants are available from October to December of 2020,however, this study focuses on long term effects of these retirements and therefore uses the more generic study that has both plants out for the entire fiscal year.

these coal plants, this study assumes that all the cost effective conservation as targeted in the 6th Power Plan is achieved between 2020 and 2021, which totals 350 average megawatts. This leaves the net load growth to 40 aMW from 2020 to 2021 or .18 percent. There are no other resource changes assumed from the 2020 to the 2021 preliminary assessment.

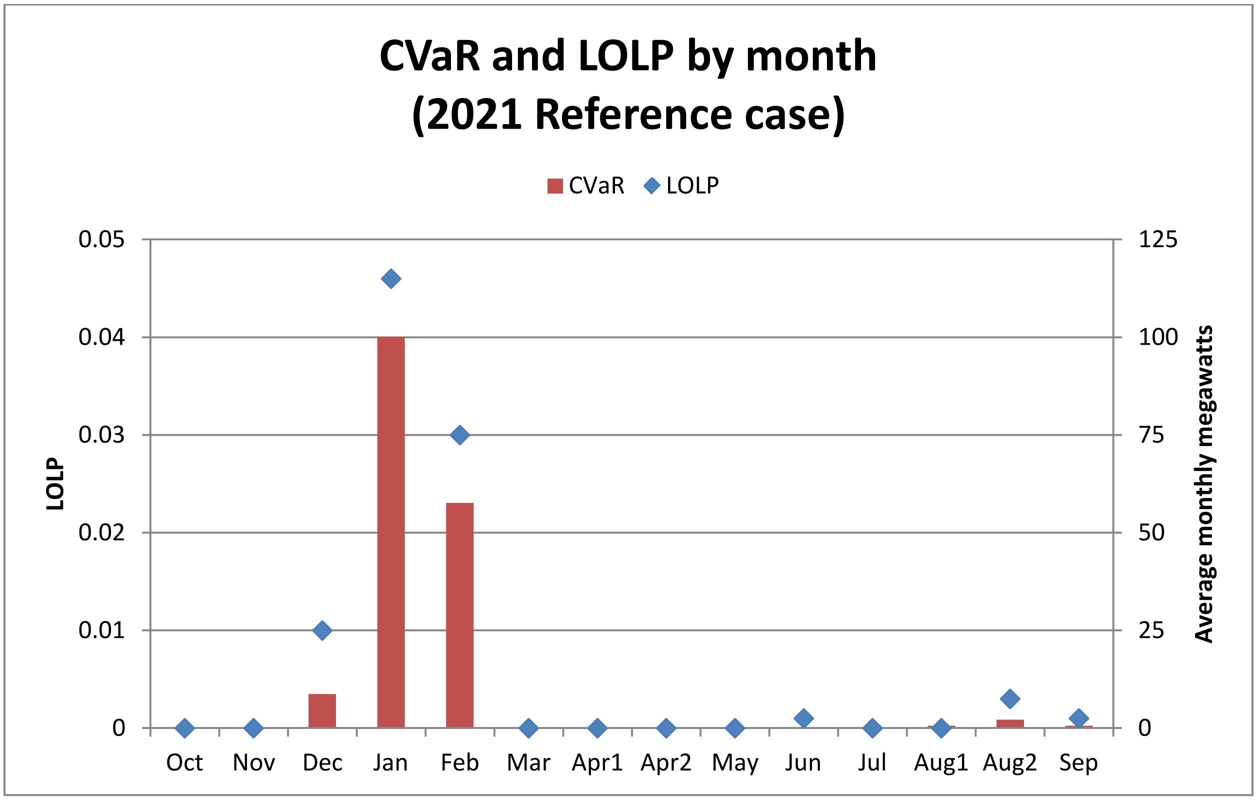
The LOLP for 2021 is 8 percent which exceeds the 5 percent adequacy standard adopted by the Council in 2011. This is up from the 5 percent LOLP for 2020.

While the LOLP adequacy standard is a useful metric, it does not reflect the magnitude nor the time of year that shortage events occur. For this reason, the 2021 preliminary assessment focuses in on the LOLP distribution by month and the magnitude of the monthly curtailments.

For 2021 curtailment events would primarily occur in January and February. The respective LOLP values for all months are shown in the graph below (measured on the left axis and represented by the diamonds). For example, the LOLP for January is 4.5 percent represented by the blue diamond. The conditional value at risk or CVaR (the average amount of energy not served in the worst 5 percent of cases) for January is 100 average megawatt-months, represented by the red bar.

As one can see in the graph, LOLP is not distributed evenly throughout the year. Therefore, solutions to improve adequacy should focus on these critical months of January and February (and to a lesser extent December) and be less concerned with just providing energy regardless of what season the generation occurs.

Figure 1: CVaR and LOLP by Month (2021 Reference Case)



In Table 7 below, the average generation values for all 6,160 games for different resource types is provided.

Table 7: Expected Resource Dispatch for 2021

	OCT	NOV	DEC	JAN	FEB	MAR	APR1	APR2	MAY	JUN	JUL	AUG1	AUG2	SEP	AVG
Coal Generation	3216	2831	3172	2571	2550	2135	1929	1084	534	855	1964	2980	3236	3529	2331
Gas Generation	2824	1596	2371	2127	1861	1238	1273	692	516	815	1295	1926	2539	3086	1747
IPP & SW Market	500	721	1172	1086	869	499	507	151	43	92	185	315	450	527	532
Wind Generation	1108	1145	1128	1202	1228	1455	1714	1754	1650	1572	1445	1316	1277	1100	1339

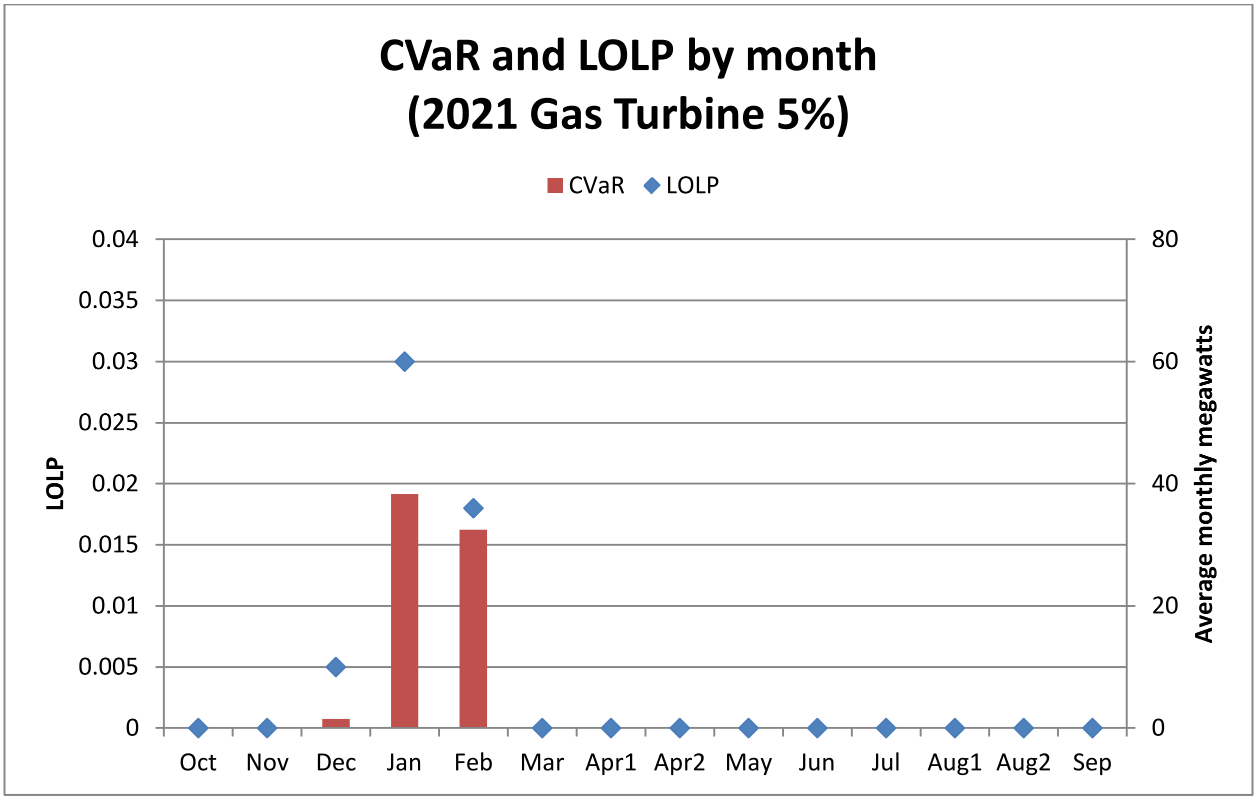
Three book-end scenarios were developed in an attempt to reduce the 2021 LOLP from 8 percent to the 5 percent resource adequacy standard: gas turbines; wind; and solar. These are book end scenarios and are only focused on meeting the LOLP adequacy standard. No assumptions are made about the cost of these resources (including integration), positive and negative environmental attributes, or siting and permitting cost or lead times. Developing a strategy to provide the region with an adequate, efficient, economical and reliable power supply is beyond the scope of this analysis. Designing such a strategy is more appropriately done in the Council's Power Plan which is due out later this year.

In addition to examining meeting the adequacy standard, the impacts on regional oversupply and on thermal displacement are also examined.

Gas Turbine Scenario

Gas Turbines were added to the study until the 2021 LOLP was equal to 5 percent. Three gas turbines sized at 400, 400, and 350 MW nameplate returned the 2021 power system to 5 percent. For the month of January the LOLP was reduced from 4.5 percent to 3 percent, and the January CVaR was reduced from 100 aMW-months to 38 aMW-months.

Figure 2: CVaR and LOLP by Month (2021 Gas Replacement Case)



The table below shows the average amount of generation dispatched for each resource type. Compared to the base case, there was no change in the amount of coal and wind generation because the two cases have the same amount of installed coal and wind capacity (with 4,532 MW of wind earmarked to serve PNW loads). Also, IPP and SW markets and gas generation are relatively the same. However, looking at average generation across 6,160 games masks the use of imports and gas generation in games with less hydro and wind generation, higher forced outages, and more extreme temperatures.

Table 8: Expected Resource Dispatch (2021 Gas Replacement Case)

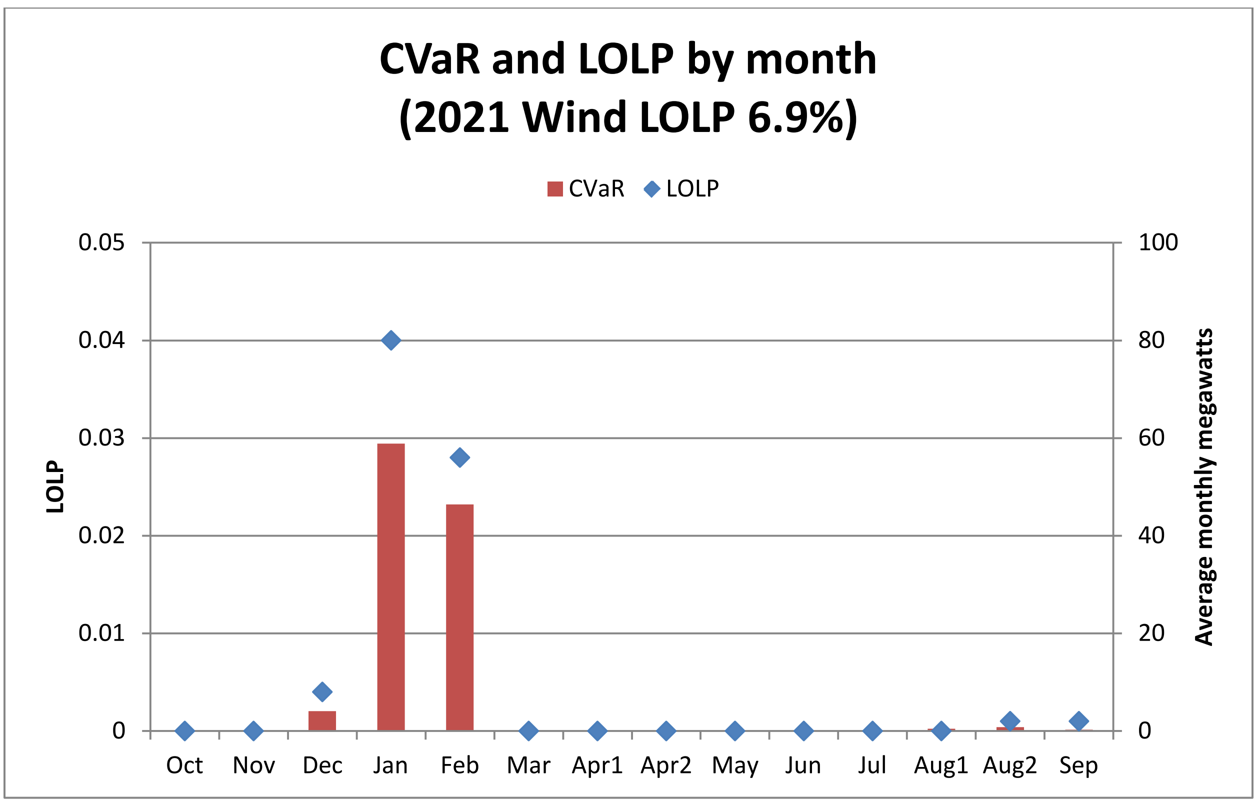
	OCT	NOV	DEC	JAN	FEB	MAR	APR1	APR2	MAY	JUN	JUL	AUG1	AUG2	SEP	AVG
Coal Generation	3217	2831	3173	2572	2550	2135	1929	1084	534	855	1964	2981	3237	3529	2331
Gas Generation	2843	1601	2402	2204	1895	1242	1275	693	516	831	1301	1943	2579	3117	1768
IPP & SW Market	489	716	1150	1030	838	494	504	150	43	82	178	301	418	505	516
Wind Generation	1108	1145	1128	1202	1228	1455	1714	1754	1650	1572	1445	1316	1277	1100	1339

Wind Scenario

Adding 10,000 MW of wind turbine capacity lowered the LOLP to 7 percent, which obviously does not meet the 5 percent resource adequacy standard. Adding further amounts of wind capacity did not lower the LOLP. Note that all wind generation (a total of 14,523 of installed MW) for this study was based on load center temperature and wind generation correlation of the BPA balancing authority wind fleet. Adding coastal wind and/or Montana wind may bring diversification that could improve the study results, but this data was unavailable for the study.

The wind scenario lowered the January LOLP from 4.5 to 4 percent and lowered the CVaR from 100 aMW-months to 59 aMW-months.

Figure 3: CVaR and LOLP by Month (Wind Replacement Case)



In the table below, average wind generation increased to 4,293 aMW from 1,339 aMW (as 10,000 MW of installed wind capacity was added to the 4,532 MW of existing wind capacity). Wind generation peaks in the last half of April at 5,625 aMW-months. This amount of wind reduced the need to run thermal generation but increased the amount of potential oversupply (this is examined more thoroughly in the conclusion section).

Table 9: Expected Resource Dispatch (Wind Replacement Case)

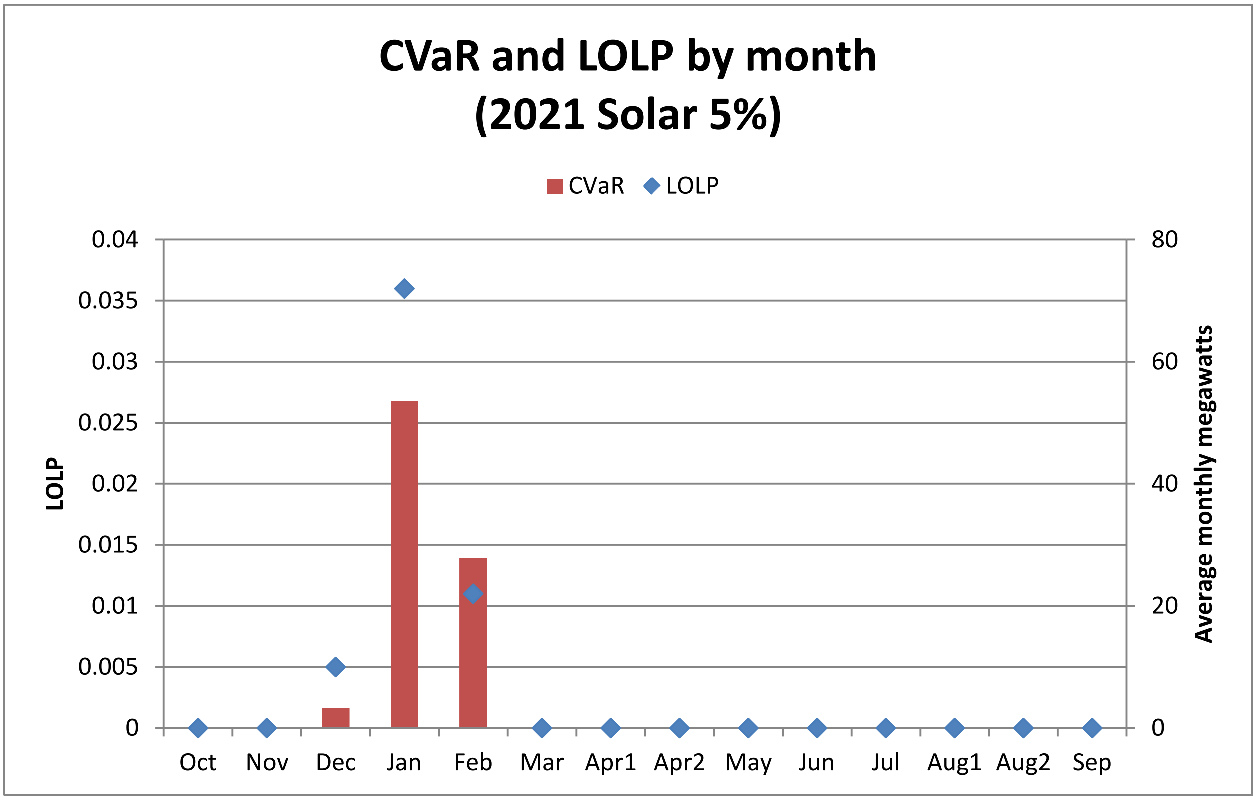
	OCT	NOV	DEC	JAN	FEB	MAR	APR1	APR2	MAY	JUN	JUL	AUG1	AUG2	SEP	AVG
Coal Generation	2402	1780	2315	1852	1736	1157	1002	414	285	477	1078	1839	2190	2660	1539
Gas Generation	1744	1107	1609	1575	1349	825	735	527	469	587	820	1156	1550	1922	1166
IPP & SW Market	275	357	704	718	526	211	172	54	25	40	91	154	237	302	296
Wind Generation	3553	3670	3615	3853	3937	4666	5496	5625	5290	5040	4633	4220	4094	3526	4293

Solar Photovoltaic Scenario

A total of 12,700 MW of installed solar capacity was required for the LOLP to reach 5 percent. It should be noted that this is based on actual average hourly solar data, but for only 26 months of a small set of solar projects located in south Oregon. Fifteen percent of the new solar generation assumed to be in the west side and 85 percent on the east side. A more robust set of actual solar generation data and data from Idaho solar once installed may produce different results.

The solar scenario reduced the January LOLP down from 4.5 percent to approximately 3.5 percent and reduced the monthly ENS from 100 aMW-months down to 54 aMW-months.

Figure 4: CVaR and LOLP by Month (Solar Replacement Case)



Solar generation produced on average 2,534 aMW-years of energy, most of it occurring in June (4,032 aMW-months) and July (4,030 aMW-months).

Table 10: Expected Resource Dispatch (Solar Replacement Case)

	OCT	NOV	DEC	JAN	FEB	MAR	APR1	APR2	MAY	JUN	JUL	AUG1	AUG2	SEP	AVG
Coal Generation	2783	2486	3041	2286	2131	1322	1196	290	97	285	645	1606	2069	2873	1709
Gas Generation	1441	1201	1983	1759	1406	787	696	506	460	505	609	810	971	1333	1081
IPP & SW Market	221	460	962	830	565	192	155	35	24	24	52	81	123	196	309
Wind Generation	1108	1145	1128	1202	1228	1455	1714	1754	1650	1572	1445	1316	1277	1100	1339
Solar Generation	2170	1135	776	1176	1536	2465	2978	3645	3579	4032	4030	3274	3458	2764	2534

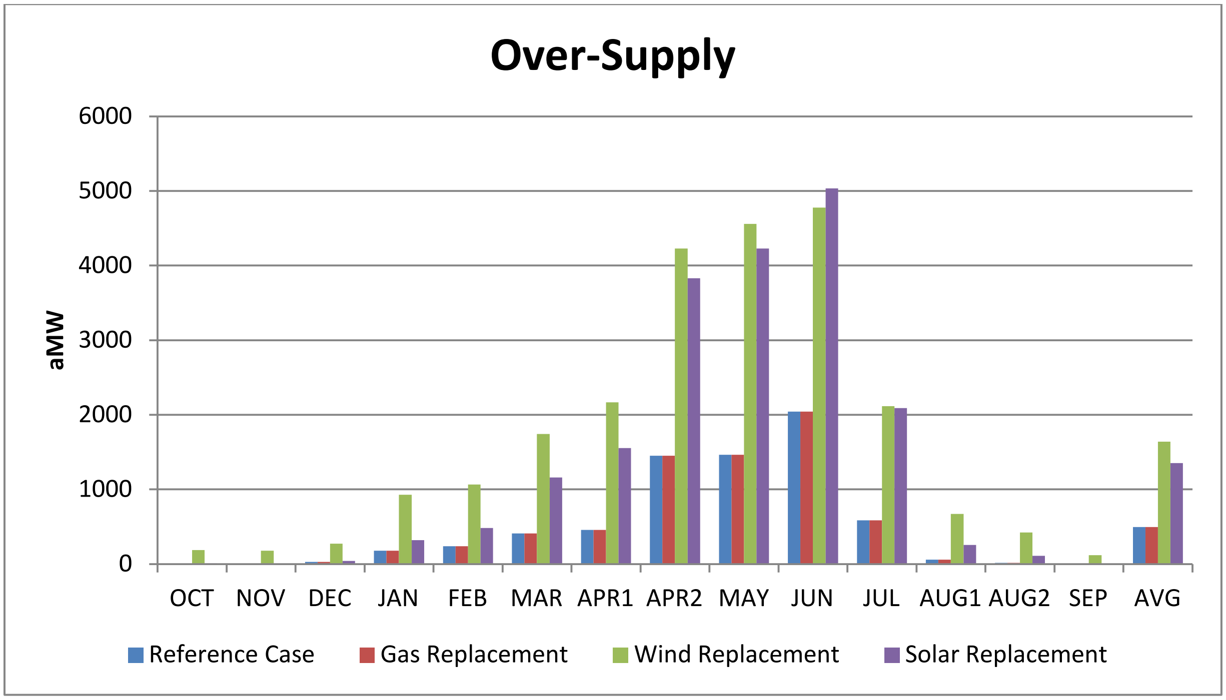
Conclusions for 2021

Most of the LOLP events in the 2021 study occur in January and February. Wind generation is negatively correlated to extreme weather conditions (which are likely to produce LOLP events) and wind produces less energy overall during the December to February time frame compared to the spring and summer. Solar energy production is also limited in the winter season by cloud cover and the low angle of the sun. Because of these factors, adding gas turbines into the 2021 assessment resulted in the lowest amount of installed capacity (1,150 MW) required to meet the 5 percent adequacy criterion as compared to wind (10,000 MW) which could not meet the criterion and solar (12,700 MW).

Adding large amounts of wind and solar also increases the oversupply conditions that occur when must-run resources, such as hydro (run-of-river hydro or hydro drafted for flood control), wind, and solar, produce more energy than the electric loads can absorb.

The reference case with the 8 percent LOLP has a base amount of oversupply due to hydro and the existing wind fleet. The gas replacement scenario does not add to the oversupply situation as these plants are shut-down during over-supply. The wind and solar scenarios more than double the average amount of oversupply in the region.

Figure 5: Expected Oversupply Energy by Month



The wind and solar cases also reduce the average amount of thermal generation (coal, gas, and thermal imports) required by the power system. The wind scenario on average reduces thermal generation by 35 percent and solar scenario on average reduces thermal generation by 33 percent compared to the gas replacement scenario.

Table 11: Reduction in Thermal Dispatch for Wind and Solar Cases

	Thermal Generation (aMW)		
	Gas Replacement	Wind Replacement	Solar Replacement
Coal	2331	1539	1709
Gas	1768	1166	1081
IPP/Import	516	296	309
Total	4616	3001	3099
Reduction from Gas:		35%	33%

FUTURE ASSESSMENTS

The Council will continue to annually assess the adequacy of the region's power supply. This task is becoming more challenging because the power system is evolving to one that is even more complex than just five years ago. Because of increasing amounts of variable generation, combined with changing patterns of electricity demand, utility planners and operators must carefully assess what resources are needed in reserve so demand can be met minute to minute. The current adequacy assessment assumes a certain amount of within-hour balancing reserves, but it's not certain this will be sufficient for future power supplies. Regional planners are evaluating various methods to quantify and plan for these flexibility needs and the Council will include new data when available.

Another emerging concern is the lack of access to supplies for some utilities due to insufficient transmission or other factors. For the current adequacy assessment, the Northwest region is split into two subsections 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. For the next adequacy assessment, scheduled for release in May 2015, the Council is planning to separate the southern Idaho area from the currently modeled eastern region.

Issues identified by the Council's Resource Adequacy Advisory Committee to consider for next year's assessment include:

- Reviewing the Council's adequacy standard – is there a better metric?
- Quantifying market friction (which could limit the availability of shareable resources) and possible solutions to reduce market friction
- Coordinating with the existing Western Gas-Electric Regional Assessment Task Force to develop gas-limited scenarios and assess their effect on adequacy
- Reevaluating the availability of imports

q:\jf\raac\2015\2020-21 sos report final 100815.docx