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



May 1, 2018

**MEMORANDUM**

**TO:** **Power Committee Members**

**FROM:** **John Fazio, Senior Systems Analyst**

**SUBJECT:** **Resource Adequacy Assessment for 2022-23**

## BACKGROUND:

Presenter: John Fazio

Summary: For the regional power supply to be deemed adequate under the Council's standard, its Loss of Load Probability (LOLP) must be 5 percent or less. The Northwest power supply is expected to remain adequate through 2020. In 2021, however, with the retirement 1,330 megawatts of capacity, the LOLP is projected to be over 6 percent, meaning that the supply would no longer be deemed adequate. In 2022, with an additional retirement of 479 megawatts, the LOLP increases to about 7 percent. The projected LOLP for 2023 remains at about 7 percent because no major retirements are planned and the net load growth (after accounting for energy efficiency savings) is very low.

These results assume the Council's energy efficiency targets through 2023 will be achieved. However, the region will have to acquire on the order of 300 megawatts of capacity by 2021 and an additional 300 to 400 megawatts by 2022 in order to maintain adequacy through 2023. Utility integrated resource plans identify about 800 megawatts of dispatchable resource capacity that should be available by 2021. In addition, the Council has identified about 400 megawatts of demand response to be available by 2021.

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It should be noted that the LOLP can change significantly if either demand or market conditions change. For example, the 2023 LOLP can range from a low of 3.5 percent (low load and high market) to a high of 14 percent (high load and low market), although those cases would be extremely rare. The need for additional capacity to maintain adequacy ranges from zero (low load and high market) to 1,650 megawatts (high load and low market).

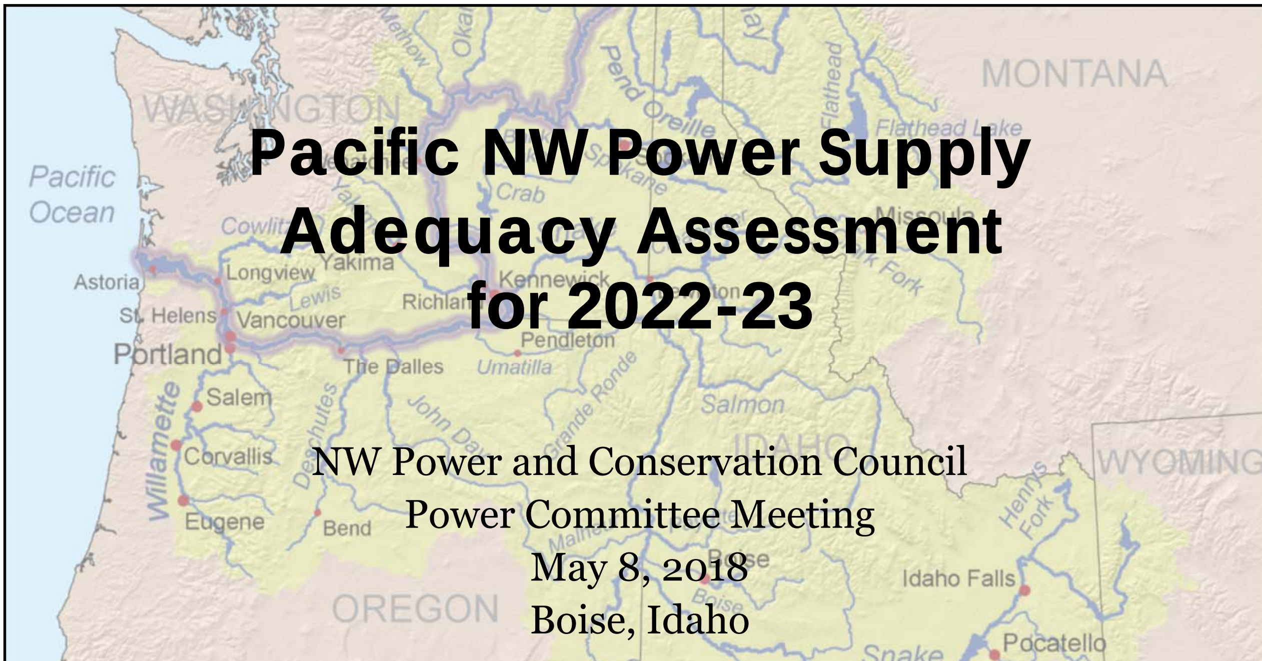
Relevance: Besides being an early warning to ensure that the regional power supply remains adequate, the Council's adequacy standard is converted into Adequacy Reserve Margins (for both energy and capacity) that are fed into the Regional Portfolio Model to ensure that resource strategies developed by that model will produce adequate supplies.

Workplan: A.5.2 Complete Annual Adequacy Assessments

Background: In 2011, the Council adopted a methodology to assess the adequacy of the Northwest's power supply. The purpose of this assessment is to provide an early warning should resource development fail to keep pace with demand growth. The Council's standard defines an adequate power supply to have no more than a 5 percent chance of a resource shortfall in the year being assessed. This metric is commonly referred to as the loss-of-load probability (LOLP) and any future power supply with an LOLP greater than 5 percent is deemed to be inadequate. The Council makes this assessment every year, investigating the adequacy of the power supply five years into the future.

More Info: For more information please go to the Resource Adequacy Advisory Committee webpage:

http://www.nwcouncil.org/energy/resource/home/




# Pacific NW Power Supply Adequacy Assessment for 2022-23

NW Power and Conservation Council
Power Committee Meeting
May 8, 2018
Boise, Idaho



## Outline

- 2023 Resource Adequacy Assessment
  - Loss of load probability
  - Capacity needed for adequacy
  - Potentially available resources
  - Monthly adequacy assessments
  - 2023 NERC adequacy metrics
- Key Sensitivity Studies
- Additional Slides
  - Resource and load updates
  - Nameplate vs. "Firm" capacity (for the tech savvy)

## 2023 Resource Adequacy Assessment

- LOLP — Max for adequacy 5%
  - 2018-20 < 5%
  - 2021 6+% — 1330 MW retired: Boardman, Centralia 1
  - 2022 7% — 479 MW retired: Colstrip 1 & 2, Pasco and N Valmy 1
  - 2023 7% — No major resource change
- Need[1] — ≈ 300 MW by 2021 (range 0 to 750 MW)
  300 to 400 MW by 2022 (range 0 to 750 MW)
- Available[2] — ≈800 MW of dispatchable + ≈400 MW of DR

[1]Capacity need is based on generic CT additions. Low-end need assumes low load and high SW imports and high-end need assumes high load and low SW imports.

[2]Available dispatchable capacity for 2021 is taken from the 2018 PNUCC NRF. The 400 MW of demand response is the remaining part of the 600 MW of estimated availability for 2021 from the Council's 7th power plan.



## 2023 LOLP Heat Map (%)

| SW Import (MW) | 1500 | 2000 | 2500 | 3000[1] |
|---|---|---|---|---|
| High Load (+2%) | 14.3 | 12.1 | 10.1 | 7.8 |
| Med Load | 11.0 | 8.6 | 6.9 | 5.1 |
| Low Load (-2%) | 8.0 | 6.4 | 4.9 | 3.5 |

[1]The "3000 MW import" case represents the maximum amount of market import capability from California. This is based on the Bonneville Power Administration's recommendation to use 3400 MW as the maximum S-to-N transfer capability for the transmission interties and accounts for approximately 400 MW of space required for firm capacity imports.

# 2023 Estimated[1] Capacity Need (MW)

| SW Import (MW) | 1500 | 2000 | 2500 | 3000 |
|---|---|---|---|---|
| High Load (+2%) | 1650 | 1500 | 1100 | 600 |
| Med Load | 1400 | 1050 | 650 | 50 |
| Low Load (-2%) | 950 | 550 | 0 | 0 |

[1]The amount of additional capacity needed in 2023 to maintain adequacy (i.e. an LOLP of 5%) is estimated by using a surrogate dispatchable resource, in this case a combined cycle combustion turbine. GENESYS studies were run for the “2500 MW import medium load” case and for the “1500 MW import high load” case to estimate nameplate capacity needed to get to 5% LOLP. Other values were estimated using linear interpolation and are rounded to the nearest 50 MW.



# Potentially Available Resources

## 2018 NRF Planned Resource Nameplate Capacity

| (MW) | **2021** | **2022** | **2023** |
|---|---|---|---|
| Solar | 0 | 266 | 266 |
| Hydro | 28 | 28 | 28 |
| Wind | 540 | 540 | 540 |
| Generic/Gas | 809 | 809 | 809 |
| Battery | 39 | 39 | 89 |
| **Total Nameplate** | **1416** | **1682** | **1732** |
| Firm Capacity[1] | 930 | 1000 | 1050 |
| Demand Response[2] | 400 | 400 | 400 |

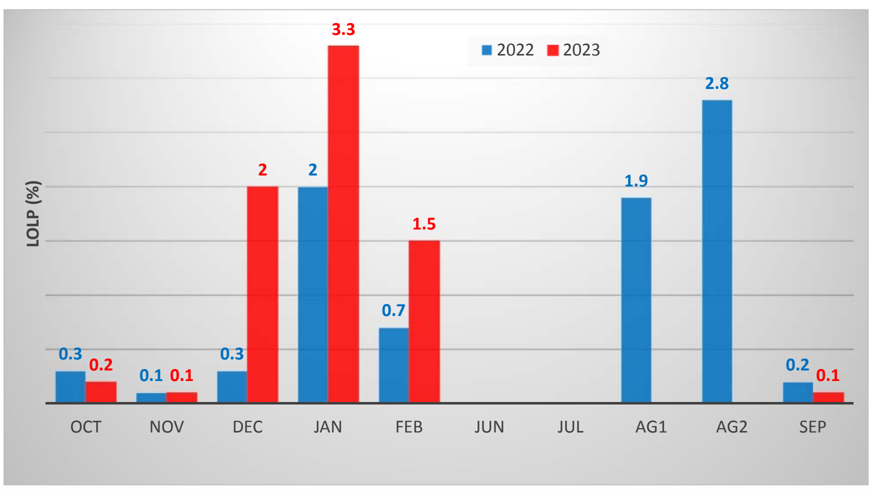
[1]Firm capacity is the amount of capacity that can be counted on for planning reserve margin calculations. It is often referred to as the effective load carrying capability (ELCC). See the last 2 slides for more detail.
[2]Available DR for 2021 is taken from the 7th power plan.

# Monthly Adequacy Assessments

| Period | 2022 | 2023 | Diff |
|---|---|---|---|
| October | 0.3 | 0.2 | -0.01 |
| November | 0.1 | 0.1 | 0.0 |
| December | 0.3 | 2.0 | 1.7 |
| January | 2.0 | 3.3 | 1.3 |
| February | 0.7 | 1.5 | 0.8 |
| June | 0.0 | 0.0 | 0.0 |
| July | 0.0 | 0.0 | 0.0 |
| August 1-15 | 1.9 | 0.0 | -1.9 |
| August 16-31 | 2.8 | 0.2 | -2.6 |
| September | 0.2 | 0.1 | -0.1 |



# 2022[1] vs. 2023 LOLP




[1]The 2022 assessment is based on a hybrid load forecast, which has a different load shape than the previously used STM forecast. Based on a RAAC recommendation, the 2023 assessment uses a revised STM, which includes EE in its structural equations.

# 2023 NERC Adequacy Metrics

| Metric | Definition |
|---|---|
| LOLEV (events/year) | **Loss of load events** = Total events divided by total number of games (event = contiguous set of curtailment hours ) |
| EUE (MW-hours) | **Expected Unserved Energy** = Total curtailment energy divided by the total number of games |
| NEUE (ppm) | **Normalized Expected Unserved Energy** = EUE divided by average annual load in MW-hours times 1,000,000 |
| LOLH (hours/year) | **Loss of load hours** = Total curtailment hours divided by total number of games |

| SW Import (MW) | 1500 | 2000 | 2500 | 3000 | 3500 |
|---|---|---|---|---|---|
| LOLEV (events/year) | 0.28 | 0.20 | 0.14 | 0.10 | 0.07 |
| EUE (MW-hours) | 11,450 | 8,440 | 6,190 | 3,908 | 2,516 |
| NEUE (ppm) | 61 | 45 | 33 | 21 | 13 |
| LOLH (hours/year) | 5.1 | 3.9 | 3.0 | 1.9 | 1.3 |

While NERC is NOT likely to establish metric thresholds (i.e. a standard), a commonly accepted threshold for LOLEV is 1-event-in-10 years or LOLEV = 0.1



# Key Sensitivity Studies

1. Temperature record length (88 vs. 77 years)

   Previously limited to 77 temperature-year profiles because temperature-correlated wind capacity factors were only available through 2005. Added historic wind CFs for 2006 through 2016 to give us 88 years.

2. Non-zero summer imports

   Previously assumed no summer peak-hour imports. Added 2500 MW of available summer imports from 7am to 2pm to reflect increasing California solar surplus.

3. Thermal resource balancing reserves

   Previously only accounted for hydro balancing reserves (INC and DEC). Added thermal resource INC reserves by derating specific thermal resources.

# Key Sensitivity Studies
## (Medium Load, 2500 SW Import)

| Metric | Ref Case 88 years | Case 1 77 years | Case 2 Summer Import | Case 3 Thermal INC[1] |
|---|---|---|---|---|
| LOLP (%) | 6.9 | 7.3 | 6.5 | 9.9 |
| CVAR_E (MW-Hour) | 121883 | 122915 | 121759 | 181828 |
| CVAR_P (MW) | 3216 | 3192 | 3214 | 3974 |
| EUE (MW-Hour) | 6190 | 6253 | 6170 | 9625 |
| LOLH (Hour) | 3.0 | 3.1 | 3.0 | 4.5 |
| LOLEV (Event/year) | 0.14 | 0.15 | 0.14 | 0.20 |

[1]It should be noted that even though the LOLP increases when applying thermal resource INC reserves, an argument can be made that these reserves would be used during an emergency.



# Additional Slides

# Resource and Load Updates

- Load Forecast
- Resources
  - Thermal resources
  - Wind
  - Solar
  - Standby resources
- Hydro operations
- Balancing reserves and hydro sustained-peak
- Firm contracts



# Load Forecast

- Used Council's Short-Term Load (STM) model instead of Hybrid model
- Added EE and codes & standards to STM structural equations
- Increased temperature year range from 77 to 88 years (1929-2005 to 1929-2016)

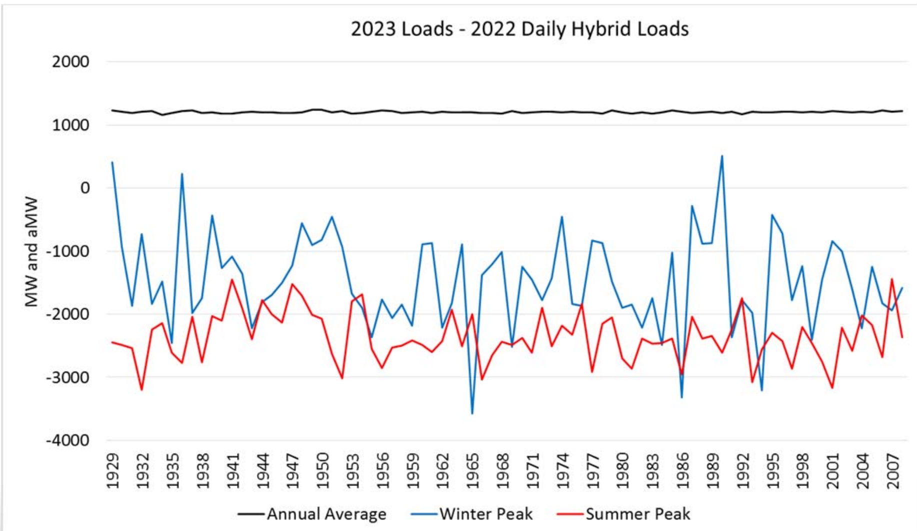
# 2022 vs. 2023 Load Forecast

| Load | 2022 Hybrid | 2022 STM | 2023 STM |
|---|---|---|---|
| Annual average load (aMW) | 20,150 | 21,307 | 21,353 |
| Winter average peak (MW) | 35,121 | 33,568 | 33,649 |
| Summer average peak (MW) | 29,112 | 26,670 | 26,755 |

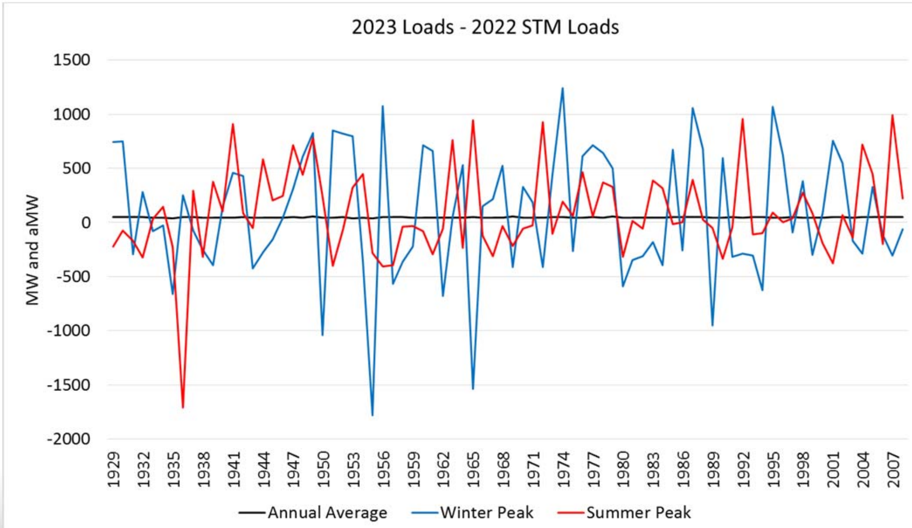
- The use of the STM load model instead of the Hybrid model for this year's assessment is supported by RAAC comments.
- While the 2022 LOLP results using the Hybrid and STM load forecasts were nearly identical, the additional capacity needed to comply with the Council's 5% LOLP standard was much higher for the STM loads (roughly 1,200 MW for the STM loads vs. 400 MW for the Hybrid loads).
- This is because the STM loads have a significantly higher annual average load (about 1,000 aMW higher), even though the Hybrid peak loads are higher and the Hybrid minimums are lower (see next slides).



# 2023 vs. 2022 Hybrid Load Forecast



# 2023 vs. 2022 Load Forecast





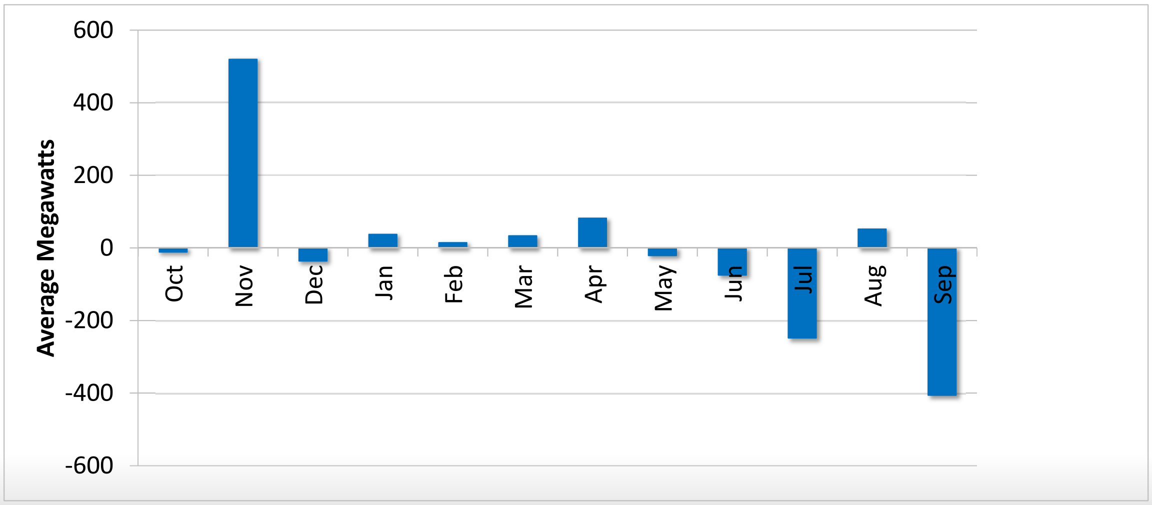

# Resource Changes 2022 to 2023

| Annual Values | 2022 | 2023 | Difference |
|---|---|---|---|
| Nuclear (MW) | 1,144 | 1,144 | 0 |
| Coal (MW) | 3,323 | 3,323 | 0 |
| Gas and Misc (MW) | 7,497 | 7,877 | 380 |
| IPP (MW) | 2,653 | 2,273 | - 380 |
| **Thermal Resource Total** | **14,661** | **14,661** | **0** |

| | | | |
|---|---|---|---|
| Wind Nameplate (MW) | 4,906 | 5,098 | 202 |
| Solar Nameplate (MW) | 407 | 550 | 143 |
| Winter Spot Imports (MW) | 2,500 | 2,500 | 0 |
| Winter Standby Cap (MW) | 661 | 740 | 79 |
| Summer Standby Cap (MW) | 1,079 | 1,140 | 61 |
| Standby Energy (MW-hours) | 41,900 | 41,900 | 0 |

# Difference in Hydro Generation

(2023 minus 2022)

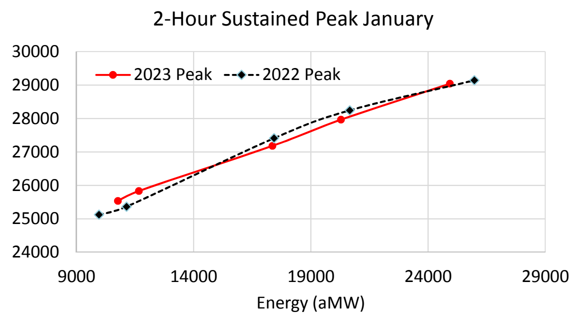


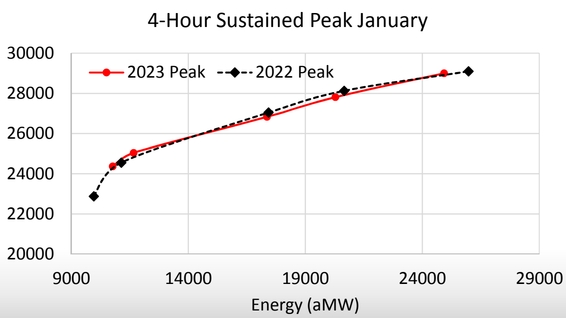


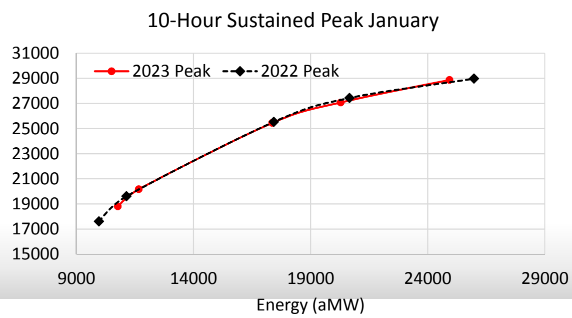

# BPA INC and DEC Balancing Reserves

| Period | 2022 INC | 2023 INC | 2022 DEC | 2023 DEC |
|---|---|---|---|---|
| Oct | 900 | 602 | 662 | 729 |
| Nov | 900 | 602 | 899 | 729 |
| Dec | 900 | 602 | 687 | 729 |
| Jan | 900 | 602 | 751 | 729 |
| Feb | 900 | 602 | 728 | 729 |
| Mar | 900 | 602 | 690 | 729 |
| Apr1 | 400 | 602 | 713 | 729 |
| Apr2 | 400 | 602 | 713 | 729 |
| May | 400 | 602 | 748 | 729 |
| Jun | 400 | 602 | 723 | 729 |
| Jul | 900 | 602 | 629 | 729 |
| Aug1 | 900 | 602 | 609 | 729 |
| Aug2 | 900 | 602 | 609 | 729 |
| Sep | 900 | 602 | 746 | 729 |

# January
# Hydroelectric Sustained-Peak Capability 2023 vs. 2022

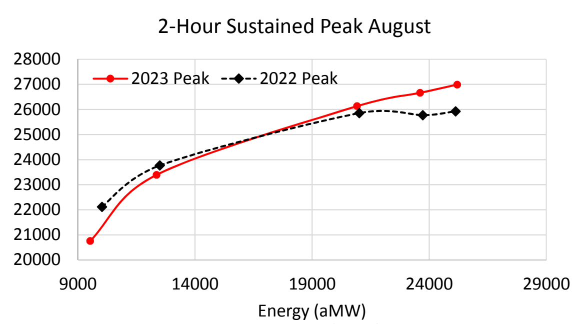


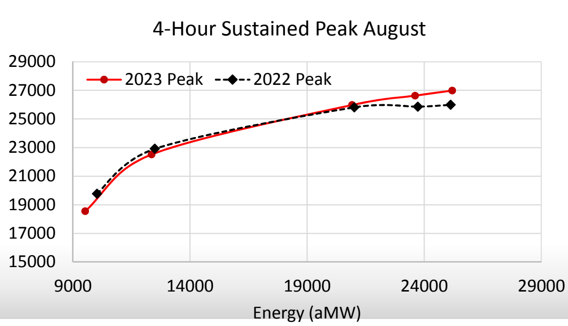



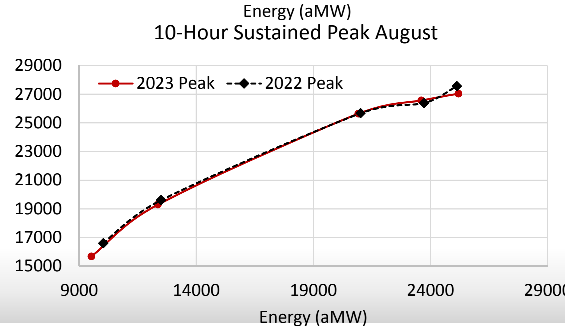






# August 1-15
# Hydroelectric Sustained-Peak Capability 2023 vs. 2022



# Firm Contracts (aMW)

| 2023 | Oct | Nov | Dec | Jan | Feb | Mar | Ap1 | Ap2 | May | Jun | Jul | Au1 | Au2 | Sep |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Imports | 22 | 40 | 51 | 65 | 71 | 63 | 30 | 30 | 30 | 39 | 28 | 21 | 21 | 16 |
| | | | | | | | | | | | | | | |
| PNW West/Canada | 455 | 455 | 455 | 455 | 455 | 455 | 473 | 437 | 455 | 455 | 479 | 568 | 572 | 455 |
| PNW West/S Cal | 21 | 18 | 13 | 7 | 11 | 13 | 23 | 27 | 29 | 28 | 28 | 18 | 23 | 22 |
| Total Exports | 476 | 473 | 468 | 462 | 466 | 468 | 496 | 464 | 484 | 483 | 507 | 586 | 595 | 477 |

| 2022 | Oct | Nov | Dec | Jan | Feb | Mar | Ap1 | Ap2 | May | Jun | Jul | Au1 | Au2 | Sep |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Imports | 9 | 17 | 21 | 27 | 30 | 26 | 13 | 12 | 13 | 16 | 11 | 9 | 9 | 7 |
| | | | | | | | | | | | | | | |
| PNW West/Canada | 434 | 476 | 435 | 476 | 454 | 454 | 413 | 413 | 498 | 454 | 442 | 511 | 509 | 429 |
| PNW West/S Cal | 32 | 18 | 16 | 14 | 13 | 22 | 27 | 30 | 29 | 92 | 196 | 23 | 31 | 29 |
| Total Exports | 466 | 494 | 451 | 490 | 467 | 476 | 440 | 443 | 527 | 546 | 638 | 534 | 540 | 458 |

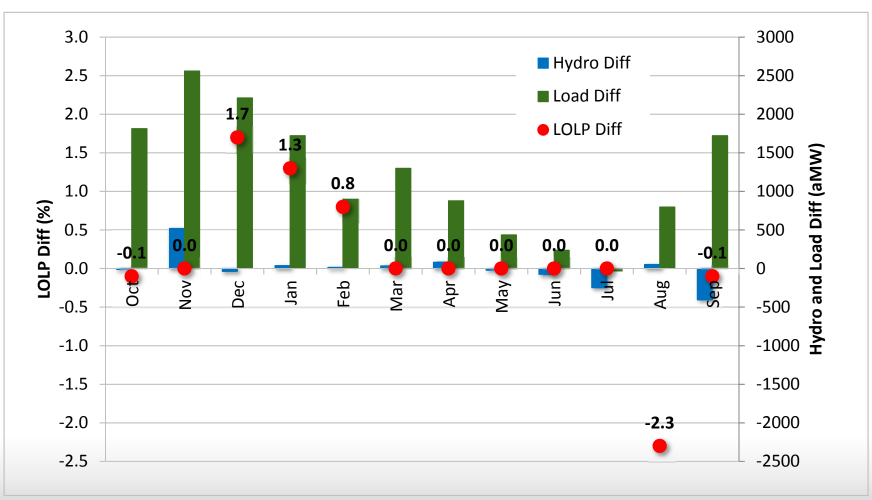
Difference in Firm Contracts (2023 – 2022)

| 2023 – 2022 | Oct | Nov | Dec | Jan | Feb | Mar | Ap1 | Ap2 | May | Jun | Jul | Au1 | Au2 | Sep |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Imports | 13 | 23 | 30 | 38 | 41 | 37 | 17 | 18 | 17 | 23 | 17 | 12 | 12 | 9 |
| | | | | | | | | | | | | | | |
| PNW West/Canada | 21 | -21 | 20 | -21 | 1 | 1 | 60 | 24 | -43 | 1 | 37 | 57 | 63 | 26 |
| PNW West/S Cal | -11 | 0 | -3 | -7 | -2 | -9 | -4 | -3 | 0 | -64 | -168 | -5 | -8 | -7 |
| Total Exports | 10 | -21 | 17 | -28 | -1 | -8 | 56 | 21 | -43 | -63 | -131 | 52 | 55 | 19 |



# Difference in LOLP, Load & Hydro

## (2023 minus 2022 Hybrid)



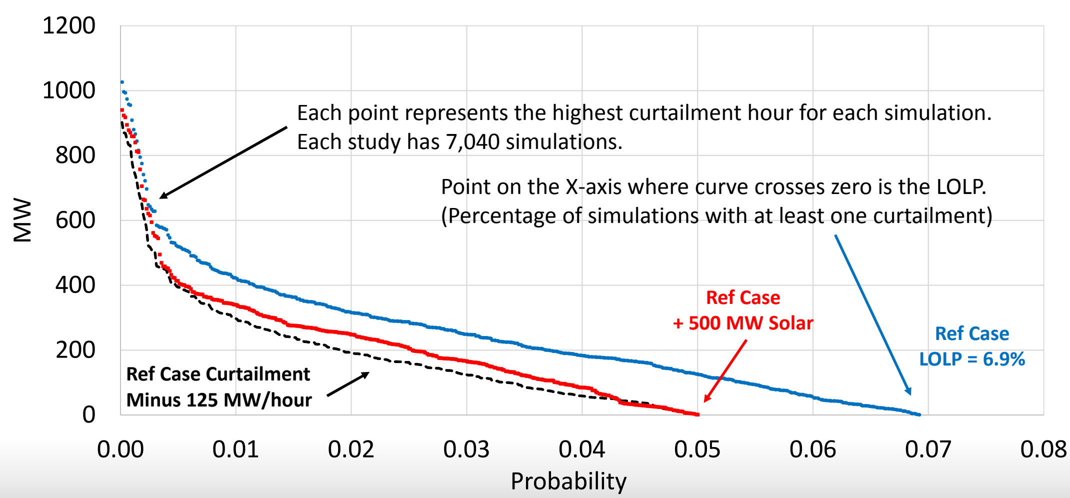
# Nameplate vs. Firm Capacity

- Firm capacity is capacity that can be counted on for system expansion plans (e.g. in planning reserve margin calculations). It is often referred to as the effective load carrying capability (ELCC).
- Peak-hour curtailment duration (PHCD) curves can be used to calculate ELCC.
- PHCD curves are created by taking the highest single-hour curtailment for each game and sorting from highest to lowest.
- Assuming that each game has an equal likelihood of occurrence, assign the highest curtailment a probability of 1/games. Assign the second highest curtailment a probability of 2/games, etc.
- Plot the PHCD curve with curtailment MWs on the y-axis and probability on the x-axis. The probability at any point on the x-axis represents the likelihood of the peak-hour curtailment being the corresponding value on the y-axis or higher.
- The point on the x-axis where the curve crosses zero is the LOLP.
- The effective capacity needed for adequacy is the amount of capacity (MW) that when added mathematically to each peak-hour curtailment shifts the duration curve so that it crosses the x-axis at 5%.

- Next, add incremental amounts of a new resource until the LOLP drops to 5%.
- The ELCC for this resource is calculated by taking the ratio of effective capacity divided by nameplate capacity (referred to as the associate system capacity contribution or ASCC) and multiplying this ratio by the resource nameplate capacity.
- In the example on the next slide, the effective capacity is 125 MW, the amount of added solar resource to get to a 5% LOLP is 500 MW, so the ASCC is 125/500 or 0.25. The ELCC for a 100 MW nameplate capacity solar array is 100 times the ASCC or 25 MW.
- What this means is that adding 100 MW of solar nameplate contributes 25 MW of firm capacity.



# Peak-Hour Curtailment Duration Curves



## 2023 Resource Adequacy Assessment
## Executive Summary

Accounting for existing resources, planned resources that are sited and licensed, and the implementation of the Council's energy efficiency targets, the Northwest power supply is likely to become inadequate by 2021, primarily due to the retirement of the Centralia 1 and Boardman coal plants (1,330 megawatts combined). The loss-of-load probability (LOLP) for that year is estimated to be over 6 percent, which exceeds the Council's standard of 5 percent.

By 2022 the LOLP is projected to rise to about 7 percent, due to the additional retirements of the North Valmy 1 coal plant, the Colstrip 1 and 2 coal plants and the Pasco gas-fired plant (479 megawatts combined). In 2023 the LOLP is expected to remain at about 7 percent. The increase in LOLP would be higher except for the Council's targeted energy efficiency savings and savings from codes and federal standards. Additional capacity needed to maintain adequacy is estimated to be on the order of 300 megawatts in 2021 with an additional need for 300 to 400 megawatts in 2022.

It should be noted that this analysis examines the adequacy of the aggregate regional power supply. Individual utilities within the Northwest have varying resource mixes and loads and, therefore, have varying needs for new resources. In aggregate, Northwest utilities have identified 540 megawatts of wind, about 800 megawatts of dispatchable capacity and other small resources that could be developed by 2021, if needed.[1] These planned resources are not included in this assessment because they are not sited and licensed. Also excluded from this analysis are approximately 400 megawatts of demand response, which is the remaining part of the 600 megawatts identified in the Council's Seventh Power Plan as likely being available by 2021. While the Council believes this level of demand response will be available, it is not included in this analysis because of ongoing concerns regarding barriers to its acquisition.

While it appears that regional utilities are well positioned to face the anticipated shortfall beginning in 2021, different manifestations of future uncertainties could significantly alter the outcome. For example, the results provided above are based on medium load growth. Reducing the 2023 load forecast by 2 percent[2] results in an LOLP of just under 5 percent and has roughly the same effect as adding 650 megawatts of capacity. Increasing the load forecast by 2 percent[3] raises the 2023 LOLP to about 10 percent and almost doubles the amount of capacity needed (from 650 to 1,000 megawatts) to satisfy the Council's 5 percent standard.

The reference case results assume a conservative level of available Southwest market supply. Increasing that supply by 500 megawatts lowers the 2023 LOLP to a little over 5

[1] Source: Pacific Northwest Utilities Conference Committee's 2018 Northwest Regional Forecast.
[2] This means multiplying the load in each hour of the year by 0.98.
[3] This means multiplying the load in each hour of the year by 1.02.

percent and only about 50 megawatts of additional capacity are needed to meet the Council's 5 percent standard. However, decreasing the Southwest market supply by 500 megawatts raises the LOLP to 8.6 percent and would require 1,050 megawatts of additional capacity.

Reducing the load forecast by 2 percent and increasing the Southwest market availability by 500 megawatts lowers the LOLP to 3.5 percent and no additional capacity is required for adequacy. However, increasing the load forecast by 2 percent and decreasing the Southwest market by 500 megawatts raises the LOLP to 12 percent and requires about 1,500 megawatts of additional capacity to satisfy the Council's adequacy standard.

Potential shortfall events for the 2023 operating year occur almost exclusively during December, January and February. Event durations range from a single hour to over 24 hours and average about 20 hours. The most common event duration is 16 hours, which occur over the commonly defined peak hours of the day. Events also tend to have a uniform hourly magnitude because, whenever possible, the hydro system is operated in a way to spread out projected shortfalls evenly across the peak hours of the day. For example, it is much easier to resolve a flat 100 megawatt shortfall over the 16 peak hours of the day than a 2-hour 800 megawatt shortfall.