Northwest Power and Conservation Council

May 6, 2025

MEMORANDUM

TO: **Council Members**

FROM: **Jennifer Light, Director of Power Planning**

SUBJECT: **Columbia Generating Station Extended Power Uprate**

BACKGROUND:

Presenter: Ryan Egerdahl, Manager of Long Term Power Planning, and Carla Essenberg, Market Policy & Pricing Operations Research Analyst, Bonneville Power Administration

Summary: Bonneville has been considering a potential extended power uprate to Columbia Generating Station (CGS). The extended power uprate is an option that will increase the generating capacity of CGS by around 160 MW. In addition to conducting a business case analysis, Bonneville modeled the CGS uprate as a resource option to be considered in its 2024 Resource Program Addendum Study. Bonneville staff will present the analysis and results of this 2024 Resource Program Addendum Study.

Relevance: The Resource Program is informational and not a decision-making process, nor a decision document, but the results do inform Bonneville's resource acquisition strategies. For the past several years, Bonneville has been working with its customers and the region on new contracts for the post-2028 period. These conversations have highlighted that Bonneville may need to acquire additional resources to serve its obligations under these new contracts. In addition to acquiring new resources, Bonneville has considered upgrades to its existing system as a means of serving those obligations. The CGS extended power uprate

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is one of these. By including this as an option in the Resource Program analysis, Bonneville is able to compare the costs and benefits of this option along-side the potential for new resources.

Background: Bonneville presented its 2024 Resource Program results to the Council in January 2025. At that time, Bonneville staff noted that it planned to conduct an addendum study focused on considering the CGS extended power uprate. This addendum study focuses on potential resource needs for Tier 1 augmentation.[1] Bonneville's initial analysis presented in January showed that the Tier 1 augmentation could best be met through a mix of renewable energy resources (wind, solar, and geothermal). Based on Bonneville's estimated costs and other assumptions around the CGS extended power uprate, this addendum analysis shows that including the uprate would reduce the overall cost for meeting those Tier 1 system needs.

More info: Bonneville's 2024 Resource Program results were presented to the Council at its January 2025 meeting. Bonneville presented the results of its CGS extended power uprate business case and the 2024 Resource Program Addendum Study at a public workshop on April 8, 2025.

[1] Under the Bonneville Provide of Choice Policy, which is guiding its post-2028 contract development, Bonneville has agreed to sell 7250 aMW of power at a Tier 1 rate. Based on the existing system capability, Bonneville may need to acquire additional resources to meld into the existing Federal Base System in order to meet that obligation. This study focused specifically on the question of which resources would be least-cost to meet that obligation.

B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

2024 Resource Program Addendum Study: CGS Extended Power Uprate

Presented to the Northwest Power and Conservation Council

May 14th, 2025

Agenda

- Describe T1 System Augmentation Sensitivity Needs
- Review candidate resource options and characteristics
- Explain results of CGS Extended Power Uprate (EPU) Sensitivity study

BPA Generating Resource Portfolio

- 31 Federal Hydro Projects
  - US Army Corps of Engineers (operator)
  - US Bureau of Reclamation (operator)
  - ~ 22,000 MW nameplate capacity
- Columbia Generating Station
  - Nuclear power plant near Richland, WA
  - Energy Northwest (operator)
  - ~1,169 MW capacity
- Other
  - Small amounts of wind and non-federal hydro

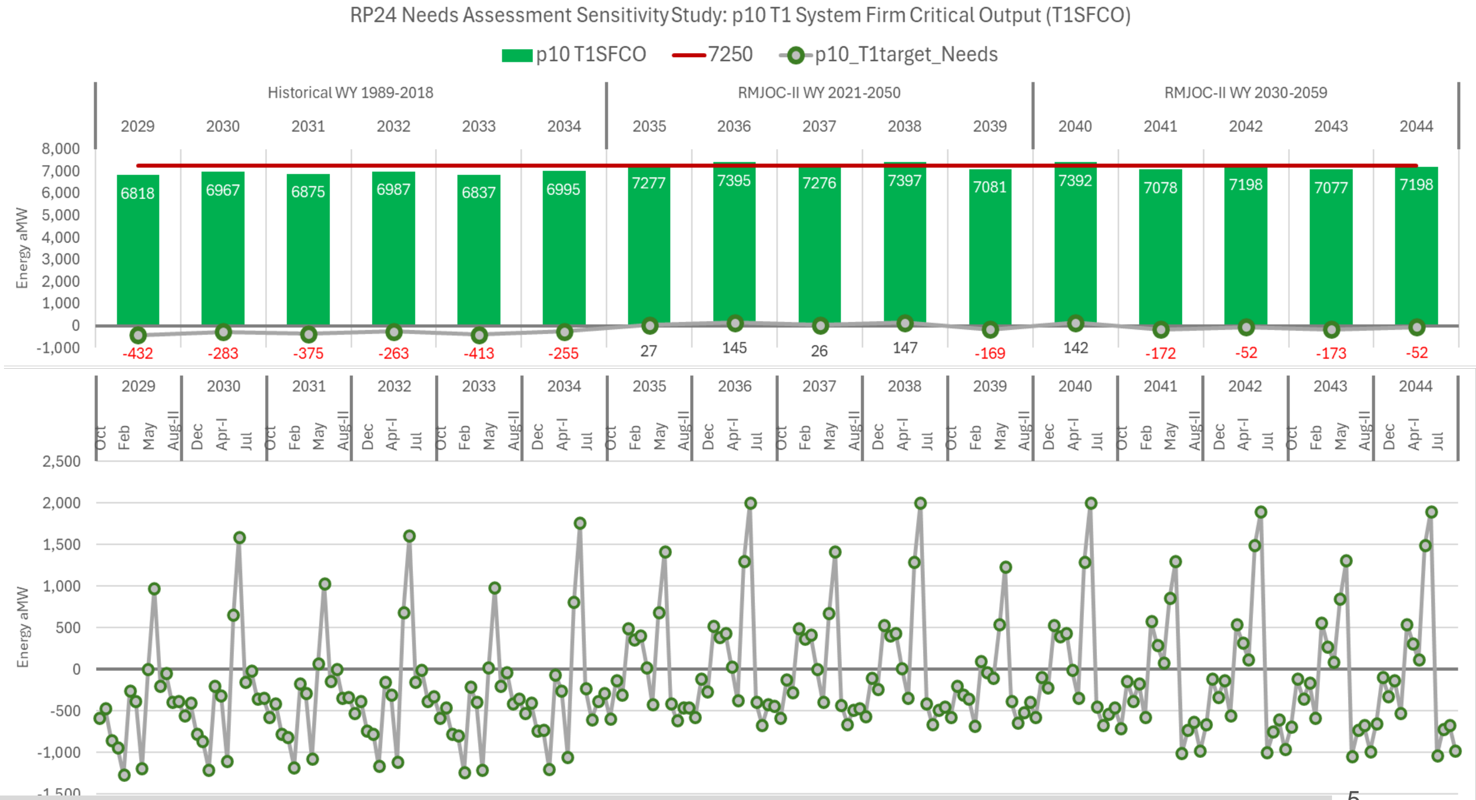
Nuclear Energy: Columbia Generating Station

T1 System Size Needs - Overview

- Methods:
  - T1 System Firm Critical Output (T1SFCO) is calculated at the hourly level as the sum of existing hydro and non-hydro resource capabilities net of transmission losses, USBR sales, CER exports, and Slice product returns
  - Target T1SFCO is 7250 annual aMW shaped to reflect hourly shape of T1 obligations
  - Metric is the month-average delta between the hourly forecast and target T1SFCO under P10 hydro conditions
- Main findings:
  - Near term annualized needs range from 250 – 400 aMW, which imply much larger monthly needs during late winter and before spring runoff begins
  - Magnitude of needs in outyears significantly influenced by streamflow assumptions under RMJOC-II, ranging from 72 to 272 aMW

T1 System Size Needs - Results

- Annualized view of output (top) masks variation at monthly level (bottom)
- Fluctuations in resource capability due to CGS refueling, system operations, and streamflow sets over 20-yr study horizon



Key Differences, Business Case vs RP

- The business case evaluates potential for energy revenues to outweigh project costs over a range of potential costs and conditions.

- RP analysis is deterministic and selects resources / projects based on meeting BPA needs at the lowest total portfolio costs.
  - Sensitivities are limited.
  - Solutions can and do include resources with costs higher than revenues.

- For this study of increasing Tier 1 system size, the CGS EPU is only competing against other supply side resources (discussed on the following slide). We assume that market purchases / energy efficiency / demand response cannot contribute to these needs.
  - Generation in excess of the needs is valued at forecast Mid-C prices and reduces total portfolio costs.

- The Resource Program does not consider explicit carbon reduction benefits beyond what's included in the market price study.

Candidate Resources

- Only supply-side resources located in the Mid-C region are allowed to contribute to meeting T1 System Size needs:
  - CGS EPU
  - Other candidate resources:
    - Solar, wind, 6- and 12-hour storage, hybrid (solar + 4-hour storage), geothermal, SMR
    - Available to come online in 2026*, 2031*, 2037, and 2043
    - Interconnection cost is set 8x higher for additions beyond 300 MW (wind, storage), 450 MW (hybrid, SMR), or 900 MW (solar) per period**
    - Geothermal limited to 100 MW per period
    - We do not include options for contracting with existing resources or for acquiring output from resources for less than their expected plant life

*Geothermal is not available in 2026. SMR is not available in 2026 or 2031.

**Interconnection costs were estimated in collaboration with Transmission SMEs. They can vary substantially across projects and are difficult to estimate.

RP2024 Sample years

2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045

20XX Indicates sample years that are explicitly modeled.

- Sampling is used to facilitate and simplify extending the Resource Program horizon from 10 to 20 years.
- Resources that come online in 2031 are intended to more broadly represent resources that could come online any time from 2029-2034. Online years of 2037 and 2043 are also representative for their respective sample windows.
  - The model has not been altered to account for the potential need to rely on market purchases for 2029-2030 needs in case the CGS uprate is selected, or if other resources have actual online dates later then FY2029.

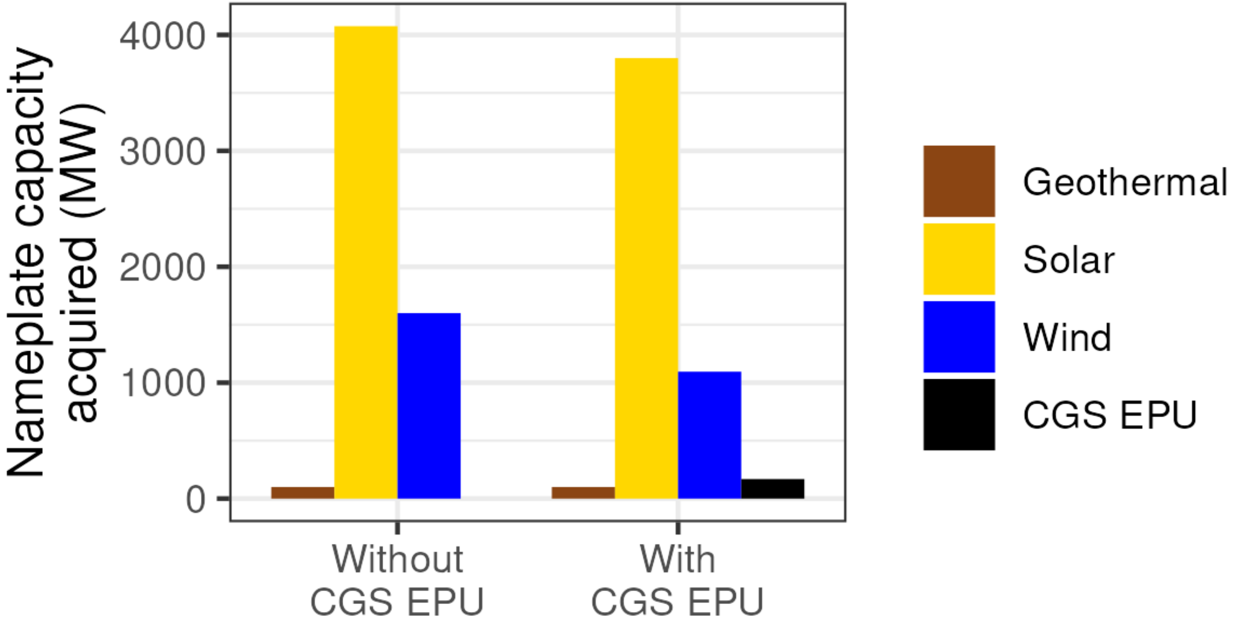
Sensitivities and Results

Sensitivity	Plant life (years)	Fixed costs	CGS EPU selected in least-cost portfolio?	Reduction in total portfolio cost* (billions of $, NPV, 2024)
13-year	13	Current best estimate**	Yes	0.9
33-year	33	Current best estimate**	Yes	1.3
13-year, cost over-run	13	2 x current best estimate**	Yes	0.1
33-year, cost over-run	33	2 x current best estimate**	Yes	0.9

*Reduction in total portfolio cost = Portfolio cost without CGS EPU – Portfolio cost with CGS EPU

**Current best estimate P50 overnight capital cost in $2025 (~$700M). This is inclusive of project estimate, uncertainty with project estimates, and discrete initiative portfolio risks.

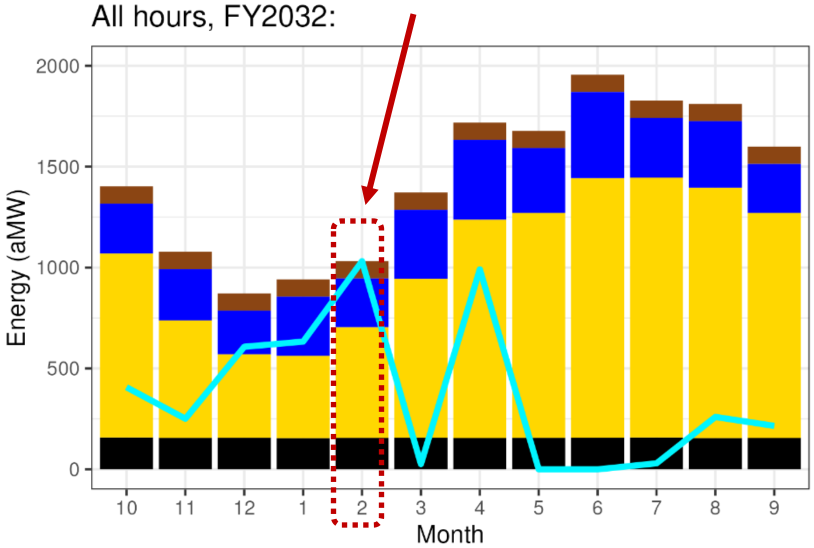
Least-cost portfolios with and without CGS EPU

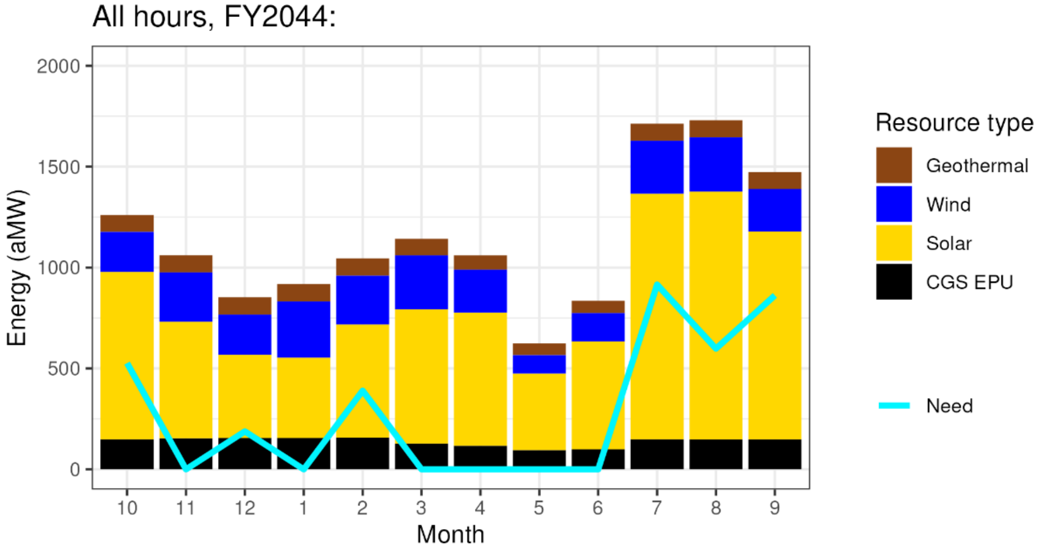


aMW generation compared to P10 monthly needs

Model is building to meet February needs in 2031-2

Acquired generation greatly exceeds needs in almost all months even under P10 conditions





Note that needs have not been adjusted for sensitivities that assume that CGS does not extend its license (i.e., 13 year / FLR cases). Total portfolio costs and resource acquisitions for these cases are likely substantially understated.

Key Takeaways

- BPA and its customers have agreed to increase the Tier 1 System Size for the post 2028 contract period to an annual output of 7,250 aMW
- Near term annualized needs for more power range from 250 – 400 aMW, with much larger monthly needs during late winter and before spring runoff begins
- The CGS EPU is included in the least-cost portfolio for meeting these needs, reducing the amount of new solar and wind capacity the agency would need to acquire if the EPU were not available

Questions and reactions?

CGS EPU cost assumptions

IRA treatment	PTC
PTC (2025 $/MWh)	$28.25
Tax liability	WA generation (Privilege) tax
FOM (2025 $/kW-year)	$0
VOM (2025 $/MWh)	$0
Overnight capital costs (2025 $/kW)	$4,324
Weighted average capital cost (nominal)	3.40%
Plant life (years)	13 or 33 years
Construction time (years)	7 years**

*WA generation tax = 1.07 x annual generation (MWh) x wholesale preference rate ($/MWh, nominal) x 1.5%. Wholesale preference rate is assumed to have a constant real value of $34.33/MWh (2025 $)

**Some construction costs (2.1% of total) extend into years 8 and 9, after uprate comes online

Capacities available of resources other than CGS EPU

Resource type	Nameplate capacity available per start year* and type	Special restrictions in 2026 or 2031
Solar	300 MW + 1000 MW at higher interconnection cost** at each of 3 locations	Only 600 MW available per location in 2026
Wind and 6- and 12-hour storage	300 MW + 1000 MW at higher interconnection cost	Only 600 MW available in 2026
Hybrid (solar + storage)	450 MW + 1500 MW at higher interconnection cost	Only 900 MW available in 2026
Geothermal	100 MW	Not available in 2026
SMR	450 MW + 1000 MW at higher interconnection cost	Not available in 2026 or 2031***

*Start years: 2026, 2031, 2037, 2043. ***We have also run a sensitivity in which SMR is available in 2031

**Higher interconnection cost is 8x higher than the interconnection cost used for the initial 300-450 MW