MEMORANDUM

TO: Power Committee

FROM: Jennifer Light, Director of Power Planning

SUBJECT: Bonneville Resource Program: Needs Assessment and Market Assessment

BACKGROUND:

Presenter: Ryan Egerdahl and Eric Graessley, Bonneville Power Administration

Summary: Bonneville is working on its upcoming Resource Program, aiming to complete the work in the fall of this year. Bonneville’s resource program is an analysis of potential system needs and resources available to meet those needs. Ryan Egerdahl and Eric Graessley will join the Power Committee to share the results of the needs assessment and market assessment that will be used in the upcoming resource program.

Relevance: The Resource Program is an analysis by Bonneville of its potential system needs and the resources available to meet those needs. 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.

The upcoming Resource Program is anticipated to be completed this fall. This is expected to provide direct information into Bonneville’s post-2028 contract negotiations. Based on post-2028 discussions to date, there is an expectation that Bonneville may need to acquire resources beyond conservation. This Resource Program will provide some insight to
customers around potential resources that may need to be acquired under future contracts.

Background: The needs assessment and market assessment are two studies conducted by Bonneville for its Resource Program that are similar to studies performed here at the Council in power planning. The needs assessment focuses on Bonneville’s existing resources and future obligation, including any sensitivities around future obligation, to identify needs. The Resource Program is then ultimately looking for a resource solution to fill those needs. The market assessment looks at the market depth and cost, providing insight on potential market availability as one of the solutions (in addition to conservation, demand response, and generating resources) considered in the Resource Program. Council staff have worked closely with Bonneville staff on technical questions and assumptions for these two studies.

As noted above, Bonneville’s resource acquisition is to be consistent with the Council’s plan under the Northwest Power Act. The current plan, the Council’s 2021 Power Plan, provides specific recommendations to Bonneville. The recommendations around resource acquisitions include:

- Acquire between 270 and 360 aMW of cost-effective energy efficiency by the end of 2027, of which at least 243 aMW must be from programmatic savings, and at least 865 aMW by 2041
- Work to enable and encourage its customer utilities to pursue low-cost and high value demand response, including time-of-use rates and demand voltage regulation
- Look to mid-term and long-term market resources for additional energy when needs are beyond those met by the recommended energy efficiency and demand response resources
- Compare market products, both in price and capacity, to renewable power purchase agreements to ensure that the lowest-cost product that suffices to meet any need is identified.

Today’s Agenda

• Review key takeaways from BPA Power Service’s 2024 Resource Program studies:
  – Needs Assessment: Long-term surplus/deficit inventory positions associated with scenarios and sensitivities
  – Market Assessment: Expected WECC-wide buildout, MidC hub market price forecast, and estimates of market availability for BPA resource adequacy
RP24 Needs Assessment Results
Needs Assessment Overview

Objective

• To understand expected long-term inventory position of BPA Power services under varying load and resource conditions

Methods

• Compare hourly forecasts of BPA power service obligations and resource capabilities to develop set of metrics which describe expected future needs
Needs Assessment Metrics

- **Annual Energy**
  - Evaluates the annual average energy surplus/deficit under p10-by-month critical water conditions

- **P10 Heavy Load Hour (HLH)**
  - Evaluates the monthly average surplus/deficit over heavy load hours (hours ending 7-22, Mon – Sat, excluding holidays) under p10-by-month critical water conditions

- **P10 Superpeak (SPK)**
  - Evaluates the monthly average surplus/deficit over the six peak HLH per weekday (Mon – Fri) under p10-by-month critical water conditions
  - The ~120 superpeak hours per month are a subset of the ~384 heavy load hours month

- **18-Hour Capacity**
  - Evaluates the monthly average surplus/deficit over six peak load hours per day across three-day extreme weather load events under median water (p50) conditions
    - Cold Snap – temperatures from January 2024 event for Dec/Jan/Feb
    - Heatwave – temperatures from June 2021 event for July/August
Major Updates for RP24

- Conduct separate analysis in MidC and SWEDE zones
- Incorporate impacts to generation from variation in fish operations by modeling return to CRSO preferred alternative after expiration of RCBA ("12/14 Agreement")
- Streamflows informed by climate change through both recent historical record (2020 Level Modified Flows) and RMJOC-II projections
- Updated modeling of hourly hydro generation (RiverWare)
Key Takeaways

1. Deficits generally increased relative to 2022 Resource Program (RP22) due to increased load obligations and decreased resource generation.

2. P10 SPK metric experiences the most significant increase in deficits due to updated hourly modeling.

3. 18hr capacity metric shows summer deficits for overall system and Mid-C, while SWEDE zone sees deficits in outyears winter months.

4. P10 HLH metric remains most constraining governing metric in most periods.
P10 Energy Metrics Results
Annual System surplus/deficit
RP24 Base and Fast Transition Scenarios
RP2024 Time Horizon and Sample Years

**Fish Operations:**
- RCBA (December 14th Agreement)
- Columbia River System Operations (CRSO)

**Hydro:**
- RMJOC-II Flows (2020-2049 & 2030-2059)

Indicates simulated years.
- 2026-2028 all separately modeled
- 2031 & 2032 represent 6 years, 2029 to 2034
- 2037 & 2038 represent 6 years, 2035 to 2040 (pairs of years to incorporate odd/even operations)
- 2043 & 2044 represent 5 years, 2041 to 2045

**HYDSIM Run**
- 2020-2029
- 2030-2039
- 2040-2049
- 2050-2059

Subset of results used for 2035-2040
Subset of results used for 2041-2045
Columbia Generating Station refueling schedule contributed to the every-other-year effect.

LLH shows largest deficits due to load factoring behavior embedded in hourly modeling.

HLH the most constrained between HLH & SPK.

Variability in results for RMJOC-II years highlights uncertainties from incorporating climate change projections into hydro studies.
Deficits are larger relative to RP24 Base case from increased obligation forecasts and unchanged system capabilities.
P10 HLH
Metric Results
Monthly System surplus/deficit
RP24 vs RP22
Overall, RP24 more deficit than RP22
• Largest deficit shifted from October to Apr-II; largest surplus shifted from May to Jun
• Aug-I inversion can be attributed to RCBA (“12/14 Agreement”) operation change
• Loads increased from RP22 to RP24 overall while resource capabilities decreased due to various operational changes
P10 SPK
Metric Results
Monthly System surplus/deficit
RP24 vs RP22
RP20 used HOSS for hourly hydro modeling

RP22 and RP24 used Riverware

RP24 refined peaking behavior of projects which resulted in SPK deficits more aligned with pre-RP22 results
P10 SPK Surplus/Deficit – FYs 26 & 27

- Aug-I inversion attributed to RCBA ("12/14 Agreement") operation change
BONNEVILLE POWER ADMINISTRATION

P10 SPK Loads & Resources – FYs 26 & 27

- Larger SPK loads in RP24 summer months than RP22
- Reduced hydro capabilities in many months due to refined hourly hydro modeling to better capture operational and fish constraints
P10 HLH &
P10 SPK
Monthly System surplus/deficit

RP24 Base and Fast Transition Scenarios
Key Takeaways

Overall results are consistent with prior Resource Program Needs Assessment results showing P10 HLH metric deficits to be the most constrained periods and conditions for BPA to meet its obligations.

Notable exception: average SPK deficits consistently exceed average HLH deficits in Apr-II.
Overall, HLH more deficit than SPK except for Apr-II in non-RMJOCII FYs
Following RP24 Base trends, HLH more constrained than SPK with Apr-II the exception.
FT has slightly deeper deficits/smaller surpluses than RP24 Base
P10 Energy Metrics – by Zone

RP24 Base and Fast Transition Scenarios
Western Resource Adequacy Program (WRAP) likely requires BPA load in each zone to be served with a combination of physical resources (with qualifying capacity) and firm transmission (from resource to the load).

Currently, without B2H, the SWEDEN region has heavily constrained transmission paths.

Mid-C (outside of the shaded enclosure)

**BPA SWEDEN (South-West East Diversity Exchange)**

Pink lines are BPAT, purple dots are Hydropower, purple lines are other transmission, P# is a WECC path
Transfer from Mid-C to SWEDE by Design

- This calculation takes place at the hourly level
- Without transfers from MidC, SWEDE is always deficit

1. Is SWEDE deficit?
   - NO: Do nothing, record result
   - YES: Supply from Mid-C to SWEDE until one of the following requirements is met:
     1. SWEDE s/d = 0, or
     2. Exceeding transmission limit (1000MW)

Supply MidC to SWEDE even if MidC is deficit already
RP24 Base Mid-C Energy metric results

- MidC results reflects previously shown system-wide trends
- RP24 FT Mid-C results (not shown here) follows RP24 Base results, with increased deficits in all metrics, respectively.
By design, Swede is net zero for all metrics.

RP24 FT SWEDE results (not shown here) are the same as Base, with all metrics achieving surplus/deficit balance due to the build-in transfer design.
• Morgan Stanley contract (Intra_Regional transfer (IN)) expires after April 2026.
18hr Capacity Metric
Monthly System surplus/deficit
RP24 Base and Fast Transition Scenarios
Key Takeaways

- The 18hr “capacity” metric evaluates the monthly average surplus/deficit over six peak load hours per day across three-day extreme weather load events.
- Load excursions under extreme weather events modeled using actual temperatures from Jun21 and Jan24 heat/cold events, respectively.
- Resources modeled under p50 hydro to show sustained peaking capabilities of system with typical fuel supply.
- Results show System-wide 18hr deficits during summer months for FY2035+.
Example of Extreme Weather Load Excursion

Note: This shows a reference winter event.
Capacity 18Hr: System Surplus/ Deficit aMW

- Jul & Aug started to see deficits of 500 MW to 1500 MW in RMJOC-II outyears
- Winter months (Dec/ Jan/ Feb) did not show any deficits
• P10 HLH still most constraining metric across months studied for 18Hr metric
• FT (not pictured) shows same relationship amongst metrics with deeper deficits/smaller surpluses from increased loads
18hr Capacity Metric – by Zone

RP24 Base and Fast Transition Scenarios
Key Takeaways

MidC experiences 18hr deficits during summer months for FY2035+ in RP24 Base and FT

SWEDE experiences small but meaningful 18hr deficits during winter months as early as FY28 in RP24 FT

Zonal approach assumes no expansion in transmission capabilities from MidC to SWEDE over the entire 20-yr study horizon
• 18hr capacity Mid-C results matches System results
• No deficits in winter months
• Summer months deficits only observed in RMJOC-II outyears
• 18Hr Metric in SWEDE only have deficits in the Winter Months
  – Deficits in Base case begins to show in RMJOCII out years.
  – FT case, non-RMJOCII out years begins to show small deficits.
• No deficits observed in summer months.
RP24 Sensitivity Study Results
Sensitivities for Needs Assessment

Original Sensitivity Plan
- Flat block/NR Load Service
- Above-RHWM Load Service
- B2H Delay
- T1 System Size

Updated Sensitivity Plan
- Block High Load Adder
- Shaped Medium Load Adder
- B2H Delay (no change)
- T1 System Size (no change)
Load Adders
Load Adders - Overview

• **Methods:**
  – High load adder is a flat block load added to every hour uniformly across the year.
  – Medium load adder is shaped load added to each hour. Shaping is based on current Slice Block load shape.

• **Main findings:**
  – Under High block load adder sensitivity, p10 HLH metric will see deficits in all periods of the year as early as FY2027
  – Under Medium shaped load adder sensitivity, p10 HLH metric deficits increase by ~30% by FY2031 from RP24 Base case, and deficits swell to more than double by FY 2044
• Medium load adders (shaped) presents a gradual load increase:
  – Starts in FY2029 with additional 400 aMW and ends in FY2045 with additional 2,500 aMW

• High load adders (block) are more aggressive
  – Starts in FY2026 with additional 975 aMW reaching almost 4,800 additional aMW by FY2040.

• RP24 FT load is slightly higher than RP24 Base
High load growth implemented by shifting all hours by adder

Medium load growth implemented by scaling all hours by implied annual growth rate

Shaping preserves load factor while shifting increases it
Load Adders in p10 HLH surplus/deficit – RP24 Base
Load Adders in p10 HLH surplus/deficit – RP24 Base

- MidC follows System trend
- SWEDEx begin to see meaningful deficits in RMJOCII outyears
T1 System Augmentation Metric Results
**Methods:**

- Forecasted 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 forecasted hourly shape of T1 obligations.

- Metric is the month-average delta between the hourly forecasted and target T1SFCO under P10 hydro conditions.

**Main findings:**

- Annualized needs of close to 500 aMW in Historical WY FYs, which imply much larger monthly needs during fall and winter.

- Magnitude of needs significantly impacted by streamflow assumptions under RMJOC-II, ranging from 72 to 272 aMW.
Bonneville Power Administration

T1 System Size Sensitivity Results

2029: 6,715 T1FCO, 6,839 T1_needs, 6,717 T1_Systemsize
2030: -535 T1FCO, -411 T1_needs, -533 T1_Systemsize
2031: -535 T1FCO, -411 T1_needs, -533 T1_Systemsize
2032: -425 T1FCO, -572 T1_needs, -413 T1_Systemsize
2033: -425 T1FCO, -572 T1_needs, -413 T1_Systemsize
2034: 7,118 T1FCO, 7,238 T1_needs, 6,918 T1_Systemsize
2035: -132 T1FCO, -12 T1_needs, -332 T1_Systemsize
2036: -132 T1FCO, -12 T1_needs, -332 T1_Systemsize
2037: 7,099 T1FCO, 7,099 T1_needs, 7,099 T1_Systemsize

Graph showing T1FCO, T1_needs, and T1_Systemsize over years 2029 to 2044.
• Shaped monthly T1_target annualized to 7250 aMW.
• Gap between T1_target line and T1SFCO bar indicates T1_target_needs.
Boardman to Hemingway (B2H) Delay - Overview

• **Methods:**
  – Analyze impact to 18hr capacity metric from 2-yr delay in B2H energization leading to temporary periods of curtailed transmission capability from MidC to SWEDZ zones

• **Main findings:**
  – Delay coupled with expiration of Morgan Stanley contracts causes small but meaningful deficits during extreme weather events during Jan/Feb in SWEDZ zone
  – Deficits appear under RP24 Base and FT load forecasts as early as FY27
B2H Delay Planning

- Assume B2H delayed until July 2028.
  - Reduce transmission capacity from 1000 MW firm to 900 MW.

- Extreme Weather Load
- p50 Resource

Calculate S/D in Mid-C & SWEDE

Is SWEDE deficit?

- NO
  - Do nothing, record result
- YES
  - Supply from Mid-C to SWEDE until one of the following requirements is met:
    1. SWEDE s/d = 0, or
    2. Exceeding transmission limit
       - Prior to July 2028 = 900 MW
       - Post July 2028 = 1000 MW

Supply MidC to SWEDE even when MidC is deficit already
• Mid-C saw deficits only in summer months of RMJOC-II outyears.
• SWEDE only saw deficits in winter months towards the outyears.
B2H Delay Results – 18Hr Capacity

- With reduced transmission capacity to 900MW:
  - RP24Base: Jan in 2027 & 2028 showed additional deficits
  - RP24FT: Jan and Feb in 2027 & 2028 show additional deficits
  - Morgan Stanley contract expires in April 2026.
Questions?
RP24 Market Assessment Results
Key Takeaways

- Northwest average price forecast levels have increased moderately, and the distribution of prices across ranges of potential future conditions has increased substantially.

- Inflation Reduction Act (IRA) impacts (including electrification load increases) significantly increase expected buildouts throughout the WECC.

- The combination of additional new resource buildout and improved modeling of short duration storage resource operation resulted in an increase to projected market depth available to meet BPA energy needs.
Market Prices, Key Inputs, and LTCE
Indicates simulated years.

- 2031 & 2032 represent 6 years, 2029 to 2034
- 2037 & 2038 represent 6 years, 2035 to 2040
- 2043 & 2044 represent 5 years, 2041 to 2045

The sensitivity will be part of our automated checks and will help understand which resources are being selected because of out-year (2035 and beyond) assumptions.
Mid-C / NW Average Prices

Price increases are more pronounced from early fall through winter

Delta, Alternative - RP2024

Monthly Flat $/MWh, Nominal
Mid-C / NW Price Distributions

Flatter and wider distributions mean larger price swings are occurring with more moderate changes to conditions from one period to the next.
Larger buildouts throughout the WECC combined with improved modeling of short duration storage increase limits relative to RP2022
BPA Uses of Aurora Long Term (LT) Price Forecasts

- Resource Program
- Competitiveness / LT rates
- Associated Lack of Market (LOM) spill impacts projected inventories
- Treaty negotiations
- Alternative fish operations
- Independent hydro efficiency upgrade evaluation
- CGS economic analysis
- Evaluate impacts of various carbon policies
- LT build assumptions also influence rate case price forecasts
- Inform other, one-off LT valuations
Aurora is a versatile production cost model widely used to evaluate the economics, evolution, and operation of wholesale electricity grids (utilities, regulators, system operators, planning entities, consultants, and investment firms across the globe).

Production cost models solve for the least cost method of meeting load, given resource and transmission constraints (resource limits and variable costs, line capability, wheeling costs, and losses), and assume the marginal cost (cost of the next incremental MW) of producing and delivering energy is a good proxy for energy prices.

We calibrate the model based on recent Day Ahead (DA) prices (2018-2022), but we do not explicitly account for the following:

- Market design differentiation (NO: forward curves / firm contracts / DA - RT markets & forecast error, source & sink, local commitment considerations), all of the WECC is effectively modeled as a single ISO (centrally optimized and dispatched)
- Behavioral components of power markets (in reality, bids may differ from actual marginal cost)
- AC flows / nodal prices, and transmission system is fixed over time (Aurora has the capability, not yet implemented)
- Ancillary services (again, Aurora has the capability, not yet implemented)
- No thermal resource duct firing / peak heat rates / unit dependency

Aurora is a deterministic model, we produce a distribution of price forecasts by using a Monte Carlo technique that draws from historical variation of: loads, hydro generation, gas prices, transmission capability, wind generation, and CGS availability.

We use a 46-zone topography of the Western Interconnection that is mostly aligned with BAs (see next slide), and solve for hourly prices.
Aurora Topology

Zone Short Names
01 Alberta
02 APS
03 BC
04 IID
05 LADWP
06 PG&E North
07 PG&E ZP26
08 SCE
09 SDG&E
10 BANC
11 PG&E Bay Area
12 TIDC
13 EPE
14 Baja
15 NV North
16 NV South
17 NW MT
18 Olympia
19 PAC W
20 Puget North
21 Avista
22 BPA IDMT
23 BPA OR
24 BPA WA
25 Chelan
26 Douglas
27 Grant
28 ID Power FE
29 ID Power MV
30 ID Power TV
31 PAC E ID
32 PAC E UT
33 PAC E WY
34 Portland GE
35 Puget East
36 Seattle CL
37 Tacoma
38 PS CO
39 PS NM
40 Salt River
41 Tucson
42 VEA
43 WAPA CO
44 WAPA LwCO
45 WAPA UprMO
46 WAPA WY

Line Rating (MW)
- 1,000
- 2,000
- 3,000
- 4,000
- 5,000 +

Zone Load (aMW)
3,000
6,000
9,000
12,000
Aurora and Market Design (WEIM / Resource Adequacy)

- Aurora does not explicitly account for differences in market structure (bilateral vs ISO or different time horizons). It simulates the interconnect as if the WECC were centrally dispatched in a single ISO, and we assume that prices will tend to converge on the marginal cost of generating & delivering electricity.

- Aurora has capabilities to model components of the Western Energy Imbalance Market (WEIM), but these tend to be computationally prohibitive and incompatible with existing models and methodologies. For example:
  - Sub-hourly (incompatible with risk and rate case models, requires significant investment)
  - Nodal topography (Locational Marginal Prices—LMP, including congestion, this change requires significant investment)
  - Can use commitment logic to lock in DA commitment, and add deviations load and renewable resources + reliability commitments to better approximate Real Time (RT) – DA dynamics

- Alternatively, attempting to modify Aurora to depict price differences resulting from the current bilateral structure of NW markets would be highly speculative (we could adjust wheeling adders… but by how much?)

- Aurora assumes regions will meet reliability targets in a coordinated, efficient manner. Effectively, the base assumption is that Resource Adequacy (RA) efforts are successful and well-designed throughout the interconnection

Ultimately, we are not making any adjustments to account for possible differences resulting from participation in Western Energy Imbalance Market (WEIM) or Western Resource Adequacy Program (WRAP)
Aurora Inputs

• Calibration
• Negative Prices
• Gas Prices
• Clean Policy
• Loads & Electrification
• Transmission Builds
• Long Term Capacity Expansion (LTCE)
There are two main reasons Aurora price forecasts are wrong:

1) Get the fundamentals* wrong

2) Get the relationship between fundamentals and prices wrong (not capturing important details of how markets and the grid work / behavioral effects)

Benchmarking (running Aurora with actual fundamentals and comparing results to actual prices) allows us to isolate and address the 2nd problem through calibrating thermal resource bid behavior

* ‘Fundamentals’= loads, hydro generation, gas prices, transmission capability, renewable generation, etc.
Negative Prices

- **Main drivers: policy.** Incentives and requirements introduce costs to curtailing renewable resources
  - Forgone RECs / PTCs (IRA) / PPA revenue / Potentially having to build additional resources
  - ‘replacement cost’ of renewable energy

- Generally, consultants and other production cost modelers *do not* include negative prices

- **BPA models all renewable resources bidding at ~negative $23/MWh**

- We include mechanisms to reflect maximum hydro spill up to latest TDG limits and set BPA BA wind to curtail at $0/MWh, approximating Oversupply Management Protocol (OMP) effects. All other hydro is set to -$25/MWh, to curtail after renewables.

![Negative Prices, Observed and Assumed](image)

BPA OMP weighted avg price: ~ -$29/MWh
CAISO Negative DA Bids

Most negative bids seem to be solar, bids are getting more negative recently.

Nearly 5 GW bidding at \(-30/\text{MWh}\). Roughly 1 GW bidding at \(-150/\text{MWh}\).
Increase in RP2024 avg forecast gas price driven mostly by increases in upper bound risk included in the distribution of forecast prices.
Clean Policy

- Including the IRA resulted in very significant increases in renewable buildout
  - Modeled as production tax credit at the base level for solar and wind (PTC tends to yield more value for these resources), and 30% ITC for all other eligible resources.
  - Assume benefits will begin to taper off in 2035.

- Modeling is focused on capturing supply-side policy requirements and includes the following:
  - WA's RPS, CETA, and carbon prices
  - OR RPS and decarbonization requirements
  - CA Carbon prices and SB100
  - Alberta RPS and carbon prices
  - Best estimates of all WECC state, utility, and municipal RPS and clean standards (see next slide)

- Rely on other studies to estimate policy impacts on the load side, discussed in later slides
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The Fast Transition (FT) represents a scenario where all states in the WECC transition to mostly zero emission (ZEM) resources by 2050.

The FT is not a net zero study and modeling continues to struggle to achieve 100% zero emission scenarios.
While the WECC load forecast has increased from electrification, these estimates are more conservative than other projections that capture greater electrification impacts from decarbonization of other sectors.
Loads and Electrification

- **RP2024 Includes Increased Electrification**
  Consistent with the BPA load forecast, WECC load forecasts were adjusted to account for increased electrification largely relying on the EIA 2023 AEO, which leveraged NREL electrification studies to help capture IRA impacts.

- **NREL Electrification Futures Study** includes increased loads due to electrification from four sources:
  - Transportation
  - Commercial
  - Residential
  - Industrial

- **Electrification adders are flat increases to load and do not include modifications for hourly shaping**

- **RP2024 Fast Transition** uses the increased load values from RP2024 plus an adjustment factor to capture higher load forecast values, consistent with BPA load forecasts in the needs assessment.
New Transmission Builds

- B2H (2027)
- Gateway West (2026 to 2030)
- Gateway South (2025)
- TransWest Express (2028)
- SunZia (2027)
- North Gila-Imperial Valley (2026)

Does not include potential increases in PNW transfer capabilities from BPA investments

Line Rating (MW)
- 1,000
- 2,000
- 3,000
- 4,000
- 5,000 +

Zone Load (aMW)
- 3,000
- 6,000
- 9,000
- 12,000

Zone Short Names
01 Alberta
02 APS
03 BC
04 IID
05 LADWP
06 PG&E North
07 PG&E ZP26
08 SCE
09 SDG&E
10 BANC
11 PG&E Bay Area
12 TIDC
13 EPE
14 Baja
15 NV North
16 NV South
17 NW MT
18 Olympia
19 PAC W
20 Puget North
21 Avista
22 BPA IDM
23 BPA OR
24 BPA WA
25 Chelan
26 Douglas
27 Grant
28 ID Power FE
29 ID Power MV
30 ID Power TV
31 PAC E ID
32 PAC E UT
33 PAC E WY
34 Portland GE
35 Puget East
36 Seattle CL
37 Tacoma
38 PS CO
39 PS NM
40 Salt River
41 Tucson
42 VEA
43 WAPA CO
44 WAPA LwCO
45 WAPA UpMO
46 WAPA WY

Does not include potential increases in PNW transfer capabilities from BPA investments.
New Resources and Emerging Tech

- Continue to rely on two types of clean, firm flexible resources to achieve clean policy goals and maintain system reliability:
  - **Base**: Very high fixed cost, low variable cost resource. Modeled after Small Modular Reactor (SMR), also comparable to traditional fossil fuel base resource with Carbon Capture & Sequestration (CCS)
  - **Peaker**: Low fixed cost, high variable cost resource. Modeled after hydrogen (H2) combustion turbine with onsite electrolysis and storage, also ~comparable to combustion turbine running on other bio/renewable fuels / traditional peaking resource with CCS

- Other new resource options also included solar, wind, four and eight hour Battery Energy Storage Systems (BESS), limited offshore wind, small amounts of geothermal, and limited natural gas (NG) where not policy restricted.
Aurora Resource Build: LT Capacity Expansion

1. Start with existing resources

2. Lock in high likelihood builds and retirements over the duration of the next rate period (through 2028) – sources include IRPs, data from consultants, EIA, and the BPA generation interconnection queue (exceptions being Diablo Canyon retirement, some once through cooling (OTC) generation in CA, and Site C in BC)

3. Allow Aurora to build and retire additional resources based on economics, ensuring pool planning reserve margins are satisfied and all relevant state policies (Renewable Portfolio Standards (RPS) / zero emission targets) are met
   - Use dynamic peak credits for variable resources (wind and solar), updated iteratively
   - Get policy constraint shadow prices which should help inform expectations of costs of policy compliance and negative price behavior
Cumulative WECC (US) Builds and Retirements (2020 Start)
Incremental WECC (US) Builds and Retirements by Year (RP2024)
Price increases are more pronounced from early fall through winter

Delta, Alternative - RP2024
Flatter and wider distributions mean larger price swings are occurring with more moderate changes to conditions from one period to the next.
Relative to RP 2022, increased levels of storage buildout and better modeling of storage behavior moderates diurnal impacts of significant variable resource buildouts.
Key Market Price Uncertainties

- Clean policy and system reliability are assumed to be maintained over the study horizon. A reduced clean policy scenario (slower transition) has not been modeled for RP 2024.

- Additional load risks:
  - Have not included rapid load increases from data centers or other sources.
  - Electrification levels and differing impacts on seasonal/diurnal loads.

- Other than NW hydro, potential climate change impacts to WECC loads and resources are largely not captured.

- New resource risks: other new technologies / cost reductions in new resources or cost increases / lack of new resource availability from supply chain or transmission restrictions.

- Impacts from longer duration / seasonal storage or changes in demand-side behavior that could mitigate occurrence of negative prices.

- Changes in ancillary service requirements associated with greater reliance on variable res
Market Depth
Market Limits in Aurora

- ‘Market’ definition: any combination of NW energy acquisitions from less than 5 years out, down to and including real-time, based on the projected marginal cost of producing and delivering energy.

- Prior to the 2018 Resource Program, market limits were set using historical liquidity assessments and SME judgment.

- 2018 changed to rely on a fundamentals-based method using Aurora, primarily to capture more forward-looking considerations.
Fundamental Method Review

We’re trying to find the difference between regional energy availability (considering physical load resource balance and ignoring contractual obligations) when all participants / BAs plan and build for zero market reliance*, and when all regional participants increase market reliance right up to the reliability threshold (building fewer new resources / retiring more resources than the ‘no reliance’ base). Keep in mind:

- **Relying on the market does not increase WECC loads.** Our expectations of loads is not changing, it’s a question of which resources will serve loads and whether we can serve expected load with fewer resources than a zero market reliance base.

- **Relying on the market does not require regional surplus generation** (even when the region just meets reliability requirements, there’s still significant room for market reliance by leveraging load and resource diversity within and among regions).

*Zero market reliance for the region means that each BA builds resources to meet 100% of their individual needs (energy, capacity, and clean policies). This produces an overbuilt system for the region.*
PNW Region

Zone Short Names
01 Alberta
02 APS
03 BC
04 IID
05 LADWP
06 PG&E North
07 PG&E ZP26
08 SCE
09 SDG&E
10 BANC
11 PG&E Bay Area
12 TiDC
13 EPE
14 Baja
15 NV North
16 NV South
17 NW MT
18 Olympia
19 PAC W
20 Puget North
21 Avista
22 BPA IDMT
23 BPA OR
24 BPA WA
25 Chelan
26 Douglas
27 Grand
28 ID Power FE
29 ID Power MV
30 ID Power TV
31 PACE ID
32 PAC E UT
33 PAC E WY
34 Portland GE
35 Puget East
36 Seattle CL
37 Tacoma
38 PS CO
39 PS NM
40 Salt River
41 Tucson
42 VEA
43 WAPA CDO
44 WAPA LoCO
45 WAPA UpMO
46 WAPA WY

Line Rating (MW)
- 1,000
- 2,000
- 3,000
- 4,000
- 5,000+

Zone Load (aMW)
3,000
6,000
9,000
12,000
1. Start with our base resource build and assume this reflects zero market reliance in the region (this is the key shortcoming)

2. Add incremental load increases to approximate greater resource retirements / fewer resource additions associated with higher levels of regional market reliance

3. On a monthly basis, determine level at which greater market reliance causes region to exceed 1 day in 10 years (2.4 hours / year) Loss of Load Expectation (LOLE)

4. Allocate a share of the market reliance to BPA and accept this as our market reliance limit
Base, Zero Market
Reduce Energy Until LOLE

Zero Market Reliance Build
- BPA
- Rest of Region

1 in 10 LOLE Threshold

Allocation
BPA Market Depth

Larger buildouts throughout the WECC combined with improved modeling of short duration storage increase limits relative to RP2022
• RP2024 assessment is more dependent on assumed overbuild of the WECC.

• Assumes benefits of market reliance are allocated by share of regional load, ignoring contractual obligations and potential for free riding / planning misalignments (different metrics, forecast methodologies, etc).

• Aurora is simplistic depiction of the grid (no nodal topology/AC flows) and operations—might overestimate resource capabilities / underestimate ability to better utilize existing resources.
  – Single time step (~Aurora runs are most analogous to DA market) misses impacts of load / renewable forecast error.
  – No ancillary services (do we need more resources or can we just run the system with more reserves?).

• Risk modeling in Aurora has room for improvement.
  – Models operate independently and rely on historical, observed fundamental variation.
  – Resource outages are not stochastic (other than CGS).
  – No pipeline outages / derates (potentially overestimates reliability contributions of NG resources).
Questions?
Next Steps

- **Public Workshop Schedule**
  - August 2024: Resource Solutions for all scenarios and sensitivities

- **Final publication of 2024 Resource Program expected in September 2024**
# Resource Program and Provider of Choice

## 2024 Resource Program

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- **2024 RP Development Processes**
  - Stakeholder Engagement continues (Spring/Summer 2024)
  - 2024 RP Doc. Published *(Sep 2024)*

- **Final Policy & ROD (Mar 2024)**

- **Policy Implementation and Contract Development (Mar 2024 - Sep 2025)**
  - Contracts Signed *(Dec. 2025)*

- **Power Deliveries Under New Contracts Begin (Oct. 1, 2028)**

## 2026 Resource Program

- **2026 RP Development Processes**
  - 2026 RP Doc. Published *(Sep. 2026)*
Get in Touch

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