BONNEVILLE POWER ADMINISTRATION

BP-26 Rate Case Workshop

September 25-26, 2024

(Day 1)

Agenda – Sept 25 (Day 1) – Hybrid

BP-26 Pre-Proceeding Workshop		
Time*	Topic	Presenter
9:00 – 9:10 a.m.	Introduction, Meeting Protocols, Comments and Agenda	Daniel Fisher
9:10 – 10:30 a.m.	Power Rates Follow Up: • WRAP • UAI • Demand Rate • Tier 2	 Steve Bellcoff Leon Nguyen Garth Beavon Scott Reed
10:30 – 10-40am	**Break**	
10:40 – 11:10 a.m. 11:10 – 11:30 a.m. 11:30 a.m. – 12:30 p.m.	Power Rates - Electricity Market Price Power Rates - Net Secondary Revenue Forecast Power Rates – NR ESS	Eric Graessley James LaBelle IV Daniel Fisher & Peter Stiffler
12:30 – 1:30pm	**Lunch**	
1:30 – 2:00 p.m. 2:00 – 2:15 p.m. 2:15 – 2:45 p.m. 2:45 – 3:15 p.m.	Power Rates - FCRPS Balancing Capacity with New Canadian Agreement Power Rates – Transmission Costs in Power Rate Power Rates Follow Up - Risk Power Rates Follow Up - Gen Input Capacity Cost	Juergen Bermejo Stephanie Adams Zach Mandell Jonathan Ramse
	Closing Remarks	

** Times are approximate*

Agenda – Sept 26 (Day 2) – Virtual Only

BP-26 Pre-Proceeding Workshop		
Time*	Topic	Presenter
10:00 – 10:10 a.m.	Introduction, Meeting Protocols, Comments and Agenda	Brian McConnell
10:10 – 11:00 a.m.	Generation Inputs Rates Shortfall	Eric King, Bill Hendricks, Frank Puyleart
11:00 – 11:30 a.m.	Non EIM Balancing	Bill Hendricks, Frank Puyleart
11:30 – 11:45 a.m.	Utility Delivery Segment Charges	Brian Halbert
11:45 a.m. – 12 p.m.	Power Rates - Transfer Service Delivery	Dan Yokota and Kim Upham
	Closing Remarks	

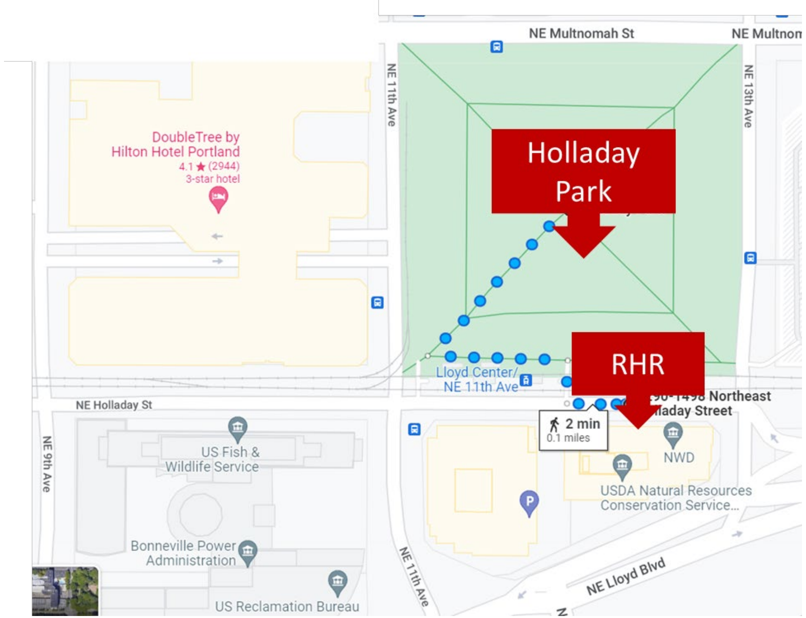
** Times are approximate*

Webex Format Update

- Bonneville has adjusted its public stakeholder virtual engagement approach.
- The Webex format is moving to a “webinar” style.
    - Webex attendees can no longer mute/unmute themselves or enable their webcam.
- The all-chat feature is disabled. Attendees can only message panelists.
    - To participate, attendees must raise their hand (Bonneville will unmute you to enable your participation) or send a question to panelists in the chat.
- If you are Webex by phone only: press *3 to request to be unmuted.
- Moderators will continue to address raised hands in the order received.
    - Please continue to state your name and affiliation.
- As necessary, Bonneville may evolve these procedures and take other measures at its discretion to prevent future disruptions.

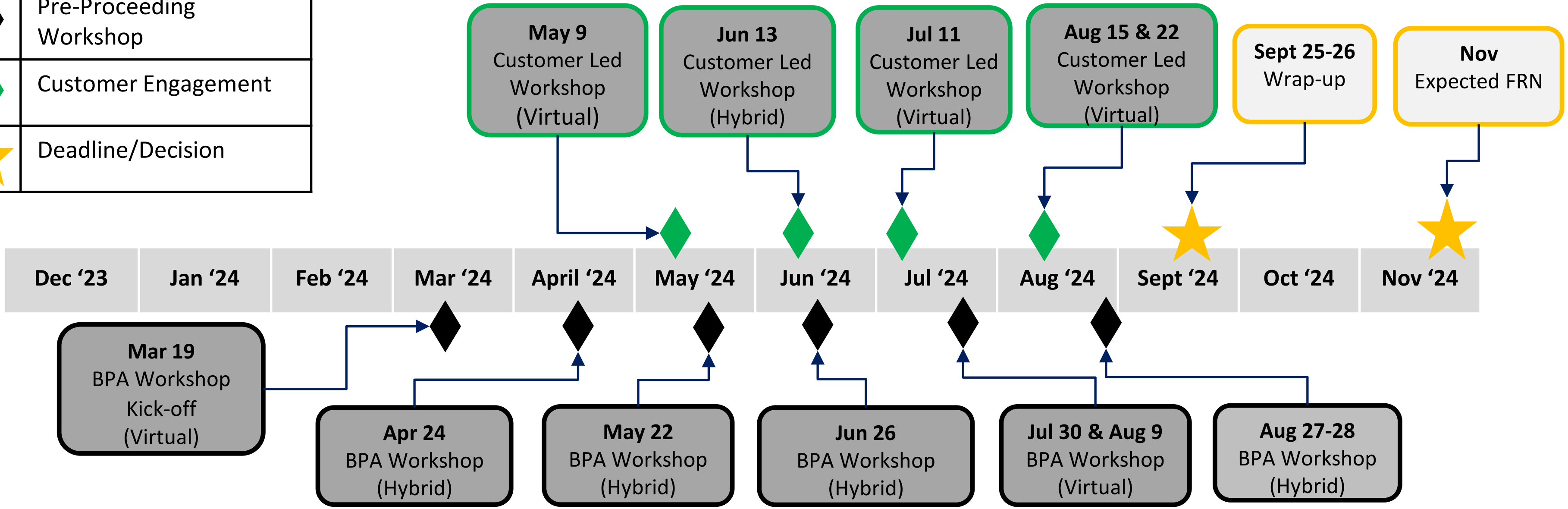
Safety Moment

- The Rates Hearing Room has two exits.
- In the event an alarm sounds, please meet at Holladay Park across the street.



Proposed BP/TC-26 Pre-Proceeding Workshop Schedule

◆	Pre-Proceeding Workshop
♦	Customer Engagement
★	Deadline/Decision



May 9
Customer Led Workshop (Virtual)

Jun 13
Customer Led Workshop (Hybrid)

Jul 11
Customer Led Workshop (Virtual)

Aug 15 & 22
Customer Led Workshop (Virtual)

Sept 25-26
Wrap-up

Nov
Expected FRN

Dec '23	Jan '24	Feb '24	Mar '24	April '24	May '24	Jun '24	Jul '24	Aug '24	Sept '24	Oct '24	Nov '24

Mar 19
BPA Workshop Kick-off (Virtual)

Apr 24
BPA Workshop (Hybrid)

May 22
BPA Workshop (Hybrid)

Jun 26
BPA Workshop (Hybrid)

Jul 30 & Aug 9
BPA Workshop (Virtual)

Aug 27-28
BPA Workshop (Hybrid)

Procedural schedule dates are draft only

Approach to Customer Engagement

Most identified issues will be presented according to the following process at workshops (multiple steps might be addressed in a single workshop):

Phase One: Approach Development

Step 1: Introduction & Education

Step 2: Description of the Issue

Phase Two: Evaluation

Step 3: Analyze the Issue

Step 4: Discuss Alternatives

Phase Three: Proposal Development

Step 5: Discuss Customer Feedback

Step 6: Staff Proposal

Teams will follow the steps that may be covered in one workshop or more based on the complexity of the issue.

Customer Comment Process

- Thank you to everyone who submitted comments on the August 27-28 workshop topics.
- Bonneville is using the same comment tracking and response process that was developed in BP/TC-24, which includes the following:
    - All customer comments will be posted to the BP-26 Rate Case website.
    - Bonneville will create a consolidated customer response (CCR) document for each workshop that will be posted/updated at the same time as other workshop materials.
    - The CCR is organized to address comments listed by the workshop date where the comments were received.
    - The CCR will provide direct responses or identify other forums or future BP/TC-26 workshops where Bonneville expects to provide a response.
        - To the extent possible, Bonneville will endeavor to provide responses prior to the next workshop in the Customer Comments section on the BP-26 website (updated CCR will be posted with workshop materials).
    - Bonneville will not be responding to comments received for the September 25-26 workshop.

BONNEVILLE POWER ADMINISTRATION

Western Resource Adequacy Program (WRAP)

Resource Adequacy - WRAP

- Bonneville is an active WRAP participant
- During BP-26 Rate Period – WRAP program will become binding, all participants currently active in non-binding status
- Difference between Binding and Non-binding
  - Forward Showing:
    - Both Data Submittal and calculations are the same, all loads and all physical resource used to meet those loads submitted
    - Non-Binding deficiencies do not result in charges
    - Binding program deficiencies result in charges

  - Operations Program
    - Both – All data submittal, and sharing calculations required for all participants
    - Non-Binding holdbacks and deliveries are voluntary
    - Binding program holdbacks and deliveries are part of program requirements
    - Both – Deliveries issued and accepted as part of program (binding and non-binding) are settled through WRAP settlement amounts

Resource Adequacy – Data Requirements

Complete Data Submittals

As a WRAP Participant Bonneville is expected to make complete program data submittals. As an LRE, under the program rules Bonneville is responsible to have resources available to serve the peak Total Retail Load of its load Following customers plus a Planning Reserve Margin (PRM). The resources used to serve that load is a combination of federal and non-federal resources as defined in contracts for each customer. WRAP has 3 different time periods with specific data requirements in each:

- Advanced Assessment
  - Loads = 10 years of historical actual hourly load
  - Resources = 10 years of historical actual hourly generation, resource test data, outage information

- Forward Showing
  - Loads = P50 Loads as calculated by program
  - Resources = QCC of all resources used to serve load and PRM
  - PRM = as calculated by program

- Operations Program
  - Loads = current forecast
  - Resource
    - Current forecast for ROR, Wind, Solar
    - Forced Outages for Storage Hydro and Thermal

Non-Federal Resource Data

- Non-Federal Resource Data Needed
  - Advanced Assessment

    Submitted each January, calculates values for year 2 and advisory values for year 5
    - February 2025 = Winter 26/27 and Summer 2027 QCC's and PRM's
    - February 2026 = Winter 27/28 and Summer 2028 QCC's and PRM's

    Register Non-Federal Resources
    - Registration can be done by LRE or project owner
    - 10 Years of Historical hourly Generation
    - Program calculated Qualifying Capacity Contribution QCC
  - Forward Showing

    Submittal due 7 months in advance of start of season (March 31 and October 31)

    BPA needs data a minimum of 2 month in advance of deadline to compile, check and verify, complete submittal attestation (9 months)
    - QCC of physical resource (or share of resource) used to serve load QCC
    - WRAP Joint Contract Accreditation Form (JCAF) used to detail resource capacity amounts by both buyer and seller
  - Operations

    Multi-Day ahead submittal submitted for 6 days ahead of Pre-schedule day

    Operating Day Submittal = hourly during Operating Day, Actuals = after the fact actual generation by hour
    - Current generation forecast for resources submitted in Forward Showing - 30 days before Operating Day (Run of River, wind, solar)
    - Forced Outage information for Storage Hydro and Thermals
    - Actual Generation for projects submitted in Forward Showing and OPS program

BP-24 Language - Above-RHWM Load

Resource Adequacy Service

This service will only be applicable if Bonneville begins participation in the Western Resource Adequacy Program (WRAP) 3B Binding Program and elects a binding summer 2025 season (June 2025 through September 2025).

1. Credit for Above-RHWM Load

A Load Following customer with non-Federal resources serving Above-RHWM Load will be eligible to receive a monthly credit in FY 2025 if the customer meets the WRAP forward-showing qualifying capacity capability (QCC) requirement for such non-Federal resources. The customer must submit QCC resource information to Bonneville by September 15, 2024, for the summer 2025 season.

- **Rate**
  FY 2025 monthly rate is -2.73 mills/kWh.

- **Billing Determinant**
  The qualifying non-federal resource amounts for October 2024 through September 2025 (in kilowatthours) identified in Exhibit D of the customer's CHWM contract.

BP-24 Language - New Large Single Loads

1. Charge for New Large Single Loads

A Load Following customer with a New Large Single Load (NLSL) will be subject to a monthly charge in FY 2025 if the customer does not submit to Bonneville, by September 15, 2024, for the summer 2025 season, either: (a) an approved exclusion attestation for the NLSL in accordance with the WRAP; or (b) QCC resource information for all non-Federal resources serving the NLSL.

- **Rate**
  FY 2025 monthly rate is 2.73 mills/kWh.

- **Billing Determinant**
  The qualifying forecast NLSL amounts for October 2024 through September 2025 (in kilowatthours) are identified in Exhibit D of the customer's CHWM contract.

BP-26 - Above-RHWM Load Concept

Resource Adequacy Service

Bonneville is an active participant in the WRAP Program – meaning Bonneville needs information on the resources being used to serve the non-federal resource share of loads

1. **Credit for Above-RHWM Load**

   Continue principles put in place in BP-24.

   Load Following customer with non-Federal resources serving Above-RHWM Load will be eligible to receive a monthly credit (winter and summer season) for non-federal resources submitted by the customer that meets the WRAP forward-showing qualifying capacity capability (QCC) requirement. Resource information submittals are complete and submitted to BPA 9 month prior to the beginning of each season (January 31 for Winter, and August 31 for Summer).

   - **Rate**

     Calculated as part of Rates process.

   - **Billing Determinant**

     The qualifying non-federal resource amounts identified in Exhibit D of the customer's CHWM contract.

BP-26 - New Large Single Loads Concept

2. Charge for New Large Single Loads

Continue principles put in place in BP-24, A Load Following customer with a New Large Single Load (NLSL) will be subject to a monthly charge (winter and summer season), any peak MW NLSL that the customer does not, either: (a) submit a jointly approve a load exclusion attestation for the NLSL in accordance with the WRAP, and meeting any requirements Bonneville may have; or (b) submit qualifying resources with program QCC's in to Bonneville nine months prior to the beginning of each season (January 31 for winter, and August 31 for summer) that will be used to serve the NLSL.

- **Rate**
  Calculated as part of Rates process.

- **Billing Determinant**
  The qualifying non-federal resource amounts identified in Exhibit D of the customer's CHWM contract.

BP-26 UAI Wrap Up

Contents

- Review Comments Received
- Follow up on Comments Received
- Staff Proposed Modifications Design for UAI
- Next Steps

Approach to Customer Engagement

Most identified issues will be presented according to the following process at workshops (multiple steps might be addressed in a single workshop):

Phase One: Approach Development	Phase Two: Evaluation	Phase Three: Proposal Development
Step 1: Introduction & Education	**Step 3: Analyze the Issue**	**Step 5: Discuss Customer Feedback**
Step 2: Description of the Issue	**Step 4: Discuss Alternatives**	**Step 6: Staff Proposal**

Completed

- Teams will follow the steps that may be covered in one workshop or more based on the complexity of the issue.

UAI Comments

- Seattle City Light supports Bonneville staff Alternative 3 which reflects hourly market energy cost conditions and monthly capacity demand rate conditions and supports the proposed UAI Waiver Language.
- For purposes of BP-26, NWCPUD recommends maintaining BP-24 implementation for purposes of assessing penalties, supports the proposed UAI Waiver Language.
- The NLSL Group supports a holistic re-evaluation of UAI charges in the context of implementing best practices used in organized markets to disincentivize customers from using uncontracted Federal resources to meet load. Until then, the NLSL Group prefers to maintain the agreement reached in the BP-24 settlement.

UAI Comments (cont.)

- NRU appreciates the presentation on UAIs and the alternatives shared during the workshop. Support Alternative 4, setting the energy component at two times the cost of energy during the hour in which the penalty occurred and moving to a daily demand penalty. Supports the proposed UAI Waiver Language.

Proposed Response to Comments Received

- Thank you for your comments. We plan to add the proposed waiver language to the Initial Proposal.
- We also believe we can build on the proposed recommendations by proposing Alternative 3 with an hourly event limit (more than 4 hours in a month) before the demand component of the UAI applies. In a way, this folds in the tempering of demand like the cap included in BP-24, allows time to fix interrupted resource schedules without being subject to the demand UAI, and keeps the rate aligned with the way BPA measures capacity – monthly and not daily.
- Assuming an average demand penalty rate of $13,025/MW/mo, and a customer that took exactly 5 hours of 1 MWh UAI energy, the UAI demand would add $2,605 MWh. The BP-24 cap is $2,500/MWh.

Reminder of Alternative 3

Calculate the energy component of the penalty based on the cost of energy during the hour in which the unauthorized increase occurred:

- Energy charge: the greater of two times the hourly Energy Imbalance Market (EIM) Load Aggregation Point (LAP) price for firm power for the hour in which the overage occurred or 150 mills/kWh.
- Demand charge: if the overage occurs during a HLH billing hour, a demand charge would be billed at 1.25 times the applicable monthly demand rate.
- No cap

Staff Proposed Modifications for UAI BP-26

- Alternative 3 “Plus”, the same as Alternative 3 but with a conditional demand UAI for non-Load Following customers, except the Slice portion of the Slice/Block product.
- For Load Following customers, a demand UAI will be assessed when the customer’s non-Federal resource provides less than its contractually determined amount during the customer’s system peak as used for setting the demand billing determinant. No change from BP-24, but also no cap.
- For non-Slice non-Load Following customers, the monthly demand UAI would apply if more than four hours of demand UAI apply in a month. The monthly demand UAI would be assessed once on the fifth hour of demand UAI only. Energy UAI would apply in all hours.
- For the Slice portion of the Slice/Block product, we need to discuss.

BP-24 Slice Demand UAI

- **BP-24:** For a Slice customer, the Slice portion of the Slice/Block product will be subject to a demand UAI if the Slice demand is in excess of the Slice entitlement during the peak Delivery Request (Right To Power) HLH of a month. The Slice demand in excess of the Slice entitlement is measured by subtracting (i) the largest final hourly Delivery Request (Right To Power) computed using the Slice Water Routing Simulator for any HLH of a month from (ii) the hourly amount of Slice power delivery (tagged + untagged energy) from BPA for the same HLH of the same month, as such terms are defined in the Slice/Block CHWM Contract.
- **BP-26:** BPA is open to keeping the same language or applying the same approach as being proposed for non-Load Following customers.

BONNEVILLE POWER ADMINISTRATION

Demand Rate

Demand Rate Comments

- Bonneville had proposed to limit the increase in the Demand Rate to a 10% increase. Northwest Requirements Utilities supports Bonneville’s proposal to use the TRM dampening methodology to limit the increase to the BP-26 demand rate.
- Seattle City Light suggests that Bonneville ramp in a substantial amount of the 23% increase in the Demand Rate yearly over the rate period. This could occur with a 7% increase applied in each of the three years of the rate period.

Response to Comments Received

- Thank you for your comments. Responding to comments, Bonneville is proposing to implement a faster phase-in of the Demand Rate change.
- We considered whether to apply an increase to each year of the Rate Period but determined that this would add an excessive amount of complexity. We would like to keep 12 values rather than 36 values for the Demand Rate during BP-26.
- For the faster phase-in, Bonneville will propose a dampener that will allow half of the increase for the Rate Period. This is illustrated in the next slide.
- Phasing-in only part of the change recognizes that the Marginal Capacity Cost Model for BP-29 may have different inputs, included a lower cost of debt. Also, on a related theme, it is important to remember that the Demand Charge serves as long-run price signal rather than a cost-recovery charge.

Example Calculation

Initial Value	$9.54 kW/mo
Model Results	$11.70 kW/mo*
Half of increase	$1.08 (11.3%)
Phased-In Value (Half of Increase)	$10.62 kW/mo

* This calculation assumes that the BP-26 Initial Proposal model produces a result of $11.70 kW/mo. The results in the Initial Proposal may be different due to updated inputs.

Compared to the comment provided by SLC, a stronger signal will be sent during FY26, and a weaker signal will be sent during FY28.

SCL Proposal $/kW/mo	SCL Annual Impact	BPA Staff Proposal $/kW/mo	BPA Staff Annual Impact
10.21	7.04%	10.62	11.32%
10.93	7.04%	10.62	0%
11.70	7.04%	10.62	0%

Tier 2 Pricing

Tier 2 Customer Comments

NRU: Proposes using one of the historically utilized marginal price forecasts, specifically firm (P10) Aurora prices, to value any Firm Surplus used to serve power sold at Tier 2 rates, else Bonneville should use the BP-24 methodology that averaged P10 Aurora and forward market prices.

Central Lincoln and Mason 3: Support Bonneville staff’s proposal discussed on August 9. View the BP-24 Settlement as allowing some costs to shift from the Tier 2 Rate into Tier 1 to mitigate the effects of rising market prices. Concerned about any Tier 2 pricing that would provide a subsidy via Tier 1 rates.

Response to Comments Received

- We agree that Bonneville will use marginal prices for Tier 2 that do not undermine the cost-shift principle in TRM. There are, however, multiple ways to measure marginal prices. We would not characterize the method used in the settlement as a subsidy of Tier 2 rates. Rather, the settlement used an average of two previously used methods to calculate the marginal price of power.

- **Spot Market Prices.** Bonneville has used Aurora as its primary method to forecast spot market prices for decades, including the augmentation costs and the secondary net revenue credit.
  - **P10 Aurora.** Historically, when Aurora is used to forecast the cost of augmentation, a forward adjusted price is used – the firm Aurora price using a monthly 10th percentile hydro generation forecast. This risk-adjusted method was applied to protect against risk-related cost shifts between rates (such as Slice to Non-Slice and Tier 1 to Tier 2).

  - **Average Aurora.** When Bonneville is forecasting the market value of power in the spot market, an expected Aurora price is used (most often called the average Aurora price). This is used for forecasting net secondary revenue and Bonneville's balancing purchase costs.

- **Forward Market Prices.** When Aurora P10 prices started diverging from forward market prices (ICE index), Bonneville started using the forward market prices to set the rate of any unpurchased Tier 2 amounts. Sometimes the ICE index is higher than P10 Aurora and sometimes it is lower than P10 Aurora.

- **Operationally.** Bonneville does not always buy flat blocks of power to meet its augmentation needs (Tier 2 or otherwise). While the full range of operational strategies are used, it is not uncommon for Bonneville to target pinch points in advance (forward market purchases), such as winter and summer, and then manage the remaining needs in the spot market. Thus, even operationally, a hybrid rate-setting approach (such as the approach used in the BP-24 settlement) is justifiable.

Tier 2 Pricing New Proposal

Given Bonneville's operational practice and new market trends, such as more reliance on a pricing that includes a fixed premium with market index energy, we want to adopt a new approach to how we set the Tier 2 rates. This new approach also aligns with new markets and capacity planning standards, where capacity is paid for and committed in advance of energy markets that dispatch that capacity in the most economically efficient way possible.

1. **Unpurchased Tier 2 Amounts.** T2 sourced from firm surplus would be priced as follows: capacity + energy:
    - capacity element will be priced at the Demand Rate
    - energy element will be priced at customer choice between:
        - **Formula Option.** Actual Market Price – ICE Daily Index (customer bears risk / benefit from market)
        - **Fixed Option.** Aurora P10 (customer certainty)
2. **Purchased Tier 2 Amounts.** Bonneville would use the actual power purchase costs if BPA were to purchase flat blocks of power prior to setting the final rates.
3. Tier 2 Rates would be calculated using the volumetric combination of I and II.
4. Why we like this approach:

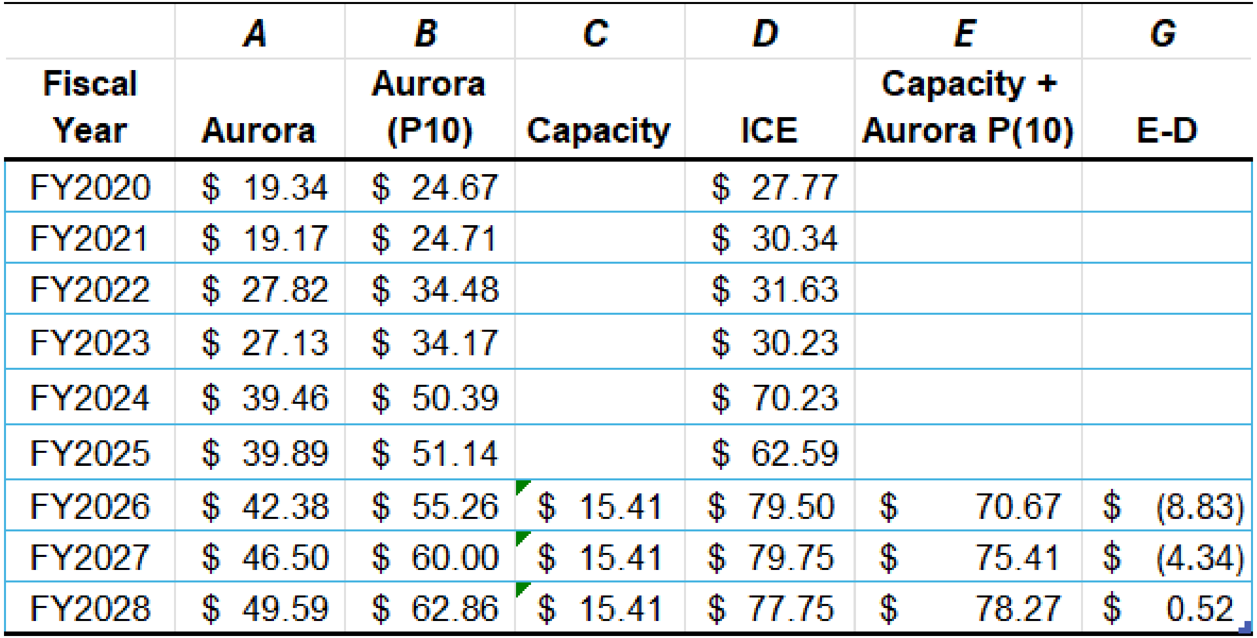
- Introduces capacity component consistent with market trends and future policy direction
- Retains low-cost-shift risk between T2 and T1
- Transparency, and opportunity-cost based

Proposal Example

Realistic, but not final example: Tier 2 obligation = 600aMW

- 100aMW sourced by forward, flat market purchase (i.e., purchased amounts)
  - Equal to the cost incurred by Bonneville
- 500aMW sourced from FCRPS (i.e., unpurchased amounts)
  - Capacity: 500aMW*1000*$11.25kW/month*12month/ (8760hours*500MW) = $15.41/MWh
  - Energy: Aurora P10 @ $60 (*or Actual Market Price)*
  - *$60 + $15.41 = $75.41*

A Snapshot of Index Prices & Proposal



	A	B	C	D	E	G
Fiscal Year	Aurora	Aurora (P10)	Capacity	ICE	Capacity + Aurora P(10)	E-D
FY2020	$ 19.34	$ 24.67		$ 27.77		
FY2021	$ 19.17	$ 24.71		$ 30.34		
FY2022	$ 27.82	$ 34.48		$ 31.63		
FY2023	$ 27.13	$ 34.17		$ 30.23		
FY2024	$ 39.46	$ 50.39		$ 70.23		
FY2025	$ 39.89	$ 51.14		$ 62.59		
FY2026	$ 42.38	$ 55.26	$ 15.41	$ 79.50	$ 70.67	$ (8.83)
FY2027	$ 46.50	$ 60.00	$ 15.41	$ 79.75	$ 75.41	$ (4.34)
FY2028	$ 49.59	$ 62.86	$ 15.41	$ 77.75	$ 78.27	$ 0.52

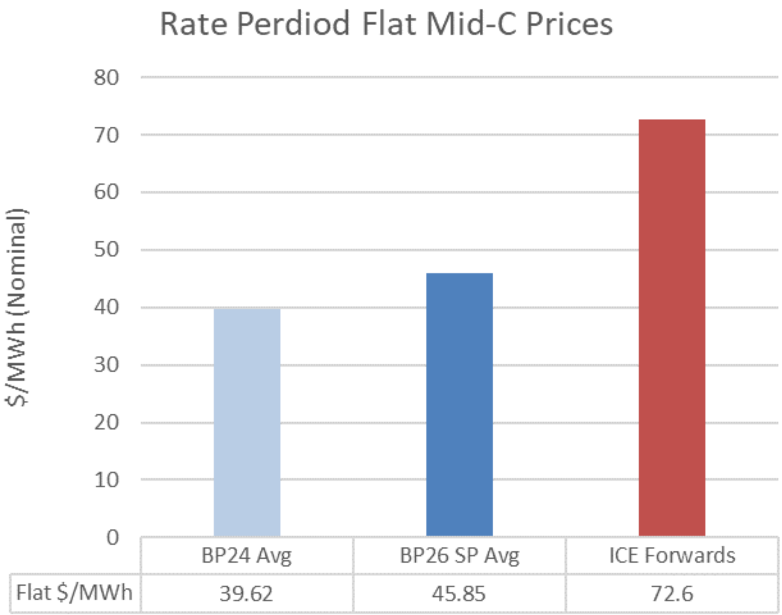
** realistic, but number are examples only*

BONNEVILLE POWER ADMINISTRATION

Electricity Market Price

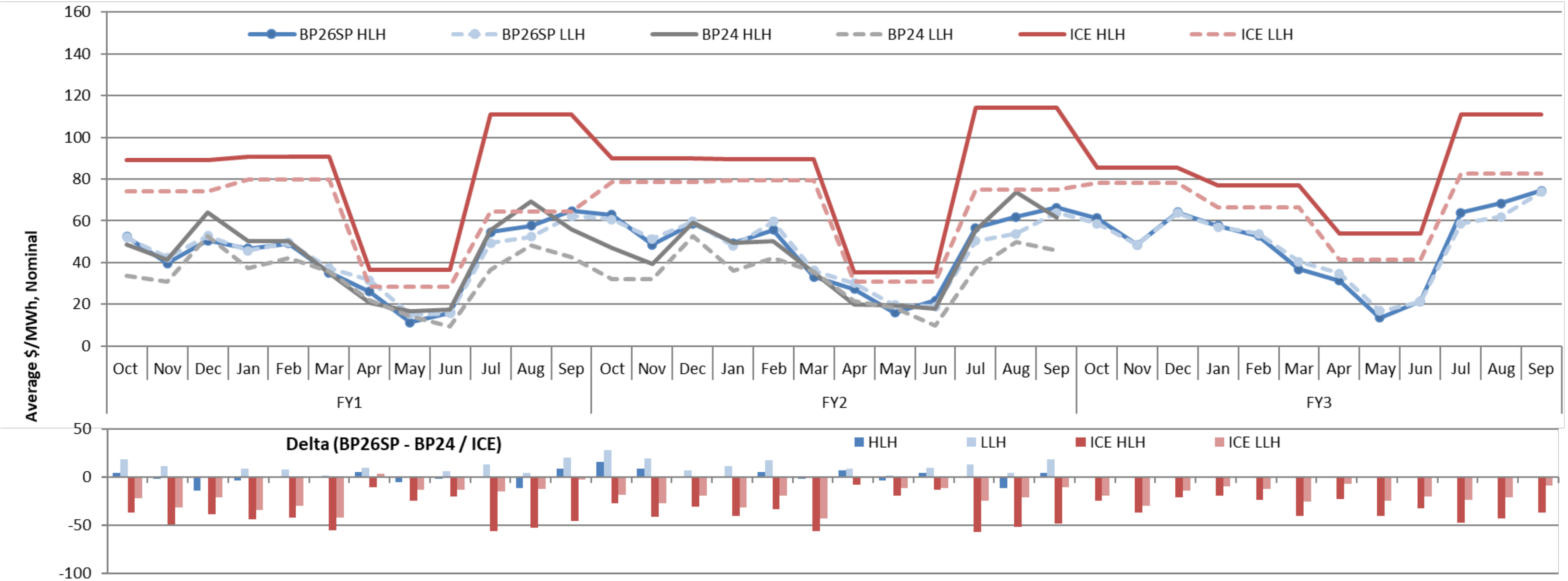
Summary

- Continue to use a production cost model (Aurora) to forecast electric market prices.
- The most significant change for BP-26 is the update to resource builds throughout the Western Interconnection. The new builds combined with improved modeling of short-duration storage resources has greatly reduced the forecast HLH – LLH spreads.
- Overall forecast price levels are otherwise moderately higher on average, but not significantly different from BP-24.



ICE forwards are an average taken from June - September 2024 for the BP-26 rate period. **‘SP’ is the Sneak Peek vintage.**

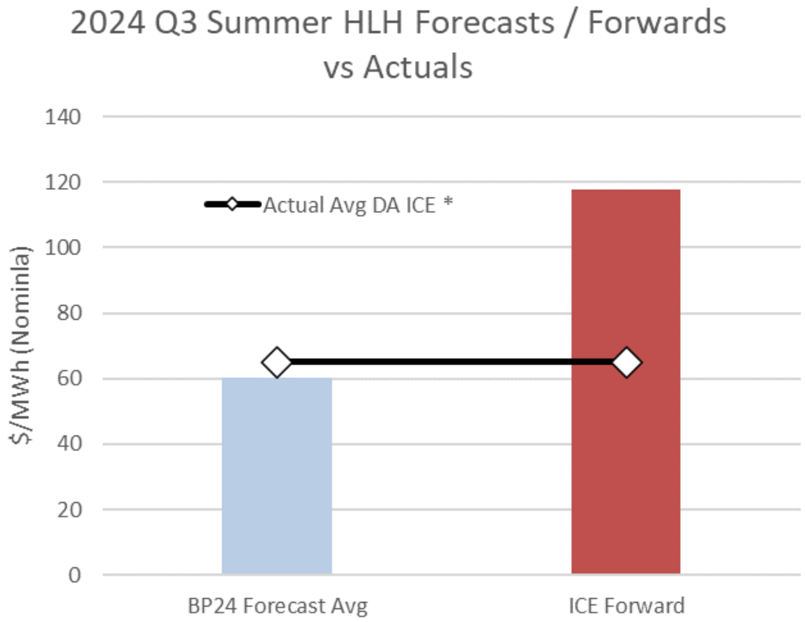
Mid-C / NW Prices



FY1-3 = 2026-2028 for BP-26 SP + ICE and 2024-2025 FY2024 for BP-24

Summer HLH Forwards and Forecasts vs Actuals

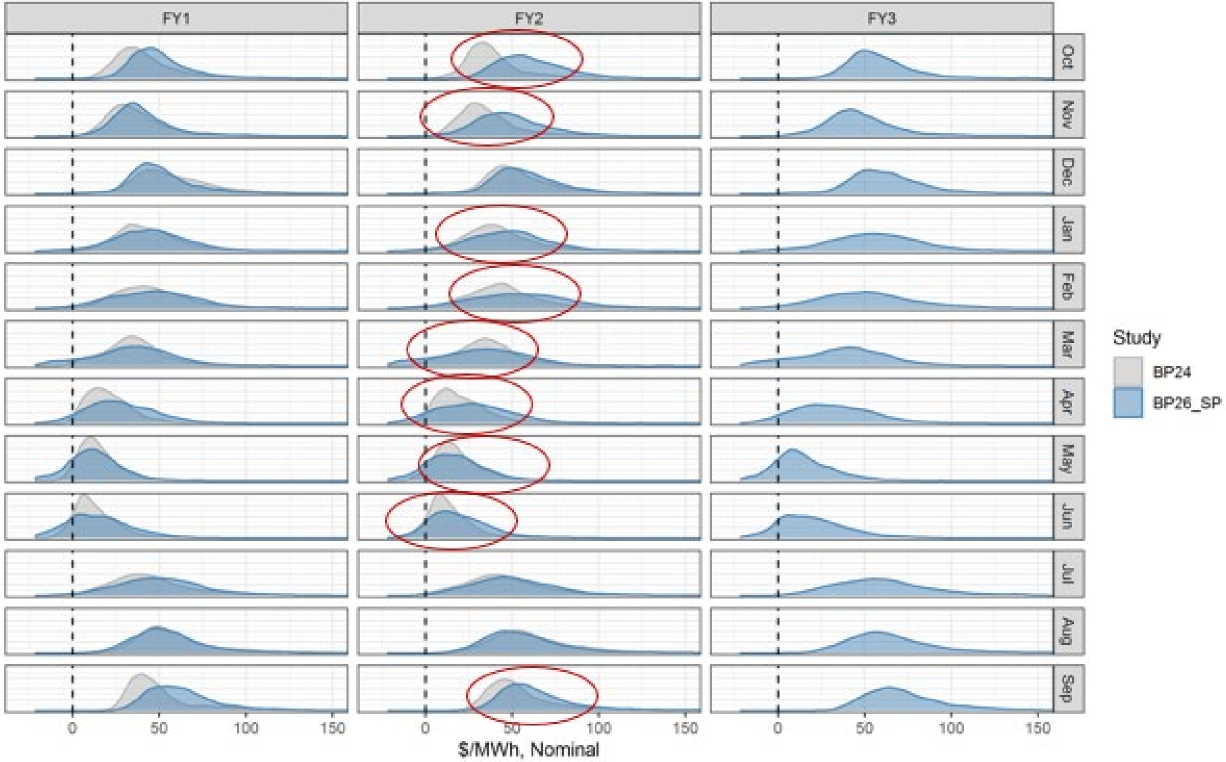
- A major driver of the difference between ICE forwards and the average Aurora forecast are the highly elevated Q3 Summer forward prices.
- We saw the same relationship in BP-24. Despite having especially high July temperatures, 2024 Q3 summer prices came in slightly above the average Aurora forecast, and well below ICE forwards.
- The average Aurora forecast was a far better predictor of actual, day-ahead Mid-C prices (largely because summer conditions were closer to average).
- Bonneville produces a distribution of Aurora forecasts to reflect risks of different future conditions.



* As of September 19th, actual prices for the remainder of Q3 are expected to come in even lower. ICE forwards are an average from June to September 2022 for the BP-24 period.

Mid-C / NW Price Distributions

Flatter and wider price distributions (highlighted in FY2 with ○) mean **larger price swings are occurring with more moderate changes to conditions from one period to the next.**

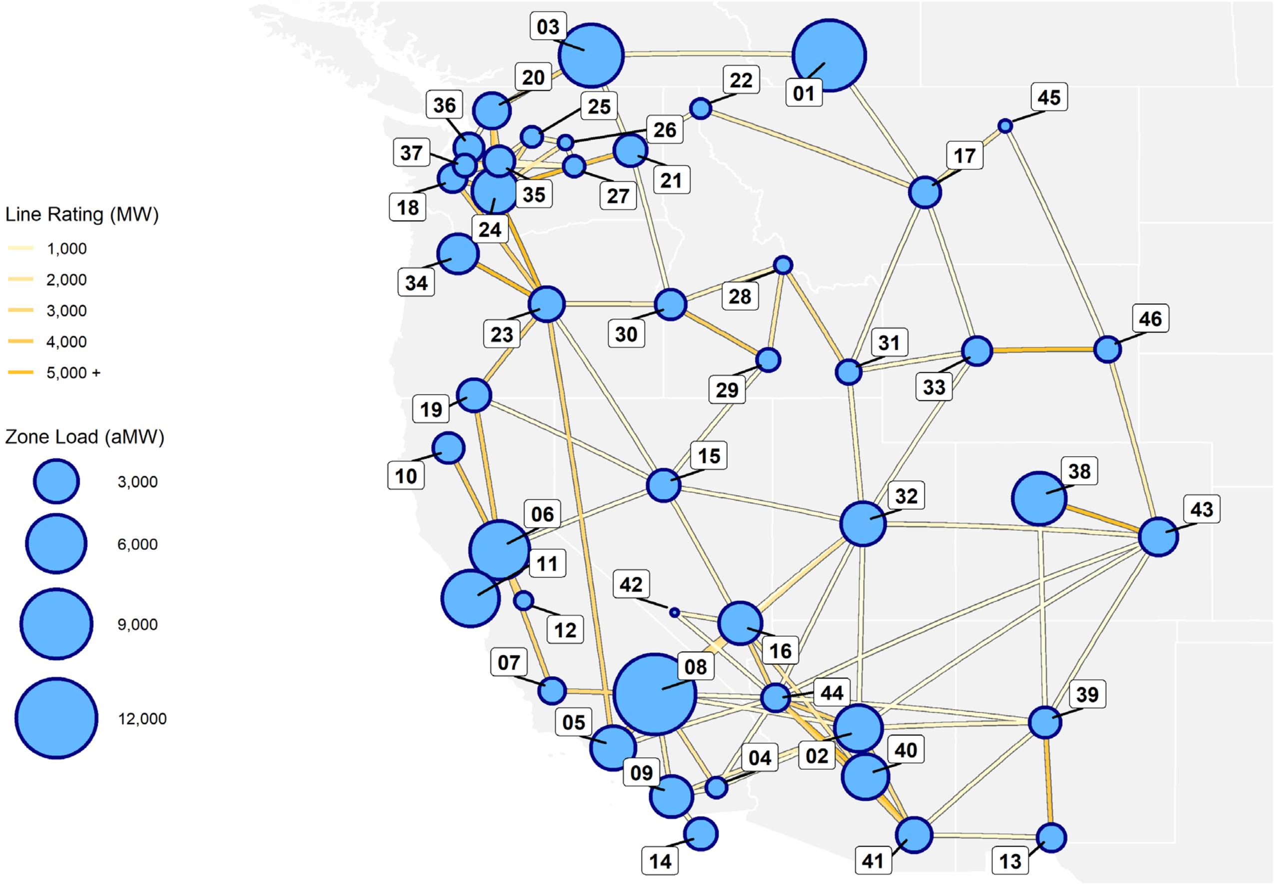


Aurora Refresher

- 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	Tuscon
42	VEA
43	WAPA CO
44	WAPA LwCO
45	WAPA UprMO
46	WAPA WY



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 Day Ahead Markets, Western Energy Imbalance Market (WEIM) or the Western Resource Adequacy Program (WRAP).

Rate Period Avg Natural Gas and Carbon Prices

- Our gas price forecast is increasing moderately for the rate period.
- We continue to rely on the simplifying assumption that CA and WA carbon prices should be close during the rate period but have not modified the forecast to reflect potential impacts of a merged carbon market. The carbon price forecast has increased substantially due to observed and expected tightening of allowances vs demand for emissions over the period. The carbon price forecast has not been adjusted for potential impacts of WA Initiative 2117 (potentially ending the program).

		BP-24	BP-26SP		Delta
Gas ($/MMBTu)	Henry	$4.22	$4.76		$0.55
	NW*	$4.08	$4.33		$0.26
Carbon ($/MTCO2e)	CA + WA	$34	$63		$29

* NW is a simple average of Stanfield and Sumas hub prices (not basis values)

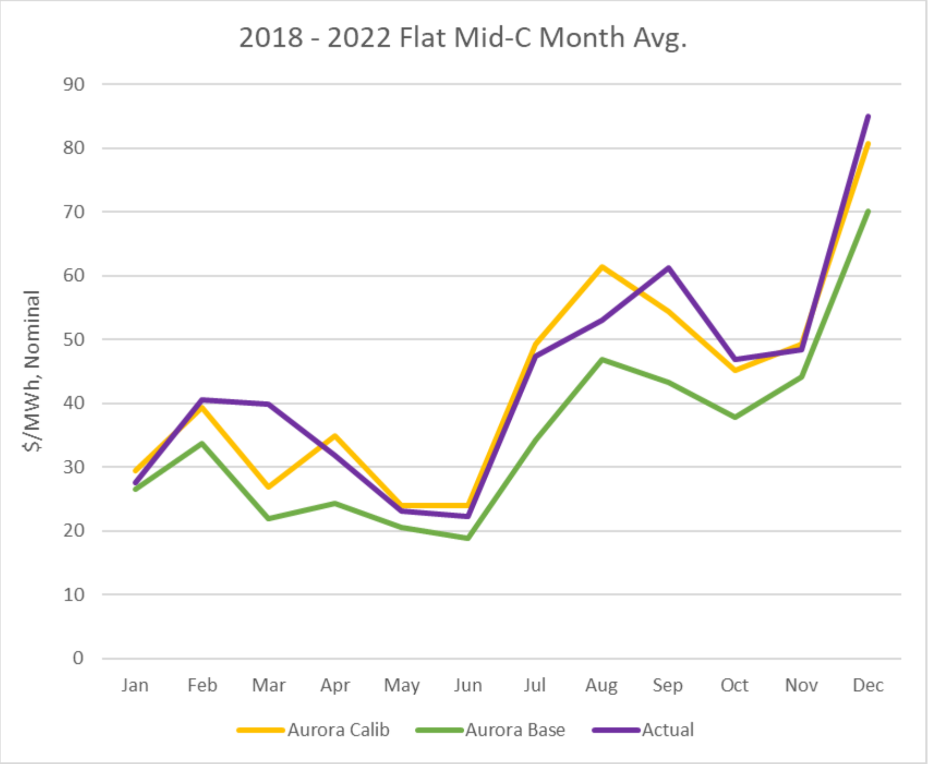
Aurora Calibration 2018-2022

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)

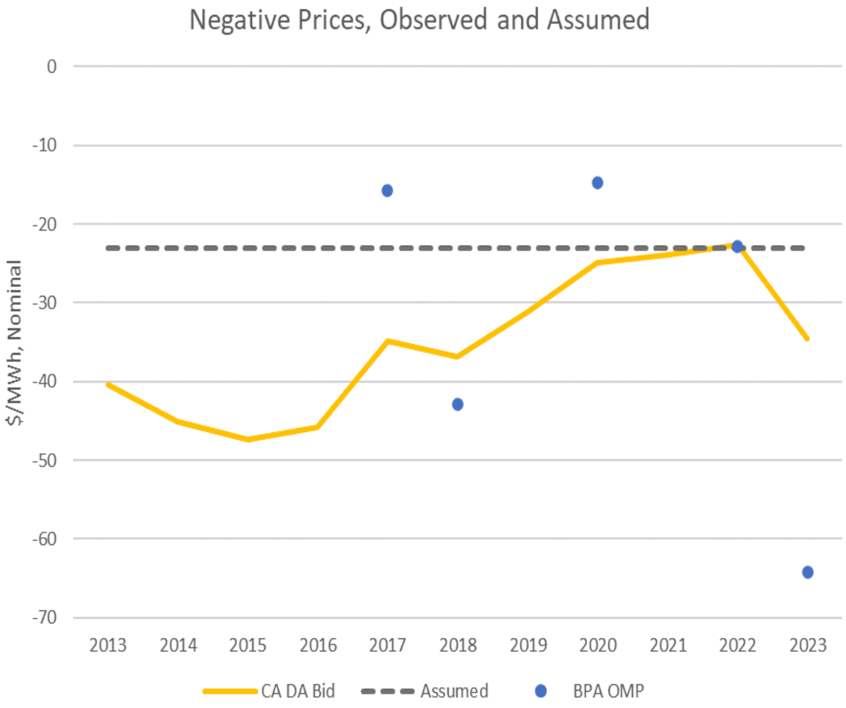
Benchmarking (running Aurora with actual fundamentals and comparing results to actual prices) allows us to isolate and address the 2nd problem through calibrating thermal resource bid behavior.

* 'Fundamentals'= loads, hydro generation, gas prices, transmission capability, renewable generation, etc.



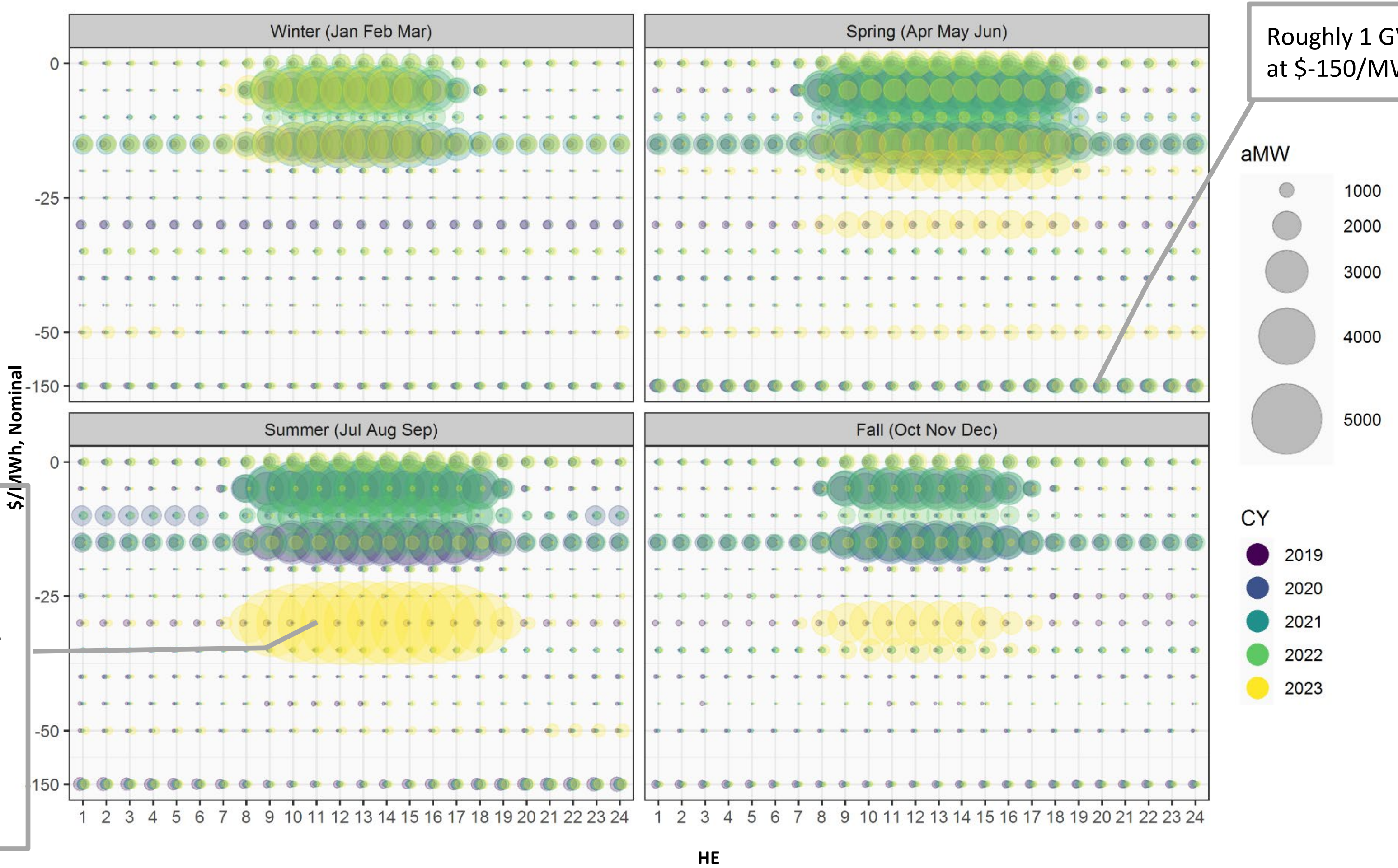
Negative Prices

- **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
- **Bonneville models all renewable resources bidding at ~negative $23/MWh**
- We include mechanisms to reflect maximum hydro spill up to latest TDG limits and set Bonneville 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.



BPA OMP weighted avg price: ~ -$29/MWh

CAISO Negative DA Bids



Roughly 1 GW bidding at $-150/MWh

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

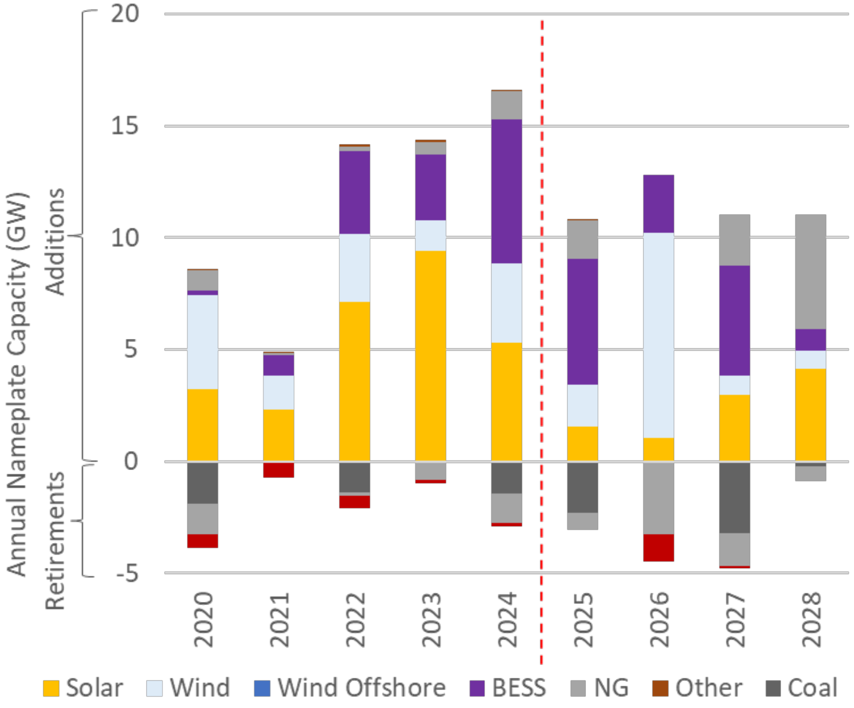
Nearly 5 GW bidding at ~ -$30/MWh

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

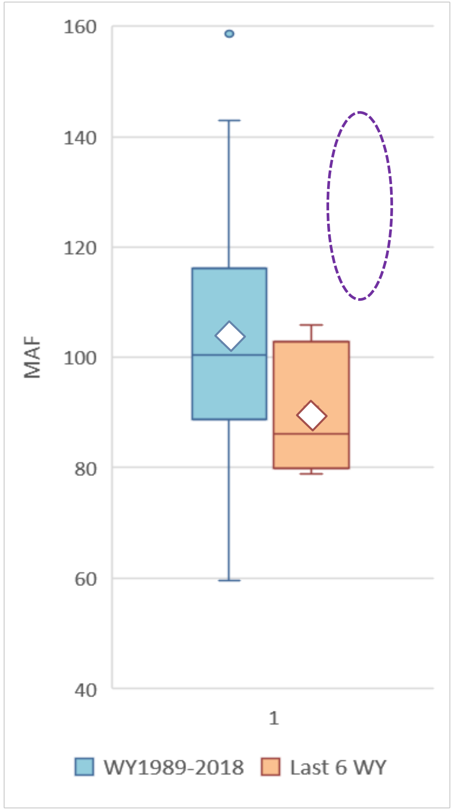
WECC (US) Additions and Retirements 2020-2028

- Cumulative additions from 2020 to 2028 are around 100,000 MW—mostly solar, wind, and Battery Energy Storage Systems (BESS).
- More than half of these additions (about 58,000 MW) are already in the ground and operating.



Recent Jan-Jul Volumes at The Dalles

- Over the last 6 years, flows have tended to be lower than average, somewhat masking the market price impacts of the substantial growth in renewables.
- The region has not experienced the combination of large additions to renewable generation and high water + hydro generation in the NW.
- If these conditions materialize, there's the potential to experience prices lower than the average Aurora forecast, and lower than what the region has historically experienced.



BONNEVILLE POWER ADMINISTRATION

Net Secondary Revenue Forecast

Method

- Net Secondary Revenue (NSR) is forecast by RevSim
- RevSim helps assign an expected value to Bonneville's ability to generate energy in excess of firm obligations to serve load
- Calculated as the mean of a 2,700 game distribution
- Largest source of variation is the water year

Change to RevSim Modeling of Reserves

- GARD provided an accounting for the impacts of holding reserves that tracked energy shift, spill, and efficiency in a diurnal shape at the monthly level.
- RevSim will replace its GARD-based accounting for the changes in inventory with inputs from the new RiverWare-based reserves model that account for net energy impacts of holding balancing reserves – i.e., lost generation that results from increased spill and lost efficiency.
- The energy shift cost of holding balancing reserves is captured through Bonneville’s hydro models upstream of RevSIM.

Change to RevSim Modeling of Reserves

- A small change in RevSim is needed to accommodate the new approach to calculating the variable cost of holding reserves – the move from GARD to RiverWare.
- The new RiverWare-based reserves model provides more granular data but does not track whether these impacts happen in HLH or LLH periods, which RevSim requires.
- Therefore, an additional step is needed to convert the monthly amounts of lost generation into a HLH/LLH shape. We propose to assume a flat shape to this lost generation. 2/3 of each monthly total can be deducted from HLH generation and 1/3 from LLH.

BONNEVILLE POWER ADMINISTRATION

BP-26 NR Energy Shaping Service (ESS)

Seattle City Light ESS Comments

- City Light supports Bonneville recovering the full cost of load uncertainty using cost causation principles. City Light suggests that Bonneville explore ESS charges that fully recover the costs for load uncertainty, including uncertainty for extreme weather conditions.

Northen Wasco PUD ESS Comments

- Northern Wasco typically manages its load and resource positions in a very tight band (<5 MWs) during on-peak hours
- Recommends a continued BP-24 approach to ESS
- In the spirit of compromise, recommends only Threshold 3 discount be increased if needed

NLSL Group ESS Comments

- New Large Single Loads Group
    - Given the nature of the load, the NLSL Group believes that there should be very little load uncertainty associated with over-/under-scheduling generation to NLSL load.
    - The NLSL Group does not support Bonneville staff's workshop idea to increase salvage value penalties.
    - The NLSL Group wants to better understand ESS Capacity. Specifically, how it is, or isn't, factored into WRAP requirements.

NLSL Group Proposed Concept

- The NLSL Group proposed that Bonneville offer a “Market-Enabled NLSL Service”.
- The objective of this option is to provide a path for NLSL service that is aligned with the existing energy imbalance market (“EIM”) as well as anticipating the development of a day-ahead market (“DAM”) during the next contract period.
- Some key BP-26-relevant features:
  - Align with how Transmission manages Energy Imbalance.
  - Energy Imbalance charged/credited at EIM prices.
  - Improved sharing of data/scheduling information.
  - Capacity credits for behind-the-meter generation and demand response.

Response to the ESS Capacity-Related Questions

Will NR ESS Capacity be treated as qualified capacity for the purposes of NLSL WRAP participation? **Bonneville is not deciding WRAP requirements in the BP-26 rate setting process. That said, from a rate setting perspective, it should have the same value as any other capacity BPA is planning for and holding to support load.**

Will NR ESS Capacity be held out of Bonneville's secondary marketing through the operating hour or will it be released prior to the operating hour? **This is an operational question and doesn't change the nature of this capacity. Bonneville would be taking on this capacity obligation and managing it the same as it does any other load following capacity obligation.**

How will Bonneville ensure that a Customer's purchase of NR ESS Capacity be used when NLSL load exceeds generation? **Within the bounds of the NR ESS Capacity amount, Power Services will not apply a UAI when scheduled generation is less actual load. This is the same application as when a non-Federal resource is taking Resource Support Services and the non-Federal resource produces less than its contractually specified Exhibit A amount.**

Does the Federal system have a limit on the amount of NR ESS Capacity that can be supplied? **Yes.**

Response to the “Market-Enabled NLSL Service” Option

- Bonneville staff agree that there should be very little load uncertainty associated with over-/under-scheduling generation to NLSL load. This is one of the reasons why we want to change the BP-24 approach.
- We also like many of the features built into the “Market-Enabled NLSL Service” option.
- Some of the features are premature for application in BP-26 – such as those parts that contemplate business practice changes and Day Ahead Market ideas.
- We do not believe this should be adopted as another option on the BP-24 approach. As previously stated, the BP-24 approach no longer works for Bonneville.
- We want to build a better mouse trap and use many of the features included in the NLSL Group’s “Market-Enabled NLSL Service” option.

Quick Background

- Bonneville provides a service called NR Energy Shaping Service to Load Following customers serving their own NLSLs.
- The service was created with the understanding that there will always be differences between scheduled generation and actual load. As such, a service was needed to give Load Following customers the ability to service their own NLSLs.
- Bonneville originally created the service to mirror other capacity-based services it provides. Capacity is purchased up front and that capacity amount is used to set the customer's contractually acceptable bounds it can operate.
- Customers ultimately decided to use the service in a way that avoided capacity-based charges by purposefully overscheduling HLH periods (the period that Power currently measures capacity use).
- Although allowed, and certainly creative, this behavior was not how Bonneville envisioned the service be used. Given the size of the loads among other capacity-related trends, Bonneville needs to move the service back to its original intent.
- The intent of the service is for Bonneville to provide the unavoidable capacity obligation that remains after the customer has done its best at meeting the load in every scheduling period.

Staff Proposed ESS for BP-26

Move to a more traditional capacity and energy construct – **all evaluated at the aggregate NLSL level and after grandfathered load has been removed**.

- **Minimum ESS Capacity.** All ESS customers will be required to purchase a minimum of 2% ESS capacity cost equal to:
  - $Monthly\ ESS\ Capacity\ Cost = Actual\ Hourly\ Load\ Peak\ in\ a\ Month\ \times Monthly\ Demand\ Rate\ \times 2\%$
  - A 100 aMW mostly flat load would pay approximately $0.30/MWh for this Energy Shaping Service assuming a $10.49/kW/mo average monthly demand rate.
- **Maximum ESS Capacity.** Customers can purchase a maximum of 5% ESS capacity, in whole % election amounts. (Equal to approximately $0.75/MWh if 5%).
- **Total Allowable Hourly Forecast Error.** This ESS capacity would be combined with the average forecast load error on BPA's system (4%), as quantified through BPA's Incremental Standard Deviation for Load, to determine the maximum hourly load deviation a customer can have without triggering a UAI Charge.
  - Assuming a 100 MWh actual load and a minimum amount of ESS capacity, the hourly schedule would need to be 94 MWh or larger to avoid a UAI Charge.
- **Energy.** Hourly deltas between scheduled generation and actual load charged/credited at Load Aggregation Point (LAP) for BPA. This treatment excludes amounts of energy applicable to the UAI and periods where the Power Persistent Deviation applies.
- **Power Persistent Deviation.** Power will apply a persistent deviation penalty charge, modeled of Transmission Services Persistent Deviation penalty charge, when such scheduling conditions exist.

Power Persistent Deviation – Applicable to No Data Sharing

With no data sharing agreement:

- The Power Persistent Deviation Penalty Charge applies to all hours or scheduled periods in which either a negative deviation, over-schedule (the actual load of the NLSL(s) is less than the scheduled energy to those NLSL(s)) or positive deviation, under-schedule (the actual load of the NLSL(s) is greater than the scheduled energy to those NLSL(s)), exceeds:
  - Both 6 percent of the integrated hourly schedule and 10 MW in each scheduled period for four consecutive hours or more in the same direction;
  - Both 1.5 percent of the integrated hourly schedule and 2 MW in each scheduled period for 24 consecutive hours or more in the same direction.

Power Persistent Under Deviation – Applicable to Data Sharing

With data sharing agreement:

- The Power Persistent **Under** Deviation Penalty Charge applies to all hours or scheduled periods in which a **positive** deviation, **under-schedule** (the actual load of the NLSL(s) is greater than the scheduled energy to those NLSL(s)), exceeds:
  - Both 6 percent of the integrated hourly schedule and 10 MW in each scheduled period for four consecutive hours or more in the same direction;
  - Both 1.5 percent of the integrated hourly schedule and 2 MW in each scheduled period for 24 consecutive hours or more in the same direction.

Power Persistent Over Deviation – Applicable to Data Sharing

With data sharing agreement:

- The Power Persistent **Over** Deviation Penalty Charge applies to all hours or scheduled periods in which a **negative** deviation, **over-schedule** (the actual load of the NLSL(s) is less than the scheduled energy to those NLSL(s)), exceeds:
    - Both 1.5 percent of the integrated hourly schedule and **5 MW** in each scheduled period for 24 consecutive hours or more in the same direction.

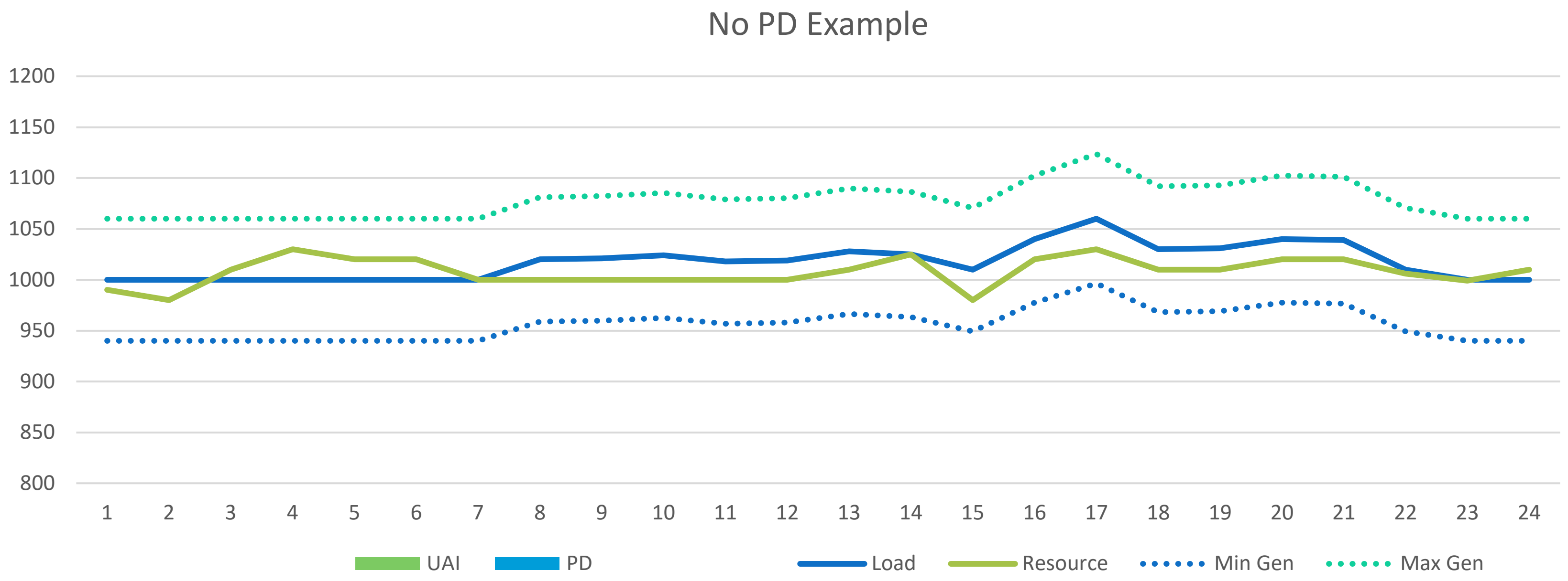
Power Persistent Deviation – Rate

- **Over-Schedule.** When a Power Persistent Deviation applies and scheduled generation is greater than actual load
  - For hours when the energy index is positive, no credit is given.
  - For hours when the energy index is negative, the customer will be charged the energy index multiplied by negative one times the over scheduled generation.
- **Under-Schedule.** When a Power Persistent Deviation applies and scheduled generation is less than actual load
  - The rate applicable to each under-schedule hour is the greater of (i) 125 percent of the highest LAP during the period of penalty, or (ii) 100 mills per kilowatthour.
- **No double counting.** In hours where a UAI occurs during a Power Persistent Deviation period, BPA will not include the portion of the under-schedule that was charged a UAI in the calculation of the Power Persistent Deviation penalty charge.

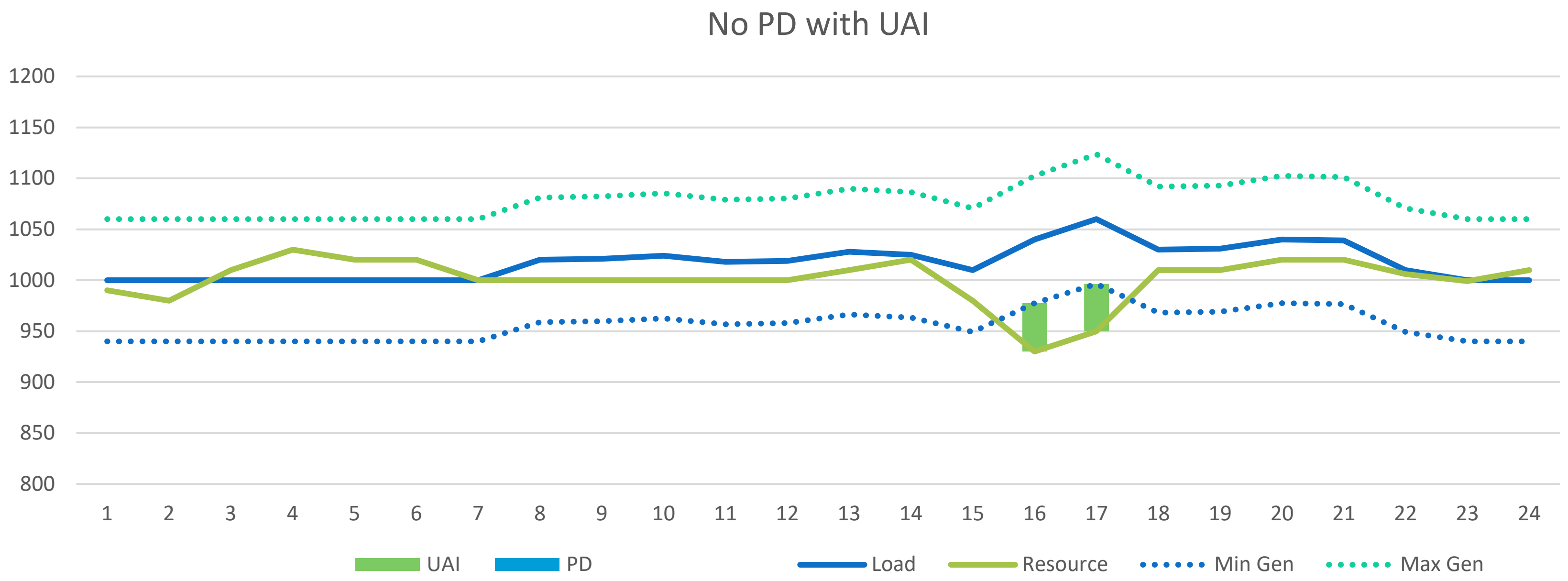
Pattern and Waiver

- **Pattern of Conduct.** Bonneville will apply the Power Persistent Deviation for periods of time when Bonneville identifies a Pattern of Conduct as measured by the customers scheduled generation and its actual load. A Pattern of Conduct is defined as a pattern of under- or over-schedule occurs generally or at specific times of day.
    - For example, if a customer a regularly under schedules for 23 hours and over schedules for 1 hour
- **Reduction or Waiver of Power Persistent Deviation.** Bonneville, at its sole discretion, may waive all or part of the Power Persistent Deviation penalty charge if (i) the customer took mitigating action(s) to avoid or limit the Power Persistent Deviation, including but not limited to, changing its schedule to mitigate the magnitude or duration of the deviation, or (ii) the Power Persistent Deviation was caused by extraordinary circumstances.

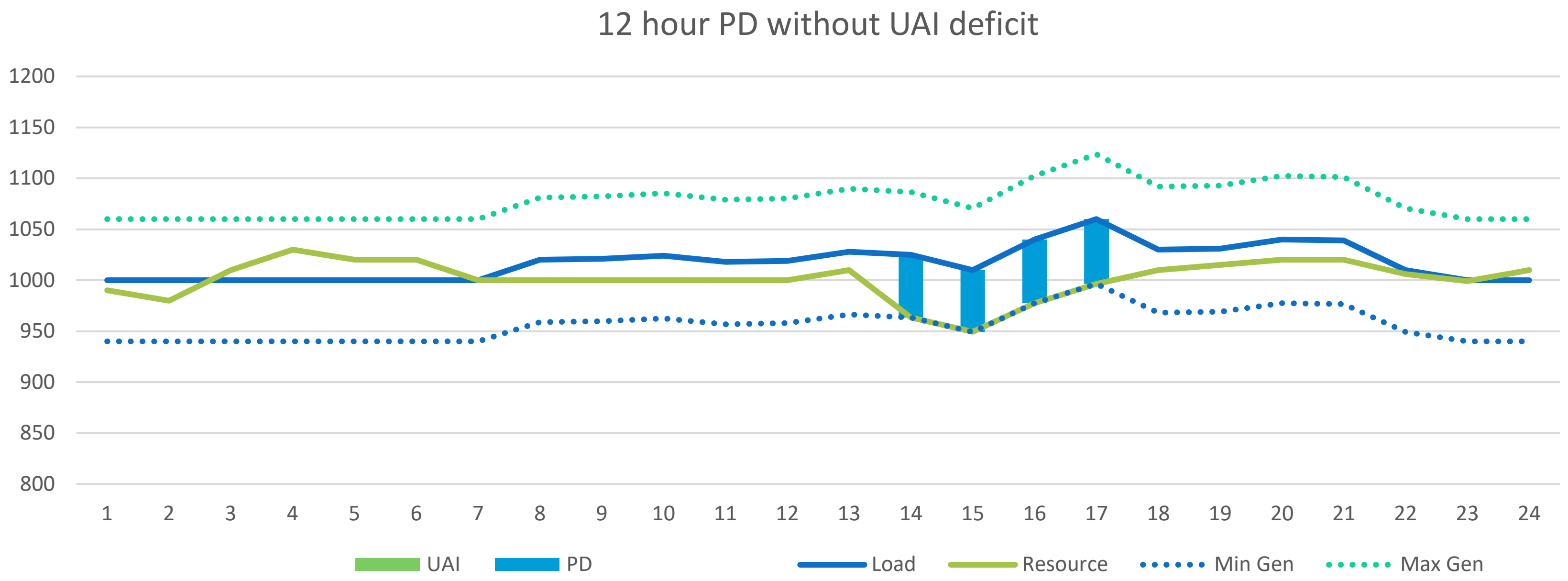
Under-Schedule with No Penalty



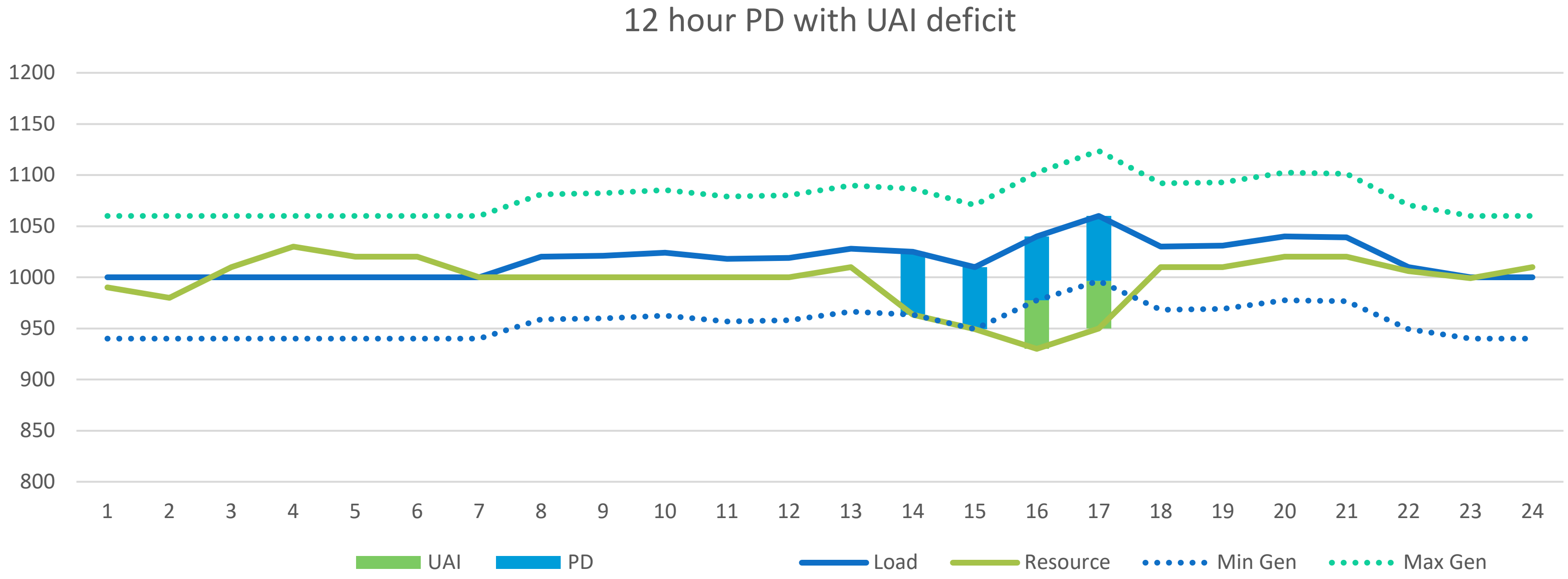
Under-Schedule – UAI without PD



Under-Schedule – PD without UAI



Under-Schedule – UAI and PD



Forward Looking Features

Looking to the Future. With NLSLs growing quickly, increasing by roughly **one gigawatt** in size over the last decade, and with projections potentially reaching **five gigawatts** in the next decade, we will have to increase coordination and sophistication to reliability and efficiently work together to serve these loads. For reference, **Bonneville's current total firm power capability is about seven gigawatts**. As such, we propose these door-opening features to start that process:

- **Data Sharing Discount.** ESS customers that provide Bonneville a 7-day-ahead and a day-ahead forecast of load and each hour and corresponding hourly resource schedules will receive a 10% discount on purchased ESS capacity. ESS discount will not be given for months in which Bonneville determines that a Power Persistent Deviation has occurred.

- **Demand/Resource Response Credit.** An ESS customer receiving the Data Sharing Discount may be eligible to further offset its ESS capacity costs by providing Bonneville access to capacity, via a demand or a resource response, based on terms and conditions negotiated between Bonneville and the ESS customer.

ESS Capacity and Revenue Treatment

- Staff proposes to change the allocation of ESS capacity revenue relative to the BP-24 approach. In the BP-24 approach, if Bonneville had any forecast ESS revenue, it would have been allocated to the Non-Slice Cost Pool.
- Staff proposes to treat ESS capacity the same as all other NR and RSS capacity by allocating it to the Composite Cost Pool.
- Any energy impacts would remain in the Non-Slice Cost Pool as energy is intended to be energy neutral and inventory impacts that result from over- or under-scheduling would financially net to zero as Bonneville manages Non-Slice inventory.
- Consistent with this approach, the capacity held to support ESS would be a Designated System Obligation.

Capacity for Canadian Entitlement (CE) and Balancing Capacity

Purpose

- The term “capacity” is a general term used in industry to describe many, often different, forms of machine capability or contractual flexibility/optionality. It is a term that often belies operational nuances and/or product characteristics.
- The purpose of this presentation is to quickly describe the natures of capacity for CE and Balancing Capacity. The goal is to demonstrate how these two forms of capacity are different and not interchangeable.

Contents

- Overview of Capacity for Canadian Entitlement (CE)
- Capacity Gained with the Reduction to CE as of August 2024
- Nature of Balancing Capacity
- Comparing/Contrasting Capacity for CE and Balancing Capacity

Reduction in Canadian Entitlement

- A substantial reduction in the monthly energy the US is required to return to Canada went into effect August 2024.

- Additionally, the ability to shape the returns is commensurately reduced and the CE schedule is now finalized before bids are due in the CAISO day-ahead market.

- Power Service's benefit is an increase in Shaping Capacity and reduced uncertainty in marketing/water management/planning. Hence forth, this presentation will refer to capacity for CE as Shaping Capacity.

Nature of Balancing Capacity

- Balancing Capacity is machine capability held as an off-the-top obligation for deploying energy to meet unplanned, within hour variances.
- Balancing Capacity is continuously and dynamically deployed by Automatic Generation Control (AGC) in real-time to maintain load/resource balance and system frequency.
- The direction, magnitude and duration of Balancing Capacity deployments are unknown until after-the-fact.

Comparing/Contrasting Shaping Capacity and Balancing Capacity

Shaping Capacity

- No obligatory machine commitment.
- Scheduled (deployed) day ahead for static hourly energy.
- Known deployment quantity and duration.
- Ability to pre-plan energy and hydraulic impact.
- Deployment follows WECC top of hour ramp.

Balancing Capacity

- Off-the-top commitment of physical machine capability.
- Capacity held to be deployed as needed in the moment.
- Unknown quantity varying moment to moment.
- Manage energy and hydraulic impact after-the-fact.
- Ramps as quickly/slowly as needed when needed.

BONNEVILLE POWER ADMINISTRATION

Transmission Costs in Power Rates

Follow-up

- NIPPC/RNW requested a primer on how transmission rates flow through power rates.
- The following table categorizes the areas in which power rates are impacted by transmission rates.
- Not included in the list are any transmission costs included in any power purchases Power may make, such as the ancillary and control area service costs bundled in the Power Purchase Agreement for Klondike III wind.

Line Item in RAM	Summary	Description	PF Public Rate Design Cost Pool	BP-26* ($000)
Transmission & Ancillary Svcs (non-slice)	Transmission used to sell surplus.	Cost include a combination of Long and Short-Term Point to Point (PTP) Transmission supporting secondary sales. Allocated to power rates using a General allocation factor.	Non-Slice Cost Pool	$79,774
Transmission & Ancillary Svcs (sys oblig)	Transmission costs associated with System Obligations	This cost is a combination of Grandfathered Transmission and Point to Point (PTP) transmission to meet system obligations (Canadian Treaty, etc.). Allocated to power rates using a General allocation factor.	Composite Cost Pool	$34,129
Third Party GTA Wheeling	Transfer Costs	Over half of Bonneville's power customers are served by the transmission systems of third parties (not BPA). Bonneville acquires transmission from these third parties to deliver Federal power to Bonneville's power customers. These costs are reflected in this category. The PF Load portion is allocated to the PF Rate Pool and the NR Load Portion allocated to the NR Rate Pool.	Composite Cost Pool	$92,843
Power 3rd Party Transmission & Ancillary Services	Transmission supporting Lost Creek	Cost in this category reflect Long-Term PTP transmission costs and financial settlement of losses associated with Lost Creek hydro facility. Allocated to power rates using a General allocation factor.	Composite Cost Pool	$3,459
Transmission Acq. Generation Integration	Generation Integration	These costs support generation integration, which consists of transmission facilities that integrate federal resources into BPA's network. Allocated to power rates using a General allocation factor.	Composite Cost Pool	$20,194
Balancing Capacity for Federal Resources	Balancing CGS and non-AGC FCRPS generation	Power self supplies (provides to Transmission for zero cost) balancing capacity to balance the portion of the BPA BAA's balancing capacity needs associated with Columbia Generating Station and non-AGC FCRPS generation.	Off-the-Top Obligation	Last estimated to be 22 MW of INC and 24 MW of DEC for BP-26

**Reported values are preliminary and will be updated for the BP-26 Initial Proposal*

Power and Transmission Risk

August Risk Discussion

In August Bonneville staff communicated three areas where potential changes may occur in the risk modeling for BP-26:

1. Accrual to Cash risk model removal (NORM)
2. Modeling tool conversion (NORM)
3. Changes to Treasury Note modeling (Toolkit)

August Risk Discussion Takeaway

- Bonneville staff sees merit in the customer suggestion to limit changes in BP-26 and take a holistic look for BP-29. Particularly if the change is not needed in BP-26 to ensure BPA's recovery of costs.
  - We will still propose to remove the accrual-to-cash risk model in NORM.
  - We will not pursue NORM model conversion for BP-26.
  - We will not pursue a change to the Treasury Note modeling for BP-26 (Toolkit).

Treasury Note Modeling Details

- In August Bonneville staff discussed potentially reducing the amount of the Treasury Note modeled as available end-of-year liquidity when calculating Bonneville’s Treasury Payment Probability (TPP).

- **Origin:** The concept was floated in response to a recent increase in market volatility and the potential impacts on Reserves For Risk (RFR) and liquidity management for the Agency.

- **Still important but not yet ripe**: Due to the changing risk landscape, Bonneville staff believe a review of the risk mitigation package is warranted and agrees with customers that this should be a **holistic and collaborative** review. This should be completed prior to BP-29.

BP-24 Redux

- Bonneville staff found that the approach used in BP-24 served us all very well over the last two years.
- The BP-24 approach, specifically including in rates $129 million in PNRR, supported rate stability during a time in which BPA was close to triggering an RDC in one year and a surcharge/CRAC in the next.
- We have heard similar sentiments from customers, that the BP-24 approach served us well and we even considered building on that success in the PRDM.
- Ultimately, it was a bridge too far for the PRDM, but we believe it's not too far to build in something for BP-26.

BP-26 Staff Initial Proposal

- **PF Power Rate.** Bonneville staff will propose in the Initial Proposal to add Planned Net Revenues for Risk (PNRR) to the BP-26 rates until the BP-26 PF Effective Non-Slice Tier 1 Rate is no greater than $38.85/MWh (9% change from BP-24). No additional PNRR will be added if the BP-26 PF Effective Non-Slice Tier 1 Rate is equal to or higher than $38.85. Bonneville may still need to add PNRR if the risk modeling determines it is needed to support TPP.

- The same as BP-24, we propose to reflect this change in Power's RDC language.

- **Power FY 2026, FY 2027 and FY 2028 RDC.** The FY 2026-2027 Power Rate Schedules and General Rate Schedule Provisions will specify that: a. For FY 2026, FY 2027 and FY 2028, the Administrator shall apply the RDC Amount to reduce power rates through a Power DD in an amount that is the lesser of 1) the RDC Amount, or 2) the Planned Net Revenues for Risk included in power rates for the same year in which the RDC is applied ([amount] in FY 2026. [amount] FY 2027, and [amount] in FY 2028). Any remaining Power RDC Amount may be applied to reduce debt, incrementally fund capital projects, further decrease rates through a Power DD, distribute to customers, or any other Power-specific purposes determined by the Administrator. b. A Maximum RDC Amount (Cap) will not be applicable to the calculated Power RDC Amount for FY 2026, FY 2027, and FY 2028.

Generation Inputs: Proposed Variable Cost Model Follow-up

Questions

- NIPPC/Renewable Northwest: Why are the calculated Energy Shift costs so different between the GARD model and the RiverWare approach?
- Seattle City Light: When removing the Gen Delta Outliers, were any months impacted more than others?

GARD vs RiverWare Cross-walk

- GARD and the RiverWare approach are different in several ways:
  - GARD measures the impacts of holding reserves on four projects while the RW approach looks at the impacts on the whole system.
  - Project and turbine specifications differ between the two models.
  - Pricing assumptions differ significantly between the two models.
  - GARD measures Energy Shift, Efficiency, and Spill costs.
  - RW approach measure Energy Shift and Net Gen Delta. Net Gen Delta includes, among other impacts, the efficiency and spill impacts of the system not only four projects.

GARD vs RiverWare Cross-walk

	Energy Shift:			Efficiency & Spill:		
	Annual MWh	Price (Monthly Averages)	Total Annual Cost ($ Millions)	Annual MWh	Price (Monthly Averages)	Total Annual Cost ($ Millions)
GARD	367,000	SpPk GvYd Spread ($13.62 MW/hr)	8.1	226,000	HLH Avg ($44.19 MW/hr)	3.5
	Energy Shift:			**Net Gen Delta:**		
RW+P	318,000	High low Spread ($2.39 MW/hr)	0.8	668,000	HLH/LLH Avg ($41.96 MW/hr)	9.9

- The primary difference in the Energy Shift costs can be explained by the difference in pricing assumptions between the two models.
- Efficiency and Spill, from the GARD model, cannot be directly compared to the measure of Net Gen Delta from the RiverWare approach.

Observations Removed by Month

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Oct	Nov	Dec
DEC Reserves	79	70	77	72	76	73	77	76	72	81	77	79
INC Reserves	76	69	77	72	76	72	76	76	14	11	72	76

- Removing outliers impacts most months in a similar way. For INCs, Sept. and Oct. have a smaller number of outliers removed because there is very little variation in the Gen Delta for those months.
- The average number of observations before outliers were removed was 730 (the average number of hours in a month).

Meeting Wrap Up and Next Steps

- Please send any feedback, with the topic you are addressing to Bonneville's Tech Forum at techforum@bpa.gov **by October 9**, with a cc to your Power and/or Transmission Account Executive.
- Bonneville will not be responding to comments for this workshop.

Near-Term Schedule (Proposed)

- Oct. 23 (Wed) – Training on Bonneville’s new secure portal
- Nov. 13 (Wed) – Federal Register Notices for BP-26 and TC-26 published
- Nov. 15 (Fri) – Prehearing Conferences for BP-26 and TC-26
- Nov. 15 (Fri) – TC-26 Initial Proposal issued
- Nov. 22 (Fri) – BP-26 Initial Proposal issued