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

BP-24 Rate Case & TC-24 Tariff Proceeding Workshop

July 27-28, 2022

Bonneville
POWER ADMINISTRATION

Agenda – Day 1 July 27th

TIME*	TOPIC	Presenter
9:00 to 9:05 a.m.	Introduction, Meeting Protocols and Agenda	Rebecca Fredrickson Daniel Fisher
9:05 to 9:35 a.m.	Power Rates • EIM Benefits in Power Rates • Customer concerns regarding EIM and Generation Inputs	Steve Gaube Eric Graessley Jonathan Ramse
9:35 to 10:35 a.m.	Power Rates • Washington Cap-and-Invest Program	Alisa Kaseweter Nancy Parker
10:35 to 10:45 a.m.	**BREAK**	
10:45 to 11:30 a.m.	Power Rates • Demand Rate	Emily Traetow
11:30 to 12:00 p.m.	Power Rates • Transfer Service	Jason Boen Derrick Pleger
12:00 to 1:00 p.m.	**LUNCH**	
1:00 to 1:30 p.m.	Generation Inputs • OCBR	Frank Puyleart
1:30 to 1:45 p.m.	Generation Inputs • Load Reliability Service	Libby Kirby
1:45 to 2:15 p.m.	Generation Inputs • Persistent Deviation/Intentional Deviation Review	Bill Hendricks
2:15 to 2:30 p.m.	**BREAK**	
2:30 to 3:25 p.m.	Generation Inputs • VERBS, DERBS, and Load Balancing Services (BP-22 Settlement Commitment)	Libby Kirby Bill Hendricks Eric King
3:25 to 3:30 p.m.	Wrap-up and Day 2 Preview	Rebecca Fredrickson

** Times are approximate*

Agenda – Day 2 July 28th

TIME*	TOPIC	Presenter
9:00 to 9:05 a.m.	Introduction and Agenda	Rebecca Fredrickson Daniel Fisher
9:05 to 9:35 a.m.	Transmission Rates • Sales, Load and LGIA Forecast	Danny Chen Peter Stiffler Todd Foxall Araceli Contreras Jason McKee
9:35 to 10:35 a.m.	Transmission Rates • Concurrent Loss Return Service Rate Proposals (steps 1-4)	Eric King Zach Buus
10:35 to 10:45 a.m.	**BREAK**	
10:45 to 11:30 a.m.	Tariff • Attachment C: Short-Term ATC (steps 5-6)	Margaret Olczak
11:30 to 11:45 a.m.	Tariff • EIM Resource Sufficiency (inform)	Matt Hayes
11:45 to 12:30 p.m.	Tariff • FERC Order 881: Transmission Line Ratings (inform)	Gage Marek Tonya Van Cleave
12:30 to 12:35 p.m.	Wrap-up and Next Steps	Rebecca Fredrickson

** Times are approximate*

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):

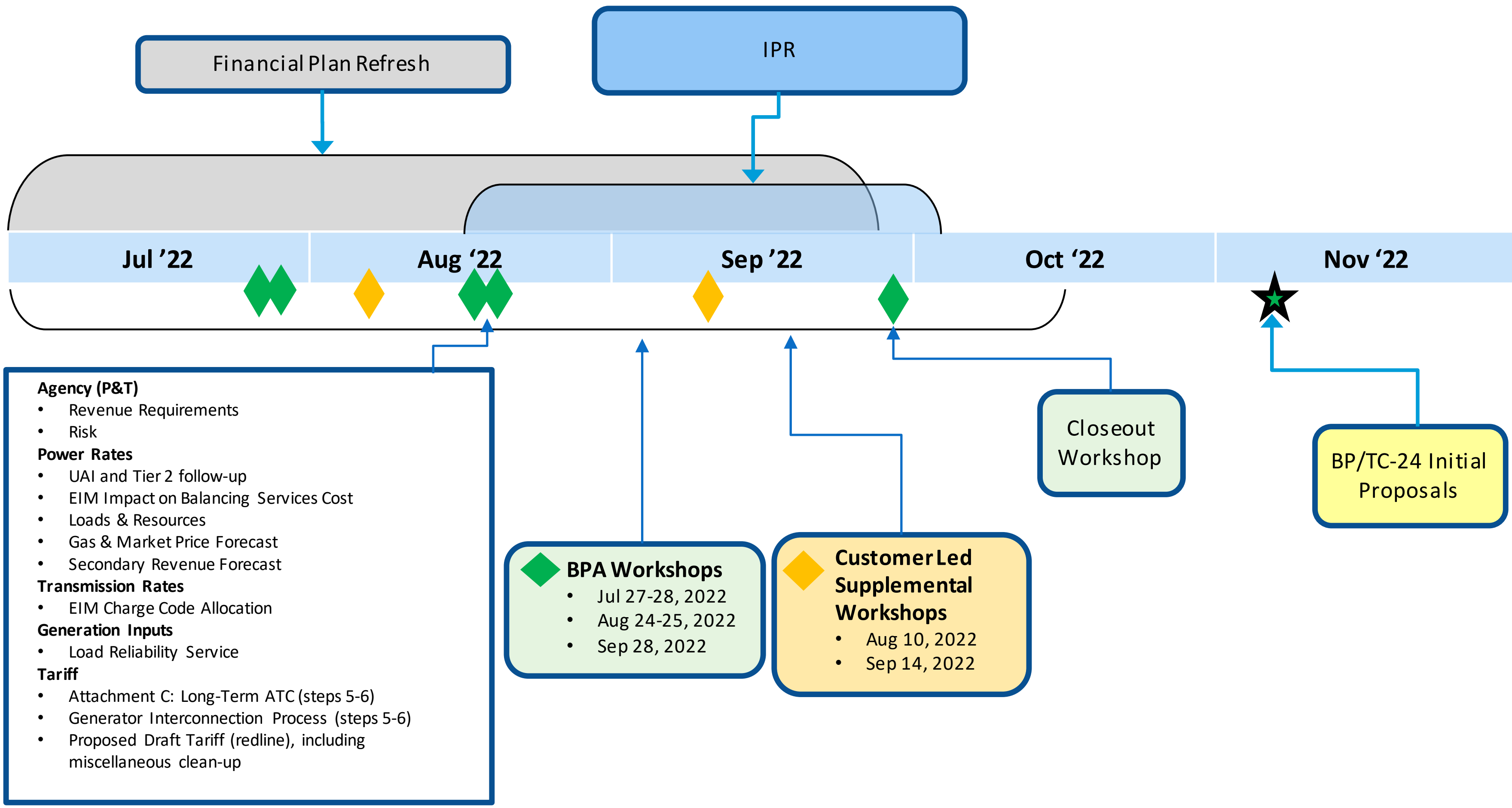
Phase One: Approach Development	Phase Two: Evaluation	Phase Three: Proposal Development
Step 1: Introduction & Education **Step 2: Description of the Issue**	**Step 3: Analyze the Issue** **Step 4: Discuss Alternatives**	**Step 5: Discuss Customer Feedback** **Step 6: Staff Proposal**

- 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.
- In order to be as transparent and responsive as possible, BPA is developing a comment tracking and response process that includes the following:
  - All customer comments will be posted to the BP-24/TC-24 website.
  - BPA will be posting 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-24 workshops where BPA expects to provide a response.
    - To the extent possible, BPA will endeavor to provide responses prior to the next workshop on the BP-24 website (updated CCR will be posted with workshop materials)
    - All comments will have a response

BP/TC-24 Pre-Proceeding Timeline



BP-24 Topics – Day 1

Power Rates

- EIM Benefits in Power Rates
- Customer concerns regarding EIM and Generation Inputs
- Washington Cap-and-Invest Program
- Demand Rate
- Transfer Service

Generation Inputs

- OCBR
- Load Reliability Service
- Persistent Deviation/Intentional Deviation Review
- VERBS, DERBS, and Load Balancing Services (BP-22 Settlement Commitment)

BP-24 Topic
EIM Benefits in Power Rates

- Step 5: Discuss Customer Feedback
- Step 6: Staff Proposal

Step 5: Discussion of Customer Feedback

Customer Feedback

After presenting this topic at the May 25 workshop, we were asked to provide:

"…additional analysis around the likelihood and magnitude of over- and under-estimation relative to [the levels produced by BPA's proposed methodology]"

As explained in our response to this comment, we do not have sufficient information or experience operating in the EIM to more rigorously evaluate such factors at this time, and we have not received any specific, analytic recommendations. We will continue to monitor EIM operations and incorporate any lessons learned throughout the BP-24 rate case, if appropriate.

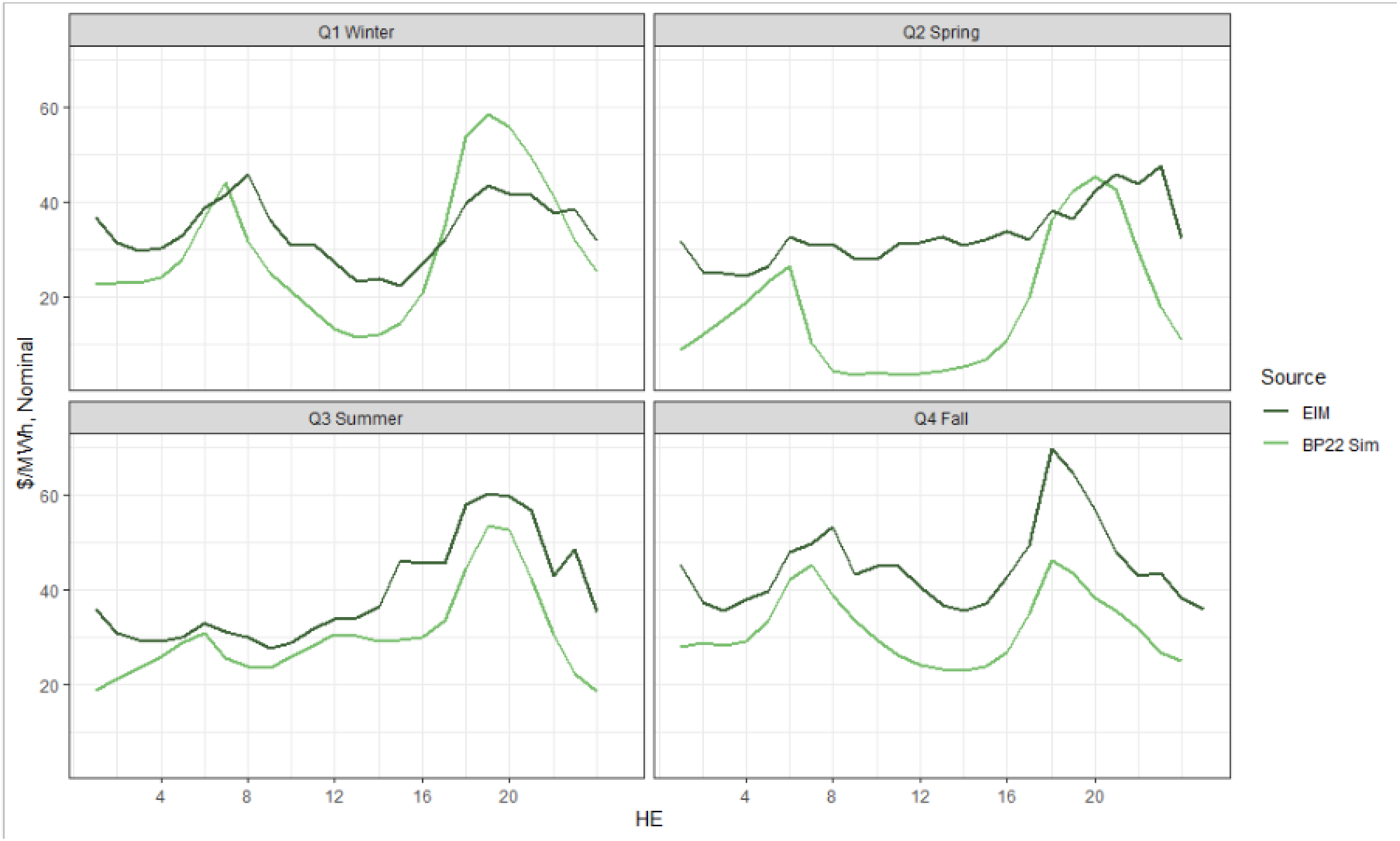
Customer Feedback, Cont'd

We were also asked to provide a comparison of Aurora prices used in the analysis (based on BP-22 hourly NW prices) and actual EIM prices.

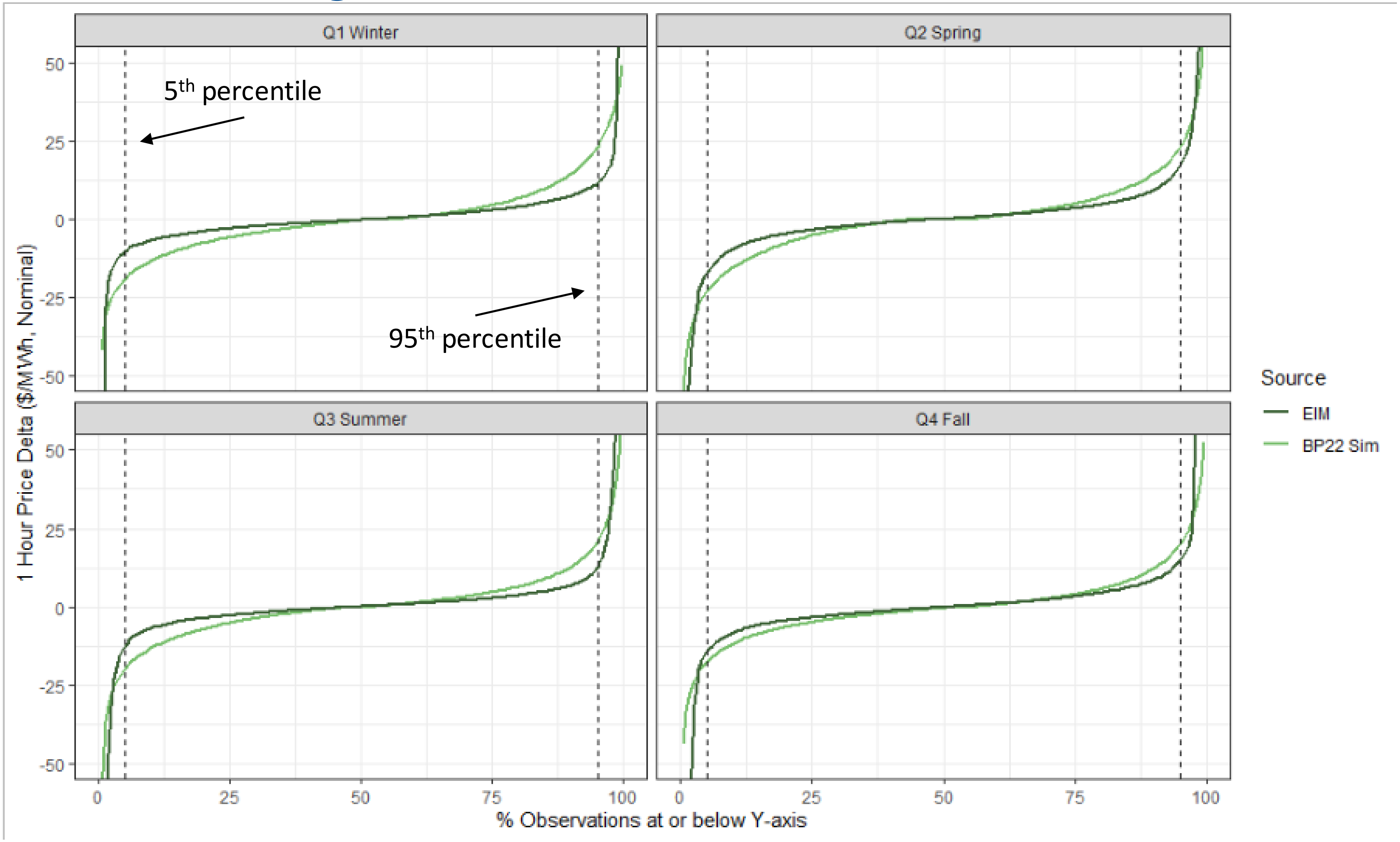
See the next two slides for comparison figures. Regarding these comparisons:

- They are based on BP-22 Aurora prices; values will change for BP-24.
- We are comparing 3200 simulated *futures* under 80 different water years and a variety of other conditions to a *historical* period of the last 3 years (July 2019 – June 2022).
- There are geographic differences: we are comparing the hourly average of PGE, PSE, and PAC-W ELAPs (FMM/RTPD, equally weighted) to Aurora hourly prices in the area of Grant and Chelan PUDs (around Mid-C).

NW Avg. Hourly Prices, by Season



NW Hourly Price Delta Duration Curves



Conclusions

Simulated price shapes and within-day variability align well with recent observed prices and provide a reasonable basis for estimating future EIM prices and associated revenues.

Step 6: Staff Proposal

Recap of EIM Benefits Estimation

The staff proposal is to use the methodology presented in the May 25 workshop:

1. Allow hydro modeling (RiverWare) to assume a lower level of required reserves, freeing up additional flexibility to shape into high-value periods.
2. Use 5th and 95th percentiles of the RiverWare hourly generation deltas for each month and each water year to establish a reasonable range of expected EIM participation under a variety of conditions.
3. Simulate EIM dispatch associated with the corresponding hourly Aurora prices with the following objective and constraints:
   - Assume perfect price knowledge and aggressively dispatch the system to maximize revenue.
   - Maintain daily energy neutrality.
   - Operations must remain within the expected ranges for all hours of the year
4. Use the resulting revenues to estimate EIM benefits for the BP-24 rate period.

Note that the $18M value we shared at the May workshop will be changing for BP-24, as BP-24 assumptions and models are updated.

BP-24 Topic
Customer concerns regarding EIM and Generation Inputs

- Step 5: Discuss Customer Feedback (from previous forums)
- Step 6: Staff Proposal

Objectives

- Overview and review of NIPPC concern.
- New customer comments.
- Staff response and proposal.

Understanding NIPPC's Concern

- NIPPC believes that a portion of the capacity costs allocated to non-regulation balancing reserves should be borne by customers other than ACS customers. This is because a portion of the capacity used to provide ACS is a key component of realizing EIM benefits.
- Specifically, it is our understanding that NIPPC is arguing that while ACS customers gain the benefits of more efficient deployment of energy to meet imbalance, BPA's Power customers (who are also ACS customers) receive incremental EIM-related revenue benefit from non-regulation balancing capacity without directly being allocated a portion of the costs of that capacity.

New Customer Comments

PPC:

- Disagrees with NIPPC’s arguments for two reasons:
  - The PPC believes NIPPC’s argument implies that ACS customers are entitled to some ‘ownership’ of the capacity providing ACS services.
  - The PPC believes it is incorrect to identify gen inputs capacity as the primary driver of BPA’s ability to pass the RS test.
- See PPC Comments on NIPPC Gen-Inputs Presentation for the full PPC comment.

BPA Staff Response

- BPA staff remains unpersuaded by NIPPC's arguments.
- **BPA operates its system to provide a variety of services:**
  - **BPA's current cost allocation methodology applies a system approach.** This reflects that the system is operated as one large interconnected system optimized to meet all system uses. Capacity that is used to support base load is treated the same as capacity that is used to meet peak loads which is treated the same as capacity that is used to cover forecast error.
  - **NIPPC's suggestion is incompatible with the current cost allocation methodology** and is, in BPA's staff opinion, myopically focused on a single system use and impact rather than the interconnected and co-optimized nature of BPA's operations.

BPA Staff Response

- **BPA operates its system to provide a variety of services (cont'd):**
  - **EIM dispatch benefits received by BPA Power are a product of the system and not just capacity used to support ASC.** For example, DEC capacity can be used to store EIM energy (BPA allocates zero fixed costs to DEC capacity) so that the stored energy can later be used to support an hour-to-hour capacity system use.
  - **The EIM does not create a new capacity system use**. Rather, the EIM allows existing capacity system uses to be dispatched (energy) more efficiently across the EIM footprint.
    - The dispatched energy benefits are provided to all EIM participants bidding into the EIM, including any load or resource with forecast error in need of being balanced.

BPA Staff Response

- **EIM costs and benefits are appropriately and consistently allocated to energy uses**
  - **BPA allocates zero Power EIM implementation costs to its capacity uses of the system**. To be consistent, benefits of the EIM should be allocated to energy uses and not to lower the cost of capacity uses.
  - **A significant portion of BPA's EIM energy benefits are already allocated to BPA's balancing services**. The efficiency gained through the EIM lowers the variable energy costs allocated to balancing service. BPA staff's proposed reduction in allocated variable costs represents up to 20% of forecast EIM energy benefits. For reference, non-regulating INC balancing capacity represents roughly 3% of total INC capacity system uses.

BPA Staff Response

- **Additional staff points**:
  - Ancillary and Control Services is a *service* and customers paying for it are not entitled to the underlying capacity or the derivative revenue sourced from that capacity.
  - All of BPA's system capacity uses produce energy revenue when that capacity is used.
    - This is not a unique characteristic of the capacity services that require non-regulating capacity.
    - This energy revenue is used to recover the other two-thirds of Power's revenue requirement that is not allocated to system capacity uses.

Staff Proposal

- Reduce variable costs allocated to non-regulating capacity by the historical percentage of time the BPA BAA has passed the EIM's resource sufficiency test (expected to be more than 90%).

- All of Power's remaining EIM energy benefits will be used to reduce BPA's PF, IP, and NR power rates.

Next Steps

- Comments or questions? Email techforum@bpa.gov and copy your Account Executive

- Please provide comments by August 10th.

BP-24 Topic Washington Cap-and-Invest Program

- Step 1: Introduction & Education
- Step 2: Description of the Issue
- Step 3: Analyze the Issue
- Step 4: Discussions on possible alternatives to solve issue

- Step 1: Introduction & Education

Introduction/Background

- Washington state passed the Climate Commitment Act (CCA), an economy-wide cap-and-invest program, in 2021. The program begins January 2023. Rules are still being finalized.

- The program includes in-state generation and imported electricity. The entity with the obligation of complying with the program for the electricity sector is called the First Jurisdictional Deliverer or FJD.
  - BPA power is considered imported electricity.
  - The program covers imported electricity if the importer's cumulative annual total from both unspecified and specified sources > 25,000 metric tons carbon dioxide equivalency (MT CO_2e) per year.
    - 25,000 MT CO_2e is equal to ~7 aMW of unspecified market purchases or ~142 aMW of BPA power purchases in a relatively average water/emissions year.
  - The CCA gives BPA the option to decide if it will participate in WA's program as the FJD.

Introduction/Background

- All utilities are eligible for no-cost (free) allowances for their "cost burden" under the program, calculated consistent with a forecast of emissions, as long as they are in compliance with CETA.
  - Exact method and quantity of allocations are TBD. Final rules not expected until October.
  - Customers must register with Washington Department of Ecology to receive no-cost allowances. BPA encourages customers to register and work with Ecology to ensure an accurate forecast of power purchases and associated emissions is used in the calculation.
  - BPA also encourages customers to coordinate with BPA to get the best available information on forecasted emissions for the federal system.
  - Allowances can be transferred to BPA who can in turn use them directly for compliance.

Introduction/Background

- BPA will not be the FJD for 2023 but is considering whether it will be the FJD in 2024 or later. In early 2023, BPA intends to make a decision about whether it will be the FJD in 2024, after Washington finalizes the program rules but before the final BP-24 rates are calculated.
- This decision is outside the scope of the rate case, but relevant background information and context is provided in the following slides in order to provide context on the related rate case issues.
- For the initial proposal, BPA may include language enabling cost recovery in the event BPA decides to be the FJD for Washington's cap-and-invest program during the BP-24 rate period.

FJD Considerations: Background

- BPA has an opportunity to decide if it will participate in WA's program as the FJD.
  - There are pros and cons associated with BPA being the FJD.

- BPA is the FJD for California's cap-and-trade program.
  - The California Air Resources Board (CARB) explicitly states BPA and WAPA are the FJDs for imports into CA.
  - Congress authorized BPA to voluntarily purchase allowances in 2019. Prior to that, BPA used third parties to deliver power into CA to not trigger a compliance obligation. This was costly and inefficient, and the Congressional authorization was widely supported by public power.
  - BPA started incurring CA carbon allowance obligations in 2020 related to secondary sales to the CAISO. BPA procures allowances in CARB's auctions to cover our compliance obligation for surplus sales into the state.
  - BPA has one preference customer with load in CA. That customer receives a free allowance allocation from CARB and transfers allowances to BPA to cover the compliance obligation for service to its retail load in California.
  - Significant difference from WA law: CA does not have a threshold for imported power. All imports incur a compliance obligation.

Summary of FJD Considerations

	If BPA is not the FJD	If BPA is the FJD
Annual WA PF Sales covered under program	BPA is not responsible for compliance. • Sales to large WA customers are covered; those customers would be the FJD (~560,000 MT CO2e) • ~42-50 small customers would be under the threshold and not covered under the program (~170,000 MT CO_2e)	All PF sales (~730,000 MT CO_2e) All customers indirectly covered under program
Annual costs for compliance for PF sales	BPA costs are zero ($1.85 million in costs for customers over the threshold who would be the FJD)	$2.4 million total (including $550,000 attributed to emissions for sales to smaller customers brought under the program)
Trading Floor impacts	Additional revenues expected due to program increasing market prices. But some of this would be offset due to increased risks to secondary revenues: • Transactional Friction • Potential future EIM lost benefits	Additional revenues expected due to program increasing market prices. Reduces risks to secondary revenues: • Removes transactional friction • Potential future EIM benefits
Administrative Workload	Lower administrative workload BPA will still report ACS emissions factor and sales	Increased administrative workload associated with compliance with the program

Based on current estimates for compliance in early years of program.

Threshold Considerations

- WA's 25,000 MT CO_2e threshold for imported power makes the decision of whether BPA should be the FJD complicated.

- If BPA does not opt to be the FJD, many (~42-50) of our smaller customers will fall under the 25,000 MT CO_2e threshold and will not need to comply with the program.
  - However, 6-7 large customers exceed the threshold just based on purchases from BPA (> ~142 aMW).
  - Impacts to remaining customers are unclear and could vary annually (depends on federal system emissions, BPA purchases & nonfederal purchases).

- If BPA opts to be the FJD we would indirectly bring all customers and BPA WA sales into the program.
  - But utilities receive free allowances that can be transferred to BPA to be used for compliance.
  - A few of BPA's larger customers could have FJD compliance obligations for nonfederal purchases in combination with their federal purchases if BPA is not the FJD, but could avoid triggering the threshold and thus compliance under the program for those non-federal purchases if they are only the FJD for their non-federal purchases.

Cost Considerations for PF Sales

While a majority of customers by count (42-50) would have emissions under the threshold if BPA is not the FJD, the majority of federal emissions (75-80%) will be covered under the program regardless of who is the FJD.

Estimated Annual Program Costs **Assuming Need to Buy 10% of Allowances**	
Costs for PF Power Sales Regardless of who is the FJD 75-80% of federal emissions attributable to WA PF customers will be covered under the program regardless of whether BPA or customers are the FJD.	$1.85 million
Incremental Costs associated with BPA being the FJD The additional ~170,000 MT CO_2e associated with sales to smaller WA customers, which are only covered under the program and incurred if BPA opts to be the FJD.	$550,000
Total Costs if BPA is the FJD Cost for ~730,000 MT CO_2e associated with firm (PF) power sales into WA.	$2.4 million

There are several ways these costs could be allocated. Recovery of costs would be determined in the applicable rate case.

Assumptions:

- Customers receive 90% of allowances needed for compliance free from Washington, which are transferred to BPA to be used for compliance with the program.
- Average federal system emissions (0.02 MT CO_2e/MWh)
- WA allowance price = currently expected cost of CA allowances in 2025 (~$32 per allowance, i.e. per MT CO_2e).

Actual cost will vary based on emissions/water year and price of allowances. Costs can be expected to increase over time as the price of allowances increase, particularly if federal system emissions do not decrease over time.

Trading Floor Considerations (Transactional Friction if BPA is not the FJD)

- **Liquidity:** Decision could negatively impact market liquidity if BPA counterparties chose not to transact with BPA due to FJD costs or risk of exceeding the 25,000 MT threshold.
- **Price:** Value of BPA energy is expected to increase regardless. However, if BPA opts not to be the FJD, the price BPA receives is expected to be lower due to unique FJD cost exposure rules when buying BPA power that could be used to serve WA loads.
- **Competitiveness:** If BPA opts not to be the FJD, unique FJD cost exposure, scheduling challenges, and administrative workload requirements for purchasing BPA power is expected to negatively impact BPA competitiveness in the market.
- **EIM Benefits:** BPA must be FJD in the CA cap-and-trade program to receive EIM dispatch orders for CA loads. Same rules may apply for WA loads in the future.
- **Administrative Workload:** BPA is the FJD for one Preference Customer in CA. If BPA opts to be the FJD in WA, the administrative workload will increase significantly to accommodate WA Preference Customers (~ 60 Customers).
- **Compliance Costs:** If BPA opts to be the FJD, our GHG compliance hedging program will increase in volume and complexity.

Trading Floor Considerations

- Trading Floor sales used to serve WA load were ~4,000,000 MWhs in FY21.
- Trading Floor sales used to serve WA load are expected to increase as WA customers pursue strategies to lower their compliance costs.
- If BPA opts to be the FJD, the Trading Floor is able to claim all transactions (ICE, broker and bilateral) as low carbon Specified Source ACS energy.
- If BPA opts not to be the FJD, counterparties will be exposed to claiming BPA power as Unspecified Sourced energy.
- Small impacts to Trading Floor price, volume, and competitiveness in the market could have a large impact on secondary revenues.
- Trading Floor is participating in the evolution of markets, contracts, and marketing platforms to address new WA cap-and-invest rules.

Administrative Workload Considerations

- There will be additional work for BPA regardless of whether it is the FJD, but there is additive work associated with being the FJD.

- Initial Start Up Work
  - BP-24 rate case to determine recovery of costs. This needs to occur unless BPA decides it will not be the FJD until 2026.
  - Contract revisions to enable automatic transfer of allowances, and associated discussion around specifics of quantity, etc. (Needs to be included for POC contracts too.)

- Ongoing Work
  - Annual reporting (emissions factor, sales). Required regardless of whether BPA is the FJD.
  - Management, validation, and transfer of allowances from customers to BPA and BPA to Ecology for compliance. BPA requested Ecology automate some of this to make it less burdensome.
  - Calculating allowance need and budget. Monitoring and participating in auctions and procuring allowances.

Next Steps for BPA's FJD Decision

- Washington's cap-and-invest program will create additional costs and administrative work for BPA and its customers and impact power markets regardless of BPA's decision.

- BPA will not be the FJD for 2023.
  - BPA must ensure recovery of costs. BPA needs customers to transfer no-cost allowances they receive for the federal system to BPA, which BPA would use directly for compliance. BPA needs assurance that this will happen through contract revisions and/or rates. As a practical matter, January 2023 is not enough time for BPA to obtain these contract revisions.

- BPA is weighing customer and constituent feedback before it makes a decision on whether it will be the FJD in 2024 or later.

- BPA intends to include language in the BP-24 initial rate proposal to enable cost recovery should BPA be the FJD, and reflect BPA's FJD decision in the final rate proposal (see next section for specifics).

- Steps 2, 3 & 4: Issue Description, Analysis, and Alternatives

BP-24 Power Rate Proposal Issues

- Issues to include in BP-24 that would apply in the event BPA opts to be the FJD:
  1) Treatment of costs associated with customers that do not agree to transfer their allocation of no cost allowances for the federal system to BPA.
  2) Treatment and forecast of costs associated with compliance for PF and surplus sales (above those costs covered by transfer of no cost allowances).

- Washington's program is evolving and rules are not yet final. An update between BPA's initial proposal and final proposal may be necessary to reflect final WA CCA program rules and BPA's decision on whether to be the FJD in 2024.

- Given that this is a new program, BPA will take a fresh look at these issues for BP-26.

Issue 1: Treatment for Transferring No Cost Allowances

- BPA expects customers will register for and transfer to BPA the no-cost allowances that customers receive from Ecology for federal system emissions. The allowances will be used by BPA to cover the compliance obligation associated with power sales to the customer.

- This is not a rate case topic, but some background for customers agreeing to transfer allowances:
  - The specific mechanics and contract language around transferring allowances will be included in an exhibit D revision if and when BPA decides to be the FJD. This would be a bilateral revision.
  - BPA currently envisions customers will transfer their no-cost allowances to BPA in an amount up to the amount needed by BPA for actual compliance for federal system emissions attributed to sales to the individual customer.
  - Customers would retain any excess no-cost allowances, which customers could bank for later use or consign to auction in accordance with CCA program rules.

Issue 1: Treatment for Transferring No-Cost Allowances

- Applies to customers that either 1) do not execute the Exhibit D revision and thus do not to transfer no-cost allowances to BPA or 2) do not register with Ecology for allowances and thus do not receive any allowances.
- Staff intend to include language in the BP-24 initial rate proposal to address this scenario.
- Staff Leaning: The customer would receive a one-time annual charge on their power bill for actual costs incurred by BPA to purchase allowances necessary to cover all emissions attributed to sales from BPA to the customer for the previous compliance year, plus a cost adder for the service.
  - BPA would determine the compliance obligation for the customer after the state reporting deadline (post-June 1) and would then procure allowances at the next program auction to cover the entire compliance obligation for the customer.
  - BPA expects to include an additional cost adder to cover the service of purchasing all of these allowances and related risks.

Issue 2: Forecast of Costs for BP-24

- Regardless of BPA's decision on whether to be the FJD, BPA expects to realize benefits to surplus sales in terms of increased market prices due to the CCA.
  - A discussion on forecast market prices is scheduled for the August workshop.

- If BPA is not the FJD, some of these benefits will be offset by costs associated with increased transactional friction for surplus sales. BPA is unable to quantify these cost impacts at this time, so it will not be reflected in BP-24.

- If BPA is the FJD, there will be less transactional friction but will be additional costs associated with procuring allowances for surplus sales and potentially PF sales (i.e., the difference between the forecast of no-cost allowances and actual compliance obligation).

Issue 2: Forecast of Costs for BP-24

- For BP-24, staff have identified two options:

  1) Assume $0 for costs of purchasing allowances for PF and surplus sales.
     - Pro: Simple; BPA has not yet made a decision and costs are expected to be relatively small.
     - Con: If BPA opts to be the FJD, this results in an inequitable allocation between Slice and non-Slice products.
  2) Assume a cost (e.g., $2.4 million) that is included in the composite cost pool.
     - Pro: More equitable allocation between Slice and non-Slice products.
     - Con: Won't necessarily capture all costs and benefits. There are still significant uncertainties around how the program will function.

Either option could be subject to the Slice true-up; however, it would be complicated and based on forecasts as well.

Issue 2: Forecast of Costs for BP-24

- BPA will revisit this issue in BP-26 after additional information is known.

- In the future, BPA may consider several options for forecasting and allocating costs in the event the number of no-cost allowances transferred from customers and the amount direct charged to customers (discussed under issue 1) are not sufficient to cover the emissions associated with PF sales to WA customers.
  - Options may range from direct assignment of costs to spreading costs over all customers.

Next Steps

- Comments or questions? Email techforum@bpa.gov and copy your Account Executive
- Please provide comments by August 10th.

BP-24 Topic Demand Rate

- Step 1: Introduction & Education
- Step 2: Description of the Issue
- Step 3: Analyze the Issue
- Step 4: Discuss Alternatives

Steps 1 & 2: Introduction, Education and Description of Issue

Background on Demand Rates

- The Demand Rate applies to customers purchasing PF Load Following and Block with Shaping Capacity, and power sold at the IP and NR rates.
- The TRM states that the demand rate will be based on the annual fixed costs (capital and O&M) of the marginal capacity resource as determined in each 7(i) process.
- The TRM gives BPA discretion to determine the source data for the costs of the marginal capacity resource.
- Since BP-12, BPA has used a General Electric LMS100 intercooled gas turbine for the marginal capacity resource.
- The choice to use the LMS100 was primarily based on its operational flexibility as well as its use by others in capacity-benchmark analyses.
- The Northwest Power and Conservation Council (NWPPC or the Council) discussed the LMS100 in its Sixth Power Plan as a reasonable source of flexible capacity.

Previous Demand Rates

- Average monthly PF/NR/IP demand rate in $/kW/mo:

BP-12	BP-14	BP-16	BP-18	BP-20	BP-22
$9.62	$9.32	$9.88	$9.79	$10.29	$9.67

- Revenues from demand rate are credited to the non-slice cost pool.

- Increasing the demand rate increases effective rates for low load factor customers (i.e., peaky Load Following customers) and decreases effective rates to high load factor customers (i.e., Block customers).

Demand Rate Inputs

Input	Source
Heat Rate Btu/kWh	NWPPC microfin model*
All-in Capital Costs $/kW	NWPPC microfin model* in 2012 dollars
Fixed O&M $/kW/yr	NWPPC microfin model* in 2012 dollars
Fixed Fuel Costs $/kW/yr	NWPPC microfin model*, average of the existing eastside and westside Pacific Northwest fixed fuel costs
Insurance Rate %	NWPPC 7th power plan, appendix H
Cost of Debt %	BPA's third-party tax-exempt 30-Year borrowing rate forecast
Inflation %	5 year average inflation rate based on Bureau of Economic Analysis' gross domestic product implicit price deflator
Monthly shape (convert annual rate to monthly rates)	HLH Load Shaping rates (based on Aurora market prices at average water)

* BP-12 demand rates used a version of microfin developed as a tool for the sixth power plan. Since then demand rates have been updated using microfin versions developed for the seventh power plan.

BP-22 Demand Rate

	A	B	C	D	E	F	G	H	I	J
1				Calendar Year	Chained GDP IPD		Month	Load Shaping Rate HLH $/MWh	Demand Shaping Factor	Monthly Demand Rate $/kW/mo
2	Start Year of Operation (FY)	2022		2015	104.624		Oct	29.92	8.50%	$ 9.87
3	Cost of Debt	2.42%	/1	2016	105.722		Nov	31.71	9.01%	$ 10.46
4				2017	107.710		Dec	38.76	11.01%	$ 12.78
5	Inflation Rate	1.66%		2018	110.296		Jan	34.29	9.74%	$ 11.31
6	Insurance Rate	0.25%	/2	2019	112.265		Feb	34.79	9.88%	$ 11.47
7				2020	113.625		Mar	27.57	7.83%	$ 9.09
8	Debt Finance Period (years)	30	/2				Apr	20.71	5.88%	$ 6.83
9	Plant Lifecycle (years)	30	/2		101.66%	5-year Ave.	May	16.28	4.62%	$ 5.36
10							Jun	17.15	4.87%	$ 5.65
11	Plant in service 2022 Vintaged Heat Rate Btu/kWh	8,541	/3				Jul	36.83	10.46%	$ 12.14
12				Chained GDP IPD from BEA -- Table 1.1.9. Implicit Price Deflators for Gross Domestic Product (2012 Base year) - Last Revised April 29, 2021			Aug	35.87	10.19%	$ 11.83
13	Eastside Fixed Fuel $/kW/yr with 10000 Heat Rate 2012$	$ 41.42	/3				Sep	28.15	8.00%	$ 9.29
14	Westside Fixed Fuel $/kW/yr with 10000 Heat Rate 2012$	$ 46.03	/3						Average $/kW/mo	$ 9.67
15	Eastside Fixed Fuel $/kW/yr with 10000 Heat Rate 2022$	$ 48.85								
16	Westside Fixed Fuel $/kW/yr with 10000 Heat Rate 2022$	$ 54.29								
17	Average of Existing Eastside and Westside with 10000 Heat Rate 2022$	$ 51.57								
18	Average of Existing Eastside and Westside with 8541 Heat Rate 2022$	$ 44.05								
19										
20	All-in Nominal Capital Cost LMS100 $/kW	$ 1,179.47	/4	End of Fiscal Year	Midyear Assessed Value	Debt Payment	Fixed O&M	Insurance	Fixed Fuel	Cash Expense Each Year
21	Fixed O&M $/kW/yr 2022$	12.97	/5	2022	$ 1,159.81	$55.75	$ 12.97	$ 2.90	$ 44.05	$ 115.67
22	Fixed Fuel $/kW/yr	$ 44.05		2023	$ 1,120.50	$55.75	$ 13.19	$ 2.80	$ 44.78	$ 116.52
23							Rate Period Average Expense $/kW/year			$ 116.10
24										

Steps 3 & 4: Analyze and Discuss the Issue

2021 NW Power Plan

- There are two major types of natural gas resources that the Council assessed for the 2021 Power Plan – 1) combined cycle combustion turbines (CCCT), and 2) gas peakers (which include various simple cycle combustion turbine (SCCT) technologies and reciprocating engines).
  - CCCTs are highly efficient generating resources that can provide baseload and dispatchable power.
  - Gas peakers are generating units that can ramp up and down quickly to meet sharp spikes in demand.

- The Council selected two gas peakers as reference plants in the 2021 NW Power Plan:
  - Simple Cycle Combustion Turbine (SCCT): GE 7HA.02 Frame
  - Reciprocating (Recip): Wartsila 18V50SG gensets

- There are three primary SCCT technologies available today: frame, aeroderivative, and intercooled.
  - The LMS100 plant (which has been used as the basis for the demand rate) is an intercooled SCCT, a hybrid of frame and aeroderivative technologies.
  - The Council settled on the frame technology as the SCCT reference plant because it is the least expensive option, although it is the least flexible of the gas peakers.

- More recently, recip plants have been used for peak load-following, and for shaping the output of wind and solar variable energy resources.
  - These large internal combustion engines offer rapid response and quick start-up capability.
  - The fixed O&M costs and the heat rates of a Wartsila recip have decreased over the years.

BP-24 Demand Rate Proposal

- Should we continue to use the LMS100 as the marginal capacity resource or move to the Wartsila reciprocating generating plant that the Council used as a reference plant in the 2021 NW Power Plan?

- The LMS100 is still a reasonable benchmark for the marginal cost of capacity, but staff is leaning towards proposing the Wartsila as the marginal resource in the Initial Proposal.

- Of the two gas peakers selected as reference plants by the Council, (the SCCT frame and the recip) the Wartsila recip is most like the LMS100. The LMS100 and Wartsila recip are fast and flexible resources that are primarily used for peak load-following and resource shaping, as compared to the slower and less flexible SCCT frame.

- Within the Pacific Northwest, PGE installed Wartsilla reciprocating engine generation units at Port Westward in 2014.

Demand Rate Proposal Comparison

Demand Rate Summary:	BP-22 Final	BP-24 Workshop	BP-24 Workshop
	LMS-100	Wartsila - Gas Recip	LMS-100
Inflation %	1.66%	2.28%	2.28%
Cost of Debt %	2.42%	3.06%	3.06%
All-in Capital Cost $/kW	$ 1,179	$ 1,575	$ 1,311
Debt Payment $/kW/yr	$ 56	$ 81	$ 67
Fixed O&M $/kW/yr	$ 13	$ 6	$ 15
Insurance $/kW/yr	$ 3	$ 4	$ 3
Fixed Fuel $/kW/yr	$ 44	$ 24	$ 50
Demand Rate $/kW/yr	$ 116	$ 115	$ 135
Monthly Average $/kW/mo	**$ 9.67**	**$ 9.54**	**$ 11.25**
Forecast Annual Average Demand Revenue Credit* in Millions $	$ 55	$ 54	$ 64
	Inputs not adjusted for inflation		
Microfin Vintage	7th power plan	2021 power plan	7th power plan
Average Heatrate btu/kWh	8,541	8,797	8,541
Microfin Dollars	2012	2016	2012
Insurance Rate %	0.25%	0.25%	0.25%
All-in Capital Cost $/kW	1000	1315	1000
Fixed O&M $/kW/yr	11	5	11
Eastside Fixed Fuel $/kW/yr	35	17	36
Westside Fixed Fuel $/kW/yr	39	23	40

* BP-22 forecast annual average demand revenue credits are based on FY22/23 load forecasts from BP-22 final proposal. The BP-24 forecasts are based on FY24/25 load forecasts from the BP-24 RHWM Process.

Draft BP-24 Wartsila Demand Rate

	A	B	C	D	E	F	G	H	I	J
1				Calendar Year	Chained GDP IPD		Month	BP-22 Load Shaping Rate HLH $/MWh	Demand Shaping Factor	Monthly Demand Rate $/kW/mo
2	Start Year of Operation (FY)	2024		2016	105.740		Oct	29.92	8.50%	$ 9.74
3	Cost of Debt	3.06%	/1	2017	107.747		Nov	31.71	9.01%	$ 10.32
4				2018	110.321		Dec	38.76	11.01%	$ 12.61
5	Inflation Rate	2.28%		2019	112.294		Jan	34.29	9.74%	$ 11.16
6	Insurance Rate	0.25%	/2	2020	113.648		Feb	34.79	9.88%	$ 11.32
7				2021	118.370		Mar	27.57	7.83%	$ 8.97
8	Debt Finance Period (years)	30	/2				Apr	20.71	5.88%	$ 6.73
9	Plant Lifecycle (years)	30	/2		102.28%	5-year Avg.	May	16.28	4.62%	$ 5.29
10							Jun	17.15	4.87%	$ 5.58
11	Lifetime Average Heat Rate Btu/kWh	8,797	/2				Jul	36.83	10.46%	$ 11.98
12				Chained GDP IPD from BEA -- Table 1.1.9. Implicit Price Deflators for Gross Domestic Product (2012 Base year) - Last Revised April 28, 2022			Aug	35.87	10.19%	$ 11.67
13	Eastside Fixed Fuel $/kW/yr with 8797 Heat Rate 2016$	$ 16.57	/2				Sep	28.15	8.00%	$ 9.16
14	Westside Fixed Fuel $/kW/yr with 8797 Heat Rate 2016$	$ 22.54	/2					**Average $/kW/mo**		**$ 9.54**
15	Average Eastside and Westside 2016$	$ 19.56								
16										
17	All-in Capital Cost Recip $/kW 2024$	$ 1,575.18	/3	End of Fiscal Year	Midyear Assessed Value	Debt Payment	Fixed O&M	Insurance	Fixed Fuel	Cash Expense Each Year
18	Fixed O&M $/kW/yr 2024$	5.99	/4	2024	$ 1,548.93	$80.99	$ 5.99	$ 3.87	$ 23.42	$ 114.27
19	Fixed Fuel $/kW/yr 2024$	23.42		2025	$ 1,496.42	$80.99	$ 6.13	$ 3.74	$ 23.95	$ 114.81
20							**Rate Period Average Expense $/kW/year**			**$ 114.54**

* Uses data from a microfin model developed for the 2021 power plan.

Draft BP-24 LMS100 Demand Rate

	A	B	C	D	E	F	G	H	I	J
1				**Calendar Year**	**Chained GDP IPD**		**Month**	**BP-22 Load Shaping Rate HLH $/MWh**	**Demand Shaping Factor**	**Monthly Demand Rate $/kW/mo**
2	Start Year of Operation (FY)	2024		2016	105.740		Oct	29.92	8.50%	$ 11.47
3	Cost of Debt	3.06%	/1	2017	107.747		Nov	31.71	9.01%	$ 12.16
4				2018	110.321		Dec	38.76	11.01%	$ 14.86
5	Inflation Rate	2.28%		2019	112.294		Jan	34.29	9.74%	$ 13.15
6	Insurance Rate	0.25%	/2	2020	113.648		Feb	34.79	9.88%	$ 13.34
7				2021	118.370		Mar	27.57	7.83%	$ 10.57
8	Debt Finance Period (years)	30	/2				Apr	20.71	5.88%	$ 7.94
9	Plant Lifecycle (years)	30	/2		102.28%	5-year Avg.	May	16.28	4.62%	$ 6.24
10							Jun	17.15	4.87%	$ 6.57
11	Lifetime Average Heat Rate Btu/kWh	8,541	/3	Chained GDP IPD from BEA -- Table 1.1.9. Implicit Price Deflators for Gross Domestic Product (2012 Base year) - Last Revised April 28, 2022			Jul	36.83	10.46%	$ 14.12
12							Aug	35.87	10.19%	$ 13.75
13	Eastside Fixed Fuel $/kW/yr with 10000 Heat Rate 2012$	$ 41.67	/3				Sep	28.15	8.00%	$ 10.80
14	Westside Fixed Fuel $/kW/yr with 10000 Heat Rate 2012$	$ 46.31	/3						**Average $/kW/mo**	**$ 11.25**
15	Eastside Fixed Fuel $/kW/yr with 8541 Heat Rate 2012$	$ 35.59								
16	Westside Fixed Fuel $/kW/yr with 8541 Heat Rate 2012$	$ 39.55								
17	Average Eastside and Westside 2012$	$ 37.57								
18				**End of Fiscal Year**	**Midyear Assessed Value**	**Debt Payment**	**Fixed O&M**	**Insurance**	**Fixed Fuel**	**Cash Expense Each Year**
19	All-in Capital Cost LMS100 $/kW 2024$	$1,311.01	/4	2024	$ 1,289.16	$67.41	$ 14.42	$ 3.22	$ 49.26	$ 134.31
20	Fixed O&M $/kW/yr 2024$	14.42	/5	2025	$ 1,245.46	$67.41	$ 14.75	$ 3.11	$ 50.38	$ 135.65
21	Fixed Fuel $/kW/yr 2024$	49.26							**Rate Period Average Expense $/kW/year**	**$ 134.98**

* Uses data from a microfin model developed for the 7th power plan.

Next Steps

- Comments or questions? Email techforum@bpa.gov and copy your Account Executive
- Please provide comments by August 10th.

BP-24 Topic
Transfer Service

Transfer Service

BPA's Transfer Service group acquires transmission across third-party transmission systems for service to loads outside Bonneville's Balancing Authority Area. The current annual cost to provide this service to all transfer customers is roughly $85 million.

The following slides look at the rates that impact Transfer Service customers:

- Transfer Service Operating Reserve Charge
- Transfer Service Regulation and Frequency Response Charge
- Transfer Service Delivery Charge (TSDC).
- Transfer Service Regional Compliance Enforcement Charge.

Transfer Service Operating Reserve Charge

- Transfer Service Operating Reserve Rate – no changes from previous rate case
  - The rate for the Transfer Service Spinning Operating Reserve Charge shall be equal to the ACS-24 Operating Reserve – Spinning Reserve Service rate.
  - The rate for the Transfer Service Supplemental Operating Reserve Charge shall be equal to the ACS-24 Operating Reserve – Supplemental Reserve Service rate.

Transfer Service Regulation and Frequency Response Charge

- Transfer Service Regulation and Frequency Response Rate – no changes from previous rate case
  - The rate for the Transfer Service Regulation and Frequency Response Charge shall be equal to the ACS-24 Regulation and Frequency Response.

Transfer Service Delivery Charge (TSDC) Rate

- Current TSDC rate is $1.27/kW.
- Estimated TSDC for BP-24 is $1.24/kW.
- This is a **decrease of approximately 2%.**
- The rate decrease is mainly due to slightly lower costs BPA is incurring from providers for energy delivered over non-Federal low voltage facilities.

Transfer Service Regional Compliance Enforcement Charge

- BPA charges the Transfer Service Regional Compliance Enforcement Rate (TSRCE) to customers served by transfer to recover WECC-related costs for loads located on the systems of third-party transmission providers.
  - Current TSRCE rate is 0.03 mills/kWh.
- Upon reviewing the BP-22 TSRCE rate calculation, staff noticed that not all TSRCE WECC costs incurred by Bonneville for Transfer Customers' loads were being recovered.
  - The TSRCE rate currently recovers WECC costs that are directly charged to BPA by third-party providers. Some TP's, though, roll in these costs into other rates (*e.g.,* the network rate). The TSRCE does not recover WECC costs that are rolled into the network rate.
  - Costs of Network transmission service for Transfer Service are recovered from the Composite Cost Pool.
- Because rolled-in WECC charges are included in the Network transmission charges, these costs are being paid, in part, by all power customers through the Composite Cost Pool.
  - Power customers located on BPAT's system, however, already pay directly for their own share of WECC charges.

Transfer Service Regional Compliance Enforcement Charge

- BPA Staff propose to update the TSRCE to recover both directly charged WECC costs and imputed WECC costs (i.e., rolled into other rates).
- This proposal avoids the problem of unequal allocation of WECC charges, with non-transfer customers paying for a portion of the overall TSRCE costs BPA's Transfer Customers were incurring.
- The imputed WECC charge is calculated by comparing the per MWh WECC charges assessed by other Transmission Providers and imputing that rate as the cost for the Transmission Providers that do not directly assign these costs. Using this methodology, BPA estimates the WECC charge for all Transmission Providers is around 0.048 mills/kWh.
  - When applying the same rounding as done to establish the Regional Compliance Enforcement within BPA's Transmission Rates, Transfer Service comes up with 0.05 mills/kWh.
- BPA staff estimate this rate change to increase costs to Transfer Customers by roughly $250,000 per year. The Composite Cost Pool will receive a corresponding reduction in Transfer Service Costs.

Next Steps

- Comments or questions? Email techforum@bpa.gov and copy your Account Executive

- Please provide comments by August 10th.

BP-24 Topic
OCBR Changes for EIM

Presentation Agenda

- Changes to OCBR Triggers
- Changes to OCBR Limitations
- Changes to OCBR Curtailments

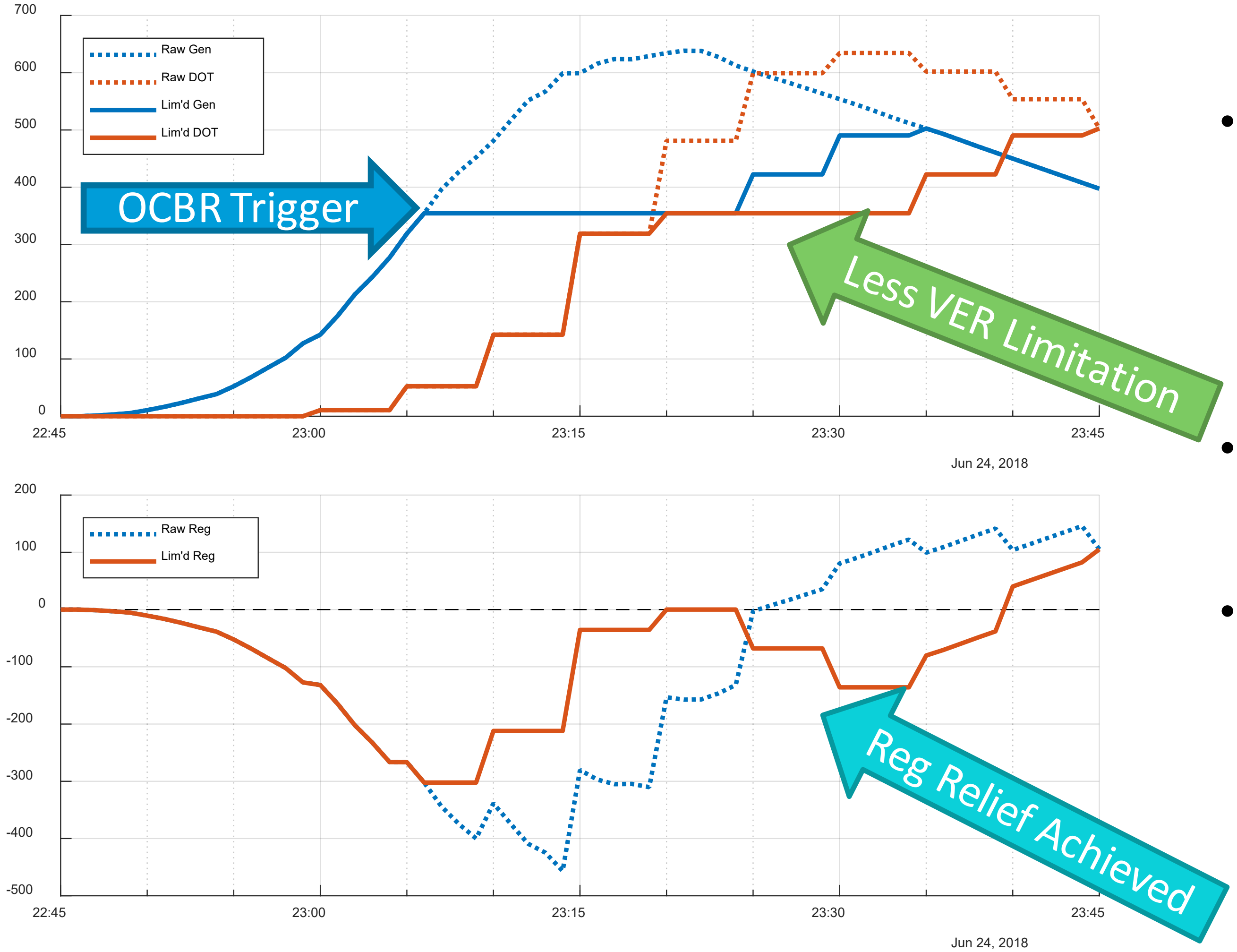
Changes to OCBR Triggers

- OCBR Triggers
  - Outside of EIM will trigger off of Balancing Reserves Deployed versus the full Balancing Reserves held
    - Balancing Reserves held is Regulation plus Non-Regulation
  - In the EIM will trigger off of Regulating Reserves Deployed versus the amount of Regulation Reserves held and indicated to the EIM

OCBR Limitations

- Limitations
  - Deployed for DEC over-generation events
  - Limits VER Generation Output
- Level 1 Limitation
  - Triggers at 90% Reserves Deployed
  - Limits generation to output at the time of OCBR trigger.
- Level 2 Limitation
  - Triggers at 97% Reserves Deployed
  - Limits generation to schedule (same as before EIM)
- Limitation duration <u>in the EIM</u>
  - Limitation holds until EIM DOT catches up and then releases over the next 4 RTD intervals (~ 7 intervals in total)
    - Level 1 can retrigger during the 4 RTD release periods
- Limitation duration <u>outside of the EIM</u>
  - XX:00 to XX:44:59 – Last until the top of the hour
  - XX:45 to XX:59:59 – Last until the top of the **<u>next</u>** hour

OCBR Limitations in the EIM

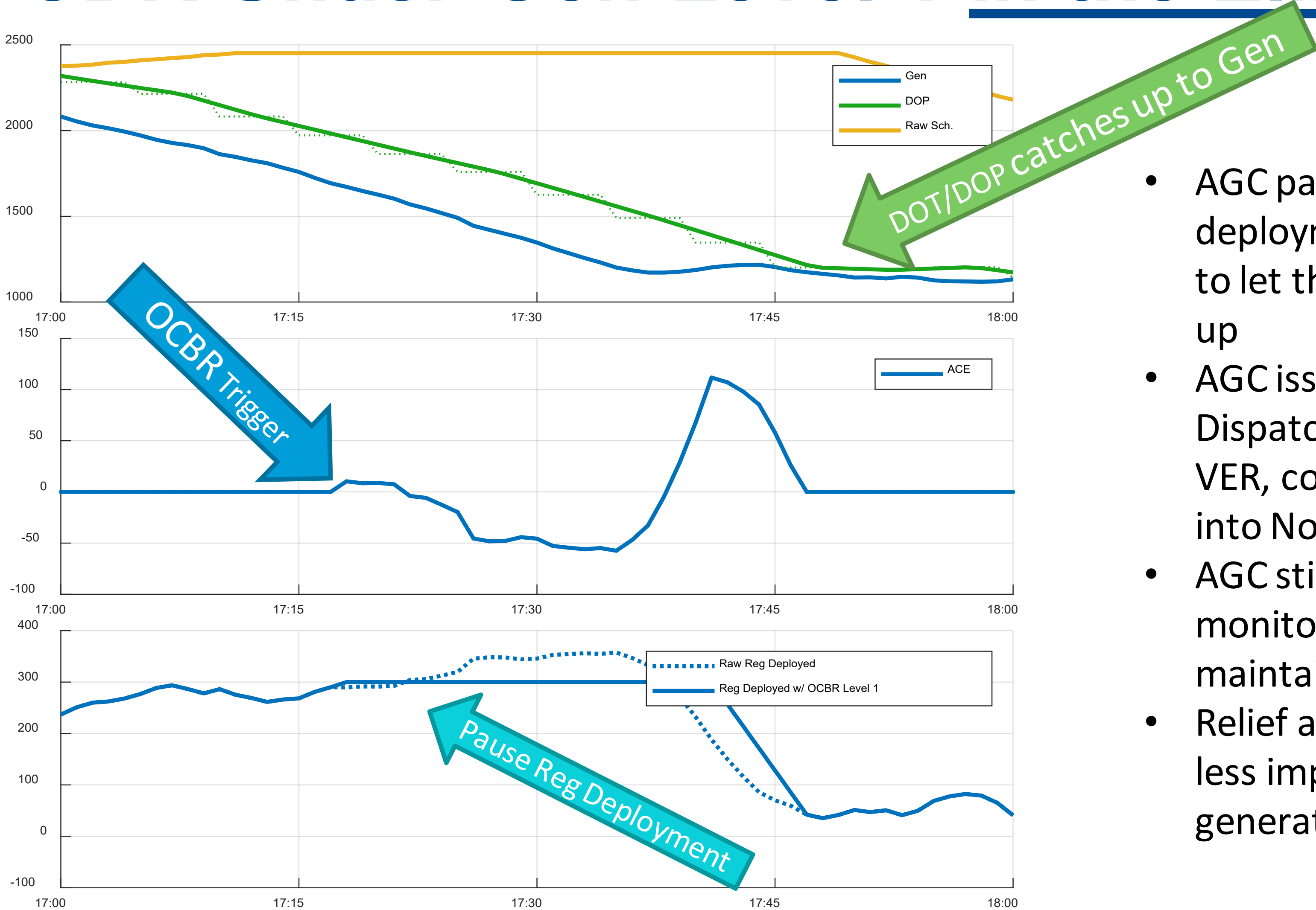


- Pauses VER generation and Reg deployment at current level and lets DOT catch up
- Allows for slow release of limitation
- Relief achieved with less VER impact

OCBR Under-Generation <u>in the EIM</u>

- Deployed for INC under-generation events
- Level 1
  - Triggers off of 95% Regulation Reserves Deployed
  - AGC pauses deployment of Regulation at the onset of OCBR trigger
    - Allows for the DOT from the market to catch up to VER generation, relieving the event.
  - Manual Dispatches issued for Non-VERs (Federal and Non-Federal) under-generating at the time of the OCBR trigger
    - Converts Regulation into Non-Regulation deployment
  - AGC still deploys Regulation to maintain compliance
  - Duration is set to 45 minutes from OCBR trigger

OCBR Under-Gen Level 1 in the EIM

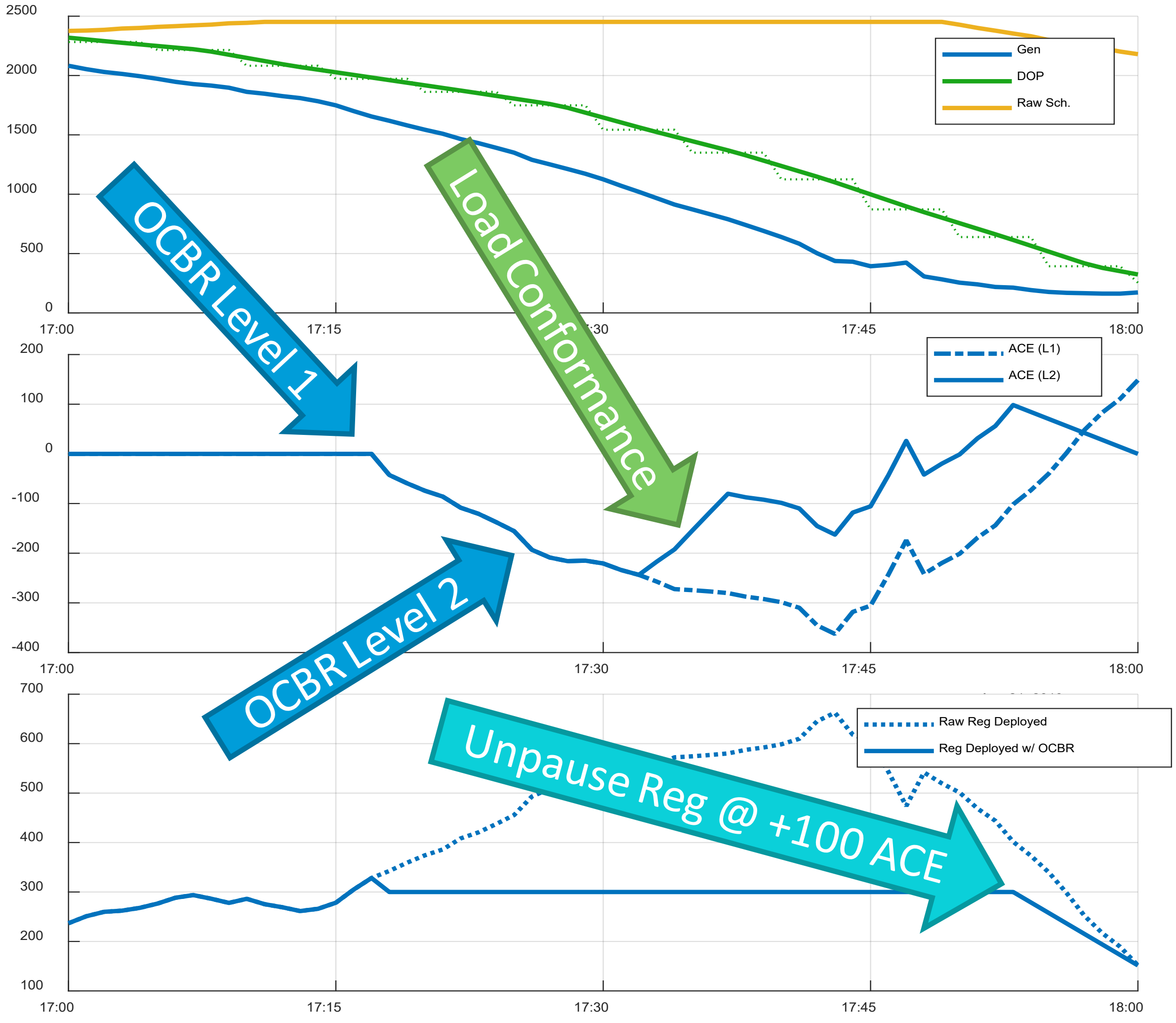


- AGC pauses deployment of Reg to let the DOT catch up
- AGC issues Manual Dispatches for Non-VER, converting Reg into Non-Reg
- AGC still monitors/controls to maintain compliance
- Relief achieved with less impact to generators

OCBR Under-Generation in the EIM

- Level 2
  - – Triggers off of ACE or compliance indicators
  - – AGC continues to pause deployment of Regulation
  - – Manual Dispatches updated for under-generating Non-VERs
  - – Load Conformance issued to counter VER under-generating error at the time of the OCBR trigger
    - Converts Regulation into Non-Regulation deployment
  - – Level 2 can retrigger during a Level 2
  - – Duration is refreshed for 45 minutes from OCBR Level 2 trigger.

OCBR Under-Gen Level 2 in the EIM



- AGC requests a Load Conformance for VER error, requesting additional energy from EIM
- AGC issues Manual Dispatches for Non-VER,
- Level 2 can occur multiple times as needed
- AGC still monitors/controls to maintain compliance
- Relief achieved with less impact to generators

OCBR Under-Generation <u>in the EIM</u>

- Level 3 – Future Deployment, TBD
  - Needed for high ABC-REG deployment by the EIM to prevent infeasible EIM solutions in combination with OCBR INC Criteria
    - These conditions were seen during parallel operations and OCBR Under-Gen Level 1 & 2 actions will not alleviate these conditions
  - Curtailments for under-generating non-Federal resources would be issued for a Level 3
    - Needed to reduce the high ABC-REG deployment by the EIM
    - NOTE: Curtailments will still not be a part of Level 1 or Level 2 in the EIM

OCBR Under-Generation outside of EIM

- OCBR Curtailments continue outside of the EIM
  - Deployed for INC under-generation events
  - OCBR triggered off of Balancing Reserves Deployed
    - Level 1 at 90% Balancing Reserves Deployed
    - Level 2 at 97% Balancing Reserves Deployed following a Level 1
  - Curtails eTags for any non-Federal generation in the BAA that is under-performing at the time

Questions

Next Steps

- Comments or questions? Email techforum@bpa.gov and copy your Account Executive

- Please provide comments by August 10th.

BP-24 Topic
Load Reliability Service

Background

- What is the issue?
  - Staff are concerned that the current method used in the balancing reserves model does not account for potential pre-hour imbalance that may result in within-hour balancing reserves deficits.
  - In the balancing reserves model, load error is calculated using the base point setting process that was established prior to joining the EIM.
  - This process assumes balancing to an adjusted load forecast every hour.
  - System reliability may require additional capacity in order to match those adjusted forecasts.

- What has changed? Why are we talking about this now?
  - Joining the EIM has provided more visibility to pre-hour scheduling.
  - Regardless of the EIM, there is the potential for pre-hour imbalance.

Considerations

- What are we planning on doing?
  - BPA Power will continue to provide any additional capacity to ensure load reliability.
  - Staff will monitor this issue over the BP-24 rate period. These questions will guide our thinking:
    - Is additional capacity required in the pre-hour timeframe to maintain BPA's 99.7% balancing quality of service within-hour?
    - If it is required, how much is required?
    - Should this be embedded within the current balancing service or will it require a separate load reliability service?
      - Can these be analyzed coincidentally with the current balancing reserves or do they need a separate requirement?
    - If additional capacity is deemed necessary, how will the costs be allocated?

Next Steps

- Collect and analyze relevant data throughout the BP-24 rate period.
- Provide updates to customers prior to the BP-26 rate case on the results of this analysis.

QUESTIONS

Next Steps

- Comments or questions? Email techforum@bpa.gov and copy your Account Executive
- Please provide comments by August 10th.

BP-24 Topic
Persistent Deviation/Intentional Deviation Review

PD Penalties

- PD applies to loads and DERs
- Minimize accumulation of imbalance energy in either a positive or negative direction
- Provide a mechanism for identifying and deterring schedule errors that are inconsistent with BPA's rate case assumptions regarding capability for accurate scheduling
  - Rate case assumes energy imbalance will net to zero over time
- Provide an incentive to adopt best scheduling practices, and discourage use of balancing services as an alternative to corrective market actions

PD Penalty Tiers

The PD Penalty applies to all hours or scheduled periods in which either a negative or positive deviation exceeds:

(1) both 15 percent of the integrated hourly schedule and 20 MW in each scheduled period for 4 consecutive hours or more in the same direction

- In BP-22, this tier from 3 hours to 4 hours to account for scheduling being due at T-57 instead of T-20, as a result of joining the EIM

(2) both 7.5 percent of the integrated hourly schedule and 10 MW in each scheduled period for 6 consecutive hours or more in the same direction

(3) both 1.5 percent of the integrated hourly schedule and 5 MW in each scheduled period for 12 consecutive hours or more in the same direction

(4) 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

PD Penalty Rate

Positive Deviations

- Actual generation less than scheduled
- The charge is the greater of:
  i. 125 percent of either BPA's highest incremental cost that occurs during that day for service under ACS III.B, or the highest LMP at the closest point of interconnection during the period of penalty for service under ACS IV.A.2
  ii. 100 mills per kilowatt-hour
- For Participating Resources in the EIM the charge is the greater of:
  i. 25 percent of the highest LMP at the closest point of interconnection during the period of penalty
  ii. 100 mills per kilowatt-hour minus the highest LMP at the closest point of interconnection during the period of penalty

PD Penalty Rate

Negative Deviations

- Actual generation greater than scheduled
- No credit is given for negative deviations
- If the energy index is negative in any hour(s) in which there is a negative deviation that BPA determines to be a Persistent Deviation, the charge is the energy index for that hour.

Waiver or Reduction

- BPA, at its sole discretion, may waive all or part of the Persistent Deviation penalty charge if
  1. the customer took mitigating action(s) to avoid or limit the Persistent Deviation, including but not limited to, changing its schedule to mitigate the magnitude or duration of the deviation, or
  2. the Persistent Deviation was caused by extraordinary circumstances.

PD Penalty Example

Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	Sum
Scheduled (MW)	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	168.0
Actual (MW)	4.2	4.1	4.2	4.2	4.2	4.2	4.2	4.2	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.2	4.1	4.1	4.1	4.2	4.1	4.2	4.1	102.6
Deviation (MW)	**2.8**	**2.9**	**2.8**	**2.8**	**2.8**	**2.8**	**2.8**	**2.8**	**2.5**	**2.5**	**2.5**	**2.5**	**2.5**	**2.5**	**2.5**	**2.5**	**2.8**	**2.9**	**2.9**	**2.9**	**2.8**	**2.9**	**2.8**	**2.9**	**65.4**
Deviation (%)	**40**	**41**	**40**	**40**	**40**	**40**	**40**	**40**	**36**	**36**	**36**	**36**	**36**	**36**	**36**	**36**	**40**	**41**	**41**	**41**	**40**	**41**	**40**	**41**	

- Deviations are measured relative to:
  - T-57 for loads
  - Five Minute Market schedule for DERs, last submitted schedule
- This falls under Tier 4
  - 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
- The total deviation is 65.4 MWh
- Assuming EIM participation, the total penalty charge will be the greater of:
  I. 65.4 x (LMP x .25)
  II. 65.4 x (100 – LMP)

ID Penalties

- ID applies to VERs
- Maintain balancing reserve capacity availability and preserve system reliability
- Provide a mechanism for identifying and deterring schedule errors that are inconsistent with BPA's expectations regarding accurate scheduling
- Provide an incentive to adopt best scheduling practices, and discourage use of balancing services as an alternative to corrective market actions

ID Penalty Rate

- For each Intentional Deviation event, the Intentional Deviation Penalty Charge rate shall be $100 per megawatt-hour (MWh) times the deviation minus 1

$100 x (abs(IDMV – Resource Schedule) – 1)

- The Intentional Deviation Measurement Value (IDMV) is one of the following:
  1) for wind generating customers taking VERBS under rate schedule Section 2.a., the applicable schedule value provided by BPA
  2) for solar generating customers taking VERBS under rate schedule Section 2.b., the applicable schedule value provided by BPA
- In BP-22, the IDMV was defined as equal to the forecast value BPA supplies to the customer prior to T-57

Exemption

- A customer that schedules its resource to a value other than the Intentional Deviation Measurement Value is exempt from the Intentional Deviation Penalty Charge for a scheduling period if:

abs(Resource Schedule-based SCE) ≤
abs(IDMV-based SCE) + 1 MW

Waiver or Reduction

- BPA may, in its sole discretion, waive or reduce an Intentional Deviation Penalty Charge if requested by a customer for good cause shown. In order to qualify for a waiver or reduction of an Intentional Deviation Penalty Charge, a customer must submit a request demonstrating that the events resulting in an Intentional Deviation Penalty Charge were:
  a. Due to a technical error or malfunction that could not have been avoided through the exercise of reasonable care; and
  b. Immediately corrected upon discovery of the technical error or malfunction.
- BPA will also consider the customer's history of incurring Intentional Deviation Penalty Charge in deciding whether to waive or reduce an Intentional Deviation Penalty Charge. PD applies to loads and DERs

ID Penalty Example

Hour	12	13	14	15
IDMV	168	168	168	168
Resource Schedule	168	168	150	150
abs(Schedule Deviation)	**0**	**0**	**18**	**18**

Actual Output	160	250	140	180
IDMV-based SCE	8	82	28	12
Resource Schedule-based SCE	8	82	10	30

- Hour 12 – No penalty because Resource Schedule was equal to IDMV
- Hour 13 – No penalty because Resource Schedule was equal to IDMV, no matter how large the deviation
- Hour 14 – Incur a penalty for 17 MWh, however, this is exempt from the penalty as the Resource Schedule-based SCE is less than IDMV-based SCE
- Hour 15 – Incur a penalty for 17 MWh and be charged a penalty in the amount of $1,700

$$\$100 \times (\mathrm{abs}(168 - 150) - 1)$$

EIM Over/Under Scheduling Penalty

- CAISO developed the Over/Under (O/U) Scheduling Penalty to discourage EIM entities from leaning on the market to serve load
- The O/U Scheduling Penalty is applied to the BAA when the following two conditions <u>are not</u> met:
  1. The BAA scheduled within 1% of the CAISO's Area Load Forecast (ALF)
  2. The BAA scheduled within 5% of its actual area load

EIM Over/Under Scheduling Penalty

- BPA sets Balancing Reserves Capacity based on expected variability of scheduling practices
- Poor scheduling by load and generators could make it more difficult for the BAA to pass the RS tests
- The O/U scheduling penalty doesn't apply if the BAA balances to the CAISO ALF
  - O/U scheduling penalty dis-incentivizes the BAA from leaning on the market to serve load, and the PD penalty dis-incentivizes individual customers from leaning on the BAA to serve load

QUESTIONS

Next Steps

- Comments or questions? Email techforum@bpa.gov and copy your Account Executive

- Please provide comments by August 10th.

BP-24 Topic
VERBs, DERBs, and Load Balancing Services
(BP-22 Settlement Commitment)

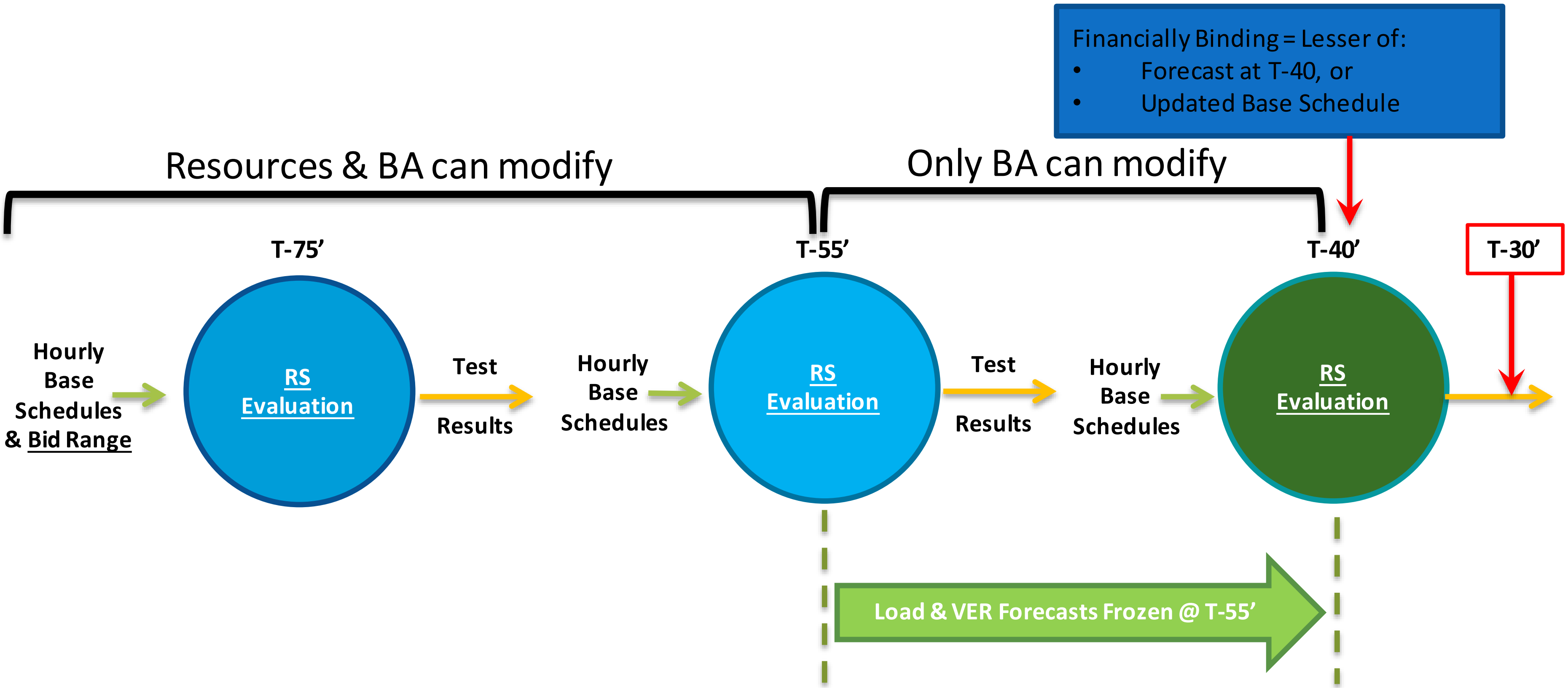
Today's Topics

- Review of adjustments made in BP-22
- Overview of Balancing Reserve Methodology
- BP-24 forecast
- Capacity Costs
- VERBS solar
- DERBS

Changes to VERBS Rate in BP-22

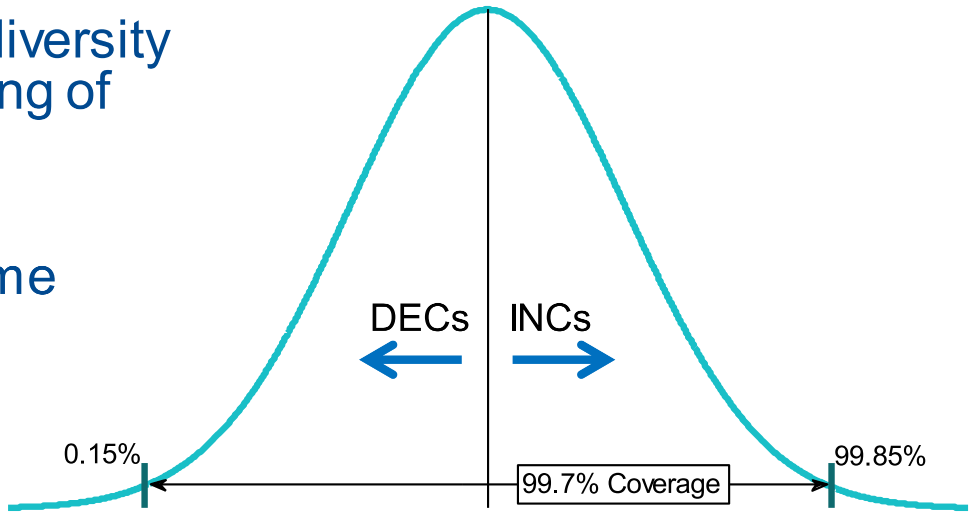
- Change from existing three components to two
  - Previously provided for Regulation, Following, and Imbalance
  - Change to Regulation and Non-Regulation
- Elimination of Scheduling Elections
  - Previously provided for 30/60, 30/15, and Uncommitted scheduling options
  - Change to use of Forecast scheduling only

Scheduling Timeline in the EIM



Balancing Reserve Methodology

- BPA holds capacity for balancing reserves to meet the NERC standards and OATT requirements to maintain load-resource balance within its BAA.
- Balancing reserves needed for the BPA BAA is set in advance of the start of each two-year rate period.
- BPA performs statistical evaluations of combined load and generation fleet error to yield a final amount of balancing reserve capacity needed to meet BPA's 99.7% planning standard.
- This evaluation captures BA diversity benefits, the difference in timing of INCs and DECs deployed for generators and load.
- They don't all move in the same direction at the same time.



Balancing Reserve Components in EIM

- BPA defines balancing capacity as "regulation" and "non-regulation" capacity to promote consistency with definitions in the EIM.
  - Regulation Capacity
    - The difference between actual Load net Generation and the net EIM dispatch operating target (DOT) of Load net Generation
  - Non-Regulation Capacity
    - BPA makes available to the EIM the "non-regulation" reserve portion of its balancing reserve, by bidding or designating as Available Balancing Capacity (ABC)

Balancing Reserve Capacity Forecast

A statistical analysis examining historical error in our BA which is performed every two years for the BPA Gen Inputs Rate Case

- Uses 6 years of 1-minute data on an individual plant level
- Measures Station Control Error (“SCE”) of each plant and the error of load
  - Plant SCE is the difference between the value to which a plant scheduled its output for a given time interval and the actual output of the plant during that time
  - Load error is the difference between the BPA hourly load forecast (using the Applied Adjusted Load Forecast methodology) and actual load usage
- Calculates the net error of the BA for each minute of the 6 year set
- Calculates the empirical distribution of the net error signal and identifies the incremental balancing reserves (INCs) and decremental balancing reserves (DECs) at a given level of service (99.7% coverage)
  - The above calculations are done for all generation and load combinations forecasted for the rate period. For plants that do not yet exist, various methodologies are used to synthesize representative 1-minute data, depending on the type of generation.

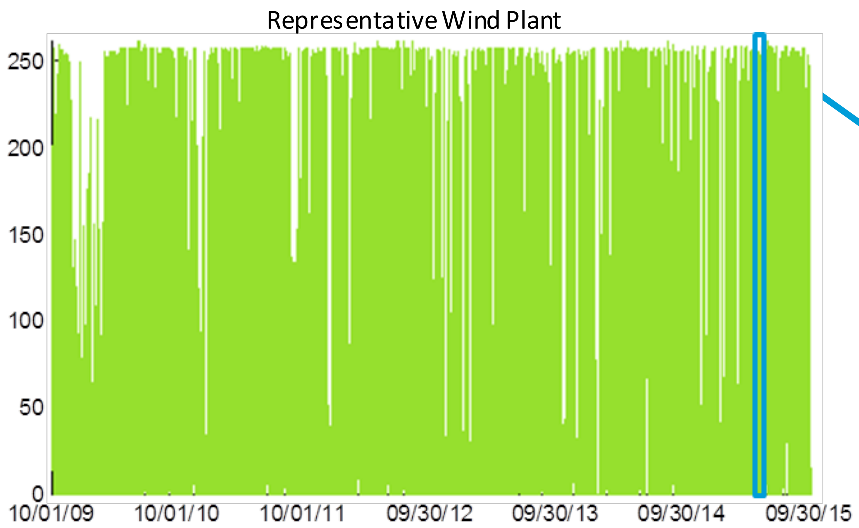
Balancing Reserve Capacity Forecast

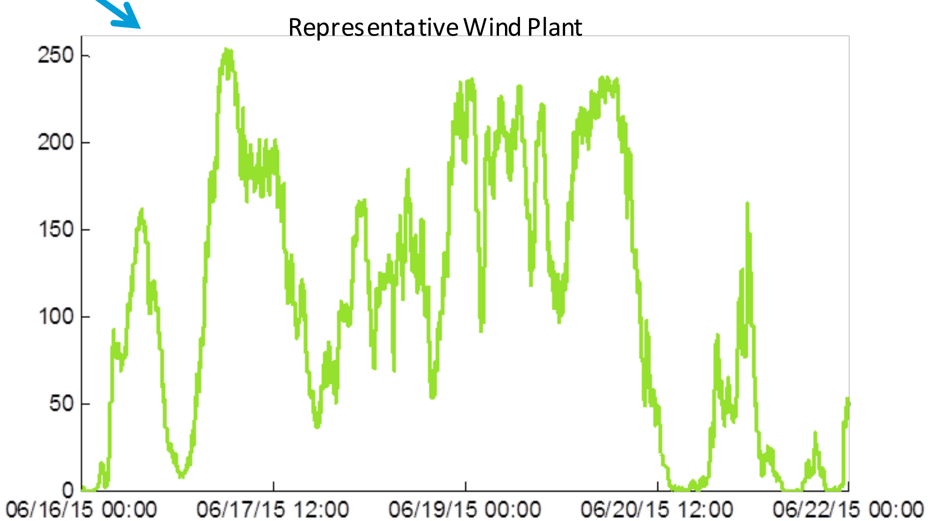
- The INC and DEC amounts previously calculated are subdivided in two ways:
  - Service type
    - Regulation
    - Non-Regulation
  - Allocation
    - Distribution of the total capacity to load and each type of generator
    - Based on Incremental Standard Deviation (ISD) methodology

BRCF, Step by Step (1)

A statistical analysis examining historical error in our BA which is performed every two years for the BPA Gen Inputs Rate Case

- Uses 6 years of 1-minute data on an individual plant level



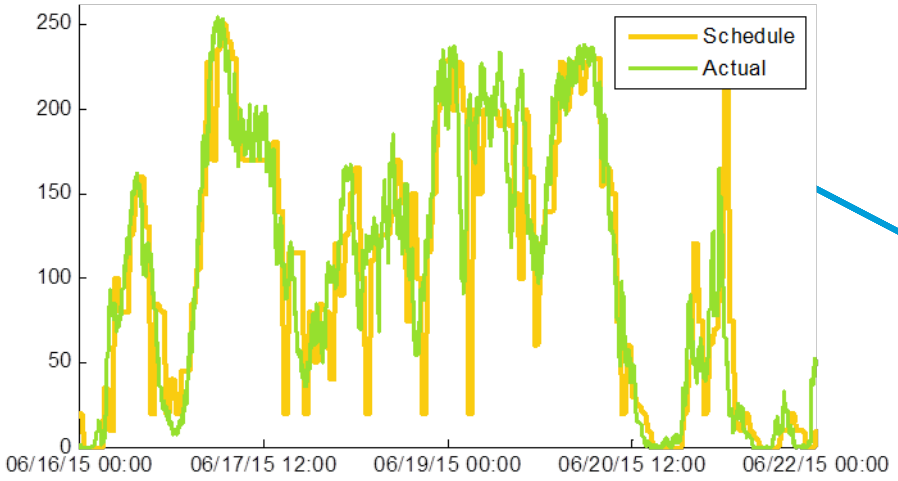


BRCF, Step by Step (2)

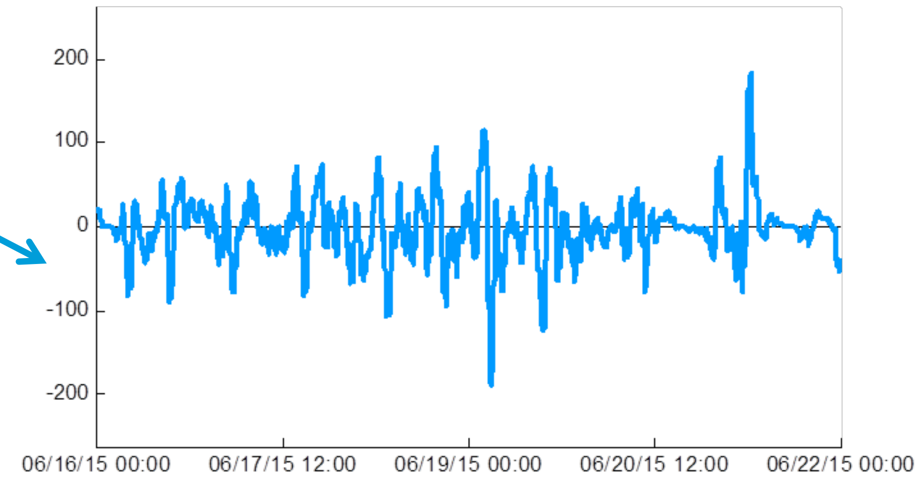
A statistical analysis examining historical error in our BA which is performed every two years for the BPA Gen Inputs Rate Case

- Uses 6 years of 1-minute data on an individual plant level
- Measures Station Control Error ("SCE") of each plant and the error of load
  - Plant SCE is the difference between the value to which a plant scheduled its output for a given time interval and the actual output of the plant during that time

Representative Wind Plant



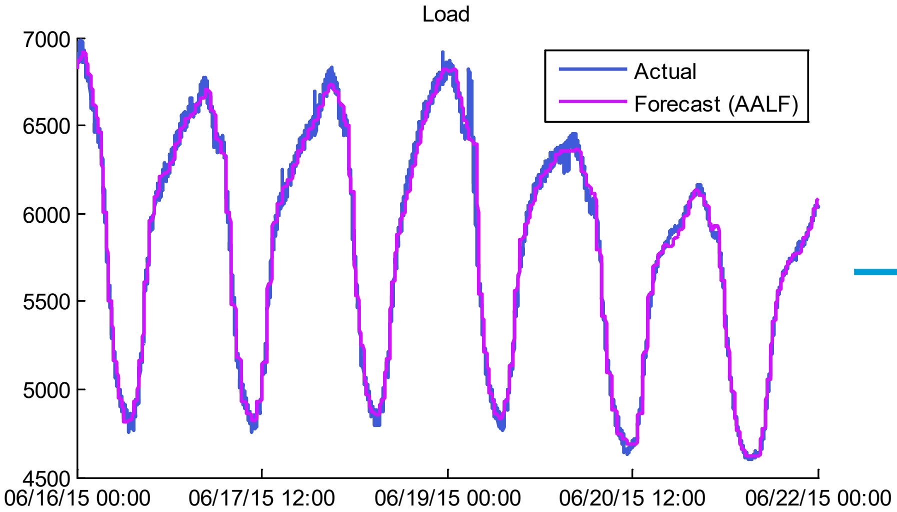
Representative Wind Plant Station Control Error



BRCF, Step by Step (3)

A statistical analysis examining historical error in our BA which is performed every two years for the BPA Gen Inputs Rate Case

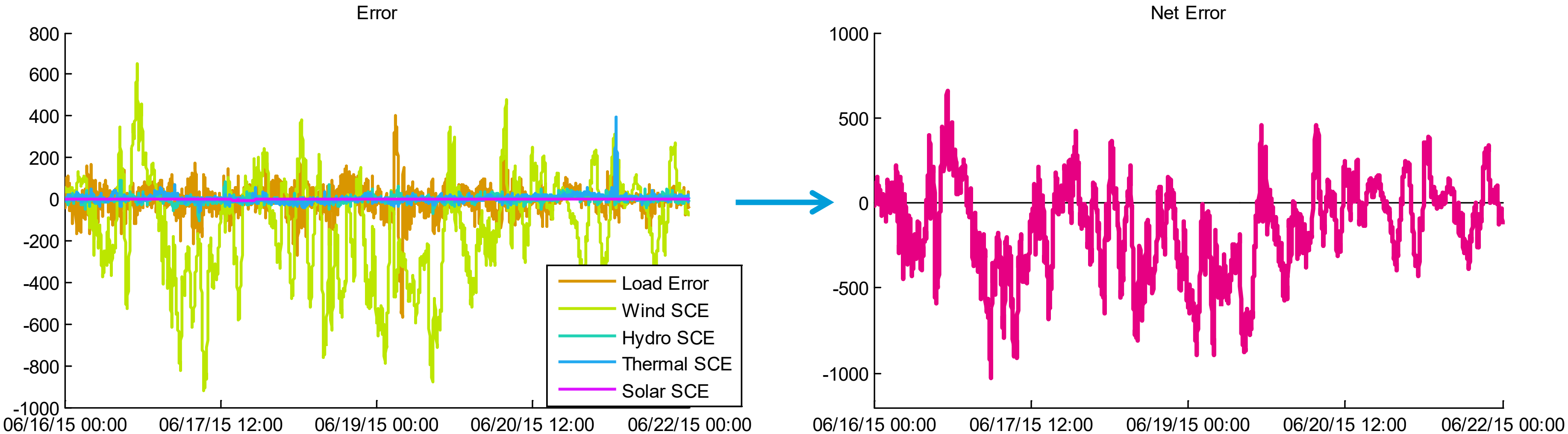
- Uses 6 years of 1-minute data on an individual plant level
- Measures Station Control Error ("SCE") of each plant and the error of load
  - Plant SCE is the difference between the value to which a plant scheduled its output for a given time interval and the actual output of the plant during that time
  - Load error is the difference between the BPA hourly load forecast (using the Applied Adjusted Load Forecast methodology) and actual load usage



BRCF, Step by Step (4)

A statistical analysis examining historical error in our BA which is performed every two years for the BPA Gen Inputs Rate Case

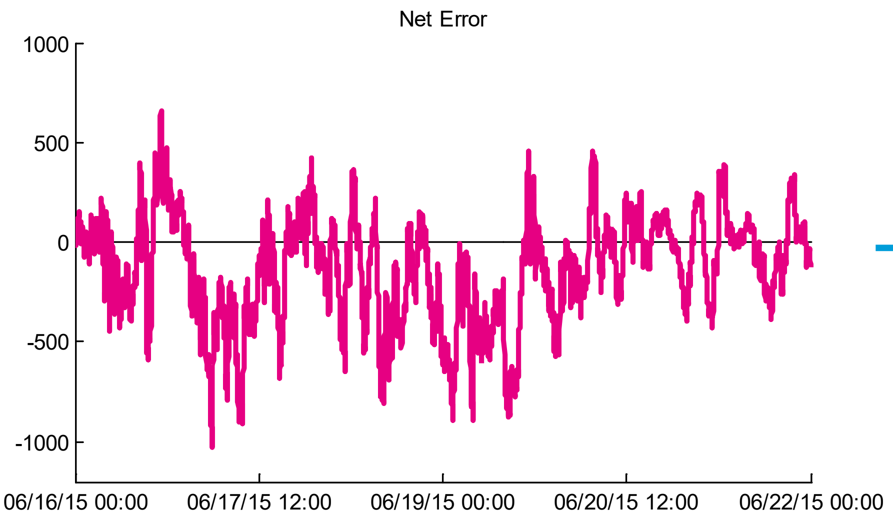
- Uses 6 years of 1-minute data on an individual plant level
- Measures Station Control Error ("SCE") of each plant and the error of load
  - Plant SCE is the difference between the value to which a plant scheduled its output for a given time interval and the actual output of the plant during that time
  - Load error is the difference between the BPA hourly load forecast (using the Applied Adjusted Load Forecast methodology) and actual load usage
- Calculates the net error of the BA for each minute of the 6 year set

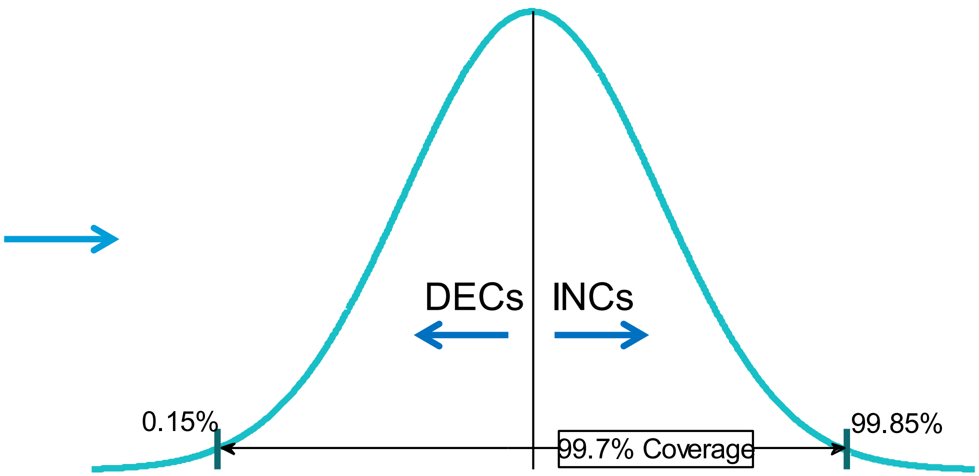


BRCF, Step by Step (5)

- Calculates the net error of the BA for each minute of the 6 year set

- Calculates the empirical distribution of the net error signal and identifies the incremental balancing reserves (INCs) and decremental balancing reserves (DECs) at a given level of service (99.7% coverage)





BRCF, Step by Step (6)

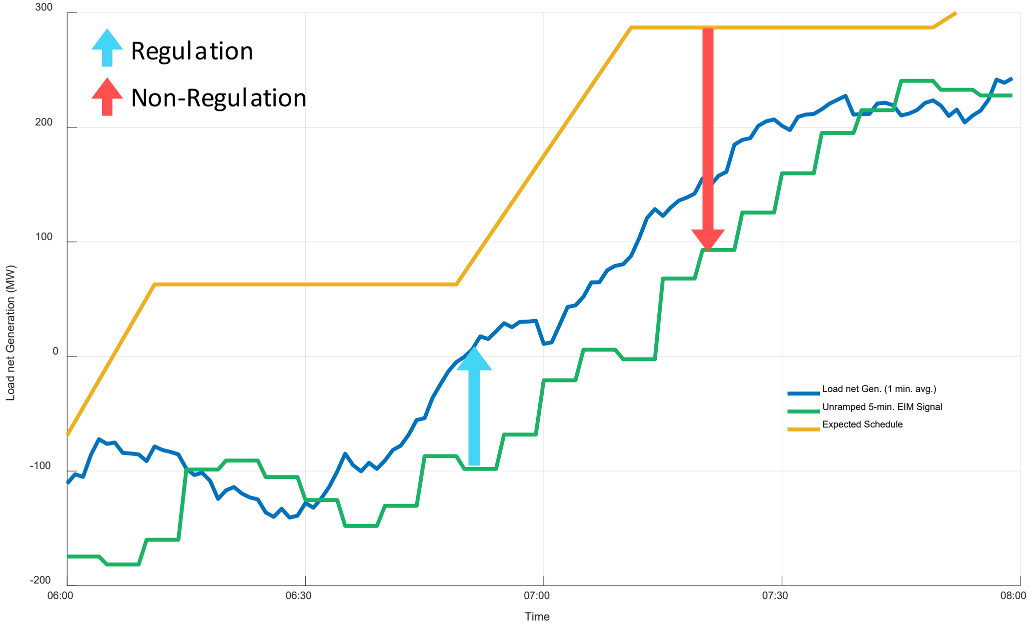
– Calculates the empirical distribution of the net error signal and identifies the incremental balancing reserves (INCs) and decremental balancing reserves (DECs) at a given level of service (99.7% coverage)

- The above calculations are done for all generation and load combinations forecasted for the rate period

DATE	TOTAL	
17-Oct	710	
...	...	
18-Jan	646	→ Wind Departure
...	...	
18-Jun	620	→ Wind Departure
18-Jul	620	→ New Wind Online
...	...	
18-Oct	618	→ Thermal Departure, Load Increase
18-Nov	618	→ New Solar Online
...	...	
19-Jan	619	→ New Solar Online
...	...	
19-Aug	579	→ Wind Departure
19-Sep	602	→ New Wind Online

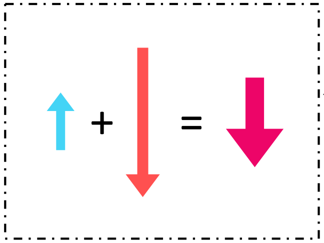
BRCF, Step by Step (7a)

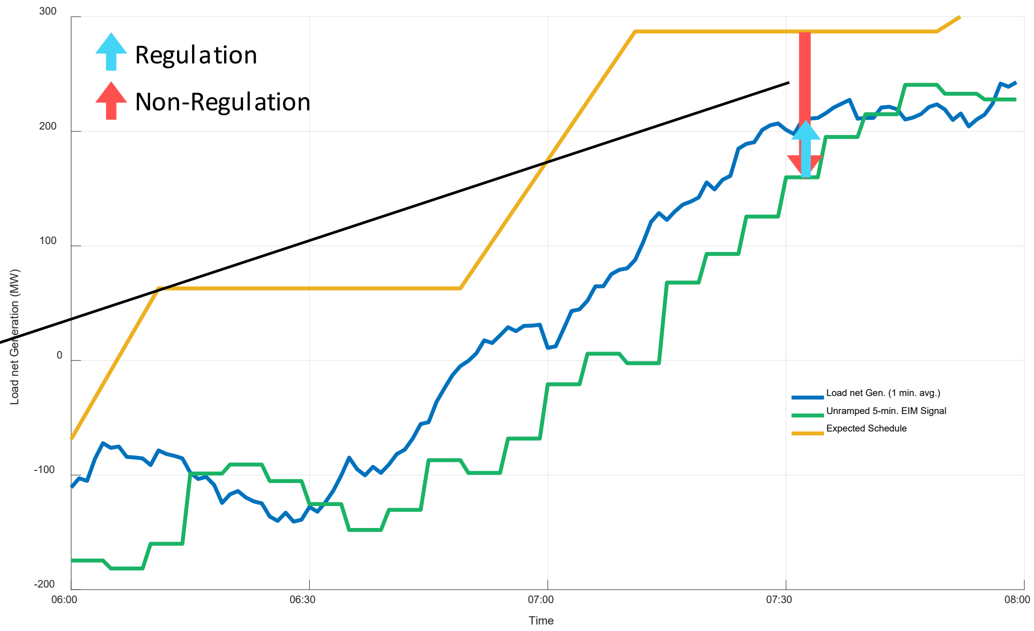
- For rate purposes, the INC and DEC amounts previously calculated are subdivided in two ways:
  - Service type
    - Regulation
    - Non-Regulation



BRCF, Step by Step (7a)

- For rate purposes, the INC and DEC amounts previously calculated are subdivided in two ways:
  - Service type
    - Regulation
    - Non-Regulation





BRCF, Step by Step (8)

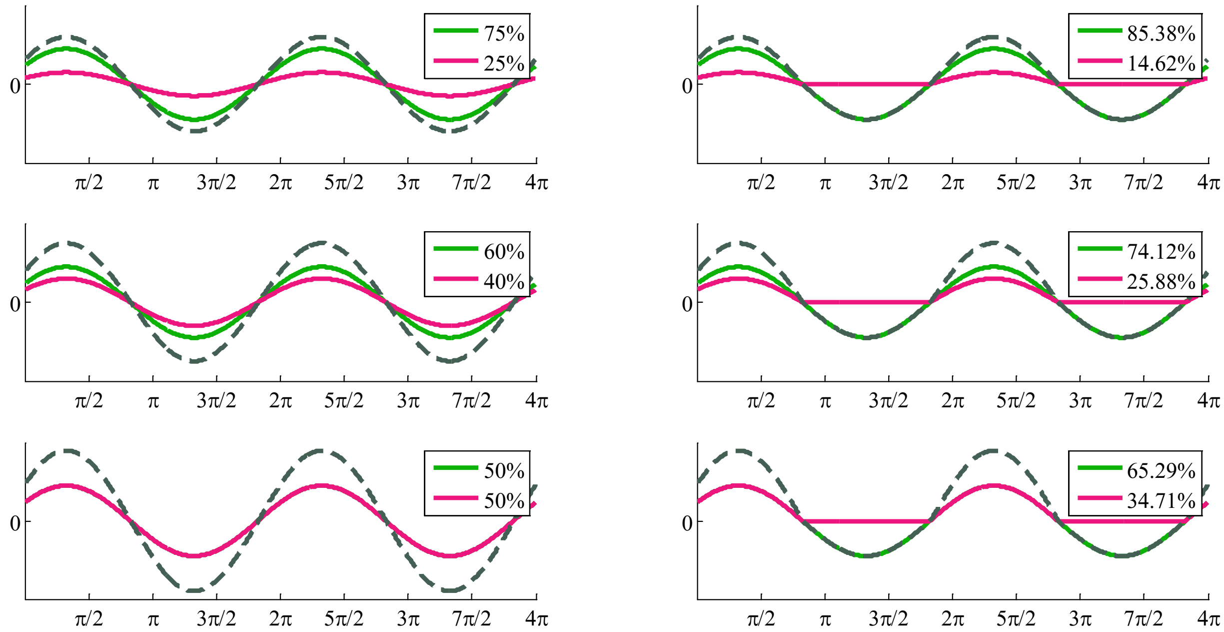
– Allocation

- Distribution of the total capacity to load and each type of generator

DATE	TOTAL	LOAD	WIND	CSGI	SOLAR	DERBS	
17-Oct	710	258	367	68	0.2	17	
...	...	...	...	...	...	...	
18-Jan	646	253	309	65	0.2	18	→ Wind Departure
...	...	...	...	...	...	...	
18-Jun	620	252	349	0	0.2	20	→ Wind Departure
18-Jul	620	252	349	0	0.2	20	→ New Wind Online
...	...	...	...	...	...	...	
18-Oct	618	259	350	0	0.2	9	→ Thermal Departure, Load Increase
18-Nov	618	259	350	0	0.3	9	→ New Solar Online
...	...	...	...	...	...	...	
19-Jan	619	259	350	0	1.3	9	→ New Solar Online
...	...	...	...	...	...	...	
19-Aug	579	259	309	0	1.3	9	→ Wind Departure
19-Sep	602	262	330	0	1.3	9	→ New Wind Online

BRCF, Step by Step (9)

- Allocation
  - Distribution of the total capacity to load and each type of generator
  - Based on Incremental Standard Deviation (ISD) methodology
    - ISD Methodology aims to allocate reserves to load and each generation in a statistically accurate manner based on each class' contribution to the overall error signal



Preliminary BP-24 Reserve Forecast

Rate Case Average	Wind Capacity (MW)	Solar Capacity (MW)	DERs Capacity (MW)	Total INC Bal. Res. (MW)	Total DEC Bal. Res. (MW)
BP-22	2,834	99	1,548	680	-827
BP-24	3,096	318	1,995	743	-888

Rate Case Average	Wind Res. (MW)	Solar Res. (MW)	DERs Res. (MW)	Load Res. (MW)	Fed Res. (MW)
BP-22	349	6	11	291	23
BP-24	373	34	14	302	21

Rate Case Average	Wind Reserves (% Nameplate)	Solar Reserves (% Nameplate)
BP-22	12.30%	6.08%
BP-24	12.05%	10.57%

Preliminary BP-24 Reserve Forecast

Month	Wind Capacity (MW)	Solar Capacity (MW)	DERs Capacity (MW)	Total INC Bal. Res. (MW)	Total DEC Bal. Res. (MW)
Oct ’23	3080	139	1537	732	-877
Nov ‘23	3080	239	1537	734	-878
…	…	…	…	…	…
Dec ’24	3080	439	2637	750	-894
…	…	…	…	…	…
Sept ‘25	3472	439	2637	806	-965
BP-24 Avg	3,096	318	1,995	743	-888

Preliminary BP-24 Reserve Forecast

Month	Wind INC Res. (MW)	Solar INC Res. (MW)	DERs INC Res. (MW)	Load INC Res. (MW)	Fed INC Res. (MW)
Oct '23	378	8	11	313	22
Nov '23	376	18	11	308	21
…	…	…	…	…	…
Dec '24	363	56	18	292	20
…	…	…	…	…	…
Sept '25	424	54	16	295	18
BP-24 Avg	373	34	14	302	21

Preliminary BP-24 Reserve Forecast

Month	Wind INC Res. (% Nameplate)	Solar INC Res. (% Nameplate)
Oct ’23	12.3%	5.5%
Nov ‘23	12.2%	7.7%
…	…	…
Dec ’24	11.8%	12.9%
…	…	…
Sept ‘25	12.2%	12.3%
BP-24 Avg	12.0%	10.6%

Preliminary BP-24 Rates

Rate	Units	BP-22 Rates /1	BP-24 Rates	Percent Change
RFR				
Regulation and Frequency Response	mills/kWh	0.44	0.51	15.9%
OR				
Operating Reserves - Spinning	mills/kWh	11.05	12.04	9.0%
OR - Spinning Default	mills/kWh	12.71	13.85	9.0%
Operating Reserves - Supplemental	mills/kWh	7.22	7.37	2.1%
OR - Supplemental Default	mills/kWh	8.30	8.48	2.2%
DERBS				
DERBS Inc	mills/kWh	21.30	36.46	71.1%
DERBS Dec	mills/kWh	1.24	4.03	225.0%
VERBS				
VERBS Wind Regulating	mills/kW-mo	0.36	0.37	3.4%
VERBS Wind Non-Regulating	mills/kW-mo	0.40	0.45	13.9%
VERBS Solar Regulating	mills/kW-mo	0.28	0.71	151.8%
VERBS Solar Non-Regulating	mills/kW-mo	0.17	0.42	141.4%

/1 BP-22 Rates on this table reference Post EIM values.

Preliminary BP-24 Capacity Costs

- A market based value delta is applied to the incremental regulation and non-regulation balancing reserve costs. This delta does not change the total revenue forecast, but rather fixes the total revenue and delta between the reg. and non-reg. unit costs and solves for the unit costs themselves.
- INC unit costs include both embedded and variable costs while DEC unit costs only include variable costs.

Component:	BP-22 ($/kW/mo):	BP-24 ($/kW/mo):	Change:
Value Delta:	$ 2.80	$ 3.41	22%
Unit Costs:			
Reg. BAL INC	$ 7.64	$ 8.52	$0.88 (12%)
Reg. BAL DEC	$ 0.37	$ 0.71	$0.34 (92%)
Non-reg. BAL INC	$ 4.84	$ 5.11	$0.27 (6%)
Non-reg. BAL DEC	$ 0.10	$ 0.36	$0.26 (276%)

Preliminary BP-24 Capacity Costs

Two Cost Component:	BP-22 Unit Cost ($/kW/mo):	BP-24 Unit Cost ($/kW/mo):	Change:
Embedded Cost:	$5.87	$5.98	$0.11
Variable Costs:			
BAL INC	$0.26*	$0.62*	$0.36
Reg. BAL DEC	$0.37	$0.71	$0.34
Non-reg. BAL DEC	$0.10*	$0.36*	$0.26

* Both BP-22 and BP-24 costs assume 50% EIM cost offset for non-reg. BAL capacity. For BP-24 staff leaning is to propose greater than 90% EIM cost offset for non-reg. BAL capacity. This will likely result in a decrease in BAL INC and non-reg. BAL DEC unit costs relative to BP-22.

Preliminary BP-24 GARD Costs

- Variable Capacity Costs are calculated by the Generation and Reserves Dispatch (GARD) Model.
- Both BP-22 and BP-24 costs include 50% EIM cost offset for non-reg. balancing reserves.

GARD Components:	BP-22:	BP-24:	Change:
Energy Shift	$ 11,452,150	$ 22,120,516	93%
Spill	$ 2,940,851	$ 4,532,540	54%
Efficiency	$ (5,684,312)	$ (4,648,977)	-18%
Total:	**$ 8,708,690**	**$ 16,938,354**	**94%**

- Key cost drivers:
  - Primary driver - delta between HLH and LLH prices (increased by 112%)
  - Other driver – increase in quantity of balancing reserves (increased by 8%)
  - An additional consideration – the reserve requirement does not relate to GARD costs in a linear relationship. An increase in reserves tends to increase GARD costs, but not in a linear fashion. This is due to the non-linear relationship between turbine specifications and optimal hydro operations with and without reserves.

Forecast Solar Generation Profile

Month	Nameplate	Reserves	% of Nameplate
BP-22 Average	99	6	6.08%
Oct ‘23	139	8	5.50%
Nov ‘23	239	18	7.66%
…	…	…	…
Dec ‘24	439	56	12.85%
…	…	…	…
Sep ‘25	439	54	12.28%
BP-24 Average	**318**	**34**	**10.57%**

Drivers of the % Nameplate Increase

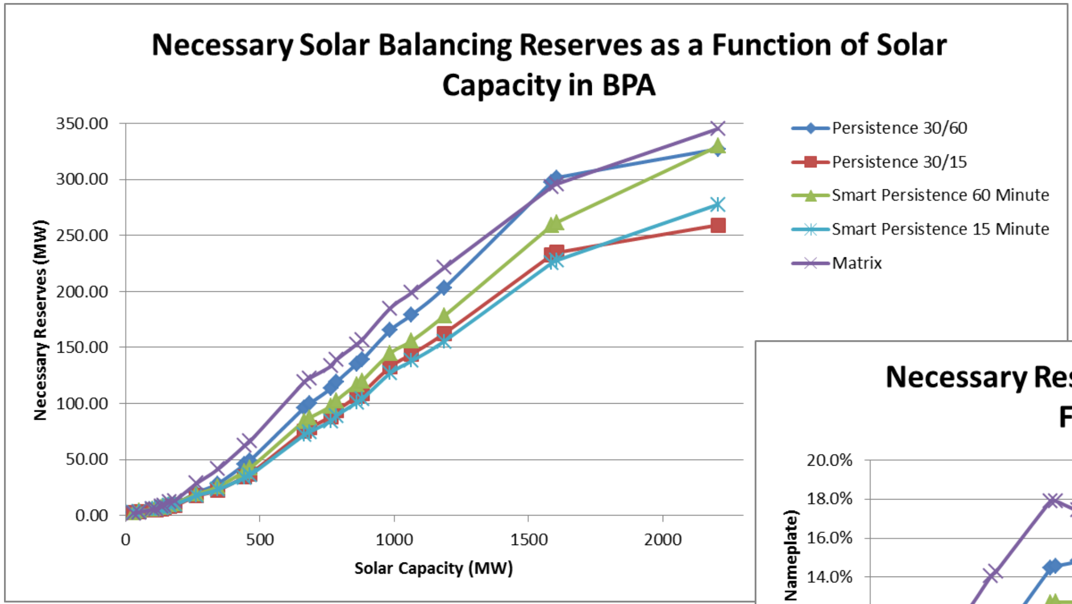
Two main drivers for increase:

1. Contribution to total reserve profile
2. Geographic diversity

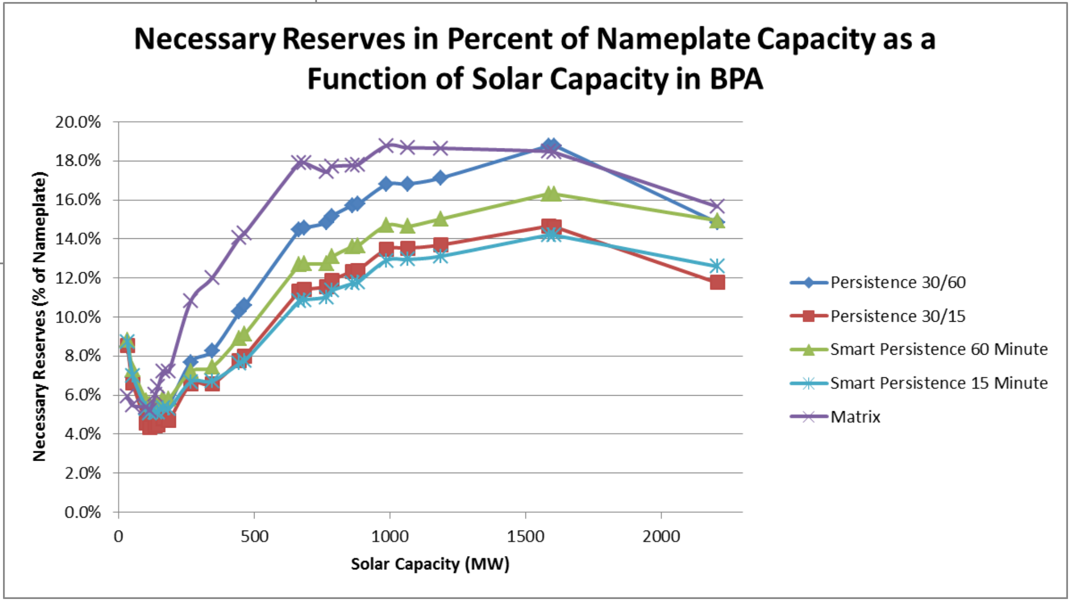
Drivers of the % Nameplate Increase

1. Contribution to total reserve profile.
   - Reserves are allocated based on imbalance correlation to the total imbalance signal relative to other reserve classes.
   - When **solar penetration is low**, there is little correlation between solar imbalance and total imbalance.
   - If there is a **significant increase in solar penetration**, solar will be a much **bigger contributor** to the total imbalance signal.
   - **This outcome is expected**.
     - As part of a settlement agreement, we provided a solar study in BP-18 that showed a balancing reserve forecast assuming solar growth across the BA up to 2000 MW. We showed that the solar reserves as a percent of nameplate grows significantly as solar penetration grows, until it eventually levels off. In that study, we saw reserves as a percent of nameplate get as high as 19%.

BP18 Solar Balancing Reserve Forecast



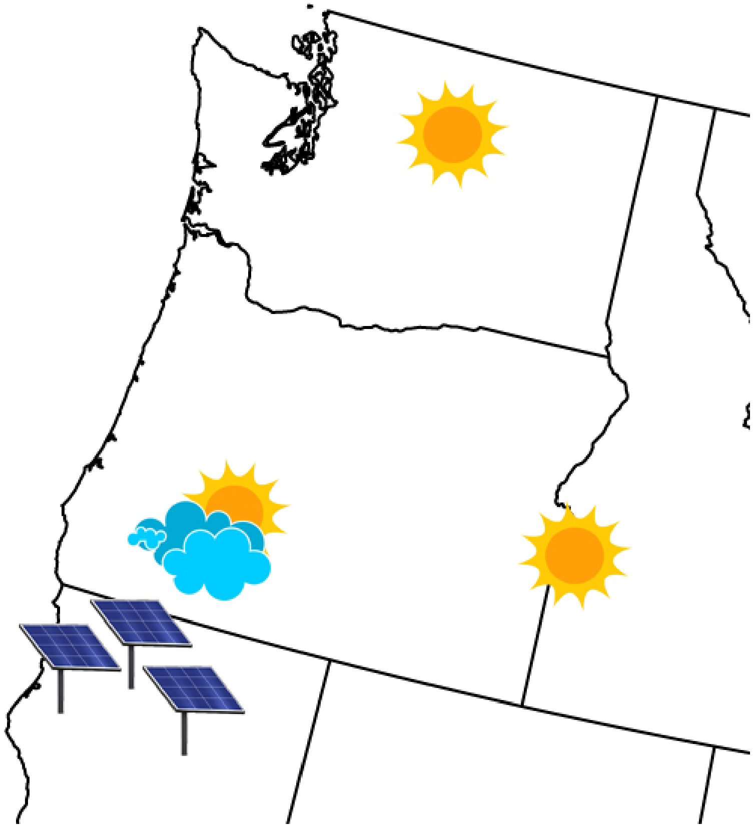
February 13, 2018 Generation Inputs Workshop



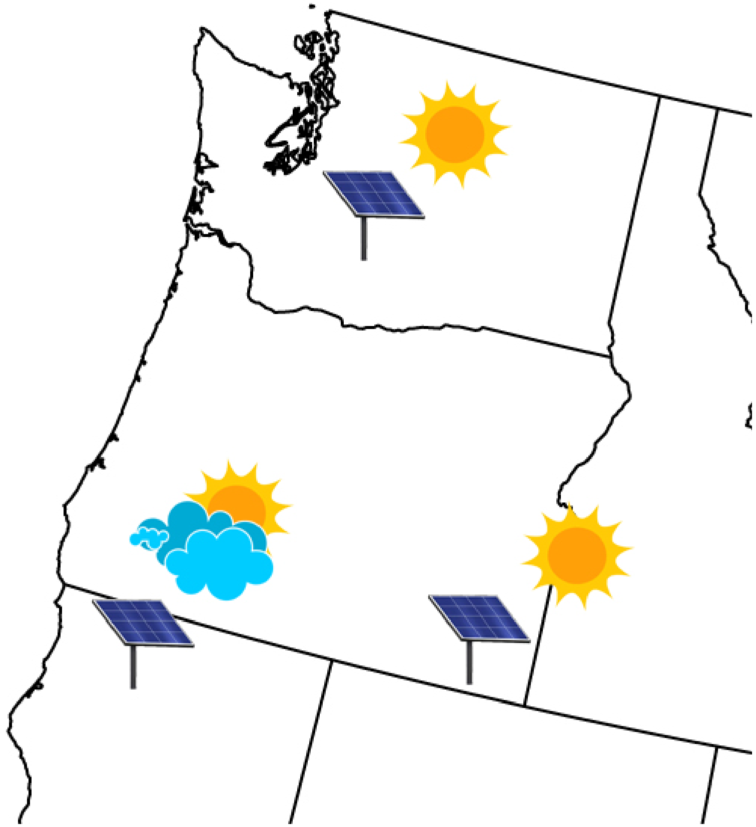
Drivers of the % Nameplate Increase

2. Geographic Diversity
   - In general, a **single large VER plant has a larger imbalance contribution** than a few plants with the same aggregate nameplate spread out across a wider area (e.g. a single 600 MW plant in one location vs. three 200 MW plants spread throughout the BA).
   - This is because the spread-out plants have **geographic diversity**, meaning weather impacts leading to imbalance at one site may not be occurring at the others (e.g. intermittent clouds at one site vs. clear day at others).
   - We ran a **small study** to test this, assuming three 200 MW plants at three different locations where solar exists in the BA today as a comparison to a single 600 MW plant. This resulted in **reserves as a percent of nameplate around 13%** for the geographically diverse scenario compared with approximately 17% for the non-geographically diverse.

Geographic Diversity



Non-Diverse Distribution



Diverse Distribution

Test Case: 600 MW Plant

- Assume a single 600 MW solar plant entered the Balancing Area in BP-24

	Nameplate	Reserves	% of Nameplate
BP-22 Average	99	6	6.08%
BP-24 Average	318	34	10.57%
Test Case Average	788	131	16.66%

BP-22 New Generation Technology Pilot

G. New Generation Technology Pilot Program

A customer and BPA may jointly develop a pilot program at the individual generation project level in order to integrate new uses of technology, such as a solar project coupled with a co-located battery. The goal of the pilot is to reduce the project's balancing reserve capacity burden placed on the BPA BAA. In place of any normally applicable RFR, VERBS or DERBS rates, BPA will instead directly assign the cost of balancing reserve capacity to the pilot project customer in accordance with the following capacity rate components:

(a)	Regulating Reserves	$0.261 per kilowatt-day
(b)	Non-Regulating Reserves	$0.168 per kilowatt-day
(c)	DEC Balancing Reserves	$0.012 per kilowatt-day

These rates are applied to the balancing reserve capacity BPA determines is needed for the pilot (not the installed nameplate of the project), and shall not exceed the total cost of the normally applicable RFR, VERBS, or DERBS rates. On a monthly basis, BPA shall revisit the amount of balancing reserves required for the project based on actual operational data for that project. All other rates required for the project shall apply.

A customer participating in a pilot program may still be subject to any applicable Intentional Deviation or Persistent Deviation penalties if operation of the project is not consistent with the pilot program expectations, resulting in the pilot adding to rather than reducing the Station Control Error of the project.

DERBS Settlement in BP-22

- The rate increase will be limited to 50% of the calculated impact in the Final Proposal compared to BP-20, with the excess costs allocated to other ACS rates (VERBS Wind, VERBS Solar, and RFR).

DERBS Settlement in BP-22

• DERBS Cost in BP-20	$615k
• DERBS Cost in BP-22	$1,053k
• Difference	$438k
• Mitigation (diff/2)	$219k
• Adjusted DERBS Cost in BP-22	$834k

• RFR	+$116k
• VERBS Wind	+$100k
• VERBS Solar	+3k

DERBS Settlement in BP-22

- Rates With Mitigation
  - DERBS INC 21.303 mills/kW-hour
  - DERBS DEC 1.240 mills/kW-hour

- Rates Without Mitigation
  - DERBS INC 26.902 mills/kW-hour
  - DERBS DEC 1.566 mills/kW-hour

DERBS Settlement in BP-22

- A portion of the rate increase for BP-24 is the non-mitigated portion of the BP-22 increase.

Rate	Units	BP-22 Rates /1	BP-24 Rates	Percent Change
DERBS with BP-22 mitigation				
DERBS Inc	mills/kWh	21.30	36.46	71.1%
DERBS Dec	mills/kWh	1.24	4.03	225.0%
DERBS without BP-22 mitigation				
DERBS Inc	mills/kWh	26.90	36.46	35.5%
DERBS Dec	mills/kWh	1.57	4.03	156.7%

/1 BP-22 Rates on this table reference Post EIM values.

Next Steps

- Comments or questions? Email techforum@bpa.gov and copy your Account Executive

- Please provide comments by August 10th.

BP-24 Topics – End of Day 1

BP-24 Topics – Day 2

Transmission Rates

- Sales, Load and LGIA Forecast
- Concurrent Loss Return Service – Rate Proposals

BP-24 Topic
Transmission Sales, Load and LGIA Forecast (FY 2024-2025 Preview)

Sales and Revenue Forecast

Transmission Preliminary Sales Forecast Assumptions

- Forecast of sales and revenues will continue to evolve as assumptions are updated for the BP-24 Initial Proposal
- Temperature normalized loads sourced from Agency Load Forecast (ALF) for NT, UD, and RFR. Assumed load growth of 2.1% through the BP-24 rate period.
- Network Point-to-Point (PTP LT)
  - Deferral and Renewal forecasts informed by AE input
  - TSEP forecasts (PTP LT Firm and CF) informed by AE and Planning inputs
  - Projections are made for the 2022 TSEP, whereas there were no TSEP projections for BP-22.
- Network Conversions informed by AE inputs and market expectations.
- Intertie Point-to-Point
  - Renewals forecast informed by AE input
  - IM Service includes existing and future service, informed by AE Inputs.
- Short Term
  - Average hydro from TDA hydro study
  - Average price spreads from Aurora

Sales Changes from BP-22 to FY24-25 Preliminary Forecast

- **PTP LT** increase of +2,441 MW
  - New Service for (1) 2021 and 2022 TSEP PTP LT and Conditional Firm for 1,991 MW, (2) Non-TSEP service of 450 MW, and (3) generation projected to come online for 420 MW /1
  - 376 MW of renewals originally not forecast to renew that are taking service.
  - Offset made by (1) 800 MW of an FPT conversion starting later than expected by 2.3 months in FY22 (2) 687 MW converting from PTP LT to NT due via TC-20 and end of contract, and (3) 200 MW of LGIA already accounted for in 2020 TSEP results
- **NT Load Service** increase of +1448 MW
  - Network conversions from PTP to NT service
  - Data Center and Cryptocurrency new load in the region
- **Short Term** increase of +178 MW.
  - Slightly greater overall hydro expected compared to BP22, with notably higher hydro during summer months
  - Higher price spreads expected compared to BP22.

Transmission Preliminary Sales Forecast

UNITS: MW per month

			BP-22 RATE CASE						
PRODUCT GROUP	PRODUCT CATEGORY	PRODUCT	2022	2023	BP-22 AVG	2024	2025	IPR-24 AVG	IPR-24 less BP-22
NETWORK	FORMULA POWER TRANSMISSION	FPT 1 YEAR	2	2	2	2	2	2	
		FPT 3 YEAR	0	0	0	0	0	0	
		FPT Sub-Total	**2**	**2**	**2**	**2**	**2**	**2**	**0**
	NETWORK INTEGRATION	NT SERVICE CHARGE	6,855	6,971	6,913	8,248	8,433	8,341	
		NT SHORT DISTANCE DISCOUNT	-120	-120	-120	-99	-99	-99	
		NT Sub-Total	**6,735**	**6,851**	**6,793**	**8,149**	**8,333**	**8,241**	**1,448**
	POINT-TO-POINT LONG TERM	PTP LONG TERM	27,931	27,919	27,925	29,966	30,765	30,365	
		PTP SHORT DISTANCE DISCOUNT	-274	-274	-274	-274	-274	-274	
		PTP LT Sub-Total	**27,657**	**27,645**	**27,651**	**29,692**	**30,490**	**30,091**	**2,441**
	POINT-TO-POINT SHORT TERM	PTP DAYS 1-5	262	259	261	312	312	312	
		PTP DAYS 6+	685	679	682	752	752	752	
		PTP HOURLY	211	209	210	253	253	253	
		PTP ST Sub-Total	**1157**	**1147**	**1152**	**1317**	**1317**	**1317**	**165**
INTERTIE	MONTANA INTERTIE LONG TERM	IM LONG TERM	29	56	43	88	88	88	
		IM LT Sub-Total	**29**	**56**	**43**	88	**88**	**88**	**45**
	SOUTHERN INTERTIE LONG TERM	IS LONG TERM	6025	6025	6025	6025	6025	6025	
		IS LT Sub-Total	**6025**	**6025**	**6025**	**6025**	**6025**	**6025**	**0**
	SOUTHERN INTERTIE SHORT TERM	IS DAYS 1-5	1	1	1	6	6	6	
		IS DAYS 6+	2	2	2	4	4	4	
DELIVERY		IS HOURLY	45	46	45	51	51	51	
		IS ST Sub-Total	**48**	**49**	**48**	**62**	**62**	**62**	**13**
	UTILITY DELIVERY	UD CHARGE	152	153	153	154	154	154	
		UD CHARGE Sub-Total	**152**	**153**	**153**	**154**	**154**	**154**	**1**

Transmission Preliminary Revenue Credits

REVENUE CREDITS		BP-22 Rate Case			FY24-25 Prelim		
Product	2022	2023	Avg BP-22 Rate Case	2024	2025	Avg FY24-25 Prelim	VAR
DSI DELIVERY CHARGE	408,336	408,336	**408,336**	408,336	408,336	**408,336**	0
FIBER OPERATIONS & MAINTENANCE	1,954,888	1,201,671	**1,578,279**	1,244,616	949,490	**1,097,053**	-481,226
FIBER LEASES	7,743,009	5,606,169	**6,674,589**	7,435,483	5,500,883	**6,468,183**	-206,406
PCS WIRELESS LEASES	7,008,131	7,008,131	**7,008,131**	7,159,377	7,156,596	**7,157,987**	149,856
PCS CONSTRUCTION	3,720,000	3,720,000	**3,720,000**	3,720,000	3,720,000	**3,720,000**	0
PCS OPERATIONS & MAINTENANCE	312,000	312,000	**312,000**	312,000	312,000	**312,000**	0
SINT AC NON FEDERAL O&M	2,209,800	2,209,800	**2,209,800**	2,209,800	2,209,800	**2,209,800**	0
LAND USE/LEASE/SALE	216,103	216,103	**216,103**	216,103	216,103	**216,103**	0
RIGHT-OF-WAY LEASE	79,200	79,200	**79,200**	79,200	79,200	**79,200**	0
MISC SERVICE FEES	3,312	3,312	**3,312**	3,312	3,312	**3,312**	0
TRANSMISSION PROCESSING FEE	39,600	39,600	**39,600**	39,600	39,600	**39,600**	0
AMORT NONFED PNW AC INTERTIE	3,488,076	3,488,076	**3,488,076**	3,467,664	3,467,664	**3,467,664**	-20,412
O&M FEDERAL FACILITY	234,308	234,308	**234,308**	234,308	234,308	**234,308**	0
O&M NON-FEDERAL FACILITY	1,093,308	1,093,308	**1,093,308**	1,086,012	1,086,012	**1,086,012**	-7,296
MISC LEASES	104,859	104,859	**104,859**	104,859	104,859	**104,859**	0
3RD AC RAS GENERATION DROPPING	38,112	38,112	**38,112**	76,572	76,572	**76,572**	38,460
PTP RESERVATION FEE	407,056	357,616	**382,336**	247,200	206,000	**226,600**	-155,736
UFT FIXED DOLLAR AMOUNT	3,419,736	3,406,128	**3,412,932**	3,526,872	3,351,628	**3,439,250**	26,318
UFT VARIABLE SERVICE AMT	228,192	228,192	**228,192**	228,192	228,192	**228,192**	0
TS SHARE OF RES ENRGY - BOR	0	0	**0**	0	0	**0**	0
TS SHARE OF RES ENRGY/WHLG-COE	245,697	245,697	**245,697**	245,697	245,697	**245,697**	0
BPA EQUIPMENT USE	186,384	186,384	**186,384**	185,186	172,008	**178,597**	-7,787
	33,140,107	**30,187,002**	**31,663,554**	**32,230,388**	**29,768,260**	**30,999,324**	**-664,230**

NON-REVENUE CREDITS	BP-22 Rate Case			FY24-25 Prelim			
Product	2022	2023	Avg BP-22 Rate Case	2024	2025	Avg FY24-25 Prelim	VAR
REGIONAL COMPLIANCE ENFORCEMT	2,110,646	2,148,690	**2,129,668**	2,208,814	2,208,814	**2,208,814**	79,146
REGIONAL COORDINATOR	2,110,646	2,148,690	**2,129,668**	2,204,525	2,204,525	**2,204,525**	74,857
TRANSMISSION OPERATOR SERVICES	673,320	673,320	**673,320**	673,320	673,320	**673,320**	0
TGT FIRM DEMAND	12,227,640	12,227,640	**12,227,640**	12,420,708	12,420,708	**12,420,708**	193,068
GENERATION INTEGRATION BBL	14,723,007	14,809,252	**14,766,129**	14,989,000	14,989,000	**14,989,000**	222,870

Risks to Preliminary FY24-25 Sales Forecast

- PTP LT
  - Refinements to the TSEP forecast as the TSEP process advances
  - Deferrals for confirmed reservations
  - Renewals that do not occur
  - Conversions that do not happen or are delayed
- NT
  - Delayed server deployment/coming online
  - Temperature departures from normal resulting in load variation
  - Impacts from economic changes across the region
- ST
  - Changes in market inputs on NW – CA price spreads
  - Changes in hydro forecast

Transmission Loads

BP-24 Preliminary Load Forecast

- Loads in the BPA Balancing Area are expected to increase by about 360 aMW – from 6,576 aMW in BP-22 to 6,935 aMW in BP-24.
- The higher loads in the BP-24 period are primarily associated with increases in data center and cryptocurrency loads in the region.
- Load growth is anticipated in residential sectors, as well as commercial sectors following the termination of stay-at-home orders associated with the pandemic.
- Other industrial and irrigation loads are expected to be comparable with the BP-22 period.

Interconnection Credits (GI and Non-GI)

Interconnection Credit Background

- A customer may request that BPA advance the completion of Network Upgrades that are necessary to enable the customer's project and that would otherwise not be completed in time to support the project's timeline, provided that customer commits to advance any associated expediting costs. This construct results in transmission credits, for any expediting costs paid.

- Interconnection deposits are considered advanced payment of future revenues. The deposited funds are used for construction or upgrades to network facilities. Advanced funds earn interest from the day of deposit and for the duration of the repayment period. The customer receives a transmission credit until the deposit is repaid or forfeit at the end of the repayment period.

- The net effect of Interconnection Credits appears in three places in the revenue requirement. The sum of all three, the net effect on the revenue requirement, is equal to the total credit.

Interconnection Credits Effect on Revenue Requirement =

(1) Interest accrued on outstanding deposit balances
(2) Depreciation on the assets
(3) Minimum Required Net Revenues (MRNR = revenue credit minus #1 & #2)

- Generally, credits are repaid in a shorter timeframe than the useful life of the assets. Credits tend to be repaid in 5-12 years while the assets may have much longer service lives.

Credit Policies

- Interconnection credits are managed under two policies:
  - Generator Interconnection (see GI Transmission Credits Business Practice)
    - SGI/LGI
  - Non-GI (see Transmission Credits for Non-GI Transmission Upgrades Business Practice)
    - LLI
- Each policy has its own unique requirements that must be considered in developing the forecast.

GI vs. Non-GI Credit Plans

	GI	Non-GI
Repayment Rate	Dollar-for-dollar at current rate for reserved Transmission Service (Method 1) or Generator Nameplate * Capacity Factor * Current Rate (Method 2)	Metered Incremental POD Demand per Credit Agreement (NT), or Eligible Incremental Transmission Service (PTP)
Repayment Term	20 Year	
Interest Rate	USD Government Agency BVAL Curve	
Start Date	Transmission Service Commencement Date (Method 1) or Commercial Operation Date in LGIA/SGIA (Method 2)	Energization Date of Network Upgrades
20-Year Balance	Cash refund (Tariff Requirement)	Forfeit

Transmission Credits Rate Case Forecast Process

- The Generation Interconnection (GI) and Line and Load Interconnection (LLI) Queues are assessed to determine which projects have a high likelihood to be completed prior to or during the upcoming rate period.
- To the extent possible, projects are tied to a request(s) in the Transmission Queue to forecast sales eligible to receive Transmission Credits.
- When a request in the queue cannot be tied to a request(s) in the Transmission Queue, a percentage of the nameplate is used to forecast the sales eligible to receive credits based on historical models.
    - 30% - Year 1
    - 50% - Year 2
    - 70% - Year 3
- For NT LLI requests, a load shape is applied to the forecast for the project.
- The dollar value of the Transmission Credits is forecasted based upon historical transmission credit averages, TSRs at the LT PTP rate, or projected new generation/load.
- Interest expense is calculated based on the applicable interest rate at the time of deposit or, for forecast deposits, based on the average interest rates of the most recent 12-month period.

BP-24 Transmission Credit Preliminary Forecast Results

- BPA currently holds $190 million in funds advanced for Network Upgrades. Of this total:
  - $141 million is currently in the repayment period, with customers actively receiving Transmission Credits
  - $49 million is pending project completion and are accruing interest.
- For the BP-24 rate period, BPA is forecasting approximately $52 million in additional funds to be advanced for Network Upgrades for continuing and future interconnection projects.
- The average transmission credit is $25.3 million per year in FY 24-25.
- The average interest expense is $3.3 million per year in FY 24-25.

BP-24 Credit and Interest Forecast Comparison

Rate Case Comparison Forecasts

	BP_22 FINAL		IPR-24			
	2022	2023	2023	2024	2025	IPR-24 AVG less BP-22 AVG
Forecasted Credit ($000)	23,135	30,282	21,487	24,112	26,501	(1,402)
Forecasted Interest ($000)	4,855	4,252	4,251	3,656	2,918	(1,267)

Next Steps

- Comments or questions? Email techforum@bpa.gov and copy your Account Executive
- Please provide comments by August 10th.

BP-24 Topic Concurrent Loss Return Service Rate Proposals

- Step 1: Introduction & Education
- Step 2: Description of the Issue
- Step 3: Analyze the Issue
- Step 4: Discuss Alternatives

Background

- In-Kind Concurrent Loss Return Service will replace the existing Delayed Loss Return Service effective October 1, 2023
- The Concurrent Losses Workshops held from December 2021 – May 2022 created the policy foundation for rates implementation
  - Workshop materials are available on the BP-22 Rates Settlement Implementation webpage at https://www.bpa.gov/energy-and-services/rate-and-tariff-proceedings/bp-22-rates-settlement-implementation
- Today will be working through the rate design implementation to support the Concurrent Loss Return Service

Policy Foundation for Rate Design

(Slide 1 of 2)

For customers electing in-kind concurrent loss return service or Slice output loss return service, BPA Transmission will financially settle loss imbalance. The total loss imbalance will be a combination of kW Remainder Imbalance and Time-based Imbalance, settled at a single energy rate:

- **kW Remainder Imbalance due to Rounding:** BPA will apply standard rounding when calculating a customer's loss obligation for the hour of flow. All kW remainders due to rounding will be settled financially (credit or charge).
- **Time-based Imbalance:** BPA will calculate and post the final pre-flow total loss obligation for the hour at T-80 for Slice output and at T-30 for in-kind concurrent. The difference between the pre-flow total loss obligation compared to the final loss obligation calculated at T+180 will make up the time-based imbalance to be financially settled (credit or charge). These imbalances are tracked for settlement at the kW level.

The policy foundation is the outcome from the Concurrent Losses Workshops held from December 2021 – May 2022

Policy Foundation for Rate Design

(Slide 2 of 2)

- Transmission customers who choose in-kind concurrent loss return service will be assessed a penalty charge for invalid loss returns.

- Waivers (if any) to the penalty charge for invalid concurrent loss returns due to Transmission Provider issued reliability events and/or OMP events will be described in the rate schedules.

The policy foundation is the outcome from the Concurrent Losses Workshops held from December 2021 – May 2022

Rate Design Areas to Address

1) Loss Imbalance:

Energy rate design for financially settling imbalances associated with the in-kind concurrent loss return service and Slice output loss return service

2) Invalid Loss Return (ILR) Penalty:

Rate design for financial penalties associated with over or under delivery of losses prior to the start of the hour of flow

- Includes penalty waiver provisions for reliability events and OMP events

Financial Settlement of Imbalances

Options:

1) Settle utilizing the average hourly EIM LAP
2) Settle utilizing the EIM LMP

Under either of these options, if an EIM market contingency occurs under OATT Section 10, BPA would plan to utilize the average hourly Powerdex Mid-C Index price for firm power as the alternate settlement approach

Option 1: EIM LAP for Settlement

- Pros:
  - Consistent with pricing used for other EIM load-based charges/credits
  - Consistent with prior approaches utilized for losses (e.g. FFI penalty structure and the energy pricing for financial loss returns)
  - Consistent pricing across BPA's Balancing Authority Area (BAA), as the BAA only has one LAP
  - Implementation would require less programming logic than the LMP, given that LMP requires mapping of generation in order to support the pricing structure
- Cons:
  - The LAP used for load-based imbalance and the specific LMPs for generation imbalance will be different values
    - Being an average, the LAP is a less specific price structure than using the LMP

Option 2: EIM LMP Imbalance

- Pros:
  - Pricing would be based on the LMP for the generator supplies the losses, thereby closely following the system topography
- Cons:
  - Inconsistent with the price used for other EIM load-based charges/credits
  - Inconsistent with prior approaches utilized for losses (e.g. FFI penalty structure and the energy pricing for financial loss returns)
  - Would be utilizing different pricing across the BPA BAA
  - Implementation would require additional programming compared to the EIM LAP

Current Staff Leaning

Based on the evaluation of the options, the current staff leaning is to pursue financially settling all concurrent loss imbalances (due to rounding and time-based imbalance) using the EIM LAP.

If an EIM market contingency occurs under OATT Section 10, BPA would settle utilizing the average hourly Powerdex Mid-C Index price for firm power.

Penalty Charge Structure

Options:

1) Utilize the existing Financial for Inaccuracy (FFI) penalty charge structure as the base, with modifications to the language to reflect the Invalid Loss Return (ILR) penalty and updating waiver provisions
2) Re-design the penalty structure for the Invalid Loss Returns (ILR) penalty

Option 1: Existing FFI Structure with Language Modifications for ILR

- Pros:
  - Losses penalty structure was already created in BP-22
  - Per recent review of the FFI penalty structure, BPA still believes the design is applicable
  - Minimal adjustments would be required to support the ILR penalty, thereby streamlining BPA’s implementation
- Cons:
  - *BPA staff has not identified cons to utilizing this structure*

Option 2: Re-Design FFI Structure for ILR Penalty

- Pros:
  - Opportunity to develop an alternative design, to incentivize accurate loss returns
- Cons:
  - This would move away from a rate structure that customers are already familiar with
  - This would require studies to determine a new structure and currently there is limited data available, recognizing BPA only recently joined the EIM

Current Staff Leaning

Based on the evaluation of the options, the current staff leaning is to base the ILR penalty on the existing FFI penalty charge structure, with modifications to the language and updating waiver provisions.

Next Steps

- Please submit your comments to techforum@bpa.gov with a CC to your Account Executive by August 10th
- Topic will be returning at the August Workshop to discuss feedback received and the staff proposal

TC-24 Topics – Day 2

Tariff

- Attachment C: Short-Term ATC (steps 5-6)
- EIM Resource Sufficiency (inform)
- FERC Order 881: Transmission Line Ratings (inform)

TC-24 Topic
Short-Term Available Transfer Capability (ST ATC)
Attachment C

- Step 5: Discuss Customer Feedback
- Step 6: Staff Proposal

Introduction

- In the meeting today, Bonneville is continuing the discussion on our Attachment C for the ATC methodology covering Bonneville's ATC calculations for the 0-13 month horizon
  - Bonneville refers to these calculations as ST ATC
- Bonneville's Attachment C approach for the ATC methodology covering the beyond 13 month horizon, referred to as Long-Term ATC, is being addressed as a separate topic in these workshops

Introduction (cont.)

- At the May 25th TC-24 meeting, Bonneville introduced and described the issues with our current short-term Attachment C, and presented alternatives for updating this document
- Bonneville indicated a leaning toward bringing our Attachment C up to date and including additional content on Bonneville's ST ATC methodology within this document, while maintaining the details of the ST ATC methodology that change frequently in the ATC Implementation Document and Transmission Reliability Margin Implementation Document
  - This approach brings our Attachment C more in line with FERC pro forma
    - Moves ATC process flowchart into Attachment C
    - Includes Existing Transmission Commitment formulas in Attachment C
  - Allows Bonneville to engage with customers to update the portions of the ST ATC Methodology that change more frequently using the current ST ATC engagement process and not a Tariff proceeding

Discuss Customer Feedback

- Bonneville did not receive extensive feedback from the May 25th meeting
- One party indicated general support for Bonneville's recommended approach, but requested that Bonneville present a draft Attachment C as early as possible to fully evaluate the recommendation

Staff Proposal

- Review draft Attachment C (separate document)
- Review draft ATC flowchart (separate document)
  - This document is currently posted to Bonneville's ATC Methodology website but is being updated
  - The ATC flowchart will be incorporated into Bonneville's Attachment C as part of the TC-24 effort

Next Steps

- Bonneville would like feedback on the draft short-term Attachment C and ATC flowchart
- Please send your comments and thoughts to techforum@bpa.gov with a copy to your Account Executive
- Comments are due by close of business on August 10, 2022

TC-24 Topic
EIM Resource Sufficiency
(inform)

Review of RS Related Policy Decisions

- BPA did not set a target pass rate for Resource Sufficiency
  - At this time and for the foreseeable future, Power will not adjust its policy for purchasing transmission or how it operates the FCRPS to increase the likelihood of passing RS
    - This policy decision will be reviewed at a later date as BPA gains more EIM experience and gathers operational data

- BPA did not pursue a Sub-BA Balancing standard
  - BPA will collect and analyze scheduling and other after-the-fact EIM data to determine whether to recommend a Sub-BAA RS Standard at a later date

Review of RS Related Policy Decisions

- BPA is working to establish multiple EIM data analytics teams and a process for evaluating RS failures
- BPA will internally review the causes for RS failures and how these could be avoided in the future if BPA were to try to do so
  - Any attempt to avoid RS failures would adhere to BPA’s existing marketing and operational strategies and policies

Plans for a Sub-BA Analysis

- Per the discussion yesterday, the Gen Inputs team will examine the idea of a Load Reliability Service that will determine the aspects of any such service.

- While this was identified as part of EIM entry analysis, it is pertinent regardless of our participation in the WEIM.

Questions/Comments

Next Steps

- Comments or questions? Email techforum@bpa.gov and copy your Account Executive
- Please provide comments by August 10th.

TC-24 Topic
FERC Order 881: Managing Transmission Line Ratings (inform)

Agenda

- FERC Order 881 – Timeline
- Current BPA Ratings Overview
- FERC Order 881 – Overview
- FERC Order 881 – BPA Next Steps
- FERC Order 881 – Resources

FERC Order 881 - Timeline

- Notice of Proposed Rulemaking (NOPR) regarding Ambient Adjusted Ratings (AAR) reviewed and commented on by BPA
- FERC Order 881 was published in the federal register on January 13, 2022 based on the AAR NOPR
  - Entities have:
    - 120 days from the effective date to submit Attachment M
    - 3 years from the OATT submittal to be in compliance
- On January 21, 2022, a handful of entities submitted requests for rehearing or clarification
  - However, at the February Commission Meeting FERC denied the requests
- FERC Notice of Inquiry (NOI) regarding Dynamic Line Ratings (DLR) released February 17th 2022
  - FERC evaluating the additional benefits of DLR use for increasing transmission capacity
  - DLR has been mentioned by FERC in several other rule-making proceedings

Ambient Adjusted Ratings

- Transmission lines and Transformers are rated for their Maximum Operating Temperature (MOT)
  - Transmission line MOT is a sag limit
  - Transformer MOT is a loss of life limit
- Lines and Transformers are heated by transfer of electric power and by external factors
- To prevent hitting the MOT we limit power transfers based on the external factors
  - Primary Factor: Ambient Temperature
  - Secondary Factors: Solar irradiance, wind speed, wind direction, precipitation, etc.
- As ambient temperatures change our equipment limits (ratings) also change

Seasonal Ratings

- Operational Planning Studies are performed on a 1 year to 2 week time horizon
- Studies require a single conservative, but realistic, ambient temperature assumption
- Broken into 3 Seasonal Timeframes
  - Summer (June 1 – October 31): 30C Assumption
  - Winter (November 1 – March 31): -5/-15C assumption
  - Spring (April 1 – May 31): 20C Assumption

Emergency Ratings

- Emergency ratings only apply for a finite period of time
- Reflect an operating range with acceptable loss of life and/or acceptable physical or safety limitations
- Must reflect the most limiting element of a transmission facility
- BPA uses a “Time to MOT” calculator called the by-line tool to assess post contingency acceptable operating time

FERC Order 881

- Requires implementation of Ambient Adjusted Ratings (AARs)
  - AARs to be used for providing near-term (10 days out) transmission service
  - Must have day and night ratings
  - Must be updated at least each hour
  - Rating database must be created by Regional Transmission Organizations (RTO) and Independent System Operators (ISO) to which Transmission Owners (TO) will submit AARs.
  - TOs must share ratings and methodologies with their transmission providers and/or market monitors
  - Transmission Providers must maintain a database of TO's ratings and methodologies on the Open Access Same-Time Information System (OASIS) site or equivalent
  - Must have "reasonable confidence" in the forecasted ratings

FERC Order 881

- Requires implementation of Seasonal Ratings
  - Must have at least 4 seasons
  - Must be re-evaluated annually
  - Must be based on historic temperatures
  - Used for longer range transmission availability studies >10 days out
- Requires implementation of Emergency Ratings
  - Emergency ratings to apply to a “finite period of operation” opposed to continuous operation
  - Used for post contingency operation of the power system
  - Emergency ratings are adjusted for ambient temperatures

FERC Order 881 – BPA's Comments

- "Bonneville does not believe that substantial additional congestion relief will result from the use of AAR on its system, due in part to long lines which cross multiple climate zones, and lack of impact on voltage or transient stability-limited facilities"

- "Bonneville does not find a benefit for the use of AAR for "near-term point-to-point transmission service" when evaluating requests, responding to requests for information on the availability of potential service, or for posting ATC or other information related to transmission service on OASIS.

- "Curtailments far in advance of the operating hour may prove to be unnecessarily implemented if weather forecasts change (as they often do). Unnecessary curtailments could result in more costly re-dispatch and increased workload for transmission customers

FERC Order 881 – BPA Next Steps

- Technical team has been formed to review the order and evaluate gaps between our current policies and procedures and FERC Order 881 implementation requirements
  - Engineering
  - Operations
  - Compliance
  - Marketing
- Developing and evaluating options
- BPA plans to engage customers on implementation of FERC Order 881 and corresponding tariff language during the BP/TC-26 pre-proceeding workshops
  - BPA is not proposing any new tariff language related to 881 in TC-24

Questions for Consideration

- What infrastructure changes are needed to allow for actively updated ambient adjusted equipment ratings?

- Are there value propositions beyond increasing path limits to implementing ambient adjusted ratings?

FERC Order 881 - Resources

- Technical Conference on Transmission Line Ratings (Docket AD19-15-000)
- FERC Staff Paper on Managing Transmission Line Ratings
- Transcripts of Technical Conference – Day 1 and Day 2
- NOPR on Managing Transmission Line Ratings (Docket RM20-16-000)
- Notice of Proposed Rule Making (NOPR) on Managing Transmission Line Ratings
- Order 881: Final Rule on Managing Transmission Line Ratings
- Final Rule – see Appendix B starting on pg. 291 for *pro forma* tariff language
- FERC staff presentation on the draft final rule

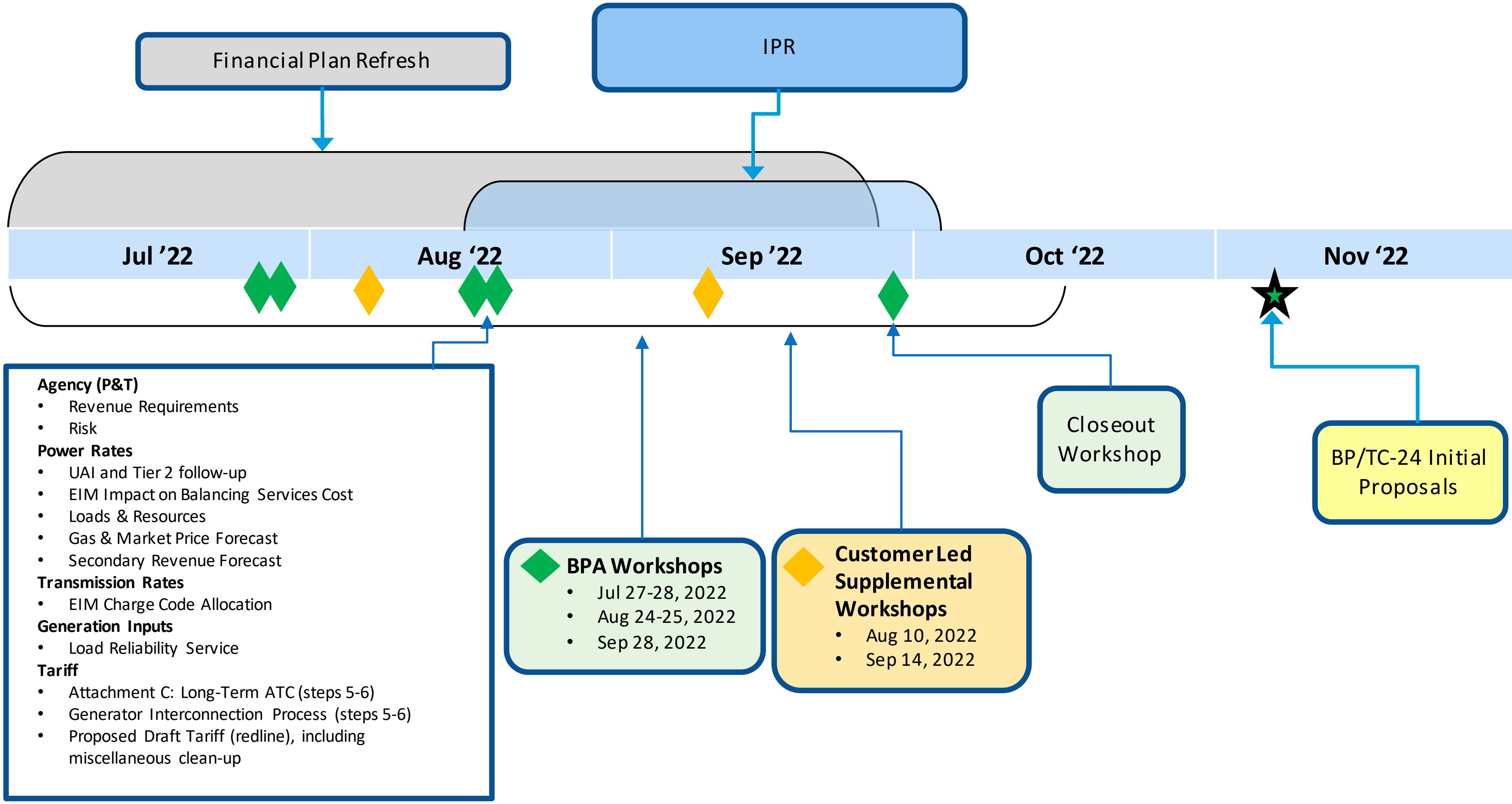
Questions

Next Steps

- Comments or questions? Email techforum@bpa.gov and copy your Account Executive

- Please provide comments by August 10th.

BP/TC-24 Pre-Proceeding Timeline



Next Steps: BP/TC-24 for Process

- Upcoming Customer Engagement deadlines
  - August 3, Deadline to request customer-led workshop (scheduled for August 10) with topics and amount of time
    - Submit **request** to techforum@bpa.gov and cc your Power and Transmission AE
  - August 10, Deadline for customer comments on the July 27-28 materials
    - Submit **comments** to techforum@bpa.gov and cc your Power and Transmission AE
- August 24 & 25
  - Next BP/TC-24 workshops

Appendix

Customer Led Workshops

- Within one week after every workshop, customers can request a Customer Led workshop that would focus on topics presented in the previous workshop.
- Customers should provide the topic and estimated time needed for discussion with BPA SMEs.
- BPA will not create new content – this is an opportunity to ask further questions on materials previously presented.
- Opportunities for customers to present on topics of interest, where BPA will be in listening mode.

BP-24 & TC-24 Workshops: Proposed Dates for Rate and Tariff Topics

Date	Rate/Tariff Topics
April 27 (Wed)	**Generation Inputs** • Operating Reserves with Western Power Pool (WPP) **Tariff** • Attachment C: Long-Term ATC (steps 1-5) • Conditional Reservation Deadline for Daily Firm PTP (all steps)
May 25 (Wed)	**Power Rates/Generation Inputs** • EIM Benefits in Power Rates • EIM Impact on Balancing Services Cost • Customer concerns regarding EIM and Generation Inputs **Transmission Rates** • EIM Charge Code Allocation • Segmentation Study **Tariff** • Attachment C: Short-Term ATC (steps 1-4)
June 7 (Tues)	• *RHWM Process Workshop*
Jun 14-16	• *IPR (pre-rate case process)*

BP-24 & TC-24 Workshops: Proposed Dates for Rate and Tariff Topics (cont.)

Date	Rate/Tariff Topics
Jun 29 (Wed)	**Power Rates** • Tier 2 Rates • Unauthorized Increase (UAI) Charge **Transmission Rates** • Eastern Intertie Process Update (BP-22 Settlement Commitment) • Unauthorized Increase/Failure to Comply Charges (Inform) **Tariff** • Generator Interconnection Process (steps 1-4) • Attachment C: Long-Term ATC (step 5) • Generator Interconnection Process (steps 1-4) • Utility and DSI Delivery Losses (all steps) • Monthly Loss Factors on the Network Segment (all steps)

Agenda changes to note:
- EIM Benefits in Power Rates and EIM Impact on Balancing Services Costs topics moved to July
- Topics no longer needed and removed from agenda: Gen Inputs discussion on Losses (Power's capacity cost and recovery of losses)

BP-24 & TC-24 Workshops: Proposed Dates for Rate and Tariff Topics (cont.)

Date	Rate/Tariff Topics
Jul 27-28 (Wed-Thu)	**Power Rates** • EIM Benefits in Power Rates • Transfer Service • Washington Cap-and-Invest Program **Transmission Rates** • Sales Forecast (includes LGIA Forecast and Load Forecast) • Concurrent Loss Return Service Rate Proposals **Generation Inputs** • Load Reliability Service • EIM Impact on Balancing Services Cost • Persistent Deviation/ Intentional Deviation Review • VERBS, DERBS, and Load Balancing Services (BP-22 Settlement commitment) **Tariff** • Attachment C: Short-Term ATC (steps 5-6) • EIM Resource Sufficiency (inform) • Order 881: Transmission Line Ratings (inform)

Agenda changes to note:

- Revenue Requirements and Risk topics moved to August workshop.
- Added Concurrent Loss Return Service Rate Proposals topic.

BP-24 & TC-24 Workshops: Proposed Dates for Rate and Tariff Topics (cont.)

Date	Rate/Tariff Topics
Aug 24-25 (Wed-Thu)	**Agency (P&T)** • Revenue Requirements • Risk **Power Rates** • UAI and Tier 2 follow-up • EIM Impact on Balancing Services Cost • Loads & Resources • Gas & Market Price Forecast • Secondary Revenue Forecast **Transmission Rates** • EIM Charge Code Allocation **Generation Inputs** • Load Reliability Service **Tariff** • Attachment C: Long-Term ATC (steps 5-6) • Generator Interconnection Process (steps 5-6) • Proposed Draft Tariff (redline), including miscellaneous clean-up
Sept 28 (Wed)	Workshop Close-out and Summary of Staff Leanings

Meeting topics and workshop dates are subject to change. Please check the BPA Event Calendar for the most up-to-date information.

Proposed Procedural Schedules

	BP-24	TC-24
Federal Register Published (estimated)	Nov 10	Nov 10
Pre-Hearing Conference/BPA Direct Case	Nov 17	Nov 17
Clarification of BPA's Direct Case	Dec 7-8	Dec 6
Parties File Direct Cases	Jan 24	Jan 20
Litigants File Rebuttal	Mar 7	Mar 1
Cross Examination	Apr 6-7	Mar 23-24
Initial Briefs	Apr 25	April 13
Hearing Officer's Recommendation	n/a	May 23
Draft ROD	Jun 13	Jun 23
Briefs on Exceptions	Jun 27	Jul 7
Final ROD	Jul 26	Jul 26

Preliminary proposal subject to change.

Transmission Sales, Load and LGIA Forecast (FY 2024-2025 Preview) Appendix

Non-Cash Revenues: Effect on Revenue Requirements

- A basic premise for setting rates is that Revenues from Proposed Rates must be greater than or equal to the Revenue Requirement, as measured on both an accrual and cash perspective.
- If there will be non-cash revenues in the revenue forecast, then the Revenues from Proposed Rates must be greater than the Cash Requirements to demonstrate cost recovery
- To capture this in determining the Revenue Requirement, then, the Revenue Requirement is the sum of all Cash Requirements and Non-Cash Revenues
- In the context of rate setting, then, LGIA credits function more like a cost than a revenue:
  - LGIA credits are based on rates that must recover in full the projected rate period costs
  - Until the LGIA credits are exhausted, interconnection customers do not contribute cash revenues and therefore do not contribute to the recovery of rate period costs
  - Consequentially, the remaining customers have to make up the difference

BP-24 GI & LLI Credit and Interest Forecast

#	Request	Type	Tx Credit Balance as of 6/1/2022	Upgrade Deposits During FY23-25	Forecasted Credits ($000) FY 2023	Forecasted Credits ($000) FY 2024	Forecasted Credits ($000) FY 2025	Forecasted Interest ($000) FY 2023	Forecasted Interest ($000) FY 2024	Forecasted Interest ($000) FY 2025
1	GI Request 1	GI	$ 1,088	$ -	$ 795	$ -	$ -	$ 15	$ -	$ -
2	GI Request 2	GI	$ 48,660,233	$ -	$ 6,615	$ 6,482	$ 2,644	$ 749	$ 456	$ 403
3	GI Request 3	GI	$ 7,501,603	$ -	$ 954	$ 664	$ -	$ 41	$ 8	$ -
4	GI Request 4	GI	$ 614,912	$ -	$ 705	$ 705	$ 705	$ 360	$ 347	$ 334
5	GI Request 5	GI	$ 810,857	$ -	$ 1,075	$ -	$ -	$ 2	$ -	$ -
6	GI Request 6	GI	$ 7,918	$ -	$ 129	$ 129	$ 129	$ 66	$ 64	$ 62
7	GI Request 7	GI	$ 32,856	$ -	$ 129	$ 129	$ 129	$ 41	$ 39	$ 36
8	GI Request 8	GI	$ 1,681,922	$ -	$ 184	$ 184	$ 184	$ 42	$ 38	$ 33
9	GI Request 9	GI	$ 2,491,547	$ -	$ 1,410	$ 2,146	$ 2,175	$ 349	$ 311	$ 256
10	GI Request 10	GI	$ 467,327	$ -	$ 331	$ 552	$ 773	$ 202	$ 195	$ 181
11	GI Request 11	GI	$ 1,644,429	$ -	$ 276	$ 445	$ 644	$ 65	$ 58	$ 46
12	GI Request 12	GI	$ 21,797,147	$ -	$ 1,656	$ 1,759	$ 2,286	$ 182	$ 117	$ 23
13	GI Request 13	GI	$ 2,945,031	$ 3,829	$ -	$ 101	$ 178	$ 50	$ 50	$ 47
14	GI Request 14	GI	$ 10,250,055	$ 1,047	$ -	$ 1,223	$ 3,019	$ 196	$ 234	$ 174
15	GI Request 15	GI	$ 409,952	$ 5,993	$ -	$ -	$ 1,012	$ 79	$ 80	$ 72
16	GI Request 16	GI	$ 6,797,367	$ -	$ -	$ 1,548	$ 2,277	$ 156	$ 239	$ 208
17	GI Request 17	GI	$ 1,012,732	$ 14,200	$ -	$ 375	$ 1,376	$ 40	$ 63	$ 45
18	GI Request 18	GI	$ 499,900	$ 3,147	$ -	$ -	$ 419	$ 25	$ 56	$ 53
19	GI Request 19	GI	$ 9,212,542	$ 300	$ -	$ 1,012	$ 1,778	$ 62	$ 66	$ 40
20	GI Request 20	GI	$ 10,805,937	$ 3,000	$ -	$ 110	$ 184	$ 74	$ 74	$ 73
21	GI Request 21	GI	$ 568,185	$ 988	$ 413	$ 163	$ 65	$ 14	$ 1	$ 53
22	GI Request 22	GI	$ 653,764	$ 2,657	$ -	$ -	$ 329	$ 95	$ 46	$ 33
23	GI Request 23	GI	$ 698,233	$ 1,422	$ -	$ 293	$ 498	$ 16	$ 12	$ 53
24	GI Request 24	GI	$ 654,019	$ 2,748	$ 130	$ 228	$ 64	$ 64	$ -	$ -
25	GI Request 25	GI	$ 424,603	$ 1,455	$ 521	$ 257	$ 17	$ -	$ -	$ -
26	GI Request 26	GI	$ 953,759	$ 888	$ -	$ 126	$ 222	$ 63	$ 63	$ 53
27	GI Request 27	GI	$ 275,992	$ 2,544	$ -	$ 1,279	$ 1,024	$ 244	$ 293	$ 60
28	GI Request 28	GI	$ 2,979,820	$ 1,244	$ 418	$ 99	$ -	$ 8	$ 56	$ 53
1	LLI Request 1	LLI	$ 1,055,769	$ -	$ 348	$ 159	$ -	$ 8	$ 0	$ -
2	LLI Request 2	LLI	$ 1,192,469	$ -	$ 109	$ -	$ -	$ 0	$ -	$ -
3	LLI Request 3	LLI	$ 8,203,324	$ -	$ 675	$ 1,204	$ 1,975	$ 381	$ 300	$ 270
4	LLI Request 4	LLI	$ 1,710,028	$ -	$ 128	$ 204	$ 298	$ 16	$ 12	$ 5
5	LLI Request 5	LLI	$ 37,490,417	$ -	$ 3,171	$ 821	$ -	$ 72	$ -	$ -
6	LLI Request 6	LLI	$ 31,406	$ -	$ 154	$ 239	$ 128	$ 11	$ 6	$ 1
7	LLI Request 7	LLI	$ 73,797	$ -	$ 128	$ 82	$ -	$ 4	$ 1	$ -
8	LLI Request 8	LLI	$ 1,644,408	$ -	$ 533	$ 273	$ -	$ 14	$ 1	$ -
9	LLI Request 9	LLI	$ 456,886	$ -	$ 8	$ 31	$ 18	$ 1	$ 1	$ 0
10	LLI Request 10	LLI	$ 1,217,283	$ -	$ -	$ -	$ -	$ 17	$ 18	$ 18
11	LLI Request 11	LLI	$ 1,451,747	$ -	$ 55	$ 113	$ 149	$ 16	$ 10	$ 10
12	LLI Request 12	LLI	$ 112,467	$ -	$ -	$ 70	$ 117	$ 2	$ -	$ -
13	LLI Request 13	LLI	$ 50,781	$ 20	$ -	$ 81	$ 24	$ 2	$ 1	$ 0
14	LLI Request 14	LLI	$ 6,361	$ -	$ -	$ 478	$ 985	$ 221	$ 215	$ 197
15	LLI Request 15	LLI	$ 697	$ -	$ 48	$ 90	$ 128	$ 10	$ 12	$ 10
16	LLI Request 16	LLI	$ 24,183	$ 1,255	$ -	$ 105	$ 175	$ 73	$ 70	$ -
17	LLI Request 17	LLI	$ 56,823	$ 328	$ 392	$ 155	$ 62	$ 13	$ 1	$ -
18	LLI Request 18	LLI	$ 279,549	$ 2,211	$ -	$ -	$ 313	$ 90	$ 44	$ 21
	Total Forecast		**$ 189,912,128**	**$ 49,277**	**$ 21,487**	**$ 24,112**	**$ 26,501**	**$ 4,251**	**$ 3,656**	**$ 2,918**

Appendix: Sales and Revenue Forecast

Preliminary Sales by Month FY 2024

ProductGroup	ProductCategory	ProductName	2024 1	2	3	4	5	6	7	8	9	10	11	12
NETWORK	FORMULA POWER TRANSMISSION	FPT 1YR LONG TERM FIRM	2	2	2	2	2	2	2	2	2	2	2	2
	FORMULA POWER TRANSMISSION Total		**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**
	NETWORK INTEGRATION	NT SERVICE CHARGE	7,274	8,426	9,636	9,484	9,027	8,512	7,542	7,230	7,905	8,331	8,075	7,538
		NT SHORT DISTANCE DISCOUNT	(114)	(92)	(107)	(111)	(109)	(115)	(115)	(41)	(79)	(92)	(106)	(114)
	NETWORK INTEGRATION Total		**7,160**	**8,334**	**9,529**	**9,373**	**8,918**	**8,397**	**7,427**	**7,188**	**7,827**	**8,240**	**7,969**	**7,424**
	POINT-TO-POINT LONG TERM	PTP LONG TERM FIRM	28,283	28,283	28,483	28,483	28,483	28,993	29,013	29,023	29,060	29,060	29,060	29,260
		PTP LTF CANADIAN ENTITLEMENT	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120
		PTP LTF CONDITIONAL FIRM	56	56	56	56	56	56	56	56	56	56	56	56
		PTP SHORT DISTANCE DISCOUNT	(274)	(274)	(274)	(274)	(274)	(274)	(274)	(274)	(274)	(274)	(274)	(274)
	POINT-TO-POINT LONG TERM Total		**29,185**	**29,185**	**29,385**	**29,385**	**29,385**	**29,895**	**29,915**	**29,925**	**29,962**	**29,962**	**29,962**	**30,162**
	POINT-TO-POINT SHORT TERM	PTP DAILY FIRM DAYS 1-5	0	0	64	88	225	700	478	622	798	736	35	0
		PTP DAILY FIRM DAYS 6+	0	0	185	234	435	1,105	1,015	2,011	2,113	981	585	360
		PTP HOURLY NONFIRM	230	263	117	139	208	547	320	302	417	404	37	47
	POINT-TO-POINT SHORT TERM Total		**230**	**263**	**366**	**461**	**867**	**2,351**	**1,813**	**2,936**	**3,328**	**2,121**	**657**	**407**
NETWORK Total			**36,577**	**37,785**	**39,283**	**39,221**	**39,172**	**40,646**	**39,157**	**40,051**	**41,119**	**40,325**	**38,591**	**37,995**
INTERTIE	MONTANA INTERTIE LONG TERM	IM LONG TERM FIRM	88	88	88	88	88	88	88	88	88	88	88	88
	MONTANA INTERTIE LONG TERM Total		**88**	**88**	**88**	**88**	**88**	**88**	**88**	**88**	**88**	**88**	**88**	**88**
	SOUTHERN INTERTIE LONG TERM	IS LONG TERM FIRM	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025
	SOUTHERN INTERTIE LONG TERM Total		**6,025**	**6,025**	**6,025**	**6,025**	**6,025**	**6,025**	**6,025**	**6,025**	**6,025**	**6,025**	**6,025**	**6,025**
	SOUTHERN INTERTIE SHORT TERM	IS DAILY FIRM DAYS 1-5	35	35	2	1	0	1	1	1	1	1	0	0
		IS DAILY FIRM DAYS 6+	13	14	1	2	3	2	3	2	2	2	3	3
		IS HOURLY NONFIRM	48	48	47	49	51	50	48	55	62	54	50	50
	SOUTHERN INTERTIE SHORT TERM Total		**96**	**97**	**50**	**51**	**55**	**53**	**52**	**58**	**66**	**57**	**54**	**53**
INTERTIE Total			**6,209**	**6,210**	**6,163**	**6,164**	**6,168**	**6,166**	**6,165**	**6,171**	**6,179**	**6,170**	**6,167**	**6,166**
DELIVERY	UTILITY DELIVERY	UTILITY DELIVERY CHARGE	131	163	192	193	176	161	138	121	141	153	150	124
	UTILITY DELIVERY Total		**131**	**163**	**192**	**193**	**176**	**161**	**138**	**121**	**141**	**153**	**150**	**124**
DELIVERY Total			**131**	**163**	**192**	**193**	**176**	**161**	**138**	**121**	**141**	**153**	**150**	**124**

Preliminary Sales by Month FY 2025

ProductGroup	ProductCategory	ProductName	2025 1	2	3	4	5	6	7	8	9	10	11	12
NETWORK	FORMULA POWER TRANSMISSION	FPT 1YR LONG TERM FIRM	2	2	2	2	2	2	2	2	2	2	2	2
	FORMULA POWER TRANSMISSION Total		**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**
	NETWORK INTEGRATION	NT SERVICE CHARGE	7,459	8,623	9,846	9,681	9,257	8,675	7,701	7,395	8,074	8,518	8,256	7,710
		NT SHORT DISTANCE DISCOUNT	(114)	(92)	(107)	(111)	(109)	(115)	(115)	(41)	(79)	(92)	(106)	(114)
	NETWORK INTEGRATION Total		**7,345**	**8,531**	**9,739**	**9,570**	**9,148**	**8,560**	**7,586**	**7,354**	**7,995**	**8,426**	**8,150**	**7,597**
	POINT-TO-POINT LONG TERM	PTP LONG TERM FIRM	29,276	29,276	29,306	29,691	29,691	29,689	29,689	29,689	29,689	29,689	29,689	29,689
		PTP LTF CANADIAN ENTITLEMENT	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120
		PTP LTF CONDITIONAL FIRM	56	56	56	56	56	56	56	56	56	56	56	56
		PTP SHORT DISTANCE DISCOUNT	(274)	(274)	(274)	(274)	(274)	(274)	(274)	(274)	(274)	(274)	(274)	(274)
	POINT-TO-POINT LONG TERM Total		**30,178**	**30,178**	**30,208**	**30,593**	**30,593**	**30,591**	**30,591**	**30,591**	**30,591**	**30,591**	**30,591**	**30,591**
	POINT-TO-POINT SHORT TERM	PTP DAILY FIRM DAYS 1-5	0	0	64	88	225	700	478	622	798	736	35	0
		PTP DAILY FIRM DAYS 6+	0	0	185	234	435	1,105	1,015	2,011	2,113	981	585	360
		PTP HOURLY NONFIRM	230	263	117	139	208	547	320	302	417	404	37	47
	POINT-TO-POINT SHORT TERM Total		**230**	**263**	**366**	**461**	**867**	**2,351**	**1,813**	**2,936**	**3,328**	**2,121**	**657**	**407**
NETWORK Total			**37,755**	**38,975**	**40,316**	**40,626**	**40,610**	**41,504**	**39,992**	**40,883**	**41,917**	**41,140**	**39,401**	**38,597**
INTERTIE	MONTANA INTERTIE LONG TERM	IM LONG TERM FIRM	88	88	88	88	88	88	88	88	88	88	88	88
	MONTANA INTERTIE LONG TERM Total		**88**	**88**	**88**	**88**	**88**	**88**	**88**	**88**	**88**	**88**	**88**	**88**
	SOUTHERN INTERTIE LONG TERM	IS LONG TERM FIRM	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025	6,025
	SOUTHERN INTERTIE LONG TERM Total		**6,025**	**6,025**	**6,025**	**6,025**	**6,025**	**6,025**	**6,025**	**6,025**	**6,025**	**6,025**	**6,025**	**6,025**
	SOUTHERN INTERTIE SHORT TERM	IS DAILY FIRM DAYS 1-5	35	35	2	1	0	1	1	1	1	1	0	0
		IS DAILY FIRM DAYS 6+	13	14	1	2	3	2	3	2	2	2	3	3
		IS HOURLY NONFIRM	48	48	47	49	51	50	48	55	62	54	50	50
	SOUTHERN INTERTIE SHORT TERM Total		**96**	**97**	**50**	**51**	**55**	**53**	**52**	**58**	**66**	**57**	**54**	**53**
INTERTIE Total			**6,209**	**6,210**	**6,163**	**6,164**	**6,168**	**6,166**	**6,165**	**6,171**	**6,179**	**6,170**	**6,167**	**6,166**
DELIVERY	UTILITY DELIVERY	UTILITY DELIVERY CHARGE	132	164	193	193	178	162	139	121	141	154	150	125
	UTILITY DELIVERY Total		**132**	**164**	**193**	**193**	**178**	**162**	**139**	**121**	**141**	**154**	**150**	**125**
DELIVERY Total			**132**	**164**	**193**	**193**	**178**	**162**	**139**	**121**	**141**	**154**	**150**	**125**

Concurrent Loss Return Service Rate Proposals Appendix

BP-22 FFI Rate Schedule Language

(Slide 1 of 3)

a. Energy Price

The Energy Price for the FFI Penalty Charge will differ depending on whether BPA is a participant in the Western EIM.

(1) Energy Price when BPA is not an EIM Participant

If BPA is not a participant in the EIM, then the Energy Price will be the applicable average hourly Powerdex Mid-C Index price for firm power for the hour in which the loss occurred. In the event the hourly Powerdex Mid-C price index is no longer a reliable price index, the index will be replaced by an applicable new hourly energy index at a hub at which Northwest parties can trade between October 1, 2021, and September 30, 2023. BPA will provide notice of such a change as soon as practicable.

(2) Energy Price when BPA is an EIM Participant

If BPA is a participant in the EIM, then the Energy Price will be the applicable hourly average Load Aggregation Point (LAP) price for BPA as determined by the Market Operator (MO) under Section 29.11(b)(3)(C) of the MO Tariff for the hour in which the loss occurred.

BP-22 FFI Rate Schedule Language

(Slide 2 of 3)

b. Under-Delivery Event (UDE)

For each hour that the Transmission Customer returns less energy than its real power loss obligation, the FFI penalty rates shall be:

(1) UDE Capacity Rate: 5.58 mills per kilowatthour
(2) UDE Energy Rate: the greater of $0 or 250 percent of the Energy Price.

c. Over-Delivery Event (ODE)

For each hour that the Transmission Customer returns more energy than its real power loss obligation, the FFI penalty rates shall be:

(1) ODE Capacity Rate: 5.58 mills per kilowatthour
(2) ODE Energy Rate: 250 percent of the absolute value of the Energy Price

The ODE Energy Rate shall not be assessed when the Transmission Customer returns more energy than its real power loss obligation and the Energy Price is equal to or greater than $0 per MWh.

BP-22 FFI Rate Schedule Language

(Slide 3 of 3)

2. Billing Factors

a. Under Delivery Event

The Billing Factor (in kWh) for the UDE rates shall be for each hour:

Customer's Real Power Loss Obligation

Minus

The quantity of loss returns provided by the customer.

b. Over Delivery Event

The Billing Factor (in kWh) for the ODE rates shall be for each hour:

The quantity of loss returns provided by the customer

Minus

Customer's Real Power Loss Obligation

3. Other Provisions

BPA will exempt a Transmission Customer from the FFI Penalty Charge during times of BAA or Transmission Provider reliability adjustments to real power loss returns.