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

May 25, 2022
# Agenda

<table>
<thead>
<tr>
<th>TIME*</th>
<th>TOPIC</th>
<th>Presenter</th>
</tr>
</thead>
</table>
| 9:00 to 9:05 a.m. | Introduction, Meeting Protocols and Agenda                            | Rebecca Fredrickson  
                        |                                                                        | Daniel Fisher          |
| 9:05 to 9:15 a.m. | Customer Logistics and Norms                                          | Rebecca Fredrickson          |
| 9:15 to 9:45 a.m. | Power Rates/Generation Inputs                                          | Steve Gaube                   
                        | • EIM Benefits in Power Rates (steps 1-4)                              | Eric Graessley         |
| 9:45 to 10:10 a.m.| Power Rates/Generation Inputs                                          | Jonathan Ramse                |
| 10:10 to 10:30 a.m.| Power Rates/Generation Inputs                                          | Jonathan Ramse                |
| 10:30 to 10:45 a.m.| **BREAK**                                                            |                                |
| 10:45 to 11:00 a.m.| Transmission Rates                                                    | Bill Hendricks                |
| 11:00 to 11:30 a.m.| Transmission Rates                                                    | Miranda McGraw                |
| 11:30 to 12:30 p.m.| **LUNCH**                                                            |                                |
| 12:30 to 1:25 p.m.| Tariff                                                               | Margaret Olczak              |
| 1:25 to 1:30 p.m. | Wrap-up and Next Steps                                                |                                |

*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):

- 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

Financial Plan Refresh

IPR

May '22

Jun '22

Jul '22

Aug '22

Sep '22

Oct '22

Nov '22

Power Rates
- Unauthorized Increase (UAI) Charge
- Tier 2 Rates

Transmission Rates
- Eastern Intertie Process Update (BP-22 Settlement Commitment)

Generation Inputs
- Load Reliability Service
- Losses
  - Power’s Capacity cost of providing losses
  - Cost Recovery of Losses

Tariff
- Attachment C: Long-Term ATC (steps 4-5)
- Generator Interconnection Process (steps 1-4)
- Utility and DSI Delivery Losses (all steps)
- Monthly Loss Factors on the Network Segment (all steps)

BPA Workshops
- May 25, 2022
- Jun 29-30, 2022
- Jul 27-28, 2022
- Aug 24-25, 2022
- Sep 28, 2022

Customer Led Supplemental Workshops
- Jun 8, 2022
- Jul 13, 2022
- Aug 10, 2022
- Sep 14, 2022

Closeout Workshop

BP/TC-24 Initial Proposals
BP-24 Topics

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
BP-24 Topic

EIM Benefits in Power Rates

- Step 1: Introduction and Education
- Step 2: Description of the Issue
- Step 3: Data and/or analysis that supports the issue
- Step 4: Discussions on possible alternatives to solve issue
Steps 1: Introduction and Education
Background

- The EIM Cost Benefit Study (modeled by E3) indicating annual net EIM benefits of $36-$40M/year.
- For reasons discussed in the BP-22 rate proceedings, BP-22 rates assume incremental benefits equal to costs (zero net benefit).
- BPA committed to working with stakeholders on a BP-24 proposal that would better reflect expected benefits, and BPA has a desire to fully integrate EIM participation in modeling, avoiding the false precision that results from itemized credits to the NSR Forecast.
- According to the E3 study, EIM dispatch benefits accrue in 2 key areas, with the vast majority being attributed to #1:
  1) Additional Load Factoring
     - Previously undeployed reserves can be monetized in EIM, allowing more sales (INCs) in high-value periods and more purchases (DECs) in low-value periods.
  2) Volatility
     - Significant real-time volatility allows participants to market at triggers more effectively than bilateral hour-ahead trading.
Steps 2-3: Description of Issue & Data and/or Analysis
Initial Approach

- Recognizing that most EIM dispatch benefits come from additional load factoring, evaluate whether we can model increases to NSR by allowing hydro modeling to assume a lower level of required reserves, freeing up additional flexibility to shape into high-value periods.

- This process involves rerunning RiverWare using BP-22 assumptions, but relaxing the amount of non-reg balancing reserves held in RiverWare.
  - ~370 MW INC
  - ~500 MW DEC

- The difference between hourly generation in the rate case and the test case are then valued at the corresponding Aurora hourly Mid-C price (BP-22 final proposal prices).
Initial Approach: Problem

- Hourly RiverWare generation deltas coupled with BP-22 hourly Aurora prices produce an annual average EIM benefit of about $4M.

- This low value is not reflective of our expected EIM benefits or of our expected operations as the flexibility is not responsive to EIM price signals.
  - RiverWare shapes using heuristics informed by recent historical behavior, which tends to load factor in a way that maximizes HLH and super-peak generation.
  - EIM prices reflect hourly load-net-of-resource needs across the region, requiring shaping that is more flexible and dynamic in order to produce benefits.
Alternative Approach

1) Leverage the RiverWare hourly generation deltas from the initial approach to estimate a range of EIM flexibility and participation.
   – The full range of hourly generation deltas could contain a number of extreme outcomes, which could result in overestimating a reasonable range of EIM flexibility and participation.
   – Instead, we use 5\textsuperscript{th} and 95\textsuperscript{th} percentiles of the RiverWare hourly generation deltas for each month and each water year to establish a reasonable range of expected EIM participation. See next two slides
Monthly EIM Ranges from RiverWare 5\textsuperscript{th} and 95\textsuperscript{th} Percentiles
FY22, WY 1963

EIM Range
Monthly EIM Ranges from RiverWare 5th and 95th Percentiles FY22, All 80-Water Years
2) Once we’ve used the RiverWare generation deltas to produce ranges of expected EIM participation and operations by month and water year, we then 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

See next two slides
Aurora Prices and Simulated EIM Dispatch
Jan 2022 Week 1, Iteration 1865
Aurora Prices and Simulated EIM Dispatch
FY22 Averages by Hour and Month
Alternative Approach: Results

- Simulated EIM dispatch using the ranges from RiverWare and BP-22 Aurora prices produces an annual average EIM benefit of about $18M. Results for BP-24 will differ.

The dashed lines are rate period annual averages ($4M with RiverWare versus $18M with simulated EIM dispatch)
Step 4: Discuss additional considerations and possible alternatives to solve issue
### Further Considerations

#### The potential to **overestimate** benefits

- Actual EIM ranges could be lower because:
  - Forecasts will be imperfect.
  - Increased ramping may incur additional costs which could lead to more conservative bids that reduce responsiveness.
  - The potential to fail sufficiency tests.
  - Potential transmission limitations.
  - We employ more sophisticated or conservative marketing strategies that result in lower levels of EIM participation.
- Actual EIM prices will respond to dispatch and our generation levels, but this approach holds prices constant for each iteration (exogenous prices).

#### The potential to **underestimate** benefits

- Actual EIM ranges could be higher because:
  - We employ more sophisticated marketing strategies that result in greater levels of EIM participation.
- Actual EIM prices may be more variable than the Aurora hourly price forecasts.
- We expect to gain additional benefits from sub hourly variability and responsiveness that are not included in the alternative approach.
- BPA expects to eventually participate in EIM with more reserves than just non-reg reserves (E3’s study assumed all spinning capability).
Appendix - Power
Monthly EIM Benefits (Averages and Range, Min - Max)

Riverware
- Oct-21: 0.2
- Nov-21: 0.0
- Dec-21: 0.2
- Jan-22: 0.3
- Feb-22: 0.5
- Mar-22: 0.2
- Apr-22: 0.5
- May-22: 0.2
- Jun-22: 0.4
- Jul-22: 1.3
- Aug-22: 0.4
- Sep-22: 0.0
- Oct-22: 0.2
- Nov-22: 0.1
- Dec-22: 0.2
- Jan-23: 0.4
- Feb-23: 0.7
- Mar-23: 0.3
- Apr-23: 0.2
- May-23: 0.0
- Jun-23: 0.2
- Jul-23: 1.0
- Aug-23: 0.4
- Sep-23: 0.1

SimEIM
- Oct-21: 1.6
- Nov-21: 0.5
- Dec-21: 0.9
- Jan-22: 1.0
- Feb-22: 1.1
- Mar-22: 1.3
- Apr-22: 1.3
- May-22: 1.5
- Jun-22: 2.1
- Jul-22: 2.7
- Aug-22: 1.5
- Sep-22: 1.3
- Oct-22: 2.0
- Nov-22: 1.3
- Dec-22: 1.3
- Jan-23: 1.3
- Feb-23: 1.3
- Mar-23: 1.8
- Apr-23: 1.3
- May-23: 1.0
- Jun-23: 2.2
- Jul-23: 2.5
- Aug-23: 1.3
- Sep-23: 1.5
BP-24 Topic
EIM Impact on Balancing Services Cost

- Step 1: Introduction and Education
- Step 2: Description of the Issue
- Step 3: Data and/or analysis that supports the issue
- Step 4: Discussions on possible alternatives to solve issue
Steps 1 & 2: Introduction, education and description of issue
EIM associated Cost Reductions for Generation Inputs

• During the BP-22 rate case, BPA acknowledged the potential for EIM participation to offset variable costs of holding non-reg balancing reserves.
  – The BP-22 settlement includes a 50% cost offset for non-reg variable costs that is triggered upon BPA’s entry into the EIM.
  – BPA committed to readdressing this issue during BP-24.
• We have limited EIM experience to inform a permanent approach to measure the true cost offset that EIM revenue has on the variable cost of holding non-reg reserves.
• The potential to offset costs arises from BPA’s EIM participation because the variable costs incurred due to holding reserves and deoptimization of the Federal System, may be partially reoptimized through EIM operations utilizing the non-reg reserves.
The Generation and Reserves Dispatch (GARD) Model forecasts the variable costs of holding reserves on the Federal system.

Stand-ready energy costs are incurred due to changes in efficiency. These general costs are categorized into three buckets: energy shift, spill and efficiency.

Under the EIM we are still required to hold all reserves, including the non-reg portion of the Balancing Reserves. Because of this, the costs of deoptimizing the Federal system need to be calculated.

The EIM provides a new opportunity to economically dispatch capacity that would have otherwise been dispatched based solely on forecast error. This provides BPA the ability to maintain some control over the non-regulation capacity it is holding, which — subject to market conditions — would result in the ability to offset most if not all its stand-ready energy costs.

- This approach is consistent with the assumptions made in modeling used to forecast EIM benefits in Power rates.
Steps 3 & 4: Analyze and discuss the issue
GARD and EIM Cost Offset Results

<table>
<thead>
<tr>
<th></th>
<th>Reg Balancing INC</th>
<th>Reg Balancing DEC</th>
<th>Non-reg Balancing INC</th>
<th>Non-reg Balancing DEC</th>
<th>Operating Reserves INC</th>
<th>Total:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy shift</td>
<td>1.91</td>
<td>1.71</td>
<td>2.30</td>
<td>2.61</td>
<td>5.38</td>
<td>13.91</td>
</tr>
<tr>
<td>Spill</td>
<td>0.49</td>
<td>0.44</td>
<td>0.59</td>
<td>0.67</td>
<td>1.38</td>
<td>3.57</td>
</tr>
<tr>
<td>Efficiency</td>
<td>-0.78</td>
<td>-0.70</td>
<td>-0.94</td>
<td>-1.07</td>
<td>-2.20</td>
<td>-5.68</td>
</tr>
<tr>
<td>Total</td>
<td>1.62</td>
<td>1.45</td>
<td>1.95</td>
<td>2.21</td>
<td>4.56</td>
<td>11.79</td>
</tr>
<tr>
<td>EIM Cost Offset</td>
<td>0.00</td>
<td>0.00</td>
<td>1.95</td>
<td>2.21</td>
<td>0.00</td>
<td>4.16</td>
</tr>
<tr>
<td>Adjusted Total</td>
<td>1.62</td>
<td>1.45</td>
<td>0.00</td>
<td>0.00</td>
<td>4.56</td>
<td>7.63</td>
</tr>
</tbody>
</table>

Values in $ Millions

- All values are from BP-22 Final Proposal
- The total EIM variable cost offset of $4.16M assumes the full quantity of non-reg reserves being available for EIM dispatch.
- Staff believe that up to a 100% variable cost offset for non-reg balancing reserves may be justified for the BP-24 rate period.
Results Summary and EIM Benefits in Power Rates Crosswalk

<table>
<thead>
<tr>
<th></th>
<th>Alternative Approach</th>
</tr>
</thead>
<tbody>
<tr>
<td>Estimated EIM Benefits:</td>
<td>~ $18M</td>
</tr>
<tr>
<td>Gen Inputs EIM Cost Reduction:</td>
<td>~ $4M</td>
</tr>
<tr>
<td>Net EIM Benefit in Power Rates:</td>
<td>~ $14M</td>
</tr>
</tbody>
</table>

• Estimated EIM benefits are pre-Slice estimates and shared across Slice and Non-Slice products.
• Approximately 50% of revenue received for balancing services is from BPA Power Preference customers.
BP-24 Topic

Customer concerns regarding EIM and Generation Inputs

• Step 1: Introduction and Education
• Step 2: Description of the Issue
• Step 3: Analyze the Issue
• Step 4: Discuss Alternatives
Objectives

• Background education on Generation Inputs and capacity costs
• Understand the relationship between Generation Inputs and the EIM
• Address customer concerns regarding Generation Inputs cost allocations and EIM benefits
• Provide staff responses to customer concerns
Generation Inputs

• Generation Inputs are the reserve generation capacity and other services needed for Ancillary and Control Services (ACS) and transmission.

• BPA holds two types of reserve capacity:
  – Balancing (INCs and DECs): Regulation and Non-regulation
  – Operating Reserves (INCs): Spinning and Supplemental
Generation Inputs Costs

• BPA Power allocates the total power revenue requirement (excluding conservation costs) as either:
  – Energy (approx. $2 Billion) or,
  – Capacity (approx. $1 Billion)

• Generation Inputs costs are composed of two parts:
  – **Embedded unit costs** are calculated by dividing the revenue requirement allocated to capacity divided by the 1-hour peaking capacity of the federal system. For BP-22 this was:
    
    \[
    \frac{\$1.004 \text{ Billion}}{14,249 \text{ MW}} = \$5.87 \text{ kW/month}
    \]

  – **Variable unit costs** are calculated for each reserve type in the Generation and Reserve Dispatch (GARD) Model. For BP-22, total variable costs were $11.8 Million.

• Incremental capacity unit costs = embedded unit cost + variable unit cost
• Decremental capacity unit costs = variable unit cost
Generation Inputs and the EIM

- In BP-22, BPA allocated both the costs and benefits of the EIM to Energy. None of the implementation costs or benefits of the EIM were allocated to Capacity.
- BPA anticipates offering most, if not all, of the non-reg balancing reserves in the EIM.
- Variable costs of holding non-reg balancing reserves
  - During the BP-22 rate case, BPA acknowledged the potential for EIM participation to offset variable costs of holding non-reg balancing reserves. As a result, BPA reduced GARD costs associated with non-reg balancing reserves by 50% for the BP-22 rate period when in the EIM.
  - For the BP-24 rate period, staff believe up to a full (100%) non-reg balancing variable cost offset may be appropriate assuming BPA will have the opportunity to bid most, if not all, of the non-reg balancing reserves in the EIM.
  - See EIM Benefits in Power Rates presentation, above, for full discussion of this topic.
Outstanding Customer Concerns

- It is our understanding that NIPPC believes that a portion of the capacity costs allocated to non-reg balancing reserves should be borne by customers other than ACS customers. This is because this capacity is a key component of realizing EIM benefits.
- Specifically, NIPPC is arguing that while all Generation Input customers gain the benefits of more efficient and lower cost energy for imbalance, BPA’s Power customers (who are also ACS customers) receive incremental EIM-related revenue benefit from non-reg balancing capacity without directly being allocated a portion of the costs of that capacity.
- BPA staff’s analysis of this issue is presented in the following slides.
# Ingredients that make EIM benefits possible and EIM benefactors

<table>
<thead>
<tr>
<th>EIM Ingredients:</th>
<th>Source:</th>
<th>Paid for by ACS customers:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capability</td>
<td>Operational costs (IT systems, staff, etc.)</td>
<td>✗</td>
</tr>
<tr>
<td>Energy</td>
<td>Federal Hydro System</td>
<td>✗</td>
</tr>
</tbody>
</table>
| Capacity         | • Any entity bidding INC/DEC capacity into EIM  
|                  |   ➢ BPA non-reg balancing reserves INC  
|                  |   ➢ BPA non-reg balancing reserves DEC  
|                  |   ➢ Additional capacity provided by BPA  
|                  |   ➢ Additional capacity provided by Non-federal sources | ✓ ✗ ✗ ✗ |
| Transmission     | BPA Transmission donation | ✗ |

<table>
<thead>
<tr>
<th>EIM Benefit:</th>
<th>Benefactors:</th>
<th>Received by ACS customers:</th>
</tr>
</thead>
</table>
| Efficient Energy Deployment | • Any entity that is offering INC or DEC balancing capacity into the EIM.  
|                  | • Any entity that has energy imbalance in the EIM. | ✓ |
Staff Response

• **EIM does not reduce Bonneville’s capacity costs.** Bonneville recovers its embedded cost of capacity associated with having to hold balancing reserves through ACS rates. This cost is incurred in or out of an EIM.

• **The existence of forecast error creates the need to hold capacity.** This balancing capacity is used to manage that error. The EIM re-optimizes resource generation in response to that forecast error and thus provides benefits (reduces the cost of meeting forecast error) compared to the alternative (meeting forecast error with resources that are deployed out of merit order).
Staff Response

• **Energy benefits flow to ACS rates through GARD:** Bonneville calculates the energy de-optimization cost of holding balancing reserve capacity through GARD. This variable cost is minimized, or potentially eliminated, when in an EIM. This is consistent with staff leaning to remove up to 100% of the variable cost for balancing capacity that can be offered into the EIM.

• **EIM benefits are a result of several ingredients.** Bonneville’s non-reg balancing reserves is only one and energy benefits are realized by all entities in the EIM footprint. Importantly, Bonneville’s requirement to hold non-reg balancing reserves is both the cause of BPA’s balancing cost as well as a source of potential energy to more efficiently meet the forecast error across the EIM footprint.
Staff Response

- Taken together, we believe that:
  - Basing the unit cost of non-reg balancing reserves on the entire embedded capacity cost is appropriate.
  - It is appropriate to reduce the de-optimization costs allocated to non-reg balancing reserves because the EIM allows for that capacity to be re-optimized.
  - All entities in the EIM footprint will receive energy benefits from an efficient dispatch of resources. These benefits flow through EIM settlements. This includes those that offer in INC or DEC balancing capacity into the EIM as well as any entity that has energy imbalance in the EIM.
Next Steps: EIM & Gen Inputs

- Stakeholders to provide comments.
- Discuss stakeholder comments (Step 5)
- Staff Proposal (Step 6)
BP-24 Topic
EIM Charge Code Allocation

• Step 1: Introduction and Education
• Step 2: Description of the Issue
Issue: Introduction and Education
Objectives

- Review the BP-22 EIM Charge Code Allocations
- Update the rolled-in charges for BP-24
Bonneville Power Administration

• In the EIM, BPA will receive charges and credits from the CAISO. BPA will need to, in turn, recover these charges or distribute these credits through sub-allocating them to customers or rolling them into rates.

• There is no pro forma method for allocating the various charge codes.

• While most EIM entities have followed similar cost allocation methodologies, that is not always the case.
  – For example, PGE sub-allocates the real time cost of marginal loss offset charges based on measured demand, but PAC does not sub-allocate these charges.

• While FERC-approved methods are considered as a starting point, there may be rationale to modify methods to align with cost-causation.

Context
Phased In Approach

**BP-22**

Begin Charge Code Allocation and Modify Existing Rate Structures (as needed)

**BP-24**

Review and Leverage Preliminary Data to Modify Charge Code Allocation and/or Rate Structures (as needed)

**BP-26**

Utilize Two Years of Data to Complete Refinement of Charge Code Allocation and/or Rate Structures (as needed)

Approach implementation is subject to change by rate period, given factors such as information availability and market changes.
SUB-ALLOCATED CODES
## Sub-Allocated Charge Codes for BP-22

<table>
<thead>
<tr>
<th>Base Codes</th>
<th>Neutrality Codes</th>
<th>Over/Under Scheduling Codes</th>
</tr>
</thead>
</table>

May 25, 2022
Pre-Decisional. For Discussion Purposes Only.
# Base Codes

<table>
<thead>
<tr>
<th>Code Number</th>
<th>Description</th>
<th>Transmission Rates Schedule</th>
<th>FERC Allocation Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>64750</td>
<td>Uninstructed Imbalance Energy (Schedule 4 and Schedule 9)</td>
<td>§4(A) §4(B)</td>
<td>Direct Assignment</td>
</tr>
<tr>
<td>64600</td>
<td>FMM Instructed Imbalance Energy (Energy Imbalance)</td>
<td>§4(A) §4(B)</td>
<td>Direct Assignment</td>
</tr>
<tr>
<td>64700</td>
<td>Real-Time Instructed Imbalance Energy (Energy Imbalance)</td>
<td>§4(A) §4(B)</td>
<td>Direct Assignment</td>
</tr>
</tbody>
</table>

**Method for All Codes : Direct Assignment**

**Rationale:** Aligned with cost-causation, consistent with other entities/approved approach.

**Definition:** Direct allocation of the charges and credits to customers based on customer behavior in the CAISO EIM. The charges and credits are based on granular customer level detail behind the CAISO settlements to the EESC.
# Neutrality Codes

<table>
<thead>
<tr>
<th>Code Number</th>
<th>Description</th>
<th>Transmission Rates Schedule</th>
<th>FERC Allocation Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>64770</td>
<td>Real-Time Imbalance Energy Offset EIM</td>
<td>§4(D)(1)</td>
<td>Measured Demand</td>
</tr>
<tr>
<td>64740</td>
<td>Real-Time Unaccounted For EIM Energy Settlement (UFE)</td>
<td>§4(D)(5)</td>
<td>Measured Demand</td>
</tr>
<tr>
<td>69850</td>
<td>EIM Entity Real-time Marginal Cost of Losses Offset</td>
<td>§4(D)(3)</td>
<td>Measured Demand</td>
</tr>
<tr>
<td>6478</td>
<td>Real-Time System Imbalance Energy Offset</td>
<td>§4(D)(4)</td>
<td>Measured Demand</td>
</tr>
<tr>
<td>67740</td>
<td>EIM Entity BAA Real-Time Congestion Offset</td>
<td>§4(D)(2)</td>
<td>Measured Demand</td>
</tr>
</tbody>
</table>

**Method for All Codes: Measured Demand by Magnitude**

**Rationale:** Consistent with other entities/approved approach, mirrors CAISO BAA allocation.

**Definition:** Takes each customer’s load ratio share, measured as the customer’s Measured Demand (Metered Demand + Export Schedules) divided by the Total BAA Measured Demand multiplied by the amount billed to the BAA under each neutrality charge code. The Metered Demand for each customer is their metered load, including losses.
# Over/Under Scheduling Codes

<table>
<thead>
<tr>
<th>Code Number</th>
<th>Description</th>
<th>Transmission Rates Schedule</th>
<th>FERC Allocation Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>6045</td>
<td>Under/Over Schedule Load Charge</td>
<td>§4(C)(1) §4(C)(2)</td>
<td>Imbalance by Direction</td>
</tr>
<tr>
<td>6046</td>
<td>Under/Over Schedule Load Allocation</td>
<td>§4(C)(3)</td>
<td>Metered Demand by Magnitude</td>
</tr>
</tbody>
</table>

**Method for 6045: Imbalance by Direction**

**Rationale:** Allocates costs only to those that caused the penalty.

**Definition:** Takes each customer’s imbalance in the same direction as the BAA imbalance, divided the sum of the customer imbalances in the same direction as the BAA multiplied by the amount billed to the BAA under code 6045.

**Method for 6046: Metered Demand by Magnitude with Imbalance Threshold**

**Rationale:** In addition to mirroring CAISO BAA Allocation, incentivizes individual customer scheduling accuracy in order to receive share of credit.

**Definition:** Same as metered demand by magnitude, but only allocates to those customers with imbalance at or below a predetermined imbalance tolerance (within 5-percent / 2 MW of schedule). Note that code 6046 is a credit to EIM entities on days in which they did not receive any penalty charges associated with code 6045, but other EIM entities did.

May 25, 2022  
Pre-Decisional. For Discussion Purposes Only.
UNALLOCATED CODES
# Rationale for Unallocated Codes

<table>
<thead>
<tr>
<th>Administrative</th>
<th>Flexible Ramping</th>
<th>Real Time Bid Cost Recovery</th>
</tr>
</thead>
</table>
| • Not directly tied to customer behavior  
• Some fees could be forecast  
• Some codes would not be forecast (e.g. penalty fees or rarely used administrative codes) | • EESCs are billed costs to fund resources to address future interval forecast ramp needs (interchange schedule ramps, change in net load forecast) and uncertainty (net load forecast error).  
• Payments to resources respects the opportunity cost of awarding flexible ramping, so prices are marginal or the delta between resource’s bid and LMP. | • Recovers daily “Shortfalls” (net non-zero positive amounts) for units dispatched in the RTM.  
• Charges to the EESC are based on non-zero positive amounts for units within the BAA and the BAA’s pro-rata share of EIM transfers in. |

Unallocated charge codes do not impact financial settlement chains of proposed set of sub-allocated charge codes. While these codes are not primary drivers of customer behavior in the EIM, they warrant review in this rate case and will be further reviewed as part of BP-26 once more data is available.
Recovering Unallocated Codes

• Unallocated codes with fixed charges are forecast within revenue requirement and segmented to the Network, Southern Intertie, and Eastern Intertie, using the O&M percentages.

• Unallocated codes without fixed charges are not forecast, however, BPA will continue to review available data to assess ability to incorporate in revenue requirement and/or risk assessment.
### Ability to Forecast

<table>
<thead>
<tr>
<th>CC #</th>
<th>Charge Code Name</th>
<th>CC #</th>
<th>Charge Code Name</th>
<th>CC #</th>
<th>Charge Code Name</th>
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</thead>
<tbody>
<tr>
<td>701</td>
<td>Forecasting Service Fee</td>
<td>5900</td>
<td>Shortfall Receipt Distribution</td>
<td>7087</td>
<td>Daily Flexible Ramp Down Uncertainty Award Allocation</td>
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<td>1592</td>
<td>EP Penalty Allocation Payment</td>
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<td>Shortfall Allocation Reversal</td>
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<td>Monthly Flexible Ramp Down Uncertainty Award Allocation</td>
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<tr>
<td>2999</td>
<td>Default Invoice Interest Payment</td>
<td>5910</td>
<td>Shortfall Allocation</td>
<td>7989</td>
<td>Invoice Deviation Interest Distribution</td>
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<tr>
<td>3999</td>
<td>Default Invoice Interest Charge</td>
<td>5912</td>
<td>Default Loss Allocation</td>
<td>7999</td>
<td>Invoice Deviation Interest Allocation</td>
</tr>
<tr>
<td>4564</td>
<td>GMC-EIM Transaction Charge</td>
<td>7070</td>
<td>Flexible Ramp Forecast Movement Settlement</td>
<td>5024</td>
<td>Invoice Late Payment Penalty</td>
</tr>
<tr>
<td>4575</td>
<td>SMCR -Settlements, Metering, and Client Relations</td>
<td>7071</td>
<td>Daily Flexible Ramp Up Uncertainty Capacity Settlement</td>
<td>5025</td>
<td>Financial Security Posting (Collateral) Late Payment Penalty</td>
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<tr>
<td>4989</td>
<td>Daily Rounding Adjustment</td>
<td>7076</td>
<td>Flexible Ramp Forecast Movement Allocation</td>
<td>66200</td>
<td>Bid Cost Recovery EIM Settlement</td>
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<tr>
<td>4999</td>
<td>Monthly Rounding Adjustment</td>
<td>7077</td>
<td>Daily Flexible Ramp Up Uncertainty Award Allocation</td>
<td>66780</td>
<td>Real Time Bid Cost Recovery Allocation EIM</td>
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<td>5024</td>
<td>Invoice Late Payment Penalty</td>
<td>7078</td>
<td>Monthly Flexible Ramp Up Uncertainty Award Allocation</td>
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<tr>
<td>5025</td>
<td>Financial Security Posting (Collateral) Late Payment Penalty</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- Codes highlighted in green are ones that BPA would not forecast.
  - 701 is for a service that BPA already performs at lower cost and was granted an exemption.
  - 7071 & 7081 are charged directly to the PRSC.
  - The rest are penalty charges or rarely used administrative charges.
- The remaining codes could, theoretically, be forecast.
Codes with Fixed Charges (BP-22)

• Of the forecastable codes, two are based on fixed monthly charges or posted rates.
• 4575 (Settlements, Metering & Client Relations) is a flat $1,000/month charge.
• 4564 (Grid Management Charge) has two defined rates:
  – EIM Market Service Charge Rate: $0.0841/MWh (2019 Rate)
  – EIM System Operations Charge Rate: $0.1091/MWh (2019 Rate)
    • The EIM ROD includes estimates of the 5 minute and 15 minute purchases and sales as simulated by E3.
    • The base scenario estimates a total of 791.9 aMW or about 6.9 million MWh.
    • This would produce an annual cost of $1.34 million.
• Total charges for these codes = $1.35 million/year in BP-22:
  – Network $1,173k
  – S. Intertie $ 156k
  – E. Intertie $ 22k
Codes with Fixed Charges (BP-24)

- Of the forecastable codes, two are based on fixed monthly charges or posted rates.
- 4575 (Settlements, Metering & Client Relations) is a flat $1,500/month charge.
- 4564 (Grid Management Charge) has two defined rates:
  - EIM Market Service Charge Rate: $0.0935/MWh (2022 Rate)
  - EIM System Operations Charge Rate: $0.1002/MWh (2022 Rate)
- The EIM ROD includes estimates of the 5 minute and 15 minute purchases and sales as simulated by E3.
- The base scenario estimates a total of 791.9 aMW or about 6.9 million MWh.
- This would produce an annual cost of $1.34 million.
- Total charges for these codes = $1.36 million/year in BP-24:
  - Distribution of these costs have not been finalized.
Codes Without Fixed Charges

- There is limited data on the remaining codes.
- CAISO provided data on the range of monthly costs of other EESCs of our size.

<table>
<thead>
<tr>
<th>Code</th>
<th>Description</th>
<th>Maximum Monthly Average</th>
<th>Minimum Monthly Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>7070</td>
<td>Flexible Ramp Forecast Movement Settlement</td>
<td>$49,000.00</td>
<td>($7,000.00)</td>
</tr>
<tr>
<td>7076</td>
<td>Flexible Ramp Forecast Movement Allocation</td>
<td>$7,000.00</td>
<td>($13,000.00)</td>
</tr>
<tr>
<td>7077</td>
<td>Daily Flexible Ramp Up Uncertainty Award Allocation</td>
<td>$34,000.00</td>
<td>$0.00</td>
</tr>
<tr>
<td>7087</td>
<td>Daily Flexible Ramp Down Uncertainty Award Allocation</td>
<td>$8,000.00</td>
<td>($1,000.00)</td>
</tr>
<tr>
<td>66780</td>
<td>Real Time Bid Cost Recovery Allocation EIM</td>
<td>$510,000.00</td>
<td>$0.00</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>$608,000.00</td>
<td>($21,000.00)</td>
</tr>
</tbody>
</table>

- Continuing to further evaluate these codes to determine the best approach with CAISO.
- Working to receive updated information as there have been changes in the market structure since the original data was provided by the CAISO.
Outstanding Items

- For August 24/25 Workshop:
  - Review what market activity is available to determine if better forecasts are possible for rolled-in costs
  - Discuss any charge codes that are not currently sub-allocated that may be better suited as sub-allocated

- For BP-26:
  - Review 2 years of market data for further discussion to complete refinement of charge code allocation and/or rate structures
BP-24 Topic
Segmentation Study
BP-24 FY21 Segmentation

• BPA is proposing no methodology changes or changes to segment definitions.
• The Segmentation Study assigns plant investment to segments based on their function.
• Segmented net plant is used to allocate capital related costs in the revenue requirement to specific segments.
• Existing plant in service is updated with actuals through FY 2021 for the BP-24 Initial Proposal.
Description of Segments

- **Generation Integration** – Transmission facilities that connect Federal generation to BPA’s transmission facilities.
- **Network** – Core of BPA’s transmission system. Transmission facilities that transmit power from Federal and non-federal generation sources or interties to the load centers of BPA’s transmission customers in the PNW or other segments.
- **Southern Intertie** – Transmission facilities used primarily to transmit energy between the PNW and California.
- **Eastern Intertie** – Transmission facilities connecting network facilities in the PNW to Eastern Montana, primarily to transfer energy from Colstrip to the PNW (these facilities were constructed pursuant to the Montana Intertie Agreement).
- **Utility Delivery** – Low voltage transmission lines and substation equipment associated with supplying power directly to utility customers’ distribution systems (below 34.5 kV).
- **DSI Delivery** – Transformers and low-side switching equipment and protection equipment necessary to step down power to DSI customers at industrial voltages (6.9 or 13.8 kV).
- **Ancillary Service** – Communications and control equipment necessary for BPA to provide Scheduling, System Control and Dispatch (SCD) service.
# Segments

<table>
<thead>
<tr>
<th>Segments</th>
<th>Corresponding Rates</th>
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<tr>
<td>Network</td>
<td>PTP, NT, FPT</td>
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<tr>
<td>Utility Delivery</td>
<td>UDC</td>
</tr>
<tr>
<td>DSI Delivery</td>
<td>UFT</td>
</tr>
<tr>
<td>Southern Intertie</td>
<td>IS</td>
</tr>
<tr>
<td>Eastern Intertie</td>
<td>IE, IM, TGT</td>
</tr>
<tr>
<td>Generation Integration</td>
<td>Assigned to power rates</td>
</tr>
<tr>
<td>Ancillary Services</td>
<td>ACS</td>
</tr>
</tbody>
</table>
BP-22 FY20 Plant Investment Summary

BPA Plant Investment as of September 30, 2020
Total: $10,662,286 ($000)

- Segmented Lines & Subs, 8,418,105, 79%
- Non-Transmission Plant, 132,640, 1%
- Ancillary Service, 208,460, 2%
- Gen. Plant (Unseg), 1,230,469, 12%
- Land, 242,237, 2%
- Trans. Plant (Unseg), 212,223, 2%
- Funded in Advance, 218,152, 2%

May 25, 2022
Pre-Decisional. For Discussion Purposes Only.
BP-24 FY21 Plant Investment Summary

BPA Plant Investment as of September 30, 2021
Total: $10,797,951 ($000)

- Segmented Lines & Subs, 8,608,428, 80%
- Funded in Advance, 221,262, 2%
- Trans. Plant (Unseg), 211,445, 2%
- Ancillary Service, 178,783, 2%
- Gen. Plant (Unseg), 1,227,325, 11%
- Land, 245,411, 2%
- Non-Transmission Plant, 105,297, 1%

May 25, 2022
Pre-Decisional. For Discussion Purposes Only.
# Segmented Lines and Substations Investment ($000)

## BPA Plant Investment Investment, through Sept. 30, 2020

<table>
<thead>
<tr>
<th></th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
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<th>I</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>Generation Integration</td>
<td>Southern Intertie</td>
<td>Eastern Intertie</td>
<td>Utility Delivery</td>
<td>DSI Delivery</td>
<td>Segmented Total</td>
<td>Ancillary Services</td>
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<td>815,595</td>
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<td>Sub Total</td>
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## BPA Plant Investment Investment, through Sept. 30, 2021

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<th>A</th>
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<th>C</th>
<th>D</th>
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<th>I</th>
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<tr>
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<td>Generation Integration</td>
<td>Southern Intertie</td>
<td>Eastern Intertie</td>
<td>Utility Delivery</td>
<td>DSI Delivery</td>
<td>Segmented Total</td>
<td>Ancillary Services</td>
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<tr>
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<td>823,742</td>
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<td>18,917</td>
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<td>3,475,249</td>
<td>316,676</td>
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<td>590</td>
<td>-</td>
<td>3,910,940</td>
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<td>Sub Total</td>
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<td>8,819,874</td>
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<td>% of Segmented Total</td>
<td>1.8%</td>
<td>83.6%</td>
<td>12.9%</td>
<td>1.4%</td>
<td>0.2%</td>
<td>0.1%</td>
<td>100.0%</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Station and Line Totals Tie to Segmented Lines and Subs plus Unsegmented Transmission Plant from Prior Slide
O&M Segmentation Methodology

- Consistent with prior O&M methodology
- Based on a 7 year historical average
- Direct O&M are historical O&M costs associated with a specific asset
  - The O & M is directly charged to the asset.
  - The O & M is then assigned to the different segments based on the segmented investments.
- Non-direct O&M are historical O&M costs not associated with a specific asset
  - These costs are allocated to Lines, Substations, and Metering stations in proportion to the direct O&M in each respective group
  - Transmission Line and Right-of-way Maintenance, and Vegetation Management (all non-direct) are allocated to Lines only
# Segmented Historical O&M ($000)

## BPA Historical Operations and Maintenance (O&M)
### Fiscal years 2014 through 2020 (Seven Years)

<table>
<thead>
<tr>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
<th>F</th>
<th>G</th>
<th>H</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generation Integration</td>
<td>Southern Intertie</td>
<td>Eastern Intertie</td>
<td>Utility Delivery</td>
<td>DSI Delivery</td>
<td>Total</td>
<td>Ancillary Services</td>
<td>Overhead</td>
</tr>
<tr>
<td>Stations</td>
<td>3,338</td>
<td>108,436</td>
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<td>791</td>
<td>1,118</td>
<td>401</td>
<td>132,737</td>
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<tr>
<td>Lines</td>
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<td>48,833</td>
<td>2,252</td>
<td>2,107</td>
<td>13</td>
<td>-</td>
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<tr>
<td>Sub Total</td>
<td>3,956</td>
<td>157,268</td>
<td>20,905</td>
<td>2,898</td>
<td>1,131</td>
<td>401</td>
<td>186,560</td>
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<td>% of Segmented Total</td>
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<td>84.3%</td>
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## BPA Historical Operations and Maintenance (O&M)
### Fiscal years 2015 through 2021 (Seven Years)

<table>
<thead>
<tr>
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<th>C</th>
<th>D</th>
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<tbody>
<tr>
<td>Generation Integration</td>
<td>Southern Intertie</td>
<td>Eastern Intertie</td>
<td>Utility Delivery</td>
<td>DSI Delivery</td>
<td>Total</td>
<td>Ancillary Services</td>
<td>Overhead</td>
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<td>Stations</td>
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<td>Lines</td>
<td>621</td>
<td>49,531</td>
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<td>1,081</td>
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<td>84.8%</td>
<td>11.1%</td>
<td>1.2%</td>
<td>0.6%</td>
<td>0.2%</td>
<td>100.0%</td>
</tr>
</tbody>
</table>
Segmentation – Future Plant in Service

- The Segmentation Study reflects historic plant in service through FY 2021.
- A future plant in service forecast will be used for FY 2022-25 in the Initial Proposal to project segmented net plant investment during the rate period.
  - The plant in service forecast will be based on proposed capital spending levels slated for discussion in the 2022 IPR process.
Next Steps: Segmentation

- The future plant in service will be updated based on IPR capital projections.
- The segmentation study will be updated for the BP-24 Final Proposal to reflect plant placed into service and retirements through FY 2022.
TC-24 Topics

- Attachment C: Short-Term ATC
TC-24 Topic
Attachment C: Short-Term ATC

- Step 1: Introduction and Education
- Step 2: Description of the Issue
- Step 3: Data and/or analysis that supports the issue
- Step 4: Discussions on possible alternatives to solve issue
Introduction and Education

• In the meeting today, Bonneville is discussing 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 and Education (cont.)

- The following requirements outline where Transmission Providers (TPs) need to document their ATC and Transmission Reliability Margin (TRM) methodologies:
  - Attachment C, required by Federal Energy Regulatory Commission (FERC)
  - TRM Implementation Document (TRMID), required by NERC MOD-008
  - ATC Implementation Document (ATCID), required by NERC MOD-001
  - NAESB WEQ-023, mirrors the NERC ATC MOD requirements for a TRMID and ATCID
- Unlike other parts of the tariff, FERC only has pro forma guidance for Attachment C and not specific language
  - This means that not all jurisdictional TPs’ Attachment Cs are identical, however, are all approved by FERC
Introduction and Education (cont.)

• The pro forma requires TPs to include the following in their Attachment C:
  – Mathematical algorithm used to calculate firm and non-firm ATC for scheduling, operating and planning horizons
  – Process flow diagram that illustrates the steps through which ATC is calculated
  – Explanation of how the ATC components are calculated for the operating and planning horizons
  – For Total Transfer Capability (TTC), definition of TTC, calculation methodology, list of databases used in TTC assessments, and the assumptions used in TTC assessments regarding load levels, generation dispatch, and modeling of planned and contingency outages
Introduction and Education (cont.)

- For Existing Transmission Commitments (ETC), definition of ETC, calculation methodology used to determine the transmission capacity set aside for native load (including network load) and non-OATT customers, how point-to-point transmission service requests are incorporated, how rollover rights are accounted for, processes for ensuring that non-firm capacity is released properly

- For TRM, definition of TRM, calculation methodology (e.g., assumptions on load forecast errors, forecast errors in system topology or distribution factors and loop flow sources), databases used in TRM assessments, and the conditions under which the transmission provider uses TRM

- Explanation of practices for Capacity Benefit Margin (CBM); statement if CBM is not used
Description of the Issue

- Bonneville’s current Attachment C is over a decade old
  - Current Attachment C was approved by FERC
  - However, it is outdated and does not correctly reflect Bonneville’s current ST ATC methodology
  - It is also high-level, and although Bonneville provides all the ST ATC methodology information required by the pro forma Attachment C, the information is provided in other documents posted on our website rather than in Attachment C itself
- Bonneville sees benefits to making updates to Attachment C in TC-24 as the current document is outdated
- We need to determine the level of detail that is appropriate for our Attachment C
Data and/or Analysis

- Bonneville staff have benchmarked the Attachment Cs and ATCIDs/TRMIDs of other TPs
  - Although there is a range of approaches, other TPs generally include more detail in their Attachment Cs than Bonneville
  - Also, generally speaking, other TPs include less detail in their ATCIDs than Bonneville
  - TRM is not being widely used by the TPs Bonneville benchmarked
  - Bonneville observed that some TPs are breaking out their Attachment Cs into separate sections, one covering their 0-13 month ATC methodology and one covering their beyond 13 month methodology
Possible Alternatives

- Bonneville staff have considered three alternatives for the ST ATC Attachment C within TC-24
- The alternatives are outlined in the following slides, and differ based on:
  - How much content to update in the current Attachment C
  - What level of detail to provide in Attachment C
Alternative #1

- In this alternative, Bonneville would not update the current Attachment C to align with our current ST ATC methodology
  - Although this does not require any work, Attachment C would remain out of date and out of alignment with Bonneville’s ATCID
- Bonneville does not believe this is a viable alternative
Alternative #2

- Under Alternative #2, outdated information in Attachment C would be revised to reflect Bonneville’s current ST ATC methodology.
- Attachment C would be expanded to include information on TTC, ETC and TRM calculations that are not updated regularly, such as the ATC formulas, TTC and ETC definitions, and process flow diagram.
  - Adding this information to Attachment C would bring Bonneville more in line with pro forma.
Alternative #2 (cont.)

- Bonneville would continue to provide all the information required by the pro forma Attachment C
  - Attachment C would continue to direct customers to Bonneville’s TRMID and ATCID for details on Bonneville’s TTC, ATC and TRM methodologies (such as load and generation assumptions)
  - Bonneville has an established process for customer engagement on our ST ATC methodology and would continue to use this process for any future ST ATC methodology changes being considered by Bonneville
Alternative #3

- Under Alternative #3, Bonneville would have a fully updated and pro forma Attachment C
  - Outdated information in Attachment C would be revised to reflect Bonneville’s current ST ATC methodology
  - Attachment C would include detailed information on Bonneville’s TTC, ETC and TRM calculations, including such details as load and generation assumptions used in the studies
  - BPA would continue to maintain ATCID and TRMID, as required by other regulatory requirements
Alternative #3 (cont.)

• Including details of the ATC, TTC and ETC methodologies in Attachment C has several limitations for the region
  – Decreases region’s flexibility to change Bonneville’s ST ATC and TRM methodologies, as changes would require a Tariff proceeding
    • This limits Bonneville’s ability to have an accurate and up to date ST ATC methodology
    • Posting too much ST ATC due to inaccuracies in the methodology can result in overselling when the capacity is not there. Conversely, not making capacity available to customers when it’s actually there impedes the market. Both outcomes are detrimental.
    • Bonneville can most nimbly achieve ST ATC accuracy by making improvements as they’re identified, without the time needed for a tariff proceeding
Alternative #3 (cont.)

- Could negatively impact reliability needs
  
  • Example: Bonneville staff recognizes the need for TRM on a path and Bonneville has to go through a tariff proceeding before one can be implemented to allow for TRM methodology to be included in Attachment C
  
  • Makes it harder to stay compliant with NERC standards, as the timeline for running a tariff proceeding could be in conflict with timelines for updating documentation related to TTC methodologies
Staff Leaning on Alternatives

• Staff leans towards Alternative #2
  – Brings Attachment C up to date
  – Brings Attachment C more in line with FERC pro forma
  – Allows Bonneville to engage with customers using existing processes for portions of the ST ATC Methodology that require more frequent changes than is practical for a Tariff proceeding

• We want to hear leanings from customers on this issue
Next Steps: Attachment C

- Bonneville would like feedback on this issue
- Please send your comments and thoughts to techforum@bpa.gov with a copy to your Account Executive
- Comments are due by June 8th, 2022
- Bonneville will review comments as we draft the ST ATC portion of Attachment C
- We will be presenting the draft Attachment C at the August workshop on this topic
Next Steps: BP/TC-24

- **Wednesday, June 1**
  - Deadline for requests for June 8 customer-led workshop, including specific topics and amount of time.

- **Wednesday, June 8**
  - Deadline for feedback and comments on May 25 materials. Please submit feedback and comments to techforum@bpa.gov, with a cc to your Power and/or Transmission Account Executive.

- **June 29 & 30**
  - 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

<table>
<thead>
<tr>
<th>Date</th>
<th>Rate/Tariff Topics</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>April 27</strong>&lt;br&gt;(Wed)</td>
<td><strong>Generation Inputs</strong>&lt;br&gt;• Operating Reserves with Western Power Pool (WPP)&lt;br&gt;<strong>Tariff</strong>&lt;br&gt;• Attachment C: Long-Term ATC (steps 1-5)&lt;br&gt;• Conditional Reservation Deadline for Daily Firm PTP (all steps)</td>
</tr>
<tr>
<td><strong>May 25</strong>&lt;br&gt;(Wed)</td>
<td><strong>Power Rates/Generation Inputs</strong>&lt;br&gt;• EIM Benefits in Power Rates&lt;br&gt;• EIM Impact on Balancing Services Cost&lt;br&gt;• Customer concerns regarding EIM and Generation Inputs&lt;br&gt;<strong>Transmission Rates</strong>&lt;br&gt;• EIM Charge Code Allocation&lt;br&gt;• Segmentation Study&lt;br&gt;<strong>Tariff</strong>&lt;br&gt;• Attachment C: Short-Term ATC (steps 1-4)</td>
</tr>
<tr>
<td><strong>June 7</strong>&lt;br&gt;(Tues)</td>
<td>• <em>RHWM Process Workshop</em></td>
</tr>
</tbody>
</table>
## BP-24 & TC-24 Workshops: Proposed Dates for Rate and Tariff Topics (cont.)

<table>
<thead>
<tr>
<th>Date</th>
<th>Rate/Tariff Topics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jun 14-16</td>
<td>• <em>IPR (pre-rate case process)</em></td>
</tr>
<tr>
<td>Jun 29-30 (Wed-Thu)</td>
<td><strong>Power Rates</strong>&lt;br&gt;• EIM Benefits in Power Rates&lt;br&gt;• Unauthorized Increase (UAI) Charge&lt;br&gt;• Tier 2 Rates&lt;br&gt;<strong>Transmission Rates</strong>&lt;br&gt;• Eastern Intertie Process Update (BP-22 Settlement Commitment)&lt;br&gt;<strong>Generation Inputs</strong>&lt;br&gt;• EIM Impact on Balancing Services Cost&lt;br&gt;• Load Reliability Service&lt;br&gt;• Losses&lt;br&gt;  • Power’s Capacity cost of providing losses (if needed)&lt;br&gt;  • Cost Recovery of Losses&lt;br&gt;<strong>Tariff</strong>&lt;br&gt;• Attachment C: Long-Term ATC (steps 4-5)&lt;br&gt;• Generator Interconnection Process (steps 1-4)&lt;br&gt;• Utility and DSI Delivery Losses (all steps)&lt;br&gt;• Monthly Loss Factors on the Network Segment (all steps)</td>
</tr>
</tbody>
</table>
BP-24 & TC-24 Workshops: Proposed Dates for Rate and Tariff Topics (cont.)

<table>
<thead>
<tr>
<th>Date</th>
<th>Rate/Tariff Topics</th>
</tr>
</thead>
</table>
| Jul 27-28 (Wed-Thu) | Agency (P&T)  
|                  | • Revenue Requirements  
|                  | • Risk  
|                  | **Power Rates**  
|                  | • UAI and Tier 2 follow-up (if needed)  
|                  | • Transfer Service  
|                  | • Washington Cap-and-Invest Program  
|                  | **Transmission Rates**  
|                  | • Sales Forecast (includes LGIA Forecast and Load Forecast)  
|                  | **Generation Inputs**  
|                  | • 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)  

May 25, 2022  
Pre-Decisional. For Discussion Purposes Only.  
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# BP-24 & TC-24 Workshops: Proposed Dates for Rate and Tariff Topics (cont.)

<table>
<thead>
<tr>
<th>Date</th>
<th>Rate/Tariff Topics</th>
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</thead>
<tbody>
<tr>
<td>Aug 24-25</td>
<td><strong>Power Rates</strong>&lt;br&gt;• Loads &amp; Resources&lt;br&gt;• Gas &amp; Market Price Forecast&lt;br&gt;• Secondary Revenue Forecast&lt;br&gt;&lt;br&gt;<strong>Transmission Rates</strong>&lt;br&gt;• EIM Charge Code Allocation&lt;br&gt;&lt;br&gt;<strong>Generation Inputs</strong>&lt;br&gt;• Losses&lt;br&gt;  • Power’s Capacity cost of providing losses (if needed)&lt;br&gt;  • Cost Recovery of Losses&lt;br&gt;• Load Reliability Service&lt;br&gt;&lt;br&gt;<strong>Tariff</strong>&lt;br&gt;• Attachment C: Long-Term ATC (steps 5-6)&lt;br&gt;• Generator Interconnection Process (steps 5-6)&lt;br&gt;• Proposed Draft Tariff (redline), including miscellaneous clean-up</td>
</tr>
<tr>
<td>(Wed-Thu)</td>
<td></td>
</tr>
<tr>
<td>Sept 28</td>
<td>Workshop Close-out and Summary of Staff Leanings</td>
</tr>
<tr>
<td>(Wed)</td>
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</table>

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

<table>
<thead>
<tr>
<th>Event</th>
<th>BP-24</th>
<th>TC-24</th>
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<tbody>
<tr>
<td>Federal Register Published (estimated)</td>
<td>Nov 10</td>
<td>Nov 10</td>
</tr>
<tr>
<td>Pre-Hearing Conference/BPA Direct Case</td>
<td>Nov 17</td>
<td>Nov 17</td>
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<tr>
<td>Clarification of BPA’s Direct Case</td>
<td>Dec 7-8</td>
<td>Dec 6</td>
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<tr>
<td>Parties File Direct Cases</td>
<td>Jan 24</td>
<td>Jan 20</td>
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<tr>
<td>Litigants File Rebuttal</td>
<td>Mar 7</td>
<td>Mar 1</td>
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<tr>
<td>Cross Examination</td>
<td>Apr 6-7</td>
<td>Mar 23-24</td>
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<tr>
<td>Initial Briefs</td>
<td>Apr 25</td>
<td>April 13</td>
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<tr>
<td>Hearing Officer’s Recommendation</td>
<td>n/a</td>
<td>May 23</td>
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<tr>
<td>Draft ROD</td>
<td>Jun 13</td>
<td>Jun 23</td>
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<tr>
<td>Briefs on Exceptions</td>
<td>Jun 27</td>
<td>Jul 7</td>
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<tr>
<td>Final ROD</td>
<td>Jul 26</td>
<td>Jul 26</td>
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Preliminary proposal subject to change.