TC-22, BP-22 and EIM Phase III Customer Workshop

December 12, 2019
## Agenda

<table>
<thead>
<tr>
<th>TIME</th>
<th>TOPIC</th>
<th>Presenter</th>
</tr>
</thead>
<tbody>
<tr>
<td>9:30 to 9:40 a.m.</td>
<td>Agenda Review, Prior Workshop Feedback &amp; Safety</td>
<td>Rebecca Fredrickson, Rachel Dibble</td>
</tr>
<tr>
<td>9:40 to 10:45 a.m.</td>
<td>Transmission Losses</td>
<td>Mike Bausch, Katie Sheckells, Doug Johnson, Andy Meyers</td>
</tr>
<tr>
<td>10:45 to 11:00 a.m.</td>
<td>BREAK</td>
<td></td>
</tr>
<tr>
<td>11:00 to 12:00 p.m.</td>
<td>EIM Losses</td>
<td>Todd Kocheiser</td>
</tr>
<tr>
<td>12:00 pm to 1:00 pm</td>
<td>LUNCH</td>
<td></td>
</tr>
<tr>
<td>1:00 to 2:00 p.m.</td>
<td>EIM Charge Code Allocation</td>
<td>Miranda McGraw, Derrick Pleger</td>
</tr>
<tr>
<td>2:00 to 3:30 pm</td>
<td>TC-20 Settlement Update</td>
<td>Katie Sheckells, Kevin Johnson, Margaret Olczak</td>
</tr>
</tbody>
</table>
Agenda Review and Feedback from Prior Workshop
Bonneville Power Administration

BP/TC-22 Proposed Workshop Timeline

BP-22 Topics

TC-22 Topics

EIM Topics

Sept. 26 EIM ROD

Nov. 12 ATC 101 Southern Intertie Studies

Integrated Program Review


BPA Workshops
- Oct 23, 2019
- Nov 19, 2019
- Dec 12, 2019
- Jan 28, 2020
- Feb 25, 2020
- Mar 17, 2020
- Apr 26, 2020
- May 19, 2020
- Jun 23, 2020
- Jul 28, 2020
- Aug 25, 2020

Customer Led Supplemental Workshops
- Dec 3, 2019
- Jan 15, 2020
- Feb 12, 2020
- Mar 11, 2020
- Apr 15, 2020
- May 13, 2020
- Jun 10, 2020
- Jul 15, 2020
- Aug 12, 2020

Just as a reminder: The Customer led workshops are reserved for customer collaboration or time that could be used to receive clarification on BPA workshop materials.
Engaging the Region on Issues

- After every workshop, BPA will provide a two-week feedback period for customers.
  - Input can be submitted via email to techforum@bpa.gov. Please copy your Power or Transmission Account Executive on your email.
- Issues will be presented according to the following process at workshops (multiple steps might be addressed in a single workshop):

  Phase One: Approach Development
  - Step 1: Introduction & Education
  - Step 2: Description of the Issue

  Phase Two: Evaluation
  - Step 3: Analyze the Issue
  - Step 4: Discuss Alternatives

  Phase Three: Proposal Development
  - Step 5: Discuss Customer Feedback
  - Step 6: Staff Proposal
## EIM Priority Issues

<table>
<thead>
<tr>
<th>#</th>
<th>Issue</th>
<th>BP-22</th>
<th>TC-22</th>
<th>Future BP/TC</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>EIM Charge Code Allocation</td>
<td>X</td>
<td>?</td>
<td>X</td>
</tr>
<tr>
<td>2</td>
<td>EIM Losses</td>
<td>X</td>
<td>X</td>
<td>?</td>
</tr>
<tr>
<td>3</td>
<td>Resource Sufficiency</td>
<td>X</td>
<td>X</td>
<td>?</td>
</tr>
<tr>
<td>3a</td>
<td>- Balancing Area Obligations</td>
<td>X</td>
<td>X</td>
<td>?</td>
</tr>
<tr>
<td>3b</td>
<td>- LSE Performance &amp; Obligations</td>
<td>X</td>
<td>X</td>
<td>?</td>
</tr>
<tr>
<td>3c</td>
<td>- Gen Input Impacts</td>
<td>X</td>
<td>X</td>
<td>?</td>
</tr>
<tr>
<td>4</td>
<td>Development of EIM Tariff Changes</td>
<td>X</td>
<td></td>
<td>?</td>
</tr>
<tr>
<td>5</td>
<td>Transmission Usage for Network</td>
<td>X</td>
<td>X</td>
<td>?</td>
</tr>
<tr>
<td>6</td>
<td>Non-federal Resource Participation</td>
<td>X</td>
<td>X</td>
<td>?</td>
</tr>
<tr>
<td>7</td>
<td>Metering &amp; Data Requirements</td>
<td>X</td>
<td></td>
<td>?</td>
</tr>
<tr>
<td>8</td>
<td>Evaluation of Operational Controls</td>
<td>X</td>
<td>X</td>
<td>?</td>
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# Rates & Tariff Topics

<table>
<thead>
<tr>
<th>#</th>
<th>Topics</th>
<th>BP-22</th>
<th>TC-22</th>
<th>Future BP/TC</th>
</tr>
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<tbody>
<tr>
<td>9</td>
<td>Transmission Losses</td>
<td>X</td>
<td>X</td>
<td></td>
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<tr>
<td>10</td>
<td>Ancillary Services</td>
<td>X</td>
<td>?</td>
<td></td>
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<tr>
<td>11</td>
<td>Debt Management (Revenue Financing)</td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>Generator Interconnection</td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>Regional Planning</td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>14</td>
<td>Creditworthiness</td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>15</td>
<td>Incremental/Minor Changes to Agreement Templates</td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>16</td>
<td>Seller’s Choice</td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>17</td>
<td>Loads</td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>18</td>
<td>Sales</td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>19</td>
<td>Generator Interconnection (assumed for BP-22)</td>
<td>X</td>
<td></td>
<td></td>
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<tr>
<td>20</td>
<td>Risk</td>
<td></td>
<td>X</td>
<td></td>
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<tr>
<td>21</td>
<td>Revenue Requirements</td>
<td></td>
<td>X</td>
<td></td>
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<tr>
<td>22</td>
<td>Review of Segments</td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>23</td>
<td>Review of Sale of Facilities</td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>24</td>
<td>Financial Leverage Policy Implementation</td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>25</td>
<td>Power-Only issues</td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>#</td>
<td>Issue</td>
<td>BP-22</td>
<td>TC-22</td>
<td>Future BP/TC</td>
</tr>
<tr>
<td>----</td>
<td>----------------------------------------------------------------------</td>
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</tr>
<tr>
<td>26</td>
<td>Simultaneous Submission Window</td>
<td></td>
<td></td>
<td>?</td>
</tr>
<tr>
<td>27</td>
<td>Study Process</td>
<td></td>
<td></td>
<td>?</td>
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<tr>
<td>28</td>
<td>Attachment C (Short-term &amp; Long-term ATC)</td>
<td></td>
<td></td>
<td>?</td>
</tr>
<tr>
<td>29</td>
<td>Hourly Firm (TC-20 Settlement – Attachment 1: section 2.c.ii)</td>
<td></td>
<td></td>
<td>?</td>
</tr>
<tr>
<td>30</td>
<td>Required Undesignation</td>
<td></td>
<td></td>
<td>?</td>
</tr>
<tr>
<td>31</td>
<td>Reservation window for Hourly non-firm</td>
<td></td>
<td></td>
<td>?</td>
</tr>
<tr>
<td>32</td>
<td>Non-federal NT Redispatch</td>
<td></td>
<td></td>
<td>?</td>
</tr>
<tr>
<td>33</td>
<td>PTP/NT Agreement Templates</td>
<td></td>
<td></td>
<td>?</td>
</tr>
</tbody>
</table>
# Feedback Summary

<table>
<thead>
<tr>
<th>Themes</th>
<th>BPA's Response: Updated 12/12</th>
</tr>
</thead>
<tbody>
<tr>
<td>Provide a detailed summary timeline with topics for each workshop</td>
<td>We will keep an agile schedule and adjust as we hear feedback from customers.</td>
</tr>
<tr>
<td>Customers concurred with BPA’s proposal for engagement for certain topics</td>
<td>No change</td>
</tr>
<tr>
<td>Customers want early discussions on the following topics:</td>
<td>Based on customer feedback, we have started discussion on the identified topics from customers in Jan. and Feb. This is reflected in the schedule on the Meetings and Workshops page</td>
</tr>
<tr>
<td>• Transmission Usage</td>
<td></td>
</tr>
<tr>
<td>• Creditworthiness</td>
<td></td>
</tr>
<tr>
<td>• EIM Metering and Data Requirements</td>
<td></td>
</tr>
<tr>
<td>• EIM Non Federal Resources</td>
<td></td>
</tr>
<tr>
<td>Provide customers information on where/if there will be changes for Rate Case topics</td>
<td>We recognize rates have dependencies on EIM policy topic decisions and we will stay coordinated with the topics. We also recognize their dependencies on charge code, gen inputs and Priority Firm Load; therefore, we will begin these discussions in Dec. and Jan.</td>
</tr>
<tr>
<td>Provide an explanation of why the proposed future tariff topics are not part of TC-22</td>
<td>The future deferred tariff topics are due to possible changes in industry standards and developing markets. As we discussed in the Oct. 23 workshop, we are focusing on EIM for this proceeding.</td>
</tr>
<tr>
<td>Identify early in steps 1 &amp; 2 where there are dependencies for other topics</td>
<td>We will identify the steps and to the extent we know the dependencies, will include them.</td>
</tr>
<tr>
<td>Provide a crosswalk of the Tariff issues from TC-20 to TC-22</td>
<td>Please see appendix at workshop in Nov. 19.</td>
</tr>
</tbody>
</table>
Feedback Summary (cont.)

<table>
<thead>
<tr>
<th>Themes</th>
<th>BPA's Response: Updated 12/12</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDAM impact on rates and tariff</td>
<td>EDAM policy is out of scope in the rates and tariff. Customers have the ability to participate directly in the CAISO’s EDAM policy initiative process. Bonneville’s evaluation of whether and how to join EDAM is anticipated to be another decision process – much like EIM – including the development of principles for our evaluation. We also anticipate that process would then be followed by rates and tariff cases.</td>
</tr>
<tr>
<td>EIM governance</td>
<td>EIM governance is out of scope in the rates and tariff process. Customers have the ability to participate in CAISO’s governance review process.</td>
</tr>
<tr>
<td>Leverage customer led workshops to share experiences and challenges</td>
<td>We worked with other participants to get a better understanding of their experiences and challenges. We also agree the monthly customer led workshops are an excellent forum to share experiences and challenges with other customers.</td>
</tr>
<tr>
<td>Carry larger ancillary services reserves</td>
<td>This will be addressed in the Gen Inputs discussion.</td>
</tr>
<tr>
<td>More discussion is needed on steps 1 &amp; 2 for resource sufficiency. Customers provided several questions to gain a better understanding.</td>
<td>We will look at the schedule and update it to address these questions.</td>
</tr>
</tbody>
</table>
Feedback Summary (cont.)

<table>
<thead>
<tr>
<th>Themes</th>
<th>BPA's Response: Updated 12/12</th>
</tr>
</thead>
<tbody>
<tr>
<td>Develop a roadmap of how future deferred tariff topics are addressed.</td>
<td>The future deferred tariff topics are due to possible changes in industry standards and developing markets. We don’t have roadmaps at this time. We would look to develop roadmaps after the conclusion of TC-22 if warranted.</td>
</tr>
<tr>
<td>Regional Planning Organization may have a couple of options</td>
<td>This will be addressed in steps 3-6 of the RPO discussion.</td>
</tr>
</tbody>
</table>
| Oversupply discussion and if it is needed in EIM                       | As noted in the EIM discussions at https://www.bpa.gov/Projects/Initiatives/EIM/Doc/20190312-March-13-2019-EIM-Stakeholder-Mtg.pdf  
BPA believes OMP is compatible with EIM. As we gain experience with EIM operations, we will continue to evaluate implementation and consider any potential changes in future tariff cases. |
Transmission Losses #9
Step 1: Introduction and Education
Step 2: Description of the Issue
Step 3: Data and/or Analysis that Supports the Issue
Agenda

- Introduction and education (Step 1)
- Description of the issue (Step 2)
- Data and/or analysis that supports the issue (Step 3)
  - Value
  - Actual vs Expected Returns
  - Administrative Burden
Objective

- Update the BPA process for the provision and settling of losses which captures the value of capacity and energy used to provide losses and minimizes load uncertainty, the administrative burden of system administration, maintenance, and reconciliation of deviations.
Current Loss Energy Return Options

BPA provides customers with three methods for returning their loss energy obligations to BPA:

- In-Kind (168 Hours later) – 88.77%
- Financial Settlement – 0.82%
- Slice – 10.41%

*Percentage breakdown of MW Obligations year to date 2019.*
In-Kind Challenges

In-Kind is the most challenging option due to:

- **Value**: In-kind replacement of losses results in mismatches in value between the time the losses occur and the time the energy is returned 168 hours later.

- **Actual vs. expected returns**: BPA receives losses from the parties where parties do not schedule the entire loss obligation or schedule the incorrect amounts of losses.

- **Administrative Burden**: Current process requires significant FTE time to manage routine daily processes and system maintenance. Losses app requires a monthly maintenance fee.
Value: Physical Loss Returns Compensation

- Returning physical losses at $t+168$ hours results in roughly neutral energy-related revenue for the loss provider
  - Assuming flat MW quantities
  - Energy values fluctuate but generally equalize over time
- The loss provider (Power Services) is not compensated for holding out capacity necessary to provide losses.
Actual vs Expected Returns
Percent of Days with Deviation

April, May, June monthly totals including losses waived by Power Services during over supply season.
# Actual vs Expected Returns

<table>
<thead>
<tr>
<th>Year:</th>
<th>Month:</th>
<th>Total Obligation MWh</th>
<th>Return Total MWh</th>
<th>MWh Difference</th>
<th>Days Reviewed</th>
<th>Days With Difference</th>
<th>Percent of Days with Deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>2018</td>
<td>October</td>
<td>200,010</td>
<td>199,770</td>
<td>240</td>
<td>31</td>
<td>13</td>
<td>42%</td>
</tr>
<tr>
<td></td>
<td>November</td>
<td>187,305</td>
<td>186,896</td>
<td>409</td>
<td>30</td>
<td>16</td>
<td>53%</td>
</tr>
<tr>
<td></td>
<td>December</td>
<td>218,803</td>
<td>218,869</td>
<td>-66</td>
<td>31</td>
<td>10</td>
<td>32%</td>
</tr>
<tr>
<td></td>
<td>January</td>
<td>246,744</td>
<td>246,674</td>
<td>70</td>
<td>31</td>
<td>19</td>
<td>61%</td>
</tr>
<tr>
<td></td>
<td>February</td>
<td>194,324</td>
<td>194,132</td>
<td>192</td>
<td>28</td>
<td>21</td>
<td>75%</td>
</tr>
<tr>
<td></td>
<td>March</td>
<td>213,126</td>
<td>213,028</td>
<td>98</td>
<td>31</td>
<td>22</td>
<td>71%</td>
</tr>
<tr>
<td></td>
<td>April</td>
<td>207,187</td>
<td>206,656</td>
<td>531</td>
<td>30</td>
<td>24</td>
<td>80%</td>
</tr>
<tr>
<td></td>
<td>May</td>
<td>225,901</td>
<td>212,846</td>
<td>13,055</td>
<td>31</td>
<td>19</td>
<td>61%</td>
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<tr>
<td></td>
<td>June</td>
<td>235,718</td>
<td>235,478</td>
<td>240</td>
<td>30</td>
<td>20</td>
<td>67%</td>
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<tr>
<td></td>
<td>July</td>
<td>259,763</td>
<td>259,605</td>
<td>158</td>
<td>31</td>
<td>13</td>
<td>42%</td>
</tr>
<tr>
<td></td>
<td>August</td>
<td>275,905</td>
<td>275,564</td>
<td>341</td>
<td>31</td>
<td>16</td>
<td>52%</td>
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<tr>
<td></td>
<td>September</td>
<td>266,291</td>
<td>266,053</td>
<td>238</td>
<td>30</td>
<td>8</td>
<td>27%</td>
</tr>
<tr>
<td>2019</td>
<td>October</td>
<td>207,522</td>
<td>207,312</td>
<td>210</td>
<td>31</td>
<td>18</td>
<td>58%</td>
</tr>
</tbody>
</table>

Monthly totals including losses waived by Power Services during over supply season.
Administrative Burden

- Current State Daily Process - ~1.4 FTE
  - Calculation Review
  - Obligations vs Actuals
  - Checkout & Carry Forward
- Software
  - Recurring maintenance of customized loss module
  - Application Regression Testing
- Management and resolution
  - Issues around changes in loss return elections
  - Uncollected/unreturned loss obligations
Administrative Burden

Workflow Process for Current State 168 Hour Loss Returns - does not include time estimates for software maintenance, testing, or resolution of periodic contract problems.

BPA Transmission Total = 230 Hrs/Mo = 1.4 FTE

130 Hrs/Mo

40 Hrs/Mo

50 Hrs/Mo
Administrative Burden

Workflow Process for Current State 168 Hour Loss Returns – does not include time estimates

Calculate & Verify Routine
- Loss Reports Metered vs. Internal System
  - Calculate Losses 20 Hrs/Mo
- Loss Variance Report 30 Hrs/Mo
- Resale Check 30 Hrs/Mo
- Unmatched Tag Check 30 Hrs/Mo
- Verify Loss Exemptions 20 Hrs/Mo

Day Prior to Preschedule
- Post Losses to CDE

BPA Transmission
- Start

BPA Power
- Planning Runs (Forecasts Gen & Load)
- OSM Management Loss Waiver in Spring 1 HR/Day

Customer
- Download Schedules from CDE
Administrative Burden

- BPA Transmission Total = 230 Hrs/Mo = 1.4 FTE

Diagram:
- OASIS Validate TSR
- E-Tag Validate Tag
- Check Schedule Against Obligation 20 Hrs/Mo
- Daily Checkout w/CUSTOMERS 20 Hrs/Mo
- Preschedule
- Real Time Schedule

40 Hrs/Mo
Administrative Burden

Diagram showing the process of prescheduling, real-time scheduling, and after-the-fact calculations.
Software Maintenance/Testing

- FTE impacts not included on process diagram
  - App is prone to errors/software variances
  - App needs testing during monthly software upgrades even when not included.

- Financial
  - Monthly maintenance fee
Uncollected Obligations

- BPA engages customers when physical losses are not returned on time – this can be the result of:
  
  - A customer allowing its loss return agreement to lapse after repeated attempts from BPA to renew;
  - A PTP agreement expiring before a replacement agreement can be signed for a contract to be in place to bill losses against;
  - A generator returning losses in-kind ceases operation before an “in-kind” loss obligation is satisfied.
Consequences

- BPA Transmission AEs work with the BPA Power Services Trading Floor to make alternate arrangements to make BPA whole.
- Trading Floor performs a “lookback” to calculate the financial value of the losses.
- BPA Transmission AE executes a Letter Agreement allowing for the one-time financial settlement of losses.
- Customer is billed for losses.
- This process is labor intensive and takes all involved off task for a one-off solution.
  - In the last calendar year we have had multiple instances which have required review, analysis and resolution.
  - These issues arise each year.
EIM Losses #2
Step 1: Introduction and Education
Objective

- Inform BPA stakeholders of how losses are handled in the EIM
- Identify EIM charge codes that are impacted by losses
- Determine Bonneville’s current practices regarding transmission losses

"Bonneville will discuss with stakeholders the extent to which the EIM's handling of losses should lead to changes in Bonneville's current practices regarding transmission losses, or what new opportunities are available for more efficient repayment of losses. This may include the potential for moving to a practice which losses are only settled financially instead of a physical repayment. Decision in this process will likely influence and/or be memorialized in the BP-22 and TC_22 cases.” (Excerpt from ROD)
Transmission vs. EIM Losses

- **Transmission Losses:** Losses produced by the use of the FCRTS and recovered based on scheduled demand.

- **EIM Losses:** A mechanism to account for and ensure that 1) the total Balancing Authority Area (BAA) losses have been planned and provided for prior to each hour and 2) that the impact of the EIM market awards/dispatches on losses are taken into considering in the market solution and Locational Marginal Prices (LMP).
EIM Base Losses

- In the EIM, each participating Balancing Authority Area (BAA) is expected to submit hourly base schedules for resources and interchange to meet the expected demand forecast (a.k.a. load forecast) of the BAA.
- The demand forecast for the BAA includes load and losses.
- Similar to today, the majority of BAA losses (i.e., base losses) are planned for and supplied prior to the hour as part of the base scheduling activity.
EIM Incremental Losses

- The Locational Marginal Prices (LMP) produced by the EIM include the Marginal Cost of Losses (MLC) at each pricing node, relative to the cost of providing energy to the weighted/distributed load reference bus.

- As such, as the market is running, it is taking into consideration the cost of marginal (incremental) losses at each LMP node in its optimization.
EIM Load Base Schedule

- For settlement of load imbalance, an hourly Load Base Schedule (LBS) is calculated by the market

\[
LBS = \text{Sum}(\text{GENbase}) - \text{Sum}(\text{INTbase}) - \text{Demand Forecast} \times \text{Loss}\%
\]

Where:

- **GENbase**: Generation Base Schedules
- **INTbase**: Interchange Base Schedules
- **Loss\%**: Provided by each EIM Entity for their BAA - can be a static value or a lookup table that contains different values for hour of day and day of week
EIM Load Meter

- A Load Meter (LM) for the BAA must be submitted by the EIM Entity (EESC) ATF
- A “top down” approach is generally used

\[ LM = \text{Sum(GENmeter)} - \text{Sum(INTmeter)} - \text{Losses} \]

Where:

- **GENmeter**: Generator/Resource meter
- **INTmeter**: Interchange meter
- **Losses**: Typically calculated using the same loss% that was used when establishing the Load Base Schedule (LBS)
Uninstructed Imbalance Energy (UIE)

- Uninstructed Imbalance Energy (CC64750) for Load is calculated as follows:

\[ \text{UIE}_{\text{Load}} = \text{LBS} - \text{LM} \leftarrow \text{Hourly Settlement} \]

- Hourly Load Aggregation Point (LAP) LMP is used for load UIE settlement
- If the same loss% is used for both the LBS calculation and the LM submittal, it should help minimize the UIE for load charges and allow them to be more easily shadowed
Unaccounted for Energy (UFE)

- Unaccounted for Energy (CC64740) uses the hourly LAP LMP and is calculated as follows:

\[ \text{UFE} = \text{Sum(\text{GEN}\text{meter})} - \text{Sum(\text{INT}\text{meter})} - \text{LM} - \text{NALosses} \]

- NALosses: actual losses calculated using an AC Power Flow (ACPF) from the EIM’s Network Analysis application

- Differences between the loss% used in the LBS and LM calculations and actual losses (via ACPF) will be captured in UFE.
Real-Time Marginal Losses Offset

- Marginal Loss Charges are implicitly collected by the CAISO in the Real-Time settlement
- There are no holders of rights to receive Real-Time Marginal Loss revenues so they are accumulated in special and separate BAA neutrality accounts
- Allocated to the associated EESC of an EIM BAA in Real Time Marginal Losses Offset (CC 69850)

* The product of (1) the contribution of that BAA’s Transmission Constraints to the marginal Loss component of the LMP at each resource location in the EIM Area and (2) the imbalance energy at that resource location
Imbalance Energy Offset (RTIEO)

- Real-Time Imbalance Energy Offset (CC64770) is intended to help ensure that the EESC is revenue neutral
- RTIEO: If the Sum(IIE, UIE, UFE, GHG) less Congestion and Losses does not = $0, charges or payments will be made to the EESC
  - Large errors in UIE_{load} or UFE will ultimately be reconciled for in 64770
  - The financial value of EIM Transfers is also included in RTIEO, unless an EIM Entity has chosen to settle ETSRs through the market
EIM Losses Summary

- The EIM does not provide system or BAA losses, but takes them into consideration when ensuring each BAA is balanced prior to the hour.
- The EIM also takes into consideration marginal (a.k.a. incremental) losses that result from market awards and dispatches.
- Losses are embedded in load UIE, UFE, and RTIEO.
- Bonneville will need to determine how it calculates the loss percentages used by the EIM.
Next Steps

- Feedback on Transmission and EIM Losses
  - Please submit to techforum@bpa.gov (with copy to your account executive)
  - Comments will close Jan. 3, 2020

- Transmission Losses:
  - Step 4: Discussion of Alternatives March 17th customer workshop
  - BPA plans to evaluate methodology for calculating Loss percentage this spring and incorporate into decision making

- EIM Losses
  - Steps 2-4: Issue, Analysis and Alternatives March 17th customer workshop
EIM Charge Code Allocation #1

Step 1: Introduction and Education

Step 2: Description of the Issue
Objective

- Address charge code allocation policy issues to determine the approach Bonneville should adopt to recover its costs (or distribute credits) for charge codes it receives as an EIM Entity.

Note: Settlement mechanics (e.g. frequency or type of BPA customer billing) will be addressed separately in future workshops, if there is a sub-allocation methodology adopted.
Organizational Relationships: CAISO

CAISO Tariff

Invoice

Participating Resource Scheduling Coordinator (PRSC)

BPA Power & Non-Federal PRSCs

CAISO to BPA Relationship
(Not in Scope)

Invoice

EIM Entity Scheduling Coordinator (EESC)

BPA Transmission

CAISO Tariff
Organizational Relationships: EESC

EIM Entity Scheduling Coordinator (EESC)

BPA Transmission

EESC to Customers Relationship
(In Scope for Charge Code Allocation Policy Team)

Charge Code Allocation

BPA Transmission Customers

Load
Non-Participating Resources
Wheel-Through & Interchange

Rate Design – Hold for Future BP-22 Rates Workshops

BPA Tariff & Rates

December 12, 2019
Pre-decisional. For Discussion Purposes Only.
Organizational Relationships: PRSC

- EIM Entity Scheduling Coordinator (EESC)
  - BPA Transmission
    - Charge Code Allocation
      - BPA Transmission Customers
        - Load
          - Non-Participating Resources
          - Wheel Through & Interchange
      - BPA Power
        - Cost Recovery
  - BPA Power Customers
    - Rate Schedules
    - Product Type
    - Transfer Policy

- Participating Resource Scheduling Coordinator (PRSC)
  - BPA Power
    - Charge Code Allocation
      - BPA Power Customers
        - Rate Schedules
        - Product Type
        - Transfer Policy

- PRSC to Customers Relationship
  (In scope for Charge Code Allocation Policy Team)

- BPA Contracts & Rates

Rate Design – Hold for Future BP-22 Rates Workshops
CAISO Settlement Process Consideration

- Direct sub-allocation of EIM Charge Codes to customers would indirectly expose customers to CAISO Settlement process.

- CAISO Settlement Process is Complex and Administratively Burdensome
  - CAISO bills weekly; re-calculates Charge Codes multiple times for up to 3 years.
  - Disputes over sub-allocated EIM Charge Codes would have to be submitted to Bonneville; could lead to Bonneville bringing customer dispute to CAISO.

Bonneville is still considering settlement mechanics, which will be addressed in a future workshop. While developing the charge code allocation methodology, there is awareness that if a sub-allocation methodology is adopted, it could have broad administrative impacts on customers’ and Bonneville’s billing.
The following slides provide lists of the charge codes by category for context. The charge code lists contain information on Bonneville’s experience with other EIM entities as examples to illustrate the range and volatility that can exist. Examples of Bonneville’s experience focused on the largest EIM balancing authorities that Bonneville has load in.
## CAISO EIM Charge Code List

### Primary Imbalance Charges

<table>
<thead>
<tr>
<th>CC #</th>
<th>Charge Code Name</th>
<th>EIM Entity Sub Allocation</th>
<th>PacifiCorp BPA Peak Load 400+ Monthly</th>
<th>Idaho Power BPA Peak Load 300+ Monthly</th>
<th>NV Energy BPA Peak Load 100&lt;&gt; Monthly</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Min Charge</td>
<td>Max Charge</td>
<td>Min Charge</td>
</tr>
<tr>
<td>64600</td>
<td>FMM Instructed Imbalance Energy EIM Settlement</td>
<td>EESC PRSC</td>
<td>Yes</td>
<td>Varies</td>
<td>Varies</td>
</tr>
<tr>
<td>64700</td>
<td>Real Time Instructed Imbalance Energy EIM Settlement</td>
<td>EESC PRSC</td>
<td>Yes</td>
<td>Varies</td>
<td>Varies</td>
</tr>
<tr>
<td>64750</td>
<td>Real Time Uninstructed Imbalance Energy EIM Settlement</td>
<td>EESC</td>
<td>Yes</td>
<td>Varies</td>
<td>Varies</td>
</tr>
<tr>
<td>64740</td>
<td>Real Time Unaccounted for Energy EIM Settlement</td>
<td>EESC</td>
<td>No</td>
<td>Varies</td>
<td>Varies</td>
</tr>
</tbody>
</table>

### Primary Ancillary Service Charges

<table>
<thead>
<tr>
<th>CC #</th>
<th>Charge Code Name</th>
<th>EIM Entity Sub Allocation</th>
<th>PacifiCorp BPA Peak Load 400+ Monthly</th>
<th>Idaho Power BPA Peak Load 300+ Monthly</th>
<th>NV Energy BPA Peak Load 100&lt;&gt; Monthly</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Min Charge</td>
<td>Max Charge</td>
<td>Min Charge</td>
</tr>
<tr>
<td>7070</td>
<td>Flexible Ramp Forecast Movement Settlement</td>
<td>EESC PRSC</td>
<td>Yes</td>
<td>Varies</td>
<td>Varies</td>
</tr>
<tr>
<td>7071</td>
<td>Daily Flexible Ramp Up Uncertainty Capacity Settlement</td>
<td>PRSC</td>
<td>No</td>
<td>Varies</td>
<td>Varies</td>
</tr>
<tr>
<td>7076</td>
<td>Flexible Ramp Forecast Movement Allocation</td>
<td>EESC</td>
<td>Yes</td>
<td>Varies</td>
<td>Varies</td>
</tr>
<tr>
<td>7077</td>
<td>Daily Flexible Ramp Up Uncertainty Award Allocation</td>
<td>EESC PRSC</td>
<td>Yes</td>
<td>Varies</td>
<td>Varies</td>
</tr>
<tr>
<td>7078</td>
<td>Monthly Flexible Ramp Up Uncertainty Award Allocation</td>
<td>EESC PRSC</td>
<td>Yes</td>
<td>Varies</td>
<td>Varies</td>
</tr>
<tr>
<td>7081</td>
<td>Daily Flexible Ramp Down Uncertainty Capacity Settlement</td>
<td>PRSC</td>
<td>No</td>
<td>Varies</td>
<td>Varies</td>
</tr>
<tr>
<td>7087</td>
<td>Daily Flexible Ramp Down Uncertainty Award Allocation</td>
<td>EESC PRSC</td>
<td>Yes</td>
<td>Varies</td>
<td>Varies</td>
</tr>
<tr>
<td>7088</td>
<td>Monthly Flexible Ramp Down Uncertainty Award Allocation</td>
<td>EESC PRSC</td>
<td>Yes</td>
<td>Varies</td>
<td>Varies</td>
</tr>
</tbody>
</table>
## CAISO EIM Charge Code List

### Market Clearing / Neutrality / Cost Recovery Charges

<table>
<thead>
<tr>
<th>CC #</th>
<th>Charge Code Name</th>
<th>CAISO &gt; EIM Entity Allocation</th>
<th>EIM Entity Sub Allocation</th>
<th>PacifiCorp BPA Peak Load 400+ Monthly Min Charge</th>
<th>Idaho Power BPA Peak Load 300+ Monthly Min Charge</th>
<th>NV Energy BPA Peak Load 100&lt;&gt; Monthly Min Charge</th>
</tr>
</thead>
<tbody>
<tr>
<td>6478</td>
<td>Real Time Imbalance Energy Offset - System</td>
<td>EESC</td>
<td>Yes</td>
<td>(114,282)</td>
<td>(79,394)</td>
<td>(32,986)</td>
</tr>
<tr>
<td>64770</td>
<td>Real Time Imbalance Energy Offset EIM</td>
<td>EESC</td>
<td>Yes</td>
<td>(133,420)</td>
<td>(461,270)</td>
<td>(16,279)</td>
</tr>
<tr>
<td>67740</td>
<td>Real Time Congestion Offset EIM</td>
<td>EESC</td>
<td>Yes</td>
<td>(79,394)</td>
<td>(3,683)</td>
<td>(2,173)</td>
</tr>
<tr>
<td>69850</td>
<td>Real Time Marginal Losses Offset EIM</td>
<td>EESC</td>
<td>Yes</td>
<td>(6,825)</td>
<td>(1,348)</td>
<td>(1,348)</td>
</tr>
<tr>
<td>67740</td>
<td>Real Time Bid Cost Recovery EIM Settlement</td>
<td>EESC</td>
<td>Yes</td>
<td>(59,009)</td>
<td>(18,121)</td>
<td>(6,825)</td>
</tr>
<tr>
<td>67780</td>
<td>Real Time Bid Cost Recovery Allocation EIM</td>
<td>EESC</td>
<td>Yes</td>
<td>(32)</td>
<td>(7)</td>
<td>(78,549)</td>
</tr>
<tr>
<td>8989</td>
<td>Daily Neutrality Adjustment</td>
<td>EESC</td>
<td>Yes</td>
<td>951</td>
<td>1,093</td>
<td>(56,642)</td>
</tr>
<tr>
<td>8999</td>
<td>Monthly Neutrality Adjustment</td>
<td>EESC</td>
<td>Yes</td>
<td>31,738</td>
<td>36,584</td>
<td>3,476</td>
</tr>
</tbody>
</table>

### Penalty Charges

<table>
<thead>
<tr>
<th>CC #</th>
<th>Charge Code Name</th>
<th>CAISO &gt; EIM Entity Allocation</th>
<th>EIM Entity Sub Allocation</th>
<th>PacifiCorp BPA Peak Load 400+ Monthly Min Charge</th>
<th>Idaho Power BPA Peak Load 300+ Monthly Min Charge</th>
<th>NV Energy BPA Peak Load 100&lt;&gt; Monthly Min Charge</th>
</tr>
</thead>
<tbody>
<tr>
<td>6045</td>
<td>Overscheduling and Under scheduling Charge</td>
<td>EESC</td>
<td>Yes</td>
<td>(0)</td>
<td>8,217</td>
<td>(511)</td>
</tr>
<tr>
<td>6046</td>
<td>Under Scheduling and Over Scheduling Allocation</td>
<td>EESC</td>
<td>Yes</td>
<td>(5,369)</td>
<td>368</td>
<td>776</td>
</tr>
</tbody>
</table>
# CAISO EIM Charge Code List

## Administrative Charges

<table>
<thead>
<tr>
<th>CC #</th>
<th>Charge Code Name</th>
<th>CAISO &gt; EIM Entity Allocation</th>
<th>EIM Entity Sub Allocation</th>
<th>PacifiCorp BPA Peak Load 400+ Monthly</th>
<th>Idaho Power BPA Peak Load 300+ Monthly</th>
<th>NV Energy BPA Peak Load 100&lt;&gt; Monthly</th>
</tr>
</thead>
<tbody>
<tr>
<td>491</td>
<td>Green House Gas Emission Cost Revenue</td>
<td>PRSC</td>
<td>No</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>701</td>
<td>Forecasting Service Fee</td>
<td>PRSC</td>
<td>Yes</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1592</td>
<td>EP Penalty Allocation Payment</td>
<td>EESC</td>
<td>PRSC</td>
<td>No</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2999</td>
<td>Default Invoice Interest Payment</td>
<td>EESC</td>
<td>PRSC</td>
<td>No</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3999</td>
<td>Default Invoice Interest Charge</td>
<td>EESC</td>
<td>PRSC</td>
<td>No</td>
<td></td>
<td></td>
</tr>
<tr>
<td>4515</td>
<td>GMC Bid Transaction Fee</td>
<td>PRSC</td>
<td>No</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4564</td>
<td>GMC-EIM Transaction Charge</td>
<td>EESC</td>
<td>PRSC</td>
<td>Yes</td>
<td>2,130</td>
<td>4,026</td>
</tr>
<tr>
<td>4575</td>
<td>SMCR -Settlements, Metering, and Client Relations</td>
<td>EESC</td>
<td>PRSC</td>
<td>Yes</td>
<td>-</td>
<td>121</td>
</tr>
<tr>
<td>5024</td>
<td>Invoice Late Payment Penalty</td>
<td>EESC</td>
<td>PRSC</td>
<td>No</td>
<td>-</td>
<td>10,870</td>
</tr>
<tr>
<td>5025</td>
<td>Financial Security Posting (Collateral) Late Payment Penalty</td>
<td>EESC</td>
<td>PRSC</td>
<td>No</td>
<td>-</td>
<td>10,870</td>
</tr>
<tr>
<td>5900</td>
<td>Shortfall Receipt Distribution</td>
<td>EESC</td>
<td>PRSC</td>
<td>No</td>
<td></td>
<td></td>
</tr>
<tr>
<td>5901</td>
<td>Shortfall Allocation Reversal</td>
<td>EESC</td>
<td>PRSC</td>
<td>No</td>
<td></td>
<td></td>
</tr>
<tr>
<td>5910</td>
<td>Shortfall Allocation</td>
<td>EESC</td>
<td>PRSC</td>
<td>No</td>
<td></td>
<td></td>
</tr>
<tr>
<td>5912</td>
<td>Default Loss Allocation</td>
<td>EESC</td>
<td>PRSC</td>
<td>No</td>
<td></td>
<td></td>
</tr>
<tr>
<td>7989</td>
<td>Invoice Deviation Interest Distribution</td>
<td>EESC</td>
<td>PRSC</td>
<td>No</td>
<td></td>
<td></td>
</tr>
<tr>
<td>7999</td>
<td>Invoice Deviation Interest Allocation</td>
<td>EESC</td>
<td>PRSC</td>
<td>No</td>
<td></td>
<td></td>
</tr>
<tr>
<td>8526</td>
<td>Generator Interconnection Process GIP Forfeited Deposit Allocation</td>
<td>EESC</td>
<td>No</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Policy Question

- What approach should Bonneville adopt in recovering its costs (or distributing credits) for charge codes that it will receive as an EIM Entity from the CAISO?
  - Should Bonneville roll-in the costs/benefits to its current transmission rates? (completely insulating customers from direct CAISO costs/credits)
  - If not, how should Bonneville recover from customers? (partial insulation, no insulation from costs/credits)
    - E.g. Sub-allocation by each charge code or sub-allocation by charge code grouping
Potential Bonneville Charge Code Allocation Principles

- Full and timely cost recovery, considering cost causation while balancing with simplicity.
- Develop understandable and transparent methodology that we can build upon as we gain experience in the market.
- Feasibility of implementation, recognizing forecasting constraints and administrative implications.
Potential Transmission Charge Code Allocation Principles

- Equitable cost allocation between Federal and non-Federal users of the transmission system.
- Behavior-driven cost causation where practical, to incentivize appropriate market behaviors.
- Mitigate seams and potential for charge code allocation misalignments with other EIM Entities.
Potential Power Charge Code Allocation Principles

- Costs and benefits are allocated among cost pools consistent with the Tiered Rates Methodology and power product purchased from BPA.
- To the extent possible, treat directly connected and transfer customers comparably.
- Maintain similar level of exposure to actual market conditions as is included in power products today.
Methodology Spectrum

<table>
<thead>
<tr>
<th>Factors to Evaluate:</th>
<th>Complete Insulation</th>
<th>Partial Insulation</th>
<th>No Insulation</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Charge Code Allocation</strong></td>
<td>No Allocation of Charge Codes</td>
<td>Sub-Allocate Some Charge Codes</td>
<td>Pass-through All Charge Codes</td>
</tr>
<tr>
<td><strong>Forecast in Rates</strong></td>
<td>Full Costs Forecast</td>
<td>Some Costs Forecast</td>
<td>No Costs Forecast</td>
</tr>
<tr>
<td><strong>Cost Recovery Mechanism</strong></td>
<td>Risk Mechanism within Rate Structure</td>
<td>Combination of Direct Assignment and Rate Structure</td>
<td>Direct Assignment</td>
</tr>
<tr>
<td><strong>Potential Structural Changes</strong></td>
<td>Minimal Changes to Product / Rate Structure</td>
<td>Some Changes to Product / Rate Structure</td>
<td>Changes to Product / Rate Structure</td>
</tr>
<tr>
<td><strong>Billing Implications</strong></td>
<td>Minor Changes to Billing</td>
<td>Some Changes to Billing</td>
<td>Re-structuring of Billing</td>
</tr>
<tr>
<td><strong>Customer Impact</strong></td>
<td>Low Impact</td>
<td>Moderate Impact</td>
<td>High Impact</td>
</tr>
</tbody>
</table>

Phase Two (Issue Analysis and Alternative Development) will evaluate the feasibility of the factors across the methodology spectrum, which will lead to identifying feasible alternatives.
Complete Insulation

**Advantages**

- No charge code sub-allocation
- No settlement re-calculation process with customers
- Limited rate schedule changes
- No significant change to customer bills
- Disassociates customer/BPA disputes from BPA/CAISO disputes
- Customers would not need resources to verify CAISO data
- BPA gains experience in the market to provide understanding for future charge code allocation development

**Potential Challenges**

- Separation of market behavior and cost causation, reducing customer visibility
- Cost recovery would not occur through the EIM design and a financial cost recovery mechanism would need to be determined
- BPA's existing behavioral price signals may not fully align with CAISO's structure for the same action
- Unable to pass on EIM-specific price signals
- Potential seams issues between EIM BAAs
Partial Insulation

Advantages

• Incentivize appropriate market behaviors through charge code allocation
• Enables BPA to develop experience in the market, but begins to stage implementation of sub-allocating
• Customers begin developing experience with CAISO price signals
• Potential for closest alignment with other EIM entities, may reduce seams issues

Potential Challenges

• Opens up potential customer exposure to EIM settlement process, potentially increasing need for customers to validate data
• Begins to create billing complexity, given the volume of settlements
• Bonneville takes on risk of consolidating and allocating charge codes
No Insulation

Advantages

- Cost causation incentivizes appropriate market behavior
- Allocation of costs tie closely to behaviors
- Close alignment with other EIM entities, may reduce seams issues
- Reduces need to design risk mechanisms
- Greatest transparency in the allocation of specific charge codes from CAISO to BPA to customers

Potential Challenges

- Significant change to customer bills to address CAISO settlement processes
- Aligning disputes between CAISO/BPA and Customer/BPA would be complex to administer
- BPA and customers would need to consider increasing resources to validate EIM data
- Not all EIM settlements with BPA will be 100% verifiable, which could create challenges when passed to customers
- With direct assignment, may create greater uncertainty for customers in bills
- May go beyond structure other EIM entities use today, increasing settlement complexity
EIM Charge Code Next Steps

- Feedback on policy questions and charge code allocation principles
  - Please submit to techforum@bpa.gov (with copy to your account executive) by Friday, January 3

- Next Charge Code Allocation Workshop: February 25
  - Phase 2
    - Step 3: Analysis of the Issue
    - Step 4: Alternatives
WRAP UP & NEXT STEPS
Next Steps

- By Jan. 3, please provide feedback on the following via techforum@bpa.gov (with copy to your account executive):
  - Transmission Losses
  - EIM Losses
  - Charge code allocation policy questions and principles

- Next workshop is on Jan. 28, 2020.
Proposed January Workshop Agenda

- Proposed TC-22, BP-22 & EIM Topics
  - EIM Transmission Network Usage
  - Metering Policies for EIM
  - Non-Federal Resources Participation in EIM
  - Exploring Section 7(f) Rate Options
  - Debt Management

- Proposed BP-20 Settlement Update Topics
  - Attachment 2, Generation inputs

- Proposed TC-20 Settlement Update Topics
  - NT Roadmap
  - Intertie Studies
Customer Led Workshop Protocol

- Submit a workshop request no later than one week before the scheduled date (see slide 4 for dates).
- Requests must include a list of topics/issues you wish to cover if you are requesting Bonneville SME support.
- Discussions/workshops will only cover previously reviewed materials.
- Customers must inform BPA if A/V resources are required to include remote participants and/or present materials within the Rates Hearing Room.
- BPA will verify that it will staff for the requested topics within three business days via Tech Forum.