Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

FREEDOM OF INFORMATION ACT/PRIVACY PROGRAM

August 10, 2021

In reply refer to: FOIA #BPA-2020-00739-F

Andrew Missel
Advocates for the West
3701 SE Milwaukie Avenue, Suite B
Portland OR 97202
Email: amissel@advocateswest.org

Dear Mr. Missel,

This communication is the Bonneville Power Administration (BPA) third partial and final response to your request for agency records made under the Freedom of Information Act, 5 U.S.C. § 552 (FOIA). BPA received your records request on April 30, 2020; formally acknowledged your request on May 1, 2020; sent you a first partial response of records on June 22, 2021; and sent you a second partial release of records on July 29, 2021.

Request
"1. Any communications between BPA and CAISO concerning (a) BPA's decision to sign the Implementation Agreement and/or (b) the steps BPA is taking to carry out the Implementation Agreement. This includes both pre-signing communications and post-signing communications.

2. Any communications between BPA and the Northwest Power and Conservation Council ("NWPCC") concerning BPA's decision to (a) sign the Implementation Agreement and/or (b) the steps BPA is taking to carry out the Implementation Agreement. This includes both presigning communications and post-signing communications."

Third Partial Response
As described in the July 29, 2021 release letter, some of the records provided to CAISO for objection contained information belonging to BPA. BPA denied CAISO's objections with regard to those records. In accordance with DOE's FOIA regulations at 10 C.F.R. § 1004.11, BPA provided CAISO a pre-release notice of seven business days. Seven days have passed, so BPA is releasing the remaining 442 pages of responsive records as follows:

- 11 partial pages withheld under 5 U.S.C. § 552(b)(6) (Exemption 6).
- 18 partial pages withheld under 5 U.S.C. § 552(b)(2) (Exemption 2).
- 73 pages withheld in full under 5 U.S.C. § 552(b)(4) (Exemption 4).
- 170 partial pages withheld under Exemption 4.

Please note that this record set also includes the 103 pages of publicly-available records (a FERC Order entitled, “Order Conditionally Accepting In Part And Rejecting In Part Proposed Tariff Revisions to Implement Energy Imbalance Market” (Docket No. ER-14-1578-000)) released to you on July 29, 2021. That FERC Order is attached to an email and is contained in this record set to keep the record family intact for context.

Explanation of Exemptions
The FOIA generally requires the release of all agency records upon request. However, the FOIA permits or requires withholding certain limited information that falls under one or more of nine statutory exemptions (5 U.S.C. §§ 552(b)(1-9)).

<u>Exemption 2</u>
Exemption 2 permits withholding of material “related solely to the internal personnel rules and practices of an agency.” BPA relies on Exemption 2 here to protect internal internet portals, telephonic meeting call-in numbers and related passwords and passcodes from public release.

<u>Exemption 4</u>
Exemption 4 protects from disclosure two types of information: (1) trade secrets; and (2) information that is (a) commercial or financial, and (b) obtained from a person, and (c) privileged or confidential. Prior to publicly releasing agency records, BPA is required by Executive Order 12,600 and Department of Energy regulations at 10 C.F.R. § 1004.11 to solicit objections to the public release of any third party’s confidential commercial information contained in the responsive records set. On June 22, 2021, BPA provided CAISO with an opportunity to formally object to the public release of their information contained in BPA records. CAISO provided their objections on July 22, 2021. BPA largely accepted those objections, based on guidance available from the U.S. Department of Justice, and is withholding CAISO’s confidential commercial information from public release.

<u>Exemption 6</u>
Exemption 6 serves to protect Personally Identifiable Information contained in agency records when no overriding public interest in the information exists. BPA does not find an overriding public interest in a release of the information redacted under Exemption 6—specifically, cell phone numbers and personal communications not related to agency business. This information sheds no light on the executive functions of the agency and BPA finds no overriding pubic interest in its release. BPA cannot waive these redactions, as the protections afforded by Exemption 6 belong to individuals and not to the agency.

Certification
Pursuant to 10 C.F.R. § 1004.7(b)(2), I am the individual responsible for the release and exemption determinations described above. Your FOIA request BPA-2020-00739-F is now closed with the responsive agency information provided.

Appeal
The adequacy of the search may be appealed within 90 calendar days from your receipt of this letter pursuant to 10 C.F.R. § 1004.8. Appeals should be addressed to:

Director, Office of Hearings and Appeals
HG-1, L'Enfant Plaza
U.S. Department of Energy 1000
Independence Avenue, S.W.
Washington, D.C. 20585-1615

The written appeal, including the envelope, must clearly indicate that it is a FOIA appeal. You may also submit your appeal by e-mail to OHA.filings@hq.doe.gov, including the phrase "Freedom of Information Appeal" in the subject line. (The Office of Hearings and Appeals prefers to receive appeals by email.) The appeal must contain all the elements required by 10 C.F.R. § 1004.8, including a copy of the determination letter. Thereafter, judicial review will be available to you in the Federal District Court either (1) in the district where you reside, (2) where you have your principal place of business, (3) where DOE's records are situated, or (4) in the District of Columbia.

Additionally, you may contact the Office of Government Information Services (OGIS) at the National Archives and Records Administration to inquire about the FOIA mediation services they offer. The contact information for OGIS is as follows:

Office of Government Information Services
National Archives and Records Administration
8601 Adelphi Road-OGIS
College Park, Maryland 20740-6001
E-mail: ogis@nara.gov
Phone: 202-741-5770
Toll-free: 1-877-684-6448
Fax: 202-741-5769

If you have any questions about this communication, please contact FOIA Public Liaison Jason Taylor at jetaylor@bpa.gov.

Sincerely,

Candice D. Palen, Freedom of Information/Privacy Act Officer
Enclosure: responsive records

From: Bentz,Roger E (BPA) - B-3

Sent: Tue Apr 07 12:23:51 2020

To: Ristanovic, Petar; Khaled,Ali M (CONTR); 'GAngelidis@caiso.com'; Alai, Joanne; Daouk, Jamil; Wan, Yu

Cc: Kochheiser,Todd W (BPA) - TOI-DITT-2; Rick Schaal (rschaal@utilicast.com); Ryan Kroelinger; McManus,Bart (BPA) - TOOC-DITT-2; Kirsch,David J (TFE)(BPA) - TOOC-DITT-2; Ryan Kroelinger; Zach Gill Sanford

Subject: BPA Operations Scenario Documentation

Importance: Normal

Attachments: BPA BAAOP Manual Actions Presentation.pptx; BPA BAAOP Manual Actions (White Paper).docx; BAAOP Scenario 3 - NPR Trip.docx; BAAOP Scenario 4 - RAS Event.docx; BAAOP Scenario 5 - Slice.docx; BAAOP Scenario 1 - NWPP Request.docx; BAAOP Scenario 2 - GCL Trip.docx

Hi all,

Just to make sure that everyone has this full set of documentation fresh at their fingertips, I'm sending you all a complete set of the latest versions of the documents that BPA has assembled to facilitate our discussions.

Looking forward to continuing the discussion in a couple of hours.

Roger Bentz

Bonneville Power Administration

Business Transformation Office: B-3

EIM Technical Implementation Program Manager

Desk: 503-230-4338

Cell: [redacted]

BAAOP Manual Actions Analysis

OVERVIEW

- Purpose
- Operating Reserve Background
- Remedial Action Schemes
- Impacts and Concerns

SCENARIO SETUP

- CAISO Training Recommendations
- Assumed CR allocations and obligations
- Self Suppliers
- BPA CR Obligation

SCENARIOS

- Scenario 1 – NWPP Request
- Scenario 2 – GCL Trip
- Scenario 3 – NPR Trip
- Scenario 4 – RAS Event
- Scenario 5 - Slice

Purpose

- To detail specific operational scenarios for the amount of operator effort in estimated clicks, keystrokes and time it takes to complete a task and the expected manual processes in BAAOP as surmised from CAISO online training, NWPP training, consultants, and other EIM entities.

- The scenarios highlight the need to automate specific operations, data entry and data transfers between existing EMS systems and the Balancing Authority Area Portal (BAAOP) used by the CAISO Energy Imbalance Market (EIM).

Operating Reserve Background

- Hydro resource Overlapping Resource Aggregations (ORA's)
  - Upper Columbia River
  - Lower Columbia River
  - Snake River

- BPA's Contingency Reserve supply of the ORA

- BPA's assumptions of the ORA
  - All response plants are in an ORA
  - More manual dispatches for non ORA plants
  - ORA design change(s) impacts

Operating Reserve Background

- Automatic and manual Contingency Reserve entries in AGC
  - Can happen manually or automatically
  - AGC programmatically monitors plant net generation values
    - 250 MW Deviation w/ corresponding decline in system frequency
    - Automatic reserve entry in AGC / CR deployed

- BPA's participation in the Northwest Power Pool (NWPP)
  - BPA automatically receives dynamic requests for CR
  - BPA automatically requests CR from NWPP
  - NWPP reserve request can happen spontaneously

Operating Reserve Background

- CR from "self-suppliers"
  - Self-suppliers are BA's owning load/generation in BPA's BA
  - BA's receive dynamic signal from BPA during contingency events
  - Self-suppliers have varying real-time obligation

Remedial Action Schemes

- BPA RAS Schemes
  - Dedicated RAS Dispatcher
  - RAS event impacts BPA's RAS, Generation and Transmission dispatch desks

  - RAS vs. NERC BAL-002 (contingency)
    - 15 minute ACE recovery (not required)
    - 30 minute ACE recovery (obligation)

  - NSI change supports correcting BPA's ACE

Impacts and Concerns

- Scenarios conscripted in current state of the system with BPA Dispatchers using AGC without automation

- CAISO contingency training recommendations for operators

(b)(4) [redacted]

Scenario Setup

- Assumed Reserve Obligation in place

Upper Columbia (70%)	Lower Columbia (28%)	Snake (2%)
• GCL – 50% • CHJ – 20%	• JDA – 10% • TDA – 18%	• LMN – 2%

- Self Suppliers
  - BA's supply their required contingency reserves
  - Supply accomplished through an automated dynamic signal
    - Self-supply Obligation 1 – 73 MW
    - Self-supply Obligation 2 – 40 MW

- BPA Contingency Reserve Obligation = 50 MW

BAAOP Scenario 1 – NWPP Request

BAAOP Scenario 1 – NWPP Request

- Supporting Documentation
  - **BAAOP Scenario 1 – NWPP Request.docx**

- Scenario Description
  - The NWPP reserve sharing system requests 325 MW from BPA, then the request later grows to around 500 MW until it is ramped out and cancelled after 30 minutes.

- NWPP Reserve Requests
  - Requests can happen at any time (several times a day)
  - Requests received through BPA EMS as a dynamic signal
  - Requests on a 60 minute timer
  - Request value changes throughout the hour

BAAOP Scenario 1 – NWPP Request

- Scenario Action Details

(b)(4)

[redacted]

BAAOP Scenario 1 – NWPP Request

- Detailed Procedure Description
  - AGC receives NWPP as Dynamic Schedule for 325 MW
  - AGC Dispatch CR plants
  - Load forecast is adjusted to 325 MW

(b)(4)

[redacted]

BAAOP Scenario 1 – NWPP Request

(b)(4)

[redacted]

BAAOP Scenario 1 – NWPP Request

- Manual Dispatch Overlapping Resources (ORAs) based on deployed CR.

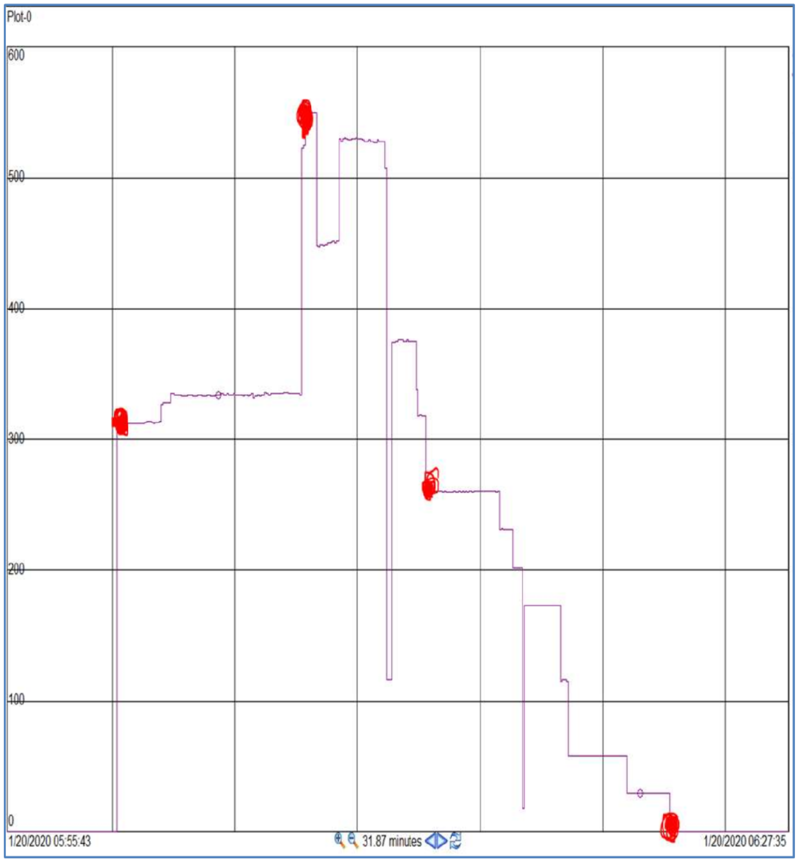
- Manual Dispatch Overlapping Resources (ORA's)

(b)(4)

[redacted]

BAAOP Scenario 1 – NWPP Request

- NWPP requests are dynamic and the value can change throughout the 60 min deployment.



BAAOP Scenario 1 – NWPP Request

- Updating Load Conformance for 100 MW NWPP dynamic changes

(b)(4)

[redacted]

BAAOP Scenario 1 – NWPP Request

- 100 MW manual dispatch reallocation adjustment

(b)(4) [redacted]

- Removing load forecast and manual dispatches
  - Load conformance and manual dispatch time-outs
  - NWPP requests ending prior to 60 minutes

BAAOP Scenario 1 – NWPP Request

- Scenario Issues
  - Timely and accurate manual entries difficulty
    - Significant initial BAAOP entries = entry errors
    - Delay with RDT runs
    - NWPP signal is a moving target
    - Self-suppliers signal is a moving target

BAAOP Scenario 2 – GCL Trip

BAAOP Scenario 2 – GCL Trip

- Scenario Action Details
  - BAAOP Actions Include

(b)(4)

[redacted]

BAAOP Scenario 2 – GCL Trip

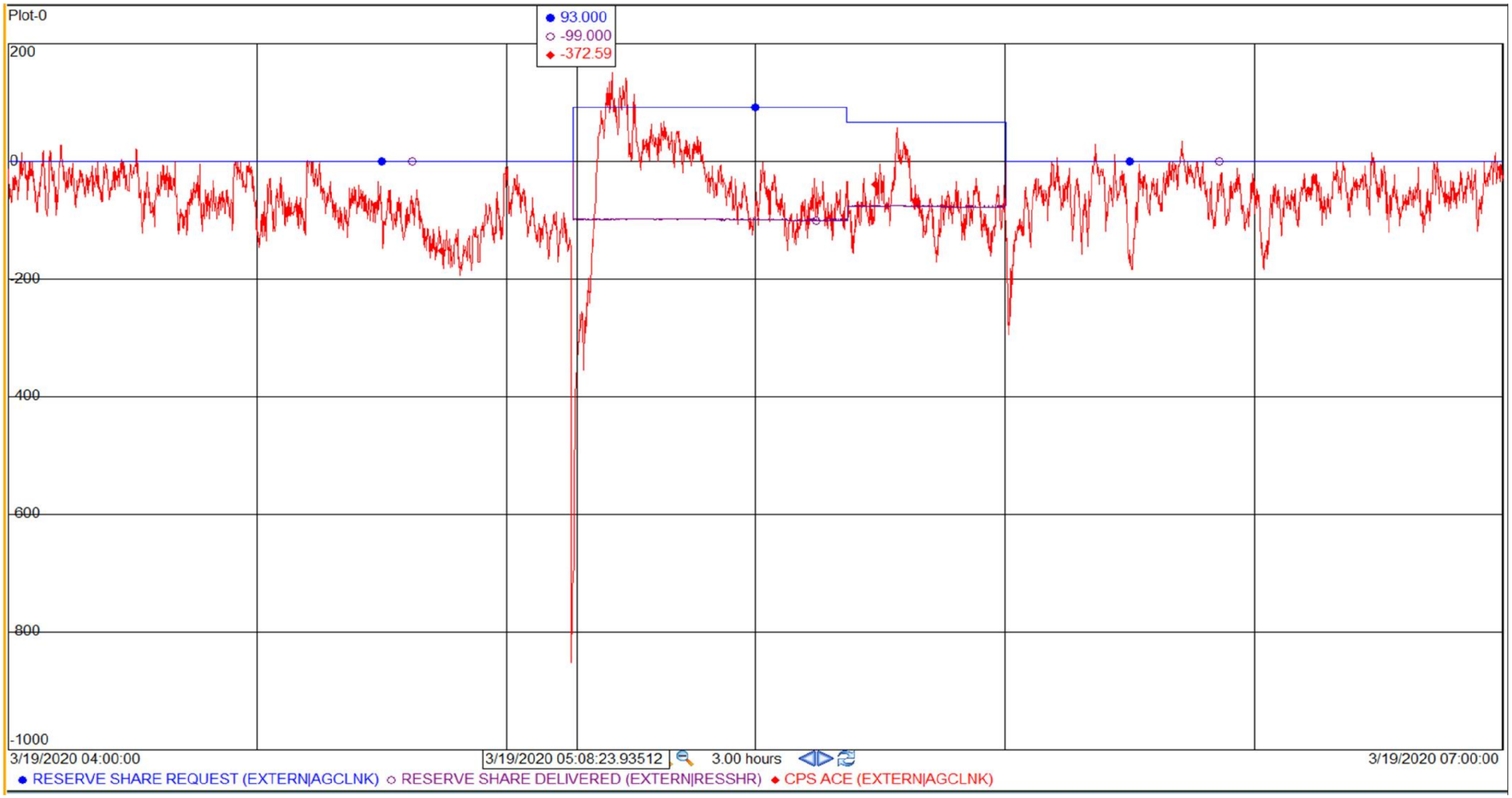
- Supporting Documentation
  - **BAAOP Scenario 2 – GCL Trip.docx**

- Scenario Description
  - Grand Coulee unit trips 560 MW offline losing 623 MW of capacity.

(b)(4)
[redacted]

BAAOP Scenario 2 – GCL Trip

- BPA's ACE



24850063(01).pdf

BAAOP Scenario 2 – GCL Trip

- Procedure Details
  - AGC detects loss and creates automatic reserve entry
  - AGC sends automatic requests to NWPP (60 minute timer)
  - AGC deploys internal CR

(b)(4)

[redacted]

BAAOP Scenario 2 – GCL Trip

- Dispatchers verifies reserve entry and contingency
- 3.5. Load Bias down NWPP dynamic + self-suppliers

(b)(4)

[redacted]

BAAOP Scenario 2 – GCL Trip

- Manually dispatch CR from Overlapping Resource Aggregates

(b)(4)

[redacted]

- Back out Load Bias when CR ends

BAAOP Scenario 2 – GCL Trip

- Scenario Issues
  - Difficulty in keeping up with manual entries
    - Initial BAAOP entries can lead to entry errors
    - Time taken to enter into BAAOP will delay 1-2 RDT runs
    - Dynamic NWPP signal is a moving target for BAAOP entries
    - Dynamic self-suppliers signal is a moving target for BAAOP entries

BAAOP Scenario 3 – NPR Trip

BAAOP Scenario 3 – NPR Request

- Supporting Documentation
  - **BAAOP Scenario 3 – NPR Trip.docx**

- Scenario Description
  - A combined cycle non-participating (NPR) resource loses a gas turbine 150 MW, then within 10 minutes the plant loses another 400 MW from their other gas turbine and steam generator.
    - Plant loss of 400 MW

BAAOP Scenario 3 – NPR Request

- Scenario Action Details
  - BAAOP Actions Include

(b)(4)

[redacted]

BAAOP Scenario 3 – NPR Request

- Manually dispatch CR plants for energy delivered

(b)(4) [redacted]

- Manually dispatch contingent plant to "fixed" at current generation

(b)(4) [redacted]

BAAOP Scenario 3 – NPR Request

- Adjust load forecast down for self-suppliers dynamic schedule
  (b)(4) [redacted]
- Secondary contingency occurs at plant
- AGC automatically requests CR from NWPP once CR deployed is greater than CRO
- Request to self-suppliers (per CRO share)

BAAOP Scenario 3 – NPR Request

- Adjust manual dispatch of CR plants

(b)(4) [redacted]

- Black-out manual entries upon contingency end

BAAOP Scenario 3 – NPR Request

- Scenario Issues:
  - No. of initial BAAOP entries can lead to errors
  - Time taken to 3 enter BAAOP entries will delay entry 1-2 RDT runs

BAAOP Scenario 4 – RAS Event

BAAOP Scenario 4 – RAS Event

- Supporting Documentation
  - **BAAOP Scenario 4 – RAS Event.docx**

- Scenario Description
  - A major transmission line trips to lockout while a parallel line is out of Service, triggering a RAS event. Pre-contingency the COI/NWACI has a limit of 3850 MW Limit N>S . Assume path scheduled up to its limit

(b)(4)

[redacted]

BAAOP Scenario 4 – RAS Event

- Detailed Procedure Description
  - RAS Gen Drop
  - BPA AGC off control
  - AGC suspends signal
  - Chief Jo Brake Inserts
  - Reactive algorithm trips
  - Notify RC West
  - Notify adjacents

Note: Steps 3.8, 3.9, 3.10, and 3.11 must be entered in the same market run.

BAAOP Scenario 4 – RAS Event

- Detailed Procedure Description *(continued)*
  - Block market dispatches
  - Freeze ETSR's EMS to EMS
  - Adjust ETSR limits in BAAOP
  - Adjust Load Forecast down

(b)(4)

[redacted]

BAAOP Scenario 4 – RAS Event

- Detailed Procedure Description *(continued)*

(b)(4) [redacted]

  - Manually dispatch ORA's

(b)(4) [redacted]

BAAOP Scenario 4 – RAS Event

- Test Transmission Line
- Line Tests Good
- Line Tests Bad

- End of process – call out to transmission and power scheduling

BAAOP Scenario 5 – Slice

BAAOP Scenario 5 – Slice

- Supporting Documentation
  - **BAAOP Scenario 5 – Slice.docx**

- Scenario Description
  - Adjusting a customers “slice” changed at T-30 resulting in a net increased obligation on Power Services of 275 MW

(b)(4) [redacted]

BAAOP Scenario 5 – Slice

- Slice Steps (performing slice procedure)

(b)(4)

[redacted]

BAAOP Scenario 5 – Slice

- Tags updates into NSI via RTSI
  - Base ETSR increased
  - TID increased

- Scenario Issues
  - Cumbersome manual entries at top of the hour

End

BAAOP MANUAL ACTIONS ANALYSIS

For effective participation in the Energy Imbalance Market (EIM) – ensuring reliable and effective outcomes

March 27, 2020

Table of Contents

1.0 Overview

1.1 Purpose

This document and supporting artifacts detail four specific operational scenarios and one commercial scenario, and the expected manual processes in BAAOP as surmised from CAISO online training, NWPP training, consultants, and other EIM entities. The amount of operator effort is estimated in clicks, keystrokes as well as minutes and seconds to complete a task.

The scenarios highlight the need to automate specific operations, data entry and data transfers between existing EMS systems and the Balancing Authority Area Portal (BAAOP) used by the CAISO Energy Imbalance Market (EIM).

1.2 Operating Reserve Background

BPA will operate in the EIM using Overlapping Resource Aggregations (ORA's). These three aggregations are made up of hydro resources in the Upper Columbia, Lower Columbia, and Snake River. BPA often holds Operating Reserves, including Contingency Reserves (CR), on hydro resources in all three of these ORA's. BPA plans to supply the CR from the Non –Participating-Resource (NPR) ABC (Ancillary Services, Balancing Reserve, Contingency Reserve) portion of the ORA.

In these scenarios BPA is assuming that all response plants are in an ORA. If any response plants end up not being part of an ORA, there would be more manual dispatches than stated in these scenarios. For example, it could be that the lower Columbia or the Snakes are only partial ORAs with a few plants stand-alone that may also need to be manually dispatched (5-10 depending). If the design of the ORA's changes then there could be more manual dispatches required than what is described in these scenarios.

Contingency reserve entries can happen automatically or manually in AGC. BPA AGC programmatically monitors plant net generation values and looks for a 250 MW deviation with a corresponding decline in system frequency. When this occurs an automatic reserve entry will be put in AGC and CR will be deployed.

Aside from BPA supplying its own CR, BPA also participates in the NWPP. As a member of the NWPP BPA automatically receives dynamic requests for CR from the NWPP Pro Rata Reserve Sharing (PRRS) system. BPA also automatically requests CR from the NWPP for internal Contingencies that exceed BPA's Contingency Reserve Obligation (CRO) (which is approximately 500 MW on average). NWPP reserve requests can happen at any time, often multiple times a day. A reserve sharing system request occurs when another NWPP BA has a contingency and calls upon pool reserves.

Another source of CR is from “self-suppliers.” Self-suppliers are Balancing Authorities (BA’s) that own generation or load in BPA’s BA. Instead of paying for the BPA to supply their reserve share, these BA’s receive a dynamic signal from BPA during Contingency events for the amount of CR they must provide. The self-suppliers have a varying real-time obligation that can vary from zero to approximately 100 MW combined.

1.3 Remedial Action Schemes

BPA has numerous RAS schemes across its transmission system that are used to protect lines and equipment and in turn increase transfer limits. BPA has a RAS dispatcher in addition to a generation, and transmission dispatcher. When a RAS event occurs there often actions that need to be taken by all three desks. RAS is not considered a NERC BAL-002 contingency, BPA is not required to recover its Area Control Error (ACE) within 15 minutes. However, BPA must recover ACE within 30 minutes to meet the BAAL requirement of NERC BAL-001. For RAS that require transmission schedules to be cut, the change in NSI will help correct BPA’s ACE.

1.4 Impacts and Concerns

BPA’s primary concerns are the timely and accurate entry of data into BAAOP to sync the market information with our grid reliability activities. (b)(4) [redacted] (b)(4) [redacted] (b)(4) [redacted] The timing of the event according to the market run is critical and BPA also has been advised that it will be necessary to make entries into various BAAOP screens before finalizing them all in one market run. With this in mind, the amount of manual effort required to manually dispatch three Overlapping Resource Aggregates, Load Bias, etc. is labor intensive and would be difficult to make in time to all be included in the next market run. The speed and volume at which these entries need to be made also carries a risk of operator error. Specific concerns are listed for each scenario.

2.0 Scenario Setup

The following scenarios were imagined as if a BPA dispatcher had to use AGC as it exists today and BAAOP as it exists today, without new automation.

CAISO training recommends that during a contingency, BA operators:

(b)(4) [redacted]

(b)(4) [redacted]

For the following scenarios assume these CR allocations and Contingency Reserve Obligations are in place:

Upper Columbia (70%)
GCL - 50%
CHJ - 20%:

Lower Columbia (28%)
JDA – 10%
TDA – 18%

Snake River (2%)
LMN – 2%

Self-Suppliers
These BA's supply their required contingency reserves due to gen/load in BPA's BA. Supply is accomplished through an automated dynamic signal:

Self-Supply Obligation 1 – 73 MW
Self-Supply Obligation 2 – 40 MW

BPA Contingency Reserve Obligation = 500 MW

3.0 BAAOP Scenario 1 – NWPP Request

3.1 Scenario Description

In this scenario, the NWPP reserve sharing system requests 325 MW from BPA, and then the request later grows to around 500 MW until it is ramped out and cancelled after 30 minutes.

BPA is a member of the NWPP. When any NWPP Balancing Authority (BA) has a contingency they can request CR from other pool members. NWPP reserve requests can happen at any time, often multiple times a day. These requests come into the BPA EMS as a dynamic signal from the NWPP reserve sharing computer. The requests are on a 60 minute timer but can be cancelled at any time by the requesting BA. The signal is dynamic and can be as large as BPA's Contingency Reserve Obligation (CRO), which is generally over 500 MW for BPA. The request often changes value throughout the hour based on the requesting BA's system need. They are not required to be a flat MW request.

3.2 Scenario Action Details

BAAOP actions include: Load Conformance, Manual Dispatch: Fixed for three ORA's, and more. NWPP dynamics can vary during the 60 minute deployment from zero to BPA's CRO (500 MW).

(b)(4)

[redacted]

3.3 Scenario Issues

- BPA sees difficulty in making timely and accurate manual entries
    - The initial numbers of BAAOP entries can lead to entry errors
    - The time it takes to enter into BAAOP will delay entry 1-2 RDT runs
    - The NWPP signal is dynamic and a moving target for BAAOP entries
    - The self-suppliers signal is dynamic and a moving target for BAAOP entries

3.4 Supporting Documentation

For detailed description of the steps taken, please see supporting document: **BAAOP Scenario 1 - NWPP Request.docx**

4.0 BAAOP Scenario 2 – Grand Coulee Trip

4.1 Scenario Description

In this scenario, Grand Coulee unit trips 560 MW offline losing 623 MW of capacity. BPA AGC will automatically detect an event like this and make a Contingency Reserve (CR) entry in AGC and make a MW estimate based on plant telemetry. Any CR entry greater than BPA's Contingency Reserve Obligation (CRO) will prompt an automatic request to the NWPP. The return signal from the NWPP is used as a dynamic signal for reserves in BPA's NSI term of ACE. Any CR entry also prompts an automatic signal to the self-suppliers of CR.

4.2 Scenario Action Details

BAAOP actions include: Load Conformance, Manual Dispatch: Fixed for three ORA's, Manual Dispatch: Max for the Upper Columbia ORA.

(b)(4) [redacted]

4.3 Scenario Issues

BPA sees difficulty in keeping up with the manual entries:

- The initial numbers of BAAOP entries can lead to entry errors
- The time it takes to enter into BAAOP will delay entry 1-2 RDT runs
- The NWPP signal is dynamic and a moving target for BAAOP entries
- The self-suppliers signal is dynamic and a moving target for BAAOP entries

4.4 Supporting Documentation

For detailed description of the steps taken, please see supporting document: **BAAOP Scenario 2 - GCL Trip.docx**

5.0 BAAOP Scenario 3 – Non Participating Resource Trip

5.1 Scenario Description

In this scenario, a combined cycle non-participating (NPR) resource loses a gas turbine 150 MW, then within 10 minutes the plant loses another 400 MW from their other gas turbine and steam generator. It is assumed that this plant is modeled as one NPR and not multiple for each stage of generator. BPA AGC automatically detects plant losses over 250 MW. In this case the reserves are called on by the operator of the NPR and the contingency is manually entered into BPA AGC. Once the contingency is entered, BPA's AGC tracks the Station Control Error (SCE) for plant and dynamically adjusts the Contingency Reserves (CR) deployed to equal the plant SCE. BPA AGC also automatically sends a dynamic signal to the self-suppliers and dispatches plants on CR response. Once the CR deployed crosses the Contingency Reserve Obligation, then AGC automatically requests CR from the NWPP via a dynamic signal.

5.2 Scenario Action Details

BAAOP actions include: Load Conformance, Manual Dispatch: Fixed for three ORA's, Manual Dispatch: Fixed for the NPR, removing generator from market participation:

(b)(4)

[redacted]

5.3 Scenario Issues

BPA sees difficulty in keeping up with the manual entries:

- The initial numbers of BAAOP entries can lead to entry errors
- The time it takes to enter into BAAOP will delay entry 1-2 RDT runs

5.4 Supporting Documentation

For detailed description of the steps taken, please see supporting document: **BAAOP Scenario 3 - NPR Trip.docx**

6.0 BAAOP Scenario 4 - RAS

6.1 Scenario Description

In this scenario, a major transmission line trips to lockout while a parallel line is out of Service, triggering a RAS event. Pre-contingency the COI/NWACI has a limit of 3850 MW North to South. The COI is assumed to be scheduled up to its limit. During this RAS the tripped line will be tested, if it tests good it can be put and service and generation restored. If the line tests bad, then schedules on the COI will need to be cut.

6.2 Scenario Action Details

BAAOP actions include: Load Conformance, Manual Dispatch:

(b)(4) [redacted]

6.3 Scenario Issues

- EIM Dispatcher will have to manually block market instructions for 1-2 RDT runs until BAAOP entries can be made
- If the existing ETSR dynamic limiting interface with BAAOP cannot be used to automatically limit all ETSRs post RAS then manually limiting ETSRs will add another 2 minutes of manual entry.
- BPA sees difficulty in keeping up with the manual entries
    - The initial numbers of BAAOP entries can lead to entry errors
    - The time it takes to enter into BAAOP will delay entry 1-2 RDT runs
    - RAS is an inherently complicated scenario that could lead to errors in manual entry

6.4 Supporting Documentation

For detailed description of the steps taken, please see supporting document: **BAAOP Scenario 4 RAS Event.docx**

7.0 BAAOP Scenario 5 – Slice Adjustment

7.1 Scenario Description

BPA has contracts with several entities for a “slice” of the Federal Columbia River Power System (FCRPS). Slice customers can schedule power output up to their contract amount. This power schedule can be changed up to T-30 min prior to the beginning of each hour. Since T-30 is after the T-40 EIM pre-hour deadline, a manual dispatch is required for this change in Slice. In this scenario, Slice is changed at T-30 resulting in a net increased obligation on Power Services of 275 MW.

7.2 Scenario Action Details

BAAOP actions include: Manual Dispatch:

(b)(4) [redacted]

7.3 Scenario Issues

- Cumbersome manual entries at the top of the hour

7.4 Supporting Documentation

For detailed description of the steps taken, please see supporting document: **BAAOP Scenario 4 RAS Event.docx**

BPA Transmission Services
Technical Operations

BAAOP Automation Scenario 3

Multiple Contingencies on a Combined Cycle Plant (Non-Participating Resource) Procedure

VERSION: 1.0
UPDATED: 27MAR2020

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For more information on Standards of Conduct please use the following resources.
BPA SOC Help Line: 503-230-4677
BPA SOC Web Page: [redacted] (b)(2)
SOC e-mail box: SOC@BPA.gov

Table of Contents

1. Purpose

This procedure details discrete steps in BPA systems and also BAAOP that BPA staff assume will be needed when operating in the EIM.The number of mouse clicks and keystrokes were counted and used to estimate the time required to complete the action in BAAOP.

(b)(4) [redacted]

2. Scenario Overview

In this scenario, a combined cycle non-participating (NPR) resource loses a gas turbine 150 MW, then within 10 minutes the plant loses another 400 MW from their other gas turbine and steam generator. It is assumed that this plant is modeled as one NPR and not multiple for each stage of generator. BPA AGC automatically detects plant losses over 250 MW. In this case the reserves are called on by the operator of the NPR and the contingency is manually entered into BPA AGC. Once the contingency is entered, BPA's AGC tracks the Station Control Error (SCE) for plant and dynamically adjusts the Contingency Reserves (CR) deployed to equal the plant SCE. BPA AGC also automatically sends a dynamic signal to the self-suppliers and dispatches plants on CR response. Once the CR deployed crosses the Contingency Reserve Obligation, then AGC automatically requests CR from the NWPP via a dynamic signal.

3. Detailed Procedure Description

The following steps are used to perform the Multiple Contingencies on a Combined Cycle Plant (NPR) procedure.

3.1. Contingency occurs and plant calls BPA for 150 MW of Contingency Reserves. Operator takes down information [Manual]

3.2. BPA dispatcher enters Contingency into AGC. [Manual][AGC]

3.3. CR deployed from three overlapping resources, and self suppliers. [automatic][AGC]

3.4. Manually dispatch CR plants for energy delivered [Manual][BAAOP]

3.4.1. Manually Dispatch Upper Columbia ABC ORA

(b)(4) [redacted]

(b)(4)

[redacted]

3.4.2. Manually Dispatch Lower Columbia ABC ORA

(b)(4)

[redacted]

3.4.3. Manually Dispatch Lower Columbia ABC ORA

(b)(4)

[redacted]

3.5. Manually dispatch contingent plant to “fixed” at current generation (If unit unavailable for more than 30 minutes submit an outage card) [manual][BAAOP]

(b)(4) [redacted]

3.6. Adjust Load Forecast down for self-suppliers dynamic signal [manual][BAAOP]

(b)(4) [redacted]

3.7. Second contingency occurs at plant, SCE increases from 150 MW to 550 MW on NPR. Plant SCE grows to 550 MW and increases CR deployed [automatic][AGC]

3.8. Once CR deployed is greater than CRO, then AGC automatically requests CR from the NWPP [automatic][AGC]

3.9. Request to self-suppliers will per their share of CRO [automatic][AGC]

3.10. Adjust Manual Dispatch of CR plants [manual][BAAOP]

3.10.1. Adjust Manual Dispatch for Upper Columbia ABC ORA

(b)(4) [redacted]

3.10.2. Manual Dispatch for Lower Columbia ABC ORA

(b)(4) [redacted]

3.10.3. Manual Dispatch for Snakes ABC ORA

(b)(4) [redacted]

3.11. Adjust load bias for NWPP request and change in self-supplier dynamic [manual][BAAOP]

(b)(4) [redacted]

(b)(4) [redacted]

(b)(4) [redacted]

3.12. Flag entire resource as in a contingency due to output being zero. (b)(4) [redacted] (b)(4) [redacted]

3.13. Back-out all manual entries when contingency ends

4. Key Contacts (for questions about the procedure)

Role	Contact Name/BPA Organization
	Rian Sackett, TOOC
	Brent Kingsford
	Bart McManus
	Todd Kocheiser

5. Change Log Table

Document Name: ***Multiple Contingencies on a Combined Cycle Plant (NPR)***
Location: (b)(2) [redacted]
Combined [redacted]

Revision	Date Revised	Revised by	Description of Changes
.01	3/25/20	B. Jackson	Created draft of Scenario 3, 3.8 BAAOP Automation Analysis for CAISO
.02	3/26/20	B. Jackson	Saved edits version; accepted edits in this version; minor formatting adjusted; confirmed number of clicks/keystrokes
.03	3/27/20	C. Higgins	Finalized Version

6. Appendix A Supporting Documentation

Include documentation (names and path) to any documentation that will aid the person performing this procedure.

Document name	Document location or link
BAAOP 3.8,3.8 (OneNote)	(b)(2) [redacted]

BPA Transmission Services
Technical Operations

BAAOP Automation Scenario 4

RAS Event

VERSION: 1.0
UPDATED: 27MAR2020

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For more information on Standards of Conduct please use the following resources.
BPA SOC Help Line: 503-230-4677
BPA SOC Web Page: (b)(2) [redacted]
SOC e-mail box: SOC@BPA.gov

Table of Contents

1. Purpose

This NWPP Request for Contingency Reserve (CR) procedure details discrete steps in BPA systems and also BAAOP that BPA staff assume will be needed when operating in the EIM. The number of mouse clicks and keystrokes were counted and used to estimate the time required to complete the action in BAAOP.

(b)(4) [redacted]

2. Scenario Overview

In this scenario, a major transmission line trips to lockout while a parallel line is out of Service, triggering a RAS event. Pre-contingency the COI/NWACI has a limit of 3850 MW North to South. The COI is assumed to be scheduled up to its limit. During this RAS the tripped line will be tested, if it tests good it can be put and service and generation restored. If the line tests bad, then schedules on the COI will need to be cut.

3. Detailed Procedure Description

The following steps are used to perform the RAS event procedure and actions both automatic and manual:

Actions:

3.1. RAS Gen Drop

RAS Gen drop trip 1700 MW of Generation (1500 MW in BPA [Automatic][RAS]

- 750 MW BPA Hydro Plant 1
- 550 BPA Hydro Plant 2
- 100 MW BPA Hydro Plant 3
- 50 MW BPA Wind Plant
- 100 MW Joint Owned Unit (BA 1, BA 2, BA 3)
- 100 MW BA 1 Wind Plant
- 50 MW BA 2 Wind Plant

3.2. BPA AGC off control

- BPA will note be controlling to previous DOTS in the mark [Automatic][AGC]

3.3. AGC suspend signal to BA 1, BA 2, BA 3

- BPA does not know what other BA's enter into BAAOP for this event

3.4. Chief Jo brake inserts

- Load increase of 1400 MW for 30 cycles [Automatic][RAS]

3.5. Reactive algorithm trips [Automatic][RAS]

3.6. Notify RC West [Manual][RAS Dispatcher]

3.7. Notify adjacent BA 1, BA 2, and BA 3 of RAS action [Manual][RAS Dispatcher]

Note: Steps 3.8, 3.9, 3.10, and 3.11 must be entered in the same market run. The dispatcher will have to manage the timing by either waiting till the current RTD run ends or entering all in the current run. Dispatcher could manually enter all data in BAAOP and then finalize the entry in BAAOP once all data is entered and the timing is correct.

3.8. Block all market dispatches until manual entries can be made in BAAOP

3.9. Freeze all ETSR's EMS to EMS. BPA assumes that it will install the ability to limit ETSR's when the dynamics are established with other BA's. ETSR's will be frozen for up to thirty minutes

3.10. Adjust ETSR limits in BAAOP using the ETSR Dynamic Limit Interface. BPA will use the Dynamic Limit Interface to inform the market via BAAOP of the dynamic limitation

3.11. Adjust Load Forecast down the amount of BPA Gen that was dropped [manual][BAAOP]

(b)(4)

[redacted]

(b)(4) [redacted]

3.12. Manually Dispatch ORA's to "fixed" post RAS generation value.

- There were 2 ORA's affected by this RAS [manual][BAAOP]

3.12.1. Manually Dispatch Upper Columbia ABC ORA [manual][BAAOP]

(b)(4) [redacted]

3.12.2. Manual Dispatch for Lower Columbia ABC ORA

(b)(4) [redacted]

[redacted]

3.12.3. Mark wind plant resource as unavailable [manual][BAAOP] [redacted]

3.13. Test transmission line (up to 10 minutes) – Line test good or bad [manual]

Line Tests Good

3.14. Transmission limit on path stays the same

3.15. Calls to BA 1, BA 2, BA 3 to return gen to normal and put their AGC on control

3.16. Remove the adjustment on the load forecast [manual BAAOP]

3.17. Manually dispatch RAS'd plants back to their base schedule to recover the ACE [manual BAAOP]

3.18. BAP AGC on control, RAS event cleared in EMS

3.19. Calls to individual powerhouses and wind farm (BPA) to return units to service and ramp to basepoints

3.20. After ACE recovers from RAS event, then remove manual dispatches on RAS'd plants

Line Tests Bad

3.21. Limit set on path by Path Operator to 600 MW, corresponding tags are cut affecting BPA and BA 1, BA 2, and BA 3

3.22. Manually dispatch RAS'd plants back to their base schedule based on new intertie limit, lower than previous schedule

3.23. BA 1, BA 2, and BA 3 return to control

3.24. BPA AGC on control

3.25. Individual powerhouses and wind farm called to return basepoint (new)

At the end of this process, there is a phone call to transmission and power scheduling to inform them of the Contingency Reserve Delivery

4. Key Contacts (for questions about the procedure)

Role	Contact Name/BPA Organization
Electrical Engineer	Rian Sackett, TOOC
BPA Real-Time Dispatch Senior	Brent Kingsford
Electrical Engineer	Bart McManus
Electrical Engineer	Todd Kocheiser

5. Change Log Table

Document Name: ***NWPP Request for CR***
Location: (b)(2) [redacted]
(b)(2)

Revision	Date Revised	Revised by	Description of Changes
.01	3/25/20	C. Higgins	Created draft of Scenario 4, 3.8 BAAOP Automation Analysis for CAISO
.02	3/26/20	C. Higgins	Finalized Version
.03	4/2/20	B. Jackson	Double checked clicks/strokes against WP and slide deck.

BPA Transmission Services
Technical Operations

BAAOP Automation Scenario 5

Slice Increase Procedure

VERSION: 1.0
UPDATED: 27MAR2020

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For more information on Standards of Conduct please use the following resources.
BPA SOC Help Line: 503-230-4677
BPA SOC Web Page: [redacted] (b)(2)
SOC e-mail box: SOC@BPA.gov

Table of Contents

1. Purpose

This Slice procedure details discrete steps in BPA systems and also BAAOP that BPA staff assume will be needed when operating in the EIM.The number of mouse clicks and keystrokes were counted and used to estimate the time required to complete the action in BAAOP.

(b)(4) [redacted]

2. Scenario Overview

BPA has contracts with several entities for a "slice" of the Federal Columbia River Power System (FCRPS). Slice customers can schedule power output up to their contract amount. This power schedule can be changed up to T-30 min prior to the beginning of each hour. Since T-30 is after the T-40 EIM pre-hour deadline, a manual dispatch is required for this change in Slice. In this scenario, Slice is changed at T-30 resulting in a net increased obligation on Power Services of 275 MW.

- Of the 275 MW, 75 MW is sinking internal to the BAA and 200 MW is sinking external to the BAA,
- Two existing e-Tags are updated
  - One sinks to an LSE internal to the BPA BAA (75 MW)
  - One sinks to an LSE in a non-EIM BAA (50 MW)
- One new e-Tag is created that sinks external to the BAA that is an EIM Entity (150 MW)

3. Detailed Procedure Description

The following steps are used to perform the *Slice* precedure. **(**Each step should identify if there is a role change as outlined in the process map and describe what triggers this role change (approval, rejection, etc.) and whether this terminates or pauses this procedure.)

3.1. Manually Dispatch Overlapping Resources (ORAs). [Manual] [BAAOP]

As an hourly contractual obligation, these changes would need to be made from the 4 RTPD and 12 RTD intervals during the hour.

(b)(4) [redacted]

Manual Dispatch for Upper Columbia ABC ORA

(b)(4) [redacted]

a. Select EIM Tab (1 click)

(b)(4)

[redacted]

3.1.1. Manual Dispatch for Lower Columbia ABC ORA

(b)(4)

[redacted]

3.1.2. Manual Dispatch for Snakes ABC ORA

(b)(4)

[redacted]

[redacted]

3.2. The new and updated tags would automatically be incorporated into our NSI via the RTSI interface

- A Base ETSR will be increased by 150 MW for the transfer to the EIM entity
- A TID will be increased by 50 MW (note: would have been a Ghost if the e-Tag was new)

4. Key Contacts (for questions about the procedure)

Role	Contact Name/BPA Organization
	Todd Kocheiser
	Rian Sackett/TOOC
	Bart McManus/TOOC

5. Change Log Table

Document Name: ***NWPP Request for CR***
Location: [redacted]
(20200323)

Revision	Date Revised	Revised by	Description of Changes
.01	3/27/20	R. Sackett	Created draft of Scenario 5
.02	3/27/20	C. Higgins	Finalized Version

6. Appendix A Supporting Documentation

Include documentation (names and path) to any documentation that will aid the person performing this procedure.

Document name	Document location or link
BAAOP 3.8,3.8 (OneNote)	(b)(2) [redacted]

BPA Transmission Services
Technical Operations

BAAOP Automation Scenario 1

NWPP Request for Contingency Reserve Procedure

VERSION: 1.0
UPDATED: 27MAR2020

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For more information on Standards of Conduct please use the following resources.
BPA SOC Help Line: 503-230-4677
BPA SOC Web Page: (b)(2) [redacted]
SOC e-mail box: SOC@BPA.gov

Table of Contents

1. Purpose

This NWPP Request for Contingency Reserve (CR) procedure details discrete steps in BPA systems and also BAAOP that BPA staff assume will be needed when operating in the EIM.The number of mouse clicks and keystrokes were counted and used to estimate the time required to complete the action in BAAOP.

(b)(4) [redacted]

2. Scenario Overview

BPA is a member of the NWPP. When any NWPP Balancing Authority (BA) has a contingency they can request CR from other pool members. NWPP reserve requests can happen at any time, often multiple times a day. These requests come into the BPA EMS as a dynamic signal from the NWPP reserve sharing computer. The requests are on a 60 minute timer but can be cancelled at any time by the requesting BA. The signal is dynamic and can be as large as BPA's Contingency Reserve Obligation (CRO), which is generally over 500 MW for BPA. The request often changes value throughout the hour based on the requesting BA's system need. They are not required to be a flat MW request.

In this scenario, the NWPP reserve sharing system requests 325 MW from BPA, and then later grows to around 500 MW until it is ramped out and cancelled after 30 minutes.

3. Detailed Procedure Description

The following steps are used to perform the NWPP Request for CR procedure.

3.1. NWPP comes into AGC as Dynamic Schedule for 325 MW [Automatic] [AGC]

- NWPP Request is on a 60 minute timer [Automatic] [NWPP System]
- AGC alarms there is a new NWPP request [Automatic] [BPA AGC System]

3.2. AGC dispatches CR plants according to CR allocation % and Self Suppliers [Automatic] [BPA AGC]

- CR will deployed by all plants on CR response
- Self-suppliers will be sent a dynamic signal (72 MW) based on percent allocation of BPA CRO
- BPA will have an instantaneous -253 (325 less self-supply dynamic) ACE
- ACE lower limit will be set to zero

- CR deployment will correct ACE

The graph below shows the dynamic signals sent to the self-suppliers which is also used in BPA's NSI term in ACE:

(b)(4) [redacted]

3.3. Adjust the load forecast up 325 MW less the self-suppliers to show market you have an increase in demand. Ego Desk will have to identify proper timing for operator to enter all information into BAAOP in one market interval [Manual] [BAAOP]

(b)(4) [redacted]

(b)(4) [redacted]

3.4. Manual Dispatch Overlapping Resources (ORAs) based on deployed CR. Dispatch would have to do math to determine how much CR is coming from specific plant aggregate (e.g. sum GCL, CHJ, separate from JDA). Used “fixed” manual dispatch for the amount of MW the ORA is providing as CR [Manual] [BAAOP]

3.4.1. Manual Dispatch for Upper Columbia ABC ORA

(b)(4) [redacted]

3.4.2. Manual Dispatch for Lower Columbia ABC ORA

(b)(4) [redacted]

(b)(4) [redacted]

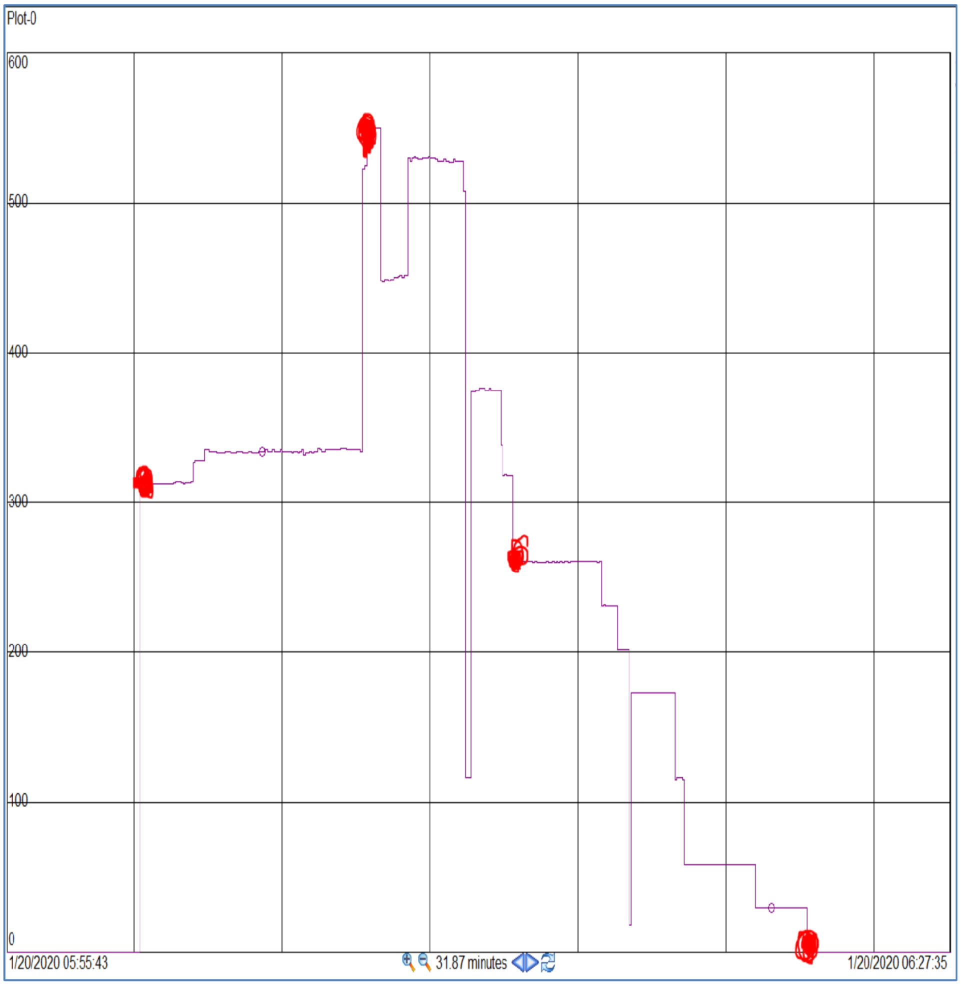
3.4.3. Manual Dispatch for Snakes ABC ORA

(b)(4) [redacted]

3.5. NWPP requests are dynamic and the value can change throughout the 60 min deployment. If the value changes then the Load Forecast, and all of the manual dispatches would need to be updated. [Manual] [BAAOP]

The graph below shows the NWPP dynamic signal requests. It starts at 325 MW increases to 525 MW and then is ramped to zero. The red dots on the graph indicate a manual entry in BAAOP.

At the end of this process, there is a phone call to transmission and power scheduling to inform them at the Contingency Reserve Delivery.



3.6. If NWPP Dynamic Changes by more than 100 MW the Load Conformance and Manual Dispatchers will need to be updated.

Adjust Load Forecast by 100 MW

(b)(4)

[redacted]

(b)(4)
[redacted]

3.7. Adjust Manual Dispatch by the reallocated 100 MW

3.7.1. Adjust Manual Dispatch for Upper Columbia ABC ORA

(b)(4)
[redacted]

3.7.2. Manual Dispatch for Lower Columbia ABC ORA

Clicks: 6
Keystrokes: 4

(b)(4)
[redacted]

3.7.3. Manual Dispatch for Snakes ABC ORA

(b)(4)
[redacted]

(b)(4) [redacted]

3.8. If the NWPP request ends prior to 60 minutes the load forecast and manual dispatch entries will need to be removed. [Manual] [BAAOP]

BPA understands that the load conformance and manual dispatch entries will time out and be removed from BAAOP automatically. If the NWPP request ends earlier than 60 minutes Load conformance and manual dispatchers will have to be manually removed from BAAOP.

4. Key Contacts (for questions about the procedure)

Role	Contact Name/BPA Organization
	Rian Sackett, TOOC
	Brent Kingsford
	Bart McManus
	Todd Kocheiser

5. Change Log Table

Document Name: ***NWPP Request for Contingency Reserve***
Location: (b)(2) [redacted]
- NWPP R[redacted]

Revision	Date Revised	Revised by	Description of Changes
.01	3/24/20	B. Jackson	Created draft of Scenario 1, 3.8 BAAOP Automation Analysis for CAISO
.02	3/24/20	B. Jackson	Accepted Rian's edits from 3/24/20 and saved that file for reference
.03	3/25/20	B. Jackson	Recounted clicks and keystrokes for accuracy – some still missing; also adjusted formatting for consistency
.04	3/27/20	B. Jackson	Finalized version

6. Appendix A Supporting Documentation

Include documentation (names and path) to any documentation that will aid the person performing this procedure.

Document name	[redacted]
BAAOP 3.8,3.8 (OneNote)	(b)(2) [redacted]

BPA Transmission Services
Technical Operations

BAAOP Automation Scenario 2

Grand Coulee Trip 600 MW Procedure

VERSION: 1.0
UPDATED: 27MAR2020

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BPA SOC Help Line: 503-230-4677
BPA SOC Web Page: [redacted] (b)(2)
SOC e-mail box: SOC@BPA.gov

Table of Contents

1. Purpose

This Grand Coulee(GCL) Trip 600 MW procedure details discrete steps in BPA systems and also BAAOP that BPA staff assume will be needed when operating in the EIM.The number of mouse clicks and keystrokes were counted and used to estimate the time required to complete the action in BAAOP.

(b)(4) [redacted]

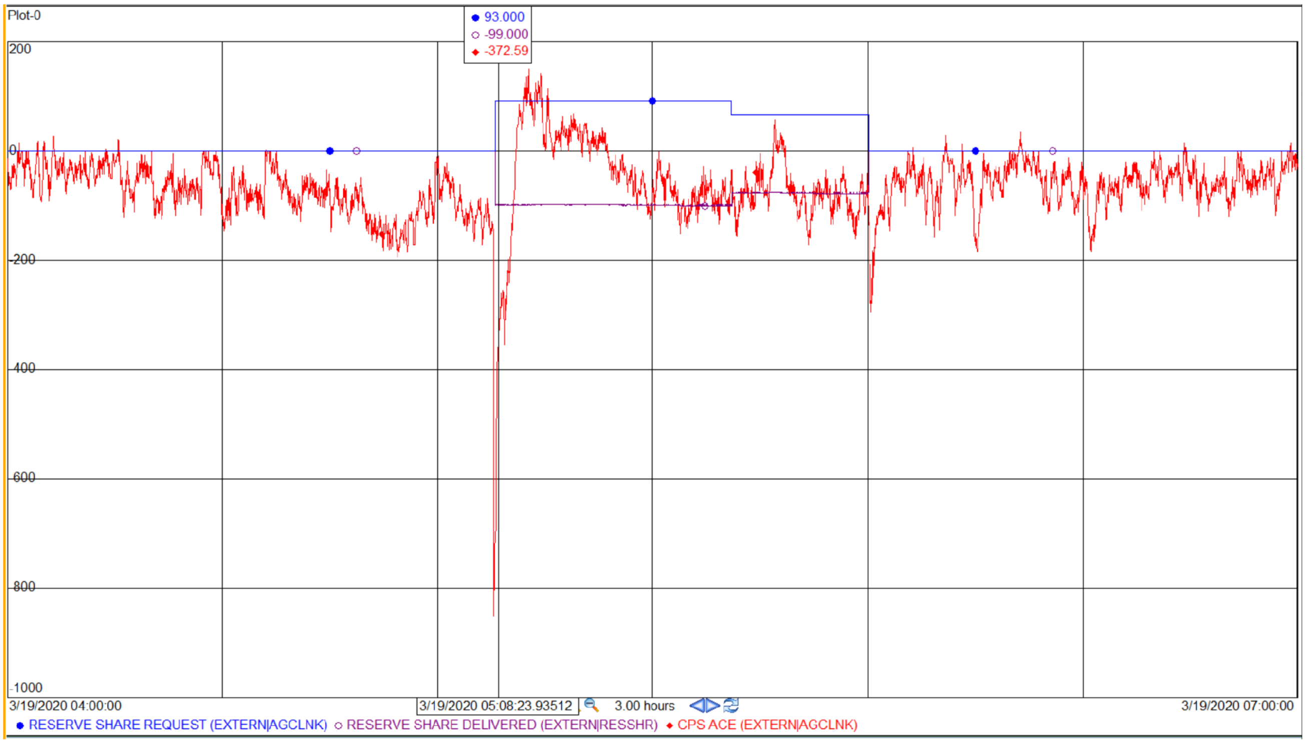
2. Scenario Overview

In this scenario, Grand Coulee unit trips 560 MW offline losing 623 MW of capacity. BPA AGC will automatically detect an event like this and make a Contingency Reserve (CR) entry in AGC and make a MW estimate based on plant telemetry. Any CR entry greater than BPA's Contingency Reserve Obligation (CRO) will prompt an automatic request to the NWPP. The return signal from the NWPP is used as a dynamic signal for reserves in BPA's NSI term of ACE. Any CR entry also prompts an automatic signal to the self-suppliers of CR.

The graph below shows GCL total generation (green) and GCL capacity (blue):

(b)(4) [redacted]

The graph below shows BPA's ACE (red), Request to the NWPP (blue), return signal from the NWPP (purple):



3. Detailed Procedure Description

The following steps are used to perform the GCL Trip 560 MW procedure. **(**Each step should identify if there is a role change as outlined in the process map and describe what triggers this role change (approval, rejection, etc.) and whether this terminates or pauses this procedure.)

3.1. AGC detects loss and creates an automatic reserve entry 560 MW for GCL [automatic] [AGC]

3.2. Automatic Request to the NWPP (this is a 60 minute timer on request) [automatic] [AGC]

3.3. BPA deploys internal CR [automatic] [AGC]

- CR plants automatically controlled based on CR % response
  - Upper Colombia ORA
  - Snakes ORA
  - Lower Columbia ORA
- Self Suppliers dynamic signal:

(b)(4)
[redacted]

3.4. Dispatcher verifies reserve entry and Contingency. If needed dispatch manually updates reserve entry in AGC. [Manual][AGC]

- AGC starts contingency timer assume 60 minutes (AGC needs to change to always use a 60 minute timer)
- If WECC BAL 002 goes away change NWPP rules to 105 minutes and update AGC to 105 min

3.5. Load Bias down NWPP dynamic + self-suppliers [Manual][BAAOP]

Adjust Load Forecast

(b)(4)
[redacted]

(b)(4) [redacted]

3.6. Manually dispatch CR from Overlapping Resource Aggregates (ORAs). [Manual][BAAOP]

3.6.1. Manual Dispatch for Upper Columbia ABC ORA

(b)(4) [redacted]

3.6.2. Manual Dispatch for Lower Columbia ABC ORA

(b)(4) [redacted]

(b)(4) [redacted]

3.6.3. Manual Dispatch for Snakes ABC ORA

(b)(4) [redacted]

3.7. Manually dispatch “Pmax” Upper-Columbia ANPR BASE ORA down by amount of capacity lost, 623 MW [Manual][BAAOP]

(b)(4) [redacted]

[redacted]

Note: Put in an outage card if Contingency will last longer than 30 minutes. [Manual][OMS]
NEED STEPS

3.8. When CR ends manually back-out Load Bias, Manual Energy Dispatch, and Manual "Pmax" Dispatch if applicable. [Manual][BAAOP]

4. Key Contacts (for questions about the procedure)

Role	Contact Name/BPA Organization
	Rian Sackett, TOOC
	Brent Kingsford
	Bart McManus
	Todd Kocheiser

5. Change Log Table

Document Name: ***Grand Coulee Trip 600 MW***
Location: [redacted]

Revision	Date Revised	Revised by	Description of Changes
.01	3/24/20	B. Jackson	Created draft of Scenario 2, 3.8 BAAOP Automation Analysis for CAISO
.02	3/24/20	B. Jackson	Saved Rian's edited version; accepted changes for this master version
.03	3/25/20	B. Jackson	Double checked number of clicks and keystrokes; revised minor formatting
.04	3/27/20	B. Jackson	Finalized version

6. Appendix A Supporting Documentation

Include documentation (names and path) to any documentation that will aid the person performing this procedure.

Document name	Document location or link
BAAOP 3.8,3.8 (OneNote)	[redacted]

	(b)(2) [redacted]

From: Kerns,Steven R (BPA) - B-3

Sent: Fri Nov 15 13:28:52 2019

To: Bentz,Roger E (BPA) - B-3

Subject: FW: 11/15/19 Bonneville Power Administration EIM Implementation - Status

Importance: Normal

Attachments: image001.jpg; image002.png; image003.jpg

Wow – I like this!

(b)(4) [redacted]

(b)(4)

[redacted]

(b)(4)

[redacted]

(b)(4)

[redacted]

(b)(4)

[redacted]

(b)(4)

[redacted]

(b)(4)

[redacted]

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(b)(4)

[redacted]

(b)(4)

[redacted]

Created with Microsoft OneNote 2016.

From: Bentz,Roger E (BPA) - B-3

Sent: Fri Mar 27 18:12:51 2020

To: 'pristanovic@caiso.com'; ''Abdul-Rahman, Khaled'; 'GAngelidis@caiso.com'; 'Alai, Joanne'

Cc: Cathcart,Michelle M (BPA) - TO-DITT-2; Mace,Allison R (BPA) - BD-3; Kerns,Steven R (BPA) - B-3; Kochheiser,Todd W (BPA) - TOI-DITT-2; Rick Schaal (rschaal@utilicast.com)

Subject: Follow-up to BPA's Perceived Automation Needs & Operations Scenario Analysis

Importance: Normal

Attachments: BPA BAAOP Manual Actions (White Paper).docx; BAAOP Scenario 1 - NWPP Request.docx; BAAOP Scenario 2 - GCL Trip.docx; BAAOP Scenario 3 - NPR Trip.docx; BAAOP Scenario 4 RAS Event.docx; BAAOP Scenario 5 - Slice.docx

Good afternoon,

I hope this email finds everyone well and virus free. (b)(6) [redacted] (b)(6) [redacted]

As mentioned in my email following our meeting on March 10, we believe that the following 3 areas of enhancements are needed to allow us to interact with the EIM in a timely, efficient, and reliable manner:

- Implementing Manual Dispatches
- Implementing Imbalance Conformance

- Implementing Telemetry Following

Our operations staff have leveraged relevant CAISO CBTs, as well as inputs from current EIM entities and EIM consultants, to document (see attached) the expected manual actions necessary to manage four sample operations scenarios and one commercial scenario. Hopefully this document helps highlight the complexity & risk of manual BAAOP data entry that, if not implemented correctly and in a timely manner, could a) produce market results that further complicate BPA's grid operations, b) introduce inaccuracies into the overall market at large and c) produce market results that have excessive settlement impacts.

In the attached document, we've also attempted to estimate the amount of time each scenario would take to perform manually. These time estimates are intended to reflect a person familiar with the task executing them at a considered pace. In other words, not as fast as possible but at a pace that should be representative of someone putting thought into their actions. It also assumes no mistakes or diagnosis of the resultant error messages. Times include navigation to the proper screen within BAAOP and make the appropriate entries. It should also be noted that all of the scenarios assume only three manual dispatches (one for each ORA), but it is likely that more than three manual dispatches will need to be performed which would further extend the amount of time the activities would take.

I hope this document is helpful in articulating our concern with the existing manual BAAOP processes and we're looking forward to collaboratively working together on an effective solution that takes into consideration each organizations needs and constraints. Given the urgency to establish our collective path forward, I'm working with Joanne to identify a date in early April to continue our discussion on these topics. And finally, if you have any feedback on these scenarios, including suggestion on how they could be performed more efficiently (or differently), would be greatly appreciated.

Best,

Roger Bentz

Bonneville Power Administration

Business Transformation Office: B-3

EIM Technical Implementation Program Manager

Desk: 503-230-4338

Cell: [redacted]

BPA Transmission Services
Technical Operations

BAAOP Automation Scenario 4

RAS Event

VERSION: 1.0
UPDATED: 27MAR2020

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For more information on Standards of Conduct please use the following resources.
BPA SOC Help Line: 503-230-4677
BPA SOC Web Page: [redacted]
SOC e-mail box: SOC@BPA.gov

Table of Contents

1. Purpose

This NWPP Request for Contingency Reserve (CR) procedure details discrete steps in BPA systems and also BAAOP that BPA staff assume will be needed when operating in the EIM.The number of mouse clicks and keystrokes were counted and used to estimate the time required to complete the action in BAAOP.

(b)(4) [redacted]

2. Scenario Overview

BPA is a member of the NWPP. When any NWPP Balancing Authority (BA) has a contingency they can request CR from other pool members. NWPP reserve requests can happen at any time, often multiple times a day. These requests come into the BPA EMS as a dynamic signal from the NWPP reserve sharing computer. The requests are on a 60 minute timer but can be cancelled at any time by the requesting BA. The signal is dynamic and can be as large as BPA's Contingency Reserve Obligation (CRO), which is generally over 500 MW for BPA. The request often changes value throughout the hour based on the requesting BA's system need. They are not required to be a flat MW request.

In this scenario, a major transmission line trips to lockout while a parallel line is out of Service. Pre-contingency COI/NWACI 3850 MW Limit N>S . Assume path scheduled up to its limit

3. Detailed Procedure Description

The following steps are used to perform the *NWPP Request for CR* procedure. **(**Each step should identify if there is a role change as outlined in the process map and describe what triggers this role change (approval, rejection, etc.) and whether this terminates or pauses this procedure.)

3.1. RAS Gen Drop

RAS Gen drop trip 1700 MW of Generation (1500 MW in BPA [Automatic][RAS]

- NWPP Request is on a 60 minute timer [Automatic] [NWPP System]
- AGC alarms there is a new NWPP request [Automatic] [BPA AGC System]

3.2. AGC Dispatches CR

AGC Dispatches CR plant according to CR allocation % and self suppliers [Automatic] [BPA AGC]

- CR will deployed by all plants on CR response
- Self-suppliers will be sent a dynamic signal (72 MW) based on percent allocation of BPA CRO
- BPA will have an instantaneous -253 (325 less self-supply dynamic) ACE

- ACE lower limit will be set to zero
- CR deployment will correct ACE

The graph below shows the dynamic signals sent to the self-suppliers which is also used in BPA's NSI term in ACE:

(b)(4) [redacted]

3.3. Load Forecast Adujust

Adjust the load forecast up 325 MW less the self-suppliers to show market you have an increase in demand. Ego Desk will have to identify proper timing for operator to enter all information into BAAOP in one market interval [Manual] [BAAOP]

(b)(4) [redacted]

[redacted]

3.4. Manual Dispatch Overlapping Resources

Manual Dispatch Overlapping Resources (ORAs) based on deployed CR. Dispatch would have to do math to determine how much CR is coming from specific plant aggregate (e.g. sum GCL, CHJ, separate from JDA). Used "fixed" manual dispatch for the amount of MW the ORA is providing as CR [Manual] [BAAOP].

3.4.1. Manual Dispatch for Upper Columbia ABC ORA

[redacted]

a. Select EIM Tab
b. Select Manual Dispatch
c. Click Edit Pencil Icon
d. Click New Row
e. Select BAA
f. Select Time Window (We don't know if this is automatic in BAAOP? Training did not show)
g. Select Resource Type
h. Select Constraint Type - Fixed
i. Select Resource Name
j. Select BC Name
k. Select Limit AS
l. Enter Constraint MW Value
m. Enter note if needed
n. Select Apply

3.4.2. Manual Dispatch for Lower Columbia ABC ORA

[redacted]

a. Select Manual Dispatch
b. Click Edit Pencil Icon
c. Click New Row
d. Select BAA
e. Select Time Window (We don't know if this is automatic in BAAOP? Training did not show)
f. Select Resource Type
g. Select Constraint Type - Fixed
h. Select Resource Name

i. Select BC Name
j. Select Limit AS
k. Enter Constraint MW Value -
l. Enter note if needed
m. Select Apply

3.4.3. Manual Dispatch for Snakes ABC ORA

[redacted]

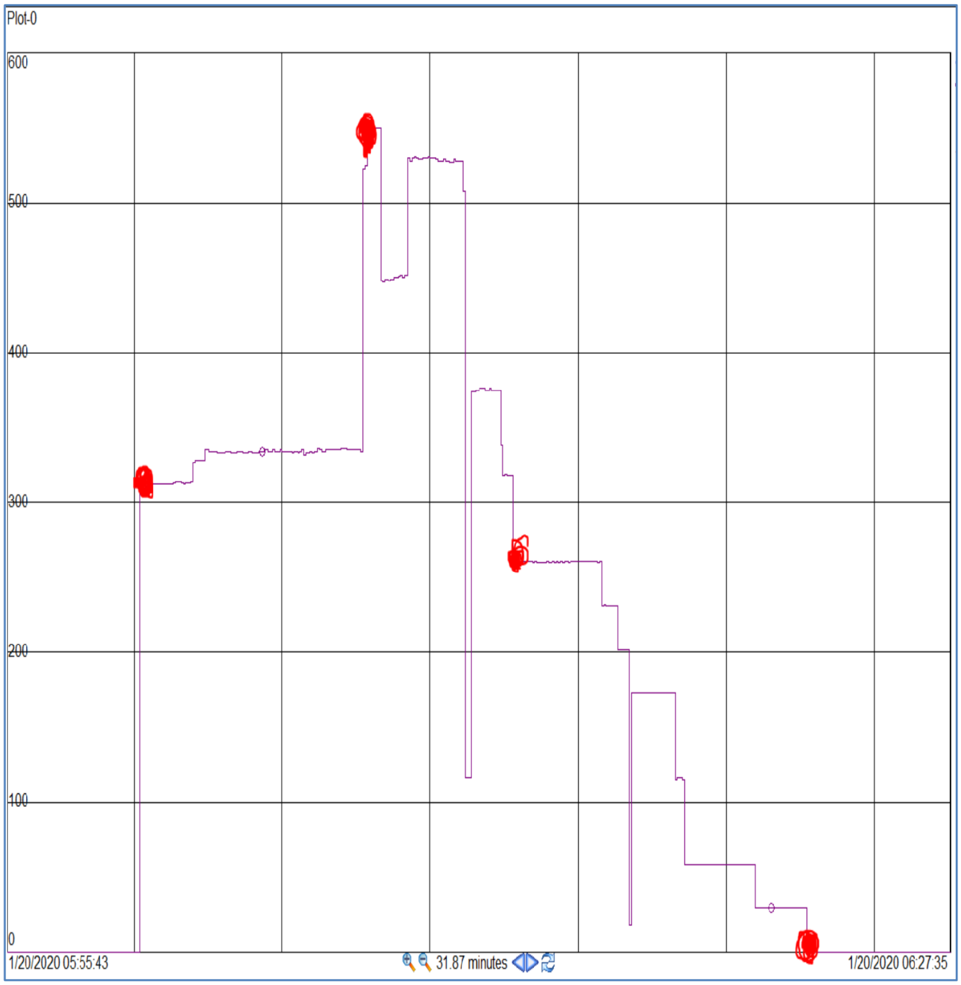
a. Select EIM Tab
b. Select Manual Dispatch
c. Click Edit Pencil Icon
d. Click New Row
e. Select BAA
f. Select Time Window (We don't know if this is automatic in BAAOP? Training did not show)
g. Select Resource Type
h. Select Constraint Type - Fixed
i. Select Resource Name
j. Select BC Name
k. Select Limit AS
l. Enter Constraint MW Value -
m. Enter note if needed
n. Select Apply

At the end of this process, there is a phone call to transmission and power scheduling to inform them at the Contingency Reserve Delivery

3.5. Changing Values

NWPP requests are dynamic and the value can change throughout the 60 min deployment. If the value changes then the Load Forecast, and all of the manual dispatches would need to be updated. [Manual] [BAAOP]

The graph below shows the NWPP dynamic signal requests. It starts at 325 MW increases to 525 MW and then is ramped to zero. The red dots on the graph indicate a manual entry in BAAOP.



3.6. NWPP Dynamic Changes

If NWPP Dynamic Changes by more than 100 MW the Load Conformance and Manual Dispatchers will need to be updated.

Adjust Load Forecast by 100 MW

(b)(4) [redacted]

(b)(4) [redacted]

3.7. Manual Dispatch Reallocation

Adjust Manual Dispatch by the reallocated 100 MW

3.7.1. Adjust Manual Dispatch for Upper Columbia ABC ORA

(b)(4) [redacted]

3.7.2. Adjust Manual Dispatch for Lower Columbia ABC ORA

(b)(4) [redacted]

3.7.3. Adjust Manual Dispatch for Snakes ABC ORA

(b)(4) [redacted]

3.8. NWPP Request End

When the NWPP request ends, there is an alarm and the load forecast and manual dispatch changes will have to be removed. [Manual] [BAAOP]

NWPP request ended sooner than 60 minutes Load conformance and manual dispatchers will have to be manually cancelled

4. Key Contacts (for questions about the procedure)

Role	Contact Name/BPA Organization
Electrical Engineer	Rian Sackett, TOOC
BPA Real-Time Dispatch Senior	Brent Kingsford
Electrical Engineer	Bart McManus
Electrical Engineer	Todd Kocheiser

5. Change Log Table

Document Name: ***NWPP Request for CR*** **Location:** (b)(2) [redacted] ***(20200323)***			
Revision	**Date Revised**	**Revised by**	**Description of Changes**
.01	3/25/20	C. Higgins	Created draft of Scenario 4, 3.8 BAAOP Automation Analysis for CAISO
.02	3/26/20	C. Higgins	Finalized Version

From: Kochheiser,Todd W (BPA) - TOI-DITT-2

Sent: Fri Mar 06 17:14:12 2020

To: ISO Regional Coordination; Abdul-Rahman, Khaled; Ristanovic, Petar; Angelidis, George; Daouk, Jamil; Glover, Angela; Bosanac, Milos; Alai, Joanne; Kerns,Steven R (BPA) - B-3; Symonds,Mark C (BPA) - B-3; Bentz,Roger E (BPA) - B-3; Morris, Janet; Mantifel,Russell (BPA) - B-3; Federovitch,Eric C (BPA) - PTM-5; Burczak,Sarah E (BPA) - BD-3; Davis,Thomas E (BPA) - B-3; Wan, Yu

Subject: RE: BPA EIM Program Level meeting

Importance: Normal

Attachments: 20200310_EIM_CAISO_Agenda.docx; BPA_EIM_Automation_Support_Clean.docx; AGC and BAAOP Actions during a Contingency_CAISO.docx; ORA_BPA_Overview.pptx

Good evening,

In preparation for our meeting on Tuesday, here are some materials that we expect to cover.

Agenda:

Automation:

ORA (slides 27+ represent BPA's potential use of this model):

I may provide some additional supplemental material and/or updates to these documents prior to Tuesday, but these should represent the vast majority of the material we'll cover.

Best,
Todd

-----Original Appointment-----
From: ISO Regional Coordination <ISORegionalCoordination@caiso.com>
Sent: Tuesday, February 4, 2020 1:22 PM
To: ISO Regional Coordination; Abdul-Rahman, Khaled; Ristanovic, Petar; Angelidis, George; Daouk, Jamil; Glover, Angela; Bosanac, Milos; Alai, Joanne; Kerns,Steven R (BPA) - B-3; Symonds,Mark C (BPA) - B-3; Bentz,Roger E (BPA) - B-3; Kochheiser,Todd W (BPA) - TOI-DITT-2; Morris, Janet; Mantifel,Russell (BPA) - B-3; Federovitch,Eric C (BPA) - PTM-5; Burczak,Sarah E (BPA) - BD-3; Davis,Thomas E (BPA) - B-3; Wan, Yu
Subject: [EXTERNAL] BPA EIM Program Level meeting
When: Tuesday, March 10, 2020 9:00 AM-4:30 PM (UTC-08:00) Pacific Time (US & Canada).
(b)(4)
[redacted]

(b)(4) [redacted]

****

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****

From: Bentz,Roger E (BPA) - B-3

Sent: Thu Apr 23 10:46:22 2020

To: Cathcart,Michelle M (BPA) - TO-DITT-2; Cooper,Suzanne B (BPA) - PT-5; Kerns,Steven R (BPA) - B-3; Kochheiser,Todd W (BPA) - TOI-DITT-2; zSchaal, Richard; Alders,Kyna L (BPA) - PGL-5; Mace,Allison R (BPA) - BD-3; Dibble,Rachel L (BPA) - TSQ-TPP-2; Miller,Todd E (BPA) - LP-7

Subject: RE: BPA/ISO EIM Monthly Project Leadership Meeting

Importance: Normal

Attachments: BPA-CAISO EIM Quarterly Leadership Meeting - April 2020.pptx; image001.jpg

Attached is the slide deck we went through this morning.

We came away with one action item: Develop a detail assessment impacts to BPA configuration & testing activities of:

1) Adjacent BA EIM Entities going live in 2022 on a timeline that is later than BPA's 3/2 date

2) Non-adjacent BA EIM Entities going live in 2022 on a timeline that is later than BPA's 3/2 date

Thanks for your participation in the call!

Roger Bentz

Bonneville Power Administration

Business Transformation Office: B-3

EIM Technical Implementation Program Manager

Desk: 503-230-4338

Cell: [redacted]

-----Original Appointment-----
From: ISO Regional Coordination <ISORegionalCoordination@caiso.com>
Sent: Thursday, April 9, 2020 5:22 PM
To: ISO Regional Coordination; Ristanovic, Petar; Abdul-Rahman, Khaled; Morris, Janet; Anders, John; Fuller, Don; Alai, Joanne; Cathcart,Michelle M (BPA) - TO-DITT-2; Cooper,Suzanne B (BPA) - PT-5; Kerns,Steven R (BPA) - B-3; Bentz,Roger E (BPA) - B-3; Kochheiser,Todd W (BPA) - TOI-DITT-2; zSchaal, Richard; Alders,Kyna L (BPA) - PGL-5; Mace,Allison R (BPA) - BD-3; Dibble,Rachel L (BPA) - TSQ-TPP-2; Glover, Angela
Subject: [EXTERNAL] BPA/ISO EIM Monthly Project Leadership Meeting
When: Thursday, April 23, 2020 9:00 AM-10:00 AM (UTC-08:00) Pacific Time (US & Canada).

(b)(4) [redacted]

(b)(4)

[redacted]

(b)(4)

[redacted]

24850642(01).pdf

(b)(4)

[redacted]

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****

(b)(4)

[redacted]

(b)(4)

[redacted]

(b)(4)

[redacted]

EIM Automation
Support & Enhancements

Version 0.6

(Draft)

March 6, 2020

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TABLE OF FIGURES

1 Purpose & Context

Bonneville (BPA) had identified the need to automate certain aspects of its interactions with the Energy Imbalance Market (EIM) prior to signing an Implementation Agreement. As part of BPA's EIM Implementation Agreement, section 14(e) was added that states the following:

> ***Automation Support***
> *In order to effectively participate in the EIM and ensure both reliable and economic outcomes, Bonneville will endeavor during implementation to automate interactions with existing EIM user interfaces based on the ISO's technical specifications. The ISO will assist Bonneville based on jointly determined requirements, feasibility and cost by 1) providing Application Programming Interfaces to interactions with existing EIM user interfaces, and 2) system or tool enhancements as jointly agreed.*

This document highlights areas where APIs or other tool enhancements may help facilitate BPA's efficient and reliable operations in the EIM. This document is organized around the following topic areas:

1. BAAOP APIs Enhancements
2. BAAOP UI Enhancements
3. Telemetry Following
4. CMRI/OASIS Enhancements
5. Miscelleanous Enhancement

This document is not an attempt to produce a detailed business or technical specification for the potential enhancements. Rather, this document attempts to provide some context and a narrative around each of the potential enhancements to help facilitate a conversation about the development of more detailed specification/requirements and the estimation of the implementation complexity, cost, and value.

Note 1: *It is assumed for the purposes of this document that the reader is familiarity with the EIM and its related systems and processes and have taken the BAAOP and ADS CBT courses.*

Note 2: *Items marked with a* ✓ have been previously discussed between BPA and the CAISO

Note 3: Some of the content in this document was derived based on interviews with existing EIM Entities

2 BAAOP API Enhancements

It is assumed that any API enhancement would implement the CAISO existing security protocols for authentication and encryption as well as be similar in design to existing SOAP based WebServices.

2.1 Market Run Status

An API to retrieve the current status of the market (RTPD/RTD). This would allow any EIM Entity BAAOP automation tasks to time their submission to avoid straddling multiple runs (e.g. load bias read in RTD1, outage read in RTD2). Examples might include: 1) gathering data 2) running 3) publishing 4) complete 5)RTCD.

2.2 BAA Contingency Status (entering and exiting) ✓

(b)(4) [redacted]

2.3 BAA Load Conformance (a.k.a. Imbalance Conformance) ✓

(b)(4) [redacted]

2.4 Manual Dispatch of Resources (including ORA Resources) ✓

(b)(4) [redacted]

- A manual dispatch may be required for a number of reasons, such as a contingency, RAS event, RSG delivery, or a resource that is not expected to follow dispatch instructions or is not expected to return to its base schedule (for whatever reason).
- Any manual dispatches should be tracked and available for reporting purposes ATF
- This API would allow for the following:
    - Set/Override the expected MW dispatch, limtis, or status of a resource (generator or intertie) by resource id between a specified start/stop time. Manual dispatches should be able to be performed on the following:
        - Generator, MSG, Load
            - Min
            - Max
            - Fixed
            - Startup
            - Shutdown
            - Offline
        - Interchange (Tie-Gen, ETSR Base, RTies, TID, etc.) *(AI:ask CAISO with types of intertie resources can be manually dispatched)*
            - Min

    - Max
    - Fixed
  - Query (Get) manual dispatches (by time and/or resource id)
  - Query (Get) effective operating limits and/or status (by time and/or resource id)
- *Note: RTSI may cover Interchanges. Can static or dynamic ETSRs be manually dispatched?*

2.5 Identifying Unavailable Resources✓

(b)(4) [redacted]

- Outage cards can and should also be submitted for resources that are not expected to return to service for the foreseeable future. The outage card would also signify to the market the unavailability of the resource but may not take effect immediately.
- *Note: If this can be done with a manual dispatch and an API exists, this need may be covered.*

2.6 Ability to retrieve effective GDFs for aggregate resources

- (b)(4) [redacted]
- An API should be available to retrieve the current effective GDFs for all aggregate resources, in an ORA or otherwise
- The API should be available via BAAOP and included in the ADS payloads

2.7 Ability to retrieve the effective limits for all resources and Static/Dynamic ETSRs

- This API would allow for the effective operating limits that the market is using for binding and advisory intervals net of all outages/rerates, manual dispatches and misc. validations.
  The API should be available via BAAOP and included in the ADS payloads

2.8 Ability to Freeze ETSRs at current level (not following advisories, but frozen at current values)

- (b)(4) [redacted] this feature would freeze ETSRs at their current level (binding) and not follow advisories.
- This would limit changes during large operational events (e.g., RAS) so dispatches can focus on just the activities required to address the event.
- Visibility of freezes for both Entities of a shared ETSR should be made available through the BAAOP UI and programmatically

2.9 Transmission Constraints

- BAAOP>Transmission>Transmission Constraint Manager
- (b)(4) [redacted]
- [redacted]

- [redacted]
- There would be significant benefit if Entities could develop an automated process to update or validate this conforming for transmission elements. This could involve adding an API to:
  - Retrieve SE MW values on transmission elements, TCORs, etc.
  - Set/Retrieve the conformance limit percentages and/or MW limits

[redacted]

Figure 1 - Transmission Constraint Manager

- Could these types of calculations (adjustments from SE solutions/limits based on actuals be performed by the market and allow operators to provide actual limits expressed in MWs to the market?

2.10 ETSR Lock Control and/or Visibility

- BAAOP>EIM>ETSR Lock
- [redacted]
- Visibility for both Entities of a shared ETSR should be made available through the BAAOP UI and programmatically

Note: A similar result may also be done via submitted limits (for BASE ETSR, or Dynamic ETSR without base schedules), but being able to lock an ETSR may be more quickly accomplished in practice.

2.11 ETSR Limit Override

- BAAOP>EIM>ETSR Detail
- (b)(4) [redacted]
- Question: Can Static or Dynamic ETSRs be manually dispatched?

2.12 Upper and Lower Operating Limits (UOL/LOL)

- Add a BAAOP API to allow the Upper and Lower Operating Limits (UOL/LOL a.k.a. Pmax/Pmin) of a resource to be set between a defined start and stop time.
- *Note: If this can be done with a manual dispatch. If that API exists, this need is covered.*

3 BAAOP UI

- Events Log/Notifications
  - (b)(4) [redacted]
  - An event log would help operators review recent events, help document events and assist oncoming shifts of events that occurred on previous shifts.
  - (b)(4) [redacted]
- Feasibility Test results for PASSING >85%
  - (b)(4) [redacted]
- Load Forecast Graph to display RTD/RTPD advisory compared to actual trend.
  - Help operators predict future load forecast errors/corrections.
- Add ETSR Lock Visibility for shared ETSRs. Add Reason/Timestamps.
- Additional Highlighting for important data fields. Pass/Fail, % or margin thresholds, etc…
- Add sound notifications for critical events that require operator attention or action.
- Move ETSR Overview Table to top of page for ETSR detail display.
  - Entities with multiple ETSRs would prefer to see totals and remaining capacities at top.
- Enhance Pop-up settings to allow for user configured pop-up windows.
  - (b)(4) [redacted]
  - Displays that provide Test statuses or constraint information (when constraints exist or update) would be very helpful popups.

- BAAOP RTD/RTPD displays to show dispatchable ETSR capacity (import/export) in addition to dispatchable Generation
- (b)(4) [redacted]
- Enhance BAAOP SVG One-Lines to view/monitor multiple data sources.
    - State-Estimator, Market Telemetry, ICCP, ManReps (Manual overrides by CAISO), Loads.

4 Telemetry Following✓

(b)(4) [redacted]

(b)(4) [redacted] Instead of an operator, or automated process using a new manual dispatch API, performing numerous manual dispatches to update the expected output of the resource, the market would use the current telemetry value as if it were a manual dispatch (similar to VER persistence). A reliability example of when this may be used is when one or more resources are delivering reserves due to contingencies, RAS events, and/or RSG deliveries.

Several questions have been raised about how long the telemetered value should be assumed to persist into the future, as this would impact future market runs (advisory and binding). Several solutions may exists, such as:

1. Specifiy a fixed horizon (## intervals or minutes) that telemetry following should be used. Outside of that horizon, revert to the base schedule or forecast. The telemetry following parameters could be set in the master file and overridden in BAAOP, including the ability to disable/enable the behavior on a resource by resource basis
2. Treat telemetry following as a special type of manual dispatch where instead of specififying a fixed MW value for the resource, a value type of "telemetry" could be specified along with a start/stop date/time or even an "until further notice" type (turn on/off).
    a. During that time interval, the current telemetry value would be used in the market solution
    b. An overlapping manual dispatch with a fixed MW value would take precedence
3. Telemetry following would be a flag/status that would be set on a resource (via API and UI):
    a. Only applied in binding intervals
    b. Advisory intervals could use ramped value between telemetry and base schedule
    c. RS tests would use submitted base schedules

5 Miscelleneous Enhancements

- (b)(4) [redacted]
- Automatic notification for loss of critical data streams.

    - RTSI submissions, dynamic limits, ICCP data/connection, VER forecasts, Load Forecasts (for entities not utilizing CAISO forecasts), etc…
- Request for Addition/Enhancement to ADS Replacement.
    - [redacted]
    - Add the internal DOT value to the payload would be valuable. The internal DOT may be required to import into our EMS to use to determine actual Market balance or when there is action required to resolve an internal DOT that indicates a market issue or discrepancy.
- Ability to retrieve specific critical market data. (could be handled outside of enhancements, if CAISO allows or provides this data to be configured through ICCP or EIDE)
    - [redacted]
    - Specific critical Generation, TCORs, or Transmission element flows would be helpful to review and compare to Actual flow.
    - This would assist in allowing EIM Entities to automate market flow validation that is impossible for operators to do, and help entities report suspicious market flow results that would not easily found or mitigated by operators.
- BSAP base schedule deviations to include Manual Dispatch data.

6 CMRI/OASIS Enhancements

- [redacted]
- CMRI to historize Manual Dispatches
    - [redacted]
    - Could possibly be added as additional "Energy" types in the RTD/RTPD results. e.g., Energy Fixed Manual, Max Manual, Energy Telemetry Manual (see Telemetry Following section) etc. data types.
- CMRI to historize ETSR Locks/Reasons.
- Publish RTPD/RTD Critical Constraints *Binding (future would be beneficial but not critical)
    - [redacted]

Appendix

7 CAISO EIM Market Enhancement (2019)

http://caiso.com/Documents/BusinessRequirementsSpecification_EnergyImbalanceMarketEnhancements2019.pdf. At the bottom is a list of Non-Implemented enhancement requests.

User group conference material: http://www.caiso.com/Documents/Agenda-ReleaseUserGroupWebConferenceNov19_2019.pdf. See slides 42-43 for 2020 enhancement requests

8 BAAOP Screen Shots (Shared 1/8/2020)

(b)(4)

[redacted]

Figure 2 - Constraint Manager

(b)(4) [redacted]

Figure 3 - ITC Limit Management

(b)(4)

[redacted]

(b)(4)

[redacted]

(b)(4)

[redacted]

(b)(4)

[redacted]

(b)(4)

[redacted]

9 Change Log

Document tracking and versioning:

Date	Description	Who	Version
12/23/2019	Initial Draft	Todd Kochheiser	0.0
1/3/2020	Added content	Todd Kochheiser	0.0
1/7/2020	Added content	Todd Kochheiser	0.0
1/8/2020	Misc. Edits	Todd Kochheiser	0.0
2/9/2020	Added UOL/LOL API	Todd Kochhesier	0.1
2/19/2020	Added BAAOP Screen Shots	Todd Kochheiser	0.2
3/2/2020	Edits based on inernal BPA workshop	Todd Kochheiser	0.3
3/6/2020	Edits based on internal BPA feedback	Todd Kochheiser	0.4
3/6/2020	Small edits based on internal feedback	Todd Kochheiser	0.5
3/6/2020	Added market run stastus	Todd Kochheiser	0.6

(b)(4)

[redacted]

(b)(4)

[redacted]

(b)(4)

[redacted]

(b)(4)

[redacted]

(b)(4)

[redacted]

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(b)(4)

[redacted]

AGC and BAAOP actions during real-time events (Contingency, RAS, etc.)

Summary

This document outlines the automatic and manual actions in BPA AGC and BAAOP that need to be taken during various system events when BPA is operating in the EIM. These steps are written as if **no** features were added to either BPA AGC or the CAISO BAAOP. The intent is to highlight burdensome manual actions that will require automation between control center systems and BAAOP.

Operational Scenarios –Contingencies

The following scenarios are written as if a BPA dispatcher had to use AGC as it exists today and BAAOP as it exists today, without automation. This is done to show the manual steps and the manual effort for an operator without automation. Even without automation, a summary screen in AGC will be needed to consolidate information from BAAOP such as CR Reserve Deployed by ORA, amount of load bias needed, etc. This screen would hold values that an EIM dispatcher would then manually enter into BAAOP.

Contingency reserve entries can happen automatically or manually in AGC. BPA AGC programmatically monitors plant net generation values and looks for a 250 MW deviation with a corresponding decline in system frequency. When this occurs an automatic reserve entry will be put in AGC and CR will be deployed

For the following scenarios assume these CR allocations and Contingency Reserve Obligations are in place:

Upper Columbia

GCL - 50%

CHJ - 20%

Lower Columbia

JDA – 10%

TDA – 18%

Snake River

LMN – 2%

Self-Suppliers

These BA's supply their required contingency reserves due to gen/load in BPA's BA. Supply is accomplished through an automated dynamic signal.

BA 4 – 73 MW

BA 5 – 40 MW

BPA CRO = 500 MW

CAISO training recommends that during a contingency BA operators

(b)(4) [redacted]

(b)(4) [redacted]

Scenario 1 - NWPP request for CR:

Description: The NWPP reserve sharing system requests 300 MW from BPA. NWPP reserve requests can happen at any time, often multiple times a day. They happen when another NWPP BA has a contingency and calls upon pool reserves.

Actions:

1. NWPP comes into AGC as Dynamic Schedule for 300 MW [Automatic] [AGC]
    - NWPP Request is on a 60 minute timer [Automatic] [PRRS System]
    - AGC alarms there is a new NWPP request
2. AGC dispatches CR plants according to CR allocation % [Automatic] [AGC].
    - CR will deployed by all plants on CR response.
    - BPA will have an instantaneous -300 ACE.
    - ACE lower limit will be set to zero
    - CR deployment will correct ACE
3. Adjust the load forecast up 300 MW less the self-suppliers to show market you have an increase in demand. Dispatcher will have to identify proper timing for operator to enter all information into BAAOP in one market interval [Manual] [BAAOP]
4. Manual Dispatch ORAs based on deployed CR. Manual dispatch needs to include previous EIM dispatches.Dispatch would have to do math to determine how much CR is coming from specific plant aggregate (e.g. sum GCL, CHJ, separate from JDA) Used “fixed” manual dispatch for the amount of MW the ORA is providing as CR [Manual] [BAAOP]
    a) Manual Dispatch for Upper Columbia ORA
    b) Manual Dispatch for Lower Columbia ORA
    c) Manual Dispatch for Snakes ORA
5. NWPP requests are dynamic and the value can change throughout the 60 min deployment. If the value changes then the Load Forecast, and all of the manual dispatches would need to be updated. [Manual] [BAAOP]

    The graph below shows an example of a dynamic NWPP request

6. When the NWPP request ends, there is an alarm and the load forecast and manual dispatch changes will have to be removed. [Manual] [BAAOP]

Scenario 2 - GCL unit trips offline, 600 MW lost

Description: Randomly a unit trips offline. As they do sometimes.

Actions:

1. AGC detects loss and creates an automatic reserve entry 600 MW for GCL [automatic] [AGC]
2. Automatic Request to the NWPP for 100 MW (this is a 60 minute timer on request) [automatic] [AGC]
3. BPA deploys internal CR [automatic] [AGC]

   • Self Suppliers dynamic signal: SCL = 73 MW, TPWR = 40

   (b)(4) [redacted]

   • 271 CR from Upper Columbia (194 GCL, 77 CHJ)

   - 106 MW CR from Lower Columbia (39 JDA, 67 TDA)
   - 8 MW from the Snakes (8 MW LMN)

4. Dispatcher verifies reserve entry and Contingency. If needed dispatch manually updates reserve entry in AGC. [Manual][AGC]

   • AGC starts contingency timer assume 60 minutes (AGC needs to change to always use a 60 minute timer)

   • If WECC BAL 002 goes away change NWPP rules to 105 minutes and update AGC to 105 min.

5. Load Bias down 100 MW for NWPP dynamic +113 MW for self-suppliers [Manual][BAAOP]
6. Manually dispatch CR from ORA's 350 for upper aggregate, and 150 from lower [Manual][BAAOP]
7. Manually dispatch "Pmax" Upper-Columbia down by amount of contingency, 600 MW [Manual][BAAOP]

- Put in an outage card if Contingency will last longer than 30 minutes. [Manual][OMS]

8. When CR ends manually back-out Load Bias, Manual Energy Dispatch, and Manual Pmax Dispatch if applicable. [Manual][BAAOP]

Scenario 3 – Multiple Contingencies on a Combined Cycle Plant (non-participating)

Description: A combined cycle NPR loses a gas turbine 150 MW, then within 10 minutes the plant loses another 400 MW from their other gas turbine and steam generator. It is assumed that this plant is modeled as one NPR and not multiple for each stage of generator. BPA's AGC tracks Station Control Error (SCE) for plant and dynamically adjusts CR deployment as needed.

Actions:

1. Contingency occurs and plant calls BPA for 150 MW of Contingency Reserves. Operator takes down information [Manual]
2. BPA dispatcher enters Contingency into AGC. [Manual][AGC]
3. CR deployed xxx MW GCL, xxx MW CHJ, xxx MW lower Columbia. Xxx MW Self-Suppliers [automatic][AGC]
4. Identify market infeasibility indications in BAAOP [Manual][BAAOP]
5. Manually dispatch CR plants for energy delivered [Manual][BAAOP]
6. Manually dispatch contingent plant to "fixed" at current generation. [manual][BAAOP]
   a. Submit outage card on Pmax if Contingency lasts longer than 30 minutes [manual][OMS]
7. Adjust Load Forecast down for self-suppliers dynamic signal [manual][BAAOP]
8. Confirm long term market balance [manual][BAAOP]

Second contingency occurs at plant, SCE increases from 150 MW to 550 MW on Contingent Plant

9. Plant SCE grows to 550 MW and increases CR deployed by BPA to 500 MW [automatic][AGC]
10. Once it reaches over CRO automatic NWPP request for 50 MW [automatic][AGC]
11. Request to self-suppliers would grow per their share of CRO [automatic][AGC]
12. Adjust Manual Dispatch of CR plants [manual][BAAOP]
13. Adjust load bias for NWPP request and change in self-supplier dynamic [manual][BAAOP]
14. Flag entire resource as in a contingency due to output being zero. [manual][BAAOP]
    a. Put in an outage card [manual][OMS]
15. Back-out all manual entries when contingency ends.

Scenario 4 – Multiple Balancing Authority Gen Drop RAS.

Description: Major transmission line trips to lockout while a parallel line is out of Service. Pre-contingency COI/NWACI 3850 MW Limit N>S . Assume path scheduled up to the limit

Actions:

1. RAS gen drop trips 1700 MW Generation (1500 MW in BPA) [Automatic][RAS]
   - 750 MW BPA Hydro Plant 1
   - 550 MW BPA Hydro Plant 2
   - 100 MW BPA Hydro Plant 3
   - 50 MW BPA Wind Plant
   - 100 MW Joint Owned Unit (BA 1, BA 2, BA 3)
   - 100 MW BA 1 Wind Plant
   - 50 MW BA 2 Wind Plant

2. BPA AGC OFF Control. [Automatic][AGC]
    - AGC Suspend signal sent to BA 1, BA 2, BA3
3. Chief Joe brake inserts (Load Increase of 1400 MW for 30 cycles) [Automatic][RAS]
4. Reactive Algorithm trips [Automatic][RAS]
5. Notify RC West [Manual][RAS Dispatcher]
6. Notify adjacent BA 1, BA 2, and BA 3 of RAS action [Manual][RAS Dispatcher]
7. Flag Contingency in BAAOP [Manual][BAAOP]
8. Block all dispatches in RTD, and RTPD. This will have to be done in the 75 second window provided with every 5 and 15 min dispatch. [Manual][BAAOP].
9. Manually Dispatch ORA's to "fixed" post RAS generation value. There were 2 ORA's affected by this RAS. [manual][BAAOP]
10. Mark Wind plant resource as unavailable [manual][BAAOP]
11. Adjust Load Forecast down the amount of BPA Gen that was dropped [manual][BAAOP]
12. Test Transmission line (up to 10 minutes) Line tests good or bad [Manual]

Line Tests Good

13a. Transmission Limit on path stays the same

14a. Calls to BA 1, BA 2, BA 3 to return gen to normal and put their AGC on control.

18a. Remove the adjustment on the load forecast.

16a. manually dispatch RAS'd plants back to their base schedule to recover the ACE.

15a. BPA AGC On Control, RAS event cleared in EMS

~~17a. Stop blocking EIM dispatches~~

19a. Calls to individual Powerhouses and wind farm (BPA) to return to units to service and ramp to basepoints

20a. After ACE recovers from RAS event, then remove manual dispatches on RAS'd plants.

Line Tests Bad

8b. Limit set on Path by Path Operator to 600MW, corresponding tags are cut affecting BPA and BA 1, BA 2, and BA3.

10b. manually dispatch RAS'd plants back to their base schedule based on new intertie limit, lower than previous schedule.

10c. Stop blocking EIM Dispatches

11b. BA1, BA2, BA3return to control

11c. BPA Power sends new basepoints

12b. BPA AGC on Control

13b. Individual Powerhouses and wind farm called to return to basepoint (new)

14b. Change import/export limit of every ETSR to current value (this is impossible manually, could only happen automatically)

- Can CAISO add functionality to lock ETSR's at current value with a stop and start time. This may be able to happen with a phone call to market operator.

Overlapping Resource Aggregation (Rule, Validations, Notes)

3/06/2020
(v3.0)
Todd Kochheiser
(DRAFT – For Discussion Purposes Only!)

Note1: BPA Model (draft) is described beginning on slide 26
Note2: Draft, Pre-Decisional, and for Discussion Purposes Only!
Warning: Content is mostly based on a whitepaper written by George Angelidis @ CAISO. It is unclear which rules/validations have been implemented, but unless noted otherwise I assume that they have.

Concept

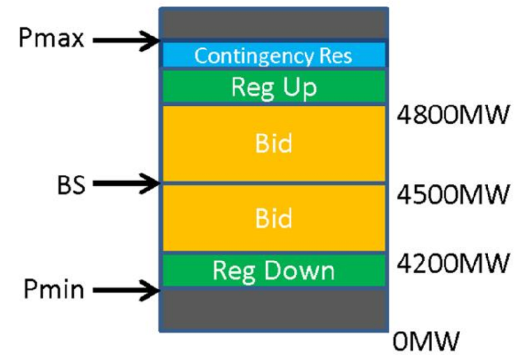
- A collection/aggregation of physical units are registered as multiple different types of resources with unique resource ids
- These resource are considered "overlapping" because the same set of aggregated units supply multiple modeled resources
- In technical terms, the aggregate locations (ANodes) of these aggregate market resources are composed of the same set of network locations (CNodes), which correspond to the physical units in the aggregation.
- This is sometimes called the "Powerex Model."

Example

Traditional Model:

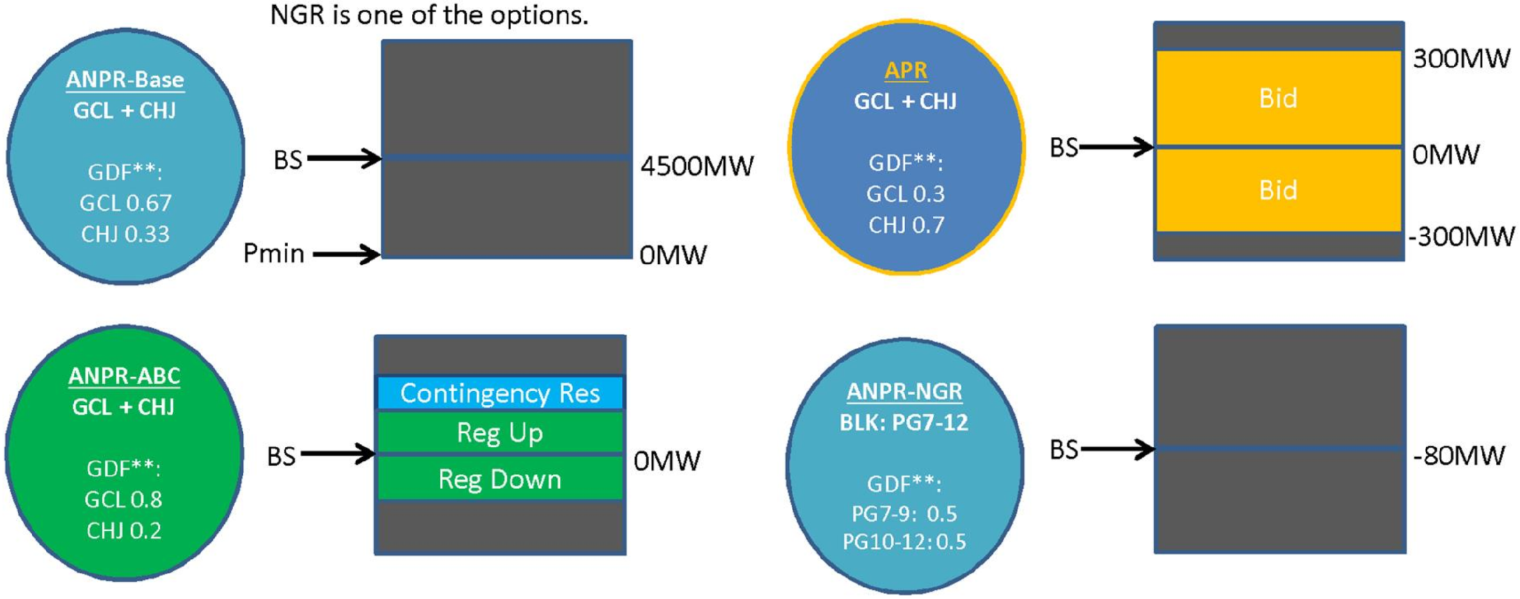
*GDF is calculated based on BP set by hydro scheduler. GDF controls the distribution of MW for both BS and bid range.

	BP (MW)	GDF
GCL	3000	3000/4500 = 0.67
CHJ	1500	1500/4500 = 0.33
SUM	4500	1



ORA Model:

**4 sets of GDFs, one for each aggregate. PGs can be modeled several different ways. ANPR-NGR is one of the options.



Background Material

- BPA ADF – Whitepaper

Microsoft Word Document

- CAISO ORA Whitepaper (rules & validations documented in this PPT are based on this document)

Microsoft Word Document

- Sample GRDT (Chief + Coulee)

Microsoft Excel Worksheet

Rules (General)

(b)(4)

- [redacted]

Rules (GDFs)

[Todd's Notes – Not From ORA Paper]

- The ANodes of all aggregate market resources associated with the same ORA shall be composed of the same set of Cnodes, but the the GDFs for these ANodes can be different.
- GDFs must be supplied at the same fidelity as the Cnodes are modelled in the Full Network Model (FNM)
  - If individual units are modeled in the FNM then GDFs are at the unit level
  - If all units are consolidated in the FNM at a high-side transformer or at the power house level, then the GDFs are provided at the transformer or power house level
  - The majority of plants for BPA have the units modeled, therefore GDFs will typically be at the unit level (i.e., 71 GDFs for the Chief + Coulee aggregate)

Rules (ANPR-BASE)

(b)(4)

[redacted]

Rules (ANPR-NCL)

[Todd: Doubt we'll use this]

(b)(4)

[redacted]

Rules (APR)

(b)(4)

[redacted]

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Rules (ANPR-ABC)

(b)(4)

[redacted]

Rules (ANPR-AM)

(b)(4)
[redacted]

Rules (PRIORITY)

(b)(4)

[redacted]

Rules (Outages)

(b)(4)

[redacted]

Rules (Derates)

(b)(4) [redacted]

Rules (Telemetry)

(b)(4)

[redacted]

Validations

(b)(4)

[redacted]

Validations

(b)(4)

[redacted]

Validations

(b)(4)

[redacted]

Validation #1 (ANPR-BASE)

(b)(4) [redacted]

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Validation #2 (ANPR-NCL)

(b)(4)

[redacted]

Validation #3 (APR)

(b)(4) [redacted]

Validation #4 (APR)

(b)(4) [redacted]

Validation #5 (ANPR-AM)

[BPA Does Not Expect have AM Resources]

(b)(4)

[redacted]

Validation #6 (ANPR-AM)

[BPA Does Not Expect have AM Resources]

(b)(4)

[redacted]

Validation #7 (ANPR-ABC)

(b)(4)

[redacted]

Validation #8 (ANPR-ABC)

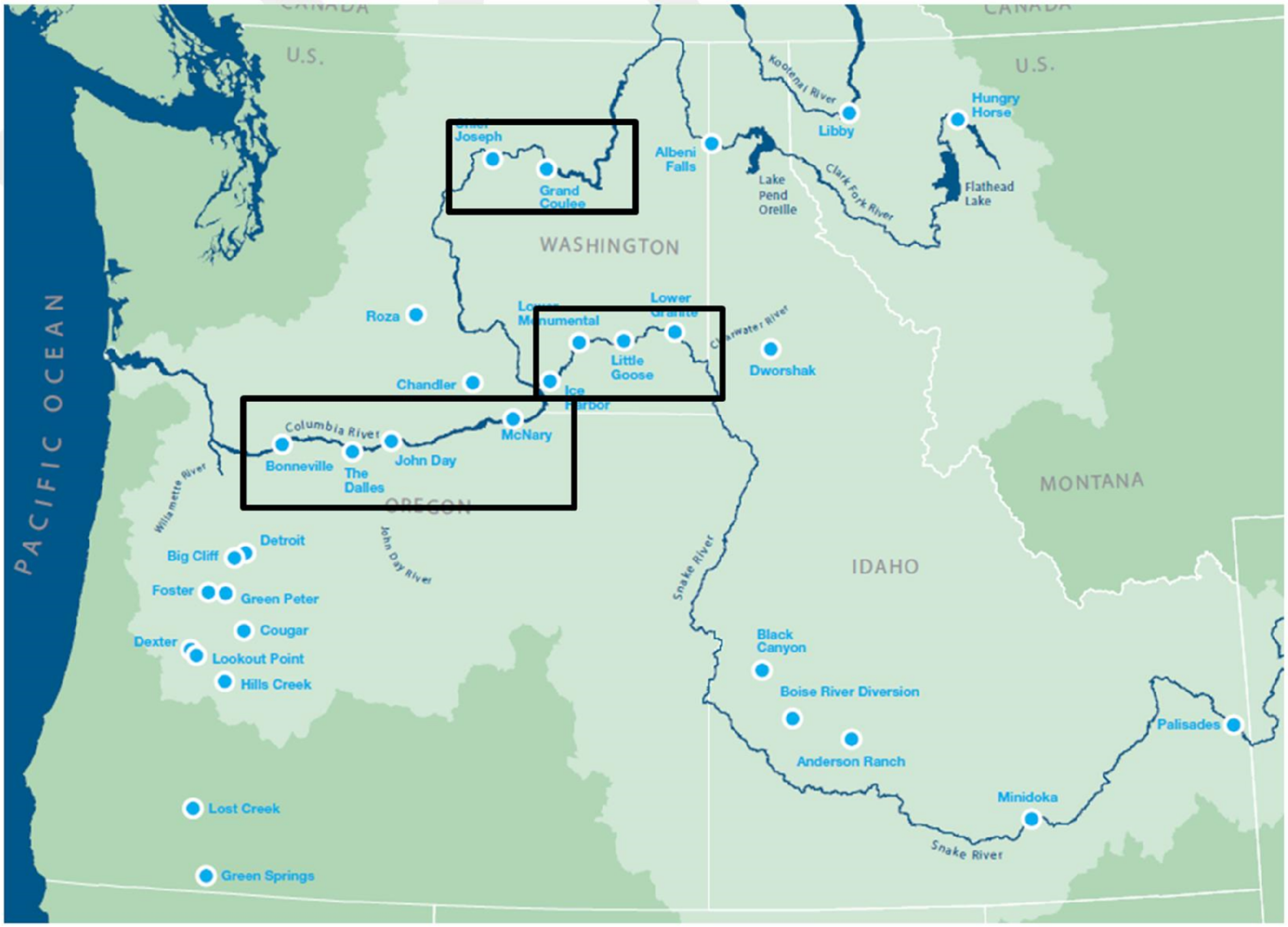
(b)(4)

[redacted]

BPA Model
(draft)

BPA ORA Model

- UPPER = Upper Columbia (Chief and Coulee)
- LOWER = Lower Columbia (Bonneville, The Dalles, John Day, McNary)
- SNAKE = Snake River (Ice Harbor, Low Mo, Little Goose, Lower Granite)



BPA Model (Draft/TBD)

[Todd: an assumption and something to debate]

- Configuration TBD based on metering and final ORA rules
- Rest of FCRPS resources that are not part of an ORA will be aggregated at the plant level and non-participating (a.k.a. NPRs)
- Each ORA would have (tentative):
  - APR (can declare contingency reserves)
  - ANPR-BASE
  - ANPR-ABC (define contingency reserves and Available Balancing Capacity)
- Not sure about need for NCL or auto-match resources
- GDFs are at the unit level (see enhancements)
- GDFs may be different for each resource (APR, ANPR-BASE, ANPR-ABC) when submitting bids and base schedules
- The EIM can not support separate INC and DEC GDFs

BPA Model (Telemetry)

[Todd: an assumption and something to debate]

- Telemetry (ICCP) must be established for each registered resource in the ORA and provided to the market
- APR: Telemetry should match ramped DOTs, reflective of any market awards and/or manual dispatches
- ANPR-ABC: Telemetry should reflect the net deployment of any regulation and contingency energy
- ANPR-BASE: Telemetry should equal the total telemetered physical output of the aggregated resources (e.g., CHJ+GCL) minus the APR and ANPR-ABC telemetry
- *Note: Instead of ANPR-BASE, ANPR-ABC could be configured to reflect all residual deployments net of BASE and APR*

BPA Model (Metering)

[Todd: an assumption and something to debate]

– Physical meters will be read for each ORA and summed together ($ORA\text{-}TOT_{meter}$) and loss adjusted as necessary

– APR meter (APR_{meter}) will be equal to the DOT and reflect the market award and any manual dispatches *(this should match telemetry)*

– ANPR-ABC meter ($ANPR\text{-}ABC_{meter}$) will be equal to the telemetered value and reflect any deployment of regulation (up/down), contingency deployments, and/or ABC supplemental dispatches

– $ANRP\text{-}BASE_{meter} = (ORA\text{-}TOT_{meter}) – (APR_{meter}) – (ANPR\text{-}ABC_{meter})$

BPA Model
(Derates, Outages, & Manual Dispatch)

- All resources in an ORA can be Manually Dispatched (MD) in BAAOP
- This rule is in production:

(b)(4) [redacted]

  - BPA may want to have outages in OMS for the APR applied.
- It is unclear if rerates in BAAOP are applied to the APR – Todd checking w/ Khaled (2/10)

BPA Model (Keys Generating Station)

- The PGs at Keys (Grand Coulee) can be modeled several different ways.
  1. Included in CHJ+GCL Aggregate (i.e., behind the meter)
  2. ANPR-NGR (i.e., scheduled)
  3. APR-NGR (i.e., bid)
  4. ANPR-NCL (i.e., ORA model)
- New metering will be installed that allows units 7-12 to be directly metered (high side)
- Todd is supposed to draft a short paper on the pro/cons of each option, per Clarisse
- Options #1 and #2 seem to make the most sense, but more analysis is needed

BPA Validation Example
(GCL + CHJ)

Example #1

- Pmax = 7000 MW w/ Derate to 6500 MW
- Base Schedule = 4500 MW
- NCL = 375 MW
- BID = -300, +400 (w/ 50 MW SP/NSP)
- ABC = -800, +900 (w/ 400 MW SP/NSP)

	MASTER FILE		OUTAGE	BASE SCHEDULES / BIDS						VALIDATED			EFFECTIVE			
RESOURCE	PMIN	PMAX	DERATE	EN	ABC_DN	ABC_UP	SP/NSP	DEC_BID	INC_BID	LOL	UOL	EN	ABC_DN	ABC_UP	DEC_BID	INC_BID
ANPR_BASE	0	7000	6500	4500						0	6500	4500				
ANPR_NCL	-400	0	-350	-375						-350	0	-350				
ANPR_AM	-100	100		0						-100	100					
ANPR_ABC	-3000	3000		0	-800	900	400			-3000	500		-800	100		
APR	-500	500		0			50	-300	400	-3700	700				-300	400

Microsoft Excel Worksheet

Potential ORA Enhancements

1. Honor Pmin/Pmax from Master File for all resource types *(probably true but was not documented)*
2. Recognize derates/outages of Pmin/Pmax/Ramp of AM, ABC, and APR resources *(assuming manual dispatches are honored)*
3. A negative/DEC limit should not be > 0MW
4. A positive/INC limit should not be < 0MW
5. Ability to submit plant level GDFs instead of unit level
6. Ability to programmatically retrieve effective GDFs (plant or unit) for each registered resource (BAAOP and/or ADS)
7. Separate INC and DEC GDFs for APR and ABC
8. min-generation validations (e.g,. Non zero Pmin on ANPR_BASE)
9. Separate declarations of ABC and regulation

1. Honor Pmin/Pmax from Master File for all resource types

- This may already be supported, but it was not explicitly discussed on the ORA whitepaper

2. Recognize derates/outages of Pmin/Pmax/Ramp of AM, ABC, and APR resources

(b)(4)

- [redacted]
- [redacted]
- [redacted]

(b)(4)

[redacted]

5. Ability to submit plant level GDFs instead of unit level

- Submitting GDFs at the unit level is a significant complication for BPA
- BPA dispatched plants and not units
- BPA currently applies plant level responses for regulation (separated for INC and DEC deployments) and contingency reserves
- The ability to submit GDFs at a plant level (sub-aggregation of units) would be a very valuable enhancement
- (b)(4) [redacted]

6. Ability to programmatically retrieve effective GDFs (plant or unit) for each registered resource (BAAOP and/or ADS)

- Including GDFs, which may have been renormalized by the market, in the ADS payloads and/or from BAAOP would:

    1. Help ensure that dispatches are consistent with the market's expectation and a more robust AGC integration
    2. Allow us to flag inconsistencies

7. Separate INC and DEC GDFs for APR and ABC

- BPA currently uses separate INC/DEC response factors for regulation
- We would likely also have different INC/DEC responses for market awards
- Providing separate GDFs would provide the best information to the market about how and where BPA will be holding and deploying these different types of energy/capacity

8. Min-generation validations (e.g,. Non zero Pmin on ANPR_BASE)

(b)(4)

- [redacted]
- [redacted]
- [redacted]

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9. Separate declarations of ABC and regulation

- CAISO enhanced for SMUD (see ID# EIM19-BRQ1195 in the BRS v1.4 on EIM 2019 enhancements). From the BRS, it states “Settle the EIM resource deviation amount that within the resource Regulation or ABC range as instructed regulation energy”
- Has this enhancement been applied to ORA and is ABC and regulation still conflated?
- BPA wants to make sure that capacity we hold out for regulation is not available for ABC, or that we have control over the deployment of ABC by the market vs. regulation deployed for our own reliability needs

From: Bentz,Roger E (BPA) - B-3

Sent: Tue Apr 07 08:00:38 2020

To: 'pristanovic@caiso.com'; ''Abdul-Rahman, Khaled'; 'GAngelidis@caiso.com'; 'Alai, Joanne'

Cc: Cathcart,Michelle M (BPA) - TO-DITT-2; Mace,Allison R (BPA) - BD-3; Kerns,Steven R (BPA) - B-3; Kochheiser,Todd W (BPA) - TOI-DITT-2; Rick Schaal (rschaal@utilicast.com); Sackett,Rian R (TFE)(BPA) - TOOC-DITT-2; Ryan Kroelinger; Zach Gill Sanford

Subject: RE: Follow-up to BPA's Perceived Automation Needs & Operations Scenario Analysis

Importance: Normal

Attachments: BPA BAAOP Manual Actions Presentation.pptx; BAAOP Scenario 4 - RAS Event.docx

Good morning,

We are looking forward to the discussion this afternoon.

Attached is a slide deck to lead the discussion through the scenarios and also a replacement documentation of scenario #4 that includes a correction in the process steps for that scenario.

Roger

From: Bentz,Roger E (BPA) - B-3
Sent: Friday, March 27, 2020 6:13 PM
To: 'pristanovic@caiso.com'; "Abdul-Rahman, Khaled' <KAbdulRahman@caiso.com>; 'GAngelidis@caiso.com' <GAngelidis@caiso.com>; 'Alai, Joanne' <JALAI@caiso.com>
Cc: Cathcart,Michelle M (BPA) - TO-DITT-2 <mmcathcart@bpa.gov>; Mace,Allison R (BPA) - BD-3 <armace@bpa.gov>; Kerns,Steven R (BPA) - B-3 <srkerns@bpa.gov>; Kochheiser,Todd W (BPA) - TOI-DITT-2 <twkochheiser@bpa.gov>; Rick Schaal (rschaal@utilicast.com) <rschaal@utilicast.com>
Subject: Follow-up to BPA's Perceived Automation Needs & Operations Scenario Analysis

Good afternoon,

I hope this email finds everyone well and virus free. (b)(6) [redacted]

As mentioned in my email following our meeting on March 10, we believe that the following 3 areas of enhancements are needed to allow us to interact with the EIM in a timely, efficient, and reliable manner:

- Implementing Manual Dispatches
- Implementing Imbalance Conformance
- Implementing Telemetry Following

Our operations staff have leveraged relevant CAISO CBTs, as well as inputs from current EIM entities and EIM consultants, to document (see attached) the expected manual actions necessary to manage four sample operations scenarios and one commercial scenario. Hopefully this document helps highlight the complexity & risk of manual BAAOP data entry that, if not implemented correctly and in a timely manner, could a) produce market results that further complicate BPA's grid operations, b) introduce inaccuracies into the overall market at large and c) produce market results that have excessive settlement impacts.

In the attached document, we've also attempted to estimate the amount of time each scenario would take to perform manually. These time estimates are intended to reflect a person familiar with the task executing them at a considered pace. In other words, not as fast as possible but at a pace that should be representative of someone putting thought into their actions. It also assumes no mistakes or diagnosis of the resultant error messages. Times include navigation to the proper screen within BAAOP and make the appropriate entries. It should also be noted that all of the scenarios assume only three manual dispatches (one for each ORA), but it is likely that more than three manual dispatches will need to be performed which would further extend the amount of time the activities would take.

I hope this document is helpful in articulating our concern with the existing manual BAAOP processes and we're looking forward to collaboratively working together on an effective solution that takes into consideration each organizations needs and constraints. Given the urgency to establish our collective path forward, I'm working with Joanne to identify a date in early April to continue our discussion on these topics. And finally, if you have any feedback on these scenarios, including suggestion on how they could be performed more efficiently (or differently), would be greatly appreciated.

Best,

Roger Bentz

Bonneville Power Administration

Business Transformation Office: B-3

EIM Technical Implementation Program Manager

Desk: 503-230-4338

Cell: [redacted]

(b)(4)

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[redacted]

(b)(4)

[redacted]

(b)(4)

[redacted]

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[redacted]

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[redacted]

1. Describe problem or opportunity

The key driver for this ADF is the need to develop a negotiation strategy prior to starting negotiations with the CAISO. The specific resource participation model that we establish for joining the Western EIM with CAISO will influence the requirements for Grid Modernization projects including developing new systems, business processes, and governance. The decision on the general structure of how FCRPS within hour flexibility will be marketed in the EIM, along with the Transmission participation model will likely influence other decisions as we learn more about what Grid Modernization and participating in organized markets means for BPA (from a one-BPA perspective). Collectively, these decisions on market participation choices will balance reliability, efficiency, and control of generation in the balancing authority (BA).

As the team learns more, as additional decisions are made, and as Grid Modernization projects progress, the decisions in this ADF will likely be revisited.

There are two questions for decision laid out in this ADF:

1. How to aggregate (or not) the FCRPS for BPA to participate in the Western EIM and
2. Whether to adopt the Powerex model to split each aggregate resource into: (1) a participating portion for the CAISO to dispatch (surplus power) and (2) a nonparticipating portion for the BA to dispatch (load and ancillary services).

Assumptions:

1. The BPA BA maintains its autonomy; contingency reserves and regulation (for load and generators) will not be dispatched by the market operator.
2. Power Services retains the autonomy on how hydro projects respond to market signals.
3. Power Services will still be able to make system sales and purchases outside of the EIM.
4. Current tagging and scheduling practices will remain.
5. A participating EIM resource will be used to reference the type of resource that the market operator sees and is limited to the dispatchable "Big10" FCRPS hydro projects.
6. Power Services retains the ability to determine how much and which, if any, of the "Big10" FCRPS hydro project to offer bid curves for any given hour.
7. A bid curve will be created for each aggregated participating resource (APR). An individual bid curve will be created for each participating resource that is not part of an aggregate.
8. Non-dispatchable FCRPS projects will be non-participating resources in an EIM.
9. Participation decisions by non-federal generators in the BPA BA are independent of this ADF decision.
10. The outcome of the "Transmission Provision in an EIM" ADF does not impact the outcome of this ADF.
11. Power Services will meet all NT load obligations.
12. All FCRPS dispatches are deliverable and feasible without violating FCRPS non-power constraints.
13. Transmission is available for dispatch instructions from the CAISO.
14. The EIM will not cause the BA to violate reliability standards.
15. EIM approved meters are in place to capture the FCRPS resource (aggregated or not) responses.

2. Define governance, scope & constraints

Name of Initiative: Federal Resource Participation in an EIM
Client Organization: Power Services, Transmission Services
POC Manager: Steve Kerns (PGS)
Decision Maker(s): Joel Cook, Richard Shaheen

Consult - Tier II steering committee: Kieran, Suzanne, Michelle M., Michelle C., Jeff C., Todd M. – Currently meets monthly (last Tuesday of every month) for one hour on March 27th at 1pm.

Executive Sponsors: Kieran Connolly, Suzanne Cooper, Michelle Cathcart, Michelle Manary, Jeff Cook (?)
ADF Lead: Steve Kerns (PGS)
Core ADF team members: Clarisse Messemer (PGST), Todd Kochheiser (TOI), Dave Dernovsek (PTKP), Eric Federovitch (PTM), Rich Greene (LP), Rebekah Pettinger (LP), Kelii Haraguchi (PTM), Eric King (TSPP), Russ Mantifel (TS), Tom Davis (LT), Mark Symonds (BD), Chris Siewert (PGSD) , Elsa Chang (PGST), Cindy Polsky (PGST), Pam Van Calcar (PGSP), Frank Puyleart (TOOC), Chris Sanford (TOR), Steve Gaube (PTF), Troy Simpson (TOI), John Schaffroth (Utilicast), Margaret Pedersen Mainzer (PTL), Mai Truong (PGST), Rob Hawkins (PGSD), Garland Will (PGST), Anna Stermer (PGSP), Sara Eaton (PTM), Dave Kirsch (TOOC)
Draft due: March 15, 2018
Final due: March 31, 2018
Decision Deadline: March 31, 2018

3. Status quo context

FCRPS Aggregation:
Since the BPA is not currently a participating entity, there is no status quo context for how the FCRPS will participate in the Western EIM. However, there is a status quo of current operations that has elements of all the alternatives. So no one alternative can be considered the status quo.

Of the 31 dams and one nuclear plant that BPA markets the energy for, only 10 projects (the Big10) are capable of being armed for Automatic Generation Control (AGC) response. This means that they are connected via AGC and can be automatically dispatched by the transmission operator to maintain reliability.

The Big10, AGC responsive projects are:
Upper Columbia:
- Grand Coulee (GCL)
- Chief Joe (CHJ)

Lower Snake:
- Lower Granite (LWG)
- Little Goose (LGS)
- Lower Monumental (LMN)
- Ice Harbor (IHR)

Lower Columbia:
- McNary (MCN)
- John Day (JDA)
- The Dalles (TDA)
- Bonneville (BON)

BPA operates these projects individually and as an aggregate depending upon the hydraulic, power, or non-power constraint that is binding. The entire system (the Big10 as well as all the remaining generators marketed by Power Services) is marketed as if coming from a single resource (system sales) at the Mid-C hub. Operationally, the Hydro Duty Scheduler generally manages the hydraulic nature of the system as three groups: Upper Columbia, the Lower Snake, and the Lower Columbia. In addition, the Hydro Duty Scheduler sets basepoints for each project individually and sets response factors for each of the projects on response individually.

Upper Columbia projects are hydraulically independent from Lower Snake projects since they are on different river reaches and from the Lower Columbia projects due to the long travel time and nonfederal projects that are in between. Assessing hydraulic linkage between Lower Snake and Lower Columbia projects is a little trickier since the travel time between water discharged from Ice Harbor and McNary is only a couple of hours. However, absent special operations or unusual outage conditions, the Lower Snake projects tend to operate in a similar manner so aggregating these projects is rational. Of the four Lower Columbia river projects, McNary, John Day and The Dalles tend to be operated in a similar manner except during high flows when McNary (which is the most turbine limited of the three) tends to run at flat generation. Bonneville dam can, at times, also operate in a similar manner, but it has frequent special operations and non-power constraints that limit operational flexibility.

Looking at hourly response factors over a ten year period (2008 – 2017), there are at least two aggregations of projects that provide a substantial amount of the within-hour FCRPS flexibility. Group 1 is GCL and CHJ. These projects are often operated in tandem such that one project will have a relatively high response factor while the other one will be lower and vice versa. Group 2 is JDA and TDA. They routinely account for an important amount of within-hour flexibility, with their response factors commonly being at similar levels. The other Big10 projects sometimes have flexibility. Depending on water conditions MCN can be limited in flexibility, but at other times MCN can be an important source of flexibility. The Lower Snake is also important as during certain periods of the year, there is flexibility and response carried on the Lower Snake projects.

Electrically similar:
In order for the Western EIM to dispatch around congested flowgates, only resources that affect a flowgate similarly are considered electrically similar enough to be considered for aggregation.

In order to determine which of the Big10 FCRPS resources are electrically similar[1] to one another relative to BPA's internal/network flowgates, a set of Generation Shift Factors (GSFs) were calculated from a 2019 all lines in service planning case. In the context of any specific flowgate, resources that have very similar GSFs are considered to be electrically similar for that flowgate - in this analysis, if the difference between any two GSFs were less than 10%, the resources were considered to be electrically similar. Three separate aggregations of resources were specifically considered: Upper Columbia (Grand Coulee and Chief Joe), the Lower Snake projects (Lower Granite, Little Goose, Lower Monumental, Ice Harbor), and the Lower Columbia projects (McNary, John Day, The Dalles, Bonneville).

Based on the preliminary/draft results[2], Upper Columbia resources can be considered electrically similar at every flowgate. For the Lower Columbia projects, Bonneville and McNary would ideally not be included in an aggregation. However, the West of John Day flowgate (WOJD) is problematic for the Lower Columbia projects in total and doesn't lend itself to any Lower Columbia aggregation - additional analysis will be required to determine if an aggregation can be allowed. For the Lower Snake projects, excluding Ice Harbor from the aggregation would probably be acceptable, pending further analysis.

ELECTRICALLY SIMILAR @ 10%

[1] There is an element of subjectivity to defining "electrically similar". This must be defined likely via path-transfer distribution factors (PTDFs, aka impacts on the transmission grid).
[2] See the Electrically Similar analysis paper is included in the Appendix of this ADF

FLOWGATE	UPPER	LOWER	SNAKE	NOTES
CCN	YES	MAYBE	YES	Bonneville slightly above 10% in Lower
CCS	YES	NO	YES	Bonneville much higher than 10% in Lower
NOEL	YES	YES	YES	
NOH	YES	MAYBE	YES	Bonneville slightly above 10% in Lower
NJD	YES	YES	NO	Ice Harbor much higher than 10%
PA	YES	MAYBE	YES	Bonneville slightly above 10% in Lower
RP	YES	MAYBE	YES	Bonneville slightly above 10% in Lower
SOA	YES	MAYBE	YES	Bonneville slightly above 10% in Lower
SOC	YES	YES	YES	
WOJD	YES	NO	YES	
WOLM	YES	YES	NO	Ice Harbor has a large impact (>80%)
WOM	YES	NO	MAYBE	Ice Harbor a little less than 20%
WOS	YES	MAYBE	YES	Impacts range from 5-32%

Congestion in the BPA BA:
For the flowgates where the aggregations considered above do not allow the market to dispatch around congestion, an analysis of congestion risk was performed. It concluded with the following:

- The number and duration of actual flows exceeding TTC has been increasing
- The number curtailments has been decreasing
- Trends are likely due to new SOL methodology that went into effect on 4/1/2017
- Overall risk of curtailments is low on most flowgates
- These trends may or may not continue – hard to predict the future!
- Very few N-1 contingencies have occurred recently – curtailments may be higher when they occur since we are running the system at higher loading than we have historically
- As of November, 2014, 15-minute intervals are curtailed – they used to be hourly

CURTAILMENT EVENTS - ALL PRIORITIES (1,2,6,7)												
Flowgate	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**Grand Total**	**Frequency (10yr)**
NJD			4	4	11		21		2	2	**44**	**0.050%**
NOEL						12	5	17		3	**37**	**0.042%**
NOH				3							**3**	**0.003%**
NOH_SN		11		1	7	1					**20**	**0.023%**
P-A		2									**2**	**0.002%**
R-P			1	4	1				7		**13**	**0.015%**
SOA	11	1		3		2	2				**19**	**0.022%**
SOA_SN	3	2		1		3					**9**	**0.010%**
SOC								1	21		**22**	**0.025%**
WOCN		1	4			1					**6**	**0.007%**
WOJD					4				6		**10**	**0.011%**
WOM					5		3				**8**	**0.009%**
WOM - MAIN-GRID									2		**2**	**0.002%**
WOMSG								4			**4**	**0.005%**
Grand Total	**14**	**17**	**9**	**16**	**28**	**19**	**31**	**22**	**38**	**5**	**199**	**0.227%**
CURTAILMENT EVENTS - FIRM (7)												

Flowgate	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Grand Total	Frequency (10yr)
NJD							5				**5**	**0.006%**
NOEL						4	1	2		1	**8**	**0.009%**
NOH												**0.000%**
NOH_SN					2						**2**	**0.002%**
P-A												**0.000%**
R-P				2					4		**6**	**0.007%**
SOA												**0.000%**
SOA_SN												**0.000%**
SOC												**0.000%**
WOCN			2			1					**3**	**0.003%**
WOJD									4		**4**	**0.005%**
WOM					5		1				**6**	**0.007%**
WOM - MAIN-GRID									2		**2**	**0.002%**
WOMSG								1			**1**	**0.001%**
Grand Total			**2**	**2**	**7**	**5**	**7**	**3**	**10**	**1**	**37**	**0.042%**

Powerex EIM Resource Aggregation Participation Model:

Powerex (PWX) has signed an agreement with CAISO to become the first non-U.S. participant in the Western EIM. PWX markets the surplus generation of parent BC Hydro, which operates large cascading hydro systems. The company's role is similar to that of BPA. Learning from PWX's EIM implementation plan and understanding the differences between PWX and BPA's systems can help us make well-informed decisions about FCRPS' participation model in EIM.

The BC Hydro BAA is largely radial to the US with a single BC-USA intertie and there is very little temporal and spatial variation in terms of reserve carrying within their BA. Under these conditions, the large 8 hydro projects are considered electrically similar and grouped into one aggregate in the EIM. PWX takes that aggregation and makes the 8 hydro projects a participating resource and makes the same 8 hydro projects a non-participating resource: 1) aggregate participating resource (APR) to respond to the EIM bids/offers and (2) aggregate non-participating resource (ANPR) to respond to load and ancillary and control area services (ACS). Separate sets (one for APR, one for ANPR) of hourly generating response factors (GDF) are submitted to CAISO to control the proportions of energy distribution among the projects. The use of APR/ANPR with GDF enables the separation of market bids/dispatches from load/ACS obligations for transparency and effective usages of system flexibility. It could also allow BPA to retain control of the congestion management and the hydraulic coordination in the BA.

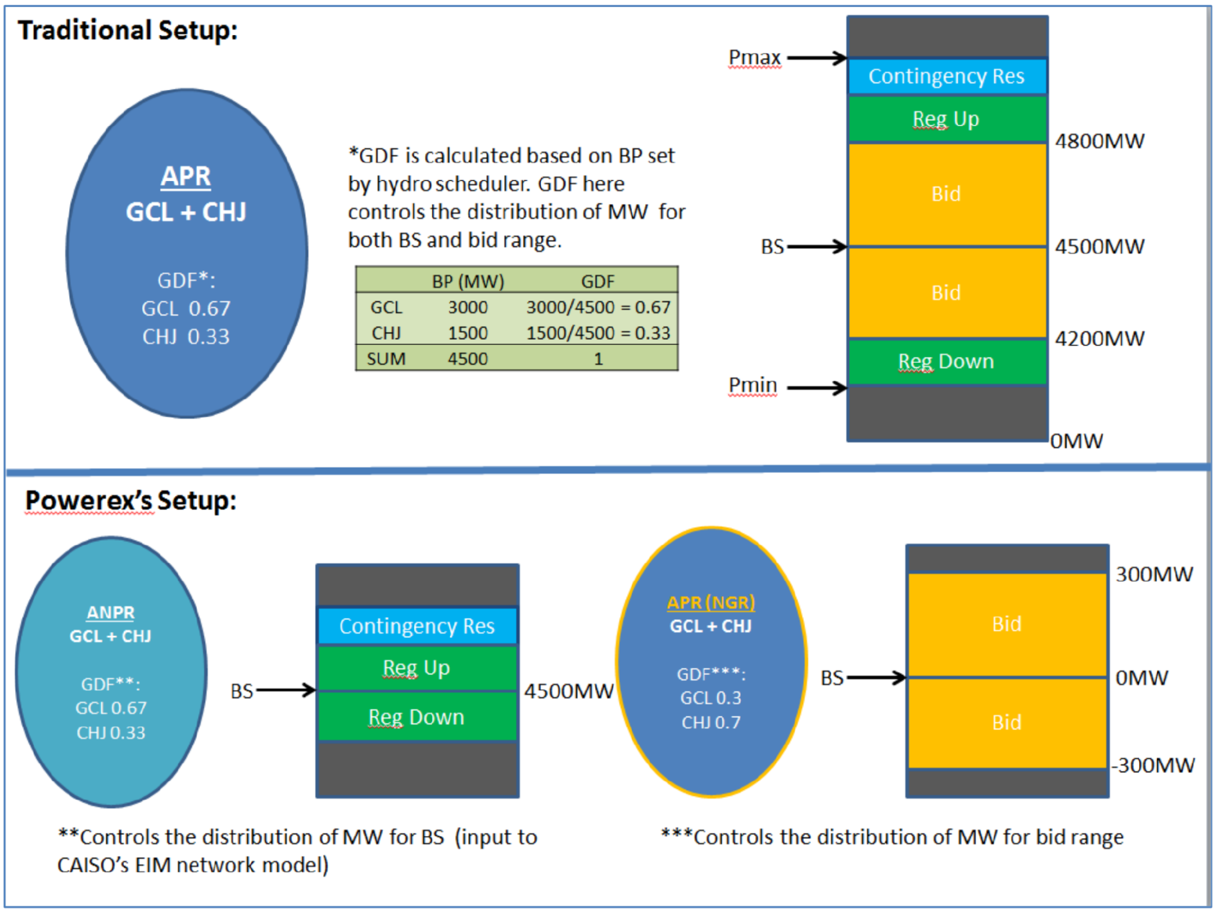
The illustration below (using the Upper Columbia aggregate resources as an example) compares the traditional and PWX's participation models.

- The traditional set-up considers the entire aggregate as a participating resource. The PWX model explicitly partitions the resource and allocates the EIM bids/offers to the APR and load and ancillary services obligations to the ANPR.

- In the traditional set-up, a base schedule (load and ancillary services) and a bid range (market bids/dispatches) are submitted to CAISO. In PWX's set-up, a base schedule for the ANPR and a bid range (zero base schedule) for the APR are submitted.

- In the traditional set-up, a base point (BP) for each project is submitted and GDF's would be computed based on those base points.

- In the traditional setup, a single set of GDFs is used to control the MW distribution for the base schedule (BS) and bid range. The GDFs are computed as the proportion of the base schedule of the individual resource to the aggregated sum. These computed GDFs are then used to determine how individual projects respond to market dispatches, which implies that the proportion of project flexibility to aggregate flexibility offered to the market would have to match these computed GDFs. PWX's set-up uses these computed GDFs (base GDF) for the ANPR's base schedule and allows the use of a different set of GDFs to respond to market dispatches.



Stakeholders:

<u>Internal</u> Stakeholders (Please Describe in Appropriate Detail)	What They Want or Need (& Why, if helpful)	What They Will Resist
Power Operations (PG)	• Ability to meet high-priority non-power obligations and constraints placed on the FCRPS • Discretion to operate the FCRPS in the most efficient manner • Cost recovery	• Difficulty in managing risk of de-optimization[3] • More manual processes
Bulk Marketing (PT)	• Maintain control over how much dispatch control at any given moment is given to the CAISO • Minimize the opportunity for CAISO to de-optimize (in revenue terms) FCRPS operations • Ability to shape *limited* energy into highest-value periods • Ability to have algorithmic/automated bid curve creation and submission	• Alternatives that limit access to other high-valued CAISO markets • Exclusion of manual processes, such that innovation is limited • Alternatives that result in local market power mitigation • Undue scheduling complexity
Transmission Operations (TO)	• The ability for the market to manage congestion proactively and in real-time • The visibility of EIM market dispatches and the impacts on the transmission system	• Participation framework that unduly limits the ability of the market to manage congestion or adversely impacts congestion.
Transmission Sales & Marketing (TS)	• Maintain/improve system reliability through enhanced congestion management • Maintain benefits of firm transmission rights to transmission customers, thus minimizing revenue loss (shift).	• Aggregation that is too big to allow for the EIM to help solve congestion.
Negotiations Team		
Legal	• Maintain compliance with all statutory requirements	• Any action that conflicts with statutory requirements

[3] For purposes of this discussion, de-optimization of the FCRPS refers to EIM dispatches that result in an un-anticipated reduction in future flexibility. For example, with the same bid curve, Lower Columbia projects could be given dispatch instructions that drafts or fills some of the projects without touching other projects. This could leave some projects too full (which risks spill) or too empty (which limits fuel).

External Stakeholders (Please Describe in Appropriate Detail)	What They Want or Need (& Why, if helpful)	What They Will Resist
CAISO	• Generator level visibility for most efficient market dispatch	• Aggregations that are not electrically similar
EIM Entities	• Enable better market liquidity for their own operations	• BPA receiving special treatment
Corps/Bureau	• Better visibility on expected generation	• Risk to BiOP or other statutory obligations. • Wear and tear on equipment. • Changes to their staffing?

4. Define objectives & decision criteria

Describe the desired end state to be accomplished or achieved:

Decision #1: Aggregation of resources

Objectives:

1. Preserve and enhance the value of Northwest hydropower and transmission operations for our customers and the region by making more efficient use of the FCRPS and FCRTS.
    a. Ability to mitigate risks of de-optimization of the FCRPS
    b. Maximize transmission congestion management benefits
    c. Capture revenue benefits from joining the CAISO EIM
2. Implementation should be straightforward with little to no manual work-arounds for submitting hourly bids to the CAISO.
3. Following the market dispatch instructions will be straightforward with little to no manual work-arounds.
4. Settlements will be as straightforward as possible.

Decision Criteria:

1. Maximum flexibility of the FCRPS offered into the market[4]
2. Maximize the value to the FCRPS of differential locational marginal pricing (LMP) generally caused by congestion
3. Maximize the value to the FCRPS from participation through explicit reflection of different opportunity costs across the system
4. Maximum transmission congestion relief
5. Systems and processes that are necessary to participate are simplest as possible to implement
6. Likely to be accepted as a model of participation from the CAISO
7. Ability to mitigate the risk of FCRPS de-optimization due to market dispatch instructions
8. Settlements are easy to implement[4]
9. Prevent unintentional cost shifts among Transmission and Power customers[4]
10. Minimize risk of local market power mitigation[4]
11. Flexibility to evolve FCRPS participation as more is learned about EIM implementation and negotiation

[4] These criteria will not be scored until more is known about EIM implementation

5. Assess risks of status quo

The status quo for EIM participation does not exist. This section is intentionally left blank.

6. Identify alternatives

Decision #1: Aggregation of resources

Alternative A – one aggregate: all "Big10" projects' data will be aggregated into one *resource*

Alternative B – Three aggregates: **"**Big10" projects will be aggregated into three resources each corresponding to a subset of the Big10 (Upper Columbia, Lower Snake, and Lower Columbia)

Alternative C – Project level: each "Big10" project will be a participating resource at the project level, no aggregation

Alternative D – Hybrid: Resource #1: Upper Columbia Resource; #2: John Day and The Dalles; Resource#3: Lower Granite, Little Goose, Lower Monumental. Ice Harbor, McNary, and Bonneville will be individual participating resources

Decision #2: Partition resource into APR and ANPR or Not

Alternative 1 – Utilize the APR/ANPR set-up: When each resource or aggregated resource is partitioned into an APR and ANPR, BPA will be able to use different GDFs to separate market bids/dispatches and load/ACS obligations.

Alternative 2 – Do Not Utilize the APR/ANPR set-up

7. Assess risks of alternatives

Decision #1: Aggregation of resources

Alternative A – one aggregate (System): all "Big10" projects' data will be aggregated into one *resource*. The risk of Alternative A is that the projects are not electrically similar enough for the CAISO to accept the proposal. BPA will get no congestion relief with this alternative nor will BPA be able to take advantage of additional revenue associated with differential LMPs.

Alternative B – Three aggregates: **"**Big10" projects will be aggregated into three resources each corresponding to a subset of the Big10 (Upper Columbia, Lower Snake, and Lower Columbia). The risk of this alternative is that it is an in-between solution meaning that it potentially has all the complexity of Alternative C but not all of the congestion relief or revenue benefits of Alternative C.

Alternative C – Project level: The biggest risk to this alternative is the difficulty in managing the risk of de-optimization of the FCRPS. In this alternative, dispatch signals will come directly from the market operator and will not reflect hydraulic optimization. For example, absent mitigation, a run-of-river project (like The Dalles) could get a dispatch from the market operator that is greater than the dispatch from the upstream storage project (John Day in this example) which would empty the run-of-river project. While this risk may be mitigated by using market tools and/or finessing the bid curve, it could be more complex than in other alternatives. In addition, there could be increased workload in managing multiple bid curves.

Alternative D – Hybrid: This alternative has all of the risks of B (congestion relief) and C (de-optimization) since it is a hybrid.

Decision #2: Partition resource into APR and ANPR or Not

The risk of Alternative 1 is unknown; it has yet to be implemented by CAISO and PWX.

The risk of Alternative 2 is artificially limited flexibility.

8. Analyze & rank alternatives

Decision #1: Aggregation of resources

Each alternative is evaluated 1-5 against the criteria above which are measures of the objectives. 1 is the lowest (least likely to meet the objective) and 5 is the highest (most likely to meet the objective). Alternative can be equally likely to meet the objective (which means ties along a row are allowed)

Decision Criteria	Alternative A 1 aggregate (System)	Alternative B 3 aggregates (GCL/CHJ, LSN, LCOL)	Alternative C Project Level	Alternative D Hybrid
Maximum flexibility (most amount) of the FCRPS offered into the market[5]				
Maximize the value to the FCRPS of differential locational marginal pricing (LMP) generally caused by congestion	1	3	5	4
Maximize the value to the FCRPS from participation due to different opportunity costs across the system	1	4	4	4
Maximum transmission congestion relief	1	3	5	4
Systems and processes that are necessary to participate are simplest as possible to implement	5	4	3	2
Likely to be accepted as a model of participation from the CAISO	1	3	5	4
Ability to mitigate the risk of FCRPS de-optimization due to market dispatch instructions	4	4	2	3
Settlements are easy to implement[5]				
Prevent unintentional cost shifts among Transmission and Power customers[5]				
Minimize risk of local market power mitigation[5]				
Flexibility to evolve FCRPS participation as more is learned	5	4	1	3

Alternative A: All projects aggregated into one resource

- This aggregation includes resources which are electrically dissimilar which provides the least efficient congestion relief, therefore, unlikely to be accepted by the CAISO.
- Duty Scheduling Center (DSC) will manage GDFs manually at the project-level in real-time; modest impact to DSC workload and manageable with no additional BFTE.
- Market operator dispatch instructions can be translated to project-level in a manner closest to the current real-

[5] These criteria will not be scored until more is known about EIM implementation

time process.

- A single price curve would need to be developed which is closest to current real-time process.
- The tools and processes to mitigate de-optimization are the most similar to current tools and processes today.
- This option decreases the ability to use market tools and information provided in advisory/future market runs.
- This alternative offers the most optionality for shifting the aggregation participation model in the future towards an un-aggregated resource participation model as we learn more (shift to Alternative B, C or D).

Alternative B: Three aggregates

- This aggregation includes resources that are *mostly* electrically similar which allows the market to dispatch around congestion. This is most similar to how redispatch is done today and adequate in most cases. There is not enough disaggregation in this alternative to relieve WoJD flowgate; moreover, WoJD congestion is expected to increase with 15 minute PDCI scheduling.
- This alternative has a greater chance than Alternative A for CAISO to accept as a participation model due to the congestion benefits mentioned in the above bullet.
- DSC will manage GDFs manually in real-time, similar to Alternative A, yet would have to manage three bid curves, one for each aggregation. Any impact to DSC workload should be marginal.
- Market operator dispatch instructions can be translated to project-level in a manner similar to the current real-time process.
- This option has potential to use market tools and information provided in advisory/future market runs.
- Has the potential to be the "sweet spot" for the starting participation model because it blends the current real-time adjustment process and new market tools in order to mitigate de-optimization between projects while providing incremental congestion relief. BPA still has the ability to further disaggregate participating resources in the future (shift to Alternative C or D).

Alternative C: No aggregations, the Big10 projects are individual resources

- This alternative would provide the most efficient market dispatches to relieve congestion on most flowgates, such as WoJD. Congestion at WoJD is expected to increase with 15 minute PDCI scheduling.
- Alternative C is CAISO's preferred participation model (individual participating resources).
- The development of the bid curve data has the greatest complexity of all the alternatives and potentially the greatest increase to DSC workload that could require additional BFTE especially if managing 10 different bid curves is required.
- Market operator dispatch instructions can be directly translated to project-level operations (no GDFs).
- Mitigation of hydraulic de-optimization would have to be managed at the project level requiring proficient use of new market tools and processes.
- If no aggregation is our beginning participation model, it will be difficult to persuade CAISO to incorporate an aggregation model in the future.

Alternative D: Hybrid

- This aggregation includes resources that are mostly electrically similar which allows the market to dispatch around congestion.
- This alternative has a greater chance than Alternative A or B for CAISO to accept as a participation model due to the congestion benefits mentioned in the above bullet.
- DSC will manage GDFs manually in real-time, similar to Alternative A, yet would have to manage multiple bid curves, one for each aggregation and one for each individual project. Any impact to DSC workload should be

marginal.

- This option has potential to use market tools and information provided in advisory/future market runs.
- This alternative blends the current real-time adjustment process and new market tools to mitigate hydraulic de-optimization which is incrementally more complex than Alternative B. For example, if the EIM participating resources operating in isolation cause downstream problems at relatively small reservoirs.

Decision #2: Partition resource into APR and ANPR or Not

Alternative 1 – Utilize the APR/ANPR set-up

- Implementation of this approach provides transparency for how the aggregated resources are allocated for base operations and for market bids/dispatches.
- BPA will be able to use different GDFs to separate market bids/dispatches and load/ACS obligations.

Alternative 2 – Do Not Utilize the APR/ANPR set-up

- Implementation of this approach would likely result in very conservative hydraulic operation and limited EIM market participation because one cannot delineate the flexibility required for base operations from the flexibility offered for market dispatches.

9. Recommendation

Decision #1: Aggregation of resources

The team recommends beginning negotiations with Alternative B, recognizing that Alternative D and possibly Alternative C may be preferred if the benefits of doing so become apparent as we learn more about the market and engage the CAISO and stakeholders. Alternative C and D might be necessary for congestion management if WoJD and WoLM flowgates are more congested in the future. Alternative B provides a reasonable “starting point” to evaluate the use of multiple APRs and adjustments to our participation model can be made as warranted by new information.

Opportunity costs within the proposed aggregates of Alternative B are likely similar. Opportunity costs across aggregates would likely differ. For these reasons, Alternative B likely captures higher revenue benefits than Alternative A, but has not been judged to be significantly less than Alternatives C and D.

An additional benefit to Alternative B is that while it is possible to disaggregate in the future, it is unlikely the CAISO will allow us to aggregate if we enter the market as individual resources (Alternative C).

Decision #2: Partition resource into APR and ANPR or Not

The team recommends Alternative 1. Pursuing the ability to adopt PWX’s aggregate participation model for aggregated resources mitigates the risk of artificially limited flexibility by allowing different GDFs for the portion of the aggregated resource dispatched by the balancing authority and that dispatched by the CAISO and is consistent with how we set basepoints and response factors today.

10. Present findings & document decision

- Develop briefing package.
- Present results to the decision maker(s), including decision insights, minority opinions, and preliminary implementation plan assumptions.
- Document decision, supporting information, high level planning estimates, and performance expectations informed by decision criteria.

See also Additional Guidance and Resources for Step 9.

On April 30, 2018, the Federal Resource Participation in an EIM ADF was presented to the following executives: Janet Herrin, Richard Shaheen, Joel Cook, Mary Jensen, Suzanne Cooper, Michelle Manary, and Michelle Cathcart. Also in attendance were Tom Davis, Nita Zimmerman, Todd Miller, Steve Kerns, and Russ Mantifel. After a brief presentation and Q&A, there was a unanimous decision from the executives on the staff recommendation for Decision 1 (Aggregation of Resources): Alternative B (Three Aggregates). While there was also broad agreement on the staff recommendation for Decision 2 (Partition Resources Into APR/ANPR): Alternative 1 (Utlilize APR/ANPR set-up), the decision was to observe PowerEx's implementation of this approach and move forward with the staff recommendation if there are no unresolved issues.

11. Transition to implementation

- Decision maker assigns management accountability for implementation.
- Form implementation team.
- Implementation team debriefs with ADF team.
- Management ensures that monitoring and reporting process is established.

See Additional Guidance and Resources for Step 10 for an implementation charter template.

12. Appendix

Definitions

Aggregate Non-Participating Resource (ANPR):

- ANPR is a defined portion of an actual physical resource used to respond to base schedules and reserve requirements. A set of base Generation Distribution Factors (GDF) is determined by the entity to distribute the energy among the projects within the aggregation. An ANPR can be AGC capable (this may be done, it is a choice, therefore the ANPR could be a mix of AGC-capable and non-AGC-capable resources)
- GDFs for the ANPR are set at t-75 minutes with bid submission for the operating hour (this must be done, it is not a choice); BA / EIM Entity may change the GDF until T-40 min.
- ANPR is "electrically similar" (this must be defined likely via path-transfer distribution factors (PTDFs, aka impacts on the transmission grid), there is an element of subjectivity to defining "electrically similar")
- An ANPR will have a base schedule quantity for every hour that adds up to the load and obligation forecast for that hour per the Resource Sufficiency check (this must be done, it is not a choice)
- ANPRs will not receive CAISO dispatches (this happens, it is not a choice)
- Physical deviation from the base schedules will result in uninstructed imbalance charges and create imbalance that will be subject to financial settlement via the CAISO EIM (this happens, it is not a choice)

Aggregate Participating Resource (APR):

- APR is a defined portion of an actual physical resource used to respond to EIM bids/offers. A set of Generation Distribution Factors (GDF) is submitted by the Entity to distribute energy among projects within the aggregation.

- APR is AGC capable (this must be done, it is not a choice)
- GDFs for the APR are set at T-75 minutes with bid submission for the operating hour (this must be done, it is not a choice); BA / EIM Entity may change the GDF until T-40 min
- APR is "electrically similar" (this must be defined likely via path-transfer distribution factors (PTDFs, aka generating resource impacts on the transmission grid), there is an element of subjectivity to defining "electrically similar")
- APR will have a base schedule quantity for every hour (this must be done, it is not a choice but it could be 0 as would likely be the case for Powerex every interval)
- APR will receive a financially binding dispatch from CAISO – Dispatch Operating Target (DOT) – every 5-minute market interval that may create imbalance which will be subject to financial settlement via the CAISO EIM (this must be done; however, how the DOT is passed to the resource is a choice, i.e. CAISO>project(PAC) or CAISO>BCH>project (PWX))
- ANPR is split into two resources: Generating Resource and Non-generating Resource
  - Generating Resource (GR):
    - GR will submit base schedules and will be carrying various ancillary services (regulation, contingency reserves, etc.)
    - GR do not submit GDFs or bid curves

  - Non-Generating Resource (NGR): Resources that operate as either Generation or Load and that can be dispatched to any operating level within their entire capacity range but are also constrained by a MWh limit to (1) generate energy; (2) curtail the consumption of energy in the case of demand response; or (3) consume energy. More generally, NGRs have a continuous operating range from a negative to a positive power injection (they can operate continuously by ether consuming energy or providing energy and can seamlessly switch between generating and consuming).
    - NGRs can provide ancillary services.
    - CAISO's NGR (Non-Generating Resource) model was originally developed to allow energy storage devices to participating in their market (e.g., Flywheels, Electric Cars, Batteries, Pumped Hydro, etc.)
    - PWX's APR is modeled as an NGR. NGR will have a base schedule of 0 MW and bids will be +/-, for example ± 250 MW.
    - GDFs for NGR will be determined for each upcoming hour

Generation Distribution Factor (GDF): The Bid template component that indicates the proportions of how the Bid is distributed for the resources participating in Physical Scheduling Plants, System Units, or Distributed Energy Resource Aggregations.

Base Generation Distribution Factor (Base GDF): A factor that indicates the proportions of how the energy is distributed among generators within an aggregated resource for a base schedule.

Non-Generating Resource Functionality: CAISO developed the concept of non-generating resources (NGRs) to allow energy storage devices to participate in their market (e.g., Flywheels, Electric Cars, Batteries, Pumped Hydro, etc.). NGRs are resources that operate as either Generation or Load and that can be dispatched to any operating level within their entire capacity range but are also constrained by a MWh limit to (1) generate energy; (2) curtail the consumption of energy in the case of demand response; or (3) consume energy.

Bid Curve

Initial thoughts:

Headwater projects, the Willamettes, and CGS carved off as non-participating resources. Here, still, there is a decision regarding how to aggregate the non-participating resources. Since there are still data –submission requirements for non-participating resources, it may be advantageous to aggregate these carved-off resources into a single non-participating resource.

For the balance of the system there is an advantage to aggregation, due to improved discretion for water management within the group of aggregated projects. Further, within the aggregation scheme chosen, BPA may have the option to partition each aggregate resource into participating and non-participating portions (i.e., the Powerex model). With respect to current BPA practice, there may be intuitive appeal to this strategy, since it represents an explicit reflection of which resources are meeting FCRPS obligations (load service, fish obligations, etc.) and which entity is making FCRPS dispatch decisions (kind of) and distinguishing these resources from those that are used for EIM marketing purposes. There is further intuitive appeal to treating the participating portion of an aggregate resource as a non-generating resource (NGR). As stated above (or in the appendix or whatever), an NGR is modeled as having a base schedule of zero. In this way, a single aggregate participating resource (with a strictly positive base schedule and surrounding dispatchable range) becomes two resources – one with a strictly positive base schedule and no EIM-dispatchable range and the other with zero-valued base schedule and the entire dispatchable range of the underlying resources. Finally, treatment of BPA's participating resource as a non-generating resource may be advantageous in avoiding mitigation of BPA's bids due to a finding of market power. The BPM on Market Operations, Appendix, Section B.1.3 states that NGR capacity is not included in the calculation of withheld capacity in determining the set of potentially pivotal suppliers. However, the Tariff, Section 34.1.5.1, states "Bids from resources comprised of multiple technologies that include Non-Generator Resources will remain to be subject to all applicable market power mitigation under the CAISO Tariff, including Local Market Power Mitigation." This latter statement appears more applicable to our participation, but may warrant verification with the CAISO.

Single Aggregate Participating Resource

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Partitioned Aggregate Resource

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Beyond aggregation, there may be an advantage to partitioning participating resources into generating resources and non-generating resources (i.e., the PWX model)

- Explicit reflection of which resources are meeting FCRPS obligations (load service, fish obligations, etc.) and which resources are used for EIM marketing purposes, explicit reflection of entity that is making FCRPS dispatch decisions
- Is there an advantage from a legal perspective in explicitly demonstrating that the FCRPS is meeting its own load?
- Simple aggregation into multiple resources (APR/ANPR) and partitioning multiple aggregated resources (PWX model) may achieve the same operational outcomes.

FCRPS Participation in EIM White Paper

FCRPS EIM v5.docx

Electrically Similar Analysis

Electrically_Similar_Analysis_v03.docx

Congestion Risk Analysis

Congestion_Risk_v04.docx

Parking Lot

Additional Considerations:

1. A more granular approach than Alternative B would allow Transmission to develop tools based on the base schedules and bids to accurately calculate ATC available to the market. This would help avoid market assumptions that strand FCRPS bid generation due to perceived congestion.
2. In lieu of a multi-state generator forbidden zone (in the outage card), BPA will have to handle deadbands via GDF.

Questions:

3. Are you able to outage card GDFs in real-time? If not, the implication is that aggregating resources severely limits your ability to make changes in real-time.
4. Automation of manual dispatches during contingency events?
5. Are GDFs submitted with bids? (We know it is not part of the master file)
6. Should Banks Lake be considered part of GCL or a "separate" resource? Banks Lake is unique in that it is a generator and a load and is non-dispatchable (cannot respond fast enough for market dispatches).

More information about EIM implementation is needed to score the decision criteria below:

A. <u>Maximum flexibility (most amount) of the FCRPS offered into the market</u>

It's unclear how much flexibility the FCRPS can offer without precedence of aggregate cascading hydro resources in the EIM. PWX will be the first EIM entity to have aggregate participating resources with an April 2018 "go-live" date.

B. <u>Settlements are easy to implement</u>

BPA does not understand the current CAISO EIM settlement process.

C. <u>Prevent unintentional cost shifts among Transmission and Power customers</u>

Unclear where the cost shifts will take place under any alternative.

D. <u>Minimize risk of local market power mitigation</u>

Broadly speaking, the likelihood that BPA's participating resource bids are mitigated in the CAISO's local market power mitigation (LMPM) process is dependent on several key factors. We currently have insufficient information to determine how (if at all) our choice of alternatives in this ADF will affect these key factors:

- The likelihood that transmission constraints (either between EIM BAAs or within BPA's EIM BAA) bind.
- The proximity (via associated shift factors) of BPA participating resources to the binding transmission constraint

- The amount of participating capacity from BPA and other EIM participating resource scheduling coordinators

At issue for the particular decision of how to aggregate our participating resources is how (or whether) the CAISO disaggregates aggregated resources for the LMPM market run. For an EIM participating resource's bid to be mitigated, it must be deemed to be "effective" at relieving congestion on a non-competitive path. Its effectiveness in achieving such relief is a function of the resource's proximity (via its associated shift factors) to the congested path and the amount of participating capacity offered by others into the market that is also effective in achieving relief on the congested path. It is currently unclear how GDFs of an aggregated resource will interact with the shift factors of the individual projects in the course of determining BPA's pivotal supplier status for binding transmission constraints in the EIM.

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Background:

The following describes the challenge of managing the risk of EIM dispatches de-optimizing the FCRPS:

Let's assume that we have a set of hydro projects that are close to each other such that the outflow of an upstream project impacts the inflow of a downstream project in an hour or two. The FCRPS has three of these sets: Coulee/Chief, the Lower Columbia projects, and the Lower Snake projects (i.e., the Big10). The real-time operation of these projects is closely monitored by hydro duty schedulers to avoid projects getting too full (risk of spill and lost generation), getting too empty (loss of storage and generating/ramping capability), or operating inefficiently (less MWs per unit of flow). Any of these three conditions are generally referred to as "de-optimizing" the hydraulic operation.

Currently, within hour movement of load and intermittent resources in our BA are accommodated by setting aside flexibility (balancing reserves) at these Big10 projects. The deployment of balancing reserves is accomplished by "response factors" that are manually set by hydro duty schedulers. For example, if Grand Coulee's response factor is .4, then Coulee will move 40 MW for every 100 MW of balancing reserves that are required to balance load and generation in the BA. Manually adjusting these response factors in real-time is the mitigation tool for dealing with de-optimization that results from reserve deployments.

Since Balancing Reserve deployment generally INCs and DECs within an hour, there tends to be little energy impact. However, if the EIM dispatches more consistently either INCs or DECs across the hour, then the energy impact would be greater as well as the risk of de-optimizing the FCRPS' operation. The method for mitigating the risk of de-optimizing the FCRPS depends on how participation of our resources is implemented.

Participation of FCRPS hydro projects in an EIM will require a decision on how these resources will be bid and how dispatch instructions from the market operator will be implemented. The intent of this paper is to discuss options on how FCRPS resources can participate in an EIM as well as pros/cons with each approach.

For discussion purposes in this paper, the term *EIM resource* will be used to reference the type of resource that the market operator sees and are limited to the dispatchable "Big10" FCRPS hydro projects. The assumption about the other non-dispatchable FCRPS projects is that they will be self-scheduled (as is the current practice) and not considered by the market operator for EIM dispatches. Data that is required to be submitted to the market operator for the *EIM resources* include base generation, minimum generation, maximum generation, and a bid curve for the upcoming hour, as well as an indication of the regulation, load following and contingency reserve requirements. The market operator will perform a calculation every five minutes and send a dispatch instruction to each *EIM resource* depending upon their submitted flexibility and the cleared price.

The fundamental question is how granular should FCRPS "Big10" resources be bid into the EIM, and there appear to be four options:

1. **BIG10 Level:** all "Big10" projects' data will be aggregated into one *EIM resource*.
2. **Zonal Level: "**Big10" projects' data will be aggregated into zones each corresponding to an *EIM resource* (Coulee/Chief, Lower Snake, and Lower Columbia, for example)
3. **Project Level:** all "Big10" projects' data will each be submitted as individual *EIM resources*.
4. **Hybrid:** Big10 will be broken up into self-scheduled resources and individual *EIM resources*. (Coulee/John Day as individual *EIM resources*, the rest of the "Big10" self-scheduled, for example)

Considerations:

As pros/cons of each of the alternatives are developed, there are a few things to keep in mind:

- For purposes of grid reliability and congestion management, there is a desire for as much granularity as possible for the *EIM resources.*
- The current practice in BPA's BA of dispatching balancing reserves to manage load and generation imbalance is market price-insensitive and generally fairly random within an hour. However, EIM market dispatches are price-driven and tend to dispatch *EIM resources* in a similar manner throughout the hour except for the *EIM resource* that is setting the price on the 5-minute interval. The result is that FCRPS *EIM resources* could be consistently dispatched at the minimum or maximum generation levels[1] that are submitted to the market operator.
- Moving to a market dispatch that is more granular than the **Big10 Level** risks de-optimizing the FCRPS[2] unless we figure out a way to reflect the costs of de-

[1] Minimum and maximum levels that are submitted to the market operator are at the discretion of the hydro duty scheduler and not necessarily the absolute generation limits.
[2] For purposes of this discussion, *de-optimization of the FCRPS* refers to EIM dispatches that result in an un-anticipated reduction in future flexibility. For example, with the same bid curve, Lower Columbia projects could be given dispatch instructions that drafts or fills some of the projects without touching other projects. This could leave some projects too full (which risks spill) or too empty (which limits fuel).

optimizing the FCRPS in the development of the price curves, limit the FCRPS flexibility that is being submitted, and/or develop a hydro-optimization post-processor. The level of complexity of how this risk is mitigated is an important consideration.

- (b)(4) [redacted]
- [redacted]
- Hydro duty scheduling workload will be impacted by the path that is chosen – perhaps significantly.

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[4] Market power to a seller is the ability to profitably maintain prices above competitive levels for a significant period of time. In economics, market power is defined as the ability to alter profitably price away from competitive level and market efficiency. For the purposes of this paper, market power references horizontal market power in which generation concentration from two or more firms is perceived to conspire to act more or less like a monopolist.

Alternatives:

1. **BIG10 Level:** all "Big10" projects' data will be aggregated into one *EIM resource*. From an implementation perspective, this is probably the easiest since the market operators' dispatch instructions could be post-processed by using the existing (or an improved version) of response factors. However, there is very little, if any, benefits to grid reliability or congestion management from this approach

   Pros:

   - Hydro and price curve data submission is fairly straight-forward
   - Market operator dispatch instructions can be translated to project-level in a manner close to status quo
   - No increased risk of hydraulic de-optimization
   - While still a potential, this option is likely has the smallest risk of market power and mitigation of bids
   - Modest impact to DSC workload and manageable with no additional BFTE

   Cons:

   - Little, if any, benefit to grid reliability or congestion management
   - No financial benefit to Power Services beyond what is expected in the cost/benefit analysis

2. **Zonal Level:** "Big10" projects' data will be aggregated into zones each corresponding to an *EIM resource.* At first blush, using three zones (GCL/CHJ, LSN, LCOL) would seem doable (but more challenging) from an implementation perspective and would allow for some benefits for grid reliability and congestion management. This approach could also potentially allow for some additional financial benefits for Power Services since the bid curves could be tuned to reflect more refined opportunity costs in each of the zones (for example, the opportunity costs of moving water around at Grand Coulee could be different than moving water around on the Lower Snakes). A challenge would be developing a methodology to post-process market operator zonal dispatch instructions to project-level.

   Pros:

   - Some benefit to grid reliability or congestion management
   - Potential of some additional financial benefit to Power Services

   Cons:

   - Hydro and price curve data creation and submission is fairly complex
   - Mitigation of hydraulic de-optimization could be complex
   - Market operator dispatch instructions translation to project-level could be fairly complex
   - More zones, increase the risk of market power findings and mitigation of bids
   - Depending on the zones chosen, there could be a large impact to DSC workload that could require additional BFTE

3. **Project Level:** all "Big10" projects' data will be submitted as individual *EIM resources*. From a hydro data submission perspective, this approach is not much different from the **Big10 Level** alternative since the data exists. However, there is a wild card in how complex the development of the bid curve data will be. This approach would maximize the benefit for grid reliability and congestion management. This approach could also potentially allow for some additional financial benefits for Power Services since the bid curves could be tuned to reflect more refined opportunity costs in the same manner as the **Zonal Level** alternative. While there is no need to develop a methodology to post-process the market instructions since they are already at the project level, there is risk of hydraulic de-optimization if we aren't careful in how the hydro and price data are constructed.

   Pros:

   - Hydro data submission is fairly straight-forward
   - Maximum benefits to grid reliability or congestion management
   - Potential of some additional financial benefit to Power Services
   - Minimizes need to post process market operator dispatch instructions

   Cons:

   - Price curve data construction and submission could be very complex
   - Mitigation of hydraulic de-optimization could be complex
   - More zones, increase the risk of market power findings and mitigation of bids
   - Large impact to DSC workload that would likely require additional BFTE

4. **Hybrid:** Big10 will be broken up into self-scheduled resources and individual *EIM resources*. The idea here is find a way that preserves the potential benefits while minimizing the risk of hydraulic de-optimization. The mix of *EIM resources* and self-scheduled resources would be set going into the EIM and would not change. Suppose we picked just a couple projects from the "Big 10" (Grand Coulee and John Day being the most obvious, but using small zones like John Day/The Dalles is also worth considering) and only offered them as *EIM resources*, and the remaining "Big 10" projects would be self-scheduled. We could also envision this approach as allowing the change of groupings and projects that define EIM resources as conditions change. Using the most operationally flexible and isolated projects minimizes the risk of hydro de-optimization within the hour and maintaining the project granularity that maximizes the grid reliability and congestion management benefits. However, to do this, we would have to completely change how we allocate regulation, load following and contingency reserves[5] so that these *EIM resources* can have maximum flexibility offered to the market operator to preserve the financial benefits for Power Services. In addition, there is a risk of incurring imbalance at the remaining "Big 10" projects.

   Pros:

   - Hydro and price curve data submission is fairly straight-forward
   - Maximum benefits to grid reliability or congestion management
   - Potential of some additional financial benefit to Power Services
   - No need to post process market operator dispatch instructions

   Cons:

   - Risk of incurring imbalance from the self-scheduled "Big10" projects
   - Mitigation of hydraulic de-optimization could be complex if the *EIM Resources* operating in isolation cause downstream problems at relatively small reservoirs.
   - Depending on the approach, there could be a large impact to DSC workload that could require additional BFTE

Information Gathering

Information gathering from the CAISO on the following topics is necessary in order for this team to give a recommendation on the "must-haves".

[5] This is part of the Reserves Enhancement Commercial Operations project.

Tools:

Currently it is unclear what operational tools will be available to mitigate de-optimization. One must have already discussed is the ability to change base schedules in response to late-breaking changes. These changes can be anything from weather and emergency ops for barge passage or Slice. Will all of the actions we take in response to these late-breaking changes be charged as imbalance? If these are all treated as imbalance, we will have to choose the bidding structure that minimizes these charges.

Settlements and Pricing:

Are INCs and DECs priced similarly to how the BPA BA charges today? ie we pay for the DEC but are paid for the INC. If there is no congestion and therefore no difference in the locational marginal price across the nodes, then redispatching to mitigate the de-optimization could be straightforward.

Reserves, self-schedules, and projects on response:

We need flexibility in how we carry reserves regardless of what option we choose and we need to know how the CAISO will treat the imbalance created by deploying those reserves.

Can the projects change from a participating resource to a self-scheduled one each hour? If things were going off the rails, would BPA self-schedule the projects that are in trouble? What is the "cons" of periodic self-scheduling individual projects?

Objective & Approach:

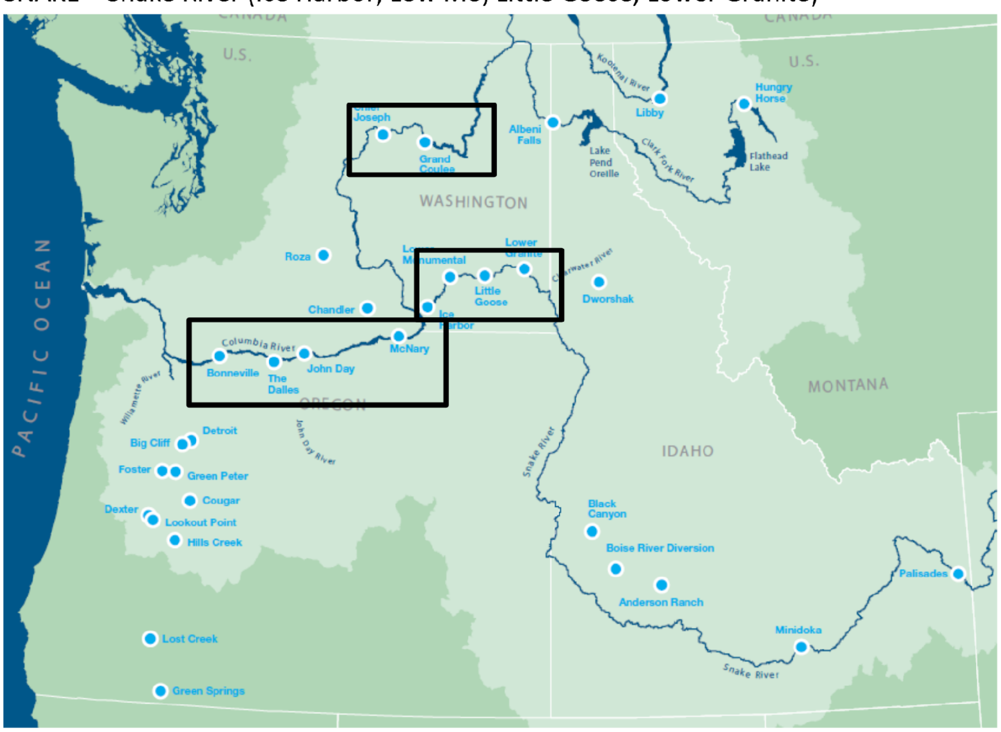
In order to determine which of the big-10 FCRPS resources are electrically similar to one another relative to BPA's internal flowgates, a set of Generation Shift Factors (GSFs) were calculated from a 2019 all lines in service planning case. In the context of any specific flowgate, resources that have very similar GSFs are considered to be electrically similar for that flowgate - in this analysis, if the difference between any two GSFs were less than 10%, the resources were considered to be electrically similar. Three separate aggregations of resources were specifically considered: Upper Columbia (Chief and Coulee), Lower Columbia (Bonneville, The Dalles, John Day, McNary), and the Snake River projects (Ice Harbor, Low Mo, Little Goose, Lower Granite).

Methodology:

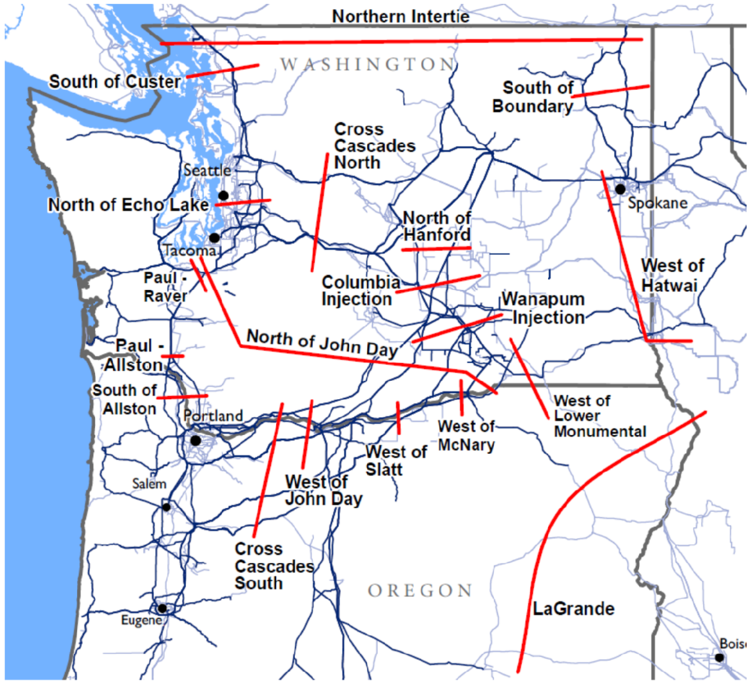
- Used 2019 planning case – all lines in service
- Used Generation Shift Factors (i.e., GSF/PTDFs) - analyzed impacts of each plant relative to one another
- Used 10% threshold
- Outages were not considered
- Not verified – draft results!

Definitions:

- UPPER = Upper Columbia (Chief and Coulee)
- LOWER = Lower Columbia (Bonneville, The Dalles, John Day, McNary)
- SNAKE = Snake River (Ice Harbor, Low Mo, Little Goose, Lower Granite)



Flowgates:



Summary:

ELECTRICALLY SIMMILAR @ 10%				
FLOWGATE	**UPPER**	**LOWER**	**SNAKE**	**NOTES**
CCN	YES	MAYBE	YES	Bonneville slightly above 10% in Lower
CCS	YES	NO	YES	Bonneville much higher than 10% in Lower
NOEL	YES	YES	YES	
NOH	YES	MAYBE	YES	Bonneville slightly above 10% in Lower
NJD	YES	YES	NO	Ice Harbor much higher than 10%
PA	YES	MAYBE	YES	Bonneville slightly above 10% in Lower
RP	YES	MAYBE	YES	Bonneville slightly above 10% in Lower
SOA	YES	MAYBE	YES	Bonneville slightly above 10% in Lower
SOC	YES	YES	YES	
WOJD	YES	NO	YES	
WOLM	YES	YES	NO	Ice Harbor has a large impact (>80%)
WOM	YES	NO	MAYBE	Ice Harbor a little less than 20%
WOS	YES	MAYBE	YES	Impacts range from 5-32%

Based on the preliminary/draft results, Upper Columbia resources can be considered electrically similar. For the Lower Columbia resources, Bonneville and McNary would ideally not be included in an aggregation. However, WOJD is problematic for the Lower Columbia resources in total and doesn't lend itself to any Lower Columbia aggregation - additional analysis will be required to determine if an aggregation can be allowed. For the Snake resources, excluding Ice Harbor from the aggregation would probably be acceptable, pending further analysis.

FLOWGATE:		CROSS CASCADES NORTH E>W														
PERCENT:		10.0%														
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	JDA	TDA	BON	ALF	DWR	HGH	LIB	BLK	LWG	LGS	LMN	IHR	GCL	CHJ
LOW1	MCN	0.0%	1.7%	3.5%	14.8%	2.2%	4.6%	3.5%	3.2%	2.2%	4.6%	4.7%	4.7%	3.2%	15.6%	17.9%
LOW2	JDA	1.7%	0.0%	1.8%	13.1%	0.5%	6.3%	5.2%	4.9%	0.5%	6.3%	6.3%	6.4%	4.9%	17.3%	19.6%
LOW3	TDA	3.5%	1.8%	0.0%	11.3%	1.3%	8.1%	7.0%	6.7%	1.3%	8.1%	8.2%	8.2%	6.7%	19.1%	21.4%
LOW4	BON	14.8%	13.1%	11.3%	0.0%	12.6%	19.4%	18.3%	18.0%	12.6%	19.4%	19.4%	19.5%	18.0%	30.4%	32.7%
OTH	ALF	2.2%	0.5%	1.3%	12.6%	0.0%	6.8%	5.7%	5.4%	0.0%	6.8%	6.9%	6.9%	5.4%	17.8%	20.1%
OTH	DWR	4.6%	6.3%	8.1%	19.4%	6.8%	0.0%	1.1%	1.4%	6.8%	0.0%	0.0%	0.1%	1.5%	11.0%	13.3%
OTH	HGH	3.5%	5.2%	7.0%	18.3%	5.7%	1.1%	0.0%	0.3%	5.7%	1.1%	1.1%	1.2%	0.3%	12.1%	14.4%
OTH	LIB	3.2%	4.9%	6.7%	18.0%	5.4%	1.4%	0.3%	0.0%	5.4%	1.4%	1.4%	1.5%	0.0%	12.4%	14.7%
OTH	BLK	2.2%	0.5%	1.3%	12.6%	0.0%	6.8%	5.7%	5.4%	0.0%	6.8%	6.9%	6.9%	5.4%	17.8%	20.1%
SNK1	LWG	4.6%	6.3%	8.1%	19.4%	6.8%	0.0%	1.1%	1.4%	6.8%	0.0%	0.0%	0.1%	1.4%	11.0%	13.3%
SNK2	LGS	4.7%	6.3%	8.2%	19.4%	6.9%	0.0%	1.1%	1.4%	6.9%	0.0%	0.0%	0.0%	1.5%	11.0%	13.3%
SNK3	LMN	4.7%	6.4%	8.2%	19.5%	6.9%	0.1%	1.2%	1.5%	6.9%	0.1%	0.0%	0.0%	1.5%	10.9%	13.3%
SNK4	IHR	3.2%	4.9%	6.7%	18.0%	5.4%	1.5%	0.3%	0.0%	5.4%	1.4%	1.5%	1.5%	0.0%	12.4%	14.8%
UP1	GCL	15.6%	17.3%	19.1%	30.4%	17.8%	11.0%	12.1%	12.4%	17.8%	11.0%	11.0%	10.9%	12.4%	0.0%	2.3%
UP2	CHJ	17.9%	19.6%	21.4%	32.7%	20.1%	13.3%	14.4%	14.7%	20.1%	13.3%	13.3%	13.3%	14.8%	2.3%	0.0%

FLOWGATE:		CROSS CASCADES SOUTH E>W														
PERCENT:		10.0%														
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	JDA	TDA	BON	ALF	DWR	HGH	LIB	BLK	LWG	LGS	LMN	IHR	GCL	CHJ
LOW1	MCN	0.0%	0.1%	2.4%	76.8%	12.8%	8.5%	11.1%	11.3%	12.8%	5.8%	5.1%	4.7%	3.3%	14.0%	15.2%
LOW2	JDA	0.1%	0.0%	2.2%	77.0%	12.9%	8.7%	11.2%	11.5%	12.9%	5.9%	5.2%	4.8%	3.4%	14.1%	15.3%
LOW3	TDA	2.4%	2.2%	0.0%	79.2%	15.1%	10.9%	13.5%	13.7%	15.1%	8.1%	7.4%	7.0%	5.7%	16.3%	17.5%
LOW4	BON	76.8%	77.0%	79.2%	0.0%	64.1%	68.3%	65.7%	65.5%	64.1%	71.1%	71.7%	72.2%	73.5%	62.9%	61.7%
OTH	ALF	12.8%	12.9%	15.1%	64.1%	0.0%	4.2%	1.6%	1.4%	0.0%	7.0%	7.7%	8.1%	9.5%	1.2%	2.4%
OTH	DWR	8.5%	8.7%	10.9%	68.3%	4.2%	0.0%	2.6%	2.8%	4.2%	2.8%	3.5%	3.9%	5.2%	5.4%	6.6%
OTH	HGH	11.1%	11.2%	13.5%	65.7%	1.6%	2.6%	0.0%	0.2%	1.6%	5.3%	6.0%	6.4%	7.8%	2.9%	4.1%
OTH	LIB	11.3%	11.5%	13.7%	65.5%	1.4%	2.8%	0.2%	0.0%	1.4%	5.6%	6.2%	6.7%	8.0%	2.6%	3.8%
OTH	BLK	12.8%	12.9%	15.1%	64.1%	0.0%	4.2%	1.6%	1.4%	0.0%	7.0%	7.7%	8.1%	9.5%	1.2%	2.4%
SNK1	LWG	5.8%	5.9%	8.1%	71.1%	7.0%	2.8%	5.3%	5.6%	7.0%	0.0%	0.7%	1.1%	2.5%	8.2%	9.4%
SNK2	LGS	5.1%	5.2%	7.4%	71.7%	7.7%	3.5%	6.0%	6.2%	7.7%	0.7%	0.0%	0.4%	1.8%	8.9%	10.1%
SNK3	LMN	4.7%	4.8%	7.0%	72.2%	8.1%	3.9%	6.4%	6.7%	8.1%	1.1%	0.4%	0.0%	1.4%	9.3%	10.5%
SNK4	IHR	3.3%	3.4%	5.7%	73.5%	9.5%	5.2%	7.8%	8.0%	9.5%	2.5%	1.8%	1.4%	0.0%	10.7%	11.9%
UP1	GCL	14.0%	14.1%	16.3%	62.9%	1.2%	5.4%	2.9%	2.6%	1.2%	8.2%	8.9%	9.3%	10.7%	0.0%	1.2%
UP2	CHJ	15.2%	15.3%	17.5%	61.7%	2.4%	6.6%	4.1%	3.8%	2.4%	9.4%	10.1%	10.5%	11.9%	1.2%	0.0%

FLOWGATE:		NORTH OF ECHO LAKE S>N														
PERCENT:		10.0%														
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	JDA	TDA	BON	ALF	DWR	HGH	LIB	BLK	LWG	LGS	LMN	IHR	GCL	CHJ
LOW1	MCN	0.0%	0.4%	0.4%	0.7%	10.7%	3.2%	5.9%	6.4%	10.7%	1.2%	0.6%	0.3%	0.3%	3.2%	10.3%
LOW2	JDA	0.4%	0.0%	0.0%	0.3%	11.1%	3.6%	6.3%	6.8%	11.1%	1.6%	1.0%	0.7%	0.7%	3.6%	10.7%
LOW3	TDA	0.4%	0.0%	0.0%	0.2%	11.2%	3.7%	6.3%	6.8%	11.2%	1.6%	1.1%	0.8%	0.8%	3.6%	10.7%
LOW4	BON	0.7%	0.3%	0.2%	0.0%	11.4%	3.9%	6.6%	7.1%	11.4%	1.8%	1.3%	1.0%	1.0%	3.9%	10.9%
OTH	ALF	10.7%	11.1%	11.2%	11.4%	0.0%	7.5%	4.9%	4.3%	0.0%	9.6%	10.1%	10.4%	10.4%	7.5%	0.5%
OTH	DWR	3.2%	3.6%	3.7%	3.9%	7.5%	0.0%	2.7%	3.2%	7.5%	2.1%	2.6%	2.9%	2.9%	0.0%	7.0%
OTH	HGH	5.9%	6.3%	6.3%	6.6%	4.9%	2.7%	0.0%	0.5%	4.9%	4.7%	5.2%	5.6%	5.6%	2.7%	4.4%
OTH	LIB	6.4%	6.8%	6.8%	7.1%	4.3%	3.2%	0.5%	0.0%	4.3%	5.2%	5.8%	6.1%	6.1%	3.2%	3.9%
OTH	BLK	10.7%	11.1%	11.2%	11.4%	0.0%	7.5%	4.9%	4.3%	0.0%	9.6%	10.1%	10.4%	10.4%	7.5%	0.5%
SNK1	LWG	1.2%	1.6%	1.6%	1.8%	9.6%	2.1%	4.7%	5.2%	9.6%	0.0%	0.5%	0.8%	0.8%	2.0%	9.1%
SNK2	LGS	0.6%	1.0%	1.1%	1.3%	10.1%	2.6%	5.2%	5.8%	10.1%	0.5%	0.0%	0.3%	0.3%	2.6%	9.6%
SNK3	LMN	0.3%	0.7%	0.8%	1.0%	10.4%	2.9%	5.6%	6.1%	10.4%	0.8%	0.3%	0.0%	0.0%	2.9%	9.9%
SNK4	IHR	0.3%	0.7%	0.8%	1.0%	10.4%	2.9%	5.6%	6.1%	10.4%	0.8%	0.3%	0.0%	0.0%	2.9%	9.9%
UP1	GCL	3.2%	3.6%	3.6%	3.9%	7.5%	0.0%	2.7%	3.2%	7.5%	2.0%	2.6%	2.9%	2.9%	0.0%	7.1%
UP2	CHJ	10.3%	10.7%	10.7%	10.9%	0.5%	7.0%	4.4%	3.9%	0.5%	9.1%	9.6%	9.9%	9.9%	7.1%	0.0%

FLOWGATE:		NORTH OF HANFORD N>S														
PERCENT:		10.0%														
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	JDA	TDA	BON	ALF	DWR	HGH	LIB	BLK	LWG	LGS	LMN	IHR	GCL	CHJ
LOW1	MCN	0.0%	4.2%	0.1%	12.2%	38.1%	14.8%	29.0%	30.7%	38.1%	1.7%	5.9%	8.4%	1.5%	56.3%	55.6%
LOW2	JDA	4.2%	0.0%	4.1%	16.3%	42.3%	18.9%	33.1%	34.8%	42.3%	2.5%	1.7%	4.2%	5.6%	60.4%	59.7%
LOW3	TDA	0.1%	4.1%	0.0%	12.2%	38.2%	14.8%	29.1%	30.8%	38.2%	1.6%	5.8%	8.3%	1.6%	56.3%	55.6%
LOW4	BON	12.2%	16.3%	12.2%	0.0%	26.0%	2.6%	16.8%	18.5%	26.0%	13.8%	18.0%	20.5%	10.7%	44.1%	43.4%
OTH	ALF	38.1%	42.3%	38.2%	26.0%	0.0%	23.4%	9.2%	7.5%	0.0%	39.8%	44.0%	46.5%	36.7%	18.1%	17.4%
OTH	DWR	14.8%	18.9%	14.8%	2.6%	23.4%	0.0%	14.2%	15.9%	23.4%	16.4%	20.6%	23.1%	13.3%	41.5%	40.8%
OTH	HGH	29.0%	33.1%	29.1%	16.8%	9.2%	14.2%	0.0%	1.7%	9.2%	30.7%	34.8%	37.4%	27.5%	27.3%	26.6%
OTH	LIB	30.7%	34.8%	30.8%	18.5%	7.5%	15.9%	1.7%	0.0%	7.5%	32.4%	36.5%	39.0%	29.2%	25.6%	24.9%
OTH	BLK	38.1%	42.3%	38.2%	26.0%	0.0%	23.4%	9.2%	7.5%	0.0%	39.8%	44.0%	46.5%	36.7%	18.1%	17.4%
SNK1	LWG	1.7%	2.5%	1.6%	13.8%	39.8%	16.4%	30.7%	32.4%	39.8%	0.0%	4.2%	6.7%	3.2%	57.9%	57.2%
SNK2	LGS	5.9%	1.7%	5.8%	18.0%	44.0%	20.6%	34.8%	36.5%	44.0%	4.2%	0.0%	2.5%	7.3%	62.1%	61.4%
SNK3	LMN	8.4%	4.2%	8.3%	20.5%	46.5%	23.1%	37.4%	39.0%	46.5%	6.7%	2.5%	0.0%	9.8%	64.6%	63.9%
SNK4	IHR	1.5%	5.6%	1.6%	10.7%	36.7%	13.3%	27.5%	29.2%	36.7%	3.2%	7.3%	9.8%	0.0%	54.8%	54.1%
UP1	GCL	56.3%	60.4%	56.3%	44.1%	18.1%	41.5%	27.3%	25.6%	18.1%	57.9%	62.1%	64.6%	54.8%	0.0%	0.7%
UP2	CHJ	55.6%	59.7%	55.6%	43.4%	17.4%	40.8%	26.6%	24.9%	17.4%	57.2%	61.4%	63.9%	54.1%	0.7%	0.0%

FLOWGATE:	NORTH OF JOHN DAY N>S															
PERCENT:	10.0%															
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	JDA	TDA	BON	ALF	DWR	HGH	LIB	BLK	LWG	LGS	LMN	IHR	GCL	CHJ
LOW1	MCN	0.0%	4.4%	1.2%	4.4%	71.3%	73.3%	69.3%	69.8%	71.3%	81.1%	83.7%	85.3%	0.5%	75.1%	74.5%
LOW2	JDA	4.4%	0.0%	3.2%	8.8%	75.7%	77.7%	73.7%	74.2%	75.7%	85.5%	88.1%	89.7%	4.9%	79.5%	78.9%
LOW3	TDA	1.2%	3.2%	0.0%	5.6%	72.5%	74.5%	70.5%	71.0%	72.5%	82.3%	84.9%	86.5%	1.7%	76.3%	75.7%
LOW4	BON	4.4%	8.8%	5.6%	0.0%	66.9%	68.9%	64.9%	65.4%	66.9%	76.7%	79.3%	80.9%	3.9%	70.7%	70.1%
OTH	ALF	71.3%	75.7%	72.5%	66.9%	0.0%	2.0%	2.0%	1.5%	0.0%	9.8%	12.4%	13.9%	70.8%	3.7%	3.1%
OTH	DWR	73.3%	77.7%	74.5%	68.9%	2.0%	0.0%	4.0%	3.5%	2.0%	7.8%	10.4%	11.9%	72.8%	1.7%	1.1%
OTH	HGH	69.3%	73.7%	70.5%	64.9%	2.0%	4.0%	0.0%	0.5%	2.0%	11.8%	14.4%	15.9%	68.8%	5.7%	5.1%
OTH	LIB	69.8%	74.2%	71.0%	65.4%	1.5%	3.5%	0.5%	0.0%	1.5%	11.3%	13.9%	15.4%	69.3%	5.2%	4.6%
OTH	BLK	71.3%	75.7%	72.5%	66.9%	0.0%	2.0%	2.0%	1.5%	0.0%	9.8%	12.4%	13.9%	70.8%	3.7%	3.1%
SNK1	LWG	81.1%	85.5%	82.3%	76.7%	9.8%	7.8%	11.8%	11.3%	9.8%	0.0%	2.6%	4.2%	80.6%	6.0%	6.6%
SNK2	LGS	83.7%	88.1%	84.9%	79.3%	12.4%	10.4%	14.4%	13.9%	12.4%	2.6%	0.0%	1.6%	83.2%	8.6%	9.2%
SNK3	LMN	85.3%	89.7%	86.5%	80.9%	13.9%	11.9%	15.9%	15.4%	13.9%	4.2%	1.6%	0.0%	84.7%	10.2%	10.8%
SNK4	IHR	0.5%	4.9%	1.7%	3.9%	70.8%	72.8%	68.8%	69.3%	70.8%	80.6%	83.2%	84.7%	0.0%	74.5%	73.9%
UP1	GCL	75.1%	79.5%	76.3%	70.7%	3.7%	1.7%	5.7%	5.2%	3.7%	6.0%	8.6%	10.2%	74.5%	0.0%	0.6%
UP2	CHJ	74.5%	78.9%	75.7%	70.1%	3.1%	1.1%	5.1%	4.6%	3.1%	6.6%	9.2%	10.8%	73.9%	0.6%	0.0%

FLOWGATE:	PAUL TO ALLSTON N>S															
PERCENT:	10.0%															
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	JDA	TDA	BON	ALF	DWR	HGH	LIB	BLK	LWG	LGS	LMN	IHR	GCL	CHJ
LOW1	MCN	0.0%	1.8%	3.3%	12.4%	10.7%	6.7%	8.7%	9.0%	10.7%	4.9%	4.4%	4.2%	2.8%	12.5%	13.6%
LOW2	JDA	1.8%	0.0%	1.6%	10.7%	12.5%	8.5%	10.5%	10.8%	12.5%	6.6%	6.2%	6.0%	4.6%	14.3%	15.4%
LOW3	TDA	3.3%	1.6%	0.0%	9.1%	14.1%	10.1%	12.0%	12.4%	14.1%	8.2%	7.8%	7.5%	6.2%	15.9%	16.9%
LOW4	BON	12.4%	10.7%	9.1%	0.0%	23.1%	19.2%	21.1%	21.5%	23.1%	17.3%	16.9%	16.6%	15.2%	24.9%	26.0%
OTH	ALF	10.7%	12.5%	14.1%	23.1%	0.0%	4.0%	2.0%	1.7%	0.0%	5.9%	6.3%	6.5%	7.9%	1.8%	2.9%
OTH	DWR	6.7%	8.5%	10.1%	19.2%	4.0%	0.0%	2.0%	2.3%	4.0%	1.9%	2.3%	2.6%	3.9%	5.8%	6.9%
OTH	HGH	8.7%	10.5%	12.0%	21.1%	2.0%	2.0%	0.0%	0.3%	2.0%	3.8%	4.3%	4.5%	5.9%	3.8%	4.9%
OTH	LIB	9.0%	10.8%	12.4%	21.5%	1.7%	2.3%	0.3%	0.0%	1.7%	4.2%	4.6%	4.9%	6.2%	3.5%	4.6%
OTH	BLK	10.7%	12.5%	14.1%	23.1%	0.0%	4.0%	2.0%	1.7%	0.0%	5.9%	6.3%	6.5%	7.9%	1.8%	2.9%
SNK1	LWG	4.9%	6.6%	8.2%	17.3%	5.9%	1.9%	3.8%	4.2%	5.9%	0.0%	0.4%	0.7%	2.1%	7.7%	8.7%
SNK2	LGS	4.4%	6.2%	7.8%	16.9%	6.3%	2.3%	4.3%	4.6%	6.3%	0.4%	0.0%	0.3%	1.6%	8.1%	9.2%
SNK3	LMN	4.2%	6.0%	7.5%	16.6%	6.5%	2.6%	4.5%	4.9%	6.5%	0.7%	0.3%	0.0%	1.4%	8.3%	9.4%
SNK4	IHR	2.8%	4.6%	6.2%	15.2%	7.9%	3.9%	5.9%	6.2%	7.9%	2.1%	1.6%	1.4%	0.0%	9.7%	10.8%
UP1	GCL	12.5%	14.3%	15.9%	24.9%	1.8%	5.8%	3.8%	3.5%	1.8%	7.7%	8.1%	8.3%	9.7%	0.0%	1.1%
UP2	CHJ	13.6%	15.4%	16.9%	26.0%	2.9%	6.9%	4.9%	4.6%	2.9%	8.7%	9.2%	9.4%	10.8%	1.1%	0.0%

FLOWGATE:	RAVER TO PAUL N>S																
PERCENT:	10.0%																
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	JDA	TDA	BON	ALF	DWR	HGH	LIB	BLK	LWG	LGS	LMN	IHR	GCL	CHJ
LOW1	MCN	0.0%	1.3%	2.6%	10.2%	8.2%	5.2%	6.7%	6.9%	8.2%	3.9%	3.6%	3.4%	2.2%	9.8%	10.6%
LOW2	JDA	1.3%	0.0%	1.3%	8.9%	9.5%	6.6%	8.0%	8.2%	9.5%	5.2%	4.9%	4.7%	3.6%	11.1%	12.0%
LOW3	TDA	2.6%	1.3%	0.0%	7.6%	10.8%	7.9%	9.3%	9.5%	10.8%	6.5%	6.2%	6.0%	4.9%	12.4%	13.3%
LOW4	BON	10.2%	8.9%	7.6%	0.0%	18.4%	15.5%	16.9%	17.1%	18.4%	14.1%	13.8%	13.6%	12.5%	20.0%	20.9%
OTH	ALF	8.2%	9.5%	10.8%	18.4%	0.0%	2.9%	1.5%	1.3%	0.0%	4.3%	4.6%	4.8%	5.9%	1.6%	2.5%
OTH	DWR	5.2%	6.6%	7.9%	15.5%	2.9%	0.0%	1.4%	1.7%	2.9%	1.4%	1.7%	1.9%	3.0%	4.6%	5.4%
OTH	HGH	6.7%	8.0%	9.3%	16.9%	1.5%	1.4%	0.0%	0.2%	1.5%	2.8%	3.1%	3.3%	4.4%	3.1%	4.0%
OTH	LIB	6.9%	8.2%	9.5%	17.1%	1.3%	1.7%	0.2%	0.0%	1.3%	3.0%	3.3%	3.5%	4.7%	2.9%	3.7%
OTH	BLK	8.2%	9.5%	10.8%	18.4%	0.0%	2.9%	1.5%	1.3%	0.0%	4.3%	4.6%	4.8%	5.9%	1.6%	2.5%
SNK1	LWG	3.9%	5.2%	6.5%	14.1%	4.3%	1.4%	2.8%	3.0%	4.3%	0.0%	0.3%	0.5%	1.6%	5.9%	6.8%
SNK2	LGS	3.6%	4.9%	6.2%	13.8%	4.6%	1.7%	3.1%	3.3%	4.6%	0.3%	0.0%	0.2%	1.3%	6.2%	7.1%
SNK3	LMN	3.4%	4.7%	6.0%	13.6%	4.8%	1.9%	3.3%	3.5%	4.8%	0.5%	0.2%	0.0%	1.1%	6.4%	7.3%
SNK4	IHR	2.2%	3.6%	4.9%	12.5%	5.9%	3.0%	4.4%	4.7%	5.9%	1.6%	1.3%	1.1%	0.0%	7.6%	8.4%
UP1	GCL	9.8%	11.1%	12.4%	20.0%	1.6%	4.6%	3.1%	2.9%	1.6%	5.9%	6.2%	6.4%	7.6%	0.0%	0.9%
UP2	CHJ	10.6%	12.0%	13.3%	20.9%	2.5%	5.4%	4.0%	3.7%	2.5%	6.8%	7.1%	7.3%	8.4%	0.9%	0.0%

FLOWGATE:	SOUTH OF ALLSTON N>S																
PERCENT:	10.0%																
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	JDA	TDA	BON	ALF	DWR	HGH	LIB	BLK	LWG	LGS	LMN	IHR	GCL	CHJ
LOW1	MCN	0.0%	2.1%	4.0%	16.0%	13.2%	8.3%	10.7%	11.2%	13.2%	6.0%	5.5%	5.2%	3.5%	15.4%	16.8%
LOW2	JDA	2.1%	0.0%	2.0%	13.9%	15.3%	10.4%	12.8%	13.2%	15.3%	8.1%	7.6%	7.2%	5.6%	17.4%	18.8%
LOW3	TDA	4.0%	2.0%	0.0%	11.9%	17.3%	12.4%	14.8%	15.2%	17.3%	10.1%	9.5%	9.2%	7.5%	19.4%	20.8%
LOW4	BON	16.0%	13.9%	11.9%	0.0%	29.2%	24.3%	26.7%	27.1%	29.2%	22.0%	21.5%	21.2%	19.5%	31.4%	32.7%
OTH	ALF	13.2%	15.3%	17.3%	29.2%	0.0%	4.9%	2.5%	2.1%	0.0%	7.2%	7.7%	8.1%	9.7%	2.2%	3.5%
OTH	DWR	8.3%	10.4%	12.4%	24.3%	4.9%	0.0%	2.4%	2.8%	4.9%	2.3%	2.8%	3.2%	4.8%	7.1%	8.4%
OTH	HGH	10.7%	12.8%	14.8%	26.7%	2.5%	2.4%	0.0%	0.4%	2.5%	4.7%	5.2%	5.6%	7.2%	4.7%	6.0%
OTH	LIB	11.2%	13.2%	15.2%	27.1%	2.1%	2.8%	0.4%	0.0%	2.1%	5.1%	5.7%	6.0%	7.7%	4.2%	5.6%
OTH	BLK	13.2%	15.3%	17.3%	29.2%	0.0%	4.9%	2.5%	2.1%	0.0%	7.2%	7.7%	8.1%	9.7%	2.2%	3.5%
SNK1	LWG	6.0%	8.1%	10.1%	22.0%	7.2%	2.3%	4.7%	5.1%	7.2%	0.0%	0.5%	0.8%	2.5%	9.4%	10.7%
SNK2	LGS	5.5%	7.6%	9.5%	21.5%	7.7%	2.8%	5.2%	5.7%	7.7%	0.5%	0.0%	0.3%	2.0%	9.9%	11.3%
SNK3	LMN	5.2%	7.2%	9.2%	21.2%	8.1%	3.2%	5.6%	6.0%	8.1%	0.8%	0.3%	0.0%	1.7%	10.2%	11.6%
SNK4	IHR	3.5%	5.6%	7.5%	19.5%	9.7%	4.8%	7.2%	7.7%	9.7%	2.5%	2.0%	1.7%	0.0%	11.9%	13.3%
UP1	GCL	15.4%	17.4%	19.4%	31.4%	2.2%	7.1%	4.7%	4.2%	2.2%	9.4%	9.9%	10.2%	11.9%	0.0%	1.4%
UP2	CHJ	16.8%	18.8%	20.8%	32.7%	3.5%	8.4%	6.0%	5.6%	3.5%	10.7%	11.3%	11.6%	13.3%	1.4%	0.0%

FLOWGATE:	**SOUTH OF CUSTER N>S**															
PERCENT:	**10.0%**															
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	**JDA**	**TDA**	**BON**	**ALF**	**DWR**	**HGH**	**LIB**	**BLK**	**LWG**	**LGS**	**LMN**	**IHR**	**GCL**	**CHJ**
LOW1	**MCN**	**0.0%**	**0.3%**	**0.4%**	**0.8%**	15.1%	3.6%	7.0%	7.7%	15.1%	1.3%	0.8%	0.5%	0.2%	0.3%	1.5%
LOW2	**JDA**	**0.3%**	**0.0%**	**0.1%**	**0.5%**	15.3%	3.8%	7.3%	8.0%	15.3%	1.6%	1.1%	0.7%	0.4%	0.1%	1.2%
LOW3	**TDA**	**0.4%**	**0.1%**	**0.0%**	**0.4%**	15.4%	3.9%	7.4%	8.1%	15.4%	1.7%	1.2%	0.8%	0.6%	0.0%	1.1%
LOW4	**BON**	**0.8%**	**0.5%**	**0.4%**	**0.0%**	15.9%	4.4%	7.8%	8.5%	15.9%	2.1%	1.6%	1.3%	1.0%	0.5%	0.7%
OTH	**ALF**	15.1%	15.3%	15.4%	15.9%	0.0%	11.5%	8.1%	7.4%	0.0%	13.7%	14.3%	14.6%	14.9%	15.4%	16.5%
OTH	**DWR**	3.6%	3.8%	3.9%	4.4%	11.5%	0.0%	3.4%	4.1%	11.5%	2.2%	2.8%	3.1%	3.4%	3.9%	5.0%
OTH	**HGH**	7.0%	7.3%	7.4%	7.8%	8.1%	3.4%	0.0%	0.7%	8.1%	5.7%	6.2%	6.5%	6.8%	7.3%	8.5%
OTH	**LIB**	7.7%	8.0%	8.1%	8.5%	7.4%	4.1%	0.7%	0.0%	7.4%	6.4%	6.9%	7.2%	7.5%	8.0%	9.2%
OTH	**BLK**	15.1%	15.3%	15.4%	15.9%	0.0%	11.5%	8.1%	7.4%	0.0%	13.7%	14.3%	14.6%	14.9%	15.4%	16.5%
SNK1	**LWG**	1.3%	1.6%	1.7%	2.1%	13.7%	2.2%	5.7%	6.4%	13.7%	**0.0%**	**0.6%**	**0.9%**	**1.2%**	1.7%	2.8%
SNK2	**LGS**	0.8%	1.1%	1.2%	1.6%	14.3%	2.8%	6.2%	6.9%	14.3%	**0.6%**	**0.0%**	**0.3%**	**0.6%**	1.1%	2.3%
SNK3	**LMN**	0.5%	0.7%	0.8%	1.3%	14.6%	3.1%	6.5%	7.2%	14.6%	**0.9%**	**0.3%**	**0.0%**	**0.3%**	0.8%	1.9%
SNK4	**IHR**	0.2%	0.4%	0.6%	1.0%	14.9%	3.4%	6.8%	7.5%	14.9%	**1.2%**	**0.6%**	**0.3%**	**0.0%**	0.5%	1.7%
UP1	**GCL**	0.3%	0.1%	0.0%	0.5%	15.4%	3.9%	7.3%	8.0%	15.4%	1.7%	1.1%	0.8%	0.5%	**0.0%**	**1.1%**
UP2	**CHJ**	1.5%	1.2%	1.1%	0.7%	16.5%	5.0%	8.5%	9.2%	16.5%	2.8%	2.3%	1.9%	1.7%	**1.1%**	**0.0%**

FLOWGATE:	**WEST OF JOHN DAY E>W**															
PERCENT:	**10.0%**															
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	**JDA**	**TDA**	**BON**	**ALF**	**DWR**	**HGH**	**LIB**	**BLK**	**LWG**	**LGS**	**LMN**	**IHR**	**GCL**	**CHJ**
LOW1	**MCN**	**0.0%**	**22.3%**	**56.4%**	**33.2%**	10.4%	7.3%	8.7%	9.1%	10.4%	6.0%	5.7%	5.5%	3.1%	12.4%	12.9%
LOW2	**JDA**	**22.3%**	**0.0%**	**78.6%**	**55.4%**	32.7%	29.5%	31.0%	31.3%	32.7%	28.2%	27.9%	27.8%	25.3%	34.6%	35.2%
LOW3	**TDA**	**56.4%**	**78.6%**	**0.0%**	**23.2%**	46.0%	49.1%	47.6%	47.3%	46.0%	50.4%	50.7%	50.8%	53.3%	44.0%	43.4%
LOW4	**BON**	**33.2%**	**55.4%**	**23.2%**	**0.0%**	22.7%	25.9%	24.4%	24.1%	22.7%	27.2%	27.5%	27.6%	30.1%	20.8%	20.2%
OTH	**ALF**	10.4%	32.7%	46.0%	22.7%	0.0%	3.1%	1.7%	1.4%	0.0%	4.4%	4.7%	4.9%	7.3%	2.0%	2.5%
OTH	**DWR**	7.3%	29.5%	49.1%	25.9%	3.1%	0.0%	1.4%	1.8%	3.1%	1.3%	1.6%	1.8%	4.2%	5.1%	5.6%
OTH	**HGH**	8.7%	31.0%	47.6%	24.4%	1.7%	1.4%	0.0%	0.3%	1.7%	2.8%	3.0%	3.2%	5.7%	3.6%	4.2%
OTH	**LIB**	9.1%	31.3%	47.3%	24.1%	1.4%	1.8%	0.3%	0.0%	1.4%	3.1%	3.4%	3.5%	6.0%	3.3%	3.9%
OTH	**BLK**	10.4%	32.7%	46.0%	22.7%	0.0%	3.1%	1.7%	1.4%	0.0%	4.4%	4.7%	4.9%	7.3%	2.0%	2.5%
SNK1	**LWG**	6.0%	28.2%	50.4%	27.2%	4.4%	1.3%	2.8%	3.1%	4.4%	**0.0%**	**0.3%**	**0.4%**	**2.9%**	6.4%	7.0%
SNK2	**LGS**	5.7%	27.9%	50.7%	27.5%	4.7%	1.6%	3.0%	3.4%	4.7%	**0.3%**	**0.0%**	**0.2%**	**2.6%**	6.7%	7.2%
SNK3	**LMN**	5.5%	27.8%	50.8%	27.6%	4.9%	1.8%	3.2%	3.5%	4.9%	**0.4%**	**0.2%**	**0.0%**	**2.5%**	6.8%	7.4%
SNK4	**IHR**	3.1%	25.3%	53.3%	30.1%	7.3%	4.2%	5.7%	6.0%	7.3%	**2.9%**	**2.6%**	**2.5%**	**0.0%**	9.3%	9.9%
UP1	**GCL**	12.4%	34.6%	44.0%	20.8%	2.0%	5.1%	3.6%	3.3%	2.0%	6.4%	6.7%	6.8%	9.3%	**0.0%**	**0.6%**
UP2	**CHJ**	12.9%	35.2%	43.4%	20.2%	2.5%	5.6%	4.2%	3.9%	2.5%	7.0%	7.2%	7.4%	9.9%	**0.6%**	**0.0%**

FLOWGATE:	WEST OF LOWER MONUMENTAL E>W															
PERCENT:	10.0%															
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	JDA	TDA	BON	ALF	DWR	HGH	LIB	BLK	LWG	LGS	LMN	IHR	GCL	CHJ
LOW1	MCN	0.0%	1.1%	1.5%	2.4%	25.0%	53.3%	33.7%	32.2%	25.0%	78.9%	86.0%	90.3%	3.2%	9.0%	8.2%
LOW2	JDA	1.1%	0.0%	0.4%	1.4%	23.9%	52.2%	32.6%	31.2%	23.9%	77.8%	84.9%	89.2%	4.3%	7.9%	7.2%
LOW3	TDA	1.5%	0.4%	0.0%	1.0%	23.5%	51.8%	32.2%	30.8%	23.5%	77.4%	84.5%	88.8%	4.7%	7.5%	6.8%
LOW4	BON	2.4%	1.4%	1.0%	0.0%	22.6%	50.9%	31.3%	29.8%	22.6%	76.4%	83.5%	87.8%	5.6%	6.6%	5.8%
OTH	ALF	25.0%	23.9%	23.5%	22.6%	0.0%	28.3%	8.7%	7.2%	0.0%	53.9%	61.0%	65.3%	28.2%	16.0%	16.8%
OTH	DWR	53.3%	52.2%	51.8%	50.9%	28.3%	0.0%	19.6%	21.1%	28.3%	25.6%	32.7%	36.9%	56.5%	44.3%	45.1%
OTH	HGH	33.7%	32.6%	32.2%	31.3%	8.7%	19.6%	0.0%	1.5%	8.7%	45.2%	52.3%	56.6%	36.9%	24.7%	25.5%
OTH	LIB	32.2%	31.2%	30.8%	29.8%	7.2%	21.1%	1.5%	0.0%	7.2%	46.6%	53.7%	58.0%	35.4%	23.2%	24.0%
OTH	BLK	25.0%	23.9%	23.5%	22.6%	0.0%	28.3%	8.7%	7.2%	0.0%	53.9%	61.0%	65.3%	28.2%	16.0%	16.8%
SNK1	LWG	78.9%	77.8%	77.4%	76.4%	53.9%	25.6%	45.2%	46.6%	53.9%	0.0%	7.1%	11.4%	82.1%	69.9%	70.6%
SNK2	LGS	86.0%	84.9%	84.5%	83.5%	61.0%	32.7%	52.3%	53.7%	61.0%	7.1%	0.0%	4.3%	89.2%	77.0%	77.7%
SNK3	LMN	90.3%	89.2%	88.8%	87.8%	65.3%	36.9%	56.6%	58.0%	65.3%	11.4%	4.3%	0.0%	93.4%	81.3%	82.0%
SNK4	IHR	3.2%	4.3%	4.7%	5.6%	28.2%	56.5%	36.9%	35.4%	28.2%	82.1%	89.2%	93.4%	0.0%	12.2%	11.4%
UP1	GCL	9.0%	7.9%	7.5%	6.6%	16.0%	44.3%	24.7%	23.2%	16.0%	69.9%	77.0%	81.3%	12.2%	0.0%	0.8%
UP2	CHJ	8.2%	7.2%	6.8%	5.8%	16.8%	45.1%	25.5%	24.0%	16.8%	70.6%	77.7%	82.0%	11.4%	0.8%	0.0%

FLOWGATE:	WEST OF MCNARY E>W															
PERCENT:	10.0%															
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	JDA	TDA	BON	ALF	DWR	HGH	LIB	BLK	LWG	LGS	LMN	IHR	GCL	CHJ
LOW1	MCN	0.0%	72.5%	70.4%	67.4%	52.4%	47.1%	50.9%	51.1%	52.4%	43.6%	42.8%	42.3%	23.8%	55.5%	55.8%
LOW2	JDA	72.5%	0.0%	2.1%	5.1%	20.1%	25.4%	21.6%	21.4%	20.1%	28.9%	29.7%	30.2%	48.7%	17.0%	16.7%
LOW3	TDA	70.4%	2.1%	0.0%	3.0%	18.0%	23.3%	19.5%	19.3%	18.0%	26.8%	27.6%	28.1%	46.6%	14.9%	14.6%
LOW4	BON	67.4%	5.1%	3.0%	0.0%	14.9%	20.3%	16.5%	16.3%	14.9%	23.8%	24.6%	25.1%	43.6%	11.9%	11.6%
OTH	ALF	52.4%	20.1%	18.0%	14.9%	0.0%	5.3%	1.5%	1.4%	0.0%	8.9%	9.6%	10.1%	28.6%	3.0%	3.3%
OTH	DWR	47.1%	25.4%	23.3%	20.3%	5.3%	0.0%	3.8%	3.9%	5.3%	3.6%	4.3%	4.8%	23.3%	8.4%	8.7%
OTH	HGH	50.9%	21.6%	19.5%	16.5%	1.5%	3.8%	0.0%	0.2%	1.5%	7.3%	8.1%	8.6%	27.1%	4.6%	4.9%
OTH	LIB	51.1%	21.4%	19.3%	16.3%	1.4%	3.9%	0.2%	0.0%	1.4%	7.5%	8.3%	8.7%	27.3%	4.4%	4.7%
OTH	BLK	52.4%	20.1%	18.0%	14.9%	0.0%	5.3%	1.5%	1.4%	0.0%	8.9%	9.6%	10.1%	28.6%	3.0%	3.3%
SNK1	LWG	43.6%	28.9%	26.8%	23.8%	8.9%	3.6%	7.3%	7.5%	8.9%	0.0%	0.8%	1.3%	19.8%	11.9%	12.2%
SNK2	LGS	42.8%	29.7%	27.6%	24.6%	9.6%	4.3%	8.1%	8.3%	9.6%	0.8%	0.0%	0.5%	19.0%	12.7%	13.0%
SNK3	LMN	42.3%	30.2%	28.1%	25.1%	10.1%	4.8%	8.6%	8.7%	10.1%	1.3%	0.5%	0.0%	18.5%	13.2%	13.5%
SNK4	IHR	23.8%	48.7%	46.6%	43.6%	28.6%	23.3%	27.1%	27.3%	28.6%	19.8%	19.0%	18.5%	0.0%	31.7%	32.0%
UP1	GCL	55.5%	17.0%	14.9%	11.9%	3.0%	8.4%	4.6%	4.4%	3.0%	11.9%	12.7%	13.2%	31.7%	0.0%	0.3%
UP2	CHJ	55.8%	16.7%	14.6%	11.6%	3.3%	8.7%	4.9%	4.7%	3.3%	12.2%	13.0%	13.5%	32.0%	0.3%	0.0%

FLOWGATE:		**WEST OF SLATT E>W**														
PERCENT:		**10.0%**														
		LOW1	LOW2	LOW3	LOW4	OTH	OTH	OTH	OTH	OTH	SNK1	SNK2	SNK3	SNK4	UP1	UP2
		MCN	**JDA**	**TDA**	**BON**	**ALF**	**DWR**	**HGH**	**LIB**	**BLK**	**LWG**	**LGS**	**LMN**	**IHR**	**GCL**	**CHJ**
LOW1	**MCN**	**0.0%**	**32.4%**	**27.7%**	**22.3%**	10.7%	8.0%	10.4%	10.4%	10.7%	5.0%	4.2%	3.7%	2.2%	11.3%	11.6%
LOW2	**JDA**	**32.4%**	**0.0%**	**4.6%**	**10.1%**	21.7%	24.4%	22.0%	22.0%	21.7%	27.4%	28.2%	28.7%	30.2%	21.1%	20.7%
LOW3	**TDA**	**27.7%**	**4.6%**	**0.0%**	**5.5%**	17.0%	19.7%	17.3%	17.4%	17.0%	22.7%	23.5%	24.0%	25.5%	16.5%	16.1%
LOW4	**BON**	**22.3%**	**10.1%**	**5.5%**	**0.0%**	11.6%	14.3%	11.9%	11.9%	11.6%	17.3%	18.1%	18.6%	20.1%	11.0%	10.7%
OTH	**ALF**	10.7%	21.7%	17.0%	11.6%	0.0%	2.7%	0.3%	0.3%	0.0%	5.7%	6.5%	7.0%	8.5%	0.6%	0.9%
OTH	**DWR**	8.0%	24.4%	19.7%	14.3%	2.7%	0.0%	2.4%	2.4%	2.7%	3.0%	3.8%	4.3%	5.8%	3.3%	3.6%
OTH	**HGH**	10.4%	22.0%	17.3%	11.9%	0.3%	2.4%	0.0%	0.1%	0.3%	5.4%	6.2%	6.7%	8.2%	0.8%	1.2%
OTH	**LIB**	10.4%	22.0%	17.4%	11.9%	0.3%	2.4%	0.1%	0.0%	0.3%	5.4%	6.2%	6.7%	8.2%	0.9%	1.3%
OTH	**BLK**	10.7%	21.7%	17.0%	11.6%	0.0%	2.7%	0.3%	0.3%	0.0%	5.7%	6.5%	7.0%	8.5%	0.6%	0.9%
SNK1	**LWG**	5.0%	27.4%	22.7%	17.3%	5.7%	3.0%	5.4%	5.4%	5.7%	**0.0%**	**0.8%**	**1.3%**	**2.8%**	6.2%	6.6%
SNK2	**LGS**	4.2%	28.2%	23.5%	18.1%	6.5%	3.8%	6.2%	6.2%	6.5%	**0.8%**	**0.0%**	**0.5%**	**2.0%**	7.1%	7.4%
SNK3	**LMN**	3.7%	28.7%	24.0%	18.6%	7.0%	4.3%	6.7%	6.7%	7.0%	**1.3%**	**0.5%**	**0.0%**	**1.5%**	7.5%	7.9%
SNK4	**IHR**	2.2%	30.2%	25.5%	20.1%	8.5%	5.8%	8.2%	8.2%	8.5%	**2.8%**	**2.0%**	**1.5%**	**0.0%**	9.1%	9.4%
UP1	**GCL**	11.3%	21.1%	16.5%	11.0%	0.6%	3.3%	0.8%	0.9%	0.6%	6.2%	7.1%	7.5%	9.1%	**0.0%**	**0.4%**
UP2	**CHJ**	11.6%	20.7%	16.1%	10.7%	0.9%	3.6%	1.2%	1.3%	0.9%	6.6%	7.4%	7.9%	9.4%	**0.4%**	**0.0%**

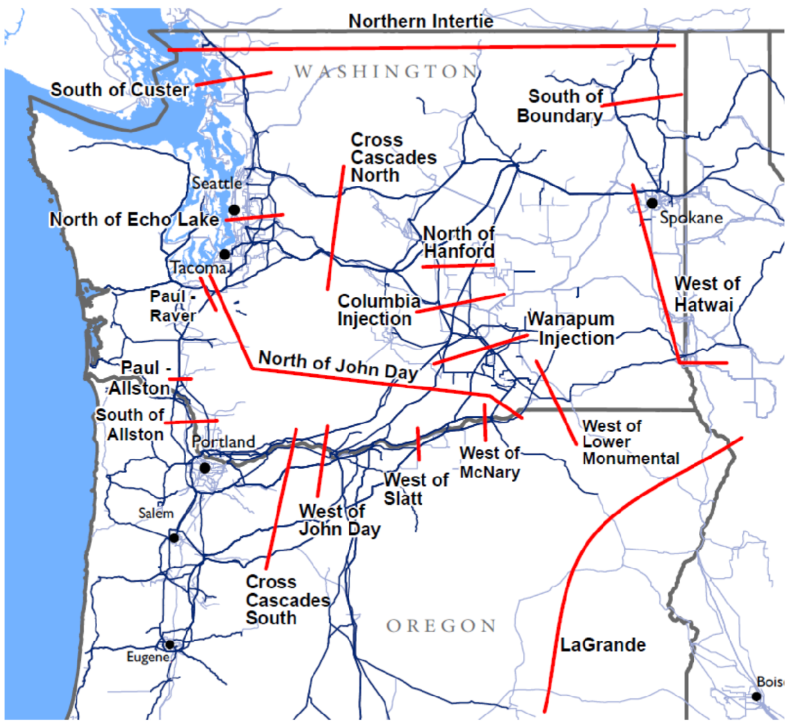
Objective & Approach:

Provide a high-level assessment of the risk of congestion on BPA internal flowgates

Methodology:

- Analyzed historical in-hour curtailments events between 2008 and present
- Discretionary Redispatch events were not analyzed
- Analyzed excursion minutes (flows > TTC) for CY2015 – FY2018 (YTD)
- Note: SOL Methodology changed 4/2017 where curtailments no longer occur when actual flows exceed the TTC
    - SOL must be exceeded on an element (thermal)
    - RTCA used as a real-time tool
    - Still curtail when MaxTTC or SSOL is reached
- Results have not been peer reviewed – draft results!

Flowgates:



Summary:

- The number and duration of actual flows exceeding TTC has been increasing
- The number curtailments has been decreasing
- Trends are likely due to new SOL methodology that went into effect on 4/1/2017
- Overall risk of curtailments is low on most flowgates
- These trends may or may not continue – hard to predict the future!
- Very few N-1 contingencies have occurred recently – curtailments may be higher when they occur since we are running the system at higher loading than we have historically
- As of November, 2014, 15-minute intervals are curtailed – they used to be hourly

Curtailment Trends:

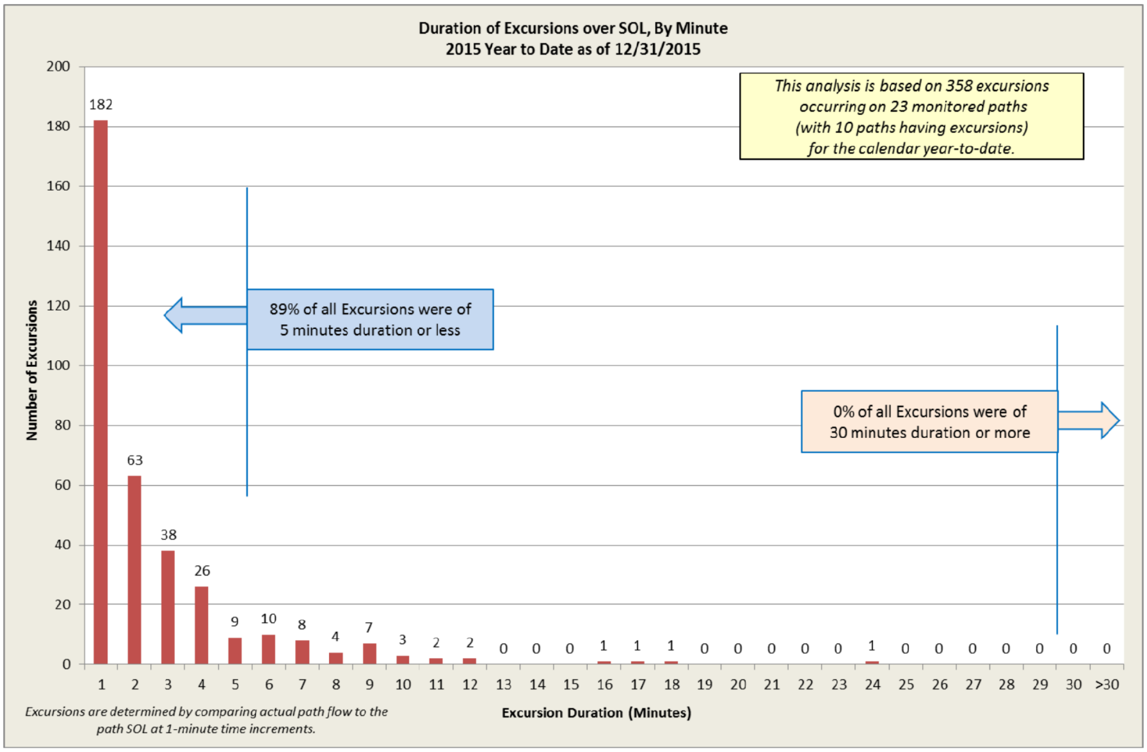
CURTAILMENT EVENTS - ALL PRIORITIES (1,2,6,7)												
Flowgate	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**Grand Total**	**Risk (10yr)**
NJD			4	4	11		21		2	2	**44**	**0.050%**
NOEL						12	5	17		3	**37**	**0.042%**
NOH				3							**3**	**0.003%**
NOH_SN		11		1	7	1					**20**	**0.023%**
P-A		2									**2**	**0.002%**
R-P			1	4	1				7		**13**	**0.015%**
SOA	11	1		3		2	2				**19**	**0.022%**
SOA_SN	3	2		1		3					**9**	**0.010%**
SOC								1	21		**22**	**0.025%**
WOCN		1	4			1					**6**	**0.007%**
WOJD					4				6		**10**	**0.011%**
WOM					5		3				**8**	**0.009%**
WOM - MAIN-GRID									2		**2**	**0.002%**
WOMSG								4			**4**	**0.005%**
Grand Total	**14**	**17**	**9**	**16**	**28**	**19**	**31**	**22**	**38**	**5**	**199**	**0.227%**

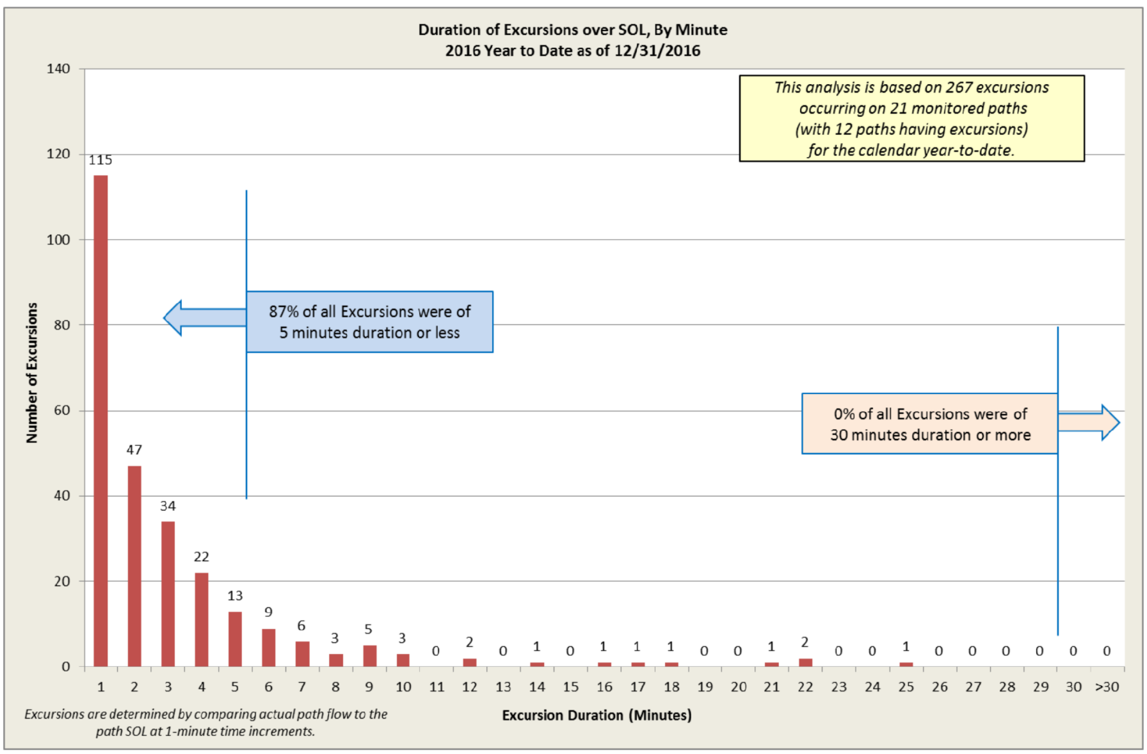
CURTAILMENT EVENTS - FIRM (7)												
Flowgate	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**Grand Total**	**Risk (10yr)**
NJD							5				**5**	**0.006%**
NOEL						4	1	2		1	**8**	**0.009%**
NOH												**0.000%**
NOH_SN					2						**2**	**0.002%**
P-A												**0.000%**
R-P				2					4		**6**	**0.007%**
SOA												**0.000%**
SOA_SN												**0.000%**
SOC												**0.000%**
WOCN			2			1					**3**	**0.003%**
WOJD									4		**4**	**0.005%**
WOM					5		1				**6**	**0.007%**
WOM - MAIN-GRID									2		**2**	**0.002%**
WOMSG								1			**1**	**0.001%**
Grand Total			**2**	**2**	**7**	**5**	**7**	**3**	**10**	**1**	**37**	**0.042%**

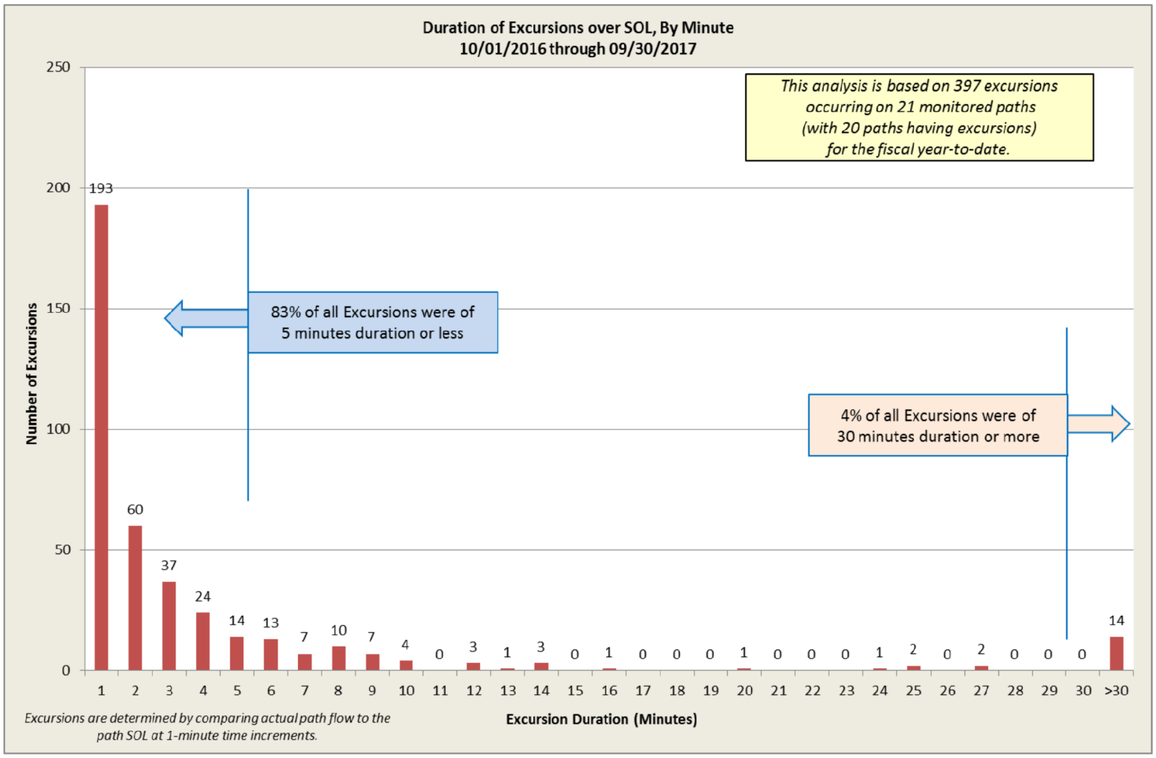
MWs CURTAILED - ALL PRIORITIES (1,2,6,7)											
FLOWGATE	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**Grand Total**
NJD			1814	930	2649		6862		632	318	**13205**
NOEL						2193	1468	4469		997	**9127**
NOH				1325							**1325**
NOH_SN		6612		215	4889	317					**12033**
P-A		1598									**1598**
R-P			709	4028	621				3232		**8590**
SOA	5369	739		1539		797	1683				**10127**
SOA_SN	1599	719		491		1830					**4639**
SOC								133	6720		**6853**
WOCN		346	2618			1298					**4262**
WOJD					1294				3388		**4682**
WOM					12590		468				**13058**
WOM - MAIN-GRID									3011		**3011**
WOMSG								1044			**1044**
Grand Total	**6968**	**10014**	**5141**	**8528**	**22043**	**6435**	**10481**	**5646**	**16983**	**1315**	**93554**

** In the graph above, this shows the total number of MWs that were requested during a curtailment. All curtailments are sub-hourly, but multiple curtailments could occur during the same hour.

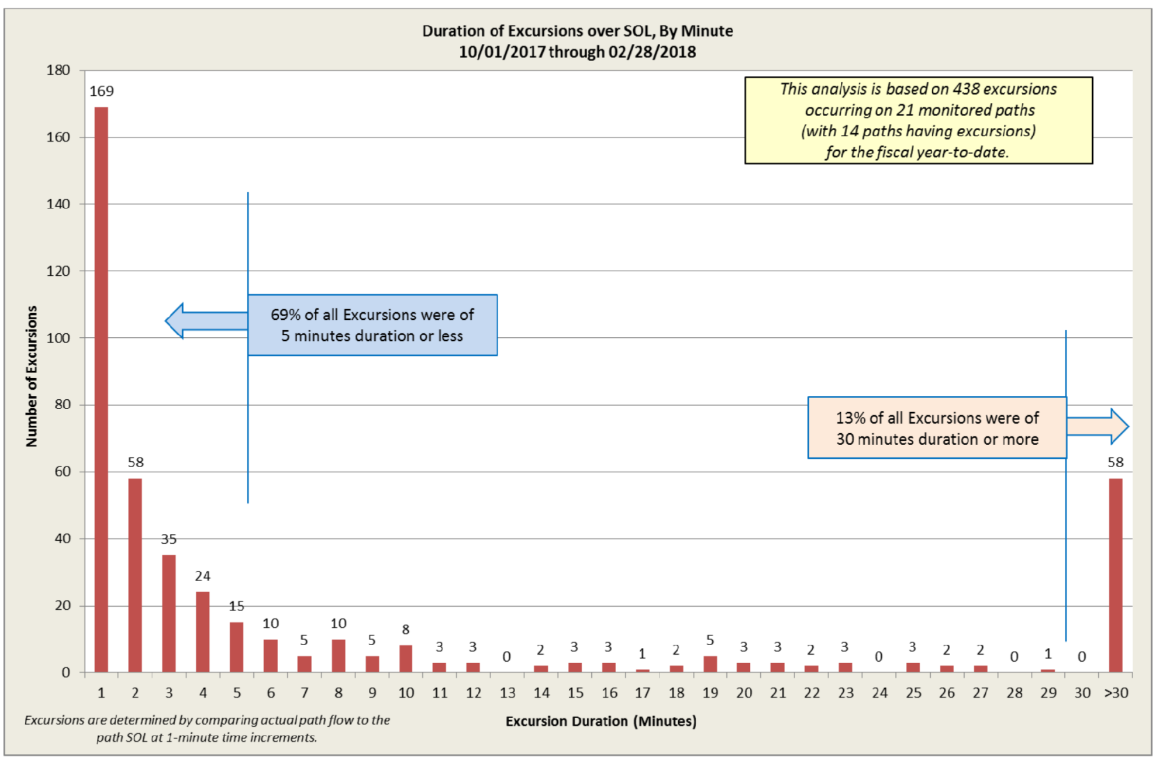
Duration of Excursions:







Duration of Excursions over SOL, By Minute
10/01/2016 through 09/30/2017
This analysis is based on 397 excursions occurring on 21 monitored paths (with 20 paths having excursions) for the fiscal year-to-date.
83% of all Excursions were of 5 minutes duration or less
4% of all Excursions were of 30 minutes duration or more
Number of Excursions
Excursion Duration (Minutes)
Excursions are determined by comparing actual path flow to the path SOL at 1-minute time increments.



Duration of Excursions over SOL, By Minute
10/01/2017 through 02/28/2018
This analysis is based on 438 excursions occurring on 21 monitored paths (with 14 paths having excursions) for the fiscal year-to-date.
69% of all Excursions were of 5 minutes duration or less
13% of all Excursions were of 30 minutes duration or more
Number of Excursions
Excursion Duration (Minutes)
Excursions are determined by comparing actual path flow to the path SOL at 1-minute time increments.

Excursion Minutes Trends:

Note: FY2018 numbers are YTD (~3/5/2018)

EXCURSION MINUTES (>TTC)					
PATH	**CY2015**	**CY2016**	**FY2017**	**FY2018**	**Grand Total**
AC INTERTIE (COI)	148	205	178	24	**555**
COLUMBIA INJECTION			14		**14**
DC INTERTIE (PDCI)	18				**18**
JOHN DAY WIND	16	2	3	6	**27**
MONTANA-NORTHWEST		1	1		**2**
NORTH-OF-ECHOLAKE	34	2	25	377	**438**
NORTH-OF-HANFORD	1	3	3		**7**
NORTH-OF-JOHN-DAY		8	25	1	**34**
NORTHWEST-BC	108	9	77	14	**208**
PAUL-ALLSTON			3	1	**4**
RAVER-PAUL	1	2	6	1	**10**
ROCK CREEK WIND			3		**3**
SOUTH-OF-ALLSTON	2		2		**4**
SOUTH-OF-BOUNDARY	14	9	15		**38**
SOUTH-OF-CUSTER	16	18	14	2	**50**
WEST-OF-CASCADES-NORTH			3	1	**4**
WEST-OF-CASCADES-SOUTH		2	2	1	**5**
WEST-OF-HATWAI			6	1	**7**
WEST-OF-JOHN-DAY		6	10	3	**19**
WEST-OF-LOWER-MONUMENTAL			3	2	**5**
WEST-OF-SLATT			4	4	**8**
Grand Total	**358**	**267**	**397**	**438**	**1460**

From: Rothleder, Mark

Sent: Fri Feb 28 15:11:31 2020

To: Kerns,Steven R (BPA) - B-3; Ristanovic, Petar

Subject: [EXTERNAL] RE: Implementation Agreement is Approved!

Importance: Normal

Congratulations! Great outcome due to your outstanding work.   Whoo-Hoo!

From: Kerns,Steven R (BPA) - B-3 <srkerns@bpa.gov>
Sent: Friday, February 28, 2020 2:25 PM
To: Ristanovic, Petar <pristanovic@caiso.com>; Rothleder, Mark <MRothleder@caiso.com>
Subject: [EXTERNAL] Implementation Agreement is Approved!

Whoo-Hoo!

Steve Kerns

Director, Grid Modernization

Bonneville Power Administration

From: Ristanovic, Petar

Sent: Fri Feb 28 15:01:27 2020

To: Kerns,Steven R (BPA) - B-3

Cc: Rothleder, Mark

Subject: [EXTERNAL] Re: [EXTERNAL] Implementation Agreement is Approved!

Importance: Normal

Great news Steve. Thank you for all the efforts last few years that got us to this point.

Petar

Sent from my iPhone

On Feb 28, 2020, at 4:25 PM, Kerns,Steven R (BPA) - B-3 <srkerns@bpa.gov> wrote:

Whoo-Hoo!

Steve Kerns
Director, Grid Modernization
Bonneville Power Administration

From: Baskerville,Sonya L (BPA) - DIN-WASH

Sent: Mon May 04 16:45:34 2020

To: Kerns,Steven R (BPA) - B-3

Subject: FW: FW: Heads-up on BPA's next EIM review milestone last Thursday and upcoming Congressional staff briefing on Wednesday

Importance: Normal

Attachments: June 20th DC Briefings clean.pptx

FOIA

From: Baskerville,Sonya L (BPA) - DIN-WASH <slbaskerville@bpa.gov>
Sent: Monday, June 24, 2019 7:37 PM
To: Marty Kanner <mkanner@KANNERANDASSOC.COM>; Barbara.smith@swpa.gov; Delia Patterson <dpatterson@publicpower.org>; Tracy Nagelbush Tolk <tan@vnf.com>; Martin Doern <martin.doern@xcelenergy.com>; Amy Thomas <athomas@publicpower.org>; Terri Moreland <tmoreland@caiso.com>; Elise Caplan <ECaplan@publicpower.org>; David Marten <david.marten@gov.wa.gov>; Kathy Tyer <Tyer@wapa.gov>; Dionne Thompson <DThompson@WAPA.GOV>; Elizabeth Kelsey Whitney <elizabeth@meguirewhitney.com>
Subject: RE: FW: Heads-up on BPA's next EIM review milestone last Thursday and upcoming Congressional staff briefing on Wednesday

The attachment might help!

Sonya Baskerville

National Relations Office

202.253.7352

On Jun 24, 2019 5:37 PM, "Baskerville,Sonya L (BPA) - DIN-WASH" <slbaskerville@bpa.gov> wrote:

Here are the slides for the briefing on Wednesday. Thanks.

From: Baskerville,Sonya L (BPA) - DIN-WASH
Sent: Monday, June 24, 2019 9:55 AM
To: Marty Kanner; Elizabeth Kelsey Whitney; Barbara.smith@swpa.gov; Amy Thomas; Martin Doern; Kathy Tyer; Delia Patterson; David Marten; Tracy Nagelbush Tolk; Dionne Thompson; Terri Moreland; Elise Caplan
Subject: Re: FW: Heads-up on BPA's next EIM review milestone last Thursday and upcoming Congressional staff briefing on Wednesday

You're invited!

Joint Staff of the Senate Committee Energy and Natural Resources invites you to attend a briefing on:

Recent Activities and Next Steps in Bonneville Power Administration's Review of Participation in the Western

EIM

Wednesday, June 26, 2019

2:30 p.m. – 3:30 p.m.

SD-366

Steve Kerns, Director of Grid Modernization, and other BPA staff will provide a briefing and answer questions about the recent letter to stakeholders in the region proposing to sign a participation agreement with the Western EIM in September, and to explain the next steps in the analysis and process. For additional information, please contact Lane Dickson (Majority staff) or Luke Bassett (Minority staff) of the Committee on Energy and Natural Resources at 4-4971.

Christopher Griffin

Staff Assistant

U.S. Senate Committee on Energy and Natural Resources

314 Dirksen Senate Office Building

Washington, D.C. 20510

(202) 224-4971

Sonya Baskerville

National Relations Office

[redacted]

On Jun 21, 2019 2:36 PM, "Baskerville,Sonya L (BPA) - DIN-WASH" <slbaskerville@bpa.gov> wrote:

FYI: the SENR committee may be doing the invitation for the Congressional staff meeting below, and I don't know yet whether it is open or not. I will keep you posted, but wanted you to know this was happening and have the document and the link to the EIM webpage. Thanks.

Sonya Baskerville

BPA National Relations

1000 Independence Ave, SW, 8G-061

Washington, DC 20585

Mailing address:

P.O. Box 3621

DIN-WASH

Portland, OR 97232

202.586.5640 (o)

[redacted]

From: Baskerville,Sonya L (BPA) - DIN-WASH
Sent: Wednesday, June 19, 2019 8:53 PM
To: Alexandra Menardy (Larsen) <Alexandra.Menardy@mail.house.gov>; Amit Ronen <amit_ronen@cantwell.senate.gov>; Andrew Neill (Fulcher) <Andrew.Neill@mail.house.gov>; Anna Breen (Herrera Buetler) <Anna.Schartner@mail.house.gov>; Brendan Woodbury (Heck) <brendan.woodbury@mail.house.gov>; Bryson Wong <bryson_wong@risch.senate.gov>; Charles Adams (Risch) <charles_adams@risch.senate.gov>; Connor Stubbs (Smith) <Connor.Stubbs@mail.house.gov>; Dan Becerra (Merkley) <Dan_Becerra@merkley.senate.gov>; Dylan Laslovich (Tester) <Dylan_Laslovich@tester.senate.gov>; Goddard, Jaron (Murray) <Jaron_Goddard@murray.senate.gov>;

Henry Ring <Henry_Ring@tester.senate.gov>; huck@mail.house.gov; Jami Burgess <Jami_Burgess@cantwell.senate.gov>; Jaxon Wolfe <jaxon.wolfe@mail.house.gov>; Jordan Evich (Herrera Buetler) <Jordan.Evich@mail.house.gov>; Kai Nuce (Herrera Buetler) <Kai.Nuce@mail.house.gov>; Kate Walker <Kate_Walker@crapo.senate.gov>; Katie Allen (Kilmer) <Katie.Allen@mail.house.gov>; Kevin Stockert (Blumenauer) <Kevin.Stockert@mail.house.gov>; Kris Pratt (DeFazio) <Kris.Pratt@mail.house.gov>; Lindsay Ownes (Jayapal) <Lindsay.Owens@mail.house.gov>; Lindsay Slater (Simpson) <Lindsay.Slater@mail.house.gov>; Liv Brumfield (Blumenauer) <liv.brumfield@mail.house.gov>; Logan Hollers (Merkley) <Logan_Hollers@merkley.senate.gov>; Lylianna Allala (Jayapal) <Lylianna.Allala@mail.house.gov>; Malcolm McGeary <malcolm_mcgeary@wyden.senate.gov>; Maxine Sugarman (Bonamici) <maxine.sugarman@mail.house.gov>; Megan Thompson <megan_thompson@cantwell.senate.gov>; Meghan Thacker <Meghan_Thacker@daines.senate.gov>; Nick Strader <Nick.Strader@mail.house.gov>; Olivia Woods <olivia_woods@merkley.senate.gov>; Rachel Berkson (Jayapal) <Rachel.Berkson@mail.house.gov>; Rebecca Ward <Rebecca_Ward@merkley.senate.gov>; Riley Bushue (Walden) <riley.bushue@mail.house.gov>; Robert Biestman (Reichert) <Robert.Biestman@mail.house.gov>; Sarah Cannon (Simpson) <sarah.cannon@mail.house.gov>; Sean O'Brien (Newhouse) <SeanV.OBrien@mail.house.gov>; Shantanu Tata (DelBene) <shantanu.tata@mail.house.gov>; Sharmin Syed (Merkley) <Sharmin_Syed@merkley.senate.gov>; Tre Easton <Tre_Easton@murray.senate.gov>; Tripp McKemey (Gianforte) <tripp.mckemey@mail.house.gov>; 'Angie.Giancarlo@mail.house.gov'; Ashley Nichols (NR EMR Min) <Ashley.Nichols@mail.house.gov>; Brandon Mooney (E&C) <brandon.mooney@mail.house.gov>; Brianne Miller (Energy) <Brianne_Miller@energy.senate.gov>; Camille Calimlim Touton (camille.touton@mail.house.gov) <camille.touton@mail.house.gov>; Dave Berick (David_Berick@finance.senate.gov) <David_Berick@finance.senate.gov>; 'Doug_Clapp@appro.senate.gov'; Farouk Ophaso (HEWD) <Farouk.Ophaso@mail.house.gov>; Jamie Shimek (HEWD) <jaime.shimek@mail.house.gov>; 'Kellie_Donnelly@energy.senate.gov'; Konolige, Rebecca (Rebecca.Konolige@mail.house.gov) <Rebecca.Konolige@mail.house.gov>; Lane Dickson <Lane_Dickson@energy.senate.gov>; Marnie Kremer (NR WPO Maj) <Marnie.Kremer@mail.house.gov>; Matthew Muirragui (Natural Resources) <Matthew.Muirragui@mail.house.gov>; Michael Brain (HEWD) <Michael.Brain@mail.house.gov>; Sam Fowler <Sam_Fowler@energy.senate.gov>
Subject: FW: Heads-up on BPA's next EIM review milestone on Thursday and upcoming Congressional staff briefing on Tuesday or Wednesday next week

Hello, all. Here is the letter to the region and related attachments. I also have included the EIM webpage below.

Please let me know if you have any questions. The letter kicks-off a comment period which ends on July 22.

A stakeholder/customer meeting will be held on July 8 from 1:00p-3:00p pacific in Portland. I will send that info to you as it gets closer to the date.

https://www.bpa.gov/Projects/Initiatives/EIM/Pages/Energy-Imbalance-Market.aspx

I will be back in touch with more information about a date and location for the briefing next week.

Thanks!

From: Baskerville,Sonya L (BPA) - DIN-WASH
Sent: Tuesday, June 18, 2019 5:10 PM
To: Alexandra Menardy (Larsen); Amit Ronen; Andrew Neill (Fulcher); Anna Breen (Herrera Buetler); Brendan Woodbury (Heck); Bryson Wong; Charles Adams (Risch); Connor Stubbs (Smith); Dan Becerra (Merkley); Dylan Laslovich (Tester); Goddard, Jaron (Murray); Henry Ring; huck@mail.house.gov; Jami Burgess; Jaxon Wolfe; Jordan Evich (Herrera Buetler); Kai Nuce (Herrera Buetler); Kate Walker; Katie Allen (Kilmer); Kevin Stockert (Blumenauer); Kris Pratt (DeFazio); Lindsay Ownes (Jayapal); Lindsay Slater (Simpson); Liv Brumfield (Blumenauer); Logan Hollers (Merkley); Lylianna Allala (Jayapal); Malcolm McGeary; Maxine Sugarman (Bonamici); Megan Thompson; Meghan Thacker; Nick Strader; Olivia Woods; Rachel Berkson (Jayapal);

Rebecca Ward; Riley Bushue (Walden); Robert Biestman (Reichert); Sarah Cannon (Simpson); Sean O'Brien (Newhouse); Shantanu Tata (DelBene); Sharmin Syed (Merkley); Tre Easton; Tripp McKemey (Gianforte); 'Angie.Giancarlo@mail.house.gov'; Ashley Nichols (NR EMR Min); Brandon Mooney (E&C); Brianne Miller (Energy); Camille Calimlim Touton (camille.touton@mail.house.gov); Dave Berick (David_Berick@finance.senate.gov); 'Doug_Clapp@appro.senate.gov'; Farouk Ophaso (HEWD); Jamie Shimek (HEWD); 'Kellie_Donnelly@energy.senate.gov'; 'Kiel.Weaver@mail.house.gov'; Konolige, Rebecca (Rebecca.Konolige@mail.house.gov); Lane Dickson; Marnie Kremer (NR WPO Maj); Matthew Muirragui (Natural Resources); Michael Brain (HEWD); Sam Fowler
Subject: FW: Heads-up on BPA's next EIM review milestone on Thursday and upcoming Congressional staff briefing on Tuesday or Wednesday next week

Hello, all. Steve Kerns, who leads BPA's EIM effort, will be in town next week to brief Congressional staff and others on the next milestone on our EIM review effort. On this Thursday, BPA plans to issue a letter to the region regarding the next phase of the EIM review effort. You may recall from the briefing last month (see attached), that the letter to the region originally was on the timeline in July. So, it has been moved up in time slightly.

I will be back in touch with more info on when and where for next week, but we are looking at either next Tuesday or Wednesday. I also will send you the letter and any related material prior to this Thursday.

Thanks.

Sonya Baskerville

BPA National Relations

1000 Independence Ave, SW, 8G-061

Washington, DC 20585

Mailing address:

P.O. Box 3621

DIN-WASH

Portland, OR 97232

202.586.5640 (o)

[redacted]

From: Davis,Thomas E (BPA) - B-3

Sent: Tue Sep 17 09:17:16 2019

To: Anders, John

Cc: Sigurdson,Ryan M (BPA) - LT-7; Pettinger,Rebekah S (BPA) - LP-7; Ristanovic, Petar; Fuller, Don

Subject: RE: BPA-CAISO Implementation Agreement

Importance: Normal

Thank you! Will do. Glad to see this part of the process coming to a close. Ready to move forward with implementation!

Tom

From: Anders, John <JAnders@caiso.com>
Sent: Tuesday, September 17, 2019 9:07 AM
To: Davis,Thomas E (BPA) - B-3 <tedavis@bpa.gov>
Cc: Sigurdson,Ryan M (BPA) - LT-7 <rmsigurdson@bpa.gov>; Pettinger,Rebekah S (BPA) - LP-7 <rspettinger@bpa.gov>; Ristanovic, Petar <pristanovic@caiso.com>; Fuller, Don <DFuller@caiso.com>
Subject: [EXTERNAL] RE: BPA-CAISO Implementation Agreement

Tom,

(b)(4) [redacted]

From: Davis,Thomas E (BPA) - B-3 <tedavis@bpa.gov>
Sent: Monday, September 16, 2019 4:56 PM
To: Anders, John <JAnders@caiso.com>
Cc: Sigurdson,Ryan M (BPA) - LT-7 <rmsigurdson@bpa.gov>; Pettinger,Rebekah S (BPA) - LP-7 <rspettinger@bpa.gov>
Subject: [EXTERNAL] BPA-CAISO Implementation Agreement

John:

Just wanted to touch base with you regarding BPA executing the Implementation Agreement. As I understand it, the plan is for Janet Herrin (BPA's COO) and Petar to sign the agreement here in Portland on the evening of September 26th.

Here is the most recent copy of the Implementation Agreement I have in my files. I just want to make sure this is the version that CAISO is good with signing. If so, I will leave it with Janet so she and Petar can sign it on the 26th. In fact, I will leave two copies so we each can have a signed original copy.

Please confirm that the CAISO is good with this version before I leave it with Janet. I would hate for a mix up to occur and Petar sign a copy that was not what you considered to be the final version.

I will be OOO starting this Friday for a few days so please communicate with Ryan Sigursdson or Rebekah Pettinger if you are not able to responde before COB, Thursday.

Thank you and take care,

Tom Davis

****
The foregoing electronic message, together with any attachments thereto, is confidential and may be legally privileged against disclosure other than to the intended recipient. It is intended solely for the addressee(s) and access to the message by anyone else is unauthorized. If you are not the intended recipient of this electronic message, you are hereby notified that any dissemination, distribution, or any action taken or omitted to be taken in reliance on it is strictly prohibited and may be unlawful. If you have received this electronic message in error, please delete and immediately notify the sender of this error.
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Briefing on BPA’s Evaluation of Joining the Western EIM

Steve Kerns
Director, Grid Modernization
Bonneville Power Administration

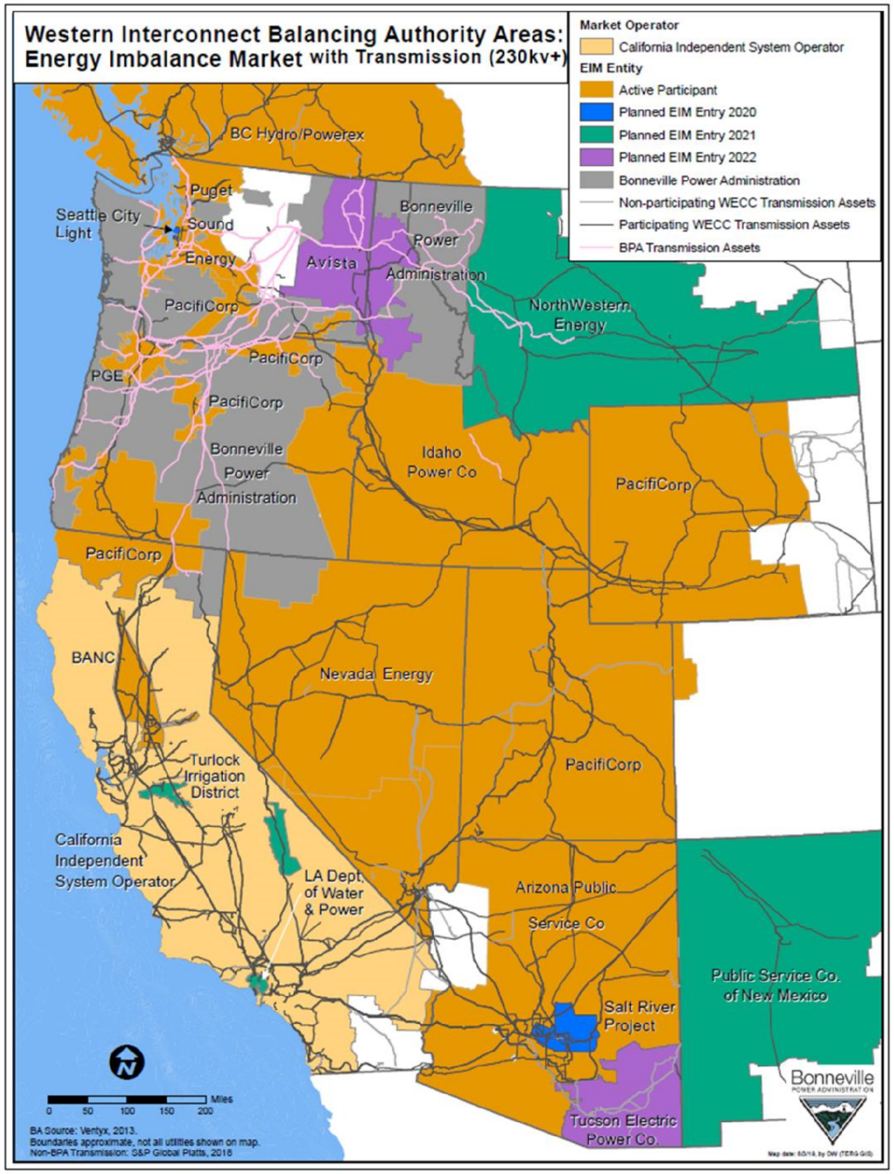
Jun 25, 2019

Agenda

- Market Context
- Western EIM Evaluation
- Business Rationale
- Letter to the Region
- Next Steps

Drivers for Market Changes

- Variable energy resources are increasing in the West
- Ability to realize the value of sub-hourly dispatch with flexible and low carbon hydro resources
- Transmission use and system operations are changing
- Western EIM footprint is growing
- Market evolution



24850898(01).pdf

Market Context

- A well designed electricity market is built on a foundation of resource adequacy and has features that:
  - Provide for intra-hour energy balancing
  - Compensate explicitly for capacity resources that provide system reliability and flexibility

- BPA views the EIM as *one piece* of a well-designed market
  - Additional market functions are required to fully compensate BPA for the capacity value of the flexible and carbon-free federal power system

- BPA will continue to work with CAISO and stakeholders to enhance regional resource adequacy by ensuring that flexible resources are appropriately compensated for the services that they provide

Western EIM Evaluation

- Bonneville initiated a formal Stakeholder process in July 2018
- Bonneville began discussion with CA-ISO in September 2018
- Four Key Principles
  - Consistent with statutory, regulatory, and contractual obligations.
  - Maintain reliability
  - Voluntary participation
  - Sound business rationale

Business Rationale

- Modeling suggests that dispatch benefits from EIM participation will quickly pay for itself and result in ongoing annual net benefits of **$29-34M:**
  - Four sensitivities that were evaluated did not fundamentally change this conclusion
- Analysis has determined that EIM participation is a cost-effective non-wires solution and an effective intra-hour congestion management tool
- EIM participation will also:
  - Result in an efficient dispatch of generation to meet load across the entire EIM footprint
  - Provide increased visibility and discipline in the dispatch and marketing of Federal power and transmission assets
  - Create additional visibility of conditions across the grid which will enhance reliability
  - Allow BPA to effectively participate in the development of future markets which will appropriately compensate flexible resources for the services that they provide

Evaluation Issues*

- Relationship of EIM to Other Emerging Markets
- BA Resource Sufficiency
- EIM Settlements
- Market Power
- Treatment of Transmission
- Generation Participation Model (FCRPS)
- Governance
- Carbon Obligation in EIM

* Additional information on these issues may be found in the Appendix

Letter to the Region

- Provides notice to the public that Bonneville is considering signing an EIM Implementation Agreement and moving forward toward joining the EIM

- Includes:
  - Description of Bonneville's decision-making process for joining the EIM
  - Discussion of legal authority to join the EIM
  - Business case for joining the EIM
  - Proposed principles for joining the EIM
  - Draft EIM Implementation Agreement
  - Policy proposals on certain policy topics
  - Brief descriptions of additional policy decisions that will need to be made in the future

- Seeking input from stakeholders
  - Letter to the Region will be issued on June 20th with comments due on July 22nd

- Record of Decision planned for September 2019
  - Bonneville will address comments received and make final decision whether to sign Implementation Agreement and on other items covered in Letter to Region

EIM Decision Process

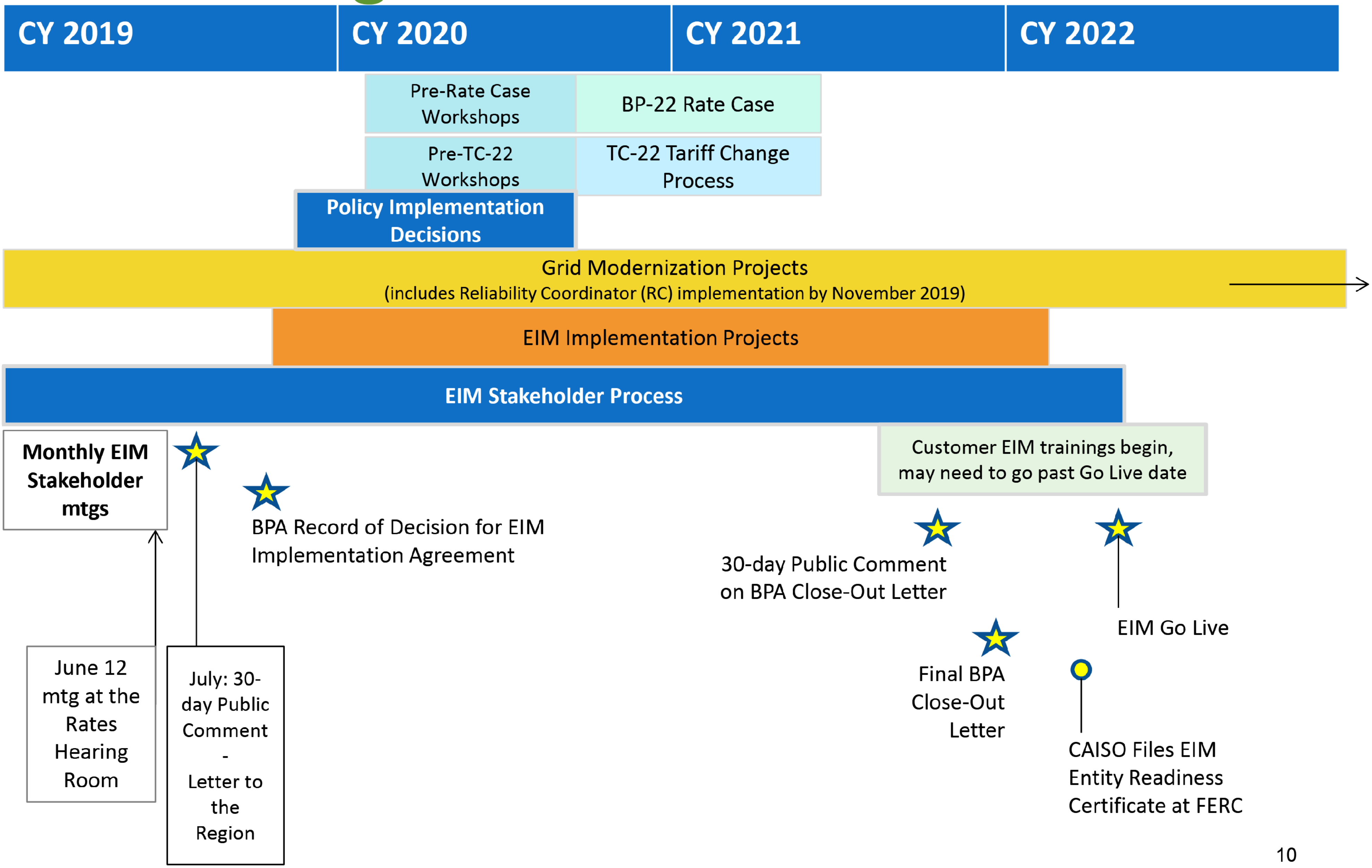
1. Letter to Region and Record of Decision — June 2019 – September 2019
    - Solicit stakeholder feedback on: Draft Implementation Agreement, Cost Benefit Analysis, Legal considerations, Roadmap of process/issues, Proposed Decisions on Certain Policy Issues, Principles for Joining
    - 30-day comment period
    - Final decision to sign Implementation Agreement, and on other items covered in Letter to Region

2. Policy Implementation Decisions — October 2019 – August 2020
    - Discuss all remaining policy issues with stakeholders.
    - Provide written proposal, solicit written stakeholder comment, and make final written decision(s) on policy issues
    - Final decisions on these policy issues

3. BP-22 and TC-22 Cases — October 2020 – July 2021
    - Settlement discussions August – October 2020
    - Follow 7(i) process and conclude with ROD / final decision

4. Draft and Final Close-Out Letters — October 2021 – December 2021
    - Draft Close-Out Letter addressing: principles for joining the EIM, any additional policy issues that have arisen, propose final decision whether to join the EIM, and incorporate final decisions made in steps 1 and 2 above.
    - 30-day comment period
    - Final Close-Out Letter: Address comments raised, Final Decision whether to join EIM, if decision is to join - move forward to sign relevant EIM Agreements

BPA's High Level EIM Timeline



Previous EIM Stakeholder Meeting Materials are available here: www.bpa.gov/goto/EIM

Next Steps

- Letter to the Region was issued on June 20th with comments due on July 22nd
- A meeting to answer clarifying questions about the Letter to the Region is scheduled for **Monday July 8th** at the Rates Hearing Room, 1-3pm.
  - WebEx and Phone participation will be available
  - A Tech Forum notice will be sent out as a reminder
- For more information on BPA's EIM Stakeholder process and meetings please visit:
  https://www.bpa.gov/Projects/Initiatives/EIM/Pages/Energy-Imbalance-Market.aspx
- For more information on BPA's Grid Modernization Initiative please visit:
  https://www.bpa.gov/goto/GridModernization

Appendix

Additional information on Evaluation Issues

Relationship of EIM to Other Emerging Markets

- While we are engaged in the development of market opportunities, Bonneville is focused on whether to sign the Implementation Agreement with CAISO and move forward toward joining the EIM.
- There are two examples of CAISO policy initiatives with potential implications for EIM:
  - **Day-Ahead Market Enhancements (DAME)**
    - High-level objective: Manage uncertainty that occurs between the day-ahead and real-time markets
    - Status: CAISO is focusing the scope on a day-ahead Flexible Ramping Product (FRP) and reforming IFM & RUC; June 20th workshop to re-launch
  - **Expansion of the Day-Ahead Market to EIM (EDAM)**
    - High-level objective: Enable EIM access to a broader pool of resources by extending the enhanced day-ahead market to some or all EIM Entity BAAs
    - Status: CAISO has not yet launched this policy initiative
- Bonneville will actively participate in the advancement of these stakeholder processes and Bonneville expects that the CAISO will complete the DAME policy initiative and implement the FRP before Bonneville goes live in the EIM.

BA Resource Sufficiency

- Bonneville's preliminary analysis indicates that it would pass the RS evaluation a significant amount of the time using historical spinning availability
  - BPA has not yet determined how it will make flexibility available for the EIM
- This provides Bonneville with a high level of confidence that it can achieve the benefits described in the business case
- The likelihood of passing the RS evaluation would increase if any additional bid flexibility is made available, whether from Federal or non-Federal Participating Resources

EIM Settlements

- Bonneville will address settlements issues in the Post-ROD Policy process, subsequent Rate and Tariff Cases, and Business Practice development processes
- Bonneville staff gathered information on settlements via trainings, benchmarking with EIM Entities, reviewing CAISO materials, and internal staff who work with CAISO settlements.
- If Bonneville joins the EIM as an EIM Entity, Bonneville will need to decide whether and how to allocate the CAISO's charge and credits to Bonneville's transmission customers
- If Bonneville decides to allocate some or all of the EIM charge codes to its customers, Bonneville will need to decide how to bill its customers for these charges
- The billing and settlement mechanics policy process will be closely linked with the policy process on allocation of EIM charge codes

Market Power

- Default Energy Bids
  - If determined to have market power, a market participant may have its EIM bid prices mitigated to a Default Energy Bid (DEB) by CAISO
  - Current construct does not adequately reflect the opportunity costs of use limited hydro resources
  - CAISO worked collaboratively with stakeholders to propose a new Hydro DEB option
  - Approval of this option and subsequent implementation is important for BPA's participation in the EIM

Treatment of Transmission

- Bonneville is proposing to adopt the Interchange Rights Holder Methodology for making transmission available to the EIM

- Bonneville expects to be a significant "net wheeler" in the EIM
  - This may lead to cost shifts and free riders

- Bonneville believes the Interchange Rights Holder Methodology better balances the need to provide transmission to the EIM with collecting enough revenue to adequately and fairly recover the costs of the FCRTS

Generation Participation Model (FCRPS)

- Bonneville will initially participate in the EIM with federal hydroelectric dams aggregated into three resource zones:
  - Upper Columbia dams (Grand Coulee, Chief Joseph)
  - Lower Columbia dams (McNary, John Day, The Dalles, Bonneville)
  - Lower Snake dams (Lower Granite, Little Goose, Lower Monumental, Ice Harbor).
- These resource groups will participate in the EIM as separate aggregated participating resources (APR)
  - The amount of generation produced by these resources not bid into the EIM will be treated as an aggregated non-participating resources (ANPR) for purposes of the EIM
  - All other federal resources in the Bonneville balancing authority area will initially be non-participating resources in the EIM

Governance

- BPA has determined that the current EIM governance structure does not contain any “showstoppers” to joining the EIM.
- However, BPA would like to see some improvements to the current governance structure, including:
  - Expand the EIM Governing Body’s primary authority,
  - Improve the durability of the current EIM governance structure
  - Allow for ability to adapt to expanded market functions, and
  - A broader role for public power in the EIM governance structure.
- BPA is supporting these improvements in a current stakeholder process that the CAISO has initiated and continues to coordinate regularly with multiple parties.

Carbon Obligation in the EIM

- Energy generated in or imported into California is subject to California's greenhouse gas (GHG) regulations.
- If BPA were to participate in the EIM, any carbon attributed to imports into California would incur a compliance obligation
- BPA currently cannot purchase carbon allowances
  - Carbon allowances are considered a state tax by the U.S. DOE, BPA, and other federal agencies.
  - Federal agencies have sovereign immunity from state taxes and cannot pay them unless Congress specifically authorizes it
- Absent Congressional authorization to purchase allowances, BPA would not be able to directly deliver EIM energy into California

From: Anders, John

Sent: Wed May 13 09:45:20 2020

To: Kochheiser,Todd W (BPA) - TOI-DITT-2; Abdul-Rahman, Khaled

Cc: King,Eric V (BPA) - TSQM-TPP-2; Kutil,Sarah M (BPA) - LT-7

Subject: [EXTERNAL] RE: Documentation for PR requirements?par **Importance**: Normal

Attachments: FERC Order (June 19 PacifiCorp EIM).pdf

(b)(4)

[redacted]

(b)(4)

[redacted]

From: Kochheiser,Todd W (BPA) - TOI-DITT-2 <twkochheiser@bpa.gov>
Sent: Wednesday, May 13, 2020 8:52 AM
To: Abdul-Rahman, Khaled <KAbdulRahman@caiso.com>; Anders, John <JAnders@caiso.com>
Cc: King (BPA), Eric <evking@bpa.gov>; Kutil,Sarah M (BPA) - LT-7 <smkutil@bpa.gov>
Subject: [EXTERNAL] Documentation for PR requirements?

Good Morning,

BPA is working on Tariff and Business Practice language regarding requirement for resources in our BAA to become PRs. Most of the existing language we've found in other EIM Entity Tariffs and BPs is fairly high-level. We were unable to find any specific requirement in your BPMs or Tariff; if you are aware of any specific requirement that you have documented for an NPR to become a PR, it would be helpful if you could point us in the right direction. We will be presenting to customers in June.

Best,
Todd

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147 FERC ¶ 61,227
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Acting Chairman;
Philip D. Moeller, John R. Norris,
and Tony Clark.

PacifiCorp Docket No. ER14-1578-000

ORDER CONDITIONALLY ACCEPTING IN PART AND REJECTING IN PART PROPOSED TARIFF REVISIONS TO IMPLEMENT ENERGY IMBALANCE MARKET

(Issued June 19, 2014)

Paragraph Numbers

1. In this order, the Commission addresses proposed revisions filed by PacifiCorp to its Open Access Transmission Tariff (OATT) in order for PacifiCorp to participate in the Energy Imbalance Market (EIM) being created by the California Independent System Operator Corporation (CAISO). PacifiCorp's OATT revisions will work in parallel with tariff revisions proposed by CAISO, whose revisions will provide neighboring balancing authority areas (BAAs) the opportunity to participate in CAISO's real-time market for imbalance energy.[1]

I. Background

2. The Commission requires public utility transmission providers to offer energy imbalance service to transmission customers and generators as ancillary services under the *pro forma* OATT.[2] PacifiCorp currently manages energy imbalances across two BAAs—PacifiCorp East and PacifiCorp West[3]—by utilizing both automated and manual processes to provide imbalance services from its resources under Schedule 4 (Energy Imbalance Service) and Schedule 9 (Generator Imbalance Service) of its OATT. On the other hand, CAISO manages its BAA through the operation of a bid-based real-time energy market that automatically dispatches the least-cost resource every five minutes to serve load while resolving transmission congestion through the use of a detailed network model.

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[1] An order on CAISO's filing is being issued concurrently in Docket No. ER14-1386-000.

[2] *See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,705 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part and rev'd in part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002); *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241 (Order No. 890), *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007) (Order No. 890-A), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[3] PacifiCorp East principally includes PacifiCorp's load and generating capacity in Idaho, Utah, and Wyoming, and PacifiCorp West principally includes PacifiCorp's load and generating capacity in Washington, Oregon, and California.

3. For several years, industry leaders in the West have examined the potential benefits of a regional energy imbalance market that could replace the energy imbalance services that utilities in the region, such as PacifiCorp, currently offer under their respective OATTs. CAISO and PacifiCorp studied the benefits of an energy imbalance market between their BAAs.[4] The EIM Benefits Study projected annual economic benefits to PacifiCorp of between $10.5 and $54.4 million with benefits for customers resulting from dispatch savings, reduced flexibility reserves, and reduced renewable energy curtailment.[5]

4. Following the EIM Benefits Study, CAISO and PacifiCorp executed a memorandum of understanding in February 2013 to begin development of a regional real-time energy imbalance market to commence operations by October 2014. On June 28, 2013, the Commission accepted an implementation agreement between CAISO and PacifiCorp to establish the scope and schedule of implementing the energy imbalance market and to account for PacifiCorp's upfront costs.[6]

5. PacifiCorp estimates that it will incur approximately $20 million in costs to implement EIM through upgrading real-time and settlement metering and telecommunications equipment, systems and support for market operations, and settlement of EIM transactions. In addition, PacifiCorp estimates annual operation and maintenance expenses associated with the EIM of $3 million starting in January 2015.[7] According to PacifiCorp, it is more cost-effective to expand CAISO's existing real-time market to include PacifiCorp's system than it would be for PacifiCorp to create a new platform.

6. On February 28, 2014, CAISO submitted its EIM proposal to the Commission.[8] In its filing, CAISO proposes to utilize its existing real-time market for EIM transactions by

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[4] *See* Energy and Environmental Economics, Inc., *PacifiCorp –ISO Energy Imbalance Market Benefits* (Mar. 13, 2013) (EIM Benefits Study), available on the CAISO website at http://www.caiso.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf and provided in Attachment E to CAISO's EIM filing in Docket No. ER14-1386-000.

[5] PacifiCorp Transmittal Letter at 15-16.

[6] *Cal. Indep. Sys. Operator Corp.*, 143 FERC ¶ 61,298 (2013).

[7] PacifiCorp Transmittal Letter at 18.

[8] *See* CAISO Filing, Docket No. ER14-1386-000 (February 28, 2014).

adding new procedures to accommodate the voluntary participation of other BAAs. Under the EIM tariff provisions proposed by CAISO, entities within BAAs outside of CAISO may sign service agreements to take part in the imbalance energy portion of the CAISO locational marginal price (LMP)-based real-time market alongside participants from within the CAISO BAA. CAISO will run its market software to economically dispatch the energy of any BAA that joins the EIM (an EIM Entity).[9] This will allow for optimization of imbalance energy across the broader EIM footprint to the extent that transmission between an EIM Entity and CAISO, or among EIM Entities, is available. The CAISO EIM tariff provisions do not propose any changes to the current North American Electric Reliability Corporation (NERC)-registered reliability roles for CAISO or EIM Entities such as PacifiCorp. Participation in the EIM does not in itself allow for participation in CAISO's day-ahead and 15-minute markets. PacifiCorp transmission customers that are not participating in the EIM will continue to take service under the PacifiCorp OATT.

7. To facilitate participation in the EIM, PacifiCorp is proposing the following amendments to its OATT: (1) a new Attachment T, which sets forth the roles and responsibilities of customers and PacifiCorp as the EIM Entity;[10] (2) revisions to OATT Schedule 1 to allocate EIM-related administrative costs charged by CAISO; (3) revisions to OATT Schedules 4 and 9 to reflect the use of LMP-based imbalance pricing for Schedule 4 and 9 imbalance service; (4) clarifying revisions to OATT Schedule10 (Real Power Losses); (5) new section 8 of Attachment T to recover EIM-related costs charged by CAISO; (6) new definitions in section 1; and (7) targeted modifications to Parts I through V of its OATT. PacifiCorp requests an effective date of June 20, 2014 with respect to certain of the proposed provisions, and requests waiver of the Commission's regulations to permit certain of the data submission requirements to go into effect just prior to the commencement of the EIM, on September 23, 2014, and the actual settlement provisions and other provisions concerning transmission service to become effective as the EIM goes live, on the later of October 1, 2014 or the date of EIM implementation.[11] PacifiCorp requests that the Commission issue an order by June 20, 2014.

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[9] The proposed tariff defines a BAA that opts to participate as an EIM Entity. *See* CAISO Filing, Docket No. ER14-1386-000, CAISO Tariff, proposed Appendix A (Master Definition Supplement).

[10] An EIM Entity is a balancing authority that opts to participate in the EIM. Proposed OATT, section 1.11G. *See also* CAISO Tariff, proposed Appendix A (Master Definition Supplement). References herein to proposed sections of CAISO's tariff refer to the revised tariff provisions filed in Docket No. ER14-1386-000.

[11] PacifiCorp Transmittal Letter at 20, 70-71, and Attachment C.

II. PacifiCorp Filing

A. Overview

8. PacifiCorp notes that the proposed OATT revisions are intended to work in concert with the proposed CAISO tariff provisions implementing the EIM filed in Docket No. ER14-1386-000; therefore, PacifiCorp has purposely included cross-references to specific sections of the CAISO tariff in its OATT revisions.[12] Moreover, while participation in the EIM is voluntary for PacifiCorp's transmission customers, PacifiCorp's participation in the EIM will impose obligations on all of its transmission and generator interconnection customers, whether or not those customers participate in EIM. For instance, all transmission and generator interconnection customers will have to provide PacifiCorp with operational data consisting of resource operational characteristics and forecast and outage data. According to PacifiCorp, this data is necessary for the EIM to properly model and account for expected load, generation, imports, and exports during the operating hour.[13]

9. While PacifiCorp's transmission customers have the option to bid into the EIM or continue to self-provide generation/load or engage in bilateral transactions outside of the EIM, PacifiCorp proposes to use the EIM and resulting LMP pricing to settle Schedule 4 and 9 imbalances under its OATT for those transmission and generator interconnection customers. PacifiCorp has also revised Schedule 1 of its OATT to clarify that administrative charges assessed by CAISO to PacifiCorp as the EIM Entity will be included in PacifiCorp's annual Schedule 1 charge based upon its formula rate. PacifiCorp proposes to hold harmless its transmission customers from certain CAISO charges while either directly assigning or allocating other charges to its transmission customers.

10. To maximize the benefits of the EIM, PacifiCorp proposes to utilize firm transmission rights offered by a transmission customer who voluntarily elects to make such capacity available for EIM Transfers,[14] which for purposes of the EIM shall not be

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[12] *Id.* at 21.

[13] *Id.*

[14] PacifiCorp's OATT defines an "EIM Transfer" as the transfer of real-time energy resulting from an EIM dispatch instruction either between PacifiCorp's BAAs, between a PacifiCorp BAA and the CAISO BAA, between a PacifiCorp BAA and another EIM Entity's BAA, or between the CAISO BAA and another EIM Entity BAA using transmission capacity available in the EIM. *Id.* at 39; Proposed OATT, section 1.11H.

considered to be sales or assignment of transmission service. PacifiCorp plans to implement the EIM using this approach for the California-Oregon Intertie between CAISO and PacifiCorp West as well as across Idaho Power Company's system between PacifiCorp East and PacifiCorp West. Bonneville Power Administration (BPA) and CAISO are the path operators for the California-Oregon Intertie.[15] PacifiCorp states that it continues to work with BPA and CAISO to effectuate operational solutions regarding use of PacifiCorp's existing transmission rights across the California-Oregon Intertie.

11. PacifiCorp proposes that, in order for generating resources that are internal to PacifiCorp's BAAs to participate in the EIM, those generating resources must secure transmission service, either firm or non-firm, from PacifiCorp. Generating resources that are external to either of PacifiCorp's BAAs also may participate in EIM by utilizing a pseudo-tie arrangement into a PacifiCorp BAA. There is no proposed additional charge for transmission into the CAISO BAA; however, CAISO and PacifiCorp will reassess the issue of EIM transmission charges based on actual data from the EIM after one year of operation.

12. PacifiCorp notes that the EIM will be subject to oversight not only by CAISO and PacifiCorp, but also by numerous other entities including the CAISO Department of Market Monitoring, the CAISO Market Surveillance Committee, other stakeholders, and regulators. PacifiCorp has also proposed additional safeguards that will allow it to suspend its participation in the EIM and default to its existing OATT Schedules 4 and 9 if certain market contingencies occur related to the EIM. In particular, proposed section 10 of the OATT sets forth three potential contingencies: (1) temporary suspension of the EIM by CAISO; (2) termination of PacifiCorp's participation in the EIM; and (3) occurrence of "temporary contingencies" related to management of short-term operational issues to maintain system reliability, communication failures, and, for the initial year of EIM operations, to work in consultation with CAISO and CAISO's Department of Market Monitoring, to mitigate market design flaws that must be remedied by a tariff modification during the period before such a filing can be made and placed into effect.

13. PacifiCorp states that participation in the EIM does not change its existing responsibilities as a balancing authority.[16] PacifiCorp notes that it must still set aside resource capacity at specific generators for contingency reserve, up-regulation and down-regulation for system balancing service for PacifiCorp's BAAs, with any remaining

[15] BPA operates the facilities to the north of the California-Oregon border while CAISO operates the facilities to the south.

[16] PacifiCorp Transmittal Letter at 23.

capacity available for the EIM, assuming that PacifiCorp chooses to bid its resources into the EIM. In addition, PacifiCorp commits that it will continue to support its reserve sharing commitments in the Northwest Power Pool.[17]

B. PacifiCorp's Roles and Responsibilities as an EIM Entity

14. PacifiCorp explains that it has a number of responsibilities as the EIM Entity that interfaces with CAISO.[18] Under the proposal, PacifiCorp must: (1) qualify (or secure representation by a qualified third-party) as an EIM Entity Scheduling Coordinator;[19] (2) process participating resource applications in PacifiCorp's BAAs; (3) provide required information regarding modeling data to CAISO and register all non-participating resources in PacifiCorp's BAAs with CAISO; (4) provide data to CAISO regarding the day-to-day operation of the EIM, including the submissions of EIM Base Schedules and Resource Plans and any changes to such plans; (5) provide CAISO with information regarding the reserved use of the transmission system and interties and any changes to transmission capacity; (6) submit information regarding planned and unplanned outages; and (7) facilitate the provision of transmission capacity for EIM Transfers offered by PacifiCorp Interchange Rights Holders.[20] According to PacifiCorp, these responsibilities are necessary to facilitate the operation of the EIM in accordance with the requirements for EIM Entities specified in proposed section 29 of the CAISO tariff.

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[17] The Northwest Power Pool is a voluntary organization of utilities in the Northwest operating a contingency reserve sharing program under a Commission-approved agreement.

[18] PacifiCorp includes references throughout its Transmittal Letter to the "PacifiCorp EIM Entity," defined in proposed section 1.30F of PacifiCorp's OATT as: "[PacifiCorp] in performance of its role as an EIM Entity under the [EIM provisions of the CAISO tariff] and [PacifiCorp's] Tariff, including, but not limited to, Attachment T. The term 'PacifiCorp EIM Entity' refers collectively to the EIM Entities for both [PacifiCorp East] and [PacifiCorp West]." To minimize confusion, we simply will refer to PacifiCorp in this order. Likewise, we will refer to CAISO instead of the "Market Operator," defined in proposed section 1.19B of PacifiCorp's OATT as "[t]he entity responsible for operation, administration, settlement, and oversight of the EIM," as CAISO is currently performing these functions.

[19] An EIM Entity Scheduling Coordinator is the entity through which a balancing authority that joins the EIM participates in the real-time market. *See* CAISO Tariff, proposed section 29.4(c).

[20] PacifiCorp Transmittal Letter at 22-23.

15. In addition to its roles noted above, PacifiCorp states that it also must make several determinations with respect to how it will implement the EIM.[21] PacifiCorp explains that the EIM settles at LMPs determined at various nodes on the CAISO system. Rather than extend LMP pricing to each node in PacifiCorp's BAAs, PacifiCorp proposes to utilize two Load Aggregation Points, one each for PacifiCorp East and PacifiCorp West, such that each BAA will have its own Load Aggregation Point price. In support, PacifiCorp argues that utilizing a single Load Aggregation Point for each BAA simplifies the process of market participation for load-serving entities located in PacifiCorp's BAAs.[22] PacifiCorp notes that not all load-serving entities are directly metered by PacifiCorp's SCADA system, which presents difficulties in obtaining and providing meter data for forecasting and pricing, without additional SCADA upgrades. PacifiCorp contends that the use of multiple Load Aggregation Points (or LMPs) could require a significant effort and investment in modifications to physical metering, meter data management systems, billing, and settlement systems, without a corresponding demonstrated benefit at this time.

16. PacifiCorp also proposes to use the CAISO load forecast for both of its BAAs. Under CAISO's market design, an entity participating in the EIM may elect to use either its own load forecast or a load forecast produced by CAISO. If PacifiCorp chooses to submit EIM Base Schedules using the CAISO load forecast, it can minimize exposure to charges for under- or over-scheduling. According to PacifiCorp, if it uses the CAISO load forecast and submits EIM Base Schedule forecasts within +/- 1 percent of the CAISO load forecast, it will not be exposed to under- or overscheduling penalties.[23] Furthermore, PacifiCorp notes that use of the CAISO load forecast also addresses certain concerns that were raised during the stakeholder process about the potential for one BAA to "lean" on the capacity of another. Because PacifiCorp will be required to submit EIM Base Schedules that match the load forecast set by CAISO, PacifiCorp asserts that it will be unable to understate its load obligation and lean on other parties' resources.[24]

17. Lastly, PacifiCorp will be a Scheduling Coordinator Metered Entity in accordance with the CAISO tariff.[25] PacifiCorp also will perform this function on behalf of all

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[21] *Id.* at 23.

[22] *Id.* at 24.

[23] *Id.* at 25.

[24] *Id.* at 26.

[25] Pursuant to proposed section 29.10 of the CAISO tariff, metering for EIM settlements is accomplished by EIM Entities becoming either CAISO Metered Entities or

(continued…)

transmission customers with non-participating resources. Accordingly, PacifiCorp shall submit load, resource, and interchange meter data to CAISO in accordance with the CAISO tariff's format and timeframes on behalf of transmission customers with non-participating resources, loads, and Interchange.[26] According to PacifiCorp, this determination strikes a balance between PacifiCorp's responsibilities as a balancing authority and transmission provider to have information on the resources within its BAAs, and CAISO's needs as the operator of the EIM to have timely and accurate meter data for EIM settlements.[27]

C. Transmission Customers' Responsibilities under EIM

18. PacifiCorp outlines the responsibilities of customers with respect to the EIM in section 4.2 of Attachment T. These responsibilities include providing: (1) initial registration data, including operational characteristics of generators; (2) updates to the initial registration data; (3) planned and forced outage information; and (4) forecast data. PacifiCorp argues that registration and outage information is necessary to comply with requirements established under proposed CAISO tariff sections 29.4(c)(4)(C) and (D) (registration) and 29.9 (outages).[28] In addition, PacifiCorp notes that outage and forecast data is necessary to ensure that CAISO can administer the EIM and properly model and account for expected load, generation, imports, and exports during the operating hour. According to PacifiCorp, this limited data requirement will enhance reliable operation of the EIM, as CAISO will have up-to-date and accurate information on resource capabilities and availability. Moreover, PacifiCorp contends that many customers already provide this type of information on their respective facilities and that the information is readily available to customers and not burdensome to produce. Lastly, PacifiCorp notes that it needs the transmission customer forecast data, as it uses that data as the baseline by which to measure imbalance energy for purposes of EIM settlement.

19. PacifiCorp proposes a set of procedures for transmission customers with resources to participate in the EIM. To become a participating resource, an applicant must submit a

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Scheduling Coordinator Metered Entities. Scheduling Coordinator Metered Entities are responsible for collecting, submitting, and ensuring the quality of their own meter data pursuant to section 10.2 of CAISO's tariff, while CAISO Metered Entities use meters directly connected to CAISO's grid, pursuant to section 10.2 of CAISO's tariff.

[26] PacifiCorp Transmittal Letter at 26-27.

[27] *Id.* at 27.

[28] *Id.*

completed application and provide a deposit of $1,500.[29] PacifiCorp states that it will make a determination as to whether to accept or reject the application within 45 days of receipt of the application, based on whether the applicant has satisfied the requirements of Attachment T, as applicable, and met the minimum telemetry and metering requirements, as set forth in the PacifiCorp EIM Business Practice. If PacifiCorp approves the application, it will notify the applicant and CAISO. If PacifiCorp rejects the application, PacifiCorp will notify the applicant and state the grounds for the rejection. PacifiCorp provides a mechanism for the applicant to cure the grounds for the rejection.

20. Upon securing approval of the application, PacifiCorp states that the transmission customer must also demonstrate to CAISO that it has: (1) met CAISO's criteria to become an EIM Participating Resource and executed CAISO's *pro forma* EIM Participating Resource Agreement; (2) qualified to become or retained the services of a CAISO-certified EIM Participating Resource Scheduling Coordinator;[30] (3) met the necessary metering requirements of PacifiCorp's OATT and proposed section 29.10 of the CAISO tariff and the EIM Participating Resource Scheduling Coordinator has executed CAISO's *pro forma* Meter Service Agreement for Scheduling Coordinators; (4) met the communication and data requirements of PacifiCorp's OATT and proposed section 29.6 of the CAISO tariff; and (5) the ability to receive and implement dispatch instructions every five minutes from CAISO.[31]

D. Transmission Service

21. PacifiCorp proposes that in order for a generating resource that is internal to PacifiCorp's BAAs to participate in the EIM, the generating resource must secure and pay for transmission service on PacifiCorp's transmission system. PacifiCorp explains that transmission customers utilizing network service have a choice for transmission service for the EIM. They may elect to either: (1) utilize their network service and continue to be billed for transmission based upon their monthly network load, plus any

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[29] PacifiCorp contends that the fee is necessary for PacifiCorp to recover its costs associated with processing the application, setting up the communications and billing accounts, and for evaluating and determining metering or telemetry requirements necessary for EIM participation. *Id.* at 28.

[30] An EIM Participating Resource Scheduling Coordinator is the entity through which owners or operators of resources that wish to bid supply into the EIM participate in the real-time market. *See* CAISO Tariff, proposed section 29.4.

[31] PacifiCorp Transmittal Letter at 29.

output of designated network resources participating in the EIM;[32] or (2) be charged for transmission associated with EIM dispatch instructions utilizing the same approach proposed for point-to-point transmission service. Under the latter approach, the transmission customer must have an umbrella service agreement for non-firm point-to-point transmission service, in which case, the network customer is required to un-designate network resources to be bid into the EIM and, if dispatched, would pay the hourly non-firm point-to-point transmission service rate consistent with section 8.7.2.2 of Attachment T.[33] The election must be made at the time of the application and may not be changed more frequently than on a quarterly basis.

22. PacifiCorp proposes that any generating resource external to PacifiCorp's BAAs is eligible to participate in the EIM if it: (1) implements a pseudo-tie into a PacifiCorp BAA; (2) has arranged firm transmission over any third-party transmission systems to a PacifiCorp BAA intertie boundary equal to the amount of energy that will be dynamically transferred through a pseudo-tie into PacifiCorp's BAA; and (3) has secured transmission service on PacifiCorp's system consistent with section 3.1 of Attachment T.[34] PacifiCorp contends that its approach is consistent with how external resources were allowed to participate in the Southwest Power Pool, Inc.'s (SPP) Energy Imbalance Service market.[35]

23. PacifiCorp argues that assessing a transmission usage charge for participating in the EIM eliminates the free ridership concern voiced by some stakeholders and ensures that all users of the transmission system contribute to its costs. According to PacifiCorp, it will not assess an incremental transmission charge for transmission use where the transmission customer with a participating resource has existing point-to-point transmission service associated with the participating resource and any dispatch instruction does not exceed the transmission customer's reserved capacity. However, if the transmission customer receives a dispatch instruction and the dispatch operating point exceeds the transmission customer's reserved capacity, the transmission customer will be

[32] A network customer's monthly network load will include any output of designated network resources participating in the EIM based upon the greatest positive dispatch operating point received during the operating hour.

[33] PacifiCorp Transmittal Letter at 31.

[34] *Id.* at 32.

[35] *Id.* at 33 (citing *Southwest Power Pool, Inc.*, 123 FERC ¶ 61,062, at P 24 (2008) ("The Commission finds that SPP's choice of the pseudo-tie approach over dynamic scheduling is just and reasonable.")).

charged on an after-the-fact basis, at the hourly non-firm point-to-point transmission service rate for any amount of the dispatch operating point in excess of the transmission customer's reserved capacity. In addition, PacifiCorp states that Schedule 11 of its OATT (Unauthorized Use) will apply to any amount of actual metered generation which is in excess of the greater of: (1) the output associated with a dispatch operating point or a manual dispatch; or (2) the transmission customer's reserved capacity.

24. PacifiCorp proposes to treat transmission revenue received from EIM transmission service as a credit under PacifiCorp's forward-looking transmission formula rate.[36] A true-up between the forecasted and actual net revenue requirement is calculated annually for the preceding calendar year and applied as a refund or surcharge to long-term firm transmission customers. As a result, PacifiCorp states that existing, non-participating transmission customers will benefit from the EIM due to either: (1) a credit for non-firm point-to-point transmission service for the EIM that will be applied annually through the formula rate; and/or (2) an increase in the transmission cost allocations to participating network customers because the output of designated network resources associated with EIM dispatch instructions will be added to the customer's monthly network load.

E. <u>Transmission Operations</u>

25. PacifiCorp explains that it does not have any unsubscribed, available transmission capacity between PacifiCorp East and PacifiCorp West or between PacifiCorp West and the CAISO BAA for EIM Transfers. Thus, in order to facilitate EIM Transfers, PacifiCorp plans to utilize firm transmission rights voluntarily offered by PacifiCorp Energy, which is the marketing division of PacifiCorp and also a transmission customer.[37] PacifiCorp proposes not to separately compensate or credit its affiliate marketer or any other potential Interchange Rights Holder for transmission capacity made available for EIM Transfers. PacifiCorp contends that its proposal to only utilize firm transmission rights that have been voluntarily turned over for the EIM will ensure that EIM Transfers will be limited to the transmission rights of PacifiCorp's transmission customers. PacifiCorp also proposes revisions to section 23 to clarify that a PacifiCorp Interchange Rights Holder who has informed PacifiCorp that it is electing to make its reserved firm transmission capacity available for EIM Transfers is not performing a reassignment under the OATT and need not comply with the procedures for assignment or transfer of service in section 23.[38]

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[36] *Id.* at 38-39.

[37] *Id.* at 39-40.

[38] *Id.* at 65-66.

26. PacifiCorp states that a dynamic e-Tag will be used to implement EIM Transfers.[39] The e-Tag will be submitted in the preschedule window during which e-Tag curtailments may take place. The e-Tag will have the same curtailment priority as the underlying firm transmission service reservation. If a derate or other operational issue necessitates transmission schedule curtailments, the transmission provider will curtail the e-Tag being used to facilitate the EIM Transfer along with other e-Tags using firm transmission rights at the same pro rata curtailment priority.

27. PacifiCorp states that EIM Transfers within PacifiCorp East or PacifiCorp West associated with EIM dispatch instructions will be controlled and managed by CAISO's EIM security-constrained economic dispatch model and will utilize as-available transmission capacity on PacifiCorp's transmission system. EIM Transfers within PacifiCorp East or PacifiCorp West will not be e-Tagged.[40] PacifiCorp will continue to manage imbalances and congestion within its BAAs through redispatch of its own resources and through transmission curtailments; however, EIM will change the manner in which these operations are performed by PacifiCorp. According to PacifiCorp, the real-time dispatch functionality of the EIM security-constrained economic dispatch model will not order an EIM dispatch over an internal transmission path that is constrained or congested either prior to the operating hour based upon forecast information or in real-time. Thus, PacifiCorp maintains that it can effectively relieve transmission constraints and avoid the need to curtail transmission rights of customers and the EIM can be viewed as an improvement over how PacifiCorp manages congestion today.

F. <u>EIM Operations</u>

28. PacifiCorp states that its participation in the EIM does not modify, change, or otherwise alter the manner in which it must comply with the applicable NERC and Western Electricity Coordinating Council (WECC) reliability standards. PacifiCorp will remain responsible for: (1) maintaining appropriate operating reserves and for its obligations pursuant to any reserve sharing group agreements; (2) NERC and WECC responsibilities; (3) processing e-Tags and managing schedule curtailments at the interties; and (4) monitoring and managing real-time flows within system operating limits on all transmission facilities within PacifiCorp's BAAs, including facilities of PacifiCorp BAA transmission owners.[41]

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[39] *Id.* at 40.

[40] *Id.* at 41.

[41] *Id.* at 42.

29. PacifiCorp explains that proposed section 6 of Attachment T (System Operations Under Normal and Emergency Conditions) is intended to ensure the EIM operations remain consistent with PacifiCorp's reliability responsibilities as a balancing authority. Specifically, PacifiCorp states that it will continue to perform its BAA responsibilities and implement real-time flow management and mitigation consistent with its current system operations, including coordinated unscheduled flow mitigation consistent with WECC's procedures, and will gain an additional tool, the EIM security-constrained economic dispatch, with the ability to automatically or manually re-dispatch generation across the EIM footprint to counter loop flow.[42] Moreover, PacifiCorp notes that WECC is currently developing an enhanced curtailment calculator tool to help address loop flow in WECC BAAs, which is expected to be completed sometime in 2015. PacifiCorp represents that it is willing to include this issue among those issues it has committed to reevaluate as part of a future stakeholder process.[43]

30. PacifiCorp states that, consistent with its current operational practices, it intends to limit requests for reliability redispatch to network resources of PacifiCorp Energy, except in very limited circumstances when only a particular generator can effectively relieve the constraint. However, PacifiCorp expressly reserves the right to revisit this practice, in which case it would seek to implement network operating agreements with network customers consistent with Commission requirements.[44]

G. <u>EIM Settlements</u>

31. PacifiCorp proposes to allocate EIM-related payments and charges from CAISO to PacifiCorp via: (1) direct assignment; (2) assignment only to PacifiCorp (and therefore no sub-allocation to transmission customers); (3) Metered Demand (metered load volumes, including losses pursuant to Schedule 10 (Real Power Losses), in PacifiCorp's BAAs); and (4) Measured Demand (Metered Demand plus e-Tagged export volumes from PacifiCorp's BAAs, including losses pursuant to Schedule 10 and excluding dynamic schedules that support EIM Transfers).[45] PacifiCorp asserts that it developed these sub-allocations consistent with the Commission's cost causation principle—that customers should be fairly allocated costs for which they are responsible or which are incurred for their benefits. PacifiCorp contends that it is appropriate for all such

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[42] *Id*. at 42-43.

[43] *Id*. at 43.

[44] *Id*. at 43-44.

[45] *Id*. at 44.

customers to bear the settlement responsibilities set forth in proposed Attachment T because PacifiCorp will continue to provide required imbalance services under Schedules 4 and 9 of its OATT to transmission customers pursuant to the EIM.

32. PacifiCorp proposes to revise Schedule 1 (Scheduling, System Control and Dispatch Service) to clarify that administrative charges imposed by CAISO to PacifiCorp for the EIM administrative charge in proposed section 29.11(i) of the CAISO tariff and other EIM-related administrative fees can be included in PacifiCorp's annual Schedule 1 charge.[46] PacifiCorp contends that this allocation: (1) reflects benefits to its transmission customers from CAISO's security-constrained economic dispatch model, increased reliability, and an expanded pool of resources to meet imbalances;[47] (2) will have been approved by the Commission in its review of CAISO's proposed EIM tariff provisions; and (3) is consistent with the manner in which PacifiCorp currently recovers Scheduling Coordinator costs for service into CAISO.

33. Under the EIM, PacifiCorp proposes to settle energy imbalances using LMPs determined by CAISO at PacifiCorp's Load Aggregation Points, instead of PacifiCorp's current practice of using an Hourly Pricing Proxy derived from the average price for each hour of the delivered energy price at the California-Oregon Border, Four Corners, Mid-Columbia, and Palo Verde.[48] Specifically, transmission customers will be charged or paid for deviations of their metered load from the load component of the transmission customer base schedules, calculated pursuant to section 4.2.4.3 of Attachment T of PacifiCorp's OATT, at the price determined under proposed section 29.11(b)(3)(C) of the CAISO tariff for the period of the deviation at the applicable Load Aggregation Point where the load is located. PacifiCorp asserts that, because the EIM is the manner in which it will continue to offer required Schedule 4 energy imbalance service to transmission customers serving load within its BAAs, it is appropriate for such customers to bear the cost allocations proposed in Schedule 4 to facilitate the EIM. Transmission customers serving load outside of PacifiCorp's BAAs using point-to-point transmission service will be charged or paid for deviations of the resource component compared to the

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[46] *Id.* at 44-46. PacifiCorp states that these administrative costs do not include PacifiCorp's implementation payments to CAISO under the Implementation Agreement and amendment for CAISO's costs in establishing the EIM, which will be booked to FERC Account No. 303, intangible assets, and allocated using the "Wage and Salary" allocator. *Id.* at 46.

[47] *Id.* at 45 (citing *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361 (D.C. Cir. 2004)).

[48] *Id.* at 46-47.

interchange component of their base schedules at CAISO's price for the period of the deviation at the applicable Load Aggregation Point.

34. Because the LMPs used in the EIM pricing contain a marginal loss component reflecting only marginal losses calculated by CAISO at 115 kV, PacifiCorp states that it will adjust LMPs to remove these losses, and will instead perform a loss calculation using Schedule 10 loss factors at the Hourly Pricing Proxy and settle losses separately from imbalance pricing.[49] Specifically, PacifiCorp Schedule 10 uses periodically updated loss factors that are currently 4.26 percent for use of transmission facilities rated at 46 kV or higher, 3.56 percent for use of distribution facilities rated at 34.5 kV and below, and 7.82 percent for use of both transmission and distribution facilities.

35. PacifiCorp proposes that the revised Schedule 9 (Generator Imbalance Service) will apply only to resources that are not participating in the EIM.[50] Unless a customer has received a manual dispatch or communicated physical changes in output to CAISO, generator imbalance service will apply to a transmission customer when there is a difference between a transmission customer's metered generation and the resource component of the transmission customer's base schedule. For these resources, Schedule 9 generator imbalance service will be settled at the price determined by CAISO, under proposed section 29.11(b)(3)(B) of the CAISO tariff, for the period of the deviation at the PNode where the generator is located. The charge will exclude the price component for marginal losses.[51]

36. For those transmission customers who have received a manual dispatch or communicated physical changes in output to CAISO, Schedule 9 generator imbalance service will apply when: (1) the transmission customer's metered generation deviates from the manual dispatch amount or from the amount of physical changes in output communicated to CAISO prior to the 15-minute market;[52] and (2) the resource component of the customer's base schedule deviates from the manual dispatch amount or

[49] *Id.* at 47.

[50] PacifiCorp EIM Participating Resources will settle imbalances directly with CAISO. *Id.*

[51] *Id.* at 48.

[52] These deviations will be settled at the price determined by CAISO under proposed section 29.11(b)(3)(B) of the CAISO tariff for the period of the deviation at the applicable PNode where the generator is located, less the price component for marginal losses.

the amount of physical changes communicated to CAISO prior to the 15-minute market;[53] or (3) the resource component of the customer's base schedule deviates from the manual dispatch amount.[54]

37. PacifiCorp notes that, while currently a transmission customer can only be charged a penalty under *either* Schedule 4 for hourly energy imbalances or Schedule 9 for generator imbalances occurring during the same hour, but not both unless imbalances aggravate each other, the revised schedules will not have this restriction because the EIM directly charges or compensates load and generation at the applicable LMP, and therefore protects against double-charging.[55] Additionally, PacifiCorp states that because the EIM will include separate penalties for over- and under-scheduling and will settle imbalances at LMPs, PacifiCorp proposes to remove the penalty tiers currently contained in Schedules 4 and 9.

38. PacifiCorp does not propose any substantive changes to the procedures and average loss factors for settlement of real power losses in Schedule 10 of its OATT (Real Power Losses) for initial implementation of the EIM, but notes that it has made a clarifying revision, based on stakeholder comments, to state that financial settlement and physical delivery options for real power losses are available to both network and point-to-point transmission customers.[56]

39. PacifiCorp proposes that any charges or payments from uninstructed imbalance energy under proposed sections 29.11(b)(3)(B) and (C) of CAISO's tariff not otherwise recovered under Schedules 4 and 9 will *not* be sub-allocated to transmission customers.[57] PacifiCorp explains that this type of imbalance energy can arise from differences between

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[53] These deviations will be settled at the price determined by CAISO under proposed section 29.11(b)(1)(A)(ii) of the CAISO tariff for the period of the deviation at the applicable PNode where the generator is located, less the price component for marginal losses.

[54] These deviations will be settled at the price determined by CAISO under proposed section 29.11(b)(2)(A)(ii) of the CAISO tariff for the period of the deviation at the applicable PNode where the generator is located, less the price component for marginal losses.

[55] PacifiCorp Transmittal Letter at 49.

[56] *Id.* at 49-50.

[57] *Id.* at 50. Proposed OATT Attachment T, section 8.2.

CAISO's projection and customers' individual expectations, even if each customer is 100 percent accurate, and asserts that its proposal will insulate its customers from bearing potential costs due to CAISO's load forecast. Likewise, PacifiCorp also proposes not to sub-allocate charges to PacifiCorp for unaccounted for energy pursuant to proposed section 29.11(c) of the CAISO tariff.[58]

40. PacifiCorp proposes to assign charges for under- or over-scheduling to transmission customers subject to OATT Schedule 4 in the BAA that contributed to the imbalance for the hour based on the BAA's respective under- and over-scheduling imbalance ratio share, and to allocate daily excess revenues from under- or over-scheduling charges to load in the EIM area that was not subject to such charges according to Metered Demand.[59] PacifiCorp also proposes to sub-allocate flexible ramping constraint charges pursuant to proposed section 29.11(g) of the CAISO tariff to transmission customers on the basis of Measured Demand.[60] PacifiCorp notes that, pursuant to a recent settlement agreement, CAISO allocates flexible ramping constraint charges 75 percent to hourly Measured Demand (consisting of metered load and exports) and 25 percent to daily gross negative supply deviations by generators.[61] However, PacifiCorp maintains that it will not have the data necessary to determine this split for generating resources participating in the EIM, and that a further sub-allocation would be costly and difficult to implement without substantial benefits. PacifiCorp notes that if it later determines that a change is appropriate, it will have better data from which to develop an alternative approach.[62]

41. PacifiCorp explains that, under CAISO's EIM proposal, each EIM Entity and CAISO will have its own real-time market BAA neutrality account, consisting of charges or credits attributable to excessive rate mitigation measures in the pricing formula for Load Aggregation Points, load forecast deviations, uninstructed generator imbalance energy, regulation energy in CAISO, the real-time marginal loss surplus, and

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[58] *Id.*, section 8.3.

[59] PacifiCorp Transmittal Letter at 51; Proposed OATT Attachment T, section 8.4.

[60] PacifiCorp Transmittal Letter at 51-52; Proposed OATT Attachment T, section 8.5.6.

[61] PacifiCorp Transmittal Letter at 51 (citing *Cal. Indep. Sys. Operator Corp.*, 141 FERC ¶ 61,012 (2013) (approving settlement agreement resolving issues concerning CAISO's flexible ramping constraint)).

[62] *Id.* at 52.

unaccounted for energy.[63] PacifiCorp states that CAISO will reallocate a portion of the amounts in each BAA's account based on the BAA's ratio of five-minute energy transfers to other BAAs to overall uninstructed imbalance energy in the BAA. PacifiCorp proposes to sub-allocate real-time imbalance energy offsets pursuant to proposed section 29.11(e)(3) of the CAISO tariff to transmission customers on the basis of Measured Demand. PacifiCorp contends that the Commission has found *pro rata* allocation of neutrality uplifts to be just and reasonable.[64]

42. PacifiCorp also proposes to allocate charges pursuant to proposed section 29.11(e)(2) of CAISO's tariff for real-time congestion offset—which arise when CAISO has to redispatch generation resources in real-time to manage congestion—to transmission customers on the basis of Measured Demand.[65] CAISO will allocate the costs of congestion attributable to transmission constraints within each BAA to the applicable EIM Entity BAA's real-time congestion account. PacifiCorp asserts that this allocation is consistent with Commission policy, because enhanced reliability provides a system-wide benefit and congestion management benefits the integrated transmission grid.

43. PacifiCorp explains that the EIM makes bid cost recovery payments to generators when real-time market revenues over a day do not cover a resource's real-time commitment and dispatched bid costs.[66] Dispatched bid cost recovery costs fall into two categories: dispatched energy production deviation from a resource's transmission customer base schedule, and commitment costs, consisting of the costs to start a generator and operate it at its minimum operating level. PacifiCorp explains that CAISO will allocate bid cost recovery costs to each BAA, taking into account energy transfers between BAAs similar to the way it will for the real-time market BAA neutrality account. PacifiCorp proposes to sub-allocate real-time bid cost recovery charges pursuant to proposed section 29.11(f) of the CAISO tariff on the basis of Measured Demand.[67]

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[63] *Id.*

[64] *Id.* (citing *Southwest Power Pool,* 114 FERC ¶ 61,289, at P 128 (2006)).

[65] *Id.* at 52-53. Proposed OATT Attachment T, section 8.5.2.

[66] PacifiCorp Transmittal Letter at 53-54.

[67] Proposed OATT Attachment T, section 8.5.5.

44. PacifiCorp proposes not to sub-allocate to transmission customers any charges for the real-time marginal cost of losses offset pursuant to proposed section 29.11(e)(4) of the CAISO tariff.[68]

45. PacifiCorp proposes to adopt the same approach as CAISO with respect to revenue neutrality.[69] PacifiCorp states that CAISO imposes daily and monthly neutrality adjustments and rounding adjustments to collect any shortfalls due to rounding, and allocates these charges on the basis of Measured Demand. PacifiCorp proposes to hold transmission customers harmless from certain charges related to the timing of payments and risk of market shortfalls that are more under PacifiCorp's control.[70] PacifiCorp asserts that it is reasonable for it to take responsibility for making timely payments to CAISO, and also reasonable for it to receive the allocation of payments from CAISO after the defaulting market participant makes a late payment.

46. PacifiCorp proposes to assign three types of charges directly to the customers causing those costs to be incurred.[71] First, to the extent PacifiCorp incurs a penalty for inaccurate or late actual settlement quality meter data, pursuant to section 37.11.1 of the CAISO tariff, PacifiCorp will directly assign the penalty to the responsible transmission customer.[72] Second, PacifiCorp will directly assign charges for tax liability pursuant to proposed section 29.22(a) of the CAISO tariff to the transmission customers triggering the tax liability.[73] Finally, PacifiCorp states that it will sub-allocate charges under proposed section 29.11(j) of the CAISO tariff for variable energy forecasting services only to transmission customers with non-participating resources that request CAISO's forecast, as CAISO has stated that it will waive the charge if an EIM Entity uses an

[68] PacifiCorp Transmittal Letter at 54.

[69] *Id.* at 54.

[70] These charges include: Invoice Deviation (distribution and allocation); Default Invoice Interest Payment; Default Invoice Interest Charge; Invoice Late Payment Penalty; Financial Security Posting (Collateral) Late Payment Penalty; Shortfall Receipt Distribution; Shortfall Reversal; Shortfall Allocation; Default Loss Allocation; and Generator-Interconnection Process Forfeited Deposit Allocation.

[71] PacifiCorp Transmittal Letter at 55.

[72] Proposed OATT Attachment T, section 8.5.7.

[73] *Id.*, section 8.6.

independent forecast, which PacifiCorp has elected to do.[74] PacifiCorp contends that each of these provisions is consistent with cost causation principles.

47. Consistent with proposed section 29.11(l) of the CAISO tariff, PacifiCorp states that it has included a provision that PacifiCorp will be subject to CAISO's payment calendar for issuing settlement statements, exchanging invoice funds, submitting meter data, and submitting settlement disputes, but that PacifiCorp will continue to follow section 7 of its OATT for issuing invoices regarding the EIM.[75] PacifiCorp also proposes revisions reflecting that CAISO has the authority to correct prices and may modify settlement statements as a result of its dispute resolution process.[76]

48. PacifiCorp states that proposed section 8.10 of Attachment T permits EIM-related charges or payments that are not captured elsewhere in the OATT to be placed in an EIM Residual Balancing Account pending Commission approval of a proposed allocation methodology pursuant to section 205 of the Federal Power Act (FPA), with interest accruing in accordance with the Commission's regulations.[77] PacifiCorp compares the EIM Residual Balancing Account to formula rate true-ups and asserts that this methodology provides even more protection from over- or under-recovery of costs than a true-up because initial charges are not based on projected costs and PacifiCorp will not allocate any amounts until the Commission has approved an allocation methodology.

H. Dispute Resolution

49. PacifiCorp proposes to add a new section 12.4A (EIM Disputes) to its existing dispute resolution procedures, specifically addressing the administration and settlement of charges under the EIM.[78] Under these proposed procedures, disputes regarding the manner in which PacifiCorp allocates EIM payments and charges from CAISO as the operator of the EIM will be processed in accordance with the existing dispute resolution

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[74] *Id.*, section 8.5.7.

[75] PacifiCorp Transmittal Letter at 55.

[76] *Id.* at 56; Proposed OATT Attachment T, section 8.11.

[77] PacifiCorp Transmittal Letter at 56-57.

[78] *Id.* at 57-58. Disputes relating PacifiCorp's administration of non-EIM OATT provisions will continue to be processed in accordance with existing sections 12.1 to 12.4 and 12.5.

procedures,[79] but disputes between CAISO and a PacifiCorp EIM Participating Resource Scheduling Coordinator related to settlement statements provided to the PacifiCorp EIM Participating Resource Scheduling Coordinator from CAISO will proceed according to the timeline in the CAISO tariff.[80] PacifiCorp may raise disputes regarding settlement statements received from CAISO in accordance with the process in the CAISO tariff.[81] Additionally, PacifiCorp proposes that, if a dispute arises regarding a CAISO charge or payment to PacifiCorp that is subsequently charged or paid to a transmission customer or interconnection customer, and such customer wishes to raise a dispute with CAISO, PacifiCorp will file the dispute on behalf of such customer and will work with the customer to resolve the dispute pursuant to the process in CAISO's tariff.[82]

50. PacifiCorp maintains that its proposed dispute resolution procedures are just and reasonable, because disputes are addressed pursuant to the procedures of the entity whose actions are being challenged.[83] PacifiCorp acknowledges that the settlement dispute timeframes in CAISO's tariff provide limited time for transmission and interconnection customers without a direct relationship to CAISO to review statements and request that PacifiCorp raise a dispute on their behalf. PacifiCorp notes that it raised this issue in the stakeholder process, plans to raise the issue in CAISO's EIM filing in Docket No. ER14-1386-000, and commits to continue to request that CAISO revisit this issue.

I. <u>Compliance</u>

51. According to PacifiCorp, proposed section 9 of Attachment T includes several provisions related to the code of conduct for customers subject to Attachment T.[84] PacifiCorp states that section 9.1 requires PacifiCorp EIM Participating Resources and PacifiCorp EIM Participating Resource Scheduling Coordinators to comply with information requests, and transmission customers to provide PacifiCorp with information necessary to respond to information requests from CAISO, the EIM market monitor, or other regulatory authorities regarding EIM activities. PacifiCorp asserts that this

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[79] Proposed OATT, section 12.4A.1.

[80] *Id.*, section 12.4A.2.

[81] *Id.*, section 12.4A.3.

[82] *Id.*, section 12.4A.4.

[83] PacifiCorp Transmittal Letter at 58.

[84] *Id.* at 58-60.

provision appropriately recognizes the need for non-participants to respond to data requests, as non-participant activities can have a material effect on LMPs.[85] PacifiCorp emphasizes, however, its continued obligation to preserve the confidentiality of information obtained from transmission and interconnection customers, unless it is required or otherwise permitted to disclose the information.

52. PacifiCorp has proposed six general rules of conduct for participation in the EIM.[86] These rules of conduct generally require customers to: (1) comply with dispatch instructions and operating orders in accordance with Good Utility Practice; (2) submit bids for resources that are reasonably expected to be available and capable of performing at the levels specified in the bid; (3) notify CAISO and PacifiCorp of outages in accordance with section 7 of Attachment T of PacifiCorp's OATT; (4) provide complete, accurate, and timely meter data to PacifiCorp and maintain responsibility to ensure the accuracy of such data; (5) provide information to PacifiCorp, including the information requested in Attachment T, by applicable deadlines; and (6) utilize commercially reasonable efforts to ensure that forecasts are accurate and based on all information that is, or should have been, known at the time of submission. Proposed section 9.3 permits PacifiCorp to refer a violation of these rules of conduct to the Commission for enforcement.

53. According to PacifiCorp, the rules of conduct are necessary and appropriate to put customers on notice as to expected conduct, and are also designed to address concerns raised by the CAISO Market Surveillance Committee in connection with its public committee process about the potential for market participants to leverage EIM activities with their participation in other CAISO markets.[87]

J. Market Contingencies

54. Under proposed section 10 of Attachment T, PacifiCorp proposes to give itself the authority to take corrective action in the event of certain market contingencies related to the EIM.[88] First, proposed section 10.1 of Attachment T provides that, if CAISO temporarily suspends the EIM pursuant to proposed section 29.1(d) of the CAISO tariff, PacifiCorp will revert to the currently-effective Schedules 4 and 9 (Temporary Schedules

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[85] *Id.* at 59.

[86] *Id.* at 59-60.

[87] *Id.* at 60.

[88] *Id.* at 61-64.

4 and 9) until either the temporary suspension is no longer in effect or PacifiCorp has terminated its participation in the EIM. Proposed section 10.2 of Attachment T addresses the corrective actions PacifiCorp may take during the 180-day period between submitting a notice of termination of its participation in the EIM and the termination effective date. Specifically, PacifiCorp may request that CAISO prevent EIM Transfers and separate the PacifiCorp BAAs from operation of the EIM in the EIM area, and that it suspend settlement of EIM charges with respect to PacifiCorp. PacifiCorp would then utilize Temporary Schedules 4 and 9.

55. Section 10 also contemplates three types of temporary contingencies, each of which would enable PacifiCorp to request the same corrective actions from CAISO and implement Temporary Schedules 4 and 9. Consistent with CAISO's proposed tariff, the first two of these temporary contingencies involve either operational circumstances that have caused or are in danger of causing an abnormal system condition in PacifiCorp's BAA requiring immediate action, or disruption of communications between CAISO and PacifiCorp, preventing PacifiCorp, PacifiCorp EIM Entity Scheduling Coordinator, or a PacifiCorp EIM Participating Resource Scheduling Coordinator from accessing CAISO systems to submit or receive information. PacifiCorp maintains that these protections are just and reasonable to protect reliability as part of PacifiCorp's balancing authority responsibilities.[89]

56. PacifiCorp also proposes a third contingency if, during the initial 12 months of EIM operation, PacifiCorp determines, after consultation with CAISO and the Department of Market Monitoring, that there exist market design flaws that could be effectively remedied by rule or tariff changes.[90] PacifiCorp asserts that the Commission has recognized the need to provide additional protections at the start of a new market.[91] Moreover, PacifiCorp contends that this protection is appropriate because PacifiCorp has an alternative methodology to provide for imbalances, should a market design flaw create material impacts in either the CAISO or PacifiCorp BAAs. PacifiCorp submits that temporarily suspending the EIM to correct a market design flaw would be preferable to terminating participation altogether, particularly in light of the substantial time and effort invested by stakeholders and regulators. Finally, PacifiCorp asserts that the actions

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[89] *Id.* at 62-63.

[90] *Id.* at 62.

[91] *Id.* at 63 (citing *New York Indep. Sys. Operator, Inc.*, 97 FERC ¶ 61,095 (2001); *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163, at P 58, *order on reh'g*, 109 FERC ¶ 61,157, at PP70-80 (2004), *order on reh'g and order on proof*, 111 FERC ¶ 61,448 (2005), *order on reh'g and compliance*, 113 FERC ¶ 61,081 (2005)).

CAISO can take to address temporary contingencies, such as price correction, do not adequately protect its customers.[92]

K. Other Proposed Changes to PacifiCorp's OATT

57. PacifiCorp describes additional proposed OATT revisions needed to implement the EIM, including: (1) revisions and additions to the Definitions in section 1 of its OATT;[93] (2) changes to ensure the applicability of Attachment T to all transmission and interconnection customers (and thereby ensure that customers will provide PacifiCorp the requisite information to meet the registration, outage reporting, and forecast requirements included throughout Attachment T);[94] and (3) a clarification to the submissions required from a transmission customer that elects to utilize non-firm point-to-point transmission service to participate in the EIM under section 18.5.[95]

58. Additionally, PacifiCorp proposes that, when network customers use network integration service to participate in the EIM, network resources bid into the EIM as Participating Resources need not be undesignated (as a network resource would otherwise need to be to make off-system sales).[96] However, network customers electing instead to use point-to-point service for EIM participation would be required to undesignate network resources, consistent with the Commission's rules and policies regarding network service. PacifiCorp states that these changes are reflected in new sections 28.7, 30.1, and 30.4.

59. Finally, PacifiCorp requests that its new market responsibilities as an EIM Entity be subject to a higher, gross negligence or intentional wrongdoing standard of liability, as opposed to its responsibilities as a transmission provider under the *pro forma* OATT, which are subject to the ordinary negligence standard of liability.[97] PacifiCorp contends that the Commission has permitted use of the gross negligence standard for CAISO and its participating transmission owners under the Transmission Control Agreement and the

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[92] *Id*. at 63-64.

[93] *Id*. at 64.

[94] *Id*.

[95] *Id*. at 65.

[96] *Id*. at 66.

[97] *Id*. at 66-68; Proposed OATT, section 10.2.

CAISO tariff, and for transmission providers in all other organized markets.[98] PacifiCorp argues that its status as EIM Entity is comparable, as excessive damage awards could lead to higher insurance premiums and a higher cost of capital, causing PacifiCorp's customers to bear additional costs.[99] PacifiCorp also notes that this higher standard of liability would encourage participation by other balancing authorities.

L. Other Considerations Related to EIM Implementation

60. PacifiCorp states that, consistent with its prior practices, it proposes to include certain, specified implementing procedures in a new PacifiCorp EIM Business Practice, which has yet to be drafted.[100] PacifiCorp states that it will follow the guidance in existing Business Practice #13 for developing and amending business practices, and that it anticipates a stakeholder process with ample opportunities for review and comment.

61. PacifiCorp notes that its Order No. 764 compliance filing is currently pending before the Commission in Docket No. ER13-2364, but asserts that the EIM will not affect that filing.[101] PacifiCorp states that, at this time, it does not support allowing external resources outside of its BAAs to participate in CAISO's 15-minute market at PacifiCorp's intertie boundaries, because PacifiCorp views this as a market expansion outside the scope of the EIM.

M. Effective Date and Waiver Requests

62. PacifiCorp appends to its filing, as Attachment C, a table of requested effective dates. Generally, PacifiCorp requests that: (1) the language associated with applicability of Attachment T and related requirements become effective June 20, 2014 to provide greater certainty with respect to the EIM design for PacifiCorp, CAISO, and customers during the July 2014 EIM market simulation; (2) the provisions related to actual implementation of the EIM become effective September 23, 2014, consistent with the effective date requested in CAISO's EIM filing and to ensure that information supporting EIM operation is in place several business days prior to the first trade date of the new market (October 1, 2014, at the earliest); and (3) the remaining provisions related to the settlement of charges associated with the EIM and additional aspects related to

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[98] PacifiCorp Transmittal Letter at 67.

[99] *Id.* at 68.

[100] *Id.* at 68-70.

[101] *Id.* at 70.

implementation of the EIM become effective the later of October 1, 2014, or the date CAISO and PacifiCorp mutually agree to commence the EIM.[102] PacifiCorp requests waiver of section 35.3(a)(1) of the Commission's regulations[103] to permit certain provisions to become effective more than 120 days after the date PacifiCorp filed the OATT amendment with the Commission. PacifiCorp submits that granting this waiver will permit the OATT amendments to be in place in a timeframe necessary to support final design, testing, and startup of the EIM, thereby providing all parties with necessary regulatory and operational certainty.

63. PacifiCorp requests that the Commission issue an order no later than June 20, 2014, to facilitate the EIM market simulation.[104]

64. PacifiCorp requests waiver of the requirement to submit full Period I and Period II cost-of-service statements pursuant to 18 C.F.R. § 35.13, consistent with prior waivers granted by the Commission for formula rates.[105] PacifiCorp states that EIM charges are addressed in the CAISO filing in Docket No. ER14-1386-000, and that PacifiCorp has no experience on which to estimate proposed amounts.

III. Notice and Responsive Filings

65. Notice of PacifiCorp's filing was published in the *Federal Register,* 79 Fed. Reg. 18,681 (2014), with interventions and protests due on or before April 15, 2014. The Commission subsequently extended the comment period to April 25, 2014. Puget Sound Energy, Inc., Sacramento Municipal Utility District, Noble Americas Energy Solutions, LLC, Idaho Power Company, J.P. Morgan Ventures Energy Corporation, Morgan Stanley Capital Group Inc., NextEra Energy Resources, LLC, Cowlitz County Public Utility District, Meadow Creek Project Company, LLC, California Municipal Utilities Association, Public Utility District No. 1 of Snohomish County, Washington, M-S-R Public Power Agency, Public Power Council, Portland General Electric Company, Western Area Power Administration, Northern California Power Agency, Goshen Phase II LLC, Balancing Authority of Northern California, California Department of Water Resources State Water Project filed timely motions to intervene. The Washington Utilities and Transportation Commission also filed a notice of intervention.

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[102] *Id.* at 70-71, and Attachment C.

[103] 18 C.F.R. § 35.3(a)(1) (2013).

[104] PacifiCorp Transmittal Letter at 70.

[105] *Id.* at 70-71.

66. Southern California Edison Company (SoCal Edison), Iberdrola Renewables, LLC (Iberdrola), Pacific Gas and Electric Company (PG&E), Western Power Trading Forum (WPTF), Electric Power Supply Association (EPSA), California Independent System Operator Corporation (CAISO), Xcel Energy Services Inc. (Xcel),[106] Deseret Generation & Transmission Co-Operative, Inc. (Deseret), Public Utility District No. 2 of Grant County, Washington (Grant County PUD) and Northwest and Intermountain Power Producers Coalition (NIPPC) filed timely motions to intervene and comments. The American Wind Energy Association, the California Wind Energy Association, the Center for Energy Efficiency and Renewable Technologies, and Renewable Northwest (collectively, Wind Parties) timely filed a joint motion to intervene and comments. Similarly, Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy (collectively, NV Energy) timely filed a joint motion to intervene and comments. Public Utility District No. 1 of Chelan County, Washington, Public Utility District No. 1 of Cowlitz County, Washington, Public Utility District No. 1 of Snohomish County, Washington, and City of Tacoma, Department of Public Utilities, Light Division (doing business as Tacoma Power) (collectively, Northwest Public Parties) filed comments. Tri-State Generation and Transmission Association (Tri-State) filed a timely motion to intervene and protest. BPA filed a timely motion to intervene, comment, and protest. Powerex Corporation (Powerex) filed a timely motion to intervene and protest. The Public Utility Commissioners' EIM Working Group (PUC EIM Group) filed timely comments. City of Redding, California (Redding), the City of Santa Clara, California (Santa Clara), Modesto Irrigation District (Modesto), Transmission Agency of Northern California (TANC) and Utah Associated Municipal Power Systems (UAMPS) filed motions to intervene, comments, and motions to consolidate Docket No. ER14-1578-000 with Docket No. ER14-1386-000. The Honorable United States Senator Harry Reid submitted comments on May 20, 2014 and Governor Edmund G. Brown, Jr. of California and Governor Brian Sandoval of Nevada submitted joint comments on June 2, 2014. The Cities of Anaheim, Azusa, Banning, Colton, Pasadena and Riverside, California (Six Cities) and Eugene Water and Electric Board filed motions to intervene out-of-time.

67. On May 12, 2014, motions for leave to answer and answers were filed by PacifiCorp and CAISO. On May 20, 2014, SoCal Edison filed a motion for leave to answer and answer to the answer filed by PacifiCorp. On May 23, 2014, Powerex filed separate motions for leave to answer and answer to the answers filed by PacifiCorp and CAISO. Also on May 23, 2014, Tri-State filed a motion for leave to answer and answer the answers filed by PacifiCorp and CAISO. On May 28, 2014, PacifiCorp filed a motion for leave to answer and answer the answers filed by Powerex and Tri-State.

[106] Xcel intervenes on behalf of Public Service Company of Colorado.

IV. Discussion

A. Procedural Matters

68. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2013), the notice of intervention and filing of timely, unopposed motions to intervene serve to make the movants parties to the proceeding. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2013), the Commission will grant the late-filed motions to intervene of Six Cities and Eugene Water and Electric Board given their interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.

69. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2013), prohibits an answer to a protest or an answer unless otherwise ordered by the decisional authority. We will accept the answers to comments and protests filed by PacifiCorp and CAISO because they have provided information that assisted us in our decision-making process. We are not persuaded to accept the answers to answers filed by SoCal Edison, Powerex, Tri-State, and PacifiCorp and will, therefore, reject them.

B. Substantive Matters

1. Overview of PacifiCorp's EIM Proposal

70. PacifiCorp's EIM proposal sets forth the rules for PacifiCorp and its customers to participate in CAISO's real-time energy imbalance market, which by virtue of CAISO's proposed tariff filing in Docket No. ER14-1386-000, will extend to PacifiCorp's BAAs.

Discussion

71. We conditionally accept, in part, subject to further modifications, and reject, in part, PacifiCorp's proposed OATT revisions, as directed in this order. We also grant the effective dates requested in Attachment C to the filing.

72. In the following sections of this order, we address aspects of PacifiCorp's proposal that have been contested by various commenters. Our review of the aspects of PacifiCorp's proposal that are not contested and not specifically discussed herein indicates that they are just and reasonable and are hereby accepted for filing, with the effective dates requested by PacifiCorp.

2. General and Legal Issues

Background

73. According to PacifiCorp, the EIM Benefits Study demonstrates that the EIM will provide both quantitative benefits—including interregional and intraregional dispatch savings and reduction in flexibility reserves and renewable energy curtailment—and qualitative reliability benefits due to increased situational awareness and responsiveness.[107] PacifiCorp calculates that its costs to implement the EIM, including upgrading metering and telecommunications equipment, systems and support necessary for efficient operation, and settlement of transactions occurring in the EIM, will total $20 million, with annual operation and maintenance costs of $3 million starting January 2015.[108]

Comments

74. UAMPS believes that the claimed annual economic benefit to PacifiCorp in the EIM Benefits Study is overly optimistic and that PacifiCorp's filing (including the EIM Benefits Study) should be set for hearing to allow for analysis of the claimed benefits versus the added cost of participation.[109] UAMPS requests that the Commission not approve PacifiCorp's EIM amendments on the basis of the instant filing, but instead requests that the Commission suspend PacifiCorp's proposed OATT changes for a nominal period and permit the changes to become effective on the dates requested by PacifiCorp, subject to refund and set the matter for hearing and hold the hearing in abeyance pending settlement talks and an investigation of the issues requested by UAMPS.[110]

75. Powerex argues that PacifiCorp has provided little to no support for many of its tariff changes and that PacifiCorp has not met its burden of proof as required under long-standing Commission precedent.[111] Accordingly, Powerex requests that the Commission issue an order rejecting the filing, and provide guidance on the areas of deficiency that

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[107] PacifiCorp Transmittal Letter at 2-3, 13-18.

[108] *Id.* at 18-19.

[109] UAMPS Comments at 5-10.

[110] *Id.* 22-23.

[111] Powerex Protest at 8-11.

PacifiCorp must address in a subsequent filing after meaningful stakeholder participation.[112] Powerex believes that the problems it identifies in PacifiCorp's proposal can be readily resolved, but admits that it has not undertaken the complex work to develop solutions.

76. BPA acknowledges that it does not seek rejection of PacifiCorp's filing; rather, it advocates that the Commission approve PacifiCorp's filing with the modifications proposed by BPA.[113] Deseret argues that the benefits of EIM have been overstated and that PacifiCorp has not demonstrated that energy imbalance charges under Schedules 4 and 9 will be lower.[114] Deseret notes that there is no indication that transmission customers will see any practical difference between CAISO's security-constrained least cost dispatch model and how PacifiCorp currently provides energy imbalance service through its least expensive, most cost-efficient resources available.[115] However, Deseret states that it supports the implementation of a CAISO/PacifiCorp EIM and, on the whole, believes that the EIM will likely produce net benefits.[116]

77. In addition to the requests for a hearing or rejection of PacifiCorp's filing, several parties request consolidation of the EIM proceedings filed by PacifiCorp and CAISO.[117] Tri-State requests that the Commission consolidate CAISO's EIM proceeding with PacifiCorp's filing in this docket, as PacifiCorp's OATT cannot be fully understood without referencing the CAISO tariff.[118] UAMPS also requests consolidation of the two proceedings, arguing that the Commission needs to take a holistic approach and evaluate CAISO's and PacifiCorp's EIM proposals together as PacifiCorp's EIM proposal is inextricably linked to CAISO's EIM.[119]

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[112] *Id.* at 7.

[113] BPA Comment and Protest at 4.

[114] Deseret Comments at 14.

[115] *Id.* at 16.

[116] *Id.* at 14.

[117] TANC Comments at 15-16; Modesto Comments at 5; Santa Clara Comments at 7; Redding Comments at 6.

[118] Tri-State Protest at 4.

[119] UAMPS Comments at 18-21.

Answers

78. In response to UAMPS, PacifiCorp argues that an evidentiary hearing is unnecessary, as the record provides sufficient evidence for the Commission to make its determination, and will delay implementation of the market improvements provided by the EIM.[120] PacifiCorp suggests that stakeholders were afforded ample opportunity to comment on the EIM Benefits Study during the stakeholder proceeding, and thus "should not be encouraged to remain on the sidelines and wait for the opportunity to raise issues after a filing with the Commission."[121] PacifiCorp contends that no party questions that the EIM will produce qualitative benefits, at a minimum.[122] CAISO similarly contends in its answer that the benefits of the EIM "have been the subject of considerable study, have been widely considered, including by Commission staff, and are more than sufficiently documented to justify the costs of moving forward," and that commenters have presented no evidence that these benefits will not materialize.[123] According to PacifiCorp, the Commission has recognized the benefits of transparent price signals from LMP-based markets,[124] and does not require benefit studies in order to determine that proposed tariff changes are just and reasonable.[125] PacifiCorp maintains that the true test of the EIM market design will be through its operation, and notes that CAISO has committed to provide ongoing reports of market performance.[126]

79. PacifiCorp asserts that Powerex's request that the Commission reject the filing and provide further guidance should be denied, as the Commission has a full record before it upon which to render a decision, and that additional stakeholder proceedings are not

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[120] PacifiCorp Answer at 7-8.

[121] *Id.* at 8.

[122] *Id.* at 8-9 (citing PacifiCorp Transmittal Letter, Attachment D, Testimony of Natalie L. Hocken at 14-15).

[123] CAISO Answer at 7-10 (citation omitted).

[124] PacifiCorp Answer at 9 (citing *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at P 63 (2006)).

[125] *Id.* at 10-11 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,172, at P 6 (2008)).

[126] *Id.* at 11.

likely to result in consensus over policy questions.[127] CAISO states that the Commission has repeatedly found CAISO's real-time market to be just and reasonable and consistent with or superior to the imbalance service provisions in the *pro forma* OATT, and asserts that Powerex has identified no changed circumstance that would render this prior precedent inapplicable.[128] PacifiCorp also states that the Commission should not consider alternatives proposed by commenters unless the Commission determines that PacifiCorp's proposed OATT revisions do not meet the standard in section 205 of the FPA.[129] PacifiCorp and CAISO state in their answers that, while they continue to believe that consolidation of the proceedings is unnecessary, they would not object to consolidation should the Commission find it appropriate.[130]

Commission Determination

80. Except as discussed below, we find that PacifiCorp has met its burden of proof to demonstrate that the proposed OATT revisions are just and reasonable pursuant to section 205 of the FPA. We also find that the record in this proceeding is sufficient to permit the Commission to make determinations and to direct compliance filings, where necessary, to modify the proposed OATT revisions. Accordingly, we deny the requests for hearing. Moreover, we find that PacifiCorp's filing and the EIM Benefits Study adequately demonstrate that the EIM will provide both quantitative and qualitative benefits to PacifiCorp's customers. We note that these benefits can be expected to increase with increased participation in the EIM because participation would bring incremental load and resource diversity in the market.[131] Accordingly, except with respect to the specific matters noted below, we find that PacifiCorp's proposed tariff revisions are just, reasonable, and not unduly discriminatory, and we therefore accept them with the modifications directed herein.

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[127] CAISO Answer at 3-7.

[128] *Id.* at 3.

[129] PacifiCorp Answer at 4.

[130] *Id.* at 6-7; CAISO Answer at 16.

[131] *See* EIM Benefits Study at 33 ("The results also confirm that the benefits of an EIM can be quite substantial as participation grows, allowing more resources to participate and lowering the costs of both imbalance energy and the costs of providing adequate dynamic reserves.").

81. We deny the requests to consolidate Docket No. ER14-1578-000 with CAISO's proposed tariff filing in Docket No. ER14-1386-000. The Commission's policy is to consolidate matters only if a trial-type evidentiary hearing is required to resolve common issues of law and fact and consolidation will ultimately result in greater administrative efficiency.[132] Because we are not setting either filing for hearing and settlement judge procedures, there is no need for consolidation.

82. We also find good cause to grant waiver of the Commission's maximum 120-day notice requirement, 18 C.F.R. § 35.3(a)(1) (2013), to permit PacifiCorp's requested effective dates. Accordingly, we grant PacifiCorp the effective dates requested in Attachment C, including the requested June 20, 2014 effective date for the language associated with the applicability of proposed Attachment T, and the requested September 23, 2014 effective date.

83. Lastly, we grant PacifiCorp's request for waiver of the requirement to submit Period I and Period II cost-of-service statements pursuant to 18 C.F.R. § 35.13 (2013) and for waiver of the applicable requirements of Part 35 of the Commission's regulations to the extent not satisfied in PacifiCorp's filing.

a. <u>Business Practice Manuals</u>

<u>Background</u>

84. PacifiCorp proposes, consistent with how it has previously implemented other elements of its OATT, to include detailed implementation procedures in a new PacifiCorp EIM Business Practice, which has yet to be drafted.[133] PacifiCorp states that its proposal is consistent with how CAISO, other regional transmission organizations, and transmission providers document OATT implementing procedures. PacifiCorp commits that, at a minimum, it will follow its own Business Practice #13 (Business Practice Guidelines) in this regard and anticipates a stakeholder process with multiple opportunities for review and comment.

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[132] *See Southern Cal. Edison Co.*, 129 FERC ¶ 61,304, at P 26 (2009), *amended by* 130 FERC ¶ 61,092 (2010); *Midcontinent Express Pipeline LLC*, 124 FERC ¶ 61,089, at P 27 (2008), *order on reh'g*, 127 FERC ¶ 61,164 (2009), *order on remand*, 134 FERC ¶ 61,155, *reh'g denied*, 136 FERC ¶ 61,222 (2011); *Startrans IO, L.L.C.*, 122 FERC ¶ 61,253, at P 25 (2008).

[133] PacifiCorp Transmittal Letter at 68-70.

Comments

85. Several parties express concern that the lack of a developed PacifiCorp EIM Business Practice makes it difficult to evaluate the scope of PacifiCorp's proposal, particularly as to whether the EIM will have adverse impacts on the transmission rights of other customers.[134] BPA, UAMPS, and Powerex argue that the EIM implementation procedures that will be included in the still-to-be-developed PacifiCorp EIM Business Practice could impact rates, terms, and conditions of service.[135] In particular, Powerex contends that items such as scheduling, priority, and allocation of transmission rights as well as penalty charges and data requirements are key provisions related to rates, terms, and conditions of service for the EIM that should be set forth in the OATT and not left to the EIM Business Practice.[136]

86. BPA recommends that the Commission hold PacifiCorp to its commitment to provide multiple opportunities for review and comment by stakeholders in advance of the proposed effective date of the EIM Business Practice.[137] In addition, BPA requests that the Commission consider a procedural mechanism for PacifiCorp or stakeholders to provide notice to the Commission of necessary tariff changes or corrections that are identified in the EIM Business Practice development process.[138] UAMPS requests that the Commission require PacifiCorp and CAISO to provide a complete draft of the EIM Business Practice as part of this filing.[139] Powerex requests that the Commission, in a future filing after rejecting the instant proposal, direct PacifiCorp to include in the proposed amendments to its tariff all provisions that affect rates, terms, and conditions of service such as the areas identified by Powerex.[140]

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[134] Santa Clara Comments at 8; Redding Comments at 9; UAMPS Comments at 14.

[135] BPA Comment and Protest at 9; UAMPS Comments at 14; Powerex Protest at 81-85.

[136] Powerex Protest at 84-85.

[137] BPA Comment and Protest at 9.

[138] *Id.* at 10.

[139] UAMPS at 14.

[140] Powerex Protest at 85.

Answer

87. PacifiCorp responds that its proposed process for developing the EIM Business Practice is consistent with PacifiCorp's prior practice, and that the specific implementation details that it proposes to include in the EIM Business Practice comport with the Commission's "rule of reason" because they do not significantly affect the rates, terms, or conditions of service in the manner contemplated by the Commission when requiring amendments to the OATT.[141] PacifiCorp states that it has commenced a robust and extended stakeholder process regarding the proposed EIM Business Practice, which will provide all stakeholders the opportunity to participate in every aspect of the process.[142] PacifiCorp commits to make the requisite filing under section 205 of the FPA should it determine during the development of the EIM Business Practice that any items currently included in the EIM Business Practice belong in Attachment T of its OATT.[143]

Commission Determination

88. Decisions on whether to place an item in PacifiCorp's OATT or the EIM Business Practice are shaped by the Commission's "rule of reason" policy,[144] which dictates that provisions that "significantly affect rates, terms, and conditions" must be included in the filed tariff.[145] The Commission has elaborated that it is appropriate for a business

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[141] PacifiCorp Answer at 107-110.

[142] *Id.* at 110-111.

[143] *Id.* at 111.

[144] *See, e.g., City of Cleveland v. FERC*, 773 F.2d 1368, 1376 (D.C. Cir. 1985) (finding that utilities must file "only those practices that affect rates and service significantly, that are reasonably susceptible of specification, and that are not so generally understood in any contractual arrangement as to render recitation superfluous"); *Public Serv. Comm'n of N.Y. v. FERC*, 813 F.2d 448, 454 (D.C. Cir. 1987) (holding that the Commission properly excused utilities from filing policies or practices that dealt with only matters of "practical insignificance" to serving customers); *Midwest Indep. Transmission Sys. Operator, Inc*., 98 FERC ¶ 61,137, at 61,401, *clarification granted*, 100 FERC ¶ 61,262 (2002) ("It appears that the proposed Operating Protocols could significantly affect certain rates and services and as such are required to be filed pursuant to Section 205.").

[145] *Cal. Indep. Sys. Operator Corp.*, 119 FERC ¶ 61,076, at P 656 (2007) (citing *ANP Funding I, LLC v. ISO-NE,* 110 FERC ¶ 61,040, at P 22 (2005); *Prior Notice and*

(continued…)

practice to contain "implementation details, such as instructions, guidelines, examples and charts, which guide internal operations and inform market participants of how the [public utility] conducts its operations under the…tariff."[146] The Commission has also found that the "rule of reason" test requires evaluation on a case-by-case analysis, comparing what is in an OATT against what is in an unfiled business practice manual.[147]

89. Based on our preliminary analysis of the references to the EIM Business Practice in the proposed OATT provisions and PacifiCorp's description in its pleadings of the information to be included therein, it appears that PacifiCorp's proposed Attachment T and related OATT revisions already contain the important factors through which PacifiCorp will interact with CAISO in operating the EIM and that—except, as discussed below, with respect to the transfer process for transmission capacity—the items that PacifiCorp proposes to include in the EIM Business Practice are appropriately classified as implementation details that may be placed in a business practice. As described in PacifiCorp's proposal, the EIM Business Practice appears to include implementation details, such as instructions, guidelines, examples, and charts, which guide internal operations, and not the significant provisions found in the OATT. Accordingly we will not require PacifiCorp to describe these technical specifications in the PacifiCorp OATT at this time, except as otherwise directed in this order. However, given that PacifiCorp is still developing the EIM Business Practice, we find that our analysis under the "rule of reason" is only preliminary. We direct PacifiCorp to continue working with stakeholders to develop the EIM Business Practice. Once this process is completed, we direct PacifiCorp to file, within 30 days after the completion of the EIM Business Practice stakeholder process, any necessary additions to its OATT identified during such process.

90. In light of the above, we disagree with Redding and Santa Clara that it is necessary to have the completed EIM Business Practice before accepting PacifiCorp's proposed EIM OATT revisions, nor will we require that PacifiCorp file the EIM Business Practice as part of this proceeding as requested by UAMPS. In addition, we also note that PacifiCorp has stated the EIM Business Practice will be issued prior to the planned market simulation. Revised portions of the EIM Business Practice were posted on PacifiCorp's Open Access Same-Time Information System (OASIS) website on

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Filing Requirements Under Part II of the Federal Power Act, 64 FERC ¶ at 61,986-89 (1993), *order on reh'g*, 65 FERC ¶ 61,081 (1993)).

[146] *Cal. Indep. Sys. Operator Corp.*, 122 FERC ¶ 61,271, at P 16 (2008).

[147] *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at P 1370 (2006), *order on reh'g*, 119 FERC ¶ 61,076, *order on reh'g*, 120 FERC ¶ 61,271 (2007).

May 6, 2014, and PacifiCorp has committed to post a revised draft including the remaining proposed procedures in June 2014.[148]

b. Proposed OATT Structure

Background

91. PacifiCorp proposes to incorporate the EIM into its existing system via revisions to its OATT, including a new Attachment T containing EIM-specific provisions, as well as revisions to existing Schedules 1, 4, 9, and 10.[149] PacifiCorp states that section 1 of proposed Attachment T explains that this attachment is intended to work in concert with the CAISO tariff's EIM provisions.[150] PacifiCorp also notes that Attachment T includes cross-references to relevant sections of CAISO's proposed EIM tariff provisions, and asserts that these cross-references "are necessary to provide PacifiCorp's customers with the full understanding of their rights and obligations," but do not create a direct contractual relationship between PacifiCorp's customers and CAISO that would not otherwise exist.[151] PacifiCorp states that section 1 of proposed Attachment T also provides that, to the extent any provision in Attachment T is inconsistent with the remainder of PacifiCorp's OATT with regard to the administration of the EIM, Attachment T will prevail.[152]

Comments

92. Several parties express concerns regarding PacifiCorp's use of cross-references to CAISO's tariff and business practice manuals in its proposed OATT revisions implementing the EIM. BPA protests PacifiCorp's continued reference to large segments of CAISO's tariff (and business practice manuals) in the PacifiCorp OATT (Attachment T and EIM Business Practice) without including a statement to the effect that, in the event of a conflict between CAISO's tariff (and business practice manuals)

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[148] *See* PacifiCorp Answer at 110-11.

[149] PacifiCorp Transmittal Letter at 3.

[150] *Id.* at 21.

[151] *Id.*

[152] Proposed OATT Attachment T, section 1 ("To the extent that this Attachment T is inconsistent with a provision in the remainder of this [OATT] with regard to [PacifiCorp's] administration of the EIM, this Attachment T shall prevail.").

and PacifiCorp's OATT (and EIM Business Practice), that PacifiCorp's OATT (and EIM Business Practice) is controlling.[153] BPA argues that the complexity associated with so many tariff cross-references makes it likely that a conflict will occur between CAISO's tariff and PacifiCorp's OATT, and that BPA has already highlighted one such conflict regarding external resources and the EIM Participating Resource Agreement.[154] UAMPS raises a similar concern that referencing CAISO's tariff in PacifiCorp's OATT creates ambiguity regarding which document governs PacifiCorp's transmission customers.[155] In addition, UAMPS argues that CAISO's EIM imposes obligations on all of PacifiCorp's transmission and interconnection customers, thereby binding PacifiCorp's transmission customers to another contractual entity.[156] UAMPS requests that the Commission provide clarity as to document priority between CAISO and PacifiCorp.

93. Tri-State asserts that PacifiCorp's numerous cross-references to the CAISO tariff make it difficult for PacifiCorp's customers to determine the terms of their service or the application of EIM charges.[157] Tri-State notes that as CAISO amends its tariff, it will become harder to track changes in the CAISO tariff that will impact PacifiCorp's OATT, especially for PacifiCorp customers that are not CAISO customers.[158] Tri-State argues that PacifiCorp's proposal to cross-reference the CAISO tariff violates section 35.1 of the Commission's regulations and Commission precedent.[159] Accordingly, Tri-State requests

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[153] BPA Comment and Protest at 20-23.

[154] *Id.* at 21.

[155] UAMPS Comments at 15.

[156] *Id.* at 16

[157] Tri-State Protest at 9.

[158] *Id.* at 11.

[159] *Id.* at 12-14 (citing 18 C.F.R. § 35.1(a) (2013); *Cal. Indep. Sys. Operator Corp.*, 146 FERC ¶ 61,205, at P 18 (2014); *Pennsylvania-New Jersey-Maryland Interconnection*, 81 FERC ¶ 61,257, at 62,241-62,242 (1997), *order on reh'g and clarification*, 92 FERC ¶ 61,282, at 61,951-61,952 (2000); *Ouachita River Gas Storage Co., L.L.C.*, 68 FERC ¶ 61,402, at 62,604 (1994); *New York Indep. Sys. Operator, Inc.*, 135 FERC ¶ 61,020, at P 14 (2011)).

that the Commission direct PacifiCorp to file a revised OATT that does not rely on cross-references to the CAISO tariff.[160]

94. BPA and UAMPS also raise the concern regarding how changes to CAISO's tariff that are referenced either directly or indirectly in PacifiCorp's OATT will be handled by PacifiCorp and whether parties will be informed of the CAISO changes or be able to participate in the CAISO stakeholder process.[161] UAMPS seeks assurances from the Commission that CAISO will clearly define the stakeholder groups where EIM issues will be addressed.[162] BPA requests that a provision be added to PacifiCorp's OATT requiring that a section 205 filing be made by PacifiCorp if CAISO modifies its tariff in a manner that impacts the terms and conditions of service in PacifiCorp's OATT or in the alternative, the Commission could simply make that clarification in the order approving PacifiCorp's proposal.[163] BPA requests that, if the Commission declines to adopt either approach, at a minimum, PacifiCorp should be required to notify its transmission customers of any changes to CAISO's tariff that affect provisions in PacifiCorp's OATT.[164]

95. BPA also argues that PacifiCorp's proposal that Attachment T shall prevail in the event of a conflict with the remainder of its OATT in the administration of the EIM compounds the problem expressed by BPA that the EIM is being designed to trump transmission customer's traditional tariff rights.[165] BPA argues that requiring PacifiCorp to include a clause in Attachment T that its OATT is controlling will place the burden of finding and correcting conflicts where it belongs—on CAISO and PacifiCorp, and not on transmission customers that have no relationship with CAISO.[166]

96. Powerex argues that PacifiCorp has not addressed why EIM transactions should receive "priority treatment" over the transactions of its OATT customers if a conflict

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[160] *Id.* at 11-14.

[161] BPA Comment and Protest at 23; UAMPS Comments at 16-18.

[162] UAMPS Comments at 18.

[163] BPA Comment and Protest at 23.

[164] *Id.* at 23.

[165] *Id.* at 22.

[166] *Id.* at 23.

should arise between the OATT and Attachment T.[167] Powerex asserts that, to the best of its knowledge, the Commission has only permitted OATT attachments to prevail over Commission-approved OATTs in the narrow context of a market monitoring plan.[168] Powerex thus requests that the Commission direct PacifiCorp to amend section 1 of Attachment T to provide that existing OATT provisions will control in the event of a conflict with Attachment T.[169]

Answers

97. PacifiCorp defends its proposed OATT structure including the use of what it states are limited and targeted cross-references to CAISO's tariff to clarify customers' rights and obligations.[170] PacifiCorp states that the Commission has approved cross-references to the CAISO tariff in other contexts, including PG&E's Grid Management Charge Pass-Through Tariff and SoCal Edison's Wholesale Distribution Access Tariff.[171] PacifiCorp asserts that replicating every relevant CAISO tariff provision in its OATT would be administratively burdensome, and that having to submit FPA section 205 filings every time CAISO revises its tariff (whether as a result of having that language incorporated into PacifiCorp's OATT, as Tri-State requests, or as a separate affirmative obligation, as proposed by BPA) is an unnecessary regulatory hurdle that could result in different outcomes and potential cost trapping.[172] PacifiCorp asserts that it will make section 205 filings to amend its OATT when amendments to the CAISO tariff (such as the addition of new charge types) warrant, and will notify its transmission and interconnection customers when it plans to do so, consistent with its current practice and Commission requirements.

[167] Powerex Protest at 76-78.

[168] *Id.* at 78-79 (citing *Southwest Power Pool, Inc.*, 137 FERC ¶ 61,046 (2011) (approving revisions to SPP's OATT, including Attachment AG, which contains a provision providing that Attachment AG will control in the event of a conflict with another tariff provision)).

[169] *Id.* at 80.

[170] PacifiCorp Answer at 33-52.

[171] *Id.* at 39-40 (citing *Cal. Indep. Sys. Operator Corp.*, 103 FERC ¶ 61,114 (2003) and SoCal Edison Wholesale Distribution Access Tariff at section 21.1).

[172] *Id.* at 36-42.

98. CAISO asserts that commenters' objections to the cross-references to its tariff are premised on a fundamental misunderstanding of the relationship between PacifiCorp's OATT and CAISO's tariff and should be dismissed.[173] CAISO explains that PacifiCorp essentially is contracting with CAISO to provide energy imbalance service—a service provided pursuant to *CAISO's* tariff—and therefore the proposed revisions to PacifiCorp's OATT to reflect the EIM are analogous to the transmission owner tariffs of CAISO's participating transmission owners.

99. CAISO states that, except for the obligations imposed on non-participants in the EIM (which arise through such participants' relationship to PacifiCorp), the cross-referenced obligations are imposed on EIM market participants pursuant to CAISO's tariff, and therefore the provisions in CAISO's tariff affecting the operation of the EIM should govern in the case of conflicts with PacifiCorp's OATT.[174] PacifiCorp asserts that Attachment T works in conjunction with, but in the case of a conflict should appropriately prevail over, the rest of its OATT.[175] PacifiCorp maintains that its proposal that Attachment T should prevail to the extent it is inconsistent with a provision in the remainder of PacifiCorp's OATT with respect to the administration of the EIM is necessary because PacifiCorp cannot assert priority over CAISO's tariff in its OATT.[176]

100. PacifiCorp states that it has not included any provision in proposed Attachment T that would create a direct relationship between CAISO as the EIM operator and a PacifiCorp transmission customer with non-participating resources.[177] It also maintains that all PacifiCorp transmission customers and other interested parties will have equivalent notice and opportunity to participate in CAISO and PacifiCorp's business practice manual development process.[178] CAISO likewise confirms that all interested parties will have the opportunity to participate in its stakeholder process, which it states is open and transparent.[179]

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[173] CAISO Answer at 11-14.

[174] *Id.* at 12-13.

[175] PacifiCorp Answer at 45-50; Proposed OATT Attachment T, section 1.

[176] PacifiCorp Answer at 45-46.

[177] *Id.* at 38.

[178] *Id.* at 42-44.

[179] CAISO Answer at 13-14.

Commission Determination

101. We conditionally accept PacifiCorp's proposed approach with respect to revising its OATT to facilitate participation in the EIM, subject to PacifiCorp making the relevant provisions of CAISO's tariff publicly available to its customers, as discussed below. Specifically, we find that PacifiCorp's proposal to include cross-references in its OATT to the relevant provisions of CAISO's tariff is appropriate to ensure PacifiCorp's seamless integration into the EIM.

102. We also find reasonable the provision in proposed section 1 of Attachment T specifying that Attachment T will control with respect to matters of EIM administration in the event of a conflict with the remainder of PacifiCorp's OATT. The Commission previously has rejected a clause in a seller's tariff that purported to give the seller's tariff priority in a conflict with CAISO's tariff, finding that the proposed clause was an impermissible attempt to unilaterally revise the terms of its market operator's tariff.[180] By the same logic, it is appropriate that Attachment T (which incorporates by reference the EIM-specific portions of CAISO's tariff) should prevail if there is a conflict with PacifiCorp's OATT regarding the EIM. Otherwise, PacifiCorp could unilaterally make changes to the non-EIM provisions of its OATT that could have the effect of changing how the EIM provisions in CAISO's—the market operator of the EIM—tariff are applied through PacifiCorp's OATT. Moreover, we note that the proposed language in section 1 of Attachment T is limited to conflicts regarding matters related to the EIM, and that PacifiCorp asserts that Attachment T is consistent with the remainder of its OATT. We expect PacifiCorp to continue to monitor the relationship between its OATT and Attachment T after the commencement of the EIM, and in light of any future amendments, to ensure that no unintended consequences arise.

103. We believe that it would create unnecessary redundancy to require PacifiCorp to make a filing pursuant to section 205 of the FPA every time CAISO modifies its tariff in a manner that affects the terms and conditions of service in PacifiCorp's OATT. We make this finding with the understanding that PacifiCorp, as explained in its answer, will make a section 205 filing to amend its OATT when amendments to the CAISO tariff warrant such a filing.[181] However, we understand commenters' concerns regarding the

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[180] *See J.P. Morgan Ventures Energy Corp.*, 142 FERC ¶ 61,190, at P 28 (2013) (citing *El Segundo Power, LLC*, 91 FERC ¶ 61,110 (2000); *USGen New England, Inc.*, 90 FERC ¶ 61,323 (2000); *Sithe New England Holdings, LLC*, 86 FERC ¶ 61,283 (1999)).

[181] For instance, if CAISO were to modify Section 29.4(e)(4)(D) of its tariff as referenced in PacifiCorp's proposed Attachment T, section 4.2.2.1, there would be nothing for PacifiCorp to submit to the Commission pursuant to section 205 as

(continued…)

burden of keeping up to date with the CAISO tariff provisions cross-referenced in PacifiCorp's OATT. Accordingly, we direct PacifiCorp to make the current version of all such CAISO provisions, as well as notice when CAISO files a proposal to amend such provisions, available on its website.

3. Market Design and Operation

a. Transfer of Transmission Rights to the EIM

Background

104. PacifiCorp states that it does not have any unsubscribed, available transmission capacity for EIM Transfers between PacifiCorp's PacifiCorp East and PacifiCorp West BAAs, or on the California-Oregon Intertie between PacifiCorp West and the CAISO BAA. Instead, PacifiCorp plans to utilize firm transmission rights voluntarily offered by its marketing division (and transmission customer) PacifiCorp Energy.[182] PacifiCorp proposes not to separately compensate or credit PacifiCorp Energy or any other potential Interchange Rights Holder[183] for transmission capacity made available for EIM Transfers.

Comments

105. Powerex asserts that this proposal violates the Commission's open access requirements and the *pro forma* OATT by effectively withholding unused capacity for the use of a select group of customers, without complying with the reassignment provisions

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PacifiCorp's tariff language would not change. However, if CAISO were to add a new section 29.5 of its tariff that impacted any provision of PacifiCorp's Attachment T, we would expect PacifiCorp to make a section 205 filing to add the relevant CAISO cross-reference to PacifiCorp's OATT.

[182] PacifiCorp Transmittal Letter at 39-40. Proposed OATT Attachment T, section 5.2. PacifiCorp also proposes revisions to section 23 of its OATT to clarify that an Interchange Rights Holder who elects to make its reserved firm transmission capacity available for EIM Transfers is not performing a reassignment under the OATT and need not comply with the procedures for assignment or transfer of service in section 23.1(a). PacifiCorp Transmittal Letter at 65-66.

[183] A PacifiCorp Interchange Rights Holder is defined as "[a] Transmission Customer who has informed the PacifiCorp EIM Entity that it is electing to make reserved firm transmission capacity for an Interchange available for EIM Transfers without compensation." Proposed OATT, section 1.30J.

in section 23 of PacifiCorp's OATT or obtaining Commission approval of non-conforming assignment agreements.[184] Powerex further contends that the proposal violates section 18.4 of PacifiCorp's OATT (which requires that unused firm transmission capacity be offered on a non-discriminatory basis to eligible customers as non-firm service), permits a merchant affiliate to engage in unauthorized transmission functions, and unfairly modifies existing OATT curtailment priorities. Powerex maintains that PacifiCorp has not met its burden of proof, particularly since CAISO admitted in its answer in Docket No. ER14-1386-000 that the EIM could operate without transfers between BAAs.[185]

106. In addition, Powerex believes that the donated rights on the California-Oregon Intertie are from a grandfathered agreement between BPA and PacifiCorp.[186] Powerex argues that if that is indeed the case (as the filing lacks any information on the matter), PacifiCorp's proposed donation violates the terms of the underlying BPA/PacifiCorp agreement and directly harms Powerex and other BPA transmission customers who could have access to the unused transmission capacity or would be credited the non-firm revenues that BPA would receive from its sale of the unused capacity.[187] Powerex requests that if the donated EIM transmission capacity is from a grandfathered agreement, the Commission should require that PacifiCorp: (1) identify and file the agreements under which each Interchange Rights Holder intends to make transmission rights available to the EIM; (2) identify all third-party transmission providers associated with those rights; (3) file an agreement between PacifiCorp and each associated transmission provider to the extent assignment is permitted under a grandfathered agreement and requires written consent; and (4) demonstrate that the donation does not constitute an unlawful departure from or modification of the underlying agreement or unlawfully abrogate the rights of other transmission customers.[188]

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[184] Powerex Protest at 62-72. Northwest Public Parties also raise this issue in their brief comments.

[185] Powerex raised this same issue in its protest of CAISO's EIM filing in Docket No. ER14-1386. *See* Powerex Protest, Docket No. ER14-1386-000 (Mar. 28, 2014) at 87-89.

[186] Powerex Protest at 68-69.

[187] *Id.* at 69-70.

[188] *Id.* at 72-73.

107. Northwest Public Parties express a similar concern that transmission customers may offer unused firm transmission capacity on a third-party system to facilitate EIM Transfers, but the voluntary offering may prohibit transmission providers on the neighboring systems from offering that same unused available capacity to other customers as set forth in their respective OATTs.[189] Northwest Public Parties request that the Commission direct PacifiCorp to demonstrate that the voluntary offer option for transmission customers will not adversely affect existing transmission rights held by customers on neighboring systems, including BPA. Alternatively, Northwest Public Parties request that the Commission reject PacifiCorp's voluntary offer option and related OATT provisions.[190]

108. BPA does not oppose PacifiCorp's proposal but points out that its tariff and pre-tariff transmission contracts with PacifiCorp do not include a mechanism for transmission rights to be used by another party without BPA's consent.[191] BPA commits to continue to work with CAISO and PacifiCorp to understand how these rights would be transferred, but asserts that the relevant PacifiCorp OATT provisions should apply only to transmission rights on PacifiCorp's system at this time.

109. Finally, Deseret does not oppose PacifiCorp's proposal in principle, but expresses concern that Interchange Rights Holders might be able to game the system by manipulating the amount and timing of release to get a trading advantage.[192] Deseret requests that the Commission direct PacifiCorp to include at least the basic procedures in Attachment T, instead of a business practice, and contends that these procedures should at a minimum require Interchange Rights Holders to release transmission rights at least two hours in advance of the applicable operating hour (given that initial base schedules are required at T-75) and to offer all unused transmission to CAISO during that time. Deseret also argues that proposed section 23.4 should be revised to clarify that Interchange Rights Holders are only exempt from the reassignment provisions in section 23 of PacifiCorp's OATT with respect to the specific capacity made available to the EIM.

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[189] Northwest Public Parties Comments at 2.

[190] *Id.*

[191] BPA Comment and Protest at 5-6.

[192] Deseret Comments at 6-8.

110. Wind Parties and Iberdrola support the proposal as consistent with the Commission's open access principles.[193] Iberdrola also asserts that the proposal is necessary as an operational matter, noting that PacifiCorp will not know prior to any operating hour which resources will be dispatched for the EIM, and thus would not be able to effectuate a reassignment of transmission rights under the OATT.

Answer

111. PacifiCorp maintains that it has demonstrated that its proposal is consistent with or superior to the *pro forma* OATT and that the use of Interchange Rights Holder transmission capacity is distinct from the continuing obligation under the OATT of any non-EIM transmission provider to make unused transmission capacity available to others.[194] In response to the concerns raised by Powerex and BPA, PacifiCorp clarifies that the proposed Interchange Rights Holder mechanism applies only to rights on PacifiCorp's transmission system.[195] PacifiCorp also explains that the rights that PacifiCorp Energy, as an Interchange Rights Holder, intends to transfer are existing firm transmission rights that were sold to PacifiCorp Energy pursuant to PacifiCorp's OATT as a result of PacifiCorp's legal ownership interests in California-Oregon Intertie, and are not transmission rights sold to PacifiCorp Energy by BPA. PacifiCorp asserts that concerns regarding the grandfathered agreements with BPA relate to discussions "between transmission operators on how to implement the EIM without undue burden on any party's transmission system within the confines of contractual agreements between the parties to those contracts," and are thus beyond the scope of this proceeding.

112. In response to Deseret, PacifiCorp asserts that its proposal to include the specifics of the tagging procedures for these transfers in its business practice is appropriate. Nevertheless, PacifiCorp addresses Deseret's request for additional detail by stating that the Interchange Rights Holders will need to indicate the amount of rights they plan to release to the EIM 75 minutes before each operating hour by submitting an e-Tag with the transmission profile equivalent to the amount of transmission rights made available to the EIM. PacifiCorp also asserts that these e-Tagging procedures constitute implementation details setting forth technical procedures that are properly included in the EIM Business Practice—not in the OATT—consistent with several other PacifiCorp business practices that contain e-Tagging procedures.[196] Finally, PacifiCorp also states

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[193] Wind Parties Comments at 6; Iberdrola Comments at 4-5.

[194] PacifiCorp Answer at 22-23.

[195] *Id.* at 26-27.

[196] *Id.* at 109.

that Deseret's requested clarification of section 23.4 is not necessary, because the provision already provides that the reassignment provisions will not apply to an Interchange Rights Holder that "voluntarily makes its transmission capacity available to the EIM."[197]

Commission Determination

113. We conditionally accept PacifiCorp's proposed approach with respect to revising its OATT to utilize firm transmission rights voluntarily offered by its marketing division and any other transmission customer to facilitate participation in the EIM, subject to PacifiCorp making a compliance filing, as discussed below. Specifically, we direct PacifiCorp to make a compliance filing within 30 days after the date of issuance of this order revising proposed section 5.2 of Attachment T to include the requirements for scheduling and using transmission rights held by an Interchange Rights Holder and deleting the last sentence of proposed section 5.2 of Attachment T, which provides that the requirements for scheduling and using transmission rights held by an Interchange Rights Holders will be set forth in the EIM Business Practice.

114. We appreciate that without transmission rights between PacifiCorp East and PacifiCorp West, and PacifiCorp West and CAISO, respectively, PacifiCorp's ability to participate in, and thus its customers' ability to benefit from, the EIM will be limited. PacifiCorp's proposal to make available transmission capacity that ordinarily will be used for bilateral transactions and scheduled accordingly, to now be used on a real-time basis to expand CAISO's real-time energy imbalance market into PacifiCorp's BAAs is a novel approach that appears to be reasonable. Based on our preliminary analysis, PacifiCorp's proposal does not appear to be a sale, assignment, or transfer of transmission service that would fall under section 23 of the *pro forma* OATT. PacifiCorp Energy is not relinquishing its transmission rights that it acquired from PacifiCorp to another party. As explained by PacifiCorp in its answer, PacifiCorp Energy will still be submitting the e-Tags in the prescheduling window (i.e., T-75) indicating the amount of transmission rights that will be available in the EIM.[198]

115. However, our understanding of PacifiCorp's proposal with respect to the transfer of transmission rights is based primarily on the information provided in the answer PacifiCorp filed in this proceeding. We agree with intervenors that PacifiCorp's proposed section 5.2 of Attachment T, on its face, does not provide us with sufficient detail regarding PacifiCorp's proposal. For instance, while PacifiCorp states in its

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[197] *Id.* at 71.

[198] *Id.* at 70.

answer that the transmission rights at issue were sold to PacifiCorp Energy pursuant to PacifiCorp's OATT resulting from PacifiCorp's legacy ownership interests in the California-Oregon Intertie, PacifiCorp provides no details on how the Commission, or other interested parties, can be assured that a subsequent transfer will not be over a third-party system whereby the underlying ability to transfer the transmission rights may not be clear. Additionally, we find that the basic terms of these transactions (such as timing) affect the rates, terms, and conditions of Commission-jurisdictional service, and therefore should be filed for Commission review and acceptance rather than contained in the EIM Business Practice.[199] Accordingly, we conditionally accept PacifiCorp's proposal, subject to PacifiCorp making a compliance filing within 30 days after the date of issuance of this order proposing specific procedures to effectuate such transfers, and reject the proposed language purporting to leave these details to the EIM Business Practice. We agree with PacifiCorp, however, that no further change is needed to PacifiCorp's proposed section 23.4 of its OATT as the provision is clear on its face.

b. Transmission Usage Charge

Background

116. PacifiCorp does not currently charge its transmission customers a separate transmission usage charge to import or export power across the PacifiCorp/CAISO interface, nor does it propose to do so in the instant filing. PacifiCorp states that it supports CAISO's proposal that CAISO and PacifiCorp (or any other BAA that joins the EIM) mutually waive transmission charges for transfers between their BAAs (and between their BAAs and the BAA of any other entity that joins the EIM).[200] PacifiCorp explains that transmission requirements will still apply in the source BAA where the load or generation is located, and thus maintains that transmission in the EIM is not "free" and that EIM Entity transmission rates will fully recover transmission revenue requirements from existing transmission customers. PacifiCorp notes that both it and CAISO have committed to reevaluate their transmission proposals through their respective stakeholder processes after the first year of EIM operations.

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[199] *See, e.g., Cal. Indep. Sys. Operator Corp.*, 122 FERC ¶ 61,271, at P 16 (2008) (finding that "[i]t is appropriate for Business Practice Manuals to contain implementation details, such as instructions, guidelines, examples and charts, which guide internal operations and inform market participants of how the CAISO conducts its operations under the MRTU tariff," but explaining that the Commission applies a "rule of reason" test to identify "those provisions significantly affecting rates, terms and conditions of service, which therefore must be filed for Commission approval") (citations omitted).

[200] PacifiCorp Transmittal Letter at 37-38.

Comments

117. Both Redding and TANC express concern that PacifiCorp's "no charge" proposal for transmission transfers across CAISO/PacifiCorp interface for EIM transactions will negatively impact non-EIM customers.[201] Tri-State notes that several parties in CAISO's EIM filing in Docket No. ER14-1386-000 raised the concern that the lack of a transmission charge for EIM Transfers across the interface could lead parties to lean on the EIM to serve load rather than use other markets, and that these concerns are equally applicable to PacifiCorp's instant filing.[202]

118. Powerex argues that PacifiCorp's proposal (with CAISO) to waive transmission charges for EIM Transfers across the interties between CAISO's BAA and PacifiCorp's BAAs is discriminatory as non-EIM Transfers using the same transmission facilities, during the same time period, will be charged for transmission service.[203] Powerex contends that PacifiCorp's proposal will shift inter-BAA transactions from the day-ahead to the real-time market, not for market efficiency reasons, but for preferential transmission rates.[204] Powerex further asserts that PacifiCorp's proposal does not eliminate rate-pancaking as claimed, but rather preserves PacifiCorp's existing transmission rates for all non-EIM transactions, while selectively waiving those transmission rates for similar transactions that occur within the EIM framework. Powerex contends that this "selective transmission discount" is contrary to Commission precedent and policies.[205] Accordingly, Powerex requests that the Commission reject PacifiCorp's proposal and order PacifiCorp to revise Attachment T to ensure non-discriminatory and non-preferential treatment for transmission used by EIM participants.[206]

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[201] Redding Comments at 9-10; TANC Comments at 13-14. Redding, Santa Clara, and Modesto adopt and incorporate by reference the comments submitted by TANC.

[202] Tri-State Protest at 19.

[203] Powerex Protest at 52.

[204] *Id.* at 53.

[205] *Id.* at 56-57.

[206] *Id.* at 58.

119. PUC EIM Group supports deferring for a year the consideration of creating an imbalance energy-specific transmission usage charge.[207] Due to the lack of data on how much energy will transact through EIM or how power flows will be impacted, PUC EIM Group requests that the Commission direct PacifiCorp and CAISO to commence a stakeholder process to develop a cost-based EIM transmission usage charge and to file OATT revisions within a specified period of time after implementation of the EIM.[208]

120. Both WPTF and EPSA believe that PacifiCorp's initial proposal not to charge for EIM Transfers across the CAISO/PacifiCorp interface is reasonable, but they both recommend that the Commission direct PacifiCorp and CAISO to review this policy, along with any other barriers to entry or market concerns, with stakeholders and file a revised proposal within 12 months of the date on which the EIM commences.[209] WPTF is particularly concerned that PacifiCorp has not extended the reciprocity concept to future EIM Entities that might join, therefore leading to rate-pancaking. WPTF and EPSA request that the stakeholder process commence within 30 days of an order accepting the filing in this proceeding.

121. Xcel requests clarification that as the EIM footprint expands, deliveries between market areas would be treated in a comparable manner and requests clarification from PacifiCorp in a future amendment to its OATT that the practice would continue.[210]

122. CAISO believes that at least initially, the approach taken by PacifiCorp and CAISO to not charge for EIM transmission transfers across the interface is reasonable as the initial amount of capability is relatively small and commits to review this issue with stakeholders in 2015.[211]

Answer

123. PacifiCorp echoes CAISO's commitment to review the matter with stakeholders in 2015, asserting that its proposal to collect data upon EIM implementation and analyze a full year's worth of data strikes the appropriate balance, and that requiring the related

[207] PUC EIM Group Comments at 2.

[208] *Id.*

[209] WPTF Comments at 4-6; EPSA Comments at 4-5.

[210] Xcel Comments at 4.

[211] CAISO Comments at 9.

stakeholder process to commence within 30 days of the order accepting the filing, as requested by EPSA and WTPF, would be premature.[212] With respect to WPTF's question regarding the extension of reciprocity to future EIM Entities, PacifiCorp clarifies that its proposed changes to its OATT to implement the EIM in its BAAs only govern PacifiCorp's transmission system, and that its filing neither prevents nor requires the extension of reciprocity to other entities joining the EIM. Finally, PacifiCorp reiterates that its proposal is not a discount or waiver, does not enable "free riders," and that transmission revenue recovery will be fully compensated by PacifiCorp's existing transmission rates.[213]

Commission Determination

124. PacifiCorp does not have a comparable exit or entrance fee such as CAISO's that can be waived for EIM transactions. While PacifiCorp supports CAISO's proposal to waive CAISO's transfer fee for EIM transactions, PacifiCorp is not proposing any reciprocal tariff language to that effect because the waiver of a CAISO fee is more appropriately addressed in CAISO's EIM filing. Accordingly, the arguments raised by commenters in this proceeding with respect to CAISO's waiver of the EIM transfer fee and any future stakeholder discussion are beyond the scope of PacifiCorp's EIM proposal. Notwithstanding, we note that the Commission is addressing this issue in the concurrent order being issued on CAISO's EIM proposal in Docket No. ER14-1386-000.

c. External Resource Participation

Background

125. PacifiCorp proposes to allow generating resources that are not physically located within the metered boundaries of one of PacifiCorp's BAAs to become an EIM Participating Resource if that resource implements a pseudo-tie into a PacifiCorp BAA, arranges for transmission service over any third-party system to transfer the power to PacifiCorp's BAA, and secures transmission service on PacifiCorp's transmission system.[214]

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[212] PacifiCorp Answer at 28-29.

[213] *Id.* at 29-33.

[214] PacifiCorp Transmittal Letter at 32.

Comments

126. CAISO notes in its comments that its proposed tariff revisions permit EIM Entities to determine the eligibility requirements for resources to participate in the EIM. In addition, CAISO states that it understands PacifiCorp's decision to refrain from opening its interties to economic bidding at the commencement of the EIM, but appreciates PacifiCorp's willingness to explore this option after it has gained operational experience.[215] Iberdrola expresses support for PacifiCorp's decision not to expand the EIM to include new intertie boundaries for other ISO markets, arguing that efforts to expand the EIM's footprint at this time are unnecessary and would only further complicate PacifiCorp's already-substantial undertaking.[216]

127. WPTF requests that the Commission direct PacifiCorp to begin a stakeholder process no later than 12 months after the EIM commences to address the feasibility of expanding the ability of external resources to participate either through dynamic scheduling or through the expansion of CAISO's 15-minute market to PacifiCorp's boundaries.[217] NIPPC characterizes it as regrettable that most independent power producers outside of California cannot participate in the initial iteration of the EIM due to the fact that the EIM is limited to BAAs and asks that the Commission monitor and encourage CAISO and PacifiCorp to expand the EIM to enable independent power producers located in WECC to participate.[218]

128. Grant County PUD believes that the requirement that external resources must use a pseudo-tie to transact in the EIM is an artificial barrier to entry and that PacifiCorp has failed to justify excluding potential market participants from participating in CAISO's 15-minute market at PacifiCorp's intertie boundaries.[219] Grant County PUD argues that static schedules could be used in the 15-minute market to import power into PacifiCorp and that there would be no need for Grant County PUD to pay a PacifiCorp transmission

[215] CAISO Comments at 6.

[216] Iberdrola Comments at 7.

[217] WPFT Comments at 6-7.

[218] NIPPC Comments at 3.

[219] Grant County PUD Comments at 3.

charge for the EIM, as PacifiCorp would be using its system to move the EIM energy to clear its imbalances.[220]

Answer

129. PacifiCorp reiterates that it intends to study the feasibility of incorporating 15-minute market features at the interties, but argues that being tied to a timetable for initiating a stakeholder process would be both unduly burdensome and inconsistent with CAISO's EIM tariff amendment, which does not require EIM Entities to provide access to the 15-minute market.[221] PacifiCorp also notes that the Commission has previously found the use of a pseudo-tie approach to be just and reasonable in the context of SPP's Energy Imbalance Service market.[222]

Commission Determination

130. We conditionally accept PacifiCorp's treatment of external resources as filed, subject to PacifiCorp eliminating from its OATT the requirement that participating resources in the EIM pay for transmission service in addition to any transmission rate that they incur as a PacifiCorp transmission customer, as discussed herein. We find that PacifiCorp's proposal to require that external resources implement a pseudo-tie arrangement to electrically move from the external BAA to PacifiCorp's BAA is consistent with the Commission's acceptance of a similar arrangement in the SPP's Energy Imbalance Service market requiring that external resources use a pseudo-tie in order to participate in that market.[223] We agree with PacifiCorp that allowing external resources to participate in CAISO's 15-minute market as proposed by Grant County PUD is an expansion of the scope of the EIM and is not necessary for PacifiCorp's proposal to be found just and reasonable and not unduly discriminatory.

131. We will not require a timetable for PacifiCorp to begin a stakeholder process to address the feasibility to expand the EIM to include dynamic schedules or bring CAISO's

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[220] *Id.*

[221] PacifiCorp Answer at 55-56.

[222] *Id.* at 55 (citing *Southwest Power Pool, Inc.*, 123 FERC ¶ 61,062, at P 24 (2008)).

[223] *Southwest Power Pool, Inc.*, 123 FERC ¶ 61,062 at P 24 ("The Commission finds that SPP's choice of the pseudo-tie approach over dynamic scheduling is just and reasonable.")

15-minute market to PacifiCorp's boundaries as requested by WPTF. We expect with additional EIM experience that PacifiCorp will seek to add additional participants or products to its boundaries to increase load and resource diversity, transfer capability, and flexible generation resources in the market, but we believe that it is premature, at this time, to direct PacifiCorp to initiate a stakeholder process. We encourage PacifiCorp to follow through with its commitment to explore this issue with stakeholders.

d. Use of Transmission Service for EIM Transactions

Background

132. PacifiCorp explains that, under proposed sections 3.1 and 8.7.2.1 of Attachment T, network transmission customers may elect either to: (1) utilize their network service and continue to be billed for transmission based upon their monthly network load, plus any output of designated network resources participating in the EIM; or (2) use point-to-point transmission service under an umbrella service agreement for non-firm point-to-point transmission service and pay the hourly rate, on an after-the-fact basis, when dispatched.[224] The customer initially makes this election when it submits its application to become a PacifiCorp EIM Participating Resource, and may change its election on a quarterly basis. In addition, PacifiCorp proposes that network customers using point-to-point transmission service to participate in the EIM be required to un-designate network resources to be bid into the EIM, but that network customers using network integration service to participate in the EIM need not un-designate their network resources (as a network resource would otherwise be required in order to make off-system sales).[225]

133. PacifiCorp also proposes to charge both network and point-to-point transmission customers that receive a dispatch instruction and the dispatch operating point exceeds the transmission customer's reserved capacity, for any amount of the dispatch operating point in excess of the transmission customer's reserved capacity.[226] In the case of network customers, depending upon whether they are using network or non-firm point-to-point transmission service for EIM transactions, that delta would be added to either their monthly network load or would be charged to them at the non-firm point-to-point transmission rate.

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[224] PacifiCorp Transmittal Letter at 30-32.

[225] *Id.* at 31, 66.

[226] *Id.* at 34; Proposed OATT Attachment T, section 8.7.2.2.

134. In addition, PacifiCorp proposes not to pass through to PacifiCorp transmission customers the costs associated with unaccounted for energy and the marginal loss Component of LMP. Instead, PacifiCorp proposes to apply the loss factors in its OATT Schedule 10 and to use the Hourly Pricing Proxy to determine the charges for its transmission customers.

Comments

135. Redding requests that the Commission clarify whether PacifiCorp's proposal to permit customers to use network service for participation in the EIM is consistent with Commission precedent, which limits the use of network integration transmission service to serving native load.[227]

136. BPA supports PacifiCorp's proposal to allow designated network resources to participate in the EIM, but argues that PacifiCorp's proposal to bill network customers using network service based upon their monthly network load, plus any output of designated network resources participating in the EIM, will cause unintended market effects, encourage gaming, and result in discriminatory distribution of EIM transmission costs.[228] BPA contends that PacifiCorp's proposal provides an incentive for network customers to participate in the EIM based upon the likelihood of being dispatched in coincidence with the system peak load, rather than based upon the economics of their resources and the market (e.g., customers would reduce EIM dispatches during system peak in order to minimize or avoid EIM transmission charges). BPA thus requests that the Commission direct PacifiCorp to revise proposed section 8.7.2.2 such that all EIM dispatches from designated network resource are charged after-the-fact based on actual use at the non-firm point-to-point transmission rate.[229] On the other hand, rather than avoid EIM transmission charges, Xcel argues that the most efficient network resources might actually pay more for network transmission service as they will be dispatched more often and would be added to the transmission customer's network load.[230]

137. Tri-State asserts that PacifiCorp is essentially offering its EIM point-to-point transmission customers the equivalent of network transmission service for the hourly

[227] Redding Comments at 10 (citing *PacifiCorp*, 118 FERC ¶ 61,026, at P 8 (2007); *MidAmerican Energy Co.*, 112 FERC ¶ 61,346 (2005)).

[228] BPA Comment and Protest at 15-20.

[229] *Id.* at 19-20.

[230] Xcel Comments at 5.

non-firm price, and questions how PacifiCorp will keep track of whether EIM transmission customers are operating within their capacity reservations.[231] Tri-State argues that, similar to the exemption from inter-EIM wheeling charges, this proposal may be unduly discriminatory and may encourage entities to lean on the EIM to serve load rather than to rely on day-ahead markets or longer-term bilateral transactions.

138. Powerex uses five hypothetical situations to illustrate its contention that PacifiCorp's proposal is discriminatory and affords unduly preferential treatment to certain customers that may pay more or less depending upon certain circumstances.[232]

139. UAMPS believes that PacifiCorp's network transmission customer pricing option will result in excess transmission charges to network customers that participate in the EIM. Network transmission service that is used for EIM transactions will be billed at the greatest positive dispatch operating point, which is a five minute interval, thus, if a transmission customer dispatched its resource between 60 and 100 megawatts (MW) over the course of the hour, it would see an additional 100 MW added to its monthly network load even though network load is averaged over the hour (80 MW) thereby resulting in an excess transmission charge to the customers.[233] UAMPS raises a similar argument with respect to non-firm point-to-point transmission service. In addition, UAMPS argues that based upon its interpretation of section 1.11B of PacifiCorp's Attachment T, the billing determinant for network transmission customers participating in EIM transactions will be the expected dispatch operating point rather than the actual operating point, thereby overcharging customers that do not meet their dispatch point.

140. Deseret believes that network customers (and those taking similar grandfathered network-like service) should be permitted to change their election as to how they will be charged for EIM transmission service for their EIM resources on a monthly, rather than quarterly, basis, which would facilitate more widespread participation from eligible customers.[234]

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[231] Tri-State Protest at 17-19.

[232] Powerex Protest at 44-51.

[233] UAMPS Comments at 11-12.

[234] Deseret Comments at 8-9.

Answer

141. PacifiCorp acknowledges that its proposal is not consistent with traditional network transmission service but asserts that its proposal is superior to the *pro forma* OATT in light of the numerous benefits of the EIM.[235] PacifiCorp also states that the Commission has previously supported the use of network transmission service for all customers participating in an imbalance market.[236] PacifiCorp argues that BPA's concerns regarding discriminatory distribution of EIM transmission costs and potential gaming are unfounded. PacifiCorp asserts that its proposal is a reasonable means to ensure that EIM resources contribute to their share of PacifiCorp's transmission system costs and that a transmission customer may select the OATT transmission service to participate in the EIM that best suits its needs. Finally, PacifiCorp argues that its proposal does not shift costs to more efficient resources; rather, it ensures that resources that choose to participate in the EIM will pay appropriately for the transmission they utilize. PacifiCorp declines to adopt Deseret's requested modification, claiming that processing monthly changes in election would be administratively burdensome and has not been shown, at this time, to be commercially or operationally necessary.[237]

142. Additionally, PacifiCorp clarifies that EIM participation using firm point-to-point transmission service requires an umbrella service agreement for non-firm point-to-point transmission service because these customers will be charged the hourly rate for non-firm point-to-point transmission service on an after-the-fact basis to the extent the EIM transaction causes the customer to exceed its reserved capacity.[238] PacifiCorp asserts that its proposal with respect to point-to-point transmission service is just and reasonable because it will encourage participation in the EIM, and because all similarly situated transmission customers will receive the same treatment.[239]

143. Lastly, PacifiCorp answers that UAMPS's assertions point out some differences between how transmission charges are applied today for traditional transmission use associated with integrated hourly loads under the OATT; however, these differences do

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[235] PacifiCorp Answer at 58-62.

[236] *Id.* at 60 n.171 (citing section 28.6 of the Midcontinent Independent System Operator, Inc. tariff and section 30.4 of the SPP tariff).

[237] *Id.* at 64-65.

[238] *Id.* at 65-66.

[239] *Id.* at 66-67.

not render PacifiCorp's EIM transmission charges unjust or unreasonable.[240] PacifiCorp contends that its proposal to base EIM transmission charges on the greatest positive dispatch operating point is a reasonable proposal for EIM participation and that the proposed billing determinant is a reasonable means of ensuring that PacifiCorp EIM Participating Resources do not free ride. In addition, PacifiCorp asserts that its proposal not to pro-rate transmission charges to sub-hourly increments is also consistent with PacifiCorp's implementation of 30-minute and 15-minute transmission scheduling.

Commission Determination

144. We reject PacifiCorp's proposal to require that participating resources in the EIM pay for transmission service in addition to any transmission rates that they regularly incur as a PacifiCorp transmission customer. We direct PacifiCorp to submit a compliance filing within 30 days after the date of issuance of this order to revise its OATT to eliminate the additional transmission charge for EIM transactions for participating resources, as discussed herein.

145. The Commission finds that PacifiCorp's proposal to require EIM resources to purchase additional transmission service to participate in the EIM would result in double recovery of transmission costs. An EIM resource located in PacifiCorp's BAA and that is charged for non-firm point-to-point transmission service will include that cost in its EIM offer price. As a result, if an EIM resource located in PacifiCorp's BAA utilizes PacifiCorp's non-firm point-to-point transmission service option and is dispatched to serve load in PacifiCorp's BAA, that load will be charged for its network transmission service and the additional transmission service that the EIM resource was required to purchase to sell into the EIM, essentially double-charging load in PacifiCorp. PacifiCorp's rationale that an EIM resource should contribute to its share of PacifiCorp's transmission system costs ignores the fact that the associated transmission costs will be included in the LMPs paid to EIM resources and paid by network load such that EIM resources would make no net payment for transmission service and network load would pay for transmission service twice. PacifiCorp's transmission formula rate will not return all of the non-firm transmission revenue to network customers due to the fact that firm point-to-point transmission customers will have to factor the non-firm point-to-point transmission rate in their bid as well due to the risk that these customers may be dispatched beyond their reservation and thus subject to the non-firm transmission rate on an after-the-fact basis. In this instance, if the firm point-to-point transmission customer stays within its transmission reservation, PacifiCorp will not collect any non-firm transmission revenues from that customer to credit against next year's revenue

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[240] *Id.* at 61.

requirement, but the network load will end up paying that additional transmission charge nonetheless.

146. In addition, PacifiCorp's proposal to charge for transmission service in association with participation in the EIM is in conflict with the proposal by CAISO to have reciprocal transmission rates for the EIM, which we accept in the concurrently issued order on CAISO's EIM proposal. CAISO proposes to assess transmission charges only in the BAA where the EIM energy sinks. In the CAISO BAA, load, which will include EIM Transfers originating in PacifiCorp, will continue to pay the CAISO transmission access charge; however, CAISO proposes to waive its wheeling access charge, normally charged on exports from CAISO, on EIM Transfers to PacifiCorp. If PacifiCorp requires EIM resources to purchase transmission service to participate in the EIM then that cost of transmission will be included in the energy bids of those resources. In effect, a participant purchasing EIM energy in CAISO from PacifiCorp would pay the CAISO transmission access charge and the PacifiCorp transmission charge embedded in the energy bid of the PacifiCorp resource. However, a participant purchasing EIM energy in PacifiCorp from CAISO would only pay the PacifiCorp transmission charge as CAISO does not propose to assess transmission charges to resources participating in the EIM. This results in similarly situated EIM participants being treated differently within the EIM footprint and is therefore unduly discriminatory.

147. Another concern with PacifiCorp's approach is that network customers utilizing the network load ratio share approach for billing have a strong incentive to sell into the EIM when their network load is low relative to the times when their network load is high. Under this circumstance, the network customer may not pay for EIM transmission service while an EIM resource that has elected to participate in the EIM using non-firm point-to-point transmission service would always pay the non-firm point-to-point transmission rate. PacifiCorp's proposal is inconsistent with Commission policy[241] and is unduly discriminatory in that network customers that choose not to participate in the EIM would not be afforded the same ability to use network service for off-system sales.

148. In addition, the Commission does not agree that network resources should be required to undesignate to participate in the EIM. Undesignation of network resources is required to allow unused available transmission capacity to be released for use by other potential transmission customers.[242] But here, the EIM will dispatch EIM resources

[241] *See, e.g., Westar Energy, Inc.*, 142 FERC ¶ 61,066, at P 4 (2013) (approving stipulation and consent agreement resolving Westar Energy Inc.'s use of secondary network integration service for the purchase of energy to facilitate off-system sales); and section 28.6 of the Commission's *pro forma* OATT.

[242] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at PP 1534, 1549.

based on a real-time model of the transmission system and will utilize any unused transmission, whether firm or non-firm, to allow EIM resources to provide imbalance energy. Therefore, there would not be a need for network resources to undesignate for the EIM to function properly. This approach is consistent with PacifiCorp's proposed change to the definition of "Network Resource," which would carve out an exception for the output of a network resource associated with an EIM dispatch instruction.

149. Furthermore, the EIM will only dispatch resources that are already running, meaning that all resources in the EIM will have an existing transmission reservation corresponding to their transactions prior to being dispatched in the EIM. Accordingly, as a prerequisite of participating in the EIM, PacifiCorp should require that EIM Participating Resources in PacifiCorp's BAAs must be a PacifiCorp transmission customer. Under a traditional OATT structure, a customer would not pay additional transmission charges for imbalance energy and would only pay charges under Schedule 4 and Schedule 9. The EIM is an alternative means of providing and charging for services similar to Schedule 4 and Schedule 9 and PacifiCorp does not provide a credible argument to justify charging participating resources for additional transmission related to EIM transactions.

e. OATT Schedules 4 and 9

Background

150. PacifiCorp proposes to change its OATT Schedule 4 (Energy Imbalance Service) and Schedule 9 (Generator Imbalance Service) to settle energy imbalances using the EIM LMP for all of its customers, regardless of that customer's participation in the EIM. Currently, PacifiCorp derives the cost of its imbalance services from an Hourly Pricing Proxy based on average delivered energy prices from the California-Oregon Border, Four Corners, Mid-Columbia, and Palo Verde. PacifiCorp proposes to replace this Hourly Pricing Proxy with LMPs from the EIM. PacifiCorp claims that the use of LMPs more accurately reflects its cost for providing imbalance services through Schedule 4 and Schedule 9. PacifiCorp also proposes to remove its three-tiered penalties for Schedule 4 and Schedule 9 imbalances.[243] Lastly, PacifiCorp will still allow its customers to self-provide energy imbalance services.

[243] PacifiCorp's OATT currently has penalty tiers of (1) +/- 1.5 percent, (2) +/- 1.5 up to 7.5 percent, and (3) greater than +/- 7.5 with applicable MW minimums for each tier.

Comments

151. Commenters request that PacifiCorp retain the three-tiered imbalance penalties found in the *pro forma* OATT. Certain commenters request that the first tier of imbalance penalties, the 1.5 percent band, should remain in place so that transmission customers can net their minor deviations over the month instead of financially settling all deviations within that band.[244] Additionally, commenters claim that the lack of the three tiers of imbalance penalties removes an incentive for transmission customers to accurately schedule their transmission use.[245]

152. Commenters claim that the use of the EIM LMP will only reflect the cost of imbalance energy provided by generators participating in the EIM and that participation in the EIM will mostly be from PacifiCorp generation.[246] Commenters claim that there is no guarantee that PacifiCorp will bid its most economical resources into the EIM. This can expose transmission customers to potentially unjust and unreasonable prices compared to the more liquid trading hubs currently used to determine imbalance charges for Schedule 4 and Schedule 9.

153. Finally, commenters argue that transmission customers will not have the same protections from imbalance charges under PacifiCorp's proposed changes compared to the current Schedule 4 and Schedule 9. Specifically, a transmission customer (or generator) has no way to shield itself from high LMPs due to transmission congestion.[247]

154. WPTF highlights a concern with the language of Schedule 9. According to WPTF, the schedule does not correctly apply charges and payments to generators.[248] WPTF indicates that it has raised this issue with PacifiCorp and that PacifiCorp has agreed to correct the language.

155. CAISO contends that it is unclear under what circumstances a non-participating resource in the EIM would be paid the instructed imbalance energy price under

[244] SoCal Edison Comments at 5.

[245] Powerex Protest at 37.

[246] *Id.* at 33.

[247] Deseret Comments at 19 and 22.

[248] WPTF Comments at 7-9.

PacifiCorp's proposed OATT amendment.[249] According to CAISO, a non-participating resource's schedule change that is properly reflected in the 15-minute market schedule by the EIM Entity will be settled by CAISO as instructed imbalance energy. CAISO requests that PacifiCorp confirm its understanding that non-participating resources will be paid the instructed imbalance energy price pursuant to Schedule 9.

Answer

156. PacifiCorp states that it supports CAISO's interpretation and confirms that resources that participate in the EIM will be settled directly with CAISO for the services they provide, and not under Schedule 9 of PacifiCorp's OATT, while loads and non-participating resources (including imports and exports) will continue to be settled under Schedules 4 and 9 of PacifiCorp's OATT, respectively.[250] PacifiCorp will make consistent changes to its OATT on compliance if directed by the Commission.

157. Regarding the removal of the three-tiered imbalance penalties, PacifiCorp states that the use of the EIM five-minute dispatch, along with CAISO's 15-minute real-time unit commitment, will allow the EIM to produce LMPs that reflect the true cost of imbalance deviations without the need for a penalty component.[251] Additionally, PacifiCorp points to Order No. 890-A, where the Commission stated that the use of five-minute dispatch in organized markets causes transmission customers and generators to minimize their deviations from operator instructions.[252]

158. Regarding the use of the EIM LMP instead of the Hourly Pricing Proxy to set prices for Schedule 4 and Schedule 9, PacifiCorp states that the Commission has found the use of LMPs to be just and reasonable as a pricing system that provides a transparent price signal reflecting the marginal cost to supply energy at specific locations.[253] Additionally, PacifiCorp points to previous Commission orders stating that LMP market designs promote efficient use of the transmission grid, encourage the use of lowest-cost generation, and allow the grid operator to operate the grid more reliably.

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[249] CAISO Comments at 14-15.

[250] PacifiCorp Answer at 86.

[251] *Id.* at 88-89.

[252] *Id.* at 89 (citing Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 270).

[253] *Id.* at 87 (citing *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at PP 62, 64 (2006), *order on reh'g*, 119 FERC ¶ 61,076 (2007)).

159. Finally, PacifiCorp agrees with WPTF's suggested revisions to Schedule 9 and will make the correction in a compliance filing.[254]

Commission Determination

160. We conditionally accept PacifiCorp's proposed revisions to Schedules 4 and 9, subject to the further compliance filing directed herein. We find that PacifiCorp's proposal to charge for Schedule 4 and Schedule 9 imbalance service using the EIM LMP more accurately reflects the cost of providing that service by PacifiCorp. PacifiCorp's current approach of using a proxy price to determine imbalance energy costs using four liquid trading hubs only provides a proxy for PacifiCorp's actual cost of providing imbalance energy, whereas the EIM LMP will reflect the actual cost that PacifiCorp pays for imbalance service. While the EIM may not be as liquid as the four trading hubs used in the proxy price, commenters have not provided evidence to persuade the Commission that the EIM will not be competitive with the combination of CAISO and PacifiCorp. Moreover, in the order on CAISO's EIM filing issued concurrently in Docket No. ER14-1386-000, we note that bidding into the EIM will be subject to CAISO's Department of Market Monitoring review and mitigation and as discussed in this order, we are directing PacifiCorp to submit a change in status filing to justify PacifiCorp's continued authority to sell at market-based rates in the EIM. PacifiCorp's bidding behavior in the EIM will be closely monitored by both CAISO's Department of Market Monitoring and the Commission.

161. Requests by commenters that PacifiCorp retain the three-tiered penalties for imbalances are not persuasive. While commenters point out that the Commission instituted the penalty tiers to incentivize accurate scheduling by transmission customers—specifically, that "the charges must provide an incentive for accurate scheduling, such as by increasing the percentage of the adder above (and below) incremental cost as the deviations become larger"[255]—the Commission has accepted alternatives to the deviation band approach. We have found the real-time LMP for imbalances to be an adequate inducement for the customer to act rationally in an energy market and that uninstructed deviation penalties provide additional incentives to keep actual energy flows close to scheduling parameters.[256] Here, PacifiCorp's proposal is to charge for imbalance service using the EIM LMP, which we find above to more

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[254] *Id.* at 85-86.

[255] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 663.

[256] *See, e.g.*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 111 FERC ¶ 61,053, at P 197 (2005).

accurately reflect the cost of providing imbalance service by PacifiCorp. Accordingly, PacifiCorp's proposal is just and reasonable.

162. While we accept the use of the EIM LMP for Schedule 4 and Schedule 9, we are concerned that the continued use of the Hourly Pricing Proxy for Schedule 10 is inconsistent with the use of the EIM LMP in Schedule 4 and Schedule 9. Therefore, we direct PacifiCorp to revise its Schedule 10 to financially settle losses using the full LMP in place of the Hourly Pricing Proxy.

163. In addition, we direct PacifiCorp to submit a compliance filing within 30 days after the date of issuance of this order to submit the clarifications regarding the concerns raised by WPTF and CAISO, as discussed above.

f. EIM Fees in Schedule 1

Background

164. PacifiCorp proposes to revise OATT Schedule 1 (Scheduling, System Control and Dispatch Service) in order to pass through the $0.19/MWh administrative charge that CAISO proposes to collect from PacifiCorp for its participation in the EIM as an EIM Entity, along with several other EIM-related administrative fees.[257]

Comments

165. Powerex argues that PacifiCorp has not supported its proposal to include CAISO's EIM administrative charge of $0.19/MWh along with three Scheduling Coordinator fees in PacifiCorp's Schedule 1 that will be charged to all transmission customers based upon their reserved capacity of PacifiCorp facilities.[258] Powerex contends that CAISO's administrative fee is charged on each MWh of both demand and supply imbalances; thus, Powerex argues, the charges to PacifiCorp rise and fall in direct proportion to PacifiCorp's transmission customers' energy imbalances.[259] Powerex states that, despite that direct correlation to supply and demand, PacifiCorp will allocate the aforementioned

[257] PacifiCorp Transmittal Letter at 44-46. PacifiCorp states that these administrative costs do not include its implementation payments to CAISO under the Implementation Agreement and amendment for CAISO's costs in establishing the EIM, which will be booked to FERC Account No. 303, intangible assets, and allocated using the "Wage and Salary" allocator. *Id.* at 46.

[258] Powerex Protest at 19.

[259] *Id.* at 19-20.

charges to all transmission customers based upon reserved transmission capacity, including transmission customers that do not participate in the EIM and have no role in causing PacifiCorp to incur these costs. Powerex asserts that PacifiCorp's reference to vague, unsubstantiated reliability benefits does not justify assessing these costs to all transmission customers and requests that PacifiCorp be directed to allocate these costs solely to load and generation imbalances.[260]

166. Deseret is concerned that 100 percent of the EIM fees may be booked to FERC Account No. 561, which would be recovered solely through Schedule 1 of PacifiCorp's OATT. Deseret contends that the function of the EIM extends well beyond what is required to schedule and control transmission service. Deseret believes that a portion of EIM costs should be recovered based upon the capacity of EIM Participating Resources.[261]

167. BPA is concerned that PacifiCorp will include start-up costs associated with metering and communication equipment necessary for EIM participation by PacifiCorp's load and resources into PacifiCorp's transmission formula rate, despite early assurances from PacifiCorp that these costs will be borne by PacifiCorp Energy. BPA argues that these capital costs should not be included in transmission rates and that PacifiCorp's transmission customers are not beneficiaries of the EIM that will be operated by CAISO.[262] BPA notes that third party resources that elect to participate in the EIM will have to bear these capital costs, and thus there is no basis for PacifiCorp to socialize these costs to transmission customers.

<u>Answer</u>

168. PacifiCorp notes that none of its transmission customers self-supply imbalance energy; thus, all of PacifiCorp's transmission customers take imbalance service from PacifiCorp under Schedules 4 and/or 9.[263] Therefore, PacifiCorp states, by extension, these customers make use of EIM services. In addition, PacifiCorp states that these same customers will benefit from: (1) the qualitative benefits provided by the EIM; (2) the revenue credits generated by the EIM; and (3) the additional supply opportunities

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[260] *Id.* at 20-21.

[261] Deseret Protest at 23-24.

[262] BPA Comment and Protest at 6.

[263] PacifiCorp Answer at 76.

provided by the EIM.[264] According to PacifiCorp, Powerex's arguments are flawed and not consistent with cost-causation principles.

169. In response to Deseret, PacifiCorp explains that the implementation payments made by PacifiCorp to CAISO are not included in Schedule 1. PacifiCorp asserts that, while a portion of these costs may be included in PacifiCorp's annual transmission formula rate filing, customers already have a mechanism to challenge the costs that go into that filing.[265] PacifiCorp also notes that it responded to the concerns raised by BPA in the stakeholder process and clarified that capital costs associated with metering and communications for PacifiCorp's own loads and resources will not be included in PacifiCorp's transmission rates.[266]

Commission Determination

170. We accept PacifiCorp's proposal regarding the recovery of EIM administrative fees through Schedule 1 of its OATT. The benefits of the EIM to PacifiCorp cannot be realized without incurring administrative charges from CAISO's implementation of the EIM. PacifiCorp will be submitting forecast data to CAISO on behalf of all transmission and interconnection customers, which CAISO will use to dispatch and settle its real-time market. The administrative fee for this service, charged by CAISO to PacifiCorp, is properly considered as a Scheduling, System Control and Dispatch Service and appropriately included in Schedule 1 of its OATT. Powerex's argument that the amount of the administrative charge assessed to PacifiCorp is solely related to the amount of supply and load imbalance is not accurate. Absent any imbalance, CAISO would still assess an administrative charge based upon five percent of the total gross absolute value of both supply and demand of all EIM market participants. In the case of PacifiCorp, that value would include non-participating transmission customers.[267] Thus, even customers that do not use the EIM potentially cause PacifiCorp to incur EIM administrative charges on their behalf. Therefore, we are not persuaded by Powerex's argument.

171. We note that in the order issued concurrently in the CAISO EIM proceeding in Docket No. ER14-1386-000, the Commission has accepted CAISO's proposed EIM administrative charge as being allocated to EIM market participants. Accordingly, it is

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[264] *Id.* at 83.

[265] *Id.* at 85.

[266] *Id.*

[267] *See* CAISO Tariff, proposed section 29.11(i)(2)(i) and (ii).

appropriate that PacifiCorp pass through the just and reasonable EIM administrative charge in PacifiCorp's OATT Schedule 1 as all of PacifiCorp's transmission interconnection customers cause PacifiCorp, as the EIM Entity, to incur these costs on their behalf.

172. In addition, if PacifiCorp registers its generation as an EIM Participating Resource, each resource will be directly assigned CAISO's administrative charge, which could remove a large portion of the administrative charges being flowed through under Schedule 1 of PacifiCorp's OATT. Lastly, the three administrative charges noted by Powerex relate to a one-time $5,000 Scheduling Coordinator application fee,[268] an additional $500/month fee for each additional Scheduling Coordinator Identification Code,[269] and a $1,000/month Scheduling Coordinator Identification Code charge for each month the Scheduling Coordinator has market activity.[270] Assuming PacifiCorp uses two Scheduling Coordinator Identification Codes (one each for PacifiCorp East and PacifiCorp West), after the initial one-time application fee, PacifiCorp would be assessed and flow through under Schedule 1, approximately $2,500/month in Scheduling Coordinator charges. The three administrative fees that PacifiCorp proposes to pass through in Schedule 1 are fees that currently are on file with the Commission as part of CAISO's tariff. Powerex has not demonstrated that CAISO's existing tariff is unjust or unreasonable, nor has Powerex demonstrated that the three administrative fees flowing through Schedule 1 are burdensome. Therefore, Powerex's arguments that PacifiCorp has not supported its proposed flow through of these charges in Schedule 1 are unpersuasive.

173. In response to the concerns raised by BPA and Deseret, we direct PacifiCorp to identify and document each EIM-related charge in in its annual transmission formula rate filing in which it proposes to collect EIM related start-up charges, to ensure that PacifiCorp is properly classifying start-up and capital costs to generation, transmission, common plant, etc. as appropriate.

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[268] PacifiCorp Transmittal Letter at 45 n.90.

[269] *Id.* at n.91.

[270] *Id.* at n.92.

g. Collection of CAISO Charges by PacifiCorp

Background

174. PacifiCorp proposes to sub-allocate the following CAISO charges to its transmission customers on the basis of Measured Demand: (1) flexible ramping constraint charges pursuant to proposed section 29.11(g) of CAISO's tariff;[271] (2) real-time bid cost recovery charges pursuant to proposed section 29.11(f) of CAISO's tariff;[272] (3) real-time congestion offset pursuant to proposed section 29.11(e)(2) of CAISO's tariff;[273] and (4) real-time market neutrality and neutrality settlement charges pursuant to proposed sections 29.11(e)(3) and 29.11(e)(5) of CAISO's tariff, respectively (collectively, EIM Uplift Charges).[274] Measured Demand consists of metered load volumes, including losses, and e-Tagged export volumes, including losses.[275] In addition, PacifiCorp proposes to allocate CAISO charges for over- and under-scheduling load based upon the transmission customer's imbalance ratio share.

Comments

175. Deseret contends that additional clarification is needed regarding the flow through of imbalance charges in sections 8.4.1 and 8.4.2 of Attachment T.[276] Deseret notes that the language of these sections in Attachment T contradicts its plain reading of Schedule 4. Deseret recommends that one consistent formula for calculating imbalance energy charges should be used in both Attachment T and Schedule 4 and that it would be optimal to have Attachment T simply reference Schedule 4.[277] Deseret also contends that neither Attachment T nor Schedule 4 address how charges or payments from CAISO to PacifiCorp for energy imbalance will either flow through dollar for dollar to transmission

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[271] *Id.* at 51-52 (citing Proposed OATT Attachment T, section 8.5.6).

[272] *Id.* at 53-54 (citing Proposed OATT Attachment T, section 8.5.5).

[273] *Id.* at 52-53 (citing Proposed OATT Attachment T, section 8.5.2).

[274] *Id.* at 52, 54 (citing Proposed OATT Attachment T, sections 8.5.1 and 8.5.4).

[275] Proposed OATT, section 1.19C.

[276] Deseret Comments at 10-12.

[277] *Id.*

customers via Schedule 4 or, if there is a difference, how that difference will either be charged/credited to transmission customers or retained by PacifiCorp.[278]

176. Powerex argues that PacifiCorp's proposal to allocate CAISO load scheduling penalties based upon a transmission customer's respective "imbalance ratio share" is an undefined term and does not provide the Commission with sufficient detail to determine whether the imbalance ratio share will provide the proper incentive for accurate scheduling.[279]

177. Powerex also takes issue with PacifiCorp's proposal to allocate the EIM Uplift Charges based upon Measured Demand. Powerex notes that CAISO's flexible ramping constraint charge reflects the cost of maintaining sufficient flexible (economic fast ramping) capacity available to provide imbalance energy and these resources are compensated for the net revenues they forego.[280] Powerex argues that PacifiCorp's proposed allocation ignores the fact that the greatest driver of flexible ramping capability is the variable output of variable energy resources; however, Powerex argues that PacifiCorp's proposal does not allocate this charge to generator imbalance contrary to cost-causation principles. Powerex requests that PacifiCorp be required to explain why the aforementioned costs are borne by Measured Demand instead of being charged to Schedule 4 and 9 customers actually receiving energy imbalance service.[281] SoCal Edison raises a similar concern to Powerex; however, SoCal Edison recognizes that its proposal to adopt the 75/25 split used by CAISO would take time to implement and SoCal Edison does not want to delay the EIM implementation date. Accordingly, SoCal Edison asks the Commission to direct PacifiCorp to implement SoCal Edison's recommendation within one year of initial EIM operation.[282]

178. Powerex contends that PacifiCorp's rationale that CAISO allocates bid cost recovery charges based on Measured Demand is a false equivalence in that CAISO incurs these costs as a result of centralized dispatch of the entirety of generation across multiple markets in California while the EIM will be limited to a real-time imbalance market and a subset of units serving the needs of entities that need imbalance service. Powerex

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[278] *Id.*

[279] Powerex Protest at 40.

[280] *Id.* at 21-22.

[281] *Id.* at 24.

[282] SoCal Edison Comments at 8.

requests that PacifiCorp be required to demonstrate why the allocation of EIM Bid Cost Recovery charges to all loads and exports is just and reasonable instead of allocating the costs to Schedules 4 and 9 customers.[283]

179. Powerex raises similar concerns and arguments with respect to PacifiCorp's proposed allocation of CAISO real-time congestion offset charges to Measured Demand.[284] Powerex explains that CAISO's real-time congestion offset charge results from two distinct congestion events: (1) the receipt of short-term transmission revenue; and (2) the cost of performing reliability dispatch when schedules are infeasible. Powerex explains that short-term transmission revenue occurs in an LMP market when the total amount paid by consumers of real-time energy exceeds the total amounts received by real-time energy suppliers (a credit). Powerex argues that under the OATT framework, customers other than loads and exports pay for transmission service, but will not receive this credit while there may be loads and exports that will get the credit but they do not pay for transmission service (e.g., generators or a physical intermediary). Powerex notes that the second congestion event, the cost of redispatch, is allocated to native and network load under the existing OATT, and PacifiCorp has not explained the rationale for deviating from long-standing Commission policy.[285] Powerex requests that the Commission reject PacifiCorp's assertions of reliability benefits and direct PacifiCorp to develop an allocation of real-time congestion offset charges consistent with the distinct circumstances that cause each to occur.

180. Lastly, Powerex repeats its concerns and arguments with respect to PacifiCorp's proposed allocation of real-time neutrality charges and EIM neutrality settlement charges on the basis of Measured Demand.[286] Powerex contends that these charges relate solely to operation of the EIM and real-time imbalances of loads and generators. Accordingly, Powerex requests that the Commission reject PacifiCorp's proposed allocation and direct PacifiCorp revise its proposal to allocate these charges to transmission customers who cause imbalance costs or who otherwise receive benefits from receiving these services.

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[283] Powerex Protest at 26-27.

[284] *Id.* at 27-30.

[285] *Id.* at 29-30 (citing *NorthWestern Corp.*, 137 FERC ¶ 61,248, at P 30 (2011)).

[286] *Id.* at 31.

Answer

181. In response to the arguments raised by Powerex and SoCal Edison regarding its proposal for allocating CAISO's flexible ramping constraint charge in a different manner than how CAISO assesses that charge to its customers, PacifiCorp again argues that its allocation reflects data limitations.[287] In addition, PacifiCorp contends that its proposal needs to be viewed in the broader context that generators on CAISO's system pay certain charges that they would not have to pay on PacifiCorp's system and vice versa. Thus, for initial implementation purposes, PacifiCorp believes that its proposed allocation of CAISO's flexible ramping constraint using Measured Demand is reasonable and that any future changes to the allocation are best left to the stakeholder process after PacifiCorp has more data.[288]

182. PacifiCorp notes that Deseret offered constructive suggestions to revise sections 8.4.1 and 8.4.2, and offers to revise sections 8.4.1 and 8.4.2 to clarify how each customer will be assessed for over- and under-scheduling charges and to define the term "imbalance ratio share," as noted by Powerex.[289] In addition, PacifiCorp clarifies that PacifiCorp Energy will be a transmission customer under Schedules 4 and 9 and will be allocated a share of EIM imbalance charges and penalties in the same manner as all the other PacifiCorp transmission customers.[290] PacifiCorp also states that there is no contradiction between sections 8.4.1 and 8.4.2 with Schedule 4 as contended by Deseret. PacifiCorp explains that the sections and Schedule 4 use the same set of data and that no further clarification is required.

183. PacifiCorp argues that Powerex's concerns regarding allocating the EIM Uplift Charges on the basis of Measured Demand is based upon the incorrect assumption that certain customers do not take imbalance service and thus do not benefit from the EIM. PacifiCorp asserts that Measured Demand is appropriate at the initiation of a new market and that actual operational experience may show that certain charges are material and could be compounded by certain market participants, at which time it may be appropriate to revise PacifiCorp's proposed allocation of the EIM Uplift Charges.[291]

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[287] PacifiCorp Answer at 80.

[288] *Id.* at 82.

[289] *Id.* at 78-79.

[290] *Id.* at 79-80.

[291] *Id.*

Commission Determination

184. We agree with PacifiCorp that Powerex's argument against the use of Measured Demand to allocate these charges is based upon the faulty reasoning that the EIM proposal is nothing more than a more complicated way to provide imbalance service under Schedules 4 and 9 of PacifiCorp's OATT. The reality of the EIM is that it will extend CAISO's security-constrained economic dispatch to PacifiCorp's BAAs, which is analogous to CAISO's operation of its BAA, whereby load and supply is balanced on a least cost basis along with resolving transmission congestion. The charges that CAISO will be assessing to PacifiCorp are an integral part of CAISO's security-constrained economic dispatch. Accordingly, it is reasonable for PacifiCorp to allocate the aforementioned charges on the same basis as CAISO, i.e., Measured Demand. With respect to the flexible ramping constraint charge, the Commission accepts PacifiCorp's rationale that it does not currently have the data to allocate that charge in the same manner as CAISO. However, we do agree that PacifiCorp should look into this issue as it gains experience with the EIM. Accordingly, we direct PacifiCorp to submit a report to the Commission 15 months after the commencement of the EIM analyzing whether continued use of the Measured Demand allocation is appropriate for the flexible ramping constraint charge and whether it now has sufficient operational data to use the 75/25 allocation factor used by CAISO.

185. In addition, we direct PacifiCorp to submit a compliance filing revising sections 8.4.1 and 8.4.2 within 30 days after the date of issuance of this order as proposed by PacifiCorp in its answer. We find that PacifiCorp's proposed change clarifies how each transmission customer will be allocated over- and under-scheduling charges.

h. Scheduling Timelines

Background

186. PacifiCorp's transmission customers will be required to submit forecast data (schedules) to PacifiCorp as the EIM Entity, which will be provided to CAISO as the market operator so that CAISO can model and account for expected load, generation, imports, and exports during the operating hour. The forecast data will be used as the baseline to measure imbalance energy for purposes of settling EIM transactions.[292]

[292] PacifiCorp Transmittal Letter at 28.

Comments

187. Deseret argues that the timeframe for submitting schedules into the EIM will increase costs to Schedule 4 and 9 transmission customers.[293] According to Deseret, the current scheduling practice on average uses load and resource forecasts that are no worse than 55 minutes old and at best, 32.5 minutes old.[294] While the EIM Business Practice has yet to be developed, Deseret understands that load and resource forecasts will stretch to 90 minutes old (based upon a requirement to submit schedules 55 minutes prior to the operating hour (T-55)), which will expose transmission customers to additional cost risks.[295] Deseret argues that, to the extent a transmission customer's load forecast varies after T-55, the transmission customer has two choices—it can leave its load/resource forecast unchanged and pay/receive the difference between its base T-55 schedule and its metered load at the Load Aggregation Point price or it can adjust its resource and interchange schedules using PacifiCorp's Business Practice #48 (Intra-Hour Transmission Scheduling) to better match its updated forecast and then pay/receive the difference between its T-55 base schedule and its metered load at the Load Aggregation Point price and receive/pay the difference between its T-55 base schedule and its metered generation at the LMP generation (or interchange) node.[296] Deseret argues that either choice increases its cost risk to manage energy imbalances due to the effects of congestion, the potential price spread between the Load Aggregation Point and LMP price, and the lack of tools to mitigate that price spread.[297]

188. BPA also is concerned that the EIM scheduling timelines will create less accurate load and resource schedules than the current practice. BPA states that, while PacifiCorp's EIM proposal will allow for 15-minute scheduling, the schedules that will be used for determining imbalances (and settlements) under Schedules 4 and 9 will be forecasts provided by transmission customers 75 minutes before the operating hour and the load schedules provided by CAISO 55 minutes before the operating hour.[298] BPA argues that changing the scheduling timeline from 20 minutes to 75 minutes or

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[293] Deseret Comments at 17-19.

[294] *Id.* at 18.

[295] *Id.*

[296] *Id.* at 18-19.

[297] *Id.* at 19.

[298] BPA Comment and Protest at 7.

55 minutes significantly increases imbalances and requires more capacity, which imposes more costs on transmission customers.[299] BPA suggests that more thought be given to using a different set of schedules for determining imbalance charges.[300]

Answers

189. PacifiCorp notes that the timelines required by CAISO and PacifiCorp are necessary for CAISO's security-constrained economic dispatch to perform all the necessary complex calculations to accurately estimate operations for the operating hour. PacifiCorp asserts that maintaining the existing 20-minute scheduling timeline is simply not workable in either CAISO's real-time energy imbalance market or CAISO's 15-minute market.[301] PacifiCorp contends that transmission customers have several options available to minimize imbalance risks such as: (1) adjusting imports and/or exports in anticipation of real-time changes in load (including on a 15-minute basis, which is available on both CAISO's and PacifiCorp's transmission systems); (2) adjusting generation, which would result in resource imbalance but could offset impacts of load imbalance; and (3) participating in the EIM to offset imbalances.[302]

190. In response to Deseret's concerns that the scheduling timelines would increase rather than reduce the cost of scheduling imbalance energy, CAISO agrees that the timeframe for Deseret to revise its schedule would be reduced, but asserts this is a necessary consequence of the operation of the 15-minute market run, which will provide countervailing benefits.[303] CAISO notes that its 15-minute market will economically reschedule the entire system, thus ensuring that expected system conditions are met with the most efficient resources. CAISO states that the Commission has recognized the overall advantages provided by the 15-minute market and determined CAISO's approach to be just and reasonable.[304]

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[299] *Id.*

[300] *Id.*

[301] PacifiCorp Answer at 75.

[302] *Id.* at 76.

[303] CAISO Answer at 10.

[304] *Id.* at 9 (citing *Cal. Indep. Sys. Operator Corp.*, 146 FERC ¶ 61,204, at PP 53-54 (2014)).

Commission Determination

191. As previously noted, we find that PacifiCorp's filing and the EIM Benefits Study adequately demonstrate that the EIM will provide both quantitative and qualitative benefits to PacifiCorp's customers. Accordingly, in order to realize those benefits, PacifiCorp and by extension, its transmission customers, must submit forecast data consistent with the timelines established by CAISO in order for CAISO to run its security-constrained economic dispatch. These are the same timelines applicable to supply resources in CAISO's real-time market. Thus, we find that PacifiCorp's proposal is just and reasonable and we therefore accept it. Neither Deseret nor BPA have demonstrated that maintaining the status quo is a workable option for EIM forecasts in the EIM.

i. EIM Market Suspension

Background

192. Under proposed section 10 of Attachment T, PacifiCorp would have authority to suspend its participation in the EIM (by requesting that CAISO prevent EIM Transfers, separate the PacifiCorp BAAs from EIM operations, and suspend settlement of EIM charges with respect to PacifiCorp, and then reverting to the currently-effective versions of Schedules 4 and 9) if, during the initial 12 months of EIM operation, PacifiCorp determines, after consultation with CAISO and CAISO's Department of Market Monitoring, that there exist market design flaws that could be effectively remedied by rule or tariff changes.[305]

Comments

193. While CAISO supports PacifiCorp's proposal as a prudent safeguard against unforeseen consequences,[306] PG&E and SoCal Edison argue that PacifiCorp should not have the ability to unilaterally suspend EIM pricing and settlement except for reliability.[307] SoCal Edison submits that PacifiCorp should be required to obtain CAISO

[305] PacifiCorp Transmittal Letter at 61-64. PacifiCorp may also take corrective actions if: (1) CAISO temporarily suspends the EIM; (2) PacifiCorp has submitted notice that it is terminating its participation in the EIM; or (3) operational circumstances are causing abnormal system conditions or communications between CAISO and PacifiCorp have been disrupted.

[306] CAISO Comments at 7-8.

[307] SoCal Edison Comments at 8; PG&E Comments at 3-5.

and the Department of Market Monitoring's concurrence before implementing this procedure, while PG&E requests outright rejection of the provision. PG&E asserts that PacifiCorp "should not be permitted to temporarily opt out of dispatch and settlement through the EIM if it does not like the market results, without proper review and approval by the Commission that temporary withdrawal is appropriate."[308] PG&E further argues that PacifiCorp should be satisfied that CAISO and the Department of Market Monitoring will act decisively if market issues arise, and that EIM Entities are also protected by FPA 206 rights and the ability to leave the EIM on six months' notice.

Answer

194. PacifiCorp asserts that its proposal does not give it the option to suspend participation in the EIM due to high prices that are justified by the present market conditions, but rather will permit PacifiCorp to protect its customers from inefficient prices directly resulting from the exploitation of a market design flaw.[309] PacifiCorp points to two recent occasions where CAISO made filings with the Commission to correct market design flaws that resulted in strategic bidding, in Docket No. ER11-4580-000, or the exercise of market power, in Docket No. ER12-2539-000, and notes that CAISO had no mechanism to mitigate the costs related to these design flaws pending acceptance of these filings by the Commission.[310] PacifiCorp also asserts that, contrary to PG&E's assertions, the ability to file a complaint pursuant to section 206 of the FPA will not adequately protect its customers, because the Commission provides only prospective relief for issues of rate design.[311] Likewise, PacifiCorp argues that exiting the EIM should be reserved as a permanent, final action and does not provide an appropriate solution for a correctable design flaw.[312]

195. PacifiCorp concedes, however, that it could only take corrective action in response to a market design flaw with the *concurrence* of CAISO and CAISO's Department of Market Monitoring, and agrees that the modifications to proposed section 10.3 of

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[308] PG&E Comments at 5.

[309] PacifiCorp Answer at 100.

[310] *Id.* at 100-101.

[311] *Id.* at 102 (citing *Black Oak Energy, L.L.C. v. PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,111, at P 40 (2012)).

[312] *Id.* at 103.

Attachment T suggested by SoCal Edison present a reasonable compromise.[313] PacifiCorp states that it will make these revisions if directed by the Commission.

Commission Determination

196. We reject PacifiCorp's proposal to unilaterally suspend its participation in the EIM due to a market design flaw and direct PacifiCorp to make a compliance filing, within 30 days after the date of issuance of this order to remove proposed section 10.3(3) of Attachment T. While the Commission has permitted market operators to take corrective actions to protect against market design flaws for limited periods at the start of a new market,[314] it is not appropriate for a market participant that joins an existing market to have the authority to suspend its participation in that market if the market participant detects a market design flaw during the first year of participation.

197. Additionally, PacifiCorp has not demonstrated that this provision is necessary. We appreciate PacifiCorp's concerns regarding protecting its customers, but it has other options at its disposal to remedy a market design flaw in addition to the ability to leave the EIM on six months' notice. For instance, if PacifiCorp detects a market design flaw and brings that flaw to the attention of CAISO and its Department of Market Monitoring, PacifiCorp need not sit idly by and wait for CAISO to file a tariff change correcting the market design flaw. PacifiCorp could file a request for waiver of the EIM tariff provisions and seek Commission authorization to separate from the EIM pending implementation of tariff revisions addressing the design flaw. The Commission has previously granted limited, one-time waivers of tariff provisions in order to remedy

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[313] *Id.* at 103-104.

[314] *See New York Indep. Sys. Operator, Inc.*, 88 FERC ¶ 61,228, at 61,754-61,755 (1999) (authorizing the New York Independent System Operator, Inc. to take certain emergency corrective actions to address "unintended design flaws which may require immediate corrective actions" during initial operation of its market); *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163, at P 58, *order on reh'g*, 109 FERC 61,157, at PP 70-80 (2004), *order on reh'g and order on proof*, 111 FERC ¶ 61,448 (2005), *order on reh'g and compliance*, 113 FERC ¶ 61,081 (2005) (requiring Midwest Independent Transmission System Operator, Inc. to file a plan to cutover to decentralized power system operations in the event of an operational failure in connection with the filing of its open access transmission and energy markets tariff); *Southwest Power Pool, Inc.*, 144 FERC ¶ 61,224, at P 403 (2013) (approving a reversion plan in connection with SPP's Integrated Marketplace, which permitted SPP to revert operations to the original Energy Imbalance Service market during a 10-30 day window after the market launch).

concrete problems.[315] Permitting PacifiCorp to unilaterally suspend its participation in the EIM without Commission approval, however, would exceed the rights appropriately afforded to market participants. Accordingly, we reject PacifiCorp's unsupported section 10.3(3) of Attachment T.

4. Market Power Mitigation

Background

198. PacifiCorp has not proposed any revisions to its OATT related to market power mitigation under the EIM. However, by participating in the EIM, PacifiCorp will be subject to CAISO's market monitoring and mitigation protocols.[316] CAISO's Department of Market Monitoring will provide market monitoring services for the participation of EIM market participants such as PacifiCorp in the real-time market. In addition, CAISO will apply market power mitigation to the participation of EIM market participants in the real-time market. As explained by CAISO in its filing in Docket No. ER14-1386-000, the market power mitigation procedures will be essentially the same as the current market rules, but CAISO will apply them separately to transmission constraints within each EIM Entity BAA. However, CAISO is not proposing to apply market power mitigation to transmission constraints limiting EIM Transfers into an EIM Entity BAA with the implementation of EIM.[317]

Comments

199. Deseret notes that there are multiple factors that initially indicate that the PacifiCorp East and PacifiCorp West BAAs may not be competitive.[318] Accordingly, Deseret requests that, absent a showing by PacifiCorp of a workably competitive market, the Commission should require that market-wide mitigation measures be imposed on EIM Participating Resources in PacifiCorp East and PacifiCorp West regardless of congestion.[319] In the alternative, Deseret argues that PacifiCorp's proposal should be

[315] *See, e.g.*, *ISO New England Inc.*, 117 FERC ¶ 61,171, at P 21 (2006); *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,069, at P 8 (2011).

[316] *See* CAISO Transmittal Letter, Docket No. ER14-1386-000 (Feb. 28, 2014) at 40.

[317] *Id.*

[318] Deseret Comments at 20.

[319] *Id.* at 22.

modified to permit a transmission customer to retain the existing Schedule 4 and 9 pricing (hourly proxy and three pricing tiers) with an annual election or require PacifiCorp to offer a net imbalance rate cap by month or year.[320] The rate cap could be based upon a formula price or index such as currently used for imbalance energy.

200. Deseret also raises another market power concern. Deseret contends that any difference between CAISO's load forecast and the aggregate load forecasts of the BAA's transmission customers will be filled by PacifiCorp's merchant entity.[321] Deseret argues that if this is the actual role that PacifiCorp's merchant entity will perform under the OATT, then that role should be incorporated in the OATT. In addition, Deseret asserts that if PacifiCorp's merchant entity is performing this stopgap function, then it will presumably be able to view the load forecasts of other transmission customers and this access to non-public information could inform PacifiCorp's merchant entity's bidding strategy and raise Standards of Conduct concerns.[322] Deseret believes that CAISO's market monitoring unit should monitor this situation for potential abuse.

201. BPA requests that the Commission put in place appropriate market power mitigation measures on day one of EIM.[323] BPA raised the same issue in CAISO's EIM filing in Docket No. ER14-1386-000. BPA contends that all the factors point to PacifiCorp having market power in its respective BAAs, particularly PacifiCorp East, and that mitigation measures are needed beginning on day one of the EIM to protect transmission customers from higher, potentially anticompetitive imbalance energy prices.[324]

Answer

202. PacifiCorp argues that market oversight and mitigation of market power are important elements of the EIM and that those issues should be addressed in CAISO's filing in Docket No. ER14-1386-000.[325] In addition, in response to Deseret's concern that PacifiCorp Energy will have sensitive market information, PacifiCorp states that

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[320] *Id.*

[321] *Id.* at 12-13.

[322] *Id.* at 13.

[323] BPA Comment and Protest at 24.

[324] *Id.* at 25.

[325] PacifiCorp Answer at 112.

PacifiCorp Energy will not have access to the load forecasts of non-PacifiCorp transmission customers.[326] PacifiCorp notes that PacifiCorp Energy will receive CAISO's load forecast for PacifiCorp's BAAs each hour and the amount needed to balance each hour; however, CAISO will not be supplying load forecasts for specific load-serving entities within PacifiCorp's BAAs in any given period.

203. Finally, with respect to Deseret's Standards of Conduct concerns, PacifiCorp notes that staff for the PacifiCorp EIM Entity will consist of personnel from PacifiCorp's grid operations and transmission services departments and will be treated as transmission function employees as appropriate. PacifiCorp affirms that these employees will treat customer information obtained in accordance with the Standards of Conduct as they do today, including with regard to separation from PacifiCorp Energy's marketing function employees.[327] Moreover, PacifiCorp notes that it has included in section 9.1 to Attachment T an ongoing obligation to comply with the Standards of Conduct.

Commission Determination

204. We agree with PacifiCorp that market power mitigation and market monitoring are more appropriately addressed in CAISO's EIM filing in Docket No. ER14-1386-000, and note that the Commission is concurrently issuing an order in that proceeding addressing these issues.

205. PacifiCorp currently has general market-based rate authority, which includes authorization to sell energy and ancillary services at market-based rates within its two BAAs. PacifiCorp originally was granted market-based rate authority in Docket No. ER97-2801-000.[328] The Commission accepted PacifiCorp's June 2010 triennial filing by order issued June 29, 2011.[329] In that letter order, the Commission found in pertinent part that PacifiCorp passed the screens in the PacifiCorp West BAA but failed the screens in the PacifiCorp East BAA; however, the Commission analyzed the delivered price test submitted by PacifiCorp for PacifiCorp East and determined that PacifiCorp satisfied the Commission's market-based rate requirements. PacifiCorp currently has pending its triennial update filed in June 2013 in Docket No. ER10-3246-

[326] *Id.* at 94.

[327] *Id.*

[328] *PacifiCorp*, 79 FERC ¶ 61,383 (1997).

[329] *PacifiCorp*, Docket No. ER97-2801-030, *et al.* (June 29, 2011) (unpublished letter order accepting updated market power analysis and notice of change in status).

002 and a more recent change in status filing in Docket No. ER10-3246-003 for the recently completed MidAmerican Energy Holding Company acquisition of NV Energy, Inc. and its public utility subsidiaries.[330]

206. The Commission determines whether to grant a seller market-based rates based upon the facts presented to the Commission in the application and the applicant passing the applicable market-based screens established by the Commission. Pursuant to section 35.42 of the Commission's regulations,[331] a market-based rate seller must timely report to the Commission any change in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority. As such, because the EIM will be a new relevant geographic market for market power purposes, PacifiCorp is required to make a market-based rate change of status filing within nine months of the launch of the EIM market so that the Commission can assess whether PacifiCorp has market power in the EIM.[332]

207. In the order on CAISO's EIM proposal issued concurrently in Docket No. ER14-1386-000, we are imposing a requirement that CAISO provide the Commission with informational status reports every six months for two years following the launch of the EIM on the presence of market power at the interties. Information in these reports may be used by the Commission to launch an FPA section 206 investigation to address market power problems at the interties. In addition, we note in the concurrent CAISO EIM order that CAISO may file with the Commission to implement EIM intertie mitigation if it believes, and can demonstrate, that such mitigation is warranted.

208. As previously discussed, we reject Deseret's request to maintain the existing Schedules 4 and 9 pricing or to implement a cap on the rates that PacifiCorp may collect for those schedules. Moreover, we disagree with Deseret that a potential Standards of Conduct violation exists with respect to PacifiCorp Energy's receipt of CAISO's load forecast for each BAA. As explained by PacifiCorp, the information will not be disaggregated to contain each load-serving entity's data; thus, PacifiCorp Energy will not see confidential customer data. In addition, as also noted above, PacifiCorp has added, to section 9.1 of Attachment T of its EIM proposal, the ongoing obligation that the EIM

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[330] *See Silver Merger Sub, Inc.*, 145 FERC ¶ 61,261 (2013).

[331] 18 C.F.R. § 35.42 (2013).

[332] The Commission believes that nine months after the launch of the EIM is an appropriate length of time for the submission of this market power study because it is unlikely that there will be sufficient data available to perform a study on this market until that time.

Entity will continue to abide by the Standards of Conduct. Failure by PacifiCorp, as the EIM Entity, to abide by the Standards of Conduct would be a violation of its OATT and could result in a Commission enforcement action.

5. Dispute Resolution

Background

209. PacifiCorp proposes to add a new section 12.4A (EIM Disputes) to its existing OATT section 12.4 to address disputes that may arise in the administration and settlement of charges under the EIM. According to PacifiCorp, disputes will be handled under either PacifiCorp's OATT or CAISO's tariff based on which entity's actions are being challenged.[333] Specifically, disputes between PacifiCorp and a transmission or interconnection customer related to the allocation of charges or payments from CAISO will be subject to the existing dispute resolution procedures in section 12 PacifiCorp's OATT, while disputes between CAISO and either PacifiCorp or a PacifiCorp EIM Participating Resource Scheduling Coordinator will be resolved according to the dispute resolution procedures in section 29.13 of CAISO's tariff.[334] To the extent that a dispute arises regarding a CAISO charge or payment that PacifiCorp then charges or pays to a transmission or interconnection customer, the customer can provide notice that it wants PacifiCorp to raise a dispute with CAISO on its behalf, and the dispute will be resolved under CAISO's tariff.[335]

Comments

210. SoCal Edison argues that there is a disconnect between CAISO's settlement dispute procedures and PacifiCorp's dispute resolution procedures with regards to non-participating resources that nonetheless will be assessed charges under the EIM.[336] SoCal Edison requests that the Commission direct PacifiCorp to make changes to its OATT, perhaps in coordination with CAISO, to ensure a workable dispute resolution process.

211. Xcel requests that with respect to the dispute resolution procedures, a method should be adopted that will inform other EIM Entity BAAs that an EIM dispute has been

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[333] PacifiCorp Transmittal Letter at 58.

[334] Proposed OATT, section 12.4A.

[335] *Id.*, section 12.4A.4.

[336] SoCal Edison Comments at 9.

resolved so that the issue leading to the dispute can be avoided or mitigated in other EIM Entity BAAs.[337] Xcel notes that other regional markets do not experience this issue as their dispute resolution procedures pertain throughout the market rather than to each BAA.

Answer

212. PacifiCorp responds that it has raised concerns on behalf of its customers during CAISO's EIM stakeholder process (and in comments on CAISO's EIM filing in Docket No. ER14-1386-000) that CAISO's timeline for issuing settlement data will leave little to no time for PacifiCorp's transmission customers to analyze the settlement statements that they receive from PacifiCorp and request that PacifiCorp bring a dispute to CAISO on their behalf.[338] PacifiCorp notes that CAISO has not accepted PacifiCorp's proposal to extend the period for raising disputes, which leaves PacifiCorp's customers in the position to have to rely upon preliminary settlement data issued by CAISO as the basis for requesting that PacifiCorp dispute a charge on their behalf.[339] With respect to the concerns raised by Xcel, PacifiCorp commits to post the information requested by Xcel and will reflect this commitment in the EIM Business Practice.[340]

Commission Determination

213. We accept proposed section 12.4A of the PacifiCorp OATT. We recognize that, upon EIM implementation, the possibility exists that PacifiCorp's transmission customers will have very little time to review the charges that they are assessed from PacifiCorp by CAISO, thereby limiting their ability to request that PacifiCorp dispute a charge with CAISO on their behalf. As noted by PacifiCorp, its transmission customers will have preliminary settlement data from CAISO in enough time that will permit transmission customers to request that PacifiCorp bring a dispute to CAISO on their behalf. We do not find the use of preliminary data to be ideal as the data is subject to change in final form thereby leading to the filing of needless disputes or worse, failure to raise a legitimate dispute if the final settlement data differs from the preliminary data. However,

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[337] Xcel Comments at 4.

[338] PacifiCorp Answer at 95-97.

[339] Unless a PacifiCorp customer signs up with CAISO to become an EIM market participant, that customer will not have a contractual relationship with CAISO to bring a dispute and must rely upon PacifiCorp to raise the dispute on their behalf. *Id.* at 95-96.

[340] *Id.* at 98.

while the timeframe to review final settlement data will be very compressed, neither SoCal Edison nor PacifiCorp state that they will be unable to review the final settlement data and bring a dispute, if needed. Moreover, in response to PacifiCorp's concerns raised in CAISO's EIM filing in Docket No. ER14-1386-000, CAISO states that it "will be mindful of the concerns of EIM Market Participants and monitor the circumstances accordingly."[341] Accordingly, we will not direct PacifiCorp to modify its dispute resolution procedures, but we expect that if a problem does arise, PacifiCorp and CAISO will address the situation expeditiously and file appropriate tariff language with the Commission.

6. Seams Issues

a. Unscheduled Flow Mitigation

Background

214. PacifiCorp proposes to use a dynamic e-Tag to implement EIM Transfers across the interface between BAAs.[342] The e-Tag will be submitted in the pre-schedule window when e-Tag curtailments take place and will include an estimated amount of energy for the energy profile, which is necessary to be compatible with WECC's unscheduled flow mitigation procedures. The e-Tag will have the same curtailment priority as the underlying firm transmission reservation and if necessary, will be curtailed on a pro-rata basis with other firm transmission rights. PacifiCorp notes that EIM Transfers within the BAA will not be e-Tagged.[343]

Comments

215. Tri-State is concerned that CAISO's and PacifiCorp's EIM filings will exacerbate the ongoing problems Tri-State is experiencing with unscheduled flow curtailments. Tri-State argues that there are a series of problems with the tagging and netting procedures to be used in the EIM that suggest that the EIM will result in discriminatory curtailments that will make the WECC curtailment problems that Tri-State previously brought before the Commission worse.[344] Tri-State notes that CAISO and PacifiCorp only intend to tag

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[341] CAISO Answer, Docket No. ER14-1386-000 (April 15, 2014) at 48.

[342] PacifiCorp Transmittal Letter at 40.

[343] *Id.* at 41.

[344] Tri-State Protest at 6.

the net EIM transactions that will occur between the two BAAs.[345] Tri-State argues that the problem with only tagging net EIM transactions is that the actual generation source and specific sink for each EIM transaction will not be identified and the actual impact on unscheduled flow relative to non-EIM interchange transactions will not be accurately represented on the tags.[346] Moreover, Tri-State asserts that because PacifiCorp is not proposing to tag intra-BAA transfers, these transfers essentially will not be curtailed under WECC unscheduled flow procedures while firm tagged non-EIM transactions will remain subject to curtailment.[347] Tri-State argues that CAISO and PacifiCorp are effectively hiding a large amount of EIM transactions from curtailments under WECC's Unscheduled Flow Mitigation Plan, which Tri-State argues is discriminatory versus similar transactions that are appropriately tagged.[348] Tri-State contends that the problem of unscheduled flow curtailments must be addressed in PacifiCorp's and CAISO's EIM proceedings and not in an unrelated WECC proceeding involving unscheduled flow mitigation procedures.[349]

Answer

216. PacifiCorp argues that Tri-State's concerns are misplaced. PacifiCorp acknowledges that operational issues associated with dynamic e-Tags may exist in WECC's Unscheduled Flow Mitigation Plan, but asserts that those issues are not a product of EIM implementation or unique to the EIM and do not require a solution other than one that would be applicable to all dynamic e-Tags in WECC.[350] With respect to Tri-State's concerns that PacifiCorp is not e-Tagging intra-BAA EIM transactions, PacifiCorp notes that WECC's Unscheduled Flow Mitigation Plan only requires e-Tagging of schedules on "qualified paths" and that PacifiCorp does not have *any* qualified paths within its BAAs.[351]

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[345] *Id.*

[346] *Id.* at 7.

[347] *Id.*

[348] *Id.* at 8.

[349] *Id.* at 9.

[350] PacifiCorp Answer at 73.

[351] *Id.* at 74.

Commission Determination

217. We dismiss Tri-State's concerns as beyond the scope of this proceeding. PacifiCorp's proposal to use dynamic e-Tags with the same curtailment priority as the underlying transmission service reservations is consistent with the existing WECC Unscheduled Flow Mitigation Plan and will ensure that curtailments of EIM schedules over qualified paths are implemented based on transmission service priority. Tri-State's concerns that the EIM will exacerbate ongoing unscheduled flow curtailments are speculative. The Commission recently accepted the revised WECC Unscheduled Flow Mitigation Plan submitted by PacifiCorp on behalf of the filing parties and supported by Tri-State.[352] The Commission directed the filing parties to submit an informational report within one year of implementation of the revised WECC Unscheduled Flow Mitigation Plan.[353] While the informational report will not be noticed nor require Commission action, the Commission will have a more complete picture of curtailments in the WECC after some experience with the EIM and WECC's Unscheduled Flow Mitigation Plan.

b. Preserving Transmission Rights

Background

218. As previously noted, PacifiCorp is proposing that EIM Transfers will be effectuated by transmission customers voluntarily offering their firm transmission rights to be used for the EIM. According to PacifiCorp, its proposal ensures that the transmission rights of other transmission customers for these transmission facilities are not used and that usage can be curtailed through the e-Tag.[354]

Comments

219. Redding requests that the Commission ensure that EIM Transfers will not negatively impact transmission rights and facilities of non-EIM market entities. Redding argues that PacifiCorp's filing never makes clear that transmission customers will be precluded from submitting EIM bids that would exceed EIM transmission rights.[355] Redding also is concerned that the EIM will devalue Redding's transmission rights on

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[352] *See PacifiCorp*, 147 FERC ¶ 61,131, at PP 16-17 (2014).

[353] *Id.* P 20.

[354] PacifiCorp Transmittal Letter at 40.

[355] Redding Comments at 8.

BPA's system through a reduction in non-firm transmission revenue which is used to offset BPA's revenue requirement, and will put new stresses on BPA's transmission system as BPA tries to integrate large volumes of wind generation.[356]

220. TANC also expresses concerns that the EIM will result in adverse impacts to non-EIM participants' transmission rights and facilities. TANC requests that the Commission require that PacifiCorp and CAISO study potential adverse impacts on other transmission rights holders on the California-Oregon Intertie and, if impacts are identified, require PacifiCorp and CAISO to enter into mitigation agreements or take mitigation measures to address the adverse impact.[357] TANC requests that this process also be applied to any expansion of the EIM or additional transmission capacity being assigned to the EIM.[358]

221. Iberdrola argues that it holds significant transmission rights across the California-Oregon Intertie and does not believe that the EIM will unduly harm those existing transmission rights.[359]

222. Deseret argues that PacifiCorp's proposal is unclear as to how transmission customers that do not take service under PacifiCorp's OATT (grandfathered customers) will be treated under the EIM as PacifiCorp intends to treat all load-serving entities in each BAA as part of Measured and Metered Demand as those terms are used in PacifiCorp's proposal for purposes of allocating charges and credits.[360] Deseret requests that the Commission direct PacifiCorp to modify its definitions to expressly describe the load, resources, and customers that it expects to be included under the provisions of the EIM.

223. Powerex argues that PacifiCorp's filing fails to contain enough information to permit the Commission to determine the scope and effects of PacifiCorp's transmission use proposal on existing transmission customers.[361] Powerex notes that PacifiCorp's filing does not address the priority that EIM flows will have under the OATT relative to

[356] *Id.* at 11.

[357] TANC Comments at 10-11.

[358] *Id.* at 13.

[359] Iberdrola Comments at 6.

[360] Deseret Comments at 5.

[361] Powerex Protest at 59-60.

other users of the grid.[362] Powerex believes that PacifiCorp should be required to address in a subsequent filing, if implementation of the EIM will result in a change in OATT curtailment and if so, PacifiCorp must propose amendments to its OATT as necessary and demonstrate to the Commission that the changes are consistent with or superior to the *pro forma* OATT.[363]

Answers

224. PacifiCorp argues that it has put in place safeguards that will preserve third-party transmission rights. PacifiCorp notes that the amount of transmission capacity that will be used for EIM Transfers comes from an existing transmission customer voluntarily offering its existing rights for the EIM. In addition, PacifiCorp will use an e-Tag to implement the EIM Transfer. The e-Tag will be pre-scheduled so that it is subject to curtailment just as other transmission rights utilizing an e-Tag will be curtailed. According to PacifiCorp, its proposal will ensure that EIM Transfers will be limited to existing firm transmission rights offered to the EIM and not the rights of other customers.[364]

225. PacifiCorp notes that any amount of transfer capability made available for EIM Transfers is indicated in the applicable e-Tag, which includes a reservation number associated with the underlying transferred transmission rights. PacifiCorp states that its scheduling system will reject any e-Tag that attempts to identify more transmission rights than are associated with the reservation number used in the e-Tag.[365] As an additional protection, the amount of the transfer capability in the e-Tag is programmed into CAISO's EIM model that controls dispatch amounts as a cap, which the model cannot exceed.

226. PacifiCorp asserts that PacifiCorp Energy does not intend to use firm transmission rights that PacifiCorp Energy has acquired from BPA for EIM implementation and states that it would be required to work with BPA if it intends to do so.[366] In addition, PacifiCorp clarifies that PacifiCorp Energy will use firm point-to-point rights purchased from BPA to deliver PacifiCorp Energy's resources (and only PacifiCorp Energy's

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[362] *Id.* at 74.

[363] *Id.* at 75.

[364] PacifiCorp Answer at 16.

[365] *Id.*

[366] *Id.* at 18.

resources) to PacifiCorp's transmission system.[367] PacifiCorp dismisses TANC's concerns that the EIM will change transmission flows and prices and must be studied as hyperbole. PacifiCorp concludes that the existing scheduling system and model used by CAISO to administer the EIM does not allow for the dispatch of EIM Participating Resources in excess of the transmission rights that are made available for EIM Transfers, so there can be no encroachment of other transmission customers' rights under any circumstances.[368]

227. With respect to transmission availability over PacifiCorp's internal transmission system, PacifiCorp notes that the security-constrained economic dispatch model will not order an EIM dispatch over an internal transmission path that is constrained or congested either prior to the operating hour based upon forecast information or in real-time.[369] PacifiCorp states that the EIM design avoids curtailments through the incorporation of future transmission constraints and system configurations in the security-constrained economic dispatch model and, during real-time, through the refreshing of real-time transmission information. Accordingly, PacifiCorp concludes that its proposal to use as-available transmission for EIM dispatch within PacifiCorp East and PacifiCorp West will not result in the diminution of the existing transmission rights of transmission customers.

228. CAISO responds that concerns raised by commenters that operation of the EIM will adversely impact commenters' transmission rights demonstrates either that commenters do not understand the operation of CAISO's security-constrained economic dispatch in the real-time market or that commenters believe that CAISO will not manage EIM Transfer limits in a manner similar to the manner in which CAISO manages internal constraints on its system.[370] CAISO notes that the EIM will model the EIM Transfer limits as additional constraints in the network model and that these additional constraints will be enforced and can bind, thereby restricting EIM Transfers to the available limit regardless of the amount of lower cost generation on the other side of the constraint. CAISO concludes that the security-constrained dispatch will not allow EIM Transfers to exceed EIM Transfer limits; therefore, third-party transmission rights cannot, and will not, be affected.[371]

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[367] *Id.* at 19.

[368] *Id.* at 22.

[369] *Id.* at 74.

[370] CAISO Answer at 14.

[371] *Id.* at 15.

229. With respect to Deseret's concerns regarding how grandfathered customers will be treated under EIM, PacifiCorp states that it will include the following language, if directed by the Commission, in section 1 of Attachment T as follows, to reinforce the circumstances under which legacy transmission customers are subject to Attachment T:

> This Attachment T shall apply to all Transmission Customers and Interconnection Customers, as applicable, with new and existing service agreements under Parts II, III, IV, or V of this Tariff, as well as all transmission customers with legacy transmission agreements that expressly incorporate by reference the applicability of PacifiCorp's OATT and/or this Attachment T in particular.[372]

Commission Determination

230. Because we are directing PacifiCorp to submit a compliance filing detailing the procedures for Interchange Rights Holders to transfer their transmission capacity to PacifiCorp for the EIM as additional provisions in PacifiCorp's OATT, we find that the issues raised by intervenors regarding the effects of PacifiCorp's proposal on third party transmission rights are not ripe for resolution until after PacifiCorp makes its compliance filing. Nonetheless, we are encouraged that the procedures proposed by PacifiCorp in its answer could possibly mitigate some of the concerns raised by intervenors. For instance, PacifiCorp's use of e-Tags for EIM Transfers could assure that if curtailments are required on the interface facilities that all firm users are curtailed pro-rata, just as all parties would be prior to EIM implementation. In addition, the procedures proposed to be in place on both PacifiCorp's and CAISO's system to prevent overscheduling above the EIM transferred transmission rights could prevent the awarding of EIM bids that exceed the assigned transfer capability, which in turn could preclude EIM Transfers from leaning on other transmission customers' transmission rights. We reserve judgment as to whether these procedures will actually prevent the possible harm alleged by intervenors until we analyze PacifiCorp's compliance filing.

231. However, in response to the concerns raised by Deseret with respect to how grandfathered contracts will be treated under EIM, we direct PacifiCorp to include in its compliance filing the proposed language to section 1 of Attachment T as proffered by PacifiCorp in its answer.

[372] PacifiCorp Answer at 51-52.

7. Other Issues

Background

232. PacifiCorp proposes a number of changes to the definitions section of its OATT to implement the EIM. In addition, PacifiCorp proposes targeted modifications to Parts I through V of its OATT for that same reason.

Comments

233. BPA identifies several technical issues in the proposed OATT amendments that need correcting such as defining the term "Dynamic Transfer" but using the term "Dynamically Transferred" which is not defined.[373] In addition, BPA points out that both PacifiCorp's transmittal letter and section 8.7.2.2 of Attachment T state that transmission customers may use firm point-to-point transmission service for EIM dispatches, but section 3.1 of Attachment T, which sets forth the transmission rights a customer must have to be an eligible resource for EIM is silent in that regard.[374]

234. BPA believes that there may be a conflict in sections 3.2.1 and 3.3.3 of Attachment T of PacifiCorp's OATT and CAISO's definition of EIM resource. BPA suggests that it is unclear whether a resource that is located outside of an EIM Entity's BAA would qualify as an EIM resource for purposes of CAISO's *pro forma* EIM Participating Resource Agreement.[375] BPA recommends that PacifiCorp (or CAISO) modify references to resource eligibility to make clear that resources that are eligible under section 3.2.1 of Attachment T of PacifiCorp's OATT qualify as EIM resource under the *pro forma* EIM Participating Resource Agreement.

235. BPA argues that the data collection requirements in section 4.2.1.2 of Attachment T of PacifiCorp's OATT are essentially limitless as they are missing a reference or statement regarding the context of the data.[376] BPA notes a similar problem exists with sections 4.2.2.2 and 4.2.1.1 and recommends that a limiting reference be applied to these sections as well.

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[373] BPA Comment and Protest at 11.

[374] *Id.*

[375] *Id.* at 12-13.

[376] *Id.* at 13.

236. BPA notes that the provision to inform CAISO and PacifiCorp of outages (section 9.2 of Attachment T) is not uniform as non-participating resources need only notify PacifiCorp of an outage.[377] BPA recommends that additional language be added to the section to note the "as applicable" need for non-participating resources to provide this information to CAISO.

237. Deseret also identifies multiple definitions along with several sections of the OATT that need clarification.[378] Deseret suggests that the proposed definition of "BAA" (section 1.4B) should be consistent with the reference in the existing OATT definition of "Control Area." Deseret suggests that the term "incremental changes" in the definition of "Dispatch Operating Point" (section 1.11B) should be changed to clarify that the reference can include both increases and decreases. Additionally, Deseret asserts that language in the definitions of "Measured Demand" and "Metered Demand" (sections 1.19C and 1.19D)—referring to losses assessed pursuant to Schedule 10 of PacifiCorp's OATT—should also refer to Schedule 10 of the "appropriate transmission provider's" OATT.

238. Deseret suggests that the definition of "Transmission Customer Base Schedule" (section 1.55A) should exclude "hourly-level load Forecast Data" since sections 4.2.4.1 through 4.2.4.3 of Attachment T provide that transmission customers will provide Forecast Data for resources, Interchange, and Intrachange, but not loads. With regard to section 1.15D, the definition of IIE, Deseret seeks clarification as to when one category of IIE applies versus the other category.

239. Deseret requests that section 8.7.2.2 of Attachment T be clarified to make clear that transmission rights acquired by a PacifiCorp EIM Participating Resource through section 23 of the OATT (i.e., through a resale or assignment from another transmission customer) be considered in the assessment of Reserved Capacity to determine whether any additional hourly non-firm transmission charges for EIM participation will apply.

Answers

240. PacifiCorp states that it has considered all comments regarding specific language proposed for the definitions and offers technical clarifications where appropriate.[379] PacifiCorp believes that the definition of "BAA" is consistent with the definition of

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[377] *Id.* at 13-14.

[378] Deseret Comments at 24-25.

[379] PacifiCorp Answer at 104.

"Control Area" retained from the *pro forma* OATT, and states that no change is required.[380] PacifiCorp agrees that the clarifying change to the definition of "Dispatch Operating Point" proposed by Deseret would be consistent with the definition, insofar as a dispatch operating point can be expressed either as a negative or positive MW quantity.[381] PacifiCorp agrees to make this clarification in a compliance filing if directed by the Commission. PacifiCorp acknowledges that, for some legacy transmission customers, losses may be settled pursuant to a different agreement or contractual arrangement than PacifiCorp's OATT.[382] PacifiCorp agrees to make Deseret's requested clarification in the definitions of "Measured Demand" and "Metered Demand" in a compliance filing if directed by the Commission.

241. With respect to Deseret's concerns regarding the definition of "Transmission Customer Base Schedule," PacifiCorp acknowledges that sections 4.2.4.1 through 4.2.4.3 of Attachment T require that Forecast Data submissions include data on all resources, Interchange, and Intrachange which balance to the transmission customer's anticipated load, as applicable.[383] In that case, PacifiCorp agrees with Deseret and will make the necessary adjustment to section 1.55A of the OATT in a compliance filing directed by the Commission. Further, PacifiCorp notes in its answer that it has modified section 9 in response to the comments of WPTF to clarify when one category of IIE applies versus the other category, and contends that this revision should provide the additional clarification requested by Deseret.[384]

242. PacifiCorp clarifies that section 3.2.1 of Attachment T refers to the term "Dynamically Transferred through a Pseudo-Tie into PacifiCorp's BAA," and such usage was in fact intended to refer to the defined term "Dynamic Transfer" in this instance. In addition, PacifiCorp agrees with BPA that transmission customers most certainly may participate in the EIM using long-term firm point-to-point transmission service; however, PacifiCorp argues that the eligibility requirements for EIM set forth in section 3.1 of PacifiCorp's OATT Attachment T are accurate as proposed by PacifiCorp.[385]

[380] *Id.* at 104-105.

[381] *Id.* at 105.

[382] *Id.*

[383] *Id.* at 105-106.

[384] *Id.* at 106.

[385] *Id.* at 65.

243. PacifiCorp does not agree with BPA that an unintentional conflict exists between Attachment T, section 3.2.1 of PacifiCorp's OATT and CAISO's defined term EIM Resource.[386] PacifiCorp understands that CAISO's intent is that its defined term, EIM Resource, includes a resource that is pseudo-tied and considers pseudo-tied resources to be within the metered boundary of the EIM Entity to which is it pseudo-tied. Therefore, PacifiCorp believes such a resource may execute CAISO's *pro forma* EIM Participating Resource Agreement. CAISO responds that it considers pseudo-tied resources to be within the BAA of the EIM market participant, and does not believe further clarification is warranted.[387]

244. With respect to BPA's concerns regarding section 4.2.1.2 of Attachment T, PacifiCorp responds that this section appropriately defines the data requirements for transmission customers with non-participating resources.[388] PacifiCorp notes that the process and data collection requirements for PacifiCorp's transmission customers with non-participating resources are substantively and appropriately explained in section 6.1.2 of the draft PacifiCorp EIM Business Practice which was posted for the first round of stakeholder comments on April 4, 2014, and on May 6, 2014, for a second round of stakeholder comments.

245. PacifiCorp agrees with BPA that PacifiCorp's rules of conduct were not intended to extend any obligations on transmission customers with non-participating resources beyond what is otherwise required in section 7 of Attachment T.[389] As such, PacifiCorp agrees to make this clarification to its Attachment T in a compliance filing if directed by the Commission.

246. PacifiCorp does not agree with Deseret's contention that while section 7.4.2 of PacifiCorp's OATT Attachment T requires PacifiCorp to report forced outages in compliance with section 29.9(e) of the CAISO tariff, there is no parallel obligation imposed on transmission customers with non-participating resources in that same section, which leaves PacifiCorp with an obligation for which it may not have appropriate data. According to PacifiCorp, section 7.4.2 of Attachment T is accurate as drafted and presents no reporting gap for PacifiCorp specifically regarding non-participating

[386] *Id.* at 56.

[387] CAISO Answer at 15.

[388] PacifiCorp Answer at 53-54.

[389] *Id.* at 99.

resources in PacifiCorp's BAAs. Therefore, PacifiCorp states that it will not be modifying this section.

247. PacifiCorp agrees with Deseret that the intention of section 8.7.2.2 of Attachment T is to include any Reserved Capacity obtained in this manner and will make the requested clarification to section 8.7.2.2 of Attachment T in a compliance filing if directed by the Commission.[390]

Commission Determination

248. We require PacifiCorp to submit a compliance filing within 30 days after the date of issuance of this order incorporating those changes discussed above which PacifiCorp agreed in its answer to make if directed by the Commission. We find that PacifiCorp's proposal to make the requested clarification regarding these matters satisfactorily addresses the issues raised by the commenters. In the following paragraphs, we discuss our determinations with respect to the specific issues as to which PacifiCorp disagrees with the commenters.

249. We disagree with PacifiCorp that the eligibility requirements in section 3.1 of Attachment T are clear with respect to firm point-to-point transmission usage. We direct PacifiCorp to submit a compliance filing within 30 days after the date of issuance of this order to add a provision stating that a resource may participate in the EIM using firm point-to-point transmission service.

250. We disagree with BPA that additional clarification is required as to whether a resource located outside of an EIM Entity's BAA would qualify as an EIM resource for purposes of CAISO's *pro forma* EIM Participating Resource Agreement. Section 29.4(d)(1)(A) of CAISO's proposed tariff submitted in its EIM filing in Docket No. ER14-1386-000 provides that an EIM resource is eligible to become an EIM Participating Resource if it meets the eligibility requirements established by the EIM Entity in whose BAA the resource will be located.[391] PacifiCorp, as the EIM Entity, is establishing the eligibility requirement and proposes to allow external resources to "move" into PacifiCorp's BAA if the resource enters into a pseudo-tie for that purpose.[392] No additional clarification is required.

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[390] *Id.* at 27.

[391] CAISO Tariff, proposed section 29.4(d)(1)(A).

[392] Proposed OATT Attachment T, section 3.2.1.

251. We disagree with BPA that a limiting reference is necessary with respect to the data collection requirements set forth in sections 4.2.1.1, 4.2.1.2 and 4.2.2.2. We find that PacifiCorp has set forth the necessary data requirements in its OATT and that it is appropriate to leave the implementation details to the EIM Business Practice as proposed.

252. We disagree with Deseret that the term "Control Area" in PacifiCorp's existing OATT and PacifiCorp's proposed definition of "Balancing Authority Area" are not consistent as each term references the other. We conclude that no additional clarification is required.

253. We agree with PacifiCorp that there is no reporting gap in section 7.4.2 of Attachment T as alleged by Deseret. The section clearly sets forth the requirement that transmission customers with non-participating resources must report outages and derates within a prescribed time and that PacifiCorp, as the EIM Entity, will report these outages on their behalf. Both participating and non-participating resources will be reporting outages to the EIM Entity that will be reporting the outages to the market operator.

8. Implementation

Background

254. PacifiCorp, as the EIM Entity, will be required to meet its portion of the combined flexible ramping constraint capacity requirement for the next operating hour.[393] The amount of flexible ramping constraint capacity requirement is a minimum requirement for each BAA in the EIM area and is based upon the EIM Transfer limit between BAAs.

255. PacifiCorp proposes to use two Load Aggregation Points, one for the PacifiCorp East BAA and one for the PacifiCorp West BAA, to compute the price that load in PacifiCorp will pay for EIM energy. PacifiCorp argues that the use of nodal LMPs would require significant costs without a corresponding demonstrated benefit at this time.

Comments

256. Powerex contends that PacifiCorp has not explained how it will meet CAISO's flexible ramping constraint requirement or how it will recover costs associated with ensuring sufficient resources bid into EIM.[394]

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[393] CAISO Tariff, proposed section 29.34(m).

[394] Powerex Protest at 80-81.

Answer

257. PacifiCorp does not anticipate that it will need to take additional measures to satisfy CAISO's flexible ramping requirement.[395] PacifiCorp explains that it currently reserves capacity on its resources, in addition to contingency reserve, to respond to load and wind variations each delivery hour. According to PacifiCorp, this amount of reserves is likely to be greater than CAISO's flexible ramping requirement. However, in the event that PacifiCorp must provide additional flexible capacity reserves indicated in its bid range for this purpose, PacifiCorp states that this would be a cost to PacifiCorp Energy as the balancing agent for PacifiCorp's BAAs, and not PacifiCorp. As such, PacifiCorp argues that these potential measures are not appropriate for inclusion in PacifiCorp's OATT or the PacifiCorp EIM Business Practice.

Commission Determination

258. We do not agree with Powerex that this information is necessary for the Commission to determine whether PacifiCorp's EIM proposal meets the just and reasonable requirements of the FPA. PacifiCorp's participation in the EIM does not alter its responsibilities as a balancing authority or the delegated system-balancing responsibilities of PacifiCorp Energy. Accordingly, we are not persuaded by Powerex's request that PacifiCorp should add provisions to the OATT addressing how PacifiCorp Energy will meet CAISO's flexible ramping requirement.

259. We accept PacifiCorp's proposed Load Aggregation Point proposal, but will require that PacifiCorp file within one year from the go live date of the EIM a study on disaggregating the Load Aggregation Points. The study should provide sufficient detail to allow the Commission to reasonably evaluate the effects of implementing a greater level of disaggregation and a proposal from PacifiCorp regarding the appropriate level of disaggregation within the PacifiCorp BAAs.

9. Greenhouse Gas Compliance

Background

260. Currently, generating resources in California, and those importing into California, need to comply with the California Air Resources Board (CARB) Greenhouse Gas (GHG) regulations, which includes procuring state-issued GHG allowances. In CAISO's EIM filing in Docket No. ER14-1386-000, CAISO proposed a mechanism that would allow resources located outside of California to include CARB GHG compliance costs in

[395] PacifiCorp Answer at 72.

their EIM bid in the form of a GHG adder to their economic energy bid.[396] Under CAISO's proposal, resources located outside of California that wanted to participate in the EIM, but not sell into California could submit a high GHG adder to avoid being dispatched into California.

Comments

261. Tri-State contends that the EIM may subject out-of-state resources to CARB requirements despite CAISO's proposal to permit a bid adder mechanism that would, in theory, allow the resource to bid high enough to avoid being dispatched into California.[397] Tri-State raised its concerns regarding out-of-state resources that do not want to be subject to CARB in CAISO's EIM filing in Docket No. ER14-1386-000 and that CAISO's answer to similar protests in that proceeding confirms that the bid adder does not guarantee that an EIM resource can avoid being required to register with CARB on the chance that it may be dispatched. Tri-State argues that the bid adder will have unintended consequences imposing additional costs on consumers through higher prices and that there must be a better way to insulate out-of-state generators from becoming subject to CARB without relying on a market distorting bid adder.[398]

Answer

262. PacifiCorp responds that it cannot provide the assurance that Tri-State seeks in avoiding being subject to CARB as PacifiCorp has no means to limit EIM Transfers to those entities that consent to CARB compliance.[399] According to PacifiCorp, CAISO (as the market operator) is the appropriate party to determine how a market participant can either comply with CARB or avoid selling into CAISO's portion of the EIM and that issue is squarely before the Commission in the CAISO EIM proceeding.

Commission Determination

263. We agree with PacifiCorp that Tri-State's concerns are beyond the scope of PacifiCorp's filing. PacifiCorp's filing properly addresses how PacifiCorp and its customers will participate in the EIM. Accordingly, rules regarding bidding into the

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[396] *See* CAISO Transmittal Letter, Docket No. ER14-1386-000 at 25-26 (Feb. 28, 2014).

[397] Tri-State Protest at 14-15.

[398] *Id.* at 16-17.

[399] PacifiCorp Answer at 114.

EIM, particularly with respect to CARB GHG compliance costs, are more appropriately addressed in the proceeding on CAISO's EIM filing in Docket No. ER14-1386-000. We note that Tri-State raised its concerns regarding CARB GHG compliance in CAISO's EIM proceeding[400] and that the Commission is concurrently issuing an order in that proceeding.

The Commission orders:

(A) PacifiCorp's proposed tariff revisions are hereby conditionally accepted for filing, in part, to be effective as of the dates requested, subject to further modifications, and rejected, in part, as discussed in the body of this order.

(B) PacifiCorp's request for waiver of the Commission's maximum 120-day prior notice requirement, 18 C.F.R. § 35.3(a)(1) (2013), is hereby granted, as discussed in the body of this order.

(C) PacifiCorp's request for waiver of the applicable requirements of section 35.13 of the Commission's regulations, 18 C.F.R. § 35.13 (2013) is hereby granted, as discussed in the body of this order.

(D) PacifiCorp is hereby directed to make the compliance filings specified in the body of this order, within the timeframes provided in the body of this order.

(E) PacifiCorp is hereby directed to file, within 30 days after the completion of the EIM Business Practice stakeholder process, any necessary additions to its OATT.

(F) PacifiCorp is hereby directed to make the current version of, and notices of proposed amendments to, CAISO tariff provisions cross-referenced in its OATT available on its website, as discussed in the body of this order.

(G) PacifiCorp is hereby directed to document EIM-related charges in its annual transmission formula rate filing, as discussed in the body of this order.

(H) PacifiCorp is hereby directed to submit a report to the Commission regarding the continued use of the Measured Demand allocation within 15 months after the commencement of the EIM, as discussed in the body of this order.

[400] *See* Tri-State Comments, Docket No. ER14-1386-000 at 4-5 (Mar. 31, 2014).

(I) PacifiCorp is hereby directed to make, within nine months after the launch of the EIM, a market-based rate change of status filing, as discussed in the body of this order.

(J) PacifiCorp is hereby directed to file, within one year after the launch of the EIM, a study on disaggregating the Load Aggregation Points, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Document Content(s)