
# BPA's Public Engagement for Establishing a Policy Direction on Potential Day-Ahead Market (DAM) Participation - Workshop 10

January 29th & 30th, 2025

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# Jan 29 Agenda

- Review of BPA's Day-Ahead Market Decision process
- E3 Case Result - Hydro Operational Limitations Scenario
- Expected Transmission Revenue Impact
- Day-Ahead Market Participation & Implementation Fees

# Jan 30 Agenda

- Day-Ahead Market Seams, Reliability and Operational Impacts


# BPA’s Continued Day-Ahead Market Decision Process

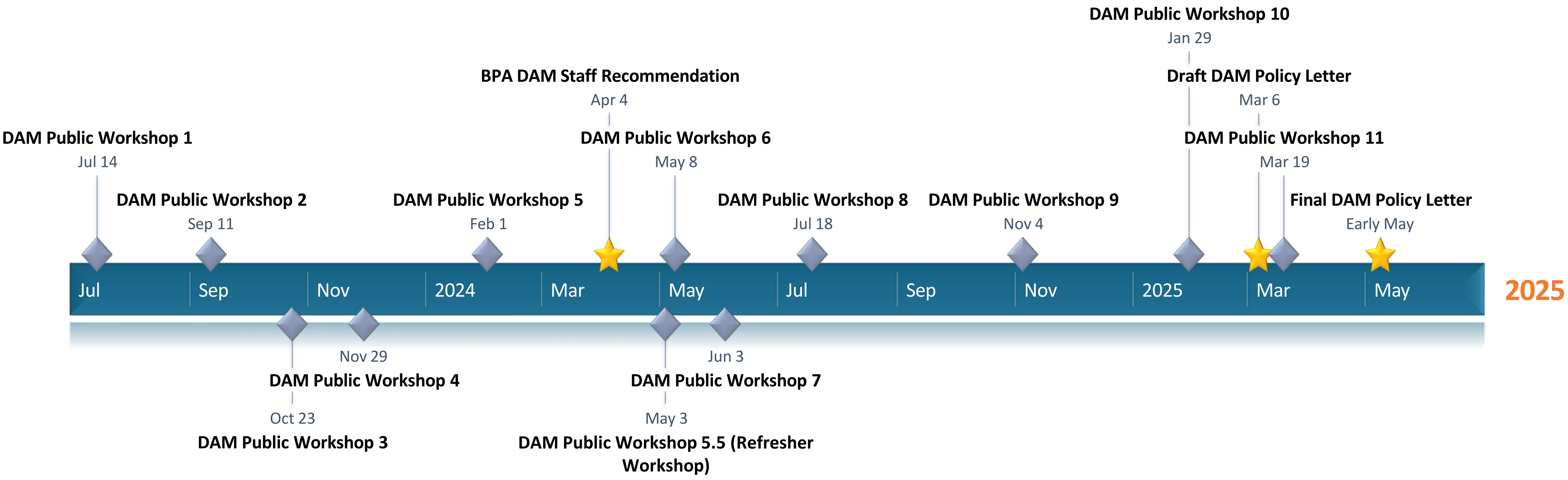
# Key Dates for CY 2025

- BPA plans to release the Draft DAM Policy Letter on March 6th
  - BPA will provide a 30-day formal comment period, seeking comments specifically on the proposed policy
  - BPA plans to hold a workshop on March 19th to walk through the Draft DAM Policy Letter
- The final DAM Policy and Record of Decision will be released in early May 2025.

# Draft DAM Policy Letter Topics

- The Draft DAM Policy Letter will discuss:
  - BPA’s evaluation of the principles for DAM participation.
  - Considerations for BPA’s DAM participation and identification of various implementation needs.
  - BPA’s recommended path forward on day ahead markets.

# BPA's DAM Decision Timeline



# Evaluation Principles

- **Statutes** – BPA meets its statutory, regulatory, and contractual obligations.
- **Reliability** – BPA maintains efficient, economical and reliable delivery of power and transmission service to its customers.
- **Reliability** – Market design includes resource sufficiency and/or resource adequacy frameworks that ensure reliability.
- **Business** – BPA's participation is supported by a sound business rationale.
- **Strategy** – BPA's participation is consistent with BPA's 2024-2028 Strategic Plan.
- **Governance** – The market has durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders. Decision-making and stakeholder engagement occurs in a transparent and inclusive manner.
- **Customers** – BPA's evaluation of DAM participation includes transparent consideration of the commercial and operational impacts on its products and services.
- **Greenhouse Gas** – BPA will evaluate how participation will impact greenhouse gas emissions attributed to the federal system and customers' ability to comply with state carbon programs. Participation must maintain the value of the low-carbon nature of the federal system to the extent possible.


# E3 Case Result - Hydro Operational Limitations Scenario


# E3 Slides - Placeholder


# Expected Transmission Revenue Impact

# DAM Transmission Revenue Recovery Mechanisms

- SPP Markets+
  - Market Transmission Use (MTU) is allocated to the Transmission Service Provider (TSP)
  - MTU rate with **scaling factor and true** up for lost revenues every 3 years
  - Lost revenues is only for PTP short-term (ST) Firm and Non-Firm revenues
  - Potential for shortfalls for wheeling through Markets+ footprint
  - Does not account for any long-term investment or long-term sales
  - Congestion Rents distributed to the customers and include PTP and NITS

# DAM Transmission Revenue Recovery Mechanisms

- CAISO EDAM
  - EDAM access charge allocated to the TSP with the following components:
    - Short-term and Non-Firm PTP transmission
    - New Transmission Capacity created from new upgrades short term and non firm revenues using load ratio share based on the baseline
    - Revenue shortfalls associated with wheeling through the EDAM BAA
  - Congestion Rents distributed by the BAA based on whatever method they choose

# BPA Assessment of Transmission Revenue Impacts in a DAM

- BPA Transmission will set rates to recover all costs.
- The short-term Firm and Non-Firm are revenues that are currently generated to offset long-term rate increases for both PTP and NITS.
- As we enter a market there is a potential to see those revenues decrease therefore shifting costs to the LT PTP and NITS rates.
- Currently the sales for **all ST Firm and Non-Firm** is approximately $40 - 60 million annually.
- If we were to include some potential **LT Firm sales** that wheel through our BAA could be approximately over $200 million annually, however, BPA LT PTP queue is over 68 GW and we believe that there are enough requests in the queue to mitigate the concerns of lost LT revenues.
- While looking at the two different markets, we looked for mechanisms to mitigate the cost shifts. The comparisons in the previous slides were the different mechanisms each market provides to mitigate the possible cost shifts.


# Day-Ahead Market Participation & Implementation Fees

# EDAM Fees

- 2 Categories of EDAM Fees
  - Initial EDAM Implementation Fee
  - Ongoing Market Participation Fees

# EDAM Implementation Fees

- CAISO projects typical EDAM implementation fee to be $1.2 million dollars on average
  - Fees are paid to CAISO in $300K increments
  - Standard implementation time is 18 months
    - Requests to extended parallel ops or market simulation can extend timeframe beyond 18 months
  - Complexity & Size of joining BAA can affect cost and implementation time

# EDAM Implementation Fees

- BPA met with CAISO to discuss approximation of fees if BPA joined EDAM
- BPA is one of the largest and complex BAA's within WECC
- BPA's high-level implementation fee is forecasted to be between $2.5 million and $3 million based on the following assumptions:
  - Requested implementation timeline up to 24 months
  - Increased cost due to complexity and size of BPA BAA
  - Extended period of parallel operations

# EDAM Participation Fee

- EDAM Market Operator recovers their annual market operating costs (staff, tools, applications) through the Grid Management Charge (GMC) charged to market participants based on their market activity
- Grid Management charge is a transactional fee assessed to each transaction
- BPA requested CAISO to forecast potential annual GMC charges utilizing an EDAM market footprint of BPA BAA and all other entities that have made declarations or leanings toward participating in EDAM
- CAISO projected ~$29 million annually in GMC fees for the BPA BAA across all scheduling coordinators, including loads and resources not represented by BPA
  - BPA would bear only a share of these charges based on its activities representing its loads and resources in the market

# Markets+ Fees

- 2 Categories of Market+ Fees
  - Phase 2 funding fees
  - Ongoing Market Participation Fees

# Markets+ Phase 2 Funding Fee

- SPP projects Markets+ Phase 2 costs to be ~$150 million
  - Costs cover staff, facilities, infrastructure, tools, and applications
- Phase 2 costs will be financed and the loan will be repaid from a market transaction fee applied to each Markets+ transaction
- Phase 2 funding participants will agree to be responsible for a portion of the Phase 2 costs roughly based on each participant's proportion of Net Energy for Load (NEL) in the market footprint.
- Certain details, including specific amounts, timing, and mechanics are still under consideration.

# Markets+ Participation Fee

- Markets+ market operator has an annual operating costs (staff, tools, applications)
- Participation fees are recovered through a transactional fee charged to each market participant
- SPP projected BPA would be charged $13-$15 million in annual operating fees

# Estimated Internal BPA Implementation Cost

- BPA is still working on estimates for internal implementation costs and will share information as it becomes available.
- Some of these costs will represent BPA assisting adjacent BAAs with their own implementation.
  - BPA expects to recover those costs from the respective BAAs.

# Questions?

# Day 1 Closeout
# Tomorrow's topic: Day-Ahead Market Seams, Reliability and Operational Impacts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# Day-Ahead Market Seams, Reliability and Operational Impacts

# Objectives

- Provide BPA's assessment of the potential impact of DAM Seams

# Seam Impacts

- Market and RC footprints produce Seams *(as do BAA and TSP footprints)*
- Seams introduce complexity
- Complexity creates operational challenges
- Market and RC Seams impact the efficient use of transmission
- Market and RC Seams impact the ability to effectively manage flows
- Market and RC Seams impact Operational Challenges and Coordination Complexity

*All slides are based on the current declared or assumed market decision of entities in WECC*

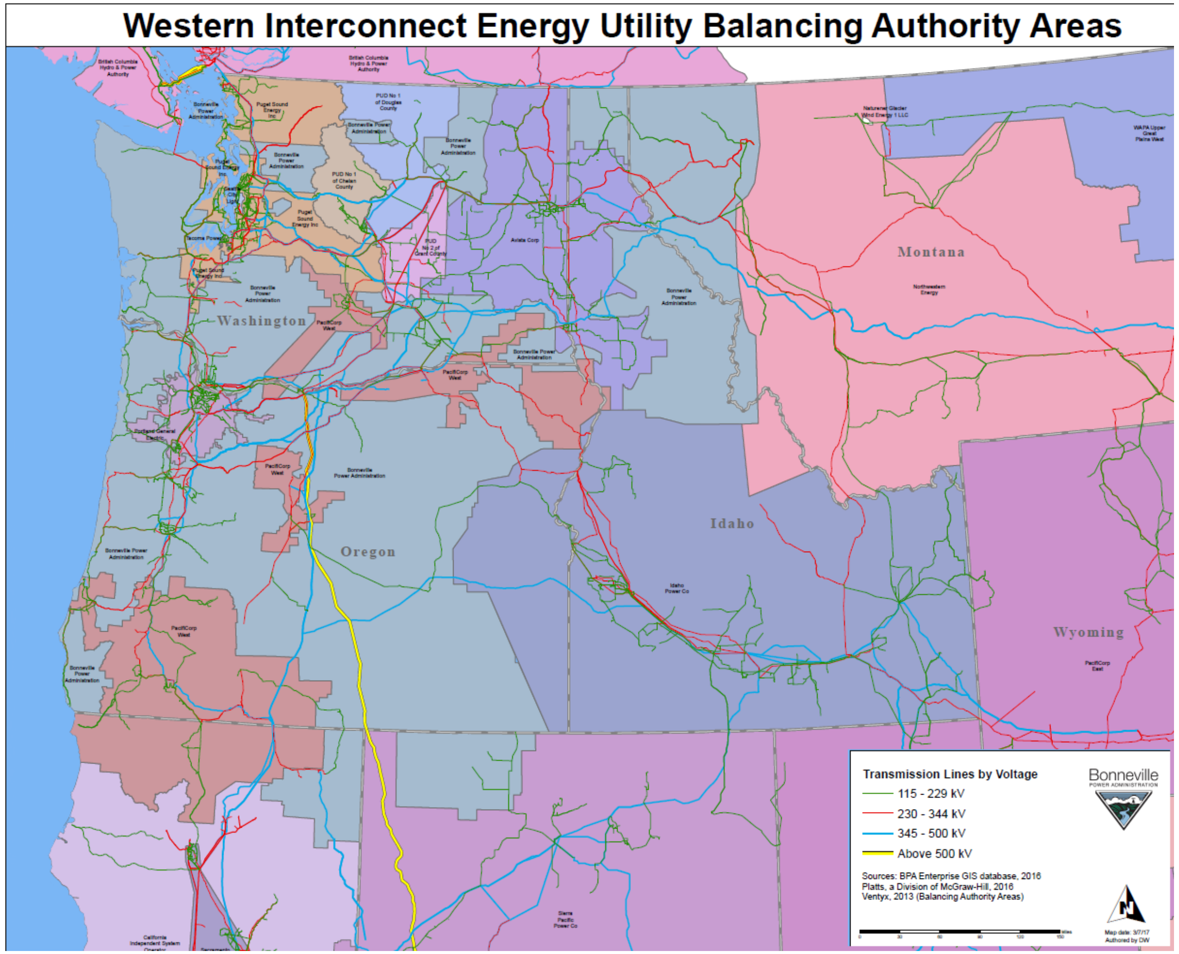


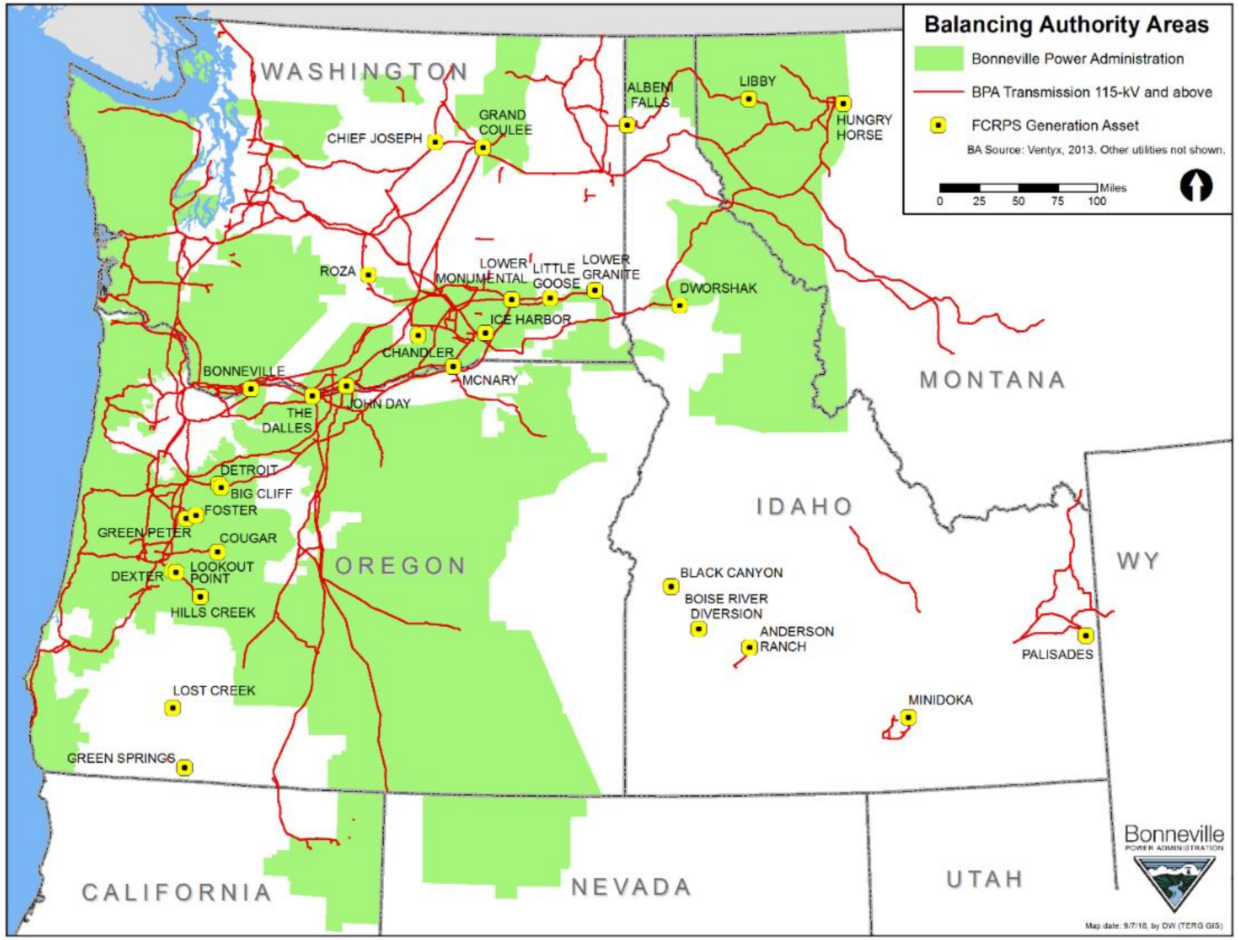
# Seam Impacts

## Complexity in WECC and the PNW Already Exists

- The WECC consists of 38 BAAs and over 30 TSPs
- In the PNW, many BAAs are non-contiguous with loads and resources pseudo-tied across multiple TSPs and geographic zones, often relying on BPA Transmission.
- BPA’s BAA is non-contiguous, located in six states, and adjacent to 18 BAAs (~360 ties) and 15 TSPs
- The creation of multiple DAMs and associated real-time markets will change existing market and RC footprints in the PNW and introduce new seams on top of those that already exist.

# Non-contiguous BAAs



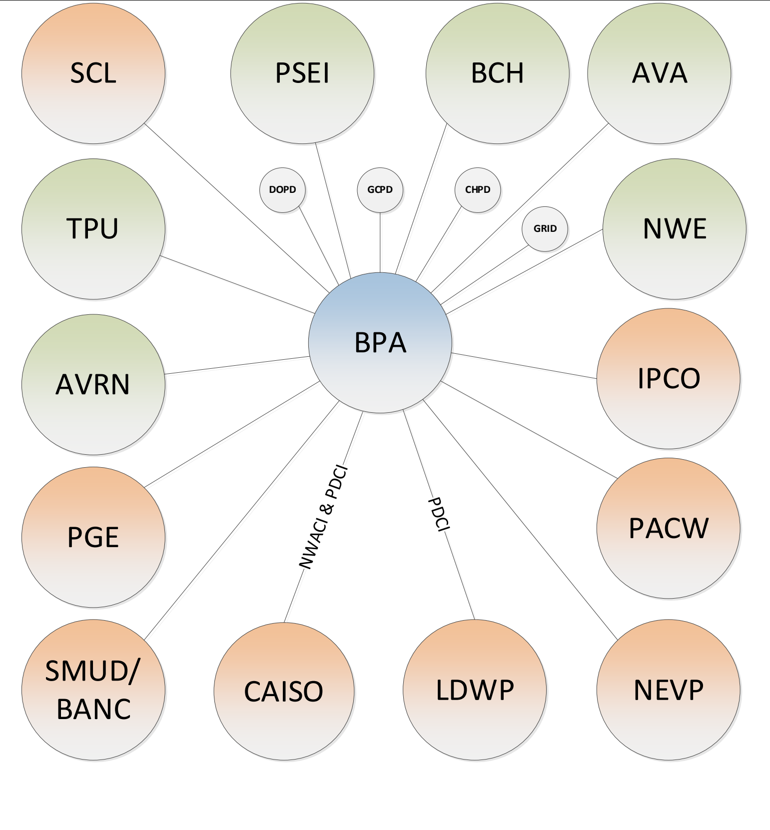



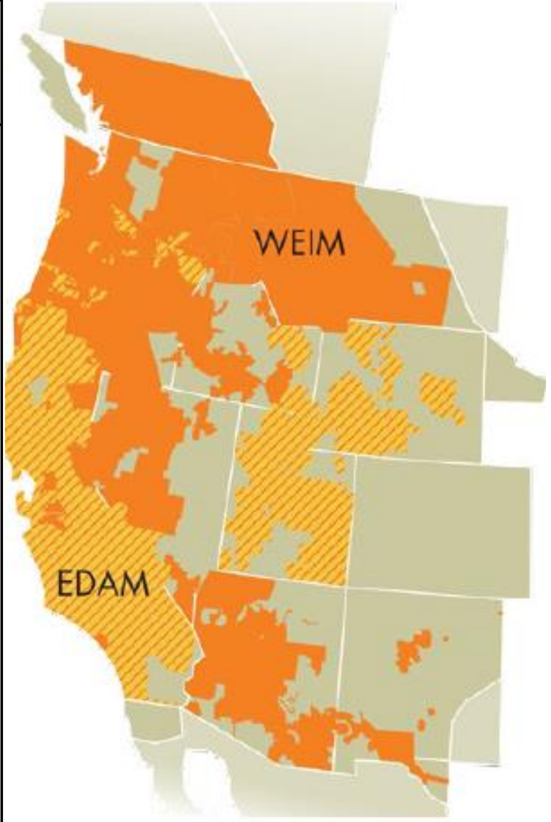
# BPA Adjacent BAAs

## BAA Adjacencies (WEIM / EDAM or EDAM Leaning)

- Avista (AVA)
- Avangrid (AVRN – Gen Only)
- Balancing Area of Northern California (BANC)
- BC Hydro (BCHA)
- Chelan County PUD (CHPD)
- California ISO (CISO)
- Douglas County PUD (DOPD)
- Grant County PUD (GCPD)
- GRID (Gen Only)

- Idaho Power (IPCO)
- LA Department of Water and Power (LDWP)
- Nevada Energy (NVE)
- Northwestern (NWE)
- PacifiCorp West (PACW)
- Portland General Electric (PGE)
- Puget Sound Energy (PSE)
- Seattle City Light (SCL)
- Tacoma Power (TPU)



# Reliability Coordinator (RC)

- While it is not required that entities take both RC and Market services from the same entity, it is presumed that some may find it more efficient to do so
  - BPA has not made any decisions regarding RC services in the context of a day ahead market decision.
- Having multiple non-contiguous RCs in the PNW with complex seams and footprints will make it more challenging to manage operational issues when they arise given the additional coordination and lack of complete regional authority
- This is further complicated by the difference in BAA and TOP areas (geographical or electrical).
  - This creates the possibility that some entities, such as BPA, that perform TOP or BAA functions over areas that transcend the footprints of more than one market may be required to take services from more than one RC.
- This will make it more complex to manage certain operational issues when they arise, as well as increase the communication and compliance burden.

# Transmission Operations (TOP)

- Some of the most important transmission in WECC is located across the Canadian border, through the BPA's Transmission System, and into California.
- Depending on the ultimate RC and MO footprints, the amount of coordination and seams on critical transmission paths may increase operational complexity (e.g., one RC and MO dealing with an operational issue north of COB and NOB while a different RC and MO is handling the portions of the interties south of COB and NOB.)
- Updated operating agreements and protocols would need to be developed

# Constraints and Congestion

- Differences in how transmission constraints are modelled, market flows are calculated, and how subsequent flows are managed in each market can result in congestion (commercial and/or physical) at interfaces between or within the two market footprints.
- This “market congestion” or “commercial congestion” may affect the efficient utilization of transmission capacity and lead to suboptimal dispatches and pricing outcomes.
- Transmission opt-outs, Service Flow constraints (SFC), Transmission Corridor (TCOR) constraints, ETSRs, and other nuances of each market’s management of transmission constraints may cause the market(s) to be commercially constrained even though the transmission system is not physically overloaded.

# DTC and IROLs

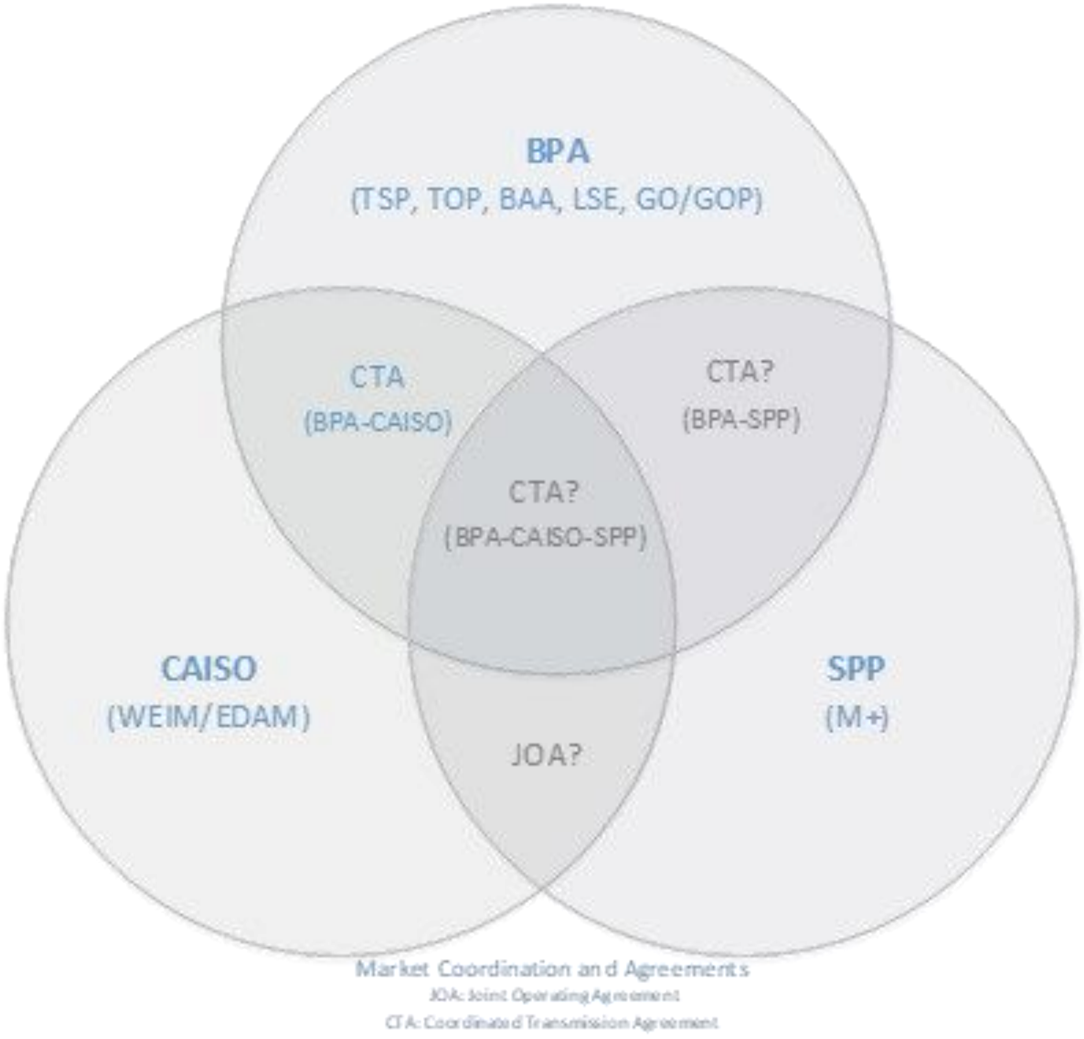
- Dynamic Transfer Capability (DTC)
  - BPA has numerous facilities with DTC limitations, such as the NI, NWACI, PDCI, Montana Intertie, and more generally across the BPA network.
  - These limitations impact the ability of the system to reliably support large sub-hourly changes in flows and are addressed in BPA's Dynamic Transfer Business Practices.
  - If there are multiple real-time markets within the PNW, DTC will need to be allocated among them and enforced within the markets. Today this is a complex process and involves a combination of commercial practices as well as constraints in the WEIM.
- Interconnection Reliability Operating Limits (IROL)
  - BPA is currently subject to two IROLs, the Oregon Net Export IROL (addresses the interactions between the NWACI and Path 75 / Path 14) and the NW WA Import IROL.
  - Today RC West is responsible for them in their near entirety.
  - Having multiple RCs involved in managing IROL's, especially the Oregon Net Export IROL, will result in operational seams and increase operational challenges.

# Seams Agreements

- BPA will likely have generation, load, and transmission participating in, or impacted by, both markets requiring various agreements, constraints, and market designs to ensure operational and commercial seams and issues are addressed.
- Different types of seams agreements will likely be needed, including agreements such as the existing Coordinated Transmission Agreement (CTA) that BPA has with the CAISO, as well as Market-to-Market Joint Operating Agreements (JOA).
- These types of agreements can be complex and lengthy requiring years to negotiate and implement
- Agreements amongst RTOs can range from 200-400 pages.

# Seams Agreements (Continued)

- Given the complexity of WECC, the potential for non-contiguous market and RC footprints, and the number of parties involved, multiple types of agreement will be necessary.



# Commercial Seams

- There are potential commercial seams in a multi-RC/multi-MO environment that will need to be considered, such as:
  - Market timing and process requirements (Bi-Lateral, DA, and RT)
  - Interplay between Resource Adequacy Programs
  - Jointly Owned Transmission (network and Interties)
  - Remote Load (i.e., load service in another BAA)
  - ATC ID, OATT, and BP Discrepancies between adjacent TSPs or joint asset owners
  - Price Formation (between markets)
  - Commercial Transmission Rights (CRRs, ATC, etc.)

# Other Considerations

- There are many other potential impacts to a multi-RC/multi-MO environment that will need to be evaluated:
  - Blackout Restoration Protocols
  - Remedial Action Schemes (RAS) Modeling
  - Market Flow Calculation and Management
  - Reserve Sharing (market to market)
  - Intra/Interchange Scheduling (timing requirements, etc.)
  - System Integration and communication between markets
  - Oversupply Protocols
  - Transmission Loss Accounting
  - NT redispatch (FCRPS and Non-Federal)
  - Data Sharing

# Conclusion on Seams

- Market and RC footprints will impact the number and type of seams and associated operational challenges
- BPA and other entities in the region will need to work collaboratively to address operational challenges & complexity from seams, regardless of market decisions
- Seams between centrally cleared markets and between markets and non-market areas will necessitate agreements between parties
- The impacted parties and scope of the issues that will need to be addressed are not yet fully known
- Addressing these challenges will require effort and time to negotiate and implement


# Questions

# Summary of Workshop 10

- Draft Policy Letter will be published March 6
- BPA Hydro Operational Limitations Scenario
- Walkthrough of:
  - Transmission’s expected revenue impact
  - Day-Ahead Market Internal Implementation Cost Estimates
  - Day-Ahead Market Implementation & Participation Fees
- Day-Ahead Market Seams, Reliability and Operational Impacts

# Wrap Up

- Please submit comments on this workshop by February 28th
- Please send comments to techforum@bpa.gov (with “DAM Participation Evaluation” in the subject heading)
  - All formal feedback received will be posted to the BPA.gov page for BPA’s DAM Participation Evaluation

# Appendix

# Transmission Revenue Recovery for M+

- MTU= Revenue Recovery Amount/(Regional Wide Net Load X 2)
  - Revenue Recovery Amount=(Annual Total Revenue Requirement X Qualified Revenue Recovery X Recovery Scaling Factor) + Prior Year Market Offset + Prior Year Market Carryover
  - Qualified Revenue Recovery = Short-Term and Non-Firm Revenues
  - Revenues collected from the MTU is allocated based on Load share ratio of the footprint
  - True up each year
    - MTU Calculation example, illustrative (not representative of BPA):

| | Sum of all TP/TSP |
|---|---|
| Total Market RRA | $71,718,916 |
| Divisor | 207,116,138 |
| MTU Rate | $ 0.17 |

| | Total Markets+ TP/TSP |
|---|---|
| 2023 ATRR | $3,176,929,359 |
| QRR | 4.51% |
| Revenue Scaling Factor | 50.00% |
| MTU Revenue Recovery Amount | $71,718,916 |

# Transmission Revenue Recovery for EDAM

- Access Charge for each specific EDAM BAA = Recoverable Revenue/Gross Load
- Recoverable Revenue = Short-term and Non-Firm PTP transmission shortfall + Costs Associated with foregone sales on new network upgrades based on estimates + Wheeling Access Charge rate
- Allocation of Access Charge will be allocated to each entity by proportionate share of the total projected EDAM Recoverable Revenue
- There are limits to the components for recoverable revenues
- Will need to provide actuals and forecasts for true up
- Access Charge Rate Calculation, Illustrative Example (not representative of BPA):

| | |
|---|---|
| Total Recoverable Revenue | $165,437,831 |
| Divisor | $207,116,138 |
| Access Charge Rate | $0.80 |

| | |
|---|---|
| Recoverable Revenue for ST and Non-Firm | $143,437,831 |
| Recoverable Revenue for Foregone sales (ST and Non Firm based on load ratio share baseline) | $20,000,000 |
| Recoverable Revenue for Wheeling | $2,000,000 |
| Total Recoverable Revenue | $165,437,831 |