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Monday, October 22, 2018
2:02PM

Day 1 (Don F, Petar, Janet, Angela, Mark, John, Tom)
Process Map
Mark S: theme - Project plan & Entity agreement; how this relates to 3rd parties (gen, donation, etc)
Janet - use Microsoft Project; assign a PM; 2 halves - agreement, up-front data set-up & then integration, testing, etc
Tom: we will need a PM to manage this on our end (Joanne Alei (?) on CAISO side? - lives in portland)
How can we stand up this function? BFTE, Slalom?... Utilicast/PCI???
Track 1 - PM to PM discussions
Janet
Recommends vendors be brought in later in the process
We should leverage the gap analysis that Utilicast developed to help flesh out the Impact Analysis *
Network Model
Costs in RC or part of EIM?
EIM Implementation fee is based on load - this is the only upfront cost (6 payments)
Major Maintenance Adder
Part of the DEB - but what is it?
Market based vs cost based rates
FERC requires market-based rates to be approved by them
Not fully resolved at BPA
Tom: has a letter from FERC granting a participant (Seattle?) a waiver
IA Attachment A
Petar - Feb would be easier than Oct
Start dates - lots of discussion on this♂
Governance:
Don: RIF is advisory, but not to the extent of a Market Advisory that is used in other markets
Charter calls for a relook by Sep 2020; EIM Governing Body is in charge but not clear how this will play out
Should we consider asking for the "relook" prior to any further progress on EDAM?
DMM - governance?; see the CA tariff (39.7);
Question on role of public power; Don suggests having this discussion with the BOSR
Day 2 (Don F, Don T, James, Angela, Mark, George, Tom, Janet)
Settlements:
Laura: we bill the largest customers first (Priority 1 is first 5 days of the month). Is this billing system really that limited?
Laura: 20% revision rate
James: currently evaluating customer's secondary settlements processes to see if CAISO's process needs tweaked (which would need FERC approval of anything tariff related - 2019/20?)
James: quarterly updates for configurations
James: no recommendation on 3rd party systems - all have pros and cons.
Laura: benchmarking has not found anyone who is happy with their 3rd party system
Laura: concern that the 3/3 month testing will mean an Oct 1 start date will have settlements testing before the rate case starts. This could be a big deal if BP-22 has any major changes
Generation Aggregation:
Still confusion on APR/ANPR
George: easier way to achieve our objectives (different GDFs for base and bid) without the NGR PowerEx approach
Todd: additional benefit of NGR PowerEx is ease of settlements
George: PowerEx's example is different that ours
Petar: NGR has issues with mitigation (flow reversal problem?)
"We don't want base schedule changes to impact our bid range" (Petar summary)
George: cannot do an auto-match on a participating resource - messes up the optimization
George: "There is no INC or DEC, only a bid range"
Todd: make sure we can deploy Reg and CR independent of base schedule GDFs. I think we are OK, but CA ISO will need to validate Pmax (and Pmin)
Todd: can we make one ANPR out of all FCRPS? Not sure
Todd: how will Reg Up sales to CA ISO work. Eric: we don't want Reg Up sales to result in imbalance. George: long answer, the EIM will see it as imbalance but it will get unwound.
Issue with validating the individual project limits within an aggregate
Metering:
Todd: it's a stretch to call the status quo as "Meters" - more like telemetry (what does that really mean)
Todd: "We don't meet our own metering standards"
Setting up a metering workshop in December
Priyanka: if we don't meet our own standards, we have to meet CA ISO standards. If neither, we will need to develop correction factors based on accuracy tests.
For Us:
Get a PM ASAP
We need a detailed timeline to get us to Apr 2022 that has key milestones identified
We need a decision on start date - is Oct 2021 possible?
Distribute (and summarize?) the Utilicast Gap Analysis
Who settles with who? Resource with CA ISO? Is there a role for T?
Should we consider asking for the "relook" on governance prior to any further progress on EDAM?
Petar "EDAM cannot hurt the C/B of the EIM".
Petar "EDAM will require a change to governance"
Mark "earliest we will see an issue paper would be mid-2019"
Get Laura and Brie specifically invited to our meetings to prep for Dec meeting
Clarity on table top scenarios
Next Time
Review GM Roadmap and Utilicast gap analysis (make sure Janet is there)
Share what we have found with Go-Live date
CAISO will share principles (and anything else they can) on EDAM
More detail on what the quarterly update cycle looks like

Negotiations

Friday, October 5, 2018 8:54 AM

Morning

- Started with overview of BiOp and FCRPS
- Aggregation
  - General agreement on 3-zone
  - Agreement on need for separate GDFs, but not necessarily the PowerEx model

Afternoon

- Late Breaking Constraints
  - Assume T-30 is the new gate closure
  - We are way overthinking this
    - Small risk that Slice RTP changes occur several seconds before T-30 and Petar willing to delay T-30 calculations several seconds
    - We should be able to write code (if necessary) to automatically adjust base schedules when between T-30 and T-3x
  - I'm not clear on the "hedging" thread
  - Auto-matched schedules/resources are not considered in the historical data set for RS check
  - If IPPs (non participating) changes schedule at T-20, auto-matching will work

Grid Modernization Overview

June 21, 2018

Grid Modernization Overview

- Bonneville released the 2018-2023 Strategic Plan in February, and has identified modernizing federal power and transmission system operations and supporting technology as a key agency strategic objective.

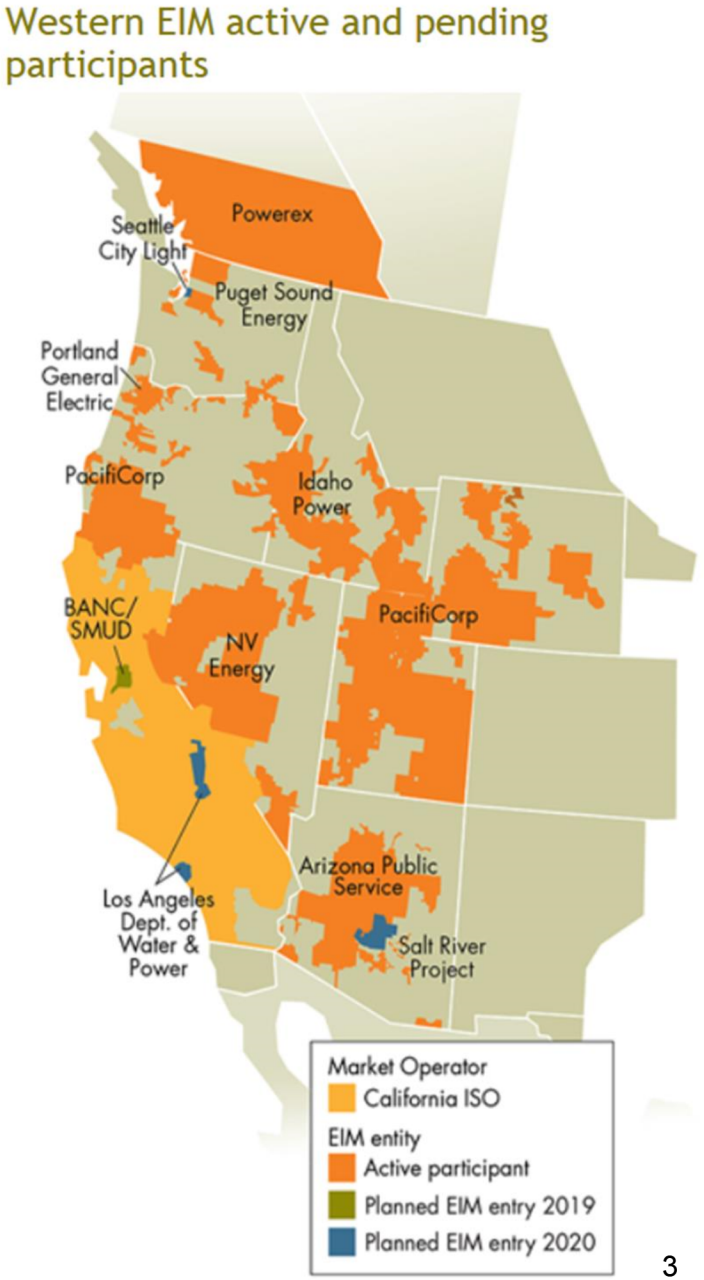
- The strategic plan describes the actions Bonneville will take over the next several years to become more competitive and responsive to customer needs, to leverage and enable industry change through modernized assets and system operations, and to deliver on our public responsibilities through a commercially successful business.

- Bonneville is mapping out the steps it needs to take to develop a grid modernization road map for the federal power and transmission system that will enhance system operations in three major ways: automation, accuracy and visibility.
  1. By automating processes, we will minimize the potential for human error and support a faster intra-hour system dispatch.
  2. By incorporating real-time data and analysis into power and transmission operations, Bonneville will be able to more accurately determine system obligations and monitor operating conditions.
  3. Increasing the visibility of loads, resources and flows, including market flows, will also help Bonneville to preserve reliability, optimize reserve levels and operate the transmission system closer to its physical limits.

- Investments in grid modernization will support a more reliable, flexible and efficient system, helping to reduce future costs and create new market opportunities for Bonneville and others.

Opportunities from Market Engagement

- As California and other Western states increase the amount of variable energy resources on the grid, we will seek opportunities to market the valuable flexibility and capacity services that clean hydropower resources can provide.
- Bonneville has been talking with other Northwest utilities who also are evaluating wholesale market changes, modernizing their systems to be in the best position to take advantage of market opportunities, and that have or are planning on joining the Western EIM.
- Many of our experiences in the market are the same, particularly the need to find ways to fully realize the value of our flexible, carbon-free hydro product.
- Thus, Bonneville has begun to study and determine how and under what conditions Bonneville could join the Western EIM.



Overview of the CAISO Western EIM

- Role of the California Independent System Operator (CAISO)
  - Within the state of California the CAISO is the grid operator and operates a full day-ahead and real-time market for the three Investor owned utilities in California.
  - Outside of California the CAISO only offers an Energy Imbalance Market and acts as the Market Operator for the Western EIM.
- Overview of the Western EIM
  - Launched in 2014.
  - Auction market for balancing supply and demand every 5 minutes.
  - Includes both a 15 minute and 5 minute market award.
  - The EIM is NOT an RTO (RTO or ISO offers transmission planning, day-ahead markets, balancing authority consolidation).
  - The EIM preserves autonomy.
  - The EIM is voluntary.
  - The EIM is security-constrained, meaning transmission and reliability constraints are not exceeded
  - Improves grid reliability, reduces energy supply cost and enhances integration of renewable resources.
    - Key Benefits
      - Reduces cost through efficient dispatch, balancing reserve reduction and congestion management
      - Provides an additional opportunity to market flexibility
      - Improves integration of renewables
      - Enhances reliability through improved congestion management visibility for transmission system operations

Next Steps

- Selling surplus energy and capacity in the western markets is essential to keeping Bonneville rates low, and Bonneville must adapt as these markets change.

- The grid modernization objective outlined in our Strategic Plan positions Bonneville to take a more active role in these evolving energy and capacity markets, while preserving preference customers statutory rights to the system

- However challenges do exist, for example:
  - Bonneville must decide how and under what conditions it could join the EIM, including how to bid in generation and how to use transmission in the market
  - Bonneville's current Open Access Transmission Tariff would also need to be updated to accommodate any necessary changes

- The grid modernization effort will enable Bonneville to better participate in markets, improve inventory management in power and transmission, and heighten our situational awareness.

- As Bonneville's grid modernization and market engagement efforts develop we will keep our stakeholders and customers informed, starting with IPR and an informational meeting this summer.
  - Multiple opportunities for stakeholder engagement will follow including in the IPR process.
  - In order to join the EIM, Bonneville would need public involvement for a final record of decision.

Transmission Qualitative Benefits

Improved Operational Controls

- Proactive Congestion Management – Transmission constraints modelled and enforced in the EIM will prevent congestion before it arises and dispatch least cost resources to stay within operating limits.
- Reactive Congestion Management – The EIM can provide more efficient, effective, and economic flow relief than traditional curtailment during real-time congestion events
- Variable Transfer Management – The Rate of Change (ROC) constraint will be more effective if BPA resources are participating in the EIM.

Improved Situational Awareness

- Improved BPA Tools - Increased and more accurate data will allow BPA to create new and improved situational awareness displays and tools allowing dispatchers and study engineers to better predict emerging operational issues.
- Access to CAISO EIM Dispatcher tools – the CAISO's Automated Dispatch System (ADS) and Balancing Authority Area Operations tool (BAAOP) will allow BPAT to review dispatches, to ensure dispatch accuracy, view Adjusted Net Scheduled Interchange, Manual Dispatch functionality, displays resource deviations, and displays BPA binding transmission constraints.

Transmission Utilization

- More Efficient Transmission Utilization – Improved operational control and situational awareness may allow for a fuller utilization of existing transmission capacity
  - Improved operational controls provide more confidence in BPA's ability to manage congestion
  - Improved situation awareness allows BPA to more accurately identify system capability
- Help Inform Transmission Investments – EIM tools and market data may be useful in BPA's transmission investment decisions

Intra-hour Dispatch Benefit Analysis

Potential Future Scenarios

We considered 2 distinct future scenarios to estimate benefits associated with joining the Western EIM:

- Both scenarios assume BPA makes investments to modernize its system and operations
- EIM scenario assumes additional investment required for full participation

Description of Scenarios			
		Modernize	EIM
Descriptor			
	Projects Participating in EIM	none	some
	EIM Market Access	none	full
Cost			
	Required Metering Investment	none	high
	Required System/Process Improvements	none	high
Benefit			
	EIM Incremental Market Revenue	none	high
	Conventional Load Factoring Revenue	moderate	none

Dispatch Benefits

Benefits estimated in each scenario are driven by the allocation of flexibility for different purposes

Flexibility Allocation (MWs)				
		Modernize	EIM	
Most of the Year (July-April)			*Must Offer**	*Surplus*
	BPA Imbalance Requirement	400	0	0
	EIM Allocation	0	400	500
	Load Factoring Allocation	500	0	0
May-June				
	BPA Imbalance Requirement	400	0	0
	EIM Allocation	0	400	0
	Load Factoring Allocation	0	0	0

*Analysis assumes that only 200 MW of the must-offer obligation will be incrementally monetized. The remaining 200 MW is utilized to serve BPA's imbalance.

Flexibility Revenue ($millions)				
		Modernize	EIM	
Most of the Year (July-April)			*Must Offer**	*Surplus*
	EIM Allocation	$0.0	$6.4	$12.3
	Load Factoring Allocation	$3.6	$0.0	$0.0
May-June				
	EIM Allocation	$0.0	$1.5	$0.0
	Load Factoring Allocation	$0.0	$0.0	$0.0
Total		$3.6	$7.8	$12.3

Scenario Cost/Benefit Summary

Scenario Costs & Benefits ($millions)			
		Modernize	EIM
Startup Costs			
	Power	-	(5.0)
	Transmission	-	(14.2)
	Power & Transmission	-	(15.1)
	CAISO Administrative	-	(1.1)
	Total Startup Costs	-	**(35.3)**
Annual Ongoing Costs			
	Power Costs	-	(3.2)
	Transmission Costs	-	(2.2)
	CAISO Administrative	-	(0.7)
	Total Annual Costs	-	**(6.1)**
Annual Benefits			
	EIM Market	-	20.1
	Load Factoring	3.6	-
	Total Annual Benefits	**3.6**	**20.1**
Annual Net Benefits		**3.6**	**14.0**

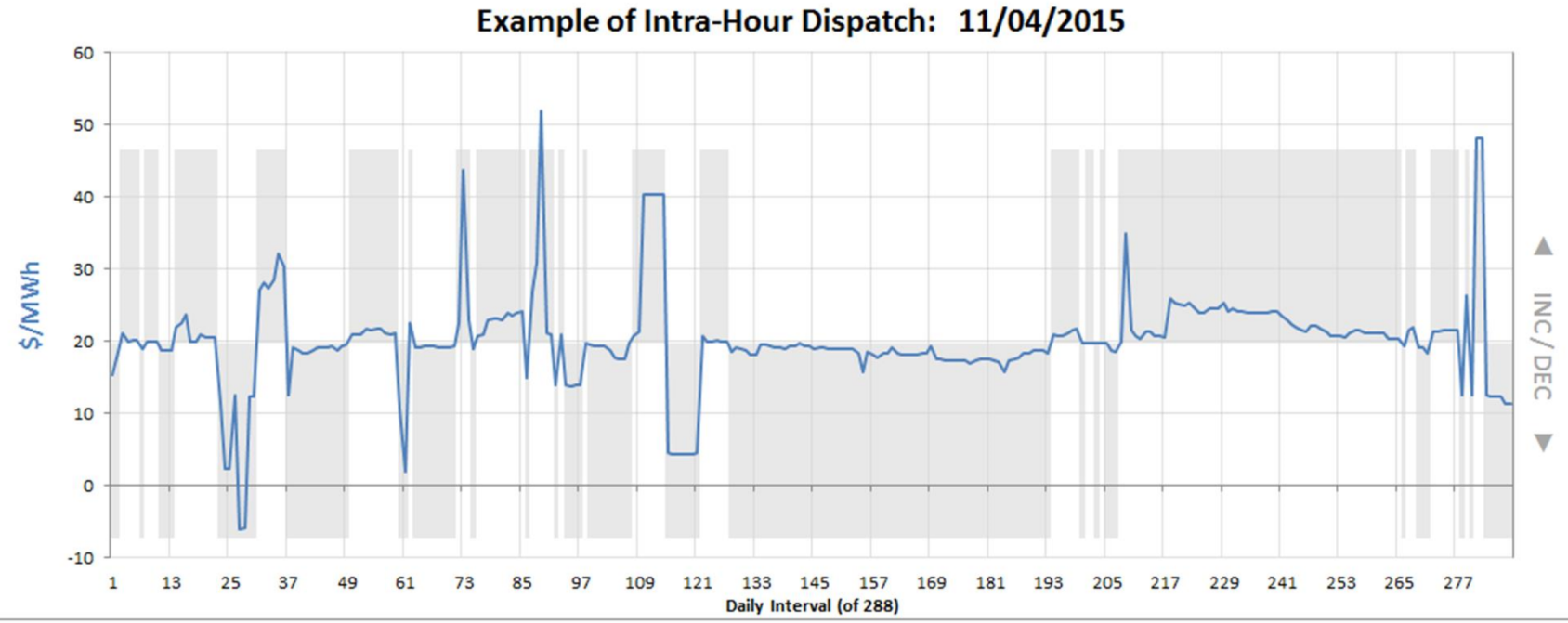
Price Construction

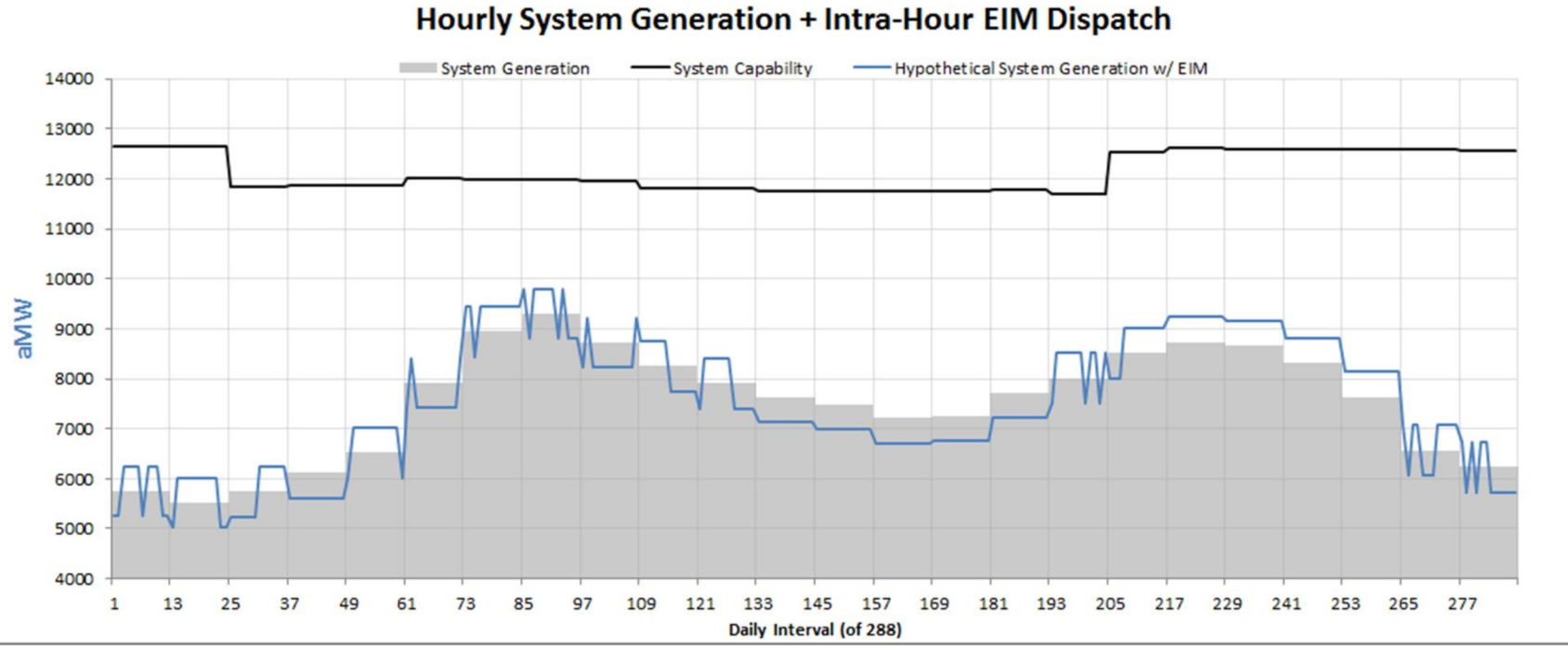
We simulated NW EIM prices using:

- Hourly-average price levels in the NW
  - Powerdex Mid-C hourly index (2015-2016)
- Within-hour variation of EIM prices
  - Pacificorp East (ELAP_PACE-APND) (2015-2016)
- Within-hour price variation applied to the NW index price
- Anticipated reduction in within-hour price volatility due to increased participation from relatively low-cost resources
  - Within-hour price variation reduced by 40%

Within-hour Dispatch Assumptions

- BPA generally offers 500 MW (up/down) for within-hour dispatch
  - Mainly sourced from freed up flexibility due to VER leaving BPA-BA
  - Significantly less flexibility in Q2
- Within-hour dispatch is energy neutral across the day
  - No effect of EIM dispatch on daily disposition of energy
- INC dispatched for price intervals above daily median
- DEC dispatched for price intervals below daily median





Notes on Estimated EIM benefit

- Analysis performed at the system level – simplifies away from finer geographic granularity with respect to:
  - Available flexibility (select projects tend to supply flexibility)
  - Pricing (EIM implementation may result in several nodes, incremental congestion impacts are unclear)

- Assumes:
  - BPA Power donates surplus transmission across the year
  - BPA BA meets resource sufficiency and flexibility requirements
  - Losses not explicitly considered
  - Bidding success rate of 75%

Issue Paper:
System-to-System Scheduling Analysis Relative to CAISO Proposal for Generator Granularity Requirement for External EIM Bidding

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EIM Steering Committee Meeting

July 17, 2018

Agenda

1. Update on EDAM Engagement
2. Any final comments/questions regarding the “Big Tent” meeting
3. Review and discuss the timeline

Update on EDAM Engagement

What the CAISO is saying about EDAM

Extended Day-Ahead Market for the Region

Key benefits:

- Allows EIM participants to take advantage of day-ahead market enhancements
- Day-ahead unit commitment and scheduling across larger footprint improves market efficiency and more effectively integrates renewables

Key elements:

- Voluntary participation, easy entry, no exit fees
- Gross benefits expected to be significant
- Ensures resource sufficiency, while Balancing Authority Area maintains autonomy regarding resource and transmission investment
- Engage stakeholders on governance structure to reflect enhanced market participation

Agenda for July 24th

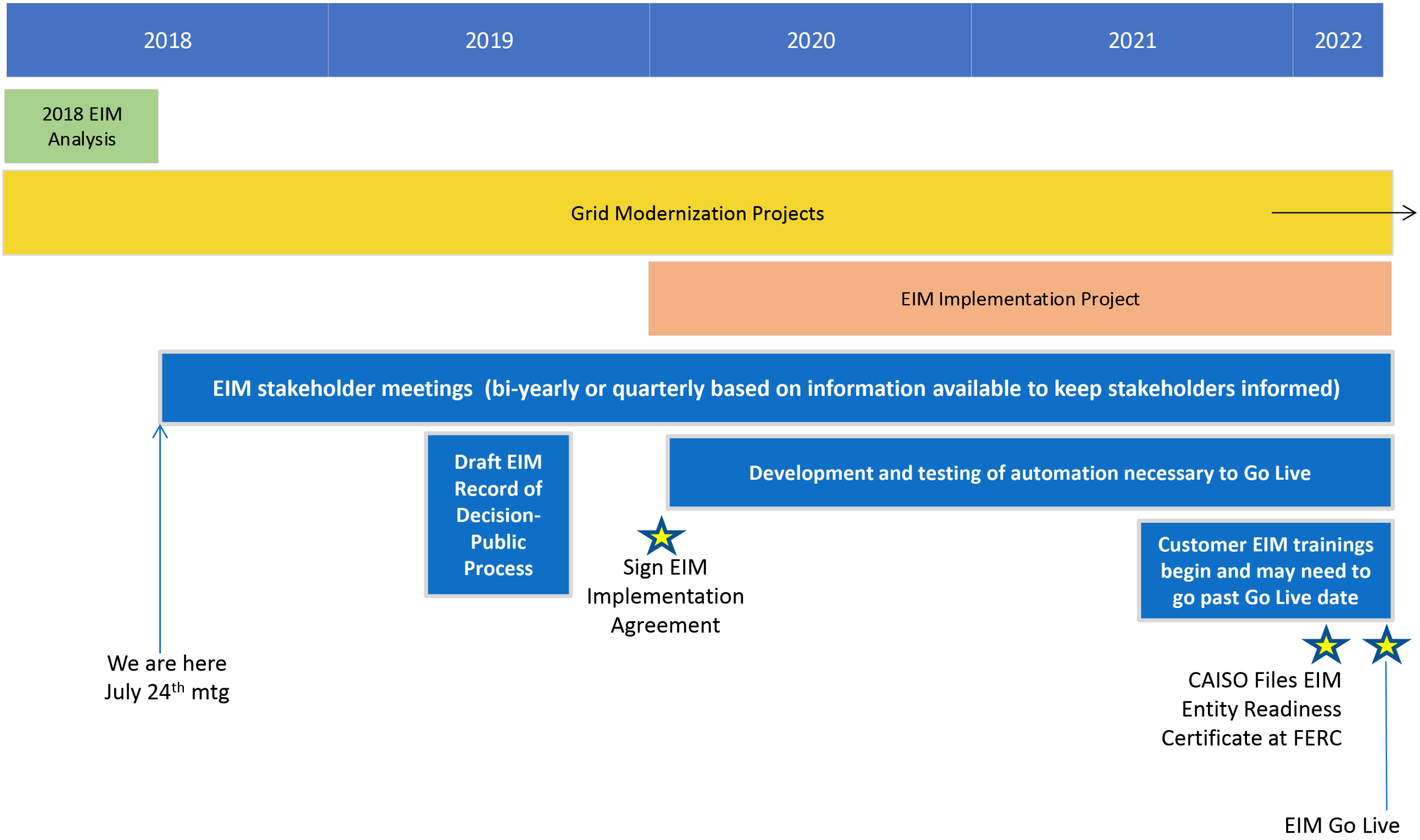
9:00-9:10	• Welcome, Safety Moment, Introductions
9:10 – 9:30	• Strategic Plan and Grid Modernization Overview
9:30 – 9:45	• EIM Overview
9:45 – 11:00	• EIM Initial Cost Benefit Analysis • Issues we are Reviewing • Draft EIM Timeline
11:00 – 11:10	• Next Steps
11:10 – 12:00	• Question and Answer Session

Link to July 24th presentation

Issues that BPA is Reviewing on July 24th

1. Market Power: Federovitch
   a) Determination (Conduct / Impact)
   b) Mitigation (DEB)
2. Carbon Obligation in EIM Federovitch
3. BA Resource Sufficiency Russ
   a) New data submissions
   b) Treatment of flexibility and uncertainty
   c) Obligations
   d) Impacts on Gen Inputs
4. EIM Settlements Russ
5. Treatment of Transmission Russ
   a) Provision: Customer vs EIM entity
   b) Who pays
6. Generation Participation Model (FCRSP, IPP) Kerns
7. Governance Kerns

Speakers identified in RED.



Link to EIM Timeline

EIM Steering Committee Meeting

Sept 25, 2018

Agenda

1. Past / Upcoming Meetings
2. Internal Staff Work
    1. Stakeholder Meeting Frequency
    2. High Level Process Map
    3. ROD Scope
    4. Matrix of Venues for EIM Decisions
    5. Proposed / Existing Sub-Teams for EIM Effort

Past / Upcoming Meetings

September 12 – PGP DEB/ RS Meeting
September 13 – EIM 101 Stakeholder Workshop
September 18 – CAISO Kickoff Meeting**
October 3 - PPC Member Forum
October 5 – CAISO / EIM Team Technical Meeting
October 11 – EIM Stakeholder Meeting at RHR

EIM Stakeholder Meetings at RHR:

- Oct 11
- Nov 20
- December to May we have a monthly day long hold at the RHR

** There will likely be more BPA/CAISO meetings scheduled in the coming weeks to discuss BPA's joining the EIM. The September 18th meeting is intended to scope the parameters for future meetings (who, when, where, and what topics). A lot will depend on CAISO's calendar.

Stakeholder Outreach

- Clarity is needed on the frequency of stakeholder outreach beyond the monthly EIM Stakeholder meetings (big tent).
  - A proposal has been made by PGP / PPC to attend a monthly customer forum, a week after each big tent, hosted by PPC / PGP for the purpose of hearing customer concerns and questions.
  - BPA would not prepare materials for these meetings.
  - This outreach would serve as a means to develop future big tent material and flesh out stakeholder concerns.
- Who should staff be meeting with?
  - Groups or individual customers
  - PPC, IOUs/EIM Entities, Slicers, IPPs, NIPPC, Renewables, CA entities other than CAISO?
- What is the proper cadence for informal meetings with key stakeholders?
  - Biweekly, monthly or other
  - Staff leaning is to have monthly meetings that occur approximately two weeks before each monthly “big tent” public meeting
  - From time-to-time, additional informal targeted customer meetings may need to be scheduled to discuss particular topics
  - Lesson learned from NWPP MC effort was that customer meetings are a significant time sink for staff. BPA and its customers are not building a market in this context; rather, BPA is evaluating whether to join an already functional/operational market.

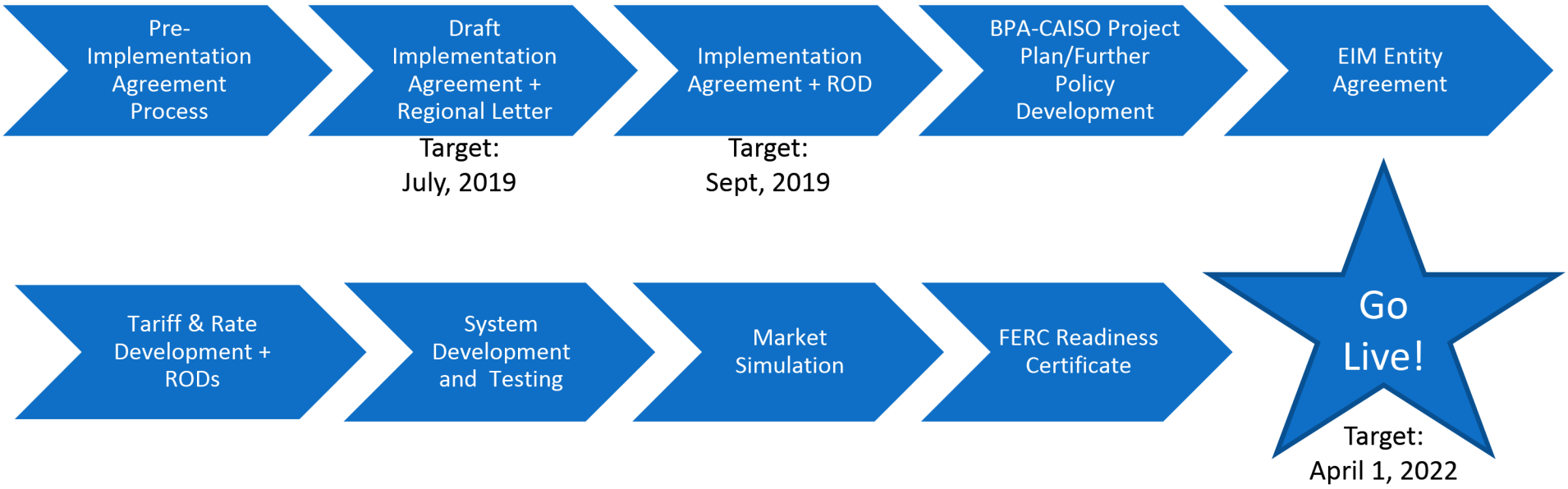
DRAFT High-Level EIM Process Map

This high-level visual represents the general steps in the process of BPA joining the EIM.

- These steps are not necessarily sequential– there will be some overlap which is not shown below.
- Staff is working on additional slides that will provide more detail and show overlap.
- The CAISO is also preparing a visual, at BPA's request, of its process for joining the EIM.

BPA can choose to not join the EIM at anytime in this process.

- This visual does not show all the respective decision points in the process.
- As the EIM process progresses, the level or degree of formality of the decision making process BPA should undertake should become more clear.
- For example, if BPA receives significant customer/stakeholder pushback, BPA may choose to prepare additional records of decision on certain topics, or, if it less receives less pushback, it may choose to notify customers using less formal methods such as letters and public meetings.



EIM Implementation Agreement

- An Implementation Agreement outlines the terms and conditions of moving forward in scoping and potentially joining the EIM. In other words, it officially starts the process toward joining but does not commit an entity to joining.

- It contains a project plan (Exhibit A) that outlines a schedule of milestones and associated payments to the CAISO for costs related to system changes, software licenses, and other configuration activities.

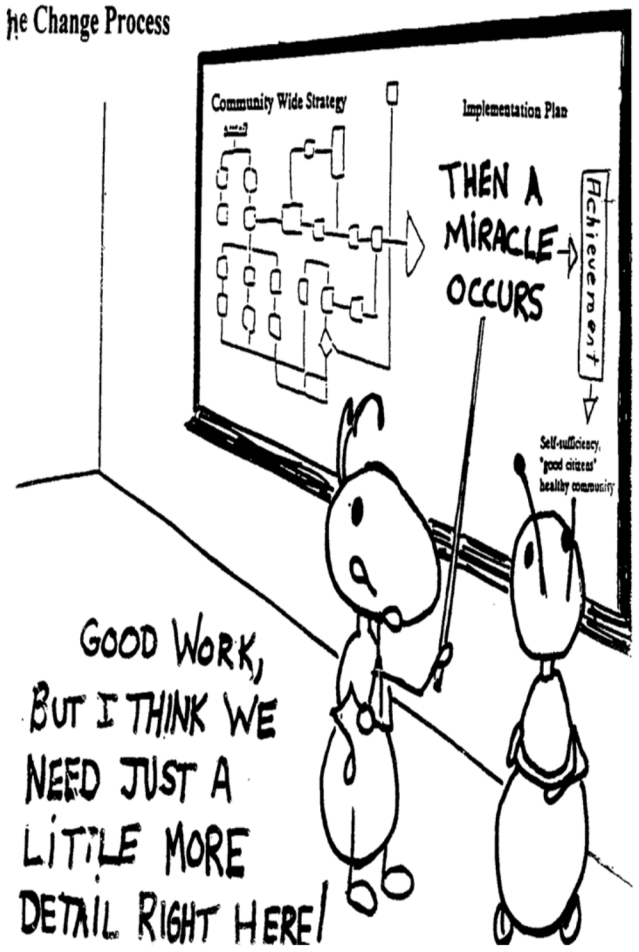
- Executing an Implementation Agreement DOES NOT mean that a potential EIM Entity has actually joined or committed to join the EIM.

- The CAISO's projected cost for work set forth in the Implementation Agreement is $2M.

Implementation Agreement Process: Regional Letter & Setting Expectations

- BPA staff/legal propose that the **draft** Implementation Agreement (IA) be presented to the region as part of a letter from the Administrator that solicits comments and feedback.

- BPA will respond to comments and feedback on the IA through a record of decision. The ROD will **not** include a decision to integrate (or join) BPA's BAA with the EIM. Rather, the ROD will include BPA's decision to sign the IA and move forward in the process to consider integrating.



Scope/Focus of Letter and ROD For the Implementation Agreement— Laying the Foundation For Joining

- Cost/Benefit Analysis– Explain why joining the EIM provides (or, alternatively, doesn't provide) business value to BPA and the region.

- Explain the legal basis for joining the EIM, assuming joining makes business sense.

- Describe substantive issues (transmission, DEB, etc.) if BPA joins, their status, and how/when they will be addressed. The letter/ROD will likely not contain final decisions on most of the identified issues on the next slide but rather a description and roadmap for resolution.

EIM Issue Resolution Matrix

Issue	Venue(s)	Timeframes
Treatment of Transmission	BPA-CAISO Negotiations, BP-22, and TC-22	Now through late 2021
Generation Participation Model (FCRPS, IPP)	BPA-CAISO Negotiations	Now through Go Live (April 1, 2022)
Governance	CAISO Stakeholder Process	2019-20
Relationship of EIM to Other Emerging Markets	TBD—Likely Combination of Venues	Ongoing
BA Resource Sufficiency	CAISO Stakeholder Process and BP-22	Now through late 2021
Market Power/DEB	CAISO Stakeholder Process	Now through Go Live (April 1, 2022)
EIM Settlements	CAISO Stakeholder Process, BP-22, and TC-22	Now through late 2021
Carbon Obligation in EIM	Legislative, BPA-CAISO Negotiations	Now through Go Live (April 1, 2022)

Proposed / Existing Sub-Teams for EIM Effort

- EIM Teams
  - EIM Core Team (5 BTO + 3 (P,T,L))
  - Sub-Teams for EIM-related issues (some are already in flight)
    - Cost/Benefit Analysis
    - Market Mitigation
    - Ancillary Services in BP-22
    - Carbon Obligation in the EIM
    - Transmission Provision in an EIM
    - Resource Sufficiency
    - EIM Implementation
    - Settlements
    - Governance
    - Impact of Emerging Markets
    - Federal Resource Participation
    - Stakeholder Strategy
    - Statutory Obligations in an EIM
  - EIM Core Team will be working on a roadmap to plan this work
  - Staff assigned to work on these teams should use the “EIM – Existing” work order

EIM Steering Committee Meeting

October 9, 2018

Agenda

1. Past / Upcoming Meetings
2. Internal Staff Work
    1. ROD Process Update
    2. CAISO Kick-Off Update
        1. Generation Participation Model
        2. EIM Transfer Transmission

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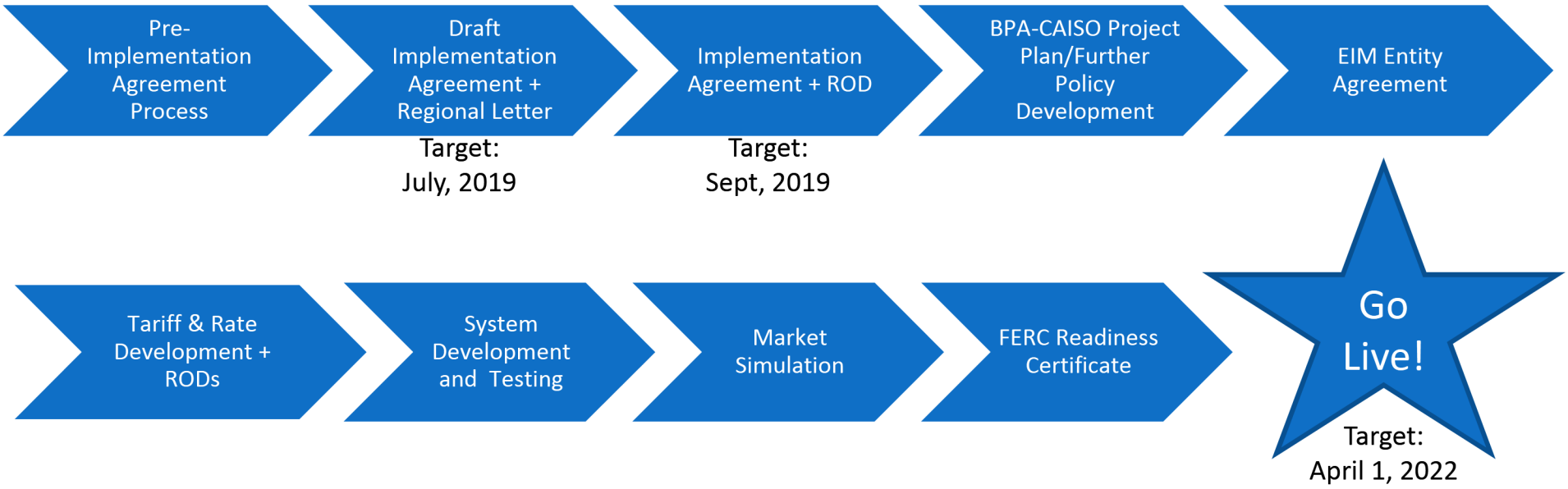
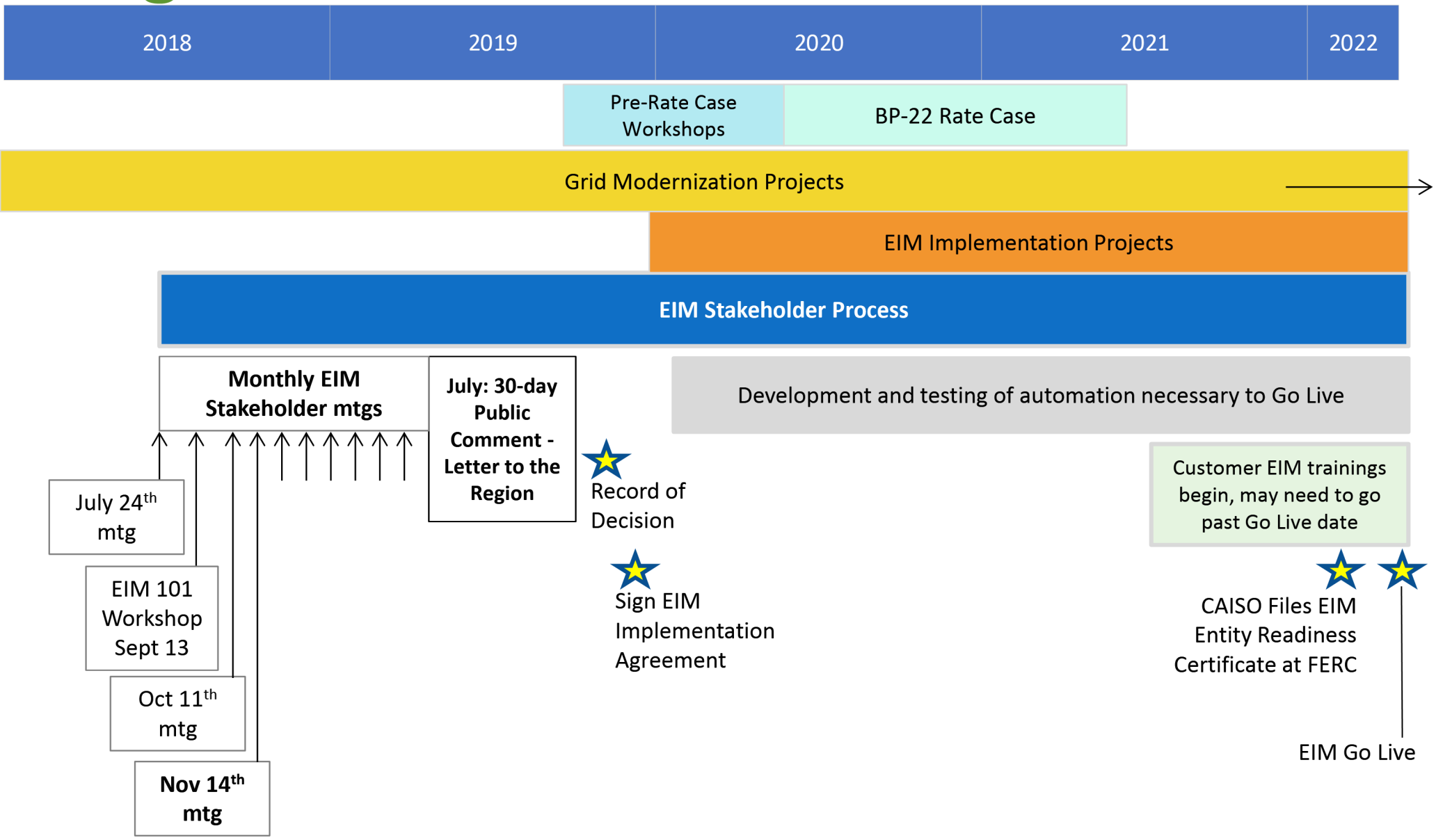


High Level EIM Timeline



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

Technical Workshops

- Elliot asked that we hold technical workshops to explore impacts on individual customers prior to the Letter to the Region/Draft ROD.
- There workshops will NOT commit to specific policies or rates, but rather will explore issues and tools available to mitigate impacts as needed.
  - That process remains intact (see table below)
- These will help inform how the ROD addresses significant issues that may be brought up by customers.

EIM Issue Resolution Matrix

Issue	Venue(s)	Timeframes
Treatment of Transmission	BPA-CAISO Negotiations, BP-22, and TC-22	Now through late 2021
Generation Participation Model (FCRPS, IPP)	BPA-CAISO Negotiations	Now through Go Live (April 1, 2022)
Governance	CAISO Stakeholder Process	2019-20
Relationship of EIM to Other Emerging Markets	TBD—Likely Combination of Venues	Ongoing
BA Resource Sufficiency	CAISO Stakeholder Process and BP-22	Now through late 2021
Market Power/DEB	CAISO Stakeholder Process	Now through Go Live (April 1, 2022)
EIM Settlements	CAISO Stakeholder Process, BP-22, and TC-22	Now through late 2021
Carbon Obligation in EIM	Legislative, BPA-CAISO Negotiations	Now through Go Live (April 1, 2022)

CAISO Face-to-Face - Generation

- **Big Picture – The CAISO is supportive of our approach to aggregation (3 Zones).**
- There is an outstanding question about whether there are any plants within zones that are on "opposite" sides (+/-) of a constraint.
- In general they agree that we can manage issues with generation distribution factors (GDF) and that more granularity wouldn't improve operations.
  - >granularity ≠ >flexibility

CAISO Face-to-Face – Transmission

- **Big Picture – Customer Donation works and there is no interest in developing a regional rate at this time.**
- 3rd-Party (i.e., non-Power Services) customers can also donate transmission on BPA's system under the current tariff.
  - We will need to figure out how to dispose of congestion revenue if their transmission binds
- BPA could also develop a rate to be directly charged to our Tx customers, as long as it's not enforced in the market.

CAISO Face-to-Face – Other Issues

- We touched on other issues, like Slice and other late breaking changes.
- There seems to be a lot that we can do to manage impacts.
  - Many are things available to other EIM Entities but they are not interested in implementing.
- The CAISO will work with us to help identify how various customer activity will play out between BPA and the CAISO.

CAISO Market Power

The CAISO Department of Market Monitoring (DMM) is responsible for protecting cons umers and market participants by identifying and reporting:

- Market design flaws
- Potential market rule violations
- Market power abuses

When there is a binding constraint, how does DMM measure market power?

- Pivotal Supplier Test
  - If supply is insufficient to meet demand with the supply of any individual supplier removed, then t his supplier is pivotal
- Residual Supply Index
  - The residual supply index is the ratio of supply from non-pivotal suppliers to demand
  - A residual supply index less than 1.0 indicates an uncompetitive level of supply
- Oligopoly
  - Consider degree to which 2 or 3 suppliers are jointly pivotal

If determined to have market power, a market participant may have its CAISO bid price s mitigated to a Default Energy Bid (DEB), triggering a re-run of the optimization

Default Energy Bids

The CAISO currently employs 3 options for calculating a participant's, or resource's, DE B

- Variable Cost Option
  - Based on heat rate, fuel price, GHG costs, etc.
- Locational Marginal Price (LMP) Option
  - Based on lowest 25th percentile of LMPs at which resource was dispatched in the last 90 days
- Negotiated Rate Option
  - Formula negotiated between the resource's scheduling coordinator and CAISO/DMM

None of the 3 options adequately reflect the opportunity cost applicable to fuel limited hydro resources

- Opportunity cost is influenced by:
  - Non-power obligations of hydro resources
  - Expected value of energy in future periods
  - Physical system characteristics (storage, flow limitations, hydrological topology, generating capab ility)
  - Risk preference of hydro operator

There are 2 principal consequences when mitigating bids under the existing construct which leads to unintended dispatch

- Uneconomic outcomes
- Overriding project owners' risk preference

Update: Market Power and Default Energy Bids

The CAISO is addressing concerns raised by NW parties

Areas of conceptual agreement currently proposed

- **Mitigate for the right time interval** Mitigation should only apply to the interval when market power has been determined (not balance of the hour)
- **Mitigate the right quantity** Do not mitigate supply that is voluntary in nature (mitigation only applies to supply needed for RS and diversity credit)
- A DEB should **reflect the opportunity cost** nature of hydro. Subject to; expected value of energy in future periods, includes markets outside of the CAISO, and physical system characteristics

Areas of continued discussion

- Distinguishing between the potential versus exercise of market power
- Specific parameters that determine opportunity cost

Areas not being discussed

- Structural changes to the market monitor

Potential Outcomes

Comprehensive

- Consistent with FERC-approved standards
- Structural changes to Market Monitor
  - Does not report to Market Operator
  - Would review market structure
  - Is insulated from influence by participants in different markets
- Stakeholder review and approval of MPM and DEB
- Include an impact test in addition to existing conduct test in market power test
  - Incorporate price thresholds where market power would not apply
  - Incorporate thresholds for economic harm to other participants where market power would not apply

Practical

- Include an impact test in addition to existing conduct test in market power test
  - Incorporate price thresholds where market power would not apply
  - Incorporate thresholds for economic harm to other participants where market power would not apply
- Expand available DEB options to allow for reasonable consideration of hydro opportunity cost
- Within reasonable limits, Hydro offer curves are not subject to mitigation

Minimum

- Escape hatch…
  - Hydro offer curves are automatically isolated to the host BAA when market power is imminent

How Will BPA Advocate?

Front Line

– Work to form a NW coalition; call for comprehensive, structural changes

Pro	Con
• Signals importance • **Would be welcomed by NW parties** • Improves chances that we get *comprehensive* reform	• Sweeping political and governance ramifications • **Significant demand on FTE** • Would likely require acquiring consultants (for expertise of industry market power tests)

Collaborator/Contributor (Current Path)

– Actively working with existing Stakeholder process; Delay EIM entry if not resolved to BPA's satisfaction

Pro	Con
• Appropriate to current staffing levels and expertise • **NW parties are already representing BPA needs/concerns without direct BPA involvement** • Builds consensus among NW & SW through collaboration • Allows for continued internal alignment • Improved chances that we get *practical* reforms	• NW parties could view this as not pro-active enough

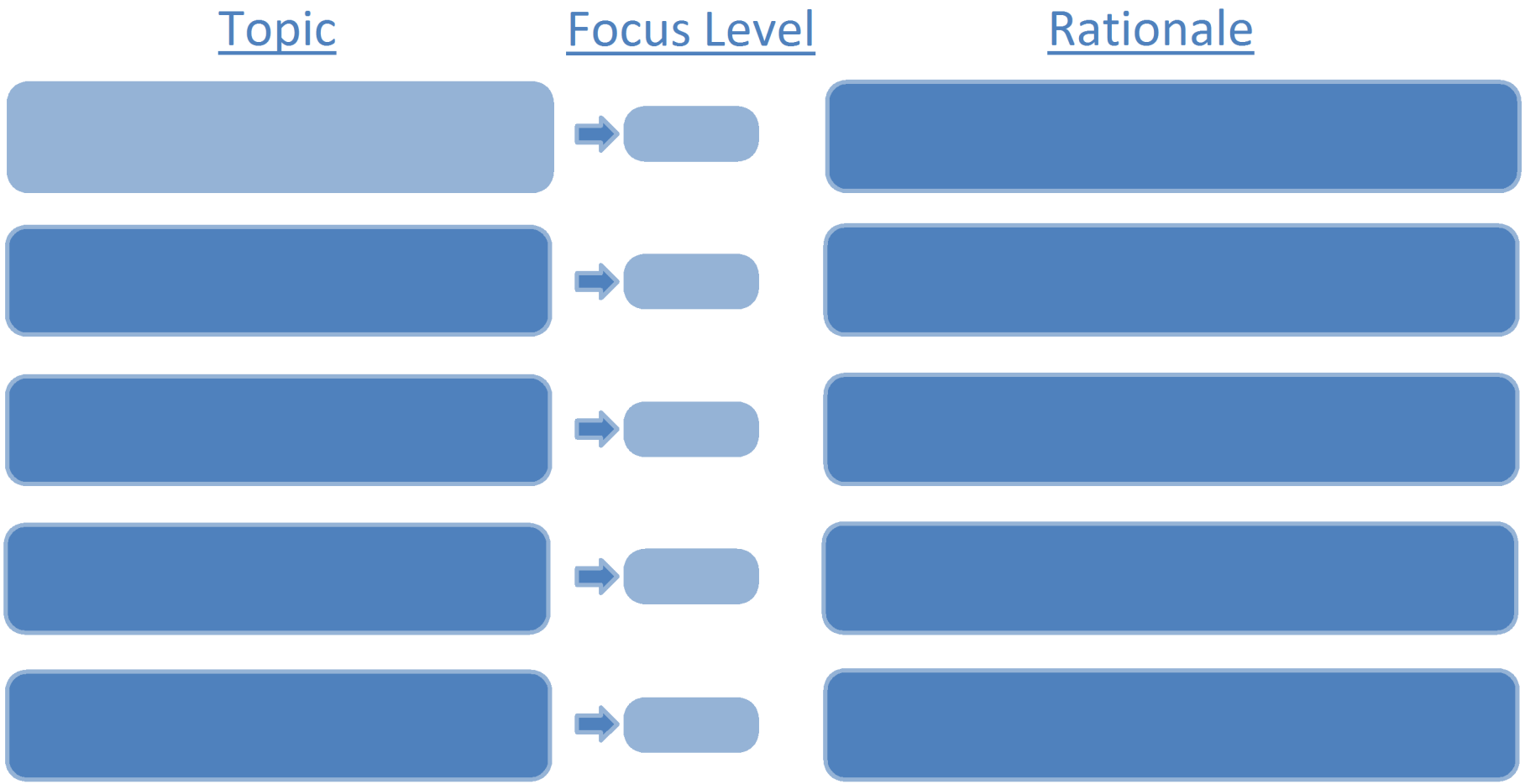
Sideline

– Actively work within Bi-
Lateral negotiations process; Passive with Stakeholder process; Address in implementation agreement

Pro	Con
• Consistent with other NW entities implementation • Allows more time to develop internal alignment	• Still required to address the issue later on, likely from a weaker negotiating position • **NW parties could view this as not pro-active enough**

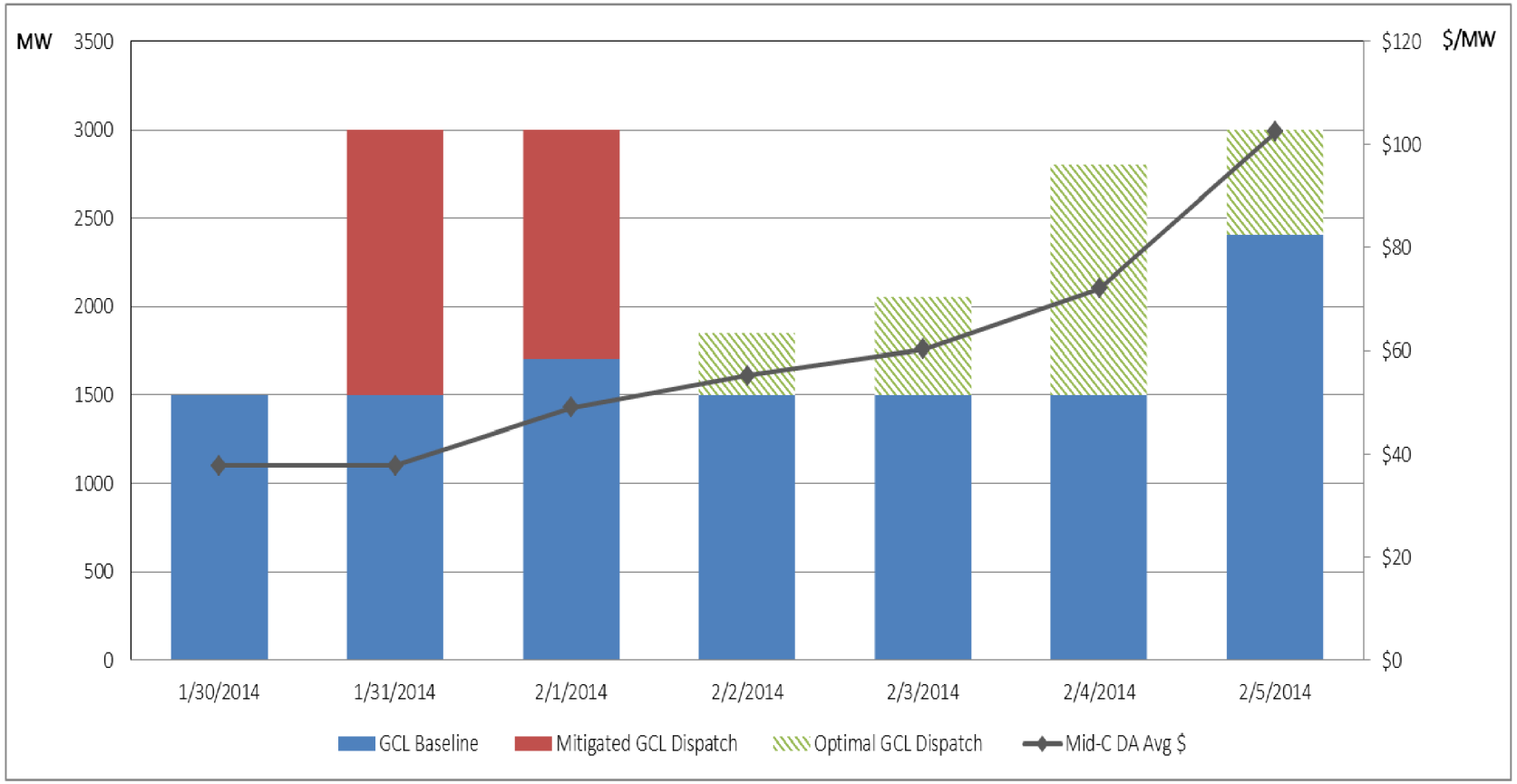
BPA Engagement Plan

Balances: Areas of BPA's expertise, current resources, likelihood of success

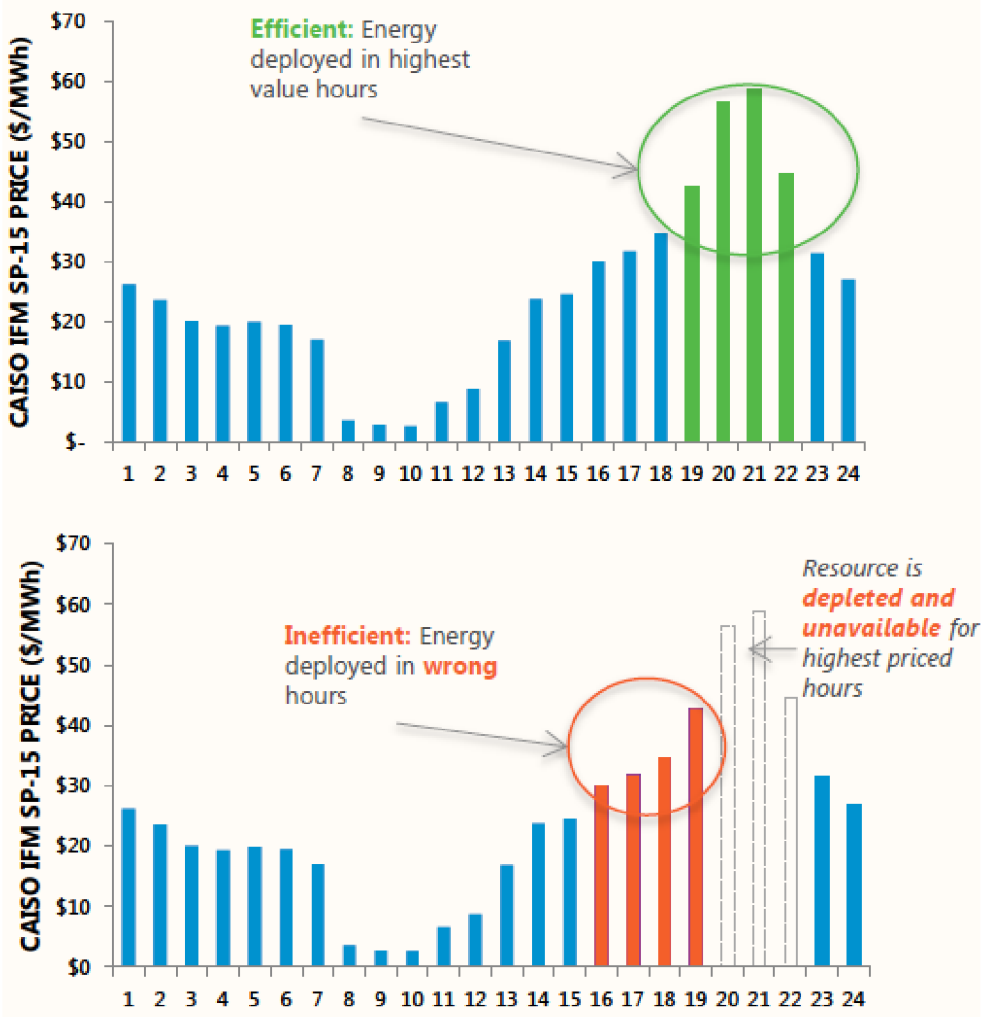


Unintended Dispatch due to Mitigation

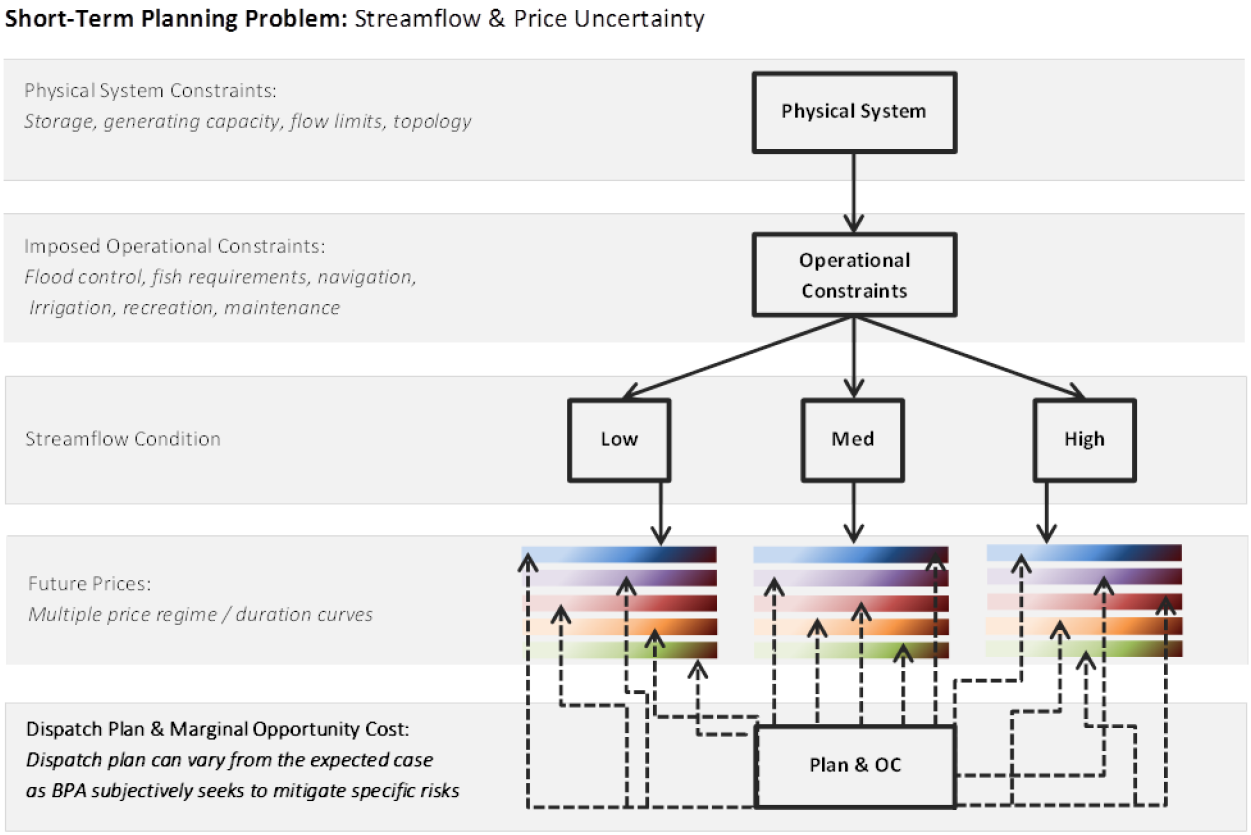
- Mitigation could negatively impact FCRPS dispatch during cold snap conditions.
- An example of potential changes to GCL's dispatch is below.



Poor Mitigation Causes Unintended Dispatch (Powerex Example)



System Dispatch/Bids are Risk Informed



Uncertainty necessitates reliance on a variety of SMEs and proprietary models when d etermining an optimal dispatch plan, with acceptable operational and economic risk

High level FCRPS Constraints

IN DEVELOPMENT

Constraint Type	Fall	Winter	Spring	Summer
Hard constraints			Fish spill	
Risk informed constraints	CHUM elevation strategies	GCL flood control draft rate	Spring runoff timing	

Idea here is distinguish between:

- **hard constraints** like full, empty, max/min discharge rates, rate of change
- **risk informed constraints** that while not binding now, will have implications and binding constraints in future periods

Additional Complications

Interdependencies of streamflow and operational constraints

- Future operational constraints are often influenced by realized streamflow or changes to streamflow forecasts

Feedback relationships between unforeseen/unintended deviations from the optimal plan

- Future operations or future operational constraints may be influenced by unforeseen deviations from the optimal op erating plan

Multiple variables determine actual prices

- Actual prices are often influenced by fundamental market conditions, not determined exogenously

Correlation in marketing position across the region

- The prevalence of hydro-based generation in the region means that market participants often have positively correlated marketing positions, exacerbating the impact of streamflow uncertainty on marginal opportunity cost

NW bilateral trading market

- In contrast to an organized market which incentivizes bidding at opportunity cost, the NW bilateral market does not
- Price formation in bilateral trading is significantly influenced by:
  - The perception of market fundamentals
  - Counterparties' opportunity cost
  - An extended (2-3 hour) trading window
  - Market timeline disalignment
  - A variety of other factors

USACE Questions for BPA for the July 10th 3-Agency EIM Discussion meeting:

1. Pertaining to CAISO's Rules of Conduct, 'The CAISO administers rules regarding reporting generator availability, gaining approval for generator outages, providing accurate and timely settlement data, and providing accurate and timely responses to the CAISO's investigations and audits. The CAISO may impose monetary sanctions for violations of these rules...' **What would constitute a violation at the generating project level and how are unexpected Forced Out of Service events accounted for?** We understand that CAISO would not be able to levy fines on the COE or Reclamation (only on BPA, since the EIM participation agreement is only between BPA and CAISO). But since BPA will be subject to sanctions that could result from a participating or non-participating federal generation resource action (or failure to act), we the COE need to understand what new/different actions or requirements BPA may want us to perform to avoid sanctions, or what the ramifications may be to the federal generating resources if sanctions are imposed, when/if we begin participating in the EIM. At the end of the day, **how would direct and indirect costs related to sanctions (such as actions taken beyond minor shifts in AGC to avoid a sanction by an Operating Project, e.g. resource costs to shift a unit outage) affect the federal generation resource partners and our ability to perform our other missions?**

Bonneville does not anticipate compliance with the Rules of Conduct to impose new or different obligations on federal generating resources than what they would already be performing. As stated in the Letter to the Region, Bonneville "generally agrees that [these Rules of Conduct] represent conduct that Bonneville would want other participants to abide by." The purpose of the Rules of Conduct is "to provide fair notice to Market Participants of the conduct expected of them, to provide an environment in which all parties may participate on a fair and equal basis, to redress instances of gaming and other instances of anticompetitive behavior, and thereby to foster confidence of Market Participants, ratepayers and the general public in the proper functioning of CAISO markets." CAISO Tariff § 37.1.1.

For example, under Section 37.4.1, forced outages do not—on their own—result in sanctions. If prior notice of an outage cannot be given, a Market Participant simply has a duty to notify the CAISO Control Center within one hour after the outage is discovered. The first failure to notify is not a violation, the second results in a warning letter, and additional failures result in sanctions of $1,000 to $5,000 depending on whether the Generating Unit was subject to prior penalties.

Section 37.4.2 requires a Market Participant to receive the CAISO's approval for planned outages; however this provision applies to participants in the larger CAISO market and does not apply to EIM Entities.

FERC administers Section 37.3.1, which requires Market Participants to submit feasible bids "that are reasonably expected to be available and capable of performing at the levels specified in the Bid, and to remain available and capable of so performing based on all information that is known to the Market Participant or should have been known to the Market Participant at the time of submission."

Finally, Section 37.5.2 requires Scheduling Coordinators to provide accurate and timely Settlement Quality Meter Data (SQMD). Failure to do so by T+48B will result in sanctions of $1,000 to $3,000. *See* Section 37.11.1. Likewise, under Section 37.6.1, all information required to be submitted to the CAISO, including responding to written investigation requests and audit materials, must be submitted when due.

Bonneville does not expect to receive sanctions due to its participation in the EIM. Although Bonneville has not yet conducted the policy work to determine how it will allocate the costs associated with participating in the EIM, we cannot imagine a scenario in which any costs would be directly assigned to Bonneville's federal partners.

2. The Initial Benefit Summary states in a footnote, 'Historical spinning capability resulted in BPA failing the flexible ramping sufficiency test (FRST) about 15% of intervals. In these intervals, no EIM benefits are assigned; in practice, should BPA choose to join, the Big 10 Hydro would be scheduled differently to ensure that the FRST was passed the vast majority of the time.' **What would be the changes in scheduling and how does BPA ensure no additional starts/stops arise from these changes?**

The 15% FRST failure rate that E3 calculated may need a little more context:

- The E3 study only used available spinning capacity during the study period, adjusted to account for 1% turbine efficiency and capped at -900 MW (DEC)
- The spinning capacity provided to E3 represented ONLY the capacity that was on AGC response and did not represent the entire amount of FCRPS spinning capacity that may have been available across the big-10
- The spinning capacity was NOT adjust for any actual deployment of Balancing Reserves (RS) or regulation
- While E3 removed 100% of the benefits for intervals where we failed FRST, in the real world the previous intervals dispatches are persisted and you are only limited in the EIM in the direction of the failure
- The E3 model did not include any non-FCRPS participating resources which would have added to the amount of flexible capacity available to the market

Without even trying to optimize the system to pass FRST and given the constraints provided to E3 for the study, the model predicted we would pass FRST 85% of the time. If we were actively participating in the EIM, we would likely adjust base schedules across the entire FCRPS fleet and bid ranges to increase the percentage of intervals that we pass all of the RS requirements, including FRST. For example, if we need more INC to pass FRST, we could move the base schedules down on a participating resource to create the needed INC capability and adjust the Base Schedule up on a different Participating Resource or Non-Participating Resource. Further, any non-federal resources that may be participating in the EIM would help us meet FRST. We would not expect these subtle changes in base schedules or bid-range adjustments to ensure passing FRST to materially impact the number of start/stops compared to today. BPA would develop specific base scheduling and bidding strategies that would fit within the FCRPS operational constraints and obligations. BPA would work with USACE and USBR to identify and verify those constraints and obligations.

Reclamation List of Questions/Clarifications for EIM Sent 4/29/2019

1. **What is the collaboration plan and coordination structure planned for federal partners to stay organized as BPA enters the EIM?**

Coordination and communication during the EIM implementation phase will be critical if BPA signs the EIM Implementation Agreement with the CAISO this summer. BPA will lead this effort, and the Three Agency Coordination Plan will continue to be used to facilitate this work. BPA will continue to have weekly Monday check-ins with USBR and USACE, and continue with the 3-Agency EIM meetings.

One are of additional EIM-related work is improving the coordination between BPA and the hydro projects on how generator units should be loaded for 1-3 future hours. This information will inform the operations for each of the Big-10 projects that would participate in the market. This work would need to be completed before the end of end of Q-3, before start of Milestone 4. In addition, collaboration between BPA and the Corps will be necessary to supply information required in the Master file.

2. **Where is the funding source to support the EIM effort? Also keep in mind that if/when BPA decides to join the EIM, there will be additional projects to support.**

The funding source for the EIM effort is a mix of expense included in the Grid Modernization Initiative budget and existing planned capital budget (BPA expense capital budget) that will be reprioritized.

3. **Has there been any research/study conducted to determine staffing impacts to Grand Coulee once BPA enters the EIM? For example, it is expected there will be changes to outage coordination, network equipment and increase in forced outages. Have these changes been considered?**

BPA has not conducted a study to determine staffing impacts to Grand Coulee or any other federal project if BPA enters into the EIM. However, BPA does not anticipate that any additional staffing will be required from USBR or USACE in order for BPA to participate in the EIM.

4. **What is the impact of the 5-minute market to unit availability determination and dispatching changes? Increased generator wear and tear? Any other impacts to note?**

In the updated cost benefit analysis we modeled three years, 2016-2018, of hydro operations and constrained the model to only bidding in the existing spinning capacity to limit start / stops. Our business case for joining the EIM is expected to be net positive with this restriction in place. Should BPA join the EIM, BPA will be responsible for the development of bidding strategies. BPA will rely on USACE and USBR to evaluate whether or not these strategies are resulting in additional wear-and-tear and will adjust our bidding strategy accordingly.

5. **What is BPA's plan for the costs/penalties associated with the EIM market? Are these costs going to be transferred to the irrigation districts?**

If BPA signs the EIM Implementation Agreement this summer then allocation of credits and debits (*e.g.,* uplift and imbalance charges) associated with BPA's EIM participation need to go through BPA's rate case, BP-22. Any determination of debits and credits transferred to irrigation districts would be decided during this phase of the process. Accurate load and scheduling plans would reduce credit and debits impacts. This will be a public process that includes stakeholder engagement with the USBR and the irrigation districts.

The EIM does not have any penalties associated with it, but rather debits and credits as discussed above.

6. **What assumptions were made (if any) for Grand Coulee's operations for the cost/benefit analysis?**

BPA's cost benefit analysis, being released in May, modeled that only the current spin capacity would be bid into the EIM and well sa daily energy neutrality (so that EIM dispatch impacts on hydraulic management of the FCRPS is minimized). BPA would not be bidding in capacity required for regulation. BPA will be presenting its updated cost benefit analysis at the May 15 EIM Stakeholder Meeting.

EIM Decision Making Process Proposal

1. Letter to Region — July 2019
    a. Solicit stakeholder comment on the following
        i. Draft implementation agreement
        ii. High-level business case
        iii. Legal Underpinnings: statutory, regulatory, and contractual
        iv. Roadmap/matrix of process and issues
        v. Propose decisions for certain policy issues
    b. 30-Day Comment Period

2. Record of Decision — September 2019
    a. Respond to stakeholder comments
    b. Decision to (or not) sign Implementation Agreement
    c. FINAL decisions made on policy issues discussed on letter to region
    d. Final roadmap/matrix of process and issues

3. Interim Policy Decisions — March 2020-August 2020
    a. For policy decisions impacting BP-22 and TC-22 cases, identify issues needing a final decision prior to the initiation of those cases
    b. March 2020-- Issue public notice that Bonneville intends to address issues and make decisions before BP-22 and TC-22 cases
    c. Prepare written materials and presentations regarding issues
    d. Solicit stakeholder comment
    e. Respond to stakeholder comment and make final decision
    f. Not necessary to do as part of a ROD per se but do need formal documentation of responding to comments and making decision
    g. These decisions are final

4. BP-22 and TC-22 Cases — October 2020-July 2021
    a. These cases follow their own processes and ultimately culminate on final decisions

5. Draft Close-Out Letter — October 2021
    a. Revisit four principles for EIM participation
    b. Address any remaining policy issues and request comment
    c. Propose final decision to join EIM
    d. Propose to incorporate final decisions made in No. 2 and 3 above for purposes of legal challenge
6. Final Close-Out Letter — December 2021
    a. Final decision to join

To: Janet Herrin and Steve Kerns
Date: April 3, 2019
Re: Bonneville's Authority to Market Power in the EIM from Federal Projects

(b)(5)

Water Management and Generation Scheduling in the Western EIM

Scott Winner BPA
Power Generation Scheduling

December 12, 2019

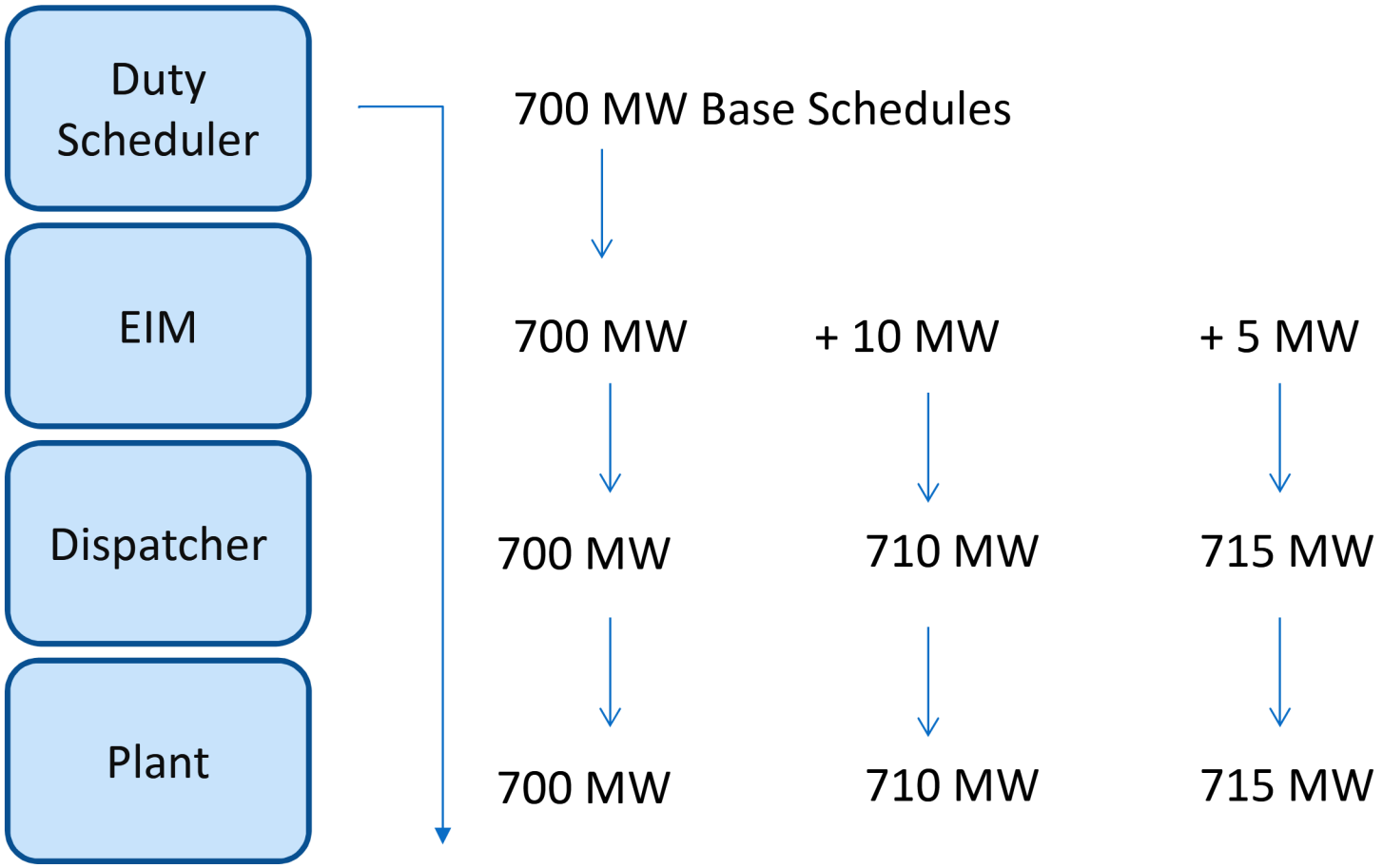
Base Schedules (basepoints)

- Today (basepoints)
  - Big 10 sets basepoints to
    - ensure all non power objectives are met and
    - meet hydraulic objectives
  - BPA uses the day ahead and real-time market to balance Load
    - Selling surplus and purchase shortfalls relative to hydraulic objectives
- In the EIM (base schedules)
  - Same as today, sent earlier in the hour

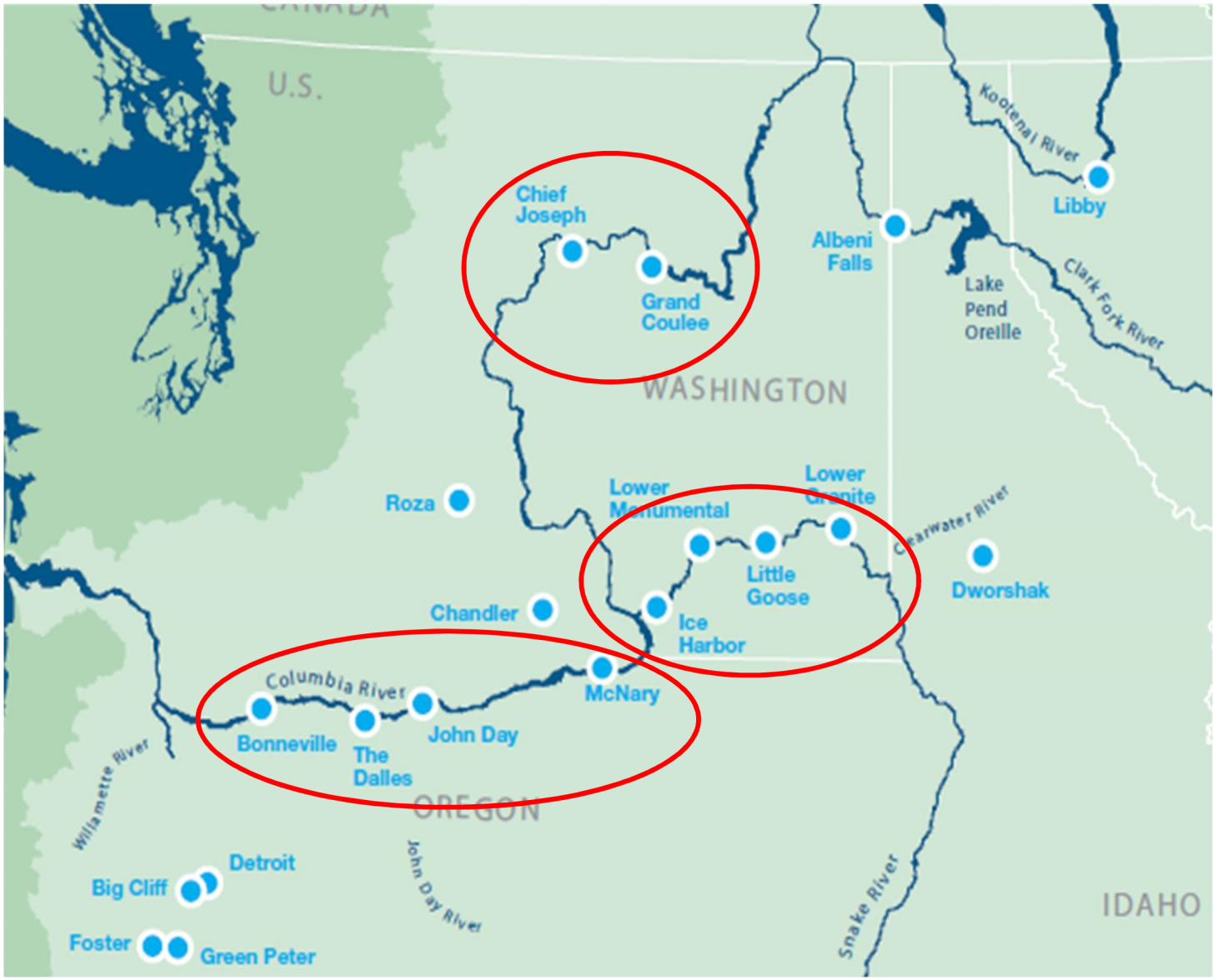
System Balancing

- Today
  - BPA holds 681 INC and -861 DEC capacity
    - The system moves on an AGC cycle every 4 sec
  - Assume the INC and DEC balance to be water neutral
  - Covers imbalance in BPA's BAA
- In the EIM
  - BPA will hold INC and DEC capacity to meet Resource Sufficiency requirements at a minimum
  - Capacities will have price curves
  - BPA may be awarded to deploy or other generator may be awarded to deploy for the netted EIM imbalance

Communication tree



Aggregation Nodes



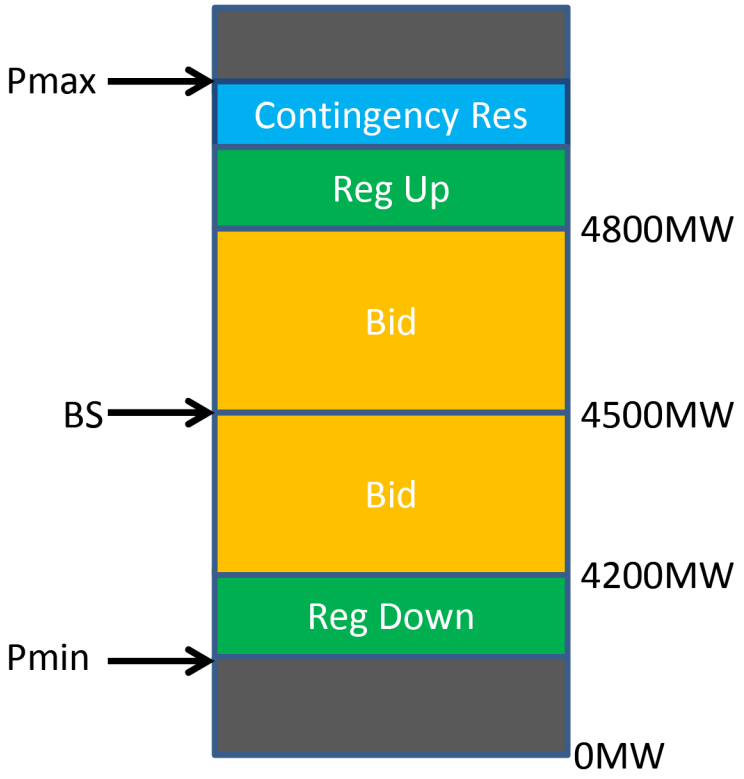
Traditional Setup:

APR
GCL + CHJ

GDF*:
GCL 0.67
CHJ 0.33

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

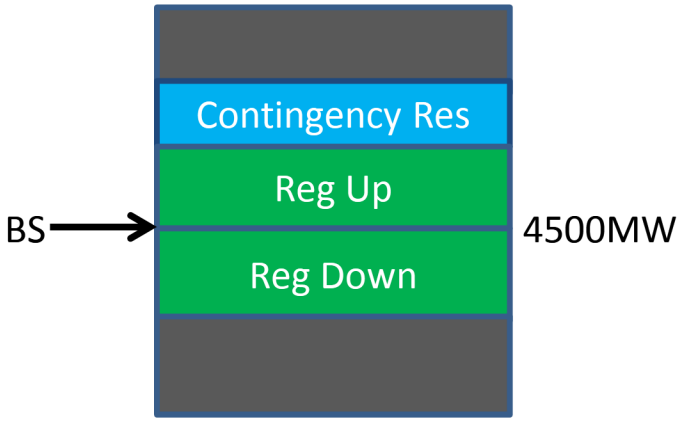
	BP (MW)	GDF
GCL	3000	3000/4500 = 0.67
CHJ	1500	1500/4500 = 0.33
SUM	4500	1



Powerex's Setup:

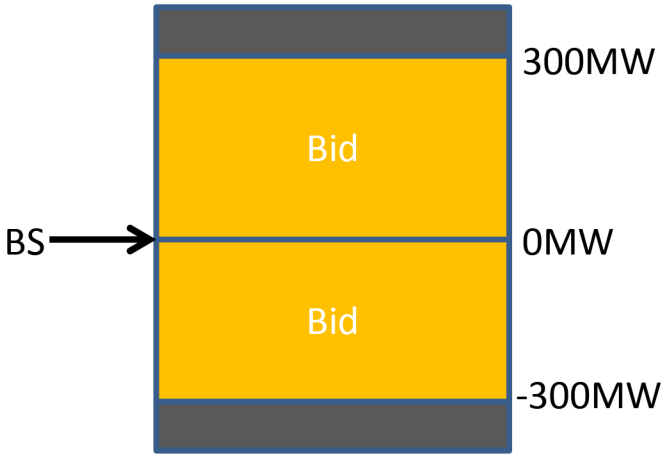
ANPR
GCL + CHJ

GDF**:
GCL 0.67
CHJ 0.33



APR (NGR)
GCL + CHJ

GDF***:
GCL 0.3
CHJ 0.7



**Controls the distribution of MW for BS (input to CAISO's EIM network model)

***Controls the distribution of MW for bid range

Outages and visibility

- The timings for planned outages may change as we work through some issues with the Western EIM
- Actual and scheduled *ins* and *outs* of service need to be tightly aligned. Schedules updated as soon as changes are known.
- Western EIM Outage Cards
  - Physical Unit outages
  - Limiting plant capacity to align with hydrology (BPA)
    - OMS/EIM Bid and Base Schedules/EIM Real-time ops
- Visibility
  - Projects will have visibility to forecasted Base Schedules
  - BPA will have visibility to forecasted unit commitment
    - FDGDM/AGC Mod

April 20 Call
Monday, March 30, 2020
9:59AM

BPA Attendees Allie Mace, Sarah Burczak, Dennis Petross, Glen Smith, Kim Johnson, Clarisse Messemer, Dave Brown, Kari Hay, Kelly Gardner, Roger Bentz, Steve Kern
Corps Shawn Worthington, Scott Thoren, Jason Williams
Reclamation Florence Webster, Mark Pfeifer, Cliff Foster
Agenda
Announcements
General Questions
EIM Update
Meeting Notes:
Announcements
General Questions
EIM Update

March 23 Call
Friday, February 28, 2020
2:05PM

BPA Attendees Steve Kerns, Dennis Petross, Kim Johnson, Clarisse Messemer, Dave Brown, Kari Hay, Kelly Gardner, Roger Bentz
Corps Shawn Worthington, Scott Thoren
Reclamation Florence Webster, Mark Pfeifer, Cliff Foster
Agenda
Announcements
General Questions
EIM Update
Meeting Notes:
Announcements
General Questions
EIM Update
AGC - going to want to do a webinar to go over new features with reserve control

EIM Stakeholder Meeting

February 20, 2019
9am -12pm
Rates Hearing Room

For our WebEx and phone participants:

- We have muted all calls on entry, if you have a question, you will need to unmute by using *6. Then please identify yourself by name and let us know who you represent.
- Please do not put this call on hold OR take other calls while you are dialed into this one.
- If we identify a noisy line, you may be disconnected from the meeting.

Agenda

9:00-9:05	• Welcome, Safety Moment, Introductions
9:05 – 9:10	• Topics for Today's Meeting • Review of BPAs EIM Principles • Review Timeline
9:10 – 10:00	• Local Market Power Mitigation
10:00 – 10:15	• Break
10:15 – 11:30	• Base Case Structured Scenario Discussion
11:30 – Noon	• Next Steps • Question and Answer Session

Topics For Today's Meeting

- Review of EIM Stakeholder Topics Discussed to Date
- Timeline Review
- Issues that BPA presented at the July 24th EIM Stakeholder meeting that we will be discussing in more depth at a future meeting.

1. Relationship of EIM to Other Emerging Markets
2. BA Resource Sufficiency
3. EIM Settlements
4. Market Power
5. Treatment of Transmission
6. Generation Participation Model (FCRPS)
7. Governance
8. **Carbon Obligation in EIM**

Issues discussed at previous EIM Stakeholder meetings.

This issue will be discussed at a future meeting.

- Question and Answer Session

Statement of BPA's Principles:

1. Participation is consistent with statutory, regulatory, and contractual obligations.

2. Maintain reliable delivery of power and transmission to our customers.

3. Resource participation in the EIM is and always will be voluntary.

4. BPA's decision to participate in the EIM will be based on a sound business rationale.

Timeline Leading up to the ROD

Agendas for previous and future monthly EIM Stakeholder meetings:

July 24	•Grid Modernization Overview, Strategic Plan Connection, Intro to 8 Issues BPA is Reviewing, Initial Cost Benefit Analysis
September 13	•EIM 101
October 11	•Process Plan, Transmission, Generation, Governance
November 14	•Process Plan, Market Power
December 18	•Settlements, Non-Federal Generation Participation
January 16	•Resource Sufficiency, Emerging Markets
February 20	•Base Case Structured Scenario, Market Mitigation
March 13	•Settlements, Structured Scenario
April 10	**Structured Scenarios:** Discussion of Impacts to Customers
May 15	
June	
July	•Letter to the Region with a 30 day public comment
August	•BPA drafts Record of Decision (ROD)
September	•Final ROD for signing the EIM Implementation Agreement

These meetings will be full day.

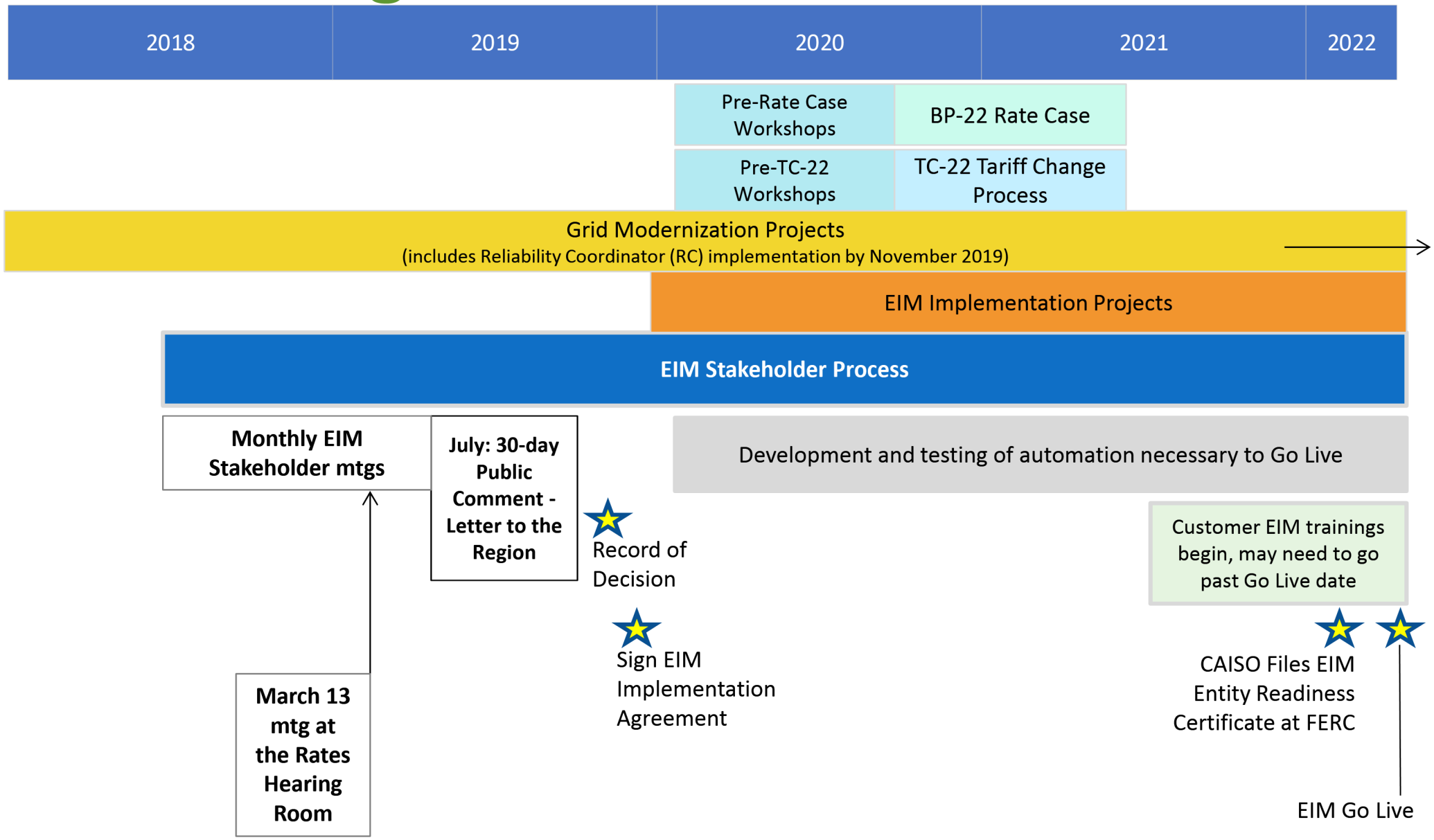
Issues to be Discussed at upcoming monthly EIM Stakeholder meetings:

1. Cost Benefit Analysis
2. Carbon in the EIM

Signing of the EIM Implementation Agreement authorizes BPA to begin spending on EIM implementation projects with the CAISO but does not bind BPA to join the EIM.

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

BPA's High Level EIM Timeline



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

EIM Issues and Venues

- BPA has been tracking EIM issues that will be resolved in future BPA processes or workshops where BPA anticipates EIM issues will be addressed.

Letter to Region/ Implementation Agreement ROD	TC-22 Tariff Terms & Conditions Case	BP-22 Rate Case	Business Practices	Other
Joining the EIM is consistent with BPA's statutory authority	Explanation of EIM charges codes	Cost Allocation – which rates recover which EIM costs		
Business Case / Cost Benefit Analysis	Dispute Resolution process for EIM charges			

Local Market Power Mitigation

CAISO Market Power

The CAISO Department of Market Monitoring (DMM) is responsible for protecting consumers and market participants by identifying and reporting:

- Market design flaws
- Potential market rule violations
- Market power abuses

When there is a binding constraint, how is Market Power measured?

- Pivotal Supplier Test
  - If supply is insufficient to meet demand with the supply of any individual supplier removed, then this supplier is pivotal
- Residual Supply Index
  - The residual supply index is the ratio of supply from non-pivotal suppliers to demand
  - A residual supply index less than 1.0 indicates an uncompetitive level of supply

If determined to have market power, a market participant may have its CAISO bid prices mitigated to a Default Energy Bid (DEB), which will be used for CAISO's optimization

Default Energy Bids

The CAISO currently employs 3 options for calculating a participant's, or resource's, DEB

1. Variable Cost Option
   - Based on heat rate, fuel price, GHG costs, etc.
2. Locational Marginal Price (LMP) Option
   - Based on lowest 25th percentile of LMPs at which resource was dispatched in the last 90 days
3. Negotiated Rate Option
   - Formula negotiated between the resource's scheduling coordinator and CAISO/DMM

There is concern that none of the cost options adequately reflect the opportunity cost applicable to fuel-limited hydro resources

- Opportunity cost is influenced by:
  - Non-power obligations of hydro resources
  - Expected value of energy in future periods
  - Physical system characteristics (storage, flow limitations, hydrological topology, generating capability)
  - Risk preference of hydro operator

Recent Developments: Market Power & DEBs

The CAISO has been receptive to concerns expressed by NW parties, and is proceeding with an initiative that proposes enhancements to current LMPM and DEB implementation. Potential market changes would apply to the entire ISO market, in addition to the EIM.

Major issues have been largely satisfied, such as:

- **Mitigate for the right time interval**: Mitigation should only apply to the interval when market power has been determined (not balance of the hour)
- **Mitigate the right quantity**: Do not mitigate supply that is voluntary in nature (mitigation only applies to supply needed for RS, Flexi Ramp Up, and diversity credit)
- A proposed **DEB option that reflects the opportunity cost of hydro**; including the recognition of the combined value of energy and firm TX rights when coupled together (see coming slides)
- The specific parameters (such as the multiplier levels) can be updated upon request

CAISO Proposed Hydro DEB Calculation

The newly proposed DEB accounts for:

- Maximum storage horizon
- Ability to sell energy at different locations inside and outside of the BA
- Opportunity cost of generation by substituting local gas resources
- Potential short-term limitations

$$DEB = MAX\ (\textbf{\textit{Gas Floor}}, \textbf{\textit{ST Floor}}, \textbf{\textit{LT Geo Floor}})$$

Where:

Gas Floor = (*Peaker Heat Rate * Gas Price Index*) * 1.1 — *Daily peaks / Replacement Cost*

ST Floor = $MAX(DA\ Index, BOM\ Index, M\ Index_{+1})*Mult$ — *Short-Term / Local OC*

LT Geo Floor = $MAX(DA\ Index, BOM\ Index, M\ Index_{+1}, \ldots, M\ Index_{+12}) * 1.1$ — *Long-Term / Different Trading Hubs OC*

Gas floor may be updated in real-time if needed

This content is taken from the LMPM Enhancements Draft Final Proposal (Updated) , page 35

http://www.caiso.com/Documents/DraftFinalProposal-LocalMarketPowerMitigationEnhancements-UpdatedJan31_2019.pdf

CAISO Proposed Hydro DEB: Stress Events

Recall that the most concerning impact of an overly restrictive default energy bid – a DEB that does not accommodate potential differences in reasonable views of a hydro resource's opportunity cost – was unintended dispatch.

- Depletion of resource's fuel prior to a stress event
- Uneconomic / unreliable market outcomes

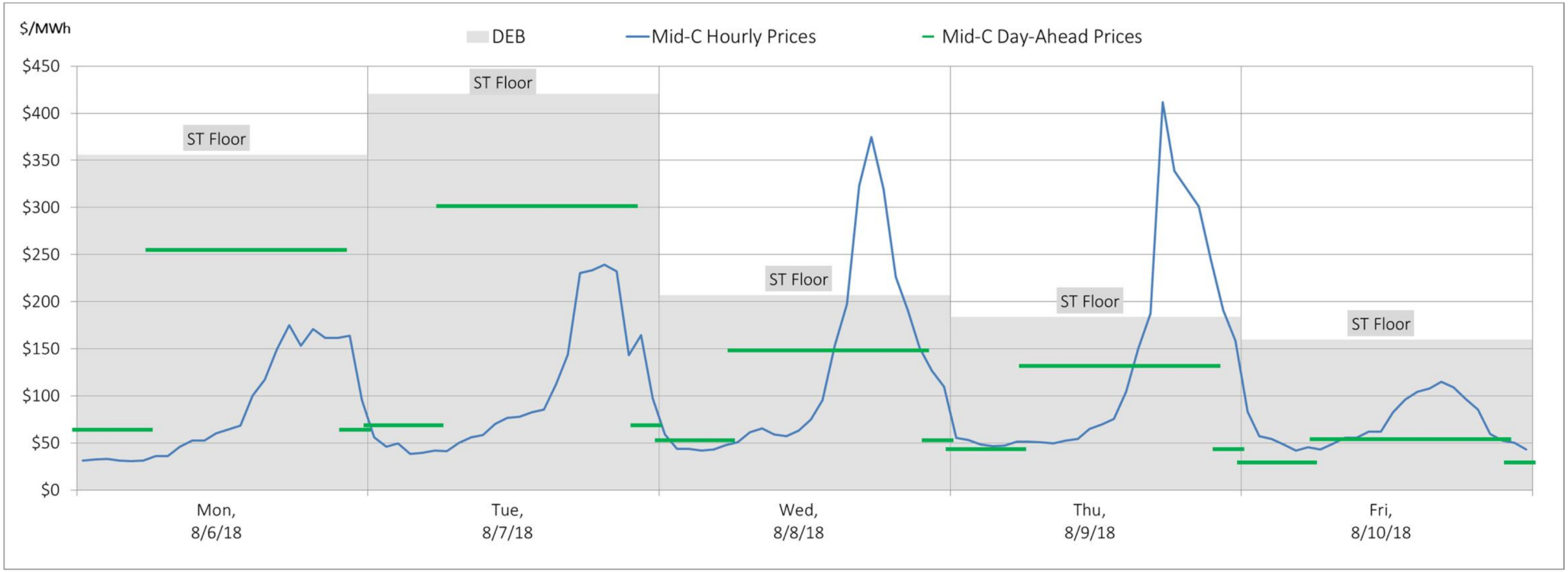
Under typical or normal conditions there appears to be little or no unintended dispatch and/or uneconomic outcomes

To estimate the potential for unintended dispatch and/or uneconomic outcomes, BPA retrospectively tested the proposed default energy bid formulation against historical market conditions, with a specific focus on several market-stress events

- Anticipated Stress Event: market and operational response is anticipated prior to event
- Unplanned Stress Event: market and operational response coming in near real-time

Note: we did not incorporate trading hubs beyond Mid-C into the LT Geographic Floor

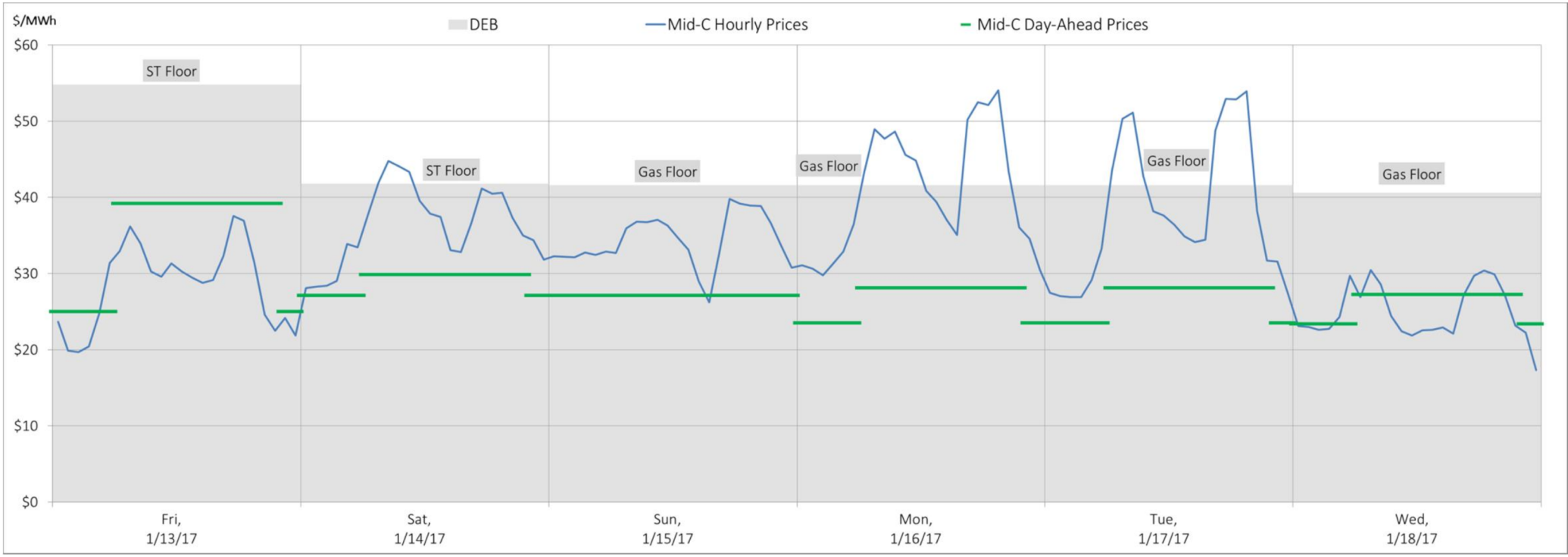
DEB Response - Anticipated Event



- **Event Description:** West-wide heat Portland, Seattle and Spokane experiencing temps in the low 90s with significantly elevated southern California gas prices drive elevated power prices across the west.

- **Observations:** DEB responds as expected to market signals; NW hourly prices remain high during the evening peak hours. Premature dispatch is avoided, preserving limited energy for periods of high market stress. Hydro resources participating in the EIM during the stress periods would have been awarded a price lower than NW hourly indexed price if they were found to have market power.

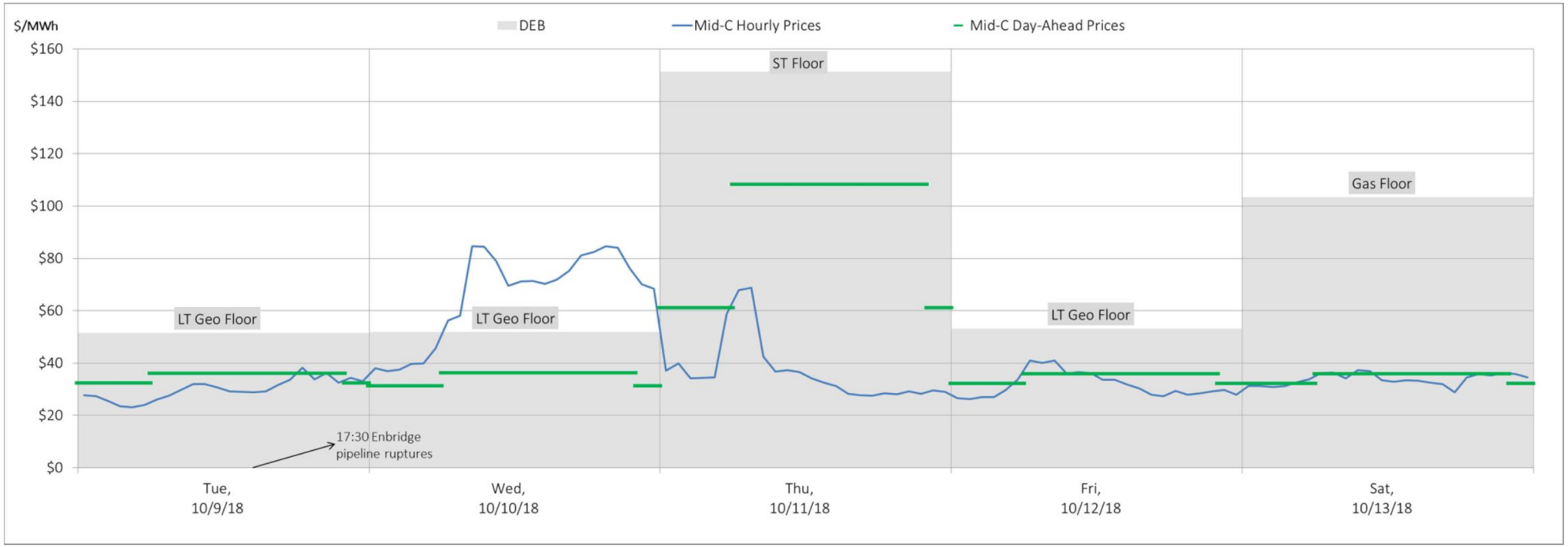
DEB Response - Anticipated Event



- **Event Description:** NW cold snap with temperatures regularly more than 15 degrees below average and spanning a holiday weekend. Holiday trading exacerbated the normal lag between trading day and delivery day (DA price on 1/17 determined on 1/13).

- **Observations:** Highlights the downside of the Gas/NW trading schedule as the DEB is indexed to stale NW day-ahead prices. NW hourly prices remain high during the morning and evening peak hours. Premature dispatch is largely avoided, preserving limited energy for periods of high market stress. Hydro resources participating in the EIM during the stress periods would have been awarded a price lower than a NW hourly indexed price if they were found to have market power.

DEB Response - Unanticipated Event



- **Event Description:** The Westcoast Pipeline explosion occurred late on October 9, 2018, and significantly impacted the main route for supplying natural gas to western Washington and Oregon. The reduced supply immediately caused industrial demand and gas-fired power generation to drop and resulted in elevated prices for natural gas and power within the region.
- **Observations:** Given the timing of the event, the DEB response is delayed. Hydro resources participating in the EIM during the event would have been awarded a price lower than NW hourly indexed price if they were found to have market power.

Summary

- The current CAISO proposal balances competing objectives
  - opportunity cost nature of hydro
  - efficient and economic market outcomes
  - current and future resource participation levels

- During the stress periods, the dispatch of hydro generation remained as planned through out the duration of the event

- While infrequent, there are conditions when hydro resources participating in the EIM would have been awarded a price lower than NW hourly indexed price if they were found to have market power.

- Current proposal addresses concerns. In addition, BPA may avail itself of any DEB option, including a negotiated option.

Structured Scenario: Base Case

Structured Scenarios: Overview

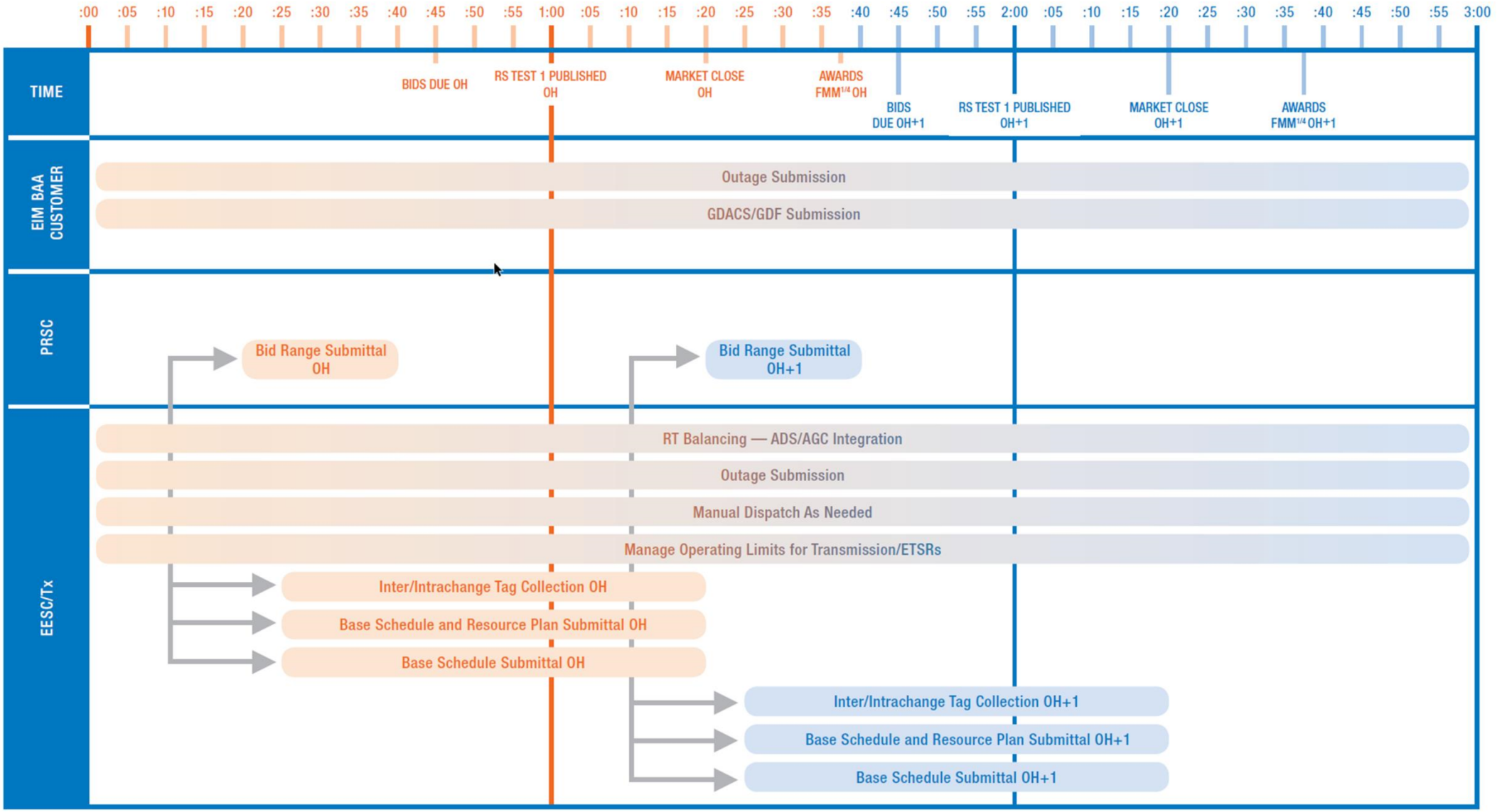
- BPA will use structured scenarios, or “table tops”, to walk through EIM mechanics for customers and stakeholders.
- These structured scenarios are intended to provide education and to identify how certain activities would impact EIM operations and settlements.
- These outcomes should help customers and stakeholders begin to understand how BPA’s EIM participation would:
  - Potentially impact their business and operations, and
  - Help them prepare for how EIM issues would be addressed in upcoming Rates and Terms & Conditions Cases.

Structured Scenarios

	Transmission Congestion In Market	Participating Resources	Scheduling	Real-Time Reliability Actions (Out of Market)
Scenario 1: Base Simple	• None – ETSRs and internal constraints are non-binding	• FCRPS aggregated into three zones	• All base schedules (inter and intrachange) completed by T-40 and flat for the hour	• None
• **Scenario 1a: Base with Export Reduction**	• "	• "	• All base schedules (inter and intrachange) completed by T-40 with reduction in exports within the hour at XX:10 by 75 MW	• "

Structured Scenario: Base Case

The base case scenario describes what actions BPA would take to engage in the EIM market during specified operating hours (OH).



Key Roles in EIM for Structured Scenarios

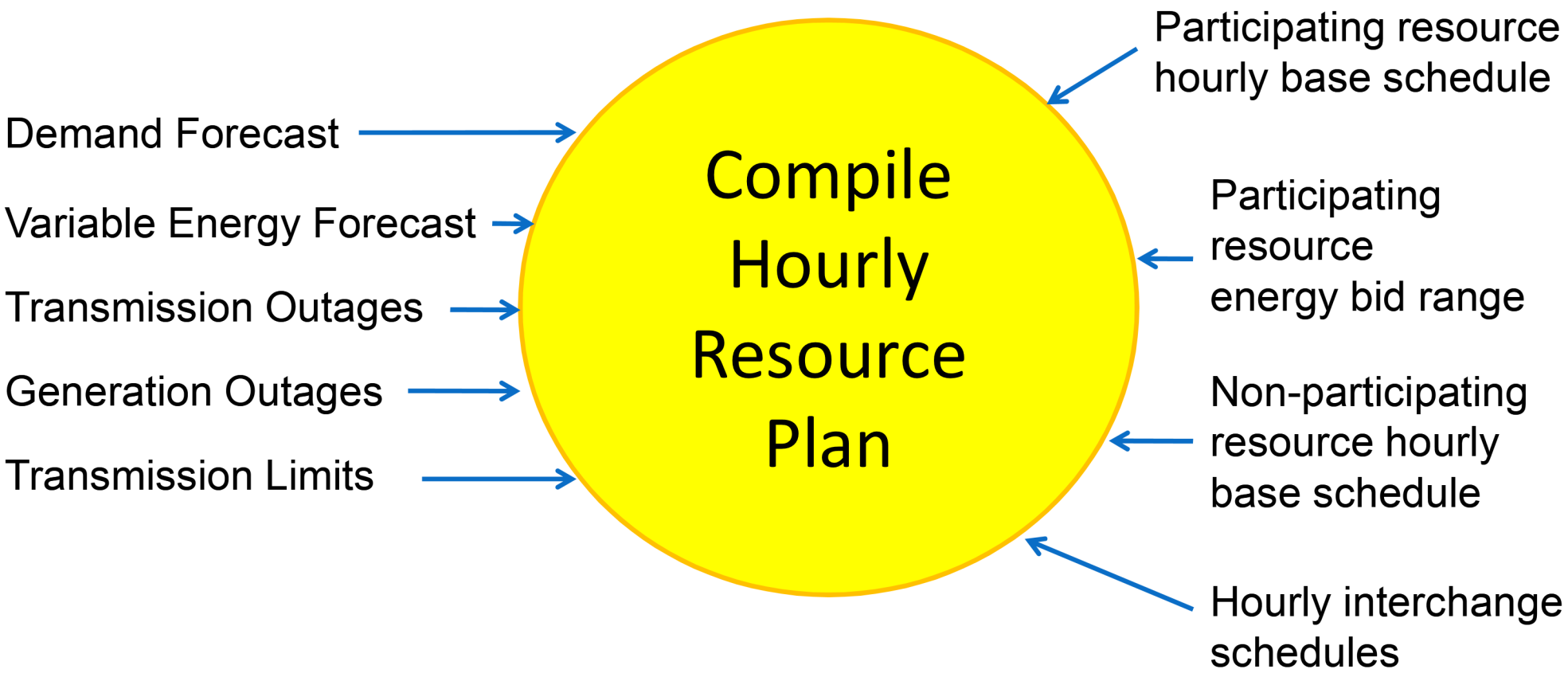
- EIM Entity Scheduling Coordinator (EESC)
  - Directly interfaces with both BPA Balancing Authority (BA/BAA) customers and with the CAISO.
  - Manages systems and processes related to real-time balancing, scheduling/tagging, and submission of Resource Sufficiency (RS) and interchange data to CAISO.
  - Settles financially with the CAISO for the BAA invoices and with customers for BPA's own Ancillary and Control Area Services (ACS) invoices.

- Participating Resource Scheduling Coordinator (PRSC)
  - May be fulfilled in BPA or customers (non-BPA) may also serve in this role.
  - Submits bids for Participating Resources.
  - Settles directly with the CAISO for Participating Resource Invoices

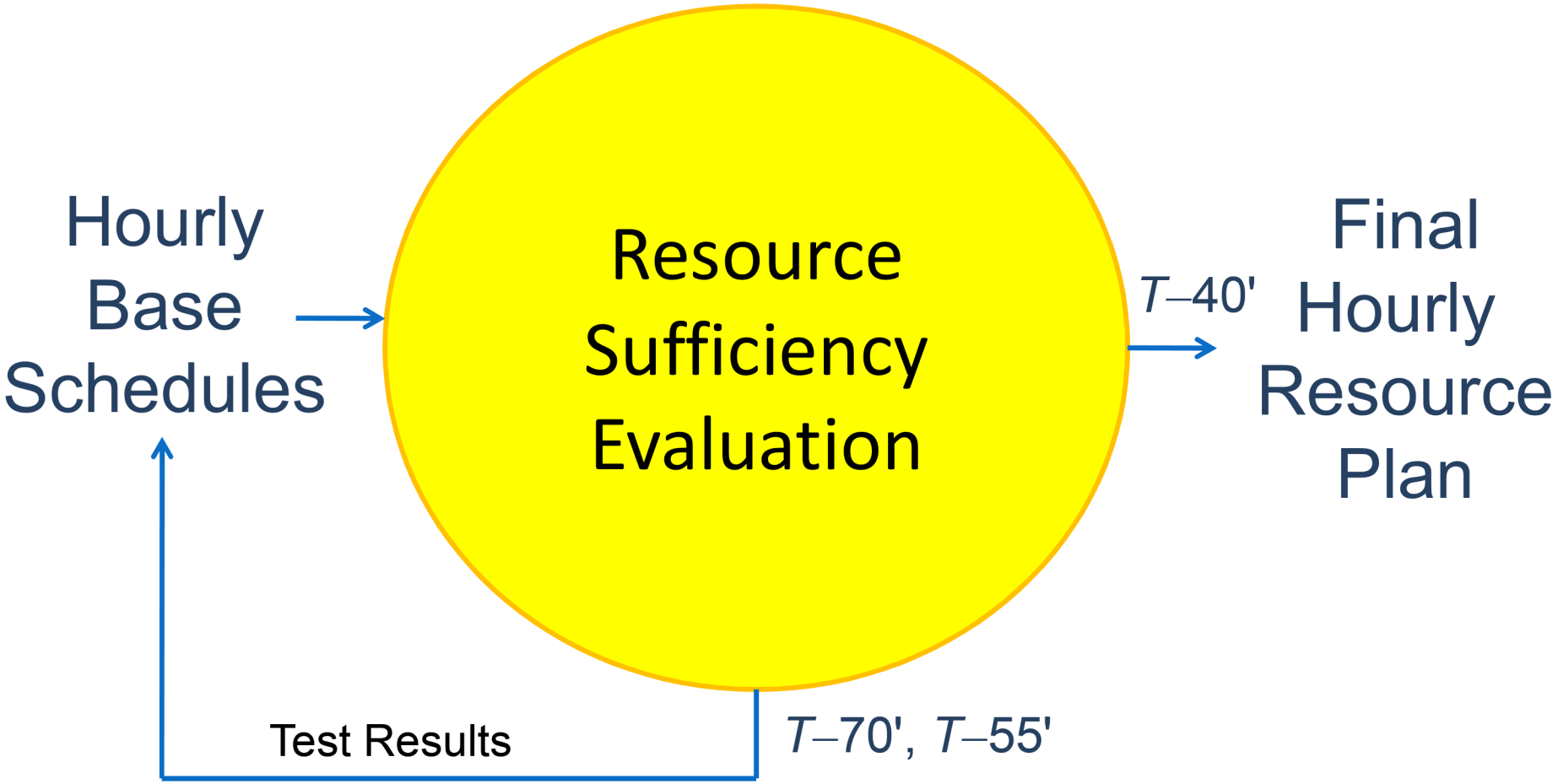
Key Roles in EIM for Structured Scenarios

- BPA BA Customers
  - Individual, non-BPA customers, may perform multiple functions when we join the EIM.
  - Non-load following customers will need to submit base schedules for load and resources to the EESC. This information is used for the EESC submission of the EIM Entity Base Schedule and Resource Plan.
  - Interacts directly with the EESC, not the CAISO if they don't own a Participating Resource.

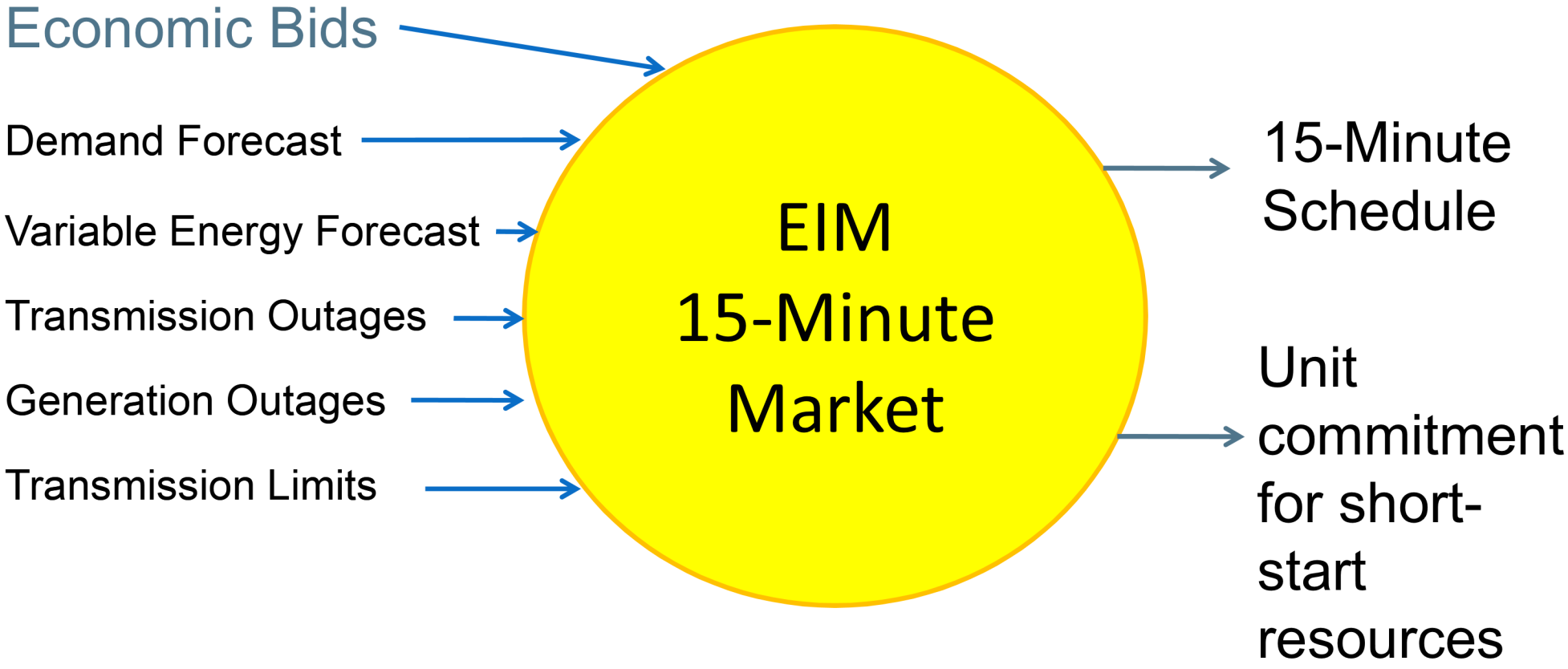
Market Activities



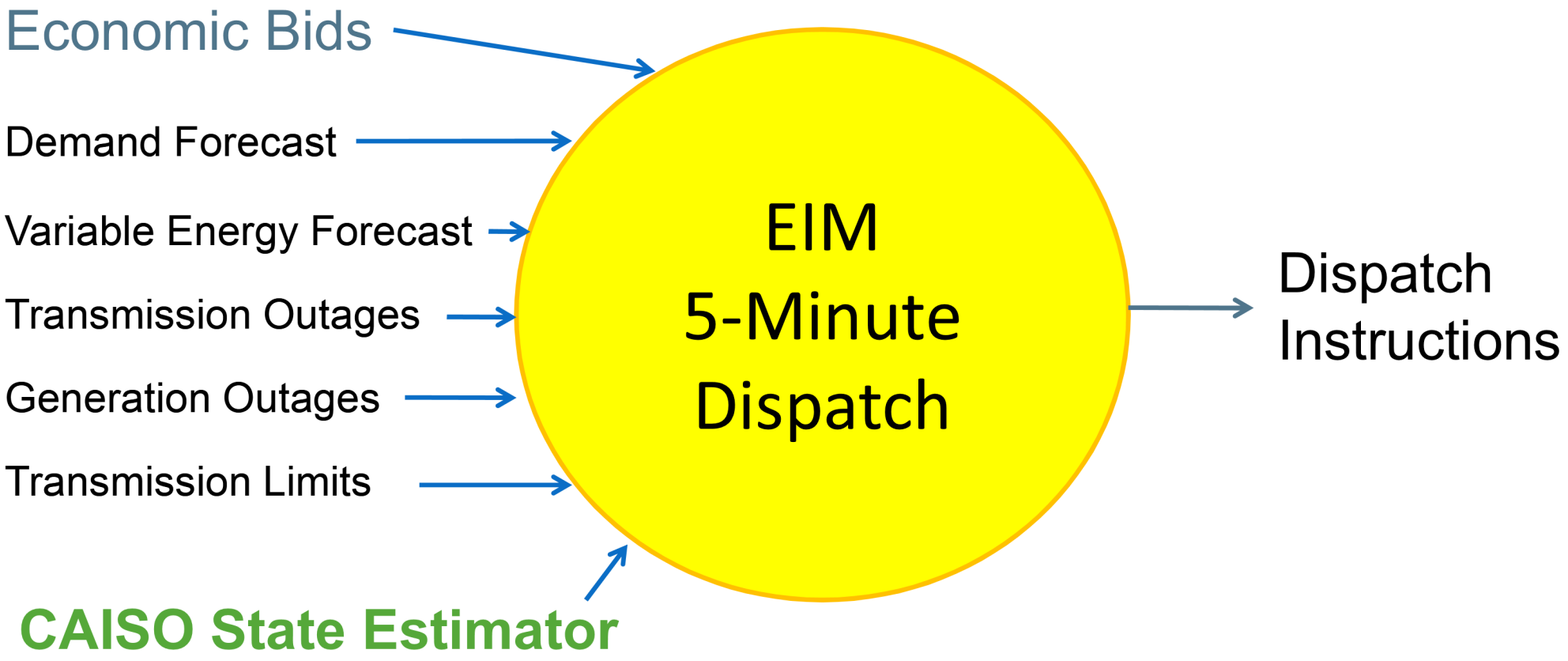
Market Activities



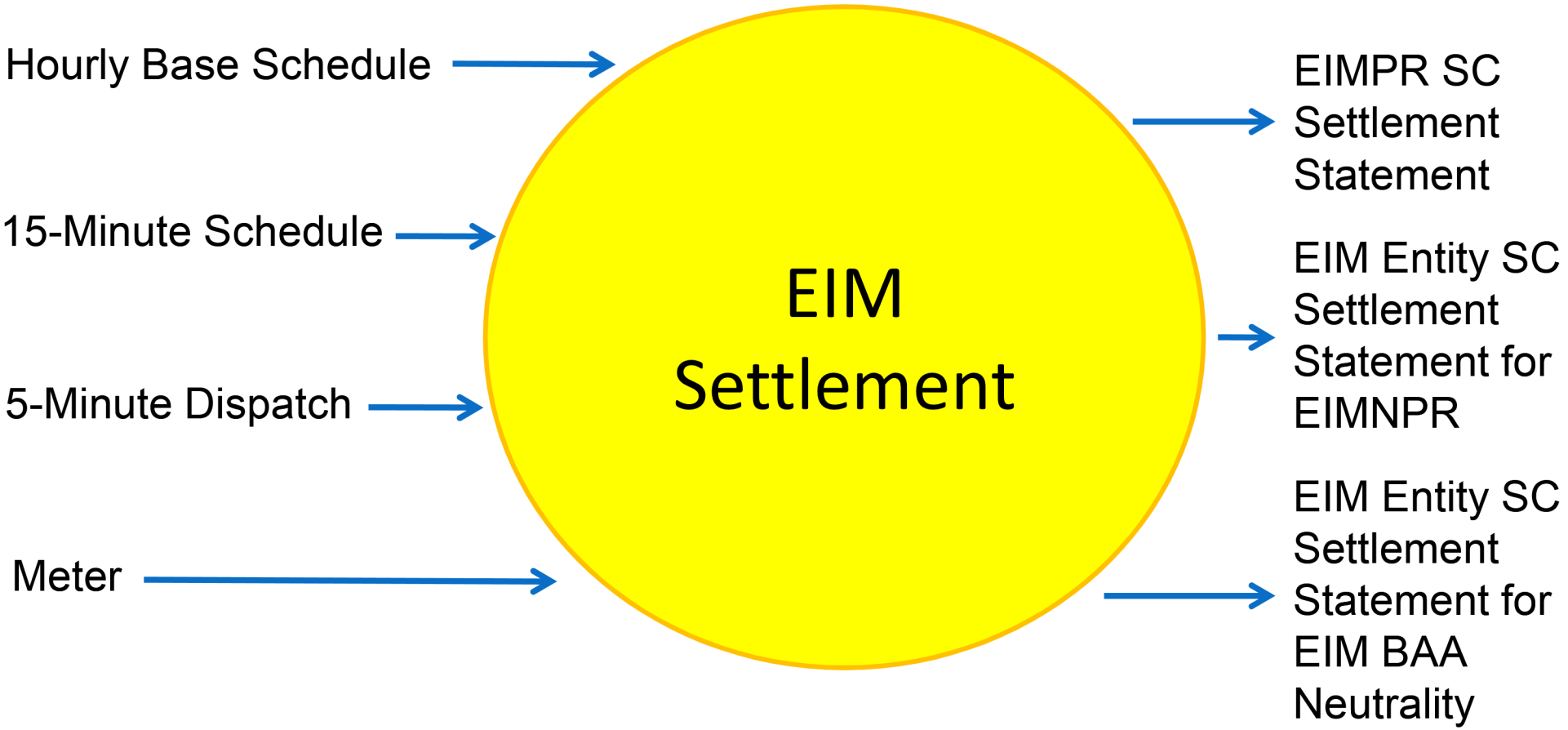
Market Activities



Market Activities



Market Activities



Structured Scenario: Base Case

- Today's focus is on a "Base Case", which is an extremely simplified example of EIM Operations intended to create a foundation of essential EIM functions.

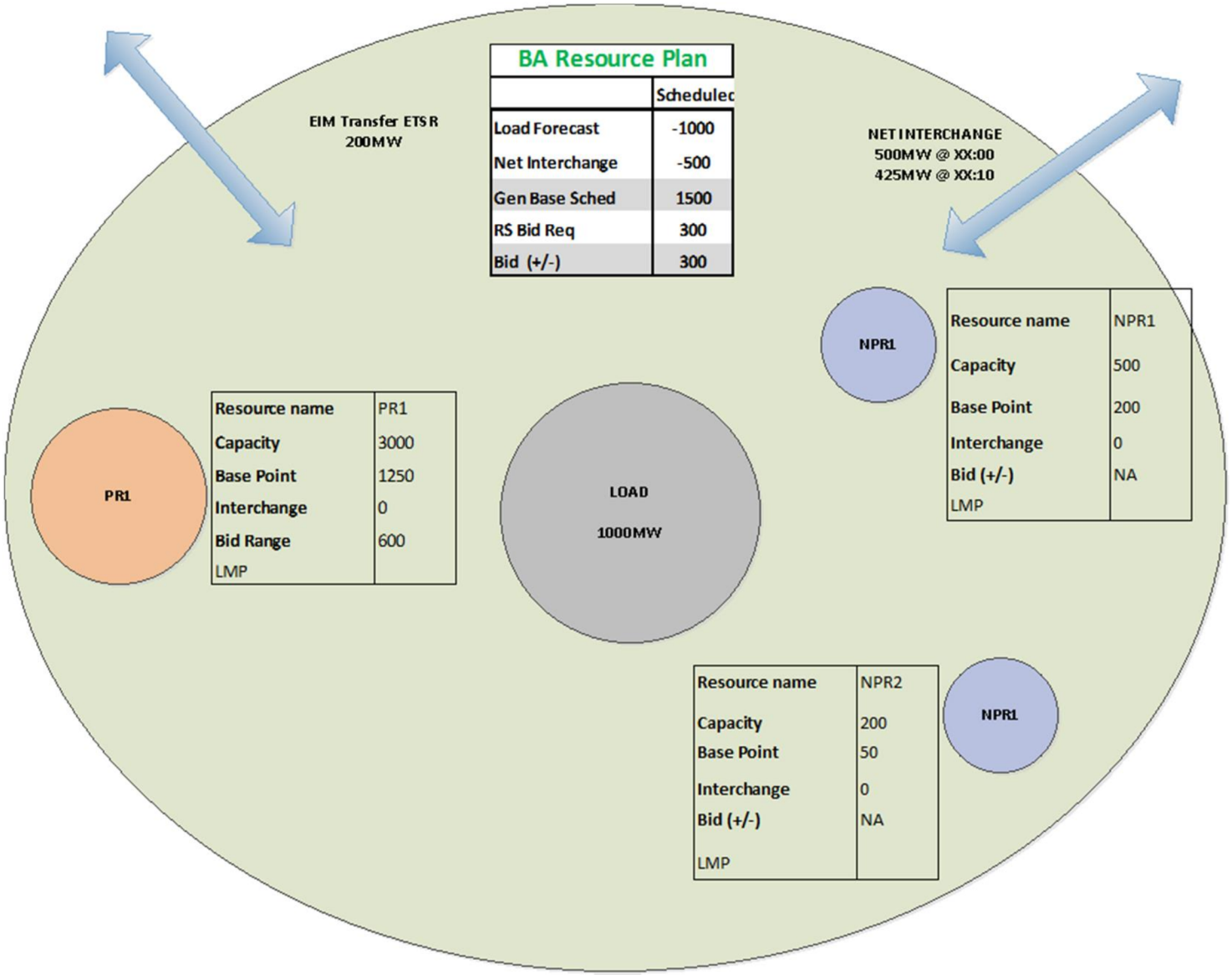
- This case is not meant to represent how BPA's actual operations would work, rather to provide a sort of "pure" example from which future scenarios and analysis can be compared.

- As such, assumptions are made for the purpose of the Base Case for multiple decisions that have not yet been made by BPA.

Base Scenario with Interchange

- Today's scenario has one source of imbalance, which is a reduction in interchange.
- Absent an auto-match the market will match the interchange deviation.
- Though there are 200MW of ETSR's made available this scenario assumes the single Participating Resource in the BAA is the economic resource.

Base Scenario Overview



Key Actions

- See BPA EIM Scenario Worksheet No. 1

BPA EIM Structured Scenario Worksheet

Structured Scenario Name: Base

Overview:

- This scenario is meant to establish a “base case” against which other scenarios will be compared. The Base scenario describes the simplest reasonable operational conditions and actions for an EIM Entity and the Participating Resources to successfully navigate a single operational hour. The Base Scenario will help develop a fundamental understanding of EIM requirements and impacts which will help stakeholders identify those elements that are intrinsic to EIM Participation and present a comparison for future scenarios to identify those elements which are particular BPA and to individual customer actions.

Assumptions:

- Only one PRSC Participating Resources (PR) in Balancing Authority Area (BAA)
- BPA is using the FCRPS to pass all resource sufficiency evaluations
- We will have ETSRs to donate, and non-constrained
  - Use "customer donation" for imports/exports
  - PRSC would redirect PTP for ETSRs
  - Not defining at this point which other EIM Entity BAAS we are setting them up for
- Bid=RS requirements
- Tx = EIM Entity
  - EIM Desk, Gen Dispatch, Tx Dispatch
  - Questions about where functions lie - EIM Desk, integrated throughout Tx, or relationship with PG et al.
- Default Energy Bid (DEB) Reference price set in DA
- Can hit whole bid range in any interval for the purposes of the Flexible Ramp Sufficiency Tests
  - I.e., not ramp limited from hitting any Dispatch Operating Target (DOT)

BPA EIM Structured Scenario Worksheet: Actions

Structured Scenario Name: Base

Up to T-55	
PRSC	• Submit bids for OH (300MW) • Update Base Schedules for OH (1250MW/0MW) • Update GDFs for OH • Submit ETSR Tags (XMW) for OH (200MW)
EESC/Operations	• Pull tags and populate Base Schedule for OH (1500MW) • Update ETSR limits (</= ETSR Tags) for OH (200MW) • Update outages and other transmission limits for OH • Evaluate preliminary RS Tests for OH
Customers	• Submit Base Schedules (200MW/50MW) • Submit tags for inter/intrachange for OH • Submit ETSR tags if desired for OH

T-55 to T-40	
PRSC	• Preparing bids for next OH1 • Update ETSR tags for OH if needed/directed
EESC/Operations	• Update Base Schedules and finalize Base Schedules and Resource Plan for OH • Outages and transmission limits as needed for OH
Customers	• Updating schedules as desired/directed for OH

BPA EIM Structured Scenario Worksheet: Actions

Structured Scenario Name: Base

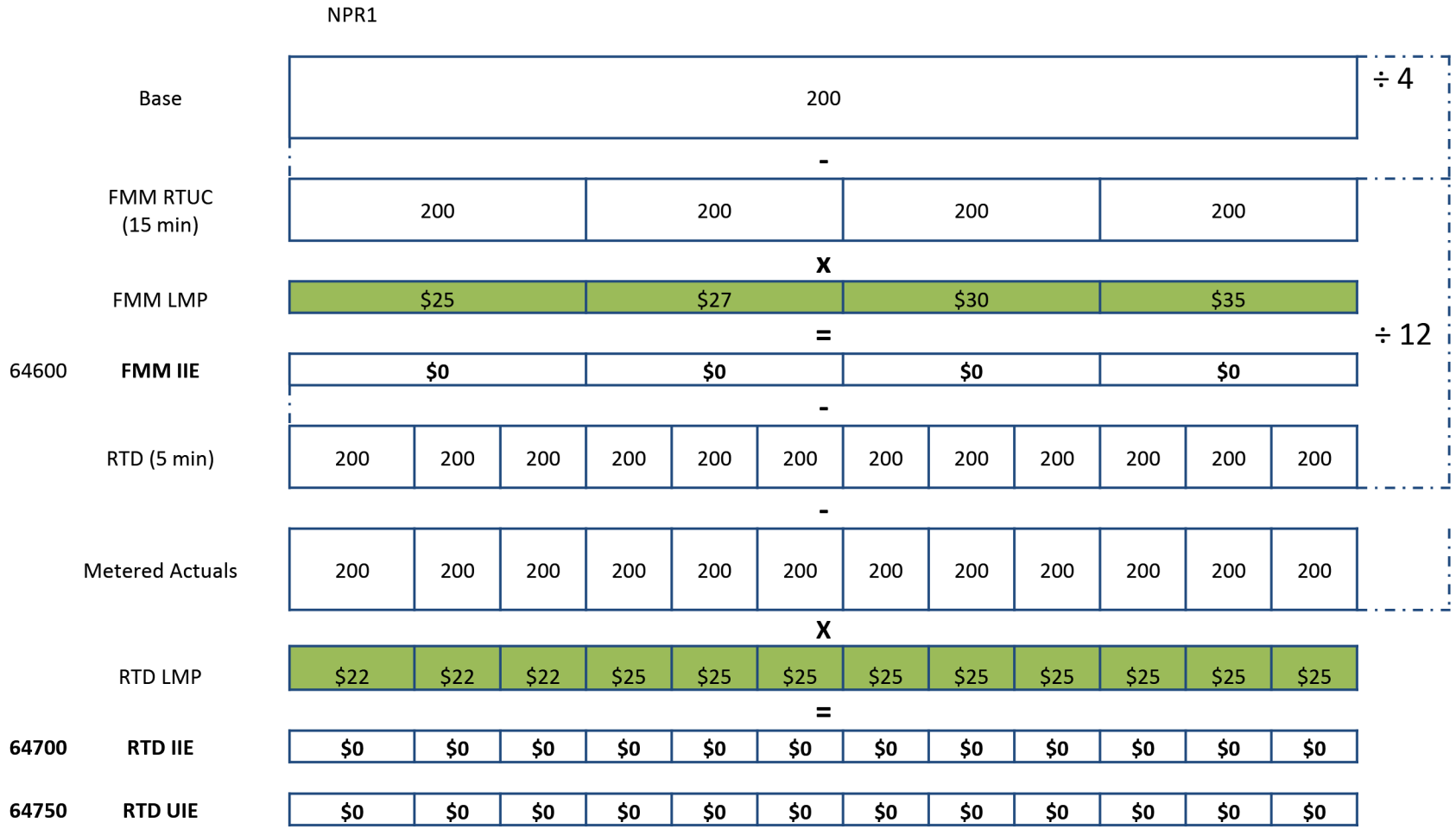
	T-40 to Start of OH
PRSC	• Submit Bids for OH1 • Submit ETSR for OH1 • Outages for PR as needed for OH • Update ETSR tags for OH as desired/directed
EESC	• Receive and implement initial dispatches and operations for OH • Update outages as needed for OH • Implement schedule updates and communicate to MO as needed for OH • Pull tags and populate Base Schedule for OH1 • Update ETSR limits (</= ETSR Tags) for OH1 • Update outages and other transmission limits for OH1 • Evaluate preliminary RS Tests for OH1
Customers	• Update tags as desired/directed for OH • Submit tags for inter/intrachange for OH1 (Reduction of 75MW at XX:10) • Submit ETSR tags if desired for OH1

BPA EIM Structured Scenario Worksheet: Actions

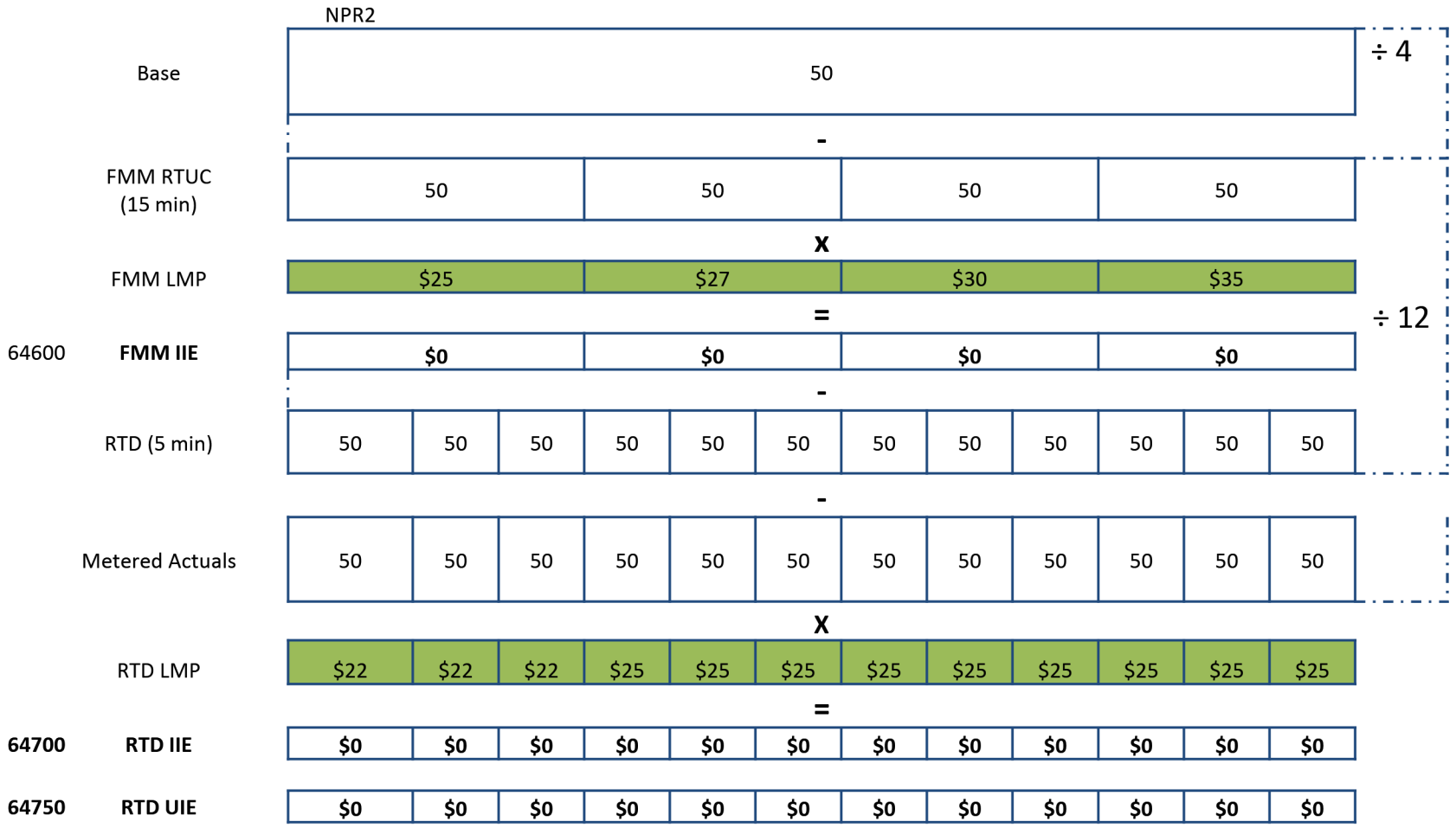
Structured Scenario Name: Base

	Operating Hour (Entire Hour)
PRSC/Bulk Marketing	• Outages as need for OH • Update ETSR tags as needed for OH1 • Submit Bids for OH2 • Submit ETSR tag for OH2 • Outages for PR as needed for OH1
EESC/Operations	• Receive and implement remainder of dispatches and operations for OH • Manage Outages and communicate to MO for OH • Receive and implement initial dispatches and operations for OH1 • Update outages as needed for OH1 • Implement schedule updates and communicate to MO as needed for OH1 • Pull tags and populate Base Schedule for OH2 • Update ETSR limits (</= ETSR Tags) for OH2 • Update outages and other transmission limits for OH2 • Evaluate preliminary RS Tests for OH2
Customers	• Update tags for as desired/directed for OH • Update tags as desired/directed for OH1 • Submit tags for inter/intrachange for OH2 • Submit ETSR tags if desired for OH2

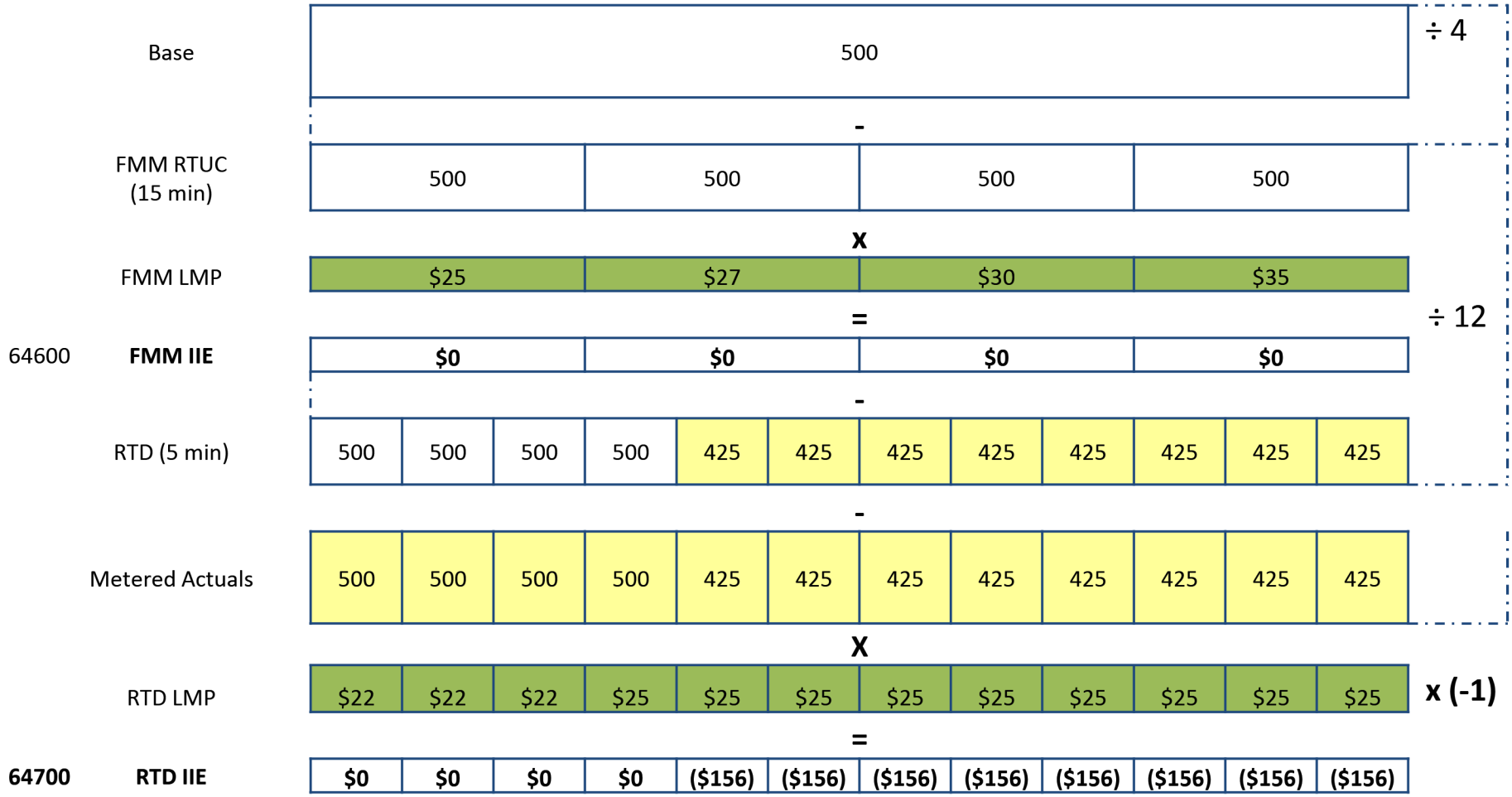
Settlement Activities NPR1



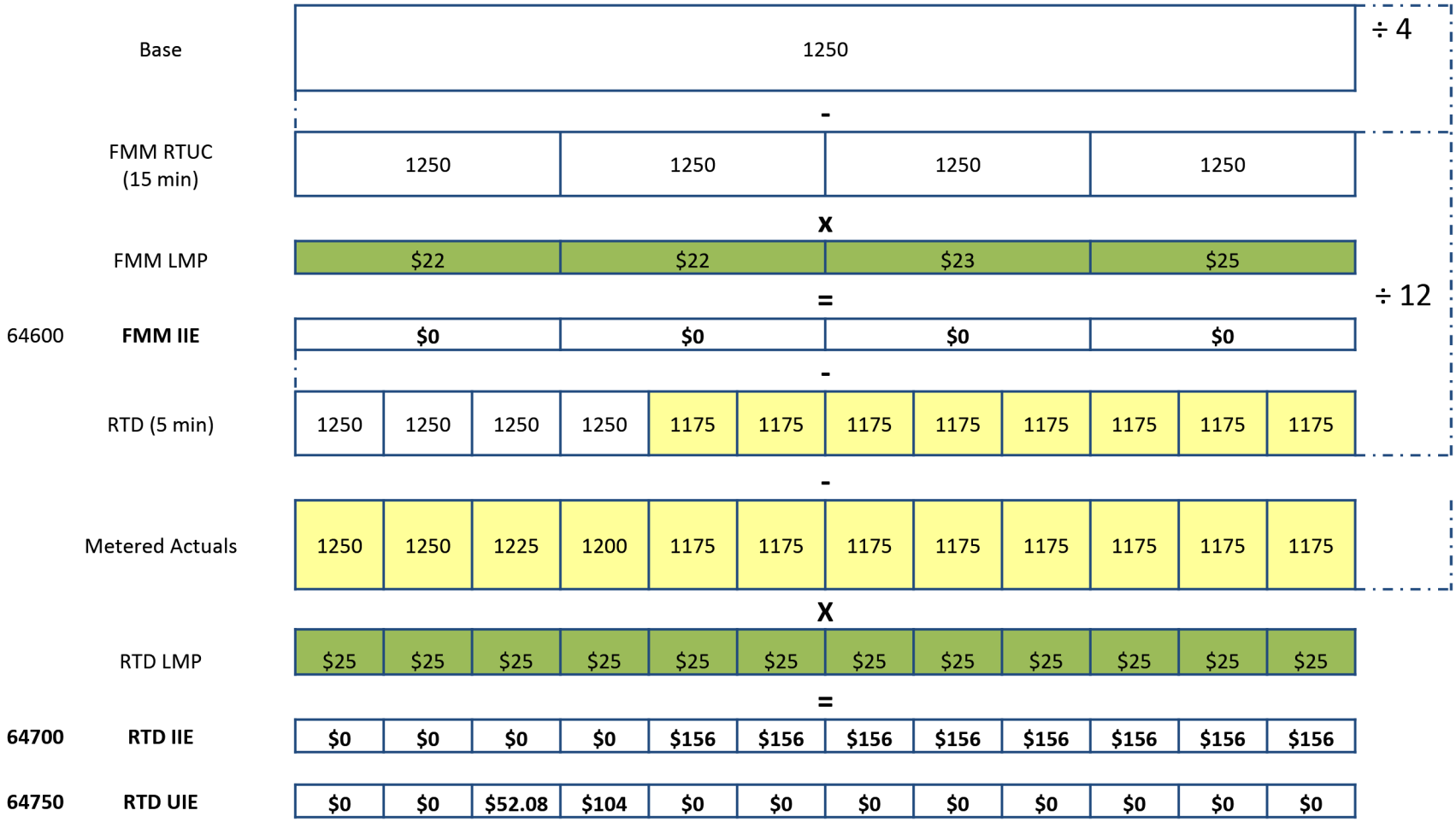
Settlement Activities NPR2



Settlement Activities Interchange



Settlement Activities PR1



Settlement Activities Load

Hourly Load Base Schedule	1000												
Submitted Hourly Load Value	994												
5-min Load Base Schedule	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	÷ 12
	-												
5 min Load "Metered Actuals"	994	994	994	994	994	994	994	994	994	994	994	994	
	X												
LAP	$26	$26	$26	$26	$26	$26	$26	$26	$26	$26	$26	$26	**x (-1)**
	=												
RTD UIE	**($13)**	**($13)**	**($13)**	**($13)**	**($13)**	**($13)**	**($13)**	**($13)**	**($13)**	**($13)**	**($13)**	**($13)**	

Outcomes

- The EIM Entity ends up collecting ~$1404 due to the reduction in exports.
  - Interchange for $1248 and Load for $156.
- The Participating Resource pay ~$1404 for decrementing it's resource.
- On balance the market is revenue neutral.
- **NOTE** – This example is purposefully very simple to demonstrate basic concepts.

Future Structured Scenarios

Scheduled for March, April and May will include:

- Slice Customers
- VERs (participating / non-participating)
- Self Supply

Next Steps

Next Steps

- Next meeting scheduled for **Wednesday March 13th** at the Rates Hearing Room. This will be an all-day meeting to discuss our first Table Top.
  - WebEx and Phone participation will be available
  - Agenda and materials will be distributed in advance via Tech Forum

- We welcome feedback on this meeting. Your comments will help shape future EIM Stakeholder Meetings, please email us at techforum@bpa.gov and reference "EIM Stakeholder Meeting" in the subject. Comments are due by March 1st Friday.

- 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

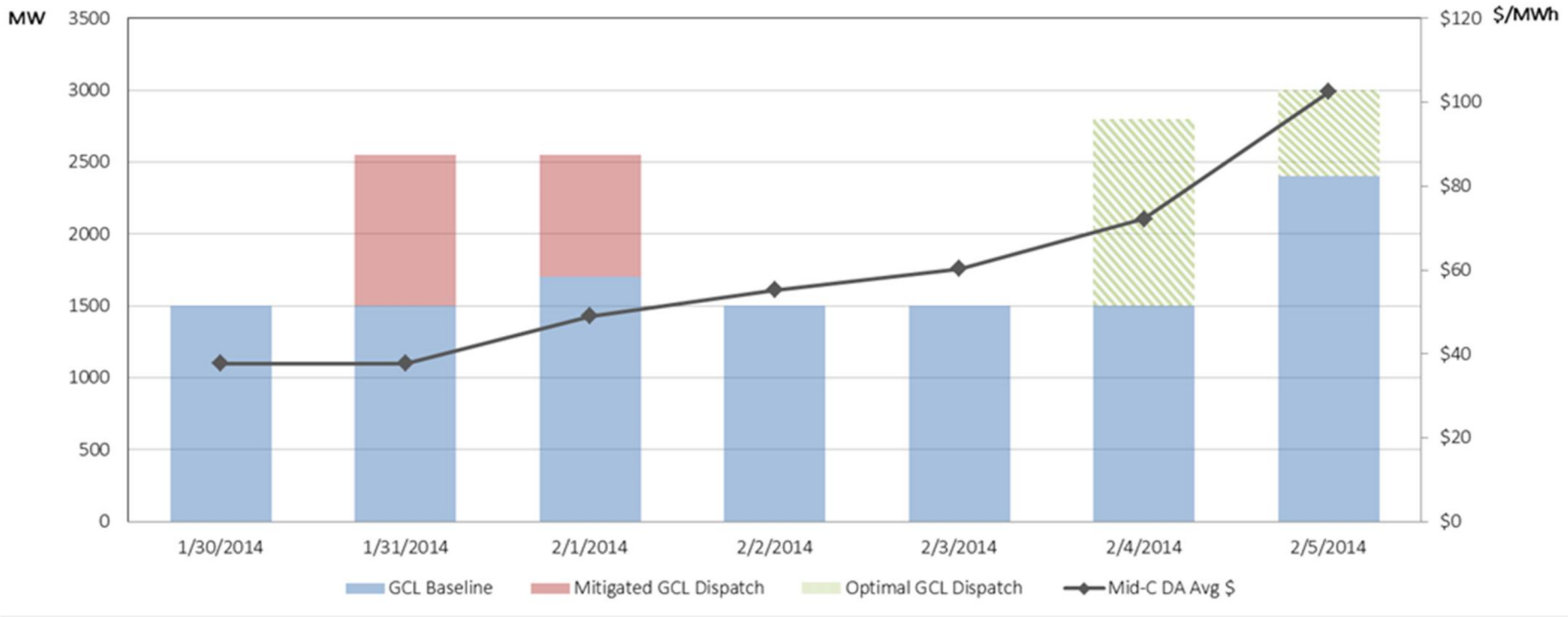
- For more information on BPA's Grid Modernization Initiative please visit: https://www.bpa.gov/goto/GridModernization

Question and Answer Session

Appendix

Why is Unintended Dispatch Bad?

- Mitigation could negatively impact FCRPS dispatch during cold snap conditions.
- An example of potential changes to GCL's dispatch is below.



Grid Mod/EIM Update
PPC Members Forum

Oct 03, 2018

Steve Kerns, Director Grid Modernization

Grid Modernization Initiative

- 2018-2023 Strategic Plan Released
- Strengthens our ability to manage our commercial business through efficiencies and improved operational capabilities
- Focus on modernizing federal power and transmission system operations
- Grid modernization projects provide independent value to bring systems, processes and skills up to date

www.bpa.gov/StrategicPlan/Pages/Strategic-Plan.aspx

Strategic Goals

#1 STRENGTHEN FINANCIAL HEALTH — Strengthen financial health by meeting objectives for cost management, liquidity, debt utilization, debt capacity and credit ratings.

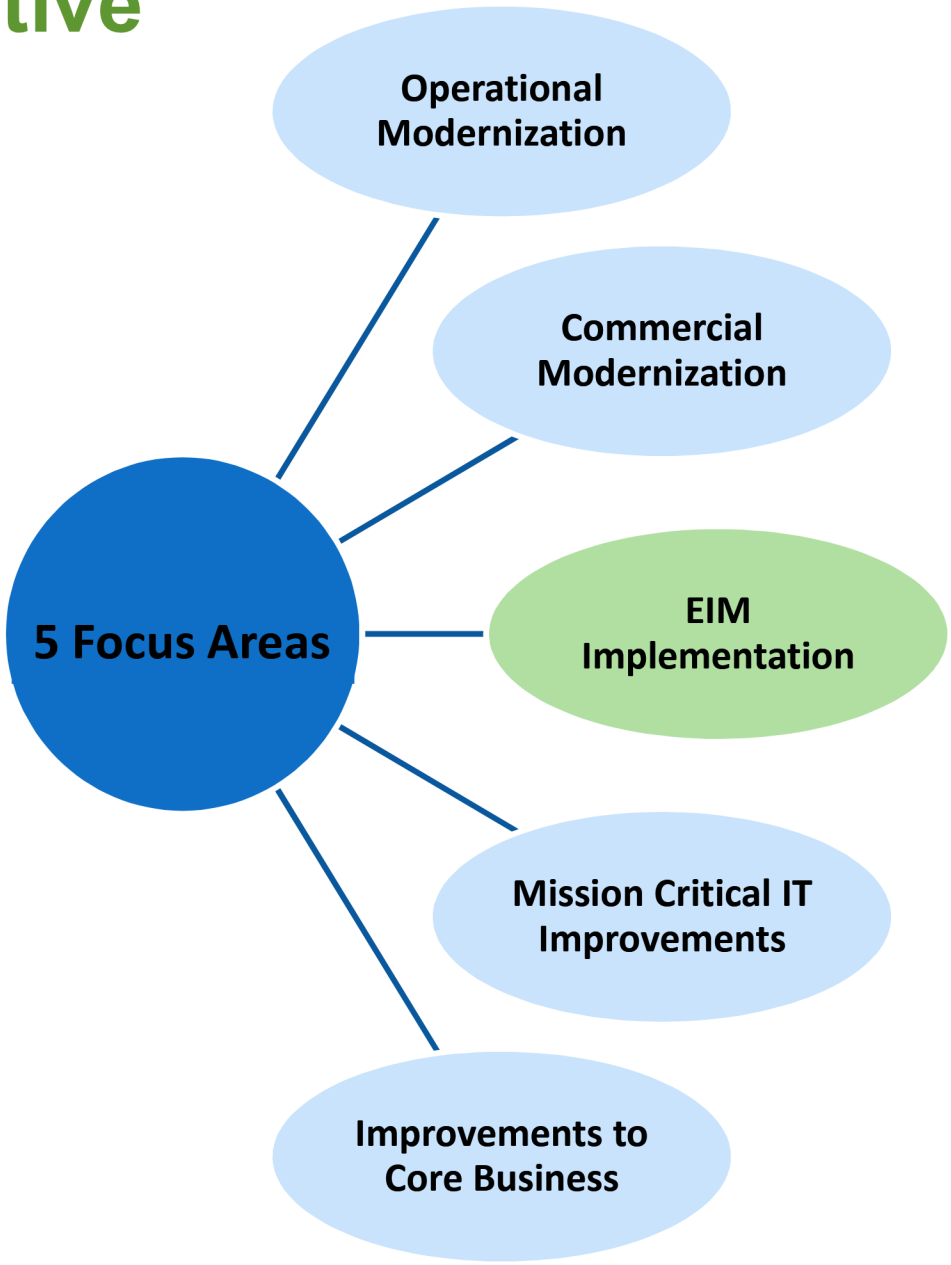
#2 MODERNIZE ASSETS & SYSTEM OPERATIONS — Modernize assets and system operations to leverage and enable industry change.

#3 PROVIDE COMPETITIVE POWER PRODUCTS & SERVICES — Provide competitive power products and services.

#4 MEET TRANSMISSION CUSTOMER NEEDS EFFICIENTLY & RESPONSIVELY — Meet transmission customer needs efficiently and responsively.

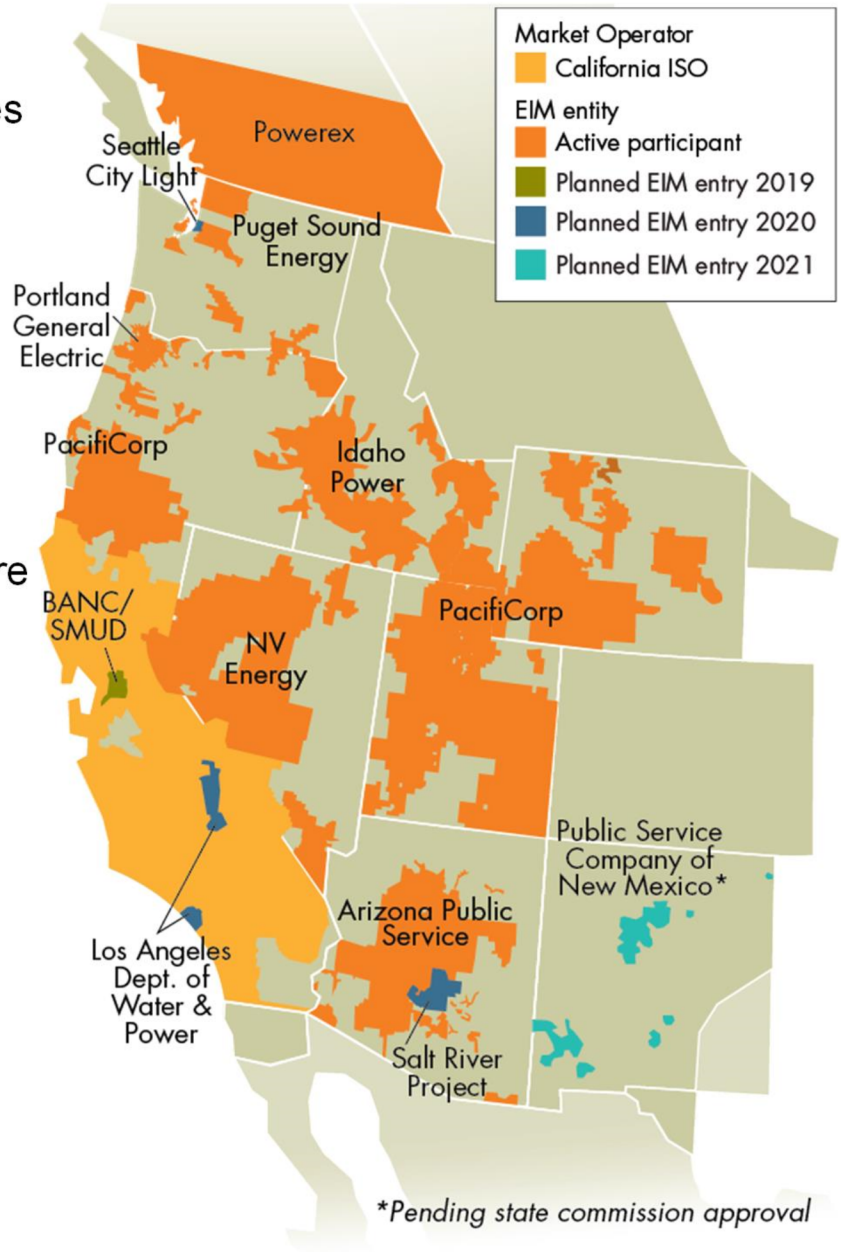
Grid Modernization Initiative

- June 20th's IPR Grid Modernization Workshop provided an overview of the completed, in-flight, and future projects.
- Grid Modernization projects bring value to BPA and its customers independent of the EIM.
- If BPA chooses not to participate in the EIM, then the EIM Implementation projects will not be pursued.



Opportunities from Market Engagement

- Variable energy resources are increasing in the West creating opportunities to capture valuable flexibility and capacity services that clean hydropower resources can provide.
- Customer transmission use and system operations are undergoing significant changes in response to market developments and new tools are needed to respond optimally.
- Bonneville has discussed lessons learned from Northwest utilities who are evaluating market changes, modernizing their systems to take advantage of opportunities, and that have or are planning on joining the Western EIM.
- Need to find ways to fully realize the value of sub-hourly dispatch, flexible, and carbon-free hydro attributes.
- The pace of evolving markets continue, recent efforts such as day ahead market enhancements highlight the need for active monitoring.
- Bonneville has begun to study and determine ***how and under what conditions Bonneville could join the Western EIM***.



Transmission Qualitative Benefits

- Controls and state awareness
  - Economically efficient congestion management functions
  - Improved rate-of-change constraint determination
  - Higher utilization of the transmission system
  - Access to CAISO EIM dispatcher tools

- Modeling and coordination between BAs and within BPA
  - Sharing data and network models
  - Closer alignment between Power and Transmission services on FCRPS dispatches

- Deferral of congestion driven capital projects
  - I5-like projects

Estimated Initial EIM Scenario Benefits – Power

Power Services' benefits from EIM result from more optimal intra-hour dispatch of the FCRPS:

- Benefits are based on monetizing surplus FCRPS flexibility
- Estimated EIM benefits are netted against traditional load factoring, which is the primary way BPA monetizes surplus flexibility today
- BPA analysis is consistent with that of other regional hydro-centric utilities

Power Services' Scenario Benefits ($millions)			
		Modernize	EIM
Annual Benefits			
	EIM Market	-	20.1
	Load Factoring	3.6	-
	Total Annual Benefits	**3.6**	**20.1**
Annual Net Benefits		**3.6**	**14.0**

Annual EIM Net Benefits	10.4

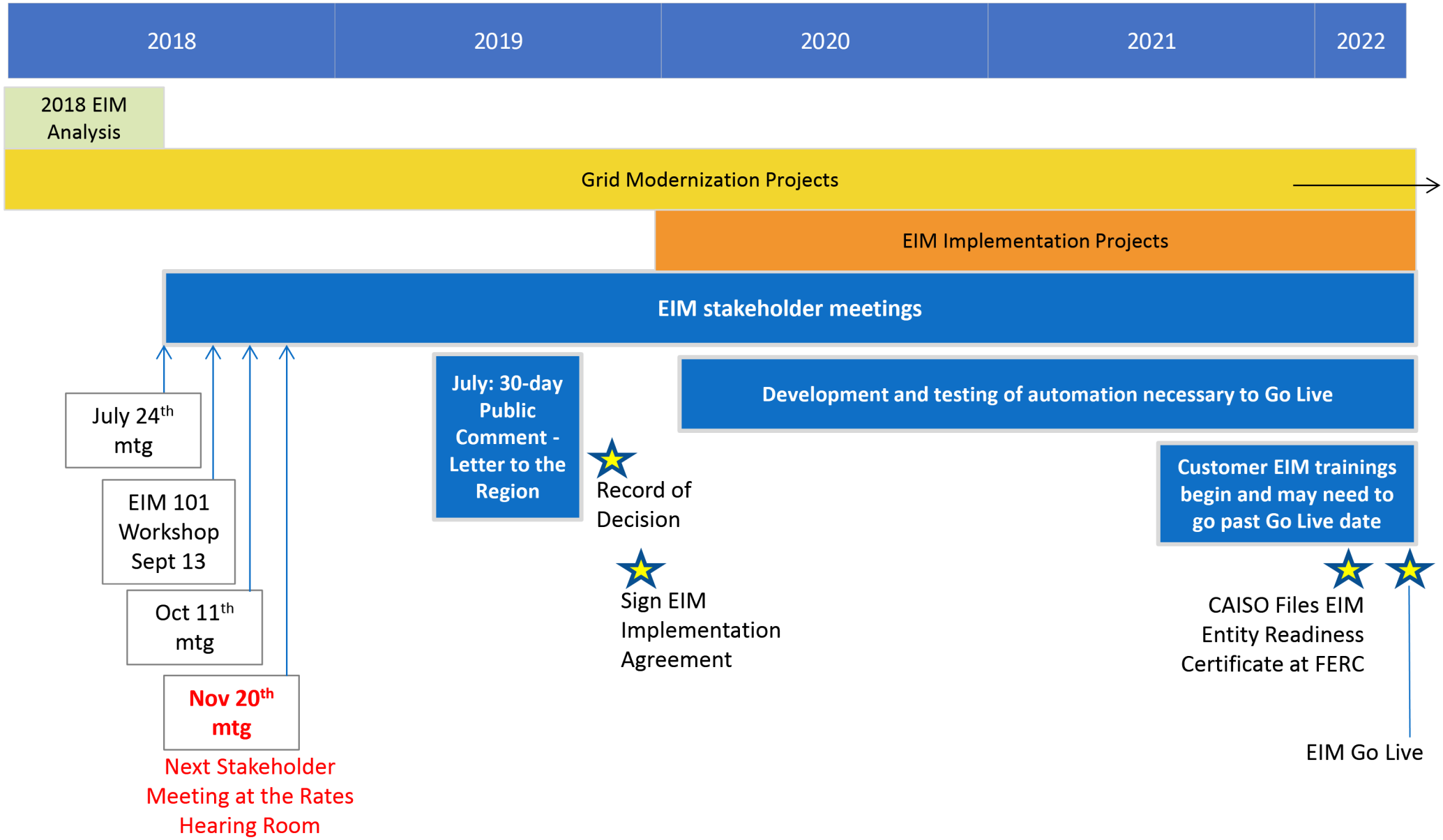
Issues that BPA is Reviewing

EIM:

1. Market Power
2. Carbon Obligation in EIM
3. Relationship of EIM to Other Emerging Markets
4. BA Resource Sufficiency
5. EIM Settlements
6. Treatment of Transmission
7. Generation Participation Model (FCRPS, IPP)
8. Governance

Other Market Design Issues:

1. EDAM
2. Capacity Market



Monthly until July

Grid Mod/EIM Update
Public Interest Quarterly

Sept 19, 2018

Steve Kerns, Director Grid Modernization
Agnes Lut, Stakeholder Lead

Grid Modernization Initiative

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- Focus on modernizing federal power and transmission system operations
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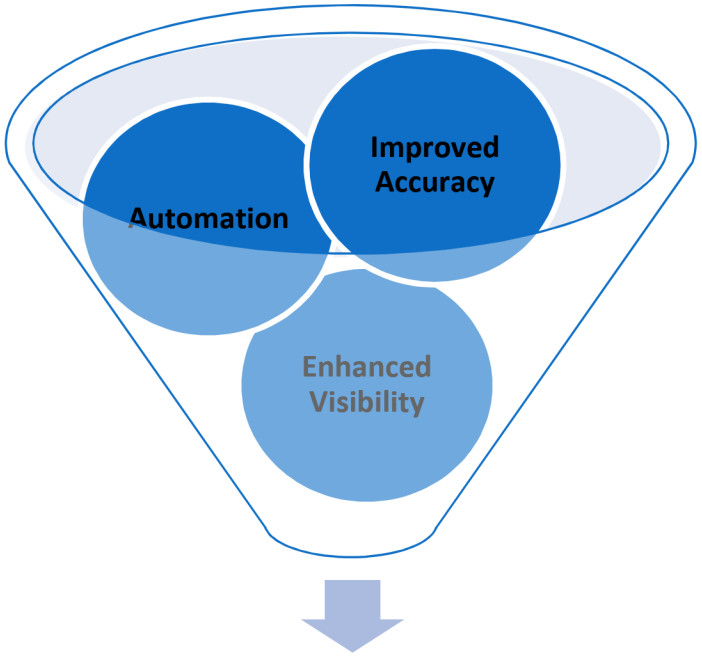
#4 MEET TRANSMISSION CUSTOMER NEEDS EFFICIENTLY & RESPONSIVELY — Meet transmission customer needs efficiently and responsively.

Grid Modernization Initiative

- Reliance on legacy systems and nonstandard commercial practices have led us to be overly conservative in our power and transmission operations, planning and marketing and are costly to maintain.

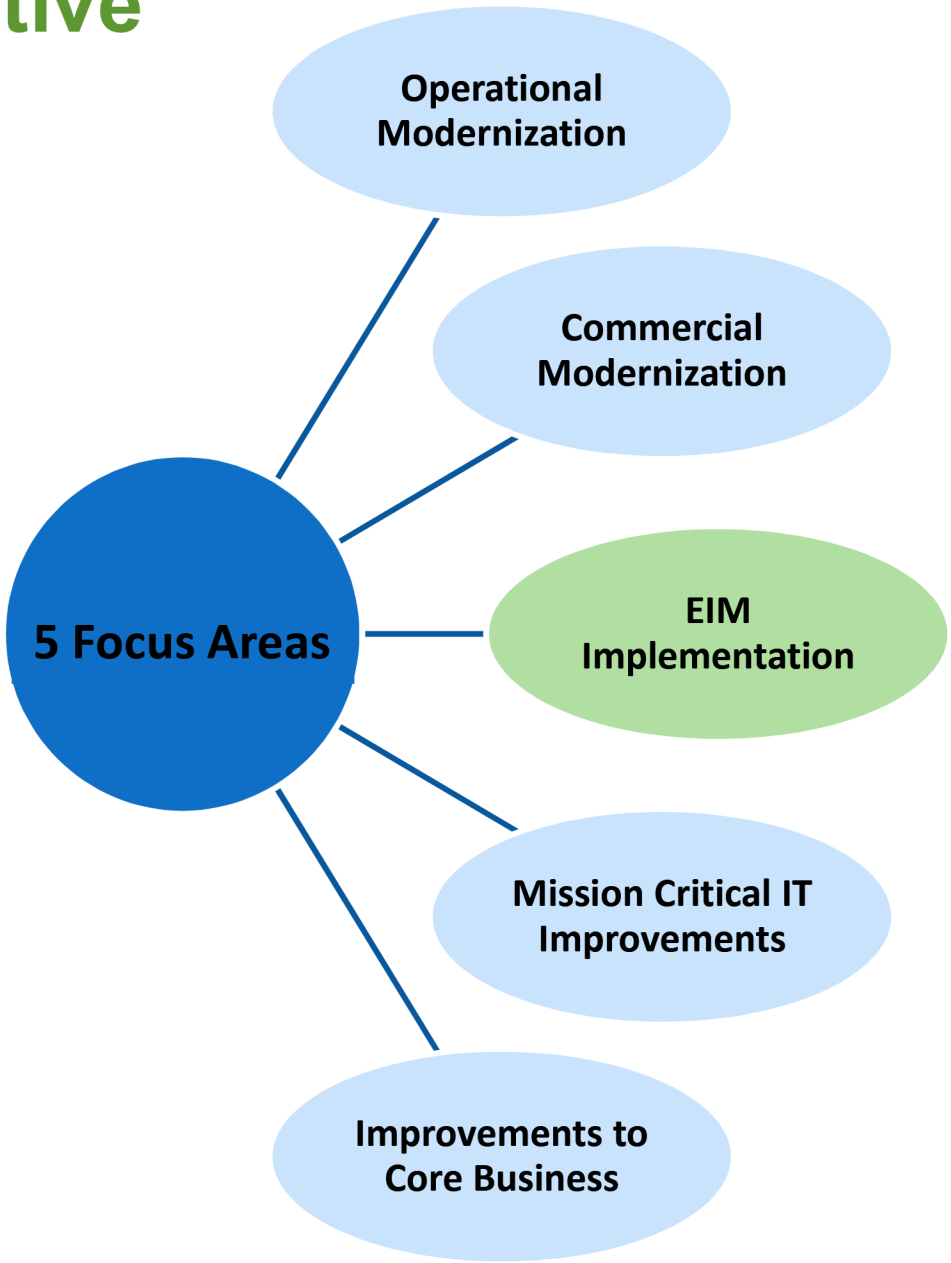
- Strategic and prioritized investments:
  - support a more reliable, flexible and efficient system,
  - help reduce future costs and
  - create new market opportunities.



Grid Modernization

Grid Modernization Initiative

- June 20th's IPR Grid Modernization Workshop provided an overview of the completed, in-flight, and future projects.
- Grid Modernization projects bring value to BPA and its customers independent of the EIM.
- If BPA chooses not to participate in the EIM, then the EIM Implementation projects will not be pursued.



Operational Modernizations

5 Focus Areas

- Improve reserve obligation calculation and deployment.
- Improve efficiency and coordination:
  - For generation planning and coordination with the Corps and Bureau.
  - Comprehensive, efficient and integrated outage management.
  - Consistent network modeling data and exchange of models.
  - Management and mitigation of operational constraints.
- Enhance control center data, visualization and situational awareness.
- Enable options for market participation.
- Preserve Bonneville's flexibility to continue evaluating RC service providers.

Commercial Modernizations

5 Focus Areas

- Optimize the commercial availability of the grid.
- Enable options for market participation.
- Enable shorter scheduling and dispatching intervals.
- Enhance comprehensive trading and risk management toolset.
- Provide a more sustainable, integrated long-term transmission planning processes.
- Enhance short-term ATC calculation, consistent with products and policies.
- Align Business Practices with changes to transmission products.
- Enhance settlement capabilities.

EIM Implementation

5 Focus Areas

- Implement tariff, policy, rate and business practice changes consistent with market participation.
- Develop ability to submit base schedules, bid curves and other data required by the EIM.
- Enable automated generator dispatches consistent with market awards.
- Manage EIM settlements with the CAISO and subsequently with BPA load and generation customers.
- Develop EIM specific training to ensure staff are able to accurately and efficiently carry out EIM roles.

Mission Critical IT Improvements

5 Focus Areas

- Develop foundational capability that allows for delivery of the suite of Grid Modernization projects.
- Establish a modern, consistent and structured architecture.
- Enable robust operational reliability.
- Consolidate IT infrastructure.
- Provide capability to virtualize environments.
- Modernize the IT network.
- Standardize delivery of IT services.
- Improve capabilities to enable systematic data driven analysis.

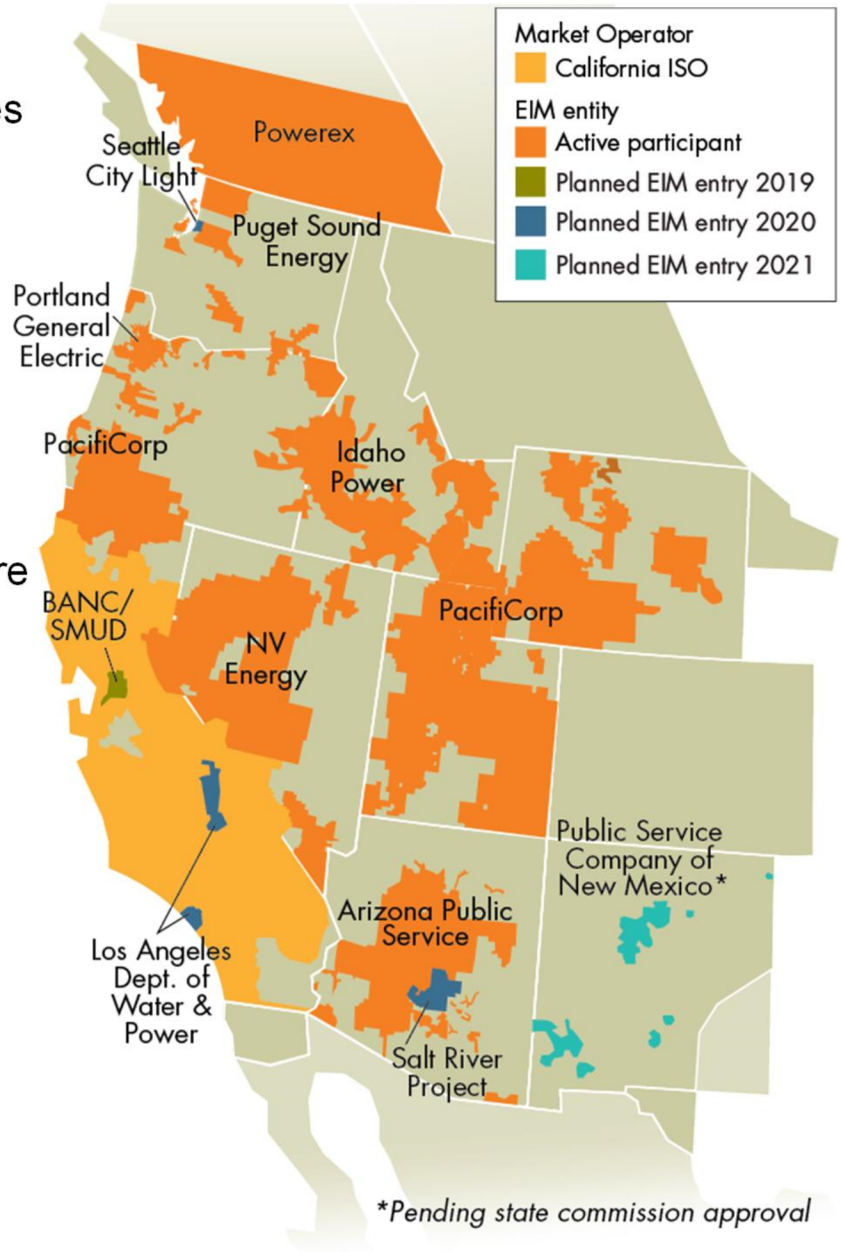
Improvements to Core Business

5 Focus Areas

- Improve consistency and coordination of visibility and controls.
- Enable and enhance structured and systematic training program.
- Improve forecasting of load & renewable generation.
- Modernize analytical capability.
- Modernize settlements systems and processes.

Opportunities from Market Engagement

- Variable energy resources are increasing in the West creating opportunities to capture valuable flexibility and capacity services that clean hydropower resources can provide.
- Customer transmission use and system operations are undergoing significant changes in response to market developments and new tools are needed to respond optimally.
- Bonneville has discussed lessons learned from Northwest utilities who are evaluating market changes, modernizing their systems to take advantage of opportunities, and that have or are planning on joining the Western EIM.
- Need to find ways to fully realize the value of sub-hourly dispatch, flexible, and carbon-free hydro attributes.
- The pace of evolving markets continue, recent efforts such as day ahead market enhancements highlight the need for active monitoring.
- Bonneville has begun to study and determine ***how and under what conditions Bonneville could join the Western EIM***.



Transmission Qualitative Benefits

Benefits accessible through EIM membership:

- Congestion management functions that are more economically efficient than present curtailment and bilateral redispatch capabilities.
- Optimized day to day operation of the power system.

Improved Controls:

- Proactive congestion management
- Reactive congestion management
- Proactive voltage control

Improved State Awareness:

- Increase accuracy and frequency of operational information
- Create new visual displays of real-time or near real-time data, allowing operators to better predict operational issues.
- Access to CAISO EIM dispatchers tools

Modeling & Coordination:

- Improved network modeling
- Improved outage modelling & coordination
- Improved Power & Transmission coordination

Transmission Qualitative Benefits

Benefits accessible through EIM membership:

- A tool used to delay or avoid transmission expansion investment decisions to address congestion issues.

Categories of capital projects that the EIM could help defer or avoid:

- Network Congestion driven projects that could be remediated with security constrained economic dispatch, *for example*:
  - I-5 Corridor Reinforcement

Categories of capital projects that are driven by other needs that the EIM would *NOT* be expected to displace:

- Sustain Program projects for safe and reliable operation of existing facilities, *for example:*
  - wood pole replacement or transformers that have reached end of life
- Generation Interconnection, Line & Load Interconnection projects that are driven by requests from customers, *for example*:
  - data center loads
- Load Service Area Reinforcement projects required to mitigate reliability criteria violations, *for example*:
  - Hooper Springs project in SE Idaho

Estimated Initial EIM Scenario Benefits – Power

Power Services' benefits from EIM result from more optimal intra-hour dispatch of the FCRPS:

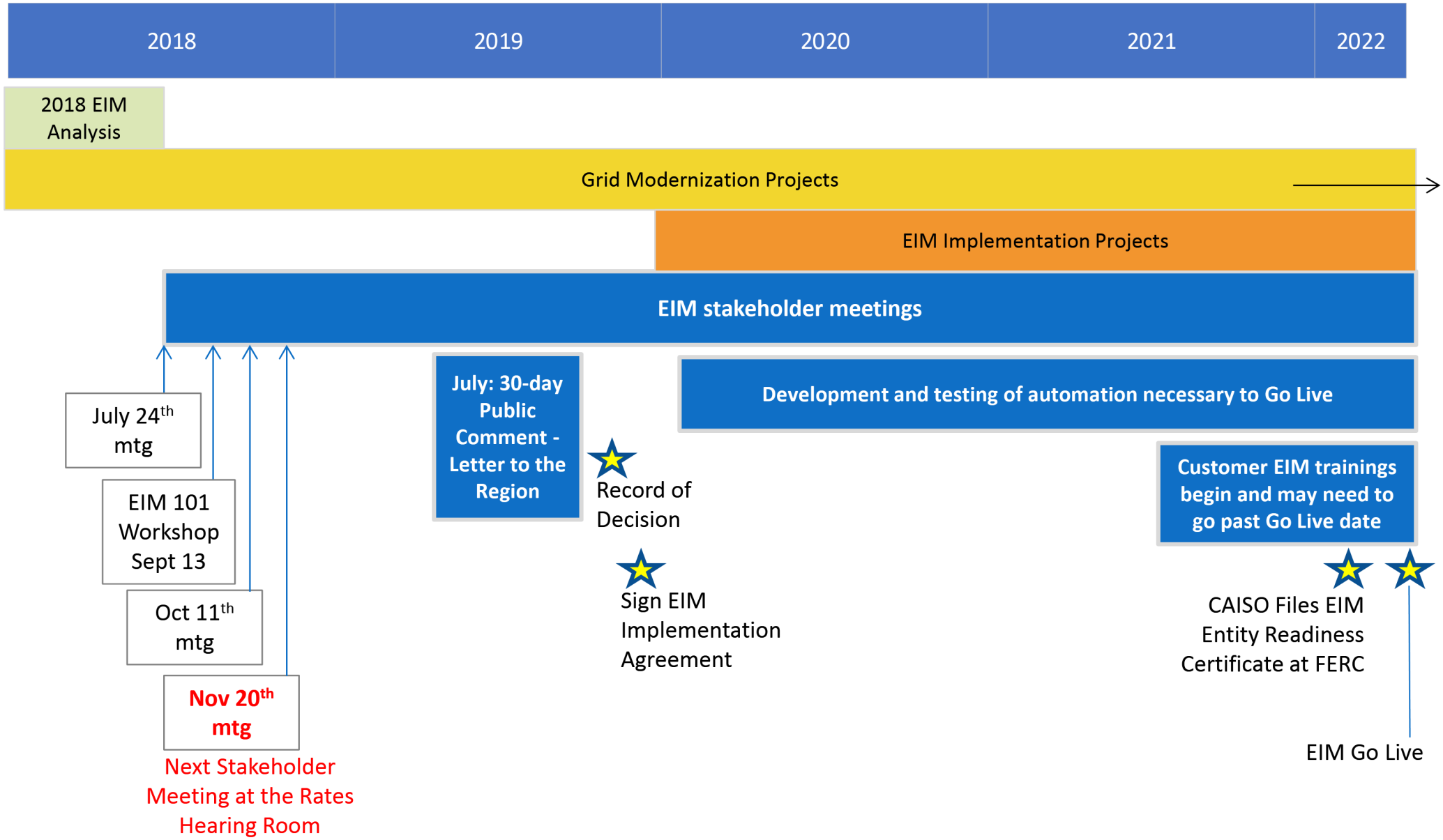
- Benefits are based on monetizing surplus FCRPS flexibility
- Estimated EIM benefits are netted against traditional load factoring, which is the primary way BPA monetizes surplus flexibility today
- BPA analysis is consistent with that of other regional hydro-centric utilities

Power Services' Scenario Benefits ($millions)			
		Modernize	EIM
Annual Benefits			
	EIM Market	-	20.1
	Load Factoring	3.6	-
	Total Annual Benefits	**3.6**	**20.1**
Annual Net Benefits		**3.6**	**14.0**

Annual EIM Net Benefits	10.4

Issues that BPA is Reviewing

1. Market Power
2. Carbon Obligation in EIM
3. Relationship of EIM to Other Emerging Markets
4. BA Resource Sufficiency
5. EIM Settlements
6. Treatment of Transmission
7. Generation Participation Model (FCRPS, IPP)
8. Governance



Monthly until July

(b)(5)

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EIM Stakeholder Meeting

January 16, 2019
9am -12pm
Rates Hearing Room

BPA Exec slide review: Friday Jan 11th, 1:30-2:30, RM 310 (Agnes will be OOO, Mark or Tom to run the mtg)
CAISO Review: Jan 8 & 9 in Folsom

For our WebEx and phone participants:

- We have muted all calls on entry, if you have a question, you will need to unmute by using *6. Then please identify yourself by name and let us know who you represent.
- Please do not put this call on hold OR take other calls while you are dialed into this one.
- If we identify a noisy line, you may be disconnected from the meeting.

Agenda

9:00-9:05	• Welcome, Safety Moment, Introductions
9:05 – 9:10	• Topics for Today's Meeting • Review of BPAs EIM Principles • Review Timeline
9:10 – 10:30	• Resource Sufficiency
10:30 – 10:40	• Break
10:40 – 11:30	• Relationship of EIM to other Emerging Markets
11:30 – Noon	• Next Steps • Question and Answer Session

Topics For Today's Meeting

- Review of EIM Stakeholder Topics Discussed to Date
- Timeline Review
- Issues that BPA presented at the July 24th EIM Stakeholder meeting that we will be discussing in more depth **today**:

  - **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**

  Issues we will be discussing today.

  Issues discussed at previous EIM Stakeholder meetings.

  This issue will be discussed at a future meeting.

- Question and Answer Session

Statement of BPA's Principles:

- Participation is consistent with statutory, regulatory, and contractual obligations.
- Maintain reliable delivery of power and transmission to our customers.
- Resource participation in the EIM is and always will be voluntary.
- BPA's decision to participate in the EIM will be based on a sound business rationale.

Timeline Leading up to the ROD

Agendas for previous and future monthly EIM Stakeholder meetings:

August	•Grid Modernization Overview, Strategic Plan Connection, Intro to 8 Issues BPA is Reviewing, Initial Cost Benefit Analysis
September 13	•EIM 101
October 11	•Process Plan, Transmission, Generation, Governance
November 14	•Process Plan, Market Power
December 18	•Settlements, Non-Federal Generation Participation
January 16	•Resource Sufficiency, Emerging Markets
February 20	•Resource Sufficiency, Generation Inputs BP-22
March 13	**Table Tops:** Discussion of Impacts to Customers
April 10	
May 15	
June	
July	•Letter to the Region with a 30 day public comment
August	•BPA drafts Record of Decision (ROD)
September	•Final ROD for signing the EIM Implementation Agreement

These meetings will be full day.

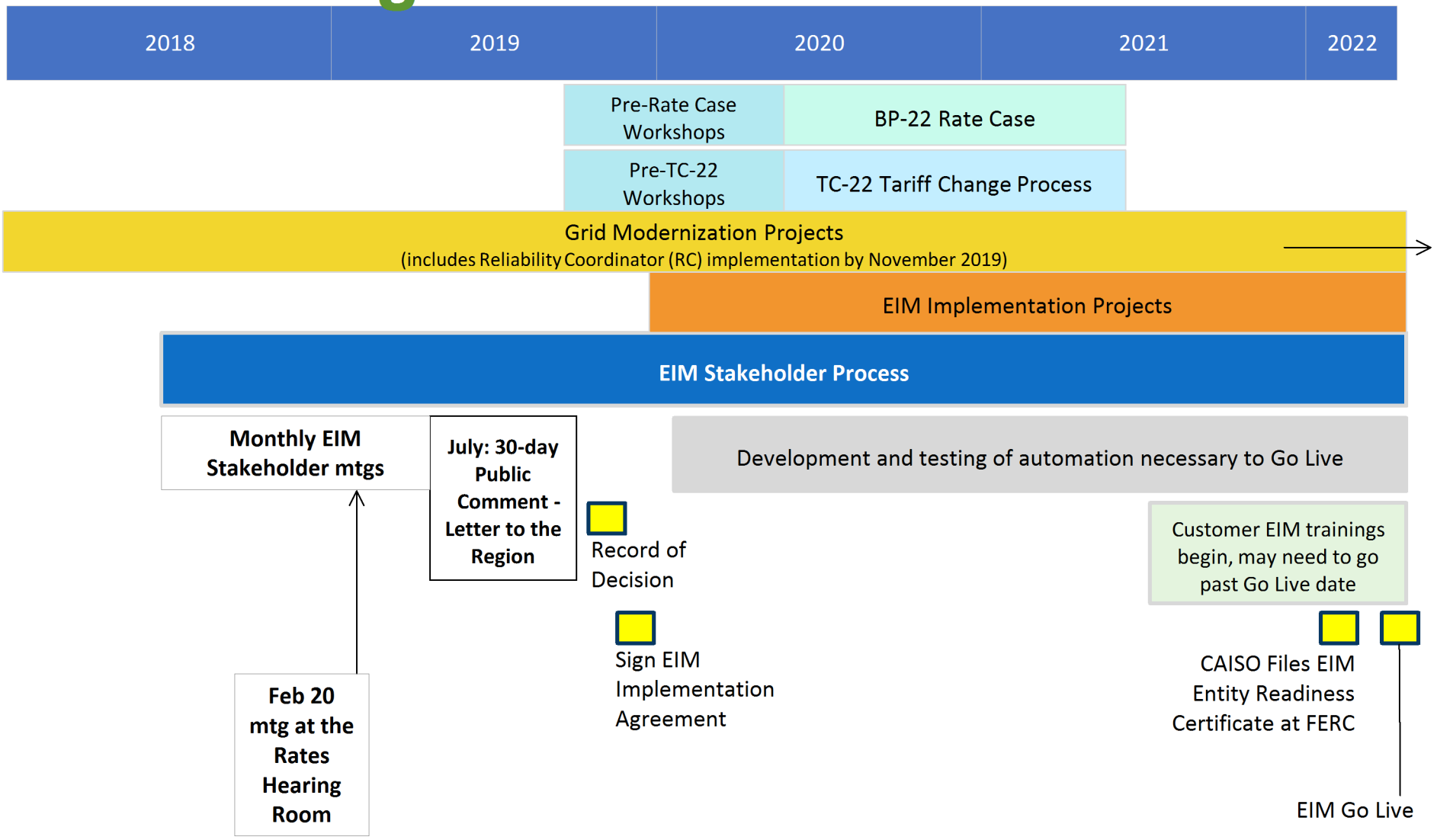
Issues to be Discussed at upcoming monthly EIM Stakeholder meetings:

- Settlements
- Cost Benefit Analysis
- Market Mitigation
- Transmission
- Carbon Issues

Signing of the EIM Implementation Agreement authorizes BPA to begin spending on EIM implementation projects with the CAISO but does not bind BPA to join the EIM.

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

BPA's High Level EIM Timeline



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

Resource Sufficiency

Resource Sufficiency - Agenda

- What is resource sufficiency?
- Base Schedules and Energy Bids
- EIM Entity Resource Plan
- EIM Resource Sufficiency Tests
- Resource Sufficiency Evaluation Example
- EIM Transfers

Presentation Assumptions

- Basic familiarity with the EIM
- Review of previous BPA stakeholder materials

What is Resource Sufficiency?

Resource Sufficiency

- The RS evaluation determines whether each EIM BAA has procured, prior to each operating hour, sufficient resources and flexibility (both internal and external) to serve the EIM BAA's area load and load/VERs uncertainty
- The goal of EIM RS is to ensure EIM BAAs do not "lean" on other EIM BAAs in real-time
  - The EIM BAA should not need to rely on EIM Import or Export transfers from other EIM BAAs to meet its needs
- EIM resource sufficiency (RS) is not CAISO's resource adequacy program
  - The EIM does not enforce resource adequacy requirements
  - There are no capacity payments or must-offer obligations associated with RS
- If each EIM BAA procures the necessary resources to meet its own needs, then EIM BAAs shouldn't need to "lean" on other EIM BAAs in real-time for energy, capacity, flexibility, or transmission (?)

Resource Sufficiency

- Each EIM BAA is evaluated every hour in real-time for RS based on four tests
  - Transmission Feasibility Test
  - Balancing Test
  - Bid Range Capacity Test (Capacity Test)
  - Flexible Ramp Sufficiency Test
- The RS tests are designed to allow market participation while preventing “leaning” on the resources of neighboring EIM BAAs
- The RS tests do not determine whether an EIM BAA is meeting or can meet NERC/WECC reliability standards
- Capacity held for regulation is not considered as part of the capacity needed to meet RS
- RS tests determine the EIM Entities access to the full market footprint

Base Schedules and Energy Bids

Base Schedules

- A Base Schedule is a forward hourly energy schedule
  - It is the reference for measuring imbalance deviations for EIM settlement
  - It includes generation and interchange schedules, and the load forecast (base scheduled load)
  - It is also used for the Balancing Test
- Participating resource's Base Schedules are due 55 minutes before the operating hour (T-55)
- EIM Entity's final Base Schedules are due 40 minutes before the operating hour (T-40)
  - Provisional base schedules can be submitted as early as a week in advance
- Used for Balancing and Capacity Tests

Energy Bids

- Participating resource's Energy Bids are due 75 minutes before the operating hour (T-75)
  - Bid curves for INCs and DECs
- Energy bids cannot be changed after this time
- Use for Bid Range Capacity and Flex Ramp Sufficiency Tests

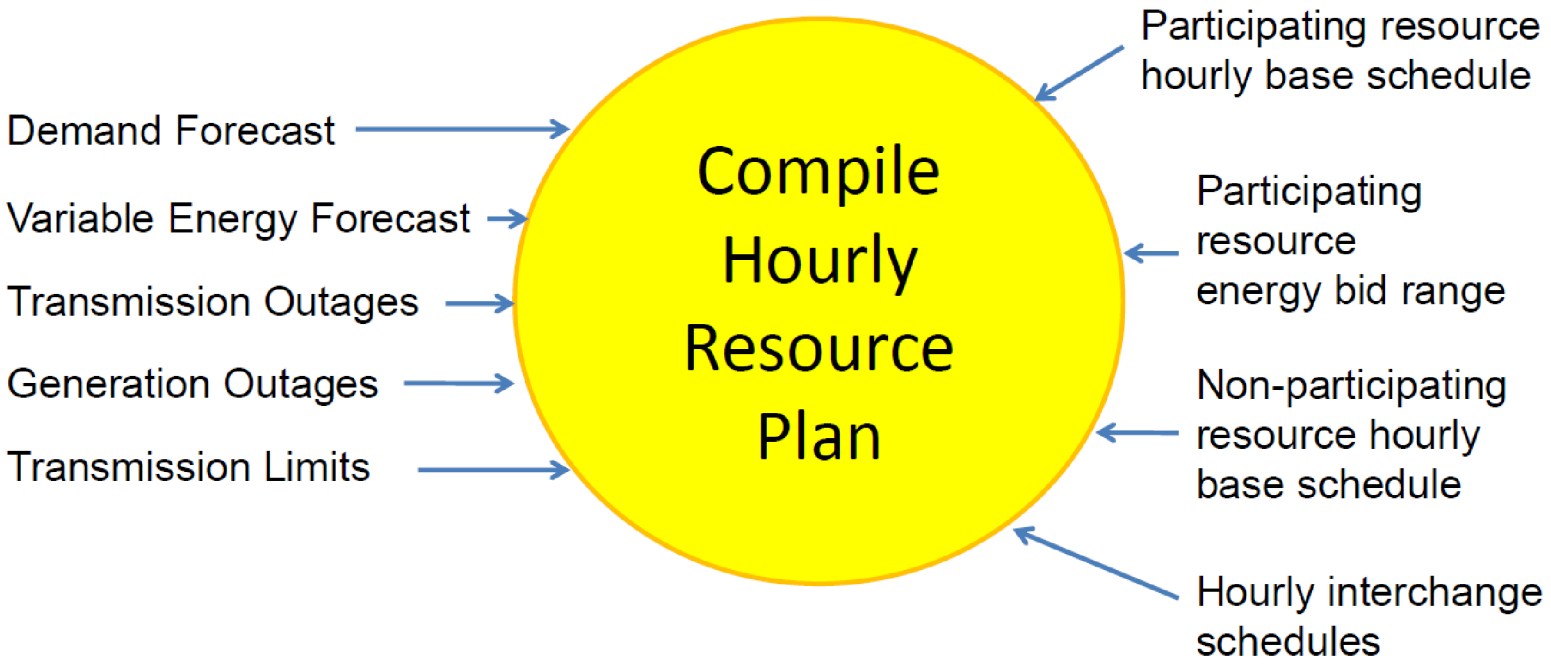
EIM Entity's Resource Plan

EIM Resource Plan

- The EIM Entity submits a resource plan to CAISO every hour, which is evaluated for RS
- The plan contains the resources the EIM Entity plans to use to serve the EIM BAA's load and uncertainty during the operating hour
- The Resource Plan contains:
  - Base schedules for participating resources (PRs), non-participating resources (NPRs), interchanges, and load
  - Energy bids, which are submitted only by participating resources
  - Ancillary service schedules
    - Reserves to meet NERC/WECC contingency reserve requirements
    - Capacity held for ACS, such as regulation service (sub 5-min)

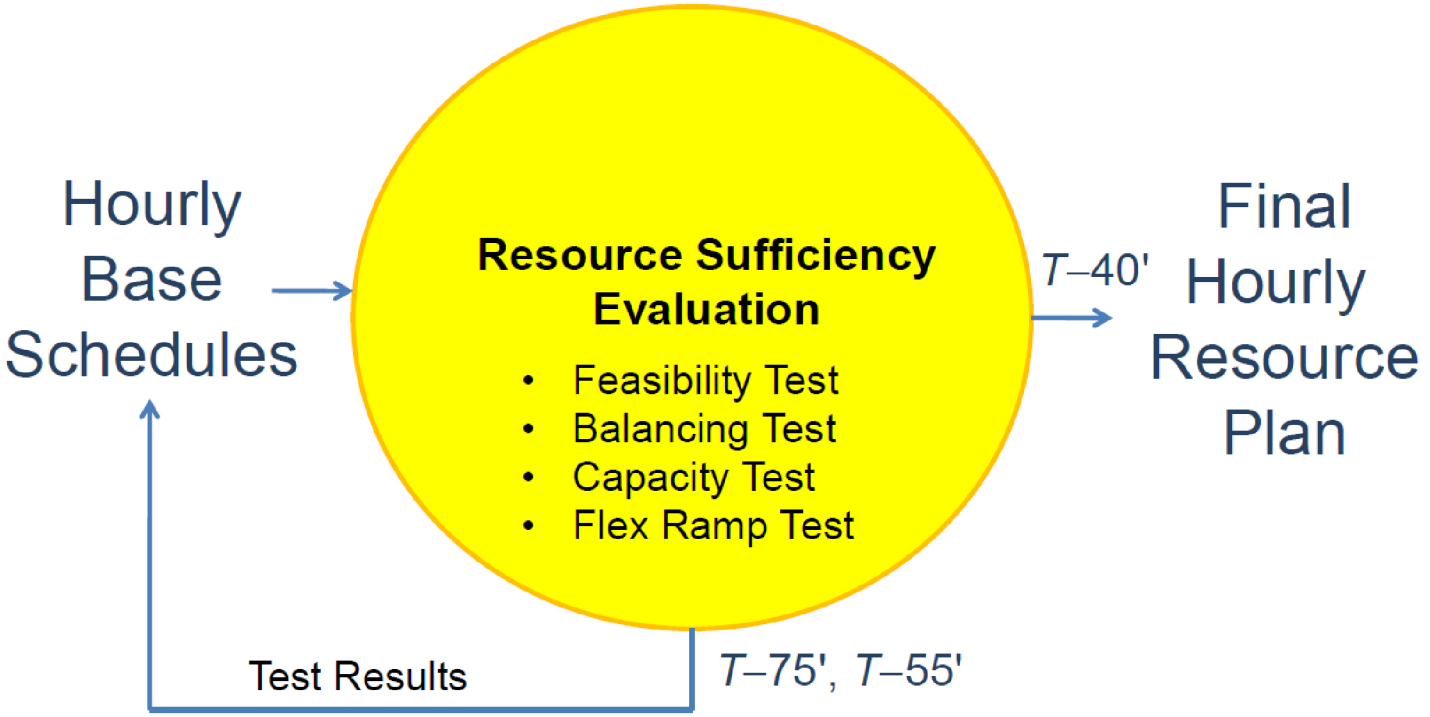
EIM Resource Plan

An EIM Entity must submit a resource plan to CAISO every hour. The plan is evaluated for resource sufficiency.

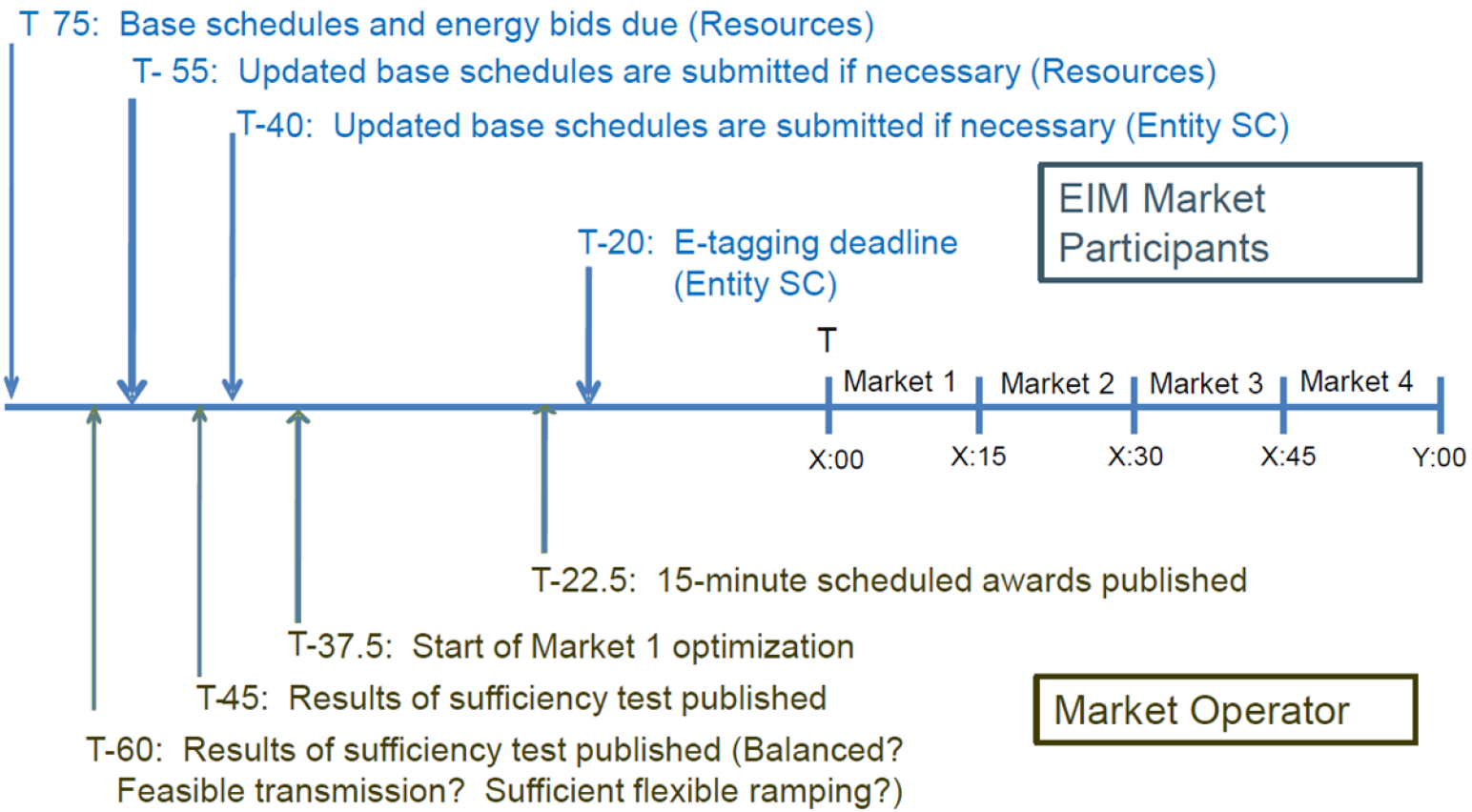


EIM Resource Plan

The resource plan is evaluated for resource sufficiency at T-75, T-55, and T-40, at which point it becomes final. Adjustments to the resource plan are allowed up to T-40.



RS Evaluation Timeline



(T = start of the hour)