Stakeholder Meeting (Q2 2020)

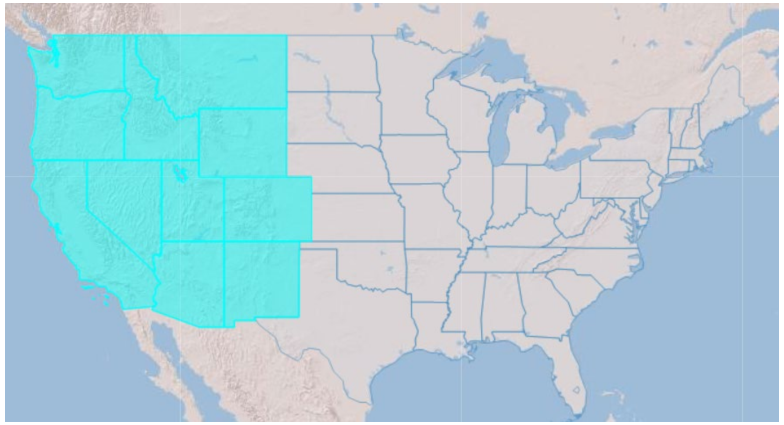
Exploring Western Organized Market Configurations: A Western States' Study of Coordinated Market Options to Advance State Energy Policies (or the "State-Led Market Study")

Webinar
May 1, 2020
1:30 – 3:30 pm MDT / 12:30 – 2:30 PDT

State-Led Market Study made possible through DOE grant

- **The last several years have featured numerous discussions and initiatives related to the formation of coordinated wholesale trading markets in the West**
- **The Utah Governor's Office of Energy Development, in partnership with State Energy Offices of Idaho, Colorado, and Montana, applied for and received a grant from the US DOE to facilitate a 2-year state-led assessment of organized market options**
- **The project is called *Exploring Western Organized Market Configurations: A Western States' Study of Coordinated Market Options to Advance State Energy Policies***
  - ❖ Or "State-Led Market Study"
- **The project provides Western States with a neutral forum, and neutral analysis, to independently and jointly evaluate the options and impacts associated with new or more centralized wholesale energy markets and potential footprints**
- **Today is the third quarterly stakeholder meeting for the project**
  - ❖ Timing of next meeting will depend on whether in-person CREPC/WIRAB meetings take place in October or not

State representatives from 11 Western States are participating in project



Lead Team

- **Representatives on Lead Team represent interest of their respective states but take all stakeholder input into consideration**
- **Work coordinated primarily through monthly calls**
- **Group seeks decisions by consensus**
  - ❖ Formal votes are an option, if necessary

Lead Team	Name	Organization
AZ Lead	Steve Olea	Arizona Corporation Commission
	Bob Burns	Arizona Corporation Commission
CA Lead	Grace Anderson	California Energy Commission
	Yulia Schmidt	California Public Utilities Commission
CO Lead	Erin O'Neill	Colorado Public Utilities Commission
	Keith Hay	Colorado State Energy Office
ID Lead	John Chatburn	Idaho Governor's Office of Energy and Mineral Resources
MT Lead	Jeff Blend	Montana Energy Office, Montana Department of Environmental Quality
	Ben Brouwer	Montana Energy Office, Montana Department of Environmental Quality

Lead Team	Name	Organization
NM Lead	Mark Gaiser	New Mexico Energy, Minerals and Natural Resources Department
	AnnaLinden Weller	New Mexico Energy, Minerals and Natural Resources Department
NV Lead	Hayley Williamson	Nevada Public Utilities Commission
	David Bobzien	Nevada State Energy Office
OR Lead	Kristen Sheeran	Oregon Energy and Climate Change Policy Advisory to Governor Kate Brown
	Letha Tawney	Oregon Public Utilities Commission
UT Lead	Chris Parker	Utah Department of Public Utilities
	Brooke Tucker	Utah Governor's Office of Energy Development
WA Lead	Steve Johnson	Washington Utilities and Transportation Commission
	Glenn Blackmon	Washington State Energy Office at the Department of Commerce
WY Lead	Kara Fornstrom	Wyoming Public Service Commission
	Bryce Freeman	Wyoming Office of Consumer Advocate

Agenda

1. **Introductions - *All***
2. **Project Overview and Progress to Date – *Energy Strategies***
   a) Project Timeline & Status Update
   b) Stakeholder Engagement Plan Reminder
3. **High-Level Review of Technical Work Plan**
4. **Review of Stakeholder Feedback and Lead Team Responses (including Changes to the Technical Work Plan)**
   a) Market Footprints
   b) Capacity Benefits for Various Market Constructs
5. **Updated Workplan Addressing Capacity Benefits**
6. **Public Comment**
7. **Next steps and future meetings – *Utah Office of Energy Development***

Project Overview and Progress to Date

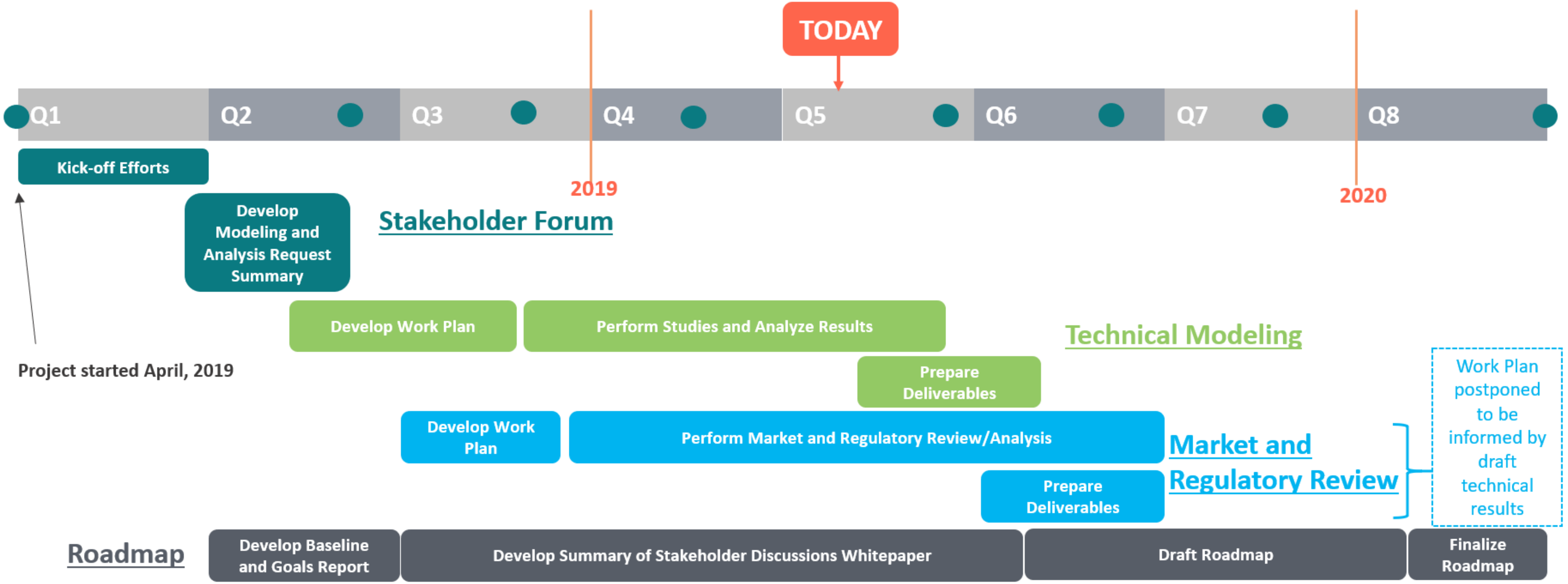
Energy Strategies

Overview of the State-Led Market Study

- **The project uses production cost modeling to evaluate relative operational benefits of alternative market constructs across various footprints**
- **It will also include a market and regulatory review, culminating in a "Market Factor Scorecard" for States to use in evaluating future market proposals in areas which may include energy market offerings, ancillary services, seams issues, transmission planning, transmission cost allocation, public policy considerations, and stakeholder processes**
- **The outcome of this project is a Roadmap that will lay out challenges and provide tools to States to use in evaluating various coordinated market options**

Summary of project timeline

- Two year timeline (eight quarters)
- Stakeholder Forum continues for project duration
- Key deliverables from each work area; body of work feeds into Roadmap



Project Status Update

- **The Modeling and Analysis Request and Guidance Summary is complete:**
  - ❖ Discussed during the October 2019 stakeholder meeting
  - ❖ Forms the basis of modeling and regulatory/market analysis conducted as part of the Technical Modeling and Market/Regulatory Review activities
  - ❖ ***<u>Highlights key technical questions posed by the Lead Team that the project will seek to address</u>***
- **Technical Work Plan**
  - ❖ Generally approved by Lead Team in December 2019 (subject to changes based on stakeholder feedback)
  - ❖ Presented to stakeholders in January 2020 meeting
  - ❖ Stakeholder feedback following that meeting resulted in some changes to the Technical Work Plan
    - ➢ Today's meeting will review feedback received and the key updates made to the Technical Work Plan
- **Technical Modeling efforts are ongoing**
  - ❖ 2020 case build and preliminary runs in progress
  - ❖ 2030 case build ongoing
- **Market & Regulatory Analysis Work Plan has been postponed until the Lead Team reviews draft Technical Results**
  - ❖ This sequencing will provide an opportunity for the Market & Regulatory Analysis to "target" key questions that may arise from the results of the technical modeling effort

Review of Stakeholder Engagement Plan

- **Objective for today's meeting**
  - ❖ Provide stakeholders with information on the feedback received and key changes made to the Technical Work Plan based on stakeholder feedback
  - ❖ Take verbal feedback from stakeholders
  - ❖ Invite the opportunity to provide written comments
    - ➢ Written comments can be submitted to kfraser@energystrat.com through May 15th
    - ➢ Note that we will review comments, but will not respond specifically to each comment received

- **To receive updates and future meeting announcements, navigate to this link to add your name to the project's stakeholder distribution list: http://bit.ly/2nBP6Gt**

- **When possible, we will distribute meeting materials in advance via this distribution list**

High-Level Review of Technical Work Plan

Energy Strategies

Technical Work Plan Status

- **The Technical Work Plan contains more detailed information on how the Contractor will perform the modeling and analysis necessary to address the questions specified in the *Request***
- **Technical Work Plan status**
  - ❖Approved by the Lead Team in December 2019
  - ❖As with the *Request* document, the Technical Work Plan was approved subject to potential modification based on stakeholder feedback either via the formal outreach to utilities/market operators or following this stakeholder meeting
  - ❖Reviewed with stakeholders in January 2020
  - ❖Lead Team considered stakeholder feedback (and responses to targeted outreach to utilities/market operators) and has made some adjustments to the Technical Work Plan in response to feedback received
- **Today's meeting will review feedback received and the key modifications made to the Technical Work Plan**

Study is focused on analyzing three "market constructs":

EIM/Real-Time Market

- ✓ Centrally optimized real-time dispatch – *Day-ahead unit commitment not optimized across market participants*
- ✓ Individual transmission tariffs
- ✓ Limited transmission dedicated to real-time market
- ✓ Balancing Authority Area (BAA) boundaries and associated reliability obligations retained
- ✓ Transmission providers retain operational control of transmission

Day-Ahead Market (DAM)

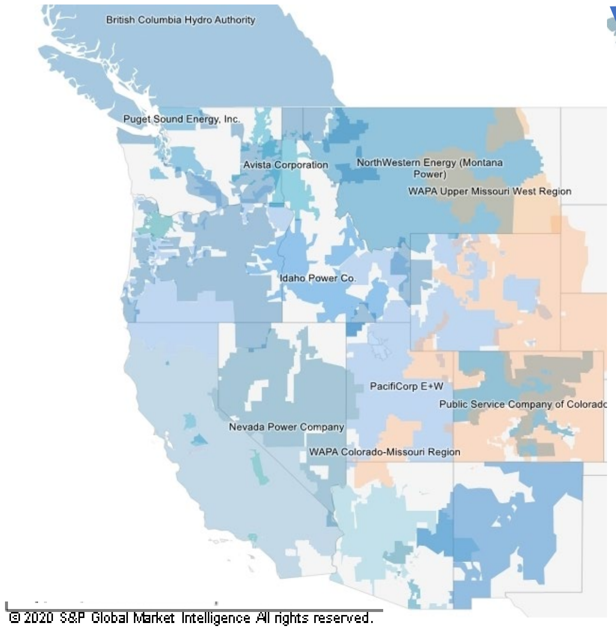
- ✓ Centrally optimized real-time and day-ahead energy market
- ✓ Individual transmission tariffs
- ✓ Limited transmission dedicated to market (other transactions must explicitly pay for transmission)
- ✓ BAA boundaries and associated reliability obligations retained
- ✓ Transmission providers retain operational control of transmission

RTO

- ✓ Centrally optimized real-time and day-ahead energy market
- ✓ Joint transmission tariff for participants in a given footprint
- ✓ Transmission used up to reliability limit
- ✓ BAA boundaries and reliability obligations consolidated
- ✓ Joint transmission planning and cost allocation
- ✓ Transmission providers transfer of operational control of transmission

Review of Market Footprints

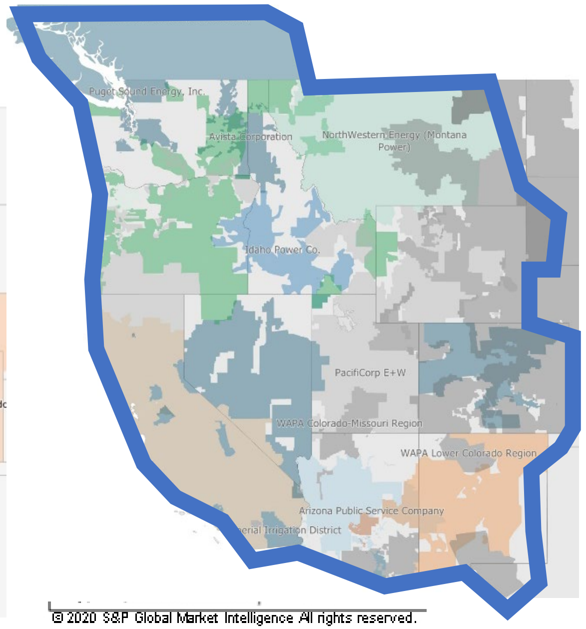
Status Quo



EIM entities that have announced intent to sign EIM Implementation Agreement (or equivalent)*

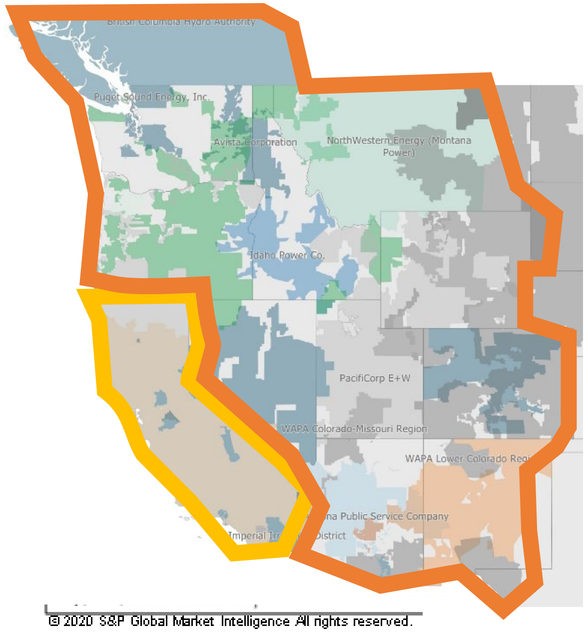
*Announcements that were made before the end of 2019 are included in the Status Quo footprint.

One Market



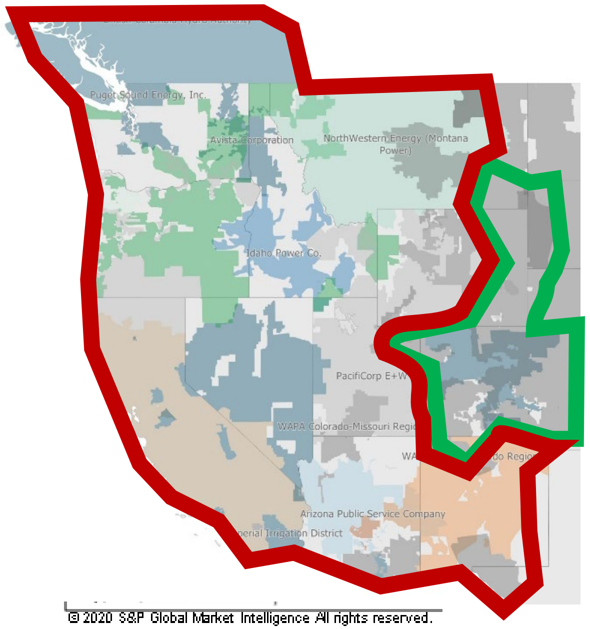
Studied in 2020 and 2030 timeframe

Two Market A



Only studied in 2030 timeframe

Two Market B



Only studied in 2030 timeframe**

**As discussed later in the presentation, the timeframe for studying this market footprint has been adjusted based on stakeholder feedback

Summary of Stakeholder Feedback

Energy Strategies

Utility, Market Operator and Stakeholder Feedback

- **In November 2019, a letter was sent to over 20 utilities and two market operators (CAISO and SPP) providing background on the State-Led Study and requesting feedback on certain study assumptions**
- **Letter requested feedback on specific topics, including:**
  - References to most recent resource and transmission planning documents
  - Input on which units should be modeled as “must-run” in the Status Quo and market cases
  - Treatment of transmission contracts and “remote” resources
  - Suggested data/assumptions for transmission availability
    - Day-ahead market assumptions of particular interest
  - CAISO export limits
  - Modeling of GHG requirements/prices
  - Parameters of Resource Sufficiency testing
- **Nine responses were ultimately received in response to the request by late January**
  - SPP
  - EIM Entities
  - Individual responses from current/future EIM participants, including: APS, Avista, BPA, Idaho Power, NVE, PacifiCorp, PSE
- **Additionally, two sets of comments were received in response to the January 17, 2020 Stakeholder Meeting on aspects of the Technical Work Plan**
  - CAISO
  - American Wind Energy Association (AWEA) and Interwest Energy Alliance joint comments

Stakeholder Feedback & Lead Team Response (part 1)

Comment	Lead Team Response
Must Run Designation: EIM Entities recommend using the WECC base case model which includes resource and load conditions and that any must-run designations not change between market constructs.	***The Technical Work Plan already planned to use the WECC base case model as a starting point. This model does not currently contain substantial information on must-run designations, with only "non-dispatchable thermal" resources (nuclear, geothermal, biomass, co-gen) designated as "must-run." This effectively means there will be no other/reliability related must-run designations in the various cases.***
Transmission Contracts & Remote Resources EIM Entities recommend utilizing the WECC base case model as a starting point and one entity pointed to FERC Electric Quarterly Reports as another data source for long-term transmission reservations.	***The Lead Team agrees with using the WECC model as a starting point and included that approach in the Technical Work Plan. FERC EQR data has been queried but does not appear to offer an efficient means of gathering and inputting other long-term transmission reservation data. In addition to information in the WECC base case, Energy Strategies will utilize other available information sources for remote resource designations and long-term transmission reservations on 3rd party systems.***

Stakeholder Feedback & Lead Team Response (part 2)

Comment	Lead Team Response
Transmission Availability and Cost: CAISO commented that applying a uniform $3/MWh rate to all day-ahead transfers under EDAM would overlook the availability of transfers that could be made at no cost under EDAM's proposed Bucket 1 transmission (resource sufficiency) and Bucket 2 transmission (donated transmission capacity). CAISO recommends exploring potential transmission charges that would apply to Bucket 3 transmission (the portion of transmission that would be subject to an EDAM transmission charge). For a day-ahead market, EIM Entities recommended running sensitives around different rates for Bucket 3 transmission (EDAM transmission that can be sold by the Transmission Provider) to inform stakeholders of the ($/MWh) rate that recovers the costs for the transmission use without harming the market benefits • $3/MWh charge in the EDAM feasibility assessment was selected as a reasonable working assumption but was not an output of a quantitative operational analysis • Hurdle rate that was used for Bucket 3 transmission in the EDAM feasibility assessment was not used for the real-time EIM	*One key principle of the study is not to focus on evaluating details of specific market proposals or potential providers (e.g. EDAM). Thus, the study is not intending to directly replicate the current EDAM transmission design proposal.* *Additionally, the Lead Team does not have sufficient information to make an assumption regarding the quantity of transmission that may be available for "free" in Buckets 1 and 2 within a day-ahead market construct.* *The study will be seeking to use production cost modeling of flows between BAs, along with transmission providers' day-ahead/hourly transmission revenues to "back into" a reasonable hurdle rate that would apply to EDAM transactions.* *Because there will likely need to be consistency in real-time and day-ahead transmission hurdle rates in a DA market, the study <u>does</u> plan to include a hurdle rate on real-time transactions for a DA market construct. But the overall hurdle rate that is necessary to recover transmission revenues will be lower as a result of this approach.*

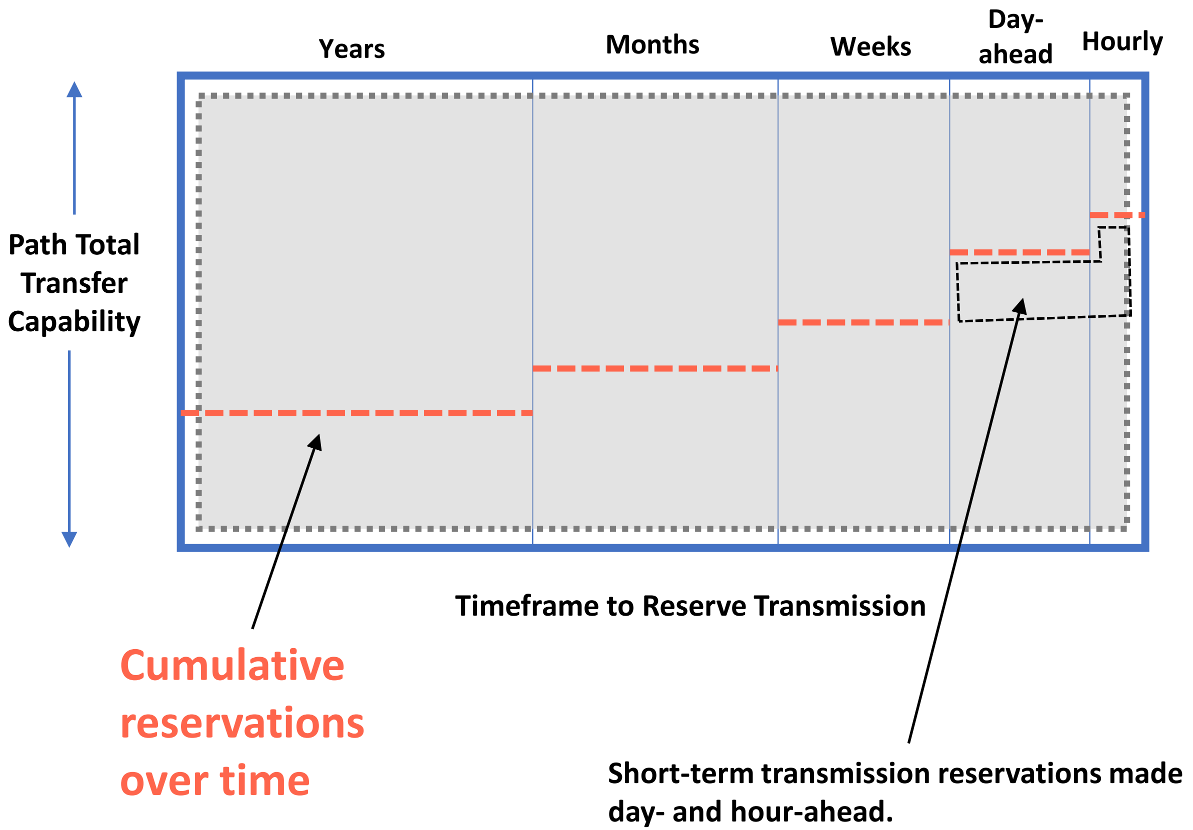
Reminder of DAM transmission rates:

We will seek to reasonably address transmission revenue challenge by testing a price (e.g., $3/MWh), then adjusting it based on actual flows and analysis of historic transmission revenues

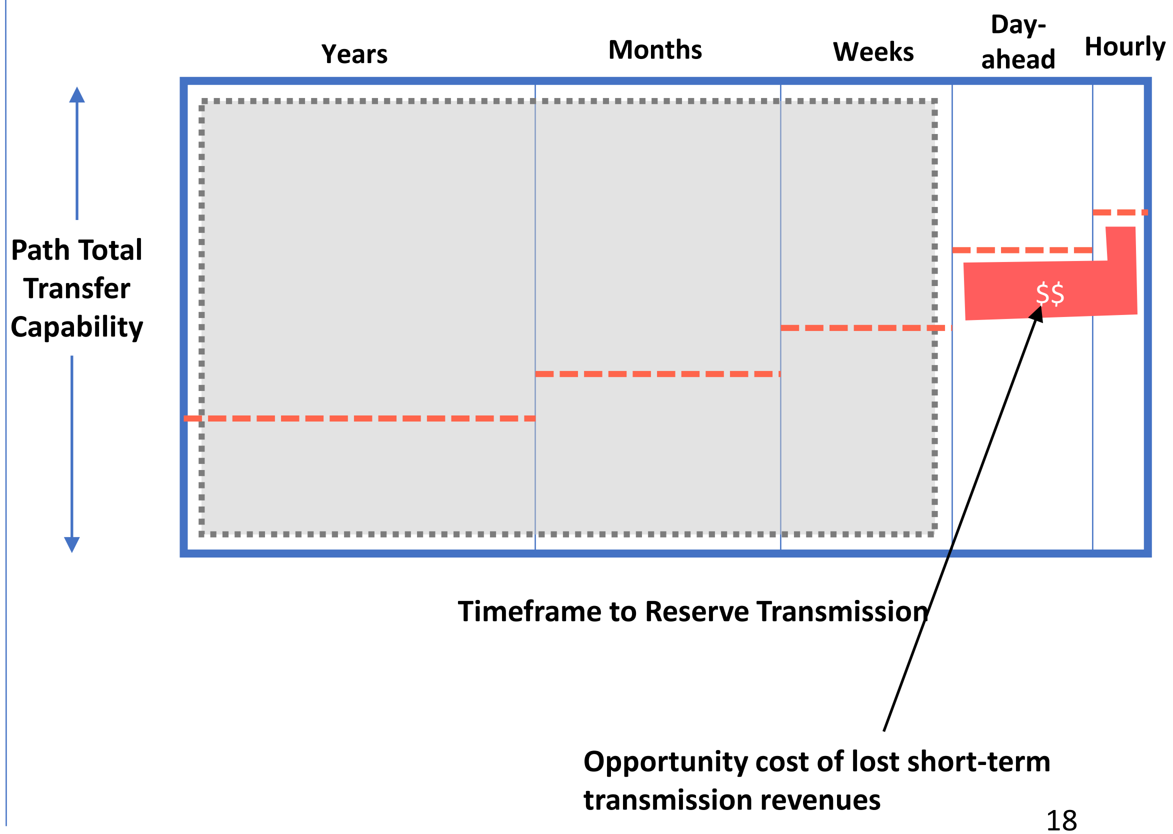
$$ Lost revenues ÷ Available for DAM Transmission used (MWh)

= Estimated market rate for DAM transmission

Today's system



DAM (generic assumptions)



Net Export Limit Importance & Use

- **CAISO Net Export Limit**
  - ❖ A modeling construct to limit exports from CAISO to the rest of the West to reflect existing market realities
    - ➢ In today's market CAISO cannot export an unlimited amount because its neighbors are not willing/able to count on those exports and/or they need to have their own generation running to meet reliability and resource sufficiency requirements, which reduces their ability to utilize exports from CAISO
  - ❖ Serve as a constraint in the model that limits exports to a <u>lower level</u> than the physical capabilities of the system
- **Why does this matter?**
  - ❖ Impacts <u>renewable curtailment</u> calculated by the model
  - ❖ Impacts <u>production cost savings (and benefits)</u> of various market options

Stakeholder Feedback & Lead Team Response (Part 3)

Comment	Lead Team Response
Export Limits Stakeholders note EDAM feasibility assessment used a CAISO net export limit of 5,000 MW in the unit commitment cycle and 7,000 MW in the dispatch and EIM cycles. CAISO suggests applying different CAISO export limits in different market timeframes, to mirror the significant differences that CAISO has found between day-ahead and real-time dispatch. • Day-ahead: CAISO net interchange has not yet resulted in net exports from CAISO • Real-time: CAISO net interchange started showing net exports in 2018 and has increased with the Western EIM expansion and growth of solar resources CAISO's recommended net export limits for day-ahead (commitment) and real-time (dispatch) **under the "Status Quo" and "Real-Time Market" constructs** which are illustrated in the table to the right. **For future market constructs, such as "Day-Ahead" and "RTO",** CAISO recommends that limits be relaxed in an equal manner such that the export is only subject to physical constraints	***The State-Led Market Study is planning to utilize net export limits that have been recommended by CAISO for the Status Quo and Real-Time Market Constructs. For 2030, the CAISO has recommended 2,000 MW net export limit in unit commitment/day-ahead and 7,000 MW net export limit in dispatch/real-time for the 2030.*** ***No net export limits, beyond will be applied to day-ahead and RTO market constructs.***

CAISO Recommended Net Export Limits in Status Quo/Real-Time Market

	Year 2019 Actual	Year 2020 Projected	Year 2030 Projected
Day Ahead (DA)	Import 1,323 MW	Import 1,000 MW	Export 2,000 MW
Real Time (RT)	Export 3,032 MW	Export 5,000 MW	Export 7,000 MW

Stakeholder Feedback & Lead Team Response (part 4)

Comment	Lead Team Response
Resource Sufficiency Tests A Resource sufficiency test was not conducted as part of the EDAM feasibility assessment. Instead each BAA was assumed to have sufficient capacity to cover their obligations. Stakeholders suggested that for the EIM and EDAM market constructs, a resource sufficiency test be performed close to the market optimization time horizon to ensure that each market participant is bringing enough generation to meet their own load obligations for the specific timeframe that the market is running.	***The EIM Entities recommend the State-Led Market Study include a resource sufficiency test close to market optimization time horizon. However, the EDAM Feasibility Assessment did not include this type of a test, nor did the EIM Entities describe the nature of the test that was recommended for this study. Therefore, the Lead Team does not have sufficient information to perform a resource sufficiency test and will, instead, make the same assumption as was made in the EDAM Feasibility Assessment, that each BAA comes to the market resource sufficient.***
Resources Optimized Commitment Status Strongly recommends including real-time unit commitment for fast-start resources in the modeling of the Western EIM, as failing to include this may overlook significant benefits of the Western EIM. Recommends a review of resources that are being made available for optimized commitment in Day-Ahead vs RTO scenario as they could be optimized in the same manner.	***One principle of the study is not to focus on specific market proposals or providers and real-time unit commitment is not always incorporated into real-time markets. Additionally, the modeling tool being utilized does not model intra-hour intervals and, given this constraint, the Lead Team does not believe it can capture real-time unit commitment. Thus, we do not believe the study will be able to incorporate the recommendation to include real-time unit commitmetn.*** ***The study is already planning to optimize unit-commitment of resources in the Day-Ahead and RTO market constructs.***

Stakeholder Feedback & Lead Team Response (part 5)

Comment	Lead Team Response
GHG Emissions Prices, Reduction Requirements, and Accounting Stakeholder note that the application of a GHG framework to a production cost model is extremely complex and suggest a review of CAISO stakeholder working groups to better understand challenges and complexities of incorporating a GHG framework. EDAM feasibility assessment modeled GHG prices only in California, Oregon, Washington and British Columbia and utilized the CEC's high forecast for GHG prices.	***The Lead Team appreciates the complexity of the existing GHG frameworks. The challenges identified by the CAISO during its stakeholder process are understood. GHG accounting and reporting will continue to be explored.***
Natural Gas Price Assumptions EDAM feasibility assessment utilized the CEC's 2019 forecast for natural gas prices.	***The Lead Team appreciates the input and generally agrees with this approach for natural gas price assumptions. The Technical Work Plan already calls for using the most recent CEC natural gas price forecast.***

Stakeholder Feedback & Lead Team Response (part 6)

Comment	Lead Team Response
Modeling Limitations Quoted aspects of the Technical Modeling Work Plan identified as “limitations” that may be problematic: • “Tool does not reflect all market intervals that occur in actual market operations “which may result in wind/solar not being fully accounted for • “Modeling assumes normal weather conditions and does not account for transmission outages, operational de-rates, gas supply reliability issues…” • “Tool does not endogenously model resource retirement or investment decisions”	*The Lead Team appreciates the feedback and offers the following responses on the different modeling issues raised:* • *The model <u>does</u> capture every hour of every day of the year. It does not capture every market <u>interval</u> (i.e. intra-hour intervals), but this approach consistent with a number of market benefits studies (including real-time market benefit studies).* • *While not all outages or fuel supply issues are captured in the model, the model does incorporate outage rates for generators based on expected outage rates.* • *The study will instead rely on resource decisions reflected in the 2028 WECC ADS, utility IRPs and, to the extent additional resources are needed, will look to other studies that have included endogenous resource decisions.*
Study Footprint Recommends removing the Two Market B scenario following a recent announcement from Colorado Joint Dispatch Agreement members (PSCo, Black Hills, Platte River Power Authority and Colorado Springs Utilities) that they intend to pursue participation in the Western EIM in 2021.	*The Lead Team appreciates the input and understands that the Colorado Joint Dispatch Agreement entities have made a decision regarding real-time energy market participation. Given this decision, the Lead Team has removed from the Study Program a case aimed at studying Two Market B as a real-time market footprint. However, no entities have committed to a day-ahead or RTO market construct and thus hypothetical footprints may still offer value to future decision making and consideration by the states.*

Study Program Detail (Changed in Response to Stakeholder Feedback)

Study Year	Type	Market Scenario	Market Footprints: Status Quo	One Market	Two Market A (No CA Expansion)	Two Market B (Mountain West & CA Expansion)
2020	Core Studies	Real-time only	✓	✓		X
		Day-ahead				
		RTO		✓		
2030		Real-time only	✓			
		Day-ahead	✓	✓	✓	
		RTO		✓	✓	✓
	Sensitivities	Real-time only (EIM)	A			
		Day-ahead				
		RTO		A & B	B	A & B

Key

Benchmark

Sensitivity Key

A - Major Transmission Build
B - Carbon Price
C - TBD

Removed following stakeholder feedback and in recognition of decisions made regarding real-time market participation

Stakeholder Feedback & Lead Team Response (part 7)

Comment	Lead Team Response
State-Level Benefits Allocation of production costs on a pro rata basis for each state's load will not capture "any additional economic development benefits from new energy projects that could be incentivized by a certain market design and constructed in a particular state" (e.g., state-specific employment, environmental and other public policy benefits).	***The Lead Team recognizes that the study will not incorporate state-level employment or economic benefits, but it will strive to report of state-level generation development, which may provide an ability for other analyses to consider these types of benefits. Additionally GHG emissions will be reported.***
Benefits Not Quantified Study's approach doesn't equate to a "value maximization" analysis that considers, in addition to production cost savings, reliability and resource adequacy benefits, environmental benefits, and public policy benefits.	***Lead Team recognizes that the study will not capture all benefits of markets and transmission; but notes that some resource adequacy benefits will be captured in assessing a range of capacity benefits for different market constructs and GHG emissions will also be reported.***
Capacity Benefits For Real-Time & Day-Ahead Markets The study intends to quantify the capacity benefit of load diversity in the RTO market structure, but there is also reason to quantify these benefits in a real-time and day-ahead market structure.	***The study intends to capture operational efficiencies of reduced flexibility requirements that result from different market constructs. Based on this feedback and further consideration, the Lead Team also plans to quantify a range of potential capacity benefits for the real-time and day-ahead market constructs (this range will go from a low of zero to a high that is some percentage of capacity benefits achievable in an RTO).***

Overview of Benefits Approach: Relative Benefits Between Market Configurations (at State-Level)

State A production cost savings benefit = Production cost savings for BA with load in State A ✖ (Load in State A / Total BA Load)

State-level Calculation Comparing Two Studies

Cost/Benefit Category	States		
	A	B	…
Adjusted Production Cost Savings			
Capacity Benefit			
Start-up/admin costs (estimated)			
Benefit			

Applies only to RTO Configuration
Capacity requirement of many footprints: X
Capacity requirement of consolidated footprint: Y
Capacity benefit (MW): X-Y
Capacity benefit ($): (X-Y)*(Capacity Value)

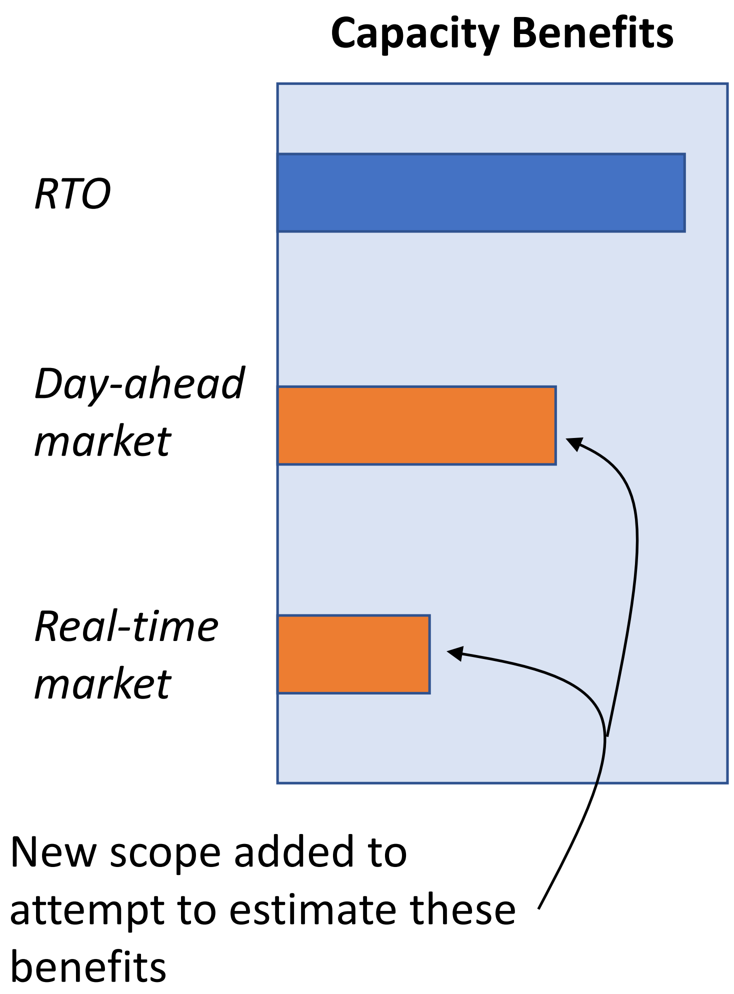
A range of potential capacity benefits will be attributed to real-time and day-ahead market constructs

Study will leverage prior and existing market proposals, and conversations with market providers, to estimate high-level (per MWh or MW) costs for market start-up and administration

Updated Workplan Addressing Capacity Benefits

Overview

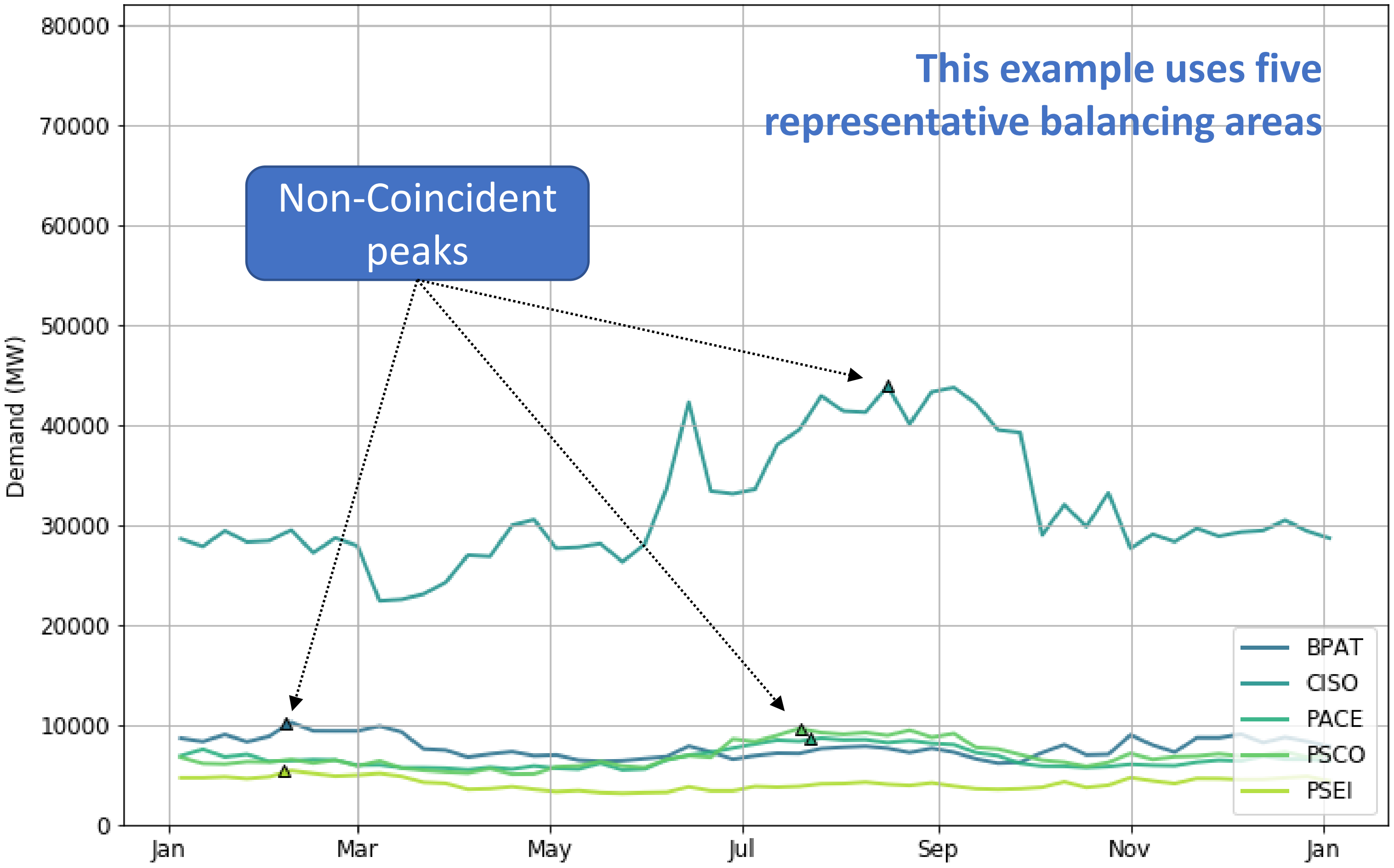
- Prior market benefit studies agree that the largest categories of quantifiable market benefits are:
  - **Production cost savings** from more efficient operations;
  - **Procurement savings** from avoided cost of unnecessary renewable procurement, and
  - **Capacity savings** from load diversity.
- Based on stakeholder feedback, the study scope for the **capacity benefit** analysis to take place as a part of this market assessment **has been expanded** to estimate capacity savings not only for RTO market configurations, but also real-time only markets and day-ahead markets
- The following materials describe the methods and assumptions we propose to use to extend the capacity benefit analysis to additional market constructs



Estimating Capacity Benefits from Market Expansion

- **Peak demand for each Balancing Authority in a given market footprint occurs at different times during the year**

Historical Peak Demand (MW) for BAs in a Conceptual Market Footprint



Estimating Capacity Benefits from Market Expansion

- Peak demand for each Balancing Authority in a given market footprint occurs at different times during the year
- **In absence of regional markets, each BA requires capacity equal to its peak (plus a reliability margin)**

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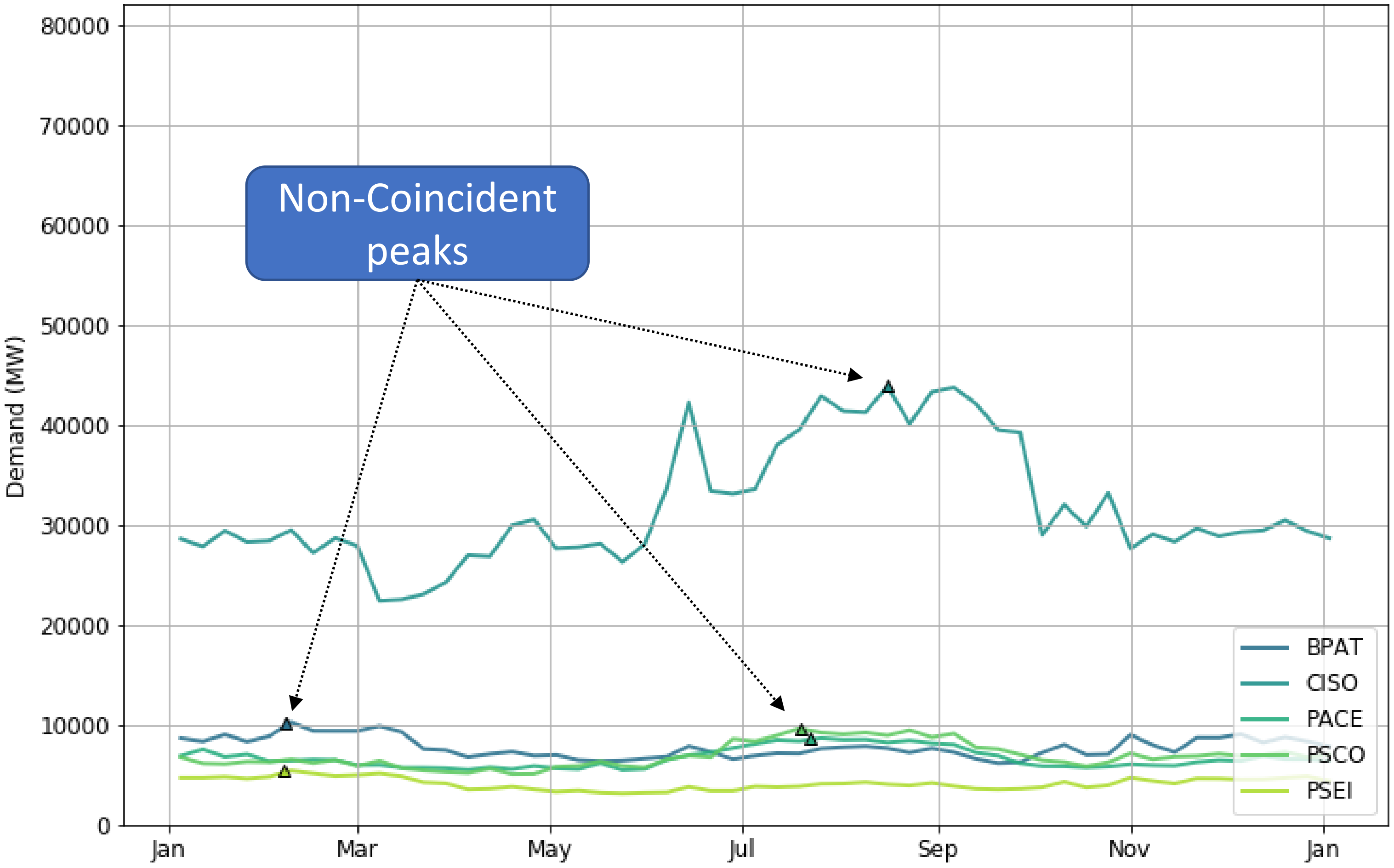
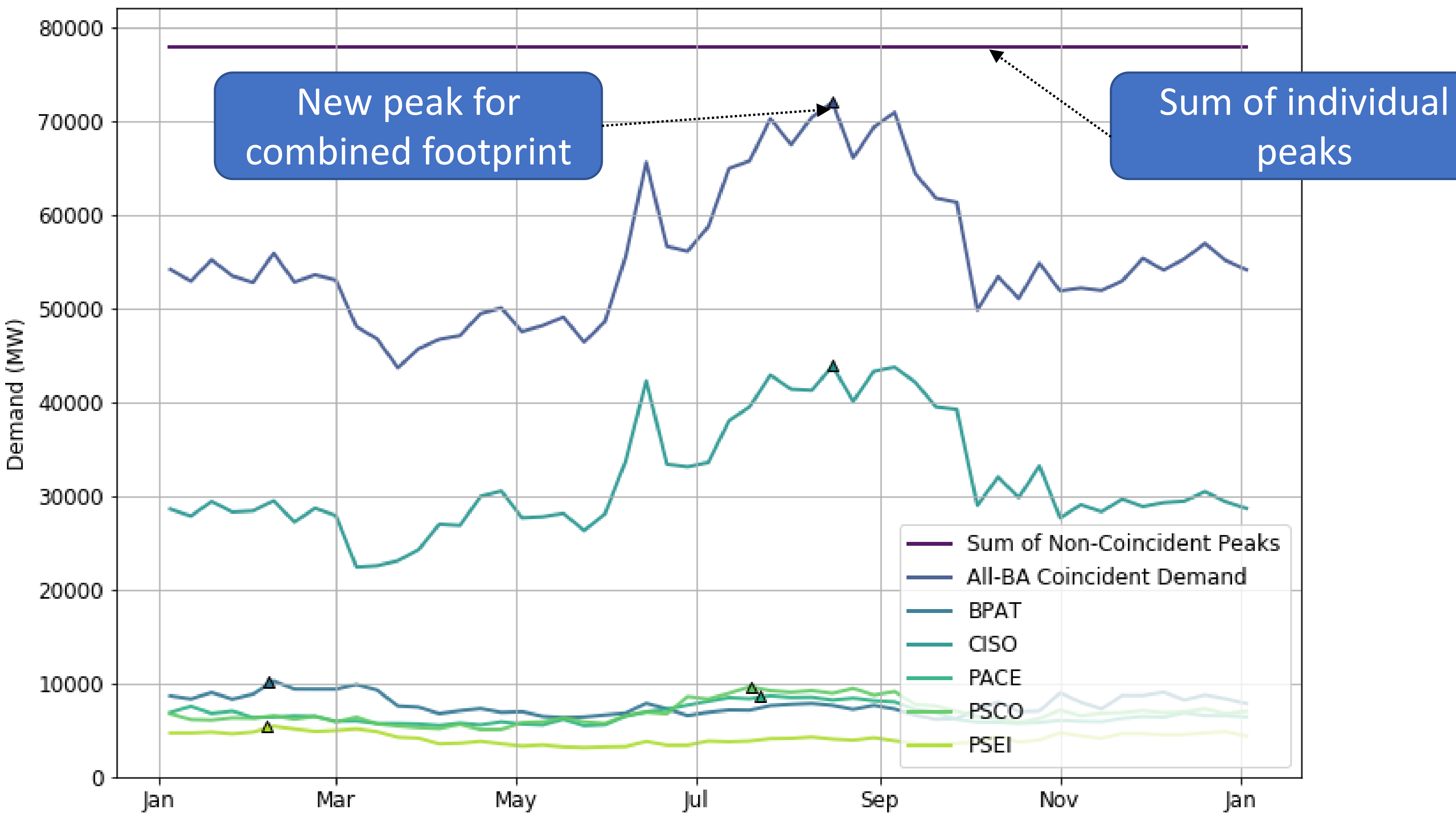


Estimating Capacity Benefits from Market Expansion

- Peak demand for each Balancing Authority in a given market footprint occurs at different times during the year
- In absence of regional markets, each BA requires capacity equal to its peak (plus a reliability margin)
- **The *coincident* peak demand for the combined footprint is usually less than sum of the individual BA peaks**

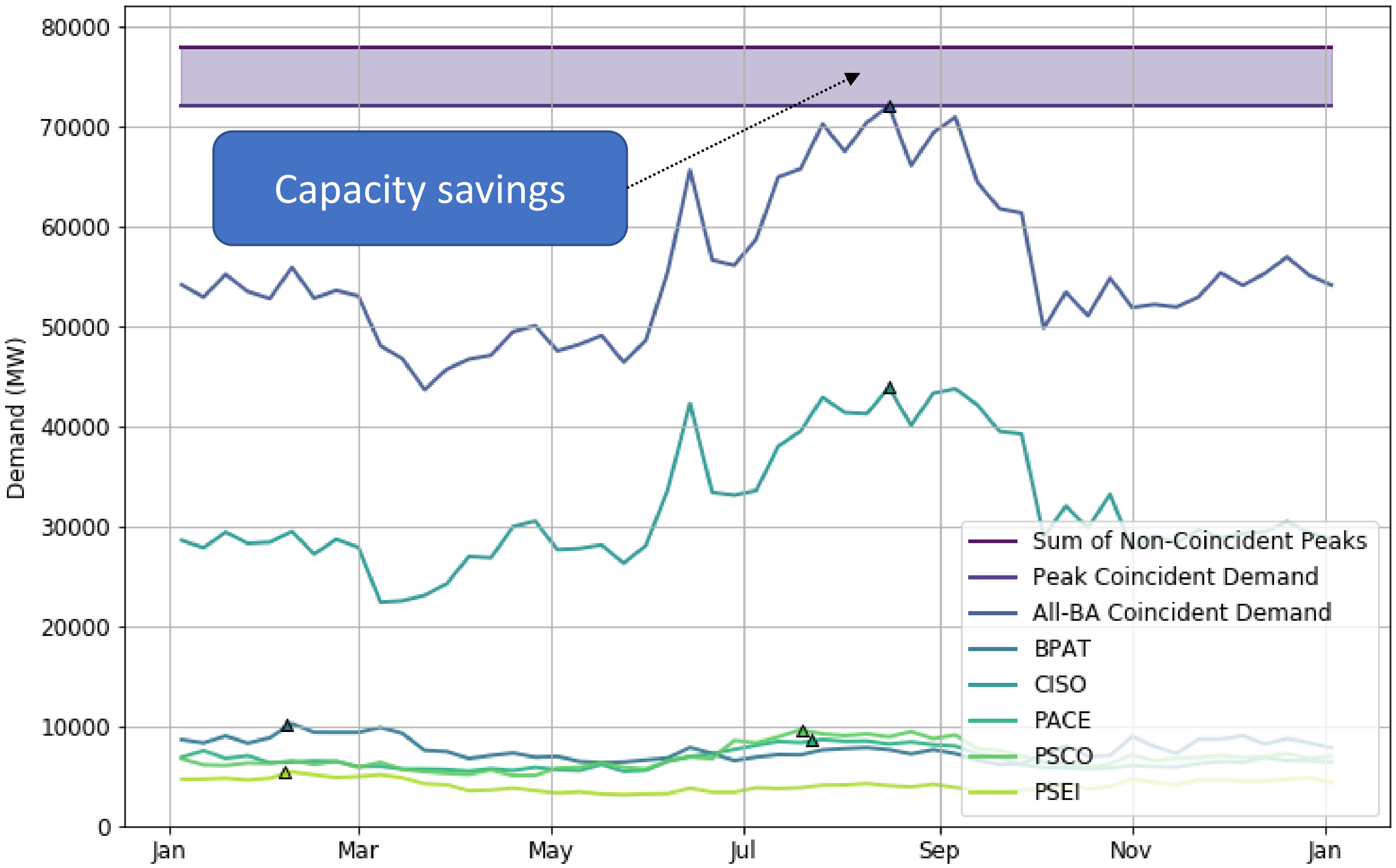
Historical Peak Demand (MW) for BAs in a Conceptual Market Footprint



Estimating Capacity Benefits from Market Expansion

- Peak demand for each Balancing Authority in a given market footprint occurs at different times during the year
- In absence of regional markets, each BA requires capacity equal to its peak (plus a reliability margin)
- The *coincident* peak demand for the combined footprint is usually less than sum of the individual BA peaks
- **Reduction in peak load allows load serving entities to build or contract less capacity to meet resource adequacy needs**

Historical Peak Demand (MW) for BAs in a Conceptual Market Footprint



Overview of Current Methodology

1 Calculate **potential capacity benefit** for each BA in footprint

- BA peak demand compared to its contribution to coincident peak of market footprint
- Capacity savings (MW) determined from hourly demand data

2 **Adjust capacity benefit** for transmission and imports

Methodology considers:

- Maximum import capability of each BA
- Extent to which BA relies on externally-owned capacity in absence of regional market (e.g., existing levels of coordination)

3 **Adjust savings** for market construct and **monetize benefit**

- Various market constructs present a range of savings opportunity requiring adjustments to calculated savings
- Avoided capacity valued changes over time and is unique to study year

4 **Determine capacity savings** across footprint and allocate to states

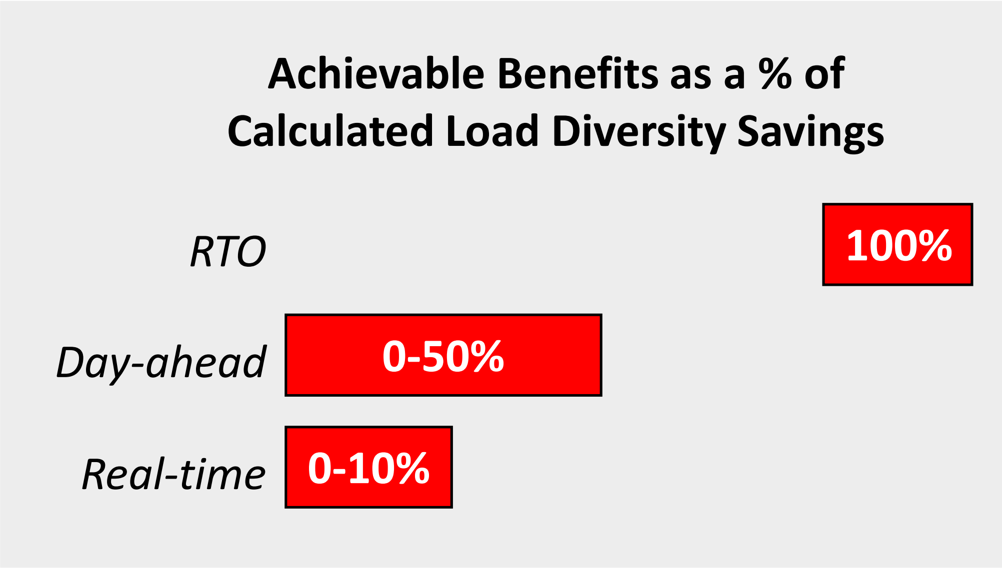
- Unique results for each study year, market footprint, and market construct
- State-level benefits apportioned based on state's % of BA load

Key data inputs:

Hourly load data	Planning reserve margins	Import capability	Net CONE and capacity price

Method will estimate a range of achievable benefits for each market construct

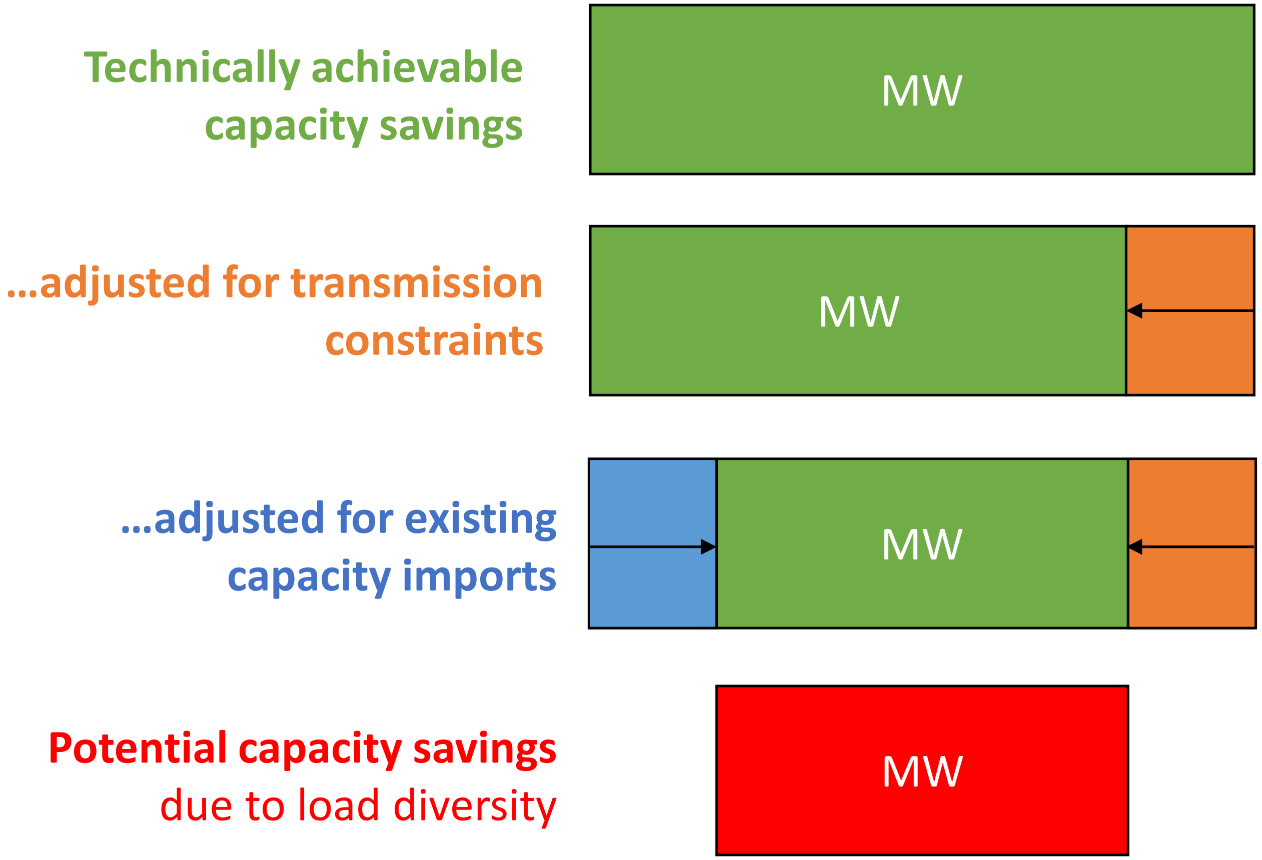
- Assumes that in **RTO scenarios, 100% of calculated load diversity benefits** can be realized
  - ➢ RTO provides structure to capture full benefit of load diversity
- Assumes that day-ahead market scenarios result in realized **savings of 0-50%** of calculated load diversity benefit, recognizing:
  - ➢ Day-ahead markets may not achieve any capacity savings and status quo planning requirements may continue;
  - ➢ However, enhanced price discovery, resource pooling, and access to transmission could cause changes to reliability requirements and coordination levels that allow some amount of load diversity benefits to be obtained.
- **Real-time only markets** are unlikely to results in significant capacity savings, therefore we assume they can achieve only **0-10% of load diversity benefits**
  - ➢ Increased access to the markets real-time imports that support reliability may, over time, lead to slight changes in amounts of reserves held



Approach is to place reasonable bounds on range of capacity benefits provided by various markets such that stakeholders can draw their own conclusions about what level of benefits is most appropriate.

Adjusting Capacity Benefits for Transmission Limits and Existing Coordination

- Method approximates local capacity requirements by taking into account transmission constraints and existing capacity imports
- BA transmission import capabilities
  - ➢ BA import limits determined from WECC path ratings, IRPs, WECC L&R, TTC postings on OASIS, among other sources
- Extent to which BA relies on externally-owned capacity in absence of regional market
  - ➢ Determined through combined effort of reviewing IRPs, leveraging known regional import capabilities, and historical BA interchange data from EIA



Method requires valuing of capacity savings

- Estimated avoided cost of capacity changes over time in recognition of changes in load-resource balance
- Study year 2020 capacity value estimate assumes no generation investment can be avoided but balancing areas can (or could have) not entered into capacity contracts and/or market purchases
- For the 2030 study year, the estimate assumes the value of capacity in the West will increase as capacity shortages appear and the need to construct avoidable capacity exists.
  - ➢ The value of capacity is assumed to be a net CONE proxy for this scenario
  - ➢ Net CONE: Cost of new entry less revenues from energy and ancillary service markets

Value of Avoided Capacity ($/kW-year)

Year	Capacity Cost	Source
2020	$40/kW-year	Based on 2018 CEC Resource Adequacy Report for 2020 capacity
2030	$110/kW-year	Net CONE proxy value

Hypothetical NGCC CONE	$150/kW-year	CEC - Estimated Cost of New Utility Scale Generation in California: 2018 Update
Estimated Net Revenue	$40/kW-year	CAISO - 2018 DMM Annual Report
Estimated Net CONE	**$110/kW-year**	

Recall that range of achievable savings across market constructs varies and serves as sensitivity to total benefit

Comments from Stakeholders

Next Steps and Future Meetings

Request for Written Stakeholder Comments & Next Meetings

- **We invite the opportunity for stakeholders to provide written comments on the items discussed today**
- **Process for submitting comments:**
  - ❖ Written comments can be submitted to kfraser@energystrat.com through May 15th
  - ❖ Note that we will review comments, but will not respond specifically to each comment received
- **Upcoming meetings**
  - ❖ If October CREPC/WIRAB meetings continue (in-person)
    - ➢ In-person meeting will take place with the CREPC/WIRAB meetings to provide an update on results and the Market & Regulatory Review
    - ➢ Later Q4 stakeholder meeting on results (if available)

Appendix

Core Questions

- **Foundational: The only market that we are “assuming” into the Status Quo future is planned expansion of the Western EIM footprint (announced entities). These 2020 and 2030 Status Quo cases will be our primary point of comparison for the other Core Studies.**

1. **In the near-term, what are the relative benefits of expanding EIM markets through either one West-wide footprint versus a two-market footprint system?**
   - 2020: EIM Status Quo vs. EIM One Market
   - 2020: EIM Status Quo vs. EIM Two Market B
2. **What is the 2020-2030 trajectory of benefits, if any, for a One Market RTO?**
   - 2020 RTO One Market vs. 2030 RTO One Market
3. **In the long-term, if the footprint of the Status Quo EIM does not grow, what incremental benefits are provided by adding services to include Day-ahead?**
   - 2030: EIM Status Quo vs. Day-ahead Status Quo
4. **In the long-term, what are the relative benefits of expanding the Status Quo EIM to a larger West-wide footprint while also expanding market services to either day-ahead or Full RTO?**
   - 2030: EIM Status Quo vs. Day-ahead One Market
   - 2030: EIM Status Quo vs. RTO One Market

How to read this terminology:

“EIM One Market”

Market service | **Footprint**

Core Questions (continued)

5. **In the <u>long-term</u>, assuming a day-ahead market forms (but not an RTO), how do the benefits of Two Market footprints compare against the One Market footprint?**
   - ❖ 2030: Day Ahead One Market vs. Day Ahead Two Market B
6. **In the <u>long-term</u>, how do the benefits of Day-Ahead services compare with an RTO in a One Market footprint?**
   - ❖ 2030: Day Ahead One Market vs. RTO One Market
7. **In the <u>long-term</u>, how are the benefits of an RTO impacted by market footprints?**
   - ❖ 2030: RTO One Market vs. RTO Two Market A
   - ❖ 2030: RTO One Market vs. RTO Two Market B

Sensitivities

1. **In the <u>long-term</u>, how do benefits change if more transmission is built?**
   - ❖ 2030: EIM Status Quo vs. EIM Status Quo w/ Transmission
   - ❖ 2030: RTO One Market vs. RTO One Market w/ Transmission
   - ❖ 2030: RTO Two Market B vs. RTO Two Market B w/ Transmission
2. **In the <u>long-term</u>, how sensitive are RTO scenarios to a Federal or West-wide carbon pricing regime?**
   1. 2030: RTO One Market vs. RTO One Market w/ Carbon Price
   2. 2030: RTO Two Market A vs. RTO Two Market A w/ Carbon Price
   3. 2030: RTO Two Market B vs. RTO Two Market B w/ Carbon Price