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Preliminary Day-Ahead Market Impacts Study

IMPACT OF MARKET FOOTPRINTS ON CALIFORNIA CUSTOMERS

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STATE OF CALIFORNIA ENERGY COMMISSION

January 24, 2025

Brattle

Overview of the Study and Drivers of Benefits

Several utilities in CA and neighboring states have committed to joining EDAM, while other utilities in the western U.S. are exploring a different day-ahead market (Markets+) that will not include CA.

- Regional markets deliver cost savings to customers due to efficiency gains, environmental benefits through lower emissions, and reliability benefits by making it easier to manage the grid during extreme weather events.
- This study calculates the benefits to CA customers if additional utilities across the western U.S. participate in EDAM.
- We study 2032 as a proxy for the first decade of market operations
  - We use resource assumptions from utility IRPs and the CAISO's TPP
  - We build off the modeling efforts conducted for over a dozen utilities in the last two years

The benefits of EDAM will depend on the size and diversity of members that join. A larger and more diverse EDAM footprint will deliver more benefits to customers in California.

Market Dynamics and Expected Outcomes

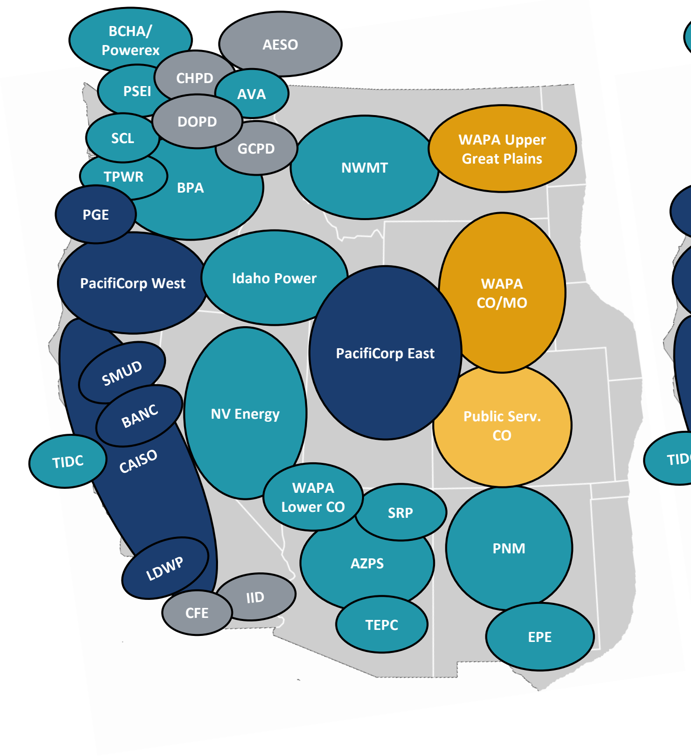
Larger and More Diverse Pool Transmission and Generation Resources	• Shift from less efficient to more efficient resources, leading to production cost savings for customers. *Customer Cost Savings* ⬆ • Emissions potentially decline due to shift to more efficient generation. *Potential Environmental Benefit* ⬌ • Better management of extreme weather events and unexpected grid challenges (e.g., outages). *Reliability Benefit* ⬆ • Reduced sale of short-term transmission service, as transmission is "donated" to the market (offset by EDAM TRR Settlement). *Customer Cost Increase* ⬇
Reduced Curtailment of Wind and Solar due to Increased Resource and Load Diversity	• Lower emissions due to avoided curtailed energy displacing fossil generation. *Environmental Benefit* ⬆ • Lower power costs for customers due to zero variable cost energy displacing higher variable cost energy. *Customer Cost Savings* ⬆ • Better investment environment for renewable projects. *Customer Cost Savings* ⬆
Increased Trading between Market Members	• Reduced bilateral trading as markets trades become more profitable, lost bilateral trading margins. *Customer Cost Increase* ⬇ • Increased market congestion and transfer revenues. *Customer Cost Savings* ⬆

Simulated Market Footprints

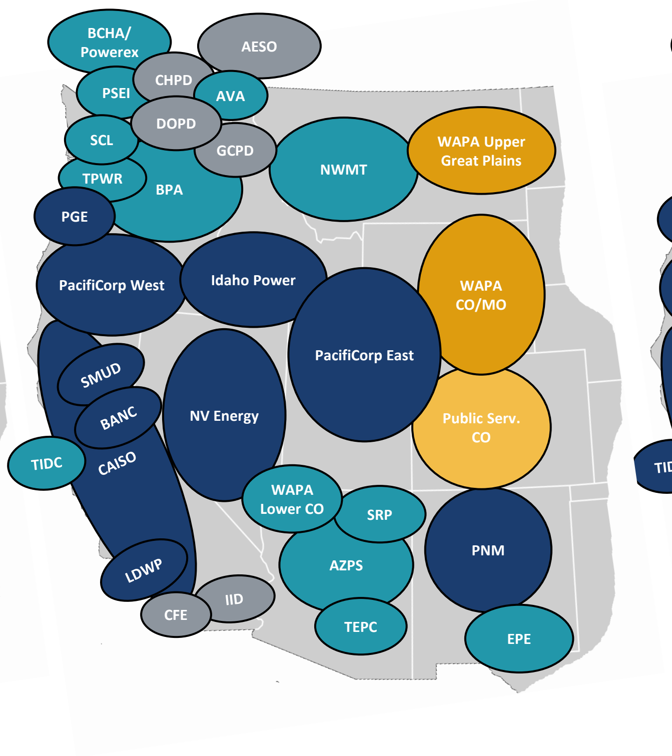
Markets+ (DA & RT)
EDAM (also in WEIM)
SPP RTO West *(co-optimizes w/ M+)*
WEIS
WEIM

To test the impacts for California DA market participation benefits of several potential DA market outcomes, we simulated four market footprints

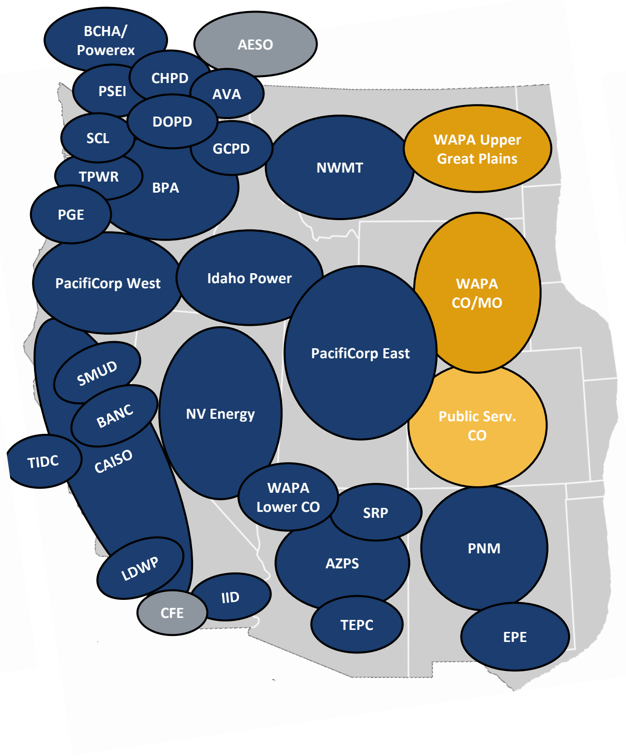
Baseline Case
(Approved EDAM Commitments)



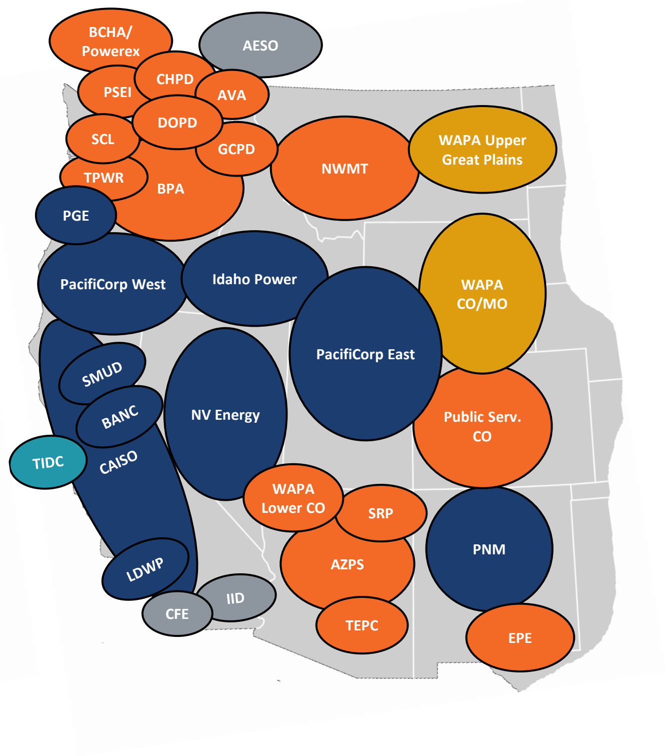
Baseline+ Case
(Likely EDAM Commitments)



Expanded EDAM Case
(Maximum EDAM Potential)



Split Market Case
(Likely EDAM Entities w/ Markets+)

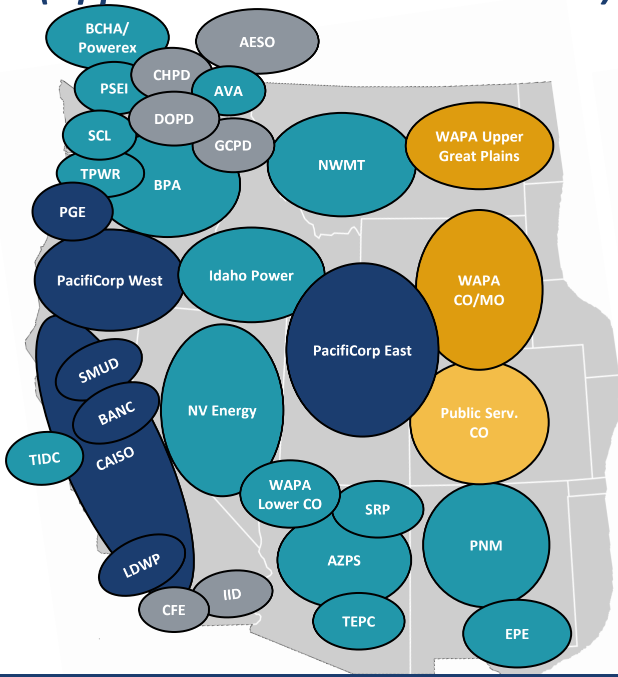


CA Customer Benefits Increase with the Size of the EDAM Footprint

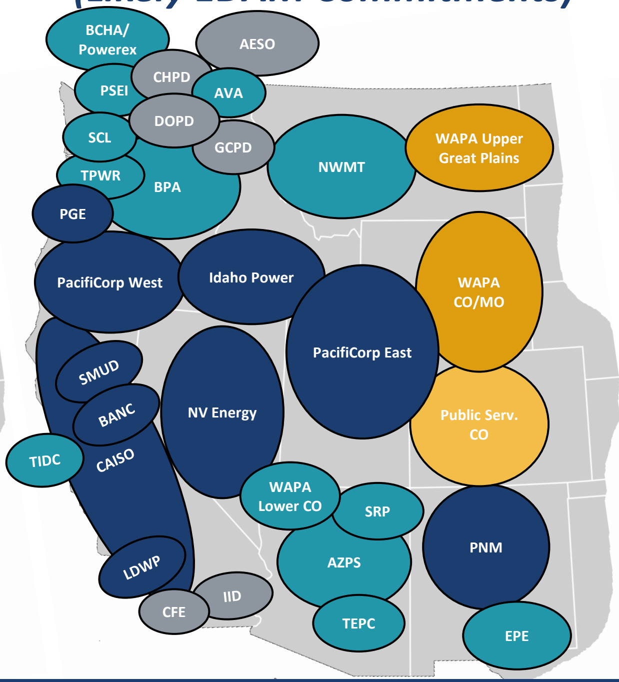
EDAM (also in WEIM)
SPP RTO West
WEIS
WEIM

Expansion of EDAM footprint could produce over $500 million/year in market benefits to CA customers

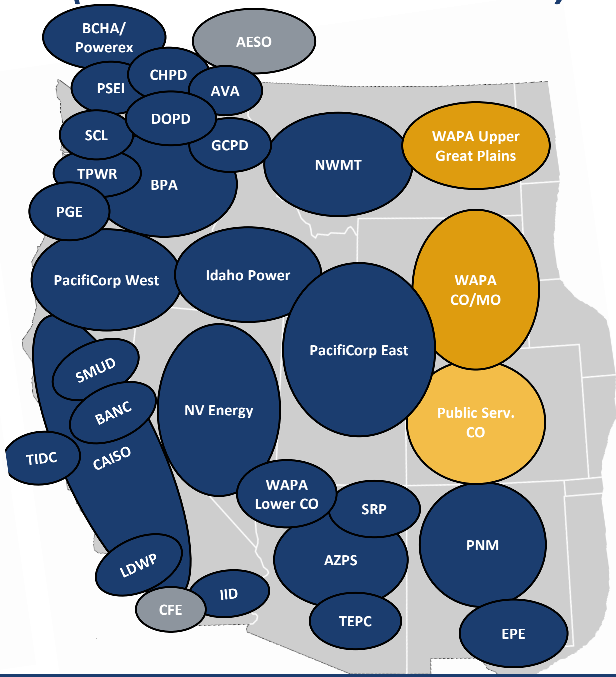
Baseline Case
(Approved EDAM Commitments)



Baseline+ Case
(Likely EDAM Commitments)



Expanded EDAM Case
(Maximum EDAM Potential)



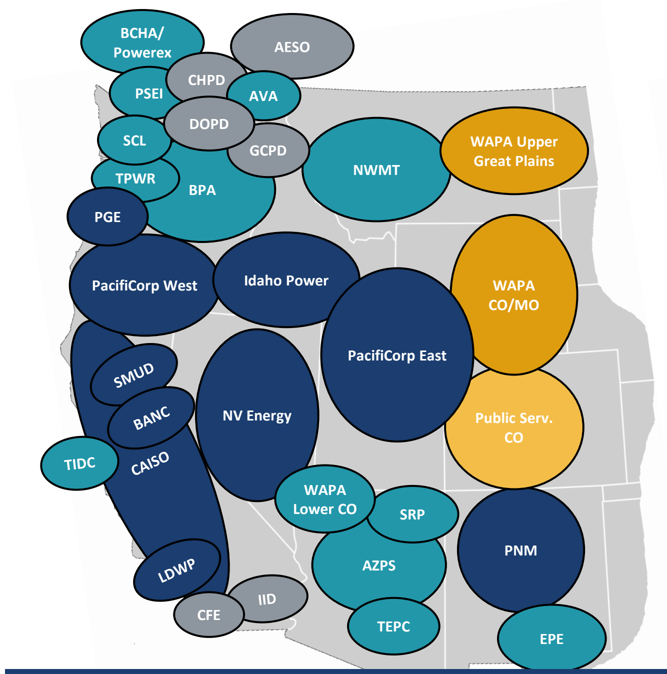
	Baseline Case	Baseline+ Case	Expanded EDAM Case
CA Total System Cost ($million per year)	**$4,511**	**$4,399**	**$3,721**
Δ to Baseline		**$112**	**$790**
Δ to Baseline+			**$678**

- These benefits are incremental to the benefits of the formation of EDAM with the Baseline footprint of committed entities
- Intermediate EDAM footprints likely to produce benefits between the Baseline+ and Expanded EDAM "bookend"

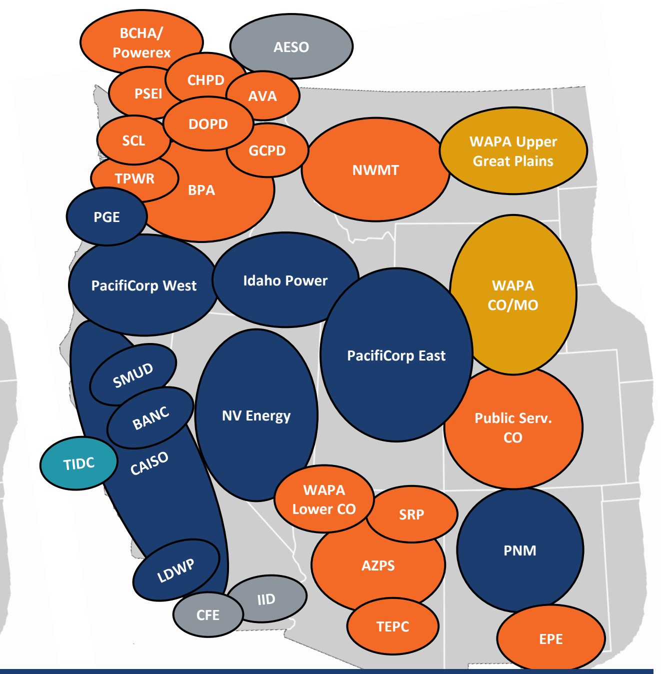
Markets+ (DA & RT)
EDAM (also in WEIM)
SPP RTO West
WEIS
WEIM

California Benefits from a Two Market Outcome

Baseline+ Case
(Likely EDAM Commitments)



Split Market Case
(Likely EDAM Entities w/ Markets+)
(Assumes Relatively Efficient Seams)



	Baseline+ Case	Split Market Case
CA Total System Cost ($million per year)	$4,399	$4,217
Δ to Baseline+		$182

CA Benefits ~$500 million/year higher in the Expanded EDAM Case *(see previous slide)*

Two offsetting effects lead to a small gain for CA customers in the Split Market case:

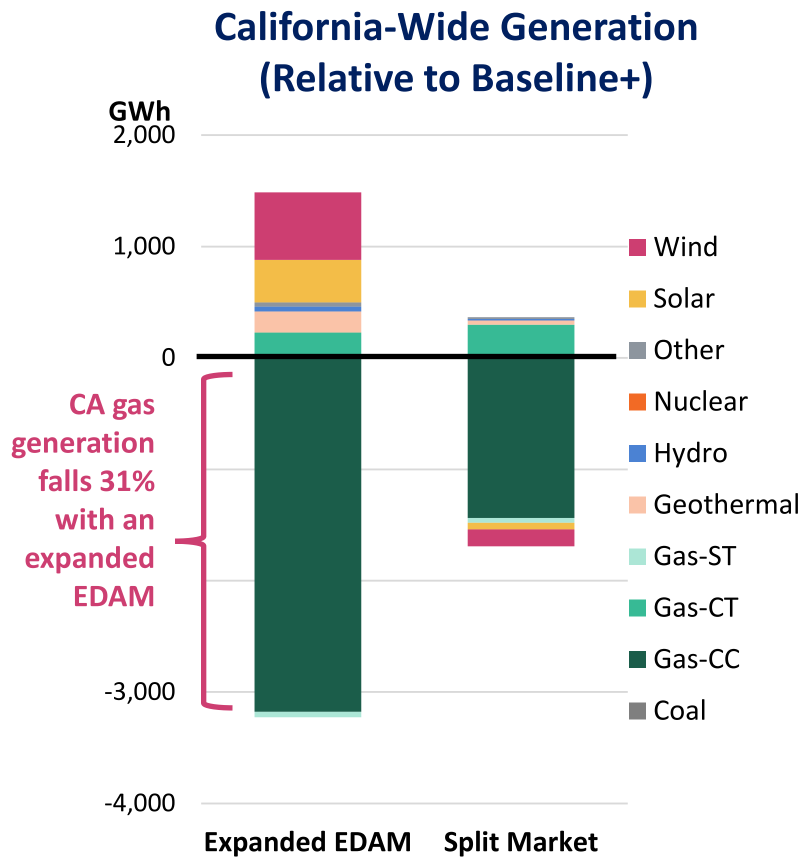
- CA customers experience a loss from utilities leaving the WEIM *(~40% of load in WEIM today).*
- CA customers benefit from increased access to low-cost resources in the M+ footprint due to elimination of seams in the WECC and increased DA trading at the market seam.

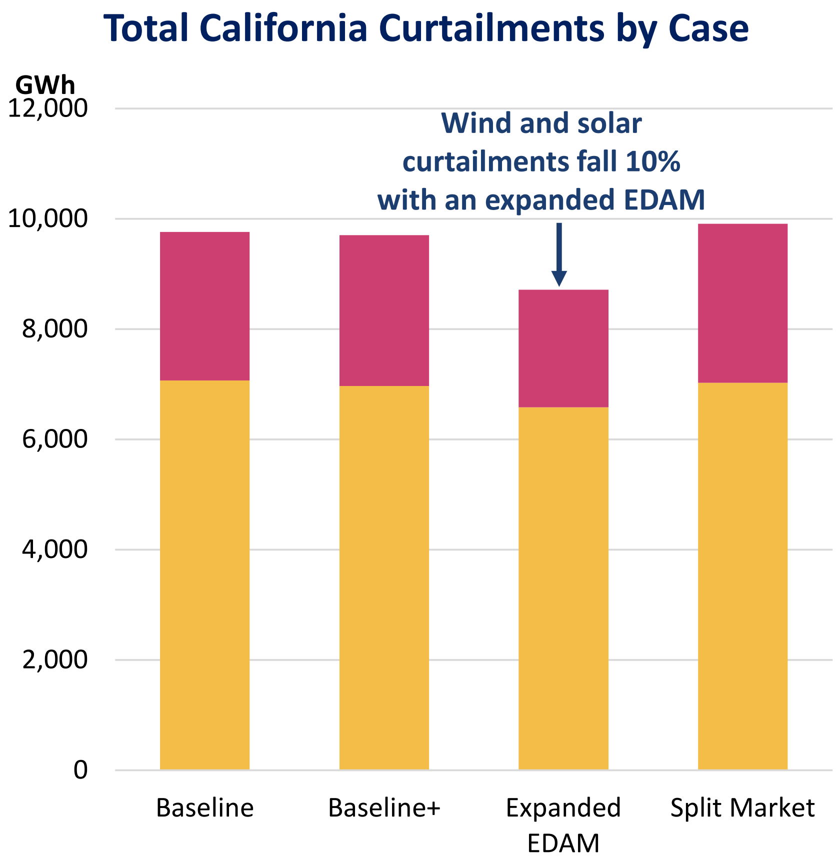
Several assumptions drive this result:

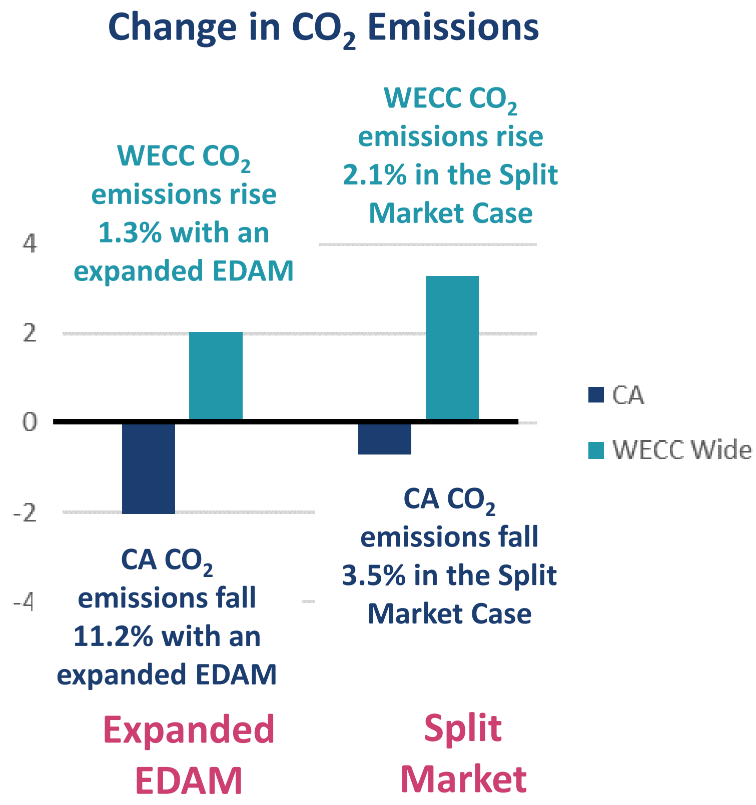
- A relatively efficient seam between M+ and EDAM *(lower trading costs than bilateral trading in the Baseline cases).*
- Hourly modeled real-time trading at the seam fails to capture full loss from utilities leaving WEIM, which optimizes on a sub-hourly level.
- M+ co-optimizes with RTO West, giving low-cost thermal resources in that region hurdle-free access major CA import locations (*e.g.*, Malin, PV).
- The Split Market case assumes ~60% of load in the WEIM today joins EDAM; assuming more of the WEIM leaves would increase the loss to CA customers.

GHG Emissions Impacts

The expansion of EDAM reduces gas generation and the curtailment of wind and solar in California, resulting in lower GHG emissions in the state.





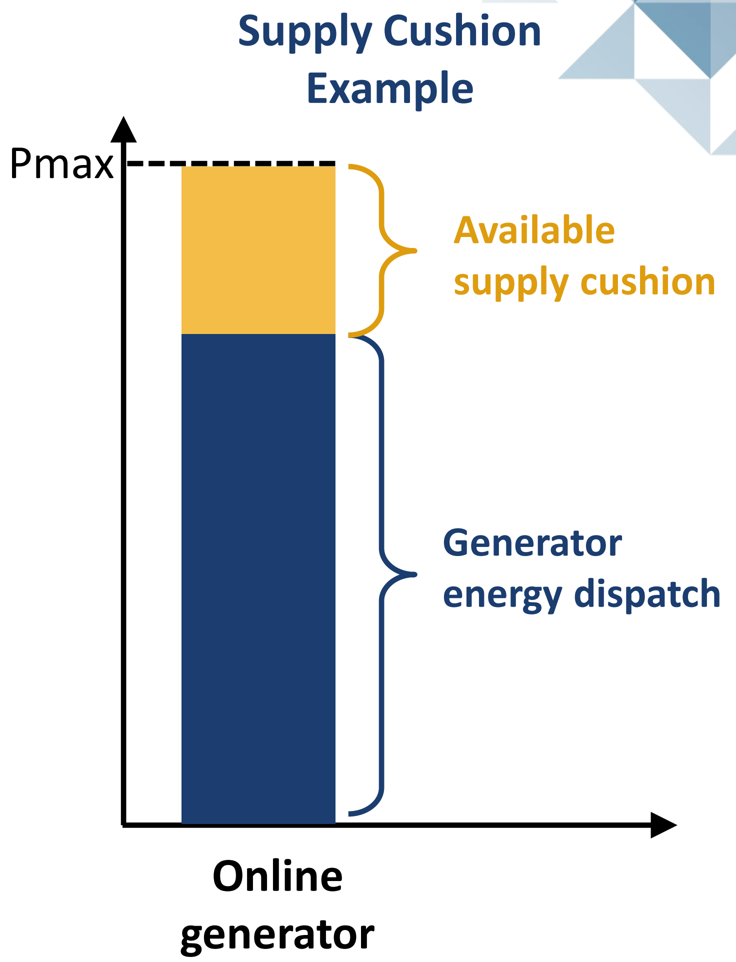


Market Supply Cushion Overview

Market supply cushion is the total unutilized capacity accessible by participants from available market generation in each hour, i.e., the available generating capacity not committed to serving load.

- It *includes* generators that are online and below maximum output
- It *excludes* resources that are on planned or forced outage
- Storage resources are further limited by their stored energy
- We conservatively assume that hydro, wind, and solar provide no incremental supply cushion.

We use this metric as a proxy for the impacts of market footprint on access to capacity, especially during tight-supply periods with high risk of resource adequacy shortfalls.



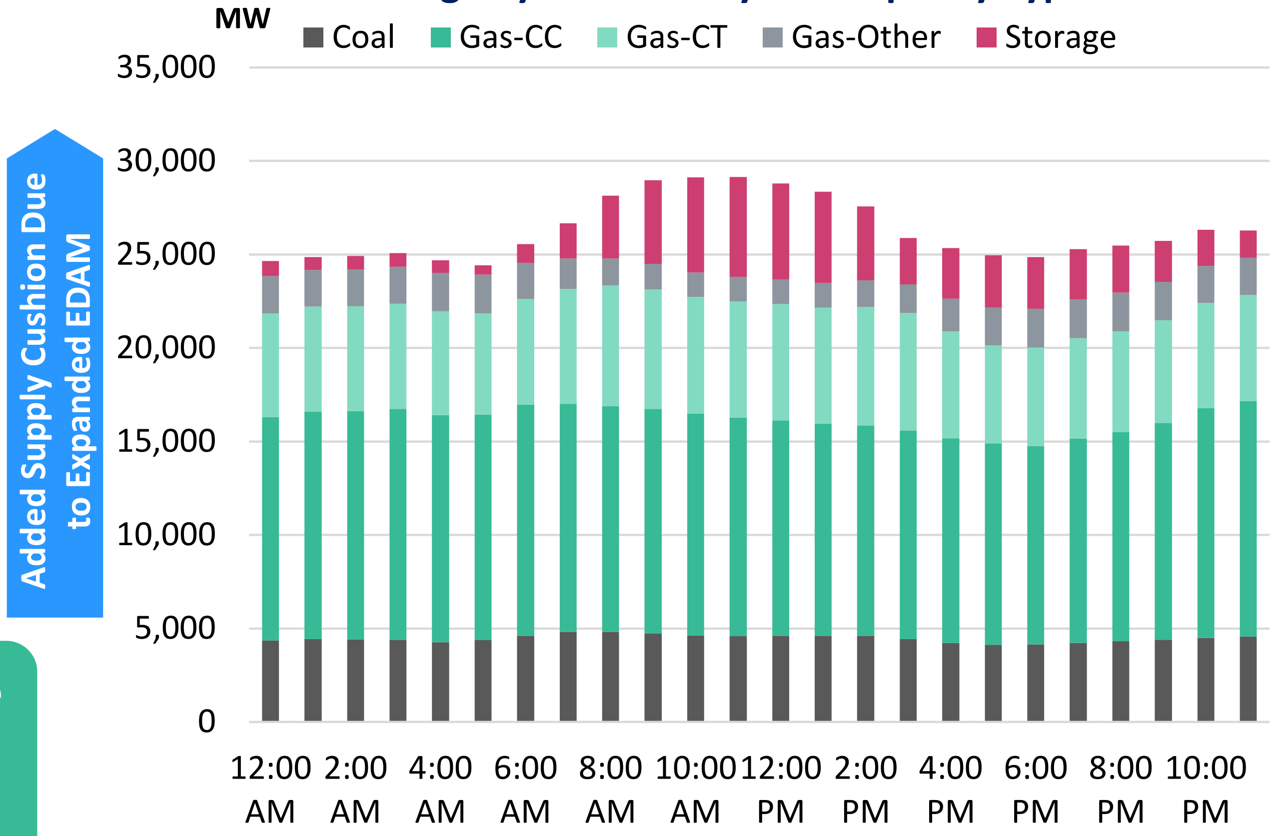
Expanding the EDAM footprint Increases Supply Cushion

The supply cushion in the EDAM footprint is significantly higher in the Expanded EDAM case relative to the Split Market case.

- The supply cushion is ~25,000 MW more in the Extended EDAM case than the Split Market case.
- Higher supply cushion in midday hours when storage is charging.
  - The Expanded EDAM case has more storage in the EDAM compared to the Split Market case, as well as a higher average state-of-charge due to increased renewables diversity in the larger footprint.

Focusing on the 10 tightest hours of the year, the supply cushion in the EDAM is 20,000 MW larger in the Expanded EDAM case than in the Split Market case (27.8% of load vs. 24% of load)

Expanded EDAM Case *minus* Split Market Case
Day-Ahead Market Supply Cushion
Average by Hour of Day and Capacity Type



Estimated Benefits are Conservatively Low

The benefits of regional markets are likely understated due to several factors:

- **Overstated Bilateral Market Efficiency:** our simulation of bilateral markets is more efficient than reality
  - Hourly model fails to captures the benefit of real-time markets to economically and reliability manage energy imbalances through sub-hourly re-dispatch and energy exchange across market members.
  - The model assumes all balancing authorities have optimal security-constrained unit-commitment and dispatch (SCUC and SCED) in both DA and RT, making the simulated dispatch more optimal than reality.
  - Inefficient utilization of transmission by bilateral trades is not fully modeled, understating the extent M+ and EDAM will be able to make better use of all physically and contractually available transmission.
  - Transmission outages are not modeled, which would magnify the benefit of SCED-based congestion management in EDAM and M+ compared to the bilateral markets.
- **Normalized loads and fuel prices:** the model uses weather-normalized loads and averaged monthly natural gas prices without daily volatility
  - Challenging market conditions (beyond the included heat wave and cold snap), such during as the 2022 gas price spikes or 2024 MLK Day cold snap, will magnify benefits from a regional market. Illustrated by the WEIM experience of much higher benefits during those events.
  - The Base Case does not reflect the limited liquidity of bilateral market during challenging market conditions

Brainstorming Possible Further Analysis

The four cases simulated provide significant insight on the impact of market expansion for CA and raise questions for future analyses to address.

- **Footprint Assumptions:**
  - Simulate a "Status Quo" case without any EDAM footprint, which would allow us to calculate the benefit of EDAM forming relative to just the WEIM.
  - The Expanded EDAM and Split Market cases represent two approximate bookends, we could test intermediate footprints with different combinations of utilities joining EDAM or Markets+.
- **Market Seam Assumptions:**
  - The level of coordination that will be achieved between the two markets is unknown. Future sensitivities could explore the impact to CA customers of different forms coordination and co-optimization across market seams.
  - Sub-hourly modeling could be used to calculate the benefit of 15-minute and 5-minute optimization conducted by the WEIM for CA customers and WEIM/EDAM members.
- **Resource mix, load forecasts, and fuel price assumptions**
- **Impact of extreme weather volatility**
  - Weather-relative system conditions – load, thermal generation outages, and renewable production
  - Daily and regional gas price volatility

Appendix A:
Modeling Assumptions and Detailed Results

Timeline of the Brattle Team's Western Markets Studies

The nodal WECC model we used for this study includes system-specific data from more than a dozen utilities in the WECC, giving us a detailed view of the western system, including:

- Long-term transmission rights, contracted resources (and transmission encumbrances), generation additions, transmission additions, renewable diversity and forecast errors, and market design detail/implementation
- **Study participants have helped refine our model by performing full reviews** of relevant modeling assumptions for their systems, including transmission rights & costs, load forecasts, fuel prices, generation mix & costs, etc.
  - Study participants include **the Balancing Authority of Northern California, El Paso Electric, Idaho Power, LA Department of Power and Water, NV Energy, Portland General Electric, PacifiCorp, Public Service Company of New Mexico, Sacramento Municipal Utility District,** and other utilities, transmission owners and independent power producers
  - Several of these reviewers were able to provide **details relevant to the CA system**, including input from CAISO and others

1 Pre-2022 Studies

Western Market Studies
- EDAM Feasibility Study
- SPP RTO Expansion Study
- CAISO EIM GHG Structure Study
- Xcel Colorado WEIS/WEIM Study
- WEIS and SPP Integration Study
- Mountain West RTO Study
- CA SB350 Study

2 2022 EDAM Study

2022 EDAM Benefits Study
We produced an updated assessment of EDAM benefits for five study participants, building on the work done for the 2019 EDAM feasibility study:
- BANC, Idaho Power, LADWP, PacifiCorp, SMUD

3 2023-24 EDAM-M+ Studies

Comparative EDAM-M+ Studies
We further refined our 2022 EDAM benefits study model with input from study participants and the Markets+ design documents to conduct benefits studies for several additional utilities , including:
- Portland General Electric, NV Energy, Public Service New Mexico, El Paso Electric, and others

4 This Study

CEC Pathways Study
We leveraged our work and modeling enhancements from all prior studies to assess the value of a nearly-WECC-wide day-ahead market (i.e., an EDAM with a large footprint) compared to an outcome with two competing day-ahead markets in the WECC (i.e., split between EDAM and Markets+).

Multi-Functional Simulation of WECC

Markets/RTO Functions & Configurations

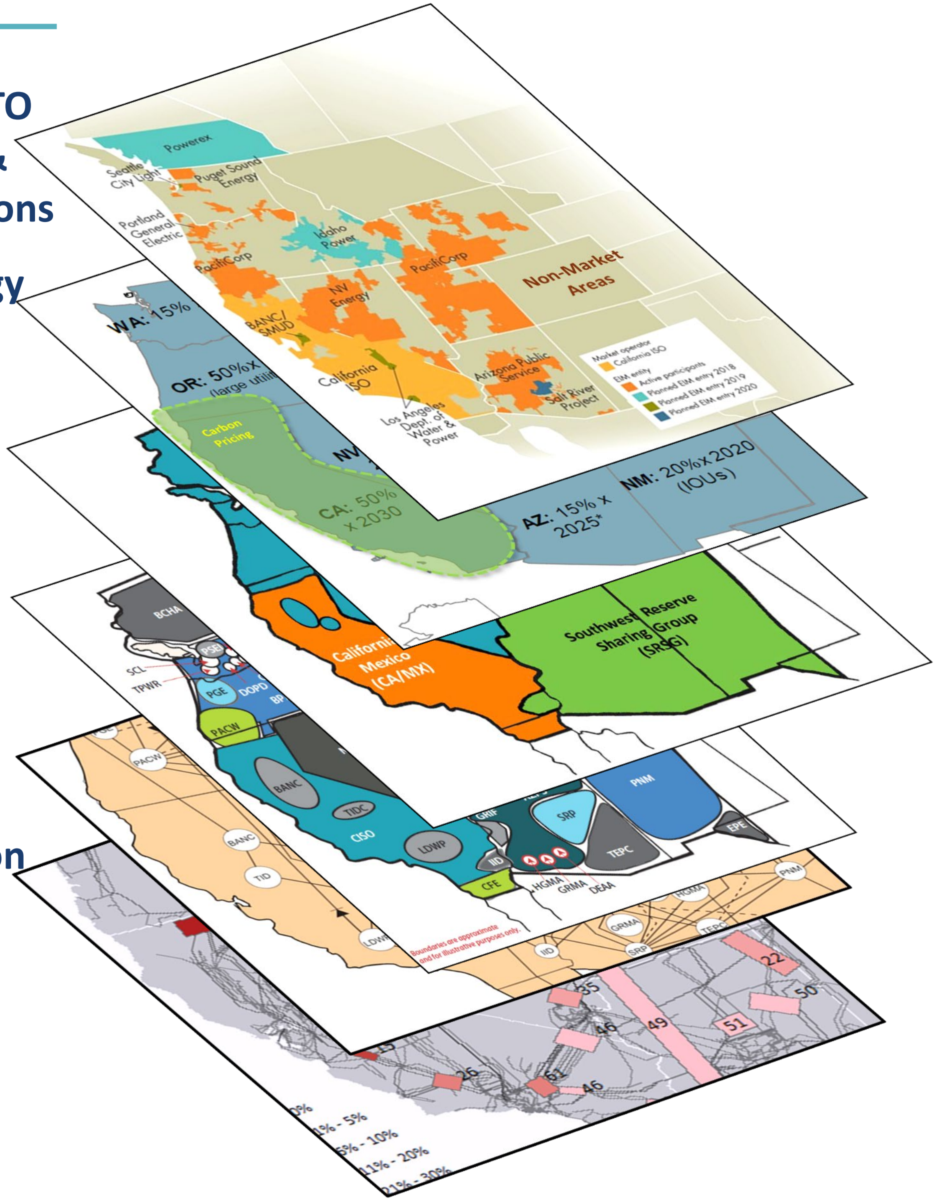
Clean Energy Policies

Reserve Sharing

BAA Functions

Bilateral Contract Paths and Transmission Rights

Physical Flows and Constraints



We employ multi-layer simulations to represent the various physical, policy, and operational facets of the WECC

- Physical grid with ~20k buses, ~25k lines and ~5k generators represented as DC power flow
- 38 Balancing Authority Areas (BAAs) and contract paths
- WECC reserve sharing groups
- Diverse state clean energy policies
- Major trading hubs (e.g., Mid-C, Malin, PV, FC)
- Bilateral (long-term) transmission rights
- Renewable diversity, day-ahead forecast uncertainty, real-time operations
- CAISO, SPP RTO West, Markets+, EDAM, WEIM, & WEIS footprints

Key Model Features

We conduct all study simulations using a **nodal production cost model of the WECC** with added markets, transmission rights, and contract-path trading functionality

- Model developed in PSO/Enelytix, which contains state-of-the-art features
  - Simultaneously optimizes contract path and physical constraints
  - Models bilateral, day-ahead, and real-time markets (including uncertainty) sequentially through multiple solution cycles
  - Co-optimizes storage resources with other resources in unit-commitment and dispatch
  - Detailed ancillary service and operating reserve modeling (including reserve sharing) and co-optimization of ancillary services with energy
- **The study year is 2032**, which aims to reflect the first decade of markets operations, representing an intermediate year that captures known changes in resource mix and transmission infrastructure
- **Model includes two extreme weather events** based on a historic cold snap and a historic heat wave
  - These events are modeled as single weeks in which we increase modeled loads (peak and energy) and gas prices, including gas price volatility beyond typical weather-normalized values to reflect the increased strain on the system and the ability of markets for addressing such strain
  - Capturing non-weather-normal impacts is becoming increasingly important due to the increasing frequency of severe weather events
- **Detailed modeling of EDAM and Markets+ specific GHG rules** which helps capture transfers into GHG pricing states
  - This includes the limits each market will place on sales to balancing authorities that price GHG emissions and the unit-type GHG cost representations instead of generic GHG charges
  - We also model BPA's status as an asset-controlling supplier for CA and WA, reflecting their lower cost to sell power into those zones

California-Wide Day-Ahead Market Expansion Benefits

California benefits from day-ahead market expansion under all four scenarios, but the incremental benefits of a nearly WECC-wide EDAM are ~3x those of a Split Market scenario

- **Under our Expanded EDAM scenario, California benefits from the wider market footprint to expand trading and reduce internal generation, resulting in $678 million lower net total system costs compared to the Baseline+ case:**
  - **Adjusted production cost savings of $366 million** from 3,200 GWh of reduced gas generation, lower purchase costs, and increased sales prices
  - **Total trading and congestion revenues increase $182 million**
  - **Short-term wheeling revenues decline of $82 million** as almost all of California's trading partners join EDAM
- **Under our Split Market scenario, California similarly reduces internal generation and increases trading, but to a lesser extent, resulting in $182 million in lower net total system costs compared to the Baseline+ case:**
  - **Adjusted production cost savings of $200 million** from 1,200 GWh of reduced gas generation and slightly increased average sales prices
  - **Relatively static trading gains and congestion revenues** as trading modestly shifts between bilateral and EDAM trading.
  - **Short-term wheeling revenues decline $23 million** as some bilateral trading dries up with the creation of Markets+

Summary of California-Wide System Costs & Revenues by Case ($ Million per year)

	Baseline	Baseline+	Expanded EDAM	Split Market
Adjusted Production Cost	$5,172	$4,952	$4,585	$4,752
Production Cost	*$1,744*	*$1,440*	*$1,258*	*$1,370*
Purchases Cost	*$3,674*	*$3,907*	*$3,968*	*$3,805*
Sales Revenue (subtracted from costs)	*$246*	*$395*	*$640*	*$423*
Short-Term Wheeling Revenues	$227	$108	$25	$84
Bilateral Trading Revenues	$199	$157	$23	$106
WEIM Congestion Revenues	$66	$73	$55	$42
EDAM Congestion and Transfer Revenues	$170	$204	$538	$292
EDAM Transfer Revenue	*$85*	*$105*	*$255*	*$112*
EDAM Congestion Revenue	*$84*	*$99*	*$283*	*$179*
Net TRR Settlement	$0	$6	$112	$6
Total System Production Cost and Market Revenues	**$4,511**	**$4,399**	**$3,721**	**$4,217**
Benefit Relative to Baseline		**$112**	**$790**	**$294**
Benefit % of Baseline Production Cost and Market Revenues		***2%***	***18%***	***7%***
Benefit Relative to Baseline+			**$678**	**$182**
Benefit % of Baseline+ Production Cost and Market Revenues			***15%***	***4%***

Note: Bilateral trading revenues refers to short-term bilateral trading of energy.

Interpretation of Benefits in CAISO

Non-vertically integrated regions, such as CAISO, may have a more complex accounting of benefits to identify the portion of benefits that flows back to customers

Metric	
Adjusted Production Cost (APC)	We anticipate the large majority of APC benefits would flow to customers. The timing will depend on provision in the PPAs: • Flow through provisions in PPAs would see benefits passed through to customers. • Over the longer-term this could happen through the renegotiation of PPAs. • Reduced curtailments will impact future renewable PPAs. • Our study does not estimate any feedback effects this may have on RA prices.
Short-term wheeling revenue	Most of the impact flows through to customers, since changes in these revenues will impact transmission access charges.
Market congestion revenues	A large share of benefit flow to customers: • EDAM Transfer Revenues are allocated to measured demand, which is mostly load. • EDAM Congestion Revenues are placed in the CRR Balancing Account. We have not analyzed the portion that will flow to customers, which will depend on the efficiency of CRR auctions in returning revenues to load-serving entities.
Bilateral trading revenues	Customers would benefit from revenues on trades executed by load-serving entities, but potentially not from those executed by third-parties or generators.
Emissions	Emissions reductions generally benefit all CA residents, but there may be distributional impacts depending on the geography of emitting generation changes.
Supply cushion	Reliability benefits flows to customers and CA residents.

California Adjusted Production Cost in the EDAM Case

California's APCs fall $366 million per year in the EDAM case, driven by:

- **(1) $182 million/yr reduction in production costs** as California generation declines on the net by ~1,700 GWh (~3,200 GWh lower gas generation offset by ~1,500 GWh more renewables and other generation)
- **(2) $61 million/yr increase in purchase costs** as California purchases about 4,000 GWh more in the day-ahead to substitute for lower internal gas generation, offset by lower real-time purchases
- **(3) $245 million/yr increase in sales revenue** as California sells about 2,500 GWh more in the day-ahead and does so at an average price about $2.5/MWh higher than in Baseline+

California-Wide Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	
Production Cost	(+)	[1]	344,267	342,584	**-1,683**	$4.18	$3.67	**-$0.51**	1,439,851	1,257,800	**-$182,051**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	66,003	69,998	**3,995**	$53.81	$52.15	**-$1.66**	3,551,652	3,650,703	**$99,051**	**(2)**
Real-Time Market		[5]	9,085	8,472	**-613**	$39.08	$37.43	**-$1.65**	355,030	317,101	**-$37,928**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	80,650	83,113	**2,463**	$2.26	$4.82	**$2.56**	182,145	400,738	**$218,593**	**(3)**
Real-Time Market		[8]	9,867	9,104	**-763**	$21.57	$26.33	**$4.76**	212,791	239,689	**$26,898**	
***Total Cost** (Negative Difference = Benefit)*		[9]	**328,837**	**328,837**	**0**	**$15.06**	**$13.94**	**-$1.11**	4,951,597	4,585,177	**-$366,419**	
% Change in APC											***-7.4%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.

California Adjusted Production Cost in the Split Market Case

California's APCs fall $200 million per year in the Split Market case, driven by:

- **(1) $70 million/yr reduction in production cost** as California gas generation falls ~1,200 GWh (non-gas generation falls also, with renewable curtailments increasing ~200 GWh)
- **(2) $100 million/yr reduction in purchase costs** despite modestly higher overall purchase volumes due to lower purchase prices in day ahead and lower real-time purchases and prices
- **(3) $28 million/yr in increased sales revenue** due to higher day-ahead sales prices and higher real-time sales prices offsetting lower real-time volumes, drive in part by the breakup of the WEIM

California Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Baseline+**	**Split Market**	**Difference**	**Baseline+**	**Split Market**	**Difference**	**Baseline+**	**Split Market**	**Difference**	
Production Cost	(+)	[1]	344,267	342,887	**-1,379**	$4.18	$4.00	**-$0.19**	1,439,851	1,370,114	**-$69,737**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	66,003	67,264	**1,261**	$53.81	$52.02	**-$1.79**	3,551,652	3,499,355	**-$52,297**	**(2)**
Real-Time Market		[5]	9,085	7,984	**-1,100**	$39.08	$38.29	**-$0.79**	355,030	305,747	**-$49,283**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	80,650	80,751	**100**	$2.26	$2.67	**$0.41**	182,145	215,481	**$33,336**	**(3)**
Real-Time Market		[8]	9,867	8,549	**-1,319**	$21.57	$24.29	**$2.72**	212,791	207,646	**-$5,145**	
Total Cost *(Negative Difference = Benefit)*		[9]	**328,837**	**328,837**	**0**	**$15.06**	**$14.45**	**-$0.61**	4,951,597	4,752,089	**-$199,507**	
% Change in APC											***-4.0%***	

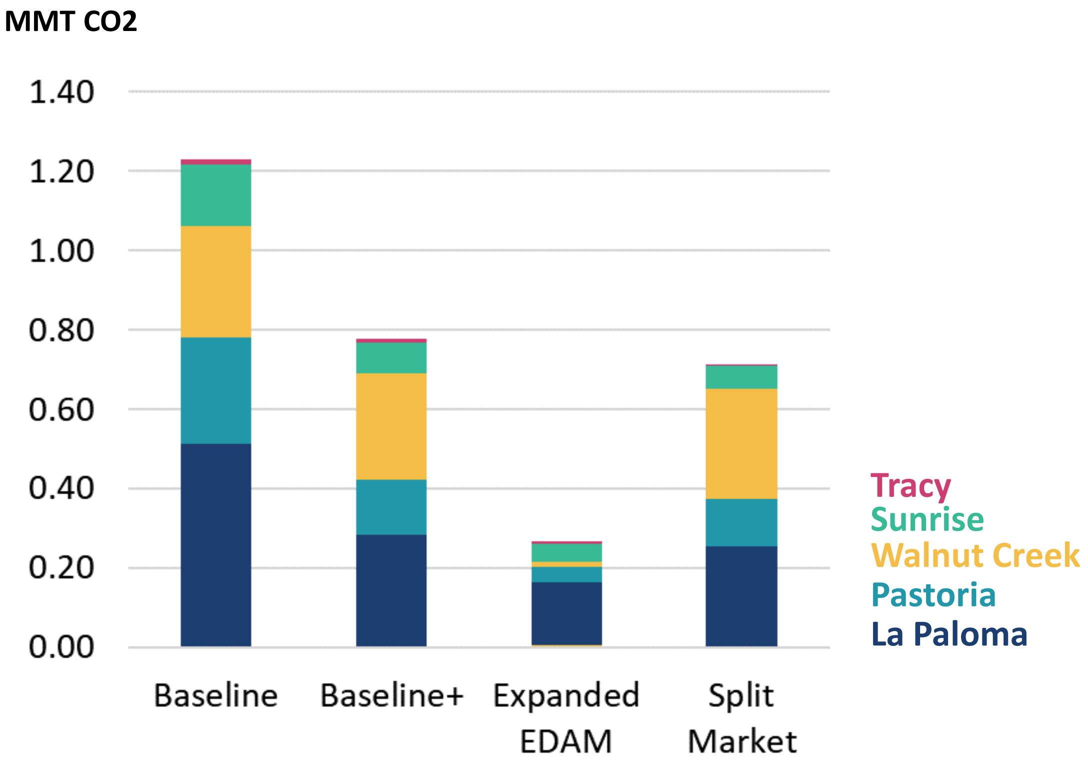
Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.

Gas Generation in California

In the Expanded EDAM case, gas generation in California declines by 31% relative to the Baseline+ Case.

- Emissions from some of the larger gas plants in California fall across the board, but dramatically more in the Expanded EDAM case.
- The decline in gas generation in the Expanded EDAM case is broadly consistent across all areas of California.

Select Plant-Specific CO_2 Emissions by Case

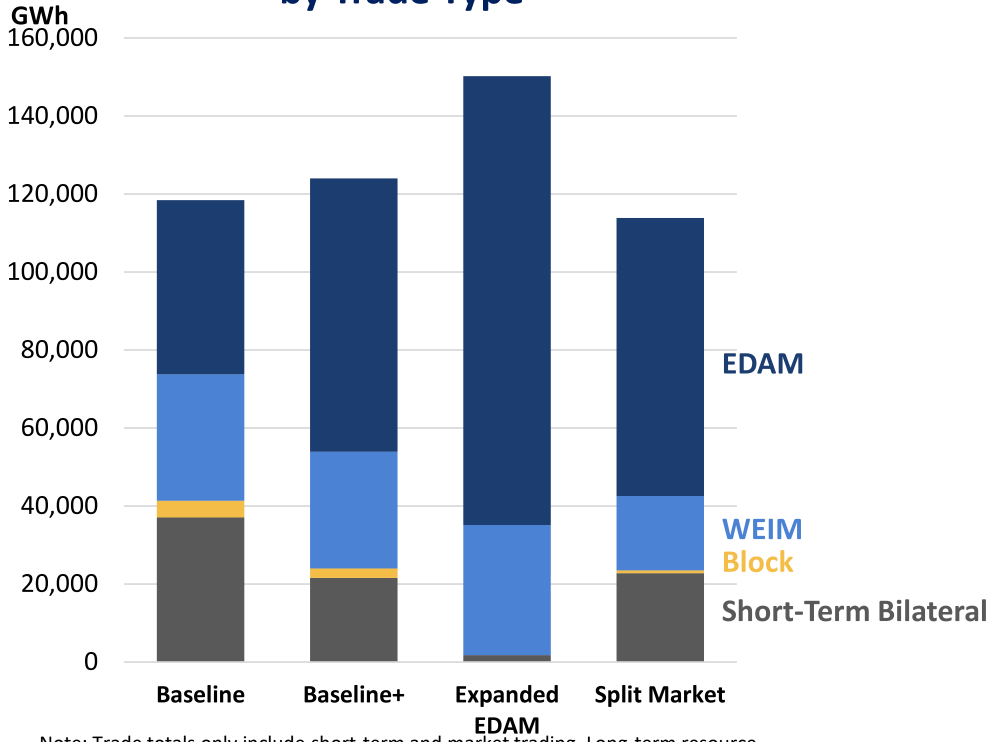


California Trading Volume by Case

California trade volumes are highest in the Expanded EDAM case, driven by increased opportunity in the broader market footprint

- **Total trade volumes increase 26 GWh (21%) for California from Baseline+ to the Expanded EDAM case**
- **Market transactions (EDAM + WEIM) make up 81% of all California trading in Baseline+ and 99% in the Expanded EDAM case**
  - Remaining bilateral transactions are with CFE in Mexico
  - Baseline market transactions are 65% of California trades
  - Split market case market transactions are 79% of California trade, as some seam trading returns with the PNW and Desert SW
- **From Baseline+ to the Expanded EDAM case, California is mainly increasing trading with the Desert Southwest and Pacific Northwest**

Total California Trading by Trade Type

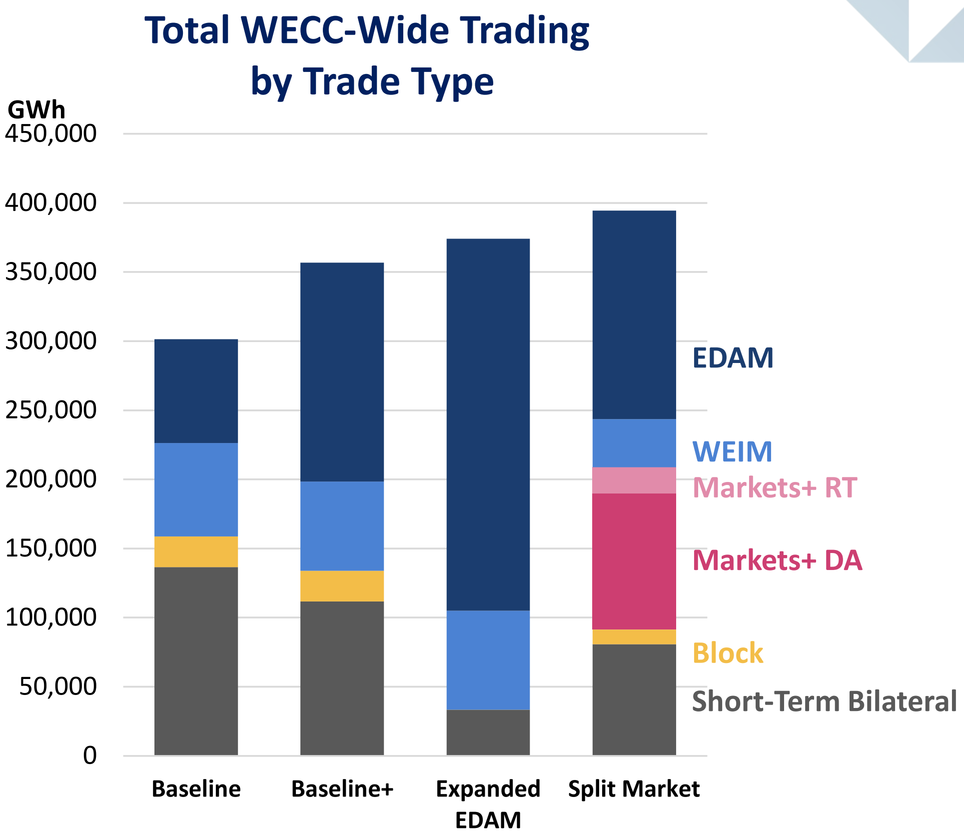


Note: Trade totals only include short-term and market trading. Long-term resource contracts are not included in these totals. Short-term bilateral trades include EDAM-Markets+ seam trades.

WECC-Wide Trading Volume by Case

WECC-wide trade volumes are highest in the Split Market case, due in part to transfers between the PNW and SW portions of Markets+

- **Markets+ transactions between the Southwest and PNW require trading across several entities compared to more direct connections in a WECC-wide market like the Expanded EDAM case**
  - For example, a trade from AZPS to BPAT in the Markets+ footprint requires power transacting several times across the M+ and RTO West entities in the Rocky Mountains
  - In the Expanded EDAM case, AZPS could trade more directly via Nevada or California into the PNW
- **Market transactions (EDAM or Markets+) are the highest share of trades in the Expanded EDAM case (93% of all WECC trading vs. 77% in the Split Market case)**
  - Remaining hourly and block trades between the markets (i.e., seam transactions) account for the majority of non-market trades



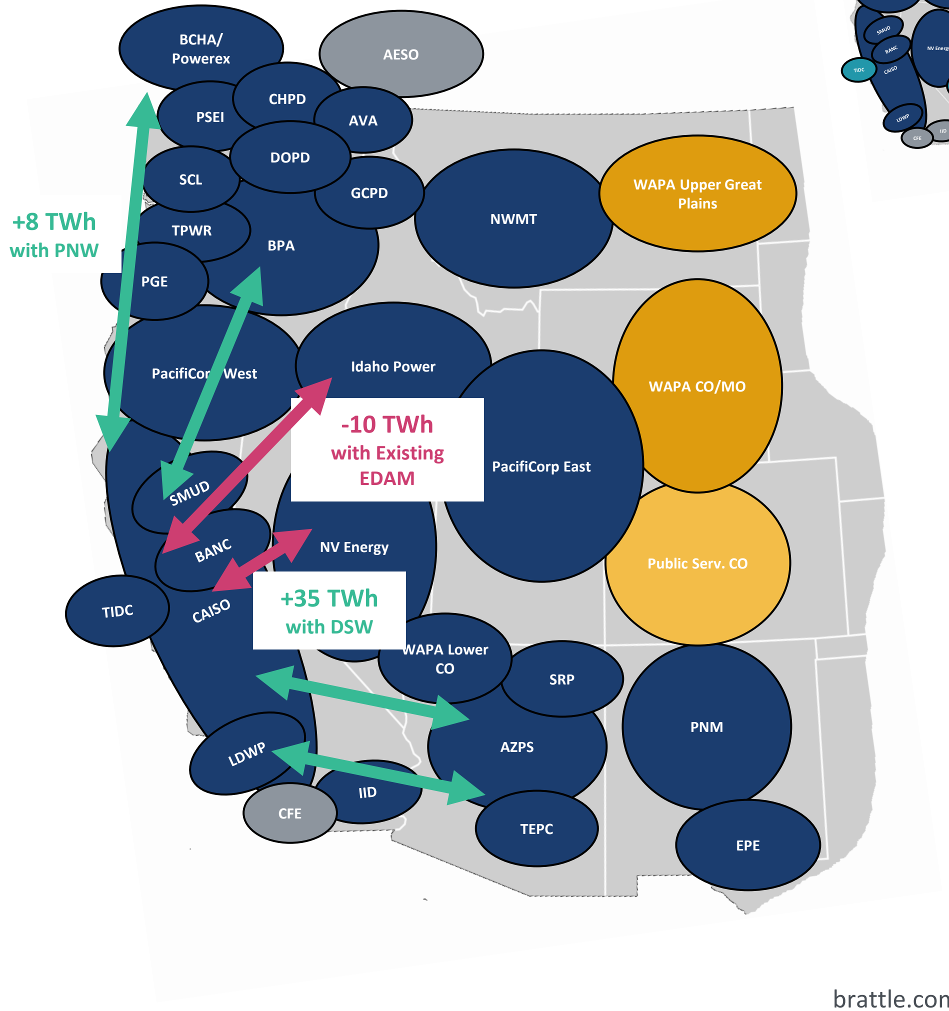
Note: Trade totals only include short-term and market trading. Long-term resource contracts are not included in these totals. Short-term bilateral trades include EDAM-Markets+ seam trades.

California Trading Changes: Baseline+ to Expanded EDAM

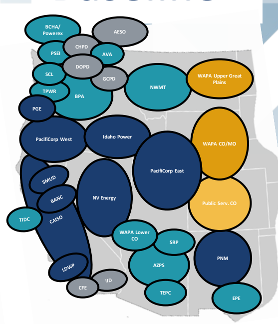
In the Expanded EDAM case, California trading increases with the new EDAM participants in the Desert Southwest and Pacific Northwest

- Hydro entities in the Pacific Northwest export 7 TWh more to California, mostly in the morning and evening
- California exports 20 TWh more to the Desert Southwest and imports 15 TWh more, exchanging renewables and efficient gas
- Trading with existing EDAM entities in the center of the WECC declines about 10 TWh
  - Idaho Power, NV Energy, and PacifiCorp increase direct trades with entities in the Pacific Northwest, Rocky Mountains, and Desert Southwest at the same time trades decease with California

Expanded EDAM Case
(Maximum EDAM Potential)



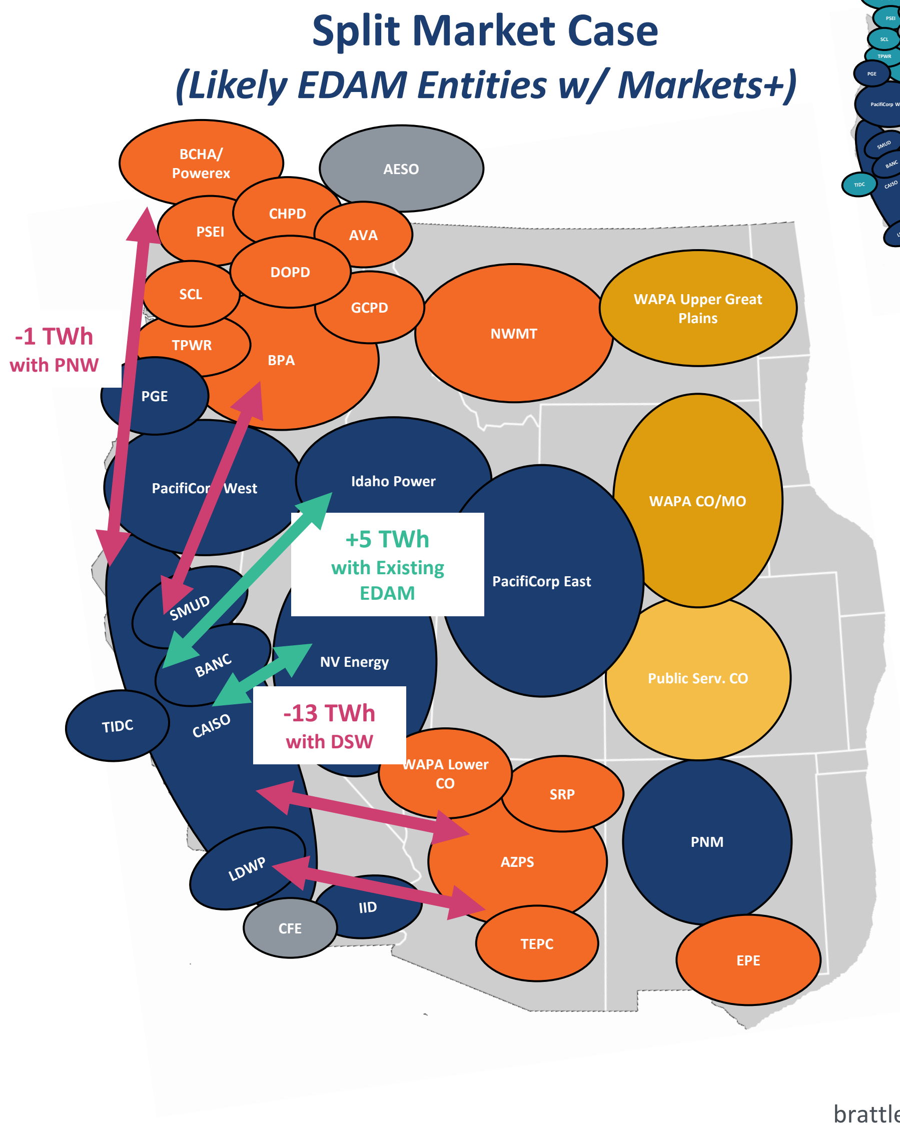
Baseline+

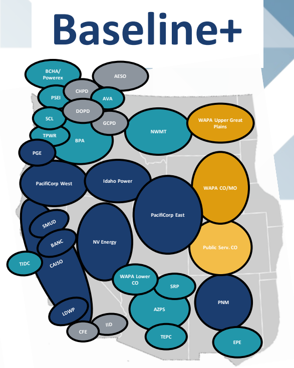


California Trading Changes: Baseline+ to Split Market

In the Split Market case, California trading increases with existing EDAM members, but falls with the Pacific Northwest and Southwest as those regions shift to trading within the Markets+ footprint

- Hydro entities in the Pacific Northwest export about the same to California, but California exports about 1.5 TWh less to the PNW
- California exports 6 TWh less to the Desert Southwest and imports 7 TWh less, reducing trading in both directions
- Trading with existing EDAM entities in the center of the WECC increases about 5 TWh
- Trading between EDAM entities within California also increases about 3 TWh





Appendix B:
Individual BAA Benefits

Individual BA Benefits: **CAISO**

Compared to the Baseline+ case, CAISO sees benefits in the Expanded EDAM case of $471 million/yr compared to $171 million/yr in the Split Market case

- **CAISO sees an APC benefits in both cases,** though about $136 million more in EDAM
- **Short-term wheeling revenues fall more in the Expanded EDAM case,** declining $22 million from Baseline+ to Split Market compared to the EDAM decline of $60 million
- **Total trading revenues increase $134 million in the EDAM case compared to just $3 million in the Split Market case**

Summary of CAISO System Costs by Case ($ Millions)

	Baseline	Baseline+	Expanded EDAM	Split Market
Adjusted Production Cost	$4,642	$4,441	$4,115	$4,250
Short-Term Wheeling Revenues	$171	$85	$25	$63
Trading Revenues				
Bilateral Trading Revenues	$111	$88	$23	$61
WEIM Congestion Revenues	$47	$55	$41	$31
EDAM Congestion and Transfer Revenues	$146	$185	$398	$238
EDAM Transfer Revenue	*$113*	*$112*	*$228*	*$123*
EDAM Congestion Revenue	*$33*	*$72*	*$170*	*$115*
Net TRR Settlement		$9	$80	$9
Total System Production Cost and Market Revenues	**$4,167**	**$4,019**	**$3,548**	**$3,848**
Benefit Relative to Baseline		**$148**	**$619**	**$319**
Benefit % of Baseline Production Cost and Market Revenues		***4%***	***15%***	***8%***
Benefit Relative to Baseline+			**$471**	**$171**
Benefit % of Baseline+ Production Cost and Market Revenues			***12%***	***4%***

CAISO Adjusted Production Cost in the EDAM Case

CAISO's adjusted production costs fall $326 million in the EDAM case, driven by:

- **(1) $112 million/yr reduction in production costs** as CAISO generation declines on the net by ~1000 GWh (~2,000 GWh lower gas generation offset by ~1,000 GWh more renewables and other generation)
- **(2) $40 million/yr increase in purchase costs** as CAISO purchases about 2,900 GWh more in the day-ahead to offset declining gas generation
- **(3) $250 million/yr increase in sales revenue** as CAISO sells about 2,400 GWh more in the day-ahead and does so at an average price about $3.0/MWh higher than in Baseline+

CAISO Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	
Production Cost	(+)	[1]	295,759	294,762	**-996**	$4.17	$3.81	**-$0.37**	1,234,372	1,121,700	**-$112,672**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	53,447	56,344	**2,897**	$56.04	$54.23	**-$1.81**	2,995,068	3,055,363	**$60,295**	**(2)**
Real-Time Market		[5]	6,488	6,488	**0**	$41.38	$38.27	**-$3.11**	268,462	248,274	**-$20,188**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	73,205	75,653	**2,448**	-$0.60	$2.44	**$3.03**	-43,575	184,255	**$227,830**	**(3)**
Real-Time Market		[8]	6,054	5,506	**-547**	$16.65	$22.93	**$6.28**	100,804	126,274	**$25,470**	
Total Cost *(Negative Difference = Benefit)*		[9]	**276,435**	**276,435**	**0**	**$16.06**	**$14.89**	**-$1.18**	4,440,673	4,114,808	**-$325,865**	
% Change in APC											***-7.3%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.
Curtailment cost/PTC value only shows the change in cost of curtailments are a price of $30/MWh for a curtailment.

CAISO Adjusted Production Cost in the Split Market Case

CAISO's APC falls $190 million in the Split Market case, driven by:

- **(1) $55 million/yr decrease in production cost** due to gas generation falling by ~930 GWh (non-gas generation also declines, with renewable curtailments increasing ~260 GWh)
- **(2) $67 million/yr decrease in purchase cost despite higher purchase volumes** as the remaining EDAM market generation mix is renewable heavy
- **(3) $58 million/yr increase in sales revenue** as volumes and average sales prices increase slightly due to opportunities to sell into EDAM and Markets+

CAISO Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Baseline+**	**Split Market**	**Difference**	**Baseline+**	**Split Market**	**Difference**	**Baseline+**	**Split Market**	**Difference**	
Production Cost	(+)	[1]	295,759	294,501	**-1,258**	$4.17	$4.01	**-$0.17**	1,234,372	1,179,767	**-$54,605**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	53,447	54,741	**1,294**	$56.04	$53.94	**-$2.09**	2,995,068	2,952,969	**-$42,099**	**(2)**
Real-Time Market		[5]	6,488	6,181	**-307**	$41.38	$39.34	**-$2.04**	268,462	243,149	**-$25,312**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	73,205	73,593	**388**	-$0.60	$0.20	**$0.79**	-43,575	14,409	**$57,984**	**(3)**
Real-Time Market		[8]	6,054	5,395	**-659**	$16.65	$20.59	**$3.94**	100,804	111,097	**$10,293**	
Total Cost *(Negative Difference = Benefit)*		[9]	**276,435**	**276,435**	**0**	**$16.06**	**$15.38**	**-$0.69**	4,440,673	4,250,380	**-$190,292**	
% Change in APC											***-4.3%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.
Curtailment cost/PTC value only shows the change in cost of curtailments are a price of $30/MWh for a curtailment.

Individual BA Benefits: **LDWP**

Compared to the Baseline+ case, LDWP sees a benefit in the Expanded EDAM case of $66 million/yr compared to $18 million/yr in the Split Market case

- **LDWP sees an APC benefits in both cases**, $38 million in EDAM and $18 million in the Split Market case
- **Short-term wheeling revenues decline most in the Expanded EDAM case, falling $13 million**
- **Total trading revenues increase $24 million in the Expanded EDAM case compared to just $6 million in the Split Market case**

Summary of LDWP System Costs by Case ($ Millions)

	Baseline	Baseline+	Expanded EDAM	Split Market
Adjusted Production Cost	$371	$354	$328	$336
Short-Term Wheeling Revenues	$38	$13	$0	$6
Trading Revenues				
Bilateral Trading Revenues	$40	$39	$0	$17
WEIM Congestion Revenues	$7	$9	$4	$5
EDAM Congestion and Transfer Revenues	$17	$13	$81	$46
EDAM Transfer Revenue	-$25	-$6	$17	-$8
EDAM Congestion Revenue	$42	$19	$64	$54
Net TRR Settlement		-$2	$26	-$2
Total System Production Cost and Market Revenues	**$269**	**$281**	**$216**	**$263**
Benefit Relative to Baseline		**-$13**	**$53**	**$6**
Benefit % of Baseline Production Cost and Market Revenues		***-5%***	***20%***	***2%***
Benefit Relative to Baseline+			**$66**	**$18**
Benefit % of Baseline+ Production Cost and Market Revenues			***23%***	***6%***

LDWP Adjusted Production Cost in the EDAM Case

LDWP's adjusted production costs fall $26 million in the EDAM case, driven by:

- **(1) $8.5 million/yr reduction in production costs** as LDWP generation declines on the net by ~3 GWh (~120 GWh lower gas generation offset by ~117 GWh more renewables and other generation)
- **(2) $14 million/yr decrease in purchase costs** due to reduced average cost of purchasing in the EDAM market by about $2/MWh
- **(3) $3 million/yr increase in sales revenue** as LDWP sells about 7 GWh more in the day-ahead and does so at an average price about $2.7/MWh higher than in Baseline+

LDWP Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	
Production Cost	(+)	[1]	21,157	21,154	-3	$1.29	$0.89	**-$0.40**	27,272	18,764	**-$8,508**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	7,928	7,955	**27**	$46.43	$44.59	**-$1.84**	368,108	354,708	**-$13,400**	**(2)**
Real-Time Market		[5]	431	412	**-19**	$27.01	$27.84	**$0.83**	11,642	11,466	**-$176**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	1,067	1,074	**7**	-$7.72	-$5.01	**$2.71**	-8,237	-5,383	**$2,854**	**(3)**
Real-Time Market		[8]	2,179	2,177	**-2**	$28.10	$28.72	**$0.62**	61,232	62,528	**$1,296**	
Total Cost *(Negative Difference = Benefit)*		[9]	**26,270**	**26,270**	**0**	**$13.48**	**$12.48**	**-$1.00**	354,027	327,793	**-$26,235**	
% Change in APC											***-7.4%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost. Curtailment cost/PTC value only shows the change in cost of curtailments are a price of $30/MWh for a curtailment.

LDWP Adjusted Production Cost in the Split Market Case

LDWP's APC falls $18 million in the Split Market case, driven by:

- **(1) $0.3 million/yr decrease in production cost** due to ~10 GWh of reduced gas generation (non-gas generation increases by ~40 GWh)
- **(2) $14 million/yr reduction in purchase costs** as the remaining EDAM market is very renewable heavy renewable heavy
- **(3) $1 million/yr increase in sales revenue** as volumes and average sales prices increase slightly due to opportunities to sell into EDAM and Markets+

LDWP Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			Baseline+	Split Market	Difference	Baseline+	Split Market	Difference	Baseline+	Split Market	Difference	
Production Cost	(+)	[1]	21,157	21,204	**47**	$1.29	$1.27	**-$0.02**	27,272	27,004	**-$269**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	7,928	7,952	**24**	$46.43	$44.53	**-$1.91**	368,108	354,077	**-$14,031**	**(2)**
Real-Time Market		[5]	431	407	**-24**	$27.01	$27.97	**$0.96**	11,642	11,379	**-$263**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	1,067	1,083	**15**	-$7.72	-$6.36	**$1.36**	-8,237	-6,886	**$1,351**	**(3)**
Real-Time Market		[8]	2,179	2,210	**32**	$28.10	$28.56	**$0.46**	61,232	63,137	**$1,905**	
Total Cost *(Negative Difference = Benefit)*		[9]	**26,270**	**26,270**	**0**	**$13.48**	**$12.80**	**-$0.68**	354,027	336,209	**-$17,819**	
% Change in APC											***-5.0%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.
Curtailment cost/PTC value only shows the change in cost of curtailments are a price of $30/MWh for a curtailment.

Individual BA Benefits: **BANC**

Compared to the Baseline+ case, BANC sees a benefit in the Expanded EDAM case of $10 million/yr compared to a loss of $4 million/yr in the Split Market case

- **BANC's adjusted production cost remains about the same in all three cases**
- **Short-term wheeling revenues decline $4 million in EDAM**
- **Total trading revenues increase $10 million in the Expanded EDAM case but decline $2 million in the Split Market case**
- ***BANC benefits and results are not inclusive of SMUD, which is reported separately***

Summary of BANC System Costs by Case ($ Millions)

	Baseline	Baseline+	Expanded EDAM	Split Market
Adjusted Production Cost	$56	$57	$56	$59
Short-Term Wheeling Revenues	$5	$4	$0	$4
Trading Revenues				
Bilateral Trading Revenues	$15	$10	$0	$8
WEIM Congestion Revenues	$2	$1	$0	$1
EDAM Congestion and Transfer Revenues	$0	$1	$21	$1
EDAM Transfer Revenue	-$6	-$5	-$6	-$5
EDAM Congestion Revenue	$7	$6	$27	$6
Net TRR Settlement		-$1	$3	-$1
Total System Production Cost and Market Revenues	**$34**	**$42**	**$31**	**$46**
Benefit Relative to Baseline		**-$8**	**$2**	**-$12**
Benefit % of Baseline Production Cost and Market Revenues		***-23%***	***7%***	***-36%***
Benefit Relative to Baseline+			**$10**	**-$4**
Benefit % of Baseline+ Production Cost and Market Revenues			***24%***	***-11%***

BANC Adjusted Production Cost in the EDAM Case

BANC's adjusted production costs fall $1.7 million in the EDAM case, driven by:

- **(1) $17 million/yr reduction in production costs** as BANC generation declines on the net by ~260 GWh (~325 GWh lower gas generation offset by ~64 GWh more renewables and other generation)
- **(2) $5 million/yr increase in purchase costs** as BANC purchases about 140 GWh more in the day-ahead to offset declining gas generation and make additional market sales
- **(3) $11 million/yr decrease in sales revenue** due to ~$5/MWh decrease in day ahead market prices received

BANC Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	
Production Cost	(+)	[1]	6,206	5,944	**-262**	$12.63	$10.28	**-$2.35**	78,379	61,077	**-$17,302**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	689	834	**144**	$44.22	$46.49	**$2.27**	30,483	38,755	**$8,271**	**(2)**
Real-Time Market		[5]	303	247	**-56**	$42.32	$37.52	**-$4.80**	12,824	9,270	**-$3,554**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	1,201	927	**-274**	$46.64	$41.74	**-$4.90**	56,015	38,684	**-$17,331**	**(3)**
Real-Time Market		[8]	193	293	**100**	$42.69	$50.17	**$7.48**	8,224	14,704	**$6,479**	
Total Cost *(Negative Difference = Benefit)*		[9]	**5,804**	**5,804**	**0**	**$9.90**	**$9.60**	**-$0.30**	57,447	55,713	**-$1,733**	
% Change in APC											***-3.0%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost. Curtailment cost/PTC value only shows the change in cost of curtailments are a price of $30/MWh for a curtailment.

BANC Adjusted Production Cost in the Split Market Case

BANC's APC rises $1.6 million in the Split Market case, driven by:

- **(1) $11 million/yr reduction in production cost** due to ~200 GWh decreased gas generation(non-gas generation falls also, with renewable curtailments increasing ~14 GWh), but does not offset revenue loss
- **(2) $3 million/yr increase in purchase costs** despite falling real time prices because of increased day ahead purchases
- **(3) $10 million/yr decrease in sales revenue** as day-ahead sales volumes decrease and real-time volumes only increase by ~12 GWh

BANC Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			Baseline+	Split Market	Difference	Baseline+	Split Market	Difference	Baseline+	Split Market	Difference	
Production Cost	(+)	[1]	6,206	5,994	-212	$12.63	$11.24	-$1.39	78,379	67,376	-$11,002	(1)
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	689	776	86	$44.22	$44.47	$0.25	30,483	34,497	$4,014	(2)
Real-Time Market		[5]	303	288	-15	$42.32	$39.35	-$2.96	12,824	11,352	-$1,471	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	1,201	1,049	-152	$46.64	$42.57	-$4.07	56,015	44,653	-$11,361	(3)
Real-Time Market		[8]	193	204	12	$42.69	$46.60	$3.91	8,224	9,530	$1,306	
***Total Cost** (Negative Difference = Benefit)*		[9]	**5,804**	**5,804**	**0**	**$9.90**	**$10.17**	**$0.28**	57,447	59,043	**$1,596**	
% Change in APC											***2.8%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.
Curtailment cost/PTC value only shows the change in cost of curtailments are a price of $30/MWh for a curtailment.

Individual BA Benefits: **SMUD**

Compared to the Baseline+ case, SMUD sees a slight loss in the Expanded EDAM case of $9 million/yr compared to a benefit of $4 million/yr in the Split Market case

- **SMUD adjusted production cost remains about the same in all three cases,** but declines slightly more in the Split Market case
- **Total trading revenues decline $6 million in the Expanded EDAM case but increase $1 million in the Split Market case due to increased internal California trading**

Summary of SMUD System Costs by Case ($ Millions)

	Baseline	Baseline+	Expanded EDAM	Split Market
Adjusted Production Cost	$74	$73	$72	$70
Short-Term Wheeling Revenues	$0	$0	$0	$0
Trading Revenues				
Bilateral Trading Revenues	$16	$15	$0	$15
WEIM Congestion Revenues	$4	$4	$4	$4
EDAM Congestion and Transfer Revenues	$6	$6	$15	$7
EDAM Transfer Revenue	$3	$4	$11	$3
EDAM Congestion Revenue	$3	$2	$5	$4
Net TRR Settlement		-$1	-$6	-$1
Total System Production Cost and Market Revenues	**$48**	**$49**	**$58**	**$45**
Benefit Relative to Baseline		**-$1**	**-$11**	**$2**
Benefit % of Baseline Production Cost and Market Revenues		***-3%***	***-22%***	***5%***
Benefit Relative to Baseline+			**-$9**	**$4**
Benefit % of Baseline+ Production Cost and Market Revenues			***-18%***	***8%***

SMUD Adjusted Production Cost in the EDAM Case

SMUD's adjusted production costs fall $1 million in the EDAM case, driven by:

- **(1) $0.1 million/yr increase in production costs** as SMUD generation increases by ~100 GWh, mostly from renewables and geothermal
- **(2) $3 million/yr increase in purchase costs** as SMUD purchases about 60 GWh more in the day-ahead
- **(3) $4 million/yr increase in sales revenue** as SMUD sells about 200 GWh more in the day-ahead and does so at an average price about $0.1/MWh higher than in Baseline+

SMUD Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	
Production Cost	(+)	[1]	12,180	12,289	**109**	$0.82	$0.83	**$0.00**	10,044	10,179	**$135**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	2,022	2,081	**59**	$50.40	$51.49	**$1.10**	101,888	107,144	**$5,256**	**(2)**
Real-Time Market		[5]	861	802	**-59**	$41.24	$41.52	**$0.28**	35,520	33,317	**-$2,203**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	2,101	2,283	**182**	$25.26	$25.38	**$0.12**	53,069	57,934	**$4,866**	**(3)**
Real-Time Market		[8]	707	634	**-73**	$30.67	$33.22	**$2.55**	21,679	21,053	**-$626**	
Total Cost *(Negative Difference = Benefit)*		[9]	**12,255**	**12,255**	**0**	**$5.93**	**$5.85**	**-$0.09**	72,704	71,652	**-$1,052**	
% Change in APC											***-1.4%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.
Curtailment cost/PTC value only shows the change in cost of curtailments are a price of $30/MWh for a curtailment.

SMUD Adjusted Production Cost in the Split Market Case

SMUD's APC falls $2 million in the Split Market case, driven by:

- **(1) $13 million/yr increase in production cost** due to a reduction of ~6 GWh of generation
- **(2)** $**4 million/yr decrease in purchases cost** because of slight reductions in price and volume in the day-ahead and real-time markets
- **(3) $2 million/yr reduction in sales revenues** due to a $1.3/MWh drop in day-ahead prices and ~50 GWh fewer sales in the real-time market

SMUD Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Baseline+**	**Split Market**	**Difference**	**Baseline+**	**Split Market**	**Difference**	**Baseline+**	**Split Market**	**Difference**	
Production Cost	(+)	[1]	12,180	12,174	-6	$0.82	$0.83	**$0.00**	10,044	10,056	**$13**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	2,022	2,015	-7	$50.40	$49.16	**-$1.24**	101,888	99,068	**-$2,820**	**(2)**
Real-Time Market		[5]	861	855	-6	$41.24	$39.91	**-$1.33**	35,520	34,121	**-$1,399**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	2,101	2,128	28	$25.26	$23.98	**-$1.28**	53,069	51,040	**-$2,029**	**(3)**
Real-Time Market		[8]	707	660	-47	$30.67	$33.15	**$2.48**	21,679	21,875	**$195**	
Total Cost *(Negative Difference = Benefit)*		[9]	**12,255**	**12,255**	**0**	**$5.93**	**$5.74**	**-$0.19**	72,704	70,330	**-$2,373**	
% Change in APC											***-3.3%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.
Curtailment cost/PTC value only shows the change in cost of curtailments are a price of $30/MWh for a curtailment.

Individual BA Benefits: **IID**

Compared to the Baseline+ case, IID sees a benefit in the Expanded EDAM case of $18 million/yr compared to a loss of $9 million/yr in the Split Market case

- **IID's adjusted production cost doesn't change in the Expanded EDAM case, but increases $9 million in the Split Market case**
- **Short-term wheeling revenues decline $6 million in EDAM and increase $6 million in the Split Market case**
- **Total trading revenues increase $13 million in the Expanded EDAM case but decline $3 million in the Split Market case**

Summary of IID System Costs by Case ($ Millions)

	Baseline	Baseline+	Expanded EDAM	Split Market
Adjusted Production Cost	-$83	-$85	-$85	-$74
Short-Term Wheeling Revenues	$13	$5	$0	$11
Trading Revenues				
Bilateral Trading Revenues	$15	$4	$0	$4
WEIM Congestion Revenues	$6	$3	$5	$0
EDAM Congestion and Transfer Revenues	$0	$0	$15	$0
EDAM Transfer Revenue	$0	$0	$6	$0
EDAM Congestion Revenue	$0	$0	$9	$0
Net TRR Settlement			$11	
Total System Production Cost and Market Revenues	**-$116**	**-$97**	**-$115**	**-$89**
Benefit Relative to Baseline		**-$19**	**-$1**	**-$27**
Benefit % of Baseline Production Cost and Market Revenues		***16%***	***-1%***	***-23%***
Benefit Relative to Baseline+			**$18**	**-$9**
Benefit % of Baseline+ Production Cost and Market Revenues			***18%***	***-9%***

IID Adjusted Production Cost in the EDAM Case

IID's adjusted production costs remains relatively steady, due to:

- **(1) $0.2 million/yr reduction in production costs** as IID generation increases by ~45 GWh, all from renewable and other non-gas generation
- **(2) $5 million/yr decrease in purchase costs** as IID purchases about 100 GWh more in the day-ahead and reduces sales in the real time market
- **(3) $5 million/yr decrease in sales revenue** as BANC reduces sales volume by ~240 GWh in the real time market despite increased prices

IID Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			Baseline+	EDAM	Difference	Baseline+	EDAM	Difference	Baseline+	EDAM	Difference	
Production Cost	(+)	[1]	7,301	7,346	**45**	$5.81	$5.79	**-$0.01**	42,401	42,551	**$150**	(1)
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	478	635	**157**	-$3.09	-$2.87	**$0.22**	-1,477	-1,823	**-$345**	(2)
Real-Time Market		[5]	858	520	**-338**	$21.90	$28.14	**$6.24**	18,778	14,631	**-$4,147**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	3,068	3,176	**108**	$40.50	$39.44	**-$1.07**	124,249	125,245	**$997**	(3)
Real-Time Market		[8]	733	489	**-244**	$28.17	$29.96	**$1.79**	20,645	14,640	**-$6,005**	
***Total Cost** (Negative Difference = Benefit)*		[9]	**4,837**	**4,837**	**0**	**-$17.61**	**-$17.48**	**$0.14**	-85,191	-84,525	**$666**	
% Change in APC											***-0.8%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.
Curtailment cost/PTC value only shows the change in cost of curtailments are a price of $30/MWh for a curtailment.

IID Adjusted Production Cost in the Split Market Case

IID's APC increases $11 million in the Split Market case, driven by:

- **(1) $0.3 million/yr increase in production cost** due to limited shifts in production and prices
- **(2) $20 million/yr decrease in purchases cost** as the remaining EDAM market is very renewable heavy, resulting in a $12/MWh decrease in day-ahead prices
- **(3) $31 million/yr decrease in sales revenue** as IID reduces sales by ~840 GWh across day-ahead and real-time markets

IID Adjusted Production Cost

Cost Components			GWh Baseline+	GWh Split Market	GWh Difference	$/MWh Baseline+	$/MWh Split Market	$/MWh Difference	Total ($1000s/Year) Baseline+	Total ($1000s/Year) Split Market	Total ($1000s/Year) Difference	
Production Cost	(+)	[1]	7,301	7,399	**98**	$5.81	$5.77	**-$0.04**	42,401	42,674	**$273**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	478	247	**-231**	-$3.09	-$14.68	**-$11.59**	-1,477	-3,623	**-$2,146**	**(2)**
Real-Time Market		[5]	858	155	**-703**	$21.90	$2.70	**-$19.20**	18,778	418	**-$18,361**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	3,068	2,893	**-175**	$40.50	$38.70	**-$1.80**	124,249	111,976	**-$12,273**	**(3)**
Real-Time Market		[8]	733	71	**-662**	$28.17	$19.58	**-$8.59**	20,645	1,385	**-$19,260**	
Total Cost *(Negative Difference = Benefit)*		[9]	**4,837**	**4,837**	**0**	**-$17.61**	**-$15.28**	**$2.34**	-85,191	-73,892	**$11,299**	
% Change in APC											***-13.3%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.
Curtailment cost/PTC value only shows the change in cost of curtailments are a price of $30/MWh for a curtailment.

Individual BA Benefits: **TIDC**

Compared to the Baseline+ case, TIDC sees a benefit in the Expanded EDAM case of $17 million/yr compared to $2 million/yr in the Split Market case

- **TIDC's adjusted production cost declines $12 million in the Expanded EDAM case but just $2 million in the Split Market case**
- **Total trading revenues increase $6 million in the Expanded EDAM case and don't change in the Split Market case**

Summary of TIDC System Costs by Case ($ Millions)

	Baseline	Baseline+	Expanded EDAM	Split Market
Adjusted Production Cost	$112	$112	$100	$110
Short-Term Wheeling Revenues	$0	$0	$0	$0
Trading Revenues				
Bilateral Trading Revenues	$1	$1	$0	$1
WEIM Congestion Revenues	$1	$0	$0	$0
EDAM Congestion and Transfer Revenues	$0	$0	$7	$0
EDAM Transfer Revenue	$0	$0	-$2	$0
EDAM Congestion Revenue	$0	$0	$8	$0
Net TRR Settlement			-$2	
Total System Production Cost and Market Revenues	**$110**	**$111**	**$95**	**$109**
Benefit Relative to Baseline		**-$2**	**$15**	**$1**
Benefit % of Baseline Production Cost and Market Revenues		***-1%***	***14%***	***1%***
Benefit Relative to Baseline+			**$17**	**$2**
Benefit % of Baseline+ Production Cost and Market Revenues			***15%***	***2%***

TIDC Adjusted Production Cost in the EDAM Case

TIDC's adjusted production costs fall $12 million in the EDAM case, driven by:

- **(1) $44 million/yr reduction in production costs** as TIDC's gas generation declines by ~575 GWh
- **(2) $30 million/yr increase in purchase costs** as TIDC purchases about 710 GWh more in the day-ahead to offset declining gas generation
- **(3) $0.4 million/yr decrease in sales revenue** and reduces day ahead sales given the large price drop of $59/MWh in the day ahead market

TIDC Adjusted Production Cost

		GWh			$/MWh			Total ($1000s/Year)			
Cost Components		**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	
Production Cost	(+) [1]	1,664	1,089	-575	$28.48	$3.24	-$25.24	47,383	3,529	-$43,854	(1)
Purchases Cost	(+) [3]										
Day-Ahead Market + Bilateral	[4]	1,439	2,150	711	$40.01	$44.91	$4.90	57,582	96,556	$38,974	(2)
Real-Time Market	[5]	144	2	-141	$54.34	$67.78	$13.44	7,804	144	-$7,660	
Sales Revenue (Negative = Cost)	(-) [6]										
Day-Ahead Market + Bilateral	[7]	9	0	-8	$73.37	$14.18	-$59.19	625	3	-$623	(3)
Real-Time Market	[8]	3	6	3	$71.28	$88.53	$17.25	207	490	$283	
Total Cost *(Negative Difference = Benefit)*	[9]	**3,235**	**3,235**	**0**	**$34.60**	**$30.83**	**-$3.77**	111,937	99,736	-$12,201	
% Change in APC										*-10.9%*	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.
Curtailment cost/PTC value only shows the change in cost of curtailments are a price of $30/MWh for a curtailment.

TIDC Adjusted Production Cost in the Split Market Case

TIDC's APC falls $2 million in the Split Market case, driven by:

- **(1) $4 million/yr decrease in production cost** due to ~50 GWh reduction of gas generation (TIDC does not have renewable generation)
- **(2) $2 million/yr increase in purchases cost** because of ~94 GWh of increased purchases to compensate for gas generation reduction
- **(3) $0.1 million/yr increase in sales revenue** caused by increases in real-time revenues despite a $2.9/MWh decrease in day-ahead prices

TIDC Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			Baseline+	Split Market	Difference	Baseline+	Split Market	Difference	Baseline+	Split Market	Difference	
Production Cost	(+)	[1]	1,664	1,617	**-47**	$28.48	$26.74	**-$1.74**	47,383	43,237	**-$4,147**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	1,439	1,533	**94**	$40.01	$40.68	**$0.67**	57,582	62,366	**$4,785**	
Real-Time Market		[5]	144	98	**-46**	$54.34	$54.32	**-$0.02**	7,804	5,328	**-$2,476**	**(2)**
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	9	4	**-4**	$73.37	$70.47	**-$2.90**	625	289	**-$336**	
Real-Time Market		[8]	3	9	**6**	$71.28	$72.23	**$0.95**	207	622	**$416**	**(3)**
Total Cost *(Negative Difference = Benefit)*		[9]	**3,235**	**3,235**	**0**	**$34.60**	**$34.01**	**-$0.59**	111,937	110,019	**-$1,918**	
% Change in APC											***-1.7%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.
Curtailment cost/PTC value only shows the change in cost of curtailments are a price of $30/MWh for a curtailment.

Appendix C:
Description of Benefit Metrics

Benefit Metric: Adjusted Production Cost

Adjusted Production Cost (APC) is a standard metric used to capture the direct variable energy-related costs from a customer impact perspective

The APC is calculated for the BAU cases and the market cases to determine the market related reductions in APC

- By using the generation price of the exporter and load price of the importer for sales revenues and purchase costs, the APC metric does not capture wheeling revenues and the remaining portion of the value of the trade to the counterparties (see next slide)

The APC is the sum of production costs and purchased power less off-system sales revenue:

(+) Production costs (fuel, startup, variable O&M, emissions costs) for generation owned or contracted by the load-serving entities

(+) Cost of bilateral and market purchases valued at the BAA's load-weighted energy price ("Load LMP")

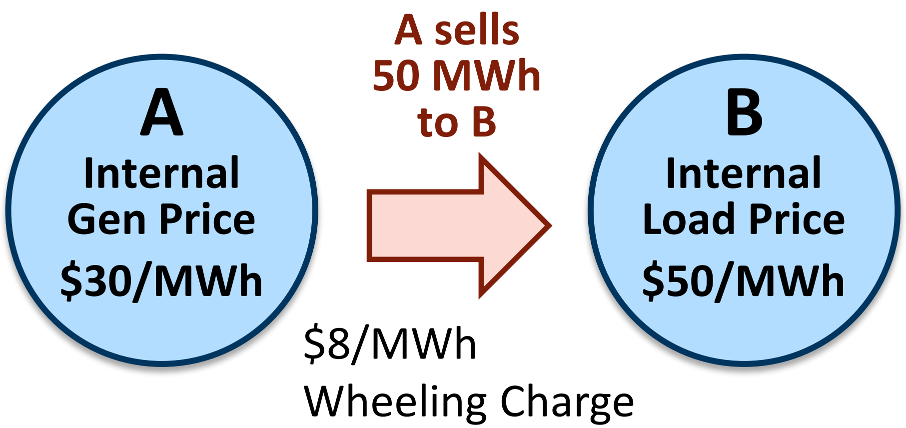
(−) Revenues from bilateral and market sales valued at the BAA's generation-weighted energy price ("Gen LMP")

Benefit Metrics: Wheeling Revenues, Trading Gains

Based on the simulation results, we also estimate several additional impacts from increased trading facilitated by the market reforms, which is not fully captured in APC

- **Wheeling Revenues:** collected by the exporting BAAs based on OATT rates
- **Trading Gains:** buyer and seller split 50/50 the trading margin (and congestion revenues in EIM/EDAM)

EXAMPLE: Bilateral Trade



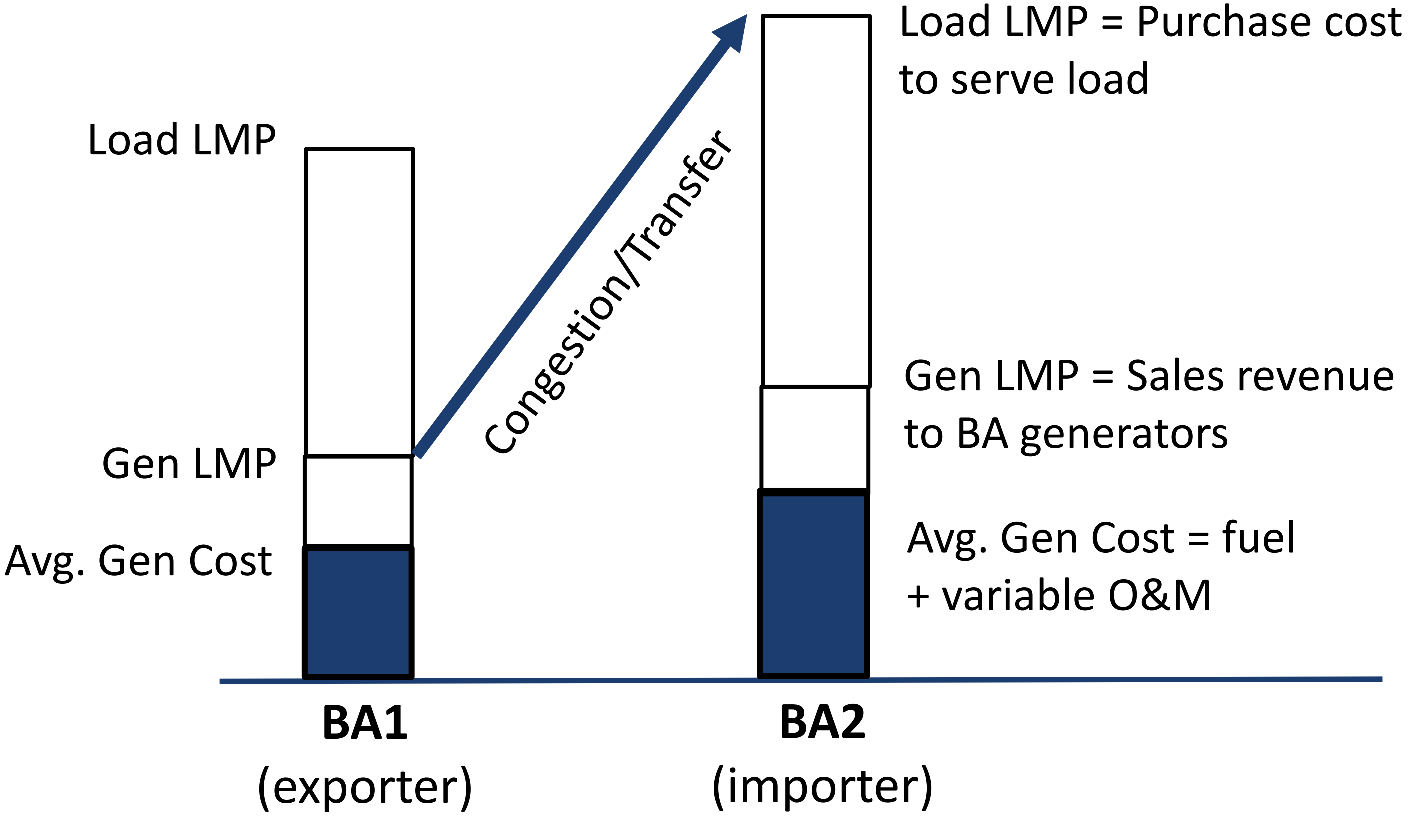
The APC metric only uses area-internal prices for purchase cost and sales revenues, which does not capture part of the value:

- A receives $30×50MWh=$1,500 in APC sales revenues
- B pays $50×50MWh=$2,500 in APC purchase costs
- ➔ $1,000 of trading value not captured in APC metric

Trading value = $20/MWh Δprice x 50 MWh = $1000

- Exporter A receives wheeling revenues: $8/MWh x 50MWh = $400
- Remaining $600 trading gain split 50/50: both A and B receive $300

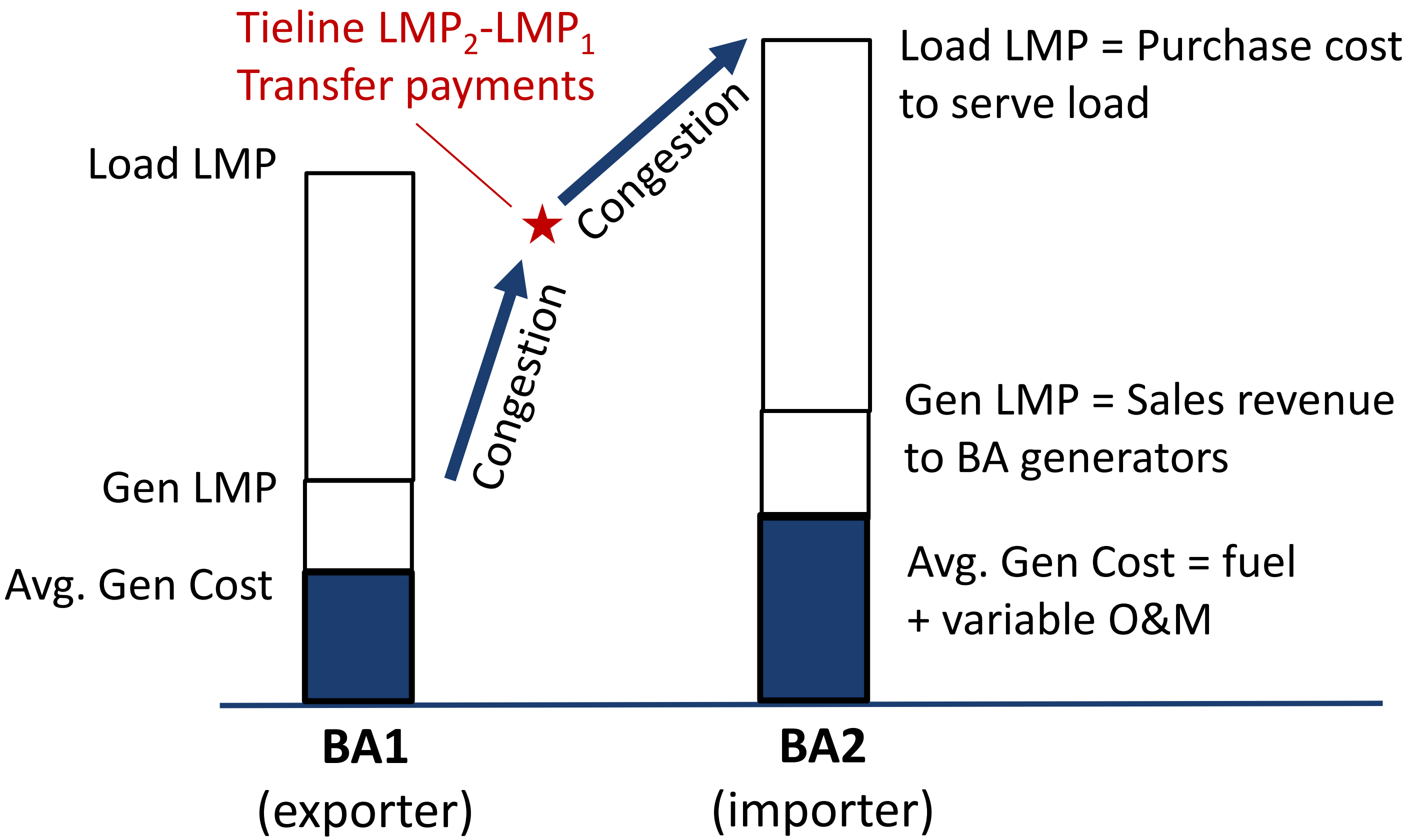
Illustration of Markets+ Congestion Revenues



Markets+ congestion revenues are rolled together and estimated based on BA load and gen LMPs:

- The BAA is assumed to own all rights on congested paths within their BAA, unless we have information on third-party contracts.
- Similarly, unless we have information on third-party contracts, we assume congestion between market members is owned 50/50 by the two BAAs
- Congestion/Transfer Revenue Payment (split 50/50) = MW x (Load LMP_2 – Gen LMP_1)

Illustration of EDAM Congestion and Transfer Revenues



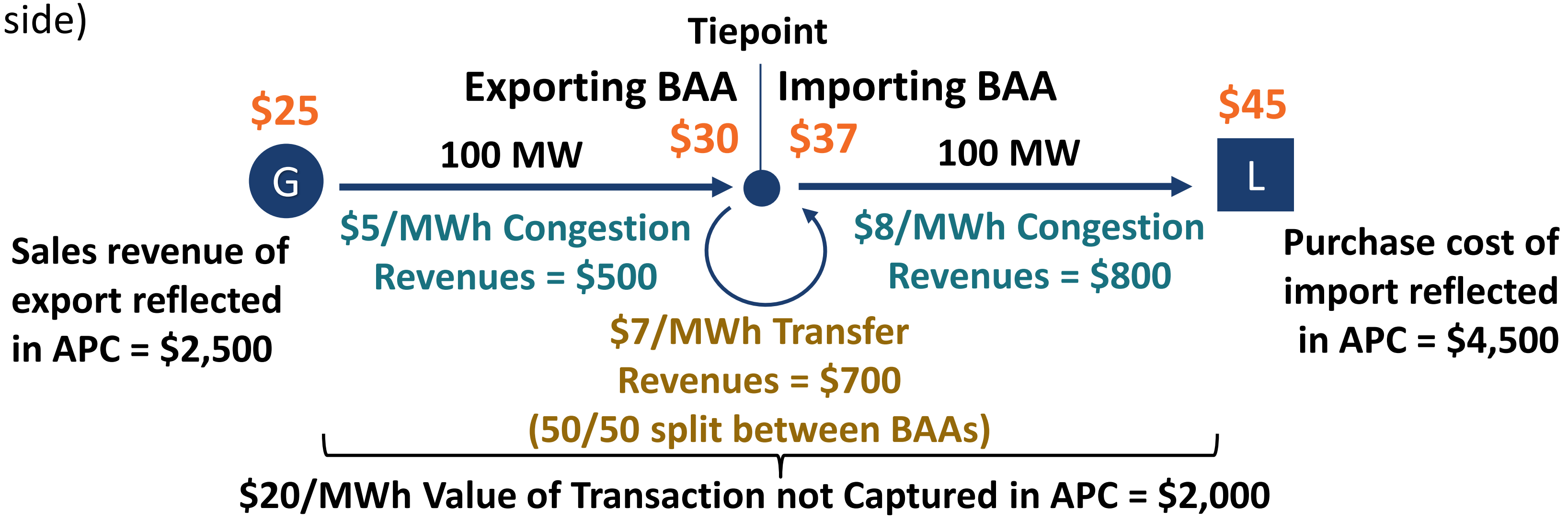
EDAM congestion and transfer revenues estimated based on individual tieline LMPs:

- **Congestion Payment (to exporter)**
  = MW x (Tie LMP_1 – Gen LMP_1)
- **Congestion Payment (to importer)**
  = MW x (Load LMP_2 – Tie LMP_2)
- **Transfer Payment (split 50/50)**
  = MW x (Tie LMP_2 – Tie LMP_1)

Illustration of Congestion/Transfer Revenues vs. APC

Generators and loads get paid/pay the prices within their BAAs

- Therefore, congestion on internal transfers (between a member's own gen and load) is captured in the APC metric.
- However, congestion/transfer revenue on external transactions (to neighboring members) is not captured in APC.
- In the example below, for an external market transaction, the selling BAA has a price of $25 and the purchasing BAA has a price of $45.
  - The $20 difference between the seller and buyer is the congestion and transfer revenue.
  - **$5/MWh of congestion revenue** is allocated to the seller ($30 on their side of the intertie less $25 internal gen price)
  - **$8/MWh of congestion revenue** is allocated to the buyer ($45 internal load price less $37 on their side of the intertie)
  - **$7/MWh of transfer revenue** is split 50/50 between the buyer and seller ($37 on the buyer side of the intertie less $30 on the seller side)



Appendix D:
Overview of Power System Optimizer (PSO)

Key Modeling Assumption Sources

Modeling assumptions based on public sources and refined with input from study participants

Assumption Category	California	Rest of WECC
Resource Mix	• CAISO resource mix assumptions reflect the 2023-2024 CAISO TPP portfolio • LADWP and BANC/SMUD provided resource mix assumptions directly during the 2022	• Participant updates for El Paso Electric, Idaho Power, NV Energy, Portland General Electric, PacifiCorp, Public Service Company of New Mexico • Recent IRP updates for Arizona Public Service, Tucson Electric Power, Avista, and Puget Sound Energy
Load	• CAISO load assumptions are based on the 2022 IEPR mid baseline load forecast • LADWP and BANC/SMUD provided resource mix assumptions	
GHG Prices	• GHG prices are based on the CEC's 2022 mid case, with the modeled CA & WA price in 2032 at ~$64/metric ton • We assume the WA and CA carbon markets are linked by 2032	
Natural Gas Prices	• Gas prices were provided by the study participants in prior iterations of EDAM/Markets+ studies.	
Transmission	• Participant updates for specific projects, and addition of interregional projects anticipated to be online by 2032, including SunZia, SWIP-N, TransWest Express, Cross-Tie, Greenlink North & West, B2H, Gateway Projects • Enforced physical limits include WECC-rated paths and specific constraints identified by pariticpants • Contract path limits based on public data and participant input and enforced for all BA-to-BA connections	

Overview of Modeling Approach

We utilize the WECC ADS nodal production cost model as a starting point imported into Power System Optimizer (PSO), as refined during the EDAM feasibility study and follow-on engagements

Utilized the Polaris Power System Optimizer (PSO), an advanced market simulation model

- Nodal mixed-integer model representing each load and generator bus in the WECC
- Licensed through Enelytix
- Detailed operating reserve and ancillary service product definition
- Detailed representation of the transmission system (both physical power flows and contract paths)
- Sub-hourly granularity (but used hourly simulations due to limited data availability)
- Designed for multiple commitment and dispatch cycles (e.g., DA and RT) with different levels of foresight
- EDAM feasibility study assumptions updated to reflect the most recent utility resource plans and forecasts of system conditions and costs

PSO is uniquely suited to simulate bilateral trading, joint dispatch, imbalance markets, and RTOs, reflecting multiple stages of system operator decision making

Independent Simulation of Multiple Time Horizons

PSO simulates multiple independent decision cycles to capture day-ahead vs. real-time unit commitment and dispatch

D-1 (am)	D-1 (~noon)	D-1 (pm-D)	D
DA Bilateral Markets • DA block trades on long-term transmission rights and incremental transmission	**Day-Ahead Market** • CAISO, EDAM, and RTO market clearing • Hourly intertie trading • Hourly trading with long-term transmission rights	**Intra-Day Markets** • Hourly bilateral trades on remaining transmission	**EIM (RT Balancing)** • WEIM/WEIS/RTO trading of economic energy • Remaining Tx released for WEIM/WEIS • RT balancing in BAAs

Independent real-time decision cycle used to simulation EIM functions

Unit Commitment Cycle → **Economic Dispatch Cycle** → **Real Time Cycle**

Decision cycles capture bilateral trading, market clearing, BAA functions in DA and RT, and market cycles (EDAM "GHG reference" pass, EDAM market, and EIM)

Independent real-time decision cycle used to simulate DA vs. RT, including <u>forecast errors</u> for wind and solar

Simulating Several Wholesale Market Cycles in PSO

The model setup for wholesale market simulation effort contains several cycles to simulate unit commitment and dispatch decisions in three different timeframes and within different market structures. For example, cycles simulated can include are:

- **Day-Ahead Unit Commitment Cycle:** the model optimizes unit commitment decisions, 24 hours at a time (with 48-hour look ahead), for long-lead time resources such as coal and nuclear plants, based on their relative economics and operating characteristics (e.g., minimum run time, maintenance schedules, etc.), transmission constraints, and trading frictions. The model ensures that enough resources are committed to serve forecasted load, accounting for average transmission losses and the need for ancillary services. Separate regions' commitment decisions are segregated through higher hurdle rates on imports and exports. Trading within a single balancing area, like the various RTO sub-zones, is not subject to any hurdles.
- **Day-Ahead Economic Dispatch Cycle:** the model solves for the optimal level of hourly day-ahead dispatch and trading in 24-hour forward-looking optimization cycles, with 48-hour look ahead periods. Dispatch across the study footprint is optimized based on resource economics. In this cycle, the model also co-optimizes ancillary service procurement for each area. The high hurdle rates for unit commitment are lowered to enable more bilateral trading between balancing areas.
- **Intra-day trading:** the model simulates market activity through one-hour optimization horizons. Trading is assumed to utilize unused transmission, represented as the difference between their day-ahead trading volume and the total contract path limits. No unit re-commitment is allowed due to the non-firm nature of the transactions. Changes to generation availability, such as forced outages, which were not "visible" during the day-ahead cycle become visible during this cycle.
- **Real-Time Cycle:** this cycle simulates the operation of the real-time imbalance markets, such as through EIM transactions. In this cycle, the model can re-optimize dispatch levels and unit commitment decisions for fast-start thermal resources (based on the assumption that the real-time market design allows for unit re-commitment). Deviations from day-ahead forecasts (due to uncertainty) need to be balanced in real-time.

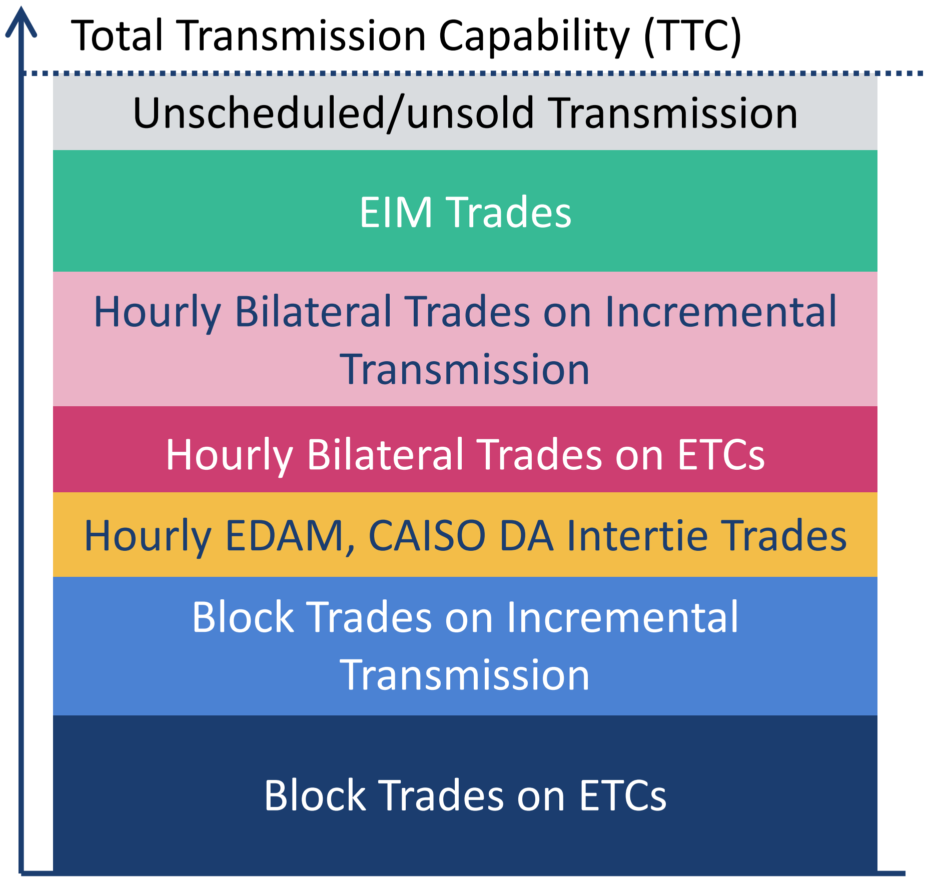
These cycles can take on different assumptions, depending on market structure. In a bilateral setting, all are set up to analyze utility-specific unit commitment and dispatch decisions, with each of them including hurdle rates and transmission fees that limit the amount of economic transactions that can take place between the utilities. In EIM and EDAM+EIM scenarios, all of the cycles are set up to simulate market-wide optimization of unit commitment and dispatch, including the EDAM "reference pass" cycle. In the EDAM case, there would be no hurdle rates between EDAM participants in any of the cycles, allowing the model to optimize both unit commitment and dispatch in the market footprint on both a day-ahead and real-time basis.

Types of Trades and Transmission Reservations Modelled

The model simulates the use of different types of contract-path transmission reservations for bilateral trading in DA and RT

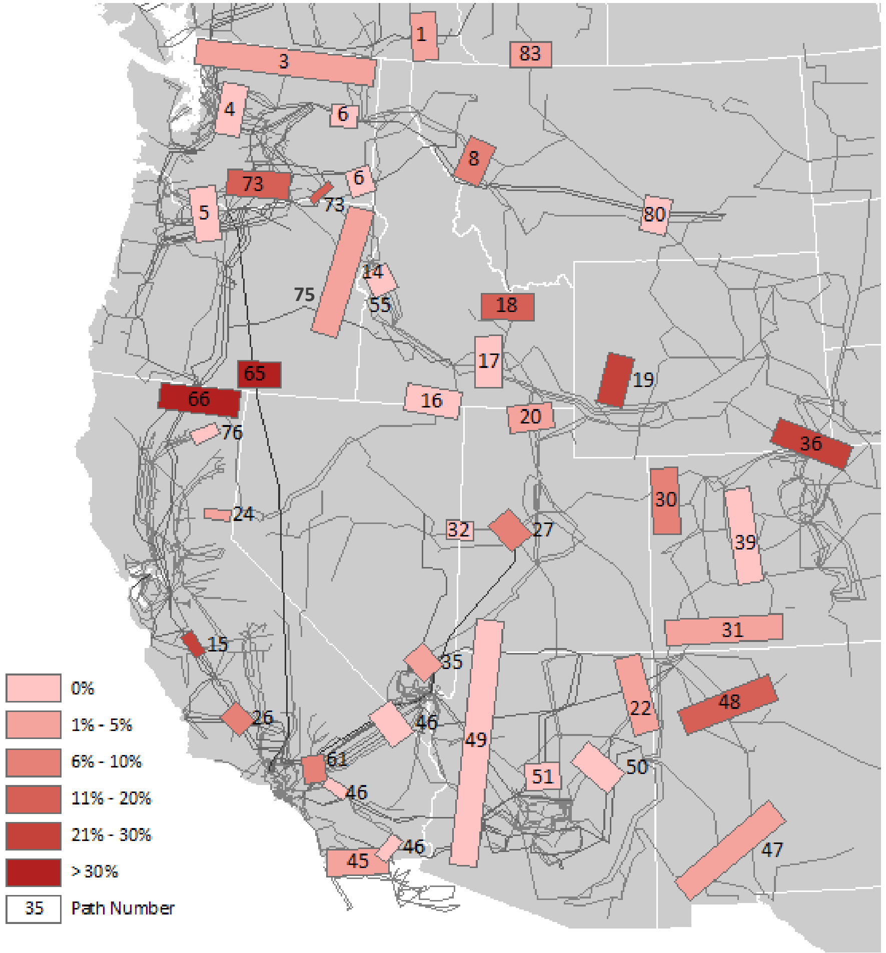
- Existing long-term transmission contracts (ETCs) and incrementally purchased transmission
- Total reservations on each contract path is limited by the total transfer capability (TTC)
- Trades are structured as blocks or hourly
- Bilateral trades between BAAs, at major hubs, or across CAISO interties
- Account for renewable diversity and day-ahead forecast uncertainty vs. real-time operations
- Unscheduled transfer capability released for EIM trades in real-time

Types of Trades Modeled



Nodal Simulations Based on Physical Transmission

WECC-Defined Paths Modeled



Limits on the physical transmission system include all the paths defined in WECC Path Rating Catalogue

- Additional transmission paths to represent congestion internal to each BA
- Limits on all paths and constraints reflect updates provided by the study participants

ENELYTIX®
powered by PSO

Power System Optimizer (PSO), developed by Polaris Systems Optimization, Inc. is a state-of-the-art market and production cost modeling tool that simulates least-cost security-constrained unit commitment and economic dispatch with a full nodal representation of the transmission system, similar to actual RTO and ISO market operations. Such nodal market modeling is a commonly used method for assessing the operational benefits of wholesale market reforms (e.g., JDAs, EIMs, RTOs).

PSO can be used to test system operations under varying assumptions, including but not limited to: generation and transmission additions or retirements, de-pancaked transmission and scheduling charges, changes in fuel costs, novel environmental and clean energy regulations, alternative reliability criteria, and jointly-optimized generating unit commitment and dispatch. PSO can report hourly or sub-hourly energy prices at every bus, generation output for each unit, flows over all transmission facilities, and regional ancillary service prices, among other results. Comparing these results among multiple modeled scenarios reveals the impacts of the study assumptions on the relevant operational metrics (e.g. power production, emissions, fuel consumption, or production costs). Results can be aggregated on a unit, state, utility, or regional level.

PSO has important advantages over traditional production cost models, which are designed primarily to model dispatchable thermal generation and to focus on wholesale energy markets only. The model can capture the effects of increasing system variability due to large penetrations of non-dispatchable, intermittent renewable resources on thermal unit commitment, dispatch, and deployment of operating reserves. PSO simultaneously optimizes energy and multiple ancillary services markets on an hourly or sub-hourly timeframe.

Like other production cost models, PSO is designed to mimic ISO operations: it commits and dispatches individual generating units to meet load and other system requirements, subject to various operational and transmission constraints. The model is a mixed-integer program minimizing system-wide operating costs given a set of assumptions on system conditions (e.g., load, fuel prices, transmission availability, etc.). Unlike some production cost models, PSO simulates trading between balancing areas based on contract-path transmission rights to create a more realistic and accurate representation of actual trading opportunities and transactions costs. This feature is especially important for modeling non-RTO regions.

One of PSO's distinguishing features is its ability to evaluate system operations at different decision points, represented as "cycles," which occur at different times ahead of the operating hour and with different amounts of information about system conditions available. Under this sequential decision-making structure, PSO can simulate initial cycles to optimize unit commitment, calculate losses, and solve for day-ahead unit dispatch targets. Subsequent cycles can refine unit commitment decisions for fast-start resources and re-optimize unit dispatch based on the parameters of real-time energy imbalance markets. The market structure can be built into sequential cycles in the model to represent actual system operation for utilities that conduct utility-specific unit commitment in the day-ahead period but participate in real-time energy imbalance markets that allow for re-optimization of dispatch and some limited re-optimization of unit commitment. For example, PSO can simulate an initial cycle that determines day-ahead unit commitment decisions that reflects the constraints faced by, and decisions made by, individual utilities when committing their resources in the day-ahead timeframe. The initial day-ahead commitment cycle is followed by cycles that simulate day-ahead economic dispatch, including bilateral trading of power, and a real-time economic dispatch, reflecting trades in real time (whether bilateral or optimized through an EIM or RTO). Explicit commitment and dispatch cycle modeling allows more accurate representation of individual utility preference to commit local resources for reliability, but share the provision of energy around a given commitment.