

Western Seams Analysis

Prepared for the Environmental Defense Fund and the
Natural Resources Defense Council

September 30, 2026



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Best seams management practices unlock the greatest trade volume across the Western US, driving cost benefits for most participants

1

- **Up to \$840M in cost savings under the best DAM seams management practices**
 - A single Day-Ahead Market (DAM) configuration across the Western US results in most efficient energy dispatch and biggest cost savings. However, in lieu of such a possibility, our modeling results demonstrate up to \$840M in ratepayer cost savings across the whole WECC for the 2032 study year when best DAM seams management practices are implemented in a partitioned DAM market

2

- **No seams to trade under a single DAM configuration can yield \$1.2B-2.0B in cost savings compared to a DAM-partitioned Western US**
 - In line with expectations, removal of trade frictions between EDAM and Markets+ can help avoid \$0.6B-1.1B in seams cost under the Single Market scenario, while also stimulating transmission-related revenues additions of \$480M-770M from more trade circulation

3

- **Bonneville Power Administration (BPA) sees a \$296M cost benefit from best seams management practices**
 - Improving seams management results in savings for BPA, which accounts for 35.2% of total cost savings across the Western US. Notably, the cost savings going from worst to best seams management is equivalent to the benefits going from best seams management to a single DAM market

4

- **In few cases, improved seams management reduces cost savings for individual BAs**
 - While Western US-wide costs are minimized with reduced seams costs, some BAs see increased costs. Puget Sound Energy (PSEI) sees costs increase with lower seams cost as BPA's hydro generation is shared across a wider footprint. Nevada Power Company (NEVP), committed to EDAM, sees minimal cost change across seams scenarios as its interconnection footprint is largely already participating in EDAM

Introduction

The Western U.S. power sector is seeing a period of transition

- With the launch of EDAM and Markets+, the Western U.S. will be partitioned into two separately optimized Day-Ahead markets
- These two Day-Ahead markets will need to manage the seams created as the market footprints continue evolve to effectively mitigate against suboptimal dispatch, trade inefficiencies, and additional administrative burden
- While a Single Western market presents the greatest opportunity for cost savings through central coordination of resource dispatch, expanding the market footprints and reducing inefficiencies across market boundaries can provide significant benefits under a two-market system
- Aurora Energy Research was commissioned by the Natural Resources Defense Council (NRDC) and the Environmental Defense Fund (EDF) to analyze and quantify the cost outcomes resulting from Western seams
- **This study quantifies WECC-wide power sector system costs under 4 scenarios for the 2032 study year, varying DAM footprint and friction charges across market boundaries.** Across scenarios, the capacity mix and demand follows published Integrated Resource Plans. Aurora employs established electricity modeling methodologies, including production cost modeling, to compare outcomes across DAM configurations and friction charge scenarios:

Scenario	Description
No friction (Single market)	Models all balancing authorities (BAs) in a single DAM, representing the most efficient theoretical configuration for resource sharing in the West
Low seams friction	Models BAs participating in either EDAM, Markets+, SPP West, or remaining uncommitted, with low frictions reflecting efficient seams management
Medium seams friction	Models BAs participating in either EDAM, Markets+, SPP West, or remaining uncommitted, with low frictions reflecting standard seams management
High seams friction	Models BAs participating in either EDAM, Markets+, SPP West, or remaining uncommitted, with low frictions reflecting poor seams management

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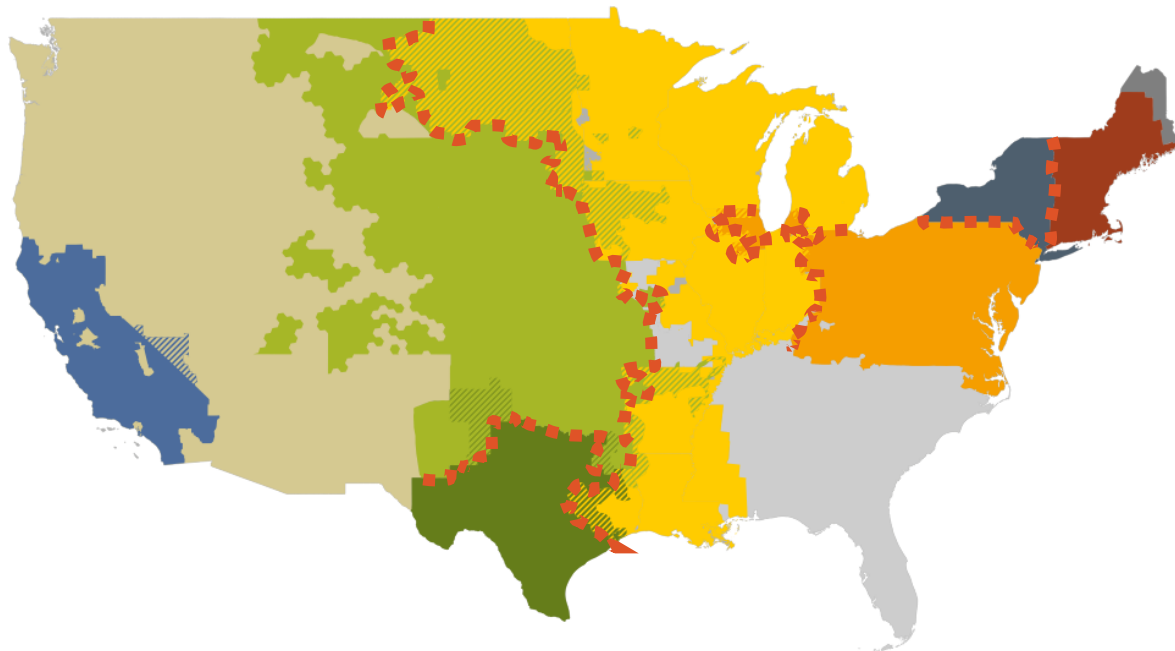
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Seams exist across the U.S. today, providing relevant historical examples of coordination practices and challenges

The formation of EDAM and Markets+ will create new market boundaries and associated market seams. The West currently manages seams through the operations of WEIM, WEIS, and transfers across individual balancing authorities, though coordination across seams between two separately optimized Day-Ahead Market (DAM) footprints is expected to create new challenges. While a single Western market may result in the most efficient use of resources, the inefficiencies of seams between two DAMs can be improved through effective coordination and management.

Map of existing U.S. ISOs/RTOs and major seams



Key

CAISO ISO-NE NYISO SERC WECC
 ERCOT MISO PJM SPP Major existing market seams

Seams exist across the U.S. at the interfaces between neighboring wholesale electric markets with shared transmission networks.

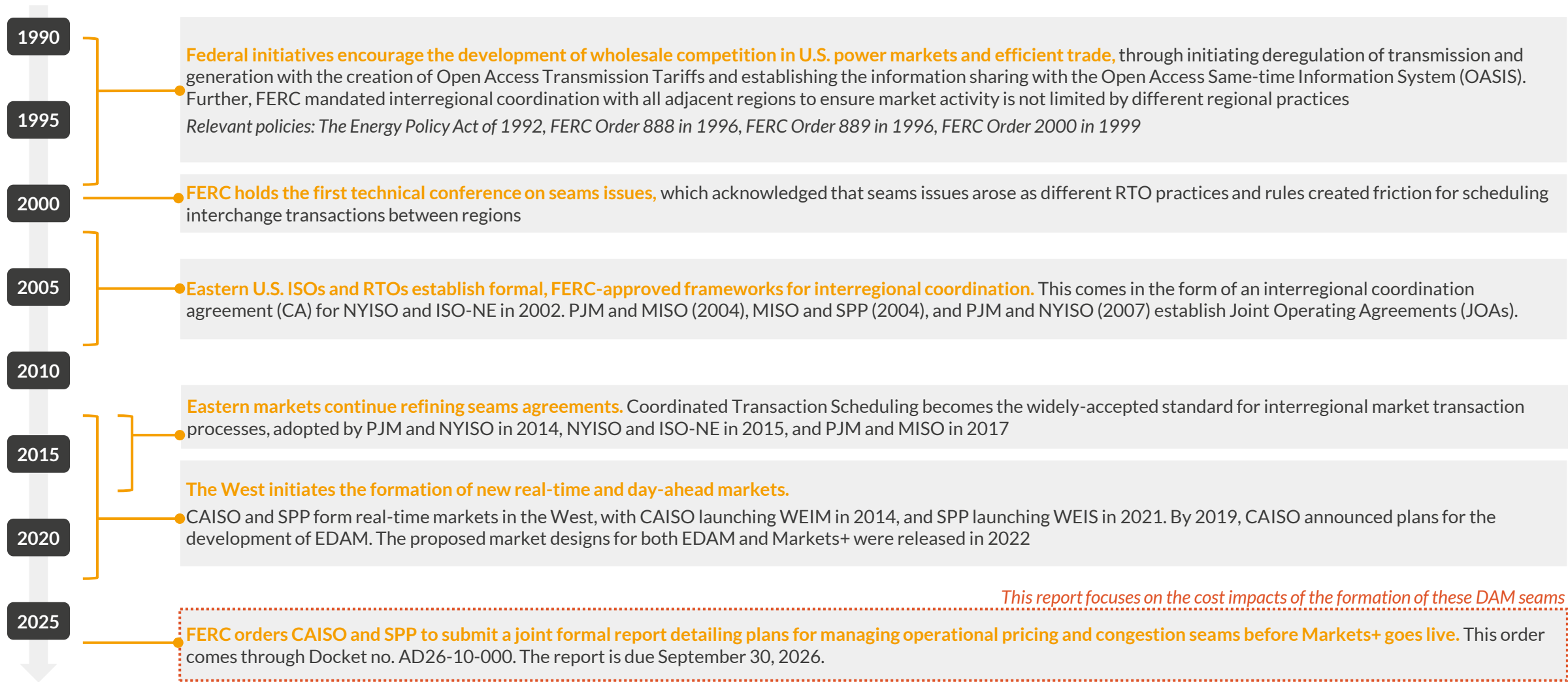
A **market seam** is the interface between adjacent wholesale ISO/RTOs, each with separate centrally optimized operations.

As separate markets have distinct tariffs, market designs, and protocols, coordination across these interfaces may result in **seams issues** that reduce overall dispatch efficiency. **Seams costs** arise from the economic and logistical inefficiencies created by exchanging power between separately optimized markets, rather than solving as one.

Seams coordination involves cooperation and coordination between market operators sharing a border to manage the dispatch and reliability at the interfaces between two markets. There are multiple mechanisms to manage seams used by ISOs and RTOs today, with varying levels of success in reducing inefficiencies.

Since the creation of ISOs and RTOs, seams practices have continuously evolved to better manage interregional trade

History of seams development in the U.S.



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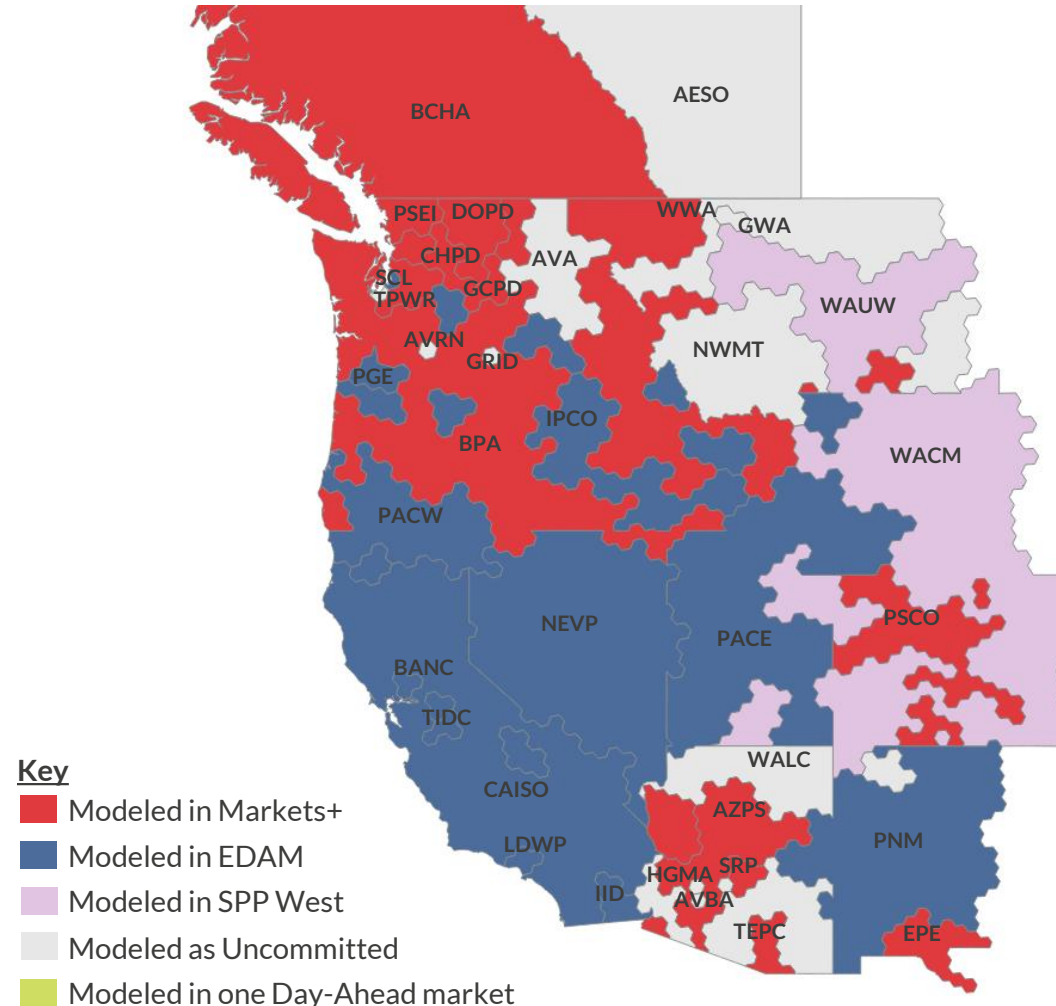
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Aurora modeled balancing authority commitments to different day-ahead markets partitioning the West, compared against a single market

Modeled Day-Ahead Market (DAM) participation – **Multiple Markets** scenario

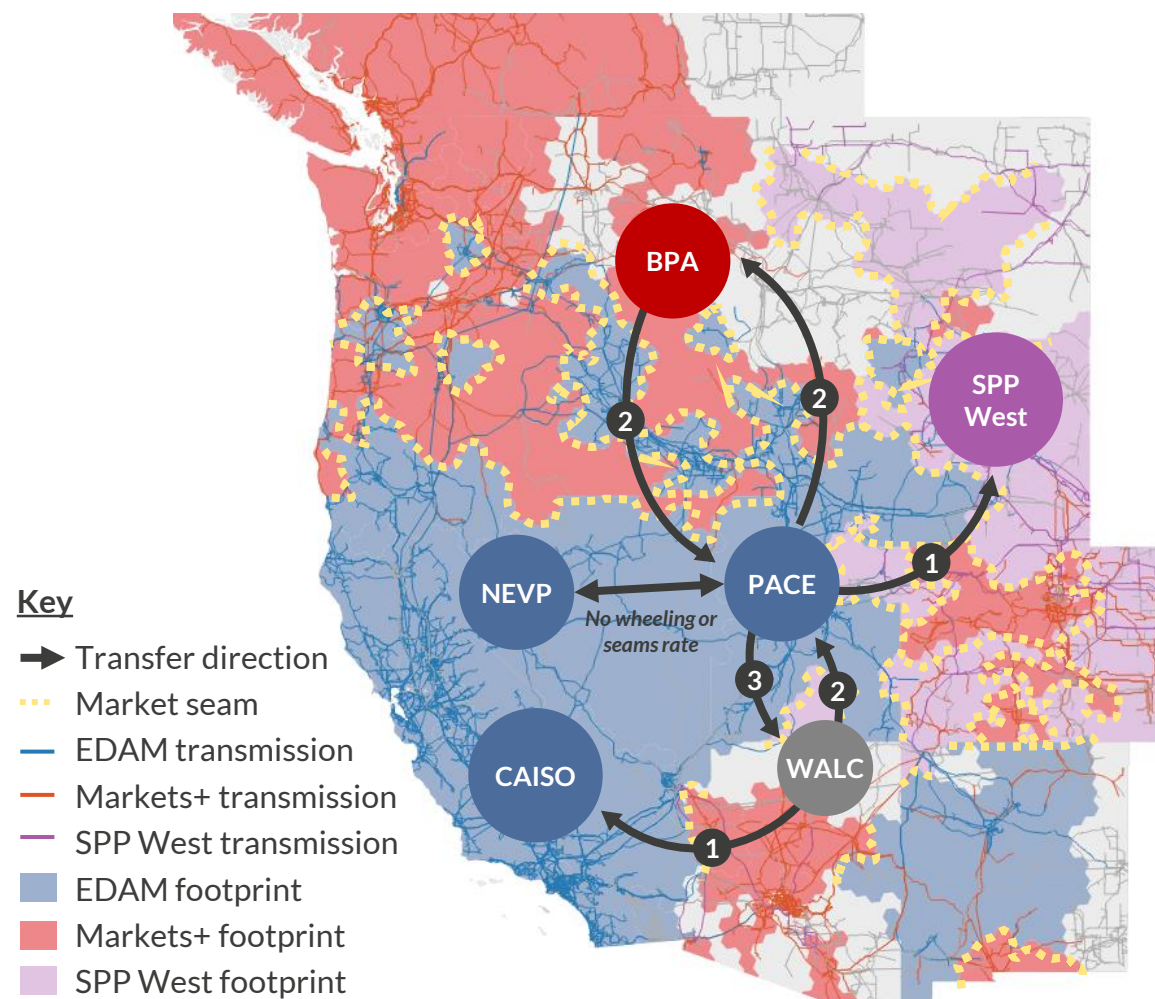


Modeled Day-Ahead Market (DAM) participation – **Single Market** scenario



Three different seams rates are applied to inter-BA transfer costs under the **Multiple Markets** footprint

Illustrative examples of modeled transfer costs between day-ahead market footprints and transmission networks



Transfer cost components

Wheeling rates (\$/MWh)¹, defined by each utility in their **Open Access Transmission Tariff (OATT)**, represent baseline costs for one utility to use another's transmission.

Seam rates (\$/MWh)², a modeling construct representing additional costs that arise when power is transferred between two distinct markets. These costs are applied to the target market by the source market.

Deep dive to follow ➔

Modeled seams rates per interchange category in **Multiple Markets** scenario

	Sink region	Low seams friction	Medium seams friction	High seams friction
1	CAISO / SPP West	+\$2.8/MWh	+\$4.9/MWh	+\$12.5/MWh
2	EDAM / Markets+	+\$2.8/MWh	+\$4.9/MWh	+\$12.5/MWh
3	Uncommitted BAs	+\$5.6/MWh	+\$9.9/MWh	+\$25.0/MWh

1) Off-peak non-firm hourly transmission service. 2) In our model, these costs are not based on utility tariffs but are assumed and applied to all transactions to reflect real-world barriers to efficient interregional trade, such as coordination challenges and scheduling hurdles.

Seams rates represent administrative hurdles and coordination challenges experienced at boundaries between different DAMs

Aurora designed three seams cost cases under the Multiple Markets scenario as a representation of differing seams management. No seams costs are applied under the Single Markets scenario, envisaging a Western US operating under a single DAM. Low friction represents an upside on seams management; Central friction represents a moderate view on seams management; and High friction represents a downside on seams management

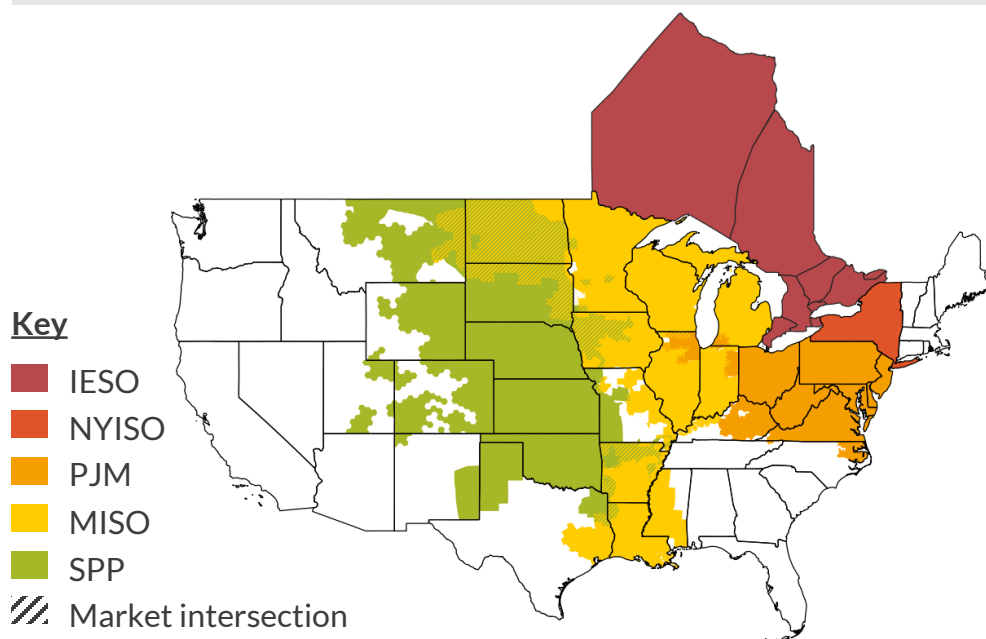
Modeled scenario			
	Low seams friction	Medium seams friction	High seams friction
	<i>Best seams management</i>	<i>Standard seams management</i>	<i>Worst seams management</i>
Illustrative translation into real-world seams management practices			
Information sharing	Highly transparent, proactive, and consistent sharing	Transparent within DAM, but limited across Regional Coordinator seams	Minimal transparency and low frequency
Data formatting	Standardized across boundaries, allows for efficient processing	Standardized with minor inconsistencies, driving lag time	Non-standardized, significant lag time
Congestion management	Network-wide cross-coordination, considering all market participants	Solutions implemented don't span multiple footprints	Siloed congestion management within internal boundary
Real-time communications	Direct, automated signals allowing for fast response	Lags in dispatch implementation from generators to manage congestion	Tools implemented don't capture real-time conditions

Assumed seams rates under the Multiple Markets scenarios are calibrated based on historical seams costs in the East...

Illustrative example of seams rates calibration for modeling the Multiple Markets scenarios

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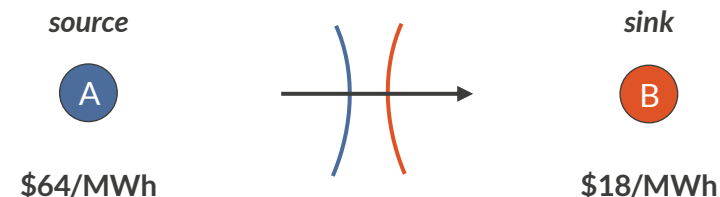
Step 1: Scraped historical hourly interchange data across market seams in the Eastern Interconnection



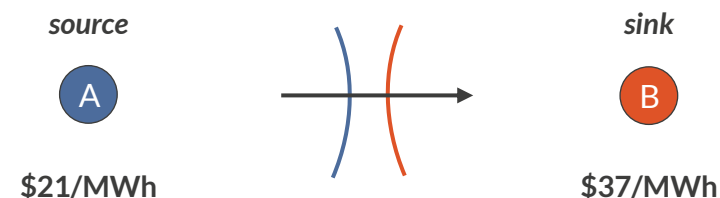
- Hourly dispatch data from 2023-2026YTD was scraped across market seams in the Eastern Interconnection for PJM-MISO, MISO-SPP, and MISO-IESO trades
- Hourly dispatch summary data¹ for 2023 used as a reference for PJM-NYISO trades

Step 2: Categorized hourly interchange flows into counter-price and consistent flows

Example of **counter-price flow**



Example of **consistent flow**



- Intuitive power flows move across a market seam from a lower-priced source to a higher-priced sink as a reflection of efficient low-cost resource sharing
- Hourly trade volumes were sorted into counter-price and consistent flows, wherein counter-price flows were considered to incur a seams cost due to inefficient market dispatch of higher-cost generation

1) Sourced from Monitoring Analytics; trade data was summarized into price buckets representing the price differential between source-sink interface nodes across seams, and the number of counter-price and consistent hours within each price bucket.

... establishing modeled costs based on 50th percentile price differential within counter-price flows for each market seam pair

Illustrative example of seams rates calibration for modeling under the Multiple Markets scenarios

Step 3: Sort price differentials during counter-price flow periods into percentile buckets, per market seam pair					
Source	Sink	Source price ¹	Sink price ¹	Price delta (Source - Sink)	Counter flow flag
PJM	MISO	32.2	56.8	24.6	0
PJM	MISO	84.2	66.2	-18.0	1
MISO	PJM	55.1	12.2	-42.9	1
MISO	PJM	44.0	42.8	-1.2	1
PJM	NYISO	8.4	13.2	4.8	0
PJM	NYISO	73.7	81.0	7.3	0
NYISO	PJM	23.1	21.2	-1.9	1
NYISO	PJM	14.9	24.5	9.6	0



Percentile buckets	MISO - PJM	PJM - NYISO	MISO - SPP	MISO - IESO
P1	\$ 0.0	\$ 0.1	\$ 0.1	\$ 0.3
P10	\$ 0.4	\$ 0.8	\$ 1.0	\$ 3.2
P25	\$ 1.2	\$ 2.3	\$ 2.4	\$ 6.6
P50	\$ 2.8	\$ 4.9	\$ 5.4	\$ 12.5
P75	\$ 5.7	\$ 11.2	\$ 10.3	\$ 21.8
P90	\$ 10.3	\$ 23.4	\$ 16.7	\$ 37.3
P99	\$ 47.7	\$ 99.0	\$ 38.2	\$ 123.0



MISO - PJM

Low friction



PJM - NYISO

Central friction



MISO - IESO

High friction

- Price deltas between source-sink pairs during counter-price flow hours were distributed across percentile buckets within each market seam pair

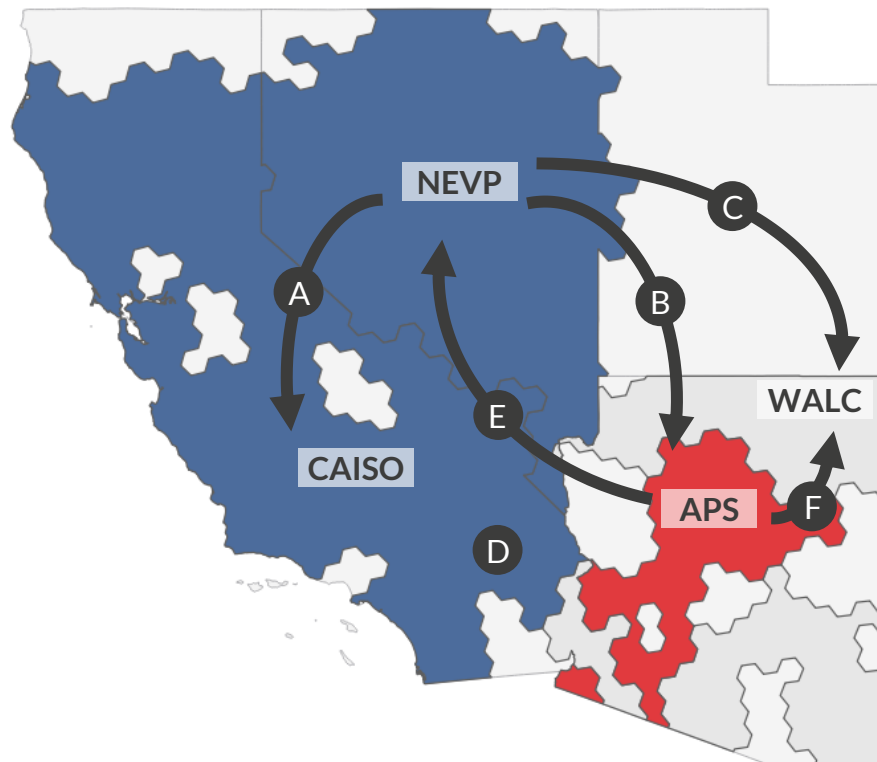
- The P50 value was chosen to represent the typical seams cost. Using the median helps to remove extreme congestion events that may skew a simple average

In this analysis, seams rates are a modeling construct assumed and applied to all transactions to reflect real-world observed barriers to efficient interregional trade, such as coordination challenges and scheduling hurdles. These costs are not associated with utility tariffs or the like.

1) Values are illustrative.

Inter-BA transfer costs comprise the base wheeling rate, DAM seams costs, and carbon adders for regions subject to a carbon price

Illustrative example of transfer cost implementation across Balancing Authority seams



Source	Tx wheeling ¹	DAM seams cost ¹	Carbon adder ^{1,2}	Sink	Final transfer cost
NEVP (EDAM)	\$4.8/MWh	\$4.9/MWh	\$6.2/MWh	CAISO (EDAM)	\$6.2/MWh
	\$4.8/MWh	\$4.9/MWh	N/A	APS (Markets+)	\$9.7/MWh
	\$4.8/MWh	\$9.9/MWh	N/A	WALC (Uncommitted)	\$14.7/MWh
APS (Markets+)	\$5.6/MWh	\$4.9/MWh	\$7.6/MWh	CAISO (EDAM)	\$18.1/MWh
	\$5.6/MWh	\$4.9/MWh	N/A	NEVP (EDAM)	\$10.5/MWh
	\$5.6/MWh	\$9.9/MWh	N/A	WALC (Uncommitted)	\$15.5/MWh

~~\$XX/MWh~~

No cost incurred as transaction is within the same DAM footprint

N/A

No carbon cost incurred as the sink region is not subject to a carbon allowance limit (CA/WA)

1) Numbers are illustrative. 2) Carbon adder scaled by exporting region's carbon intensity.

Aurora separates total system costs into primary and secondary impacts from seams creation along DAM borders

Primary seams impacts, *the inefficiency costs incurred from power purchases and sales transacting across a market seam at the assumed seams rate*

Variable	What it represents
Day-Ahead seams cost	Costs associated with operational inefficiencies due to trading across Day-ahead markets optimized separately
Real-Time seams cost	Costs associated with operational inefficiencies due to trading across Real-time markets optimized separately

Secondary seams impacts, *the costs and revenues associated with reduced access to lowest-cost generation and reduced coordination due to DAM market segmentation*

Variable	What it represents
Production cost	Cost of generation within each balancing authority area based on economic dispatch
Export revenues	Revenues associated with exporting power from a balancing authority area based on economic dispatch
Import costs	Costs from importing power into a balancing authority area based on economic dispatch
Carbon import compliance ¹	Compliance costs paid by BAs within CA/WA for emissions from imports
Congestion revenue ²	Revenue associated with transmission congestion attributed to balancing authorities based on transmission ownership
Wheeling revenue ²	Revenue associated with transmission utilization attributed to balancing authorities based on transmission ownership

1) Applicable to WA & CA only. Does not account for carbon allowances allocated to LSEs 2) Revenues divided by 2 assuming 50:50 ownership of transmission infrastructure.

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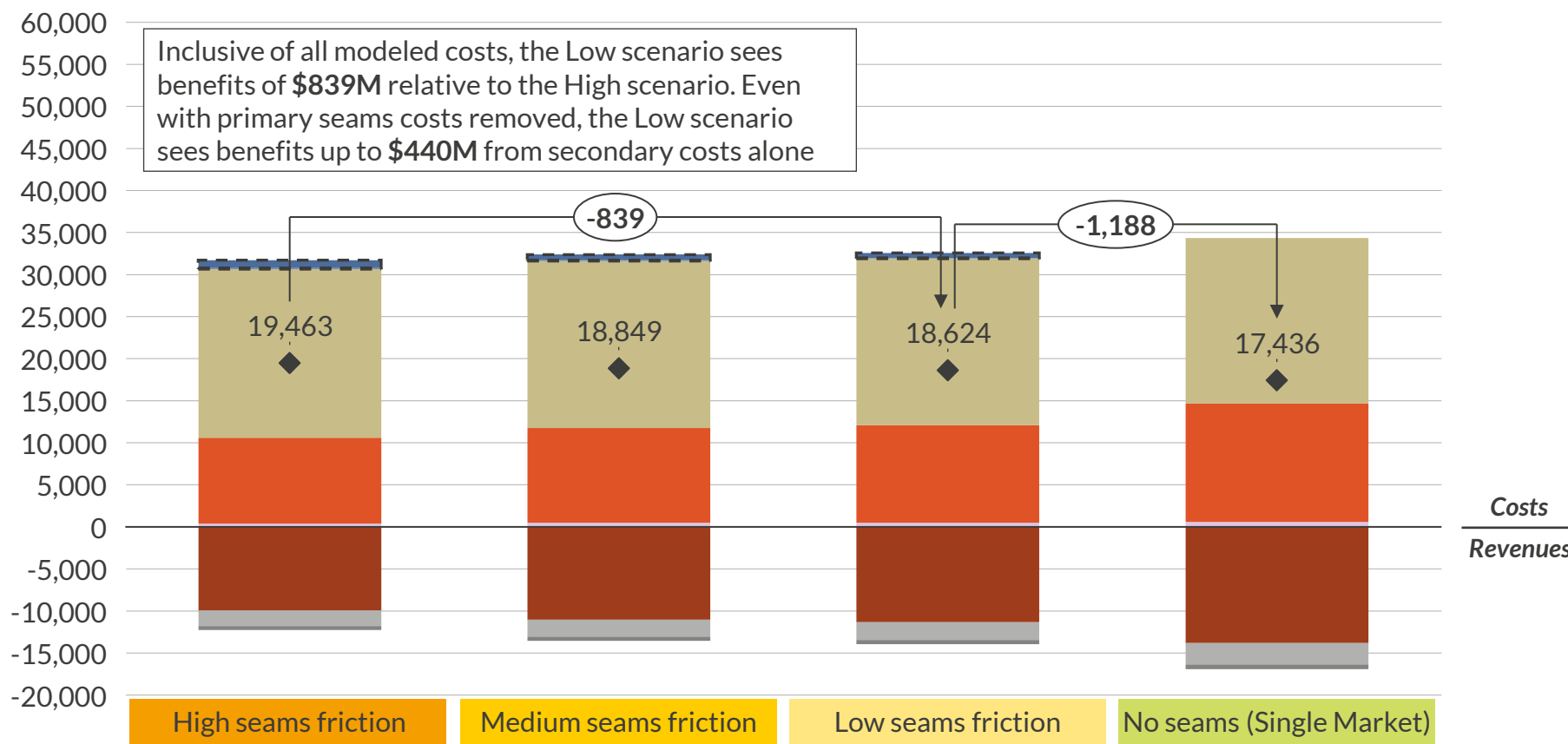
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Total costs see an \$839M reduction when the Western U.S. implements best seams management relative to worst practices

Total system costs for Western US by individual metrics, 2032
\$Million, 2025



 Day-Ahead seams cost
  Production cost
  Import cost
  Congestion revenue
  Total net cost
 Real-Time seams cost
  Export revenue
  Carbon import compliance
  Wheeling revenue

1) Average cost for ratepayers does not consider the seams cost as those are borne by the electricity coordination providers; seams costs are already reflected in pricing outcomes.

- The **No seams (Single Market)** scenario represents the best-case DAM configuration in the Western US, and is provided as a benchmark against the **Multiple Markets** scenarios which model seams frictions between DAM footprints, reflective of different real-world seams management outcomes
- Within the Multiple Market scenarios, average WECC-wide costs per demand are most expensive under the High scenario at **\$17.4/MWh**, and minimized under the Low scenario at **\$17.0/MWh**, which translates to a 2.4% decrease

In a DAM-partitioned West, effective seams management drives 1.2%-4.5% total cost reductions

Annual cost breakdown, Western US¹, 2032

\$Million, real 2025

Metric	High seams friction	Medium seams friction	Low seams friction	No seams (Single Market)
Primary seams impact				
Day-Ahead seams cost	924.1	683.1	584.7	0.0
Real-Time seams cost	139.2	96.0	79.5	0.0
Secondary seams impact				
Production cost	20,061.6	19,855.7	19,805.1	19,650.5
Net trading costs	237.4	246.2	248.8	260.4
→ Export revenue	(9,944.5)	(11,024.4)	(11,346.6)	(13,828.4)
→ Import cost	10,181.9	11,270.6	11,595.4	14,088.8
Carbon import compliance ²	407.6	481.2	501.3	603.7
Congestion revenue ³	(1,841.2)	(2,022.9)	(2,096.1)	(2,540.7)
Wheeling revenue ³	(465.8)	(490.3)	(499.5)	(537.8)
Total costs less revenues	19,462.9	18,849.0	18,623.8	17,436.1
Delta to Low seams friction	+839M (4.5%)	+225.3M (1.2%)		
Delta to No seams (Single Market)			+1,187.7M (6.8%)	

Facing reduced seams to trade under the **Low seams friction** scenario, the Western US **avoids \$115-399M** in administrative and coordination costs, demonstrating the benefits of better seams management practices

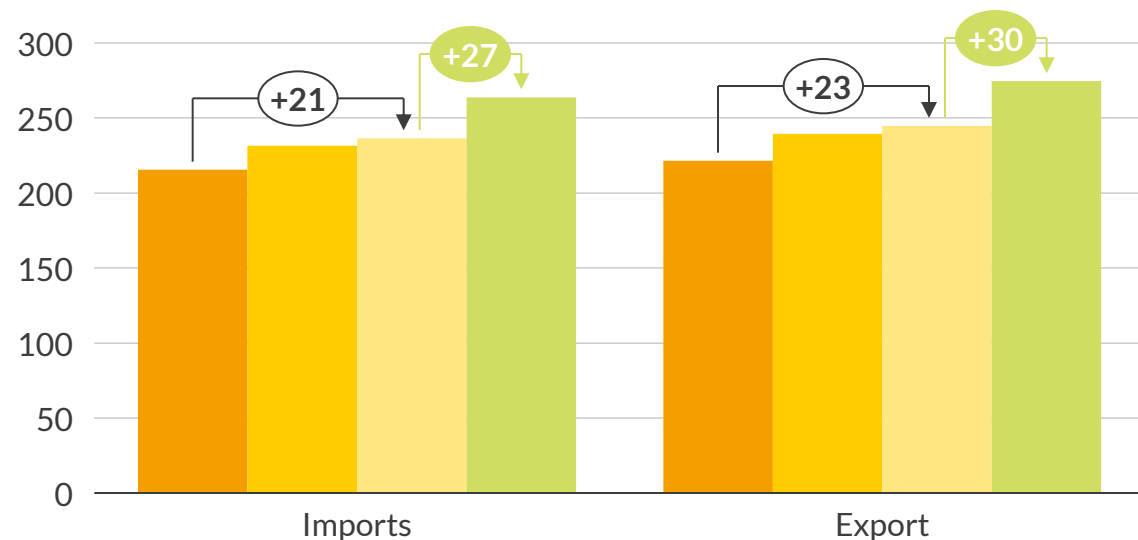
Relative to other Multiple Market scenarios, increased dispatch of **low-cost generation** and **resource-sharing** drives lowest production cost under the **Low seams friction** scenario

Although net trading costs are largely equivalent across scenarios, the **Low seams friction** scenario sees the **greatest trade volume**, which translates to increased transmission usage and associated revenues, garnering more profit for transmission owners and market participants

1) Inclusive of CAISO, California BAs, US non-ISO WECC BAs. 2) Cost associated with carbon emissions if BAs operating within CA or WA exceed their carbon allowance limit. 3) Assumes ownership of transmission is split 50:50.

Seams mgmt. practices implied under the Low seams friction scenario facilitate more trade, reducing thermal generation across the West

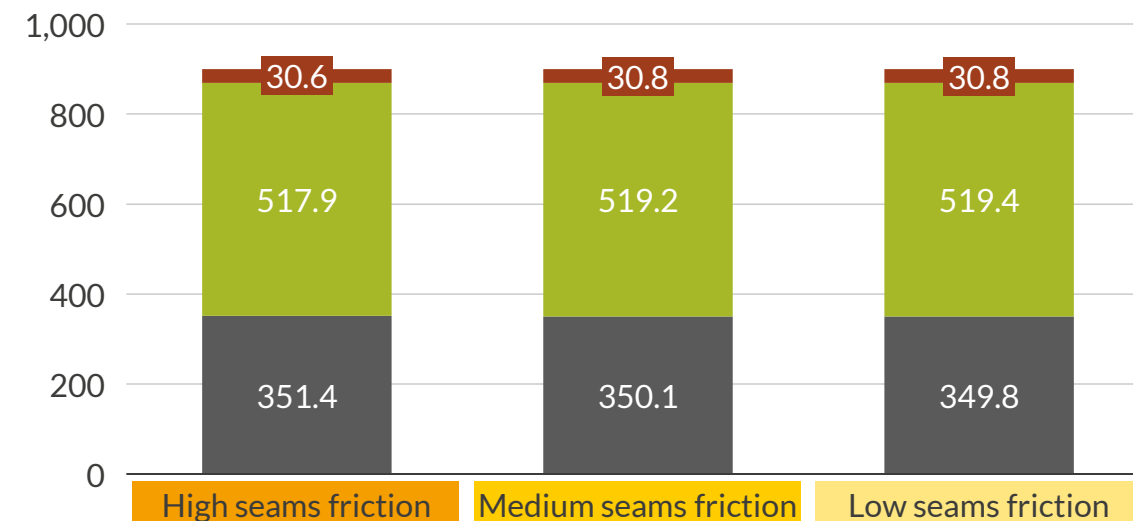
Total trade volume, Western-US, Low seams scenario vs Medium and High seams TWh



- The No seams scenario sees the highest trade volume as a centralized unit dispatch and settlement across the West results in the most efficient resource sharing
- However, within the Multiple Market scenarios, an increase of 43TWh (21TWh from imports + 23TWh from exports) in trade volume occurs when best seams management practices are implemented under the Low seams scenario, relative to the High seams scenario
- The net-positive trade volume for the Western US is due to exports to SPP

■ High seams friction ■ Low seams friction
■ Medium seams friction ■ No seams (Single Market)

Generation stack¹, West US, Low seams scenario vs Medium and High seams TWh



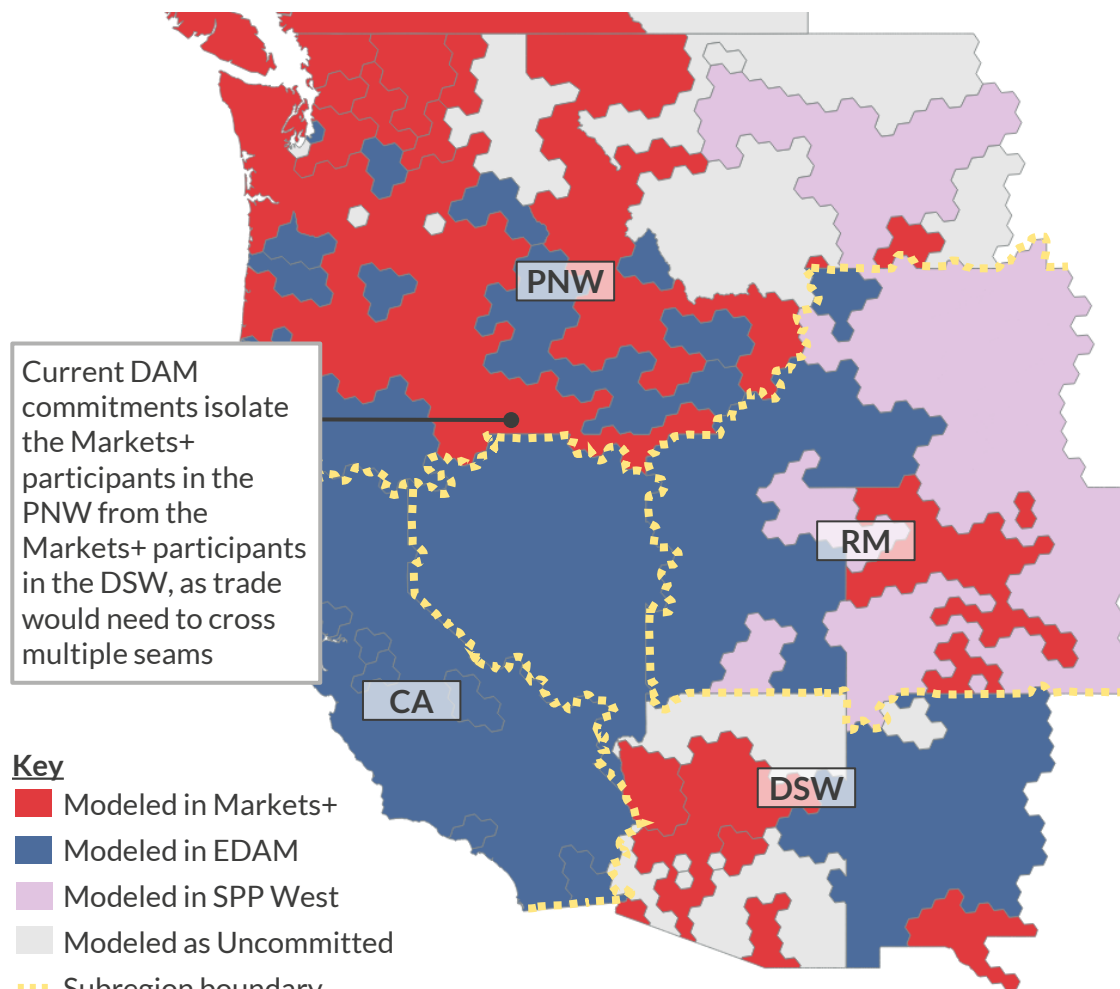
- Across both comparisons between Low scenario to the Medium and High scenarios, there is a comparable reduction in emitting thermal generation for increases in renewables generation, resulting in a cleaner WECC-wide grid
- These results are likely to underestimate the comparative benefits of renewables displacement as the capacity stack is held fixed across scenarios pursuant to each BA's respective IRPs, whereas in reality, resource procurement objectives can respond to the evolution of seams management across the West once both DAMs are operating

■ Nuclear ■ Renewables² ■ Thermal³

1) Does not include storage technologies. 2) Includes geothermal, hydro, solar, and wind. 3) Includes gas generators, coal, and peaking generators.

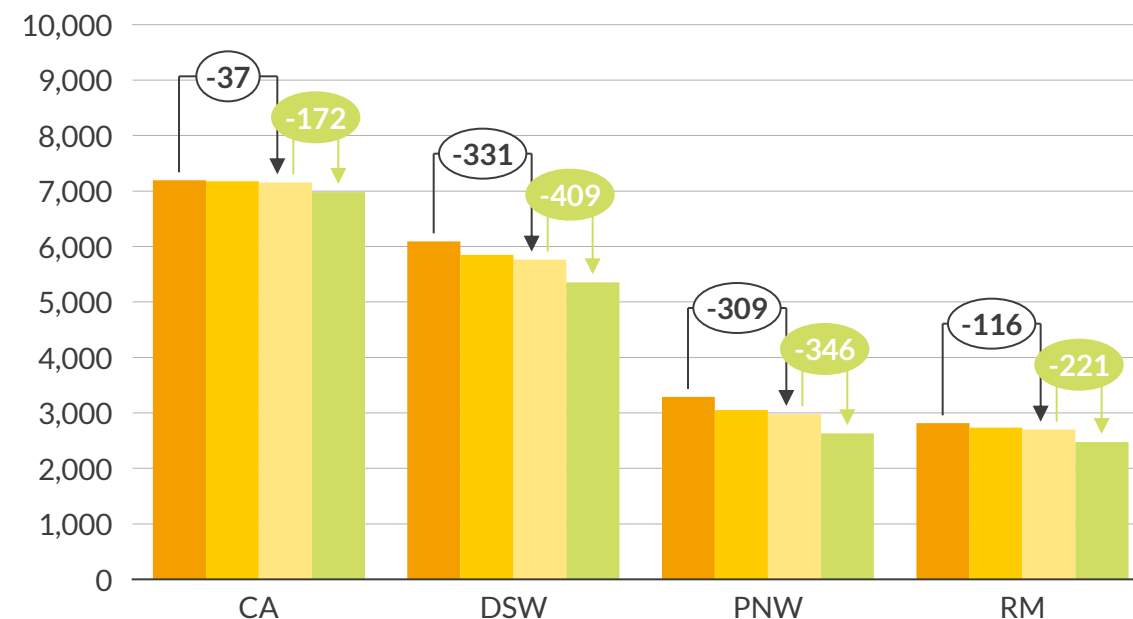
DSW and PNW see greatest benefits from better seams mgmt., reducing costs by \$640M from High to Low seams friction

Western US subregions, color-coded by DAM commitment



Annual total cost by subregion¹, 2032

\$Million, real 2025



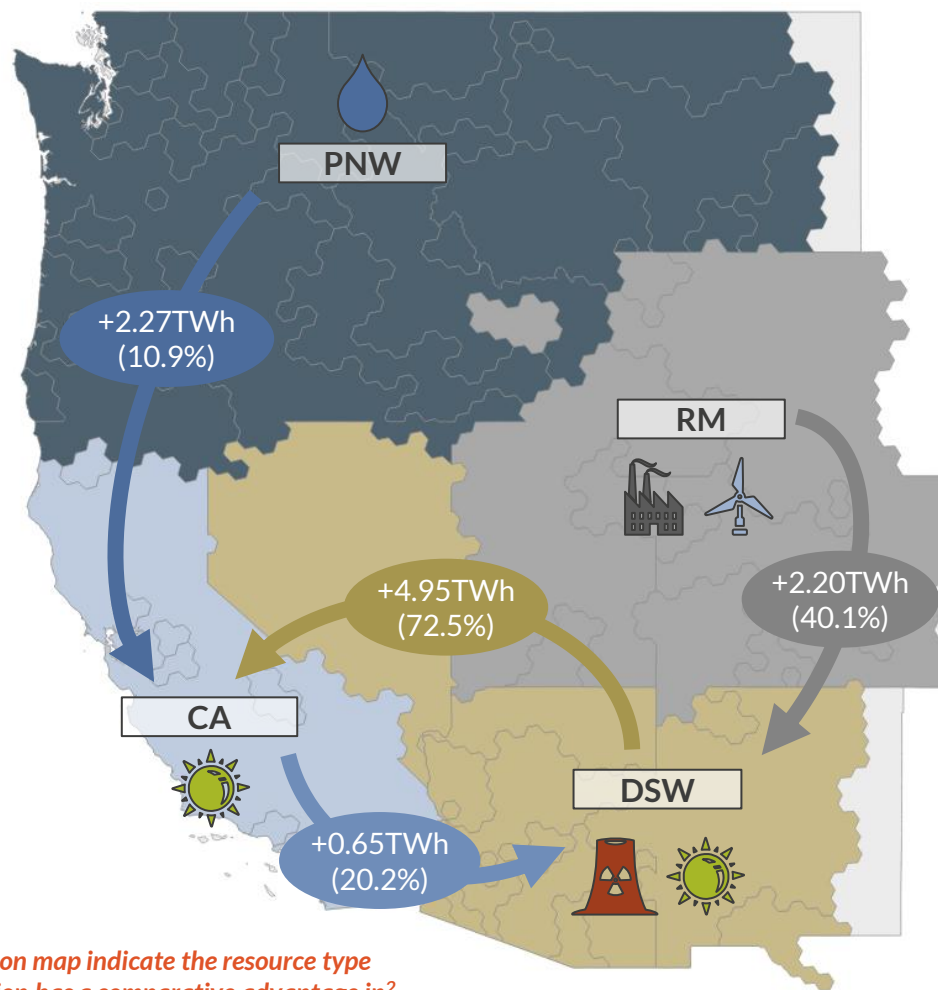
- Seams cost reductions increases connectivity across the Western US, particularly between the PNW and DSW, subregions largely committed to Markets+ but separated by EDAM entities in CA and RM
- As a result, they see greatest cost benefits with better seams management due to increased trade; they are collectively responsible for 76.3% of the system cost reductions going from the High to the Low seams friction scenario



1) RM = Rocky Mountains, PNW = Pacific Northwest, DSW = Desert Southwest, CA = California. BC (British Columbia) subregion total is excluded from graph for visualization purposes.

Reduced seams enable cross-regional firming via comparative advantage in resource mix

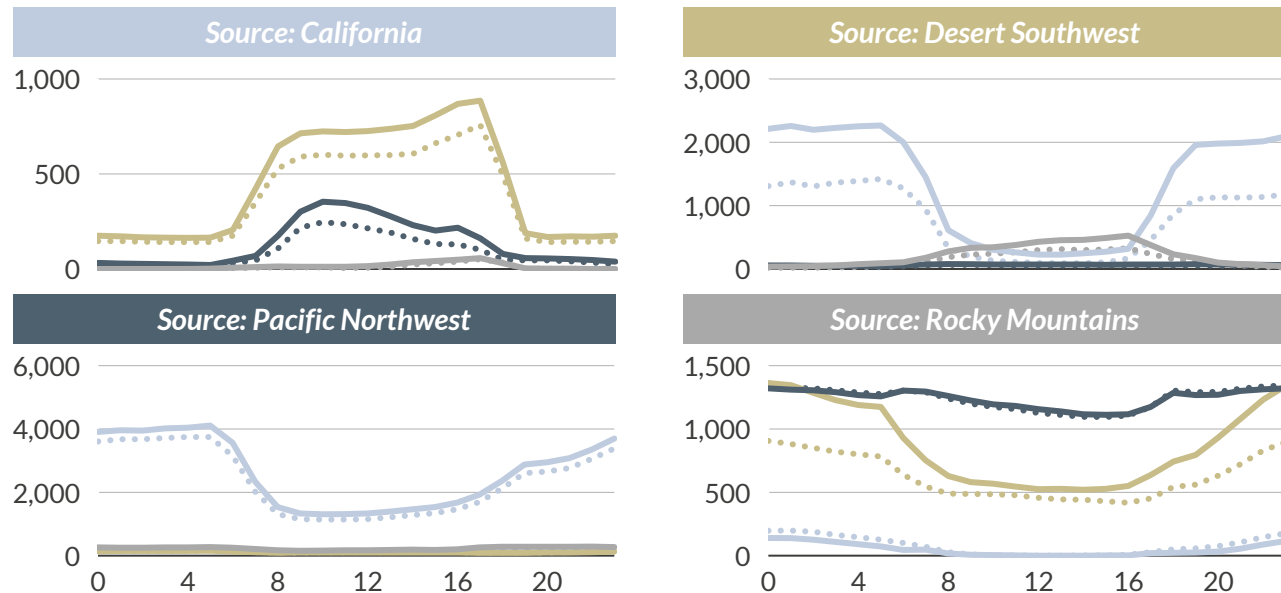
Western US regions export volumes delta¹, **Low seams** – **High seams**
TWh



Symbols on map indicate the resource type
each region has a comparative advantage in²

1) Arrows on map shown for inter-regional trade seeing largest volume delta between scenarios. 2) Comparative advantage here is defined to include the following: higher capacity factors, higher thermal efficiencies, lower input prices, higher existing capacity.

Average intraday total export volumes by region
MWh



- Reduced seams enables more efficient use of each region's resource mix:
 - CA**, with highest solar irradiance and penetration in the West, exports more generation midday, particular to DSW
 - DSW**, holding surplus baseload thermal generation, exports to CA during shoulder hours. DSW also increases midday solar exports to RM
 - PNW**, with highest hydro availability in the West, exports to CA throughout the day
 - RM**, with strongest windspeeds and surplus thermal relative to domestic load, exports more during shoulder hours, particularly toward DSW

Sink regions

Scenarios

— CA — DSW — PNW — RM •• High seams friction — Low seams friction

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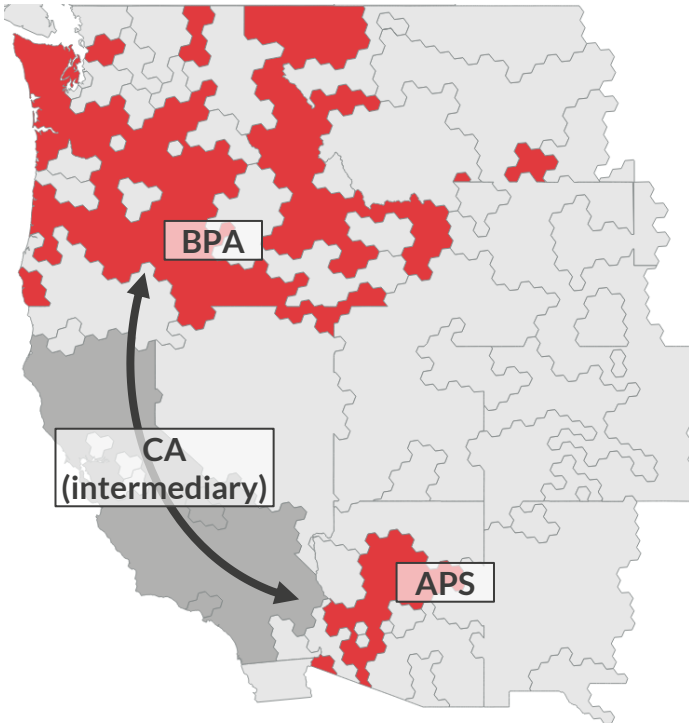
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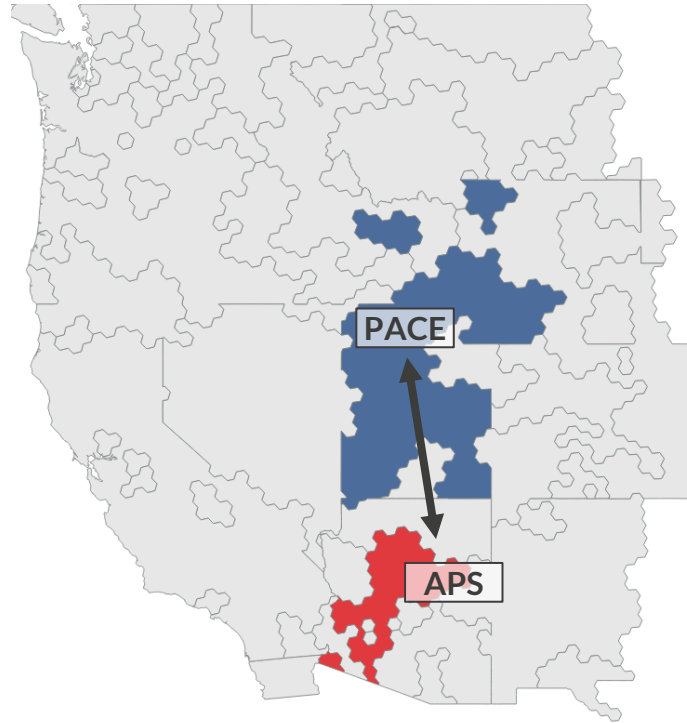
Aurora examined three trade pathways across the modeled scenarios as representation of broader subregion trading dynamics

Case study 1: BPA ↔ APS



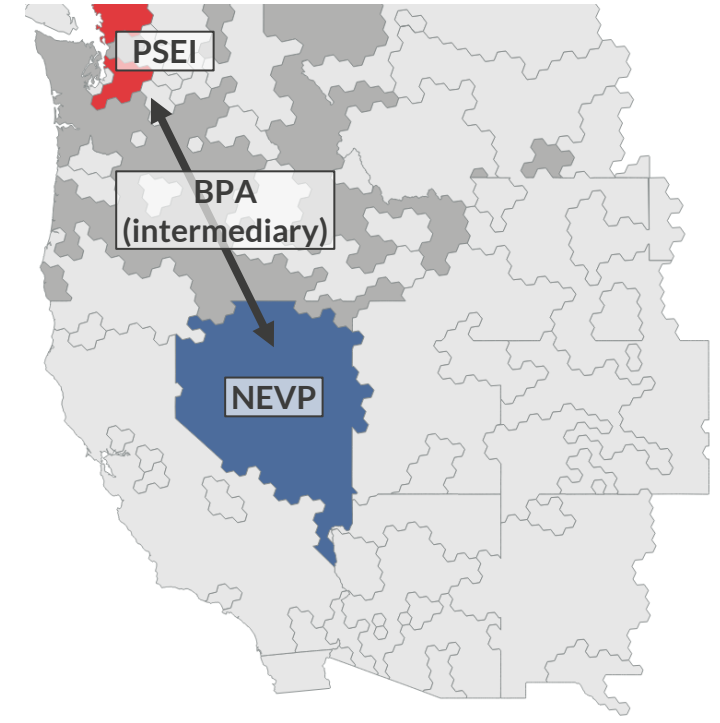
- CA is an important wheel-through pathway for BPA exports to reach the DSW. DAM seams creation that partitions BPA with California (M+ vs. E) and California with APS (E vs. M+) may affect APS's system as access to low-cost hydro generation from BPA may divert elsewhere

Case study 2: PACE ↔ APS



- PACE and APS have recorded historical direct interchange; however, by 2032 they will be in different DAMs. Examining their trade relationship will help ascertain the sensitivity of physical flows to seams creation

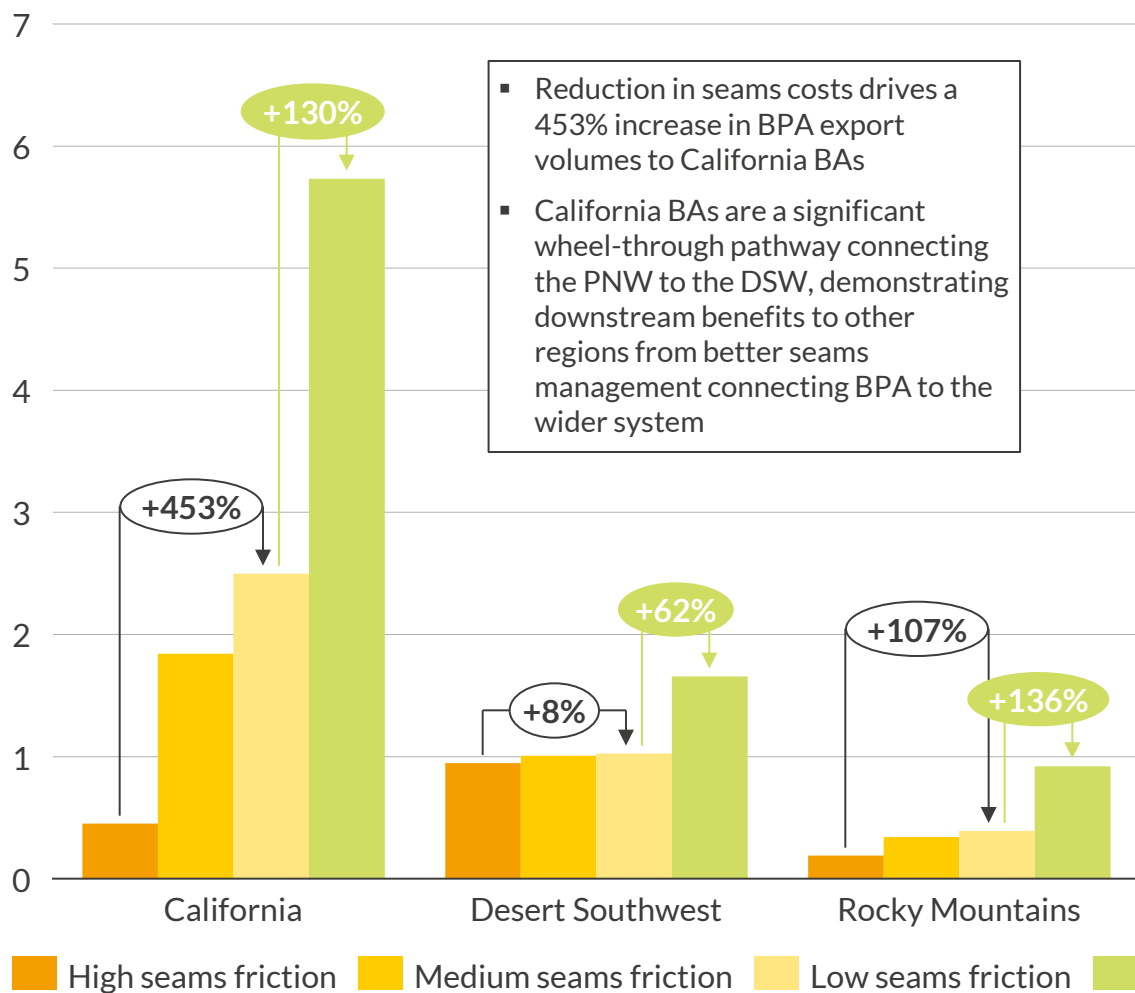
Case study 3: PSEI ↔ NEVP



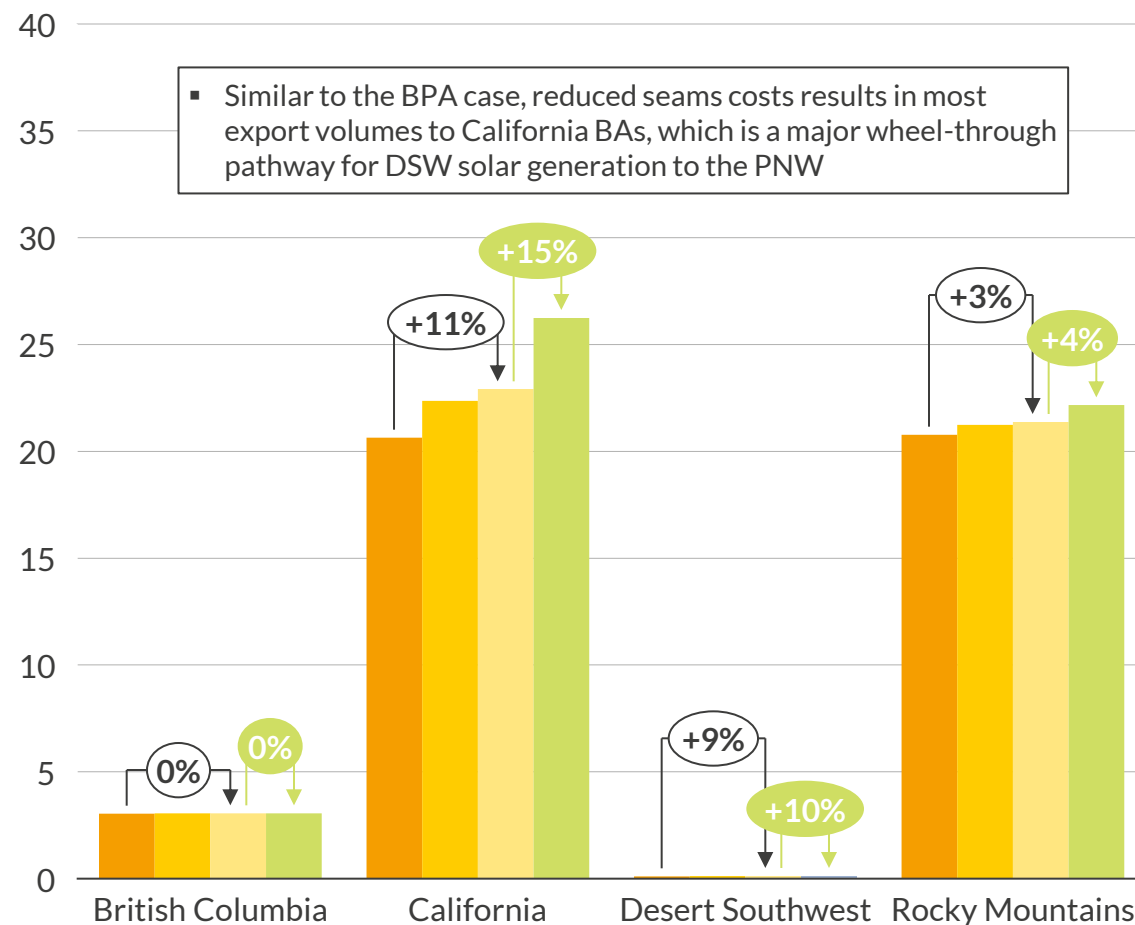
- While PSEI and NEVP have no historical documented bilateral trade, NEVP, along with PACE and California BAs, represent major wheel-through pathways for low-cost PNW generation to reach the DSW and RM regions

Improved management of DAM seams increases BPA and APS exports by up to 453%, particularly towards California BAs

Export volume delta, BPA → WECC regions
TWh

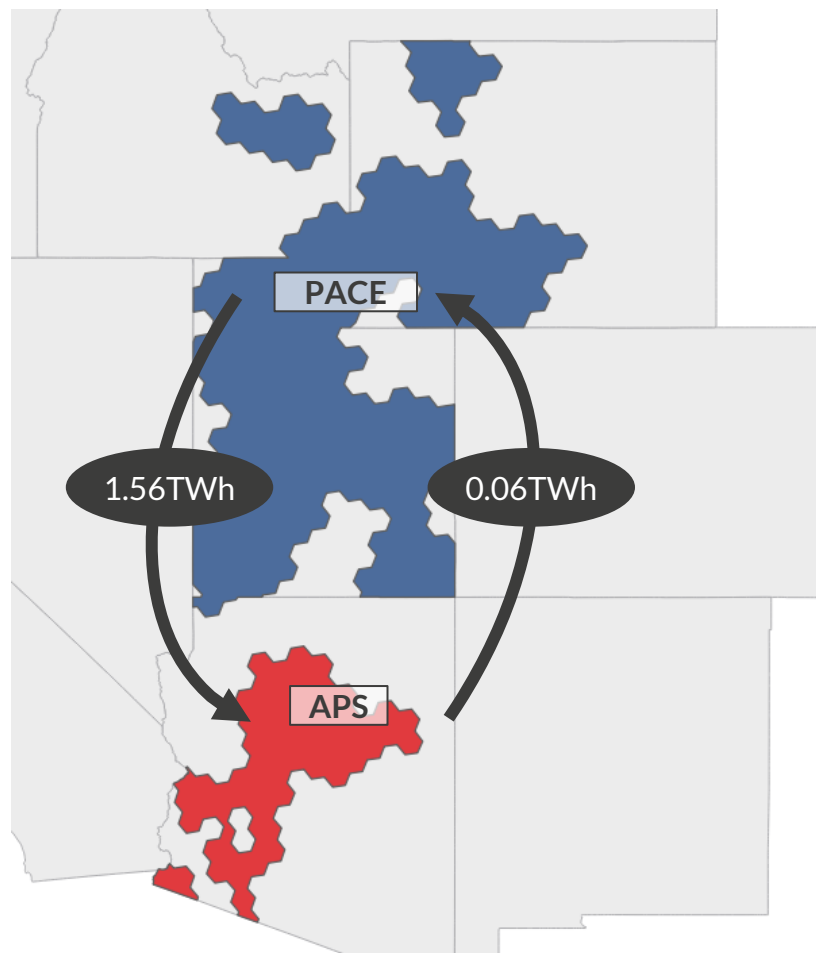


Export volume delta, APS → WECC regions
TWh

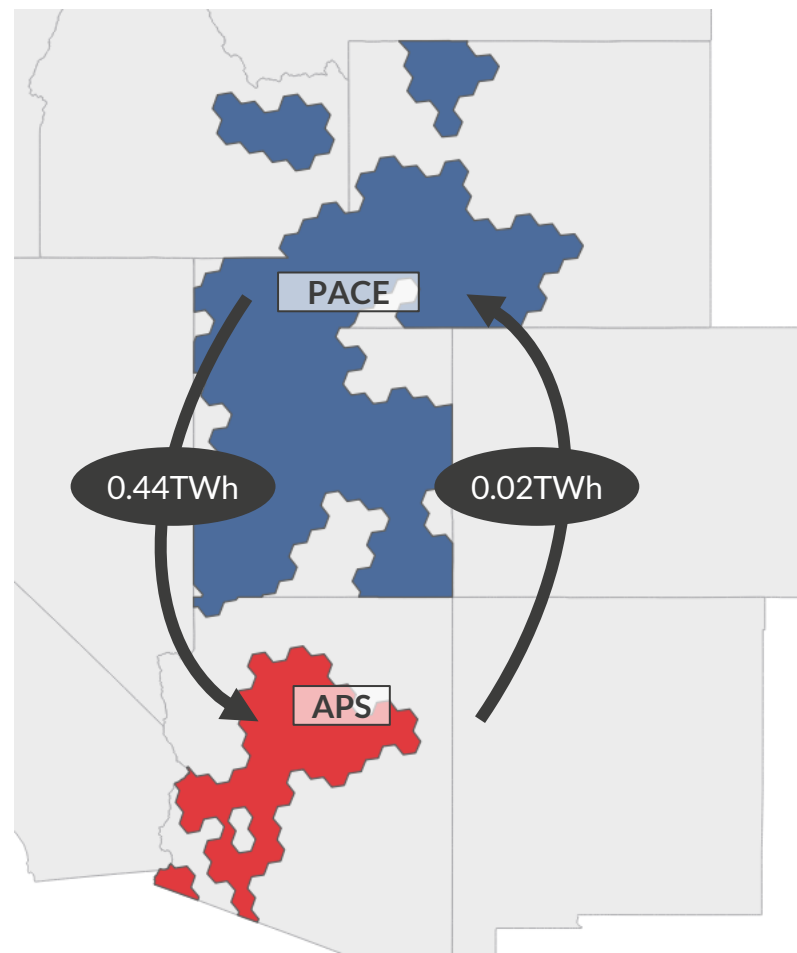


Trade between APS and PACE increase with reduced seams cost, particularly of PACE exports to APS

Trade volumes between APS and PACE, **Low seams friction**
TWh



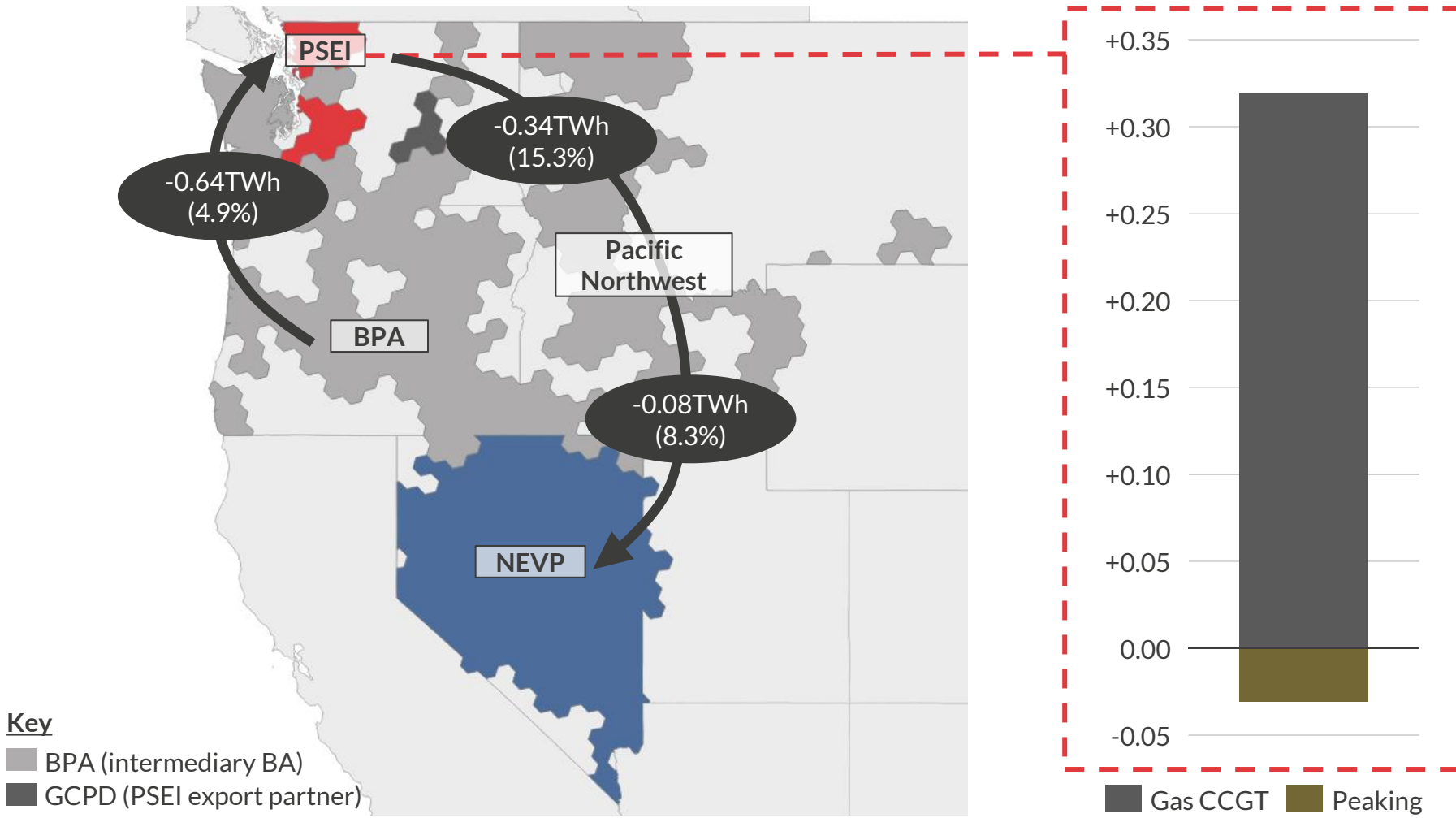
Trade volumes between APS and PACE, **High seams friction**
TWh



- As shown in the previous slide, reduced seams drives increases in APS exports of nuclear and solar generation into California
- This is in-part facilitated by the fact that PACE increases its exports of lower-cost, surplus thermal generation to APS under reduced seams, going from 0.44TWh under High seams friction to 1.56TWh under Low seams friction
- This demonstrates the broader benefit of seams management, as increased exports from PACE into APS enables APS to export more of its generation towards California in tandem

Reduce imports from BPA under the Low seams friction scenario has downstream effects on PSEI's trading with the wider PNW and NEVP

Trade and generation delta, **Low seams friction** – **High seams friction**
TWh



- Reduced seams costs allows BPA to export its hydro generation to a broader footprint, forcing PSEI to ramp up its domestic thermal generation to meet its own demand, as well as reduce exports to other PNW BAs
- As a result, the broader PNW region also sees reduced exports to NEVP of 0.08TWh, which is 8.3% of its export volume under the High seams friction scenario

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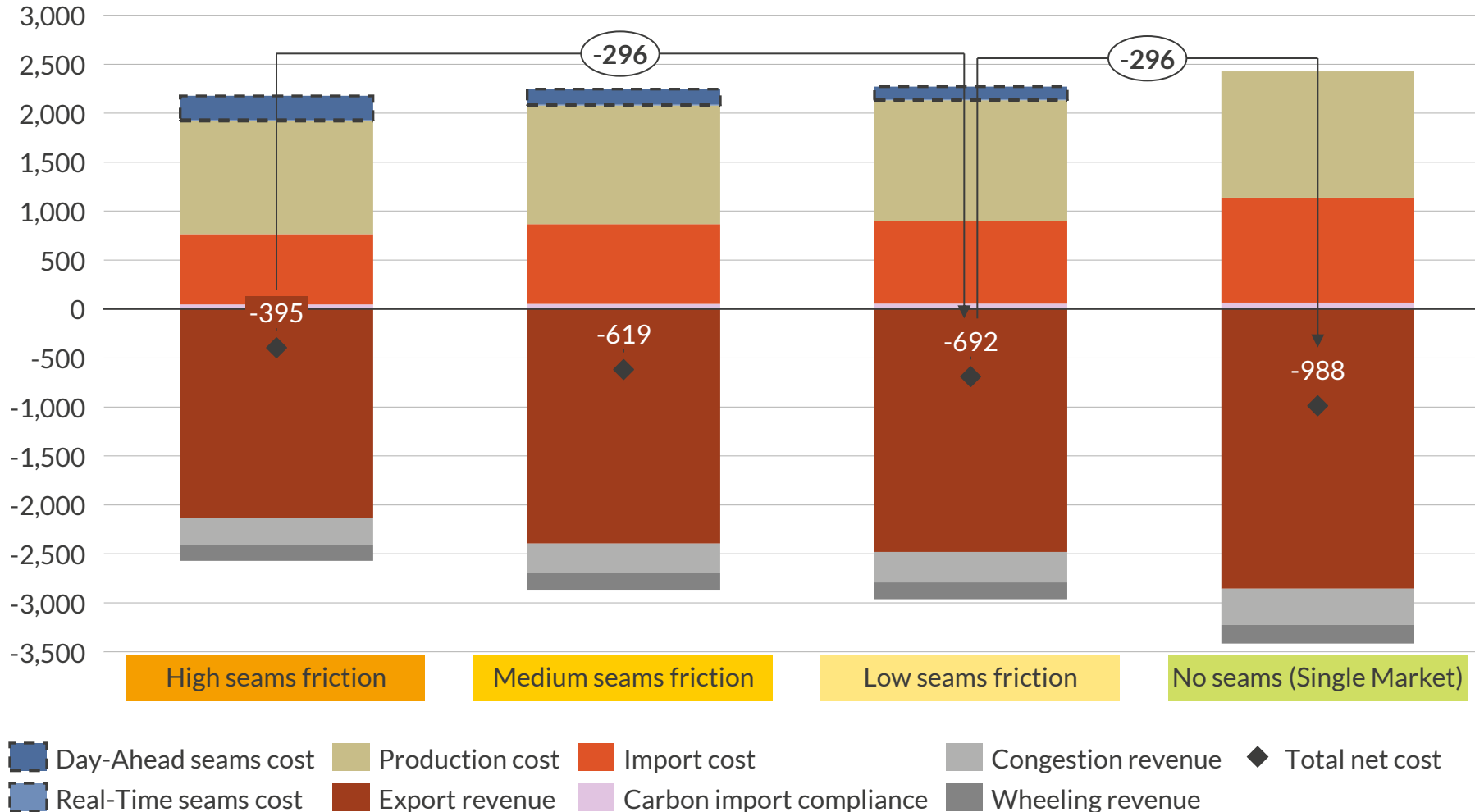
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BPA: same cost benefits are realized going from High to Low seams friction rates as going from Low seams friction to Single Market

Total system costs by individual metrics, BPA

\$Million, 2025

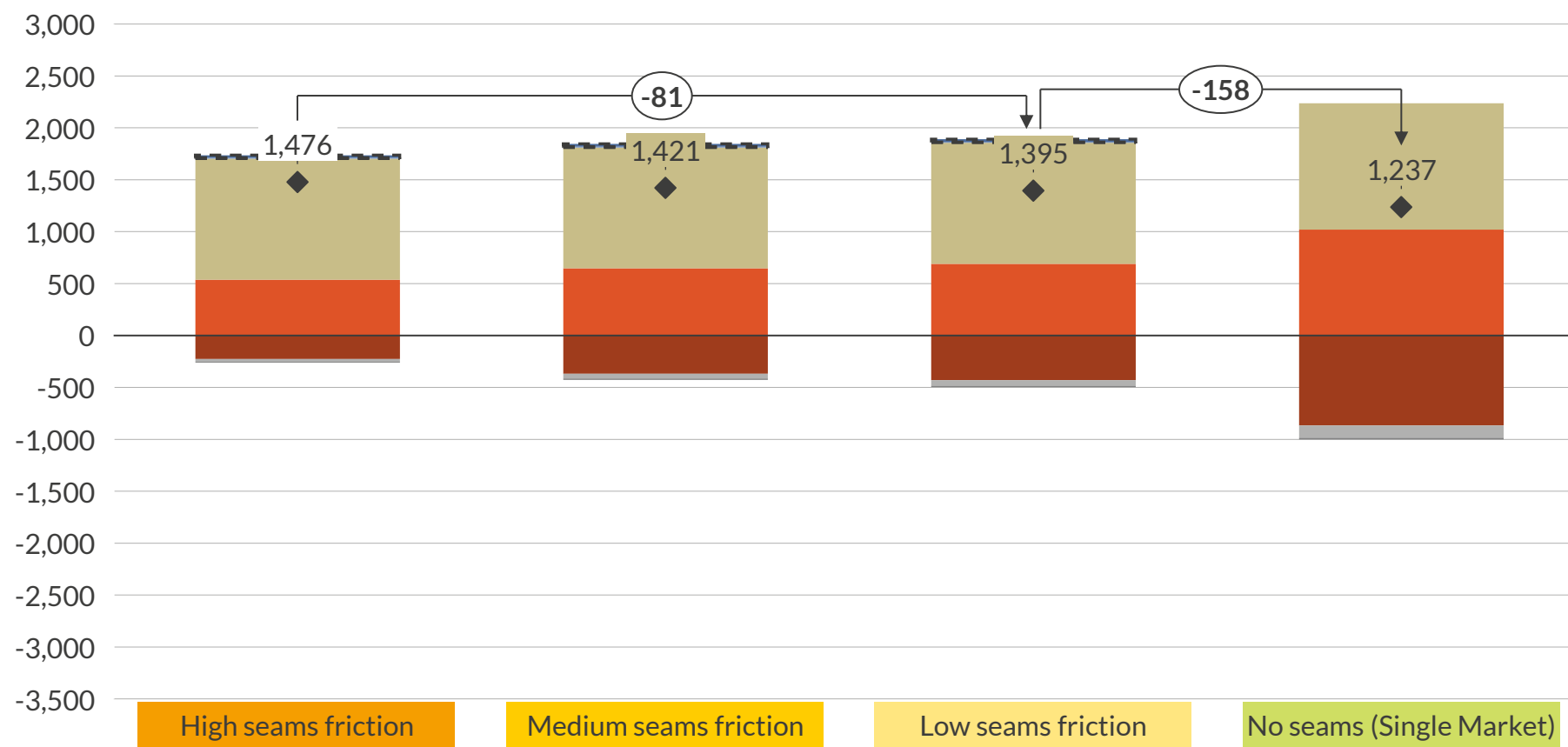


- As BPA is a net exporter with significant low-marginal cost hydro capacity, the comparative benefits of reduced seams cost yields an equivalent system cost reduction as going from a well-managed partitioned market to a single Western-wide market
- In particular, the relative increase in export revenues (3.6% - 16.1%) outweighs the increase in production cost of 1.7% - 6.8% going from High and Medium seams friction to Low seams friction, as BPA ramps up hydro generation
- BPA's cost savings from reducing seams values and moving towards a Single Market make up 25%-35% of total cost savings across the West in these scenarios

APS: Reduced seams increases its trades with other regions, particularly CA, driving a net decrease in system costs

Total system costs by individual metrics, APS

\$Million, 2025



■ Day-Ahead seams cost
 ■ Production cost
 ■ Import cost
 ■ Congestion revenue
 ◆ Total net cost
■ Real-Time seams cost
 ■ Export revenue
 ■ Carbon import compliance
 ■ Wheeling revenue

1) Production costs are within \$0.05% delta of each other across the Multiple Market scenarios. 2) Costs and revenues excluding seams costs, production cost, and carbon import compliance yield a net trade cost for APS.

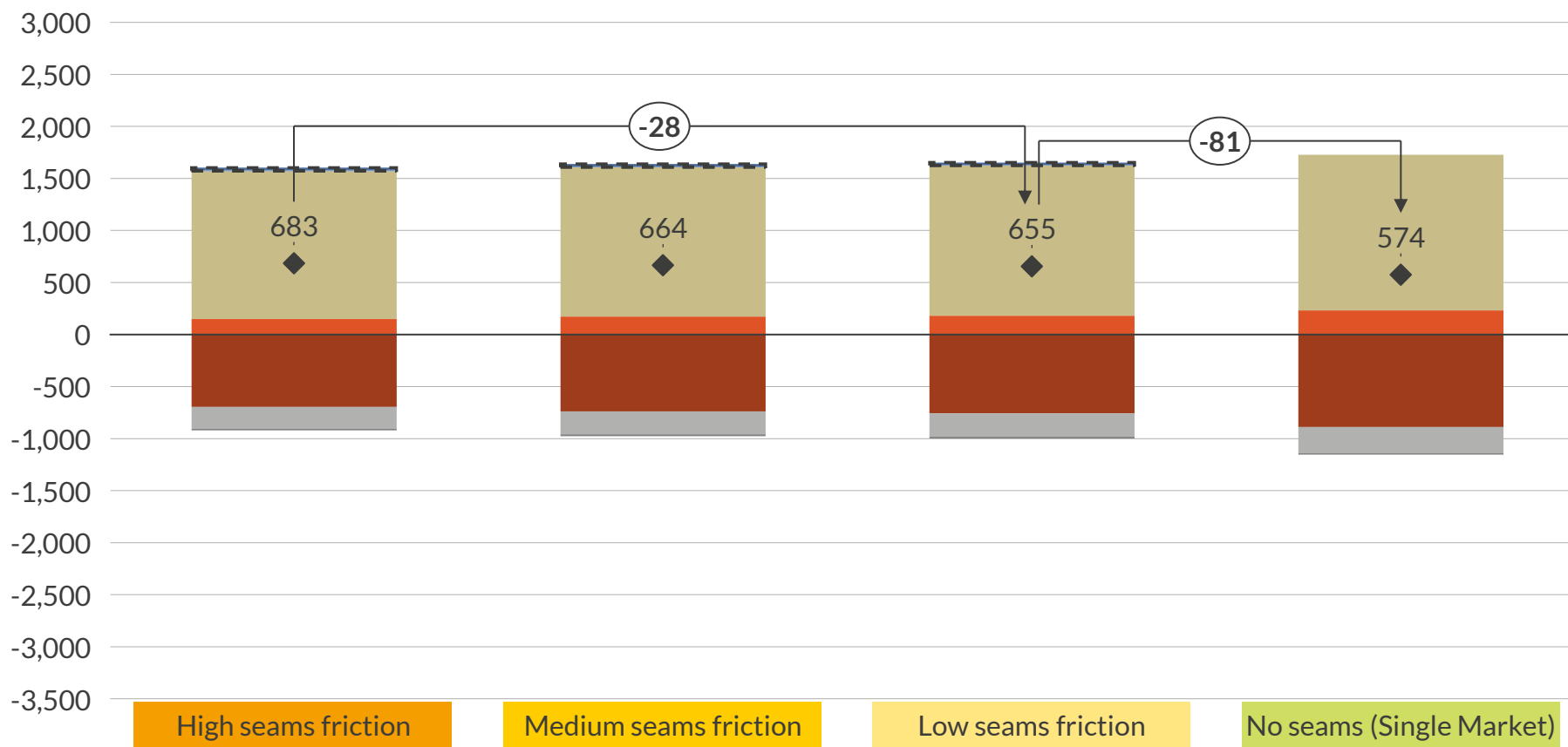
Sources: Aurora Energy Research

- Across the Multiple Market scenarios, APS's production cost does not change¹, while its net trade costs² decrease \$57-84M going from High and Medium seams friction to Low seams friction, respectively
- This is driven by increased generation of nuclear and solar generation for exports toward CA, as better seams management (implied under the Low seams friction scenario) incentivizes increased trade to offset thermal generators in CA that face a state carbon price

PACE: Higher revenues from DSW thermal exports, particularly APS, under reduced seams are partially offset by higher production costs

Total system costs by individual metrics, PACE

\$Million, 2025



 Day-Ahead seams cost
  Production cost
  Import cost
  Congestion revenue
  Total net cost

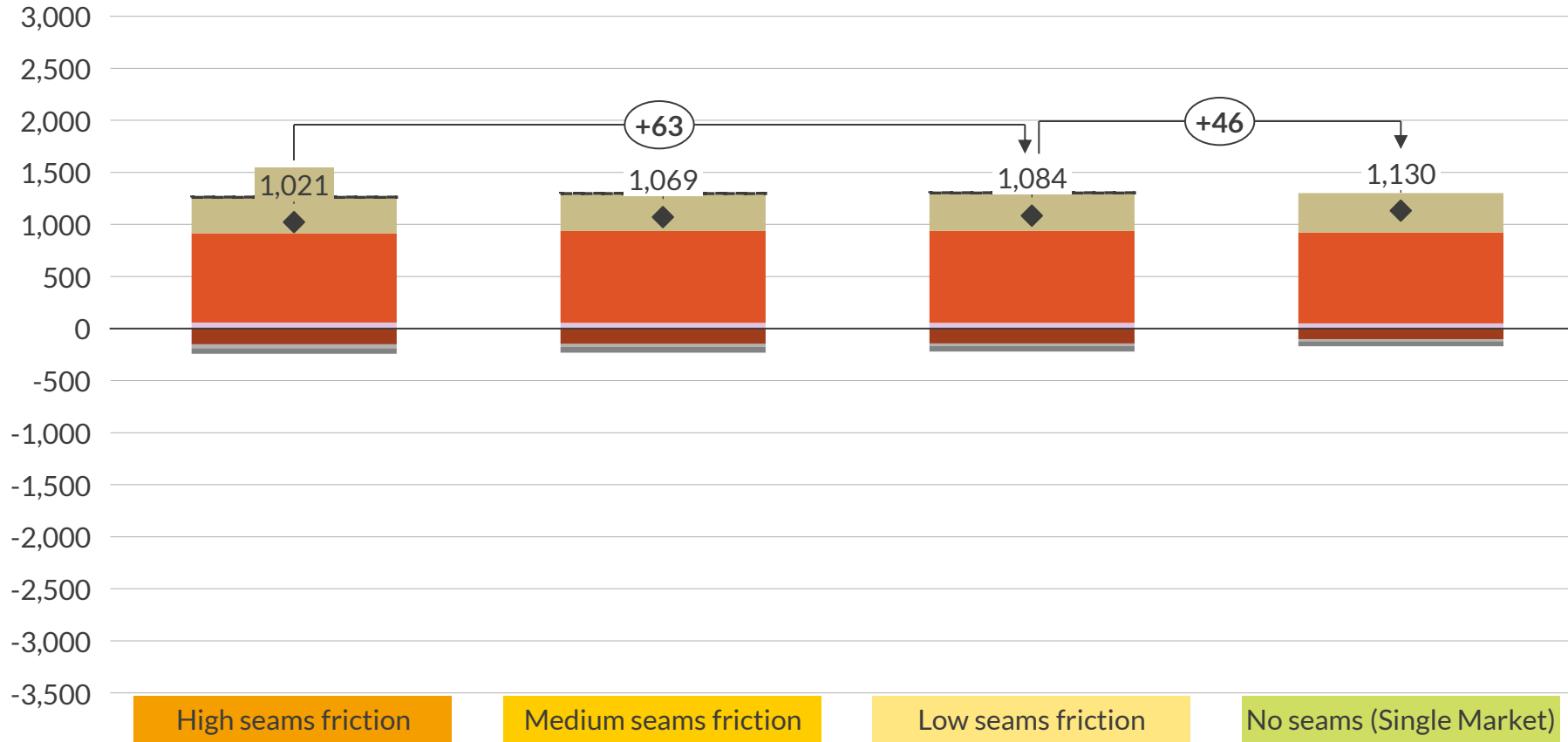
 Real-Time seams cost
  Export revenue
  Carbon import compliance
  Wheeling revenue

- PACE is a net-exporting system sitting on top of significant thermal capacity
- As PACE's thermal capacity faces carbon constraints exporting to CA, it instead exports to DSW, particularly APS which in turn ramps up its exports to CA under reduced seams costs
- Increases in export revenues are partially offset by increases in production costs as thermal generation increases; however, the Low seams friction scenario still yields a \$28M (4.1%) cost benefit for PACE relative to High seams friction scenario

PSEI: Exports decline alongside lower seams costs, while domestic thermal ramps up to compensate for reduced BPA imports

Total system costs by individual metrics, PSEI

\$Million, 2025



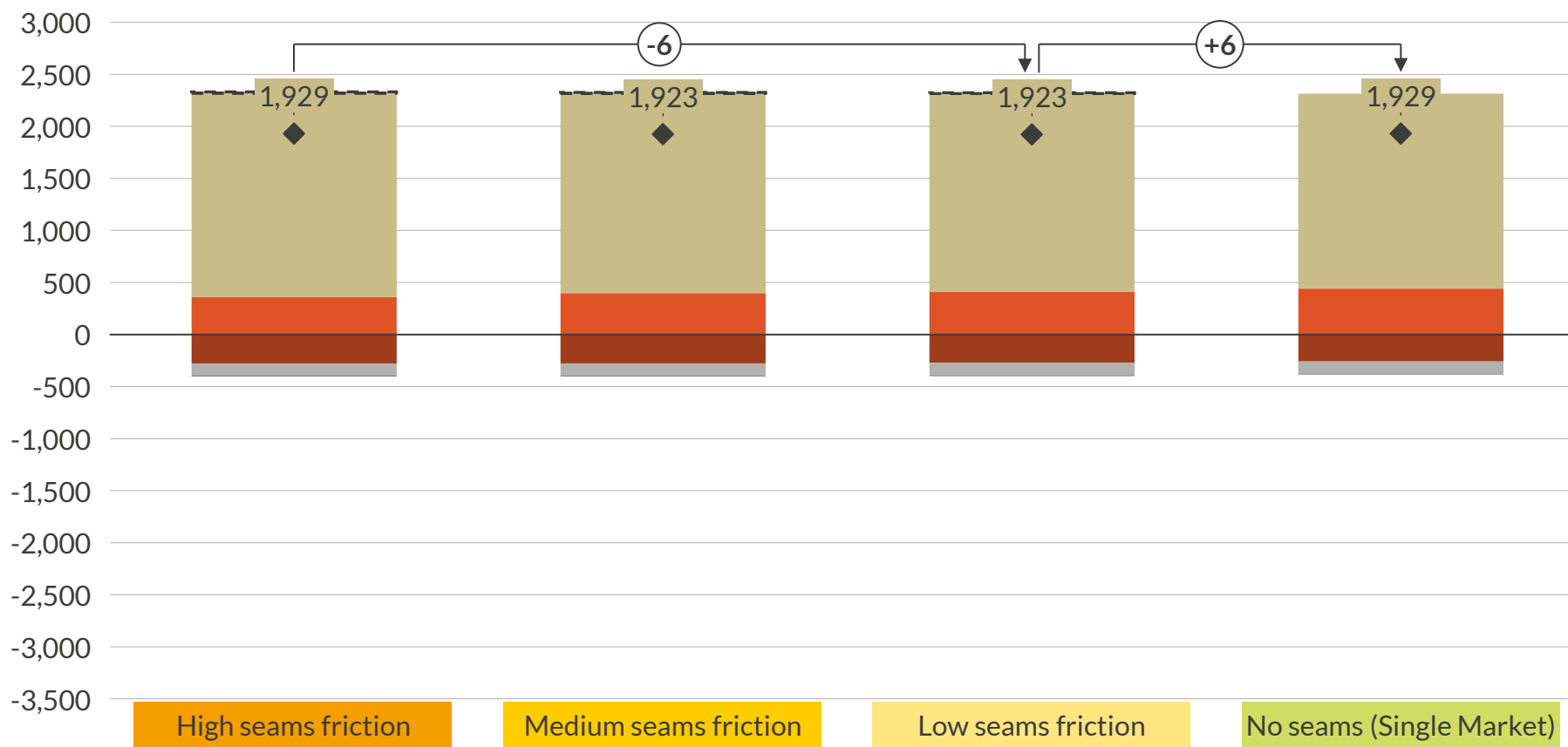
Day-Ahead seams cost Production cost Import cost Congestion revenue Total net cost
Real-Time seams cost Export revenue Carbon import compliance Wheeling revenue

- Reduced seams to trade allows BPA to export its surplus hydro generation to a larger footprint beyond the PNW
 - As a result, PSEI loses access to the previously 'captive' hydro from BPA due to the PNW's seam with CA and Rocky Mountain regions which are broadly committed to Markets+
- PSEI simultaneously ramps up baseload thermal generation while exporting less to Grant County PUD (GCPD) to compensate for reduced BPA imports, driving a net a higher system cost of \$63M going from the High scenario to Low scenario

NEVP: Already well-connected to the EDAM footprint, total system costs change <1% across all DAM market seams configurations

Total system costs by individual metrics, NEVP

\$Million, 2025



 Day-Ahead seams cost
  Production cost
  Import cost
  Congestion revenue
  Total net cost
 Real-Time seams cost
  Export revenue
  Carbon import compliance
  Wheeling revenue

- NEVP's largest trading partners (CA, IPCO, PACE) are all committed to EDAM, meaning there are no DAM seams to trade between them
- Reduced seams for trade does not drive material increases in export for NEVP. Instead, it sees lower production costs from reduced domestic thermal generation, which is met by WALC's thermal exports instead.
- This nets out to a minor change in total system cost for NEVP

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Western US can yield up to \$840M savings from seams management best-practices, with some BAs and regions seeing more benefit

Best-practice seams management is worth \$225M - \$840M

- While a single DAM is the most efficient market configuration, the rollout of EDAM in 2026 and Markets+ in 2027 means market seams will exist
- Best seams management practices incentivizes more trade, and likely firms each BA's respective systems via comparative advantage utilization of each region's resource mix strength
- The displacement of thermal generation is likely understated in this analysis as all modeling scenarios held the capacity mix constant. As a result, the emission reduction benefits are potentially understated

A single DAM with no seams to trade yields \$1.2B-2.0B in benefits

- Reduced production costs from more efficient generation dispatch, avoidance of seams costs from cross-market transactions, and increased transmission-related revenues combine to drive the observed net system benefit under a single DAM configuration
- As some BAs are restudying the cost benefits of DAM choices, this modeling scenario provides a theoretical benchmark for what BAs can expect in cost savings when exposed to no seams for trading

Gains concentrate in the PNW and DSW; BPA alone drives ~35% of total cost savings

- PNW and DSW together are responsible for 72-76% of Western US cost savings when best seams practices are utilized
 - As these regions are largely committed to Markets+ and connected by transmission passing through EDAM BAs, seams play a bigger role in overall costs
- BPA alone is responsible for \$73M-\$296M in cost savings. This is primarily driven by increased exports of surplus hydro generation, especially to California BAs and the DSW
 - As California is an important wheel-through region for cross-regional trades, this will likely unlock even further cost savings for other regions

Western US costs are minimized with best seams practices, but BAs can see variable benefits

- Costs are reduced Western-US wide with best seams practices, but BAs that see minor changes in its trade footprint, reduced exports, or more expensive generation, can accrue less savings or see cost increases:
- PSEI sees costs rising under lower seams as it ramps domestic thermal generation to compensate for reduced BPA hydro imports
- NEVP, which is largely interconnected to an EDAM footprint already, sees minor seams cost changes when best practices are implemented. As a result, it also sees minimal cost savings

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Our Global Presence

Aurora Energy Research is a leading global provider of power market analytics. Founded by university professors, we've grown into a team of over 1,000 professionals worldwide, helping major energy market participants navigate their most complex, long-term decisions.



19

Offices



950+

Subscribing
companies



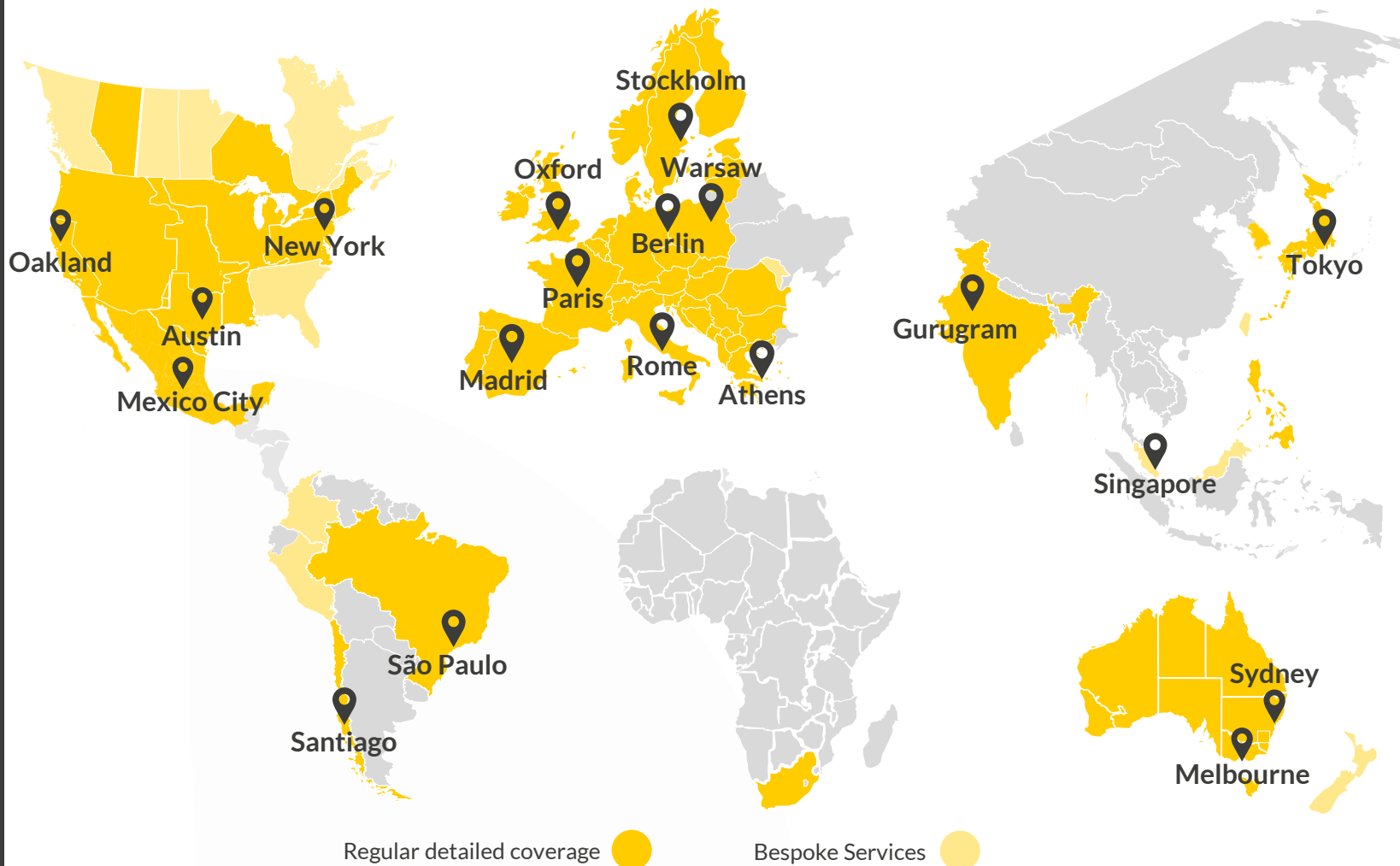
1000+

Market experts



250+

Transactions
supported in 2025



Power markets



Grid & Congestion



Renewables & PPAs



Natural Gas



Storage

CO₂

Carbon



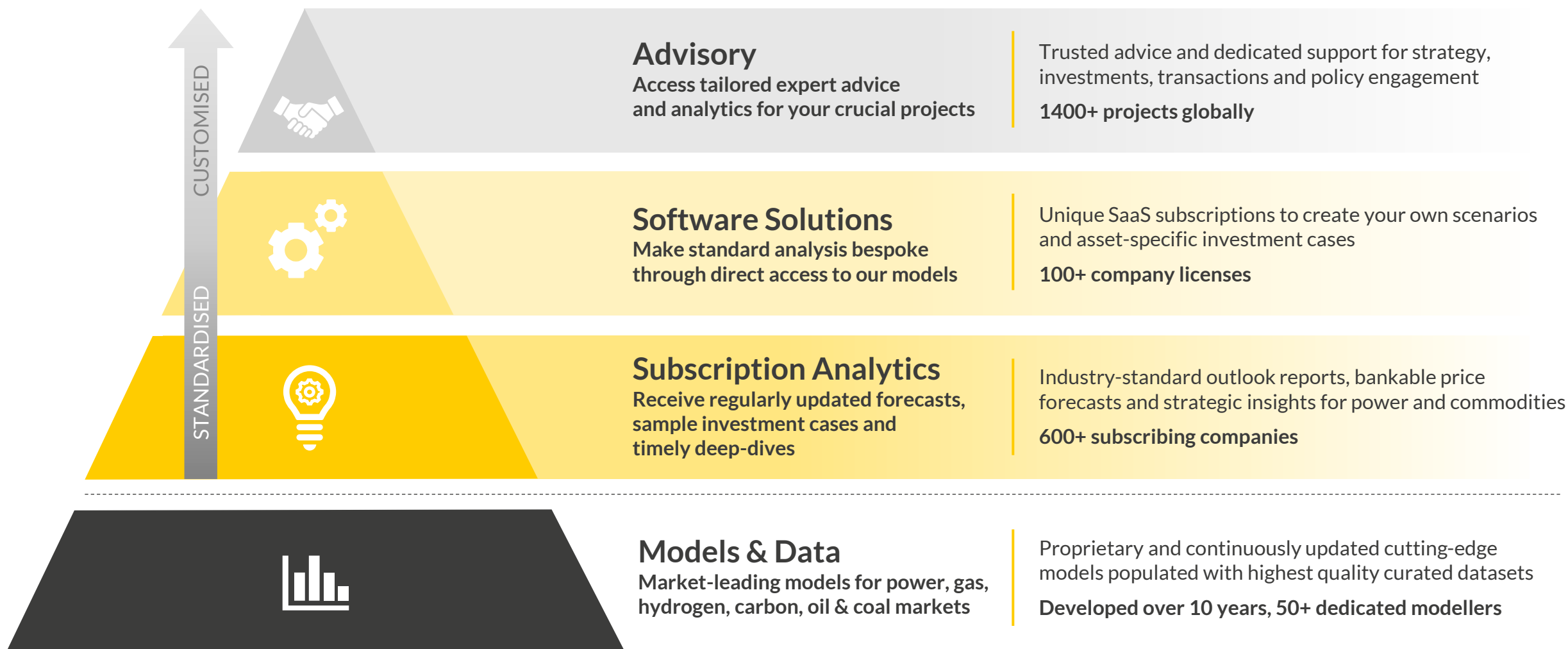
Electric Vehicles

H₂

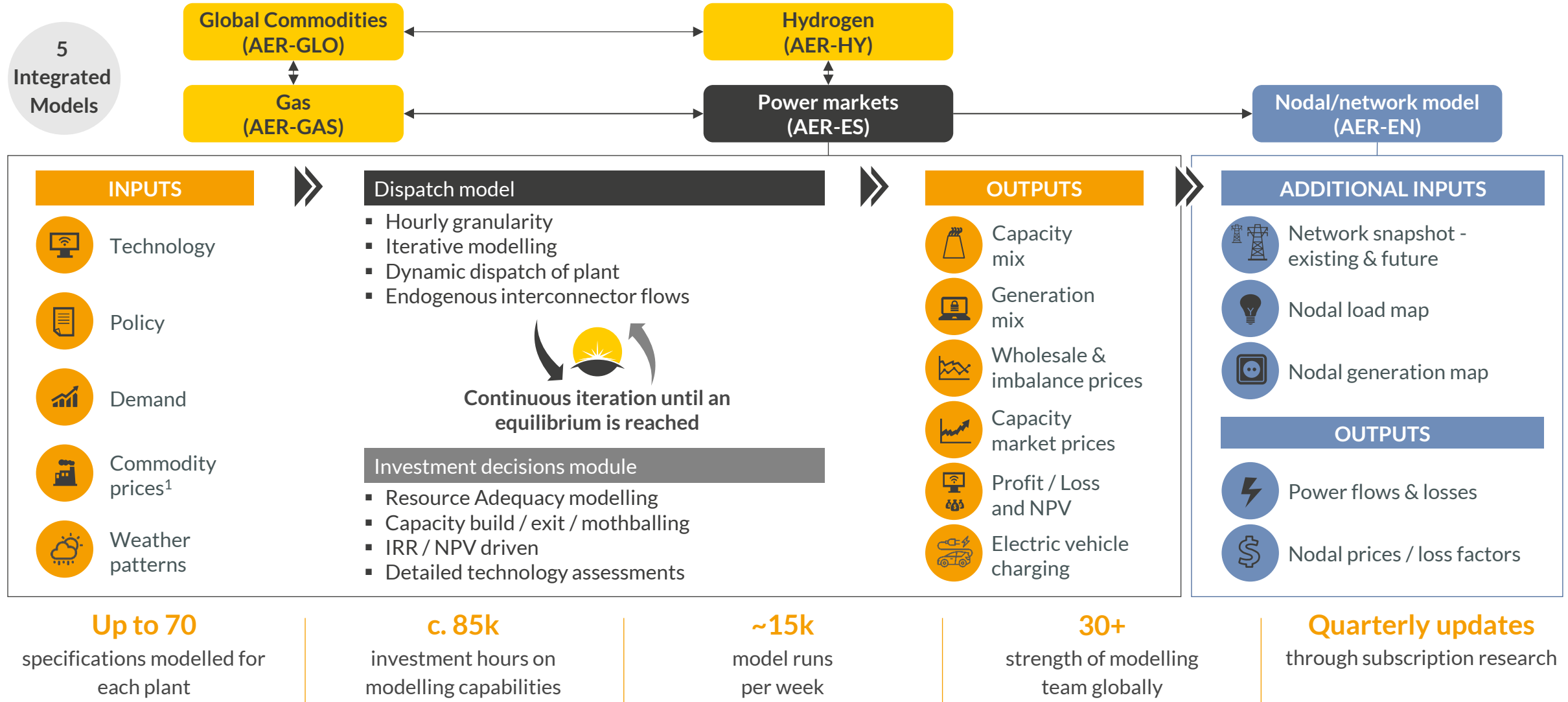
Hydrogen

*Map not to scale

Our market leading models underpin a comprehensive range of seamlessly integrated services to best suit your needs



Unique, proprietary, in-house modelling capabilities underpin Aurora's superior analysis

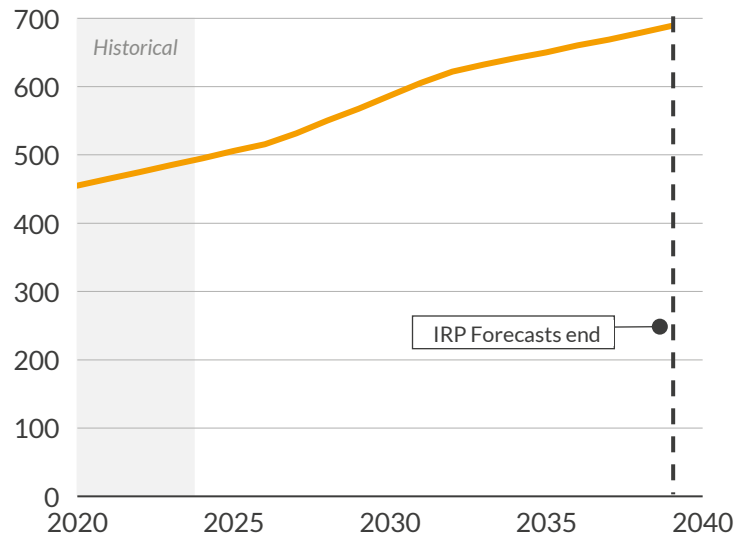


1) Gas, coal, oil and carbon prices fundamentally modelled in-house with fully integrated commodities and gas market model

Demand, capacity, and technology assumptions reflect utility integrated resource plans

Demand assumptions

Annual electricity demand
TWh

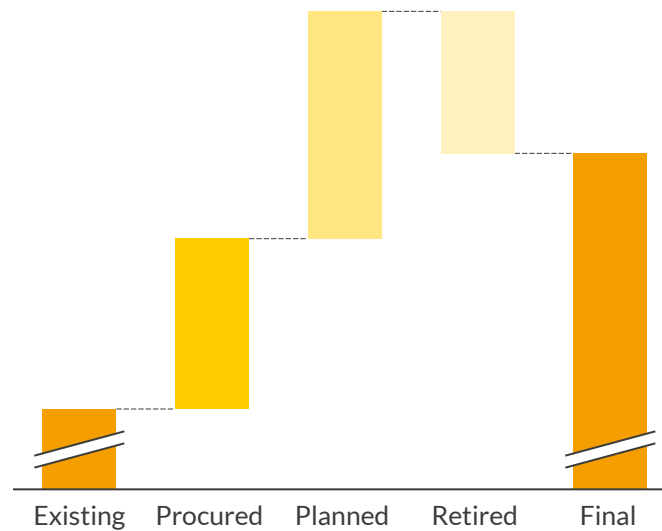


— IRP¹ Forecast

- Utility IRPs are used through their forecast horizon and reflect their assumptions on EVs, data centers and other demand drivers
- This study focuses on the 2032 forecast year

Capacity assumptions

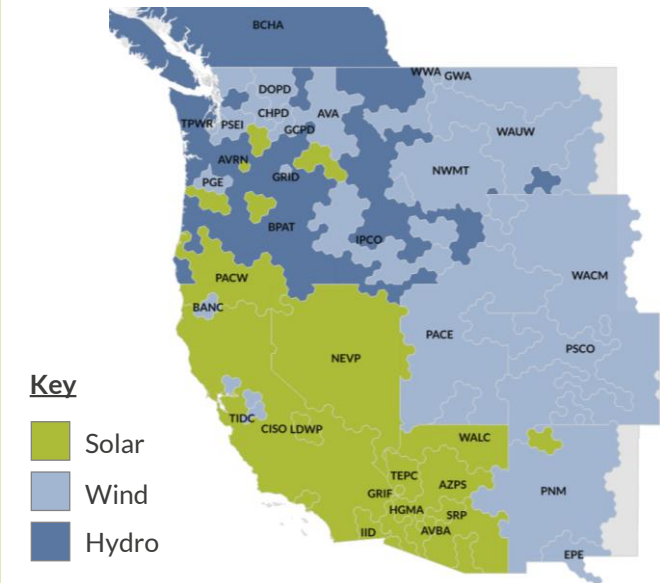
Capacity assumptions components
GW



- Capacity additions include resources procured through recent utility Requests For Proposals, and planned builds identified in IRPs. Retirements include units expected to come offline, as announced in IRPs or other public documents

Technology assumptions

Technology with highest load factor by BA²



- Load factor assumptions are based on historical performance of renewables assets across BAs
- Aurora also incorporates assumptions on thermal assets efficiency, availability, and ramping constraints using EIA³ and EPA⁴ data.

1) Integrated Resource Plan. 2) Balancing Authority. 3) Energy Information Administration. 4) Environmental Protection Agency.

Aurora separates total system costs into primary and secondary impacts from seams creation along DAM borders

Primary seams impacts, the *inefficiency costs incurred from power purchases and sales transacting across a market seam*

Variable	Valuation approach	What it represents
Day-Ahead seams cost	Seams cost (\$/MWh) * lineflow crossing a DAM seams (MWh), in Day-Ahead (Production cost model)	Costs associated with operational inefficiencies due to trading across Day-ahead markets optimized separately
Real-Time seams cost	Seams cost (\$/MWh) * lineflow crossing a DAM seams (MWh), in Real-Time (post-Production-cost model solve)	Costs associated with operational inefficiencies due to trading across Real-time markets optimized separately

Secondary seams impacts, the *costs and revenues associated with reduced access to lowest-cost generation and reduced coordination due to DAM market segmentation*

Variable	Valuation approach	What it represents
Production cost	Generator short-run marginal cost \$/MWh * Output (MWh)	Cost of generation within each balancing authority area based on economic dispatch
Export revenues	Source price (\$/MWh) * line flow from exporting (MWh)	Revenues associated with exporting power from a balancing authority area based on economic dispatch
Import costs	Source price (\$/MWh) * line flow from importing (MWh)	Costs from importing power into a balancing authority area based on economic dispatch
Carbon import compliance	For the emissions within a state (emissions from importing ¹ + domestic emissions – exported emissions) ² , Excess emissions (MMt CO ₂) * Carbon price (\$/MMt CO ₂) ³	Compliance costs paid by BAs within CA/WA for emissions from imports
Congestion revenue ⁴	[Source-sink price differential (\$/MWh) – transfer cost (\$/MWh)] * line flow (MWh) / 2 ⁴ when interface transmission sees congestion	Revenue associated with transmission congestion attributed to balancing authorities based on transmission ownership
Wheeling revenue ⁴	[Source-sink price differential (\$/MWh) – transfer cost (\$/MWh)] * line flow (MWh) / 2 ⁴ when interface transmission does not see congestion	Revenue associated with transmission utilization attributed to balancing authorities based on transmission ownership

1) Emissions accounting methodology differs between CA and WA and between Markets+ and EDAM imports. 2) Applicable to WA & CA only. Does not account for carbon allowances allocated to LSEs 3) Aurora Central carbon price for 2032 study year 4) Congestion and wheeling revenue is allocated only when price differential of source-sink exceeds transfer cost. 4) Revenues divided by 2 assuming 50:50 ownership.

Real-Time demand deviations are sourced from historical Day-Ahead-to-actual forecast error...

Illustrative example of Real-Time demand calibration

Continued next slide 

Step 1: Cleaned and summarized BA-level Real-Time imbalance signal based on historical data

Datetime	BA	Day-ahead demand forecast (MW) ¹	Realized demand (MW) ¹	Imbalance signal (%)
01/05/2025 00:00	APS	1237	1288	4.1%
01/05/2025 01:00	APS	856	890	4.0%
01/05/2025 02:00	APS	455	444	-2.4%
01/05/2025 03:00	APS	2288	2295	0.3%
01/05/2025 04:00	APS	4520	4555	0.8%
01/05/2025 05:00	APS	944	920	-2.5%
01/05/2025 06:00	APS	655	680	3.8%
01/05/2025 07:00	APS	744	731	-1.7%



Step 2: Map imbalance signals to model's demand profile on an hourly level

Datetime	BA	Model Day-ahead demand forecast (MW) ¹	Imbalance signal (%)	Model realized demand (MW)
01/05/2032 00:00	APS	1300	4.1%	1353.6
01/05/2032 01:00	APS	912	4.0%	948.2
01/05/2032 02:00	APS	518	-2.4%	505.5
01/05/2032 03:00	APS	2107	0.3%	2113.4
01/05/2032 04:00	APS	6400	0.8%	6449.6
01/05/2032 05:00	APS	1188	-2.5%	1157.8
01/05/2032 06:00	APS	933	3.8%	968.6
01/05/2032 07:00	APS	455	-1.7%	447.0

- Hourly demand and day-ahead demand forecast data was pulled from EIA-930 Hourly Grid Monitor files for 2024-2026YTD
- Aurora removed telemetry spikes (i.e., applied rolling-median filter) and de-biased the data (ex. applied regional composite for BAs with flat hourly forecasts) to isolate genuine forecast uncertainty from reporting artifacts
- Imbalance profiles were then aggregated at the BA x season x hour-of-day level

- Each historical day's signed imbalance percentage was mapped onto the corresponding datetime in the model year
- The imbalance signal was applied to the model Day-ahead forecasted demand to determine the realized demand, resulting in either additional demand to be met in Real-Time or a down-revision

1) Numbers are illustrative.

... and cleared in hourly blocks across the Western footprint via least-cost network flow to price Real-Time seams costs

Illustrative example of Real-Time (RT) demand calibration

Step 3: Gather system data for possible dispatch pathways



A Generation



B Cost artifacts



C Transmission

A

Plant-level generation data for output and headroom (maximum production less day-ahead committed output)¹ were retrieved to determine plants available for ramping to meet surplus RT demand

B

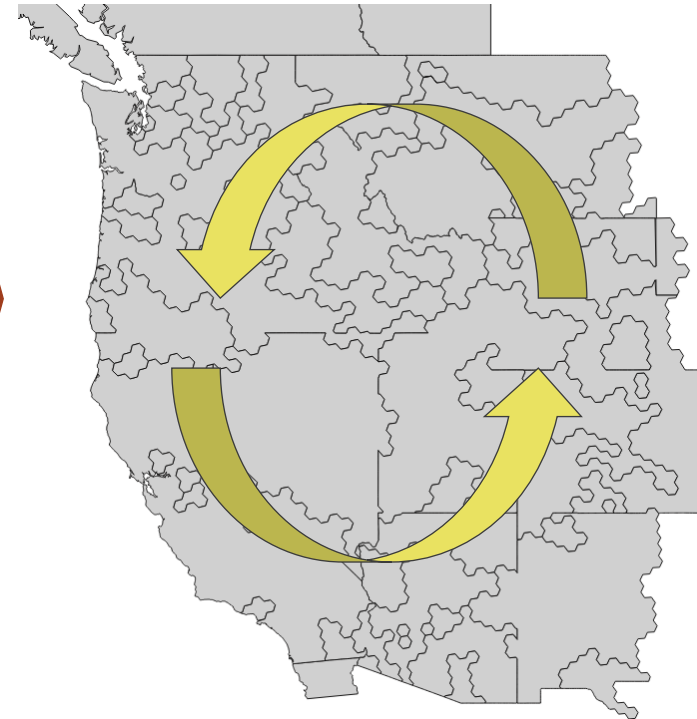
Costs for plants, such as its SRMC²; for BAs, such as its day-ahead LMP³; and for interconnector transfers, such as the wheeling, seams, and carbon import adders, were retrieved to build a cost-stack

C

Transmission usage in day-ahead dispatch and available headroom based on transfer limits were retrieved to determine possible pathways for RT dispatch



Step 4: Clear each hour WECC-wide via least-cost network flow (Linear programming)

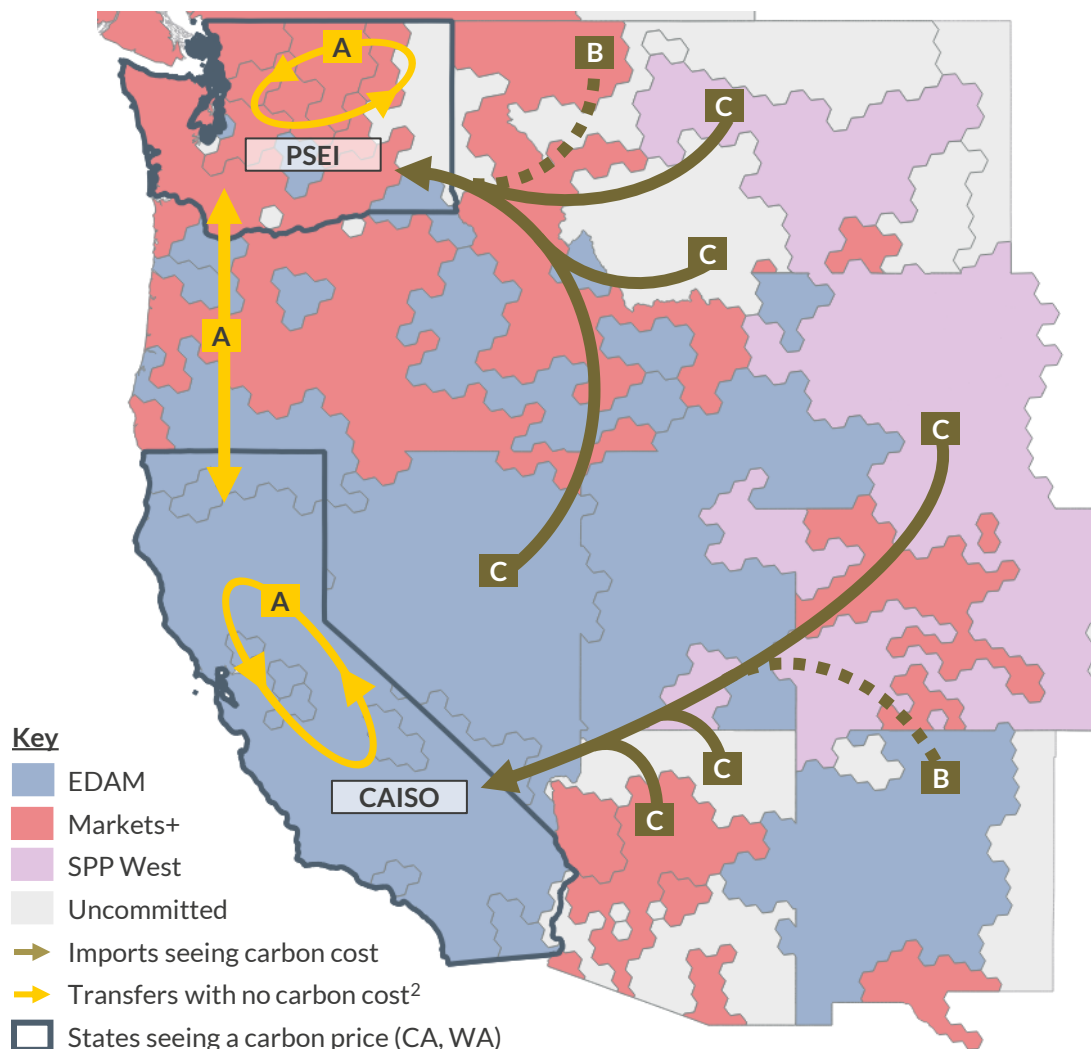


- Each hour was solved as an individual linear program (LP); deficits and surpluses were balanced across own headroom, backdown, and cross-BA trade, simultaneously WECC-wide
- Transfers crossing DAM boundaries were documented in the Real-Time seams cost term

1) Spinning units only. 2) Short-run marginal cost. 3) Locational Marginal Price.

Aurora calculates carbon import compliance as the legally-defined cost BAs must pay to the state for emissions allowances from imports

Illustrative map of trade pathways into CAISO (EDAM) and PSEI (Markets+)



Overview of carbon pricing in California and Washington

California and Washington run Cap-and-Invest programs, setting a limit on allowed emissions

- Electric utilities must hold one allowance per ton CO₂e emitted, including emissions embedded in imported electricity
- Domestic carbon costs are captured within plant production costs: a plant's SRMC¹ factors in the carbon price for its state
- Aurora separately calculates the **carbon import compliance term** as the additional allowance cost paid by electric utilities for imported electricity
- Aurora does not factor in free allowances provided by the state to electric utilities, which would reduce the number of allowances required for procurement. As a result, this represents a liberal outlook on carbon-related costs to CA and WA LSEs
- For the 2032 study year, the assumed carbon price is \$86/ton CO₂ following Aurora's in house forecast

	Transfer pathway	Transfer emissions factor (TEF) applied
A	Linked / Within state ²	TEF = 0 (no additional import charge as carbon already priced via origin state's generator SRMC)
B	Same DAM market	TEF = $\phi \times EF_{\text{specified}} + (1 - \phi) \times 0.428 \times \text{loss factor}$
C	Bilateral / cross DAM seam	TEF = $\phi \times EF_{\text{specified}} + (1 - \phi) \times 0.428 \times \text{loss factor}$

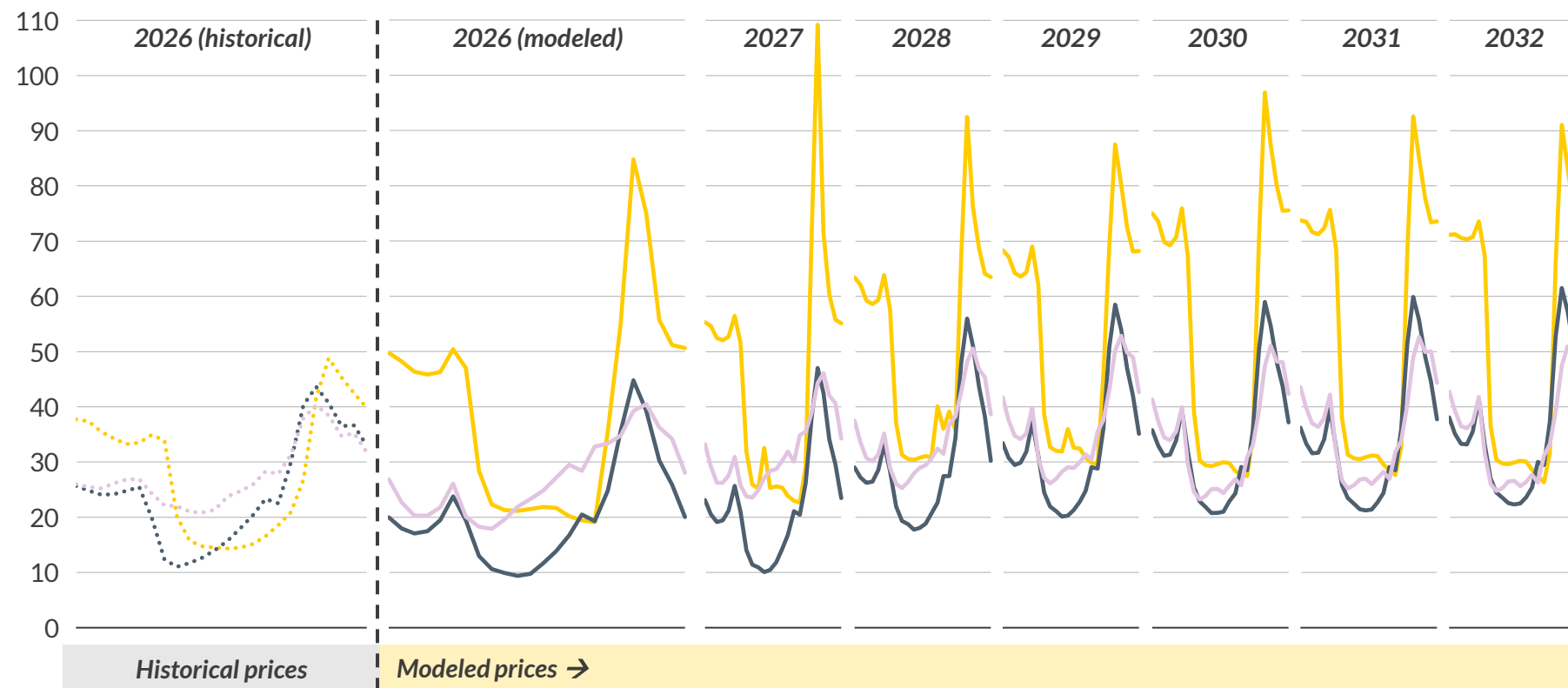
Where:

- ϕ = share of region's export that are specified contracts³, with specific emissions factors³
- $EF_{\text{specified}}$ = emissions factor of specified exports
- $(1 - \phi)$ = share of region's exports that are unspecified
- 0.428 = statutory⁴ default emissions factor (metric ton CO₂e/MWh) applied to unspecified exports
- Loss factor = accounting for transmission losses⁵

1) Short-run marginal cost. 2) June 2026, CA, WA, and Quebec signed an agreement linking their carbon markets; trade between these regions do not carry an emissions allowance cost. 3) Specified contract shares and emissions factors estimated from CARB-published Asset-Controlling Supplier factor; Aurora cross-referenced values against CEC import data. 4) As set by CARB in Mandatory Reporting Regulation. 5) Value of 1.02 applied for Washington imports, as specified in WAC 173-441-124.

Aurora's modeled Day-Ahead prices reproduce historically observed EDAM price relationships between CAISO, PACE, and PACW

Historical and modeled average Day-Ahead intraday prices for CAISO¹, PACE, and PACW, May – August
\$/MWh, real 2025



Differences between realized historical prices and modeled prices are primarily driven by differences in demand, weather dynamics, and commodity prices; Aurora's fundamental modeling approach assumes a 2019 weather year as a representative year across key metrics impacting price formation

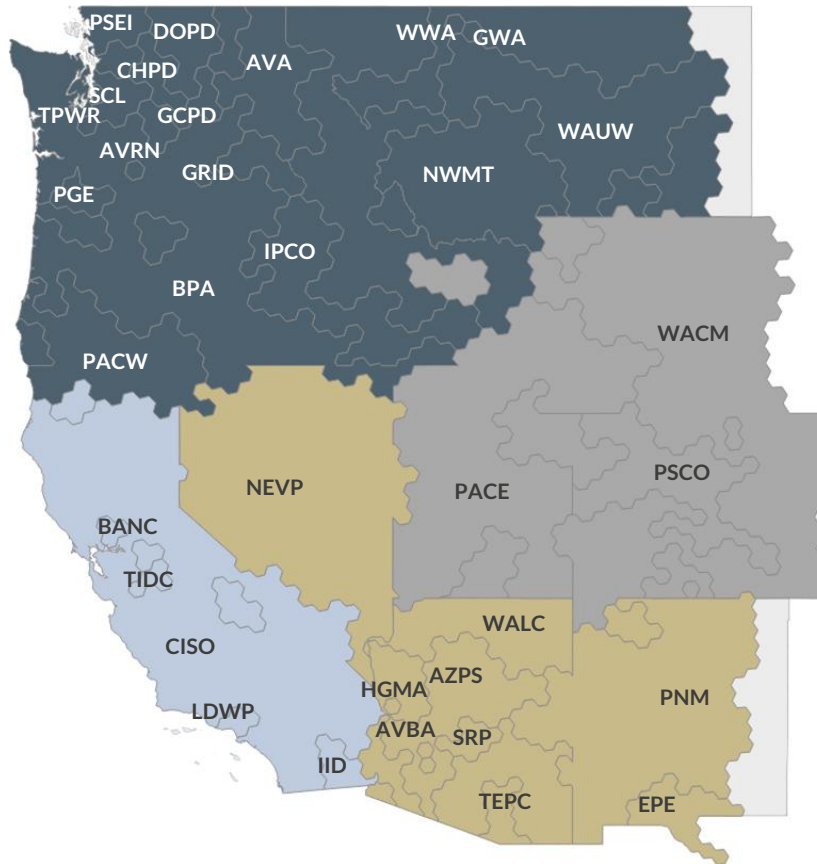
•• Historical — Modeled — CAISO — PACE — PACW

1) Simple hourly average of CAISO hub prices.

- Realized 2026 prices show CAISO trading above PACE and PACW; Aurora's modeled 2026 intraday prices reproduce this ordering, and it holds through 2032 without inverting
- The realized CAISO intraday profile, which consists a midday depression as solar generation peaks, followed by a steep evening ramp, is reproduced across the modeled years
- Realized PACE and PACW's relatively flatter intraday profiles followed by a sharp evening peak increase, is similarly captured in Aurora's nearterm forecast
- As modeled profiles peak and trough in the same hours as realized prices, the hours in which inter-regional trade is economic are consistent with observed EDAM dynamics, supporting the seams results presented earlier

Balancing Authorities in WECC subregions

WECC subregions



Subregion	Zones in Subregion	Balancing Authorities in Subregion
Pacific Northwest (PNW)	British Columbia Washington Oregon Idaho Montana	Avista Corporation (AVA); Bonneville Power Administration (BPA); British Columbia Hydro and Power Authority (BCHA); Avangrid (AVRN); Gridforce (GRID); Idaho Power Company (IPCO); NaturEner Power Watch (GWA); NaturEner Wind Watch (WWA); Nevada Energy (NEVP); Northwestern Energy (NWMT); PacifiCorp West (PACW); Portland General Electric Company (PGE); PUD No 1 of Chelan, Grant, and Douglas County (CHPD, GCPD, DOPD); Puget Sound Energy (PSEI); Seattle City Light (SCL); Tacoma Power (TPWR); WAPA - Upper Great Plains West (WAUW)
Rocky Mountains (RM)	Colorado Utah Wyoming	PacifiCorp East; Public Service Company of Colorado; WAPA – Colorado-Missouri Region
Desert Southwest (DSW)	Arizona Nevada New Mexico	Arizona Public Service Company; Arlington Valley; El Paso Electric Company; Gila River Power; Griffith Energy; Nevada Energy; New Harquahala Generating Company; Public Service Company of New Mexico; Salt River Project; Tucson Electric Power Company; WAPA – Lower Colorado Region
California/Mexico (CA/MX)	Comisión Federal de Electricidad; CAISO LDWP IID BANC TIDC	CAISO; Comisión Federal de Electricidad; Los Angeles Department of Water and Power (LDWP); Imperial Irrigation District (IID); Balancing Authority of Northern California (BANC); Turlock Irrigation District (TIDC)

Glossary of WECC Balancing Authorities

The Western Interconnection Balancing Authorities

Area	Definition
AESO	Alberta Electric System Operator
AVA	Avista Corporation
AZPS	Arizona Public Service Company
BANC	Balancing Authority of Northern California
BCHA	British Columbia Hydro
BPA	Bonneville Power Administration-Transmission
CFE	Comision Federal de Electricidad
CHPD	PUD No. 1 of Chelan County
CIPB	California Independent System Operator—Pacific Gas & Electric Bay
CIPV	California Independent System Operator—Pacific Gas & Electric Valley
CISC	California Independent System Operator—Southern California Edison
CISD	California Independent System Operator—San Diego Gas & Electric
DOPD	PUD No. 1 of Douglas County
EPE	El Paso Electric Company
GCPD	PUD No. 2 of Grant County
IID	Imperial Irrigation District
IPFE	Idaho Power Far East
IPMV	Idaho Power Magic Valley
IPTV	Idaho Power Treasure Valley
LDWP	Los Angeles Department of Water and Power
NEVP	Nevada Power Company
NWMT	NorthWestern Energy
PACW	PacifiCorp West
PAID	PacifiCorp Idaho

Area	Definition
PAUT	PacifiCorp Utah
PAWY	PacifiCorp Wyoming
PGE	Portland General Electric Company
PNM	Public Service Company of New Mexico
PSCO	Public Service Company of Colorado
PSEI	Puget Sound Energy
SCL	Seattle City Light
SPPC	Sierra Pacific Power Company
SRP	Salt River Project
TEPC	Tucson Electric Power Company
TH Malin	Trading Hub—Malin
TH Mead	Trading Hub—Mead
TH PV	Trading Hub—Palo Verde
TIDC	Turlock Irrigation District
TPWR	City of Tacoma, Department of Public Utilities
VEA	Valley Electric Association
WACM	Western Area Power Administration, Colorado-Missouri Region
WALC	Western Area Power Administration, Lower Colorado Region
WAUW	Western Area Power Administration, Upper Great Plains West

List of key acronyms

Acronym	Meaning
BA	Balancing authority
BAA	Balancing authority area
CAISO	California Independent System Operator
CAMX	California/Mexico
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CPUC	California Public Utilities Commission
DA	Day-ahead
DAM	Day Ahead Market
EDAM	Extended Day-Ahead Market
EIM	Energy Imbalance Market
EQR	Electric Quarterly Report
ETC	Existing transmission contract
EV	Electric Vehicle
FERC	Federal Energy Regulatory Committee
GWA	Generation Weighted Average
ICE	Intercontinental Exchange
IRR	Internal Rate of Return
ISO	Independent System Operator
ITC	Investment Tax Credit

Acronym	Meaning
LMP	Locational Marginal Pricing
LSE	Load-serving entity
MIC	Maximum Import Capability
NPV	Net Present Value
NQC	Net qualifying capacity
NWPP	Northwest Power Pool
OATT	Open Access TransmissionTariff
OCGT	Open Cycle Gas Turbine
PG&E	Pacific Gas & Electric
PPA	Power Purchase Agreement
PTC	Production Tax Credit
PV	Present Value
RA	Resource Adequacy
RMPA	Rocky Mountain Power Area
RTO	Regional Transmission Operator
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
TOR	Transmission Ownership Rights
WACC	Weighted Average Cost of Capital
WECC	Western Electricity Coordinating Council

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