

Western market regionalization: PSCo Day-Ahead market benefits analysis

Full report

Environmental Defense Fund

June 25th, 2025



- I. Executive summary
- II. Scenario design methodology
- III. Base Case results
 1. Cost savings
 2. Emissions
 3. WECC-wide impact
- IV. Sensitivities results
- V. Appendix: Overview of modeling approach

Executive Summary

- This study aims to quantify the potential impacts on costs, generation mix, and emissions for the Public Service Company of Colorado (PSCo) balancing authority (BA) under two Western US market regionalization scenarios: (1) PSCo participation in EDAM and (2) PSCo participation in Markets+ and three scenarios: (1) Base Case, (2) Low Emissions, and (3) High Transmission
- The analysis employs Production Cost Modeling across the WECC balancing authorities to compare the market outcomes driven by PSCo's Day-Ahead market (DAM) choice. Modeling inputs at the BA level such as capacity mix and load growth follow proposed Integrated Resource Plans and remain constant across scenarios, except for the Low Emissions sensitivity. DAM choice by BA is modeled based on announced commitments or intentions and is constant across scenarios for all BAs except PSCo
- This study finds that PSCo participation in EDAM vs. Markets+ has the following impacts:
 - Under the Base Case scenario, PSCo balancing authority can **save an average of \$13.2million/year from participation in EDAM over Markets+**, **enabled/mitigated** by:
 - **Lower production costs** due to lower reliance on thermal generation, which is replaced in large part by wind
 - **Higher congestion and wheeling revenue** due to higher utilization of transmission with the EDAM footprint
 - **Higher bilateral trading costs** due to different governance structures between EDAM and RTO West which WACM is joining, driving higher friction charges for importing from WACM
 - Under both scenarios, Xcel (PSCo) following the 2024 Just Transition Solicitation capacity mix meets the emissions targets specified under SB 19-236
 - Both the Low Emissions and High Transmission sensitivities result in lower costs for PSCo in EDAM, with benefits of \$18.3million/year and \$7.5million/year, respectively
- **Conclusion:** This study finds that PSCo consistently sees additional cost savings and similar emissions levels from participation in EDAM compared to participation in Markets+, under the specific capacity mix, load, DAM configuration, and transmission capacity assumed for the scenarios modeled in this analysis

PSCo sees total costs reduced by an average of \$13.2 million/year through 2060 when participating in EDAM as opposed to Markets+

This analysis aims to identify the potential benefits or costs for Public Service Company of Colorado (PSCo) under two Western US market regionalization scenarios: (1) PSCo participates in EDAM and (2) PSCo participates in Markets+, with all else remaining equal. Comparisons between scenarios include those of various cost categories, generation mix, and emissions outputs.

Average cost breakdown for PSCo under EDAM vs Markets+ DAM, 2028-2060

\$Million/year, real 2024

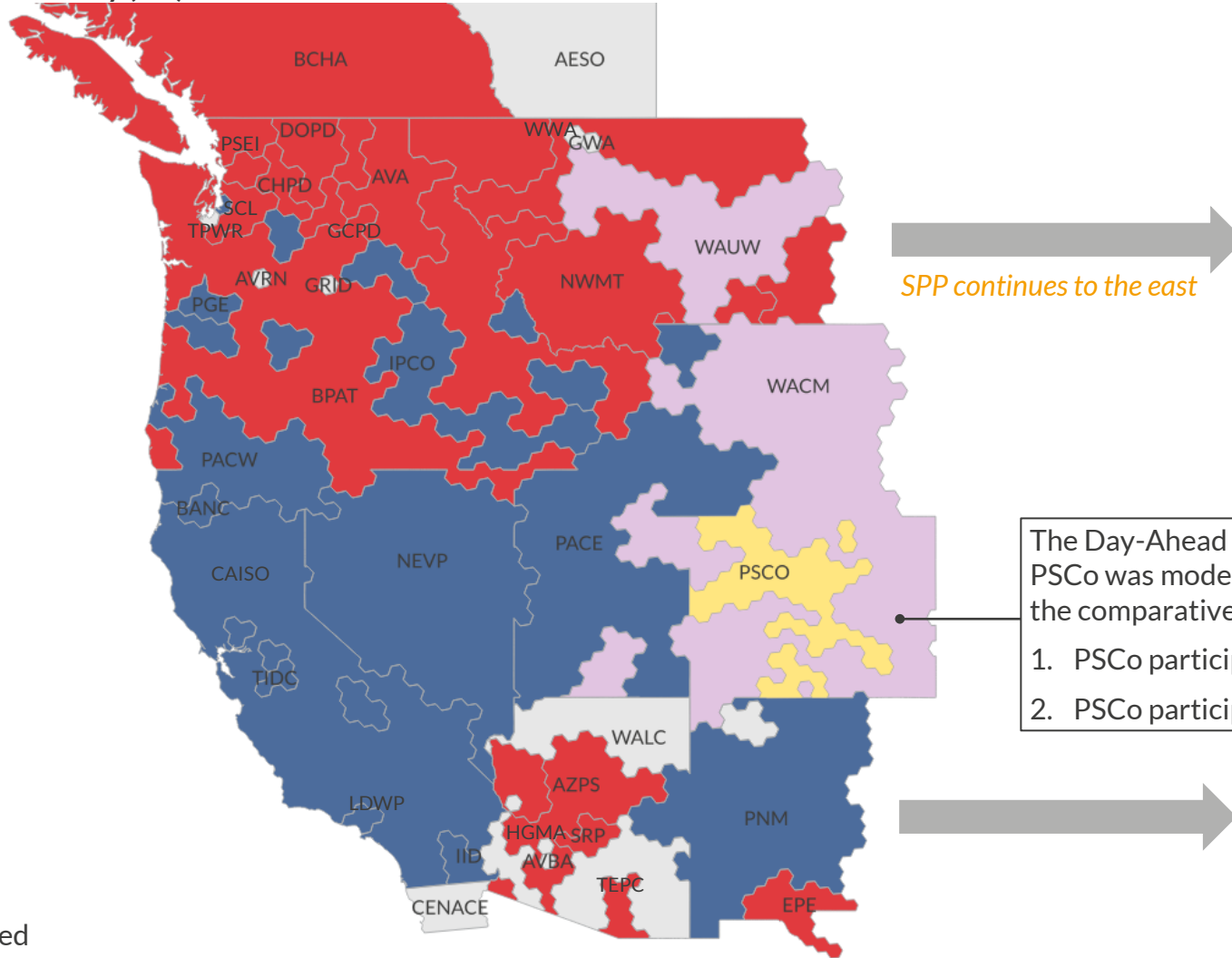
Metric	EDAM	Markets+	Delta (EDAM - Markets+) ¹	Average delta, 2028-2040	Average delta, 2041-2060
Production cost	857.4	862.3	(4.9)	(1.2)	(7.4)
Bilateral trading costs	231.9	227.0	4.9	0.2	8.0
Congestion revenue	(85.8)	(72.9)	(12.8)	(9.2)	(15.2)
Wheeling revenue	(5.5)	(5.1)	(0.4)	(1.0)	(0.0)
Costs less revenues	998.0	1,011.2	(13.2)	(11.2)	(14.6)

- PSCo sees an average \$13.2mil/year benefit in total costs when participating in EDAM vs. Markets+
- **Production costs** - When participating in EDAM, greater wind generation and lower gas production drive down energy production costs
- **Bilateral trading costs** - PSCo is a net importer in all scenarios, primarily from WACM. This dynamic creates additional bilateral trading costs for PSCo in the EDAM scenario, where imports from WACM are subject to additional friction charges
- **Congestion and wheeling revenue** - Under the EDAM scenario PSCo sees higher utilization of its transmission interconnection to facilitate trades between PACE and PNM²

1) A negative delta indicates lower costs when PSCo is modeled in EDAM compared to Markets+, demonstrating benefits to joining EDAM 2) Ownership assumed to be split 50-50 with connecting BA unless data on ownership is available

The composition of each offering in the West is modeled based on confirmed and likely commitments as announced by each BA

Map of modeled balancing authority (BA) market decisions



Key^{1,2}

- BA of focus (PSCo)
- Modeled in Markets+
- Modeled in EDAM
- Modeled in RTO West
- Modeled as Uncommitted

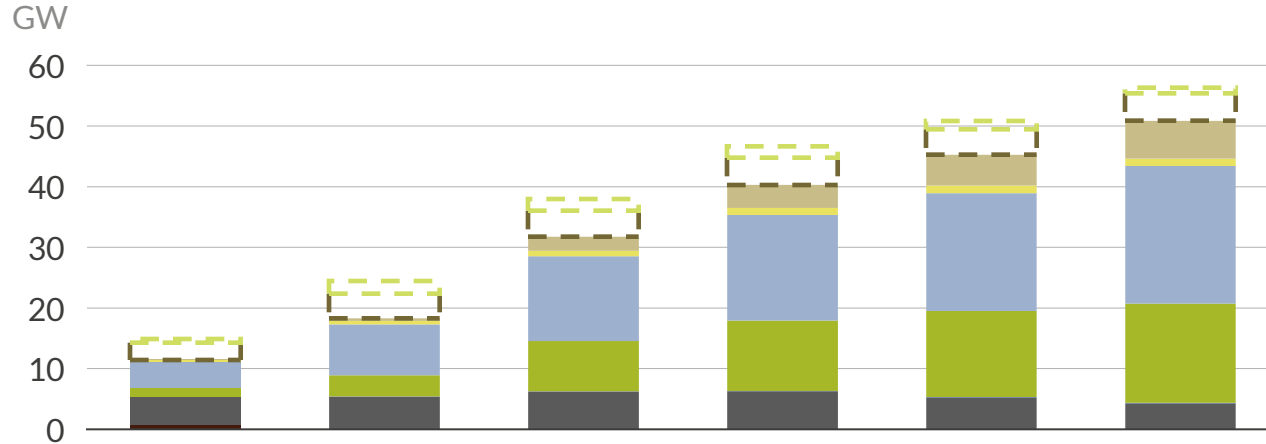
The Day-Ahead Market (DAM) commitment for PSCo was modeled under 2 scenarios to determine the comparative regionalization benefits:

1. PSCo participation in EDAM
2. PSCo participation in Markets+

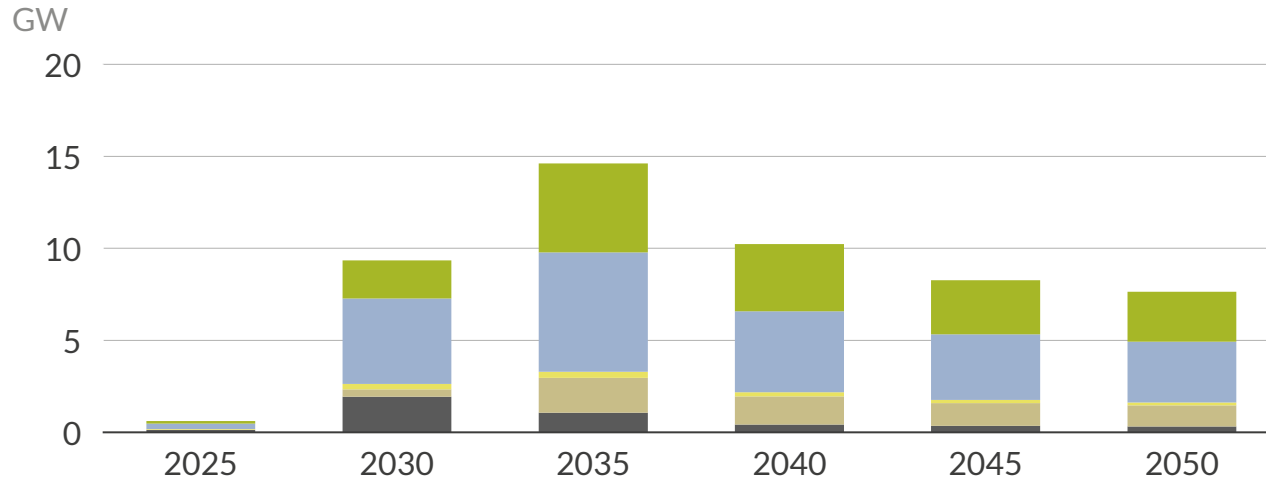
1) BAs with announced leanings or commitments as of June 9th are modeled as participating in the respective offering. BAs that are undecided or have no public leaning as of June 9th are modeled as uncommitted and therefore do not participate in any offering
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Aurora modeled PSCo utility portfolio following the JTS through 2050; PSCo BA capacity includes resources from other utilities

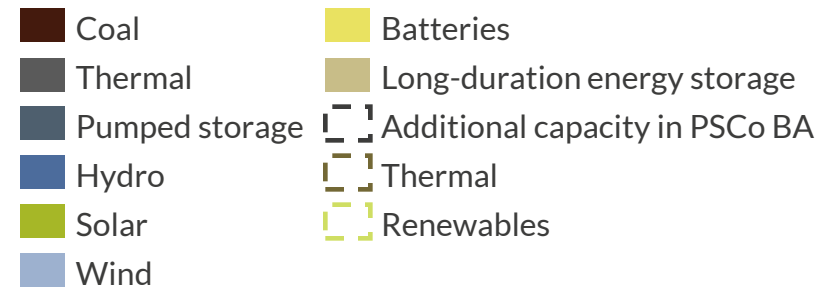
Installed capacity, PSCo utility and PSCo BA¹



Added capacity in 5-year steps following the JTS²



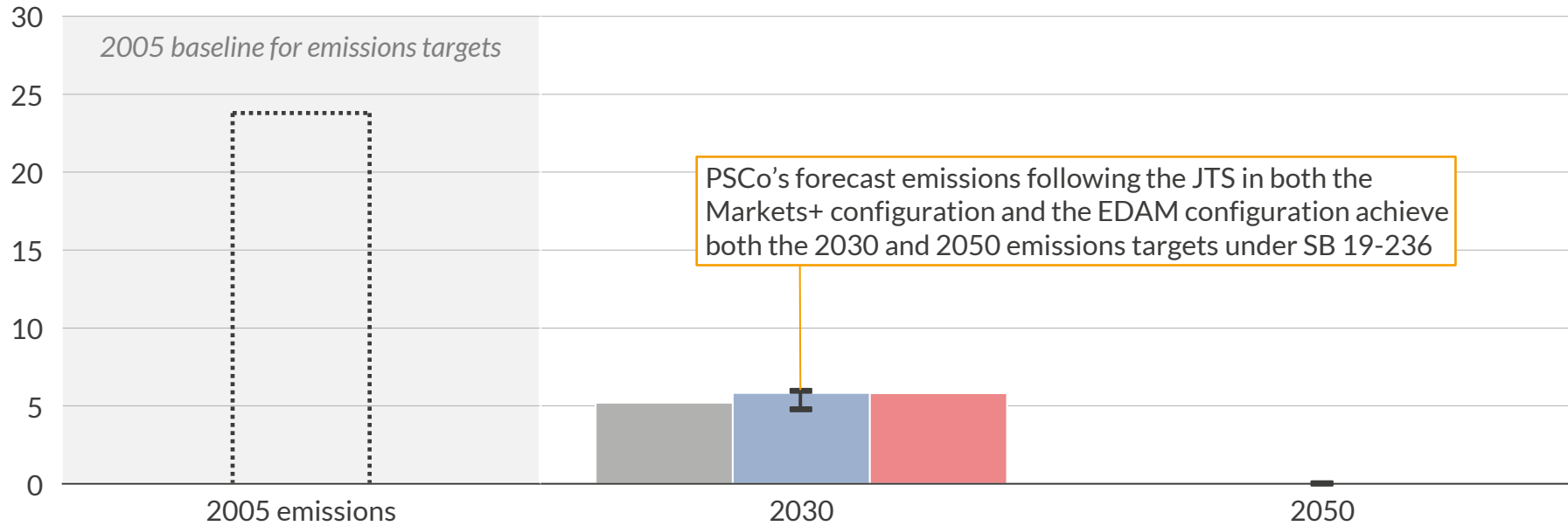
- Aurora modeled PSCo installed capacity based on existing installed capacity owned and contracted to utilities within PSCo territory, with capacity growth throughout the forecast for PSCo utility following the Just Transition Solicitation (JTS) released in 2024
- Retirements of 1.8GW of coal and gas by 2031 as outlined in the JTS are included in Aurora’s forecast
- About 10GW of renewables, storage, and new CCGTs are planned to come online in the next 5-6 years to replace the retiring conventional resources
- The technologies procured in the JTS are designed to meet 2030 and 2050 emissions targets under SB 19-236, while procuring enough capacity to meet the 108% increase in expected load by 2050 driven by data center growth and electrification



1) Capacity serving the PSCo BA load includes capacity within Blackhills, Tristate CO, and other LSEs under PSCo BA territory. 2) Xcel (PSCo) provides their preferred portfolio in lump capacity additions for the periods from 2025 through 2031 and 2031 through 2050. The lump capacity amounts have been distributed across years following annual load growth, which varies year to year

Under both Day-Ahead markets, PSCo is compliant with SB 19-236 emissions targets in 2030 and 2050

Xcel (PSCo) CO₂ emissions forecast¹
Million MTCO₂e



PSCo's forecast emissions following the JTS in both the Markets+ configuration and the EDAM configuration achieve both the 2030 and 2050 emissions targets under SB 19-236

Colorado SB 19-236 Targets

2005 Baseline

Colorado utilities are required to cut their emissions relative to their 2005 levels

2030

By 2030, **each utility must cut its emissions from Colorado retail sales by 80% from its 2005 levels.** Its plan to do so is compliant if it is found to achieve at least a 75% reduction in emissions by 2030 by the Air Pollution Control Division

2050

Utilities are required to target 100% of sales coming from clean energy by 2050

 2005 baseline emissions
 JTS forecast
 PSCo in EDAM
 PSCo in Markets+
 ⏏ Emissions compliance range²

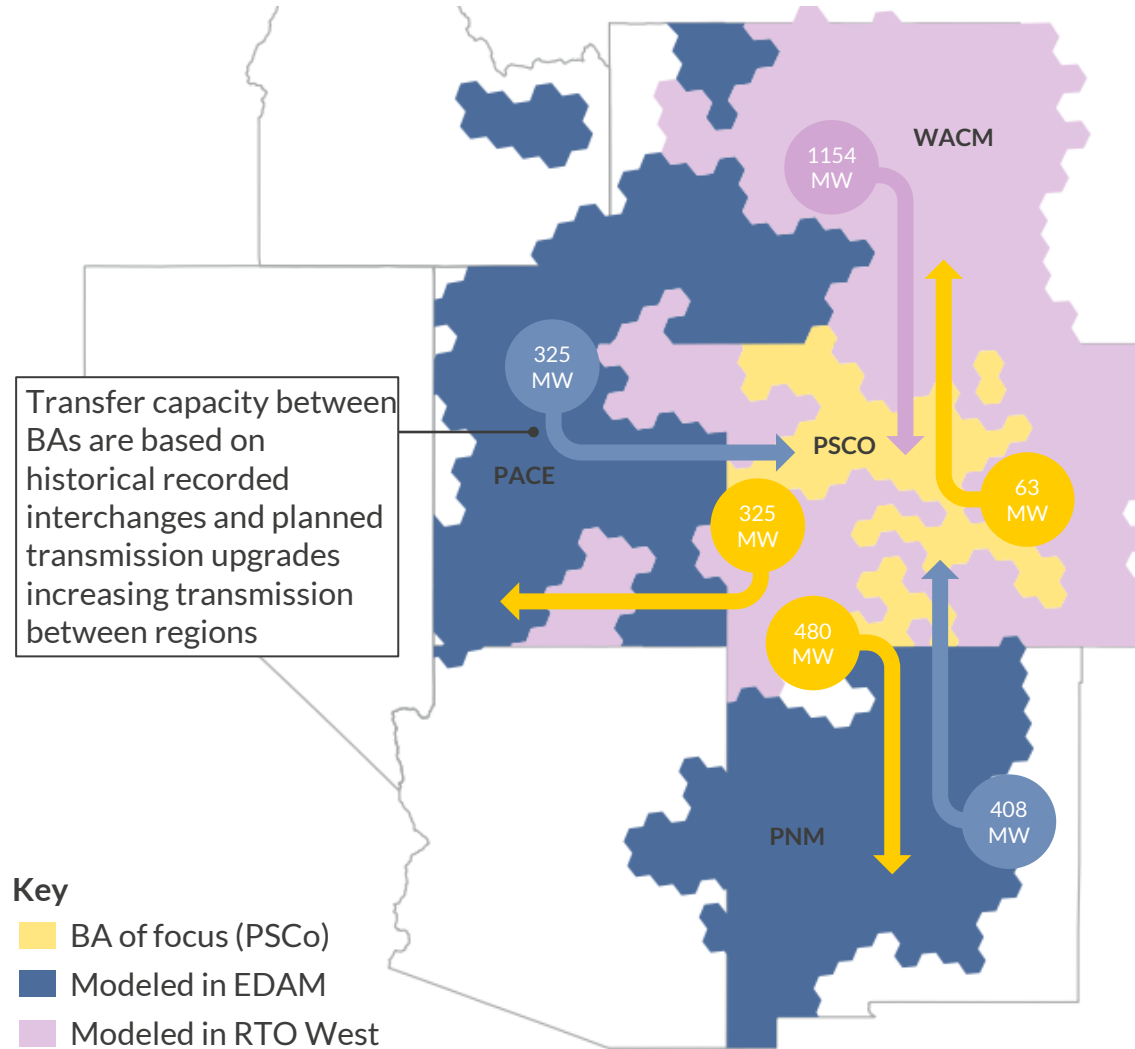
1) Results shown here are the emissions for Xcel (PSCo) utility as the largest LSE within the BA territory. SB 19-236 targets only apply to electricity providers serving at least 500,000 customers in Colorado; Xcel (PSCo), Black Hills, and Tri-State are qualifying utilities 2) Using 2005 emissions level as a baseline, which was 23.8MMTCO₂e

Sources: Aurora Energy Research, Xcel (PSCo), Colorado Air Pollution Control Division

- The CPUC accepted Xcel (PSCo)'s 2021 Clean Energy Plan. The 2024 JTS sees accelerated procurement to meet the same emissions reduction requirements while serving new load demands
- Retirements of ~1.8GW conventional coal and gas resources, with renewables and storage replacements, enables PSCo to reach 2030 targets
- Emissions are similar between the two modeled scenarios for PSCo participation in EDAM and Markets+ given the capacity mix was held constant. Marginal differences in emissions are driven by variation in carbon intensity of imports and exports

Aurora considers transfer limits between regions when modeling the Western Interconnection

Modeled transfer limits to and from PSCo in 2032¹



Transmission projects modeled with impacts on Net Transfer Capability (NTC)

Project name	Modeled year in-service	Description
Colorado Power Pathway (CPP) Segments 1-5	Segment 1: 2026 Segment 2 + 3: 2025 Segment 4 + 5: 2027	Connects PSCo system into eastern Colorado, accommodating the addition of up to 5GW nameplate capacity
CPP extension (May Valley - Longhorn)	2032	Connects PSCo system into eastern Colorado
Colorado Electric Transmission Authority (CETA) Southeast Concept	2032	345kV line from the Longhorn substation in CO to the Gladstone substation in NM
CETA Northwest Concept	2032	345kV line from CO Craig substation to UT PacifiCorp Gateway South transmission line via Coyote substation

1) Transfer limits are modeled at the BA level. BAs identified here show all modeled interchange possibilities for PSCo with neighboring BAs

PSCo sees cost reductions for participation in EDAM compared to Markets+ in all scenarios, ranging from \$7.5 to 18.3 million/year

Average cost breakdown for PSCo under EDAM vs Markets+ DAM, 2028-2060

\$Million/year, real 2024

Metric	Base Case			Low Emissions			High Transmission		
	EDAM	Markets+	Delta ¹	EDAM	Markets+	Delta ¹	EDAM	Markets+	Delta ¹
Production cost	857.4	862.3	(4.9)	601.1	596.3	4.8	780.4	784.5	(4.1)
Bilateral trading costs	231.9	227.0	4.9	(48.0)	(42.4)	(5.6)	278.8	275.0	3.8
Congestion revenue ²	(85.8)	(72.9)	(12.8)	(117.1)	(99.3)	(17.8)	(89.9)	(81.7)	(8.1)
Wheeling revenue ²	(5.5)	(5.1)	(0.4)	1.0	0.8	0.2	(7.4)	(8.4)	1.0
Costs less revenues	998.0	1,011.2	(13.2)	437.0	455.3	(18.3)	961.9	969.4	(7.5)
Comparison to Base Case				↑ (5.1)			↓ 5.7		

- PSCo sees lower costs in EDAM in scenarios, with \$5.1m/year additional benefits in the Low Emissions scenario and \$5.7m/year reduced benefits in the High Transmission scenario compared to Base Case
- **Low Emissions:** With increased renewable buildout, greater access to a larger DAM footprint under EDAM allows PSCo to export excess renewable generation more efficiently. As such, revenues from bilateral trading and congestion increase with higher trade volumes and line utilization
- **High Transmission:** Increased transmission capacity to WACM creates more value for the Markets+ scenario due to lower friction charges, reducing the congestion and wheeling benefit for PSCo in EDAM by \$5.3m/year

↑ Additional benefits to PSCo in EDAM compared to Base Case ↓ Reduced benefits to PSCo in EDAM compared to Base Case

1) EDAM – Markets+. A negative delta indicates lower costs when PSCo is modeled in EDAM compared to Markets+, demonstrating benefits to joining EDAM 2) Ownership assumed to be split 50-50 with connecting BA unless data on ownership is available

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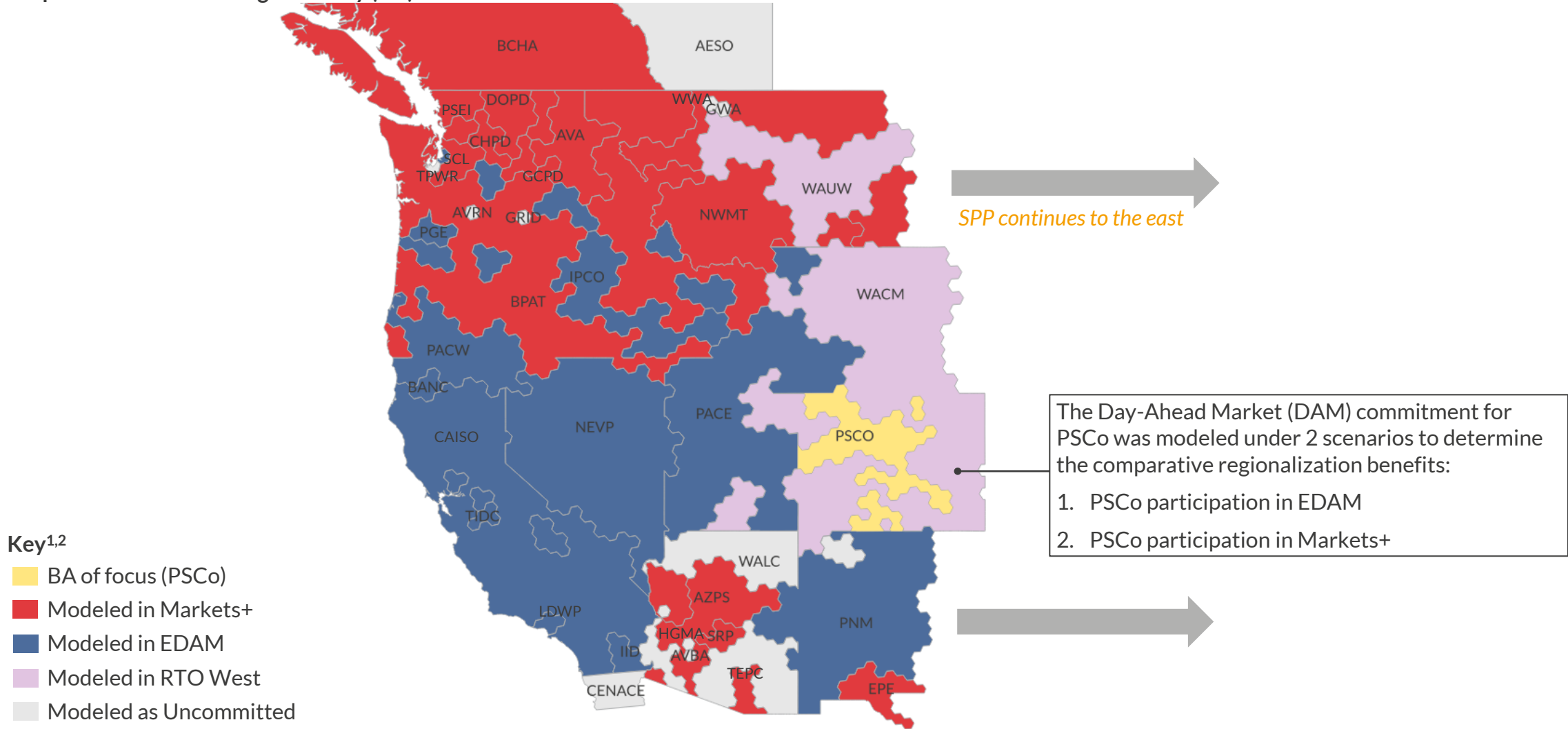
Input assumptions align with Xcel (PSCo)'s 2024 Just Transition Solicitation, with adjustments to reflect each sensitivity scenario

As in Base Case unless stated otherwise		Base Case	Sensitivity 1: Low Emissions	Sensitivity 2: High Transmission
 Demand	Underlying demand	Aligned with Xcel JTS ¹ Base forecast Annual Energy (GWh) growth rate for Xcel (PSCo) utility, with additional demand for separate LSEs within PSCo BA service area.		
 Commodities	Gas price	Henry Hub prices increase to \$4.5/MMBtu in 2030 and \$5.4/MMBtu in 2060. CIG prices, which represent PSCo, increase to \$4.1/MMBtu in 2030 and \$5.1/MMBtu in 2060.		
	Coal price	Stable coal price across forecast horizon.		
 Technology	Renewables	Consistent with the 2024 JTS plan, which adds +40GW in renewables.	Additional 19GW renewables capacity added by 2040 to accommodate thermal retirements.	
	Thermal	Consistent with 2024 JTS plan – thermal exits modeled as outlined.	PSCo utility-level thermals exit by 2040, with 3GW emissions-free thermal generation added by 2040.	
	Hydro	P60 hydro availability throughout the Western Interconnection.		
 Policy	Pollution standards	Xcel (PSCo) meets SB 19-236 emissions reductions targets applicable to LSEs serving at least 500,000 customers by 2050.	PSCo utility targets 95% reduction in emissions from 2005 levels by 2035 and 100% reduction by 2040, which is a 10-year acceleration from the Base Case.	
	Renewables incentives	ITC and PTC consistent with the Inflation Reduction Act and extended at lower levels after IRA expires.		
	Carbon price	No carbon price is applied to PSCo. Washington and California carbon markets link and prices increase to \$101/ton by 2035 and level off at \$140/ton.		
 Trade	Inter BA trade capacity	Assumes Colorado Power Pathway Segments 1-5 and the May Valley – Longhorn extension. Partial transfer capacity from the CETA Northwest Concept attributed to PSCo-PACE interconnection. Full transfer capacity assumed from the CETA Southeast Concept between PSCo and PNM.		In addition to all Base Case trade capacities, by 2040 500MW of transfer capacity enabled for PSCo-PACE representing a gradual ramp to the full transfer capacity from CETA Northwest Concept, and 294MW additional capacity between PSCo and WACM by 2040 reflecting implementation of CETA Northern.

1) The input assumptions align with Xcel (PSCo) Just Transition Solicitation IRP, which was submitted to the PUC for approval in October 2024, where available. These assumptions include demand, new build capacity, and retirements. Trade assumptions are implemented based on announced and projected line upgrades. Aurora standard input assumptions for modeling the West are used elsewhere.

The composition of each offering in the West is modeled based on confirmed and likely commitments as announced by each BA

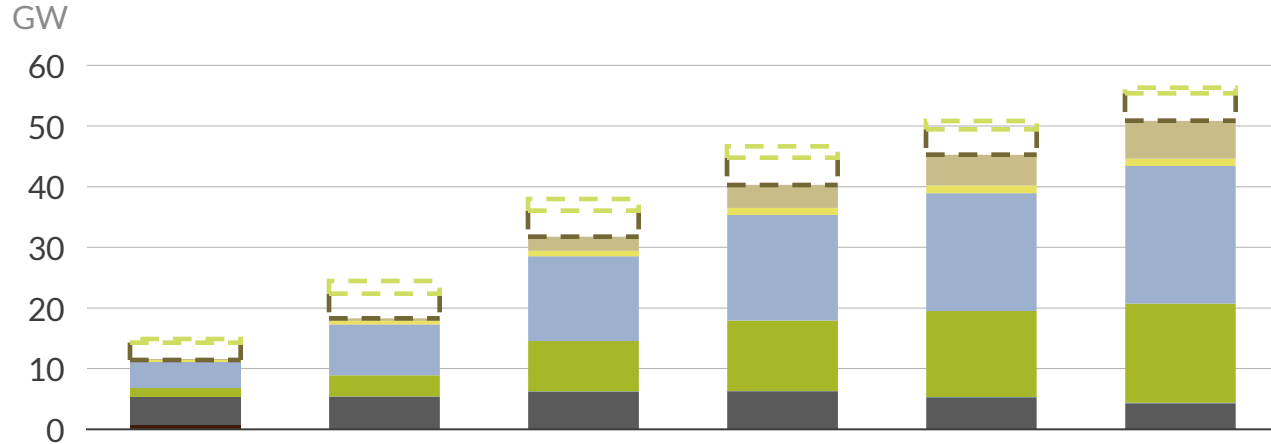
Map of modeled balancing authority (BA) market decisions



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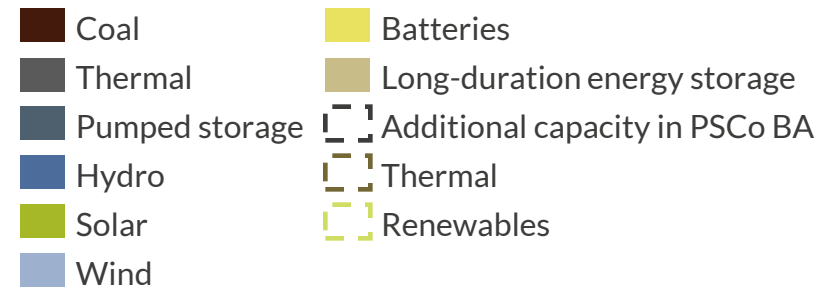
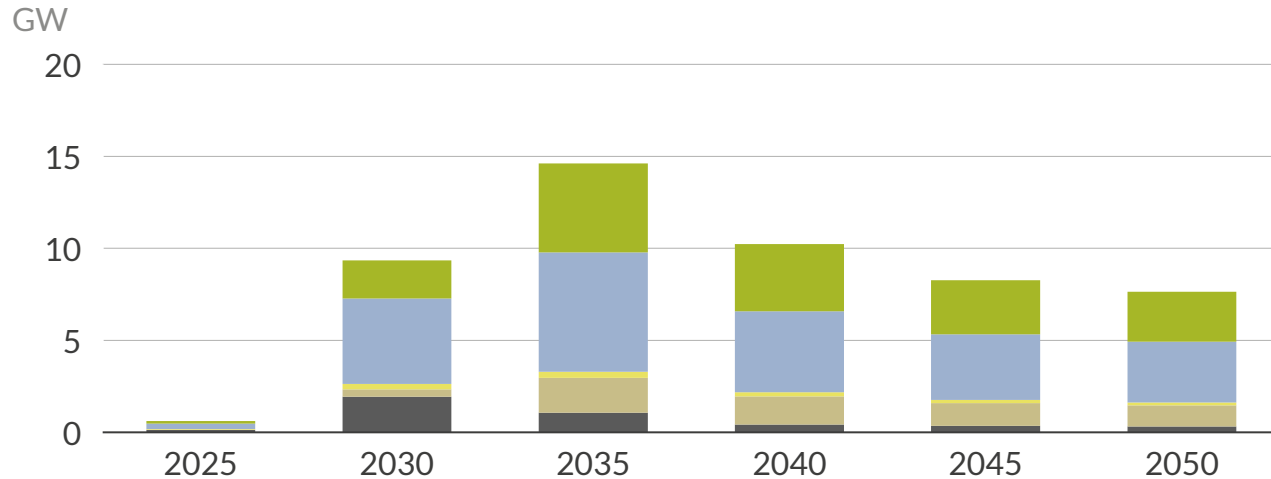
Aurora modeled PSCo utility portfolio following the JTS through 2050; PSCo BA capacity includes resources from other utilities

Installed capacity, PSCo utility and PSCo BA¹, Base Case and High Transmission scenario



- Aurora modeled PSCo installed capacity based on existing installed capacity owned and contracted to utilities within PSCo territory, with capacity growth throughout the forecast for PSCo utility following the Just Transition Solicitation (JTS) released in 2024
- Retirements of 1.8GW of coal and gas by 2031 as outlined in the JTS are included in Aurora’s forecast
- About 10GW of renewables, storage, and new CCGTs are planned to come online in the next 5-6 years to replace the retiring conventional resources
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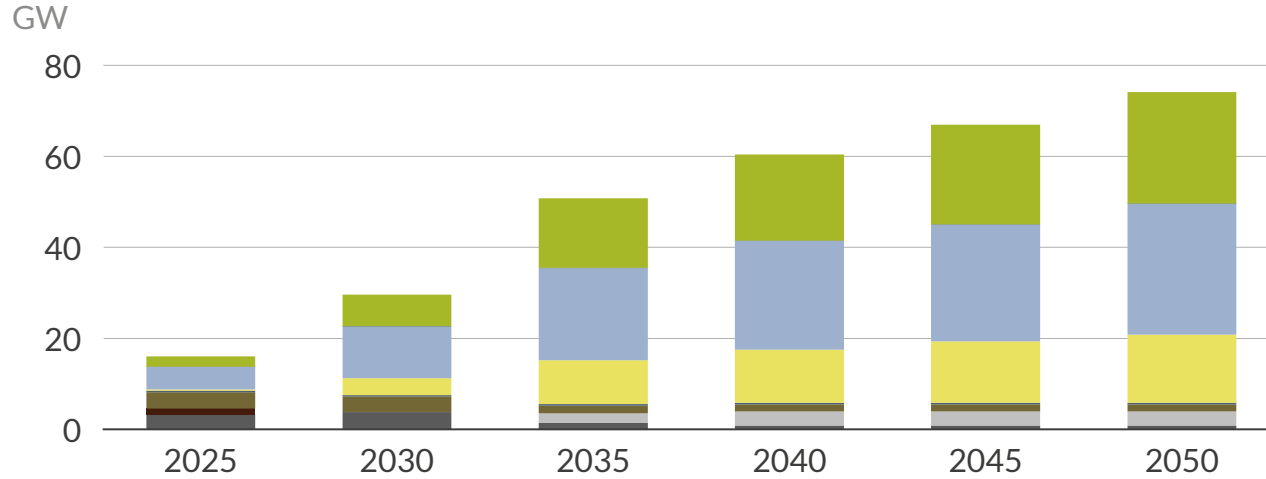
Added capacity in 5-year steps following the JTS², Base Case and High Transmission



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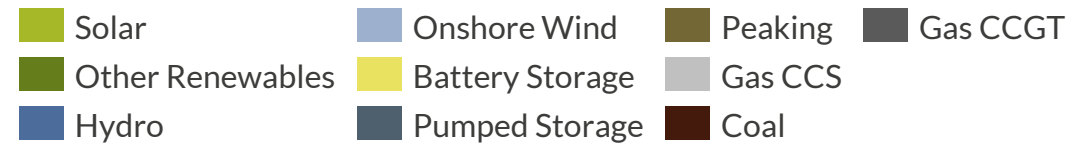
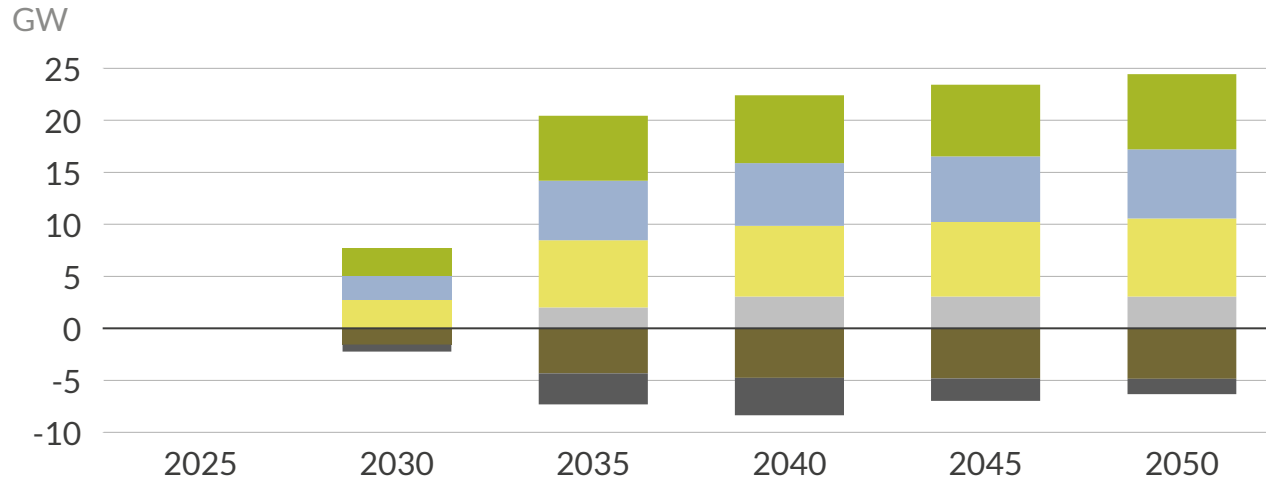
Low Emissions: Renewables growth and thermal retirements were accelerated to achieve a utility-level carbon-free system by 2040

Installed capacity, PSCo Balancing Authority Area, Low Emissions scenario



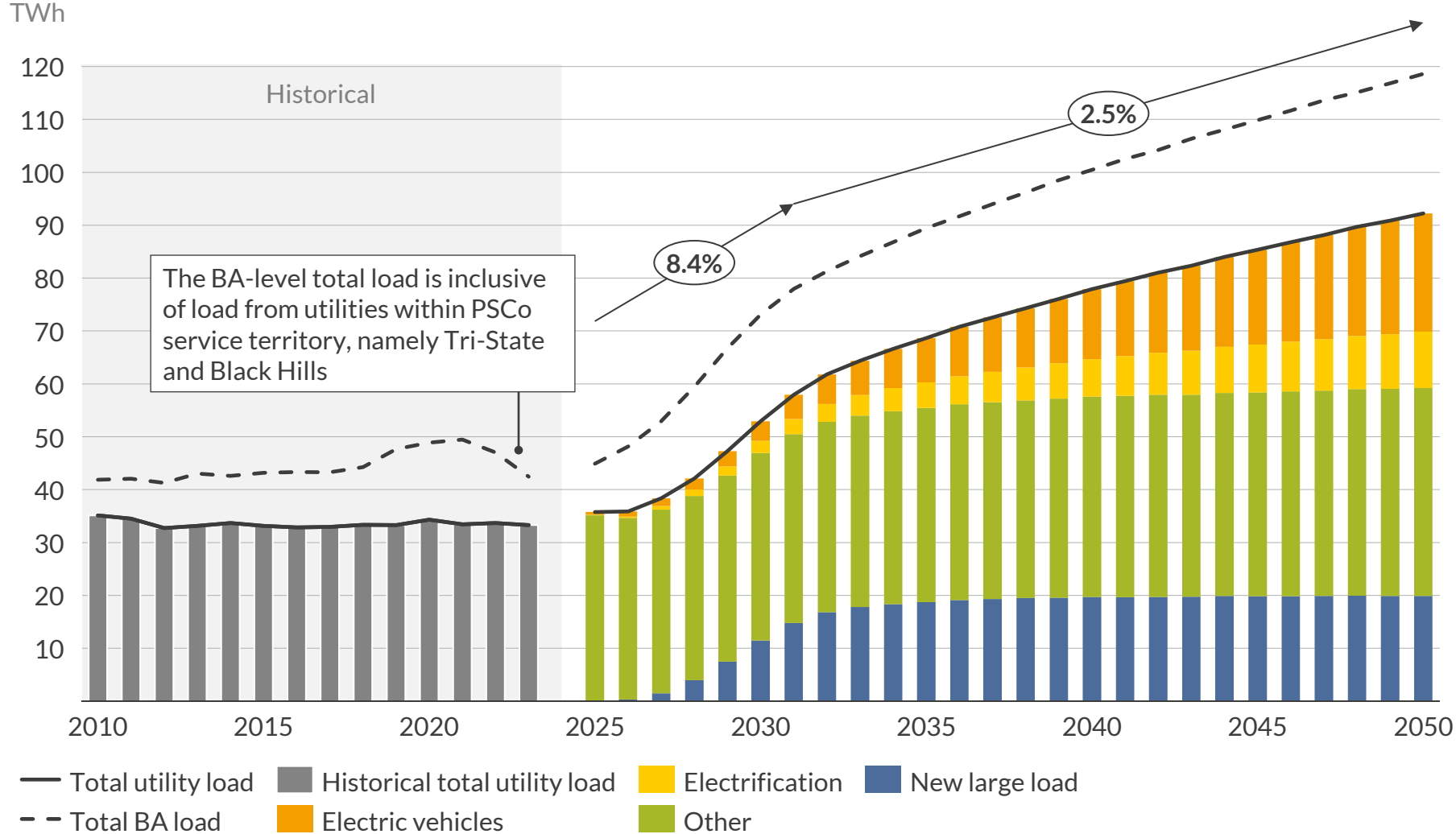
- The Low Emissions scenario envisions a more accelerated progression towards a carbon free system compared to SB19-236 targets, targeting a **95% reduction in PSCo utility level emissions from 2005 levels by 2035, and a 100% reduction by 2040**
- Aurora modeled a gradual phase out of the existing PSCo utility thermal fleet by 2040, replaced by additional renewables, storage, and emissions-free thermal generation to meet growing baseload and peak demand
 - By 2035, 7.3GW of utility-level thermal baseload and peaking generation is retired while 20.4GW of additional storage, renewables, and carbon-free baseload capacity is added on top of the Base Case scenario, which is modeled after the 2024 JTS Portfolio expansion
 - By 2040, all PSCo utility-level thermal generation is retired to achieve an emissions-free system, with 22.4GW additional renewables, storage, and carbon-free baseload on the system

Capacity delta, Low Emissions – Base Case scenario



PSCo Balancing Authority demand forecast is modeled to follow the JTS growth rates through 2050

Xcel (PSCo) segmented annual system load¹, All scenarios



- Although annual load was flat for the previous five years, Xcel (PSCo)'s base annual load forecast grows at a compounded annual growth rate of 8.4% through 2031 driven primarily by new large load customers
 - New large-load customers explain 66% of new load from 2025-2031
- Electrification adds 2.8TWh to annual load, explaining 12% of growth
- Sales to Xcel's retail customers² are also driving the increase in annual load, averaging 7.9% growth

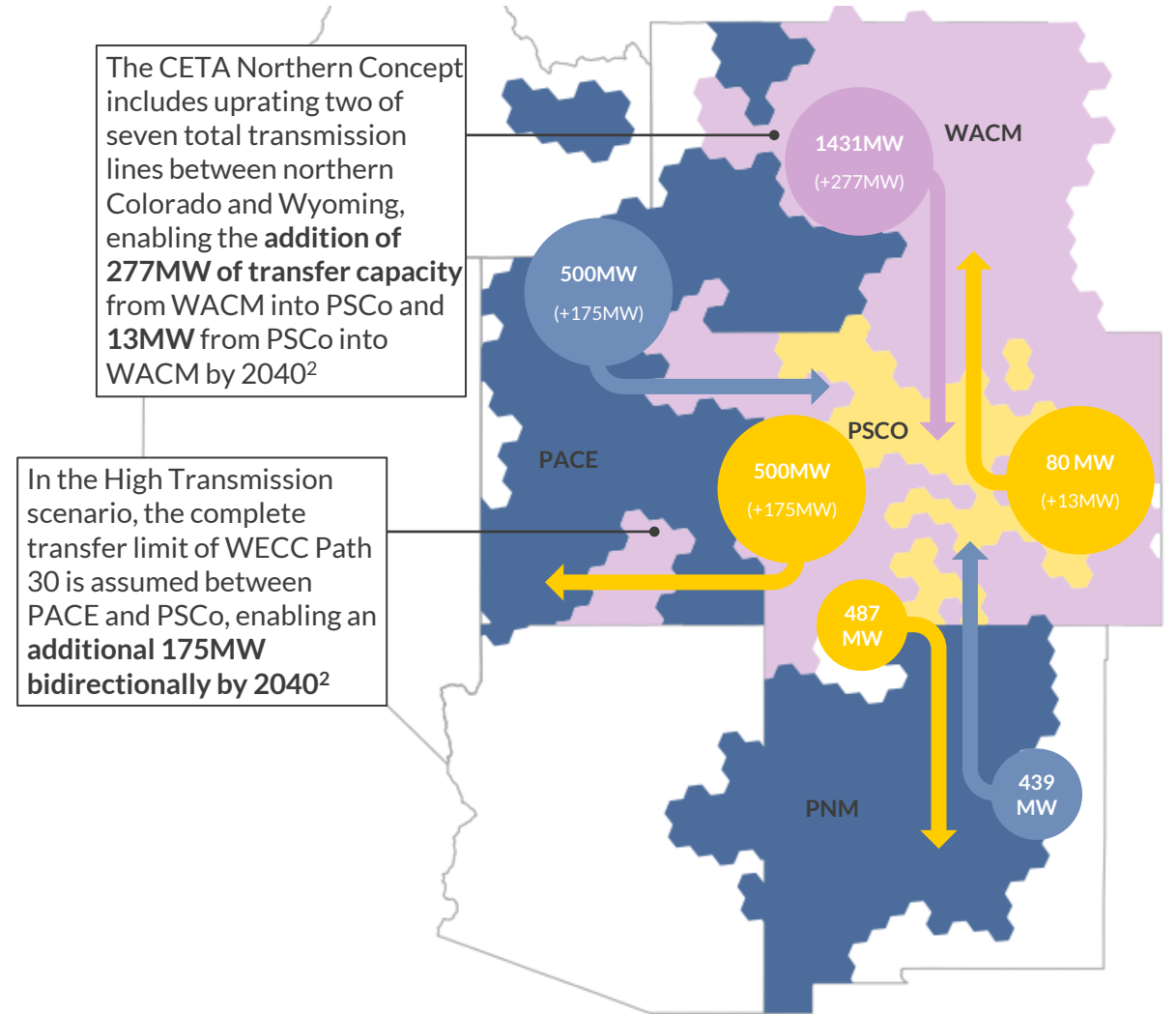
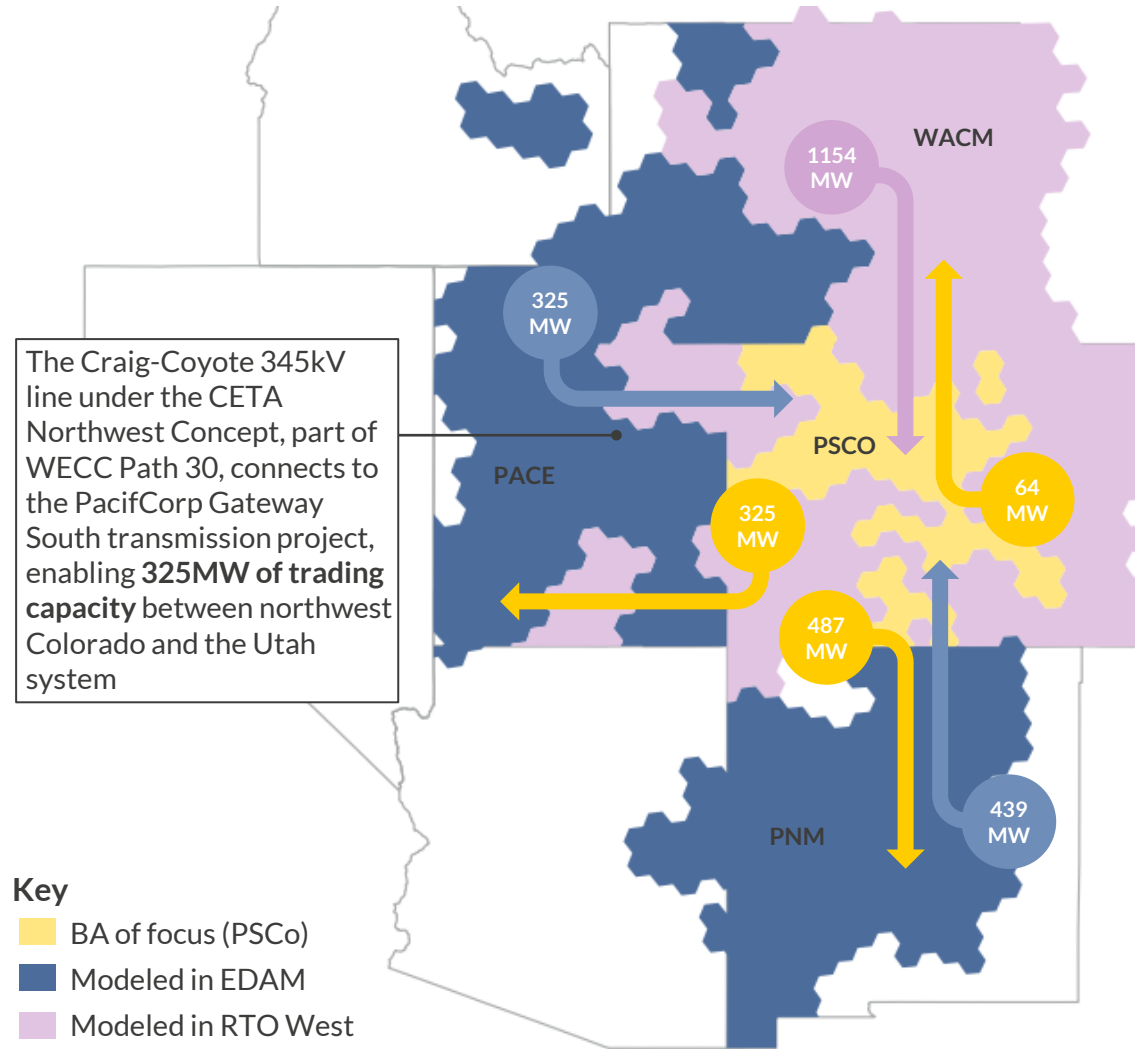
1) Forecasted annual system load is at generation, post-demand side management. 2) Customers directly serviced by Xcel (PSCo), including residential, commercial, and industrial customers. It does not include wholesale customers, including utility customers.

Sources: Aurora Energy Research, Xcel (PSCo)

The High Transmission scenario assumes further implementation of conceptual transmission projects for PSCo with WACM and PACE

Modeled transfer limits to and from PSCo in 2040¹, Base Case and Low Emissions

Modeled transfer limits to and from PSCo in 2040¹, High Transmission



1) Transfer limits are modeled at the BA level. BAs identified here show all modeled interchange possibilities for PSCo with neighboring BAs 2) Additional transfer capacity amounts in MW associated with the CETA projects are estimated based on existing transfer capacity magnitude as well as study capacity datapoints where available

Sources: Aurora Energy Research, WECC, EIA, CETA, Xcel

Aurora considers transfer limits between regions when modelling the Western Interconnection

Transmission projects modeled with impacts on Net Transfer Capability (NTC)

Project name	Modeled year in-service	Description	Modeling impact ²	Scenario
Colorado Power Pathway (CPP) Segments 1-5	Segment 1: 2026 Segment 2 + 3: 2025 Segment 4 + 5: 2027	Connects PSCo system into eastern Colorado, accommodating the addition of up to 5GW nameplate capacity		Base Case Low Emissions High Transmission
CPP extension (May Valley – Longhorn)	2032	Connects PSCo system into eastern Colorado	All: 300MW additional transfer capacity enabled for PSCo-PNM trade	Base Case Low Emissions High Transmission
Colorado Electric Transmission Authority (CETA) Southeast Concept	2032	345kV line from the Longhorn substation in CO to the Gladstone substation in NM		Base Case Low Emissions High Transmission
CETA Northwest Concept	2032	345kV line from CO Craig substation to UT PacifiCorp Gateway South transmission line via Coyote substation	All: 325MW transfer capacity enabled for PSCo-PACE trade High Transmission: 650MW transfer capacity enabled for PSCo-PACE trade by 2060	All, with additional capacity in High Transmission enabled by the end of the forecast
CETA Northern Concept	2032	Reconductoring of the 230kV Archer-Ault line and the 230kV Ault-Terry Ranch line	High Transmission: By 2060, 646MW additional transfer capacity added from WACM into PSCo, and 146MW additional capacity from PSCo into WACM	High Transmission

1) Transfer limits are modeled at the BA level. BAs identified here show all modeled interchange possibilities for PSCo with neighboring BAs 2) Additional transfer capacity amounts in MW associated with the projects referenced are estimated based on existing transfer capacity magnitude as well as study capacity datapoints where available

Sources: Aurora Energy Research, WECC, EIA, CETA, Xcel

Transfers between markets, RTOs, or uncommitted BAs are expected to face friction charges due to differences in market optimization

Transfers to Markets+		
Source BA	Sink BA	Friction charge ¹
Markets+	Markets+	\$0/MWh
EDAM	Markets+	\$3/MWh
RTO West	Markets+	\$1.5/MWh
Uncommitted	Markets+	\$3/MWh

Transfers to EDAM		
Source BA	Sink BA	Friction charge ¹
EDAM	EDAM	\$0/MWh
Markets+	EDAM	\$3/MWh
RTO West	EDAM	\$3/MWh
Uncommitted	EDAM	\$6/MWh

Transfers to RTO West		
Source BA	Sink BA	Friction charge ¹
RTO West	RTO West	\$0/MWh
EDAM	RTO West	\$1.5/MWh ²
Markets+	RTO West	\$0.75/MWh
Uncommitted	RTO West	\$1.5/MWh

Transfers to uncommitted BAs		
Source BA	Sink BA	Friction charge ¹
Uncommitted	Uncommitted	\$6/MWh
EDAM	Uncommitted	\$6/MWh
Markets+	Uncommitted	\$6/MWh
RTO West	Uncommitted	\$6/MWh

1) Friction charges are additive to wheeling rates and carbon adders (imports to CA or WA). The full hurdle rate for trades between BAs is modeled as the sum of wheeling rates, friction charges, and carbon adders. Wheeling rates between BAs in the same DAM are reduced to \$0/MWh 2) EDAM to CAISO transfers see a \$0/MWh friction charge

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X Deep dive to follow

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- **Congestion and wheeling revenue** – Under the EDAM scenario PSCo sees higher utilization of its transmission interconnection to facilitate trades between PACE and PNM²

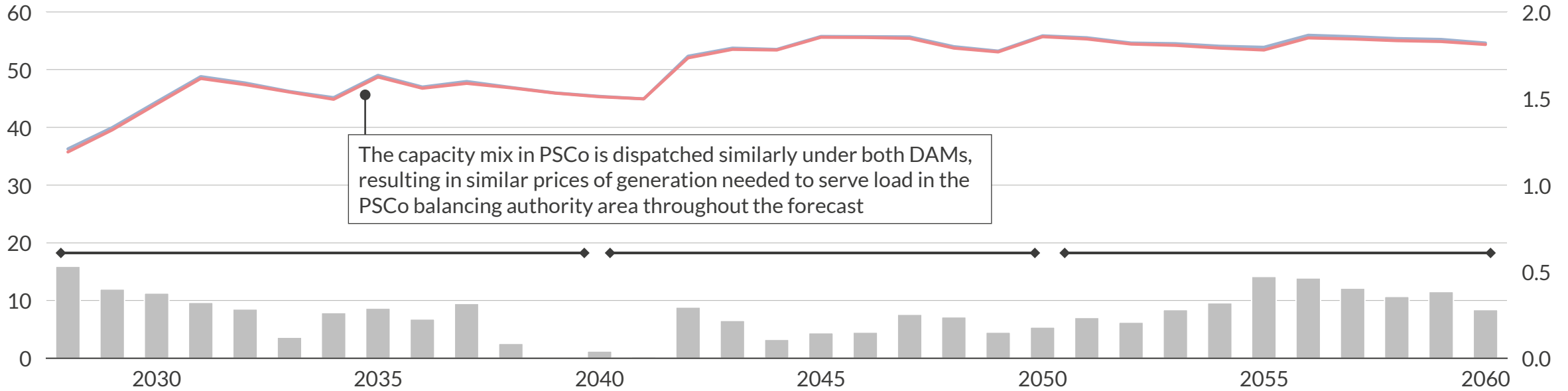
1) A negative delta indicates lower costs when PSCo is modeled in EDAM compared to Markets+, demonstrating benefits to joining EDAM 2) Ownership assumed to be split 50-50 with connecting BA unless data on ownership is available

Sources: Aurora Energy Research

A PSCo baseload prices are similar under both DAMs, with PSCo in EDAM seeing a ~\$0.25/MWh premium

Baseload energy prices, PSCo¹
\$/MWh, real 2024

Baseload energy price delta, PSCo in EDAM vs. PSCo in Markets+²
\$/MWh, real 2024



The capacity mix in PSCo is dispatched similarly under both DAMs, resulting in similar prices of generation needed to serve load in the PSCo balancing authority area throughout the forecast

2028-2040 2040-2050 2050-2060

- Near-term prices rise as projected load increases driven by new large load customers
- In combination with the increased load, near-term retirements of seven coal and five gas plants totaling ~2GW of thermal capacity puts upwards pressure on prices before stabilizing towards the 2040s
- Prices rise in the early 2040s as 1.6GW of gas plant retirements, including Manchief 11 & 12, Pawnee 1, and Ft. St. Vrain 1-4, coincide with consistently increasing load and put upwards pressure on prices
- Long-term, prices stabilize as fuel price increases moderate and increased renewable penetration in Colorado put downwards pressure on prices

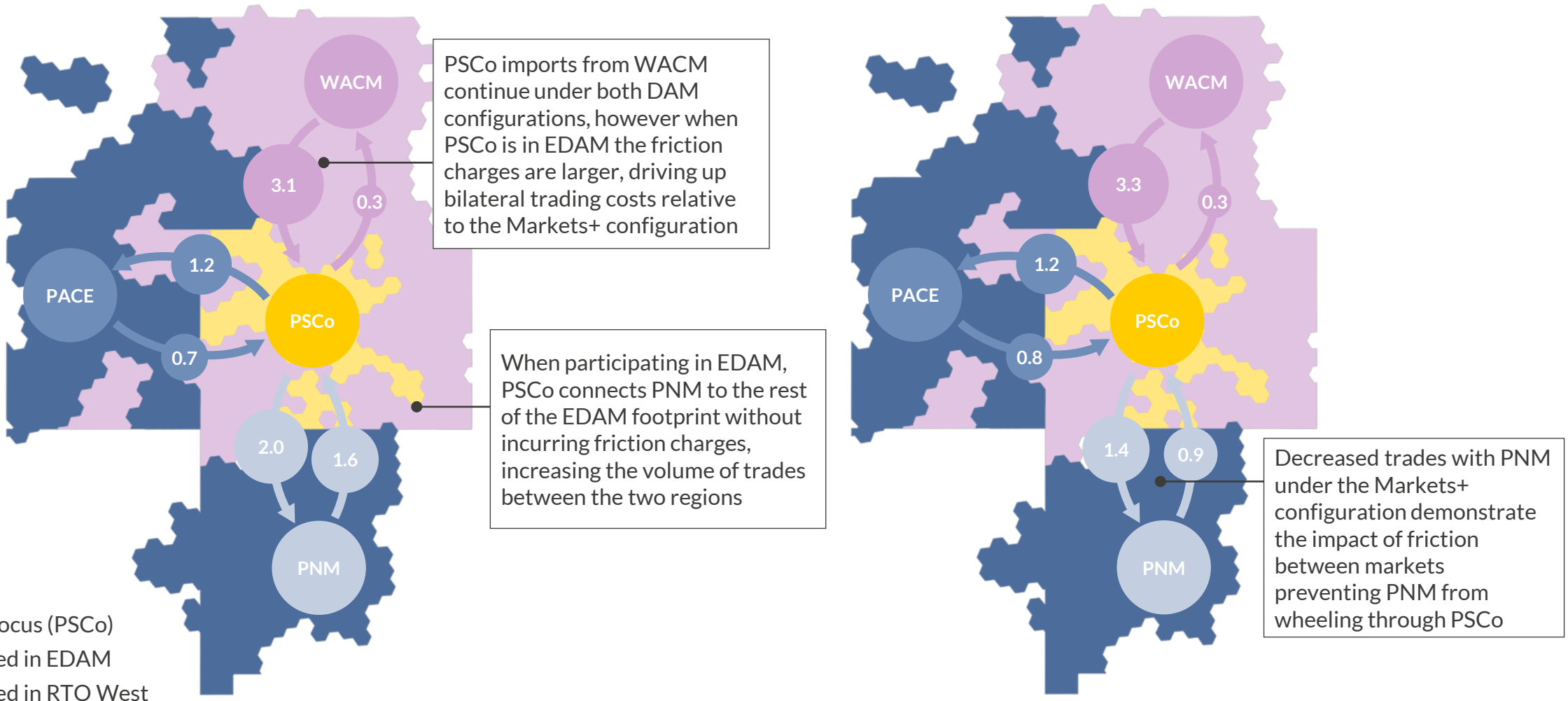
— PSCo in EDAM (LHS) — PSCo in Markets+ (LHS) — EDAM - Markets+ Delta (RHS)

1) Baseload prices in PSCo represent the price of generation, which is the cost LSEs pay for generation used to serve load 2) Delta is EDAM - Markets+

B PSCo in EDAM incurs higher bilateral trading costs due to costlier imports from WACM and increased import volumes relative to Markets+

EDAM scenario - Average PSCo imports and exports in 2028-2060 TWh

Markets+ scenario - Average PSCo imports and exports in 2028-2060 TWh



Even with lower interstate transmission build-out, PSCo sees a \$4.2million/year cost benefit to participation in EDAM

Interstate transmission projects studied to date by the Colorado Electric Transmission Authority (CETA) that have been identified as drivers of reduced congestion hours and congestion costs were modeled to quantify the cost impacts on PSCo under both Markets+ and EDAM. These projects include the Southeast Concept and the Northwest Concept, with the former increasing modeled transfer capability to PNM and the latter increasing modeled transfer capability to PACE.

Average cost breakdown for PSCo under EDAM vs Markets+ DAM, 2028-2060

\$Million/year, real 2024

No additional interstate Tx projects			
Metric	EDAM	Markets+	Delta ¹
Production cost	950.3	945.4	4.9
Bilateral trading costs	197.3	200.8	(3.6)
Congestion revenue ²	(42.5)	(43.4)	0.9
Wheeling Revenue ²	(22.4)	(16.0)	(6.4)
Costs less revenues	1082.6	1086.8	(4.2)

- Lower hurdle rates for trades with WACM when modeling PSCo in Markets+ provide access to imports at a lower cost, particularly of thermal generation
- The lower production costs for PSCo in Markets+ compared EDAM is partially mitigated by higher bilateral trading costs, reducing the benefits to Markets+ in these categories

Addition of CETA Southeast Concept			
Metric	EDAM	Markets+	Delta ¹
Production cost	903.1	908.5	(5.4)
Bilateral trading costs	221.0	215.8	5.3
Congestion revenue ²	(74.9)	(63.5)	(11.5)
Wheeling Revenue ²	(5.2)	(5.6)	0.4
Costs less revenues	1043.9	1055.1	(11.2)

- Additional transmission capacity to PNM incentivizes more trading activity between PSCo and PNM
- As PSCo is a net exporter to PNM, this increases export costs for the EDAM configuration more so relative to Markets+, resulting in comparatively higher increase in trading costs for EDAM

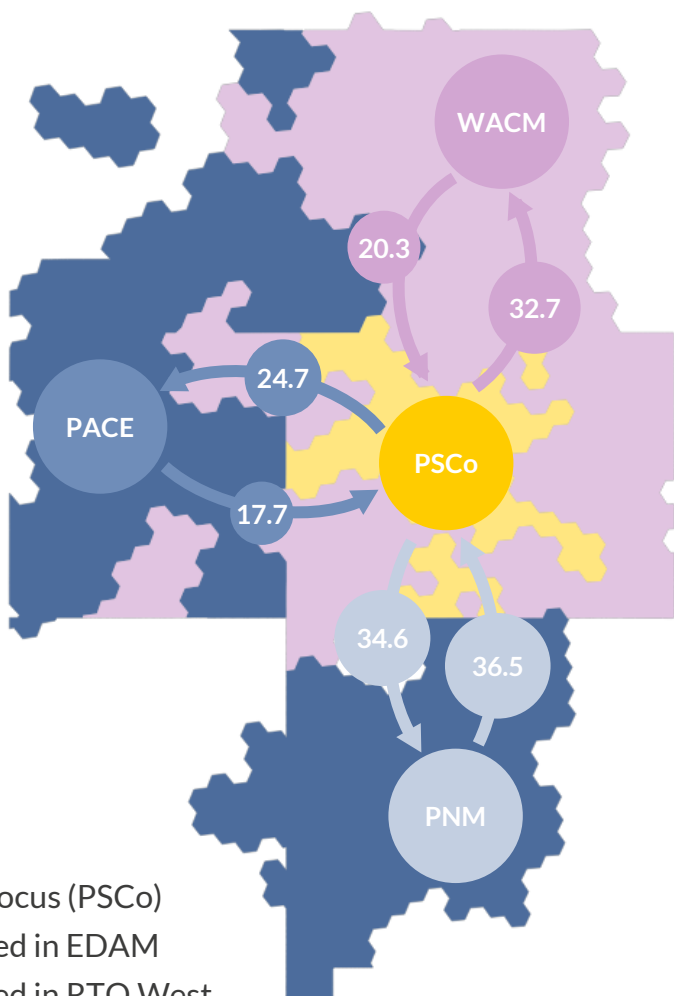
Addition of CETA Northwest Concept			
Metric	EDAM	Markets+	Delta ¹
Production cost	900.4	895.6	4.8
Bilateral trading costs	209.8	213.8	(3.9)
Congestion revenue ²	(57.2)	(56.2)	(1.0)
Wheeling Revenue ²	(21.5)	(14.4)	(7.1)
Costs less revenues	1031.6	1038.8	(7.2)

- When PSCo is modeled in EDAM, trading with PACE, which is also modeled in EDAM, is incentivized by the reduced hurdle rates within the same DAM footprint
- As a result, inter-BA line utilization to PACE increases, driving higher congestion revenues for PSCo in EDAM than in the Markets+ scenario

1) Delta calculated EDAM – Markets+. Negative values indicate a cost saving (benefit) for PSCo in EDAM. 2) Ownership assumed to be split 50-50 with connecting BA unless data on ownership is available

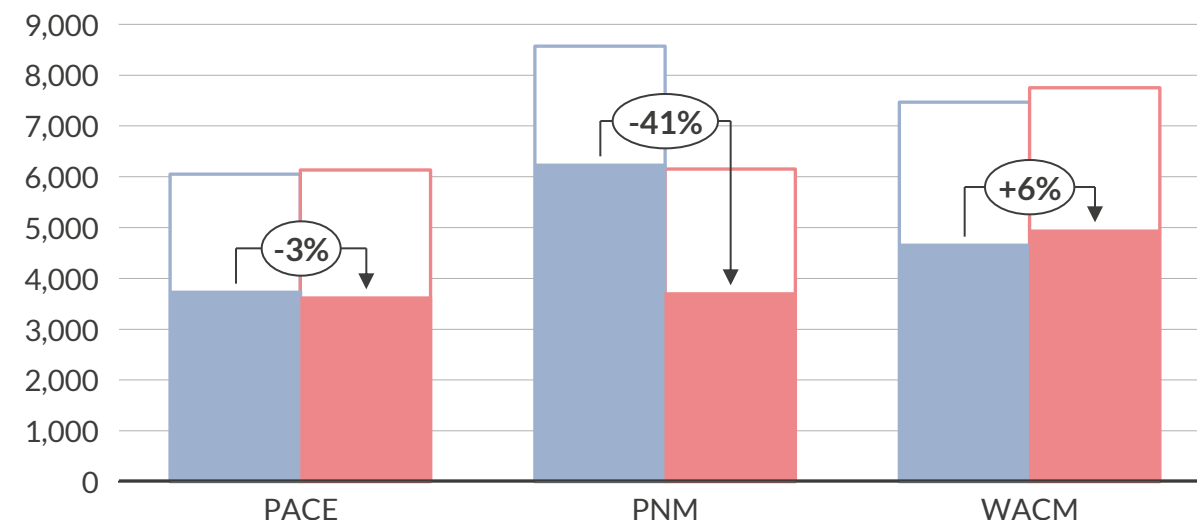
Utilization of transfer capacity to PNM significantly increases with PSCo in EDAM, driving up congestion and associated revenues

Average annual % congested hours with PSCo in EDAM scenario, 2028-2060
%



Key
 ■ BA of focus (PSCo)
 ■ Modeled in EDAM
 ■ Modeled in RTO West

Average annual inter-BA trading hours with PSCo, 2028-2060
Hours



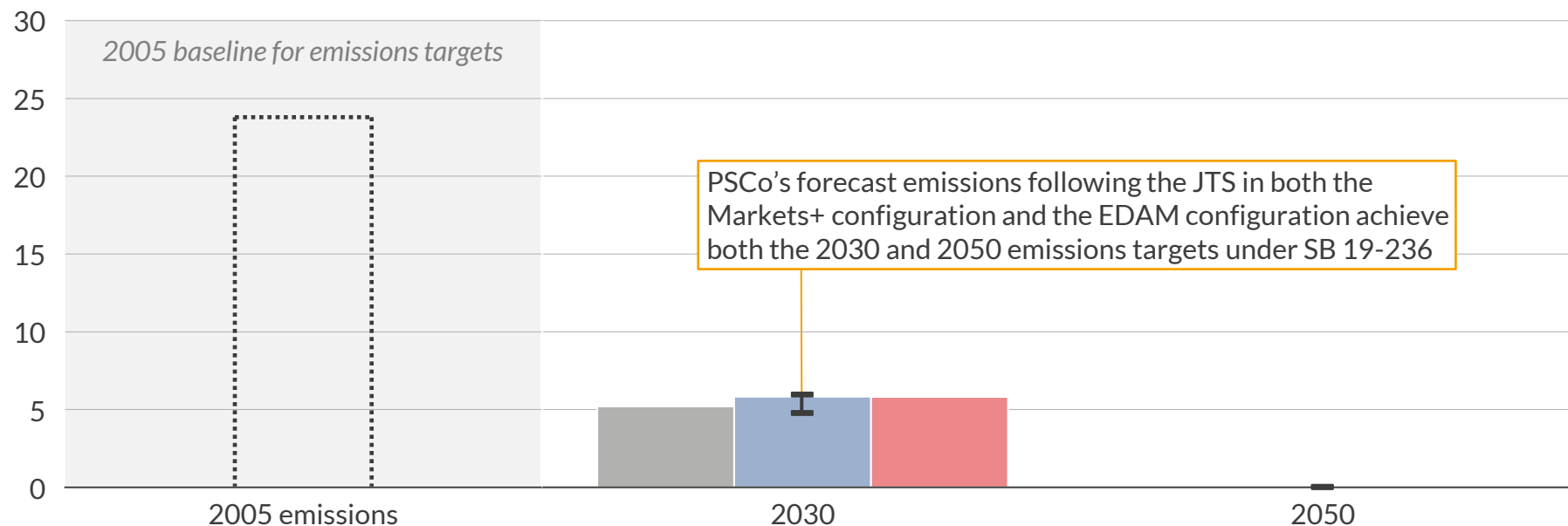
- When PSCo is in EDAM, interconnection capacity to and from PACE and PNM are more highly utilized and increase the frequency of congestion revenue relative to the Markets+ scenario¹
- Similarly, when PSCo is in Markets+, utilization of interconnection to WACM and associated congestion frequency increases as well. The delta between scenarios is less significant in this case however given PSCo consistently trades large volumes with WACM in both DAM configurations
- In trading hours without congestion, PSCo trades with BAs outside of the same DA footprint are subject to wheeling revenues and costs. When PSCo is in EDAM, these trading periods with PACE and PNM see no additional cost or revenue

■ EDAM scenario ■ Hours with congestion
 ■ Markets+ scenario ■ Hours without congestion

1) Ownership of transmission assumed to be split 50-50 with connecting BA unless data on ownership is available

Under both Day-Ahead markets, PSCo is compliant with SB 19-236 emissions targets in 2030 and 2050

Xcel (PSCo) CO₂ emissions forecast¹
 Million MTCO₂e



PSCo's forecast emissions following the JTS in both the Markets+ configuration and the EDAM configuration achieve both the 2030 and 2050 emissions targets under SB 19-236

Colorado SB 19-236 Targets

2005 Baseline

Colorado utilities are required to cut their emissions relative to their 2005 levels

2030

By 2030, **each utility must cut its emissions from Colorado retail sales by 80% from its 2005 levels.** Its plan to do so is compliant if it is found to achieve at least a 75% reduction in emissions by 2030 by the Air Pollution Control Division

2050

Utilities are required to target 100% of sales coming from clean energy by 2050

 2005 baseline emissions
 JTS forecast
 PSCo in EDAM
 PSCo in Markets+
 Emissions compliance range²

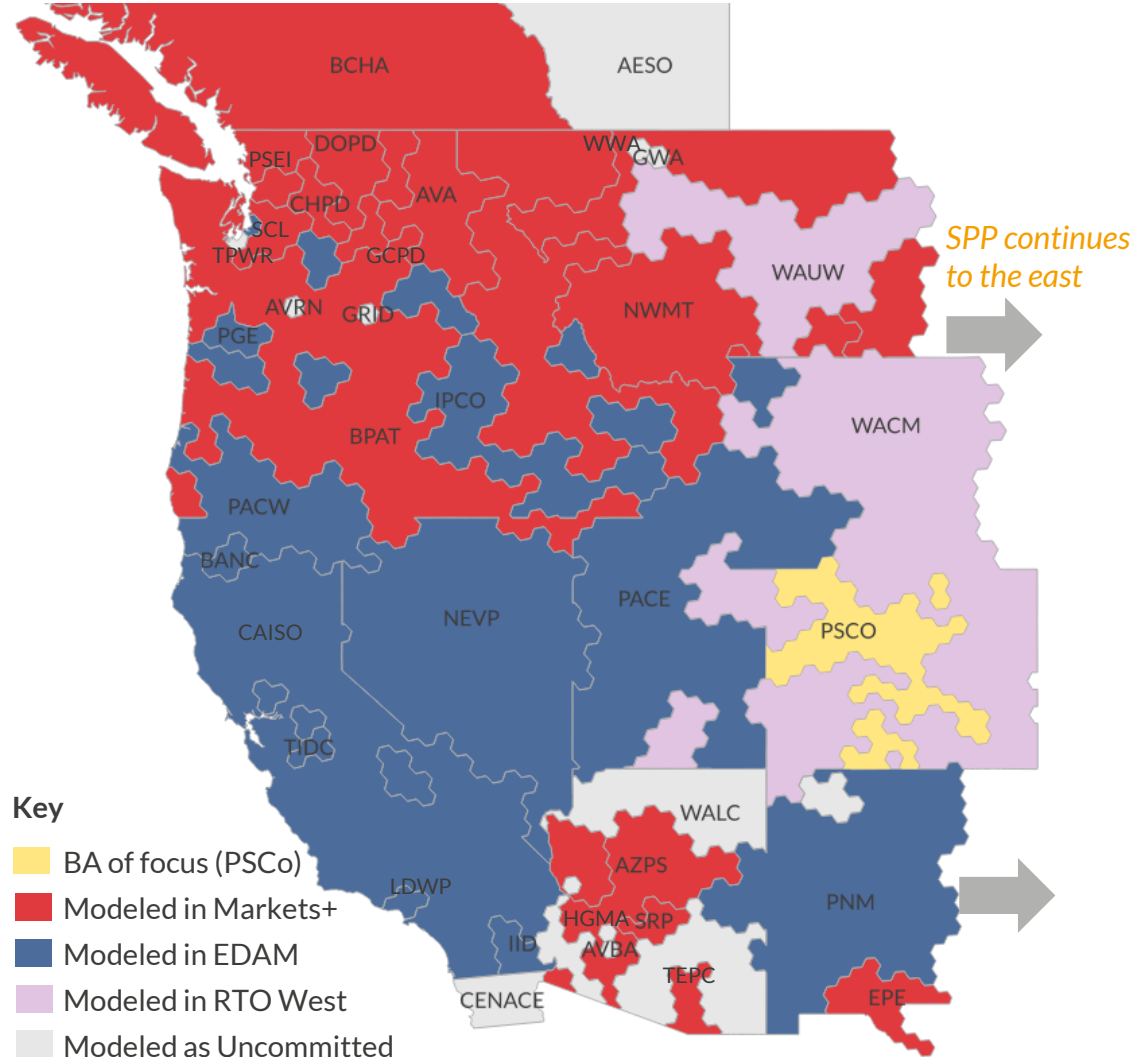
1) Results shown here are the emissions for Xcel (PSCo) utility as the largest LSE within the BA territory. SB 19-236 targets only apply to electricity providers serving at least 500,000 customers in Colorado; Xcel (PSCo), Black Hills, and Tri-State are qualifying utilities 2) Using 2005 emissions level as a baseline, which was 23.8MMTCO₂e

Sources: Aurora Energy Research, Xcel (PSCo), Colorado Air Pollution Control Division

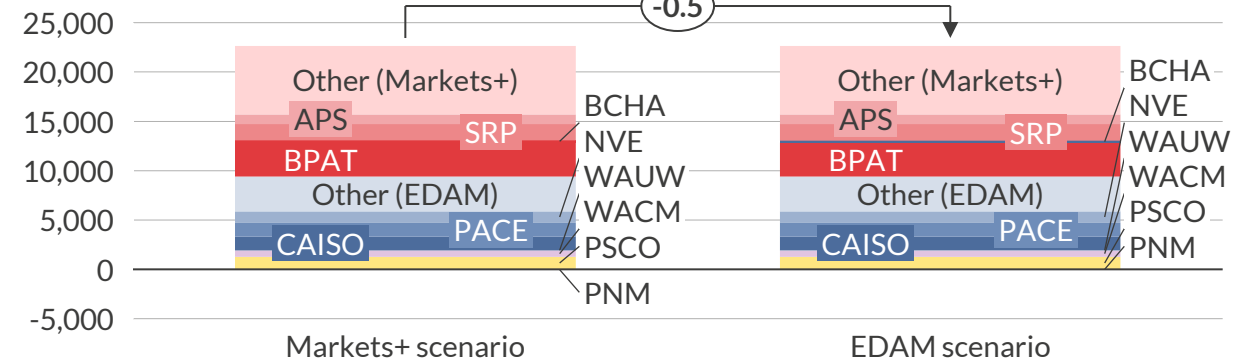
- The CPUC accepted Xcel (PSCo)'s 2021 Clean Energy Plan. The 2024 JTS sees accelerated procurement to meet the same emissions reduction requirements while serving new load demands
- Retirements of ~1.8GW conventional coal and gas resources, with renewables and storage replacements, enables PSCo to reach 2030 targets
- Emissions are similar between the two modeled scenarios for PSCo participation in EDAM and Markets+ given the capacity mix was held constant. Marginal differences in emissions are driven by variation in carbon intensity of imports and exports

WECC-wide production cost and emission impacts are similar across scenarios, with benefits in EDAM due to a more connected footprint

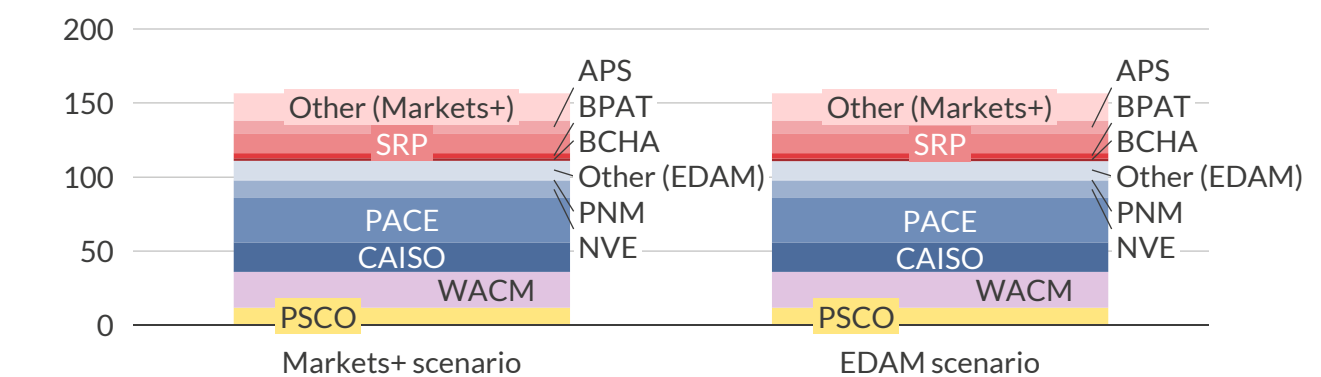
Map of modeled balancing authority (BA) market decisions



Total WECC-wide production costs in 2035¹
\$Million, real 2024



Total WECC-wide emissions, 2035
Million Mt CO₂



- With PSCo in EDAM, both it and PNM benefit from increased interconnection to the EDAM footprint, resulting in \$0.5 million lower production costs in 2035
- With the same capacity mix throughout the west, PSCo participation in either DAM results in similar dispatch of resources and similar resulting emissions

1) The "Other (Markets+)" category includes AVA, CHPD, GCPD, DOPD, NWMT, TPWR, PSEI, TEPC, and EPE. The "Other (EDAM)" category includes PACW, PGE, BANC, TIDC, LDWP, SCL, and IPCO

I. Executive summary

II. Scenario design methodology

III. Base Case results

1. Cost savings
2. Emissions
3. WECC-wide impact

IV. Sensitivities results

V. Appendix: Overview of modeling approach

Compared to the Base Case, the sensitivities assume varying emissions targets, capacity mix, and transfer capability

Changes in scenario design across Sensitivities¹

	Base Case	Sensitivity 1: Low Emissions	Sensitivity 2: High Transmission
Technology	Renewables	Consistent with the 2024 JTS plan, which adds +40GW in renewables.	Additional 19GW renewables capacity, including utility-scale solar, 4h and 8h storage, and onshore wind, are added by 2040 to accommodate thermal retirements.
	Thermal	Consistent with 2024 JTS plan – thermal exits modeled as outlined.	PSCo utility-level thermals exit by 2040, with 3GW emissions-free thermal generation ² added by 2040.
Policy	Pollution standards	Xcel (PSCo) meets SB 19-236 emissions reductions targets applicable to LSEs serving at least 500,000 customers by 2050.	PSCo utility targets 95% reduction in emissions from 2005 levels by 2035 and 100% reduction by 2040, which is a 10-year acceleration from the Base Case.
Trade	Inter BA trade capacity	Assumes Colorado Power Pathway Segments 1-5 and the May Valley – Longhorn extension. Partial transfer capacity from the CETA Northwest Concept attributed to PSCo-PACE interconnection. Full transfer capacity assumed from the CETA Southeast Concept between PSCo and PNM.	In addition to all Base Case trade capacities, by 2040 500MW of transfer capacity is enabled for PSCo-PACE representing a gradual ramp to the full transfer capacity from CETA Northwest Concept, and 294MW additional capacity between PSCo and WACM by 2040 reflecting implementation of CETA Northern Concept.

1) All other input assumptions not listed in the table are fixed across all scenario configurations to be same as Base Case. 2) Emissions-free thermal generation are assumed to be gas resources with carbon capture and storage (CCS)

PSCo sees cost reductions with participation in EDAM compared to Markets+ in all scenarios, ranging from \$7.5 to 18.3 million/year

Average cost breakdown for PSCo under EDAM vs Markets+ DAM, 2028-2060
 \$Million/year, real 2024

Metric	Base Case			Low Emissions			High Transmission		
	EDAM	Markets+	Delta ¹	EDAM	Markets+	Delta ¹	EDAM	Markets+	Delta ¹
Production cost	857.4	862.3	(4.9)	601.1	596.3	4.8	780.4	784.5	(4.1)
Bilateral trading costs	231.9	227.0	4.9	(48.0)	(42.4)	(5.6)	278.8	275.0	3.8
Congestion revenue ²	(85.8)	(72.9)	(12.8)	(117.1)	(99.3)	(17.8)	(89.9)	(81.7)	(8.1)
Wheeling revenue ²	(5.5)	(5.1)	(0.4)	1.0	0.8	0.2	(7.4)	(8.4)	1.0
Costs less revenues	998.0	1,011.2	(13.2)	437.0	455.3	(18.3)	961.9	969.4	(7.5)
Comparison to Base Case				↑ (5.1)			↓ 5.7		

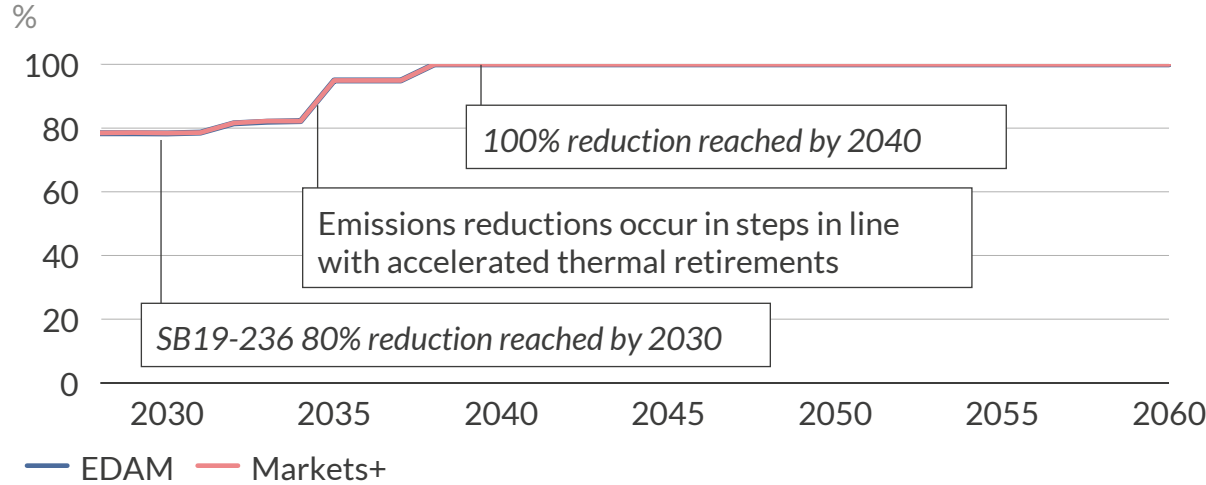
↑ Additional benefits to PSCo in EDAM compared to Base Case ↓ Reduced benefits to PSCo in EDAM compared to Base Case

1) EDAM – Markets+. A negative delta indicates lower costs when PSCo is modeled in EDAM compared to Markets+, demonstrating benefits to joining EDAM

- PSCo sees lower costs in EDAM in scenarios, with \$5.1m/year additional benefits in the Low Emissions scenario and \$5.7m/year reduced benefits in the High Transmission scenario compared to Base Case
- **Low Emissions:** With increased renewable buildout, greater access to a larger DAM footprint under EDAM allows PSCo to export excess renewable generation more efficiently. As such, revenues from bilateral trading and congestion increase with higher trade volumes and line utilization
- **High Transmission:** Increased transmission capacity to WACM creates more value for the Markets+ scenario due to lower friction charges, reducing the congestion and wheeling benefit for PSCo in EDAM by \$5.3m/year

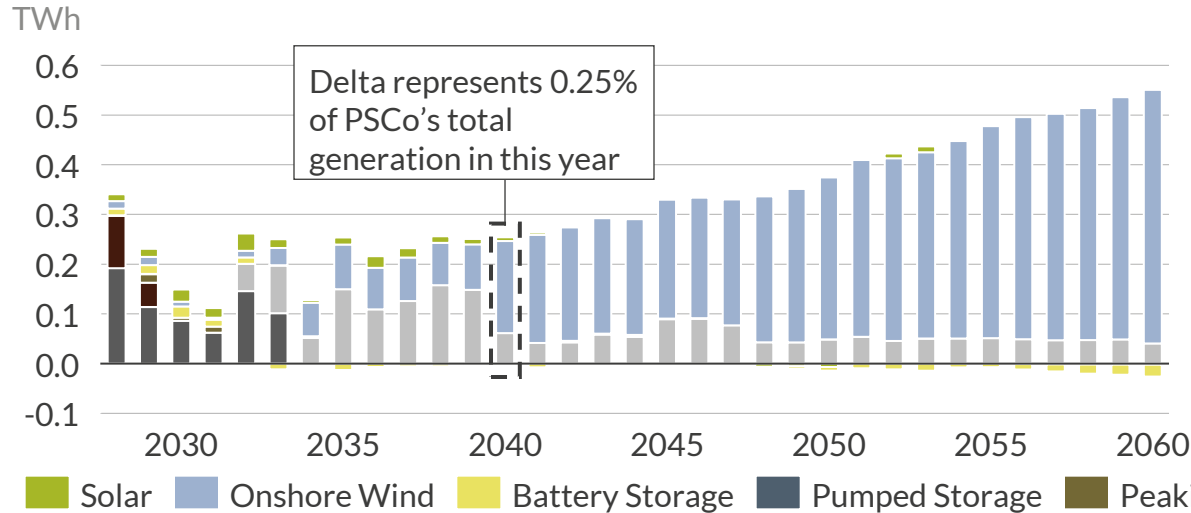
Low Emissions: Increased renewable generation necessary to reduce emissions drives up cost benefits to PSCo through exports

Percent emissions reduction from to 2005, PSCo utility level



- Under both EDAM and Markets+ configurations, the PSCo utility area achieves an emissions-free power sector by 2038, representing an accelerated progression towards meeting the SB19-236 goal of 100% reduction in emissions from 2005 levels by 2050¹
- The 95% reduction in emissions by 2035 and 100% by 2040 targets are achieved by implementing a more rapid renewables buildout and thermal retirement scheme than outlined in the JTS IRP, which targets achieving the SB19-236 emissions goal by 2050, 10 years later than when the Low Emissions target is set

PSCo BA generation delta, EDAM - Markets+ scenario



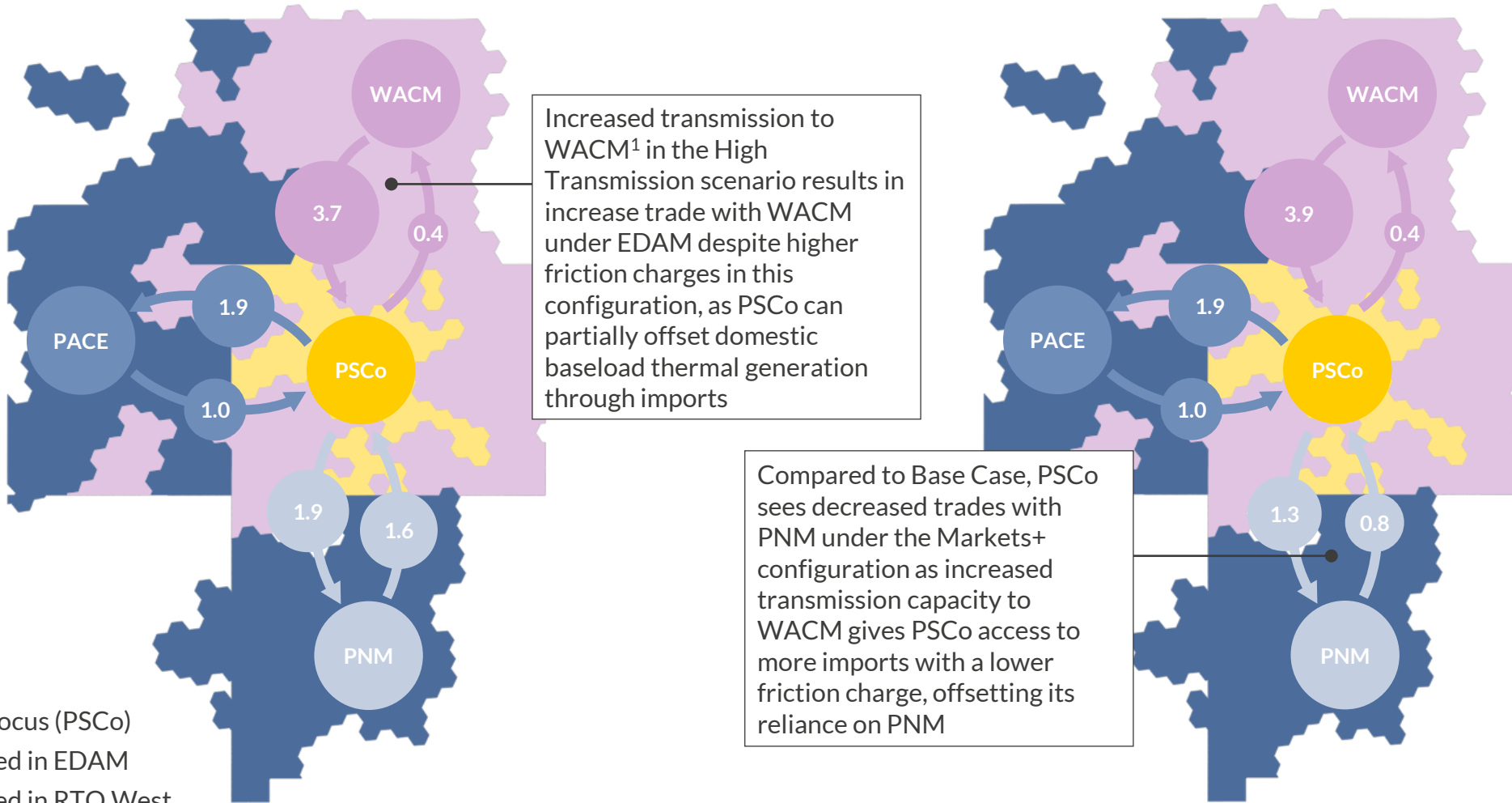
- Increased renewables buildout to accommodate thermal retirements in the Low Emissions scenario converts PSCo into a net exporter, increasing bilateral trading revenues and increasing benefits to PSCo in EDAM given greater access to a DAM footprint to share resources
- Lower friction charges for trading in the EDAM configuration further enables PSCo to more effectively export its surplus renewables generation, particularly of onshore wind towards PNM. This results in a \$5.5m/year revenue benefit to PSCo in the EDAM configuration from bilateral trading and \$17.8m/year in congestion revenues

1) In the Low Emission scenario design, all PSCo utility-level thermal generators are retired by 2040. However, by 2038, the system is able to rely entirely on its emissions-free generation fleet and imports to meet baseload and peaking demand, rendering the remaining thermal generators unused.

High Transmission: In both DAMs, majority of PSCo imports are from WACM, reducing EDAM benefits when transfer capacity is increased

EDAM scenario - Average PSCo imports and exports in 2028-2060 TWh

Markets+ scenario - Average PSCo imports and exports in 2028-2060 TWh



Increased transmission to WACM¹ in the High Transmission scenario results in increase trade with WACM under EDAM despite higher friction charges in this configuration, as PSCo can partially offset domestic baseload thermal generation through imports

Compared to Base Case, PSCo sees decreased trades with PNM under the Markets+ configuration as increased transmission capacity to WACM gives PSCo access to more imports with a lower friction charge, offsetting its reliance on PNM

- Key**
- BA of focus (PSCo)
 - Modeled in EDAM
 - Modeled in RTO West

1) In the High Transmission scenario, 646MW additional transfer capacity is added from WACM into PACE and 146MW additional capacity from PACE into WACM to reflect the CETA Northern Concept. Additionally, the full 650MW transfer capability of the CETA Northwest Concept is enabled for bidirectional trading between PSCo and PACE by the end of the forecast. Both Concepts are enabled in 5-year step increments to reflect constraints to implementing line upgrades and build infrastructure.

Agenda

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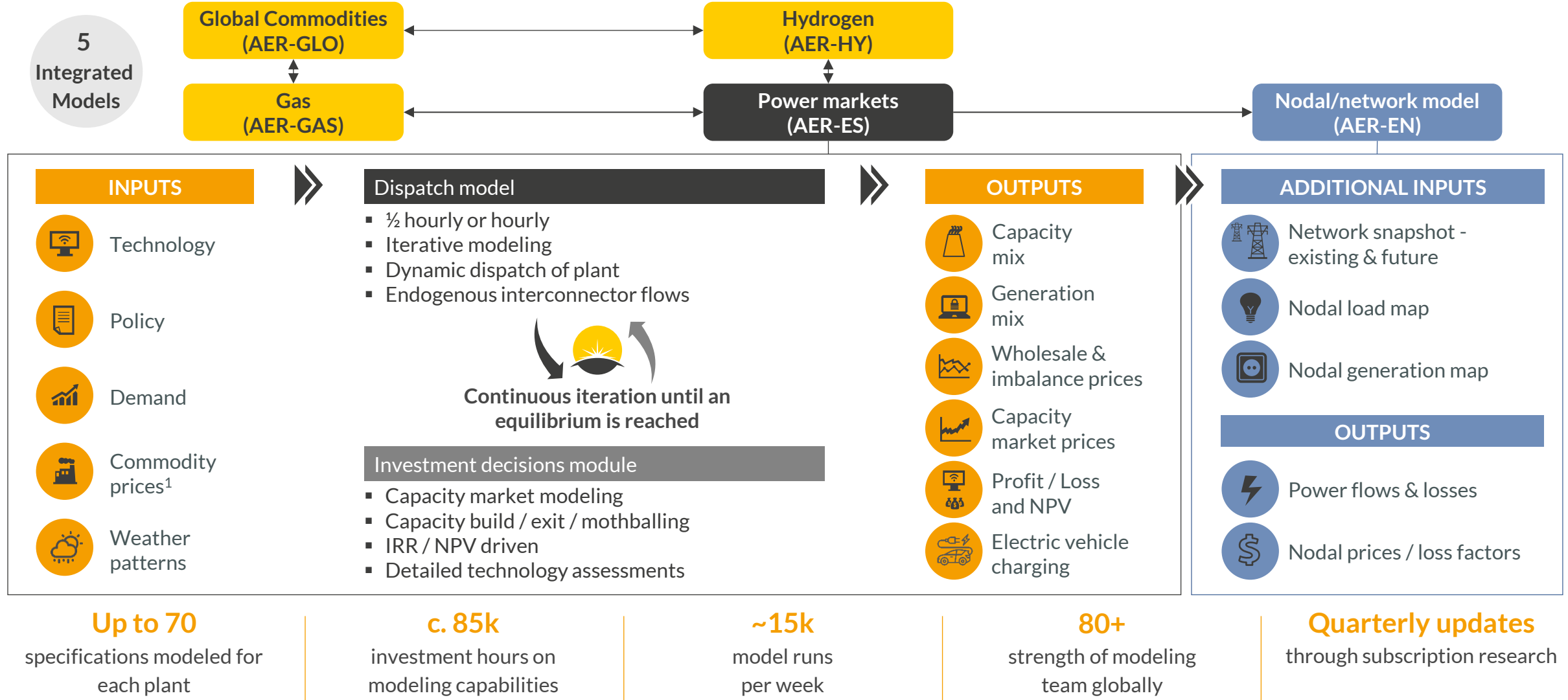
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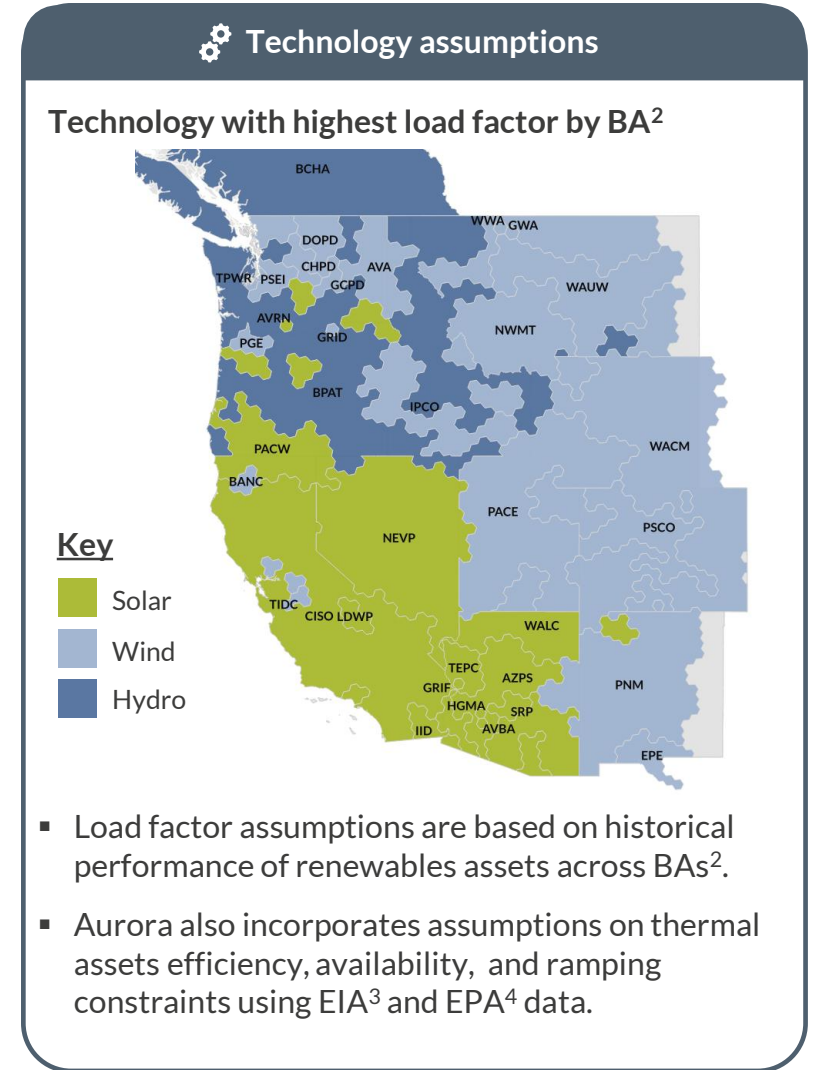
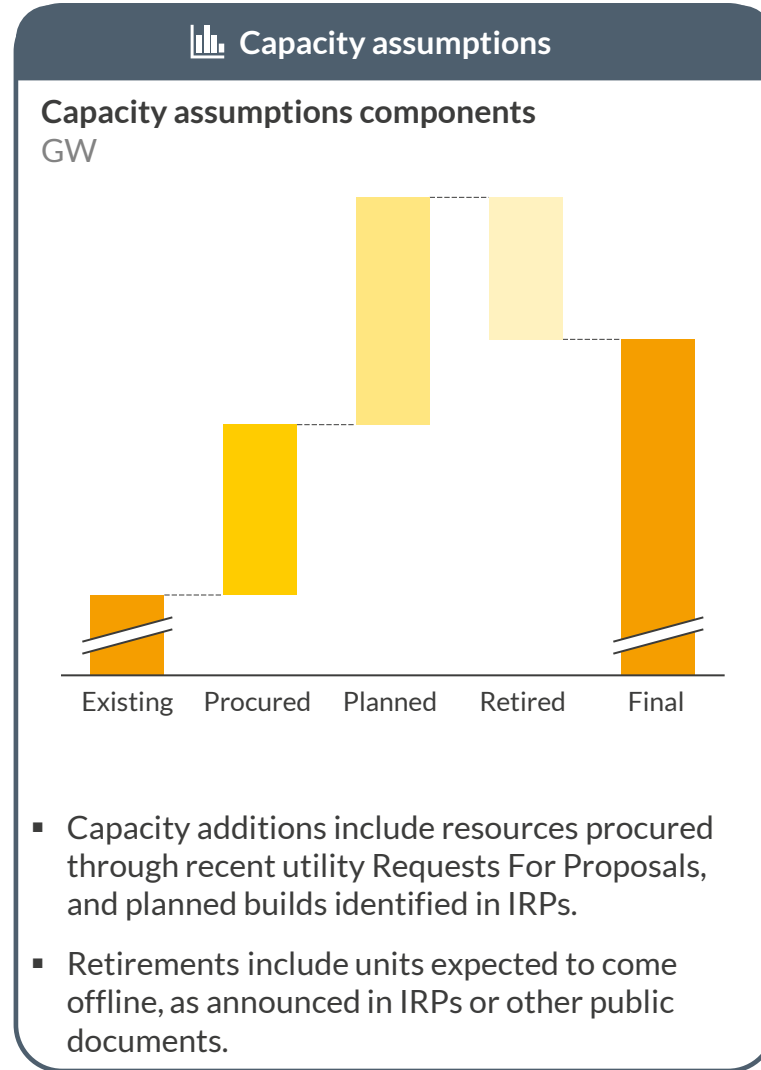
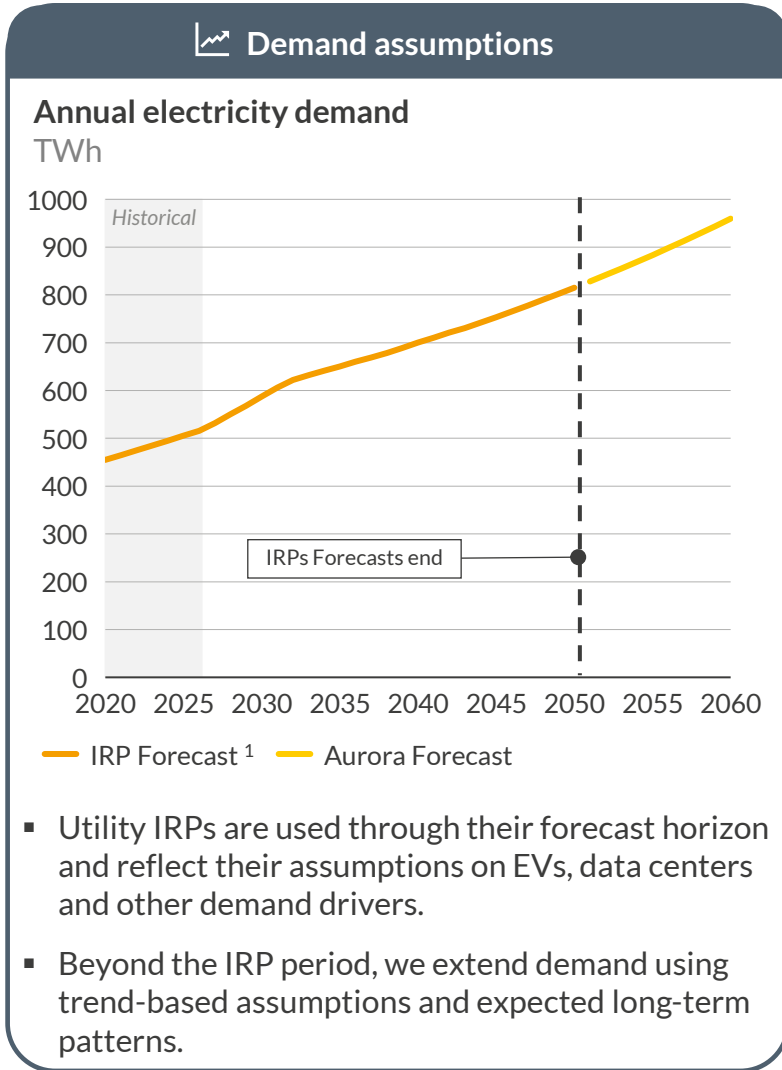
V. Appendix: Overview of modeling approach

Unique, proprietary, and integrated in-house modeling capabilities underpin Aurora's superior analysis



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

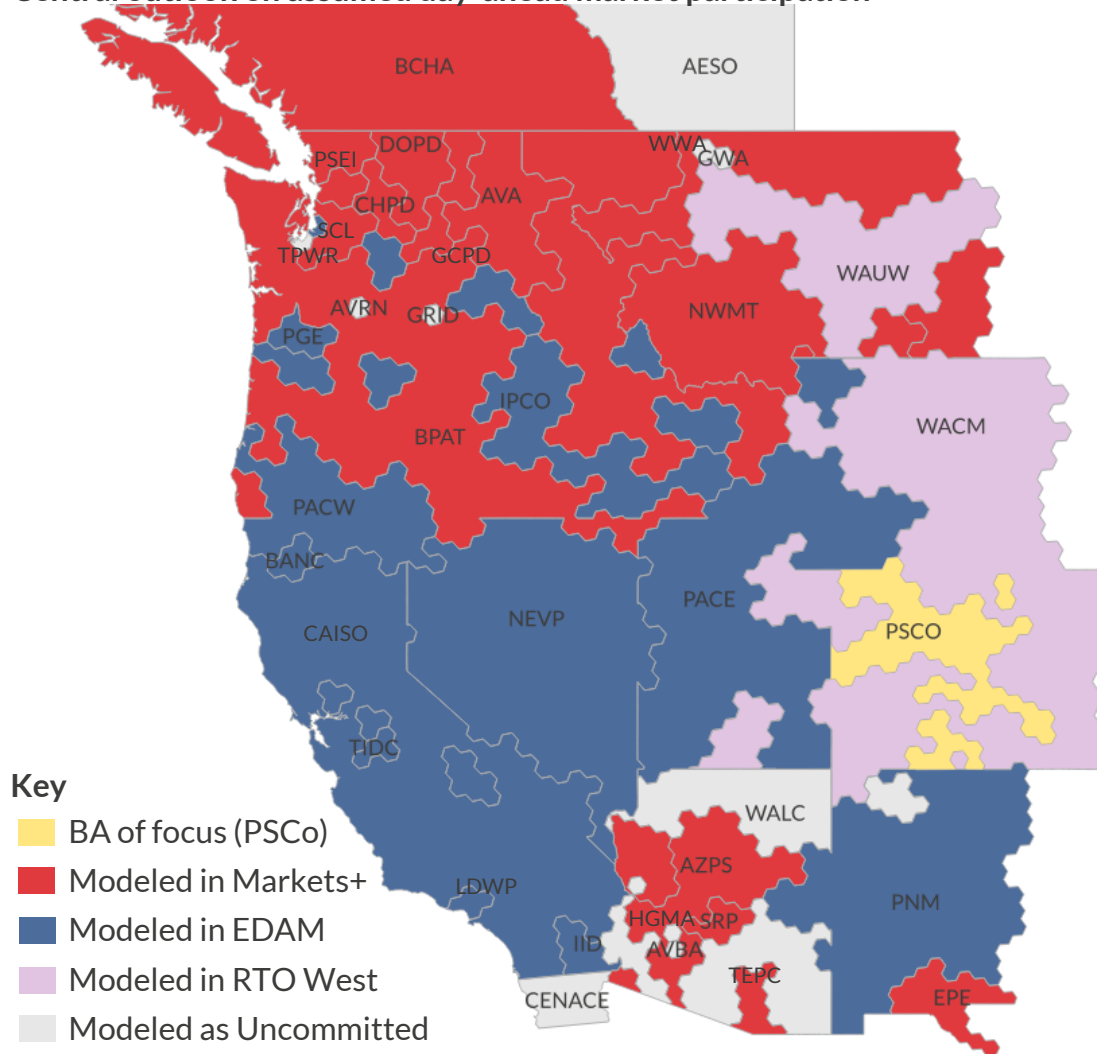
Demand, capacity, and technology assumptions reflect utility integrated resource plans and Aurora's long-term outlook



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

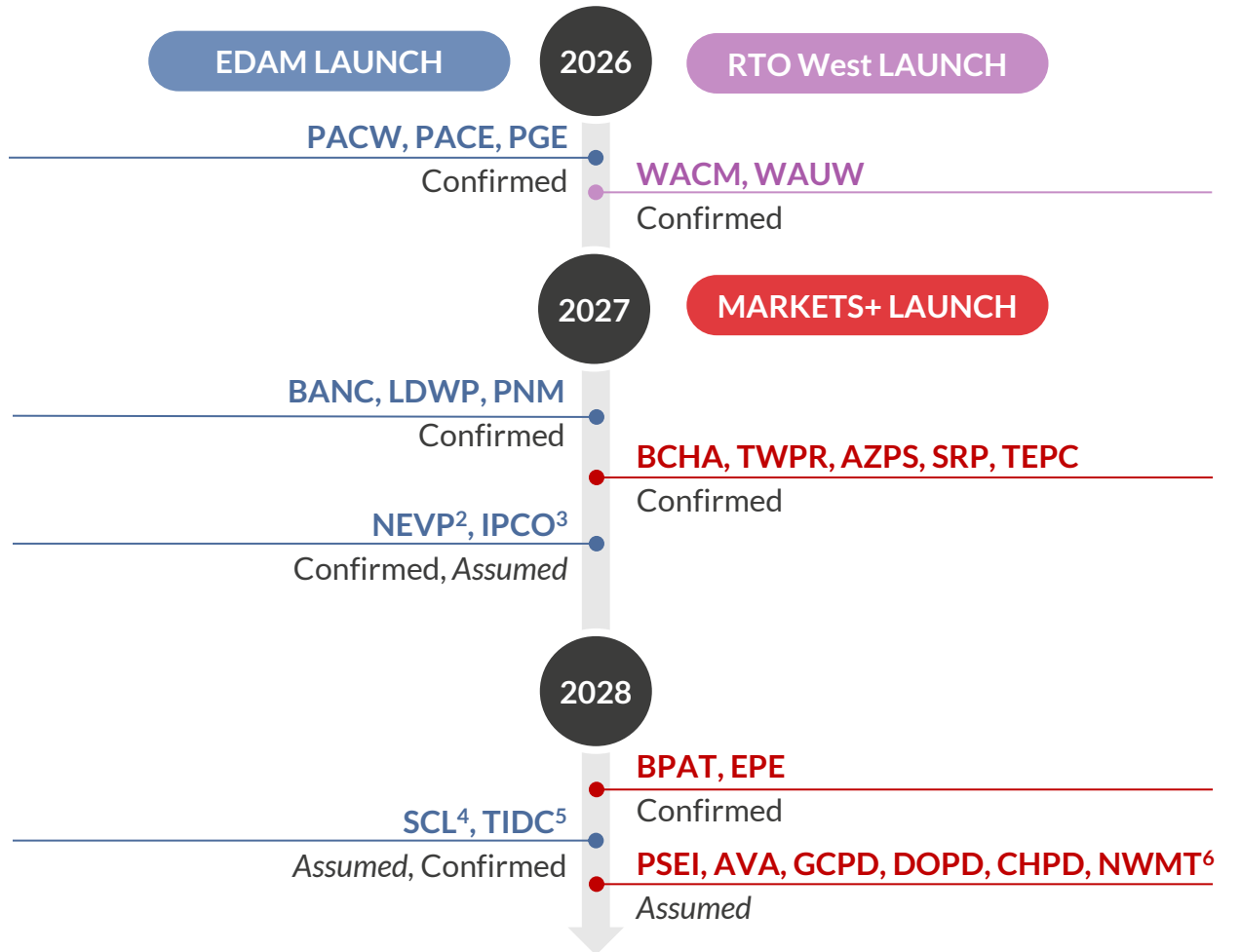
Aurora anticipates that balancing authority commitments to different day-ahead markets will partition the Western Interconnection

Central outlook on assumed day-ahead market participation¹



- Key**
- BA of focus (PSCo)
 - Modeled in Markets+
 - Modeled in EDAM
 - Modeled in RTO West
 - Modeled as Uncommitted

Timeline of assumed day-ahead market participation¹



1) As of May 1, 2025. 2) Nevada Energy is a confirmed participant assumed to begin participation in 2027. 3) Idaho Power is a likely participant assumed to begin participation in 2027. 4) Seattle City Light has expressed interest in EDAM and is modeled as participating starting 2028. 5) Turlock Irrigation District confirmed its 2027 participation in EDAM after the conclusion of Aurora's signing in May 2025. 6) Some Pacific Northwest utilities indicated they would follow Bonneville Power's market decision.

Sources: Aurora Energy Research, WECC, PacifiCorp, PNM, Xcel, APS, PGE, PSE, NVE, SRP, IPCO, AVA, TEP, CAISO, SPP, EIA

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