New Mexico Day-Ahead Market Participation Benefits Studies

COMPARATIVE BENEFITS FOR EPE AND PNM OF JOINING EDAM OR MARKETS+

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Scope of Studies

Scope: to simulate the <u>specific</u> EDAM/M+ designs for realistic market footprints, not a simplified representation of a wholesale market across the entire WECC

- **Calculate multiple benefit metrics:** (1) Adjusted Production Cost (APC), (2) impact on short-term wheeling revenue, (3) change in bilateral trading profits, and (4) EDAM/M+ congestion and transfer revenues
- **Model the EDAM and/or M+ GHG structure:** as specified in the design or contemplated design
  - EDAM: simulated the “GHG Reference Pass” to set limits on transfers into the GHG region (CA and WA).
  - M+: simulated “Resource Owner, Merit Order w/ Enhanced Floating Surplus” approach to setting transfer limits into GHG regions
  - Modeled resource-type-specific GHG costs
- **Simulate existing & prospective real-time markets:** WEIM in parallel with the EDAM, formation of a day-ahead and real-time market with M+, nodal representation of the entire WECC
  - Estimated the impact on existing WEIM and new EDAM or Markets+ trades and congestion revenues
- **Capture value of coupled day-ahead and real-time markets to manage unexpected imbalance:** modeled renewable and load forecast uncertainty between DA and RT
- **Realistically represent bilateral markets:** captured existing contract-path transmission rights, major trading hubs, block trading, CAISO/SPP West intertie trades, hourly BA-to-BA trades, and wheeling charges where applicable

Key Model Features

We conducted all study simulations using a **nodal production cost model of the WECC** with added market functionality, such as contract-path transmission.

- Model developed in PSO/Enelytix, which contains state-of-the-art features
  - Simultaneously optimizes contract path and physical constraints
  - Models bilateral, day-ahead, and real-time markets sequentially through multiple solution cycles
  - Co-optimizes storage resources with other resources in unit-commitment and dispatch
  - Detailed ancillary service and operating reserve modeling and co-optimization of ancillary services with energy
- **The study year is 2032**, which aims to reflect the first decade of markets operations, representing an intermediate year that captures known changes in resource mix and transmission infrastructure
- **Model includes two extreme weather events** based on a historic cold snap and a historic heat wave
  - These events are modeled as single weeks in which we increase modeled loads (peak and energy) and gas prices beyond the typical weather-normalized values to reflect the increased strain on the system and the ramifications of markets for addressing such strain.
  - Capturing non-weather-normal impacts is becoming increasingly important due to the increasing frequency of severe weather events
- **Modeled hydro represents average hydro year in the WECC,** using data from 2009 for hydro generation
- **Study base cases include footprints for EDAM and Markets+, in addition to existing WEIM and WEIS markets**, meaning all noted cost and benefit metrics include the impact of changes in real-time market participation, but exclude the impacts on entity WEIM and WEIS market benefits of the *formation* of the EDAM and Markets+ markets and the separation of WEIM.

See Appendix for additional model and assumptions detail, including detail related to EDAM and M+ design modeling

Multi-Functional Simulation of WECC

Markets/RTO Functions & Configurations

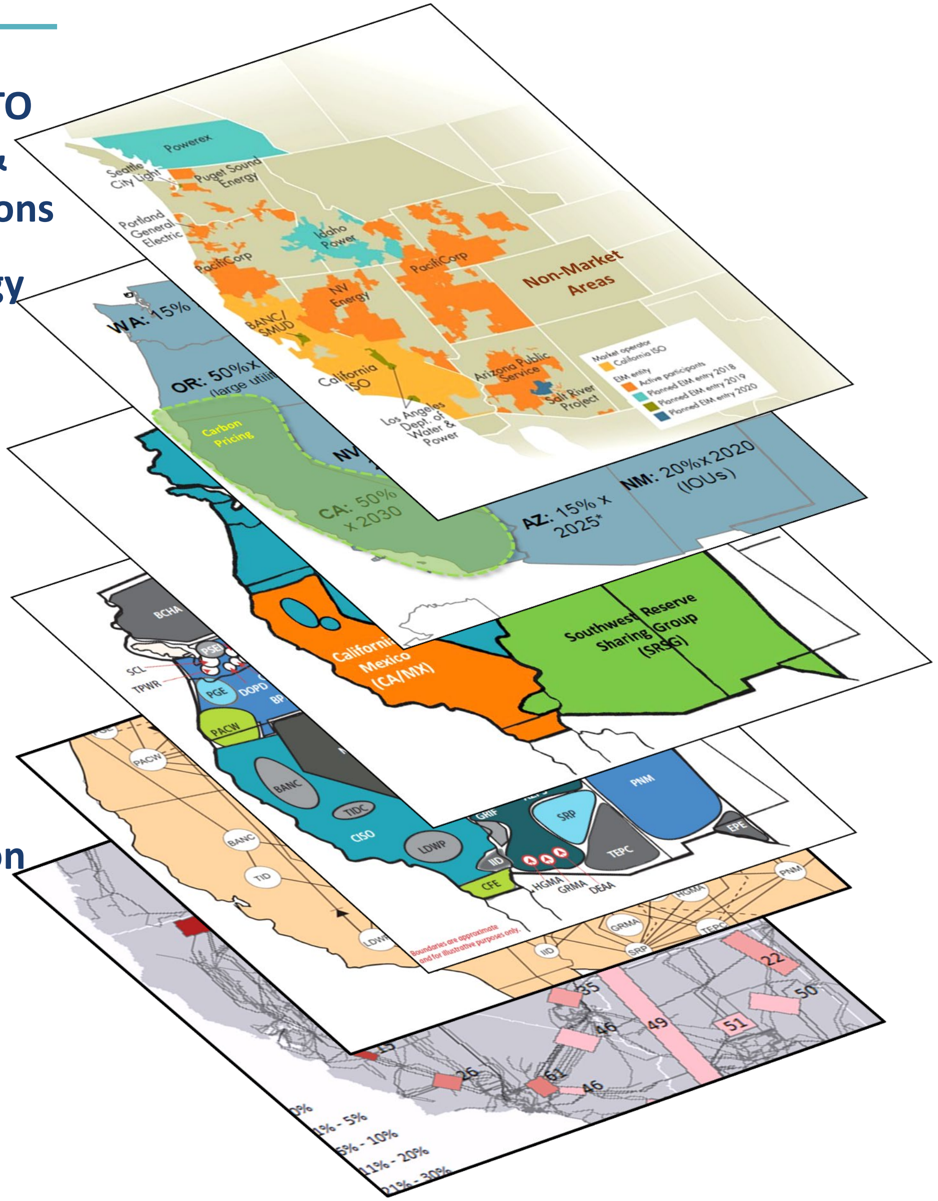
Clean Energy Policies

Reserve Sharing

BAA Functions

Bilateral Contract Paths and Transmission Rights

Physical Flows and Constraints

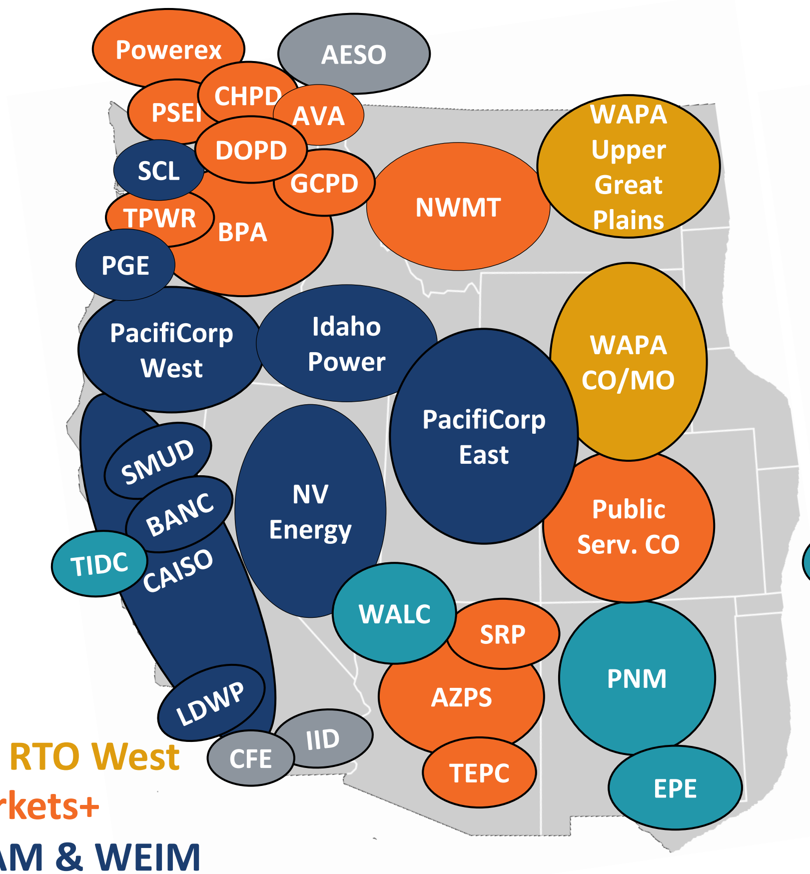


We employ a multi-layer simulations to represent the various physical, policy, and operational facets of the WECC

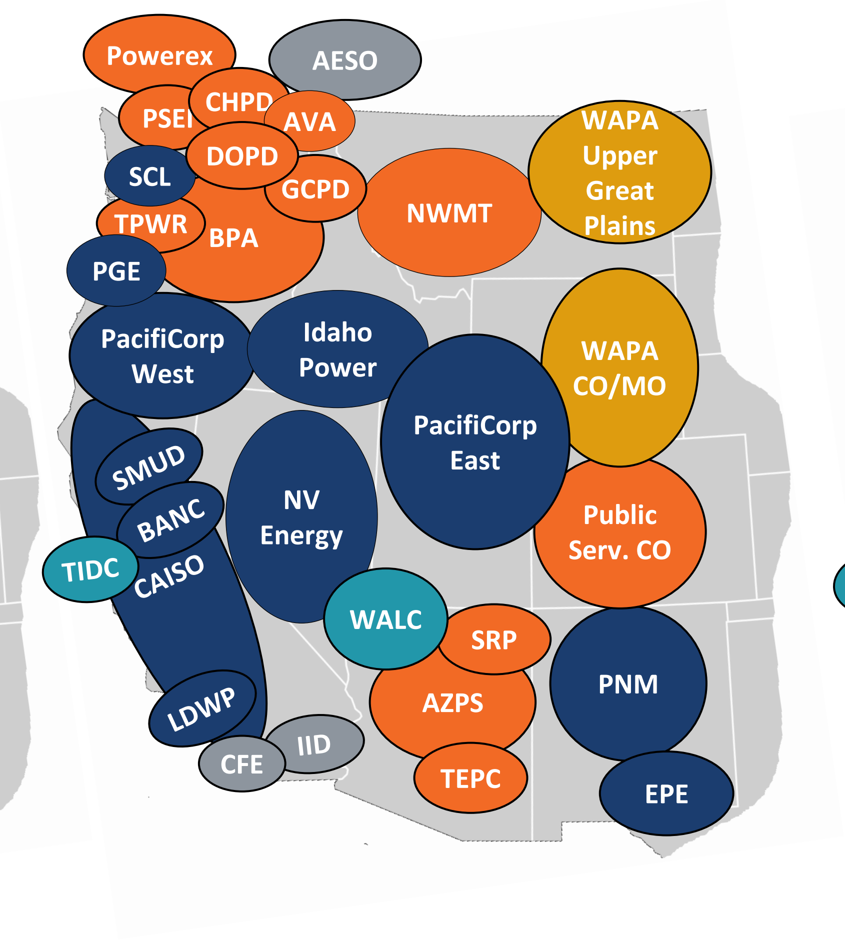
- Physical grid with ~20k buses, ~25k lines and ~5k generators represented as DC power flow
- 38 Balancing Authority Areas (BAAs) and contract paths
- The WECC reserve sharing groups
- Diverse state clean energy policies
- Major trading hubs (e.g., Mid-C, Malin, PV, FC)
- Bilateral transmission rights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

EDAM and Markets+ Footprint Analyzed

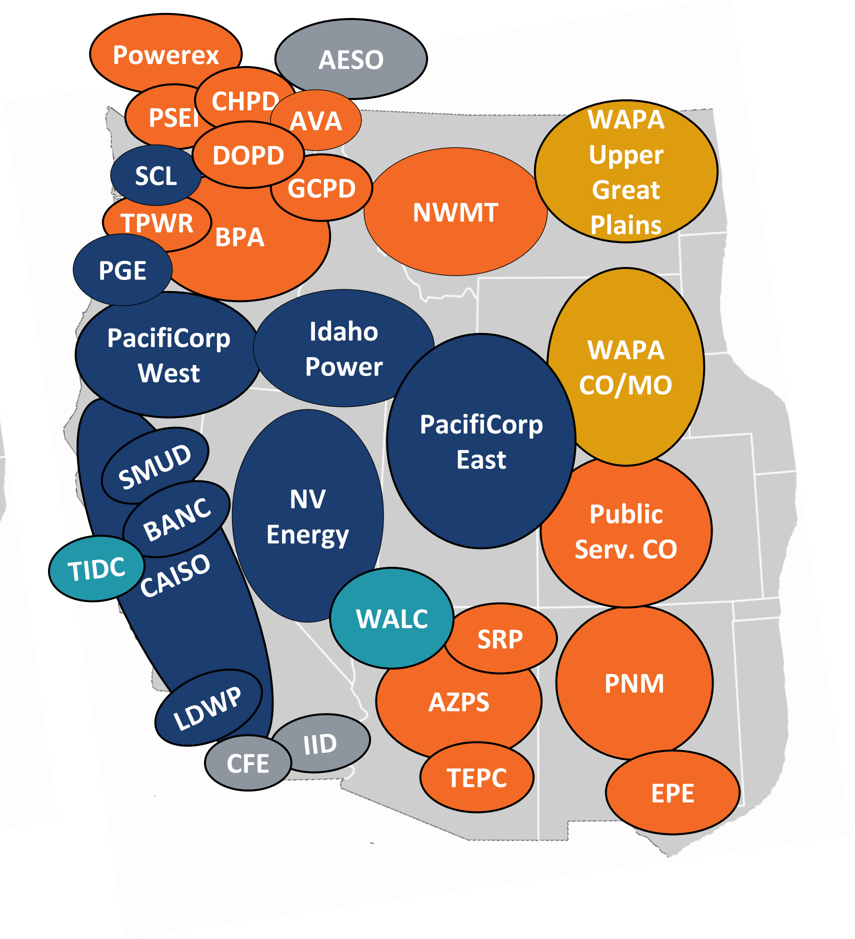
Current Trends



EDAM



Markets+

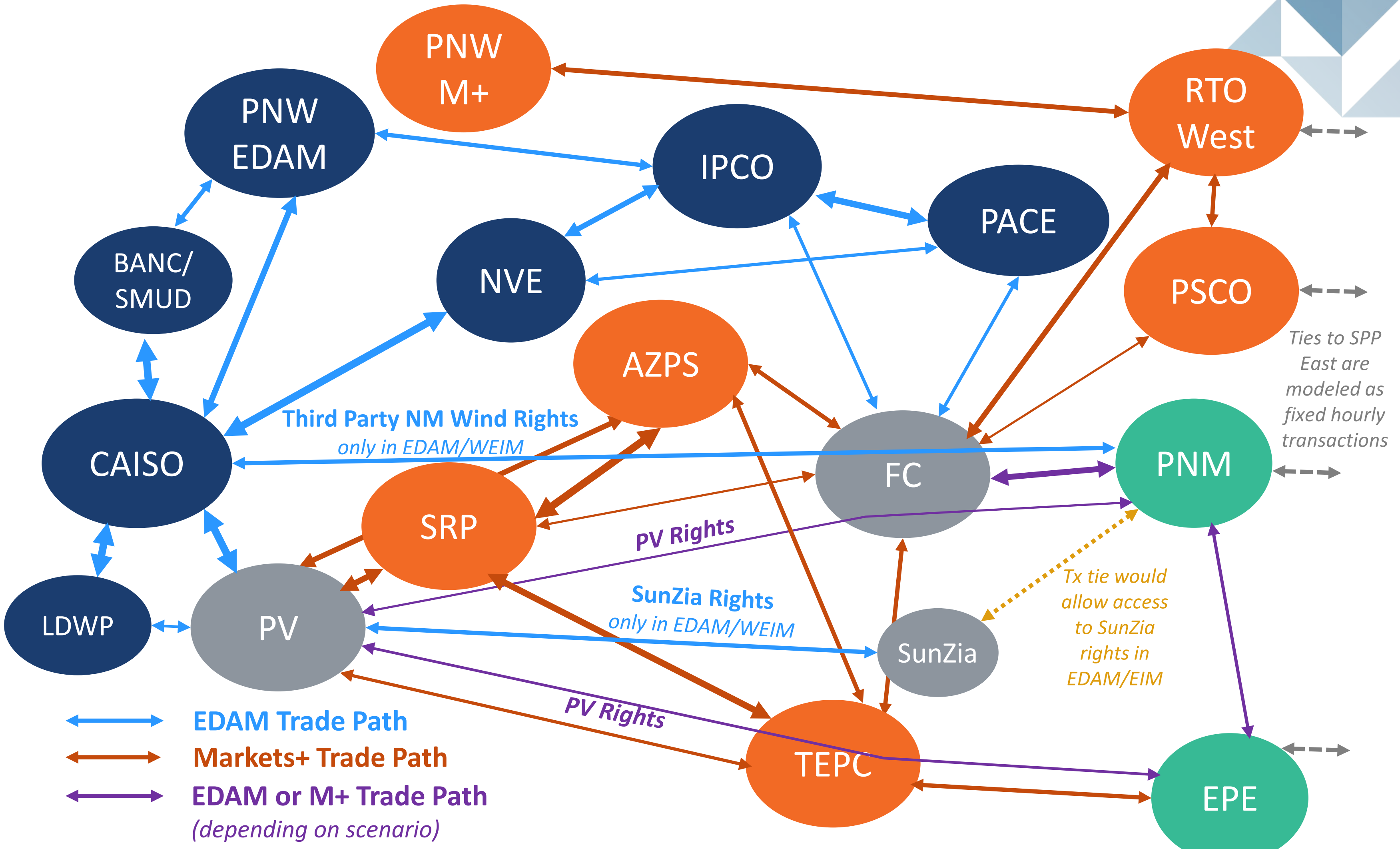


SPP RTO West
Markets+
EDAM & WEIM
WEIM only
Other BAs

PNM/EPE Modeled Contract-Path Trading Connectivity Map

Contract-path trading pathways differ considerably for PNM and EPE between EDAM & Markets+

- **Markets+**
  - **PNM** can trade directly with other M+ entities via FC, PV or via EPE
  - **EPE** can trade directly with TEPC, via PV, or via PNM
- **EDAM**
  - **PNM** can trade with EDAM via FC, third-party NM wind rights to CAISO, PV, or EPE
  - **EPE** can trade directly with EDAM entities via PV or PNM

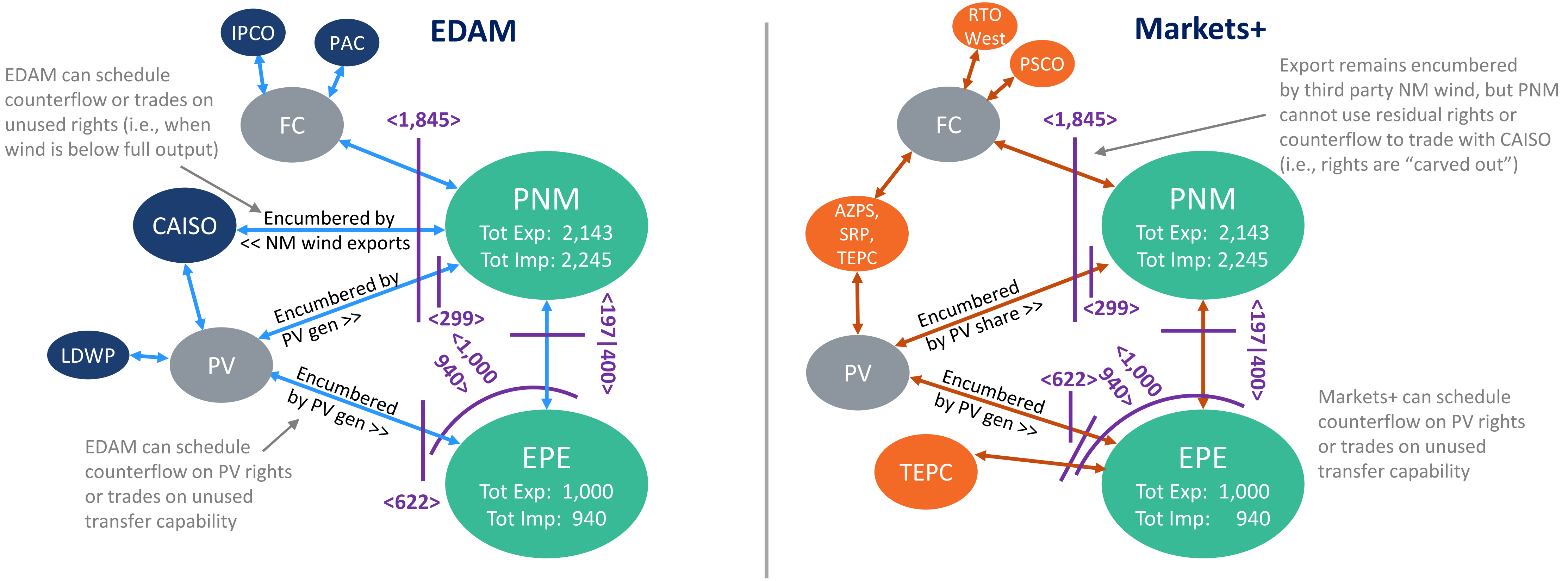


Note: Diagram shows only EDAM or M+ trading paths. We also model bilateral hourly, bilateral block, and intertie trading paths between entities, though leave them out here for simplicity. SunZia rights would only be available hurdle free in EDAM. Width of arrow indicates magnitude of TTC on path.

PNM/EPE's Rights to Trade with EDAM and M+ Entities

Contract-Path Trading Capability & Encumbrances, EDAM vs Markets+

(transfer capability values shown in MW)



Note: direct PNM/EPE to/from PV/CAISO transfers encumber Four Corners and/or AZ paths associated with rights used for transfer

Market Participation Benefits

Market Participation Benefits Overview

PNM and EPE are estimated to benefit from participation in both markets.

- Estimated EDAM net annual benefits are $39.6 million per year
- Estimated Markets+ net annual benefits are $17 million per year
- The higher benefit in EDAM is largely driven by increased opportunities to execute market-to-market transactions (e.g., with TEPC)

Summary of PNM/EPE Combined Market Participation Impacts
$ Million/Year

Benefit Metric	Metric	CT	EDAM	Markets+
Adjusted Production Cost	*Cost*	$129.0	$115.9	$106.1
Short-term Wheeling Revenue	*Revenue*	$0.5	$0.5	$0.0
EDAM Congestion Revenue	*Revenue*	-	$32.9	-
WEIM Congestion Revenue	*Revenue*	$17.8	$8.8	-
Markets+ DA Congestion Revenue	*Revenue*	-	-	$17.3
Markets+ RT Congestion Revenue	*Revenue*	-	-	$9.4
Bilateral Trading Revenue [1]	*Revenue*	$15.1	$17.7	$0.7
APC Less Revenues		**$95.7**	**$56.1**	**$78.6**
Net Benefits			**$39.6**	**$17.0**

Notes:

[1] Bilateral trading value of exports and imports with non-market member neighboring systems, potentially including trades by third party marketers.

Market Participation Benefits Overview

Summary of EPE Participation Impacts
$ Million/Year

Benefit Metric	Metric	CT	EDAM	Markets+
Adjusted Production Cost	*Cost*	$73.6	$70.5	$62.2
Short-term Wheeling Revenue	*Revenue*	$0.5	$0.4	$0.0
EDAM Congestion Revenue	*Revenue*	-	$12.4	-
WEIM Congestion Revenue	*Revenue*	$7.8	$3.6	-
Markets+ DA Congestion Revenue	*Revenue*	-	-	$8.1
Markets+ RT Congestion Revenue	*Revenue*	-	-	$4.4
Bilateral Trading Revenue [1]	*Revenue*	$6.6	$14.4	$0.0
APC Less Revenues		**$58.8**	**$39.7**	**$49.7**
Net Benefits			**$19.1**	**$9.1**

Notes:

[1] Bilateral trading value of exports and imports with non-market member neighboring systems, potentially including trades by third party marketers.

Summary of PNM Participation Impacts
$ Million/Year

Benefit Metric	Metric	CT	EDAM	Markets+
Adjusted Production Cost	*Cost*	$55.4	$45.4	$43.9
Short-term Wheeling Revenue	*Revenue*	$0.0	$0.0	$0.0
EDAM Congestion Revenue	*Revenue*	-	$20.5	-
WEIM Congestion Revenue	*Revenue*	$10.0	$5.1	-
Markets+ DA Congestion Revenue	*Revenue*	-	-	$9.2
Markets+ RT Congestion Revenue	*Revenue*	-	-	$5.1
Bilateral Trading Revenue [1]	*Revenue*	$8.6	$3.3	$0.7
APC Less Revenues		**$36.9**	**$16.4**	**$28.9**
Net Benefits			**$20.5**	**$8.0**

Notes:

[1] Bilateral trading value of exports and imports with non-market member neighboring systems, potentially including trades by third party marketers.

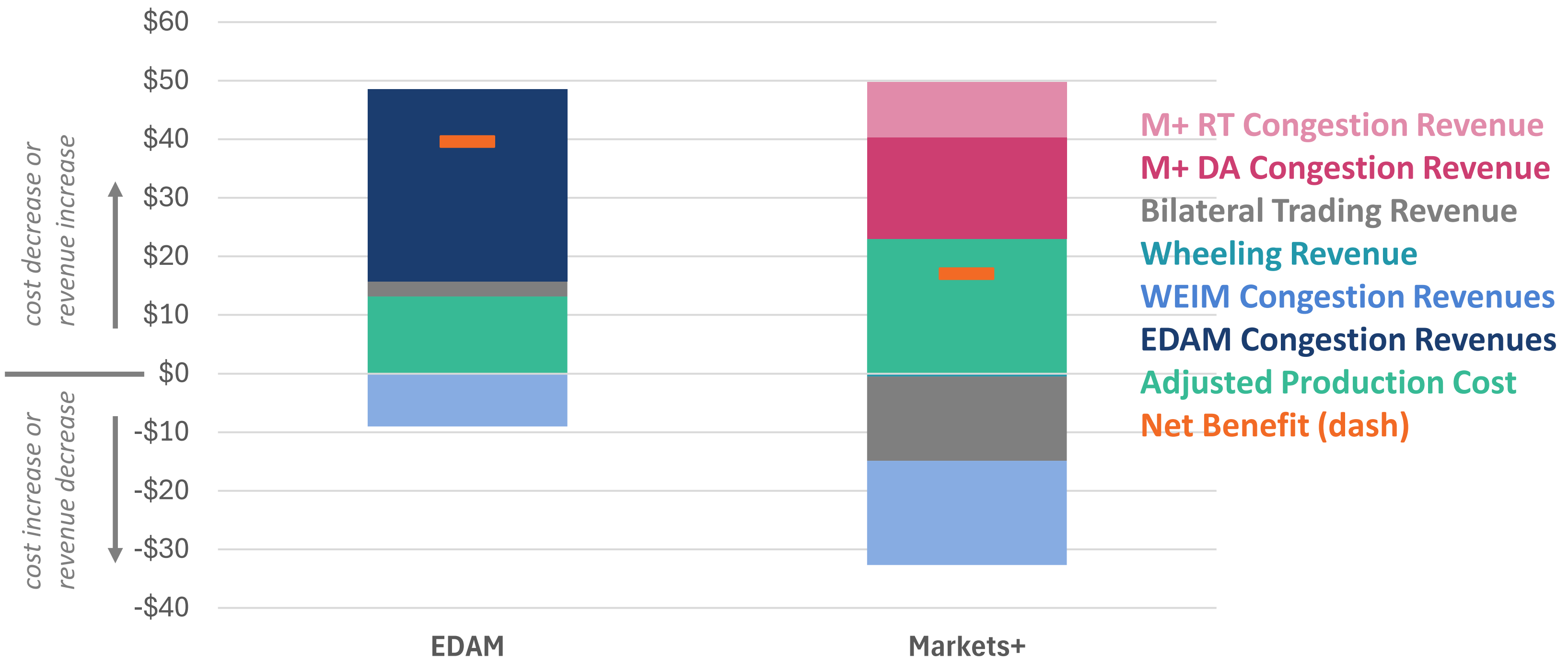
EDAM and Markets+ Benefits Driver Summary

Market congestion and bilateral trading revenue are key differentiators of net benefits between EDAM and Markets+

- EDAM benefits driven by congestion revenue and APC savings
  - The high congestion revenues reflect the high market value of transmission rights to FC and between PNM/EPE in EDAM
- Markets+ benefits are driven by a reduction in APC and market congestion revenues.
  - Gains are offset by lost WEIM congestion and bilateral trading revenue.

Summary of Benefit Drivers

$ Million/year, EDAM & Markets+ cases minus CT case



Adjusted Production Cost Benefit in EDAM

PNM+EPE Adjusted Production Cost decreases by $13 million/year in EDAM.

1. Decreased EPE/PNM generation reduces production costs by $1.9 million/year
2. Increased day-ahead purchases add $28.7 million/year to purchased power costs; offset by $14 million/year less in real-time purchases.
3. Increased day-ahead sales volumes and prices increases off-system sales revenues by almost $38.2 million/year; offset by about $12 million/year in lower real-time sales revenues

Adjusted Production Cost Comparison for PNM Utility & EPE

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**CT**	**EDAM**	**Difference**	**CT**	**EDAM**	**Difference**	**CT**	**EDAM**	**Difference**	
Production Cost	(+)	[1]	25,225	25,166	**-59**	$5.46	$5.39	**-$0.06**	137,616	135,698	**-$1,918**	(1)
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	468	1,769	**1,301**	$36.90	$26.00	**-$10.90**	17,288	46,007	**$28,719**	(2)
Real-Time Market		[5]	2,066	1,463	**-603**	$24.95	$25.64	**$0.68**	51,556	37,505	**-$14,051**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	3,170	4,227	**1,057**	$14.35	$19.80	**$5.44**	45,503	83,688	**$38,184**	(3)
Real-Time Market		[8]	1,309	890	**-418**	$24.38	$22.05	**-$2.33**	31,902	19,636	**-$12,266**	
Total Cost *(Negative Difference = Benefit)*		[9]	23,281	23,281	**0**	**$5.54**	**$4.98**	**-$0.57**	129,055	115,886	**-$13,169**	
% Change in APC											***-10.2%***	

Note: the APC metric does not capture the full value of export/import transactions over PNM and EPE transmission rights, which is reflected in the congestion revenue and bilateral trading gains metrics.

Adjusted Production Cost Benefit in Markets+

PNM+EPE Adjusted Production Cost decreases by almost $23 million/year in Markets+.

1. Increased EPE/PNM generation increases production costs by $10 million/year
2. Increased day-ahead purchases adds $37 million/year to purchased power costs; offset by almost $19 million/year less in real-time purchases.
3. Increased day-ahead sales volumes and higher prices increases real-time off-system sales revenue by $44.5 million/year; with an additional $7.5 million/year in real-time.

Adjusted Production Cost Comparison for PNM Utility & EPE

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			CT	Markets+	Difference	CT	Markets+	Difference	CT	Markets+	Difference	
Production Cost	(+)	[1]	25,225	25,512	**287**	$5.46	$5.82	**$0.36**	137,616	148,447	**$10,832**	(1)
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	468	2,351	**1,882**	$36.90	$23.13	**-$13.77**	17,288	54,375	**$37,086**	(2)
Real-Time Market		[5]	2,066	1,501	**-565**	$24.95	$21.75	**-$3.21**	51,556	32,646	**-$18,911**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	3,170	4,527	**1,357**	$14.35	$19.89	**$5.53**	45,503	90,022	**$44,519**	(3)
Real-Time Market		[8]	1,309	1,556	**247**	$24.38	$25.31	**$0.93**	31,902	39,378	**$7,476**	
Total Cost *(Negative Difference = Benefit)*		[9]	23,281	23,281	**0**	**$5.54**	**$4.56**	**-$0.99**	129,055	106,067	**-$22,988**	
% Change in APC											***-17.8%***	

Note: the APC metric does not capture the full value of export/import transactions over PNM and EPE transmission rights, which is reflected in the congestion revenue and bilateral trading gains metrics.

Trading Dynamics in EDAM and Markets+

Trading increases in both EDAM & Markets+

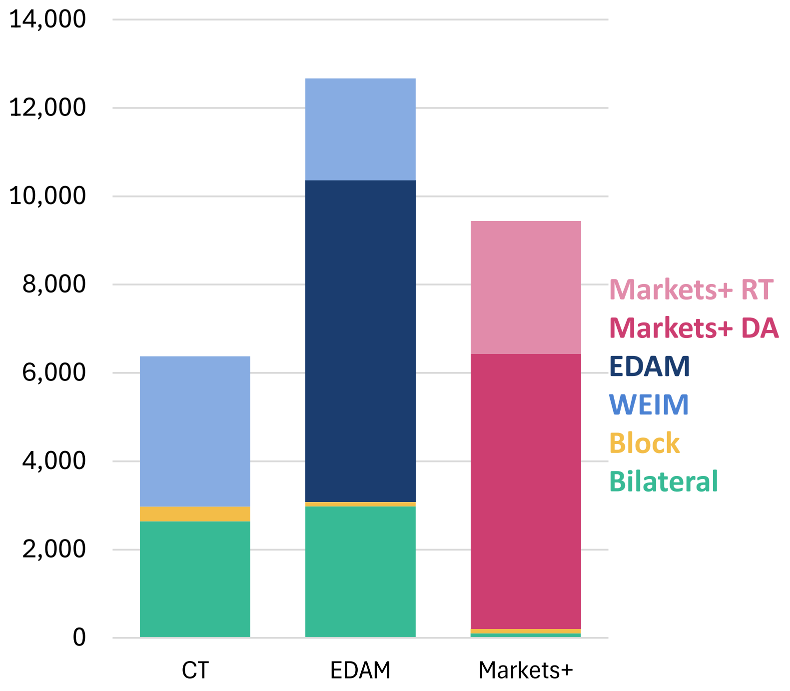
- **Markets+:** Markets+ DA and RT trades take the place of most bilateral/block trades and all WEIM trades
- **EDAM:** EDAM market trade volumes supplement bilateral trade volumes, while WEIM trades decrease modestly

Market Transactions and Congestion Revenue

	EIM (CT Case)			EDAM + EIM (EDAM Case)			Markets+ DA + RT (Markets+ Case)		
Counterparty	**Value**	**Flows**	**Value per MWh**	**Value**	**Flows**	**Value per MWh**	**Value**	**Flows**	**Value per MWh**
	$ Mil.	*GWh*	*$/MWh*	*$ Mil.*	*GWh*	*$/MWh*	*$ Mil.*	*GWh*	*$/MWh*
CAISO	-	531	-	-	1,135	-	n/a	n/a	n/a
TEPC	n/a	n/a	n/a	n/a	n/a	n/a	$4	3,903	$1.1
Four Corners	$4	1,218	$3.6	$8	3,319	$2.4	$8	2,758	$2.8
Palo Verde	$0	0	$0.0	$2	419	$4.2	$2	393	$3.9
EPE/PNM Transfers	$14	1,232	$11.0	$32	3,503	$9.2	$13	1,619	$8.2
Total	**$18**	**2,981**	**$6.0**	**$42**	**8,376**	**$5.0**	**$27**	**8,674**	**$3.1**

Note: Trades with CAISO are on third-party rights. Market congestion revenues accrue directly to third parties not PNM.

Trade Volume by Type (GWh)



Trading Volume Shifts in EDAM

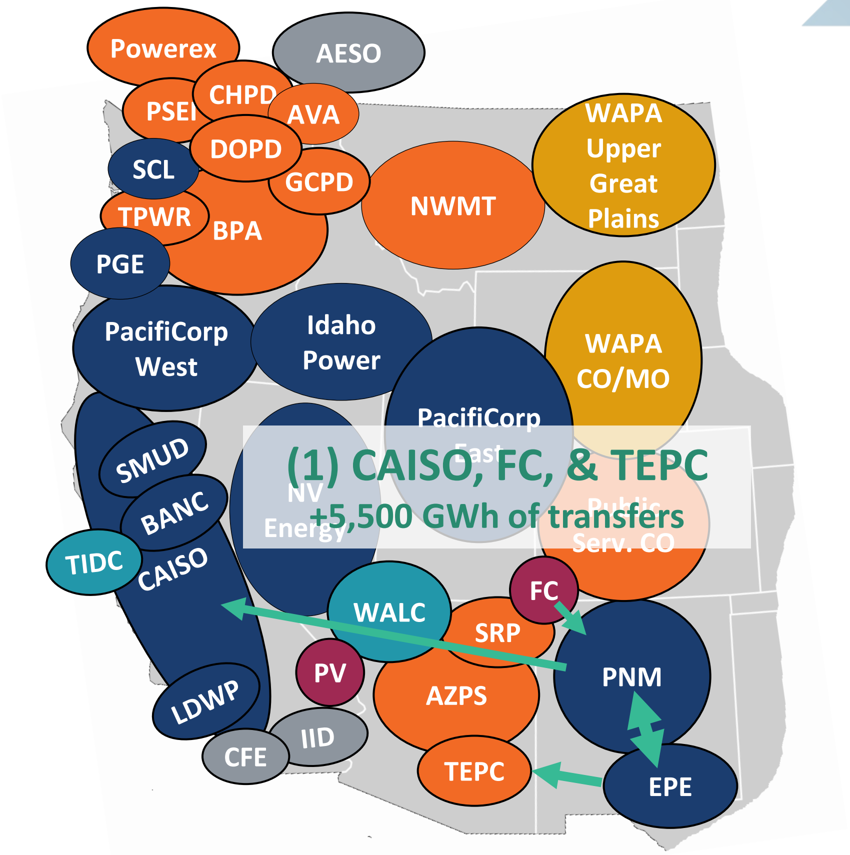
The trading patterns in EDAM reflect:

- Increased transfers between EPE and PNM, mostly flowing from PNM to EPE driven by higher market imports into PNM from Four Corners.
- While PNM doesn't receive congestion revenues from CA trades, EDAM use of third-party rights creates an increase of 500 GWh in trading between EPE/PNM and CA.
- A significant increase for EPE in bilateral (market-to-market) off-system sales to TEPC.

Total Volume by Counterparty (GWh)

Counterparty	CT		EDAM	
	Exports	Imports	Exports	Import
CAISO	232	299	758	377
TEPC	843	10	2,068	471
Four Corners	806	2,325	639	3,110
Palo Verde	0	0	94	325
EPE/PNM Transfers	1,366	1,366	3,503	3,503
Total	**3,246**	**4,000**	**7,062**	**7,786**

EDAM vs CT



SPP RTO West Member
Markets+ (DA and RT) Member
EDAM and WEIM Member
WEIM-Only Member

Trading Volume Shifts in Markets+

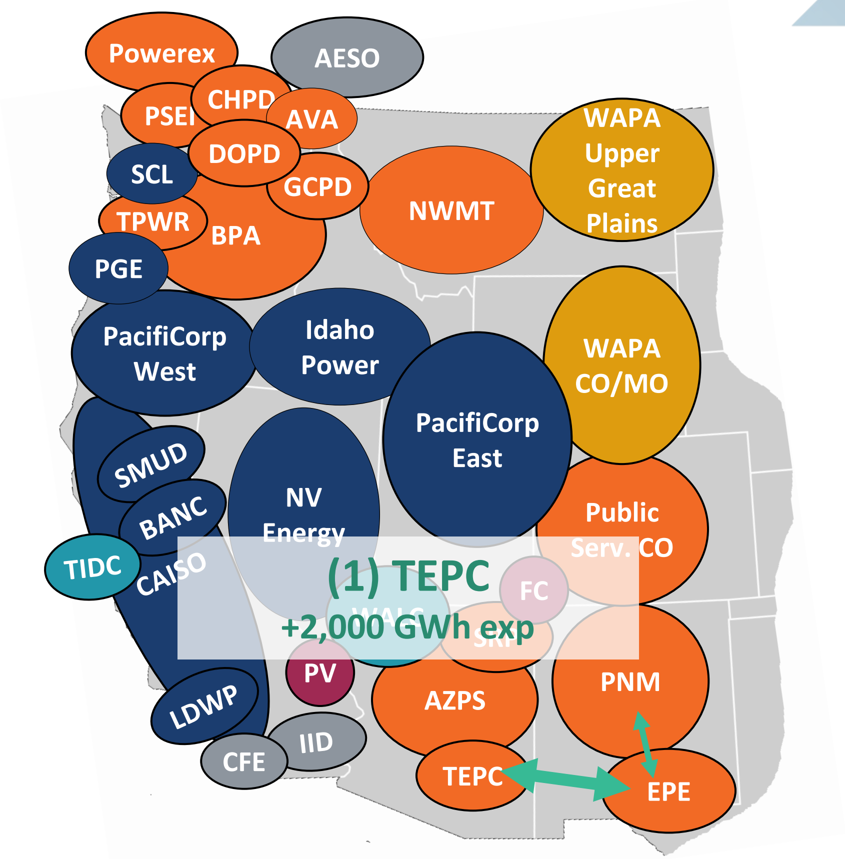
The trading patterns in Markets+ reflect:

- Markets+ reduces the cost to transact directly with TEPC, increasing transfers with TEPC.
- Markets+ leverages EPE/PNM rights through Four Corners and Palo Verde to execute markets transfers.
- Direct access to CAISO using third-party transmission is lost, but EPE/PNM conduct a small amount of bilateral (market-to-market) trading with EDAM entities via Four Corners.

Total Volume by Counterparty (GWh)

Counterparty	CT		Markets+	
	Exports	Imports	Exports	Import
CAISO	232	299	0	0
TEPC	843	10	2,266	1,636
Four Corners	806	2,325	802	2,167
Palo Verde	0	0	283	111
EPE/PNM Transfers	1,366	1,366	1,619	1,619
Total	**3,246**	**4,000**	**4,971**	**5,533**

Markets+ vs CT



SPP RTO West Member
Markets+ (DA and RT) Member
EDAM and WEIM Member
WEIM-Only Member

Total Trading Volumes and Value

Total Volume by Counterparty (GWh)

Counterparty	CT		EDAM		Markets+	
	Exports	Imports	Exports	Import	Exports	Import
CAISO	232	299	758	377	0	0
TEPC	843	10	2,068	471	2,266	1,636
Four Corners	806	2,325	639	3,110	802	2,167
Palo Verde	0	0	94	325	283	111
EPE/PNM Transfers	1,366	1,366	3,503	3,503	1,619	1,619
Total	**3,246**	**4,000**	**7,062**	**7,786**	**4,971**	**5,533**

Total Value by Counterparty ($ Millions)

Counterparty	CT		EDAM		Markets+	
	Exports	Imports	Exports	Import	Exports	Import
CAISO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
TEPC	$5.0	$0.2	$12.7	$3.7	$2.6	$1.8
Four Corners	$4.8	$6.5	$2.2	$7.1	$3.5	$5.0
Palo Verde	$0.0	$0.0	$0.5	$1.3	$1.1	$0.4
EPE/PNM Transfers	$8.3	$8.3	$16.1	$16.1	$6.6	$6.6
Total	**$18.1**	**$15.0**	**$31.4**	**$28.1**	**$13.8**	**$13.8**

Value per MWh of Transfers ($/MWh)

Counterparty	CT		EDAM		Markets+	
	Exports	Imports	Exports	Import	Exports	Import
CAISO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
TEPC	$5.9	$19.9	$6.1	$7.8	$1.1	$1.1
Four Corners	$6.0	$2.8	$3.4	$2.3	$4.3	$2.3
Palo Verde	$0.0	$0.0	$5.1	$3.9	$4.0	$3.6
EPE/PNM Transfers	$6.1	$6.1	$4.6	$4.6	$4.1	$4.1
Total	**$5.6**	**$3.7**	**$4.4**	**$3.6**	**$2.8**	**$2.5**

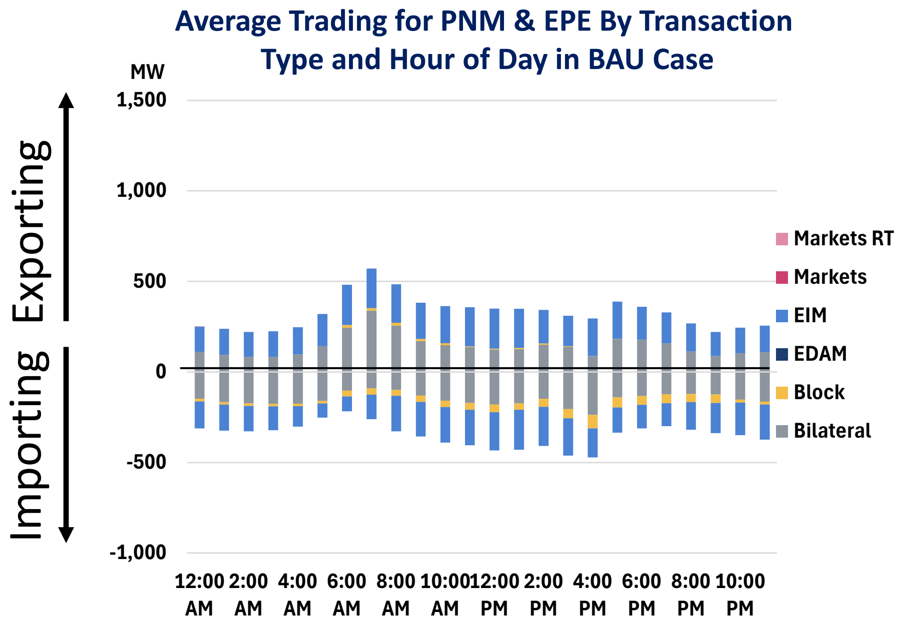
The tables show all trade types, both transfers cleared by the markets and bilateral trading.

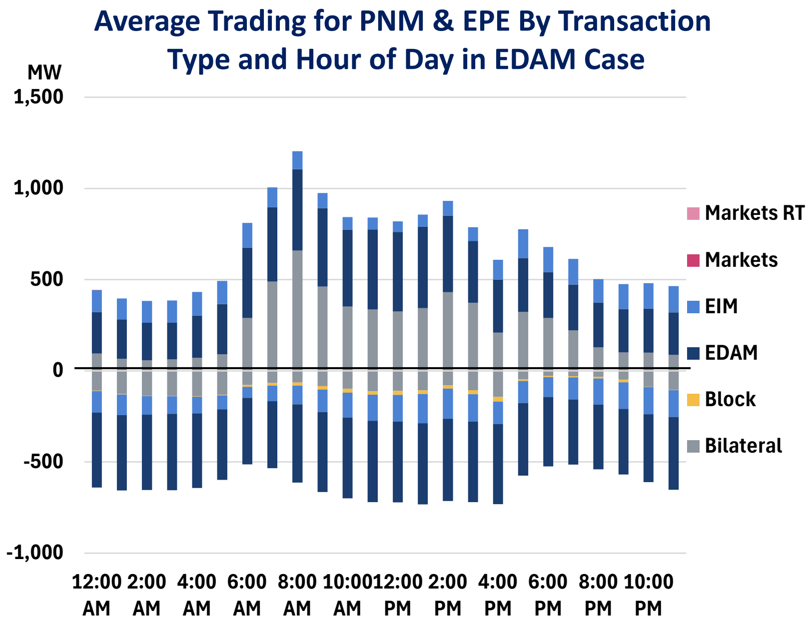
- Therefore, the value by counterparty (second table) shown includes market congestion revenues and bilateral trading gains.
- Key takeaways:
  - The **high bilateral trading value** with TEPC in the EDAM Case.
  - The **increased volume of trading between PNM and EPE** in EDAM creates market congestion.
    - On a $/MWh basis congestion between PNM and EPE is about the same in each market.
  - **Transfer through Four Corners** are significantly higher in EDAM, especially imports.

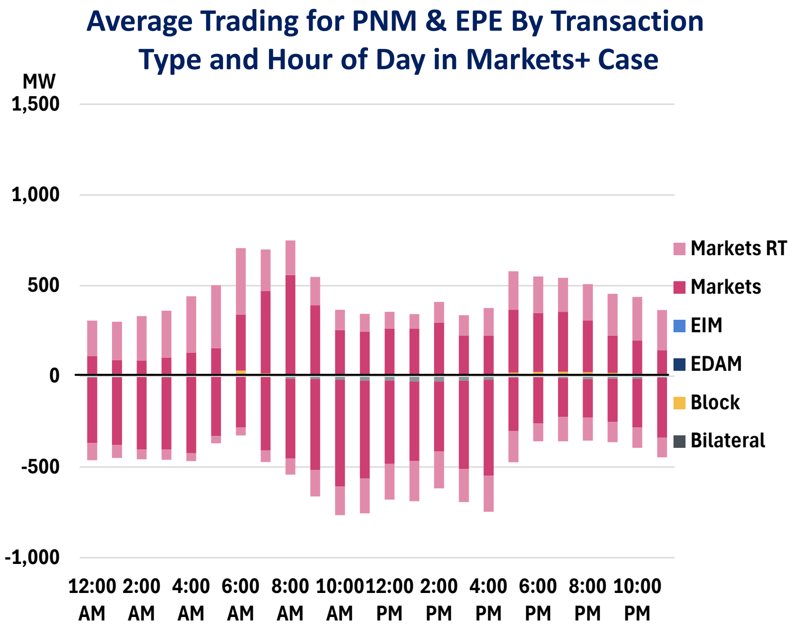
Trading Shift Due to Market Participation

Markets+ produces a slightly higher volume of market trades for the combined EPE and PNM footprint

- Average EDAM and WEIM hourly trading volume is about 950 MW of transfers, while average Markets+ hourly volume is around 990 MW
- In EDAM, EPE and PNM make significant bilateral (market-to-market) trades, while in Markets+ bilateral trading is largely reduced with limited bilateral trading with PACE and IPCO at Four Corners.



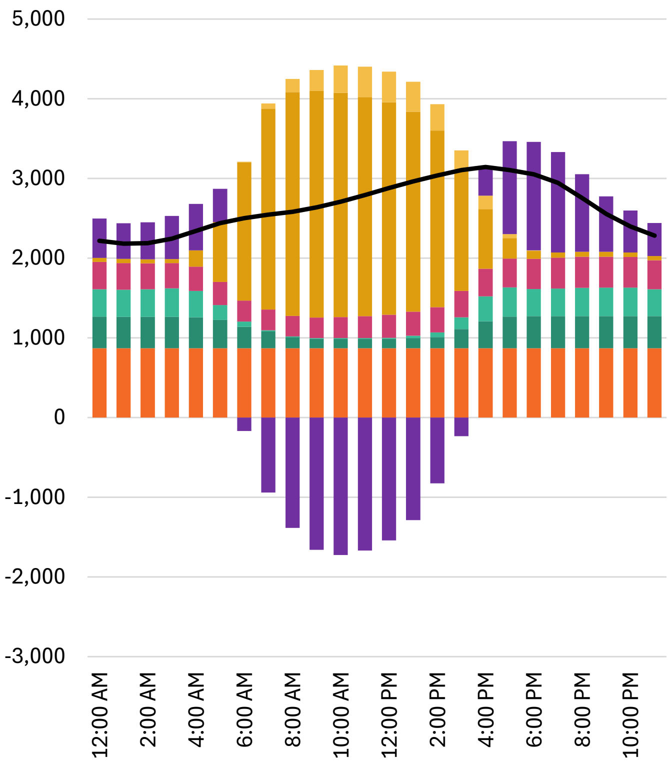




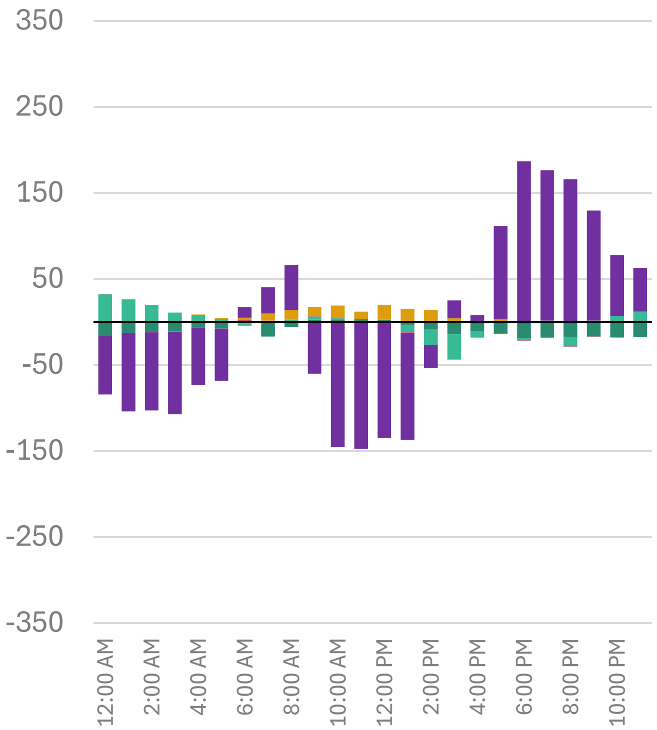
Generation Behavior Due to Market Participation

Participation in EDAM and Markets+ primarily increases utilization of batteries, but also modestly reduces solar curtailments. In Markets+ there is a small increases gas generation.

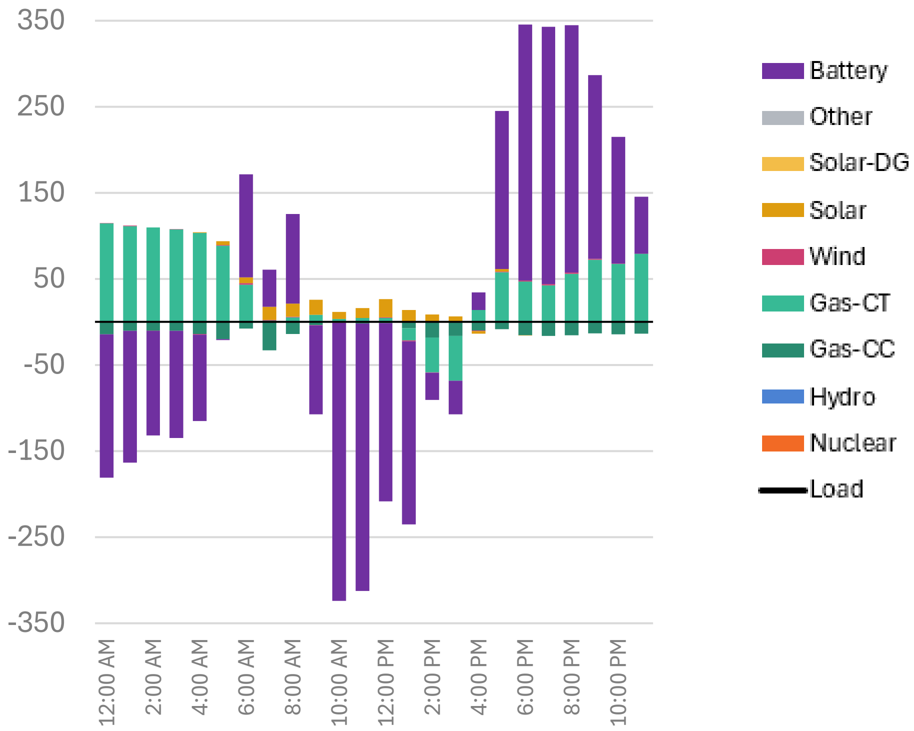
Total Generation in Current Trends Case
PNM & EPE



Change in Generation
(EDAM *minus* Current Trends)
PNM & EPE



Change in Generation
(Markets+ *minus* Current Trends)
PNM & EPE



GHG Emissions for PNM and EPE in Markets+ and EDAM

EDAM and Markets+ have a modest impact on PNM and EPE CO2 emissions relative to the Current Trends case

- **Markets+**
  - **PNM** emissions increase by 0.07 MMT
  - **EPE** emissions increase by 0.08 MMT
- **EDAM**
  - **PNM** emissions increase by < 0.01 MMT
  - **EPE** emissions decrease by 0.03 MMT
- Emissions shifts driven by increases in gas generation offset by declines in curtailment
- Curtailments fall slightly in both markets for EPE and PNM
  - EDAM curtailments fall 52 GWh for PNM and EPE
  - Markets+ curtailments fall 61 GWh for PNM and EPE
  - Both are about 0.4% of wind and solar generation in the Current Trends Case

Annual CO2 Emissions (Million Metric Tons)

Total Emissions in Million Metric Tons (2032)

Case	PNM Utility & EPE
CT Case	1.79
EDAM Case	1.75
Markets+ Case	1.93
EDAM - CT	***-0.03***
Markets - CT	***0.14***

Estimated EDAM & M+ Benefits are Conservatively Low

The estimated benefits are likely understated due to several factors:

- **Overstated Current Trends case efficiency:** our simulation of the CT is more efficient than reality
  - The CT case assumes that balancing authorities have optimal security-constrained unit-commitment and dispatch (SCUC and SCED) in both DA and RT, making the simulated dispatch more optimal than reality.
  - Inefficient utilization of transmission for bilateral trading is not fully modeled, understating the extent M+ and EDAM will be able to make better use of all physically and contractually available transmission.
  - Transmission outages are not modeled, which would magnify the benefit of SCED-based congestion management in EDAM and M+ compared to the CT case
- **Normalized loads and fuel prices:** the model uses weather-normalized loads and averaged monthly natural gas prices without daily volatility
  - We include one week with an illustrative heat wave and one with an illustrative cold snap, but challenging market conditions beyond those two weeks, will magnify EDAM/M+ benefits. This is illustrated by the WEIM experience of much higher benefits in 3Q of 2021, 3Q-4Q of 2022, and Q1 of 2024.
  - The CT case does not reflect the tendency for scarcity in bilateral markets during challenging system conditions.
- **No capacity benefits quantified:** we have not quantified the extent to which EDAM and M+ may reduce investment costs associated with lower operating reserve requirements

Appendix:
Modeling Inputs and Assumptions

PNM & EPE Capacity Mix

PNM and EPE's resource mixes are dominated by solar and batteries, as well as wind (PNM), gas, and nuclear.

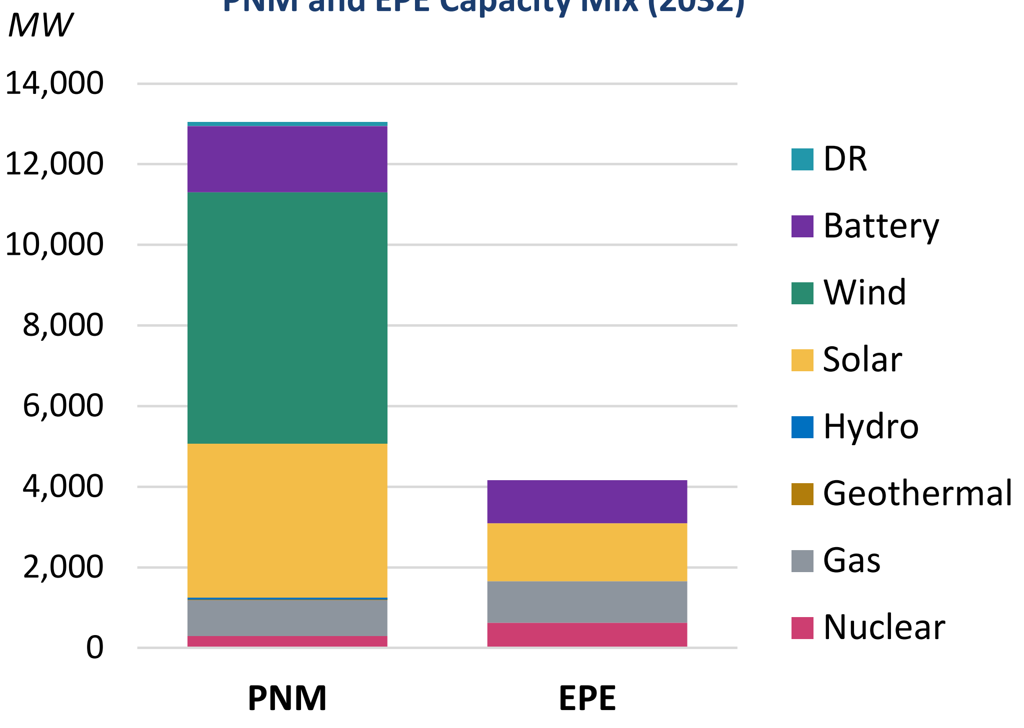
PNM and EPE Capacity Mix (2032)

Type	PNM	EPE
	MW	MW
Battery	1,645	1,066
DR	90	0
Gas	886	1,034
Geothermal	11	0
Hydro	51	0
Nuclear	299	622
Solar	3,828	1,439
Wind	6,229	0
Total	**13,040**	**4,161**

PNM BAA vs. Utility Capacity (2032)

Type	Utility	Non-Utility
	MW	MW
Battery	1,645	0
DR	90	0
Gas	701	186
Geothermal	11	0
Hydro	0	51
Nuclear	299	0
Solar	2,844	984
Wind	917	5,312
Total	**6,507**	**6,533**

PNM and EPE Capacity Mix (2032)



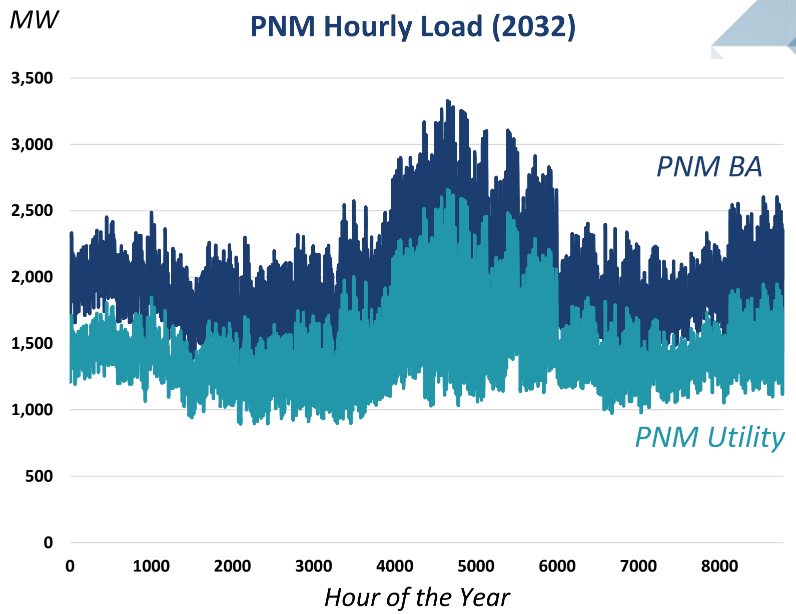
PNM & EPE Peak and Energy Forecast

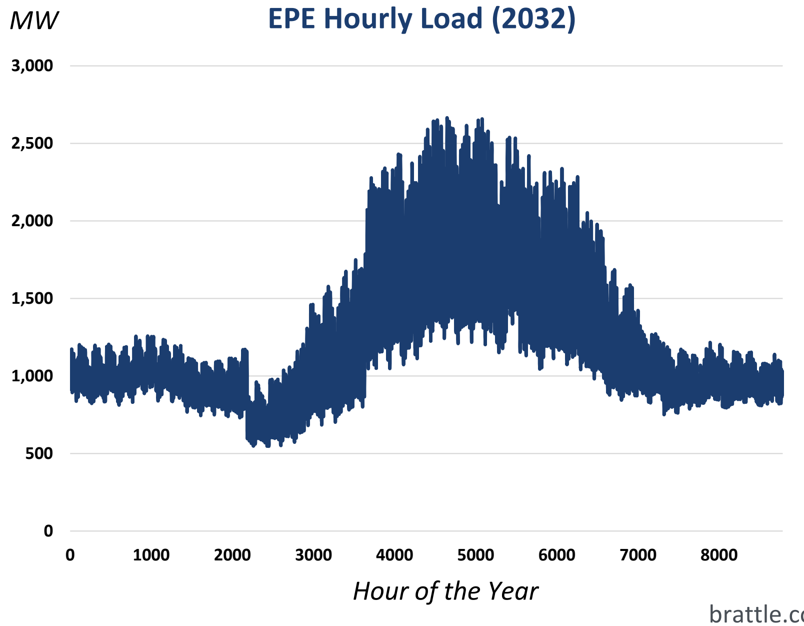
PNM and EPE are summer-peaking systems. Total annual load in 2032 is 17 TWh in PNM and 10.8 TWh in EPE. PNM's load accounts for ~74% of total BA load.

PNM & EPE Modeled Load (2032)

	PNM BA		PNM Utility		EPE BA	
Month	**Total Load (MWh)**	**Peak (MW)**	**Total Load (MWh)**	**Peak (MW)**	**Total Load (MWh)**	**Peak (MW)**
January	1,483,520	2,453	1,080,000	1,805	742,415	1,204
February	1,328,781	2,489	965,784	1,849	709,394	1,258
March	1,309,374	2,300	936,868	1,700	688,209	1,171
April	1,227,021	2,320	881,829	1,746	556,277	1,206
May	1,305,988	2,574	957,072	2,003	832,549	1,787
June	1,492,818	3,169	1,120,000	2,517	1,211,282	2,445
July	1,656,947	3,329	1,260,000	2,659	1,408,523	2,665
August	1,609,700	3,108	1,223,597	2,484	1,287,490	2,577
September	1,393,207	2,831	1,040,000	2,209	1,119,327	2,337
October	1,315,435	2,397	964,348	1,816	842,165	1,701
November	1,325,643	2,333	964,843	1,733	694,123	1,217
December	1,504,523	2,605	1,090,000	1,948	704,916	1,158
Annual	**16,952,958**	**3,329**	**12,484,342**	**2,659**	**10,796,669**	**2,665**

Note: PNM BA load includes PNM Utility load.





Hurdle Rate Assumptions

Markets+ and EDAM are modeled with separate bilateral trading frictions at the seam, as Markets+ automatically enables intertie bidding

- Bilateral transactions pay a $6/MWh friction charge for trades between two non-market entities
  - Bilateral transactions at the Markets+ seam pay $3/MWh, $1.5/MWh at an RTO seam, and $6/MWh at the EDAM seam (plus GHG and transmission service fees, if applicable).
- Exports across the market seams into a GHG zone are charged an unspecified resource GHG cost (equivalent to the emissions charge for a generic gas-CC unit, about $28/MWh)

Modeled Trading Friction Charges ($/MWh)

Transaction Type	Friction Charge	Transaction Pays OATT?
	$/MWh	*Yes/No*
Bilateral Transactions	$6	Yes*
Block Transactions	$1.5	Yes*
EDAM and WEIM Transactions	*None*	No
Markets+ DA / RT Transactions	*None*	No
RTO Intertie Transactions	$1.5	Yes*
Markets+ Seam Transactions	$3	Yes*
EDAM Seam Transactions	$6**	Yes*

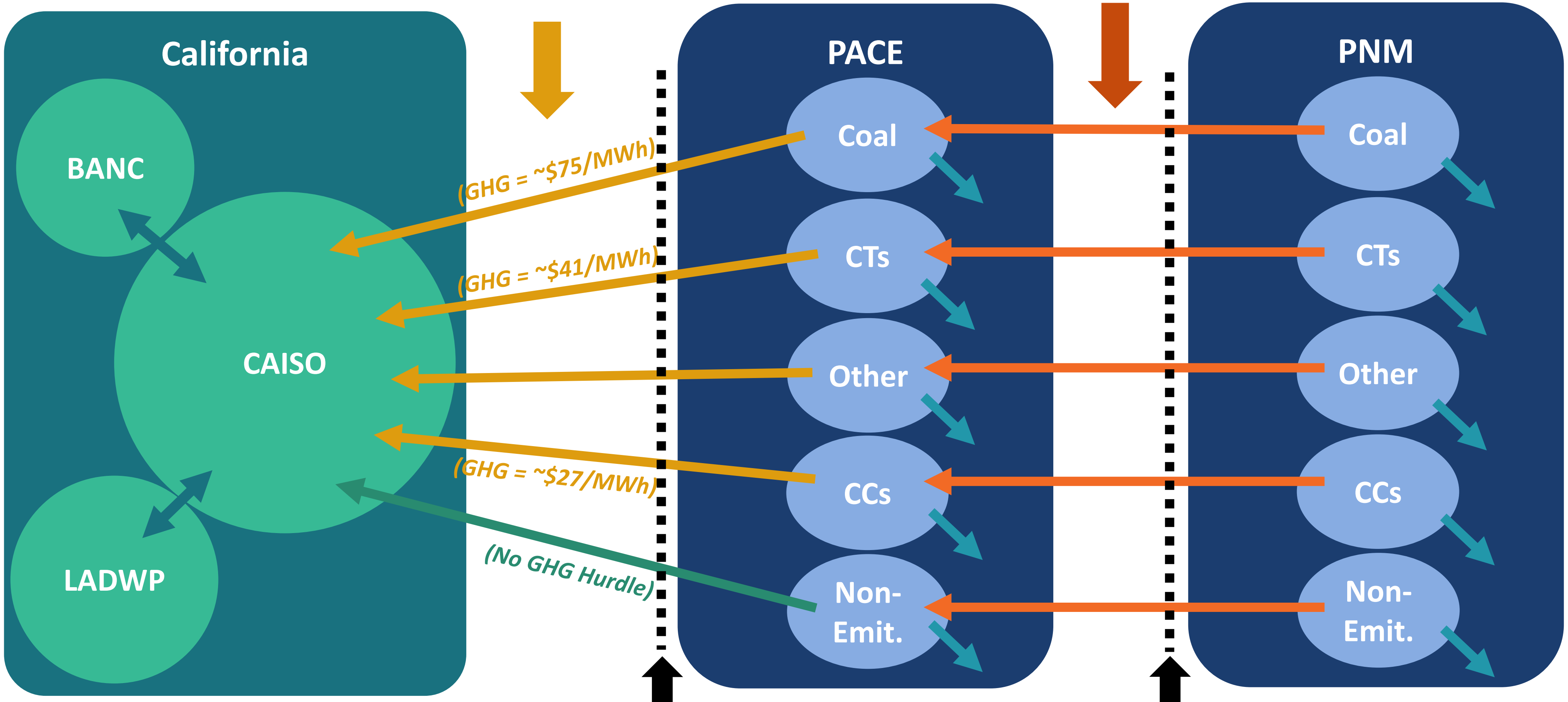
Note: *Trades across long-term transmission rights pay a friction charge, but no hourly OATT rate.
**EDAM seams with Markets+ pay the $3/MWh Markets+ friction.

GHG Structure Illustration

Sales incur unit GHG cost, relevant hurdles, and are limited by attributions from the GHG Reference Pass

Resources can sell into neighboring BAAs by paying applicable fees:

- Bilateral market: OATT fee, trading margin
- EIM: no hurdle on available transmission
- EDAM: no hurdle on Buckets 1,2, & 3



Resources serve load in their own BAA with no hurdle

Flows restricted to BAA export limit
+ BAA Net Export GHG Attribution Limit

A nomogram restricting total BAA-to-BAA flows to export limit, which varies by market type – bilateral, EIM, and EDAM

EDAM GHG Structure: "Reference Cycle"

Our GHG modeling structure accounts for two constraints specified in the EDAM design for GHG attributions relative to a baseline from EDAM's "reference pass" cycle, which we simulate as well

1. **Resource Specific GHG Attribution (resource-type attribution under proposed approach) =**

   max{0, min{GHG Bid, UEL – Reference Pass, Optimal Dispatch}}

   - GHG Bid: **Simulations assume resources bid all their capacity into the GHG Region**
   - UEL – Reference Pass: **Calculated using results of our GHG Reference Pass run**
   - Optimal Dispatch: **GHG attribution cannot exceed final dispatch of resource**

2. **BAA Total GHG Attribution <= (Net TTC Difference - BAA Net Exports hourly in reference pass)**

These reference pass results set **hourly export limits** that are enforced in the actual EDAM case for EIM and EDAM members for sales to GHG balancing authorities

Markets+ GHG Pricing Structure

Based on our review of the tariff language and the task force materials, we assume the Market+ GHG pricing structure will use the following approach:

- GHG surplus identification can happen through the Resource Operator and Merit Order approach.
  - Rules from state agencies may restrict what resources can be identified as surplus energy by the resource operator.
  - We assume the Merit Order approach will apply to all resources in the market, and we calculate BAA hourly surplus capacity available for transfer to GHG pricing states outside of the model using the load data and a merit order constructed from modeled operating cost and capacity assumptions.
  - We apply resource type-specific GHG costs to surplus transfers to the GHG zone.
- We assume the market optimization will use the “Enhanced Floating Surplus” approach
  - This allows transfer of type-specific surpluses from anywhere in the dispatch range of eligible resource

Load Following Reserves

We calculate different load following requirements for each market based on net load variability, and find that Markets+ results in lower requirements for PNM/EPE than EDAM

In both markets we calculate load following reserves (known as Imbalance Reserves in EDAM) both in the up and down directions to meet the 97.5 percentile of each BAAs historical net load variability.

- In the two market cases, participants' requirements are reduced by the diversity benefit created by pooling commitment and dispatch across the regional footprint.
- Does not impact other operating reserve types – regulation, contingency, etc.
- Higher requirement in EDAM is driven by more renewable resources in the market footprint than Markets+.
- Load Following Up requirement for EPE and PNM is about 800 GWh lower over the entire year in Markets+ vs. EDAM; the Load Following Down requirement is about the same in both markets.

Resource Sufficiency & Transmission

EDAM Resource Sufficiency Test

- EDAM will apply the Resource Sufficiency Test to each member before day-ahead market operations
  - In the 2019 EDAM Feasibility Study, E3 conducted an hourly analysis of Resource Sufficiency for each proposed EDAM member and found that failure was extremely rare.
  - For this study, conducted ex-post check and confirmed that EDAM members are resource sufficient in all hours.

EDAM Transmission

- All three buckets of EDAM transmission are modeled and assumed to be hurdle-free:
  - Bucket 1: Transmission to Support Resource Sufficiency, including existing long-term transmission contracts (ETCs)
  - Bucket 2: "Donated" Transmission Contracts, which are ETCs made available ("donated") to the EDAM by participants
  - Bucket 3: Unsold Firm Transmission (no study participant informed us that they plan to hold back any transmission)
- Simulated Bucket 1 and 2 EDAM transmission equals total ETC capacity; Bucket 3 transmission equals the remaining transfer capability (i.e., TTC less ETC) between the assumed EDAM members

Markets+ Transmission

- All transmission with other Markets+ members is modeled as available in the market without wheeling charges
- No participants identified any transmission that should be carved out for WRAP or other resource adequacy purchases.

Congestion Rent Allocation

Congestion revenues are allocated back to market participants consistent with proposed constraint-level approach

- We apply the Markets+ proposed approach is to allocate congestion based on the portion of rights each market participant owns on the constraint where congestion is collected for market transactions between members.
- Congestion on transactions internal to a member's system (to serve native load) is assumed to on transmission owned or controlled by the local TSP and all internal congestion is allocated to the local TSP.
- This differs from the EDAM where tie points were used between BAs to determine the allocation of revenue, splitting revenue into internal congestion revenue within a BA (kept by that BAA), and transfer revenue between two BAs (split 50/50 between the BAAs).

Appendix:
Benefit Metrics

Benefit Metric: Adjusted Production Cost

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

The APC is calculated for the BAU Case and the RTO case to determine the RTO-related reduction in APC

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

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

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

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

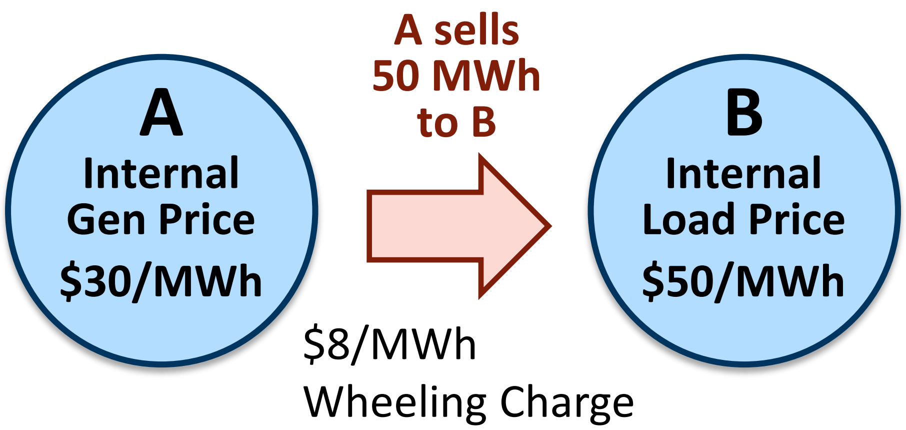
(−) Revenues from bilateral and market sales valued at the BAA's generation-weighted energy price ("Gen LMP")

Benefit Metrics: Wheeling Revenues, Trading Gains

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

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

EXAMPLE: Bilateral Trade



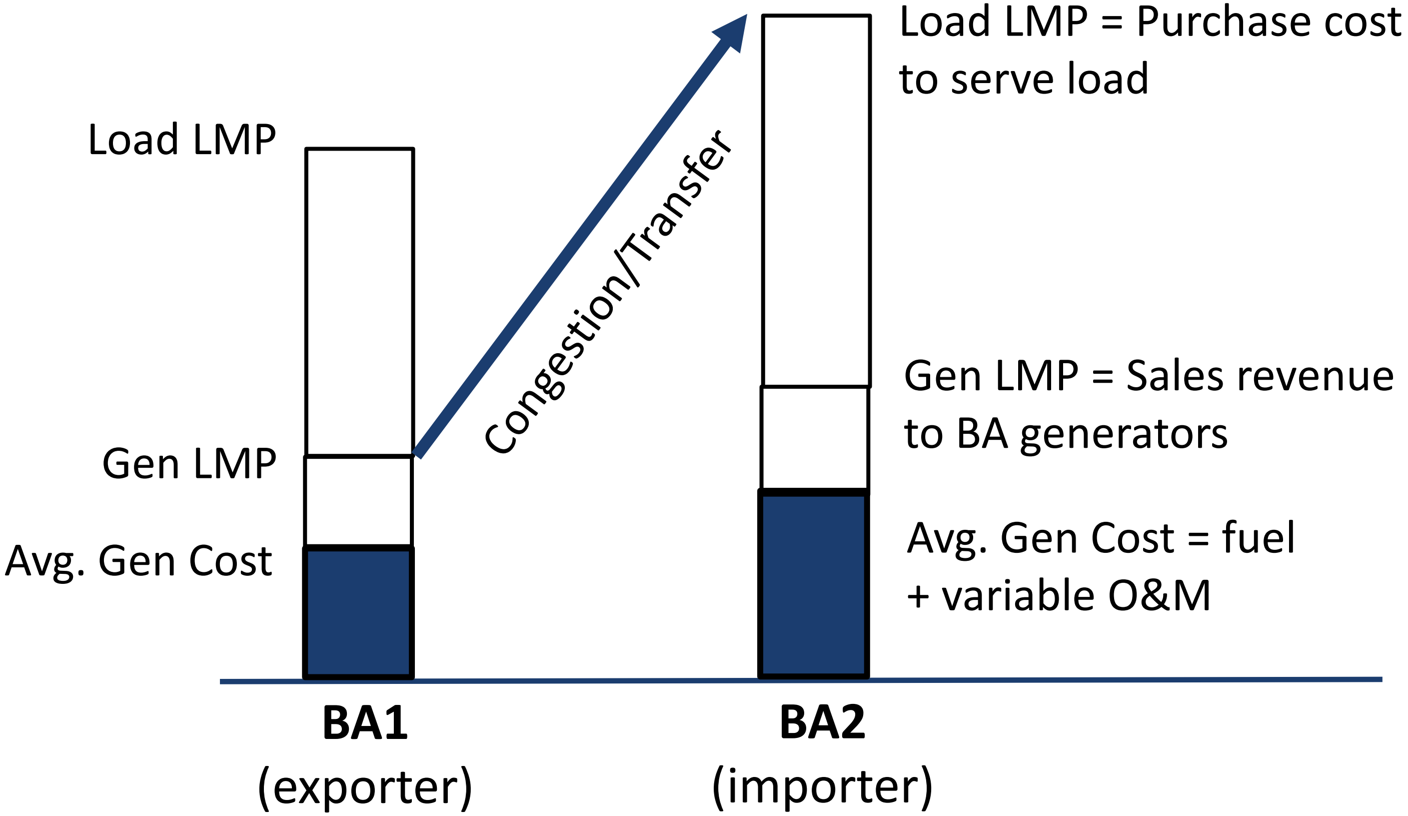
The APC metric only uses area-internal prices for purchase cost and sales revenues, which does not capture part of the value:

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

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

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

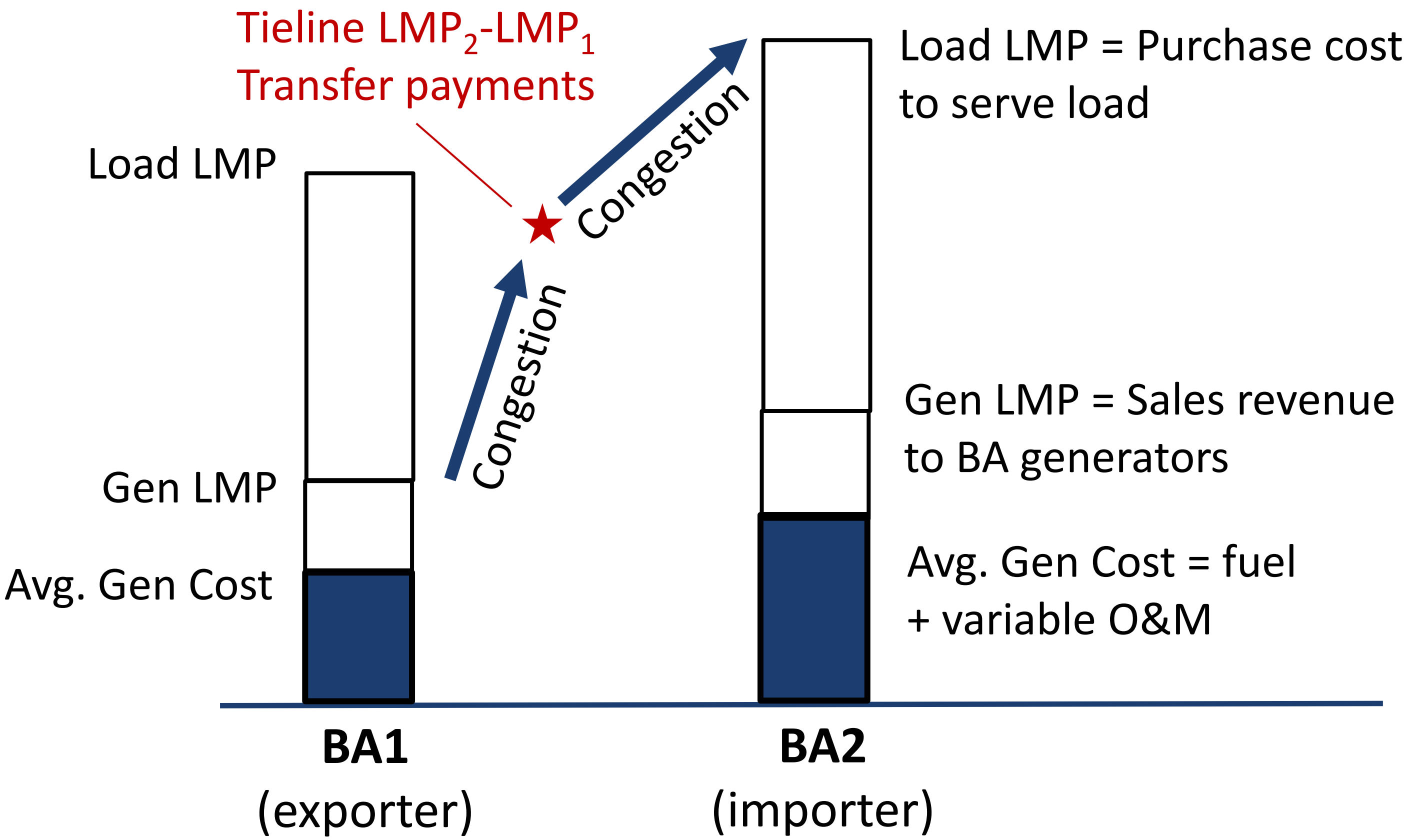
Illustration of Markets+ Congestion Revenues



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

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

Illustration of EDAM Congestion and Transfer Revenues



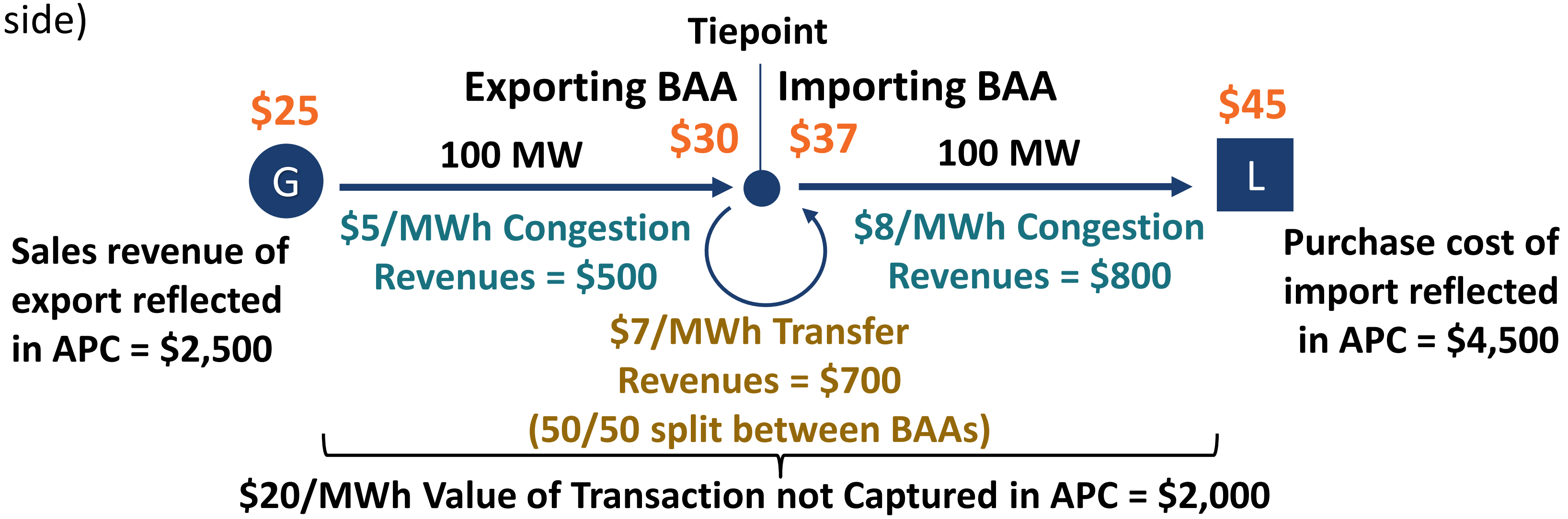
EDAM congestion and transfer revenues estimated based on individual <u>tieline LMPs</u>:

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

Illustration of Congestion/Transfer Revenues vs. APC

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

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



Appendix:
Overview of Power System Optimizer (PSO)

Overview of Modeling Approach

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

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

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

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

ENELYTIX®
powered by PSO

Independent Simulation of Multiple Time Horizons

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

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

Independent real-time decision cycle used to simulation EIM functions

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

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

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

Simulating Several Wholesale Market Cycles in PSO

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

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

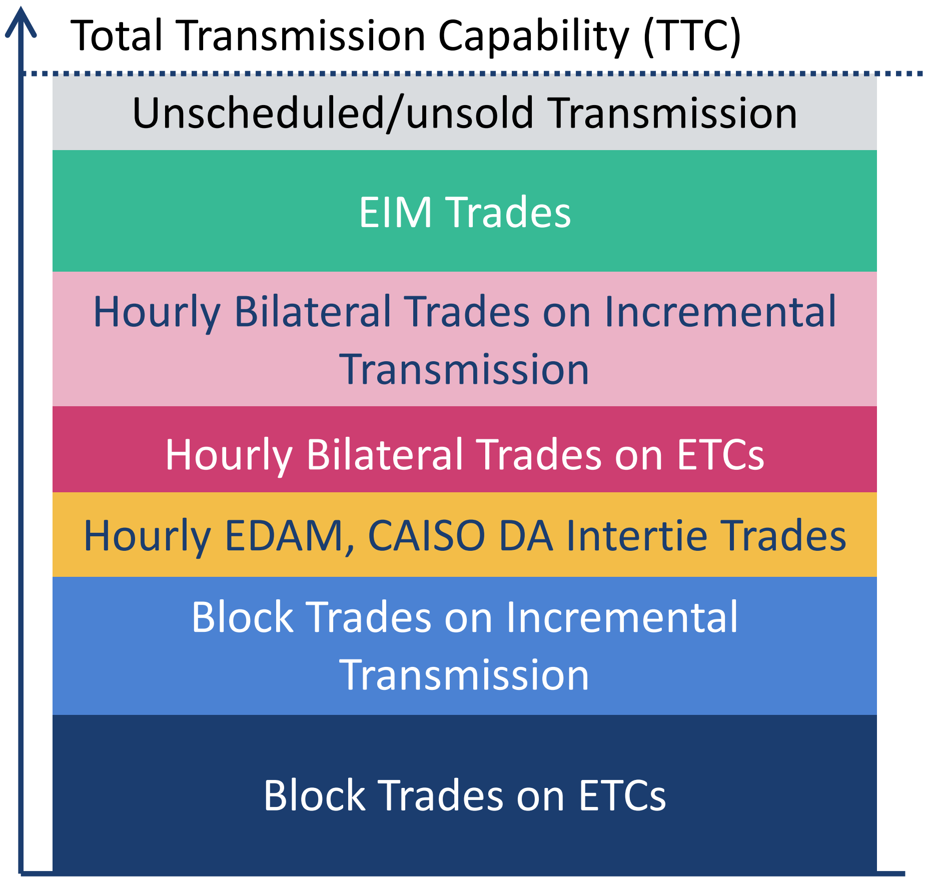
These cycles can take on different assumptions, depending on market structure. In a bilateral setting, all are set up to analyze utility-specific unit commitment and dispatch decisions, with each of them including hurdle rates and transmission fees that limit the amount of economic transactions that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

Types of Trades and Transmission Reservations Modelled

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

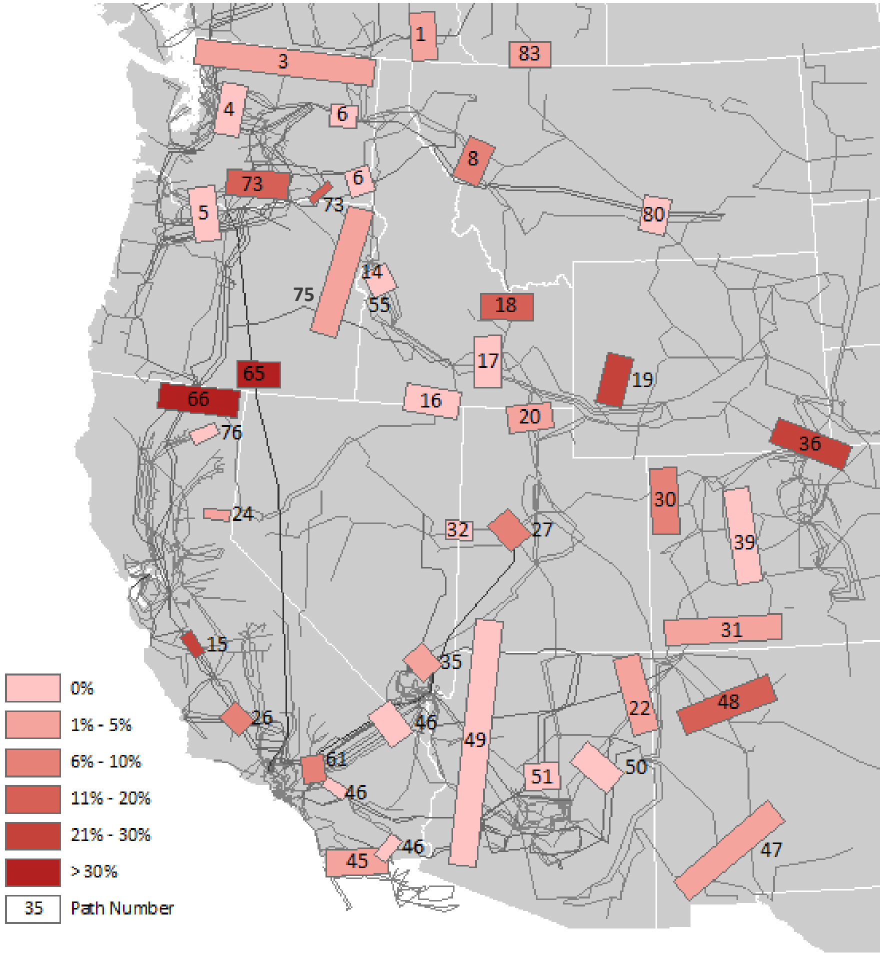
- Existing long-term transmission contracts (ETCs) and incrementally purchased transmission
- Total reservations on each contract path is limited by the total transfer capability (TTC)
- Trades are structured as blocks or hourly
- Bilateral trades between BAAs, at major hubs, or across CAISO interties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

Types of Trades Modeled



Nodal Simulations Based on Physical Transmission

WECC-Defined Paths Modeled



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

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

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

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

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

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

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