Day-Ahead Market Participation Benefits Studies for EPE

SENSITIVITY: EPE IN MARKETS+ & PNM IN EDAM WITH EDDY TIE VALUE

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Review of Studies Conducted for El Paso Electric

1 Summer 2024

2 Fall 2024

Joint EPE-PNM Study

- In this study, we analyzed three cases, each one with EPE and PNM choosing the same market:
  - Current Trends: EDAM and Markets+ form in the WECC, but PNM and EPE stay in WEIM.
  - EDAM Case: EPE and PNM both join EDAM
  - Markets+ Case: EPE and PNM both join Markets+

EPE Sensitivity Analyses

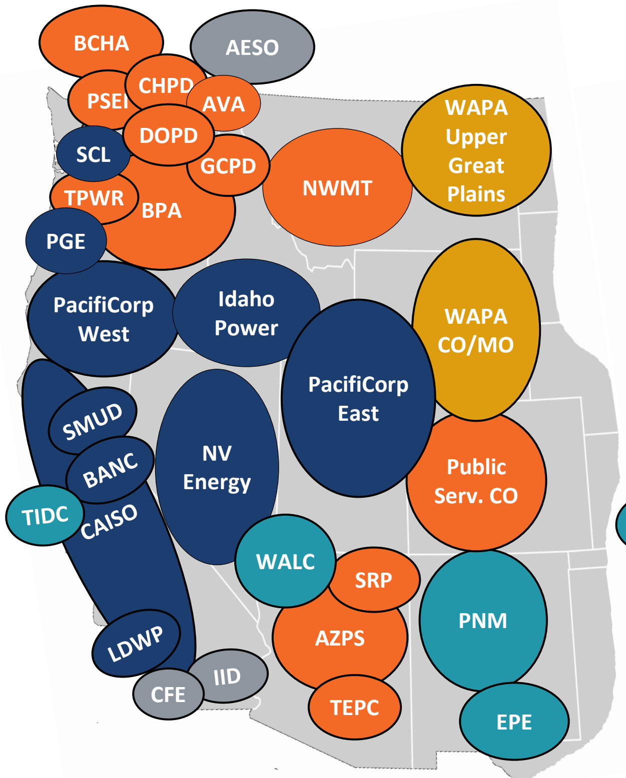
- EPE asked us to conduct to new analyses to add to the result from the Joint EPE-PNM study:
  - Different Market than PNM: in this case PNM joins EDAM while EPE joins Markets+
  - Value of the Eddy DC Tie: we analyzed the value of the DC tie for EPE customers, including the potential value in Markets+ with dispatch of the tie optimized with the SPP RTO in the east

For the new sensitivities, we used the same 2032 model of the WECC as the joint EPE-PNM study, which has been refined through numerous studies with entities across the WECC, including transmission rights, transmission costs, load forecasts, fuel prices, generation mix and costs, etc.

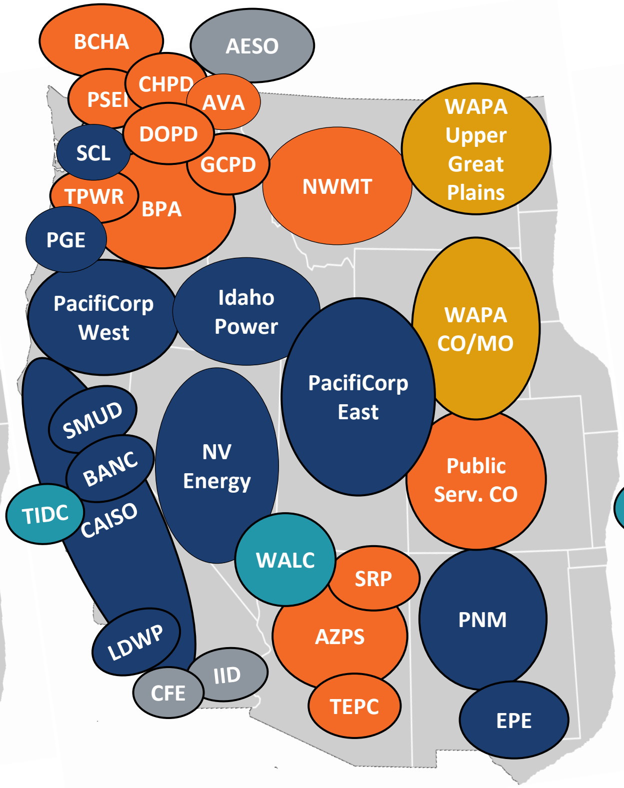
- Previous study participants include **BANC, Idaho Power, LADWP, NV Energy, Portland General Electric, PacifiCorp, Sacramento Municipal Utility District,** and other utilities, transmission owners and independent power producers
- Long-term transmission rights, contracted resources (and transmission encumbrances), generation additions, transmission additions, renewable diversity and forecast errors, and market design detail/implementation

Review of Footprints Analyzed

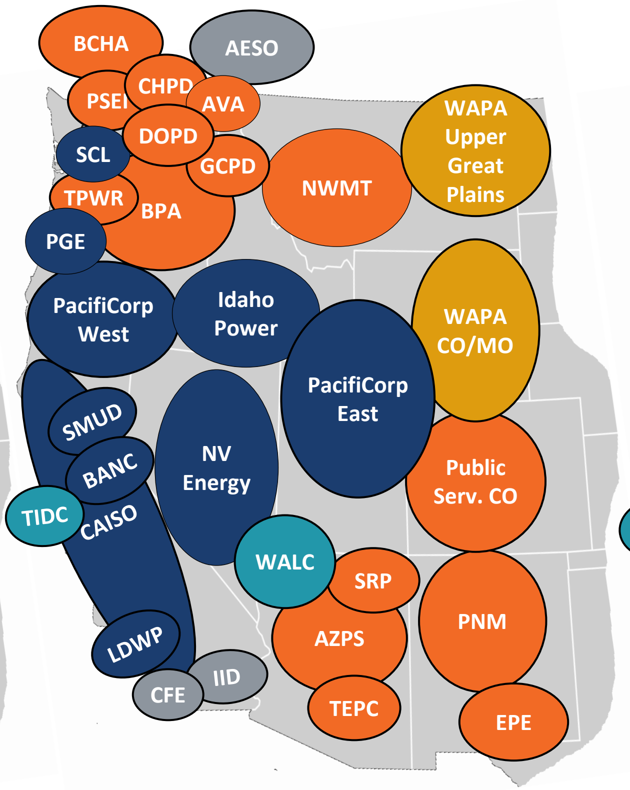
Current Trends



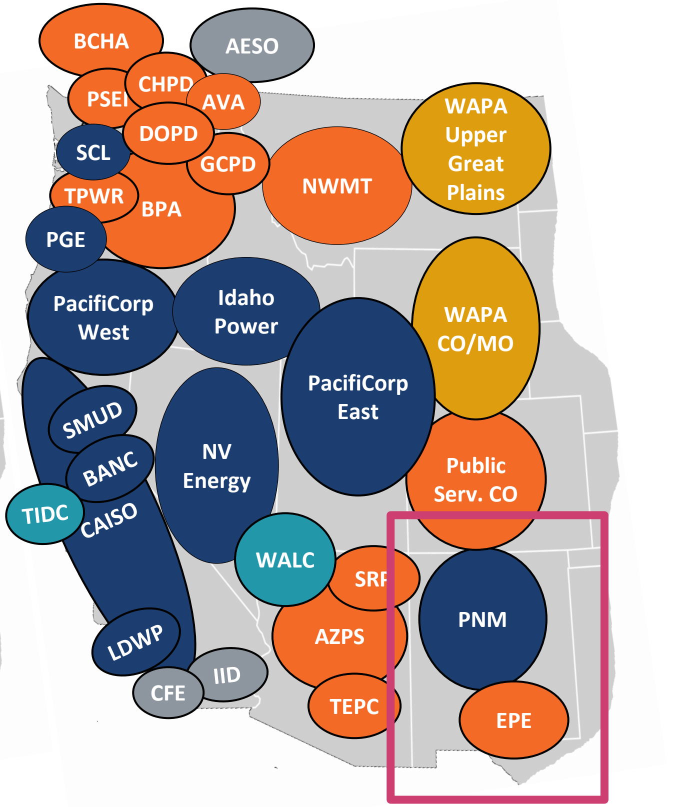
EDAM



Markets+



Sensitivity



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

The value of trading over the Eddy tie is calculated for all four cases.

EPE Markets+ Sensitivity Results

Sensitivity Case Overview

Key features of this sensitivity include:

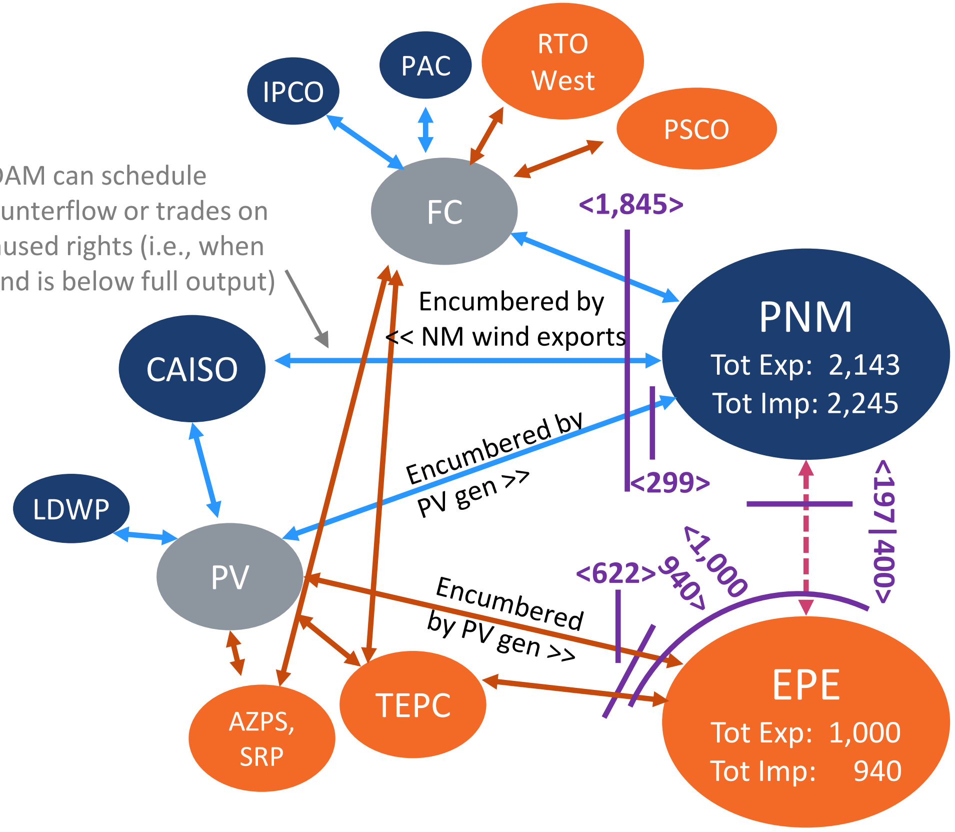
- Trading friction between EPE and PNM is lower than in the Current Trends scenario
  - The Markets+ design enables intertie bidding by default, which makes Markets+ seams as more efficient than an EDAM or bilateral seams
  - The seam between PNM and EPE becomes a Markets+ seam, resulting in lower-friction PNM-EPE trading in day ahead in the Sensitivity than in the CT case
- Being in a different market than PNM reduces the trading paths available to EPE within Markets+, but creates the opportunity to retain bilateral trading with PNM
  - With PNM in EDAM for this scenario, EPE can execute Markets+ trades with TEPC and via Palo Verde
  - EPE remains with option to trade bilaterally with PNM (via Markets+ intertie trades)
  - Eddy tie assumed to be optimized in Markets+ *(see slide 6)*

We calculated a high-level estimate of Eddy tie value for the sensitivity and all prior scenarios using scenario-specific simulation outputs and leveraging the APC calculation

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

Contract-Path Trading Capability & Encumbrances, Sensitivity

(transfer capability values shown in MW)



EDAM can schedule counterflow or trades on unused rights (i.e., when wind is below full output)

EDAM can schedule counterflow on PNM's PV rights or trades on unused transfer capability

The direct PNM/EPE connection becomes a market seam, with trading via Markets+ intertie trades in the Sensitivity rather than market trades as in EDAM and Markets+ cases, or bilateral trades as in Current Trends case

Markets+ can schedule counterflow on EPE's PV rights or trades on unused transfer capability

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

Estimated Eddy Tie Value Methodology

We calculate an "Eddy-adjusted" APC for each case assuming imports on the Eddy tie substitute for EPE market purchases and exports increase market sales in the APC calculation, thus impacting EPE's purchases, sales, and production costs associated with transfers over the tie.

- In the Current Trends and EDAM cases were estimated the tie value using historical 2023 Eddy tie flows
- In the Markets+ case we created a "market optimized" tie schedule where EPE imports at the max Eddy tie capacity in hours when it is buying from the market and exports on the tie in hours where it is selling into the market. This approach aligns DC tie flows with internal EPE price fluctuations.
  - We include tie outages from the historical 2023 profile in the optimized schedule as a proxy for typical annual outages

- We calculate the estimated Eddy tie value in each case as the difference between the Eddy-adjusted APC and the original, unadjusted APC

Our approach relies on the following assumptions:

- Eddy tie flows do not impact prices in EPE (i.e., we treat it as a price taker)
- Eddy tie flows do not shift between day-ahead and real-time (i.e., no tie imbalance impacts)
- The SPP East market is liquid enough to supply/receive all Eddy tie flows, at prices comparable to Markets+ prices.
- We have not calculated the impact on congestion revenue associated with tie flows or tie-flow-driven changes in congestion with other EPE neighbors, which could impact the estimated tie value.

EPE Benefits Overview

EPE's net benefit from joining Markets+ in the Sensitivity case is $18.8 million per year.

- **Incorporating estimates of Eddy tie value bring Markets+ benefits closer to EDAM benefits**, assuming full tie capacity is available and optimized only in Markets+
  - Our estimate of tie value for Markets+ assumes 200 MW of bi-directional capacity that can be fully optimized in the market. However, if we limit the optimized tie flow to levels observed in 2023 (~120 MW max) we find that net Eddy tie value is reduce by ~$8 million per year, or ~75% of the value relative to EDAM.
- **Compared to the case where PNM also joins Markets+, EPE's benefits decline $1.3 million per year**
  - Adjusted production cost *increases* $3.1 million per year in the Sensitivity relative to the Markets+ case, largely due to reduced off system sales to PNM, are the primary driver of lower benefits
  - Trading revenues are nearly identical between the cases (both ~$12.5 - $13 million), with the reduction in M+ congestion revenue offset by increased bilateral trading gains with PNM

Summary of EPE Market Participation Impacts

$ Million/Year

Benefit Metric	Metric	CT	EDAM	Markets+	Sensitivity
Adjusted Production Cost	*Cost*	$73.6	$70.5	$62.2	$65.3
Short-term Wheeling Revenue	*Revenue*	$0.5	$0.4	$0.0	$0.0
EDAM Congestion Revenue	*Revenue*	-	$12.4	-	-
WEIM Congestion Revenue	*Revenue*	$7.8	$3.6	-	-
Markets+ DA Congestion Revenue	*Revenue*	-	-	$8.1	$4.8
Markets+ RT Congestion Revenue	*Revenue*	-	-	$4.4	$1.3
Bilateral Trading Revenue [1]	*Revenue*	$6.6	$14.4	$0.0	$6.9
APC Less Revenues		**$58.8**	**$39.7**	**$49.7**	**$52.2**
Net Benefits			**$19.1**	**$9.1**	**$6.6**
Estimated Eddy Tie Value	*Revenue*	$9.4	$9.6	$20.4	$21.6
Net Eddy Tie Value			$0.2	$11.1	$12.3
Net Benefits Including Eddy Tie			**$19.3**	**$20.1**	**$18.8**

Notes:

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

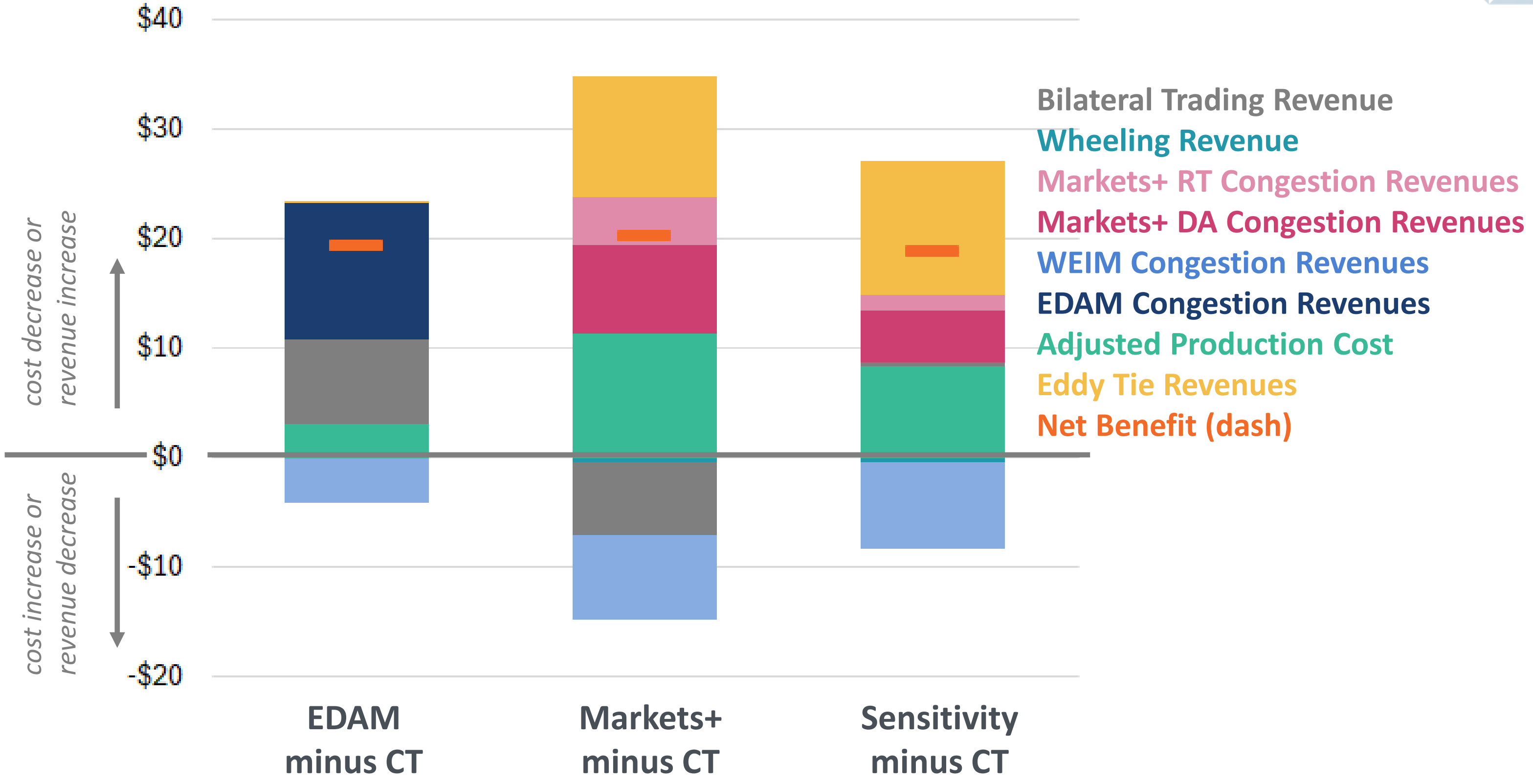
EPE Benefits Drivers by Case

EPE's stack of net benefits in the Sensitivity remains similar to the Markets+ case but is lower in most categories

- Markets+ congestion revenues decline as EPE only trades with TEPC and PV
- Adjusted production cost savings are lower due to lower EPE off system sales, especially with PNM
- Bilateral trading revenues retained at levels similar to the CT case as PNM/EPE path remains bilateral
  - Trading volumes decline with PNM, but the average trading value increases enough to nearly offset the decline
- Estimated Eddy tie value slightly higher in Sensitivity case than M+ case

Summary of Benefit Drivers

$ Million/year



Notes: Eddy tie value estimates shown assume 200 MW of bidirectional capacity optimized in Markets+, and a fixed tie schedule at 2023 historical flows in CT and EDAM

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

EPE Trading Results by Case

EPE total trading volume and value in the sensitivity is similar to the Markets+ case, though bilateral trades play a larger role

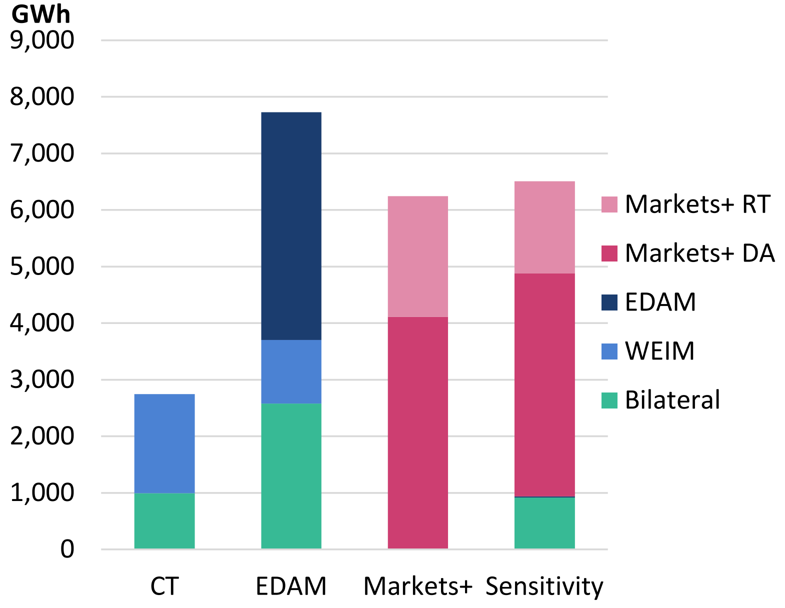
- The EPE/PNM path is assumed to be a Markets+ seam with intertie bidding in the Sensitivity
  - We model the trading cost for M+ interties at $3/MWh less than a bilateral trade but $3/MWh more than an internal Markets+ trade
- Trade volumes with PNM are cut by more than half in the sensitivity from the Markets+ case, but the value only declines about $1 million as the remaining trades increase in average value

Total EPE Trading Revenue & Volume by Counterparty and Case

	CT Case			EDAM Case			Markets+ Case			Sensitivity Case		
Counterparty	Value	Flows	Value per MWh	Value	Flows	Value per MWh	Value	Flows	Value per MWh	Value	Flows	Value per MWh
	$ Millions	*GWh*	*$/MWh*	*$ Millions*	*GWh*	*$/MWh*	*$ Millions*	*GWh*	*$/MWh*	*$ Millions*	*GWh*	*$/MWh*
TEPC	$4.5	741	$6	$14.4	2,226	$6	$4.4	3,902	$1	$5.7	5,477	$1
PNM	$9.9	1,855	$5	$14.8	4,006	$4	$7.5	2,199	$3	$6.8	913	$7
TH_PV	$0.0	0	-	$1.2	297	$4	$0.5	118	$4	$0.4	119	$4
Total	**$14.4**	**2,596**	**$5.5**	**$30.4**	**6,529**	**$4.7**	**$12.4**	**6,219**	**$2.0**	**$13.0**	**6,509**	**$2.0**

Notes: Does not include Eddy tie value estimate impacts.

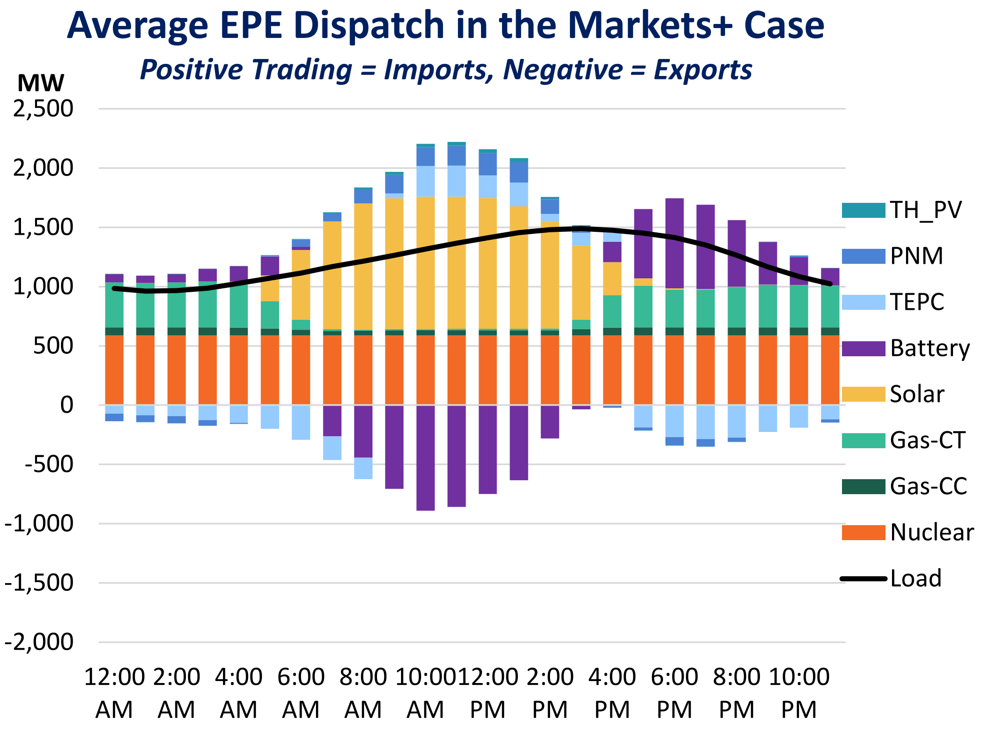
EPE Total Trade Volume by Type

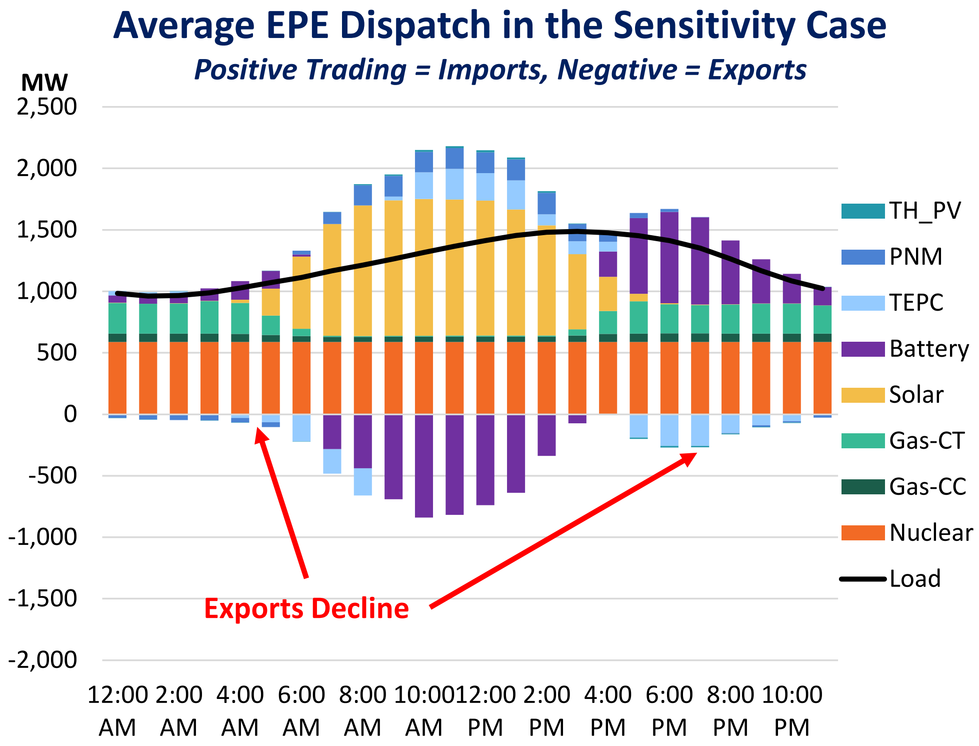


EPE Dispatch and Trading by Time of Day

EPE's trading mostly changes overnight, when it sells less off system compared to the Markets+ case

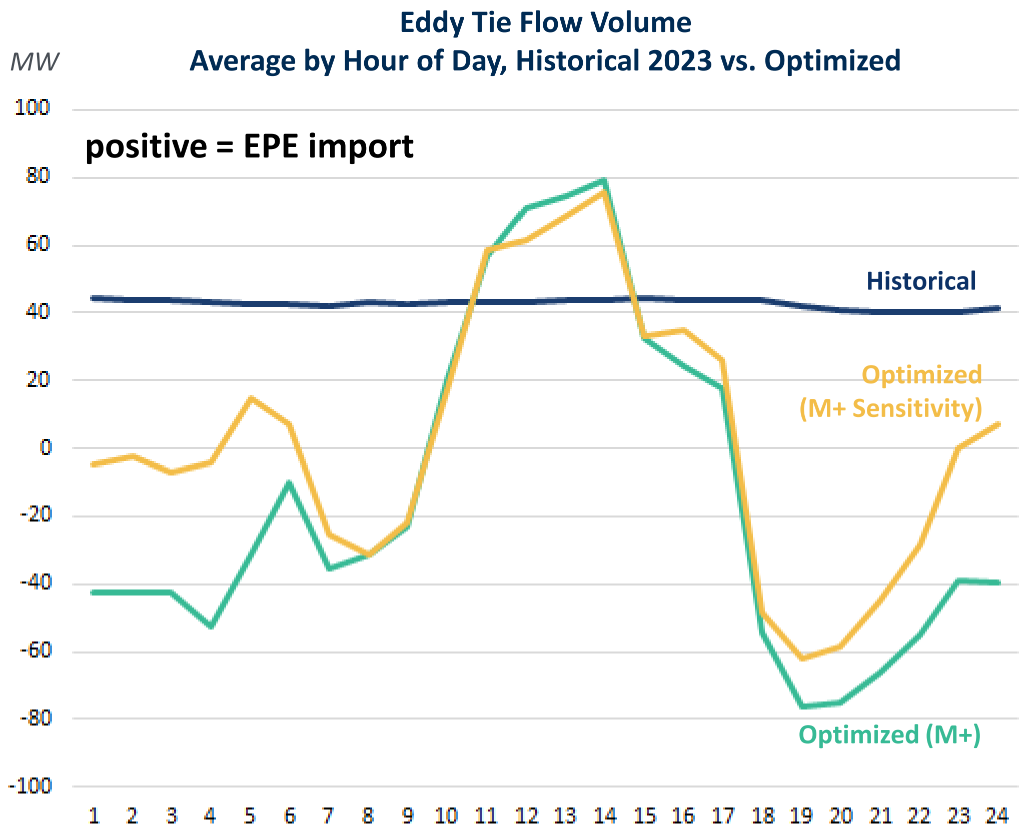
- Gas CT dispatch declines on average about 100 MW every hour in the morning and evening
- Dispatch from other resources remains nearly identical to the Markets+ case

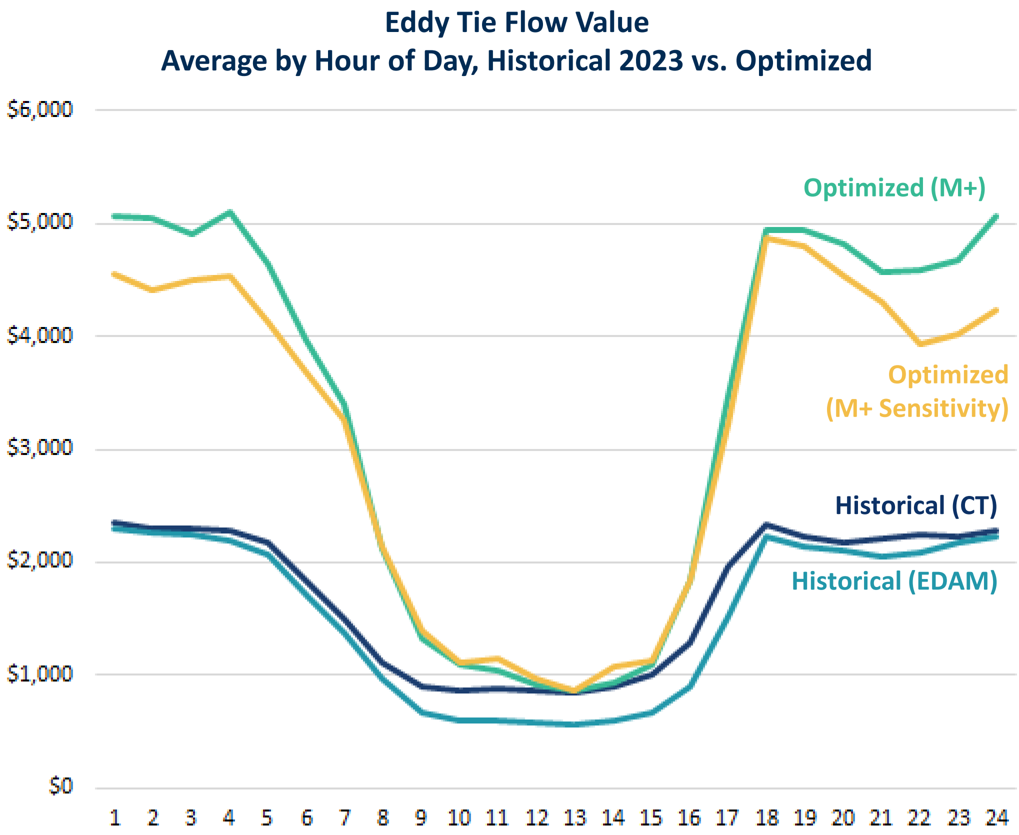




Eddy Tie Flows and Estimated Value

- Optimized tie flows differ considerably from historical 2023 flows, which are exclusively imports to EPE
- Estimated tie value shows strong diurnal pattern with most value from increased nighttime sales due to higher prices during those periods, a strong driver of higher estimated value in optimized M+ relative to fixed CT & EDAM





Appendix:
Detailed APC Results

Sensitivity – CT: Adjusted Production Cost Benefit

Compared to the CT case, EPE sees a net benefit of $8.4 million in the sensitivity

1. Generation declines about 500 GWh, saving $12 million, with most of the decline from Gas CTs
2. Purchase costs increase about $21 million as EPE buys 1,700 GWh in the day-ahead, mostly from TEPC
3. Sales revenues also increase ~$17 million as EPE sells ~500 GWh more in day-ahead, though average sales prices decline slightly ($2/MWh)

Adjusted Production Cost Comparison for EPE

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**CT**	**Markets+**	**Difference**	**CT**	**Markets+**	**Difference**	**CT**	**Markets+**	**Difference**	
Production Cost	(+)	[1]	10,936	10,458	**-478**	$7.68	$6.88	**-$0.80**	83,995	71,936	**-$12,059**	(1)
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	0	1,721	**1,721**	$40.16	$21.52	**-$18.63**	4	37,049	**$37,045**	(2)
Real-Time Market		[5]	1,172	599	**-573**	$24.09	$20.37	**-$3.72**	28,239	12,202	**-$16,037**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	833	1,320	**487**	$29.10	$27.16	**-$1.94**	24,231	35,847	**$11,616**	(3)
Real-Time Market		[8]	479	662	**183**	$30.09	$30.34	**$0.25**	14,401	20,081	**$5,680**	
Total Cost *(Negative Difference = Benefit)*		[9]	**10,797**	**10,797**	**0**	**$6.82**	**$6.04**	**-$0.77**	73,606	65,259	**-$8,347**	
% Change in APC											***-11.3%***	

Notes: Does not include Eddy tie value estimate impacts.

Sensitivity – Markets+: Adjusted Production Cost Benefit

Compared to the Markets+ case, EPE sees a $3.1 million increase in APC

1. Generation declines about 600 GWh, mostly from Gas-CTs, as EPE no longer makes as many overnight sales to PNM, saving $20 million
2. Purchase costs increase about $8 million as EPE buys more in day-ahead to replace lower generation
3. Sales revenues decline $15 million as EPE sells less gas in overnight hours, reducing their average day-ahead sales price by about $2.5/MWh

Adjusted Production Cost Comparison for EPE

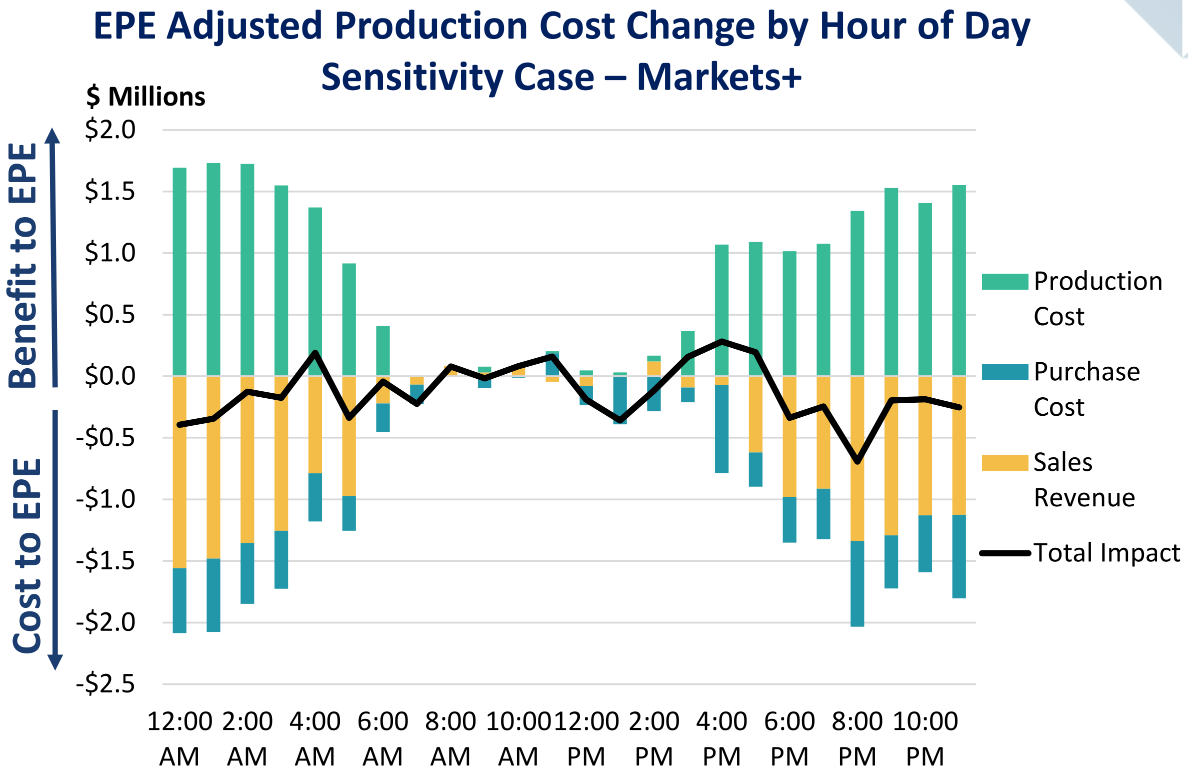
			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Markets+**	**Sensitivity**	**Difference**	**Markets+**	**Sensitivity**	**Difference**	**Markets+**	**Sensitivity**	**Difference**	
Production Cost	(+)	[1]	11,048	10,458	**-590**	$8.33	$6.88	**-$1.45**	91,977	71,936	**-$20,041**	(1)
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	1,521	1,721	**200**	$18.17	$21.52	**$3.35**	27,635	37,049	**$9,414**	(2)
Real-Time Market		[5]	610	599	**-11**	$22.21	$20.37	**-$1.84**	13,546	12,202	**-$1,344**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	1,672	1,320	**-352**	$29.61	$27.16	**-$2.45**	49,507	35,847	**-$13,660**	(3)
Real-Time Market		[8]	710	662	**-48**	$30.25	$30.34	**$0.08**	21,488	20,081	**-$1,408**	
Total Cost *(Negative Difference = Benefit)*		[9]	**10,797**	**10,797**	**0**	**$5.76**	**$6.04**	**$0.29**	62,163	65,259	**$3,095**	
% Change in APC											***5.0%***	

Notes: Does not include Eddy tie value estimate impacts.

APC Change by Time of Day

Compared to the Markets+ case, on average EPE's adjusted production cost loss is in the overnight hours

- **Midday APC remains about the same**, with reduced dispatch costs roughly netting out with changes in sales revenue and purchase costs
- **Outside of midday APC declines** as increased trading friction between PNM and EPE relative to Markets+ case reduces **EPE sales to PNM**
  - EPE sales to PNM are at a greater disadvantage to PNM transactions from other EDAM market participants with which it has connectivity, such as, PACE, Idaho, or CAISO



Appendix:
Modeling Inputs and Assumptions

Multi-Functional Simulation of WECC

Markets/RTO Functions & Configurations

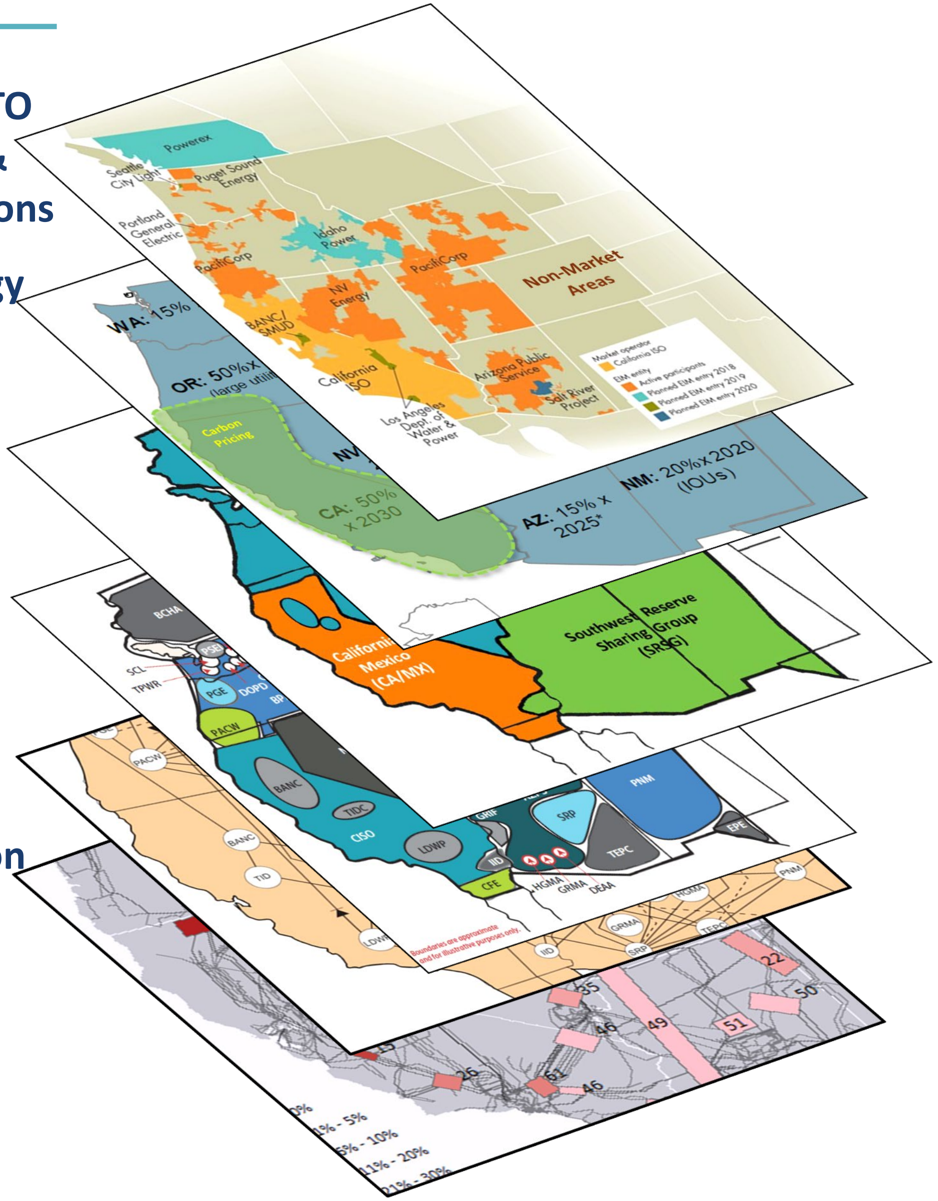
Clean Energy Policies

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

PNM & EPE Capacity Mix

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

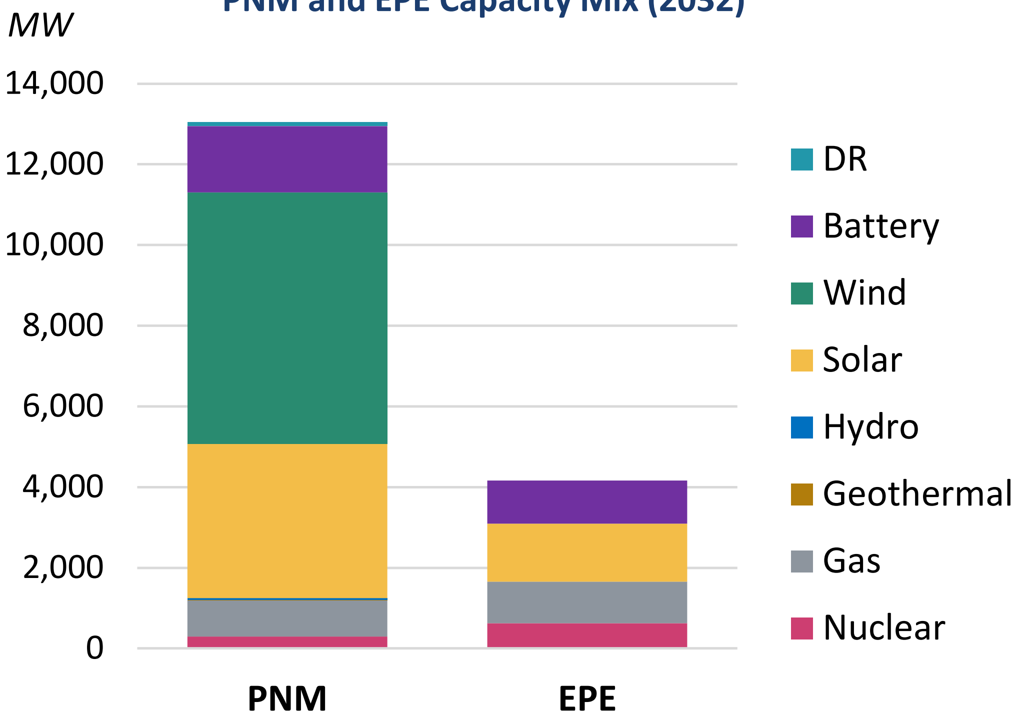
PNM and EPE Capacity Mix (2032)

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)



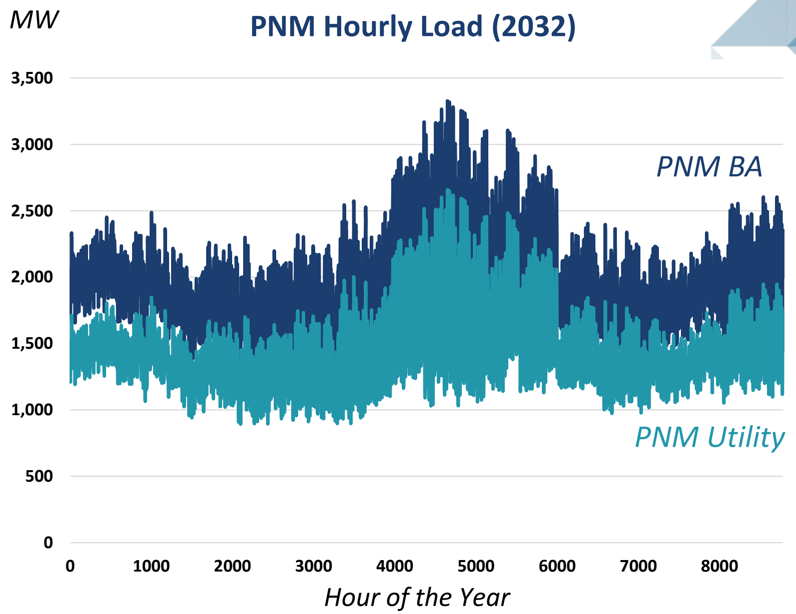
PNM & EPE Peak and Energy Forecast

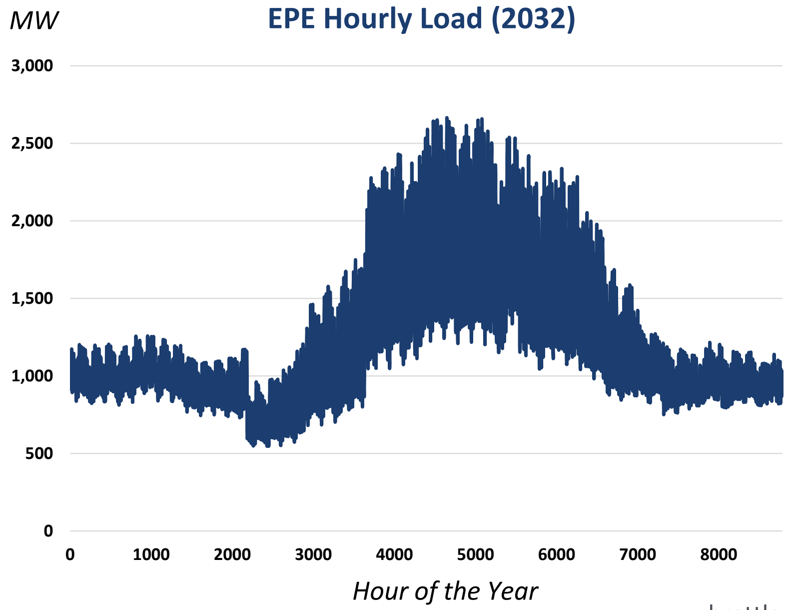
PNM and EPE are summer-peaking systems. Total annual load in 2032 is 17 TWh in PNM and 10.8 TWh in EPE. PNM's load accounts for ~74% of total BA load.

PNM & EPE Modeled Load (2032)

Month	PNM BA Total Load (MWh)	PNM BA Peak (MW)	PNM Utility Total Load (MWh)	PNM Utility Peak (MW)	EPE BA Total Load (MWh)	EPE BA 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)

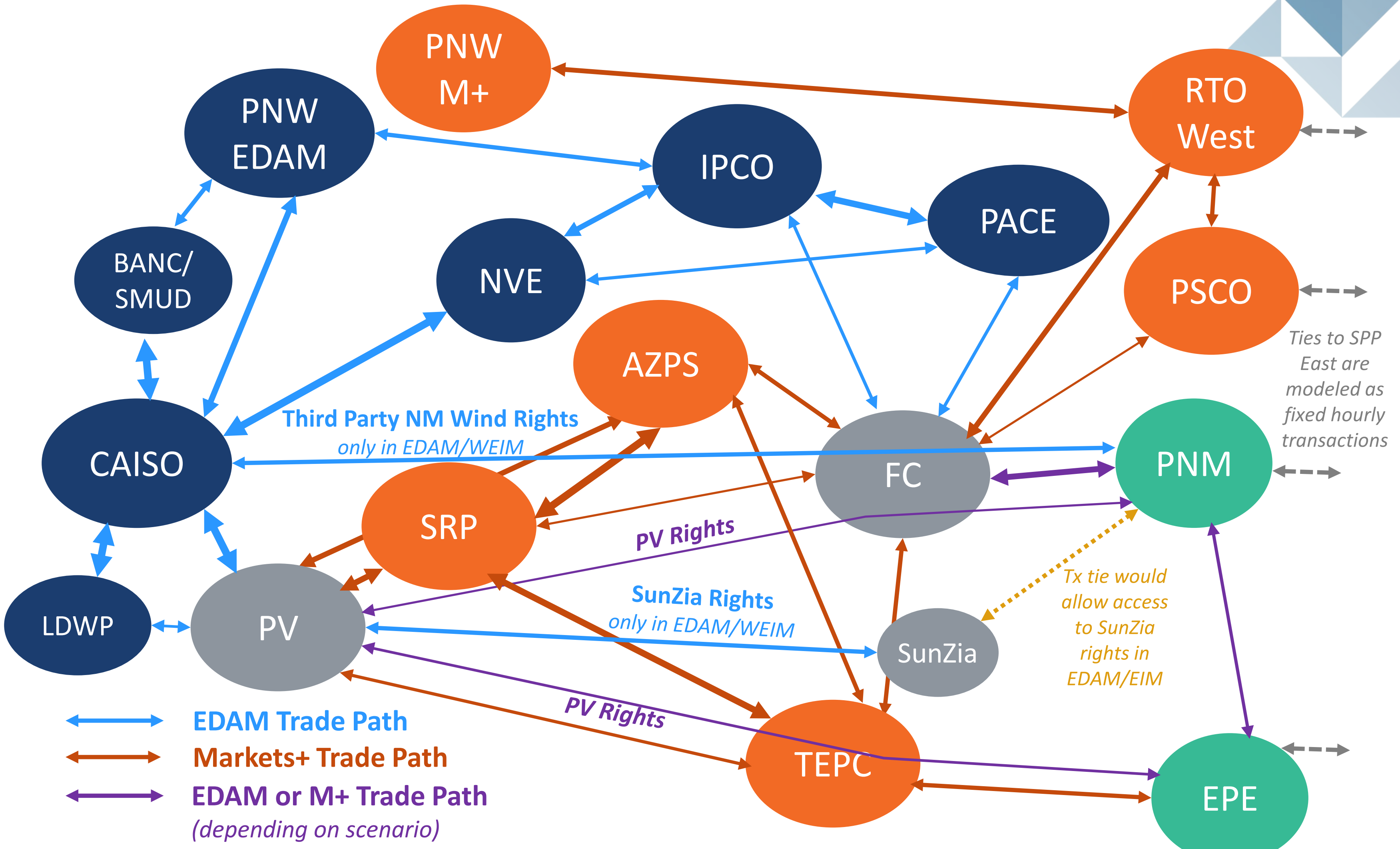
Transaction Type	Friction Charge	Transaction Pays OATT?
	$/MWh	*Yes/No*
Bilateral Transactions	$6	Yes*
Block Transactions	$1.5	Yes*
EDAM and WEIM Transactions	*None*	No
Markets+ DA / RT Transactions	*None*	No
RTO Intertie Transactions	$1.5	Yes*
Markets+ Seam Transactions	$3	Yes*
EDAM Seam Transactions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

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

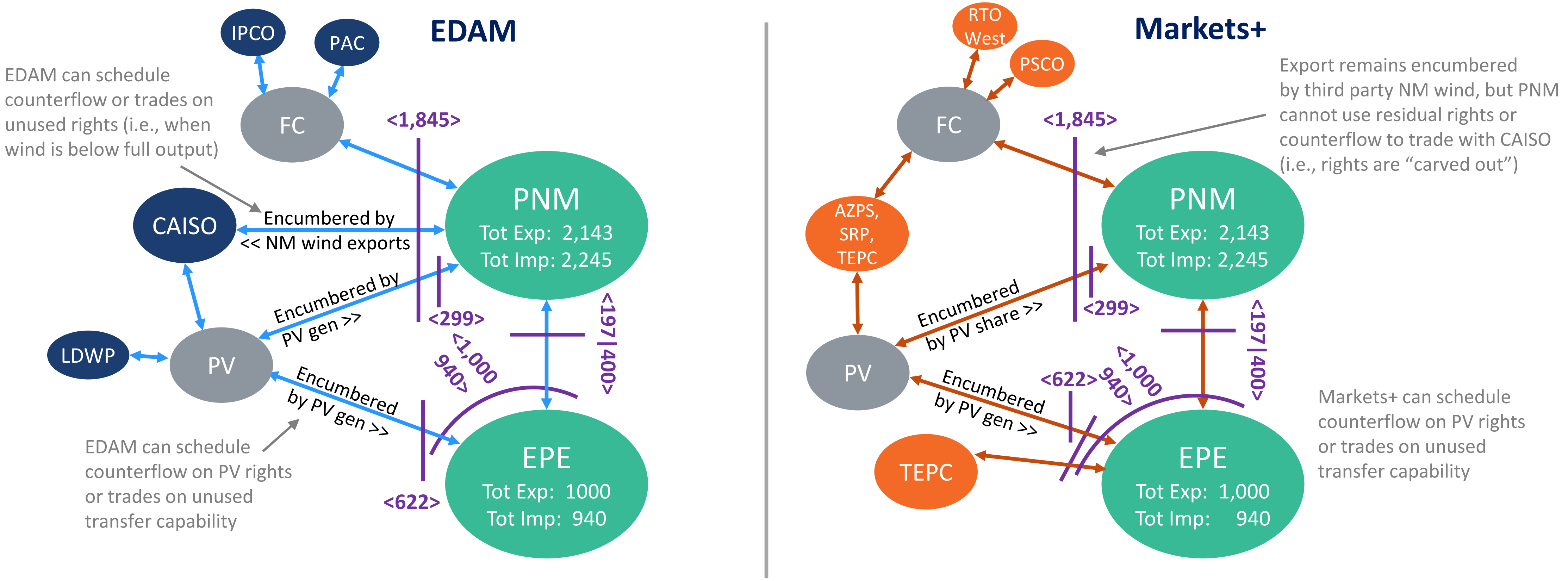


Note: Diagram shows only EDAM or M+ trading paths. We also model bilateral hourly, bilateral block, and intertie trading paths between entities, though leave them out here for simplicity. SunZia rights would only be available hurdle free in EDAM. Width of arrow indicates magnitude of TTC on path.

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