NV Energy Day-Ahead Market Benefits Studies

COMPARATIVE BENEFITS FOR NV ENERGY OF JOINING EDAM VS MARKETS+

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Brattle

Overview of NVE Market Benefits Studies

Timeline of NVE Market Benefits Studies

Brattle was engaged by NV Energy (NVE) through the second half of 2023 and into early 2024 to conduct a series of EDAM and Markets+ (M+) participation benefits studies

1 Summer 2023

EDAM Benefits Study

Expanded the modeling conducted for the Balancing Authority of Northern California (BANC), Idaho Power (IPCO), Los Angeles Dept. of Water and Power (LADWP), PacifiCorp (PAC), and the Sacramento Municipal Utility District (SMUD) to include NVE.

We studied two cases:
(1) A **business as usual (BAU) case**, maintain the existing WEIM and existing bilateral market
(2) An **EDAM case** with a market footprint including NVE, BANC, CAISO, IPCO, LADWP, PacifiCorp, and Portland General Electric (PGE).

2 Fall 2023

M+ Benefits Study

As the M+ design developed, we studied the benefits of joining M+ based on the proposed design as of October 2023.

We studied two additional cases:
(1) A **BAU case** with a small EDAM footprint (CAISO, PAC, LDWP, BANC), the WEIM with all current participants, and the SPP RTO West/Western Energy Imbalance Service (WEIS)
(2) An **M+ case** in which all non-EDAM participants in the U.S. WECC (except IID and TIDC) plus PowerEx join M+ (with a day-ahead and real-time M+ market)

3 January 2024

EDAM/M+ Footprint Scenarios

We analyzed the customer benefits for NVE under a range of EDAM and M+ market participation scenarios

We studied six additional cases:
(1) A **BAU case**, with bilateral markets & WEIM
(2) A **Bookend EDAM case**, in which most of the WECC joined EDAM
(3) A **Bookend Markets+ case**, in which most of the WECC not committed to EDAM joined Markets+
(4) - (6) three cases of **varying EDAM/M+ footprints** including different market participation for NVE

Estimated NVE market participation benefits ($million per year)

	1 Summer 2023	2 Fall 2023		3 January 2024
EDAM	$113	--	(1) EDAM and (2) M+ study benefits fall in range of (3) Footprint Scenario benefits	$62 to $149
M+	--	$5		-$17 to $16

Scope of Studies

Scope: to simulate the specific 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 wheeling revenue, (3) loss of 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 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 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 infrastruture
- **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 the existing WEIM and WEIS markets**, meaning all noted cost and benefit metrics already include an entity's benefit coming from WEIM and WEIS (and thus all results show incremental loss or gain as a day-ahead market is formed)

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

Estimated EDAM & M+ Benefits are Conservatively Low

The estimated benefits are likely understated due to several factors:

- **Overstated base-case efficiency:** our simulation of the BAU is more efficient than reality
  - The Base 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 by bilateral trades is not fully modeled, understating the extent M+ and EDAM will be able to make better use of all physically and contractually available transmission.
  - Transmission outages are not modeled, which would magnify the benefit of SCED-based congestion management in EDAM and M+ compared to the BAU
- **Normalized loads and fuel prices:** the model uses weather-normalized loads and averaged monthly natural gas prices without daily volatility
  - Challenging market conditions (beyond the included heat wave and cold snap), such during as the 2022 gas price spikes, will magnify EDAM/M+ benefits. Illustrated by the WEIM experience of much higher benefits in 3Q of 2021 and 3Q-4Q of 2022
  - The Base Case does not reflect the limited liquidity of bilateral market during challenging market 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

Summer 2023 NVE EDAM benefits study

Overview of Study Setup

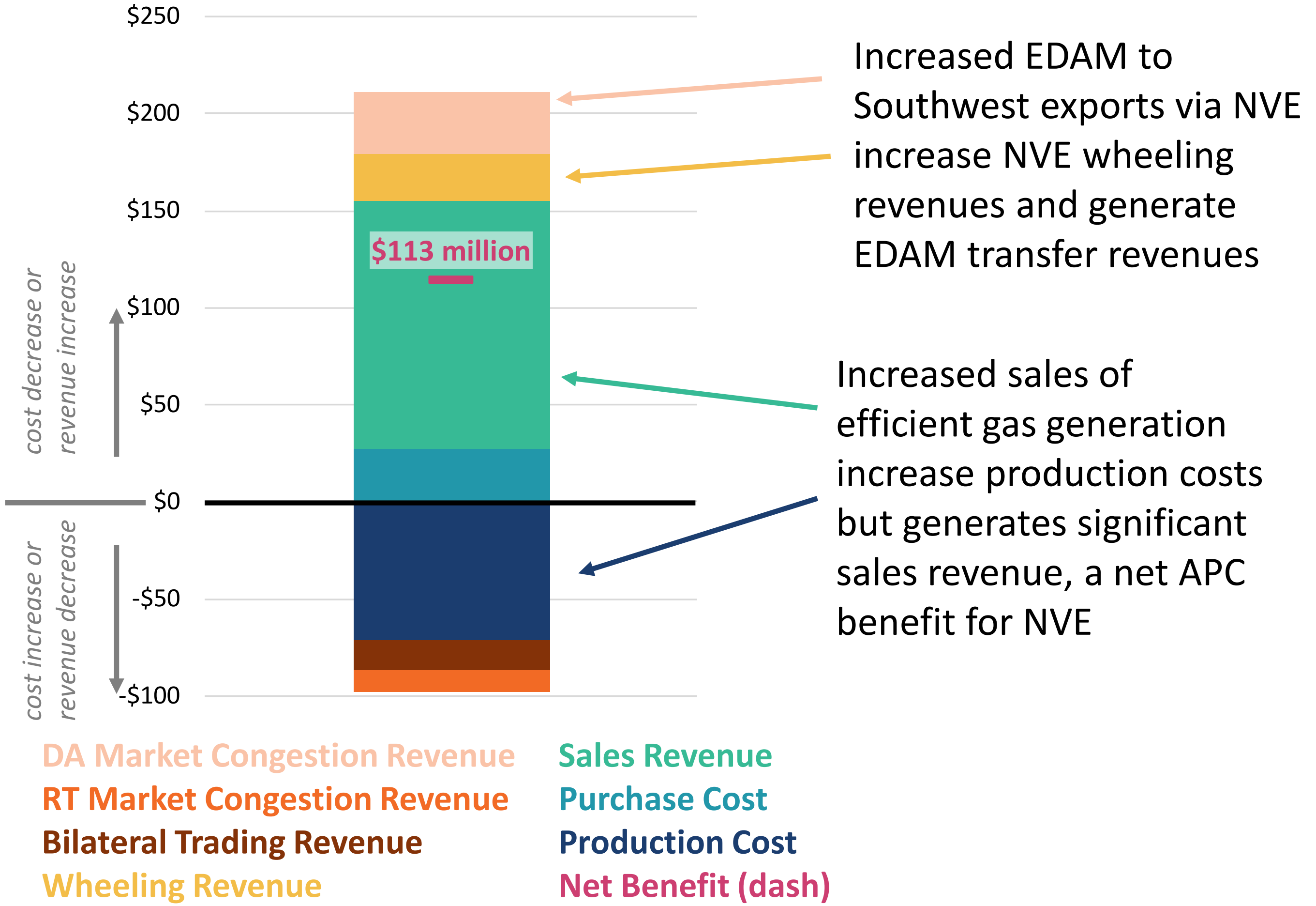
1 **2022 EDAM Benefits Study model**
BAU & EDAM scenarios

2 **Updates & Enhancements:**
- NVE resource mix, load, and transmission updates
- Other joint study funder resource mix, load, and transmission updates
- Add NVE to EDAM footprint
- Updated CAISO/PAC resource mix & load to latest IRPs
- Add Trans West Express

3 **NVE EDAM Benefits Study model**
BAU & EDAM scenarios

Summary of NVE EDAM Participation Benefit Drivers

$million, EDAM minus BAU cases



Fall 2023 NVE Markets+ benefits study

Overview of Study Setup

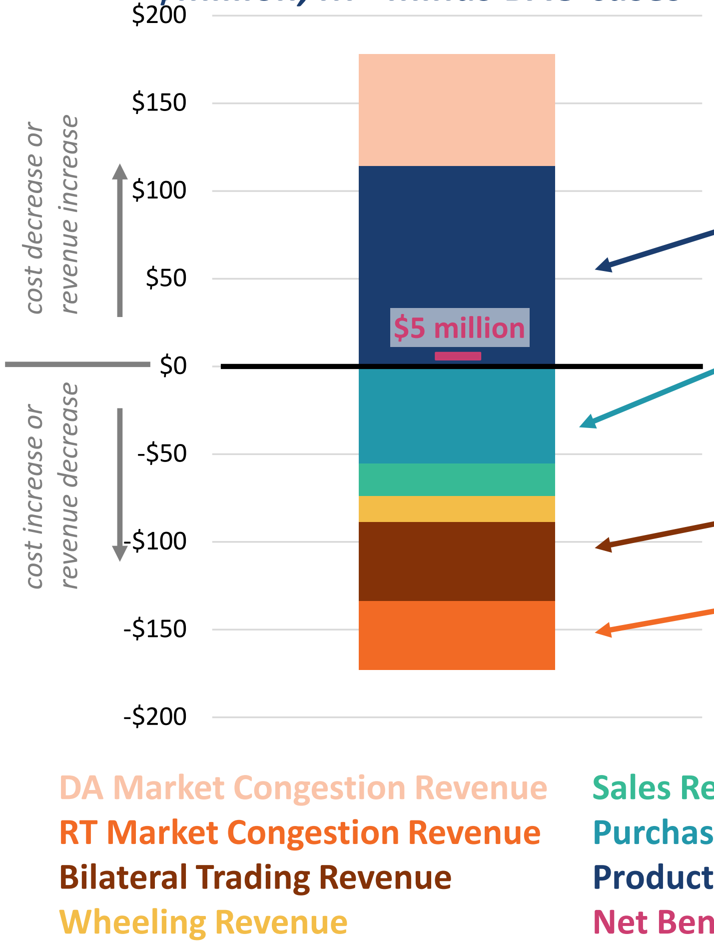
1 **NVE EDAM Benefits Study model**
BAU & EDAM scenarios

2 **Updates & Enhancements:**
- Added M+ footprint
- Added SPP West RTO and WEIS footprints
- Reduced WEIM footprint (shifts to M+)
- Expanded DA/RT forecast uncertainty modeling to all US WECC BAs (previously just study participants)

3 **NVE M+ Benefits Study model**
BAU & M+ scenarios

Summary of NVE M+ Participation Benefit Drivers

$million, M+ minus BAU cases



Decrease in gas generation, especially in real time, decreases production costs, but also reduces sales revenue and increases purchase costs

Leaving WEIM and decreased bilateral trading due to multiple market footprints results in significant lost trading revenue, only partially offset by M+ transfer revenues

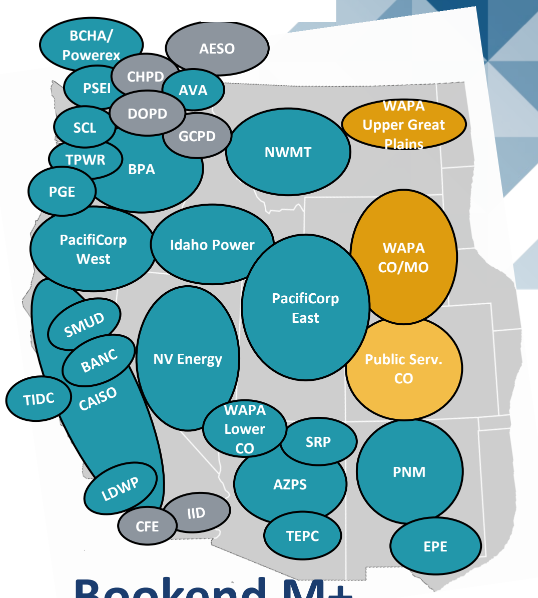
January 2024 EDAM/M+ Footprint Scenarios

Footprint scenarios designed to capture realistic range of potential future market footprints

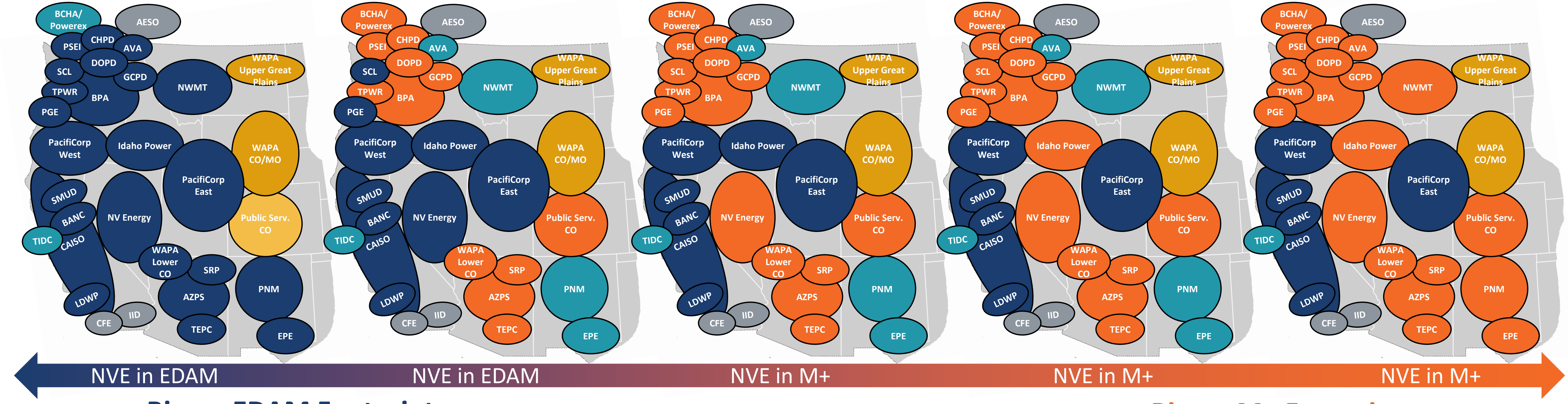
- M+ assumed to have day-ahead and real-time markets
- RTO West co-optimized with M+ where applicable

SPP RTO West
WEIS only
Markets+
EDAM & WEIM
WEIM only
Non-Market BA

BAU



Bookend EDAM | Middle View 1 | Middle View 2 | Middle View 3 | Bookend M+



Bigger EDAM Footprint | **Bigger M+ Footprint**

Nevada Benefits in the EDAM/M+ Footprint Scenarios

The footprint scenarios suggest NVE benefits are higher in EDAM than in Markets+

- EDAM benefits range from $62 million to $149 million
- Markets+ benefits range from a loss of $17 million to a benefit of $16 million

Nevada Energy System Cost by Case ($ Millions)

		BAU	Bookend EDAM	Middle View 1	Middle View 2	Middle View 3	Bookend Markets+
Market Membership	**Metric**	**EIM Only**	**EDAM**	**EDAM**	**Markets+**	**Markets+**	**Markets+**
Adjusted Production Cost	Cost	$485.5	$420.1	$357.0	$425.4	$420.8	$415.4
Wheeling Revenues	Revenue	$16.6	$0.0	$14.9	$0.5	$0.3	$0.4
Trading Revenues:							
Bilateral	Revenue	$72.2	$0.0	$10.2	$4.9	$4.0	$4.2
WEIM	Revenue	$33.2	$30.1	$19.0			
WEIS/Mk+ RT Market	Revenue				$9.3	$11.5	$11.2
EDAM	Revenue		$88.3	$98.0			
Markets+	Revenue				$30.0	$50.3	$52.2
Total System Cost		**$363.6**	**$301.6**	**$214.8**	**$380.6**	**$354.8**	**$347.3**
Benefit to BAU			**$61.9**	**$148.7**	**-$17.0**	**$8.8**	**$16.2**

January 2024 EDAM/M+ footprint scenario study benefits

Overview of Study Setup

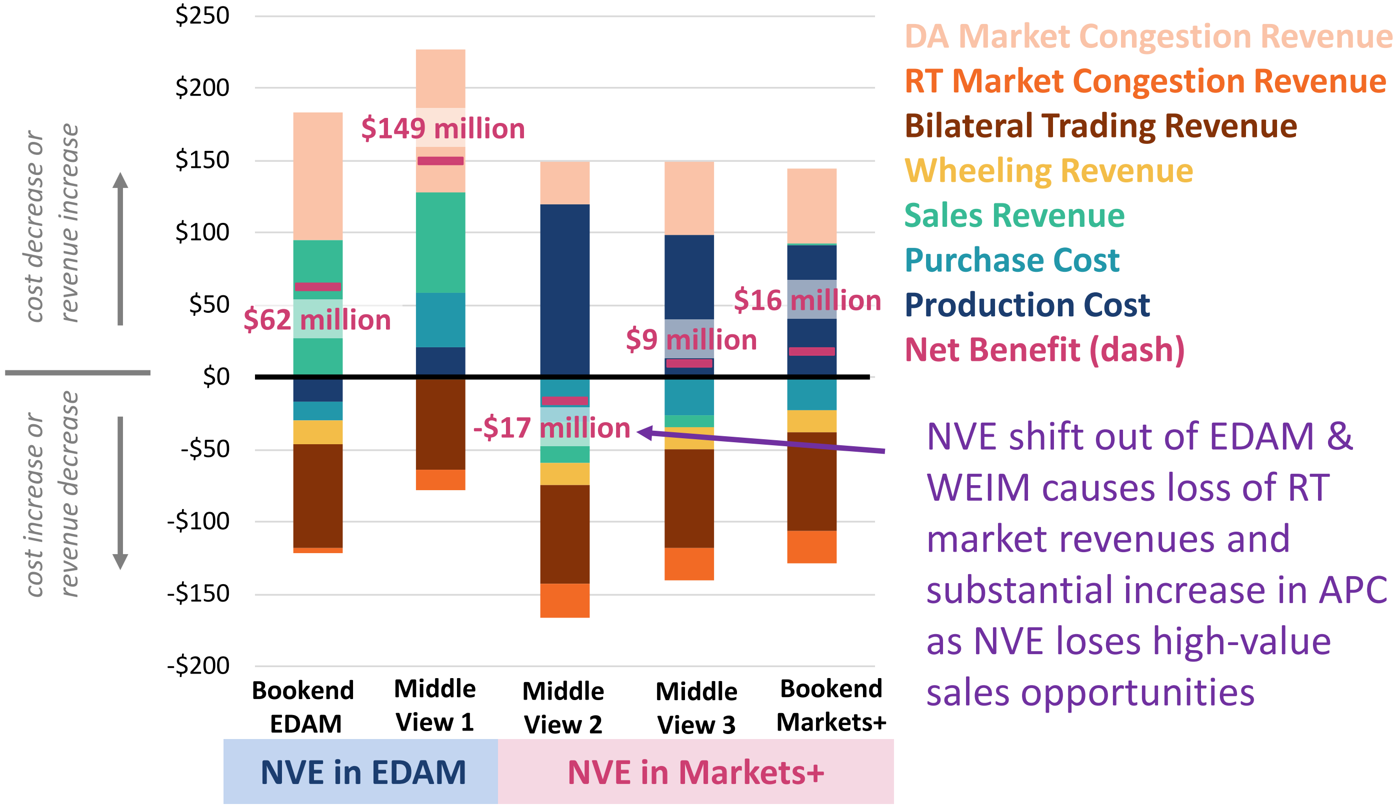
1 **NVE M+ Benefits Study model**
BAU & M+ scenarios

2 **Updates & Enhancements:**
- Constructed alternative market footprints as directed by study funders
- Added additional funder-specific resource mix, load, and transmission updates
- **Cases reflect the most up-to-date assumptions and modeling of the EDAM/M+ market designs**

3 **Updated NVE Market Benefits Model**
M+ & EDAM Footprint Scenarios

Summary of NVE EDAM/M+ Participation Benefit Drivers

$million, Footprint Scenario minus BAU case



NVE shift out of EDAM & WEIM causes loss of RT market revenues and substantial increase in APC as NVE loses high-value sales opportunities

Benefits & drivers details provided in next section

WECC-Wide Benefits

The implementation of M+ and/or EDAM produces significant WECC-wide customer benefits, with **benefits ranging from $825-$985 million per year** across the footprint scenarios

- A single market covering most of the WECC (bookend EDAM in this case) produces the highest benefits
- A two-market EDAM/M+ scenario with little market transfer capability between the Pacific Northwest and the Southwest in the M+ footprint produces the lowest benefits

WECC-Wide Benefits ($ Millions)

	BAU	Bookend EDAM	Middle View 1	Middle View 2	Middle View 3	Bookend Markets+
WECC-Wide						
Adjusted Production Cost	$10,273	$9,007	$9,880	$9,894	$9,919	$9,891
Wheeling Revenue	$446	$128	$378	$439	$434	$396
Trading Revenues:						
Bilateral	$1,327	$487	$506	$496	$477	$343
WEIM	$339	$263	$236	$192	$182	$99
WEIS/Mk+ RT Market	$28	$31	$89	$124	$125	$134
EDAM	-	$950	$946	$734	$676	$670
Markets+	-	-	$454	$606	$717	$945
Total System Cost	**$8,134**	**$7,149**	**$7,269**	**$7,303**	**$7,308**	**$7,304**
Benefit Compared to BAU		**$985**	**$865**	**$831**	**$826**	**$830**

The Bookend EDAM produces the lowest WECC-wide APC, indicating the most efficient system dispatch

Wheeling revenues, bilateral trading gains and market congestion may be higher in some split cases

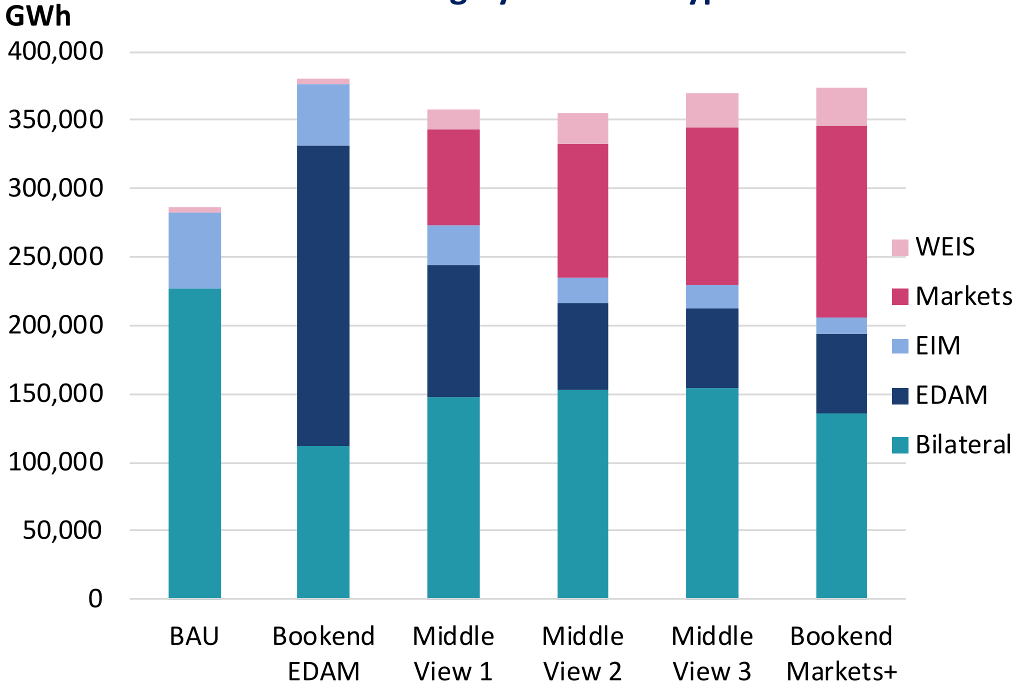
All market participation scenarios show benefits relative to BAU

WECC-Wide Trading

Implementation of organized DA markets increases WECC-wide 20-30% (60-90 TWh)

- The Bookend EDAM case, in which most WECC entities are in the same market, produces the highest total trading volume of the modeled cases
- Markets+ trades decrease considerably as the footprint shrinks
  - Removing AVA, NWMT, PNM, and EPE (Middle View 3) drops trading 26 TWh (18.5%) relative to Bookend Markets+
  - Removing also IPCO (Middle View 2) drops trading a further 18 TWh (15.4%) relative to Middle View 3
  - Removing also NVE, PGE, and SCL (Middle View 1) drops trading a further 27 TWh (28%) relative to Middle View 2
  - Middle View 1 has just 50% the original Bookend Markets+ trading volume despite having 74% of the original load

Total WECC Trading by Case and Type



Note: Bookend EDAM bilateral trades are mostly with non-market BAs like BCHA and AESO, and the SPP West RTO, which imports solar generation from WALC and AZPS.

NVE Markets+ / EDAM Footprint Scenarios Study Results

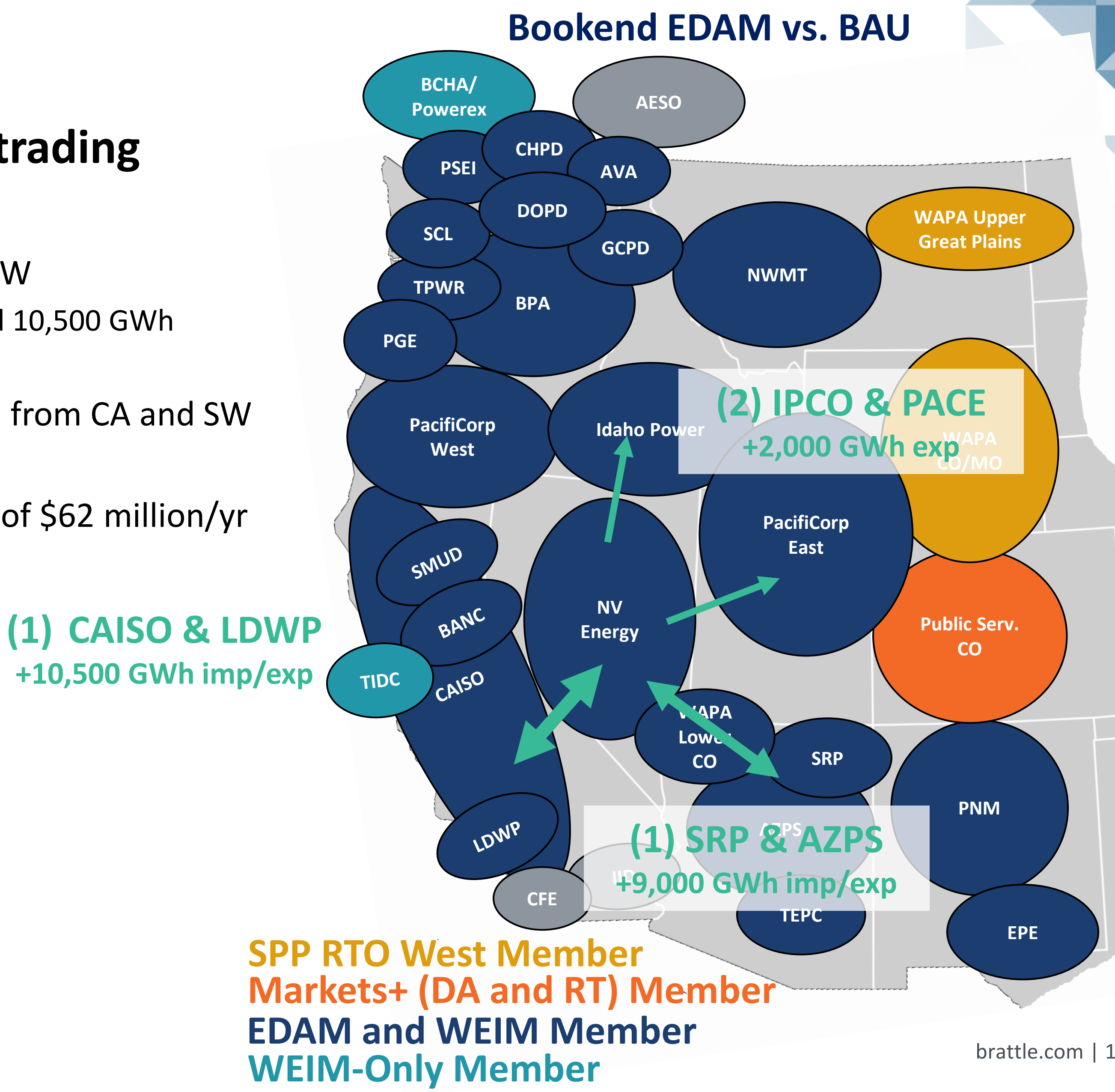
Bookend EDAM

Bookend EDAM gives Nevada its highest trading volumes, but not highest benefits

- (1) NVE facilitates market trades between CA and the SW
  - Nearly 9,000 GWh increase in trade between NVE<>SW and 10,500 GWh increase in trade between NVE<>CA
- (2) NVE enables greater transfer of low cost generation from CA and SW (solar and efficient gas) into IPCO and PACE
- APC savings and EDAM transfer revenues drive benefit of $62 million/yr

Nevada Energy Total Trading (All Types - GWh)

Partner	BAU		Bookend EDAM	
	Exports	Imports	Exports	Imports
AZPS	691	659	1,244	3,217
BPAT	768	483	918	684
CAISO	6,526	4,822	8,493	11,052
IPCO	697	1,018	1,323	766
LDWP	600	1,461	2,718	2,138
PACE	1,581	1,611	3,681	1,111
SRP	1,794	1,080	5,596	2,475
WALC	36	38	45	17
TH_Mead	864	773	921	43
Total	**13,556**	**11,944**	**24,939**	**21,503**



Middle View 1

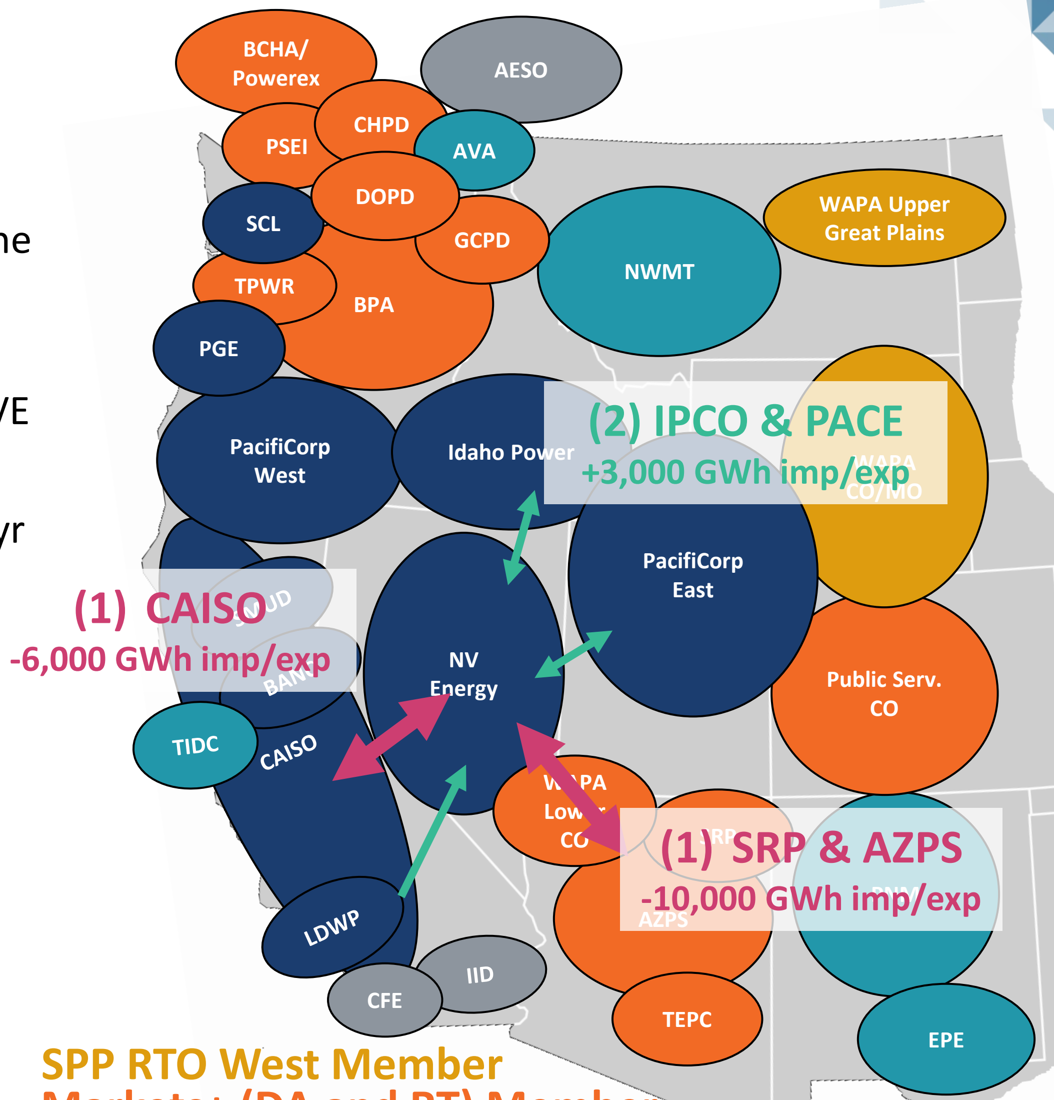
Middle View 1 sees fewer NVE trades, but more access to low-cost purchases and higher benefits

- (1) CAISO transactions fall as opportunities to sell through NVE into the SW reduced with SRP & AZPS shifting into M+
  - Some exchange with SW replaced by trading with IPCO/PACE
- (2) Less competition for in-footprint low-cost generation increases NVE imports from remaining EDAM footprint
- Higher trade value and lower APC drives benefits up to $149 million/yr

Nevada Energy Total Trading (All Types - GWh)

Partner	BAU		Bookend EDAM		Middle View 1	
	Exports	Imports	Exports	Imports	Exports	Imports
AZPS	691	659	1,244	3,217	898	0
BPAT	768	483	918	684	259	98
CAISO	6,526	4,822	8,493	11,052	4,605	9,519
IPCO	697	1,018	1,323	766	2,173	1,023
LDWP	600	1,461	2,718	2,138	2,209	3,657
PACE	1,581	1,611	3,681	1,111	4,385	2,041
SRP	1,794	1,080	5,596	2,475	558	0
WALC	36	38	45	17	233	79
TH_Mead	864	773	921	43	0	25
Total	**13,556**	**11,944**	**24,939**	**21,503**	**15,320**	**16,442**

Middle View 1 vs. Bookend EDAM



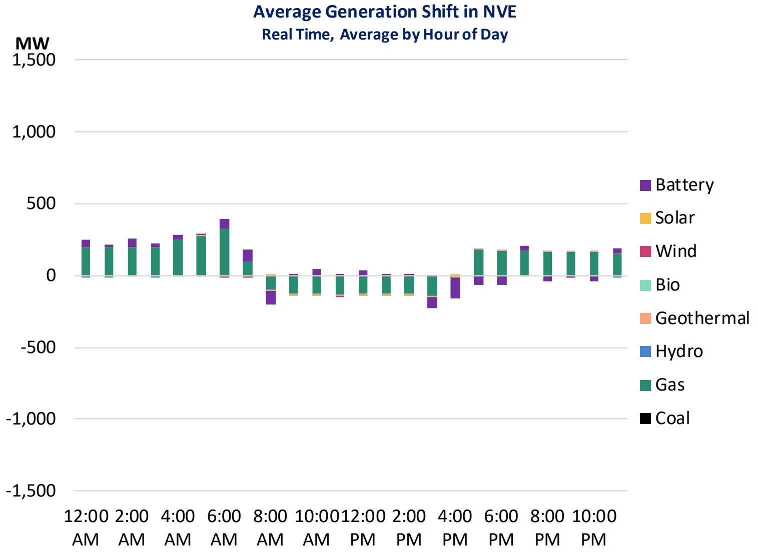
SPP RTO West Member
Markets+ (DA and RT) Member
EDAM and WEIM Member
WEIM-Only Member

Generation Shifts in NVE – EDAM Cases

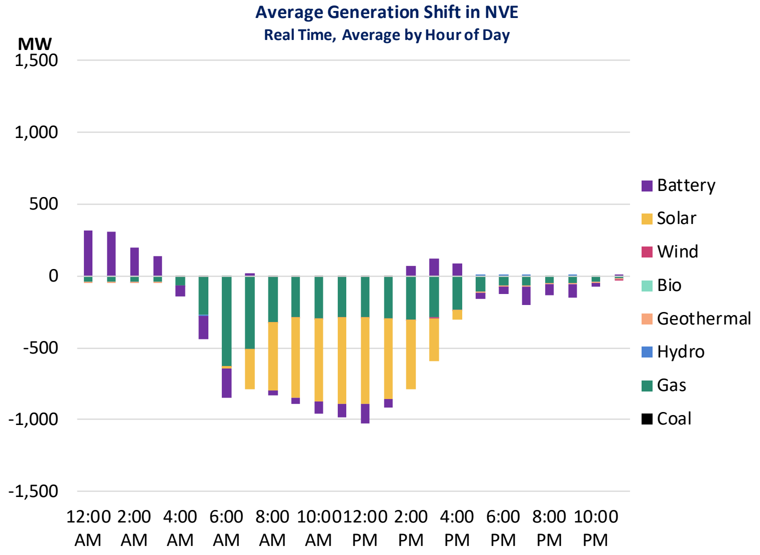
The scope of the EDAM footprint has significant impact on NVE generation

- In Bookend EDAM, NVE gas generation increase overnight to displace less efficient gas in the footprint, while modestly reducing gas generation midday to take advantage of cheap excess solar from CAISO and LDWP
- Smaller Middle View 1 EDAM footprint bottles up more midday solar resulting in more NVE purchase opportunities
  - NVE reduces generation midday to capitalize on additional excess solar
  - Increased oversupply in the EDAM footprint relative to Bookend EDAM case drives increase in NVE curtailments

Bookend EDAM vs. BAU



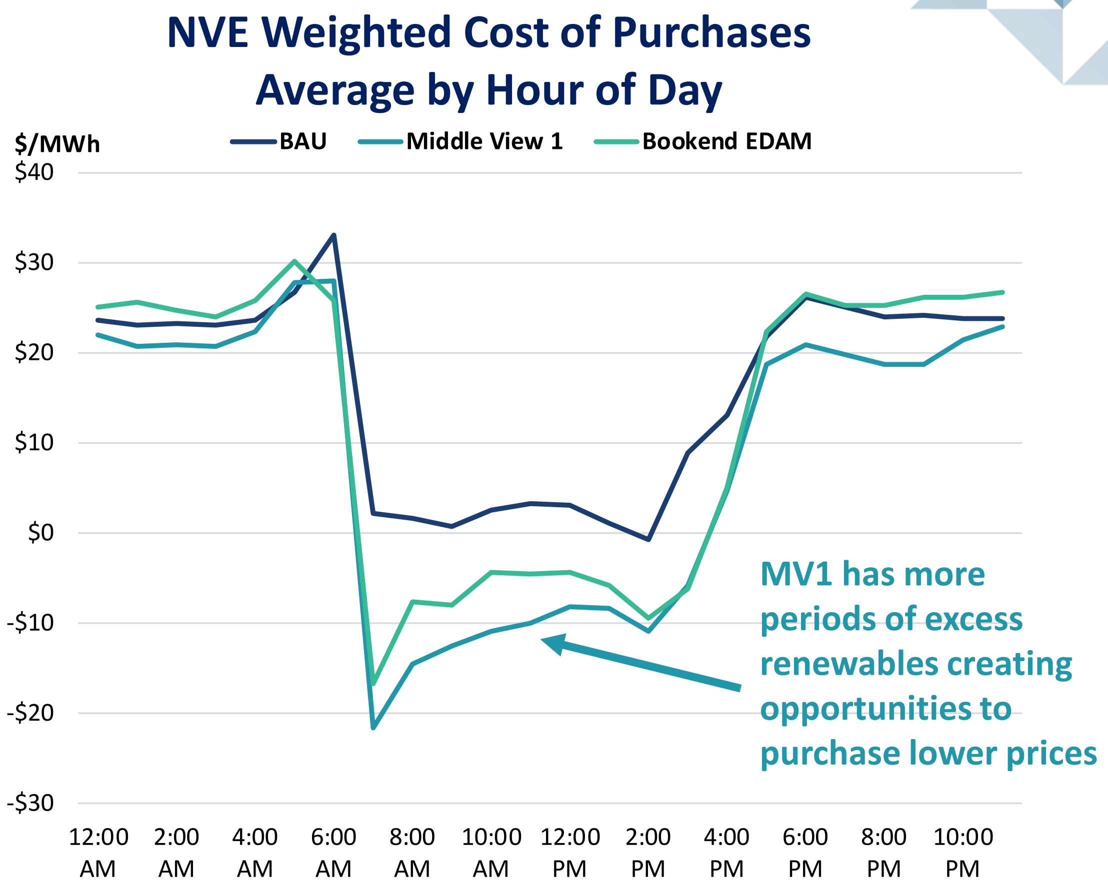
Middle View 1 vs. Bookend EDAM



Middle View 1 and Bookend EDAM

MV1 shows the highest benefits for Nevada (higher even than Bookend EDAM) due increased availability of low-cost purchases

- This is driven by the **specific footprint** assumed for Middle View 1:
  - MV1's EDAM contains the largest solar, wind, and battery storage entities in the WECC, containing 46% of WECC load but 80% of solar generation, 70% of storage capacity, and 68% of wind generation
  - In contrast Bookend EDAM contains 74% of WECC load, but 97% of solar generation, 97% of storage capacity, and 83% of wind generation
- This significant renewable excess in the MV1 EDAM footprint reduces Nevada's purchase costs by ~$50 million relative to Bookend EDAM



Bookend Markets+

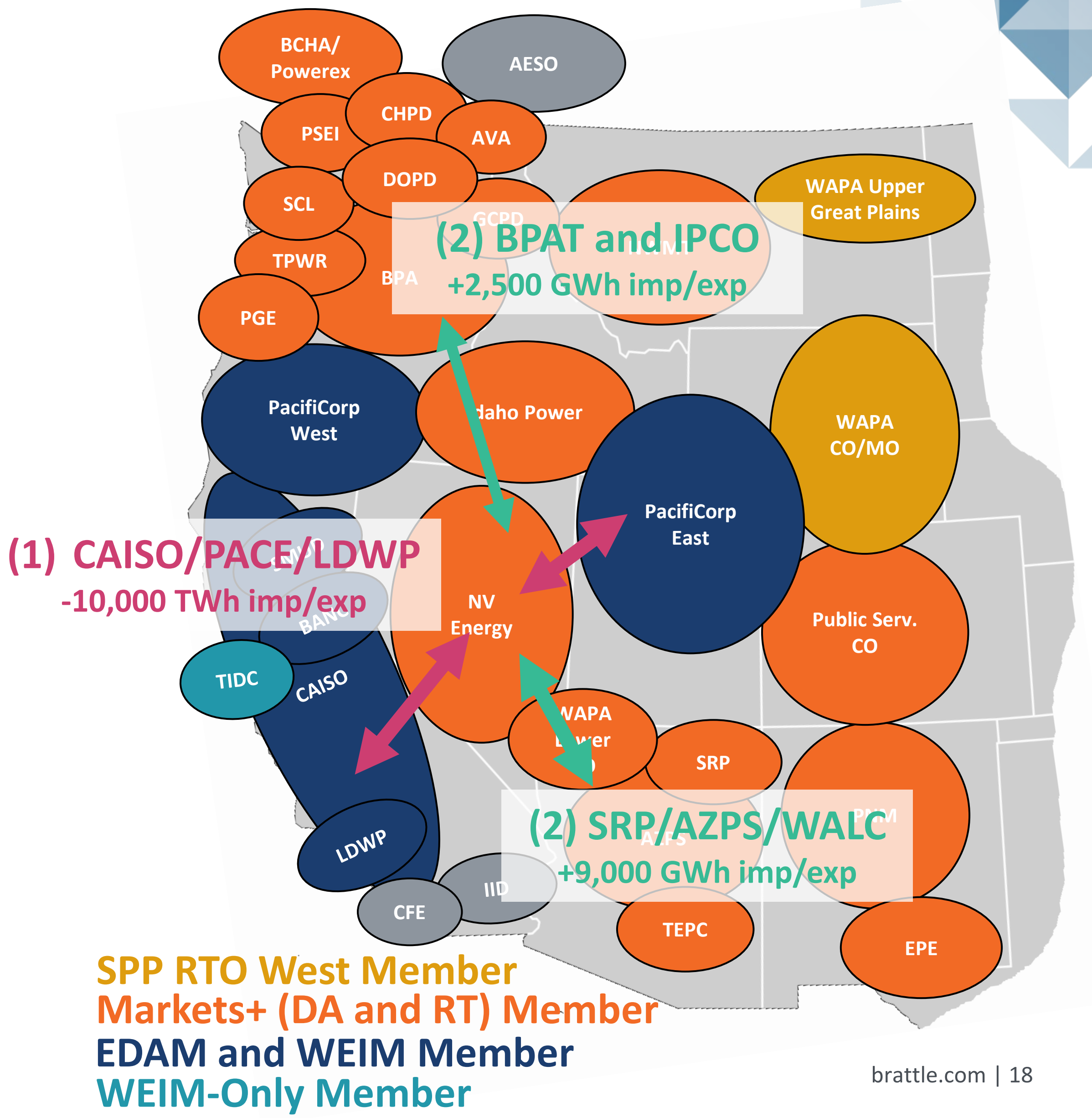
Bookend Markets+ sees big shifts in NVE trading patterns from BAU

- (1) Increased costs to access to low-cost gen in EDAM market (CAISO/PACE/LDWP) drives down trade volumes
- (2) NVE M+ trading increases with thermal heavy balancing authorities in the SW, and accesses PNW hydro via IPCO and BPA
- Significant APC reduction and M+ transfer revenue drive $17 million/yr in benefits

Nevada Energy Total Trading (All Types - GWh)

Partner	BAU		Bookend Markets+	
	Exports	Imports	Exports	Imports
AZPS	691	659	1,638	4,592
BPAT	768	483	1,328	884
CAISO	6,526	4,822	0	3,627
IPCO	697	1,018	2,176	1,640
LDWP	600	1,461	0	142
PACE	1,581	1,611	52	70
SRP	1,794	1,080	4,601	370
WALC	36	38	1,820	194
TH_Mead	864	773	0	1,381
Total	**13,556**	**11,944**	**11,615**	**12,900**

Bookend Markets+ vs. BAU



Middle View 3

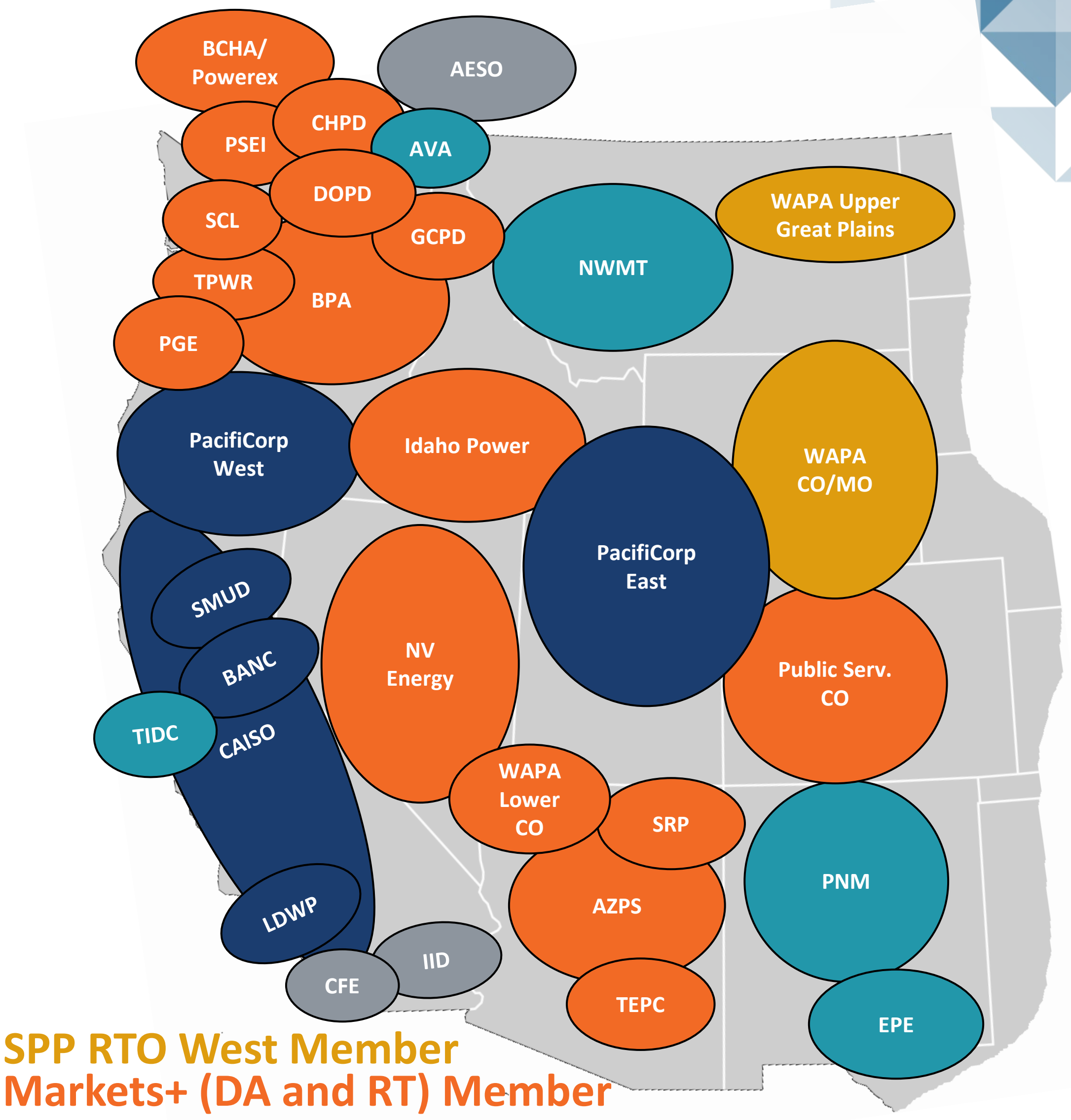
Middle View 3 drops NWMT, EPE, PNM, AVA from Markets+, modestly reducing NVE benefits

- Overall NVE trading & generation remains similar to Bookend M+, but the reduced footprint modestly reduces NV sales revenue and increases purchase costs
- NVE benefit declines to $9 million/yr
  - Decline driven by $2m in reduced Markets+ transfer revenues and $6m in higher APC

Nevada Energy Total Trading (All Types - GWh)

Partner	BAU		Bookend Markets+		Middle View 3	
	Exports	Imports	Exports	Imports	Exports	Imports
AZPS	691	659	1,638	4,592	1,769	4,773
BPAT	768	483	1,328	884	1,335	906
CAISO	6,526	4,822	0	3,627	0	3,493
IPCO	697	1,018	2,176	1,640	2,077	1,684
LDWP	600	1,461	0	142	0	154
PACE	1,581	1,611	52	70	41	39
SRP	1,794	1,080	4,601	370	4,643	306
WALC	36	38	1,820	194	1,774	197
TH_Mead	864	773	0	1,381	0	1,373
Total	**13,556**	**11,944**	**11,615**	**12,900**	**11,638**	**12,925**

Middle View 3 vs. Bookend Mkt+



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

Middle View 2

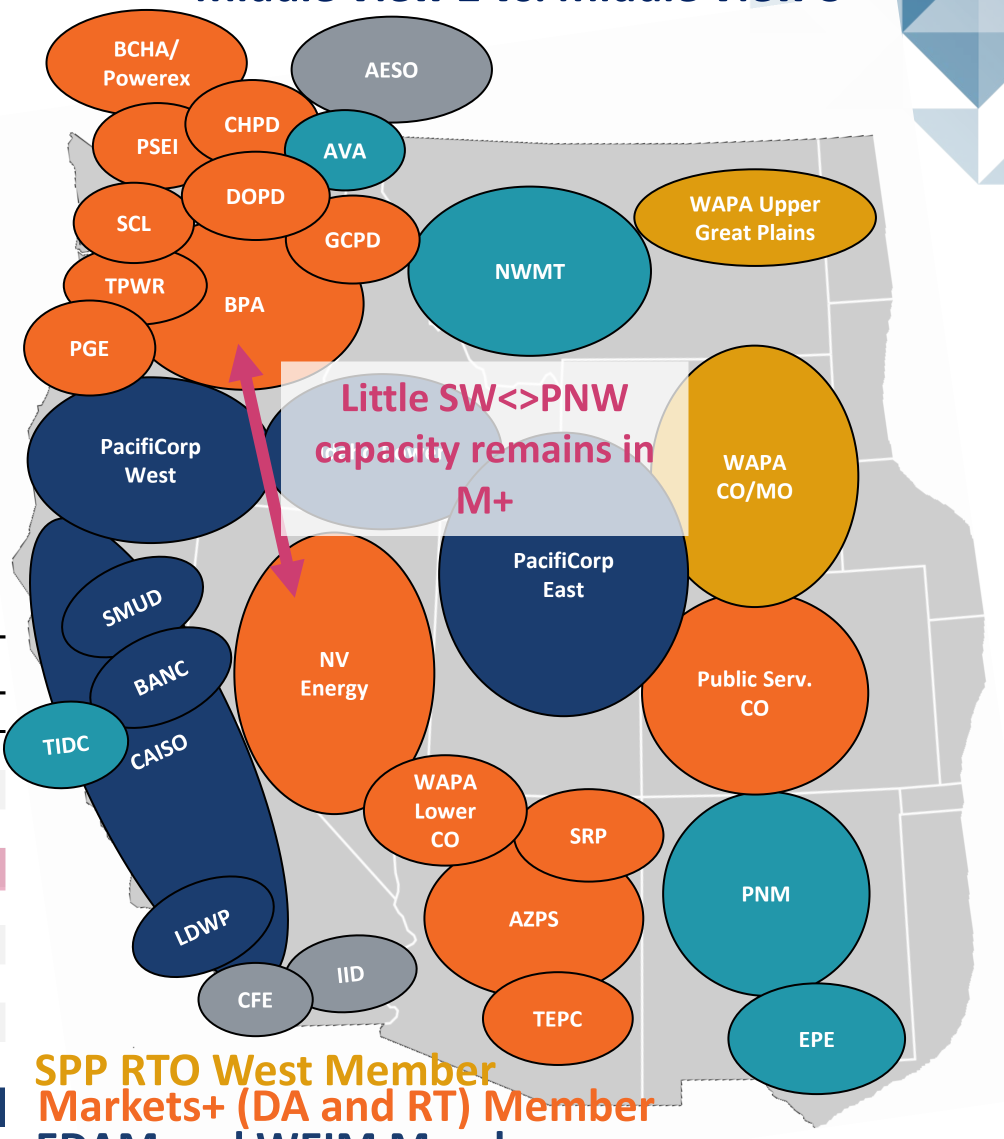
Middle View 2 removes Idaho from Markets+, cutting off a major pathway between SW and PNW in M+

- NVE becomes the only link to the PNW, but only with 200 MW from SPPC to BPAT
  - Flows with Idaho decline more than 3,000 GWh; trading with BPA already hitting limits during valuable periods in MV3, so changes little
- Small increase in APC and significantly reduced M+ transfer revenues drives NVE M+ benefits down to -$18 million

Nevada Energy Total Trading (All Types - GWh)

Partner	BAU		Bookend Markets+		Middle View 3		Middle View 2	
	Exports	Imports	Exports	Imports	Exports	Imports	Exports	Imports
AZPS	691	659	1,638	4,592	1,769	4,773	1,729	4,454
BPAT	768	483	1,328	884	1,335	906	1,415	958
CAISO	6,526	4,822	0	3,627	0	3,493	0	3,766
IPCO	697	1,018	2,176	1,640	2,077	1,684	18	174
LDWP	600	1,461	0	142	0	154	0	160
PACE	1,581	1,611	52	70	41	39	53	6
SRP	1,794	1,080	4,601	370	4,643	306	4,576	278
WALC	36	38	1,820	194	1,774	197	2,018	200
TH_Mead	864	773	0	1,381	0	1,373	0	1,561
Total	**13,556**	**11,944**	**11,615**	**12,900**	**11,638**	**12,925**	**9,810**	**11,558**

Middle View 2 vs. Middle View 3

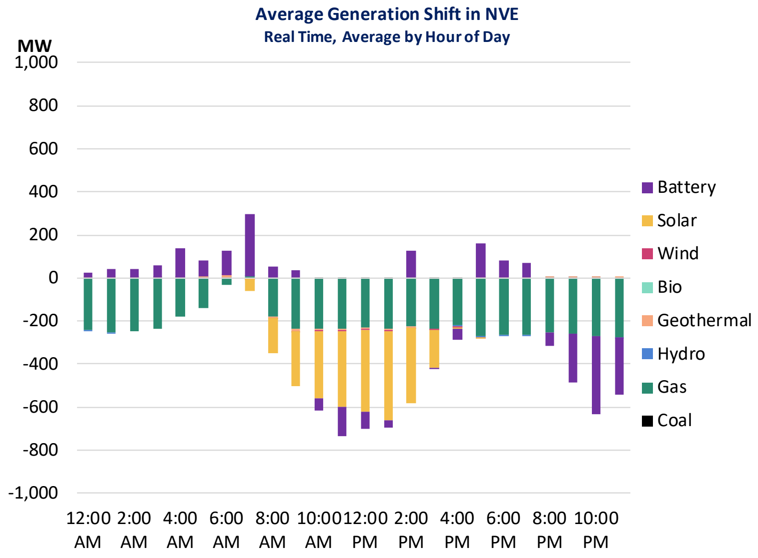


NVE Generation Shifts – Markets+ Cases

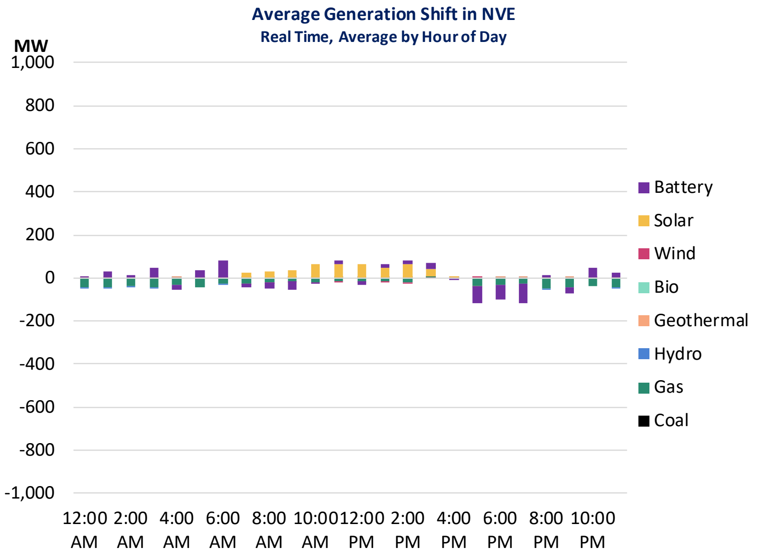
NVE gas generation shifts a driver of M+ benefits outcomes

- As M+ footprint scope declines, NVE produces less internally reducing sales revenue and increasing purchase costs

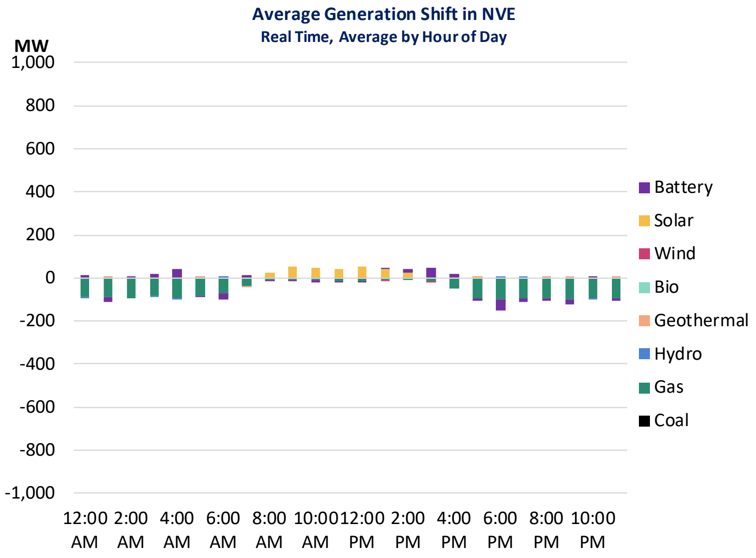
Bookend Mkt+ vs. BAU



Middle View 3 vs. Bookend Markets+



Middle View 2 vs. Middle View 3



NVE Benefits Study Takeaways

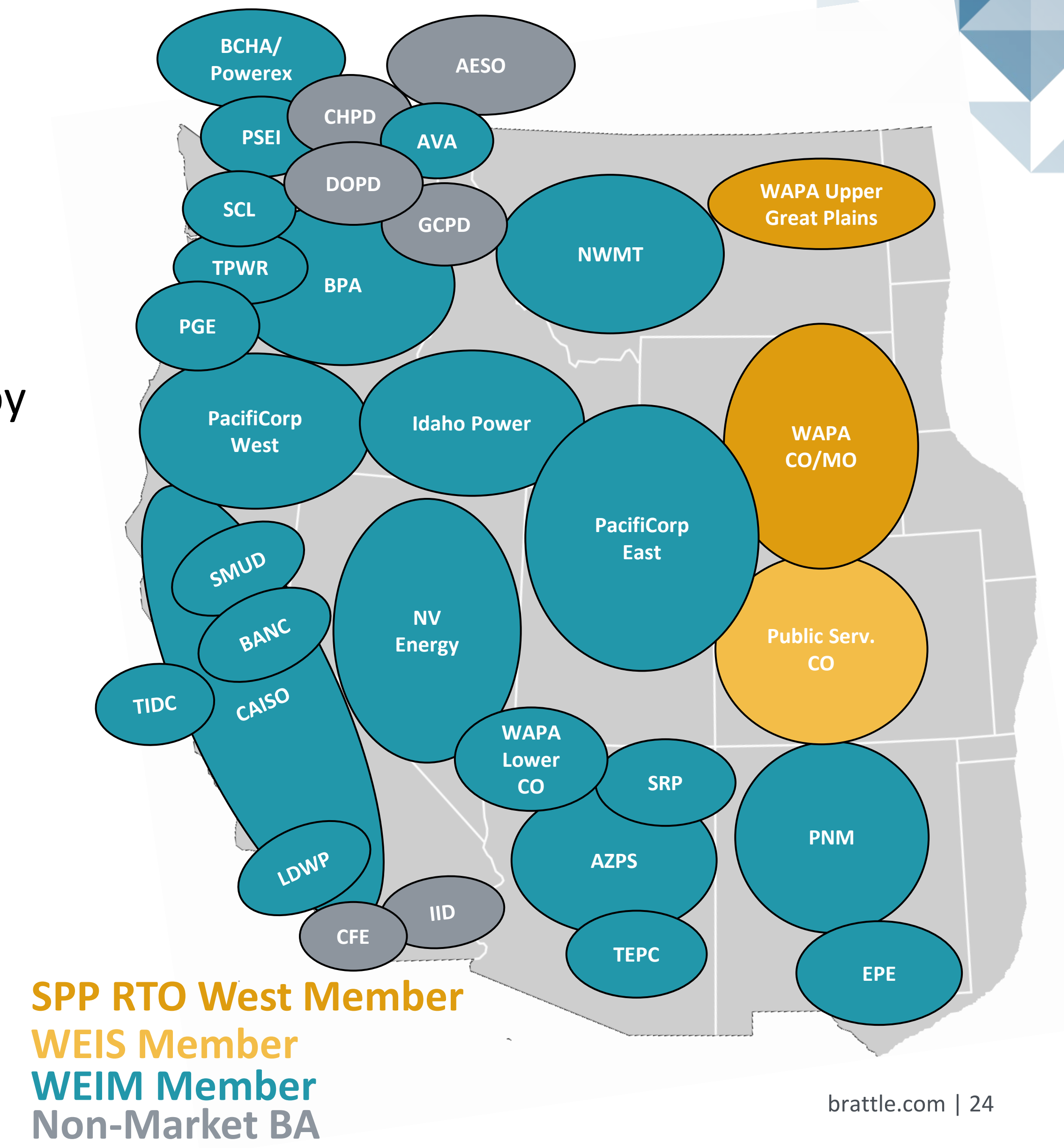
- The **highest WECC-wide market benefits in these cases accrue to a single, nearly WECC-wide market**, while the lowest WECC-wide benefits accrue to a split two-market scenario where the EDAM footprint divides a fragmented M+
- **NVE estimated benefits are highest in the EDAM**, largely due to the opportunity to sell additional generation at higher prices and buy at excess solar at lower prices
- **NVE benefits significantly influenced by market footprint** due to the its large amount of transfer capability and centrality in the WECC system
  - NVE benefits tend to be higher when it is central to the market and facilitates transfers within the market (e.g., in Bookend M+ case, in which NVE facilitates transfers between the PNW and SW; or Bookend EDAM case, in which NVE facilitates transfers between CAISO, the SW, and the PNW)
  - The opposite is also true: NVE benefits tend to be lower when it is on the margin of the market (e.g., in MV2, where it is largely disconnected from the PNW portion of the M+ footprint and on the edge of the SW portion of the M+ footprint)
- **Shifting out of the WEIM when joining M+ has a major impact on NVE** as it loses access to excess renewable supply from CAISO in real time, and sees lower prices for RT sales

Appendix: EDAM/M+ Footprint Scenario Market Footprint Assumptions

BAU Case

For the BAU case, Brattle assumes the day-ahead market will remain bilateral, except for the formation of SPP RTO West

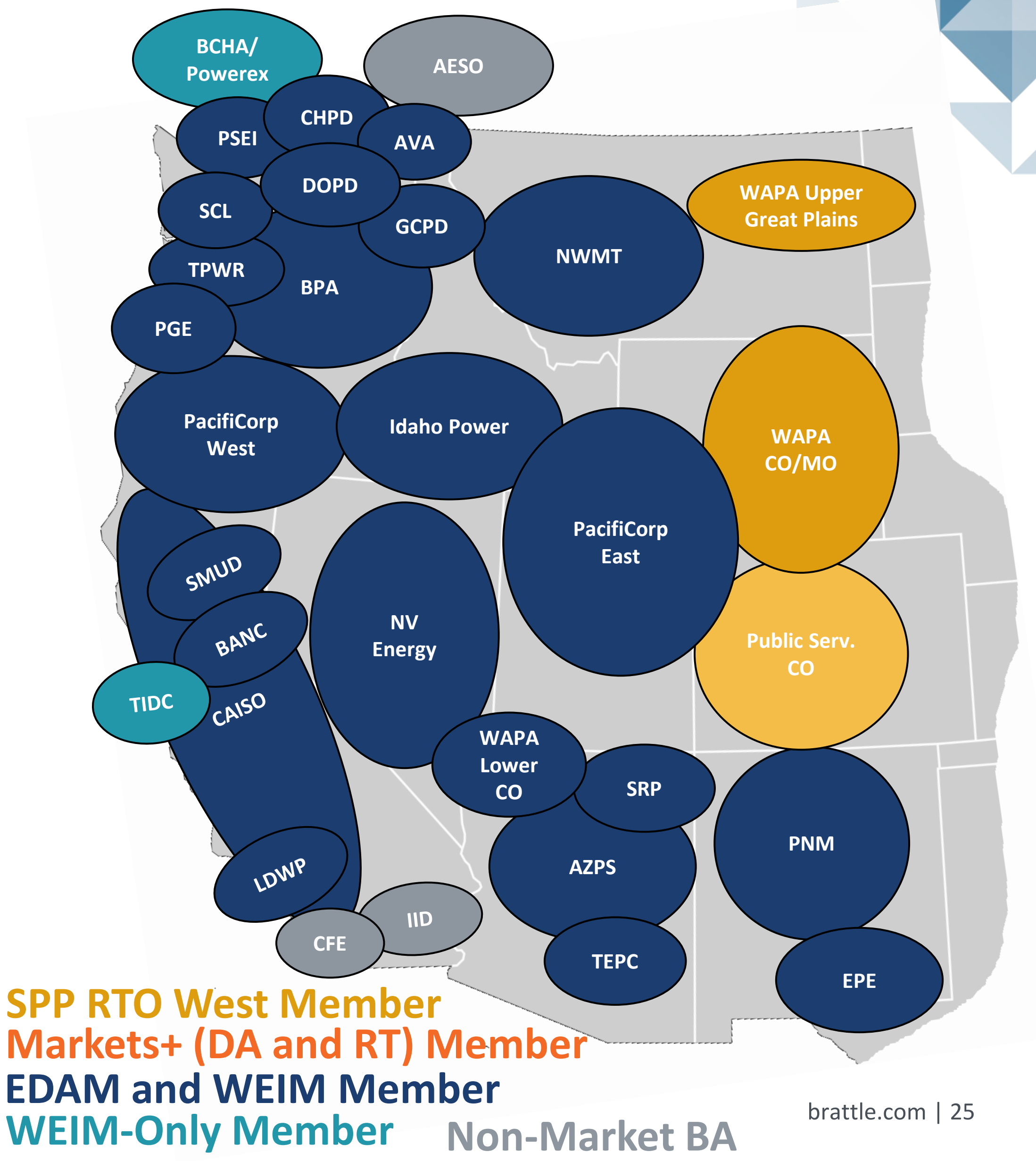
- **WEIS entities (including SPP RTO West) in Yellow**
  - Assumes SPP West RTO includes WACM and WAUW by 2032
  - Also assumes PSCO joins by 2032
- **WEIM entities in teal**
  - Existing WEIM footprint modeled



Bookend EDAM

Bookend EDAM assumes almost all WECC utilities join EDAM

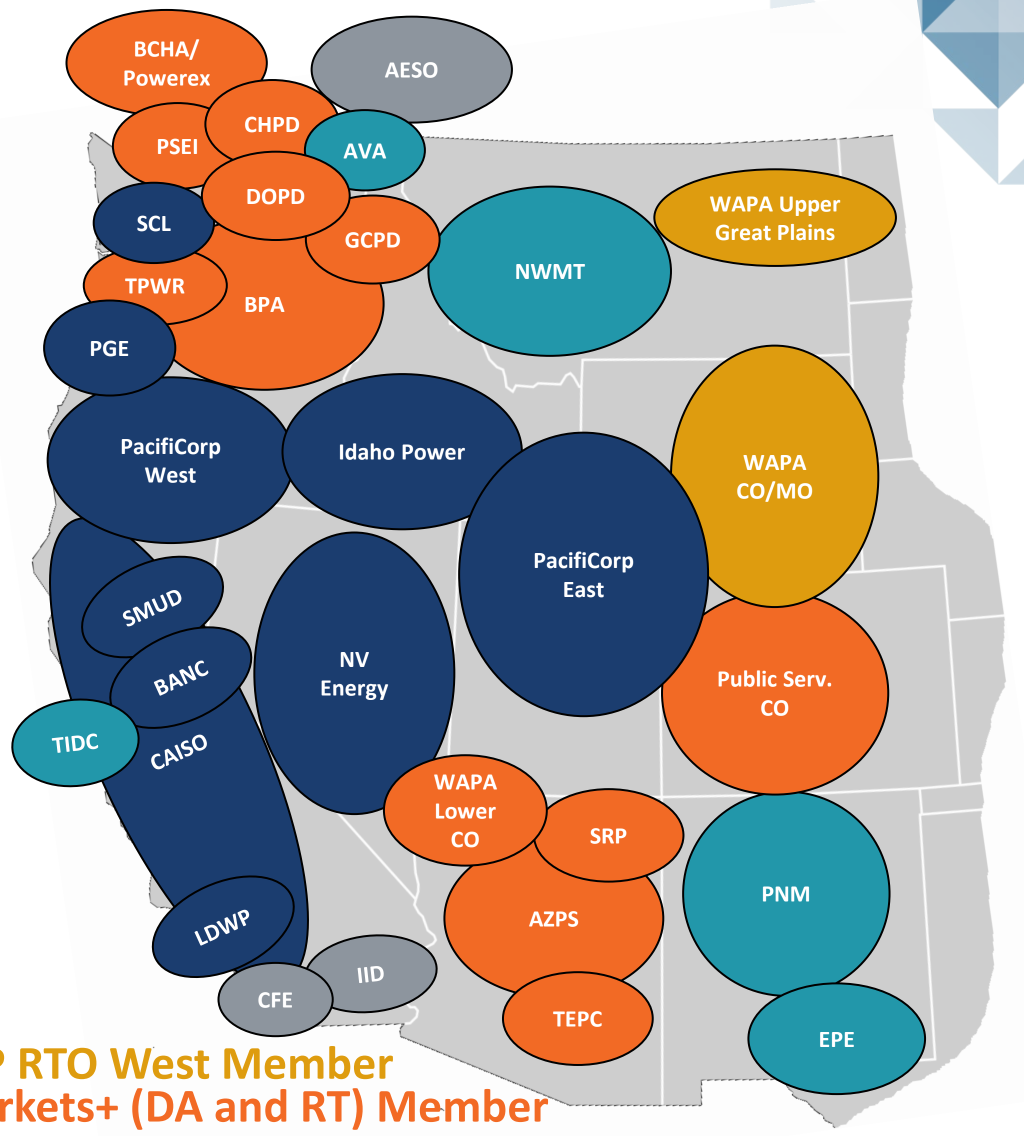
- **EDAM Entities in Blue**
  - EDAM entities assumed to also participate in the WEIM
  - Powerex and TIDC assumed to remain in WEIM
- **SPP West RTO continues to exist in the east**
  - PSCO remains in the WEIS
- IID, CFE, and AESO assumed to trade only bilaterally



Middle View 1

Middle View 1 assumes the entities that have announced they are joining EDAM go to EDAM, plus PGE, Idaho, Nevada, and SCL

- **Markets+ Entities in Orange**
  - Includes all Phase 1 Funders of Markets+, less the entities assumed to be in EDAM in this case
  - M+ entities assumed to also participate in SPP-run RT market, similar to WEIS
  - The SPP West RTO cooptimizes with Markets+
- **EDAM Entities in Blue**
  - EDAM entities assumed to also participate in the WEIM
  - TIDC would remain in WEIM
- IID, CFE, and AESO assumed to trade only bilaterally

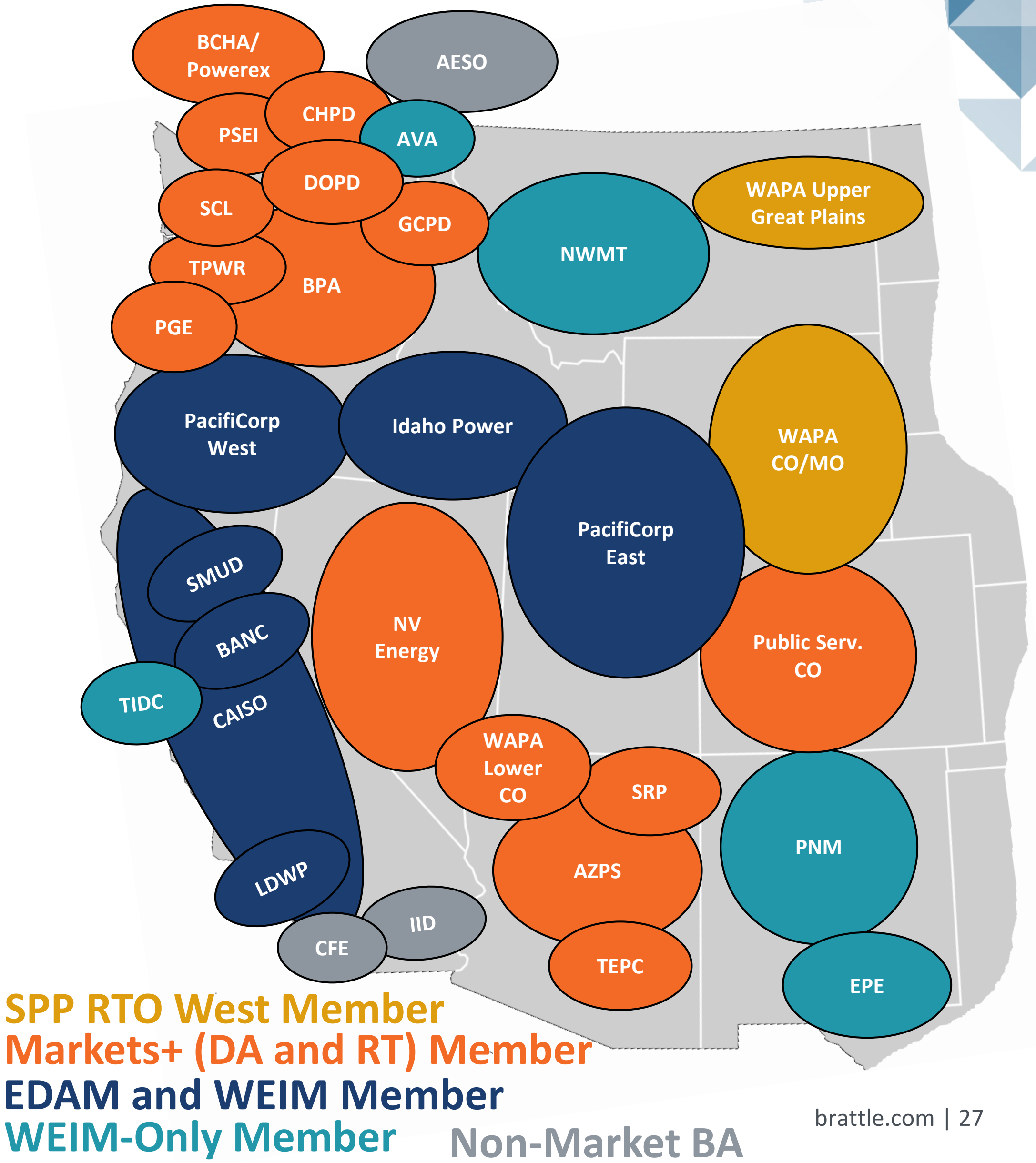


SPP RTO West Member
Markets+ (DA and RT) Member
EDAM and WEIM Member
WEIM-Only Member
Non-Market BA

Middle View 2

Middle View 2 assumes NVE, SCL, and PGE go to Markets+, but Idaho remains in EDAM

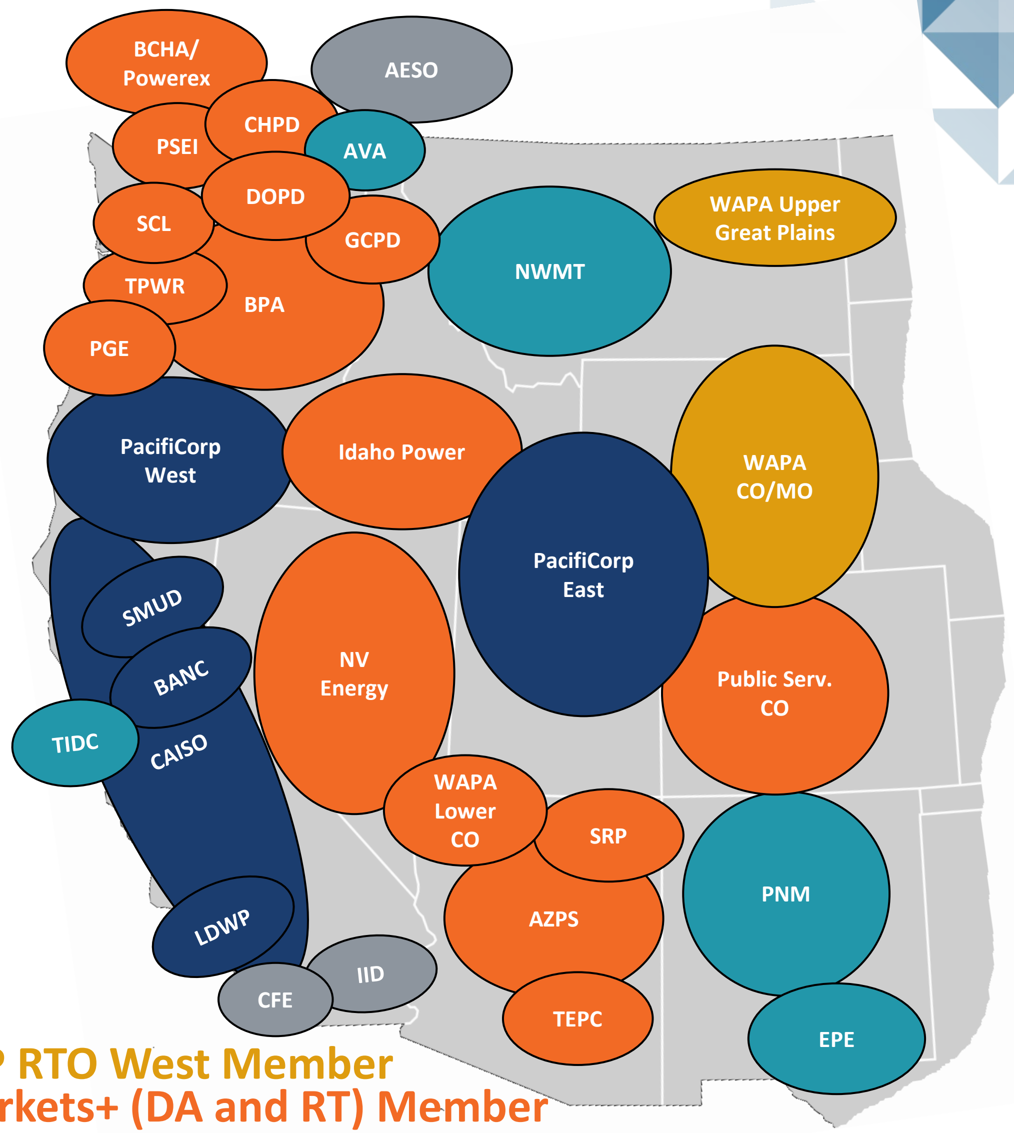
- **Markets+ Entities in Orange**
  - Includes all Phase 1 Funders of Markets+, less the entities assumed to be in EDAM in this case
  - M+ entities assumed to also participate in SPP-run RT market, similar to WEIS
  - The SPP West RTO cooptimizes with Markets+
- **EDAM Entities in Blue**
  - TIDC would remain in WEIM
- IID, CFE, and AESO assumed to trade only bilaterally



Middle View 3

Middle View 3 assumes Idaho joins Markets+ with NVE, SCL, and PGE

- **Markets+ Entities in Orange**
  - M+ entities assumed to also participate in SPP-run RT market, similar to WEIS
  - The SPP West RTO cooptimizes with Markets+
- **EDAM Entities in Blue**
  - EDAM entities assumed to also participate in WEIM
  - TIDC would remain in WEIM
- IID, CFE, and AESO assumed to trade only bilaterally

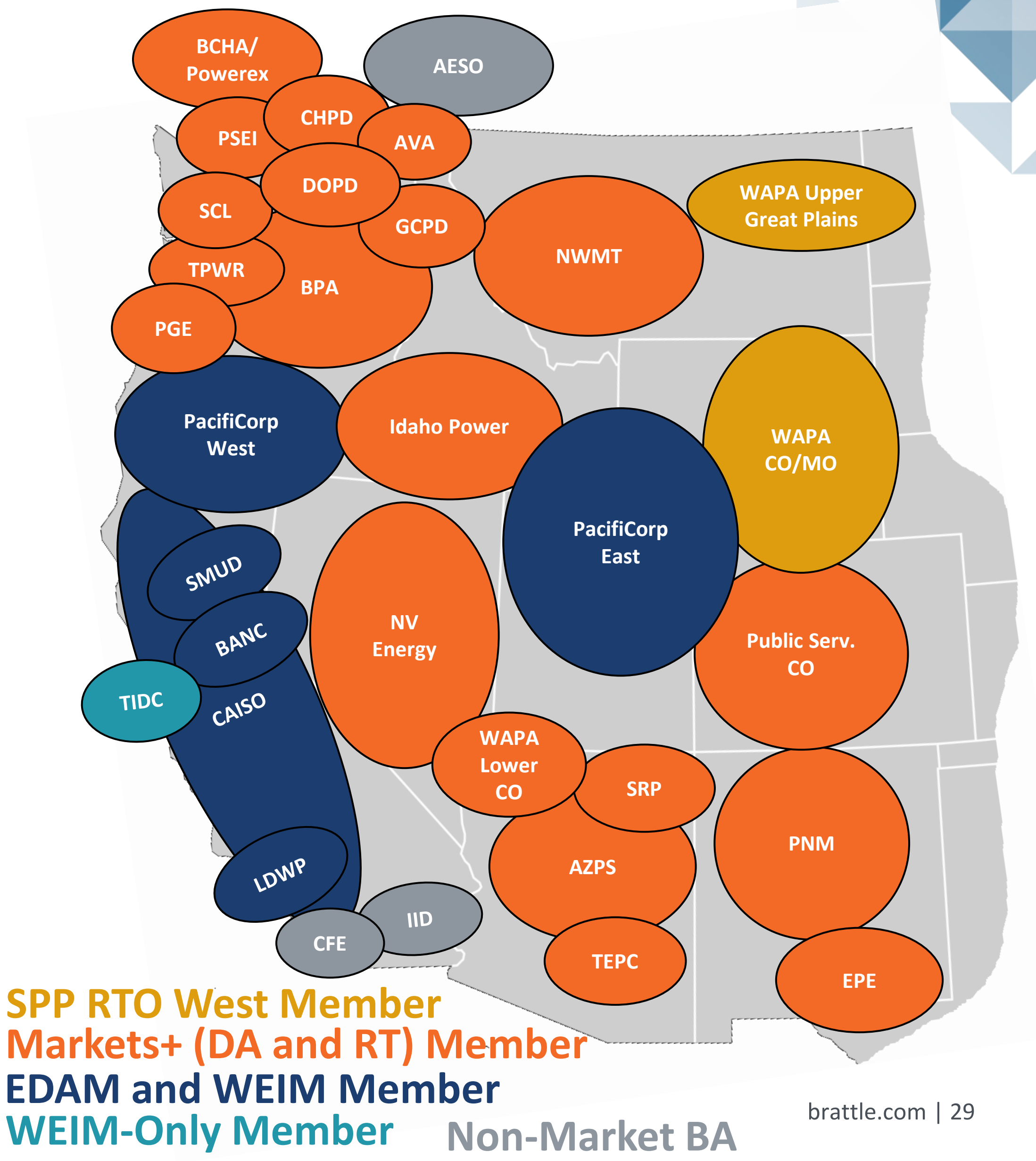


SPP RTO West Member
Markets+ (DA and RT) Member
EDAM and WEIM Member
WEIM-Only Member
Non-Market BA

Bookend Markets+

Bookend Markets+ assumes almost all WECC utilities not committed to EDAM join M+

- **Markets+ Entities in Orange**
  - M+ entities assumed to also participate in SPP-run RT market, similar to WEIS
  - The SPP West RTO cooptimizes with Markets+
- **EDAM Entities in Blue**
  - TIDC would remain in WEIM
- IID, CFE, and AESO assumed to trade only bilaterally



Appendix: EDAM/M+ Footprint Scenario Trading Detail

NVE Trading Volumes

Nevada Energy Total Trading (All Types - GWh)

Partner	BAU		Bookend EDAM		Middle View 1		Middle View 2		Middle View 3		Bookend Markets+	
	Exports	Imports	Exports	Imports	Exports	Imports	Exports	Imports	Exports	Imports	Exports	Imports
AZPS	691	659	1,244	3,217	898	0	1,729	4,454	1,769	4,773	1,638	4,592
BPAT	768	483	918	684	259	98	1,415	958	1,335	906	1,328	884
CAISO	6,526	4,822	8,493	11,052	4,605	9,519	0	3,766	0	3,493	0	3,627
IPCO	697	1,018	1,323	766	2,173	1,023	18	174	2,077	1,684	2,176	1,640
LDWP	600	1,461	2,718	2,138	2,209	3,657	0	160	0	154	0	142
PACE	1,581	1,611	3,681	1,111	4,385	2,041	53	6	41	39	52	70
SRP	1,794	1,080	5,596	2,475	558	0	4,576	278	4,643	306	4,601	370
WALC	36	38	45	17	233	79	2,018	200	1,774	197	1,820	194
TH_Mead	864	773	921	43	0	25	0	1,561	0	1,373	0	1,381
Total	**13,556**	**11,944**	**24,939**	**21,503**	**15,320**	**16,442**	**9,810**	**11,558**	**11,638**	**12,925**	**11,615**	**12,900**
Market Total			***24,939***	***21,503***	***13,371***	***16,240***	***9,739***	***7,451***	***11,598***	***9,239***	***11,563***	***9,061***
Market Share			***100%***	***100%***	***87%***	***99%***	***99%***	***64%***	***100%***	***71%***	***100%***	***70%***

NVE Total Trading Value

Nevada Energy Total Trading (All Types - $ Millions)

Partner	BAU		Bookend EDAM		Middle View 1		Middle View 2		Middle View 3		Bookend Markets+	
	Exports	Imports	Exports	Imports	Exports	Imports	Exports	Imports	Exports	Imports	Exports	Imports
AZPS	$2	$0	$3	$5	$3	$0	$6	$2	$6	$3	$6	$2
BPAT	$9	$3	$8	$1	$4	$1	$12	$0	$13	$0	$13	$0
CAISO	$35	$22	$35	$0	$53	$0	$0	$3	$0	$3	$0	$3
IPCO	$6	$6	$7	$2	$17	$2	$0	$1	$16	$4	$19	$5
LDWP	$5	$0	$18	$1	$19	$0	$0	$0	$0	$0	$0	$0
PACE	$7	$2	$13	$0	$17	$9	$0	$0	$0	$0	$0	$0
SRP	$4	$2	$16	$5	$2	$0	$14	$0	$14	$1	$14	$1
WALC	$0	$0	$0	$0	$1	$0	$4	$0	$4	$0	$4	$0
TH_Mead	$0	$0	$0	$0	$0	$0	$0	$1	$0	$1	$0	$1
Total	**$68**	**$36**	**$101**	**$15**	**$115**	**$12**	**$37**	**$7**	**$54**	**$11**	**$56**	**$12**

NVE Average Trading Value

Nevada Energy Total Trading (All Types - $/MWh)

Partner	BAU		Bookend EDAM		Middle View 1		Middle View 2		Middle View 3		Bookend Markets+	
	Exports	Imports	Exports	Imports	Exports	Imports	Exports	Imports	Exports	Imports	Exports	Imports
AZPS	$2	$1	$3	$2	$3	$0	$3	$0	$4	$1	$4	$1
BPAT	$12	$7	$9	$2	$14	$6	$9	$0	$10	$0	$10	$0
CAISO	$5	$5	$4	$0	$11	$0	$0	$1	$0	$1	$20	$1
IPCO	$9	$6	$5	$2	$8	$2	$7	$3	$8	$3	$9	$3
LDWP	$8	$0	$7	$0	$9	$0	$0	$0	$0	$0	$0	$0
PACE	$4	$1	$3	$0	$4	$4	$5	$6	$4	$4	$4	$5
SRP	$2	$2	$3	$2	$4	$7	$3	$1	$3	$2	$3	$1
WALC	$5	$3	$3	$3	$3	$5	$2	$1	$2	$1	$2	$1
TH_Mead	$0	$0	$0	$0	$0	$2	$0	$1	$0	$1	$0	$1
Total	**$5**	**$3**	**$4**	**$1**	**$7**	**$1**	**$4**	**$1**	**$5**	**$1**	**$5**	**$1**

Note: calculated as the total trade value divided by total trade volume

Appendix: EDAM/M+ Footprint Scenario Adjusted Production Cost Details

Bookend EDAM

Bookend EDAM has a $65.4 million adjusted production cost benefit for NVE

Adjusted Production Cost Comparison for NEVADA

			GWh			$/MWh			Total ($1000s/Year)		
Cost Components			**Status Quo**	**Bookend EDAM**	**Difference**	**Status Quo**	**Bookend EDAM**	**Difference**	**Status Quo**	**Bookend EDAM**	**Difference**
Production Cost	(+)	[1]	38,962	39,561	**598**	$14.93	$15.13	**$0.20**	581,683	598,517	**$16,834**
Purchases Cost	(+)	[3]									
Day-Ahead Market + Bilateral		[4]	4,450	5,432	**982**	$15.89	$12.66	**-$3.24**	70,725	68,762	**-$1,964**
Real-Time Market		[5]	1,946	2,122	**175**	$10.55	$16.60	**$6.05**	20,537	35,221	**$14,685**
Sales Revenue (Negative = Cost)	(-)	[6]									
Day-Ahead Market + Bilateral		[7]	4,003	7,261	**3,259**	$21.22	$33.13	**$11.91**	84,917	240,572	**$155,655**
Real-Time Market		[8]	3,930	2,427	**-1,503**	$26.09	$17.25	**-$8.84**	102,528	41,860	**-$60,669**
Total Cost *(Negative Difference = Benefit)*		[9]	**37,426**	**37,426**	**0**	**$12.97**	**$11.22**	**-$1.75**	485,500	420,069	**-$65,431**
% Change in APC											*-13.5%*

Middle View 1

Middle View 1 has a $128.5 million adjusted production cost benefit for NVE

Adjusted Production Cost Comparison for NEVADA

			GWh			$/MWh			Total ($1000s/Year)		
Cost Components			Status Quo	Middle View 1	Difference	Status Quo	Middle View 1	Difference	Status Quo	Middle View 1	Difference
Production Cost	(+)	[1]	38,962	36,232	**-2,730**	$14.93	$15.47	**$0.54**	581,683	560,649	**-$21,033**
Purchases Cost	(+)	[3]									
Day-Ahead Market + Bilateral		[4]	4,450	7,700	**3,250**	$15.89	$4.66	**-$11.23**	70,725	35,910	**-$34,815**
Real-Time Market		[5]	1,946	1,722	**-224**	$10.55	$10.20	**-$0.36**	20,537	17,560	**-$2,977**
Sales Revenue (Negative = Cost)	(-)	[6]									
Day-Ahead Market + Bilateral		[7]	4,003	5,663	**1,660**	$21.22	$38.06	**$16.84**	84,917	215,508	**$130,592**
Real-Time Market		[8]	3,930	2,565	**-1,365**	$26.09	$16.23	**-$9.86**	102,528	41,625	**-$60,903**
***Total Cost** (Negative Difference = Benefit)*		[9]	**37,426**	**37,426**	**0**	**$12.97**	**$9.54**	**-$3.43**	485,500	356,986	**-$128,514**
% Change in APC											***-26.5%***

Middle View 2

Middle View 2 has a $60.1 million adjusted production cost benefit for NVE

Adjusted Production Cost Comparison for NEVADA

			GWh			$/MWh			Total ($1000s/Year)		
Cost Components			**Status Quo**	**Middle View 2**	**Difference**	**Status Quo**	**Middle View 2**	**Difference**	**Status Quo**	**Middle View 2**	**Difference**
Production Cost	(+)	[1]	38,962	35,633	**-3,330**	$14.93	$12.98	**-$1.95**	581,683	462,474	**-$119,209**
Purchases Cost	(+)	[3]									
Day-Ahead Market + Bilateral		[4]	4,450	6,853	**2,403**	$15.89	$12.84	**-$3.05**	70,725	87,988	**$17,263**
Real-Time Market		[5]	1,946	1,854	**-93**	$10.55	$18.49	**$7.94**	20,537	34,281	**$13,744**
Sales Revenue (Negative = Cost)	(-)	[6]									
Day-Ahead Market + Bilateral		[7]	4,003	4,413	**410**	$21.22	$30.22	**$9.00**	84,917	133,333	**$48,417**
Real-Time Market		[8]	3,930	2,500	**-1,429**	$26.09	$10.42	**-$15.67**	102,528	26,048	**-$76,480**
Total Cost *(Negative Difference = Benefit)*		[9]	**37,426**	**37,426**	**0**	**$12.97**	**$11.37**	**-$1.61**	485,500	425,362	**-$60,138**
% Change in APC											*-12.4%*

Middle View 3

Middle View 3 has a $64.7 million adjusted production cost benefit for NVE

Adjusted Production Cost Comparison for NEVADA

			GWh			$/MWh			Total ($1000s/Year)		
Cost Components			**Status Quo**	**Middle View 3**	**Difference**	**Status Quo**	**Middle View 3**	**Difference**	**Status Quo**	**Middle View 3**	**Difference**
Production Cost	(+)	[1]	38,962	36,036	**-2,926**	$14.93	$13.40	**-$1.53**	581,683	482,903	**-$98,779**
Purchases Cost	(+)	[3]									
Day-Ahead Market + Bilateral		[4]	4,450	6,894	**2,444**	$15.89	$11.89	**-$4.01**	70,725	81,936	**$11,211**
Real-Time Market		[5]	1,946	1,896	**-50**	$10.55	$18.67	**$8.12**	20,537	35,408	**$14,871**
Sales Revenue (Negative = Cost)	(-)	[6]									
Day-Ahead Market + Bilateral		[7]	4,003	4,833	**831**	$21.22	$31.72	**$10.50**	84,917	153,307	**$68,391**
Real-Time Market		[8]	3,930	2,567	**-1,363**	$26.09	$10.17	**-$15.92**	102,528	26,099	**-$76,429**
Total Cost *(Negative Difference = Benefit)*		[9]	**37,426**	**37,426**	**0**	**$12.97**	**$11.24**	**-$1.73**	485,500	420,841	**-$64,659**
% Change in APC											***-13.3%***

Bookend Markets+

Bookend Markets+ has a $70 million adjusted production cost benefit for NVE

Adjusted Production Cost Comparison for NEVADA

			GWh			$/MWh			Total ($1000s/Year)		
Cost Components			**Status Quo**	**Bookend Mkt+**	**Difference**	**Status Quo**	**Bookend Mkt+**	**Difference**	**Status Quo**	**Bookend Mkt+**	**Difference**
Production Cost	(+)	[1]	38,962	36,117	**-2,845**	$14.93	$13.58	**-$1.35**	581,683	490,427	**-$91,256**
Purchases Cost	(+)	[3]									
Day-Ahead Market + Bilateral		[4]	4,450	6,792	**2,342**	$15.89	$10.74	**-$5.15**	70,725	72,967	**$2,241**
Real-Time Market		[5]	1,946	2,075	**129**	$10.55	$19.56	**$9.01**	20,537	40,596	**$20,059**
Sales Revenue (Negative = Cost)	(-)	[6]									
Day-Ahead Market + Bilateral		[7]	4,003	5,151	**1,148**	$21.22	$32.89	**$11.67**	84,917	169,417	**$84,500**
Real-Time Market		[8]	3,930	2,408	**-1,522**	$26.09	$7.96	**-$18.13**	102,528	19,167	**-$83,361**
***Total Cost** (Negative Difference = Benefit)*		[9]	**37,426**	**37,426**	**0**	**$12.97**	**$11.10**	**-$1.87**	485,500	415,405	**-$70,095**
% Change in APC											*-14.4%*

Appendix: Benefits 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")

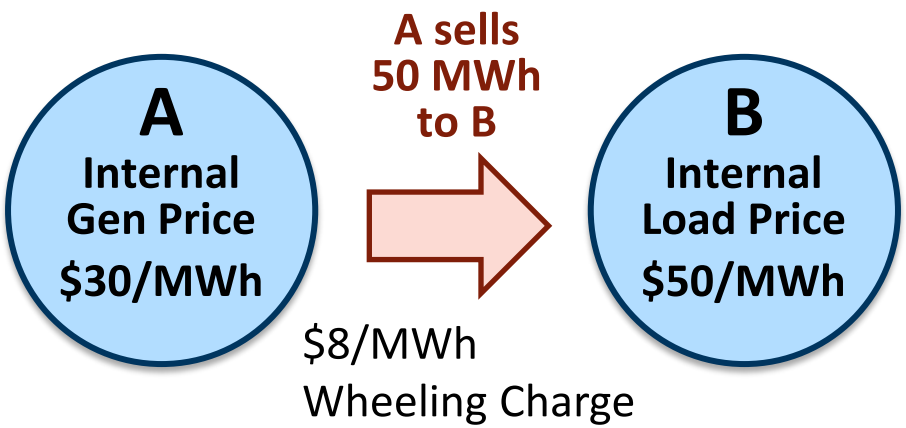
(−) Revenues from bilateral and market sales valued at the BAA's generation-weighted energy price ("Gen LMP")

Operational 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
- **Bilateral Trading Value:** buyer and seller split 50/50 the trading margin

EXAMPLE: Bilateral Trade



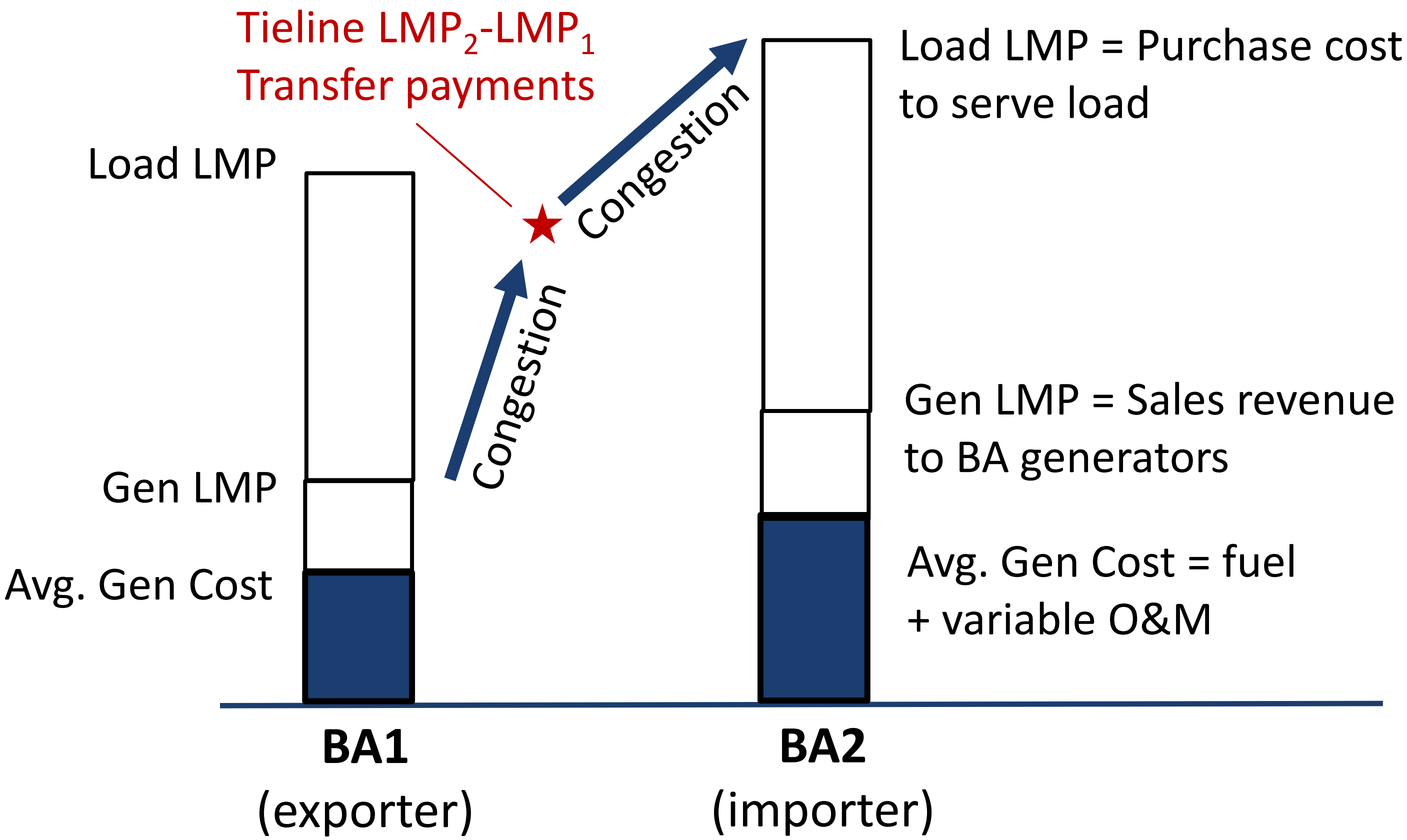
The APC metric only uses area-internal prices for purchase cost and sales revenues, which does not capture part of the value:

- 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

Bilateral 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

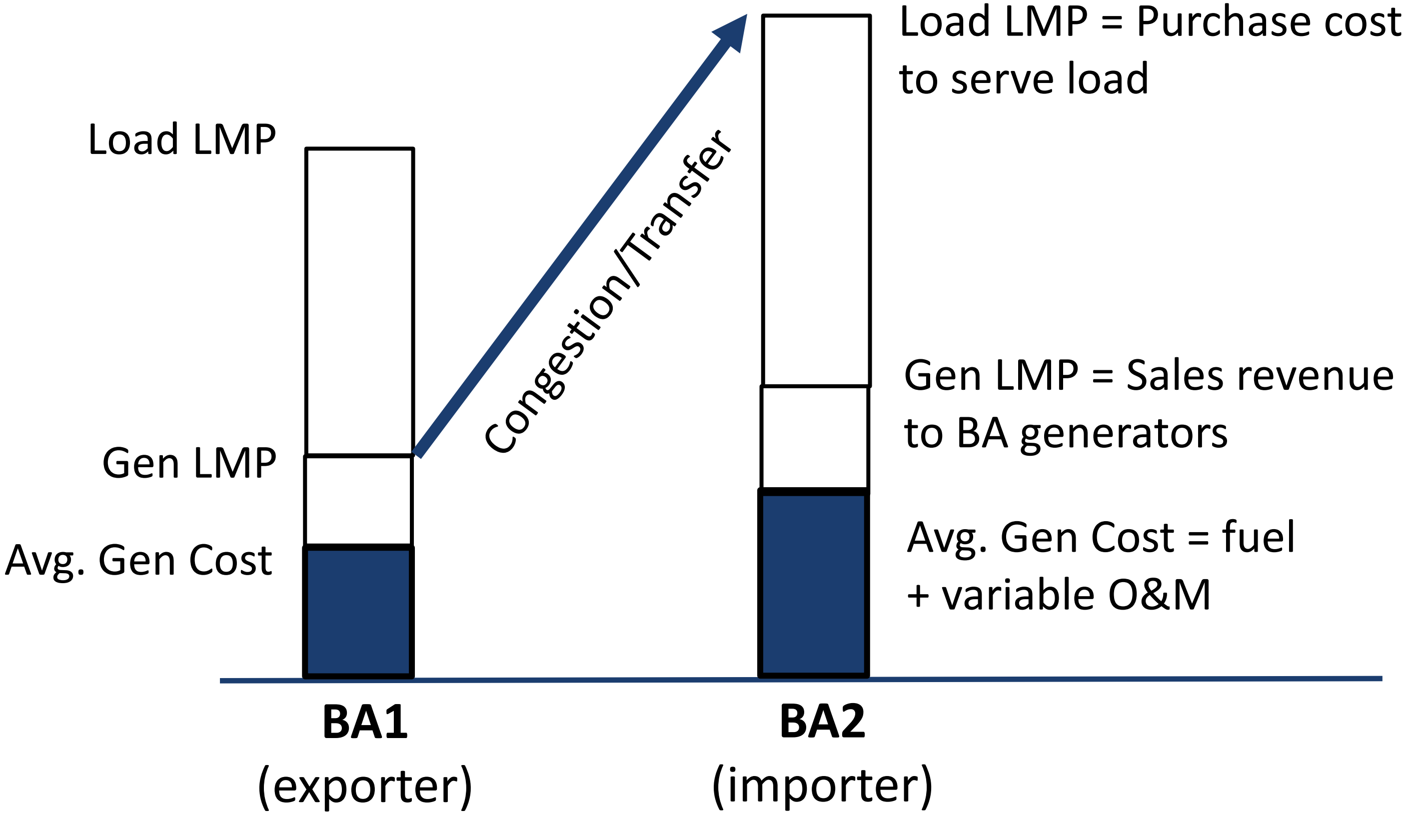
Illustration of EDAM Congestion and Transfer Revenues



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

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

Illustration of M+ Congestion/Transfer Revenues



M+ congestion revenues estimated based on BA load and gen LMPs:

- **Congestion Revenue Payment (split 50/50) = MW x (Load LMP_2 – Gen LMP_1)**

Appendix: Additional Model Details

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

ENELYTIX®
powered by PSO

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

Multi-Functional Simulation of WECC

Markets/RTO Functions & Configurations

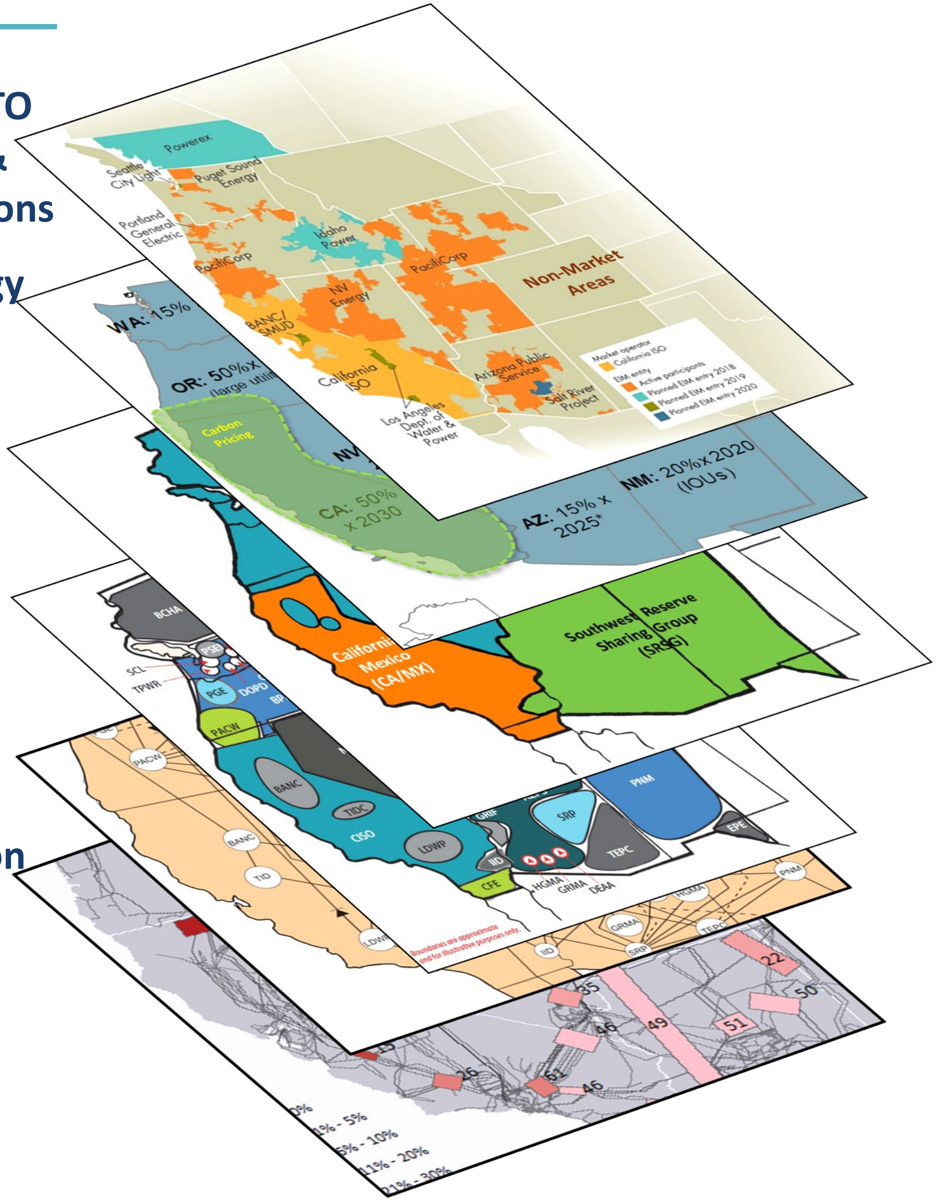
Clean Energy Policies

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)
- Bilateral transmission rights
- Renewable diversity, day-ahead forecast uncertainty, real-time operations
- CAISO, RTO West, M+, EDAM, WEIM, & WEIS footprints

Independent Simulation of Multiple Time Horizons

We simulate multiple independent decision cycles to capture day-ahead vs. real-time unit commitment and dispatch and uncertainty

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	• EIM/CAISO trading of economic energy • Transmission released for EIM • RT balancing in BAAs

Independent real-time decision cycle used to simulate EIM functions

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

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

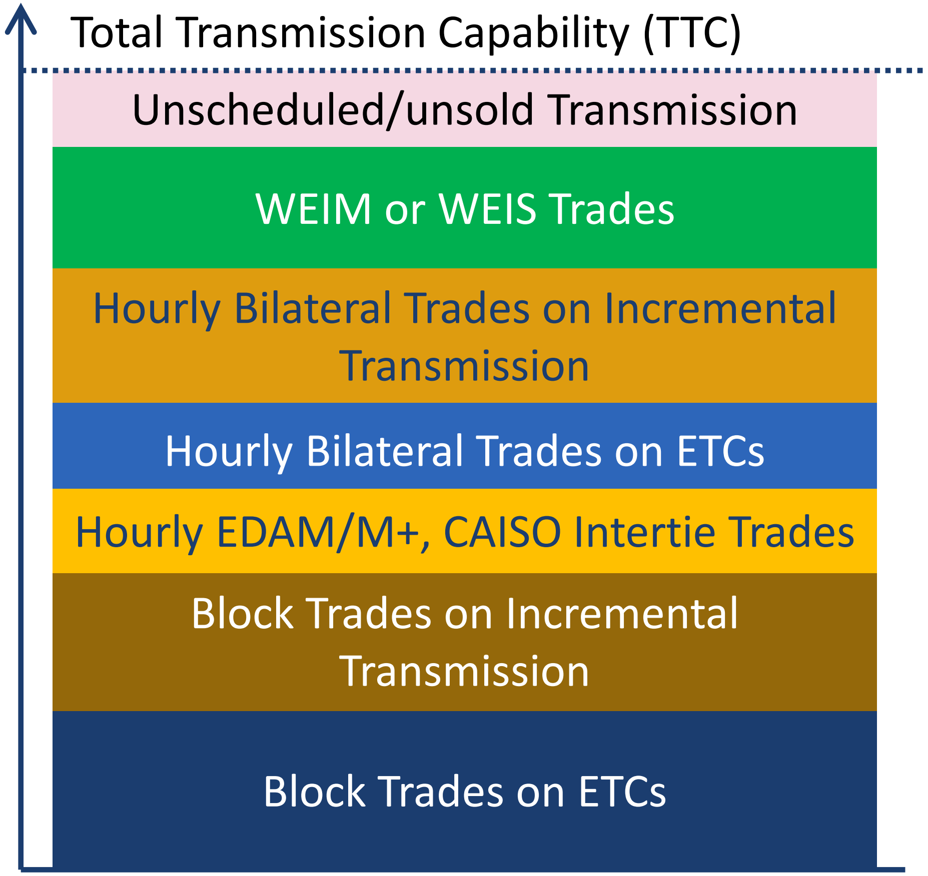
Independent real-time decision cycle used to simulate DA vs. RT, including forecast errors for wind and solar

Types of Trades and Transmission Reservations Modelled

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

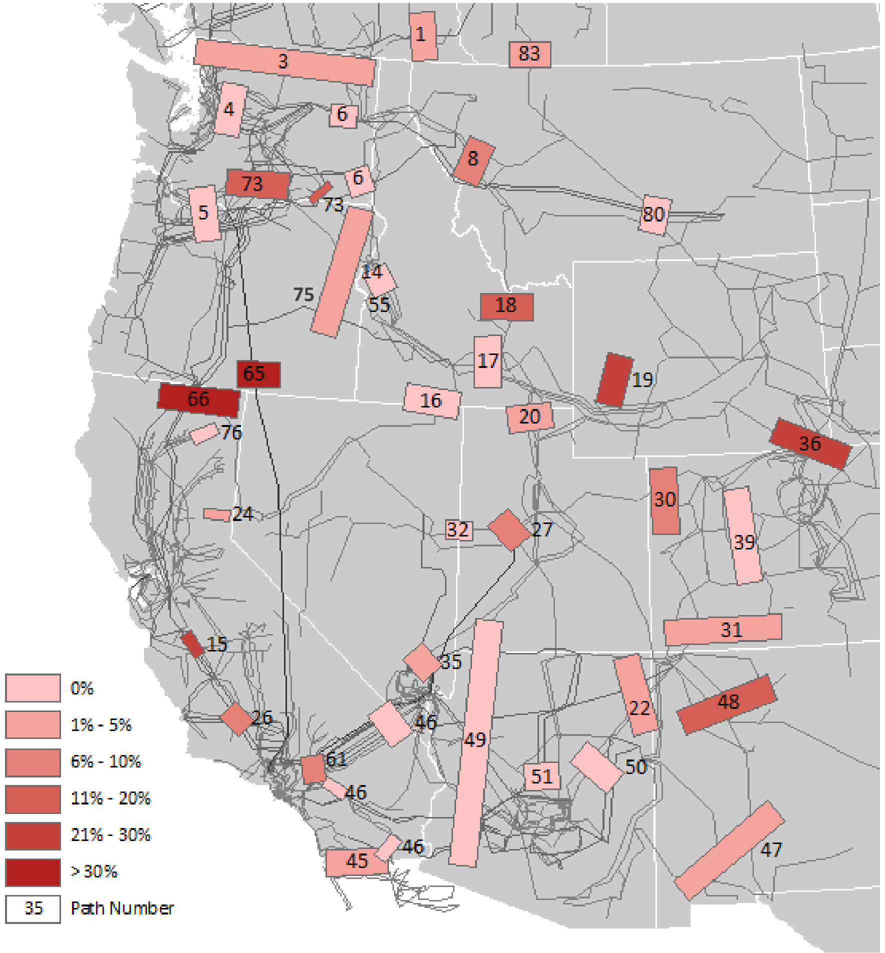
- Existing long-term transmission contracts (ETCs) and incrementally purchased transmission
- Total reservations on each contract path is limited by the total transfer capability (TTC)
- Trades are structured as blocks or hourly
- Bilateral trades between BAs, at major hubs, or across CAISO or RTO West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

Types of Trades Modeled



Nodal Simulations Based on Physical Transmission

WECC-Defined Paths Modeled



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

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

ENELYTIX®
powered by PSO

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

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

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

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

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

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.

Appendix: NVE Modeling Assumptions

Load Peak and Energy

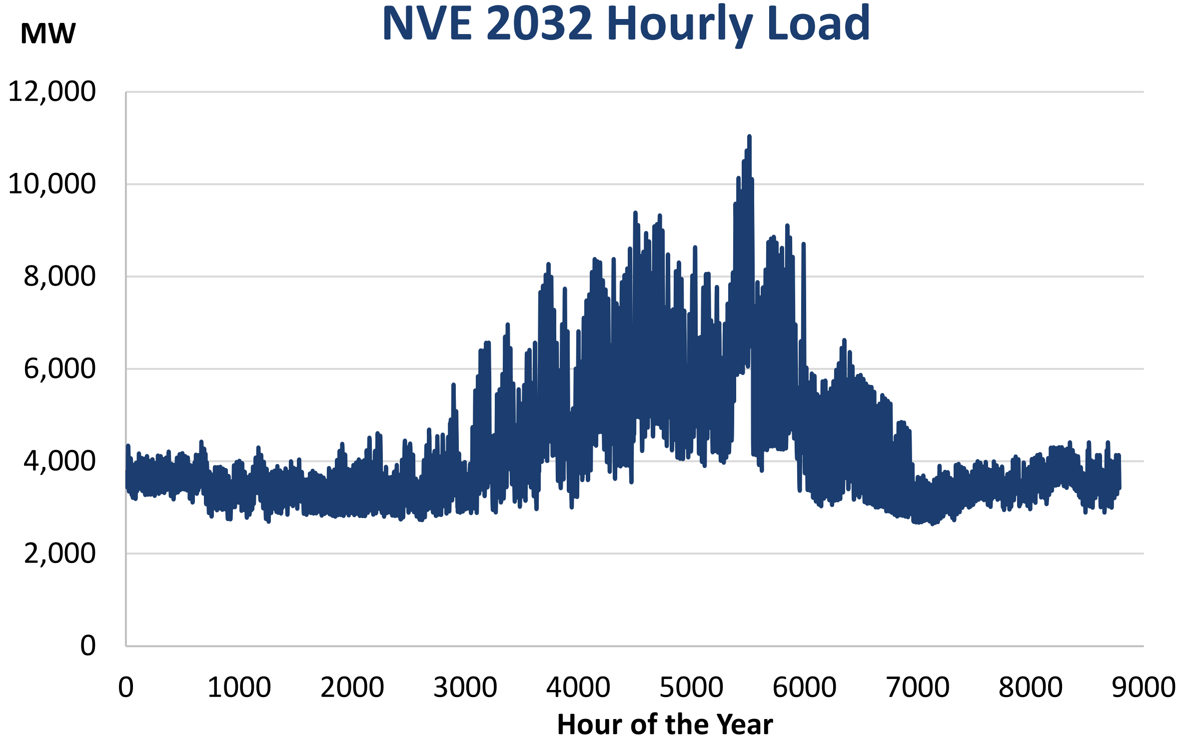
Summary of load data provided by NVE, the system is summer-peaking with ~37.4 TWh of annual demand and a 11 GW peak by 2032.

NVE Modeled Load

Month	Total Load	Monthly Peak
	MWh	MW
January	2,701,189	4,424
February	2,310,379	4,297
March	2,471,120	4,510
April	2,483,905	5,660
May	3,128,121	6,964
June	3,948,859	8,380
July	4,547,520	9,386
August	4,744,856	11,043
September	3,346,961	8,847
October	2,588,846	5,608
November	2,452,428	4,103
December	2,701,988	4,410
Annual	**37,426,172**	**11,043**

Note: NVE load is the sum of NEVP and SPPC load

NVE 2032 Hourly Load



Generation Capacity Mix

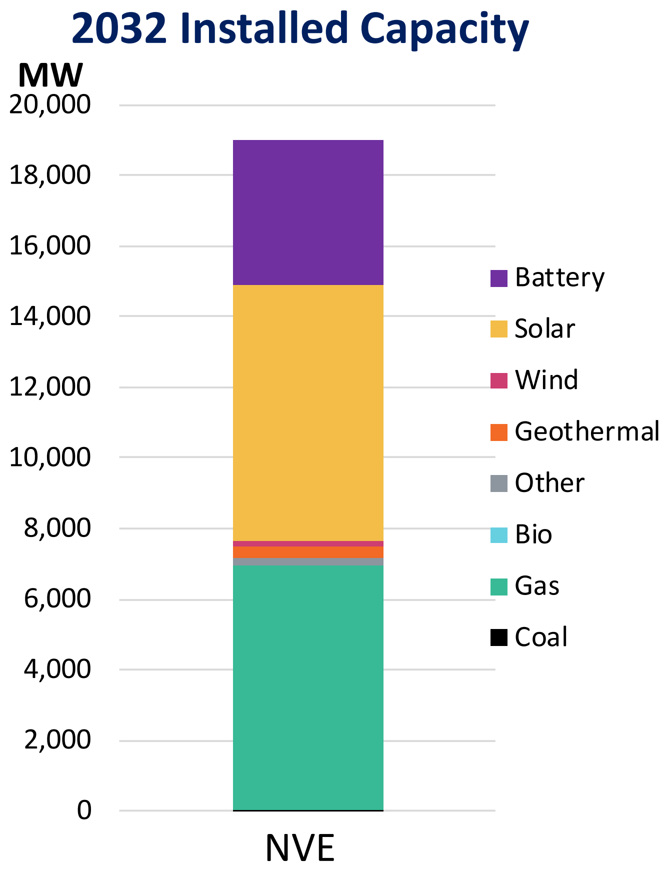
Summary of NVE modeled capacity

- Capacity mix is dominated by solar, storage, and gas

NVE 2032 Installed Capacity

Resource Type	Modeled Capacity (MW)
Coal	25
Gas	6,912
Bio	12
Other	218
Geothermal	315
Wind	152
Solar	7,248
Battery	4,128
Total	**19,010**

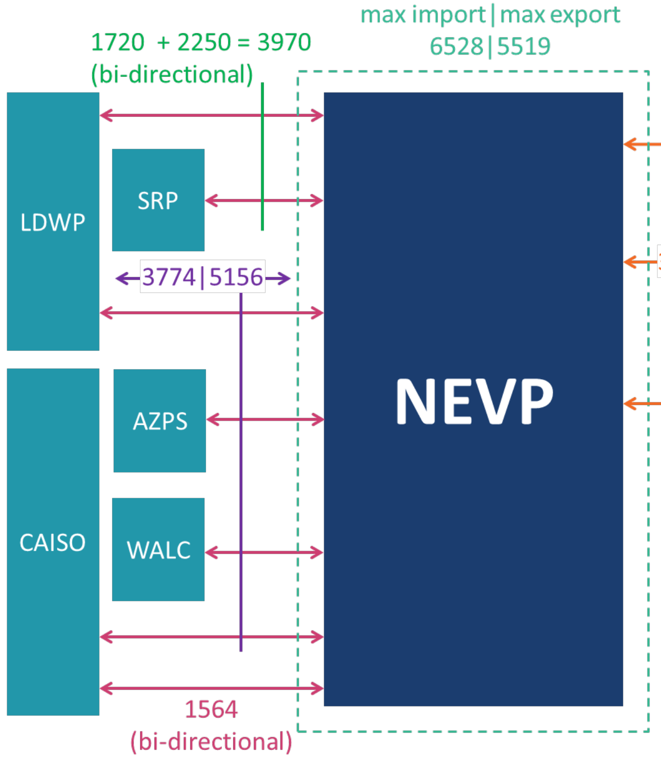
Note: capacity summary includes all generators in the NVE BAA, including a small amount of coal capacity associated with large industrial load that is not part of NVE's planned generation to meet NVE system load.



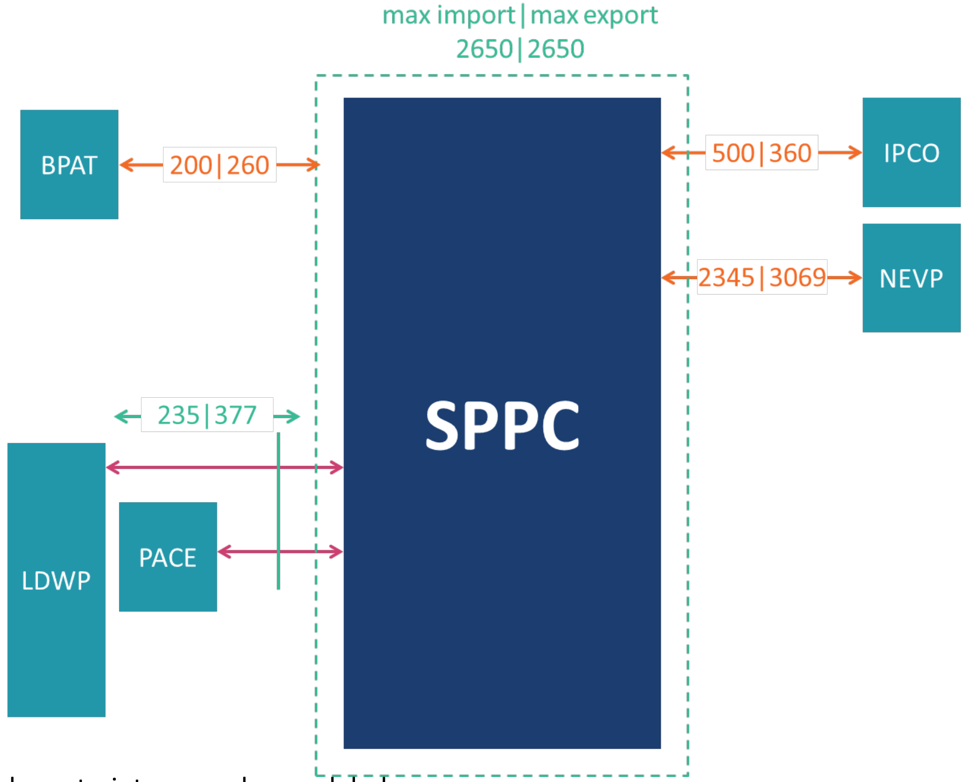
Contract Path Transfer Capacity

- We model the trading of Nevada's two subareas (NEVP and SPPC), as provided by NVE
- Bilateral and market trading is modeled with simultaneous physical limits
- Our EDAM/M+ cases assume all TTC is made available to the market

NVE-South (NEVP) Transfer Capability



NVE-North (SPPC) Transfer Capability



Note: diagrams show only the contract path constraints, WECC paths in the NVE service territories and other physical constraints were also modeled.

Appendix: EDAM Modeling Assumptions

Resource Sufficiency & Transmission

Resource Sufficiency Test

- The EDAM design applies the Resource Sufficiency Test to each EDAM member the day prior to real-time, before day-ahead market operations
  - In the 2019 EDAM Feasibility Study, E3 conducted an hourly analysis of Resource Sufficiency for each proposed EDAM member at that time
    - In that analysis, failure of the test was extremely rare
    - In fact, all current study participants (BANC, CAISO, IPCO, LADWP, SMUD, and PAC) previously passed the resource sufficiency test in all hours
  - For this study, conducted ex-post check and confirmed that all assumed EDAM members are resource sufficient in all hours

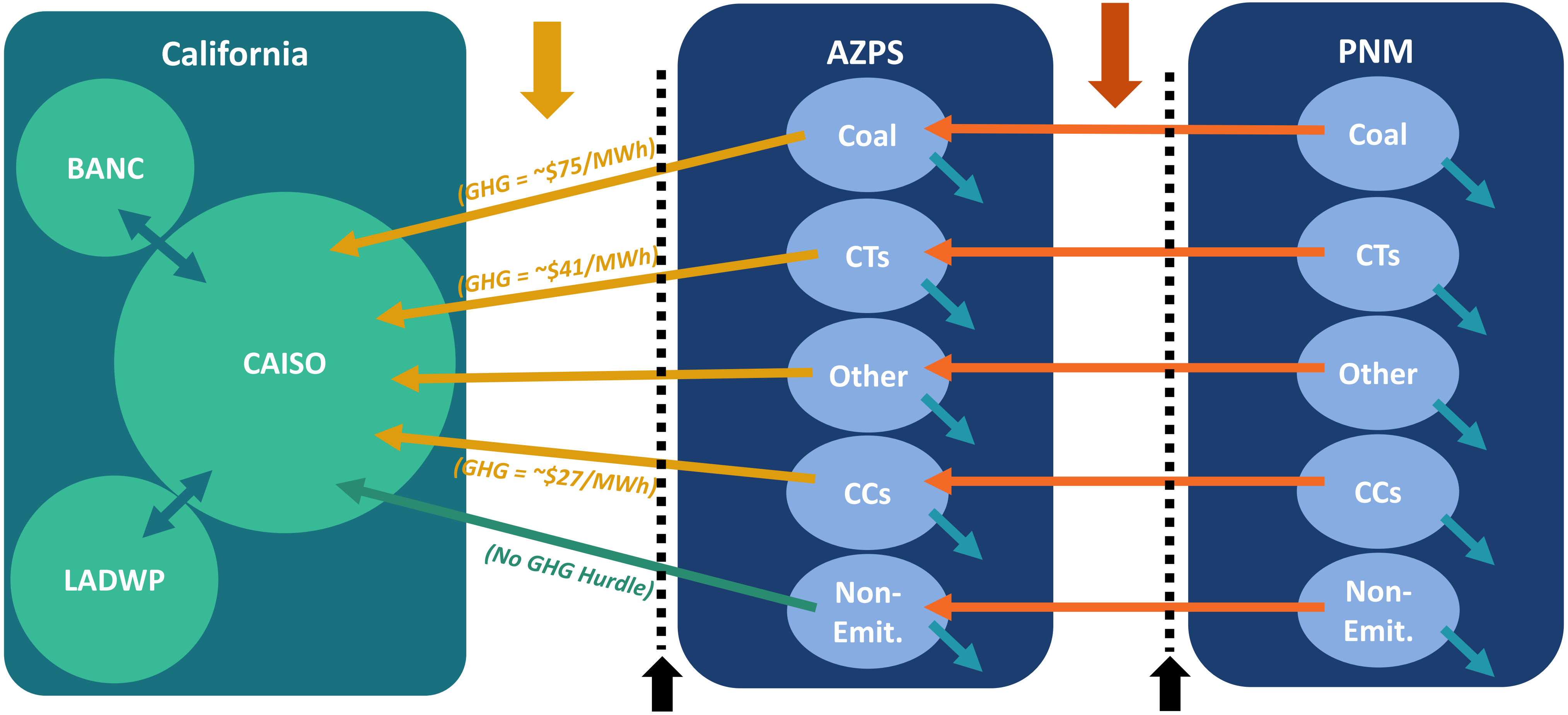
EDAM Transmission

- All three buckets of EDAM transmission are modeled and assumed to be hurdle-free:
  - Bucket 1: Transmission to Support Resource Sufficiency
    - Includes existing long-term transmission contracts ("ETCs") for energy used for sufficiency accounting purposes
  - Bucket 2: "Donated" Transmission Contracts
    - Existing transmission contracts (ETCs) made available ("donated") to the EDAM by participants
  - Bucket 3: Unsold Firm Transmission
    - Remaining transmission made available for EDAM (participants might hold back from transmission for block trading)
- 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

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

Imbalance Reserve Requirement

EDAM reserve requirement estimated to fall about 2-4.2 GWh in the EDAM Case (relative to Base Case) due to the diversity benefit achieved by the EDAM footprint

Imbalance Reserve is a new reserve product being implemented by the CAISO as part of their DA Market Enhancements (DAME) initiative, and will apply to EDAM

- The Imbalance Reserve requirement (up and down) will be set to meet the 97.5 percentile of each BAAs historical net load variability
- In EDAM, participants' Imbalance Reserve Requirement will be 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.
- **Brattle Assumption:** we calculated each EDAM participants Imbalance Reserve Requirement and the EDAM diversity benefit to reduce each member's requirement

Appendix: Markets+ Assumptions

Transmission Usage in the Market

Modeling Assumption: All transmission with other Markets+ entities was modeled as available for market transaction without any wheeling charges

- In the WEIM, BPA is modeled consistent with their level of participation, with limited transmission made available to the market. In Markets+ and EDAM, BPA is modeled as making their full transmission system available to the day-ahead market.
- We asked all study participants if you want to identify some transmission to set aside for WRAP, third party ownership, or other reasons.
  - *No study participants identified any WRAP transmission to be withheld from the market optimization*

M+ GHG Structure

Based on our review of the draft tariff language and the task force materials posted online, we assume for the purposes of these studies that M+ will use the following approach:

- Only energy identified as GHG surplus will be available to transfer to the GHG zone
- GHG surplus identification will 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
  - Resource operators make all resources available for transfer to the GHG zone
  - BA-level hourly surplus capacity available for transfer to the GHG transfer is calculated outside of the model using modeled load and a merit order constructed from modeled cost and capacity assumptions
  - We apply 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

Seams Management

Modeling Assumption: Brattle modeled the Markets+ seam consistent with the description from the Seams Task Force

- Exports into or imports out of Markets+ were charged a small bilateral friction charge plus the exporting entity's wheeling rate
- This is consistent with how we model the CAISO seam in the BAU Case
- Exports across the Markets+ seam into a GHG zone are charged an unspecified resource GHG cost (equivalent to the emissions charge for a generic gas-CC unit)
  - This makes Markets+ exports to CAISO and other GHG entities fairly expensive, as the GHG cost alone will be around $30/MWh

Modeled Trading Friction Charges ($/MWh)

Transaction Type	BAU Case	Markets+ Case	Pays OATT?
EIM & WEIS Transactions	$0	$0	No
Bilateral Transactions	$6	$6	Yes
ETC Transactions	$6	$6	No
RTO Intertie Transactions	$1.5	$1.5	Yes*
Block Transactions	$1.5	$1.5	Yes*
EDAM Transactions	$0	$0	No
Markets+ Transactions	$0	$0	No

*Note: *Block and RTO transactions won't pay an OATT rate if the transaction occurs over long-term ETC rights, just like ETC transactions broadly. The friction charge is the same regardless.*

Markets+ imports & exports pay either the bilateral or RTO intertie friction costs *(RTO for trades with CAISO or SPP West, who connects to PACE)*

Real Time Market

Brattle modeled Markets+ with a real-time market that operates like SPP's Western Energy Imbalance Service (WEIS)

- At the time the study was conducted, the Markets+ Task Forces had not discussed how the real-time market would function, but it is expected that Markets+ would include a RT market
- This also provides an apples-to-apples comparison with EDAM/WEIM

Real-time transactions at the Markets+ seam pay a small hurdle rate to capture bilateral friction + the exporting BAA's wheeling free + applicable GHG costs

- Transactions in real time across GHG zones and between markets (e.g., from EDAM to Markets+ or from Markets+ to CAISO/EDAM are charged the unspecified GHG rate)
  - For example, exports from **CAISO to Markets+** are charged the CAISO TAC + hurdle rate
  - Exports from **Markets+ to CAISO** are charged the GHG rate + exporter's OATT rate + hurdle rate

Congestion Rent Allocation

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

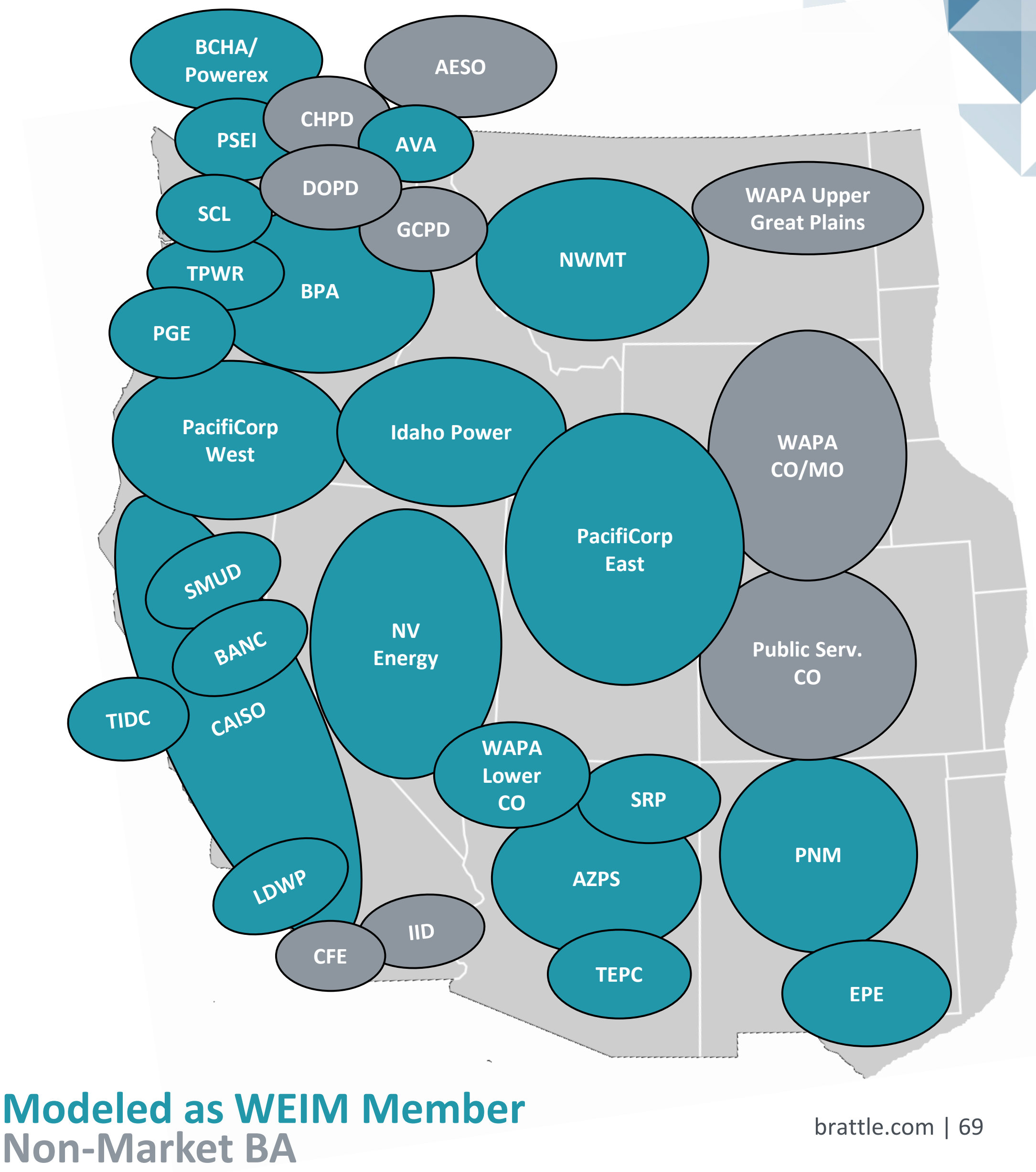
- We apply the Markets+ proposed approach is to allocate congestion based on the portion of rights each market participant owns on the constraint where congestion is collected for market transactions between members.
- Congestion on transactions internal to a member's system (to serve native load) is 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: Summer 2023 NVE EDAM Study Details

BAU Case Footprint

For the BAU case, Brattle assumes the day-ahead market will remain a bilateral market

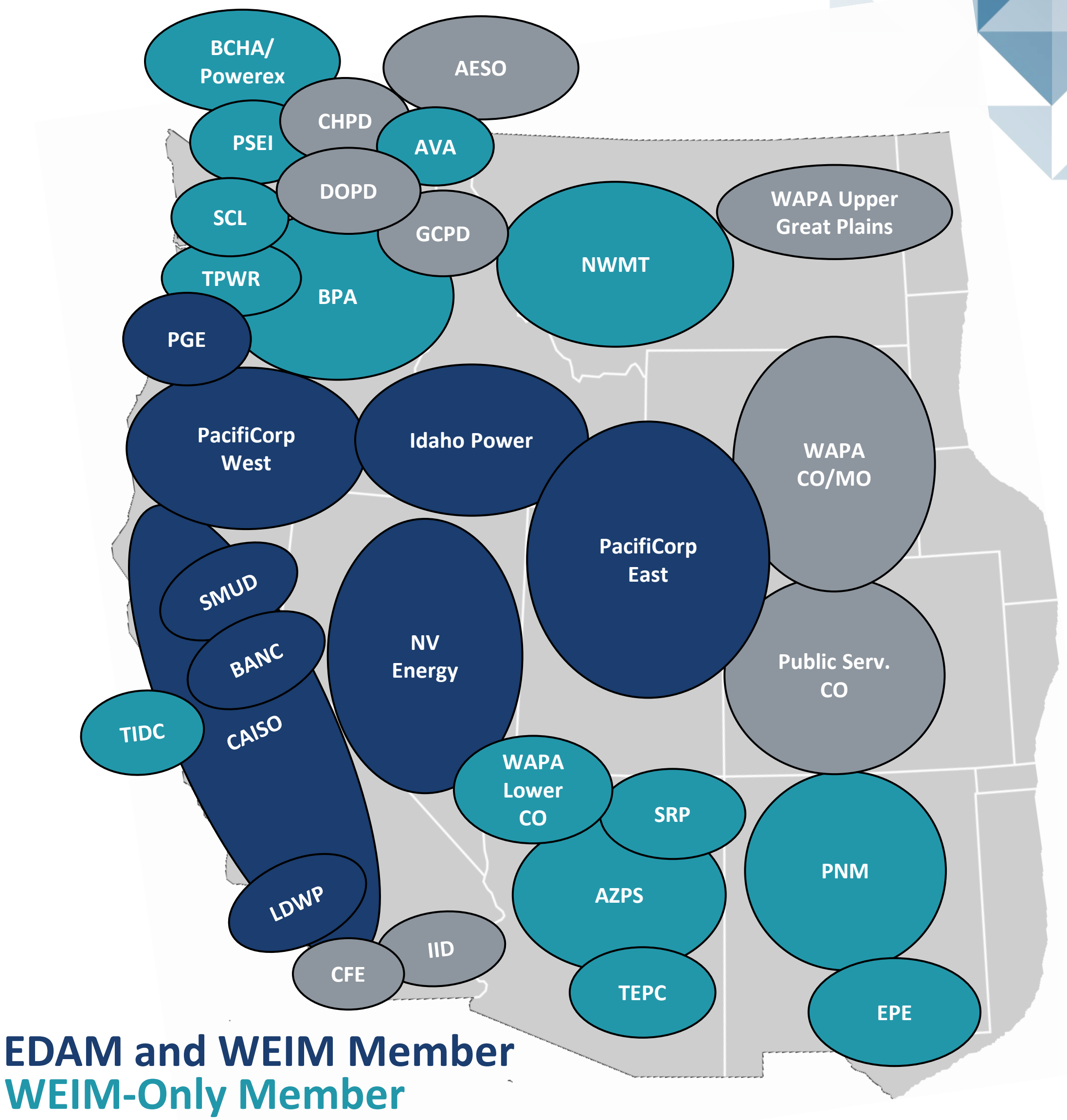
- **WEIM entities in teal**
  - Existing WEIM footprint modeled
- Original study EDAM BAU did *not* include the RTO West footprint
- Non-market BAs assumed to trade only bilaterally



EDAM Case Footprint

EDAM case assumed EDAM is the only DA market (no Markets+ footprint simulated)

- **EDAM Entities in Blue**
  - TIDC would remain in WEIM
- Case did *not* include the RTO West footprint
- Non-market BAs assumed to trade only bilaterally



EDAM and WEIM Member
WEIM-Only Member
Non-Market BA

NVE EDAM Study Benefits Results

In the initial EDAM study, Brattle simulated Nevada Power in a BAU case with no day-ahead WECC markets and Nevada Power in a limited EDAM footprint

- **Modeled benefits for Nevada Power joining EDAM totaled $101.3 million**
- **NV Benefits were driven by:**
  - Adjusted Production Cost savings of $84 million/yr
  - EDAM congestion and transfer revenues of $32 million/yr
  - Increased short-term non-firm wheeling revenues of $24 million/yr
  - Losses in bilateral and EIM congestion revenues totaling $26.5 million
  - A net EDAM TRR settlement loss of $12 million

Summary of NVE EDAM Participation Impacts
$ Million

Benefit Metric	*Metric*	Base Case	EDAM	Total Market Impact
Adjusted Production Cost	*Cost*	$470.2	$386.2	**$84.0**
EDAM Congestion Revenues	*Revenue*	-	$20.0	**$20.0**
EDAM Transfer Revenues	*Revenue*	-	$11.5	**$11.5**
Wheeling Revenues	*Revenue*	$13.0	$37.3	**$24.3**
EIM Congestion Revenues	*Revenue*	$13.8	$2.8	**-$11.0**
Bilateral Trading Value	*Revenue*	$70.4	$54.9	**-$15.5**
Net TRR Settlement	*Revenue*	-	-$12.1	**-$12.1**
Total System Cost Adjusted for Revenues		**$373.0**	**$259.6**	**$101.3**

Notes:
[1] Bilateral trading values of exports and imports from the BAs of EDAM members, includes impacts on trades by third-party marketers.
[2] Total system cost is adjusted production cost minus all the revenues.

NVE EDAM Adjusted Production Cost Benefit

NVE Adjusted Production Cost falls $84 million/year from the EDAM case:

1. Increased gas generation raises production costs by $71 million/year
2. Reduced day-ahead purchase costs due to reduced prices as NVE buys excess renewables in the EDAM footprint, lower costs by $33 million/year
3. The increased sale volume and prices (mostly the increased gas generation) in the day-ahead market raises day-ahead sales revenues by $188 million/year

Adjusted Production Cost Comparison for NV Energy

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Status Quo**	**EDAM**	**Difference**	**Status Quo**	**EDAM**	**Difference**	**Status Quo**	**EDAM**	**Difference**	
Production Cost	(+)	[1]	38,481	39,741	**1,260**	$14.87	$16.19	**$1.32**	572,114	643,306	**$71,191**	(1)
Renewable REC/PTC Value		[2]										
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	4,598	5,920	**1,323**	$14.19	$5.36	**-$8.82**	65,224	31,753	**-$33,471**	(2)
Real-Time Market		[5]	1,962	2,095	**134**	$8.67	$11.08	**$2.42**	16,998	23,220	**$6,222**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	3,829	7,724	**3,894**	$22.82	$35.62	**$12.80**	87,375	275,101	**$187,726**	(3)
Real-Time Market		[8]	3,785	2,607	**-1,178**	$25.57	$14.20	**-$11.37**	96,791	37,025	**-$59,766**	
Total Cost *(Negative Difference = Benefit)*		[9]	**37,426**	**37,426**	**0**	**$12.56**	**$10.32**	**-$2.24**	470,170	386,153	**-$84,017**	
% Change in APC											***-17.9%***	

NVE EDAM Revenues

Nevada's EDAM revenues mostly come from congestion revenues with CAISO and LDWP. These revenues are driven by the large trading volumes, not as much by high price separation

- Nevada trades about 26 TWh with CAISO, LDWP, IPCO, and PACE at an average EDAM transfer + congestion revenue value of about $1.2/MWh to NVE

EDAM Congestion + Transfer Revenues to NVE

Partner	EDAM Trade Volume	Average EDAM Value	Total EDAM Revenue
	GWh	$/MWh to NVE	$ Millions to NVE
CAISO	16,174	$1.52	$25
LDWP	3,725	$1.25	$5
IPCO	4,681	$0.30	$1
PACE	2,371	$0.36	$1
Total	**26,951**	**$1.17**	**$32**

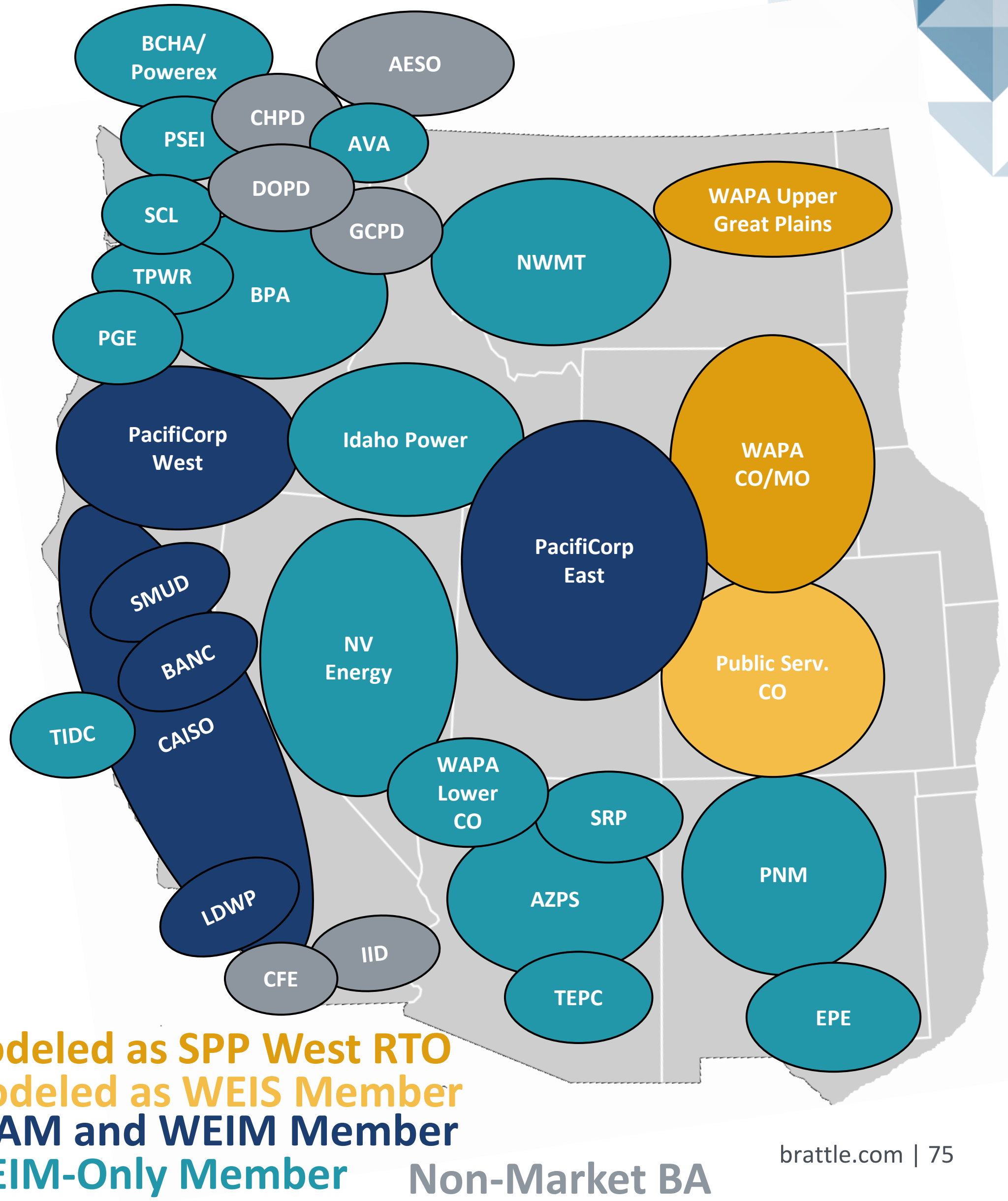
This table does not include NVE EDAM trading hub transactions which yield less than $100k in revenue.

Appendix: Fall 2023 NVE Markets+ Study Details

BAU Case Footprint

The Original Markets+ case has market footprints identical to the new Bookend Markets+ case

- **Markets+ in Orange**
  - Includes all U.S. BAAs in WECC, except for California entities and PAC
  - Also includes entities in RTO West (WACM, WAUW, PSCO), which is cooptimized with Markets+
  - Entities that join Markets+ assumed to leave WEIM and join an SPP-run RT market similar to WEIS
- **EDAM Entities in Blue**
  - TIDC would remain in WEIM
- IID, CFE, and AESO assumed to trade only bilaterally



Markets+ Case Footprint

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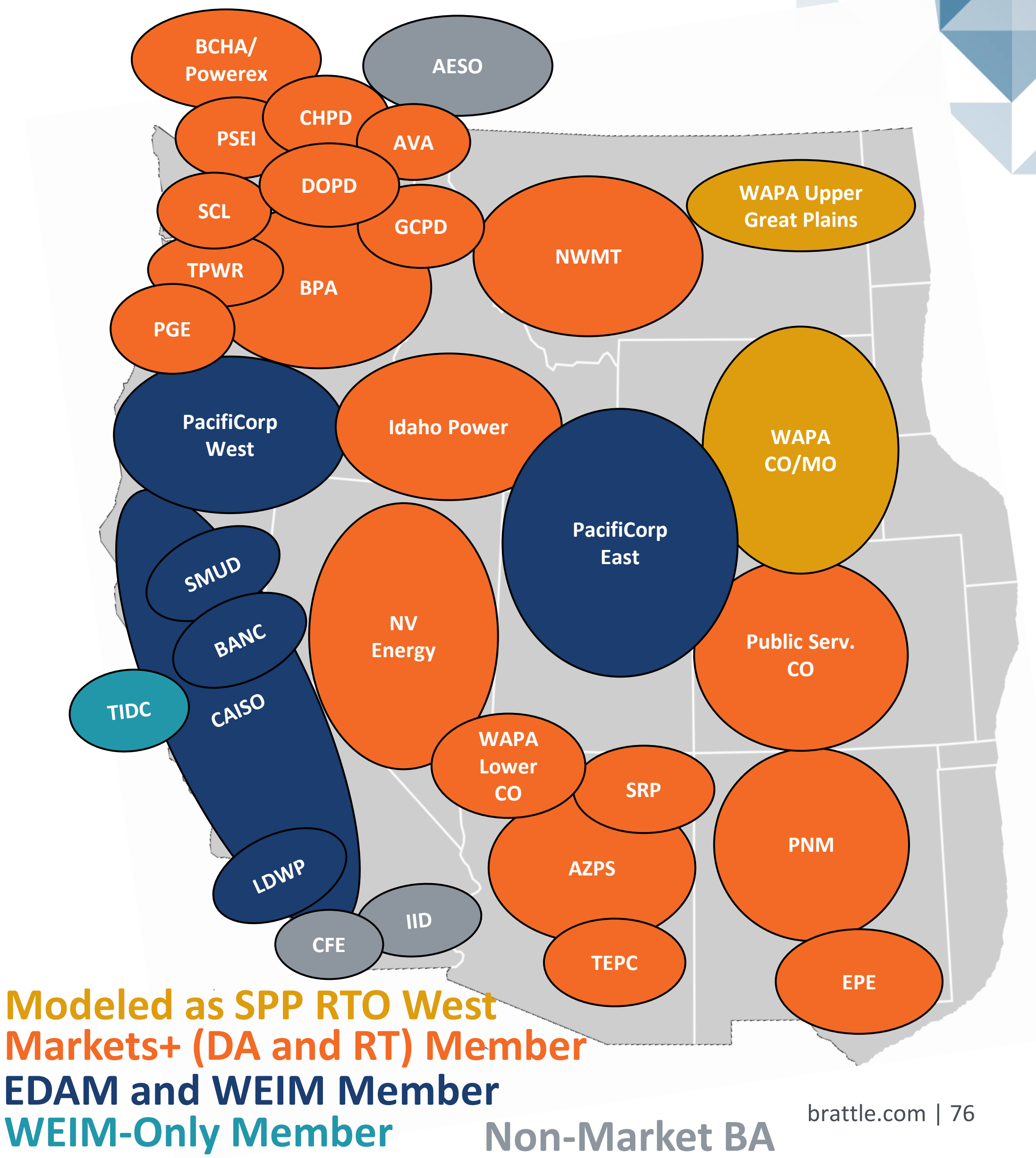
  - Includes all U.S. BAAs in WECC, except for California entities and PAC
  - Also includes entities in RTO West (WACM, WAUW, PSCO), which is cooptimized with Markets+
  - Entities that join Markets+ assumed to leave WEIM and join an SPP-run RT market similar to WEIS
- **EDAM Entities in Blue**
  - TIDC would remain in WEIM
- IID, CFE, and AESO assumed to trade only bilaterally



NVE Markets+ Benefits Results

Brattle estimated NVE's benefits from joining Markets+

- The Markets+ case showed an NVE net benefit of **$5m**
  - APC and transfer revenues are high for NVE, but low overall benefit due to large EIM and bilateral losses that accrued when NVE joined Markets+ (NVE moves from WEIM to WEIS in this scenario)

Summary of Nevada Benefits ($ Millions)

Metric	Markets+ Cases		
	BAU Case	Market Case	Benefit
Market Benefits			
Adjusted Production Cost	$477.6	$437.8	**$39.8**
Wheeling Revenues	$13.9	$0.0	**-$13.9**
Market Revenues & Trading Gains			
Markets+ Congestion Revenues	-	$63.6	**$63.6**
EDAM Congestion Revenues	-	-	**-**
EDAM Transfer Revenues	-	-	**-**
EIM Congestion Revenues	$51.8	$0.0	**-$51.8**
WEIS/Mkt+ Real Time Revenues	-	$12.7	**$12.7**
Bilateral Trading Gains	$52.7	$7.5	**-$45.2**
Total Net Benefit			**$5.2**

NVE Markets+ Adjusted Production Cost Benefit

NVE is seeing a net APC benefit of $40 million, driven by:

- **(1) Reduced thermal generation** saving $114 million in production costs (replaced by market purchases)
- **(2) Increased market purchases**, costing $55 million in both day-ahead and real-time to replace reduced generation
- **(3) Increased day ahead sales volumes and revenue**, with average sales prices going up $2.5/MWh and sales volumes increasing 1.3 TWh
- **(4) Reduced real time sales revenue due to exit from EIM,** costing $92 million from 2.1 TWh of lost sales volumes

Adjusted Production Cost Comparison for NEVADA

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			Status Quo	Markets+	Difference	Status Quo	Markets+	Difference	Status Quo	Markets+	Difference	
Production Cost	(+)	[1]	39,698	37,134	**-2,564**	$15.46	$13.45	**-$2.01**	613,616	499,521	**-$114,095**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	4,426	5,755	**1,329**	$15.39	$17.91	**$2.52**	68,102	103,079	**$34,976**	**(2)**
Real-Time Market		[5]	1,772	2,187	**415**	$10.70	$17.96	**$7.26**	18,955	39,276	**$20,320**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	4,210	5,511	**1,301**	$23.56	$31.28	**$7.72**	99,186	172,378	**$73,192**	**(3)**
Real-Time Market		[8]	4,260	2,139	**-2,121**	$29.08	$14.82	**-$14.27**	123,893	31,689	**-$92,204**	**(4)**
Total Cost *(Negative Difference = Benefit)*		[9]	**37,426**	**37,426**	**0**	**$12.76**	**$11.70**	**-$1.06**	477,594	437,808	**-$39,786**	
% Change in APC											*-8.3%*	

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

Loss of EIM sales revenue (-$92 million) partly offset by increase in Markets+ sales revenue ($73 million)

NVE Markets+ Revenues

NVE's Markets+ revenues mostly come from congestion revenues with IPCO and BPAT.

These revenues are driven by transfers aiming to use NVE's system to get to the Northwest portion of the market

- Nevada trades about 14.5 TWh with AZPS, BPAT, IPCO, SRP, and WALC at an average Markets+ value of about $4.4/MWh

Markets+ Congestion Revenues to NVE

	Markets+ Trade Volume	Average Markets+ Value	Total Markets+ Value
	GWh	$/MWh to NVE	$ Millions to NVE
AZPS	3,375	$1.44	$5
BPAT	2,033	$8.57	$17
IPCO	3,225	$7.70	$25
SRP	4,303	$2.97	$13
WALC	1,542	$2.39	$4
Total	**14,478**	**$4.39**	**$64**

This table does not include NVE Markets+ trading hub transactions which yield less than $100k in revenue.