

Western Markets Exploratory Group: Western Day Ahead Market Production Cost Impact Study

Prepared by Energy and Environmental Economics (E3)

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Energy+Environmental Economics

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1 Study Context and Key Questions

The Western Markets Exploratory Group (WMEG) is a group of 25 utilities and public power entities across the Western Interconnection. The WMEG is examining ways to develop more integrated electric power markets in the West, including emerging day-ahead market opportunities, and ways to further integrate markets services over the long term, up to and including a regional transmission organization (RTO).

The West is at a critical juncture of regionalization within the power industry, as it seeks to extend regional markets from real-time operations to the day-ahead level. Organized electricity markets have long been shown to provide various benefits to participant members including a more optimal system dispatch. The Western Energy Imbalance Market (EIM or WEIM) is the first organized market outside of the California ISO (CAISO) to bring these benefits to multiple Balancing Authority Areas (BAAs) in the Western Interconnection. The WEIM is a real-time wholesale energy market with participants across the WECC footprint. Over the past decade, it has provided millions of dollars of annual savings for members. In 2021, SPP launched a similar real-time imbalance market in the West: the Western Energy Imbalance Services (WEIS).

Recently, California ISO (CAISO) proposed plans to form a day-ahead market option for the West titled the **Extended Day- Ahead Market** (EDAM). The Southwest Power Pool (SPP) released a separate plan to offer Western entities a day-ahead market service titled **Markets+**. Both market options will augment existing functionality for real-time markets in different parts of the Western Interconnection through CAISO's Western Energy Imbalance Market (WEIM or EIM) and SPP's Western Energy Imbalance Service (WEIS or EIS) offering.

Colorado¹ and Nevada² have passed laws that require transmission utilities to join RTOs by 2030. PacifiCorp recently announced it will join EDAM³ and Powerex Corp. has announced it will join Markets+⁴. Amid the rollout of these new markets and moves towards regionalization, it is important for Western utilities to understand the impacts of these markets to help make informed decisions on their next steps.

The WMEG, through its consultant Utilicast, engaged Energy & Environmental Economics, Inc. (E3) to perform a Cost Benefit Study ("CBS" or "the study") examining the economic impact that joining either the EDAM or the Markets+ option would have for each WMEG entity and for the WECC overall. The study explores the impact that each market could have along two dimensions: (1) based on different **footprints** of which entities join either market, and (2) on the currently proposed design **features** of each market. In the CBS, E3 studies a Business as Usual (BAU) Case and three different market footprint options each comprised of different Western entities joining EDAM or Markets+ respectively by the 2026 study year.

¹ Colorado SB21-072, https://leg.colorado.gov/sites/default/files/2021a_072_signed.pdf

² Nevada SB 448, <https://www.leg.state.nv.us/App/NELIS/REL/81st2021/Bill/8201/Text#>

³ PacifiCorp, "PacifiCorp to build on success of real-time energy market innovation as first to sign on to new Western day-ahead market", <https://www.pacificorp.com/about/newsroom/news-releases/EDAM-innovative-efforts.html>

⁴ Powerex, "Powerex Commits to Markets+", <https://Powerex.com/sites/default/files/2022-11/Powerex%20Commits%20to%20Markets%2B.pdf>

Additionally, for the 2030 and 2035 study years, the CBS also examines the impact that increasing levels of market integration over a longer-term period could have for WMEG members.

Study impact focus: The WMEG guided E3 to focus the CBS only on the impact to variable generation and power purchase costs for each entity – that is, changes to the costs each entity incurs for fuel, variable O&M, and startup costs to generate electric power, as well the cost and/or revenue from power market purchases and sales. The E3 study does not estimate the cost of joining either market in terms of labor, software, or participation fees; savings in this study can be seen as gross of the cost of participation.

Additionally, this study does not consider a range of other benefits generally found to result from formation of a regional market, such as:

- a) generation investment savings due to programmatic sharing of load and resource diversity for participating entities – for example, through the proposed Western Resource Adequacy Program (WRAP),
- b) procurement savings by market enabling entities to contract with resources from across a larger market footprint (supported by a transparent locational market price and frictionless transmission access) rather than restrictions to procuring resources in one’s own local area or with direct transmission schedules to reserve transfer capability to a local area,
- c) coordinated regional transmission planning and investment, or
- d) reliability improvement during extreme weather or challenging operational conditions.

The WMEG chose to focus the CBS on variable generation and purchase cost impacts as a directly quantifiable outcome of market formation but recognizes that these other benefit components may provide significant additional long-term savings. For example, the State Led Study Market Studies found that a two-market day-ahead option relative to a BAU case with only real-time markets could yield \$85 million in adjusted production cost savings and \$416 million in capacity savings.⁵ Also, the 2016 Senate Bill 350 Study on the impact to California of a regional CAISO-led Western power market identified \$104 to \$523 million in adjusted production cost savings, \$680 to \$800 million in annual capital cost investment savings related to renewable procurement, and \$120 million in annual capacity savings due to load diversity.⁶ Additionally, for an example in the Eastern Interconnection, MISO’s 2022 Value proposition estimates that the MISO market facilitates \$890 to \$923 million in Energy and Ancillary Services savings, \$1,942 to \$2,866 million in Resource Capacity Sharing, and \$409 to \$479 million in Renewable Resource Optimization, which is procurement related.⁷ It is important to recognize that the savings estimates calculated in this study are conservative because they do not include these other types of potential savings.

⁵ <https://www.energystrat.com/s/Final-Roadmap-Technical-Report-210730.pdf>

⁶ https://www.caiso.com/documents/sb350study_aggregatedreport.pdf

⁷ <https://cdn.misoenergy.org/2022%20Value%20Proposition%20Annual%20View%20-%20Detailed%20Report628393.pdf>

2 Study Approach

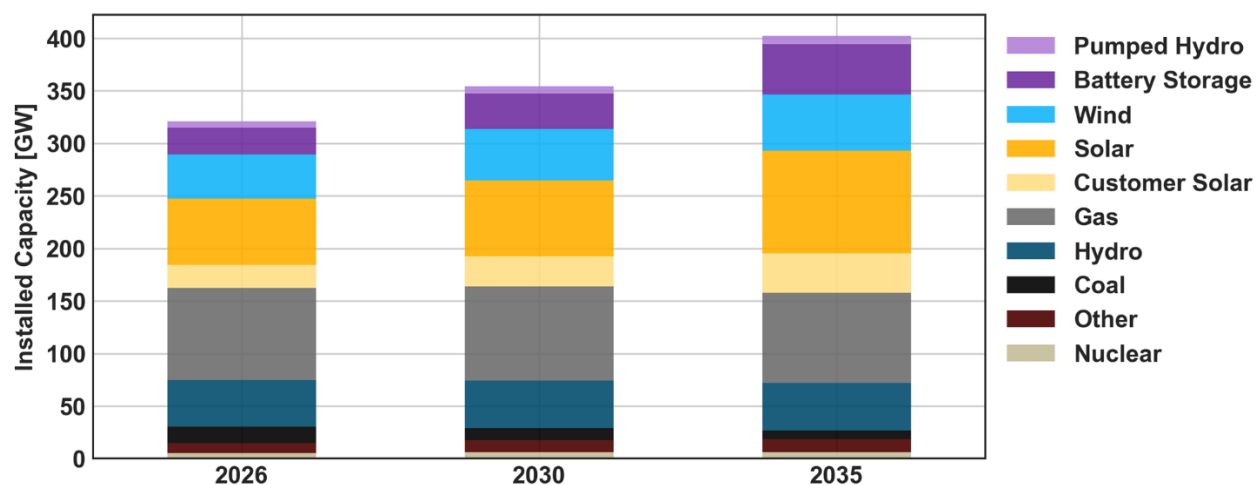
Study methodology overview: To conduct this study, E3 created a multi-stage simulation of the Western Interconnection using the PLEXOS production cost model developed by Energy Exemplar. Energy Exemplar worked closely with E3 to enhance E3's efficiency running over 4,000 cases in a Cloud-based environment, as well as customizing PLEXOS to directly address WMEG questions and represent the EDAM and Markets+ offerings in detail. In PLEXOS, E3 modeled the dispatch of all major power plants in the Western Interconnection on an hourly basis for each study year and study scenario.

E3 modeled each of these cases first on a day ahead (DA) stage to identify commitment of long-start generation and calculate day ahead transactions, and then on a Real Time (RT) stage for actual dispatch in the operating day. E3 modeled the DA stage with load, wind, and solar forecast error in DA relative to the actual load, wind, and solar values that occur in the RT stage. To manage this forecast error, the model held flexibility on generators in the form of DA forecast error reserves to respond to changes in load or variable energy resources (VERs) between the DA and RT stages.

This section provides a summary of the study data and key assumptions. Appendix A to this report contains more extensive detail on each of these assumptions.

Study data: The starting database for the study was the 2032 Anchor Data Set (ADS) created by the Western Electric Coordinating Council (WECC) with subsequent modifications for both WMEG member areas and non-WMEG areas.⁸ The CBS benefited significantly from contributions by staff from each WMEG member in providing input data – including load growth projections, updated generator additions and retirement information, as well as generator operational parameters, costs, and percentage shares that are owned and or contracted to different WMEG entities, which is necessary for calculating the adjusted production cost impact of different market participation plans for each entity. The 2026 study cases and those for subsequent years include significant generation additions, particularly of solar, wind, and storage resources based on the data developed by WECC and updated by WMEG members. The regionwide resource mix for each year is summarized in the table below.

⁸ The 25 WMEG members represented are AEP, APS, Avista, Balancing Authority of Northern California (BANC), Black Hills Energy, BPA, Chelan County PUD, El Paso Electric (EPE), Grant County PUD, Idaho Power Company, Los Angeles Department of Water & Power (LADWP), NV Energy, PacifiCorp, Public Service of New Mexico (PNM), Platte River Power Authority, Public Service of Colorado (PSCO), Puget Sound Energy (PSE), Salt River Project (SRP), Tacoma Power, Tucson Electric Power (TEP), Tri-State Generation and Transmission Authority (TSGT), and Western Area Power Administration (WAPA), which was modeled in 5 separate areas (SNR, CRCM, LAP, WALC/DSW, and WAUW). The rest of the WECC was represented as non-WMEG.

Figure 2-1 Total U.S. WECC Installed Capacity⁹

The CBS uses a zonal transmission topology based on Total Transfer Capability (TTC) between entities. The zonal option enables the study to avoid the additional complexity and significant run-time considerations of modeling a nodal topology, allowing both more cases to be run and more accurate modeling of ancillary services as well as the specific proposed market features of EDAM and Markets+. To ensure accurate modeling of transmission limitations, the study model incorporated a number of market trading hubs (or "tie zones") that connect multiple entities in today's actual operations. E3 developed the topology for these tie zones with the support of the WMEG transmission task force and staff at many WMEG entities. E3 also worked with WMEG Task Force members to develop assumptions for gas price forecasts, as well as greenhouse gas (GHG) prices, which were applied on in-state generation as well as imports into California, Washington, and Colorado. For non-WMEG areas, E3 supplemented data in the WECC ADS case with additional information gathered on resources and transmission.

Study Scenarios: The table below shows four scenarios with alternative market participation footprints that WMEG directed E3 to model for the 2026 study year.¹⁰ In the BAU case, E3 models wheeling and trading friction at the border of individual BAAs. Within each market footprint (EDAM or Markets+), transactions do not face wheeling or frictional costs, but these charges are applied to trades on the border or seams between markets. Additionally, the market footprint determines the region over which DA forecast error reserves can be held on resources.

These cases were developed by the WMEG using a collaborative process intended to explore key impacts of (a) having a single market spanning all of the US WECC (in the EDAM Bookend case) versus (b) having two Western markets, with separate market footprints that reflect intentions already announced by

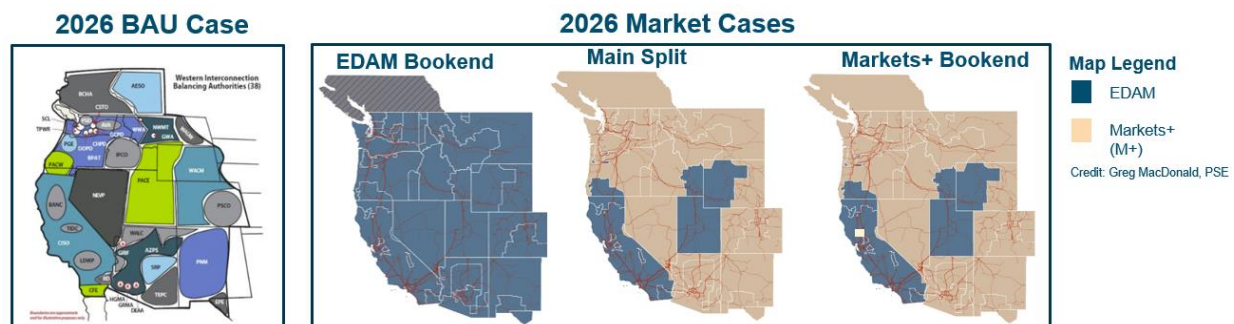
⁹ Total WECC capacity does not include AESO resources as this was implemented as a price stream within the CBS. BC resources and loads (as well as trades with Alberta) were modeled as an integrated pumped hydro facility based on the anticipated quantity of energy to be imported from or exported to the US, based on data provided by Powerex. This BC capacity is included with pumped storage in the chart.

¹⁰ For a subset of WMEG members who requested further exploration, E3 modeled four other alternative market footprints in 2026.

certain entities to join the EDAM or Markets+ as well as one potential set of assumed participation choices by the remaining Western entities that have not yet announced market decisions (in Main Split and Markets+ Bookend). These footprints do not represent the only potential maps for two Western Markets, as there are a wide range of potential combinations that could lead to different market footprints. A subset of WMEG members chose to fund additional footprint sensitivity cases, which are provided separately from this report.

The detailed participation of each entity in different markets for these scenarios is provided in Appendix B to this report.

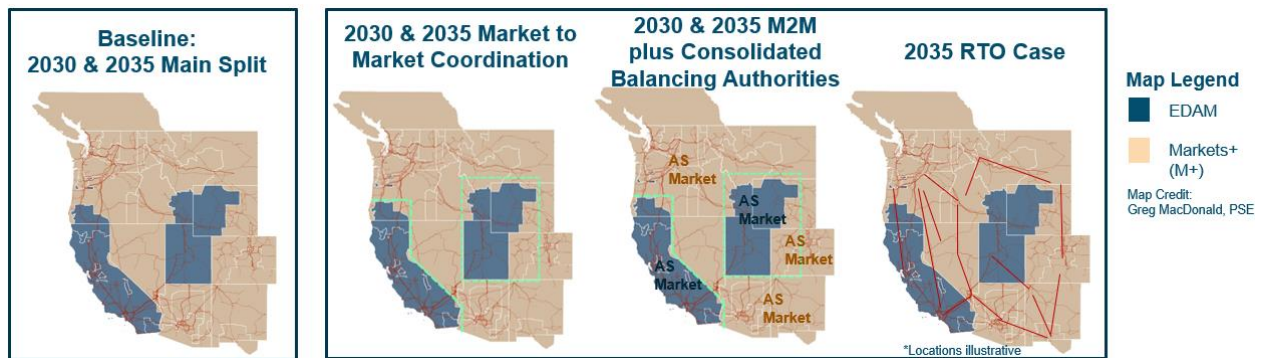
Figure 2-2 2026 Core Study Cases



Note: The Markets+ Bookend footprint matches that of the Main Split Case, except for WAPA SNR region which was represented in Markets+ in the Markets+ Bookend and in EDAM in the Main Split Case

- The **2026 BAU Case** models a day-ahead (DA) stage with bilateral trading but no organized market. In the real-time (RT) stage, the BAU case represents wheeling and friction-free trading within the existing WEIM and WEIS footprints.
- The **EDAM Bookend** case models a single DA and RT market that covers the entire U.S. portion of the Western Interconnection, excluding Alberta, British Columbia (BC), and CFE in Baja Mexico. Trades inside the Market reflect the currently proposed EDAM design and are simulated with no wheeling costs or transactional friction.
- The **Main Split** case models two separate DA and RT footprints: (a) an EDAM comprised of PacifiCorp, and the state of California (CAISO, LADWP, BANC, LADWP, TIDC, and IID), and (b) a Markets+ region consisting of the rest of the US WECC, plus BC which is modeled as a pumped hydro generator with net purchases and sales at the US-Canadian border.. Alberta and CFE are modeled as external zones not participating in either the EDAM or Markets+.
- Finally, the **Markets+ Bookend** case models market footprints similar to the Main Split, except that WAPA Sierra Nevada Region (SNR), a sub-BA of the Balancing Authority of Northern California (BANC) is modeled in Markets+ rather than EDAM.

For the 2030 and 2035 study years, the Core CBS simulates additional cases shown in the figure below. WMEG selected these cases to explore ways in which the WECC region could pursue additional integration beyond a day-ahead and real-time energy market. Each case adds an extra feature of further integration to the previous simulation. Additional detail to these scenarios is provided in Appendix B to this report.

Figure 2-3 2030 and 2035 Core Study Cases

- E3 modeled **2030 & 2035 Main Split** cases with the same market footprint as the 2026 Main Split case, but with load growth, generation retirement additions, and updated fuel and GHG prices reflected.
- The **2030 and 2035 Market to Market (M2M) Coordination** cases use the 2030 and 2035 Main Split footprint for EDAM and Markets+ but reduces the hurdle rates that are charged on trades over the seams between the two markets footprints to represent transactional friction.
- The **2030 and 2035 M2M plus Consolidated Balancing Authority (M2M + CBA)** cases reflect the Main Split footprint with M2M coordination, but also add a market for co-optimized ancillary services (AS) procurement across sub-regions of each Market footprint.
- The **2035 RTO Case** models the Main Split footprint with M2M and CBA and adds significant transmission to evaluate each market's performance with additional transmission from coordinated planning, enabling greater trading across the footprint.

Market Features: the most distinct modeling difference between the EDAM and Markets+ footprints was that E3 represented **Fast Start Pricing (FSP)** in the Markets+ portion of the WECC footprint, but not in zones that are placed in EDAM. FSP is an adjustment to settlements currently used in the SPP market in the Eastern Interconnection and proposed for Markets+. Typically, generators provide multi-part bids including (a) start costs and costs to run at minimum output, and (b) the incremental cost to dispatch at a higher level. However, the locational marginal prices (LMPs) calculated by PLEXOS and used to settle energy transactions for all loads and generators do not include the start costs. Historically in LMP-based markets, an ex-post calculation determined whether generator start costs were fully recovered through infra-marginal rents during hours when the generator operated. Any start costs that were not fully recovered were charged to all loads via an “uplift” charge. Recently, certain North American markets have incorporated FSP, which converts generator start cost and minimum load costs into a marginal cost adder and then reruns the market process to generate new, higher market clearing prices. This higher price is then used to settle generator awards and load payments.

For this study, E3 created a custom modeling process in the PLEXOS simulation to follow the same approach used by SPP for FSP and applied the resulting prices to Day-Ahead transactions in areas within the Markets+ footprint of each scenario. This resulted in higher prices in some hours in the Markets+ zones (by up to \$10/MWh in a limited number of hours and approximately \$1/MWh on average). Notably, however, the FSP price adders may not propagate to the entire market footprint when transmission congestion occurs. For example, if there is congestion between the Pacific Northwest and

Desert Southwest during a time when fast-starting pricing is triggered in the Desert Southwest, the price increases from fast start pricing do not apply to zones in the Pacific Northwest. This dynamic is observed in many hours of the simulations.

The other major market feature modeled differently between the markets was GHG revenue allocation for the EDAM Market.¹¹ The current EDAM market design proposal includes a mechanism to allocate revenue associated with imports into GHG regulated zones (California and Washington for the study; this approach was not applied for Colorado) from other EDAM locations that do not have GHG pricing. E3 created a separate “GHG Reference Case” run in PLEXOS that excluded any imports into the GHG regulated zones and then used a detailed post-processing approach to identify EDAM member zones that send incremental energy to the GHG regulated areas (when compared to the GHG Reference Case), and then to identify generators that produce incremental energy. In situations in which the identified generator with incremental dispatch to California has a lower GHG emission factor than the market clearing emissions rate, E3’s modeling allocates net revenue to the generator reflecting additional margin beyond the cost the generator would face for GHG permits on the imported energy. The Markets+ design proposal does not currently have a defined GHG allocation approach so costs for GHG are assumed to be returned to the regulating state. The state regulatory agencies can then determine whether to allocate a portion of this revenue among energy entities (or to allocate this revenue elsewhere). For this modeling study, we do not allocate GHG revenue for markets where the mechanism for allocation has not been defined at the time of this study. More detail on GHG modeling is described in Appendix A to this report, and more detail on allocation of GHG revenue is provided in Appendix C.

Individual WMEG Entity Benefit Calculations: E3 developed a comprehensive settlement process code that takes in output data from the various market model runs and generates ex-post settlement details down to the generator level for each WMEG entity over the study year. The code then aggregates these results to an entity level for each WMEG member. For each entity and each scenario, E3 calculate an entity-specific “**Net Variable Cost**” using the following formula:

Net Variable Cost = Load Cost + Generation Cost + Reserve Cost – Reserve Revenue – Generation Revenue – Wheeling Revenue – Congestion Revenue – Wheeling Revenue

Each of these components is discussed below.

- **Load Cost:** Entities incur a cost to serve load based on (a) the hourly quantity of load (in MWh) that the entity is obligated to serve in each zone of the model times (b) the hourly zonal energy price.
- **Generation Cost:** The model reports variable production costs for each generating unit as the sum of fuel costs, startup costs, and variable O&M cost for that resource. Generation Costs are attributed to each entity as (a) the total variable production cost of the unit times (b) the percentage share of that unit that is owned or contracted to the entity.

¹¹ For a subset of WMEG members who requested further exploration, E3 modeled additional market scenarios for 2026 in which transmission capability in the EDAM footprint and on market seams (as well as in the BAU) was reduced by 10%. Markets+ transmission capability was maintained at the same full TTC level to represent the potential impact of Markets+ utilizing a Mod 30 transmission rating approach.

- **Reserve Cost & Reserve Revenue:** In the BAU Case, E3 enforces ancillary service reserve requirements at the BAA level but does not settle these products at a market clearing price. For all the market cases, day ahead forecast error reserves are enforced at the level of a subregion within each market (e.g. the Northwest portion of Markets+), and each entity is assigned a Reserve Cost responsibility based on of (a) the hourly quantity of reserves that entity needs times (b) the hourly market price for reserves within that market sub-region. ; each entity is also awarded Reserve Revenue from the market based on (a) the quantity of reserves that are contributed by generators owned or contracted by the entity times (b) the hourly market price for reserves within that market subregion. In the 2030 and 2035 CBA cases, Reserve Costs and Reserve Revenues are calculated separately for each reserve product (spinning reserves, non-spinning reserves, and regulating reserves, as well as day ahead forecast error reserves).
- **Generation Revenue:** Generation Revenue is first calculated for each resource based on (a) the hourly energy produced by the generator, times (b) the hourly price at the generator's zone. This Generation Revenue is then attributed to each entity based on the percentage share of each resource that is owned or contracted to the entity.
- **Wheeling Revenue:** Wheeling revenue is revenue that transmission providers earn by selling transmission service. In the BAU Case, total Wheeling Revenue is calculated in the model for each entity based on the product of (a) the amount of energy exported over transmission lines connected to that entity, times (b) the OATT rate or market wheeling rate applicable that BAA or transmission entity, plus an additional \$/MWh charge for bilateral day ahead market friction. In the RT stage of the BAU Case, wheeling is not charged for transactions between entities in the WEIM or WEIS market. In the DA markets cases, total wheeling revenue is first determined at a market-footprint level based on the (a) amount of energy flowing exported over transmission lines connected to each market footprint times (b) the load-weighted average of OATT rates of zones participating in that market, plus an additional \$/MWh charge for transactional friction on seams between the markets. This total market wheeling revenue is then distributed among market participants based on each participant's percentage share of total load in the market (load-ratio share basis).¹²
- **Congestion Revenue:** Price differentials between zones due to transmission constraints creates congestion between entities, resulting in loads paying higher prices than remote generators receive on the other side of congested interface. The value of this difference is assigned back to the entities in the BAU case and for lines within each market footprint. Congestion on the border of each market is allocated among all participants in that market on a load ratio share basis.
- **GHG Revenue:** For established GHG revenue allocation methodologies (CAISO/EDAM) individual generators are awarded GHG revenues per the applicable allocation methodology. However, for Markets+, which does not have an established allocation methodology fully defined yet so in the model GHG revenue on imports are assigned the regulating states, which would have

¹² Separate proposals for market elements in EDAM and Markets+ that seek to provide some compensation to entities that lose current short-term firm or non-firm point to point revenues were not represented in this analysis due to the definitions of those mechanisms not being fully defined at the time when study assumptions for this analysis were finalized. Revenue from such mechanisms (or charges to derive this revenue) would be additional to any individual benefits represented in this study.

responsibility for determining any allocations of this revenue under currently proposed Markets+ rules.

For each entity, E3 then calculated the **Net Variable Cost Savings** from market participation (or the **Net Variable Cost Increase** due to market participation) as the difference between the Net Variable Costs for that entity in a market case (e.g., EDAM Bookend) compared to that entity's Net Variable Cost in the BAU case.

The sum of Net Variable Cost for all entities in the region (including WMEG members and non-WMEG entities) is equal to the regionwide Adjusted Production Cost. Therefore, the sum of Net Variable Cost Savings (or Net Variable Cost Increases) compared to the BAU for all entities in the region equals the total regionwide Adjusted Production Cost savings (or Adjusted Production Cost Increase).¹³

E3's settlement process is performed for both the Day-Ahead and Real-time market. Real-Time market settlement is typically performed as incremental to the Day-Ahead settlements – for example incremental Real-time generation dispatched at a level higher than the Day-Ahead schedule from the DA run will be valued based on RT stage prices and used for RT settlements. Similar approaches are used for Load costs and other individual benefit components. All pricing for the Day-Ahead settlement includes Fast Start Pricing for any zones included in the Markets+ footprint.

¹³ This regionwide equation is due to the fact that most of the components of Net Variable Cost represent “transfers” or payments from one entity in the region to another entity in the region, which leads the net effect of revenues and costs from these transfers to cancel or offset each other at the regionwide level. The exception to this (components that are net transfers) are (a) Generator Costs, which are payments for fuel, operations, and maintenance for the generators, (b) revenues for sales or cost for purchases from entities outside the region (in Alberta or the Eastern Interconnection), and (c) GHG compliance costs that are paid to the GHG regulating states (if GHG revenue for imports are in excess of the GHG compliance cost, then those are captured as transfers to the exporting entity as well).

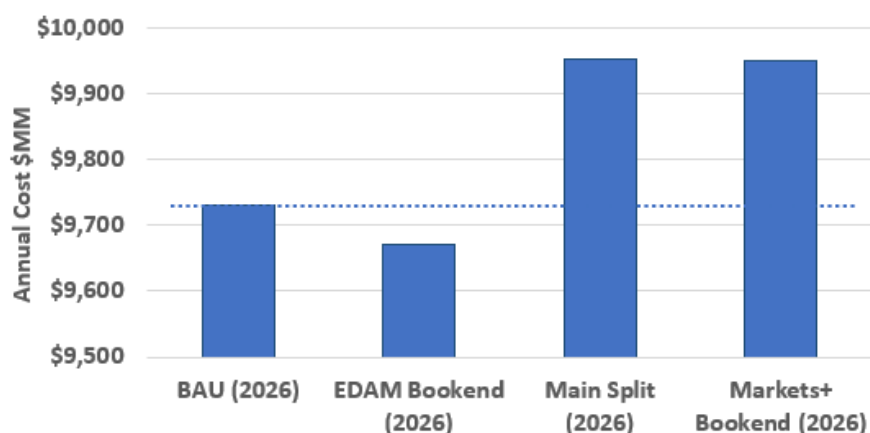
3 Study Results and Key Findings

The simulation cases that E3 modeled each produced hourly dispatch and dispatch cost for each generator, hourly reserves held on each unit, as well as hourly zonal transmission flows, and market prices. E3 used these outputs to create a set of adjusted production costs for each case on a regionwide basis, as well as a summary of the Net Variable Cost impact for each WMEG member (as well as for the non-WMEG entities, comprised of and for the rest of WECC loads and resources not associated with any WMEG member). Each case produced many results, so it is valuable to look across cases to highlight their important impacts and to explore their implications for the WMEG members and the Western Interconnection more broadly. This section describes the results of these cases, as well as key implications of their results.

3.1 Regionwide Impact

Under the BAU Case, the regionwide Adjusted production Cost is \$9,732 million in 2026. Compared to BAU case, the regionwide Adjusted Production Cost is \$60 million lower in the EDAM Bookend Case, \$221 million higher in the Main Split Case, and \$218 million higher in the Markets+ Bookend. As the next section describes, the impact for individual entities varies widely for each case, and the majority of the increase in Adjusted production Cost in the Main Split and Markets+ Bookend accrues as a Net Variable Cost increase for non-WMEG members.

Figure 3-1 Annual Regionwide Adjusted Production Cost by 2026 Study Case



Note: Y-axis in chart does not start at \$0.

The magnitude of the regionwide impact for market cases ranges from 0.6% to -2.3% as a percentage of BAU case costs. This impact is small relative to total production costs because the BAU Case includes existing real-time markets (the WEIM and WEIS), and the market cases change the footprint of these real-time markets while also adding day-ahead markets. In addition, compared to today's system, the 2026 study year has fewer long-start resources (due to retirement of existing coal generators) and more flexible

storage and quick-start thermal resources. These changes in the regional resource mix enable greater optimization in the real-time stage of operations (modeled here as hourly) relative to today's system.

The increase in regionwide production costs in the cases with two markets (Markets+ Bookend and Main Split) is due to reducing the size of the WEIM's geographic footprint. The increase in production costs due to a smaller WEIM footprint outweighs the savings that accrue from the addition of two day-ahead markets for the EDAM and Markets+ footprints.

In addition to the cases above, E3 modeled a separate BAU sensitivity case that assumed less optimized WEIM and WEIS markets. The purpose of this sensitivity is to recognize the uncertainty around how efficient and flexible RT markets (alone) could become by 2026, and to develop a bookend value that represents an optimistic case for the additional value created by DA markets. This sensitivity case constrains RT flows over each line between zones to the day ahead scheduled flow $\pm 15\%$ of the line's total transfer capability. For example, if a 1000 MW line had 500 MW scheduled to flow in the DA stage for a given hour, the RT stage flows were constrained to range between 350 MW and 650 MW for that hour ($500 \pm 15\% \times 1000$). This case results in regionwide annual production costs that are \$70 million higher than the BAU case for this study. Comparing the DA market cases to this BAU sensitivity results in regionwide production cost savings in the EDAM Bookend growing from \$60 million to \$130 million, and the regionwide Adjusted Production Cost increases in the Main Split case shrinking from \$221 million to \$151 million.

Implication of small regionwide energy cost impact: It is important to carefully assess the other sources of potential impact of a DA market or greater integration, such as compatibility with a resource adequacy market that can enable generation investment savings, coordinated transmission planning, reduced curtailment of energy production that meets state clean and renewable energy standards, and more optimal resource procurement over a geographic wider area. Because dispatch-related benefits are relatively modest, it is more likely that other benefit types are key determinants in whether one or the other market options available to WMEG members is more beneficial overall.

Analyzing these other sources of benefits was not in the scope of this CBS, but other regional market studies have shown these benefits sources to be considerable – ranging from two to ten times the DA energy cost impact from DA trading alone.¹⁴ Because this study has shown that DA energy benefits are likely relatively small, it is even more likely that other benefit types are key determinants in whether one or the other market options available to WMEG members is more beneficial overall.

3.2 Net Cost Impact for individual entities

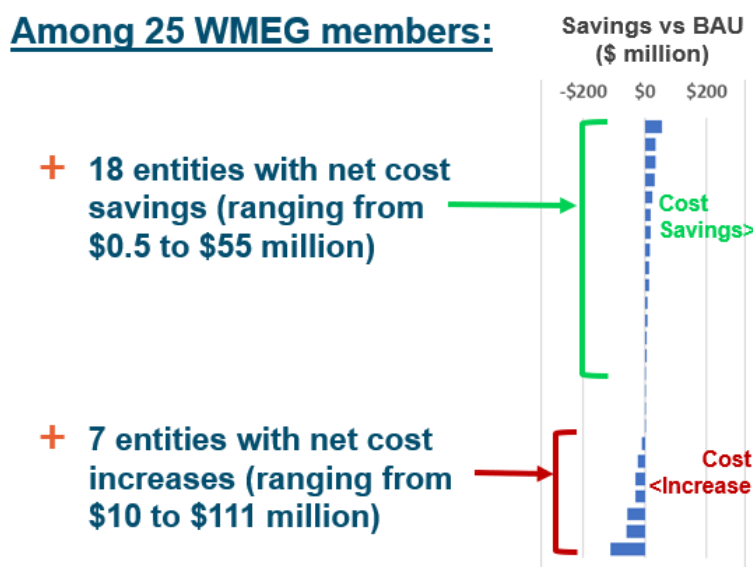
The Net Cost Impact for each individual entity was provided confidentially to each WMEG member funding this study, and the WMEG members chose to keep those results confidential. While Net Variable Cost for individual entities are not included in this summary report, this section discusses the key dynamics observed in results across different entities. The impacts on individual entities vary widely depending on the scenario.

¹⁴ See discussion of other studies in Section **Error! Reference source not found.**.

3.2.1 EDAM Bookend Case Individual Results

In the figure below, each blue bar represents the Net Variable Cost savings or increases in the EDAM Bookend versus the 2026 BAU for one of the 25 WMEG member entities.¹⁵

Figure 3-2 EDAM Bookend Case – Net Cost Impacts among WMEG members



Overall, in the EDAM Bookend case compared to the BAU, the majority of WMEG members experience Net Variable Cost savings, ranging from \$0.5 to \$55 million per year. Other WMEG members, however, show increases in Net Variable Cost, ranging from \$10 million up to \$111 million, in the EDAM Bookend case. **For all 25 WMEG members summed together, Net Variable Cost increases by \$20 million in the EDAM Bookend.** Higher Net Variable Cost for individual entities is largely due to two factors:

1. Reduced wheeling revenue compared to the BAU case since wheeling is not collected in intra-market transactions and the EDAM spans nearly the full West in this scenario. There is notable variation in wheeling revenues among study participants. The study approach did not attempt to capture existing transmission contracts in the BAU case, which may impact how these revenues would actually be distributed. Some entities may choose to discount the impact of wheeling revenues when analyzing their individual results. To facilitate this, wheeling revenues have been segregated from other benefit streams when requested. If the reduced wheeling revenue were omitted from Net Variable Costs, WMEG members would together see savings of \$369 million in the EDAM Bookend case compared to the BAU; and
2. An increase in the price of market purchases for certain entities: in the BAU case, some entities purchase energy from their immediate neighbors at a low price because those neighbors would have faced pancaked wheeling charges to sell their energy to entities farther away, but the

¹⁵ The impact for five WAPA regions is represented as a single total bar for WAPA as a one WMEG member, though individual results were provided to WAPA by sub-region. These individual impacts include reduced wheeling costs which have a significant impact on Net Variable Costs for members.

EDAM Bookend reduces the cost to transact throughout the wider EDAM footprint, which increases competition for purchases and increases market prices in some instances.

Non-WMEG entities experience a Net Variable Cost savings of **\$80 million versus the BAU case**. Non-WMEG entities include loads in the Western Interconnection that are not represented by the WMEG members as well as resources not owned or contracted to WMEG members. A significant majority of non-WMEG entities, representing 73% of non-WMEG load and 66% of non-WMEG generation capacity in the model, is based in California.¹⁶

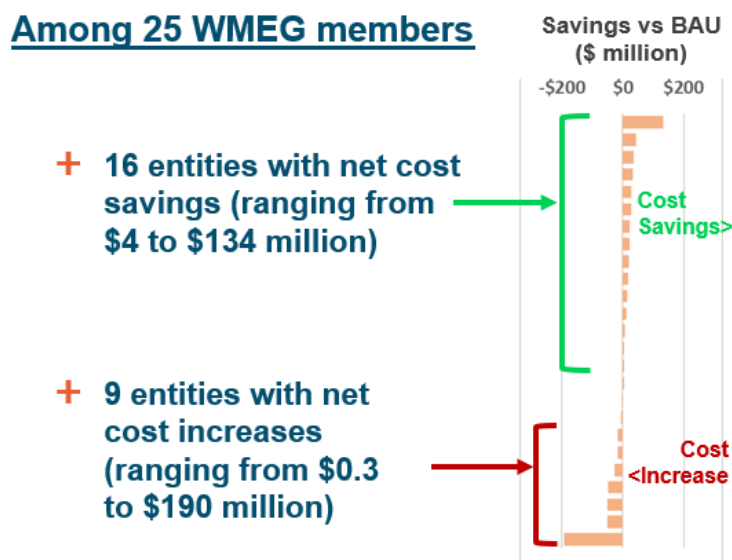
The production cost savings and individual member impacts in the EDAM Bookend relative to the BAU case are due to the day-ahead optimization over a large market footprint.

The market features simulated here for EDAM are largely similar to that of Markets+, with the exception of Fast Start Pricing (FSP) and allocation of GHG revenue for imports, which affect allocation of benefits but not regionwide savings. Therefore, if footprint identical to the EDAM Bookend market had been represented in a Markets+ scenario, the model would have produced similar regionwide result as for the EDAM Bookend, though with some differences in the allocation of participant-specific benefits.

3.2.2 Main Split & Markets+ Bookend Case Individual Results

In the figure below, each orange bar represents the net savings (or net cost increase) in the Main Split Case versus the 2026 BAU for an individual WMEG member.

Figure 3-3: 2026 Main Split Case – Individual Net Cost Impact among WMEG members



¹⁶ California based non-WMEG entities include loads and resources in CAISO, IID, and Turlock Irrigation District. Non-WMEG entities outside California include CFE, BC, Douglas PUD, Grid Force, Avangrid, and Basin Electric, as well as generation in the model that was located throughout the WECC but not identified as being owned or contracted to WMEG entities so treated as merchant generation for the purposes of summarizing cost impacts.

Similar to the EDAM bookend, the majority of WMEG members experience net cost savings in the Main Split Case though some of the members experience cost increases. **For all 25 WMEG members summed together, Total Net Costs decline by \$26 million.** The size of this cost decline reflects the net impact of reduced wheeling revenues modeled for WMEG entities compared to the BAU case. As previously noted, wheeling revenues vary significantly among study participants, and this study did not attempt to capture the impact of existing transmission contracts on wheeling revenue distribution. If the impact on the model of reduced wheeling revenue were omitted from Net Variable Costs, WMEG members would together have a \$266 million Net Variable Cost reduction in the Main Split case compared to the BAU. Individual WMEG entities that experience lower net Variable Net Costs in the EDAM Bookend do not all experience lower Total Net Variable Costs in the Main Split Case.

The **Main Split case also showed a \$247 million Total Net Cost increase for the non-WMEG entities.** The driver of this cost increase for non-WMEG members is that the Main Split Case introduces a larger cost of wheeling over the market seams.

The Non-WMEG entities, who are primarily located in California and are part of the EDAM in this case, import significant amounts of energy in the BAU case, though these entities also have significant net sales (exports) in other hours, primarily solar heavy periods.

In the Main Split case, many of the entities that export power to serve non-WMEG loads join Markets+, which causes those exports to EDAM to face a significant wheeling cost and market friction. To reduce exposure to these higher import costs, the non-WMEG entities increase dispatch of local gas generation – with a 6.7 TWh increase in non-WMEG gas dispatch overall compared to the BAU case.

Many gas units have higher fuel costs in the non-WMEG areas (compared to WMEG areas) due to pipeline transportation costs. Additionally, the implied heat rates of gas units in non-WMEG zones are also elevated during early evening ramping hours. Together, these factors result in a higher cost for the incremental local gas generation dispatched in the Main Split Case compared to the cost of market purchases in the BAU Case.

Moreover, the non-WMEG areas also face a higher cost for exporting generation, so the non-WMEG entities must curtail more solar generation when prices outside the EDAM are not high enough to justify the export cost. Batteries and pumped storage are also run more heavily in the non-WMEG areas, incurring round trip efficiency losses.

Regionwide GHG total emissions change moderately in this case, but the location of their source shifts – with California and other GHG-regulated areas facing more GHG emissions from local generation in non-WMEG areas, rather than from imports. It is possible that this local gas generation impact may have different impacts on local air quality, but E3 did not explore these changes in this study. Additionally, more gas dispatch in California could potentially have an impact on local gas prices due to higher in-state fuel use in certain hours compared to a BAU case, though these impacts were not considered in the current study.

Among WMEG entities, the impact of the Main Split Case varies widely due to three separate factors:

First, these entities overall **reduce local gas dispatch** (due to lower exports to non-WMEG areas), **resulting in lower Generator Costs but also less Generation Revenue.**

Additionally, many WMEG entities in the Main Split Case **lose wheeling revenue compared to the BAU Case** since wheeling revenue (**based on the transmission tariff and buy-sell spreads from transactional friction**) is not collected in intra-market transactions in this case. Some entities in Markets+ footprint, however, **receive increased Wheeling Revenue** due to the allocated share of wheeling charges applied on transactions over market seams when selling to the EDAM footprint. The EDAM participants also receive a share of Wheeling Revenue from EDAM exports to the Markets+ footprint.

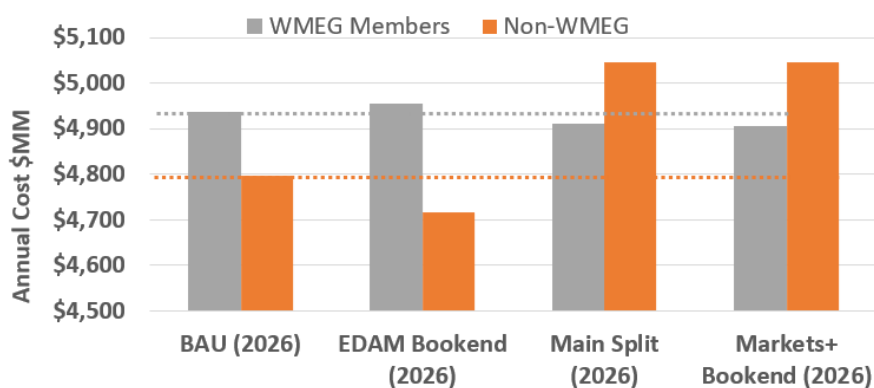
Finally, **the market footprint (and cost to transact over market seams) greatly impacts day-ahead market prices, which have a significant effect on the Load Cost and Generation Revenue for many individual WMEG entities.** Fewer exports to the EDAM area (comprised of primarily non-WMEG members) result in lower prices in the Main Split Case for the Markets+ footprint in some hours. WMEG entities that are net purchasers of energy during these hours make their purchases at a lower price than in the BAU Case (or in the EDAM case) resulting in savings. The converse is also true –net sellers in the BAU Case tend to have more negative results in the Main Split Case when prices are lower.

Fewer exports from the EDAM area during heavy solar, low load periods do lead to higher prices in the Markets+ region at certain times. The impact of these lower solar-hour prices varies, however, by entity, as some Southwest entities with significant local solar generation received more revenue for the solar generation they own or have contracted; additionally, the load levels in these hours tend to be smaller so price reductions are less impactful on total net costs.

In the Desert Southwest, there are hours with Fast Start Pricing (FSP) applied in the Main Split Case, which boosts Markets+ prices during those hours, partially offsetting the downward price impact from fewer exports to the EDAM region. Fast start pricing, however, has less of an impact in the Pacific Northwest portion of the Markets+ footprint, due to transmission constraints getting from the Northwest to the Southwest or Rockies area while avoiding transmission through the EDAM (California and PacifiCorp). The next section discusses these effects in more detail.

The table below summarizes the net cost to WMEG and non-WMEG members across different cases for 2026, highlighting the greater variation in results for non-WMEG entities vs. the sum of impact for WMEG members across cases.

Figure 3-4: Sum of Total Net Variable Cost for WMEG Members and Non-WMEG Entities



Note: Y-axis in chart does not start at \$0.

Implication of wide variation in individual entity benefits: The individual entity results discussed here have two key implications:

- Among WMEG entities: it is important to closely consider the individual entity impact. These impacts do not always have the same sign as regionwide production cost impacts, nor the sum of Total Net Costs to all WMEG members. Overall, the two factors that most affect individual entity Total Net Costs are (a) whether the entity is a net purchaser or seller and whether the market footprint increases or decreases market prices, and (b) the allocation of wheeling and congestion revenues—particularly on market seams. The market rules for these allocations are still being defined but could affect the individual benefits of many entities in the West.
- For non-WMEG entities: it is important to consider that non-WMEG entities likely receive a sizable amount of the Net Variable Cost reduction in a single market footprint (as reflected in the EDAM footprint). They would also accrue a significant share of the cost increase that results from dividing the Western interconnection into two separate market footprints. While individual WMEG entity impacts vary, the sum of changes in the Total Net Cost to all WMEG members together remains relatively stable over the cases. Non-WMEG results, by contrast, show wider differences between different market cases or different footprints. Recognizing this difference in impact, it may be useful for non-WMEG members to seek other attributes of a single market (outside of Net Variable Cost) that could provide additional encouragement for wider participation. Alternatively, it may be useful to seek opportunities for improving market-to-market coordination (discussed later in this report) that could lead to results that are more like those of a single market.

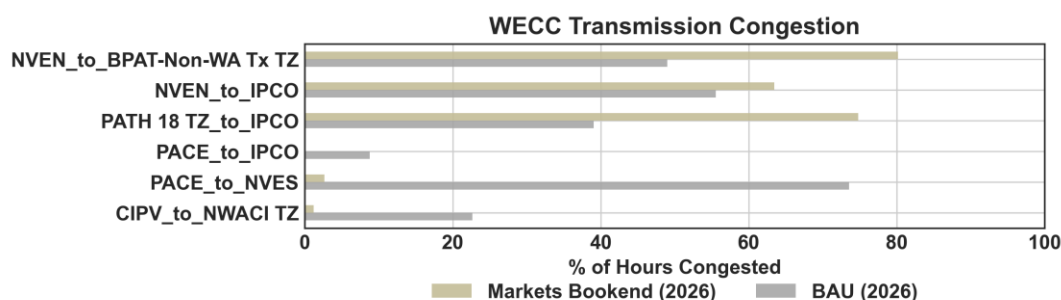
3.3 Importance of Transmission between Pacific Northwest and Desert Southwest

In the Main Split and Markets+ Bookend Case, transactions within the Markets+ Footprint between the Pacific Northwest and Desert Southwest (as well as to the Rockies) depend heavily on key paths through the states of Idaho, Nevada, and Montana. These transmission ties, which are already frequently utilized in the BAU Case, increase in importance in the Main Split Case because California and PacifiCorp are represented in a separate market (EDAM). Sending power from one part of the Markets+ footprint to California areas or PacifiCorp incurs significant wheeling charges and transactional friction on the market seam. Moreover, passing through the EDAM footprint to get to another sub-region of the Markets+ footprint would require also incurring wheeling costs a second time to get out of the EDAM, resulting in an additional “pancaked” transmission cost.¹⁷

¹⁷ Powerex, which was represented in Markets+ for all scenarios, identified additional transmission contracts it holds on paths connecting the Northwest to the Southwest. This contracted transmission is modeled as part of the Markets+ region to facilitate more trades between the Northwest and Southwest. The total demand for Northwest to Southwest transactions, however, was still greater than the transmission available when transactions over paths connecting through zones participating in EDAM are subject to wheeling charges and friction on market seams.

As a result, in the Main Split case, the model indicates a large shift of transmission flow. There is a reduction of flow and congestion on paths that cross the market seams, including the Northwest AC Intertie (NWACI) to the PG&E Valley zone in Northern California (CIPV), as well as on lines between PacifiCorp East (PACE) and NV Energy (NVES). Instead, transmission flows in this case shift to lines that connect the Northwest to other portions of the Markets+, including from BPA to Nevada, BPA to Idaho Power, and Idaho Power to Montana (via Path 18). The chart below identifies the percentage of hours in which these links are congested in the model in the BAU case as well as the Main Split case which results in a significant increase in intra-Markets+ flow.

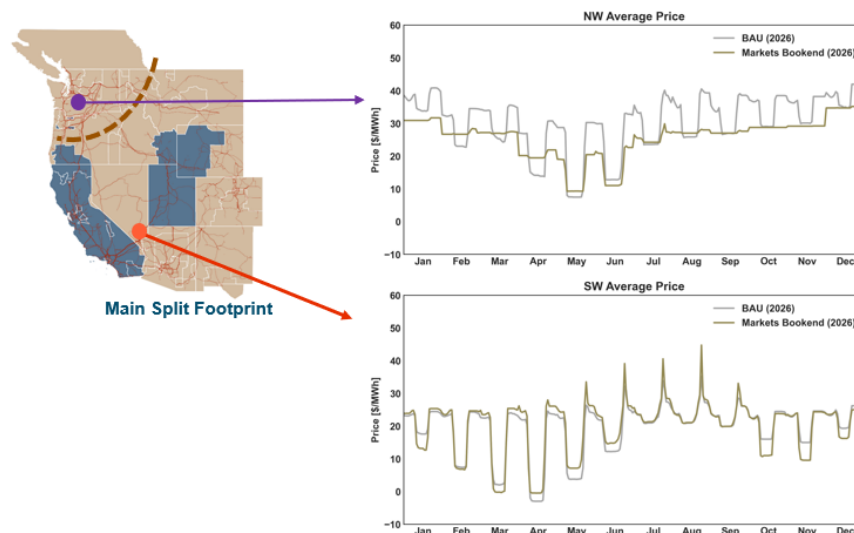
Figure 3-5: Frequency of Transmission Congestion on Key Northwest-Southwest Paths



The congestion on these lines has a significant impact on market pricing in the sub-regions of the Markets+ footprint. The figure below compares Pacific Northwest (NW) and Desert Southwest (SW) prices in the BAU case versus the Markets+ bookend on a month-hour basis. For example, the average price for all January days at 1:00 AM is shown as the first data point in each table. The Northwest prices are higher on average due to GHG pricing applied in the State of Washington, but in the BAU Case the patterns of prices between the Northwest zones are quite similar to the pattern of the Southwest, because the BAU case does not have a high cost market seam (as there is in the Main Split Case) that limits the economic transmission flow through California zones or the PacifiCorp system.

In the Markets Bookend Case, however, as well as in the Main Split Case, prices in the Northwest become much flatter than in the Southwest. The Northwest has significant quantities of flexible hydro generation that can be used to balance local loads and renewables. This flexibility is also used to make hourly exports to other zones outside of the Northwest. With the significant hurdle rate and wheeling cost now imposed on transmission to California (or through PacifiCorp), there are many evening hours with higher market prices in the Southwest. In these hours, the Northwest cannot get as much of its flexible generation directly over to the Southwest due to transmission congestion. As a result, Southwest prices spike upward (and even more so due to fast-start pricing) but Northwest prices stay flat as there is sufficient local hydro to balance out and meet local demand across most days.

In the Southwest, there are hours with Fast Start Pricing (FSP) applied in the Main Split Case, which boosts Markets+ prices during those hours, but fast start pricing has less of an impact in the Pacific Northwest portion of the Markets+ footprint, due to the transmission constraints between the Northwest and Southwest.

Figure 3-6: Month-Hour Average Market Prices in Northwest versus Southwest

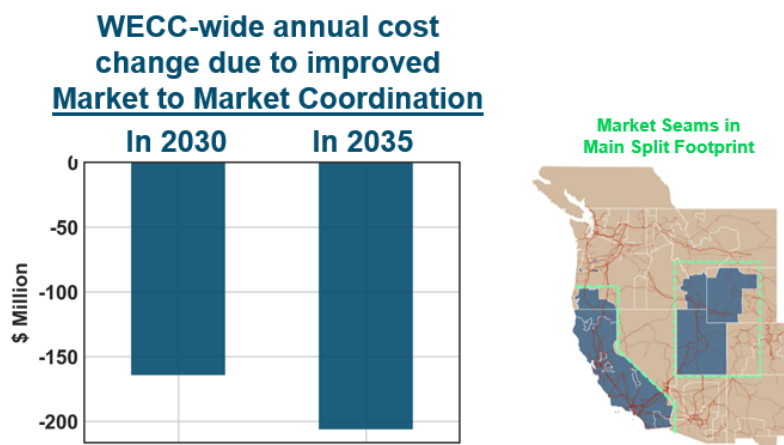
Implication of Northwest-Southwest transmission congestion within Markets+ zones: These congested lines indicate that there is value from Northwest hydro flexibility that is not being fully utilized for maximizing efficiency across the Markets+ zone. This results in higher dispatch costs and higher load prices for Southwest entities in Markets+ compared to a situation in which these lines were not congested. This dynamic also reduces revenue for Northwest entities that could export more energy at high value times if there were more transmission available within the Markets+ region.

This result implies that if the Western U.S. ends up forming two separate markets with a footprint similar to Main Split or Markets+ Bookend, it will be valuable to explore opportunities to contract for or potentially construct additional transmission to more robustly connect the Northwest and Southwest portions of Markets+.

3.4 Impact of Market-to-Market Coordination

For both 2030 and 2035, the study also modeled a Main Split with improved Market to Market (M2M) Coordination. This case was implemented by reducing the assumed cost of transactional friction in both directions on market seams between the Markets+ and EDAM footprints. For 2030, this reduction in market seams friction reduces regionwide Adjusted Production Cost by \$162 million compared to the 2030 Main Split case with no M2M coordination, and in 2035, the reduction in seams friction created a \$206 million reduction in Adjusted Production Cost compared to the 2035 Main Split Case with no M2M coordination. These results are highlighted in the figure below together with a map illustrating the approximate vicinity of the market seams between cases. The largest portion of this reduction in cost due to M2M coordination accrued as Net Variable Cost reduction for non-WMEG entities.

Figure 3-7: Regionwide Adjusted Production Cost Impact due to Improved Market to Market Coordination



Market to Market coordination could benefit WMEG members in Markets+ (reducing the Net Variable Cost for many WMEG members) by facilitating more sales to the EDAM footprint, as well as purchases from EDAM when those transactions are economic in a scenario with Market to Market Coordination but may not be economic in the absence of M2M coordination due to the high cost of transactional friction on market seams. M2M could also create opportunities to transact more between different portions of the Markets+ footprint if transactions through EDAM transmission (which may otherwise be underutilized) can be used for Markets+ to EDAM to other Markets+ areas as a result of potentially lower seams cost in M2M cases in certain period.

For EDAM participants, the Net Variable Cost savings that accrue from improved M2M coordination could also be significant. EDAM participants benefit from an improved opportunity to purchase economic imports from the Markets+ footprint at costs lower than that of local generation, as well as the opportunity to export more solar generation (with lower seams cost) during midday hours.

Key implications of M2M results: In practice, M2M coordination can involve a wide range of different processes. A separate report for WMEG, led by Utilicast, summarized existing M2M practices and experiences from other jurisdictions, highlighting some of the more valuable opportunities.

There is a large degree of uncertainty regarding the transactional friction that might occur between the EDAM and Markets+ footprints, because they are each new instances of day-ahead markets options that are not full RTOs, and because the experiences of market-to-market transactions depends significantly on details of the resources and practices of neighboring regions.

Therefore, the magnitude of transaction friction modeled on market seams the 2030 Main Split Case (\$10/MWh in Day ahead and Real time) and the reduced level in the M2M case (\$6/MWh in Day ahead and \$3/MWh in real time) carry some degree of uncertainty.¹⁸ Nevertheless, the results provide a strong indication of the positive directional impact on potential savings that pursuing M2M coordination could

¹⁸ Additional detail on hurdle rates in each scenario are provided in Appendix A to this report.

carry. The results of these cases highlight the value of prioritizing further exploration of improving M2M coordination through the process of designing either market.

When exploring M2M coordination, this study points toward the particular value of coordination in real time or near real time. Coordination during the RT stage may be more challenging than day ahead due to faster speed at which RT transactions need to be executed, but if there are two separate Western markets with both DA and RT stages, it may be useful to explore mechanisms for facilitating more liquid transactions between the markets after the DA stage but ahead of the RT stage. For example, at a period of three to four hours ahead of the operation hour (either through market mechanisms or in an improved bilateral trading format), the level of certainty for wind, solar, and load has greatly improved compared to the prior day, and there may still be time to bring additional thermal generation online if economic to do so. Therefore, better coordination in this period a few hours before real-time (either through the markets or in an improved bilateral format) is worth exploring for its potential to obtain a portion of the savings and efficiency of a single market.

3.5 Impact of Consolidated Balancing Areas

For the 2030 and 2035 simulation years, the study also modeled Consolidated Balancing Areas (CBAs) for zones within each market footprint, with footprints consistent with the Main Split Case. The model represented a CBA by aggregating the Spinning Reserve, Non-Spinning Reserve, and Regulating Reserve requirements for each BAA to a level of a sub-region of each market footprint allowing zones to purchase reserves from their neighboring zones in the same market.

The CBA case does not reduce the total quantity of reserve requirements needed within each sub-region. By setting the Spinning and Non-Spinning Reserves requirements in the BAU Case each at 3% of zonal load, the BAU case already reflects savings enabled from existing contingency reserve sharing pools in the West. It is possible that the quantity of Regulating Reserves could be reduced through BA consolidation but calculating potential changes in these needs would require intensive sub-hourly data analysis. Since this study focused on an hourly time step, Regulating Reserves quantities were not changed in this case, so potential quantity reductions represent an additional potential opportunity for savings not examined here. The CBA case also did not model any potential increase in path ratings due to BA consolidation, which if feasible would represent additional potential benefits beyond the savings included here.

This change resulted in a \$10 million annual reduction in regionwide Adjusted Production Cost compared to the Main Split M2M case for both the 2030 and 2035 study years. The size of this incremental savings change is modest, which is likely driven by the fact that the model already has significant flexible storage resources making it relatively easy to meet operational reserve requirements in most hours of the year. Since the overall cost of carrying operational reserve requirements is relatively low during these future years, the savings are also relatively small from carrying them in a more geographically flexible manner in the CBA scenarios.

It is important to note that the study covers only the operational-related cost savings from a CBA – which is largely related to more efficient commitment of less or less expensive thermal generation. The study did not seek to account for potential capacity-related savings that a CBA might provide if it enabled fewer

or more optimal investments in new resources for serving load and meeting reserve needs. Investment savings, if any, would be additional to those modeled in this study.

3.6 Impact of RTO

The 2035 Main Split RTO case modifies the 2035 M2M+CBA Case, by adding significant additional transmission facilities throughout the region to reflect coordinated transmission planning for an RTO. Additional detail on the transmission additions in Appendix B to this report. The 2035 main Split RTO case produced a \$387 million reduction in incremental regionwide Adjusted Production Cost compared to the 2035 Main Split M2M + CBA case. These savings accrued in similar levels between the non-WMEG entities and the WMEG members, though the impact to individual WMEG members varies based both on how the new lines affect market prices and on each WMEG members' net positions as sellers or purchasers.

This case was particularly important in creating more integrated pricing between the Northwest and Southwest regions by reducing transmission congestion on paths connecting these areas relative to the other cases that did not add transmission capability in those corridors. This result indicates that more transmission capability would provide value in either market footprint for improving dispatch efficiency and reducing Adjusted Production Costs on a regionwide basis, as well as improving the Net Variable costs to individual entities.

For the Core CBS Study, the RTO Case is only modeled for the Main Split Scenario, though a sub-set of WMEG members also funded additional footprint sensitivities cases for the RTO case. The CBS did not model a WECC-wide RTO scenario, but similar levels of regionwide Adjusted production Costs savings would likely accrue in a WECC-wide RTO footprint, which may not require as much additional transmission to realize these savings due to the absence of market seams.

The results of the RTO case reflect do not reflect the capital cost of constructing new transmission, nor any generation investment savings due to programmatic sharing of load and resource diversity for participating entities, or from more optimized regional resource procurement. Therefore, these results indicate that more transmission capability would provide value in either market footprint for improving dispatch efficiency and reducing Net Variable Cost, but do not represent a full assessment of benefits of any individual line to compare to the line's full costs.

3.7 Summary of key results and implications

The table below summarizes the key results of this study, along with the drivers that lead to these results, and the implication of these results for further market development and actions.

Table 3-1: Summary of Key Study Results, Drivers, and Implications

Key Result	Key Drivers of Results	Implication of Results
1. Market Cases have a relatively small impact on regionwide variable cost	The BAU case includes WEIM and WEIS real-time markets, which already provide significant savings, leaving less room for improvement.	Other benefit categories (such as generation investment savings for serving peak load, and optimized procurement over the market footprint,

(0.6 to 2.3% change vs. total BAU costs).		and coordinated transmission) may have a larger impact than Adjusted production Cost at a regionwide level or individual entity net variable costs, and therefore are important for further assessment.
2. Impacts on individual WMEG members vary widely within market cases.	<p>(a) Entities that are net purchasers benefit from reduced prices in market cases, while sellers see lower sales revenues.</p> <p>(b) Additionally, some entities receive less wheeling revenue from exports or wheel-through transactions in the market cases than in the BAU case because the market cases do not charge wheeling on intra-market transactions.</p>	<p>When an entity evaluating the Net Variable Cost impact of different market options, it is important to consider:</p> <p>(a) the entity's anticipated net sales position and also how wheeling revenues on market seams are allocated in final design, and</p> <p>(b) how much wheeling revenue the entity would receive in a BAU (no market) scenario, and whether the entity expects transmission customers will continue contracting for transmission in a market scenario (e.g., for greater certainty or to receive congestion revenue) or will reduce payments for transmission contracts</p>
3. Significant savings in EDAM Bookend accrues to non-WMEG members (primarily California) while the Main Split and Markets+ Bookend Cases create cost increases primarily in non-WMEG areas (again – primarily in California).	In the non-WMEG areas, gas generation goes down in EDAM Bookend but up significantly in the Main Split Case because higher costs of wheeling friction over market seams prevent optimal trading.	Non-WMEG members should recognize the variable cost savings that accrue to them in a situation with one Western market versus two markets and look for ways that other benefit categories may help encourage this direction.
4. If there are two Western markets (such as in the Main Split Case), transmission between the Northwest and Southwest is important for Markets+ transactions.	Results in the Main Split case show a significant amount of flexibility in the Northwest with limited transmission to reach the Southwest via Idaho and Nevada as well as through Montana to the Rockies.	If pursuing two markets in the West, it is important to seek options to contract for or build additional transmission capability in Markets+ between the Northwest and Southwest.
5. If there are two Western markets, Market to Market coordination can be valuable for achieving improved efficiency.	Market to market coordination in the 2030 M2M case reduced regionwide costs by over \$150 million due to the reduction in the transactional friction applied on market seams.	Market to Market coordination may be challenging to implement but important to investigate, particularly in the real-time market stage. Potentially, improved trading in hours leading up to real-time could help facilitate improved efficiency.

Appendix A. CBS Modeling Approach

A.1. Modeling Framework and Assumptions

The modeling framework behind the analysis focused on the key differences between the proposed EDAM and Markets+ products and how those would translate to different costs or benefits relative to one another. The study was done using Energy Exemplar's PLEXOS production simulation model, and E3's machine learning-based RESERVE tool provided reserve requirements based on load and renewable forecast error. E3 also developed renewable generation forecasts at the plant level and load forecasts for WMEG members. Lastly, E3 developed a settlements algorithm using Python that conducted hourly settlement of both EDAM and Markets+ across market participants to provide entity-specific system costs for any scenario.

EDAM and Markets+ Features

E3 incorporated differences and similarities between EDAM and Markets+ in the production cost modeling and settlement calculations. E3 used industry knowledge, conducted research, and worked extensively with Utilicast and WMEG members through multiple task forces to identify important market features including:

- Fast Start Pricing
- Transmission Availability
- GHG Revenue Allocation
- Market Seams
- Imbalance Reserves
- Transmission Congestion Rent
- Wheeling Revenue
- Resource Sufficiency Test
- 3rd Party Transmission revenue

E3 then worked with Utilicast and WMEG task forces to understand the key differences and similarities between EDAM and Markets+. For this study, a resource sufficiency test was discussed with the WMEG but was not included in the modeling. Thus, these results assume that all market participants are considered resource sufficient for each hour, but the model did not explicitly assess this compliance. Any potential resource insufficiency penalties should be assessed by the individual WMEG members. Third Party transmission revenue was not calculated within this analysis as this revenue may change in the future. E3 instead provided full transmission congestion and wheeling revenue on each line to members who could allocate a portion to 3rd parties as a post-processing step outside of the core analysis. E3,

Utilicast, and WMEG discussed the remaining market features extensively and developed the key aspects of remaining contrast and comparability.

Given that some EDAM and Markets+ rules have not been fully developed, it was challenging to know if there were indeed similarities or differences in some of the market features. For the purposes of this study, it was assumed that if a market feature has not been distinctly defined for Markets+ or EDAM, then it was treated similarly to the other market that had defined this area. This treatment is consistent with the observation that in the long run, mature markets tend to be aligned and resemble one another. The table below identifies how E3 modeled the key market features for EDAM and Markets+ within the analysis with particular attention to Fast Start Pricing and GHG revenue allocation. Transmission availability appeared to differ between the two markets, however the differences were not clear enough to be considered part of the core study and were instead changed as part of a sensitivity study (APP #3).

Table A-1 Market Feature Comparison in EDAM vs. Markets+

Feature	EDAM	Markets+
Features modeled in different ways for each market*:		
Fast Start Pricing	No	Yes
GHG Revenue Allocation	GHG Revenue allocated to out of state generators in EDAM sending incremental power to CA & WA (compared to a “GHG Reference Case”)	Distribution of revenue for GHG imports not yet specified in market design; assumed to be determined by the states; for this study was not explicitly allocated to electric power entities represented in the study
Transmission Availability	Modeled based on Zone-to-zone Total Transfer Capability (TTC) with tie zones. Sensitivity case (APP3): Reduce transmission availability in EDAM relative to M+ capability based on flow based.	
Features modeled similarly for each market:		
Market Seams	Model market footprint-wide \$/MWh export charged to exports from EDAM footprint or from M+ footprint	
Imbalance Reserves	Model as Ancillary services product needed in each zone (or sub-region) calculated based on percentile of each zone’s DA forecast net load forecast error (reduced for EDAM or M+ footprint diversity)	
Transmissions Congestion Rents	Congestion rent allocation based on ownership share of lines/paths between zones (Markets+ allocation design not yet fully defined so assumed to follow same format as EDAM)	

This Appendix section contains additional details on each of these market features as well as other modeling assumptions detail.

While not a direct feature of the market per se, Powerex provided guidance to model its system and transactions with the U.S. A consistent assumption across all modelling scenarios is that Powerex is participating in Markets+. Powerex has publicly committed to joining Markets+ and is working with SPP

to enable implementation of Markets+ real-time in 2024. The full Markets+ Day Ahead /Real-time platform is expected to go live in 2026.

For each WMEG scenario, Powerex provided information about its projected market activity in two key categories:

1. The portion of its market activity that is likely to occur in fixed 24/16/8-hour blocks; and
2. The portion of its market activity that is likely to occur on an hourly optimized basis.

Under the modelling scenarios in which BPA and other NW entities join EDAM, Powerex expects that its most attractive market opportunities would be forward sales in 24/16/8-hour blocks to utilities and large commercial and industrial customers seeking reliable firm capacity for resource adequacy purposes and/or deliveries of carbon-free energy (often on a 24/7 basis).

To supplement these block transactions, Powerex also expects that it would generally make approximately 1,000 MW of hourly flexibility available for hourly optimized transactions in Markets+, including enabling intertie bidding at the BC/US Border for transactions to and from the EDAM footprint. These assumptions are generally consistent with the present, in which Powerex's WEIM activity has been limited (to much less than 1,000MW on average), as a result of:

1. Powerex viewing price formation in the bilateral markets as more attractive; and
2. Powerex choosing not to make sales of carbon-free energy in the WEIM, due to its concerns about the CAISO's GHG algorithm inaccurately deeming Powerex's carbon-free supply as being delivered to California, with an assumed simultaneous backfilling of unspecified energy to BC.

Under the modelling scenarios in which BPA and other NW entities join Markets+ (enabling strong transmission connectivity within the NW), Powerex expects that its most attractive market opportunities will be hourly optimized transactions through Markets+ (instead of continuing to make forward transactions in fixed blocks for resource adequacy and carbon-free supply purposes).

Accordingly, Powerex indicated that it expects to make its full hourly flexibility available to a well-connected Markets+ footprint (limited only by minimum and maximum generation and transmission limits). Consequently, the modelling scenarios in which BPA (and other NW entities) join Markets+ have much more Powerex hourly flexibility available for dispatch. E3 estimates that the incremental regionwide cost reduction attributable to Powerex's increased hourly flexibility in these scenarios is approximately \$7 million.

A.2. Market Modeling

The analysis uses Energy Exemplar's PLEXOS production cost simulation software to model the current Business-as-Usual (BAU) WECC market interactions as well as the proposed EDAM and Markets+ markets.

E3 used CAISO's modified 2032 Anchor Data Set WECC-wide model as the base model for this study, which includes CAISO's resource updates for California.

Model Topology

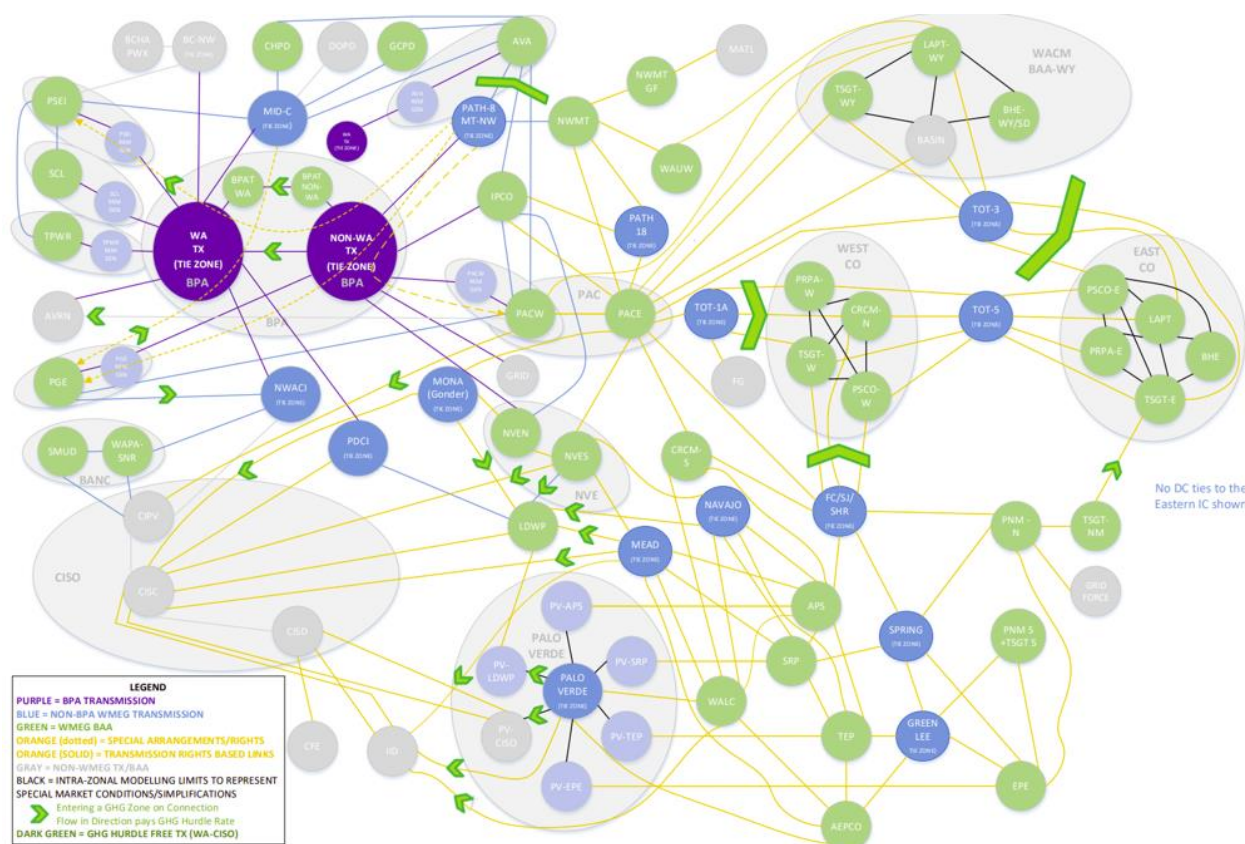
E3 worked with WMEG members and Utilicast to develop an updated model topology that reflects the geographical locations of BAAs while also capturing key transmission constraints and trading hubs throughout the West. The topology goes a level deeper than the usual hub and spoke representation of WECC.

In addition to incorporating major trading hubs in the West such as Mid-C, Palo Verde, and Mead, E3 models other areas where multiple entities can transact with one another. These junctions are defined as “Tie Zones” within the model and allow transmission paths to be broken out and allocated among WECC entities to track transactions into and out of individual zones. This is particularly an issue in the Southwest where entities can transact with each other at multiple seams across the region, and the Northwest where most entities use BPA transmission to some extent. This level of granularity allows individual members to highlight transmission constraints either within their BAA or within their region while also maintaining a more detailed accounting of transmission capacity, wheeling, and congestion revenues.

The Tie zones in the model are shown in the figure below and include the following locations:

- In the Pacific Northwest: Washington Transmission (WA TX) Tie Zone and Non-WA Transmission Tie zone in BPA, Mid-C, Path-8 (Montana-Northwest), and Path 18, as well as the NWACI, PDCI, and Mona connections to California
- In the Rockies region: Tot-3 Tot-1A, and Tot-5, and
- In the Desert Southwest: Palo Verde, Mead, Navajo, Four Corners/San Juan/Shiprock, Springerville, and Greenlee tie zones.

Each of these zones connects multiple entities that can transact with each other up to a given level of transmission capability to the tie zone and/or downstream from the tie zone to another entity.

Figure A-1 Modified Zonal Model Topology

As shown by the green chevrons in Figure A-1, E3 included a greenhouse gas (GHG) import hurdle rate on lines that flow into Washington, California, and Colorado. These are used to help calculate GHG revenue across different scenarios. The WECC system is also connected to the Eastern Interconnect via multiple DC tie lines, which are not shown on Figure A-1. The Eastern Interconnect is defined by an hourly price stream based on historical data for SPP North and South hubs and adjusted for projected future changes to gas prices for 2026, 2030, and 2035.

Canada was modeled differently from the rest of the Western interconnection. With the help and guidance of Powerex, the BC Hydro system load and generation was simplified to be represented as a single integrated pumped hydro facility. Separately, Alberta was modeled as an external market with a fixed hourly price to which the WECC could make sales or purchases.

Model Input Assumptions

E3 worked with WMEG members and Utilicast to update and add data to the base model. The model simulates all major WECC generators (except for Canadian resources, as discussed above) and optimizes a full year of operations at an hourly granularity. Based on member feedback, E3 added new and subtracted resources from the base model for the CBS study years 2026, 2030, and 2035, and modified detailed generator operational data.

The base model used 2018 weather year data for hourly renewable profiles. E3 used the large library of existing solar and wind profiles within the database as the profiles in the CBS. WMEG members provided data to E3 to help update load forecasts at the BAA level for 2026, 2030, and 2035. To model coincident weather-driven load and renewable conditions, E3 and WMEG members matched future load profiles to 2018 weather/load conditions on a daily basis. Hydro data was collected from all members that wanted to provide updated data. Though 2018 was the selected weather year for the study, members could also provide updated hydro data to reflect future weather conditions. E3 used ADS fuel prices that were either sourced from the CEC's IEPR forecasts or EIA data.

Given the modified zonal model topology, members provided Total Transfer Capability (TTC) values for each line in the forward and backward direction for 2026 and provided any TTC changes in 2030 and 2035.

All members also provided long term point-to-point Open Access Transmission Tariff (OATT) rates which were converted to \$/MWh in the day-ahead stage Business as Usual (DA BAU) case, these wheeling rates for each BAA were added to \$2/MWh of assumed friction-based hurdle rate to represent the total wheeling or "hurdle rates" applied. In the real-time (RT BAU) case, these values were set to zero within the WEIM and WEIS footprint but are still used on market seams for exports from each real-time market footprint.

The OATT-based wheeling rates for each entity were also used to develop EDAM and Markets+ wheeling rates for transactions on market seams (for exports that are delivered outside of each market footprint). The exit rate of each market was assumed to be calculated as the load-weighted average of the wheeling rate of the entities participating in that market, together with additional frictional wheeling charges discussed by scenario the table below.

Table A-2 Hurdle Rate Assumptions

BAU Hurdle Rate	Market Hurdle Rate
OATT Rate + Friction on exports from zone or collection of zones that represent one entity	Weighted Average OATT Rate of Market + Friction + Congestion Risk for exports from a zone that is in Market A to a zone that is in Market B

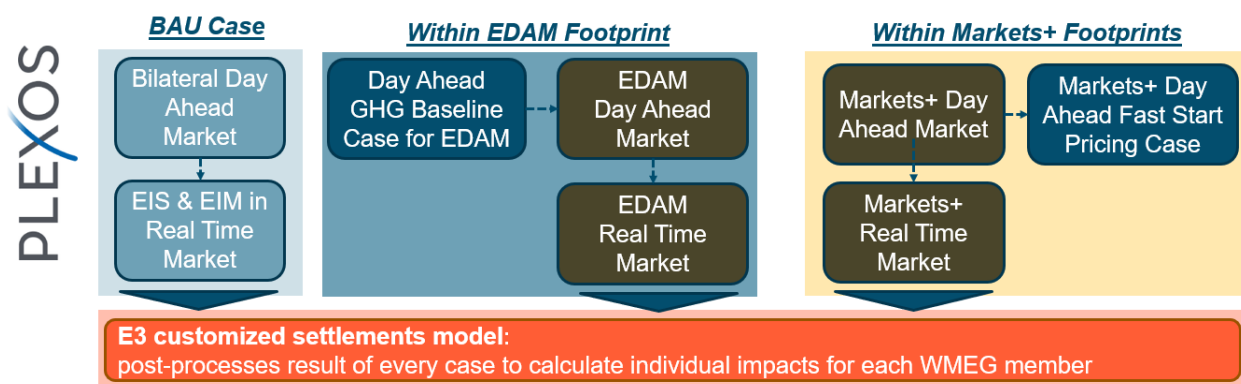
All CBS assumptions on hurdle rates are discussed in more detail later in Appendix A.

PLEXOS Model Structure

The PLEXOS model uses a multi-stage process to capture Day-Ahead and Real-Time market transactions as well as other unique market characteristics. For the BAU case, the Day-Ahead stage is a bilateral market run that creates an optimal dispatch subject to transmission based on BAA load forecasts and renewable forecasts. In this bilateral trading stage, long-start unit commitment decisions (gas and coal steam, combined cycle) are made in the context of economic dispatch. These commitment decisions are held through the Real-Time stage. In the Real-Time stage, WEIM and WEIS participants can trade with each other at no cost while non-market participants can transact bilaterally subject to OATT rates.

The market cases (representing both EDAM and Markets+) use the same two stage process as the BAU, however, the Day-Ahead stage now represents an EDAM or Markets+ footprint. Similar to the BAU cases, for the market cases during the Real-time modeling stage, commitment of longer start units are held fixed or “locked in” to their DA schedule. In the market cases, there are additional dispatch runs to capture unique characteristics of each of the various markets: (a) a GHG Baseline run and (b) a Fast Start pricing run.

Figure A-2: PLEXOS case structure and E3 settlements model



Note: The Main Split & M+ Bookend cases modeled both EDAM and Markets+ simultaneously in different portions of the WECC Footprint

Day Ahead Dispatch Period

The WMEG members determined which units are available for the model to use in the day ahead dispatch period. Each of the economic dispatch solutions honor availability and generator restrictions leading into the DA run and carry these restrictions (and day-ahead commitment for longer-start units) forward into the RT dispatch period.

The CBS does not reflect Virtual Bids or Offers in any market footprint – CAISO, EDAM or Markets+. While these products may be in all the Market designs by 2026, at the time of the CBS, WMEG does not yet have a basis for how these Virtual Transaction might be strategically used by financial participants. To the extent that WMEG wants to account for some effect, it would be more practical to assume some percentage of the benefits accrue to financial players.

There is no Residual Unit Commitment (RUC) represented process in the PLEXOS model for the CBS. It is assumed that reliability has been checked via resource adequacy programs or reserve requirements that have been calculated as inputs to the DA dispatch run.

Real-Time Market Period

The Real-Time Market for this simulation is run at an hourly granularity. This simplifying assumption may understate the benefits of the WEIM, which solves at 15-minute granularity for unit commitments and then optimizes the dispatch at 5-minute intervals and WEIS market which optimizes the dispatch at 5-minute intervals, but these real-time subhourly benefits may be similar in the BAU case and market Cases due to the presence of RT markets in the BAU.

The PLEXOS Real-Time Market stage does allow additional resource commitments of certain units. The CAISO WEIM market has a Short-Term Unit Commitment (STUC) and Real-Time Unit Commitment (RTUC) process. For the CBS, CT resources are allowed to re-commit for the RT Market. The WEIS Market does not currently have a RT Resource commitment process, but for the CBS, CT resources in that footprint were allowed to re-commit. SPP's Integrated Marketplace does have a Real-Time RUC process which commits additional resources as necessary every few hours.

GHG Baseline stage overview

The GHG Baseline run is used to mimic the GHG revenue allocation methodology in EDAM and potentially Markets+. This dispatch run is optimized by assuming no imports into the Washington and California areas¹⁹ to provide a reference dispatch against which the actual EDAM and Markets+ dispatches will be compared. In the EDAM and Markets+ Day Ahead runs these import constraints are lifted, which enables quantification of GHG imports and associated GHG revenue. As part of the EDAM benefit calculation, the settlement calculations award GHG revenue to resources. Since Markets+ GHG accounting rules have not been finalized, GHG revenue was not calculated by resource for any of the California- or Washington-based zones that are represented in Markets+ for a particular case. Instead imports into those Markets+ GHG regulated zones are represented as a total dollar amount that could be assigned to the state for determination of how to allocate. Additional detail on GHG modeling is provided later in this appendix.

Fast Start Pricing stage overview

Costs incurred as a function of generator commitment, such as start and no-load costs, have traditionally been recovered via uplift charges because these costs are not included in the marginal price of energy. As part of Markets+, units that can start quickly ("fast start" units) can potentially recover some of these costs by increasing energy prices during intervals in which they have started. To do so, first a Day-Ahead economic dispatch run is performed to establish the unit commitment of all units. Subsequently, a Fast Start Pricing run is performed, which holds unit commitment decisions constant from the initial Markets+ Day-Ahead run but adds an incremental fast start cost (\$/MWh) to units that can start quickly. This cost is added only to intervals in which the units started in the initial Day-Ahead run. Markets+ defines the fast start adder as the sum of no-load cost and start cost amortized over the minimum run time of the unit. This fast start pricing run re-optimizes the economic dispatch of the system, producing the final market clearing prices within the Markets+ footprint. Additional detail on modeling of Fast Start Pricing is provided in the next section of this Appendix.

¹⁹ The WMEG group also considered Colorado a GHG area in this study that was subject to carbon prices, however, unlike CA and WA, the WMEG group recommended that GHG revenue not be explicitly allocated to generators exporting to Colorado; instead GHG revenue associated with wheeling energy into Colorado was tracked as a total dollar figure that would then be allocated by the state. This is the same procedure that was used for addressing GHG revenue in Markets+.

A.3. Fast Start Pricing Detail

Fast Start Pricing is a market feature exclusively for Markets+. The SPP Integrated Marketplace has updated the approach to LMP determination to include an adjustment for Fast Start Resources (FSRs). This is described in the Protocols Section 3.1.1. In essence, for FSRs, the scheduling run performs normally according to the three-part offers (startup, no-load and incremental energy). When an FSR is committed in the scheduling run, SPP will “amortize” the startup and no-load costs over the Resource max and the minimum market run time based on the relevant market interval definition (rounded up). These additional costs are then added to the energy offer to create a “composite” offer for the pricing run (subject to mitigation). It appears that this could significantly increase the market clearing price when FSRs are committed. The approach applies in both DA and RT in Integrated Marketplace. It is not known whether this will be included in Markets+.

SPP defines an FSR for Marketplace as a Resource which offers in DA or RT: a Start-Up Time of 10 min or less and Minimum Run Time offer of 60 minutes or less.

Based on discussions with SPP, E3 developed a Day-Ahead Fast Start Pricing run to mimic Markets+ operations. The Day-Ahead run produces market outputs and generator schedules based on marginal cost offers. The Fast Start Pricing run fixes unit commitments from the Day-Ahead market schedule. All CTs and ICE resources are assumed to be fast start eligible and are taken as FSRs in the Fast Start Pricing run. In the pricing run, FSRs are allowed to dispatch down to 0MW and have “fast start adder” on their marginal cost bid that represented the addition costs to make the composite offer discussed above. The CBS production cost model did not incorporate no-load costs for resources therefore in this study only the start-up cost is assumed to be included in the Fast Start price offer.

The Fast Start Pricing run is then run again to generate updated Markets+ prices within its footprint which are subsequently used within the settlement calculation process. The Fast Start Pricing run was only implemented as part of the Day-Ahead market run and not the Real-Time market run. The assumption here is that most transactions occur in the Day-Ahead stage so having Fast Start Pricing in that run would capture almost all of its effect.

A.4. Wheeling Rates & Transactional Friction in Model

The following assumptions are used to model interactions between footprints of a given Market Operator by model Stage.

DA BAU enables bilateral trading between WECC entities and does not assume any market operator except the existing CAISO. In DA BAU, apart from CAISO, all BAAs will charge a hurdle rate exiting their area equivalent to their long-term point-to-point OATT rate in Q4 of 2022. CAISO has no wheeling between zones in its footprint as it is an organized market. In DA stages that include EDAM or Markets+, once EDAM is modeled in a scenario it becomes part of CAISO by removing any hurdle rate between EDAM zones and CAISO zones and they are treated as one larger market footprint. The same applies to Markets+ zones, hurdle rates between participants in DA are reduced to \$0/MWh.

Between EDAM and Markets+ footprints the hurdle rate will be large to mimic reluctance to trade across different DA markets. The assumption for these rates contains three major pieces. The first is the load weighted average of the long-term point-to-point OATT rates of the entities within the EDAM or Markets+

footprint to mimic an access charge much like CAISO has today. The second is an assumed market friction adder in DA that quantifies the opportunity cost of trading across markets. The third is a congestion risk adder.

The market wheeling rates and hurdle rates adders for each scenario included in the CBS are summarized in the table below. Appendix B provides additional detail describing each Scenario including market participation of each entity.

Table A-3 Market Wheeling rates and Sub

	2026	2030	2035
BAU	OATT Rate + \$2 Marketing Friction on exports from zone or collection of zones that represent one entity. If an entity has a split zone, there is no hurdle between their zones.		
EDAM & Markets+ [without M2M Coordination]	Within Market Footprint: \$0 Seam: Weighted Avg OATT Rate of Market* + \$2 Friction + \$8 Congestion Risk for exports from a Zone that is in Market A to a Zone that is in Market B	Within Market: \$0 Seam: Weighted Avg OATT Rate of Markets+ \$2 Friction + \$8 Congestion Risk for exports from a Zone that is in Market A to a Zone that is in Market B	Within Market: \$0 Seam: Weighted Avg OATT Rate of Markets+ \$2 Friction + \$8 Congestion Risk for exports from a Zone that is in Market A to a Zone that is in Market B
M2M Coordination		Within Market: \$0 Seam: Weighted Avg OATT Rate of Market + \$2 Friction + \$4 DA Congestion Risk (or \$1 RT Congestion Risk) for exports from Market A to a Zone that is in Market B	Within Market: \$0 Seam: Weighted Avg OATT Rate of Market + \$2 Friction + \$4 DA Congestion Risk (or \$1 RT Congestion Risk) for exports from Market A to a Zone that is in Market B
M2M Coordination + CBA and AS Market		Within Market: \$0 Seam: Weighted Avg OATT Rate of Market + \$2 Friction + \$4 DA Congestion Risk (or \$1 RT Congestion Risk) for exports from Market A to a Zone that is in Market B	Within Market: \$0 Seam: Weighted Avg OATT Rate of Market + \$2 Friction + \$4 DA Congestion Risk (or \$1 RT Congestion Risk) for exports from Market A to a Zone that is in Market B

RTO			Within Market: \$0
			Full RTO / Enhanced Transmission Portfolio – Same hurdle rates as CBA+ASM and M2M case; key difference in the RTO case is different transmission buildout

The weighted-average market wheeling rates for each footprint are represented in the table below for each market scenario and each study year.

Table A-4 Market Wheeling Rates

Weighted Average OATT of Market* (\$/MWh)

* Friction, congestion risk, and GHG adders not included in the values below

Main Split Scenario

Market		EDAM		Markets+
2026	\$	9.53	\$	4.21
2030	\$	9.56	\$	4.22
2035	\$	9.57	\$	4.25

EDAM Bookend Scenario

Market		EDAM		Markets+
2026	\$	6.43	\$	7.76
2030	\$	6.45	\$	7.76
2035	\$	6.50	\$	7.76

Markets+ Bookend Scenario

Market		EDAM		Markets+
2026	\$	9.66	\$	4.19
2030	\$	9.68	\$	4.20
2035	\$	9.69	\$	4.23

In RT BAU, entities that are not part of WEIM or WEIS may continue to bilaterally trade close to real-time for any last-minute balancing subject to BAA wheeling rates. There is a Market Operator assumption for entities in WEIM or WEIS in the BAU scenario that brings the hurdle rate to \$0/MWh between zones within the same market footprint. This also applies to all other RT market scenarios for EDAM and Markets+.

For 2030 and 2035 scenarios, cross market hurdle rates are reduced in the market-to-market (M2M) change cases. The DA case will reduce its congestion risk hurdle adder from \$8/MWh to \$4/MWh. In RT the congestion risk adder will reduce further from \$4/MWh in DA to \$1/MWh. These reductions in hurdle rates between markets represent increased coordination between markets and reduced barriers to cross-market trading that may occur with market maturity.

A.5. Reserve Modeling & Forecasting

E3 developed Day-Ahead load and renewable forecasts that are used in the Day-Ahead market stage. E3 also developed Real-Time load profiles for the study years with input from WMEG members. E3 used these forecasts as well as additional assumptions to create reserve requirements across all cases in the CBS.

Load and Renewable Forecasting

Day-Ahead forecasts for load and renewables were developed as part of the multi-stage market analysis. Decisions in the Day-Ahead market stage and market schedule outcomes are based off these forecasts.

E3 worked with WMEG members to develop real-time future year load profiles either using member specific forecasts or E3's forecast methodology. E3 wanted to maintain load and renewable correlation by modeling the same weather year within the CBS. The PLEXOS model was pre-seeded with WECC Anchor Data Set (ADS) profiles based on a 2018 weather year. Those were kept in the CBS model as the real-time renewable resource profiles. Each member forecast load for the RT stage followed observed 2018 weather patterns to ensure that weather-dependent load is realistically correlated across the study region, and overall load levels were scaled to approximate a median or 1-in-2 forecast level. E3 worked with WMEG members to obtain the real-time load profiles for the 2026, 2030, and 2035 study years.

For the Day-ahead stage, E3 then perturbed those profiles using historical day-ahead forecast error data to create load profiles that represent day-ahead forecasts of the future year profile. E3 developed a computable methodology to generate hundreds of renewable forecast profiles. These day-ahead renewable forecasts were developed by E3 based on a weighted combination of the actual real-time for matching hours from the prior day, together with month-hour average values. E3 then blended these values with the actual real-time to match data E3 previously obtained for day ahead forecast error mean average percentage error (MAPE) statistics to more accurately account for relative forecast quality. The advantage of this relatively simple forecast methodology is that unlike forecasts developed using randomized forecast error for each resource, it produces an error that captures correct correlations of errors across different projects locations. This feature allows the forecast to account correctly for geographic diversity both within individual BAAs, as well as when the forecast errors for multiple BAAs are combined into a broader market region.

Creation of load profiles directly involved WMEG members as part of a load forecasting task force. WMEG members provided hourly demand projections for E3 to use in the CBS study. Demand profiles for 2026, 2030, and 2035 were provided based on each WMEG member's latest or most applicable demand forecasts. E3 used a day matching approach to synchronize the member-submitted load forecasts with the 2018 weather year of the wind and solar profiles. The rank order of days within seasonal windows were calculated for both the member-submitted forecasts and a reference load forecast from the ADS that was based on 2018 weather conditions. Each day from the member-submitted forecast was re-arranged to correspond to the rank order of daily load values in the reference ADS load forecast. Member-submitted forecasts were used in the real-time model stage.

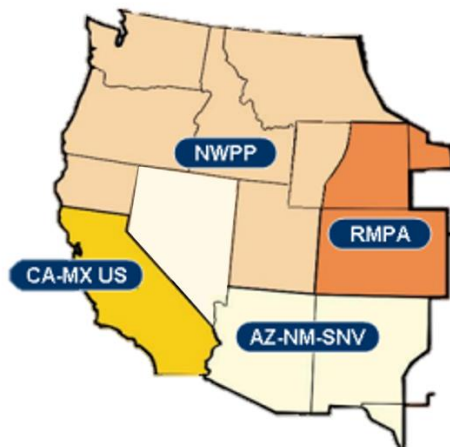
To develop day-ahead load forecasts consistent with member-submitted load profiles, E3 developed an hourly time series of forecast error percentage using historical data. To do so, day-ahead forecast and real-time demand data for each balancing area in WECC was collected from the Energy Information Administration's Hourly Electric Grid Monitor. The percentage difference between the day-ahead and real-time demand was calculated for each hour of a single year (either 2018 or 2019, depending on balancing area). Forecast error percentages were capped at 30% in any single hour to address data quality issues and were adjusted upward or downward to set the annual mean forecast error to zero. The resulting hourly time series of percentage error values were multiplied by the member-submitted forecasts, resulting in a synthetic day-ahead load forecast for each balancing authority area (BAA).

Reserves overview

Five ancillary service products are represented in the production cost model: Spinning Reserves, Non-Spinning Reserves, Regulation Up, Regulation Down, and Imbalance Up. Except for Imbalance Up reserves, the reserve requirements are calculated as a percentage of load: Spinning (3%), Non-Spinning (3%), Regulation Up (1%), and Regulation Down (1%).

Imbalance reserve requirements ensure system reliability by reserving capacity to account for forecast error associated with renewables and load. Imbalance reserves are part of proposed EDAM and Markets+ Day-Ahead market designs. For the CBS, imbalance reserve requirements were calculated using E3's in-house RESERVE model, which calculates imbalance reserve requirements given forecast errors of load, wind, and solar. Imbalance Up reserve requirements were created using RESERVE's prediction of the 97.5th percentile of net load forecast error, and as such the Day-Ahead production cost model stage is prepared to address all but 2.5th percentile of net load under-forecast events. Imbalance Down reserves were not modeled in the CBS due to the expected abundance of resources that could provide this product in the day-ahead timeframe, including the ability to de-commit thermal units, charge storage resources, or curtail renewable generators.

Depending on the CBS scenario, reserve requirements were either modeled as BA-specific or pooled as part of a market at a regional level via the subregion breakout in Figure A-3. Pooling reserve requirements across a larger area provides diversity benefits compared to a BA-specific requirement and is one of the numerous benefits of an organized wholesale market. Specifically, the imbalance or day ahead forecast error reserves were calculated in pooled cases based on the aggregated net load forecast error of sub-regions of each market footprint (for example the Pacific Northwest sub-area of Markets+). The aggregation of net load across multiple zones results in a lower reserve level needed to cover the 97.5th percentile of forecast error, so these pooled cases enable cost savings and reduced reserve needs due to geographic diversity.

Figure A-3 Market Reserve Subregions²⁰**Table A-5 Categorization of Western Zones for Reserve Subgroups**

California	Northwest	Southwest	Rockies
CAISO	PacifiCorp	NVE	BH
BANC	ID	AEPCO	PRPA
LADWP	NWMT	APS	PSCo
Turlock	Avangrid	EPE	TSGT
IID	Avista	PNM	BASIN
WAPA SNR	BPA	SRP	WAPA CRSP
	Chelan	TEP	WAPA LAP
	Douglas	WAPA DSW	
	Grant		
	PGE		
	PSE		
	SCL		
	Tacoma		
	WAPA UGP		
	BC/Powerex		

E3's RESERVE tool was used to provide both BA-specific and regional imbalance reserve requirements that were used for different scenarios within the CBS. The details of E3's RESERVE tool and its application to the CBS are discussed in more detail in the next section. **Error! Reference source not found.** includes more details on how each reserve was modeled. CBS modeling does not include capacity held and subsequently released in real-time via flexible ramping product (for the WEIM) or a similar reserve in the WEIS market.

Currently most WECC BAAs self-provide ancillary services. There are a few sales here and there, especially as it relates to some entities which do not have the ability to really provide these services reliably on their own (e.g., Avangrid, NaturEner), but there are not large volumes of transactions. As part of this study,

²⁰ NERC, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/EPA_Scenario_Final_v2.pdf

ancillary service requirements were set for each BAA in the BAU case and then at the subregional level within the market scenarios with ancillary service markets. For most of the market scenarios, the Spinning, Non-Spinning and Regulating reserve requirements were maintained at the individual BAA level with values that were the same as in the BAU Case. In the 2030 and 2035 M2M+CBA scenarios however, these reserve requirements were pooled within each market on a sub-regional basis. The same quantity of total reserves in these categories, however, is maintained, such that the CBA market cases' total reserves for each sub-region are equal to sum of the individual BAA level requirements from the BAU case for the zones in that sub-region. By contrast, Imbalance Up reserve requirements were calculated at the BAA level for the BAU case and at the subregional level in all market cases. E3 used its RESERVE tool, described in the next section of appendix, to calculate hourly requirements for Imbalance Up reserves.

Imbalance reserves are held to prepare for forecast errors between day-ahead and real-time market timeframes. Because the timeframe of required response is relatively long for imbalance reserves, thermal resources that can start quickly are able to provide the required response, even when offline. As a result, combustion turbines and reciprocating engines were modeled as contributing to Imbalance Up reserves when offline. These resources were also modeled as contributing to Imbalance Up reserves when online. Longer-start thermal resources such as gas and coal steam turbines and gas combined cycles are modeled as only contributing to Imbalance Up reserves when online because these resources may not be able to start up in time to correct for forecast errors between day-ahead and real-time markets.

We ensured that system operators would be prepared for contingency events by requiring contingency reserve headroom to be held in both the Day-Ahead and Real-Time stages. However, the model did not change the schedule of generator outages between the Day-Ahead and Real-Time, and as a result we did not model contingency reserve deployment in Real-Time.

Dispatchable hydro, thermal, and storage resources were modeled as able to contribute to all reserve products. The contribution of these resources to each reserve was limited via their ramp rates (**Error! Reference source not found.**). To address state of charge concerns, storage resources were required to keep an adequate amount of energy in storage to be able to provide the required service for one hour continuously. For upward reserves, this means that providing reserves requires energy to be stored in the battery; for downward reserves this requires the battery to have a state of charge that is less than full.

We do not model wind and solar resources as contributing to reserves in the CBS, though the exclusion of Imbalance Down reserves from the modeling is in part because renewable resources could supply downward imbalance reserve capacity by turning down (curtailing) output in real-time. Storage, online thermal, and dispatchable hydro resources are also expected to provide ample Imbalance Down capacity, thereby minimizing the impact that including this reserve would have on modeling results.

As is standard in production cost modeling, the CBS model's co-optimization of energy and reserves results in resources providing reserves at their opportunity cost; no additional cost or bid to provide reserves was added above a resource's opportunity cost when determining reserve commitments.

Table A-6 Reserve products modeled in the CBS

	Imbalance Up	Spinning	Non-Spinning	Regulation Up	Regulation Down
Purpose	Prepare for forecast errors between day-ahead and real-time market timeframes	Quickly replace capacity lost from a contingency event	Replace spinning reserve capacity	BAA ACE management outside of market signals	BAA ACE management outside of market signals
Direction	Headroom	Headroom	Headroom	Headroom	Footroom
How is the requirement calculated?	97.5% percentile of day ahead forecast error, as calculated by E3's RESERVE model	3% of load	3% of load	1% of load	1% of load
Held in Day-Ahead Stage?	Yes	Yes	Yes	Yes	Yes
Held in Real-Time Stage?	No (capacity released for dispatch)	Yes	Yes	Yes	Yes
Offline quick-start thermal capacity can contribute?	Yes	No	Yes	No	No
Timeframe (limits online resource contribution via ramp rates)	10 minutes	15 minutes	30 minutes	10 minutes	10 minutes

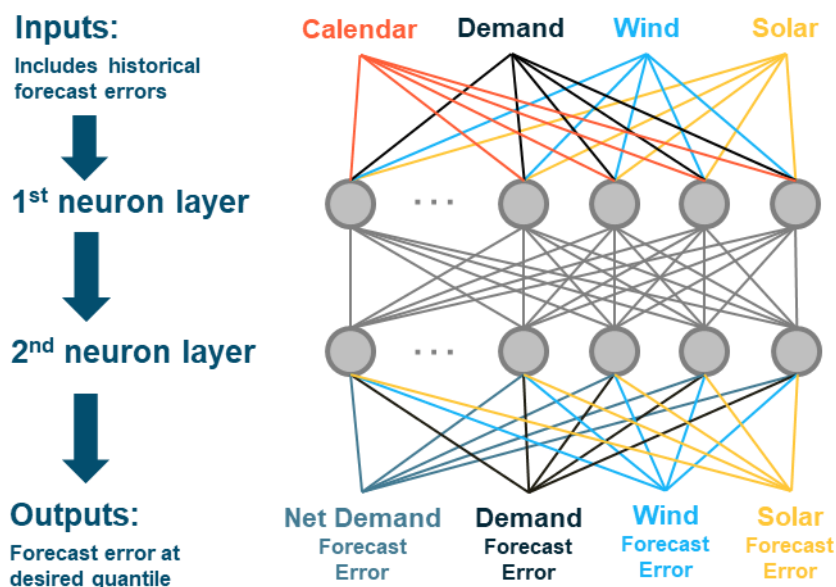
A.6. E3 RESERVE Tool Description

We use the RESERVE model²¹ to quantify the likelihood of extreme forecast error events. Extreme forecast error events are inherently infrequent and can therefore be challenging to quantify in a statistically rigorous manner. Furthermore, forecast errors can be driven not only by weather conditions themselves, but also by non-linearities in the response of load, wind output, and solar output to changes in weather conditions. As an example, the relationship between cloudiness and solar output is non-linear. With no clouds or fully overcast sky, the variability of solar output stays minimal as the solar output stays minimal, whereas in partly overcast weather we see the highest amount of uncertainty.

²¹ See Sun, Yuchi, James H. Nelson, John C. Stevens, Adrian H. Au, Vignesh Venugopal, Charles Gulian, Saamrat Kasina, Patrick O'Neill, Mengyao Yuan, and Arne Olson. "Machine learning derived dynamic operating reserve requirements in high-renewable power systems." *Journal of Renewable and Sustainable Energy* 14, no. 3 (2022): 036303. <https://doi.org/10.1063/5.0087144>

The RESERVE model employs the multi-layer perceptron method (MLP), commonly known as artificial neural network (ANN). ANNs can model highly non-linear relationships between inputs and outputs by choosing a non-linear activation for each neuron and allowing the neurons to interact and superimpose their non-linearity. RESERVE employs a pinball loss function.

Figure A-4 Illustrative diagram of the RESERVE neural network



One of the primary data sources that RESERVE uses to make forecast error predictions is renewable and load forecast and actual (real-time) data. RESERVE combines this forecast error data with calendar data such as the earth's revolution and rotation angle, as well as the solar azimuth and elevation angle. The calendar data allows the model to capture dynamics that depend on the hour of day, time of year, or position of the sun in the sky. RESERVE's neural network uses the input data to make forecast error predictions that are individually tailored to each hour of the year.

RESERVE can simultaneously produce multiple probabilistic outputs, including predictions of net load forecast error as well as the forecast error of individual net load components (load, wind, and solar). In this study we focused on net load forecast error as it directly sets the imbalance reserve requirements. The individual net load component forecast errors were used in the quality control process.

The RESERVE model can characterize reserve requirements for any user-defined percentile of forecast error. Following the EDAM Final Proposal,²² in this study RESERVE was used to calculate an Imbalance Up reserve requirement that is set at the 97.5% percentile of net load forecast error in each hour. Put another way, the day ahead net load forecast plus the imbalance reserve requirement will be higher than the realized real-time net load in all but 2.5% of hours.

²² <http://www.caiso.com/InitiativeDocuments/FinalProposal-Day-AheadMarketEnhancements.pdf>, p.28-29

A.7. Non-WMEG Entity Modeling

There are 14 Balancing Areas in the WECC which are not participants of WMEG. **Error! Reference source not found.** contains the modeling assumptions for these entities.

Figure A-5 Non-WMEG Modeling Assumptions

BAA	Description	Type	Approach
CISO	California ISO	CAISO	EDAM Transactions as CAISO
AESO	Alberta	Non-US	Assumed to be independently optimized relative to their own unique organized market. Modeled as a price stream within the WMEG model
BCHA	BC Hydro	Non-US	Described in detail below
CFE	Mexico	Non-US	Bilateral Only
SPP	SPP Marketplace	Non-WECC	Assumed to be independently optimized relative to their own unique organized market. Modeled as a price stream within the WMEG model
DEAA	Arlington Valley	IPP	Bilateral or as Contracted to WMEG; Assumed it a market in market scenarios
GRIF	Griffith	IPP	Bilateral or as Contracted to WMEG; Assumed it a market in market scenarios
GWA	NaturEner Glacier	IPP	Bilateral or as Contracted to WMEG; Assumed it a market in market scenarios
HGMA	Harquahala	IPP	Bilateral or as Contracted to WMEG; Assumed in a market in market scenarios
WWA	NaturEner Wind Watch	IPP	Bilateral or as Contracted to WMEG; Assumed it a market in market scenarios
DOPD	Douglas PUD	Muni	Bilateral or as Contracted to WMEG; Assumed it a market in market scenarios
IID	Imperial Irrigation District	Muni	Bilateral or as Contracted to WMEG; Assumed it a market in market scenarios
TID	Turlock Irrigation District	Muni	Bilateral or as Contracted to WMEG; Assumed it a market in market scenarios; WEIM in BAU
GRID	Grid Force	Multiple Clients	Bilateral or as Contracted to WMEG; Assumed it a market in market scenarios

BC Hydro was modeled uniquely with guidance from Powerex. The BC Hydro system was aggregated as a pumped-storage unit. The unit was given maximum and minimum daily energy budgets which were shaped to the WECC net load profile from the CBS study. As Powerex has committed itself to Markets+ the units flexibility was dependent on the footprint and the neighboring entities. In a single EDAM market case, Powerex is only allowed to trade in blocks and will withhold some of its generation from the market for other internal system usages. If other WECC entities are part of Markets+, BC Hydro will make its total capacity fully available and fully flexible for Markets+ interaction. The BC Hydro system can import and export to the rest of the West via its transmission into the Northwest and elsewhere.

A.8. Fuel, and Electric Market Price Modeling

Fuel Price Forecast

Fuel prices use forecasts are based on data from the CEC 2021 Integrated Energy Policy Report (IEPR) and the Energy Information Agency's (EIA) 2022 Annual Energy Outlook (AEO). The CEC IEPR forecasts originate from the North American Market Gas-trade (NAMGas) Model which considers some degree of natural gas pipeline capacity via a nodal model. All fuel prices, except natural gas, are constant over the year. Natural gas prices are developed on a monthly granularity. For 2026 and 2035, the data directly uses the forecast for Western hub locations from the CEC IEPR. That CEC forecast is based on projected Henry Hub prices of \$2.98/MMBtu on average for 2026 and \$3.26/MMBtu for 2030 (in 2022\$). For 2035, the IEPR does not have a gas projection so the monthly CEC basis differentials from 2030 are added to the EIA AEO data for Henry Hub in 2035 (\$3.74/MMBtu).

Gas prices do not vary between DA and RT stages as this may cause results to be skewed if different members provide individual views on gas price deviations at hubs or generators across WECC. The table below shows the resulting annual average of gas prices at selected Western Hub locations. Each price shown varies monthly.

Table A-7 Annual Average Gas Price for Selected Western Locations (\$/MMBtu)

Study Year	SoCal Citigate	Sumas (Northwest)	Waha (West Texas)
2026	\$4.68	\$3.17	\$2.72
2030	\$5.12	\$3.48	\$3.06
2035	\$5.60	\$3.96	\$3.55

Electric Market Price Forecasts (External regions)

E3 develops in-house price forecasts for locations across North America including the West, Canada, and SPP. For the CBS, E3 developed market prices for Alberta and SPP where WECC entities could interact with the separate organized markets. Within this model, SPP is represented via two different price streams - SPP North and SPP South - that vary between 2026, 2030, and 2035. Alberta is represented as a single price stream that connects to the model's Montana-Alberta Tie Line (MATL) zone. Hourly historical prices for SPP and AESO were selected in a year weather synchronized with WECC load and renewable data; E3 then scaled these prices to be consistent with gas price increases that E3 used for the projected study year of 2026, 2030 and 2035.

Market participants provided OATT based wheeling charge to be applied for imports and exports with Alberta (including MATL charges) and the Eastern Interconnection DC ties which.

A.9. Hydro Modeling

Several WMEG members have hydro fleets with sufficient storage to meaningfully shift generation between hours of the day, days of the week or, sometimes, on a seasonal basis. This ability to shift generation impacts the opportunity cost which will drive the Resource offer in the Day-Ahead and Real-Time Markets. These Resources also often have reservoir restrictions which do not match the generator characteristics (e.g., minimum elevation, maximum elevation, minimum flow, maximum draft).

Hydro resources are modeling two distinct ways within the production cost model:

1. Fixed Dispatch
2. Dispatchable

As a default assumption, the CBS uses 2018 hydro year, because it is representative for typical or average hydro conditions for many Western locations, and because it aligns with the wind and solar shapes used for the study; in particular cases, however, WMEG members provided alternative values if they believed that another year for their system was more representative of typical conditions than 2018.

Fixed Dispatch: resources were model with a fixed 8760 profile that was either provided by a WMEG member based on their hydro year or the original. These units were held at their fixed output with a \$0/MWh generation cost.

Dispatchable: for these resources, WMEG members shaped their hydro based on their chosen hydro year into daily hydro budgets reflective of any inherent flow restrictions or minimum flow requirements. PLEXOS optimized the hydro dispatch over each day and does not consider longer hydro budget usage. For this, members provided daily energy budgets that were shaped based on a weekend/weekday schedule. The energy budgets were considered hard constraints by the model which meant that the entirety of the budget was to be utilized by the model over the day and PLEXOS would shift hydro generation around within the day to minimize system-wide production cost. Hydro dispatch was also restricted to member-defined hourly (8760) maximum MW output and Minimum MW output profiles. This enabled members to represent minimum flow requirements or any other unique flow requirements for individual hydro units. Much like the fixed dispatch hydro, dispatchable hydro units were dispatched without a marginal cost (at \$0/MWh); the value of the energy and flexibility of dispatchable hydro is determined by the opportunity cost of the production simulation. Dispatchable units were able to contribute to all ancillary services, subject to the limits defined above.

Pumped storage represents an additional resource type that was modelled somewhat differently than hydro resources. Pumped storage units were modeled using head and tail reservoir volumes and pumping efficiencies from the WECC ADS. This was altered if members provided different data. Like other hydro units there was no offer cost. The marginal cost of these units ranged from \$0 to \$3/MWh to reflect variable O&M on certain units, in addition to pumping efficiency losses. Pumped storage units were modeled as able to provide reserves. WMEG members selectively updated pumped storage generator properties including pmax, pmin, max pump load, and pumping efficiency for certain units.

As part of the CBS, pumped storage and dispatchable hydro units were scheduled in the Day-Ahead market and were able to be re-optimized again in the Real-Time market. This may provide some additional flexibility in the model that may not be reflective of reality. Fixed profile resource outputs remained the same in Day-Ahead and Real-Time. Furthermore, hydro units within the production cost model were only allowed to bid their marginal cost, which is assumed to be \$0/MWh. There were no offer prices included in any resources as this would indicate some sort of trading strategy among participants in the West. The purpose of this modeling was to estimate costs and benefits in a market where there are not additional bidding strategies other than bidding at cost. Market power mitigation assumptions are also discussed later.

A.10. Green House Gas Modeling

E3 worked with the Green House Gas Task Force to develop the modeling assumptions for GHG in the CBS. Based on discussion within the task force, a Clean Energy Policy matrix was developed that identifies state and corporate clean energy targets, the model created three **GHG areas** to effectively represent the overlap of these different policies as part of one regionwide production cost model. The GHG areas are **California**, **Washington**, and **Colorado**.

The GHG market feature has been developed in detail for EDAM, however Markets+ had not established a GHG methodology at the time of developing assumptions for the CBS. GHG prices were based on the California Energy Commission (CEC) 2021 IEPR mid forecast. In this analysis there was no distinction between specified and unspecified imports. All imports into GHG areas were subject to the same hurdle rate that is defined by a GHG price, which was set based on the default rate used for unspecified imports into California. These values are summarized in **Error! Reference source not found.**

Table A-8 Carbon Price GHG Hurdle Rate for Imports to CA, WA, and CO

Study Year	Carbon Price (\$/metric tonne)	Unspecified Rate on Imports (tonnes/MWh)	Implied GHG Hurdle Price (\$/MWh)
2026	\$39.33	0.437	\$17.19
2030	\$62.05	0.437	\$27.12
2035	\$109.74	0.437	\$47.96

EDAM Approach

The CBS uses the following steps to represent EDAM's GHG approach in the model:

- Establish a GHG Baseline dispatch which would exist for each BAA. This is done with no transfers and all GHG bids being set to zero be not allowing any imports into GHG areas in the GHG Baseline run.
- Using E3's settlement script, generators are rewarded GHG revenue based on GHG price less compliance cost of each resource. GHG revenue allocation is described in more detail in Appendix C to this report.
- Each external resource "bids" a GHG price and MW based on compliance cost and emissions rate which is calculated on an annual basis from the Day-Ahead run (Total Emissions/Total Generation)
- Calculate the cost-based Bid for each Resource and eligible MW per Resource as the DA Award – Reference Run Award
- Calculate the BAA eligible GHG award per hour based on net exports in that hour.
- Calculate the Resource stack per BAA capped by the BAA net exports.
- Create the market resource stack based on each BAA's capped Resource stack.
- Determine the cleared resources up to the CA and WA imports.
- Calculate the potential margin per cleared Resource.
- Allocate the GHG revenue based on each unit's bid cost.

- A similar process is done for Real-Time except using the Day-Ahead Award as the baseline and the Real-Time dispatch would be incremental or decremental to that.

Markets+ Approach

For the purposes of the CBS, Markets+ uses a zonal approach for GHG with the following key steps:

- Each Resource has a GHG cost. There are three general types of resources. In-Zone, External-Specified and External-Unspecified. The Unspecified resources are assigned a proxy GHG cost.
- The market minimizes the combined cost of Energy and GHG.
- When there are imports to the GHG Zone, there is a shadow price for the marginal cost of GHG. The LMP reflects only the Energy Cost (and congestion and loss).
- Resources within the GHG zone have a compliance obligation. They receive GHG revenues in settlements. Like the EDAM approach, if the GHG shadow price is above their compliance cost, they will receive net payments.
- Specified External Resources have a compliance obligation. They receive GHG revenues in settlements. Like the EDAM approach, if the GHG shadow price is above their compliance cost, they will receive net payments.
- Unspecified External Resources do not have a compliance cost. The market operator collects that money and returns it to the state of the compliance region for further allocation, but this process has yet to be defined at the time of this study.

As part of the CBS, it is assumed that all external resources are unspecified and do not have a compliance cost and the money associated with imports into GHG areas is collected by the Markets+ operator and returned to the compliance entity, in this case the GHG area. The lump sum is provided to participants in a Markets+ in the CBS and at that point it is up to the GHG area to decide how that will be allocated among participants.

Additional Washington State Detail

For the purposes of the CBS, the California and Washington GHG market is considered linked for all cases. As a result, the study applies a GHG price at the generator level for each state but did not charge a separate GHG cost for energy that is wheeled between zones in these states.

Washington's Clean Energy Transformation Act's "No-Coal" provision excludes power purchases with a term of one-month or less.²³ The CBS has an hourly or daily transaction profile so there is no need to explicitly address this clause.

²³ See RCW 19.405.030.

A.11. Transmission Availability

E3 utilizes a hybrid nodal and zonal model that typically represents BAAs as individual zones. The model divides certain BAAs into more than one zone when needed to reflect impactful internal transmission constraints for WMEG members, or to represent cases where multiple different WMEG members operate as separate sub-BAAs or are otherwise important to distinguish in market operations. Some of these sub-zones are already reflected in the areas defined in the WECC Anchor Data set, and the CBS models a few additional sub-divisions. The CBS model typically does not charge wheeling or hurdle rates in the BAU case on transactions within each BAAs when a single entity responsible for most of the load and owning of the generation in both of the BAAs. With this approach, the CBS accurately represents the WECC system without utilizing a larger nodal model, which would have required significantly longer run time for each case, as well as additional decisions on the placement of new generators whose intended nodal points of injection have not yet been decided.

In addition to the tie-zones previously discussed, the BAAs that are modeled as more than one zone in the study include:

- California ISO, which the model divides into PG&E Bay Area (represented as CIPB in the model), PG&E Central Valley Area (CIPV), Southern California Edison (CISC) and San Diego Gas & Electric (CISC) to reflect internal transmission constraints.
- NV Energy, which the model divides into separate Northern (NVEN) and Southern (NVES) zones to reflect internal transmission constraints.
- PNM, which model divides into separate PNM North (PNM-N) and PNM South including Tri-State South (PNM-S + TSGT-S) and Tri-State Northern New Mexico (TSGT-NM) zones to reflect internal transmission constraints as well as distinct Tri-state operations.
- BPA, which the model divides into Washington (BPAT WA) and Non-Washington (BPAT Non-WA) zones to enable the Washington area to be represented with GHG pricing applied.
- NorthWestern Energy, which the model divides into the NorthWestern – Great Falls Area (NWM-T-GF) and all other NorthWestern territory (NWM-T) to reflect internal transmission constraints. The NWM-T GF zone connects directly to the MATL line for transactions with Alberta.
- The PSCO BAA, which the model divides into separate PSCO-West (PSCO-W), PSCO-East (PSCO-E) and Black Hills Energy of Colorado (BHE) zones to reflect transmission path constraints, and distinct entity operations.
- The WAPA - Lower Colorado Region, for which the model represents distinct operations for the AEPCO sub-BAA and leaves the remainder of loads and resources WALC sub-zone.
- The WAPA – Colorado-Missouri Region (WACM), which the model divides into 12 separate zones to reflect transmission path constraints, distinct entity operations, and GHG regulations applicable in Colorado. These 12 zones are CRCM-North (CRCM-N), CRCM-South (CRCM-S), Loveland Area Project (LAPT), Loveland Area Project – Wyoming (LAPT-WY), Platte River Power Authority – West (PRPA-W), Platte River Power Authority – East (PRPA-E), Tri-State G&T – West (TSGT-W), Tri-State G&T – East (TSGT-E), Tri-State G&T – Wyoming (TSGT-WY), Black Hills Energy in Wyoming & South Dakota (BHE-WY/SD), Basin Electric (Basin), and Flaming Gorge (FG).
- The WAPA Sierra Nevada Region (SNR) is a member of the BANC BAA. However, for the CBS WAPA SNR requested to be studied independently from BANC for certain scenarios. BANC members other than SNR are modeled in EDAM for all scenarios. WAPA SNR, by contrast is modeled in Markets+ region the Markets+ Bookend Case (and EDAM for the EDAM Bookend

and Main Split Case). To implement this distinction, WAPA SNR is broken out of the BANC zone and assigned its own load and transmission connections to CAISO, SMUD, and the Northwest.

- Finally, for a number of entities, sub-zones were created to represent, remote generation located at a tie zone that is owned or contracted to a receiving entity who typically takes that output (e.g. over a dynamic schedule or pseudo-tie) and does not typically face incremental transmission charges or transactional friction for bringing the output of the generation into their area, but may face limits to the transmission capability that can constrain the sum of energy brought to load from energy produced by the generator and energy purchased at the tie zone.

Transmission availability was reflected within the model as total transmission capacity (TTC) between BAs and across any relevant WECC paths.

E3, Utilicast, and WMEG developed an added layer of transmission availability to the model which created the ability to define multi-party transfer limits. This concept was labeled by the group as “Seams” or “Tie-Zones” and is depicted in **Error! Reference source not found..** Limits in and out of these locations are defined for multiple parties and enable multiple transactions to and from multiple entities across one path. Having Tie-Zone representations also allows for more accurate settlement calculations, particularly for wheeling and congestion, as all transactions can be tracked by individual entities. This concept was mainly for the Southwest and to some degree, the Northwest. For other regions, the Tie-Zone was used to represent entity-specific breakouts of WECC paths to again, keep track of individual wheeling and congestion.

Figure A-6 Tie-Zone Representation in Southwest

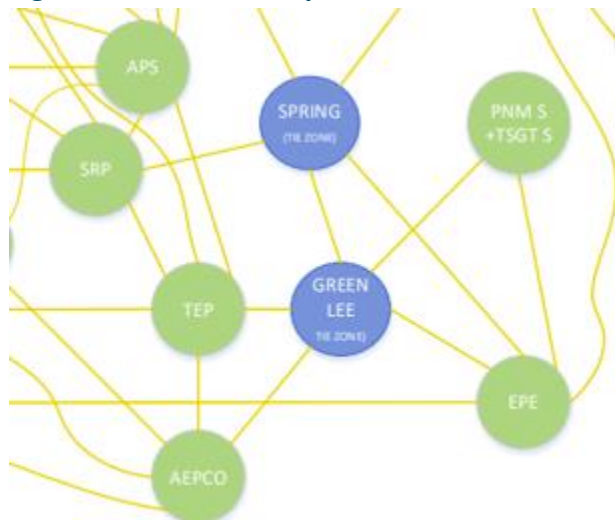
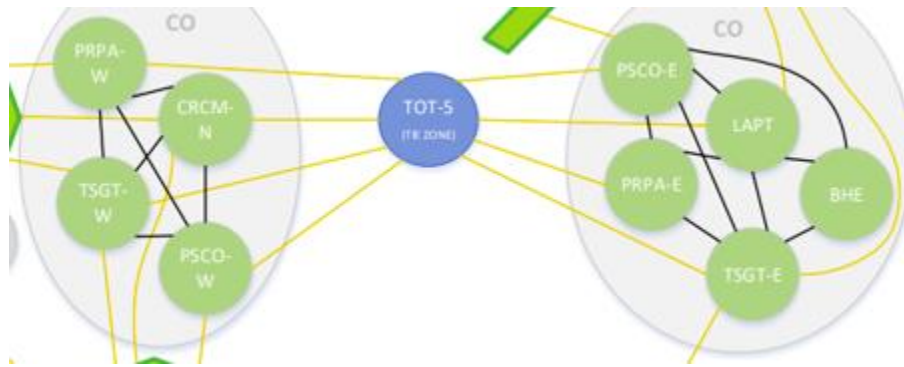


Figure A-7 Tie-Zone representation of WECC Path in Colorado

E3 incorporated an additional layer of transmission availability that included special transmission rights and special transfer obligations for WMEG members.

In the BAU case, 100% of transmission is made available for bilateral transactions within the Day-Ahead market. The Real-Time market also enables use of the full TTC which might be seen as being more flexible than reality.

To test the impact of this assumption, E3 modeled a separate BAU sensitivity case that assumed more limited efficiency in RT markets, to explore the uncertainty around how efficient and flexible RT markets (alone) could become by 2026. This sensitivity case constrained RT flows over each line between zones to the day ahead scheduled flow +/- 15% of the line's total transfer capability. For example, if a 1000 MW line had 500 MW scheduled to flow in the DA stage for a given hour, the RT stage flows were constrained to range between 350 MW and 650 MW for that hour. This case resulted in regionwide annual production costs that were \$70 million higher than the BAU case for this study. If this BAU sensitivity were instead used as a point of comparison to the DA Market Cases, the resulting impact of forming a DA market would improve by \$70 million for each of these cases, resulting in regionwide savings in the EDAM Bookend growing to \$130 million, and the regionwide net cost increase in the Main Split case instead changing to \$151 million.

According to the two different markets, there are slight differences in how they consider transmission. Though Markets+ claims to use a different transmission capacity within its market, in discussion with the WMEG it seemed like this market feature was not fully established and raised more questions than answers namely: how would each entity estimate their transmission capacity if all transactions today are done based on path ratings? Based on this, the transmission availability was not altered between an EDAM and Markets+ market. Within the CBS model each market used the available TTC between different zones.

A.12. Load Participation

The model cleared 100% of forecasted demand in the Day-Ahead run, which included day-ahead forecast error of load, wind and solar for each zone. The Real-Time run represented load and renewable "actual values", which differ from the Day-Ahead forecast values based on a simulated forecast error between the day-ahead and real-time timeframes. E3 did not model virtual bidding or other bidding behavior that

would reflect less than 100% of forecasted Day-Ahead being cleared. E3 adopted this assumption for three main reasons:

Clearing less than 100% of forecasted load in the Day-Ahead regionwide model would have resulted in resource shortages in real-time dispatch because the day-ahead timeframe will be the last commitment timeframe for longer-start units. Without an adequate amount of capacity committed from longer start units, the headroom available on committed units and the fast start capacity available in real time would have likely been insufficient to meet load on certain days, especially days with very high loads or with large forecast error events. In actual practice, the residual unit commitment process can typically provide access to enough capacity to operate reliably on these days, however it is likely that both economic and reliability concerns would result in most demand being cleared day-ahead instead.

To give the CBS model the opportunity to clear less than 100% of forecasted demand, additional data would have been required to develop pricing for the opportunity to clear different levels of demand in the day-ahead timeframe. This pricing information would have required modeling tradeoffs not ideal for this study and would have been speculative to determine for the future study years.

This CBS sought to reflect the benefits for participants assuming no other bidding strategies were utilized other than bidding at cost, to minimize system cost while reliability serving hourly load. Holding a portion of generation back from the DA stage could have artificially depressed Day-Ahead prices and increased real-time prices, thereby potentially skewing benefits.

A.13. Market Power Mitigation

Market power mitigation was addressed in discussion with the WMEG; however, the model does not address MPM as the model inherently assumes all generators are bidding in a competitive manner. A central aspect of this modeling effort is to provide an estimate of benefits among all participating WMEG members in a market where participants are all acting within power market rules to minimize cost. Introducing uncompetitive bids into the analysis may skew results.

Exploration of non-cost-based bidding strategies in a future WECC power system with higher levels of renewables and storage is not feasible within the proposed timeline of the CBS.

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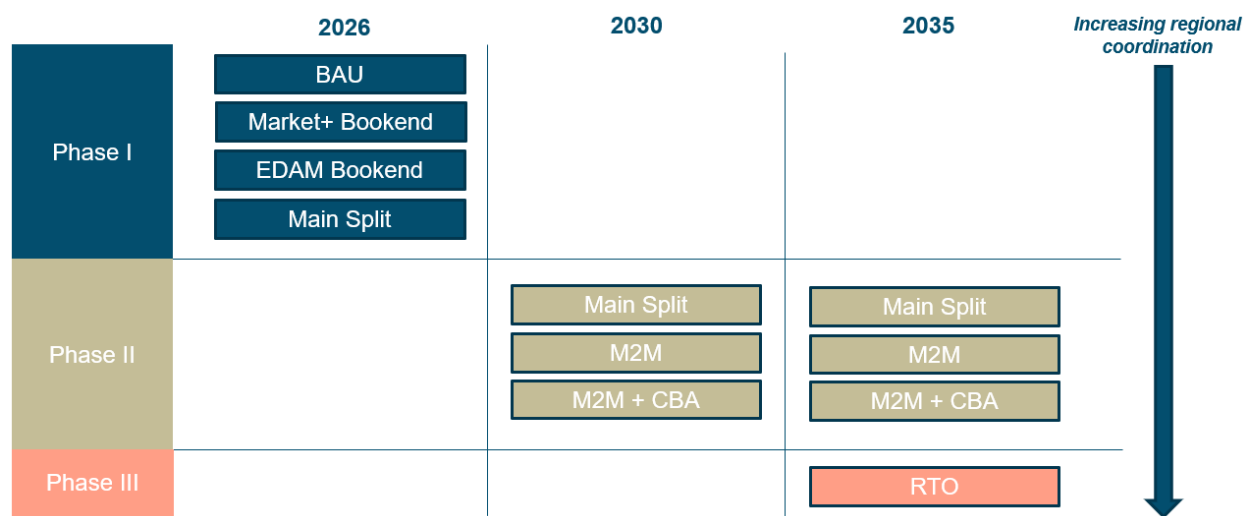
A.14. Resource Sufficiency Tests

Based on discussion with the broader WMEG members and Utilicast, E3 established that creating an additional resource sufficiency test as part of this study would require significant time to implement. Therefore, the resource sufficiency test was not conducted as part of the study, and it is assumed that all entities that participate in EDAM or Markets+ are resource sufficient in each interval of the production cost simulation as is often the case for the current WEIM.

Appendix B. Scenario Design

The scenarios within this study help address key questions surrounding the EDAM and Markets+ markets and how the different characteristics and footprints change production cost benefits. The core study has three phases of scenarios that build on one another from a BAU case to an RTO case by adding increasing regional coordination across case scenarios to provide insight to benefits of moving from a separate Day-Ahead and Real-Time market to a fully integrated RTO. Figure B-1 shows the various scenarios included in the core study and the subsequent sections of the report describe the scenarios in more detail.

Figure B-1 Study Scenario Summary



B.1. Phase I

Phase I looks at the 2026 timeframe and measures the effects of a Day-Ahead market relative to BAU.

2026 Business-as-Usual (BAU)

The BAU case sets a baseline to compare the subsequent 2026 market cases analyzed in the CBS. In the BAU case, there is no active Day-Ahead market outside of CAISO. Instead, there are scheduled bilateral transactions between zones and are subject to member long-term point-to-point OATT rate assumptions.

In the Real Time stage, the WEIM and WEIS markets are both active and additional transactions occur within their respective market footprints. WEIM and WEIS transactions are not subject to OATT rates.

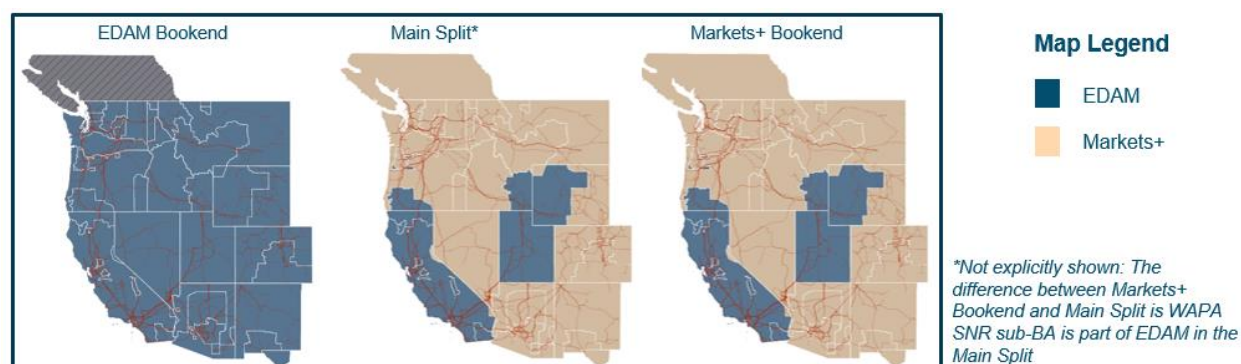
Table B-1 WMEG Member Market Participation in BAU Scenario

WMEG Member	Day-Ahead Market	WEIM	WEIS
AEPCO	✗	✓	✗

APS	x	✓	x
Avista	x	✓	x
BANC	x	✓	x
Black Hills	x	x	✓
BPA	x	✓	x
CHPD	x	x	x
EPE	x	✓	x
GCPD	x	x	x
IDP	x	✓	x
LADWP	x	✓	x
NWMT	x	✓	x
NVE	x	✓	x
PAC	x	✓	x
PGE	x	✓	x
PNM	x	✓	x
PRPA	x	x	✓
PSCo	x	x	✓
PSE	x	✓	x
SCL	x	✓	x
SRP	x	✓	x
Tacoma	x	✓	x
TEP	x	✓	x
TSGT	x	x	✓
WACM	x	x	✓
WALC	x	✓	x
WAUW	x	x	✓
WAPA SNR	x	✓	x

2026 Market Cases

Three different market footprints were analyzed as part of Phase I of the core CBS study: an EDAM Bookend, a Markets+ Bookend, and a Main Split. These are shown geographically in Figure B-2 2026 Market Scenario Footprints. Within the different footprints, each WMEG member is considered part of either EDAM or Markets+ and is assumed to also be part of the corresponding Real-Time WEIM or WEIS market respectively.

Figure B-2 2026 Market Scenario Footprints

Since some WECC entities have already announced their intentions of joining either EDAM or Markets+, these were not changed across any footprints. There was also an additional assumption that all California Entities will remain in the EDAM across all cases except for WAPA Sierra Nevada Region (WAPA SNR), a BANC sub-BA.

Table B-2 Static WECC Market Participation Assumptions

	EDAM	Markets+
WECC Members	CAISO, BANC, TIDC, IID, LADWP, PAC	BC Hydro/Powerex

The rest of the WMEG members, including WAPA SNR, were put in EDAM in the EDAM Bookend, Markets+ in the Markets+ Bookend, and agreed on where to be placed in the Main Split scenario.

Table B-3 WMEG Member Market Assumptions for 2026 Market Scenarios

WMEG Member	EDAM Bookend		Markets+ Bookend		Main Split	
	EDAM	Markets+	EDAM	Markets+	EDAM	Markets+
AEPCO	✓	✗	✗	✓	✗	✓
APS	✓	✗	✗	✓	✗	✓
Avista	✓	✗	✗	✓	✗	✓
BANC	✓	✗	✓	✗	✓	✗
Black Hills	✓	✗	✗	✓	✗	✓
BPA	✓	✗	✗	✓	✗	✓
CHPD	✓	✗	✗	✓	✗	✓
EPE	✓	✗	✗	✓	✗	✓
GCPD	✓	✗	✗	✓	✗	✓
IDP	✓	✗	✗	✓	✗	✓
LADWP	✓	✗	✓	✗	✓	✗
NWMT	✓	✗	✗	✓	✗	✓
NVE	✓	✗	✗	✓	✗	✓
PAC	✓	✗	✓	✗	✓	✗
PGE	✓	✗	✗	✓	✗	✓

PNM	✓	✗	✗	✓	✗	✓
PRPA	✓	✗	✗	✓	✗	✓
PSCo	✓	✗	✗	✓	✗	✓
PSE	✓	✗	✗	✓	✗	✓
SCL	✓	✗	✗	✓	✗	✓
SRP	✓	✗	✗	✓	✗	✓
Tacoma	✓	✗	✗	✓	✗	✓
TEP	✓	✗	✗	✓	✗	✓
TSGT	✓	✗	✗	✓	✗	✓
WACM	✓	✗	✗	✓	✗	✓
WALC	✓	✗	✗	✓	✗	✓
WAUW	✓	✗	✗	✓	✗	✓
WAPA SNR	✓	✗	✗	✓	✓	✗

As part of the market scenario set up, Imbalance reserve requirements were calculated for WECC subregions. Aggregate reserve requirements across subregions in WECC create a noticeable diversity benefit relative to a BAU framework. For the Main Split Case, diversity-related reduction in imbalance reserve requirements range from 16% in the Rockies subregion to 43% in the Southwest sub-region with California and the Northwest in between these two values.

Table B-4: Subregional Imbalance Reserve* Diversity Benefit

Subregion**	California	Northwest	Northwest	Rockies	Southwest
Market	EDAM	EDAM	Markets+	Markets+	Markets+
Mean Reserve Requirement* (MW)	2,472	634	759	414	1,180
Sum of Mean Individual Entity BAU Reserves in Subregion (MW)	3,562	770	1,161	493	2,062
Diversity Benefit Reduction	31%	18%	35%	16%	43%

*Hourly Imbalance Reserve Requirements for each subregion in the market cases were calculated as percentile of the day ahead forecast error for load, wind, and solar for that sub-regional grouping of zones and reflects diversity in forecast error among the zones in each group. The mean reserve requirement takes the average of all hourly requirements across the year. More detail on reserve requirement calculations is provided in Appendix A.

**The zones comprising each subregions listed here are listed in Table A-5 of Appendix A.

B.2. Phase II

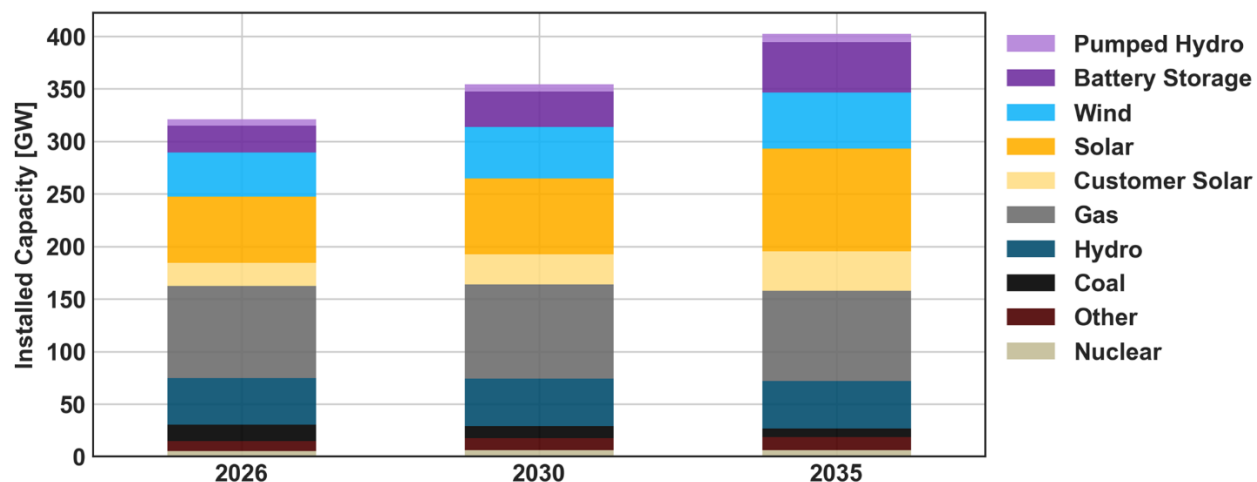
Phase II scenarios for the core CBS study involve analyzing the Main Split case for 2030 and 2035 under increasing intra- and inter-market coordination.

Main Split

The 2030 and 2035 Main Split cases account for increases in generation capacity across WECC according to WMEG member input data as well as some transmission upgrades that were considered important for individual entities. The remaining scenarios in Phase II build off each other starting with the 2030 and

2035 Main Split cases. WMEG members provided input into the resource additions and retirements for the 2030 and 2035 years. Total resource capacity across WECC shows a reduction in coal and gas capacity through 2035 while solar, wind, and storage see noticeable increases across that same timeframe.

Figure B-3 Total U.S. WECC Installed Capacity²⁴



Market to Market (M2M) Coordination

The first sensitivity involves increased market-to-market (M2M) coordination. In the future, once EDAM and Markets+ have established themselves as functional Day-Ahead markets in the West, they will continue to mature and refine market rules to enhance liquidity and lower prices. Moreover, even without production cost savings, this kind of coordination could aid reliability if market to market trading opportunities can be an option near real-time. Either EDAM or Markets+ may look to enhance the efficiency of external transactions by developing clear cross-border trading procedures and minimizing the cost associated with this type of scheduling. This type of improved market to market coordination could result in a more liquid and robust trading between markets which may provide more cost-effective than strictly trading internally within either market separately.

Table B-5: 2030 & 2035 Main Split M2M Hurdle Rate Component Breakout

Non-M2M Coordination Hurdle Rate		M2M Coordination Hurdle Rate
Within Market	\$0	\$0
Market Seam	Weighted Average OATT Rate of Market	Weighted Average OATT Rate of Market

²⁴ Total WECC capacity does not include AESO resources as this was implemented as a price stream within the CBS. BC resources and loads (as well as trades with Alberta) were modeled as an integrated pumped hydro facility based on the anticipated quantity of energy to be sent to the US for on an hourly or block schedule basis. This capacity is included with pumped storage in the chart.

+ \$2 Friction + \$8 Congestion Risk for exports from a Zone that is in Market A to a Zone that is in Market B	+ \$2 Friction + \$4 DA Congestion Risk (or \$1 RT Congestion Risk) for exports from Market A to a Zone that is in Market B
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Market to Market & Consolidated Balancing Area (M2M + CBA)

The M2M + CBA case represents a future where not only have markets been able to encourage better inter-market trading, but they have also developed into a more consolidated balancing area. This includes optimal dispatch within the market footprint in addition to ancillary services markets within the footprint. Beyond an imbalance reserve sharing between entities in a Day-Ahead market construct, the consolidated balancing area would expand reserve sharing by including Spinning, Non-Spinning, and Regulation reserve market products. These reserve groupings are aggregated on a sub-regional basis within each market, instead of for the full market footprint, to account for transmission constraints within the West that may prevent reserves from being fully sourced from across the entire market footprint.

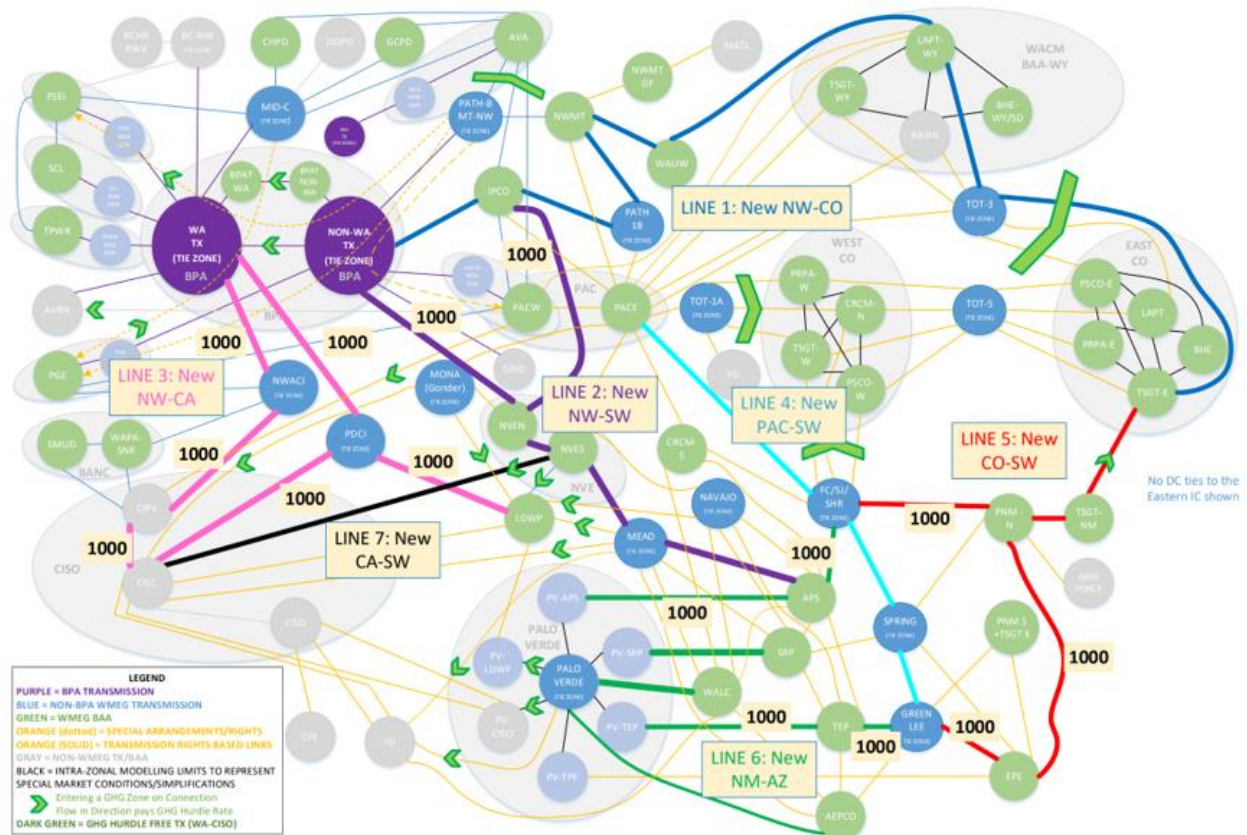
B.3. Phase III

2035 RTO Scenario

The 2035 RTO case uses the M2M + CBA case as the starting point and adds additional transmission capacity along seven major paths within the existing model topology as a representation of increased coordination of transmission development that may be facilitated through an RTO. The WMEG did not analyze individual transmission addition scenarios to determine the net cost or benefit of any individual line, nor were these linked to specific projects under development; rather, the scenario explores the aggregate impact that significant transmission additions could have for enhancing market benefits.

The map below indicates the major transmission upgrades highlighted in thicker bold coloring for the 2035 RTO Scenario, augmenting transmission links already in the existing case. The highlighted links in the figure that are marked with “1000” have added 1000 MW to the transmission capability between the linked zones compared to the transmission in the base model for 2035. The highlighted links without a number shown have added 2000 MW to transmission in the base model.

Figure B-4 RTO Case Transmission Capacity Additions



Appendix C. Settlement

E3 developed a comprehensive and detailed settlement process that takes output data from the various market model runs and generates ex-post settlement details down to the generator level for each WMEG entity over the study year. The components of settlement include the components listed below in this section.

The total **Net Variable Costs** for each entity are based on the sum of each of these components where costs are positive values and revenues are treated as negative (offsetting costs). For each entity, E3 then calculated the Net Variable Cost savings (or increase) from market participation as the difference between the Net Variable Costs for that entity from a market case (e.g., EDAM Bookend) compared to the net costs in the BAU case.

All pricing for the Day-ahead settlement includes Fast Start Pricing for any zones included in the Markets+ footprint. E3's settlement process conducts both a day-ahead market and a real-time market settlement down to the generator unit level across WECC.

C.1. Generation Cost

Generation cost for each member is the sum-product of each generator's production cost and the member's generator ownership share factor. Depending on the generator technology, its production cost could include fuel, VO&M, start/shutdown, and emission cost components (i.e., VO&M is the only relevant component for batteries). Generation costs are only incurred in real-time.

C.2. Generation Revenue

Generation revenue for each member is the sum-product of each generator's net-revenue and the member's generator ownership share factor. The net-revenue for each generator is the product of the nodal price and generation (net of any pump or charging load). DA generation revenue is calculated using DA prices and volumes, and then summed with the RT incremental volume (RT-DA) valued at the RT price. Finally, members that are off-taking hydro power from other members have those obligations (valued at the DA price at a supplying member node) added to their generation revenue (while the supplying member has it subtracted).

C.3. Loads Cost

Load cost for each member is the sum-product of nodal price, native-load,²⁵ and member load-ownership factor. The member load-ownership factors allocate balancing area load into member service load. DA load cost is calculated using DA prices and volumes, and then summed with RT incremental volume (RT-DA) valued at the RT price. RT native-load can be different from DA native-load due to load forecast error.

²⁵ Native load is the raw input load and does not include generator pumping/charging load that is accounted for in generation revenue.

C.4. Reserve Cost & Reserve Revenue

Reserve cost only includes the explicit costs for procuring market reserve products; non-market reserve cost can be considered embedded in generator net-revenues as opportunity cost. Reserve cost for each member is the sum-product of reserve price, reserve requirement, region-BAA requirement factors, native-load ratio factor, and member load-ownership factor. In cases that have region reserve markets for ancillaries, the region-BA requirement factors decompose the region-wide reserve requirement to balancing areas (defined by BA reserve requirements from the BAU 2026 case). The native-load ratio factors allocate the BA requirements to model nodes (which each represent BA or sub-BA) based on native-load. Finally, the load-ownership factors allocate cost to members. DA reserve cost is calculated using DA prices and volumes, and then summed with RT incremental volume (RT-DA) valued at the RT price. RT reserve requirement can be different from DA due to load forecast error.

Market reserve revenue for each member is the sum-product of generator reserve provision, reserve price, and generator ownership factor. Like reserve cost, DA and RT components were included.

C.5. GHG Revenue

Generator revenue for each member is the sum-product of generator GHG award, emission intensity factor and GHG price. GHG revenue can be allocated to generators outside of states with GHG programs (CA, WA, CO) when they help serve load in these localities. The hourly GHG demand is determined using the change in net imports over eligible lines²⁶ relative to a reference phase.²⁷ Generator supply caps vary for dispatchable vs non-dispatchable resources but are broadly based on differences between changes in generation and headroom between phases. After determination of the GHG demand and generator available supply caps, hourly GHG awards are allocated to generators in emission intensity merit-order. Only generators that are in BA's that are net-exporters are considered candidate resources for awards, and if there is not enough GHG supply to meet demand the remainder is allocated to a shortage resource (not owned by any member). The price that a generator receives for its GHG awards is a fraction of the GHG price proportional to its emission intensity relative to a cut-off emission intensity of 0.437 Tons/MWh. Consequently, zero-emission resources receive the full GHG price at the cut-off emissions intensity.

C.6. Wheeling Revenue

Transmission wheeling revenue is the product of line flow and the hurdle rate (constituted of OATT rate, market hurdle adder and friction adder). Broadly, when a market region is exporting power from a transmission line that crosses a market seam, the wheeling revenue is allocated to all the balancing on a native-load ratio share basis and then to members on a load-ownership share basis. Incremental RT revenue is included. The exact methodology for allocating wheeling revenue to members depends on

²⁶ GHG eligible lines are transmission connection connecting a non-GHG area to a GHG area. All flow entering the GHG area is subject to the designated GHG price and is represented as an additional hurdle rate.

²⁷ The reference phase for DA is the GHG phase (which prevented flow over GHG lines); for RT, the DA phase is used as a reference. RT demand for GHG is only considered when incrementally greater net-imports were made into GHG areas in RT than DA.

whether the line connects (1) two different markets (market-to-market), (2) a market region to a non-market region (market-to-nonmarket), or (3) an intra-market or intra-nonmarket line (non-market seam).

Wheeling revenue is distributed among entities in the BAU case based on to the amount of energy exported over transmission lines connected to their zones and their OATT rate or market wheeling rate; in the markets cases, wheeling revenue is determined based on the amount of energy flowing exported over transmission lines connected to each market footprint and then is distributed among market participants based on each participant's percentage share of total load in the market (load-ratio share basis).²⁸

C.7. Congestion Revenue

Transmission congestion revenue is only incurred when (1) a line hits its flow limit, (2) the flow is in the direction of the price premium and (3) the premium exceeds any hurdle rate applicable to the line. Like wheeling revenue, the congestion revenue methodology depends on whether the line is (1) a market-to-market line, (2) a market-to-non-market line, or (3) a non-market seam line. Like wheeling revenue, when a market region is exporting power to a zone that is outside the market footprint, any congestion on the market seam is allocated to all members of that market on a load-ratio share basis. However, for other types of lines the BA exporting on the congested line is allocated all the congestion revenue and to members by load-ownership share. When the exporting node is a tie-zone, the BAAs or zones (connected via other lines) that are receiving energy from tie-zone serve the congested region divide the congestion revenue equally. This revenue would subsequently be allocated by each WMEG member to each of its transmission customers via load ratio share. RT congestion revenue is only included when the line is congested in RT and was not DA stage.

²⁸ Separate proposals for market elements in EDAM and Markets+ that seek to provide some compensation to entities that lose current short-term firm or non-firm point to point revenues were not represented in this analysis due to the definitions of those mechanisms not being fully defined at the time when study assumptions for this analysis were finalized. Revenue from such mechanisms (or charges to derive this revenue) would be additional to any individual benefits represented in this study.