Joint Dispatch Agreement Energy Imbalance Market Participation Benefits Study

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Executive Summary

This study was conducted on behalf of the Black Hills Corporation, Colorado Springs Utilities, Platte River Power Authority, and the Public Service Company of Colorado (together, we refer to them as the Joint Dispatch Agreement (JDA) "JDA companies" or "JDA entities"). The four JDA entities were participants in the Mountain West Transmission Group (MWTG) study released in 2017, and the simulations in this study are based on the model developed for that endeavor. We analyze the production cost benefits from participation in two proposed real-time energy imbalance markets relative to continued membership in the JDA. The two options for participation in a broader regional energy imbalance market analyzed are: 1) the Western Energy Imbalance Market (EIM) that is currently in operation throughout much of the western United States and is administered by the California Independent System Operator (CAISO), and 2) the Western Energy Imbalance Service (EIS) proposed by the Southwest Power Pool (SPP).

The production cost benefits presented in this study are only one element of evaluating participation in a RTO-operated regional wholesale market. The study does not estimate any production-cost-related impacts beyond those captured in the simulations and the APC metric, such as discrepancies between congestion charges and congestion hedging or congestion revenue distribution mechanisms, marginal loss refunds, and the likely significant additional benefits related to the lower-cost, intra-hour balancing of uncertain loads and renewable generation achieved in a regional market during real-time operations. As such, the benefits quantified here are conservative, and likely understate actual achievable production cost savings. Similarly, this report does not address other considerations related to the formation of, or the participation in, a regional market such as the implications of alternative market governance structures, implementation and administrative costs related to market participation, or reliability benefits of regional market operations.

These energy imbalance market options are simulated across different market participation scenarios, which analyze different membership options for the four JDA entities and the remaining six companies of the former MWTG[1]. In total, four cases are simulated using 2024 as a test year to estimate the potential impact associated with the JDA entities participating in the two imbalance markets considered. These four cases are:

- **Status Quo Case:** Represents current market operations in the WECC. This includes a representation of the EIM for all the existing members and the utilities that had announced publicly at the start of our study that they are planning to join before 2024.

1 The remaining MWTG companies are Basin Electric Power Cooperative, Black Hills Power, Cheyenne Light Fuel & Power, Tri-State Generation and Transmission Cooperative, and Western Area Power Administration's Loveland Area Projects and Colorado River Storage Project.

The four JDA entities are represented as participating in the JDA. The other MWTG members are not represented in any regional market. This case assumes that only the current imbalance markets operating in the WECC will be operating in 2024, with their current and already-planned memberships as had been announced at the initiation of this study in the summer of 2019. The Status Quo Case serves as the baseline against which the benefits of participation in the EIM or EIS are calculated for the JDA entities.

- JDA in EIM Case: Simulates the four JDA entities as part of the broader Western EIM footprint. The other MWTG entities are not included in any regional market structure in this case. The representation of the rest of the WECC is unchanged from the Status Quo Case. Therefore, the JDA in EIM Case is compared to the Status Quo Case to estimate the benefit for the JDA companies if only they join the EIM.
- MWTG in EIM Case: Simulates the entire MWTG footprint, including the JDA entities, participate in the EIM in 2024. The representation of the rest of the WECC is the same as in the Status Quo Case. Therefore, comparing the MWTG in EIM Case with the Status Quo Case indicates the benefits if all ten MWTG companies joining the EIM.
- MWTG in EIS Case: Models the full MWTG footprint, including the JDA companies, in the Western EIS. The representation of the rest of the WECC is the same as in the Status Quo Case. Comparing the MWTG in EIS Case with the Status Quo Case indicates the benefits if all ten MWTG companies joining the EIS.

We simulated the entire WECC for this analysis. We used Power System Optimizer (PSO) to conduct the nodal production cost analysis and simulate the economic unit commitment and dispatch of generating plants that would be results from a centralized regional wholesale market. The model developed during the MWTG study was updated with new data inputs provided by the JDA entities and collected from publicly available data sources to create an updated database reflecting the expected system conditions for 2024.

The key results metric estimated in this study is the Adjusted Production Cost (APC) of the JDA entities, which is a high-level approximation of the cost to serve customers. The APC metric includes production costs of generation resources owned by the JDA entities, and the cost of market purchases less revenues from market sales. The APC metric also includes applicable make-whole payments that would be received by the JDA entities from the energy imbalance markets to compensate them for production costs included in the APC that are not covered by market revenues. These make-whole payments are called Bid Cost Recovery (BCR) payments in the EIM. The proposal for the EIS does not include such payments, and are therefore not estimated in this study. If the EIS implements similar make-whole payments, they would need to be considered as part of the benefit of participating in that market.

The majority of BCR payments received by JDA resources would be recovered from the JDA entities themselves, implying that most of the BCR payments are not benefits additive to the JDA entities' APC reduction estimated through our simulations. We estimate only the portion of the BCR payments that are related to EIM exports out of the JDA footprint, which will result in BCR payments received by the JDA entities, but funded by neighboring EIM entities. The production costs incurred by following EIM commitment and dispatch instructions, which allow for exports out of the JDA footprint to occur, are included in the APC metric, implying that any BCR payment received by the JDA entities to recover those production costs needs to be incorporated in our benefit calculation.

In this study, we have not conducted any analyses to determine any potential benefits due to the optimal dispatch of the DC intertie between the JDA entities and the SPP footprint (in the case where the JDA joins the EIS along with the MWTG) because the current proposal for the EIS imbalance market does not include the capability for SPP to optimally dispatch the DC interties that are owned or controlled by potential EIS members. Therefore, we have simulated the power flows across the interties to be constant across all the cases in this study, based on the hourly flows provided by the MWTG entities during the MWTG study. Other benefits not quantified in these market simulations of imbalance markets (neither for EIM or EIS) are noted below.

Table 1 below shows the estimated production cost savings due to market participation for all the cases simulated. The simulated production cost results for the JDA in EIM, MWTG in EIM, and MWTG in EIS Cases are compared to the Status Quo Case to determine the reduction in production cost due to market participation.

Table 1: Summary of Estimated Market Participation Benefits for the JDA Entities

	JDA in EIM		MWTG in EIM		MWTG in EIS	
	$million/yr	% of APC	$million/yr	% of APC	$million/yr	% of APC
Adjusted Production Cost Reduction	$1.24	0.28%	$16.27	3.62%	$1.62	0.36%
Bid Cost Recovery Payment	$0.74	0.17%	$1.07	0.24%	*N/A*	*N/A*
Estimated Market Participation Benefit	$1.98	0.44%	$17.34	3.86%	$1.62	0.36%

The results in Table 1 indicate that the estimated production cost benefit for the four JDA entities joining the EIM (JDA in EIM Case) are about $1.98 million/year, or 0.44% of production costs. The estimated production cost benefit for the four JDA entities increases to about $17.34 million/year, or about 3.86% of production costs, if the entire MWTG footprint joins the EIM together. The estimated production benefits for the JDA entities if the entire MWTG footprint joins the EIS is about $1.62 million/year, or about 0.36% of production costs. The MWTG in EIM Case provides the largest reduction in production costs of all three cases relative to the Status Quo Case. The large reduction in production costs in the MWTG in EIM Case is driven by two factors. First, the size and generation resource diversity of the EIM footprint provides more opportunity for trading energy in the imbalance market. The EIM footprint contains a more diverse mix of generation resources, such as solar in the Southwest and hydro in the Northwest, which creates more opportunity to economically trade power across the footprint. Second, the additional transfer capability between the JDA and the EIM footprint available in the MWTG in EIM Case provides the JDA entities with greater access to the EIM market.

The study includes two sensitivity analyses that test how the production cost benefits of market participation change under two modeling assumption changes. First, the <u>Added Transmission</u>

Sensitivity simulates the JDA in EIM Case with 200 MW of additional transmission rights to export from the JDA companies to the EIM footprint. Table 2 shows that the additional 200 MW of export rights provide $530,000/year of additional benefits in reduced APC for the JDA entities ($1.24 million/year in reduced APC in the Base JDA in EIM in Table 1 vs $1.77 million/year in reduction in Table 2). In the Added Transmission Sensitivity, increased EIM exports also yield higher BCR payments received by the JDA entities. As shown, the total benefits from EIM participation in the Added Transmission Sensitivity are about $3.66 million/year, or 0.82% of production costs.

Table 2: Summary of Estimated Market Participation Benefits for the JDA Entities
Added Transmission Sensitivity

	JDA in EIM	
	$million/year	% of APC
Adjusted Production Cost Reduction	$1.77	0.39%
Bid Cost Recovery Payment	$1.90	0.42%
Estimated Market Participation Benefit	$3.66	0.82%

The second sensitivity, the Natural Gas Price Sensitivity, analyzes the effects of changing the natural gas price assumptions used in the model. The natural gas prices used in this sensitivity are higher than the natural gas prices used in the Base Cases. This sensitivity also tests an alternative regional differential between the natural gas prices in Colorado and the Southwest region. The natural gas price differential between Colorado and the Southwest is relevant because it drives the potential for economic energy transactions between the JDA and the broader EIM footprint. The results of the Natural Gas Price Sensitivity are shown in Table 3.

Table 3: Summary of Estimated Market Participation Benefits
Natural Gas Price Sensitivity

	JDA in EIM		MWTG in EIM		MWTG in EIS	
	$million/year	% of APC	$million/year	% of APC	$million/year	% of APC
Adjusted Production Cost Reduction	$1.30	0.26%	$10.66	2.13%	$3.45	0.69%
Bid Cost Recovery Payment	$0.53	0.11%	$1.51	0.30%	N/A	N/A
Estimated Market Participation Benefit	$1.83	0.37%	$12.17	2.43%	$3.45	0.69%

The results of this sensitivity illustrate two effects of the change in natural gas price assumptions. First, the JDA in EIM Case results do not change significantly in this sensitivity. The Base JDA in EIM Case showed a market participation benefit of $1.98 million/year or 0.44% of APC, while the Natural Gas Price sensitivity shows a benefit of $1.83 million/year or 0.37% of APC. The estimated production cost benefit for the JDA entities if the entire MWTG footprint were to join the EIM together (MWTG in EIM Case) is lower than in the Base Cases ($12.17million/year vs $17.34 million/year). This illustrates the effect of the smaller natural gas price differential between Colorado and the Southwest, as there are fewer economic real-time purchases and sales between the JDA and the broader EIM footprint. Second, the higher natural gas prices in this sensitivity increase the estimated production cost benefits from having a more diverse fuel mix in the real-time energy imbalance market footprint, as the production cost savings from fuel switching are larger with the higher natural gas prices. For example, the former MWTG has a more diverse generation mix than just the four JDA entities alone, which is why this sensitivity shows higher production cost benefits for the JDA entities if all the former MWTG members participate in a single real-time energy imbalance market together. This is illustrated in the MWTG in EIS Case, which shows an estimated reduction in production costs for the JDA entities of $3.45 million/year (0.69% of production costs) in the Natural Gas Price Sensitivity compared to a $1.62 million/year (0.36% of production cost) reduction under the Base set of assumptions.

I. Scope of the Study

The Brattle Group was retained by the Black Hills Corporation, Colorado Springs Utilities, Platte River Power Authority, and the Public Service Company of Colorado (collectively referred to as the "JDA companies" or "JDA entities")[2] to analyze how participation in a real-time energy imbalance market could provide benefits in the form of lowering the overall cost of serving load. Specifically, this study analyzes the potential generation-related variable costs (production costs) of serving electricity customers in the JDA under three possible energy imbalance markets:

- **The Status Quo**: represents staying in the Joint Dispatch Agreement (JDA) as currently constituted (including Colorado Spring Utilities' participation).
- **The Western Energy Imbalance Market (EIM)**: joining the EIM footprint that is currently operated across parts of the WECC and is administered by the California ISO (CAISO).
- **The proposed Western Energy Imbalance Service (EIS)**: joining the energy imbalance market proposed by the Southwest Power Pool (SPP) in the WECC.

These three energy imbalance market options are simulated across different footprints to represent alternative market participation scenarios.

To conduct the analysis, we used a state-of-the-art production cost simulation tool, Power System Optimizer (PSO), to simulate the entire Western Electricity Coordinating Council, (WECC), which includes the JDA study region. As do most production cost simulation tools, PSO simulates the economic unit commitment and dispatch of generating plants that would be conducted in a centralized regional wholesale market. To simulate the bilateral markets in the WECC, where a centralized market operator does not optimize commitment and dispatch decisions we impose specific restrictions and limitations on the simulations to derive a unit commitment and dispatch solution for the generating units within the JDA and other areas in WECC that reflects the actual function of utility-specific decision making, including bilateral market transactions. This approach is widely used in these types of analyses.

The key metric discussed in this report, Adjusted Production Cost (APC), is a high-level approximation of the production costs, including purchase costs net of sales revenues, incurred by the JDA companies to serve their customers. The APC metric uses the simulation outputs to estimate production costs for all generating units in the JDA as well as the off-system purchase expenses and sales revenues for all participants in the group. These three components are aggregated across the JDA footprint to determine a group-wide estimate of production costs

[2] Colorado Spring Utilities is not currently a JDA participant, but is set to join the JDA in April 2020. Therefore, Colorado Spring Utilities is expected to be a full member of the JDA prior to the future year we studied in this report (2024).

incurred to serve customers. We compare the resulting APC metric across various energy imbalance market structures to estimate the likely range of production cost benefits that the JDA companies would derive as a result of joining one of the two broader regional energy imbalance markets relative to remaining in the JDA.

The production cost model simulates the wholesale electricity market on an hourly basis, with every generation resource, transmission facility, and load represented in the entire WECC, including the JDA footprint. Thus, the model provides as output simulated generation dispatch and hourly locational market prices at every generator location and for every load zone, consistent with optimized unit commitment and dispatch based on the marginal production cost of every generator and taking into account transmission constraints in the region. From the resulting generator dispatch and locational price data, we estimated the total production costs of generation owned or contracted by the JDA companies, payments made for purchasing power from others, revenues that entities receive for selling power in excess of what is needed to serve their own load, and any make-whole payment received by the JDA companies from the energy imbalance markets to compensate them for production costs that are not covered by market revenues.

Production cost impacts are only one element of evaluating participation in a RTO-operated regional wholesale market. The study does not estimate any production-cost-related impacts beyond those captured in the simulations and the APC metric, such as discrepancies between congestion charges and congestion hedging mechanisms, marginal loss refunds, and the likely significant additional benefits related to the lower-cost, intra-hour balancing of uncertain loads and renewable generation achieved in a regional market during real-time operations. This report does not address other considerations related to the formation of, or the participation in, a regional market such as the implications of alternative market governance structures, implementation and administrative costs, reliability benefits of regional market operations.

II. Modeling Approach and Assumptions

The starting point for the modeling conducted for this study was the western power market simulation model developed during the MWTG Regional Market Benefit Study we conducted in 2016 – 2017. In that study, we used the Power System Optimizer (PSO)[3] production cost model to simulate the WECC footprint, with particular focus on representing the MWTG area in sufficient detail. For that purpose, the MWTG study participants provided company-specific (confidential) input assumptions that allowed for accurate simulations of the entire MWTG area and surrounding region. The 2017 study estimated the benefits of creating a regional wholesale power market in the MWTG footprint.[4]

[3] See Technical Appendix for a detailed description of the PSO model and its functionality.

[4] The MWTG study can be accessed here: https://www.wapa.gov/About/keytopics/Documents/mountain-west-brattle-report.pdf

Over the last three years, we have been engaged by multiple former MWTG members to utilize the MWTG model developed during the original study for proprietary follow-up studies that required a detailed production cost simulation of the MWTG footprint within the WECC region.[5] During the course of these follow-up engagements, the input assumptions in the model have been updated numerous times with new confidential data provided by several different former MWTG entities.

In the current study, conducted for the four JDA entities, we are using the most recently updated version of the MWTG model and have additionally updated it with new features, functionalities, and data inputs provided by the JDA entities. Overall, we follow a similar modeling approach in this study as that used in the original MWTG study, but made the necessary adjustments to estimate the benefits of participation in a real-time energy imbalance market for the JDA companies.

One of the most important differences in the modeling approaches between the 2017 MWTG study and this current analysis is that we have developed and now represent the real-time energy imbalance markets in the model used for this study. In the 2017 MWTG study, we estimated the benefits of creating a full "day-two" regional wholesale power market that incorporated the ten members of the MWTG. The current study analyzes the potential benefit of participating in a real-time energy imbalance market for the JDA companies. Such participation could involve a broader footprint than the original MWTG areas. In addition, subsequent to the 2017 MWTG study, the JDA was developed in Colorado and the function of the JDA includes serving as a real-time dispatch entity. Therefore, the modeling approach in this study requires us to update the previous model to include both a representation of current JDA operations and the operations of the two real-time energy imbalance markets that the JDA entities are considering joining: (a) the CAISO-operated Western Energy Imbalance Market (WEIM or EIM) and (b) the SPP-proposed Western Energy Imbalance Services (WEIS or EIS) market.

Furthermore, we updated the modeling assumptions to reflect recent projections of the 2024 generation mix and fuel prices for the WECC regions, and simulated multiple cases to represent different market participation scenarios for the JDA companies and the other former MWTG members. This study includes simulations of different sensitivities to account for the possibility of adding additional transfer capabilities between the JDA and the EIM footprints and to account for different natural gas price assumptions.

5 The multi-lateral non-disclosure agreement (NDA) entered into between The Brattle Group and the ten MWTG entities allowed each individual MWTG entity to engage Brattle and utilize the model for follow-up studies. The confidential data used to augment the MWTG model were originally provided to The Brattle Group on a confidential basis and the data are not shared across the MWTG participants. All data provided to Brattle and the individual participant level results of the simulations are confidential and protected by multi-lateral NDA. Brattle has maintained this level of confidentiality in all subsequent engagements with MWTG members, including during this study. All participant level data remains confidential and are not shared across the study participants.

A. Review of the MWTG Study Modeling Approach and Assumptions

The objective of the 2017 MWTG study[6] was to simulate the benefits of a full "day-two" regional power market in the MWTG footprint. To accomplish that objective in 2016 – 2017, we used the PSO model to simulate unit commitment and dispatch decisions made in the day-ahead timeframe. We did not simulate real-time unit commitment or dispatch decisions. That day-ahead analytical approach was used in the MWTG study because the MWTG entities were interested in analyzing a full regional market, in which the large majority of production cost savings would be from a full day-two regional market, accrued from efficiency gains in the day-ahead unit commitment and dispatch decisions. The current imbalance market participation analysis, which estimates the benefits of participating in a real-time energy imbalance market, requires that we simulate both day-ahead and real-time unit commitment and dispatch decisions.

The PSO model built for the MWTG study was based on the 2024 WECC Transmission Expansion Planning Policy Committee (TEPPC) Common Case database. This publicly available (for WECC members) data was augmented with confidential data inputs provided by the MWTG study participants. The augmented Common Case database was further updated to include the following changes:

- A representation of the bilateral market in the WECC was built into the model by implementing several changes to the model:
    - Hurdle rates were applied between utilities to simulate bilateral trading frictions. The hurdle rates included an $8/MWh hurdle on the unit commitment optimization to represent utilities' preference for scheduling their own resources, a $4/MWh hurdle on the dispatch optimization to represent trading margins, the OATT wheeling fees (which vary by utility), and a $1/MWh fee for administrative charges for transmission services specified in the OATTs. These hurdles were removed in the market participation cases to represent the optimized commitment and dispatch of resources and shared transmission usage in a regional market.
    - The flow limits on defined physical transmission constraints (defined by WECC path ratings) in the MWTG footprint were de-rated to reflect the inefficiencies of bilateral transmission scheduling along contract paths.
- Long-term transmission contracts were reflected in the bilateral market structure to allow utilities to conduct bilateral trading without paying wheeling fees on a transaction-specific basis.

[6] A complete description of the model approach, study scope, and modeling assumptions in the MWTG study is provided in the study report.

- The operating characteristics of certain MWTG generating resources were updated based on the confidential operational data provided by the MWTG study participants.
- Unit-specific fuel prices (including delivery costs to individual plants) were incorporated into the model based on confidential company data.
- The reserve requirements for each utility were updated based on the information provided by the MWTG study participants.
- Projected generation retirements and additions for the MWTG participants, which were not reflected in the TEPPC Common Case, were added to the model database.

For the 2016 – 2017 MTWG analysis, the augmented model was used to simulate two test years, 2016 and 2024 and multiple market participation cases. The 2016 simulations covered four market participation cases:

- A Status Quo Case in which the MWTG entities were not participating in a market;
- A Joint Transmission Tariff Case where the MWTG shared a common (de-pancaked) transmission tariff but not an organized wholesale market;
- A Regional Market Case where all MWTG entities participated in a regional market; and
- A Regional Market Case that maintained some must-run generation.

The 2024 simulations covered two Current Trends Cases to reflect the most likely projected operating conditions in 2024, one with the Status Quo (no market in the MWTG) and a second with a full Regional Market.

We also tested the benefits of a regional market under two sensitivities, a High Natural Gas Price Sensitivity and a Market Stress Sensitivity that simulated higher loads, higher fuel prices, and lower hydro production.

B. JDA Modeling Approach and Assumptions

The starting point for the analysis conducted for this study is the 2024 Current Trends Status Quo Case from the 2017 MWTG study. The assumptions used to simulate this case have been used by multiple former MWTG entities in follow-up engagements, and all of the data updates incorporated during those follow-up engagements are reflected in the model used for this current analysis. We further augmented the model by incorporating updates provided by the JDA entities as part of this study. The updated 2024 model assumptions provided by the JDA entities include:

- Updated load forecasts for the JDA entities.
- Planned generation retirements and additions in the JDA footprint, which includes all the generation retirements and additions related to PSCo's Colorado Clean Energy Plan (such as retirement of Comanche units 1 and 2, addition of wind and solar, battery

storage, and gas generation).[7] The updated generation resources by fuel type in the JDA footprint, as shown in Table 4, includes slightly less than 2,500 MW of coal-fired generation resources, about 2,500 MW of gas-fired combined cycles, almost 3,500 MW of gas-fired peaking capacity, almost 4,500MW of wind resources, and about 1,500 MW of solar capacity.

- Updated information of long-term transmission contracts to reflect their ability to trade bilaterally with neighboring utilities without paying transaction-specific wheeling fees.
- Unit-specific fuel costs (including delivery charges) and variable operating costs for the generating resources in the JDA footprint.

Table 4: 2024 Generation Mix by Fuel Type in the JDA Footprint

	Generation Capacity (MW)
Coal	2,395
NG CC	2,516
NG Peaker	3,625
Hydro	416
Wind	4,430
Solar	1,459
Other	1,864

The model was further updated with data from public sources, specifically generation retirements and additions in the rest of the former MWTG footprint and for the EIM participants that are adjacent to the MWTG footprint, which includes PacifiCorp east (PACE), Arizona Public Service Company (AZPS), the Salt River Project (SRP), Tucson Electric Power Company (TEPC), and Public Service Company of New Mexico (PNM). The generation retirements in adjacent regions include the planned retirements of units at the San Juan, Craig, Colstrip, Cholla, and Navajo coal plants.

While we did not conduct a comprehensive review of all of the potential generation retirements and additions across the WECC region that are not directly interconnected with the former MWTG footprint, we ensured that all western states with a renewable energy requirement are simulated with adequate renewable energy generation in 2024 to be on track to meet their standard.

[7] Some of the planned retirements and additions under the Colorado Clean Energy Plan are not expected to occur until 2025 or 2026. We included these changes even though our future test year is 2024. This was done so that the simulation would reflect expected system conditions after the plan is fully implemented, which provides results that are more useful for the JDA companies as they decide on market participation. To be consistent we applied the same logic to other generation retirements or additions that have been publicly announced and are expected to be implemented prior to 2026 (e.g., Craig unit 1 is expected to come offline in 2025, so it has been retired in this study).

Other updates made for the purpose of this study include:

- Implemented new natural gas price projections based on the California Energy Commission's (CEC) 2019 Preliminary Integrated Energy Policy Report (IEPR) Mid-Demand Forecast of natural gas prices for the WECC.[8] The CEC 2019 Revised IEPR Forecast was released after we had finalized the simulations for the Base Cases for this study. We analyzed the possibility of using the 2019 CEC Revised Forecast as a sensitivity in the study, but in consultation with the JDA entities we decided the CEC 2017 Revised Forecast was a better sensitivity to test (see discussion of the Natural Gas Price Sensitivity). Table 5 below summarizes the natural gas price assumptions used in the model for all the areas in the WECC.

Table 5: 2024 Average Annual Natural Gas Price Modeling Assumptions

Region	Modeled NG Price
Colorado	$2.69
Arizona North	$2.52
Arizona South	$2.11
California Blythe	$3.61
California PGaE	$4.28
California SDGE	$4.28
California SJ Valley	$3.34
SoCal Border	$4.27
Idaho North	$2.52
Idaho South	$3.68
Montana	$2.65
New Mexico North	$2.48
New Mexico South	$2.02
Nevada North	$3.52
Nevada South	$3.39
Oregon	$3.89
Malin	$2.89
Texas West	$2.04
Utah	$2.90
Washington	$3.82
Wyoming	$2.63

- Updated the assumptions to account for inflation since the 2017 MWTG study. Therefore, all the results presented in this study are in 2019 dollars.
- Built in a modeling structure to account for the regions of WECC that have greenhouse gas (GHG) emission reduction policies. This includes California, Washington, British

[8] Accessed here: https://ww2.energy.ca.gov/assessments/ng_burner_tip.html

Columbia, and Alberta. We also include Oregon as an area with a GHG emission reduction policy, as they are in the process of developing a policy that likely will be in place by 2024. We have not implemented a GHG price in Colorado. Instead, the GHG policy in Colorado is reflected through the planned retirement of coal-fired resources and the addition of renewable energy prior to 2024.

- While these regions within WECC are far from the JDA footprint and therefore likely have little impact on the results of this study, we implemented GHG pricing in these regions to be consistent with expected policy and system operation in 2024.
- To create the GHG region in the model, we used the same approach as in the recent Brattle study of Extended Day-Ahead Market (EDAM) benefits.[9]
- To approximate the boundary of the GHG region, we used the balancing areas already defined in the model. For example, all of Bonneville Power's balancing area was included in the GHG region even though a portion of their balancing authority (BA) is outside of the three U.S. states that are expected to have GHG limit in 2024. This approach will imperfectly cover the resources that are impacted by GHG emission limits, but given that modeling the GHG region was not the focus of the study, this is an appropriate approximation.
- We imposed a GHG cost on all GHG-emitting generation resources in the affected balancing areas (see above) and imposed a GHG hurdle rate on imports into the GHG region that reflects the price of GHG emissions and the emissions rate of a natural gas-fired combined cycle unit.

The final modeling change implemented for this study was to simulate real-time unit commitment and dispatch decisions, which allows us to represent the real-time energy imbalance markets in the model. The model simulates unit commitment and dispatch decisions in three sequential optimization cycles, which are shown in Figure 1.[10] The first cycle optimizes (day-ahead) unit commitment decisions. This first cycle includes hurdle rates between utilities, which represent the utilities' preferences to commit their own resources in the day-ahead. The second cycle optimizes (day-ahead or intra-day bilateral) economic dispatch decisions subject to the results of the unit commitment cycle. This economic dispatch cycle also contains hurdle rates that limit the economic energy transactions between utilities to represent trading costs and margins in the bilateral market. These first two cycles, because they include hurdle rates that limit the model's ability to optimize across multiple utilities, are designed to simulate utility-specific unit commitment and dispatch decisions. In the 2017 MWTG study, the model was used to simulate only these first two cycles.

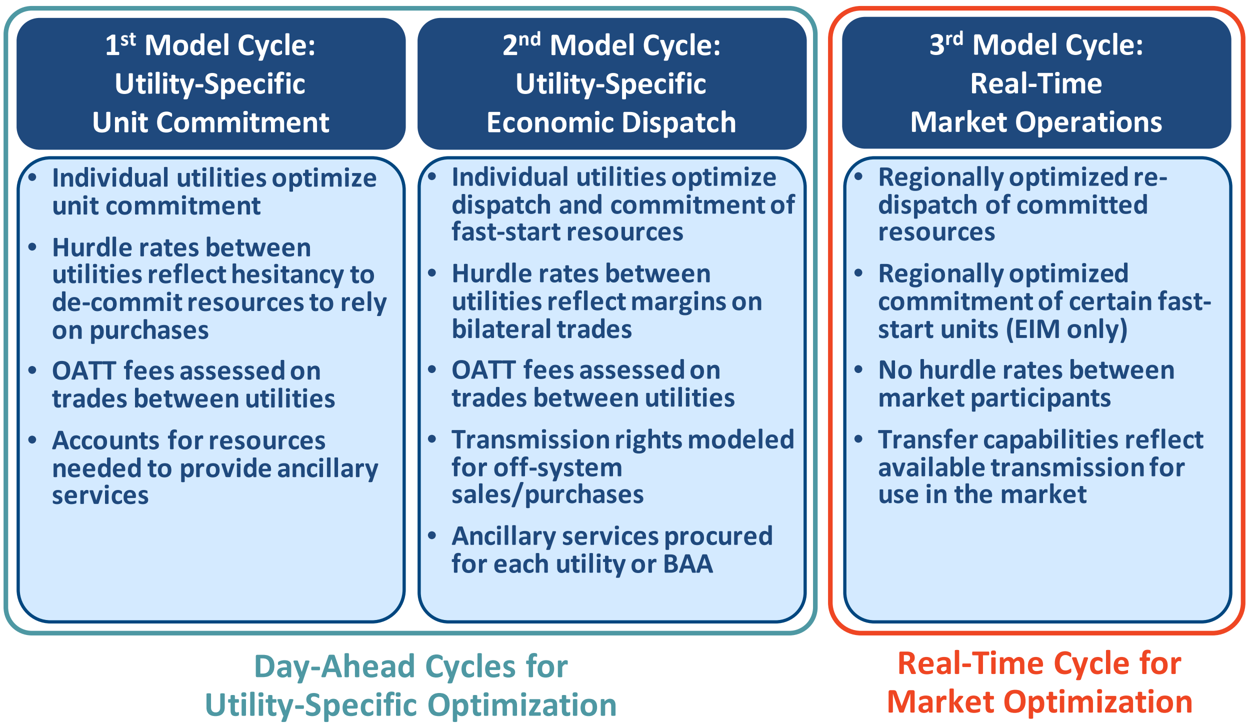
To model real-time commitment and dispatch decisions, we added a third cycle to the model. The real-time cycle re-optimizes unit commitment decisions in the EIM participation cases (if there

[9] See modeling assumptions here: http://www.caiso.com/InitiativeDocuments/Presentation-ExtendedDay-AheadMarketFeasibilityAssessmentUpdate-EIMEntities-Oct3-2019.pdf

[10] The model also conducts a fourth cycle to calculate transmission losses across the WECC.

are any resources that can be committed in real-time) and economic dispatch decisions, subject to the results of the first two cycles. The real-time cycle is subject to different modeling assumptions than the earlier two cycles. For example, the hurdle rates between utilities are reduced or eliminated to represent participation in an energy imbalance market. With the real-time cycle represented, the simulations are able to re-optimize commitment and dispatch decisions from the utility-specific cycles in the final real-time cycle based on what the reduction in hurdle rates allows.

Figure 1: PSO Model Optimization Cycles



Altering the modeling assumptions between day-ahead/bilateral and the real-time cycle (as listed in Figure 1) allows us to represent the different energy imbalance market options evaluated in this study. Specifically, the assumptions for the first two (utility-specific) cycles are the same regardless of which imbalance market that the JDA entities would join. The different real-time energy imbalance markets are represented in the model by reducing hurdle rates between utilities, modifying transfer capabilities across utilities, and allowing unit-commitment decisions in the real-time (3rd) cycle. Note, however, that our simulations have only hourly granularity (i.e., do not simulate the intra-hour dispatch of energy imbalance markets) and do not modify system conditions across these simulation cycles to reflect uncertainty in loads, generation availability, and renewable generation output. By not simulating intra-hour operation and not introducing uncertainties such as load forecast error or variable resource output errors between the simulation cycles, we the simulation results will understate the estimated benefit of real-time optimization through the contemplated imbalance markets.

We conducted this analysis with the simulation of three different energy imbalance markets: the JDA by itself, the JDA entities joining the EIM, and the JDA entities joining the Western EIS. Below, we describe the assumptions for representing each of the three options.

The modeling assumptions used **to represent the JDA** are as follows:

- A $2/MWh hurdle rate was imposed in the real-time cycle on transactions between JDA members. This hurdle rate implies that the JDA dispatch will only make economic energy transactions between JDA entities if the cost differential is $2/MWh or greater. The $2/MWh hurdle rate (based on JDA-participants' input) captures the inefficiencies of the JDA market structure. The JDA clears their transactions using zonal prices instead of nodal prices. This means that economic resources may not be dispatched if the zonal price does not fully reflect the economics of that resource. The $2/MWh hurdle rate is used to represent the inefficiency of zonal pricing compared to the nodal pricing used in the EIM and EIS.
- Transfers between JDA entities in the real-time cycle of the model are limited by the amount of transmission transfer capability that is available after accounting for the transmission that has been scheduled in the first two cycles of the model. Specifically, the transfers between the JDA entities are limited to total physical transfer capacity less the transfer capability already utilized in the utility-specific unit commitment and dispatch cycles.
- The JDA has no ability to commit or de-commit resources in the real-time cycle. Therefore, the real-time cycle is limited to re-dispatching resources that are already committed in the utility-specific dispatch cycles, subject to any operational constraints of the resources.

The modeling assumptions used in the real-time cycles **to represent the EIM** are as follows:

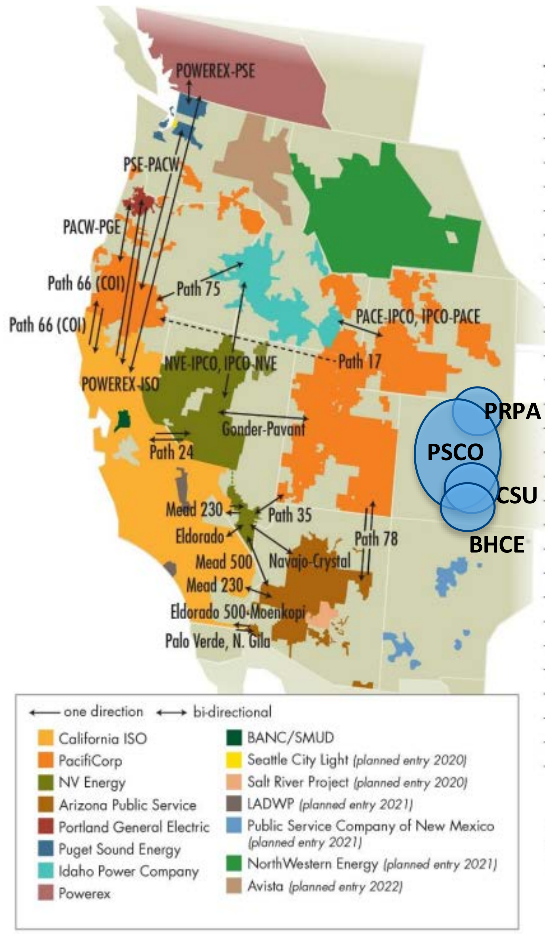
- No hurdle rate is imposed between EIM participants. This reflects the efficiency of EIM dispatch.
- The EIM has the ability to commit resources with a cycle time of less than 4.5 hours. This means that the resources that have been identified to have cycle times shorter than 4.5 hours can be committed or de-committed during the real-time cycle of the model in the scenarios when the JDA participates in the EIM.
- Participants in the EIM have two options for making transmission available for use by the EIM. First, they can elect to provide all their available physical transmission for use in the market, meaning all the physical transmission that remains unutilized after utility-specific unit commitment, economic dispatch, and bilateral transactions. Second, they can elect to only provide the transmission capabilities to which they have contracted rights (and that have not already been utilized in the prior cycles of the model). To be conservative in estimating market participation benefits, we assumed all the MWTG members, except the JDA entities and the two Wyoming utilities owned by the Black Hills Corporation (Cheyenne Light Fuel and Power and Black Hills

Power), would choose the second option and only make available for the EIM their contracted transmission capability. We assume that the JDA entities and Black Hills' Wyoming utilities choose to provide all available physical transfer capability to be used by the EIM when simulating the relevant cases.

- The amount of transfer capabilities between the JDA companies was provided by the companies. The transmission rights between the other MWTG utilities was provided by MWTG study participants during the MWTG study.
- To simulate the existing EIM market, all the existing and currently planned (as known publicly when we began the study) members of the EIM are included. Therefore, all modeling assumptions listed above were applied to all the existing and planned EIM members (see the map in Figure 2). This means that regardless of the market participation scenarios modeled in the JDA or the MWTG footprint, these assumptions are applied to the existing and currently planned EIM members. This assumption reflects the fact that the EIM is expected to continue operating with the current and planned membership regardless of the market participation decisions reached by the JDA companies.

Figure 2 lists the transfer capabilities between the existing EIM members. The figure is taken from the most recent CAISO EIM Benefit Report. We modeled the transfer capabilities between the existing EIM members as shown in the Figure 2. There is no publicly available data on the transfer capabilities between existing EIM members for the additional utilities that are planning to join the EIM. Therefore, we approximated those transfer capabilities based on WECC Path Ratings and other publicly available sources of information on the ownership of transmission rights in the WECC.

Figure 2: Transfer Capabilities between Current and Planned EIM Participants



Path	Estimated Max Capacity (MW)
Path 24 *(west to east)*	100
Path 24 *(east to west)*	35-90
Eldorado	797
Path 35 *(west to east)*	580
Path 35 *(east to west)*	538
Gonder-Pavant	130
PACW to PGE	320
Path 66 *(ISO to PGE)*	627
Path 66 *(PGE to ISO)*	296
Path 66 *(ISO to PACW)*	331
Path 66 *(PACW to ISO)*	432
Path 17	0-400[1] [2]
PSE to PACW	300
Eldorado 500-Moenkopi	732
Palo Verde, N. Gila	3,151
Path 78 *(PACE to APS)*	625
Path 78 *(APS to PACE)*	660
Navajo-Crystal	522
Mead 500	349
Mead 230 *(APS <-> ISO)*	236
Mead 230 *(ISO to NVE)*	3,443
Mead 230 *(NVE to ISO)*	3,476
IPCO to PACW (Path 75)	1,500
PACW to IPCO (Path 75)	400-510
PACE to IPCO	2,557
IPCO to PACE	1,550
NVE to IPCO	262
IPCO to NVE	390-478
Powerex <-> PSE	150
Powerex <-> ISO	150

[1] Is an optional path available for PACE-PACW EIM transfers and the capacity is a subset of PACE-IPCO/IPCO-PACE and Path 75 capacity

[2] When in use, the available capacity on PACE-IPCO/IPCO-PACE and Path 75 will be subsequently reduced by the used amount on Path 17 and not double counted.

Current as of April 2019

The modeling assumptions used in the real-time cycles **to represent the EIS** are as follows:

- There is no hurdle rate imposed between participants in the real-time cycle when representing the EIS. This reflects the expected efficiency of dispatch decisions in the EIS.
- The EIS does not have the capability to commit resources. Therefore, the real-time cycle for the EIS is limited to re-dispatching resources previously committed in one of the first two cycles of the model.
- The proposed EIS market requires that all the physical transmission capability (less what is scheduled bilaterally) is made available to the market. This is similar to current practice in the JDA. Therefore, transfer capabilities between the EIS members are modeled in the same way as in the JDA.
- The existing SPP market in the Eastern Interconnection is not represented in the model. Therefore, the model used in this study does not simulate flows across the DC interties between the MWTG footprint and the existing SPP. The interties are modeled as static hourly injections or withdrawals of power based on the data provided during

the MWTG study. The assumed physical power flows over the interties are the same across all scenarios.

Table 6 summarizes the modeling assumptions used to represent the capabilities of the three different energy imbalance options available to the JDA companies. The table summarizes the assumptions on hurdle rates between market members, unit commitment capabilities of each market, and how the transfer capabilities between members are determined for each of the options. The simulated EIM and EIS membership scenarios are discussed in the next section below.

Table 6: Differences in Modeling Assumptions for the Three Real-Time Imbalance Options

Market Design Assumption	JDA	CAISO EIM	SPP EIS
Hurdle Rate between Members	$2/MWh	None	None
Unit Commitment Capabilities	No	Yes, for resources with 4.5 hour cycle time or less	No
Transfer Capability between Members	Transfer Capability = Physical Limit less Capacity used in UC and ED Cycles	Transfer Capability = Physical Limit less Capacity used in UC and ED Cycles Or, for some entities: Transfer Capability = Transmission Rights less Capacity used in UC and ED Cycles	Transfer Capability = Physical Limit less Capacity used in UC and ED Cycles

C. Scenarios and Sensitivities Simulated

This study consists of four Base Cases that simulate the current market operations in the JDA and three different market participation scenarios, assuming the projected market conditions and resource mix for 2024. The study also consists of two sensitivities that build on the four Base Cases. The Added Transmission Sensitivity simulates the impact of additional transfer rights between the JDA and the EIM. The Natural Gas Price Sensitivity analyzes the same four Base Cases, but with new natural gas price assumptions for the WECC. All of the cases simulated, both the Base Cases and the two Sensitivities, include, as described in the previous section, to reflect expected system operating conditions in 2024.

The four Base Cases simulated in this study are:

- **Status Quo Case:** Represents current market operations in the WECC. This includes a representation of the EIM for all the existing members and the utilities that had announced publicly at the start of our study that they are planning to join before 2024.

The four JDA entities are represented as participating in the JDA. The other MWTG members are not represented in any regional market. This case assumes that only the current imbalance markets operating in the WECC will be operating in 2024, with their current and already-planned memberships as had been announced at the initiation of this study in the summer of 2019. The Status Quo Case serves as the baseline against which the benefits of participation in the EIM or EIS are calculated for the JDA entities.

- **JDA in EIM Case:** Simulates the four JDA entities as part of the broader Western EIM footprint. The other MWTG entities are not included in any regional market structure in this case. The representation of the rest of the WECC is unchanged from the Status Quo Case. Therefore, the JDA in EIM Case is compared to the Status Quo Case to estimate the benefit for the JDA companies if only they join the EIM.
- **MWTG in EIM Case:** Simulates the entire MWTG footprint, including the JDA entities, participate in the EIM in 2024. The representation of the rest of the WECC is the same as in the Status Quo Case. Therefore, comparing the MWTG in EIM Case with the Status Quo Case indicates the benefits if all ten MWTG companies joining the EIM.
- **MWTG in EIS Case:** Models the full MWTG footprint, including the JDA companies, in the Western EIS. The representation of the rest of the WECC is the same as in the Status Quo Case. Comparing the MWTG in EIS Case with the Status Quo Case indicates the benefits if all ten MWTG companies joining the EIS.

Since we began this study, certain members of the MWTG have announced that they plan to join the proposed SPP-administered Western EIS. This decision is not represented in the Status Quo or JDA in EIM Case simulations. We do not expect that modeling MWTG members in the EIS would materially impact the results of either the Status Quo or JDA in EIM Cases. In both the Status Quo and JDA in EIM Cases, the JDA and the rest of the MWTG footprint are separated by very high hurdle rates to prevent any trading of power in the real-time cycle of the simulations, which would not change by modeling any portion of the MWTG footprint in the EIS in these two cases. Table 7 summarizes the market participation assumptions in each of the four Base Cases, the Status Quo Case and the three market participation scenarios.

Table 7: Market Participation Assumptions in each Case

Case Name	Updated 2024 Assumptions	JDA Group Market Participation	Rest of MWTG Market Participation	Rest of WECC Market Participation
Status Quo	✓	JDA	None	EIM (where applicable)
JDA in EIM	✓	EIM	None	EIM (where applicable)
MWTG in EIM	✓	EIM	EIM	EIM (where applicable)
MWTG in EIS	✓	EIS	EIS	EIM (where applicable)

1. Added Transmission Sensitivity

The Added Transmission Sensitivity Case re-simulates the JDA in EIM Case, except for an increase in the transfer capability between the JDA and the broader EIM. In this sensitivity, 200 MW of additional transmission rights, in the export direction, are added to the model between PSCo and its neighboring EIM entities. Of the 200 MW, 100 MW of transfer rights is between the JDA footprint to PACE and the other 100 MW is between the JDA footprint and three EIM members in Arizona and New Mexico that interconnect at the Four Corners hub. To do so, we added 34 MW of transfer rights between PSCo and AZPS, 33 MW of transfer rights with SRP, and 33 MW of transfer rights with PNM.

Under this sensitivity, based on assumptions provided by the JDA entities, we did not add new physical transmission lines to the model. We simulate a scenario where PSCo purchases additional long-term transmission rights on existing transmission lines to PACE and down into the area around Four Corners (where they can connect with AZPS, SRP, and PNM).

The new transfer rights were added to the model connecting PSCo with the neighboring EIM members, but that does not restrict the other JDA entities from using the added transfer rights between the JDA footprint and PACE, AZPS, SRP, and PNM, when transacting with the existing EIM entities. PSCo is well interconnected with the other JDA companies and there are no hurdle rates on trades between JDA companies in the EIM. Therefore, the new transfer rights can be accessed by all the JDA companies to import or export economic energy to the broader EIM footprint.

The Status Quo Case is not re-simulated as part of this sensitivity, because the new transmission rights are not likely to be purchased if the JDA does not join the EIM. The market participation benefit in this sensitivity is estimated by comparing the Status Quo Case from the Base Cases to the JDA in EIM Case with the additional transfer rights. The cost of acquiring the added transfer rights is not estimated in this study. Therefore, one should account for the cost of adding the transfer capability when analyzing the market participation benefit estimated in this sensitivity.

2. Natural Gas Price Sensitivity

The Natural Gas Price Sensitivity Cases simulate all four Base Cases, but with adjusted natural gas price assumptions for all regions in the WECC. All the other modeling assumptions remain the same as in the Base Cases.

The motivation for the Natural Gas Price Sensitivity is to address some of the characteristics of the CEC's 2019 Preliminary IEPR natural gas price forecast, which was used in the Base Cases ("the Base Case natural gas price assumptions"). The Base Case natural gas price assumptions reflect the recent supply and demand dynamics in the WECC, which have resulted in relatively low natural gas prices compared to recent history.

This is particularly true for natural gas prices in the southwest region (Arizona and New Mexico), which are significantly lower than in the surrounding areas of WECC (e.g., Colorado and Utah) in the Base Case natural gas price assumptions. The historically low gas prices in the southwest are due to excess natural gas production from the Permian Basin in west Texas. The differential between natural gas prices in the southwest and in Colorado may have a significant effect on the market participation benefits when the JDA joins the EIM, as it will drive how much economic energy transactions occur between the JDA companies and the southwest EIM members. Therefore, the Natural Gas Price Sensitivity was developed to estimate the market participation benefits when the price differential for natural gas between Colorado and the southwest is smaller than in the Base Cases.

The CEC's Preliminary 2019 IEPR forecast is accurately depicting the current natural gas supply and dynamics in the WECC, but there is no guarantee that the excess supply from Permian will continue for the next five years as assumed in the CEC preliminary forecast. In fact, there are several planned pipeline projects meant to move excess supply away from the Permian to meet demand in other regions. The Natural Gas Price Sensitivity is designed to reflect where natural gas prices might settle in the WECC if the excess production from the Permian experienced in the last couple years does not persist into the future.

The natural gas price assumptions used in this sensitivity come from the CEC's (previous) 2017 Revised IEPR natural gas price forecast (the mid-forecast case). The 2017 CEC forecast did not yet account for the effect of the excess supply from the Permian. Therefore, the natural gas price assumptions in this sensitivity are slightly higher across the WECC. Moreover, the differential between natural gas prices in the southwest (Arizona and New Mexico) and Colorado is much lower than in the Base Cases.

Table 8 shows the natural gas price assumptions used in the Base Cases compared to the assumptions used in the Natural Gas Price Sensitivity. As Table 8 documents, the differential in natural gas prices between Colorado and the southwest is much smaller in the Natural Gas Price Sensitivity. The average annual natural gas price used in this sensitivity for Colorado is $3.61/MMBtu, compared to $3.69/MMBtu in Arizona South and $3.53/MMBtu in New Mexico South, implying almost no differential between the regions. In the Base Cases, the price differentials between Colorado and Arizona South/New Mexico South are $0.58/MMBtu and $0.67/MMBtu.

**Table 8: Average Annual Natural Gas Price Assumptions (2019$/MMBtu)
Base Cases vs. Natural Gas Price Sensitivity**

Region	Base Cases	NG Price Sensitivity
Colorado	$2.69	$3.61
Arizona North	$2.52	$3.51
Arizona South	$2.11	$3.69
California Blythe	$3.61	$3.82
California PGaE	$4.28	$4.84
California SDGE	$4.28	$4.55
California SJ Valley	$3.34	$3.62
SoCal Border	$4.27	$4.14
Idaho North	$2.52	$4.07
Idaho South	$3.68	$4.29
Montana	$2.65	$3.48
New Mexico North	$2.48	$3.41
New Mexico South	$2.02	$3.53
Nevada North	$3.52	$4.19
Nevada South	$3.39	$4.03
Oregon	$3.89	$4.87
Malin	$2.89	$3.62
Texas West	$2.04	$3.42
Utah	$2.90	$3.58
Washington	$3.82	$4.76
Wyoming	$2.63	$3.52

III. Simulation Results

This section of the report summarizes results of the simulations described above. The first part of this section focuses on two computed metrics, which we estimate using the results of the simulations as inputs. These two metrics estimate the market participation benefit for the JDA companies for the three EIM and EIS scenarios. The two benefits we focus on are (1) the Adjusted Production Cost (APC) metric, which approximates of the cost to serve load for the JDA companies, and (2) the Bid Cost Recovery (BCR) payments received by the JDA companies in the EIM participation scenarios, which are make-whole payments the EIM provides to resources that do not cover their EIM-based unit commitment and dispatch costs through EIM market settlements.

The second part of this section presents simulation results that show how the individual JDA entities' operations and market engagement change across the simulated cases. We present results to show the amount of market transactions conducted by the JDA entities, and market prices in the JDA footprint as a result of regional market participation.

We also present a list of market participation benefits that are not specifically analyzed in this study. Like all production cost simulations, this study does not capture all the operational details and nuances experienced during actual operation of the power system. Therefore, some of the benefits of participation in a regional energy imbalance market are not accounted for in this study.

A. Quantified Market Participation Benefits

The study focuses on two computed metrics to estimate the benefit of joining an energy imbalance market for the JDA companies. First, the simulated results are used to quantify the Adjusted Production Cost (APC) metric, which is an approximation of the cost of serving load. Second, the results are used to estimate the make-whole payments received by the JDA companies due to participation in the energy imbalance markets.

The APC metric is a simplified metric to estimate the cost of serving load for a utility, or group of utilities. For the JDA companies, the APC metric includes the cost of producing power at their own facilities as well as the cost of off-system purchases, while accounting for the revenues they earn through off-system sales. The metric allows us to estimate the production cost savings that the JDA companies would experience in the different market participation scenarios simulated in the study. The APC reflects the net costs associated with production, purchases, and sales of wholesale power, and is calculated as:

Adjusted Production Cost =

(+) Generator costs (fuel, start-up, and variable operation and maintenance (O&M)) for generation owned or contracted by the JDA companies;

(+) Costs of market purchases by the JDA companies from other generators and imports from neighboring regions; and

(–) Revenues from market sales and exports by the JDA companies.

The APC metric is calculated for each case, and the comparison of the metric across cases provides an estimate of how much the cost to serve load changes due to market participation. For example, the APC metric for the JDA footprint in the JDA in EIM Case minus the APC metric in the Status Quo Case indicates how much cost will decrease for the JDA companies by joining EIM.

The APC is one of two metrics computed using the simulation results to estimate the benefit from market participation. The other metric is an estimate of Bid Cost Recovery (BCR) payments that would be received by the JDA members in the EIM. The EIM provides payments to members if one of their resources is dispatched or committed by the EIM and does not recover all of their costs through market settlements.[11] We held discussions with CAISO staff to understand the methodology CAISO uses to calculate the BCR payments and replicated that methodology using our simulations.

The EIM compensates generation resources in the market with BCR payments if the resource is committed or dispatched by the EIM differently than its base schedule and does not recover the costs associated with the change from its base schedule through EIM market revenues. An EIM participating resource can have its base scheduled dispatch altered by the EIM for three reasons, 1) the EIM participating entity where the resource is located experiences a change in load or generation relative to its base schedule submitted prior to EIM, 2) it is economic to increase output from the resource and export power out of the EIM entity area where the resource is located, and 3) it is economic to decrease output from the resource and import power into the EIM entity area where the resource is located.

If any BCR payment is made to "make whole" a resource due to a change in load or generation, the BCR payment would be recovered from the same EIM participating entity where the resource is located. In that instance, the deviation in base schedule for the EIM entity caused the BCR payment and therefore it is recovered from the same EIM entity.[12] In the event that it is economic to commit or dispatch a resource in EIM to export or import power, and this causes a BCR payment to be paid to a resource in the exporting EIM entity's area, the BCR payment is recovered from the EIM entity that imports the power.

In our simulations, there are no deviations from load or generation between the utility-specific cycles and the real-time cycle that simulates the EIM. Therefore, the only reason the simulated EIM would alter a resource's base schedule would be if it was economic to trade power between EIM entities. This is born out in the simulation result, as we see resources committed or dispatched by EIM to trade power between the JDA entities and to the neighboring EIM entities. Any BCR payments that are caused due to one JDA entity exporting power to another JDA entity would be recovered from the importing JDA entity. Since we are estimating the overall benefit of market participation for the entire JDA footprint, we do not include BCR payments associated with transfers of economic energy internally in the JDA footprint (as those BCR payments would be recovered from the JDA entities).

BCR payments that are received by JDA resources related to the export of power outside the JDA footprint would be paid for by the importing EIM entity, and would be a revenue stream that offsets production costs incurred by JDA entities to dispatch their resources according to EIM instruction but are not recovered from EIM market revenues. The simulation results show that the JDA footprint frequently is export constrained in the EIM. For example, in the JDA in EIM Case the JDA footprint is export constrained during 71% of all hours of the year, while being

[11] See CAISO Business Practice Manual for the Energy Imbalance Market at p. 11. Accessed here: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Energy%20Imbalance%20Market

[12] BCR payments are recovered, typically from load, based on the tariff provisions of the EIM participating entity in that area.

import constrained during only 2% of the year. This export constraint significantly reduces the EIM price within the JDA footprint relative to the rest of the EIM area, causing a substantial increase in BCR payments in the hours when the JDA is exporting power to the neighboring EIM entities. Therefore, the JDA footprint will benefit from receiving BCR payments related to these exports, as an importing EIM entity would be responsible for funding those BCR payments. To determine how much of the BCR payments are related to JDA exports, we estimate total BCR payments in each hour and scale them based on the ratio of net exports in that hour to total transfers (JDA-internal and exports) in that hour. For example, if the JDA entities receive $1,000 of BCR payments in an hour and there are 25 MW of net exports and 100 MW of internal transfers, we assume 20% (25 MW of exports divided by 125 MW of total transfers) of the $1,000 in BCR payments are related to the exports and would provide the JDA entities with make-whole payments of $200.

The costs incurred to follow EIM commitment and dispatch instructions are included in our APC metric, but they are only partially recovered by JDA resources through EIM market revenues due to the lower prices caused by the export constraint. The BCR payments are designed to rectify this shortfall and assign the cost to the neighboring EIM entities that benefit from the low-cost power exported by the JDA. We have thus included the export-related BCR payments as part of the overall benefit of EIM participation.

The proposed EIS imbalance market does not include make-whole payment similar to the BCR payment in the EIM.[13] Therefore, in the EIS participation scenario, we only calculate the APC metric. If the EIS elects to implement a system for make-whole payments similar to the BCR payments, these revenues would also need to be included in an estimate of market participation benefits for the JDA companies. However, since the proposed EIS will not commit or de-commit fast start resources like the EIM, any make-whole payments would likely be smaller than in the EIM.

The estimated changes in the APC and the BCR payments in the EIM are combined to calculate the overall likely benefit of market participation for the JDA entities. The results from the Base Cases and the two sensitivities are presented in the sections below.

1. Base Case Results

We simulated three market participation scenarios in the Base Cases. First, the JDA in EIM Case simulates the four JDA entities joining the EIM. Second, the MWTG in EIM Case simulates the ten former MWTG members joining the EIM together. Third, the MWTG in EIS Case simulates the ten former MWTG members joining the EIS together. These three market participation scenarios are compared against the Status Quo Case to determine how the APC metric changes due to market membership. For the two EIM participation cases, the BCR payments are added to the

[13] See SPP proposal for the Western EIS here: https://www.spp.org/documents/60104/a%20proposal%20for%20spp's%20western%20energy%20imbalance%20service%20market.pdf

reduction in APC to estimate the total market participation benefits. The total estimated benefits for each case are presented in Table 9 through Table 11 below.

Table 9 contains the estimated market participation benefits for the JDA in EIM Case. In addition to show the market participation benefits, Table 9 provides information on how operations and market transactions change for the JDA entities when the JDA is in the EIM. The table focuses on the three components of the APC calculation: (a) production from JDA owned or contracted resources, (b) off-system purchases, and (c) off-system sales. Bilateral purchases and sales are shown separately from purchases and sales made in the EIM market. Details for each of these components of the APC metric are shown independently in rows 1-5 of Table 9.

The columns of Table 9 are divided into three parts. The first part of the table (columns A-C), labeled as "MWh" shows the amount of energy produced and transacted by the JDA entities in the Status Quo Case and the JDA in EIM Case. For example, the number in row 1 and column A indicates that JDA resources produce 45.9 million MWh/year in the Status Quo Case simulation. The entries in row 1, columns B and C, show that production from JDA generation decreased to 45.8 million MWh/year in the JDA in EIM Case, a change of about 112,000 MWh/year. The entries in rows 2 and 3, columns A-C, indicate that bilateral purchases and sales are relatively unchanged between the Status Quo and JDA in EIM Cases for the JDA entities. While rows 4 and 5, columns A-C, show that real-time market purchases and sales increase significantly when the JDA entities are in the EIM.

In the Status Quo Case, under the simulated JDA market structure, real-time purchases for all four JDA entities were about 438,000 MWh/year and sales were about 265,000 MWh/year. In the JDA in EIM Case the four JDA entities make over 1,000,000 MWh/year of market purchases and 715,000 MWh/year of market sales. In row 6, columns A-C, we see that the total production, purchases, and sales total the same amount in both cases, which represents total load in the JDA footprint.

The middle section (columns D-F) of the table, with the label of "$/MWh" shows the cost of production from JDA resources and the prices for the purchases and sales made by the JDA companies in each case. For example, the entry in row 1 and column D indicates that the cost of production from JDA resources in the Status Quo was $9.45/MWh, which accounts for the fact that a large portion of the JDA's generation in our 2024 simulation comes from zero-cost renewable resources. The entries in row 1, columns E and F, show that the cost of JDA production falls slightly to $9.40/MWh (or by $0.05/MWh) in the JDA in EIM Case. This is due to the fact that some higher cost generation is avoided due to market participation. Rows 2-5 in the columns D-F show the average price of purchases and sales. In the JDA in EIM Case, the price of both real-time market purchases and sales increase over the Status Quo Case. This provides a benefit for the JDA when it is making market sales in the EIM, but increases the cost of market purchases. Overall, the cost of serving the JDA's load decreases from $9.77/MWh to $9.74/MWh when the JDA joins the EIM (shown in row 6 in columns D-F).

Table 9: Market Participation Benefit for the JDA Footprint: JDA in EIM Case

		MWh			$/MWh			Total ($m/yr)		
		Status Quo	JDA in EIM	Change	Status Quo	JDA in EIM	Change	Status Quo	JDA in EIM	Change
		[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
Production	[1]	45,932,906	45,820,870	-112,036	$9.45	$9.40	-$0.05	$434.06	$430.80	-$3.26
Bilateral Market										
Purchases	[2]	2,680,167	2,660,905	-19,262	$23.46	$23.37	-$0.09	$62.88	$62.20	-$0.68
Sales	[3]	2,835,515	2,859,043	23,529	$18.27	$17.86	-$0.41	$51.81	$51.06	-$0.74
Real Time Market										
Purchases	[4]	438,437	1,044,951	606,514	$18.25	$22.47	$4.22	$8.00	$23.48	$15.48
Sales	[5]	266,257	717,945	451,687	$16.09	$24.80	$8.71	$4.28	$17.80	$13.52
Total APC Reduction	[6]	45,949,738	45,949,738	0	$9.77	$9.74	-$0.03	$448.85	$447.62	**$1.24**
Bid Cost Recovery Payments	[7]									**$0.74**
Market Participation Benefit	[8]									**$1.98**

The third section of the table (columns G-I), is labeled "Total ($m/year), shows the aggregate dollars associated with the cost of production, the cost of purchases, and the revenues from sales. For example, the entry in row 1 and column G shows that the power produced by JDA-owned and contracted resources cost $434.06 million/year to produce in the Status Quo Case. The numbers in row 1, columns H and I, show that the JDA companies save $3.26 million/year by producing less power after joining the EIM. The bilateral transactions made by the JDA companies stay about the same, which is reflected by the small changes in the total cost of bilateral purchases and sales seen in rows 2 and 3 in column I. The cost of the increased market purchases and sales are shown in rows 4 and 5 in column I. The JDA companies spend about $15.48 million/year more on market purchases in the EIM, and earn about $13.52 million/year more on market sales in the EIM.

The total change in the APC for the four JDA companies due to EIM participation is shown in row 6 and column I. The four JDA companies see a reduction in their APC of about $1.24 million/year due to joining the EIM in the JDA in EIM Case. The reduction in APC can be derived by looking at the other results in column I, which indicates that in the EIM the JDA companies save $3.26 million/year by producing less from their own resources (row 1), the reduction in the cost of bilateral purchases is offset by a reduction in bilateral sales revenue (rows 2 and 3), and the increase in the cost of real-time market purchases (row 4) is about $2 million/year more ($15.48 million/year vs. $13.52 million/year) than the increase in real-time market sales revenue (row 5). These figures together produce a reduction in APC of $1.24 million/year.

The expected BCR payments for the JDA companies due to participating in the EIM are shown in row 7 of Table 9. Based on the simulated results for the JDA in EIM Case, we estimate that the JDA companies would receive about $0.74 million/year in BCR payments that are funded by other EIM entities. Therefore, the total estimated benefit to the JDA entities from participating in the EIM in the JDA in EIM Case is $1.98 million/year (row 8). This is the sum of the $1.24 million/year in calculated APC reduction and the $0.74million/year in BCR payments. Given that the cost of serving load for the JDA companies in the Status Quo Case was about $448.85 million/year (row 6 and column G), the EIM participation benefit of $1.98 million/year represents a 0.4% reduction in the cost of serving load for the JDA entities.

Table 10 and Table 11 present the results for the MWTG in EIM and the MWTG in EIS Cases, reflecting the study assumption that the entire MWTG footprint would either join the EIM or the EIS. Table 10 and Table 11 are set up and can be read in the same way as Table 9, and show the change in production for JDA-owned and contracted resources, the change in bilateral transactions, and the change in real-time market transactions between the Status Quo Case and the two market participation cases. The columns labeled "Status Quo" in Table 10 and Table 11 are the same as the Status Quo columns in Table 9, as the Status Quo Case is used for comparison in calculating the market participation benefit for all the other cases.

Table 10: Market Participation Benefit for the JDA Footprint: MWTG in EIM Case

		MWh			$/MWh			Total ($m/yr)		
		Status Quo	MWTG in EIM	Change	Status Quo	MWTG in EIM	Change	Status Quo	MWTG in EIM	Change
		[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
Production	[1]	45,932,906	47,574,910	1,642,004	$9.45	$9.89	$0.44	$434.06	$470.35	$36.29
Bilateral Market										
Purchases	[2]	2,680,167	2,685,388	5,221	$23.46	$23.31	-$0.15	$62.88	$62.61	-$0.28
Sales	[3]	2,835,515	2,839,115	3,600	$18.27	$18.03	-$0.24	$51.81	$51.19	-$0.61
Real Time Market										
Purchases	[4]	438,437	842,643	404,207	$18.25	$20.80	$2.55	$8.00	$17.53	$9.53
Sales	[5]	266,257	2,314,089	2,047,831	$16.09	$28.83	$12.73	$4.28	$66.71	$62.42
Total APC Reduction	[6]	45,949,738	45,949,738	0	$9.77	$9.41	-$0.35	$448.85	$432.59	**$16.27**
Bid Cost Recovery Payments	[7]									**$1.07**
Market Participation Benefit	[8]									**$17.34**

In the scenario where all of the MWTG entities join the EIM together, the overall benefit of participating in the EIM for the four JDA companies is $17.34 million/year (row 8), or a 3.9% reduction in the cost of serving load relative to the Status Quo Case. The benefit in this case comes from a $16.27 million/year reduction in calculated APC savings (row 6 and column I) and $1.07 million/year in BCR payments (row 7) that reflect EIM savings not captured in the APC metric. In the MWTG in EIM Case, the access to the EIM market for the JDA companies is much larger than in the JDA in EIM Case, due to the higher transfer capability to the rest of the EIM when all ten former MWTG companies participate in the EIM. The key results, as shown in Table 10, help explain the EIM participation benefit in this case are:

- The addition of the MWTG entities to the EIM footprint and the larger transfer capability to the broader EIM market, allows the JDA entities to make over 2.3 million MWh/year of real-time market sales into the EIM (row 5 and column B). This compares to about 700,000 MWh/year of real-time market sales in the JDA in EIM Case (see row 5 and column B in Table 9).
- The JDA entities make about 840,000 MWh/year of real-time market purchases in the MWTG in EIM Case (row 4 and column B), which implies that the JDA companies are net sellers in the EIM market of about 1.5 million MWh/year (2.3 million in sales less 840,000 in purchases).
- The 2.3 million MWh/year of real-time market sales made by the JDA entities in the MWTG in EIM Case generates over $66 million/year in revenue (row 5 and column H),

while the 840,000 MWh/year of real-time market purchases costs about $17.5 million/year.

- To make the increased real-time market sales, the JDA companies experience an increase in production from their own resources of about 1.6 million MWh/year in the MWTG in EIM Case relative to the Status Quo Case. The increase in production results in higher costs for the JDA companies of about $36 million/year (row 1 and column I) relative to the Status Quo Case, which is offset by the increase in real-time market sales revenues.

Table 11 below shows the results for the MWTG in EIS Case. The overall benefit of participating in the EIS for the four JDA entities is $1.62 million/year (row 8). The benefit in this case comes entirely from the reduction in APC (row 6 and column I), since EIS does not provide make-whole payments. The $1.62 million/year reduction in the APC is a 0.36% reduction compared to the cost of serving load in the Status Quo Case.

Table 11: Market Participation Benefit for the JDA Footprint: MWTG in EIS Case

		MWh			$/MWh			Total ($m/yr)		
		Status Quo	MWTG in EIS	Change	Status Quo	MWTG in EIS	Change	Status Quo	MWTG in EIS	Change
		[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
Production	[1]	45,932,906	46,255,224	322,318	$9.45	$9.50	$0.05	$434.06	$439.25	$5.19
Bilateral Market										
Purchases	[2]	2,680,167	2,675,845	-4,322	$23.46	$23.41	-$0.05	$62.88	$62.65	-$0.24
Sales	[3]	2,835,515	2,851,553	16,038	$18.27	$18.42	$0.15	$51.81	$52.53	$0.72
Real Time Market										
Purchases	[4]	438,437	472,699	34,263	$18.25	$18.29	$0.03	$8.00	$8.65	$0.64
Sales	[5]	266,257	602,478	336,221	$16.09	$17.90	$1.81	$4.28	$10.79	$6.50
Total APC Reduction	[6]	45,949,738	45,949,738	0	$9.77	$9.73	-$0.04	$448.85	$447.23	**$1.62**
Bid Cost Recovery Payments	[7]									**N/A**
Market Participation Benefit	[8]									**$1.62**

In the MWTG in EIS Case, the benefit for the four JDA members is driven by the ability to sell power across the larger MWTG footprint, which is illustrated by the increase in real-time market sales of more than 330,000 MWh/year in the EIS relative to the JDA market (row 5 and column C). The important results that support the benefit in the MWTG in EIS, as shown in Table 11, are as follows:

- The JDA entities experience almost no change in bilateral purchases and sales by joining the EIS with the other former MWTG members (rows 2 and 3, in column C).
- The JDA companies experience a relatively small increase in real-time market purchases of about 35,000 MWh/year in this case (row 4 and column C).
- The increase of about 330,000 MWh/year in real-time market sales generates about $6.5 million/year (row 5 and column I) in additional revenue relative to real-time market sales in the JDA market under the Status Quo Case.

- The increase in real-time market revenue is partially offset by an increase in production cost of about $5.2 million/year for JDA resources (row 1 and column I). The market participation benefit is mostly derived through the increase in real-time market sales revenues less the increased cost of production.
- The number of EIS transactions made by the JDA companies is significantly less than the number of EIM transactions they make in the MWTG in EIM Case (compare rows 4 and 5 in column B between Table 10 and Table 11). The difference in the real-time market transactions between the MWTG in EIM and the MWTG in EIS illustrate the impact of the larger footprint and more diverse generation resource mix in the EIM market, and the additional transfer capability to the rest of the EIM market created when all ten former MWTG members join the EIM.

2. Added Transmission Sensitivity Results

In the Added Transmission Sensitivity, we simulated the JDA in EIM Case with additional transmission rights for the JDA companies to access the EIM market. We added 200 MW of additional export transfer rights connecting PSCo's service territory (which is well interconnected with the other JDA entities) to the neighboring EIM participants (see Section II.C.1 for details of the modeling assumptions used in the Added Transmission Sensitivity). The JDA in EIM Case with the added transmission rights is compared to the original Status Quo Case to understand the benefits for the JDA companies joining the EIM and acquiring additional transmission rights to connect to the market. Table 12 illustrates how the additional transmission rights change the results for the JDA companies.

Table 12: Market Participation Benefit for the JDA Footprint: JDA in EIM Case Added Transmission Sensitivity

		MWh			$/MWh			Total ($m/yr)		
		Status Quo	JDA in EIM	Change	Status Quo	JDA in EIM	Change	Status Quo	JDA in EIM	Change
		[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
Production	[1]	45,932,906	46,534,079	601,173	$9.45	$9.58	$0.13	$434.06	$446.01	$11.95
Bilateral Market										
Purchases	[2]	2,680,167	2,637,969	-42,198	$23.46	$23.49	$0.03	$62.88	$61.96	-$0.92
Sales	[3]	2,835,515	2,975,585	140,070	$18.27	$18.04	-$0.23	$51.81	$53.69	$1.88
Real Time Market										
Purchases	[4]	438,437	901,195	462,758	$18.25	$22.90	$4.64	$8.00	$20.63	$12.63
Sales	[5]	266,257	1,147,920	881,663	$16.09	$24.24	$8.15	$4.28	$27.83	$23.54
Total APC Reduction	[6]	45,949,738	45,949,738	0	$9.77	$9.73	-$0.04	$448.85	$447.09	**$1.77**
Bid Cost Recovery Payments	[7]									**$1.90**
Market Participation Benefit	[8]									**$3.66**

The added transmission rights to the EIM result in the JDA entities making about 1.15 million MWh/year in real-time market sales (row 5 and column B). This represents an increase of 880,000 MWh/year over the Status Quo Case (see row 5 and column C), and is a significant increase in the number of real-time market sales made by the JDA entities compared to the original JDA in EIM

Case. In the original JDA in EIM Case, the four companies made about 717,000 MWh/year (see Table 9, row 5 and column B) compared to 1.15 million MWh/year with the additional transmission rights. The other important results are:

- The increased real-time market sales results in $27.8 million/year of revenue from the EIM (row 5 and column H), which is about $23.5 million/year more than in the JDA market under the Status Quo Case (row 5 and column I).
- The additional real-time market sales made by JDA entities in this case imply an increase in production from JDA resources of about 600,000 MWh/year (row 1 and column C), which increase the production costs for the JDA companies by almost $12 million/year relative to the Status Quo Case (row 1 and column I).
- The JDA entities purchase about 900,000 MWh/year from the EIM (row 4 and column B), which is approximately 460,000 MWh/year more than in the Status Quo Case (row 4 and column C). The real-time market purchases cost about $20 million/year (row 4 and column H).
- After accounting for the increase in production costs of $12 million/year, the increases in market purchases, and the additional revenues from market sales the APC of the JDA companies is reduced by $1.77 million/year (row 6 and column I).
- The BCR payments in this case are about $1.90 million/year (row 7), which is significantly more than the amount received in the Base JDA in EIM Case.
- Overall the total benefits are approximately $3.66 million/year (row 8 column I).

Overall, we find that the 200 MW of additional export rights to the EIM increase the benefits of EIM participation for the JDA entities by almost $1.7 million/year. The additional 200 MW of export rights provide an additional $530,000/year reduction in APC for the JDA entities ($1.24 million/year in reduced APC in the Base JDA in EIM in Table 9 vs $1.77 million/year in reduction in Table 12). The increased export rights also have the effect of increasing the BCR payments received by JDA entities that we estimate will be funded by other EIM entities. This is due to the higher amount of exports the JDA entities experience in this sensitivity.

3. Natural Gas Price Sensitivity Results

In the Natural Gas Price Sensitivity, we simulated all four cases using different natural gas price assumptions for the JDA footprint as well as for all of the WECC (see Section II.C.2 for details of the modeling assumptions used in the Natural Gas Price Sensitivity). Therefore, the Natural Gas Price Sensitivity produced new results for all three market participation scenarios, which we use to estimate the benefits of market participation under the different natural gas price assumptions. The market participation benefit for the JDA entities in the JDA in EIM Case with the adjusted natural gas prices are shown in Table 13.

Table 13: Market Participation Benefit for the JDA Footprint: JDA in EIM Case Natural Gas Price Sensitivity

		MWh			$/MWh			Total ($m/yr)		
		Status Quo	JDA in EIM	Change	Status Quo	JDA in EIM	Change	Status Quo	JDA in EIM	Change
		[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
Production	[1]	46,587,141	46,402,031	-185,110	$10.55	$10.47	-$0.09	$491.61	$485.65	-$5.96
Bilateral Market										
Purchases	[2]	2,709,888	2,702,898	-6,990	$30.12	$30.06	-$0.05	$81.62	$81.26	-$0.36
Sales	[3]	3,493,586	3,482,337	-11,249	$21.78	$22.35	$0.57	$76.10	$77.84	$1.74
Real Time Market										
Purchases	[4]	266,438	786,407	519,969	$21.11	$30.43	$9.32	$5.62	$23.93	$18.30
Sales	[5]	120,143	459,261	339,118	$18.66	$30.01	$11.35	$2.24	$13.78	$11.54
Total APC Reduction	[6]	45,949,738	45,949,738	0	$10.89	$10.86	-$0.03	$500.51	$499.22	**$1.30**
Bid Cost Recovery Payments	[7]									**$0.53**
Market Participation Benefit	[8]									**$1.83**

The market participation benefit for the four JDA entities is about $1.83 million/year (row 8) in the JDA in EIM Case with the adjusted natural gas prices. The benefit consists of $1.30 million/year (row 6 and column I) due to a reduction in the calculated APC and about $0.53 million/year in BCR payments (row 7). The total market participation benefit in this case represents a reduction in the cost of serving load relative to the Status Quo Case of about 0.37% ($1.83 million over $500.5 million). The impact of the higher natural gas prices is illustrated by the following results:

- The JDA entities make about 786,000 MWh/year of real-time market purchases (row 4 and column B) and about 459,000 MWh/year of real-time market sales (row 5 and column B).
- The number of real-time market transactions in the EIM is significantly lower than in the Base JDA in EIM Case, in which the JDA entities made over 1 million MWh/year of purchases from the EIM and sold over 700,000 MWh/year into the EIM.

The reduction in real-time market purchases and sales is due in large part to the change in natural gas price differential between the JDA and the southwestern EIM entities. In the Base JDA in EIM Case, there were more opportunities for economic energy transactions between the JDA companies and the southwestern EIM entities due to the wider natural gas price differential between Colorado and Arizona/New Mexico.

Table 14 shows the results for the MWTG in EIM Case under the adjusted natural gas price assumptions. Similar to the results of the Base Cases, the MWTG in EIM Case provides the largest benefit between the three market participation scenarios. The MWTG in EIM Case provides a benefit to the JDA companies of about $12.17 million/year, which includes a reduction in the APC of $10.66 million/year and BCR payment of about $1.51 million/year. The market participation benefit of $12.17 million/year represents a 2.4% decrease in the cost to serve load relative to the Status Quo Case with the adjusted natural gas price assumptions.

Table 14: Market Participation Benefit for the JDA Footprint: MWTG in EIM Case
Natural Gas Price Sensitivity

		MWh			$/MWh			Total ($m/yr)		
		Status Quo	MWTG in EIM	Change	Status Quo	MWTG in EIM	Change	Status Quo	MWTG in EIM	Change
		[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
Production	[1]	46,587,141	47,866,025	1,278,884	$10.55	$11.07	$0.52	$491.61	$529.94	$38.33
Bilateral Market										
Purchases	[2]	2,709,888	2,697,006	-12,882	$30.12	$29.93	-$0.19	$81.62	$80.73	-$0.89
Sales	[3]	3,493,586	3,492,646	-940	$21.78	$21.86	$0.08	$76.10	$76.36	$0.26
Real Time Market										
Purchases	[4]	266,438	647,995	381,558	$21.11	$27.00	$5.89	$5.62	$17.50	$11.87
Sales	[5]	120,143	1,768,643	1,648,499	$18.66	$35.03	$16.37	$2.24	$61.95	$59.71
Total APC Reduction	[6]	45,949,738	45,949,738	0	$10.89	$10.66	-$0.23	$500.51	$489.85	**$10.66**
Bid Cost Recovery Payments	[7]									**$1.51**
Market Participation Benefit	[8]									**$12.17**

The driver of the increase in the market participation benefit in this case, relative to the JDA in EIM Case under the Natural Gas Price Sensitivity is the quantity of EIM sales made by the JDA companies. The JDA entities make about 1.77 million MWh/year in real-time market sales in the EIM (row 5 and column B) and generate almost $62 million/year from those EIM sales. The $62 million /year of EIM sales revenues is significantly more than in the JDA in this EIM Case under the Natural Gas Price Sensitivity, in which the JDA companies generate $13.78 million/year in EIM sales revenue (see row 5 and column H in Table 13). This increase in EIM sales and revenues is due to the larger footprint created when all ten former MWTG members join the EIM together, and due to the increased transfer capability to the rest of the EIM market available when all the former MWTG is in the EIM.

Comparing the MWTG in EIM Case under the Natural Gas Price Sensitivity to the Base MWTG in EIM Case illustrates that the market participation benefits decrease due to the change in regional natural gas price differentials. In the Base MWTG in EIM Case, the market participation benefit was $17.34 million/year, or about 3.9% of the JDA's Status Quo APC. In the same case, but under the Natural Gas Price Sensitivity, the market participation benefit is $12.17 million/year, or about 2.4% of the Status Quo APC. The reason for the decline in market participation benefits is due to the reduction in the amount of economic energy transactions in the MWTG in EIM Case, as the increase in natural gas prices (and the lower differential to gas prices in the southwest) in this sensitivity reduces economic energy transactions that can be made from the JDA-owned natural gas resources in the EIM market. In this Natural Gas Price Sensitivity, the JDA entities make 1.77 million MWh/year of EIM sales, which is significantly less than the 2.3 million MWh/year of EIM sales they made in the Base MWTG in EIM Case.

Table 15 below shows the results from the MWTG in EIS Case under the Natural Gas Price Sensitivity. The MWTG in EIS Case provides a benefit to the JDA companies of about $3.45 million/year, which is due entirely to a reduction in the APC of the JDA footprint. The market participation benefit of $3.45 million/year represents a 0.69% decrease in the cost to serve load relative to the Status Quo Case with the adjusted natural gas price assumptions.

**Table 15: Market Participation Benefit for the JDA Footprint: MWTG in EIS Case
Natural Gas Price Sensitivity**

		MWh			$/MWh			Total ($m/yr)		
		Status Quo	MWTG in EIS	Change	Status Quo	MWTG in EIS	Change	Status Quo	MWTG in EIS	Change
		[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
Production	[1]	46,587,141	46,815,182	228,042	$10.55	$10.60	$0.04	$491.61	$496.07	$4.46
Bilateral Market										
Purchases	[2]	2,709,888	2,694,129	-15,760	$30.12	$29.98	-$0.14	$81.62	$80.76	-$0.86
Sales	[3]	3,493,586	3,481,228	-12,357	$21.78	$22.48	$0.70	$76.10	$78.28	$2.18
Real Time Market										
Purchases	[4]	266,438	176,794	-89,644	$21.11	$23.00	$1.89	$5.62	$4.07	-$1.56
Sales	[5]	120,143	255,139	134,996	$18.66	$21.76	$3.09	$2.24	$5.55	$3.31
Total APC Reduction	[6]	45,949,738	45,949,738	0	$10.89	$10.82	-$0.08	$500.51	$497.07	**$3.45**
Bid Cost Recovery Payments	[7]									**N/A**
Market Participation Benefit	[8]									**$3.45**

The amount of real-time market transactions made in the EIS is significantly smaller than in the case where the MWTG joins the EIM. In the EIS, under the Natural Gas Price Sensitivity, the JDA entities make almost 177,000 MWh/year of purchases and about 255,000 MWh/year (rows 4 and 5 in column B) of sales in the EIS market. This is less than the almost 648,000 MWh/year of purchases and 1.77 million MWh/year of sales in the EIM market made by the JDA companies in the MWTG in EIM Case (see rows 4 and 5 in column B in Table 14). Similar to the Base Cases results, the difference in the real-time market transactions between the MWTG in EIM and the MWTG in EIS illustrate the impact of the larger EIM market size and resource diversity and the additional transfer capability to the rest of the EIM market

The MWTG in EIS Case shows higher market participation benefits in the Natural Gas Price Sensitivity Case than in the Base Cases. The market participation benefit in the Base Cases was about $1.62 million/year, or about 0.36% of the JDA's APC in the Status Quo Case. The benefit in the MWTG in EIS Case under the Natural Gas Price Sensitivity is $3.45 million/year, or about 0.69% of the Status Quo APC. The increase in the market participation benefit with the higher natural gas prices is driven by the change in what types of resources are dispatched on the margin. The higher natural gas prices put coal resources in the MWTG on the margin more frequently, allowing for more dispatch from the coal generation in the EIS market footprint. Under these assumptions, the JDA entities can generate about the same amount of benefit from economic off-system purchases and sales, but without increasing their own production costs as much as in the Base MWTG in EIS Case. This is observed by comparing column I in Table 11 vs. column I in Table 15.

B. Simulated Market Transactions and Prices

In addition to the market participation benefits described in the previous section, the simulations also allow us to understand other market results. In particular, this section will show two additional market results from the Base Cases simulations. First, the amount of simulated market transfers that occur between the JDA companies and with the rest of the MWTG entities and the neighboring EIM members are shown in Table 16 and Table 19. Second, the simulated market prices in the Base Cases are shown in Table 20. The same results for the Added Transmission Sensitivity and the Natural Gas Price Sensitivity are presented in Appendix A.

1. Simulated Real-Time Energy Imbalance Market Transactions

The results of the simulations allow us to see the volume of hourly transfers that take place in a real-time energy imbalance market between the different company-specific areas that are represented in the model. Therefore, the simulation results illustrate the quantity of transactions that take place in the different real-time energy imbalance market participation scenarios. Table 16 through 19 show the annual simulated transfers between areas that take place in the energy imbalance market under each of the market participation options.

Table 16 shows the simulated economic energy transactions that take place in the JDA under the Status Quo Case. The areas shaded in blue indicate that transactions only took place between the four JDA companies.[14] As expected, compared with the transactions in the JDA footprint in the EIM and EIS shown in Table 17 through Table 19, there are relatively few real-time energy transactions between the four JDA companies in the Status Quo Case. In total for the 2024 simulated year, PSCo made the most sales in the JDA accounting for about 86,000 MWh/year, while CSU was the largest purchaser of power in JDA with about 82,000 MWh/year.

Table 16: Simulated Annual JDA Economic Energy Transactions (MWh): Status Quo Case

		SINK															
		JDA				Rest of MWTG						EIM Connections					
		PSCO	CSU	BHCE	PRPA	LAP	CRSP	BHBE	CLFP	BEPW	TSGT	PACE	TEPC	AZPS	SRP	PNM	TOTAL
SOURCE – JDA	PSCO	X	81,788	3,007	1,670	0	0	0	0	0	0	0	0	0	0	0	**86,464**
	CSU	3,473	X	1,871	0	0	0	0	0	0	0	0	0	0	0	0	**5,345**
	BHCE	497	190	X	0	0	0	0	0	0	0	0	0	0	0	0	**687**
	PRPA	32,238	0	0	X	0	0	0	0	0	0	0	0	0	0	0	**32,238**
SOURCE – Rest of MWTG	LAP	0	0	0	0	X	0	0	0	0	0	0	0	0	0	0	**0**
	CRSP	0	0	0	0	0	X	0	0	0	0	0	0	0	0	0	**0**
	BHBE	0	0	0	0	0	0	X	0	0	0	0	0	0	0	0	**0**
	CLFP	0	0	0	0	0	0	0	X	0	0	0	0	0	0	0	**0**
	BEPW	0	0	0	0	0	0	0	0	X	0	0	0	0	0	0	**0**
	TSGT	0	0	0	0	0	0	0	0	0	X	0	0	0	0	0	**0**
SOURCE – EIM	PACE	0	0	0	0	0	0	0	0	0	0						**0**
	TEPC	0	0	0	0	0	0	0	0	0	0						**0**
	AZPS	0	0	0	0	0	0	0	0	0	0						**0**
	SRP	0	0	0	0	0	0	0	0	0	0						**0**
	PNM	0	0	0	0	0	0	0	0	0	0						**0**
	TOTAL	**36,209**	**81,977**	**4,878**	**1,670**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	

Table 17 shows the EIM market transactions that involve the four JDA companies, which includes transactions within the JDA footprint as well as transactions with the neighboring EIM entities (see blue shaded areas of the table). The table illustrates that real-time market transactions within the JDA footprint increase by about 10 times due to EIM participation relative to the Status Quo.

[14] There are transaction that take place between the current and planned EIM members listed in the table in the Status Quo Case (e.g., between AZPS and SRP), but we do not list them here because they do not involve the JDA or MWTG companies.

This is expected based on the increased efficiency of the EIM market relative to JDA, which is represented in the model by removing the $2/MWh hurdle rate between transactions in the JDA when simulating the EIM. In addition, Table 17 shows some limited transactions between the JDA companies and the neighboring EIM participants. For example, almost 185,000 MWh/year are being exported from Platte River to PACE. Note that this power may be originally sourced from another JDA company, but is using Platte River's transmission to ultimately be sold to PACE. For example, if a MWh is sold from PSCo to PACE, it would show up in Table 17 twice, first as a MWh sourced from PSCo and sinking in Platte River and second as a MWh sourced from Platte River and sinking in PACE. This interpretation applies to Table 18 and Table 19, as well as the table for the Added Transmission and Natural Gas Price Sensitivities in the Appendix.

Table 17: Simulated Annual EIM Market Transactions (MWh): JDA in EIM Case

			SINK														
			JDA				Rest of MWTG						EIM Connections				
			PSCO	CSU	BHCE	PRPA	LAP	CRSP	BHBE	CLFP	BEPW	TSGT	PACE	TEPC	AZPS	SRP	PNM	**TOTAL**
SOURCE	JDA	PSCO	X	503,498	286,346	49,140	0	0	0	0	0	0	0	0	0	0	0	**838,984**
		CSU	45,020	X	50,859	0	0	0	0	0	0	0	0	0	0	0	0	**95,880**
		BHCE	14,571	34,251	X	0	0	0	0	0	0	0	0	0	0	0	0	**48,822**
		PRPA	269,227	0	0	X	0	0	0	0	0	0	184,251	0	0	0	0	**453,478**
	Rest of MWTG	LAP	0	0	0	0	X	0	0	0	0	0	0	0	0	0	0	**0**
		CRSP	0	0	0	0	0	X	0	0	0	0	0	0	0	0	0	**0**
		BHBE	0	0	0	0	0	0	X	0	0	0	0	0	0	0	0	**0**
		CLFP	0	0	0	0	0	0	0	X	0	0	0	0	0	0	0	**0**
		BEPW	0	0	0	0	0	0	0	0	X	0	0	0	0	0	0	**0**
		TSGT	0	0	0	0	0	0	0	0	0	X	0	0	0	0	0	**0**
	EIM	PACE	0	0	0	24,249	0	0	0	0	0	0						**24,249**
		TEPC	0	0	0	0	0	0	0	0	0	0						**0**
		AZPS	75,679	0	0	0	0	0	0	0	0	0						**75,679**
		SRP	120,776	0	0	0	0	0	0	0	0	0						**120,776**
		PNM	108,413	0	0	0	0	0	0	0	0	0						**108,413**
		TOTAL	**633,686**	**537,748**	**337,206**	**73,389**	**0**	**0**	**0**	**0**	**0**	**0**	**184,251**	**0**	**0**	**0**	**0**	

Table 18 shows the simulated EIM market transactions in the MWTG in EIM Case. The blue shaded area of the table covers all the JDA companies, the other MWTG participants, and the neighboring EIM members. As expected, the real-time energy transactions involving the JDA companies is significantly higher than in the other market participation scenarios. The inclusion of the other MWTG in the EIM footprint provides significant additional transfer capabilities to the EIM market, which implies a lot more real-time energy transactions between the MWTG entities and the neighboring EIM members. Moreover, the JDA companies have the ability to purchase and sell power to the other MWTG entities in this case.

Table 18: Simulated Annual EIM Market Transactions (MWh): MWTG in EIM Case

			SINK														
			JDA				Rest of MWTG						EIM Connections				
			PSCO	CSU	BHCE	PRPA	LAP	CRSP	BHBE	CLFP	BEPW	TSGT	PACE	TEPC	AZPS	SRP	PNM	**TOTAL**
SOURCE	JDA	PSCO	X	330,912	150,178	13,331	505,239	820,292	0	0	0	218,090	0	0	0	0	0	**2,038,043**
		CSU	207,420	X	53,747	0	0	0	0	0	0	0	0	0	0	0	0	**261,167**
		BHCE	33,832	34,185	X	0	0	104,128	0	0	0	20,408	0	0	0	0	0	**192,553**
		PRPA	156,965	0	0	X	0	0	0	79,651	83,452	22,347	0	0	0	0	0	**342,415**
	Rest of MWTG	LAP	8,123	0	0	0	X	7,091	19,121	4,521	113	3,999	670,665	0	0	0	0	**713,633**
		CRSP	0	0	0	0	0	X	0	9,844	52,827	0	3,225,754	456,745	43,169	0	199,247	**3,987,586**
		BHBE	0	0	0	0	550	0	X	1,609	0	1,602	60,704	0	0	0	0	**64,464**
		CLFP	0	0	0	1,227	0	21,943	45,289	X	0	0	0	0	0	0	0	**68,459**
		BEPW	3,957	0	0	0	49,409	64,762	1,798	0	X	28,988	7,268	0	0	0	0	**156,181**
		TSGT	15,841	0	20,501	1,105	32,946	32,650	30,132	0	126	X	133,670	102,190	0	13,665	182,702	**565,530**
	EIM	PACE	0	0	0	0	26,250	8,461	41,140	0	1,201	0						**77,052**
		TEPC	0	0	0	0	0	57,785	0	0	0	14,941						**72,727**
		AZPS	47,093	0	0	0	0	0	0	0	0	0						**47,093**
		SRP	68,640	0	0	0	0	2,643,320	0	0	0	34,821						**2,746,781**
		PNM	15,252	0	0	0	0	31,657	0	0	0	0						**46,909**
		TOTAL	**557,123**	**365,098**	**224,426**	**15,663**	**614,394**	**3,792,091**	**137,481**	**95,625**	**137,719**	**345,196**	**4,098,060**	**558,935**	**43,169**	**13,665**	**381,949**	

Table 19 provides the simulated real-time market transactions in the MWTG in EIS Case. In this case, the blue shaded areas of the table indicate that all the MWTG entities are capable of purchasing and selling power within the EIS, but the neighboring EIM members are no longer in the same market. The broader MWTG footprint allows the JDA companies to make more off-system purchases and sales in the EIS marketplace relative to the JDA simulated in the Status Quo Case (compare with Table 16). Although compared with the MWTG in EIM Case (Table 18), the real-time market transactions in the EIS are significantly less, due to the larger footprint in the WECC provided by the EIM and the combined transfer capabilities of the MWTG entities with the EIM.

Table 19: Simulated Annual EIS Market Transactions (MWh): MWTG in EIS Case

			SINK															
			JDA				Rest of MWTG						EIM Connections					
			PSCO	CSU	BHCE	PRPA	LAP	CRSP	BHBE	CLFP	BEPW	TSGT	PACE	TEPC	AZPS	SRP	PNM	TOTAL
SOURCE	JDA	PSCO	X	365,774	15,342	7,108	55,500	2,719	0	0	45,489	64,046	0	0	0	0	0	**555,978**
		CSU	22,646	X	13,483	0	0	0	0	0	0	0	0	0	0	0	0	**36,129**
		BHCE	821	13,678	X	0	0	401	0	0	0	8,680	0	0	0	0	0	**23,579**
		PRPA	236,733	0	0	X	0	0	0	55,210	22,741	140,610	0	0	0	0	0	**455,294**
	Rest of MWTG	LAP	43,218	0	0	0	X	1,018	22,229	4,211	638	24,854	0	0	0	0	0	**96,169**
		CRSP	1,705	0	5,193	0	170	X	0	2,908	20	1,117	0	0	0	0	0	**11,113**
		BHBE	0	0	0	0	115	0	X	65	51	1,877	0	0	0	0	0	**2,108**
		CLFP	0	0	0	2,895	18,015	6,953	15,547	X	0	0	0	0	0	0	0	**43,410**
		BEPW	1,448	0	0	172	9,604	171	33,356	0	X	286	0	0	0	0	0	**45,037**
		TSGT	14,580	0	20,259	261	18,124	95	34,817	0	1	X	0	0	0	0	0	**88,137**
	EIM	PACE	0	0	0	0	0	0	0	0	0	0						**0**
		TEPC	0	0	0	0	0	0	0	0	0	0						**0**
		AZPS	0	0	0	0	0	0	0	0	0	0						**0**
		SRP	0	0	0	0	0	0	0	0	0	0						**0**
		PNM	0	0	0	0	0	0	0	0	0	0						**0**
		TOTAL	**321,151**	**379,452**	**54,277**	**10,437**	**101,528**	**11,358**	**105,948**	**62,395**	**68,940**	**241,469**	**0**	**0**	**0**	**0**	**0**	

2. Simulated Real-Time Energy Imbalance Market Prices

The simulations produce an hourly price that load pays for each company-specific area represented in the model. In addition, the simulations produce hourly locational prices at specific buses where we instructed the model to produce prices and at the location of all generation resources in the model. Table 20 shows the average annual simulated load area price for each of the four JDA companies, as well as five select locational prices that are in or near the JDA footprint.

Table 20: Average Annual Simulated Prices (2019$)

	Prices ($/MWh)				Difference ($/MWh)		
	Status Quo	JDA in EIM	MWTG in EIM	MWTG in EIS	JDA in EIM - Status Quo	MWTG in EIM - Status Quo	MWTG in EIS - Status Quo
Area Load Prices	[1]	[2]	[3]	[4]	[2]-[1]	[3]-[1]	[4]-[1]
PSCO	$20.13	$23.69	$22.65	$21.46	$3.56	$2.52	$1.33
CSU	$20.82	$23.69	$22.65	$21.46	$2.88	$1.84	$0.64
BHCE	$20.09	$23.69	$22.65	$21.45	$3.60	$2.56	$1.36
PRPA	$19.42	$23.70	$22.67	$21.47	$4.29	$3.25	$2.06
Locational Prices							
Ault	$23.43	$27.24	$22.67	$21.48	$3.82	-$0.75	-$1.95
Rawhide	$19.42	$23.70	$22.67	$21.48	$4.28	$3.25	$2.06
Midway	$20.12	$23.69	$22.65	$21.45	$3.56	$2.52	$1.33
Story	$20.14	$23.69	$22.65	$21.46	$3.55	$2.52	$1.32
Pueblo	$20.09	$23.69	$22.65	$21.45	$3.60	$2.56	$1.36

For each price listed, Table 20 shows the difference between the average annual price in the three market participation case and the Status Quo Case. The table shows that average load prices for the four JDA companies range from $19.42/MWh to $20.82/MWh in the Status Quo Case. The range of area load prices between the JDA companies in the Status Quo reflects the fact that there is a $2/MWh hurdle rate between the JDA companies in the model, which is meant to simulate the inefficiencies of the JDA's manual dispatch. The same range of average prices is reflected in the four locational prices that are in the JDA footprint (Rawhide, Midway, Story, and Pueblo). The locational price for Ault shown in Table 20 is taken from the WAPA area in the model to illustrate the price differential between the JDA and the rest of the MWTG footprint.[15]

In the JDA in EIM Case, the real-time area load prices in the JDA as well as the four locational prices in the JDA footprint are almost identical, only differing by $0.01/MWh. A similar result is seen in the MWTG in EIM and the MWTG in EIS Cases, in which all four JDA companies have almost exactly the same area load price. The convergence of prices within the JDA footprint in either broader regional market reflects the fact that there are no hurdle rates between the JDA companies in the three market participation cases and that there are no significant transmission constraints between the JDA companies.

The prices within the JDA footprint in the Status Quo Case are approximately $3-$4/MWh lower than the same price points in the JDA in EIM Case (see column 2 minus 1 in Table 20). The lower prices within the JDA footprint are driven by the high portion of renewable energy in the JDA. In the Status Quo Case, where the JDA companies are not in a larger regional energy imbalance market, hours when there is a high portion of renewable energy production relative to load see very low load prices due to the fact that the excess renewable energy cannot be sold across a large footprint. In all three market participation cases, this dynamic changes as the JDA companies can export power across a larger footprint. The result is that real-time prices increase slightly in all

15 The WAPA Ault point was selected because it is located close to the JDA and within the broader MWTG footprint. Pricing points in more distant parts of the MWTG footprint, such as locations north of TOT-3, (Path 36), do not illustrate the price impact of the seam between the JDA and the rest of the MWTG.

three market participation cases. Note that this is not necessarily true for prices in the bilateral market, as Table 20 only shows prices in the real-time energy imbalance market.

In the market participation scenarios where the entire MWTG footprint joins the same regional energy imbalance market (MWTG in EIM and MWTG in EIS Case), the locational price at Ault converges with prices in the JDA footprint (in columns 3 and 4, compare the Ault price to the other prices listed). In the market participation cases where the rest of the MWTG footprint is not in the same real-time energy imbalance market as the JDA companies (Status Quo and JDA in EIM Cases), the locational price at Ault is about $3.50/MWh higher than the prices in the JDA footprint, which reflects the fact that there is no energy imbalance market to optimize real-time economic transactions between the JDA and the rest of the MWTG.

C. Market Participation Benefits Not Estimated in this Study

Production cost simulations, such as those conducted in this study, are helpful for understanding the benefits of participating in a regional energy imbalance market, but one must keep in mind the limitations of such simulations. Production cost models are powerful tools: they jointly simulate generation dispatch and power flows to capture the actual physical characteristics of both generating plants and the transmission grid, including the complex dynamics between generation and transmission availability, energy production and operation, and load following requirements. These types of simulations provide valuable insights to both the operations and economics of the wholesale electric system in the entire interconnected region. For that reason, production cost models are used by every ISO and RTO, and most utilities, for transmission planning purposes. Production cost models are also used by many utilities and regulators for resource planning and to evaluate the implications of policy decisions and market uncertainties.

However, similar to most other production cost simulations, the simulations undertaken for this study have their limitations and likely yield conservatively low estimates of the benefits from participating in a regional energy imbalance market for the JDA companies. The specific limitations include:

- This study does not assess the benefits of improved **management of load and generation uncertainties** provided by a regional energy imbalance market, particularly as it relates to the **integration and balancing of increasing amounts of renewable generation** in real-time. This study simulates unit commitment and dispatch deterministically based on perfect foresight of all loads and available generation, including hourly renewable generation output, for both day ahead and real time operations. The simulations do not consider uncertainties in loads, generation outages, or the level of wind and solar generation that exist between the time utility-specific unit commitment and dispatch decisions are finalized (on a day-ahead and intra-day basis) and when the real-time energy imbalance markets would make their unit commitment (in the EIM) and dispatch decisions. The simulations thus do not capture the benefit of the real-time energy imbalance market in managing this uncertainty. Having a regional market provides the system operator with a larger pool of resources and optimization tools to manage unexpected changes of generation and load between the day-ahead and real-time operations, thereby reducing costs, reducing the need for reserves and ramping capability, and increasing reliability, particularly when integrating large amounts of variable resources, such as wind and solar generation.

- The simulations have been performed on an hourly basis and thus do not capture the additional benefits the EIM and EIS would provide by balancing loads and generation (and the related uncertainties) on an **intra-hour** basis.
- This study does not estimate the potential long-term benefits of **optimizing the usage of the DC ties to SPP (in the MWTG in EIS Case).** The MWTG footprint has over 700 MW of DC interconnection to the SPP. The current EIS proposal does not include any provisions to allow SPP to optimize the flows over the DC ties, which is why this study does not estimate any of these potential benefits. The EIS market may develop that capability over time, in which case there may be additional benefits for the JDA companies from joining the EIS. These benefits may increase if the DC intertie capabilities are expanded in the future.
- The simulations are based on **normal weather, average hydrology, normal monthly energy and peak load, and normal generation outages** without considering additional benefits realized during unusually challenging operational conditions. For example, atypical weather patterns, such as extreme cold temperatures or very hot and humid conditions, which could create large swings of power flows across a system or other operational challenges. Challenging conditions such as these tend to increase the benefit of regional energy imbalance markets.
- The study does not account for the **reliability benefits** of belonging to a larger regional energy imbalance market footprint resulting from a **reduction in reserves** needed to meet operational and flexibility requirements.
- We do not estimate any **make-whole payments due to participation in the EIS market (MWTG in EIS Case).** The EIS proposal does not allow for any possible make-whole payments, similar to the BCR payments received in the EIM. Therefore, we have not estimated any benefits related to make-whole payments in the EIS. However, because the EIS market would not commit resources, make-whole payments similar to the BCR would likely be lower in the EIS than in the EIM.
- The simulations do not consider the additional transmission constraints and operational challenges on the power grid during **transmission-related outages**. Transmission limits are reflected in the simulations, but the modeling does not account for transmission outages and the additional unexpected operational challenges they create. The greater flexibility provided by integrated regional market operations yields higher cost savings and improved reliability during transmission outages.

- We do not assume that the improved incentives of operating in a price-transparent and competitive regional market would improve **generator efficiency and availability**, as has been documented by the experience in other regional markets.
- The simulations **do not fully capture inefficiencies of bilateral trading practices** in terms of less flexible bilateral trading blocks (*e.g.*, 16 hour blocks at 25 MW increments), contract path scheduling limits, and congestion caused by unscheduled power flows.
- The simulations do not capture any benefits achievable through **improved regional coordination and optimization of hydro power resources**. We have left hydro dispatch unchanged between the Status Quo Cases and the three market participation cases, leaving out value associated with allowing the flexible portion of hydro resources to be dispatched more optimally by the regional market (subject to their operating constraints).
- This study does not quantify how changes in bilateral trades prior to the real-time balancing markets may affect how transmission costs are recovered (e.g., through changes in wheeling revenues). However, given that the impact of real-time imbalance markets is expected to be small and many bilateral transactions utilize long-term transmission rights, these impacts should be very modest in comparison to participation in full RTO markets that replace and de-pancake all bilateral transaction in day-ahead and real-time markets.
- This study does not include any estimate of the **market participation costs** incurred to participate in the EIM or EIS markets.

The benefits estimated in this study, as well as the benefits described above that are not accounted for in the study, would need to be weighed against the administrative costs associated with participating in the respective regional energy imbalance markets.

IV. Conclusion

The market simulations in this study find that the JDA companies would collectively experience a reduction in production costs by joining either the EIM or the EIS energy imbalance markets, relative to remaining in the current JDA structure. The production cost simulations are run on four different test cases:

- **The Status Quo:** simulation of the JDA as it is currently operated with the current and planned member utilities
- **The JDA in EIM Case:** representation of the four JDA companies joining the EIM market, while the remaining members of the MWTG remain outside the EIM.
- **The MWTG in EIM Case:** simulation of the effects of the entire MWTG joining the EIM market together

- **The MWTG in EIS Case:** simulation of the effects of the entire MWTG joining the EIS market together

We simulated 2024 as a test future year for these four cases. We also simulated two sensitivities to estimate the impact of added transmission rights between the JDA and the EIM footprint and a change in the natural gas price assumptions.

The results of simulations indicate that the JDA companies would realize annual **production cost savings of about $1.98 million/year (about 0.4% of production costs) if only the four companies joined the EIM.** The production cost savings for the JDA companies from joining the EIM increase to **approximately $17.34 million/year (3.9% of production costs) if the entire MWTG footprint were to join EIM.** The simulation results suggest that the production cost savings for the JDA companies would be **about $1.62 million/year from joining the EIS if the entire MWTG joined the market.**

Production cost savings are not the only benefits the JDA companies can anticipate achieving in a regional energy imbalance market. The production cost simulations conducted in this study provide only a conservatively low estimate of the savings achievable in an imbalance market. They do not capture any impacts related to operational reliability, renewable integration, or improved flexibility to manage extreme weather and outage events as discussed in Section III.C. Moreover, they do not consider the administrative costs of joining either the EIM or the EIS, relative to the cost of operating the JDA. Those costs will need to be considered along with the benefits quantified in this study, and the benefits not quantified in this study, in order to fully evaluate the decision to join either market. The decision to join a regional imbalance market will also need to evaluate other considerations such as governance of the organization.

V. Appendix A: Simulated Real-Time Market Transactions and Prices for Sensitivities

This appendix provides the same results as shown in III.B, but for the Added Transmission Sensitivity and Natural Gas Price Sensitivity. This includes the simulated real-time market transactions and the simulated real-time market prices for each case simulated as part of these sensitivities.

A. Simulated Real-Time Market Transactions

1. Added Transmission Sensitivity

Table 21 shows the simulated real-time market transfers between the four JDA companies and the neighboring regions in the EIM footprint in the JDA in EIM Case under the Added Transmission Sensitivity. This sensitivity only included simulating one new case (the JDA in EIM Case) with additional transfer rights between the JDA footprint and PACE, AZPS, SRP, and PNM.

Table 21: Simulated Annual EIM Market Transactions (MWh): JDA in EIM Case Added Transmission Sensitivity

			SINK															
			JDA				Rest of MWTG						EIM Connections					
			PSCO	CSU	BHCE	PRPA	LAP	CRSP	BHBE	CLFP	BEPW	TSGT	PACE	TEPC	AZPS	SRP	PNM	**TOTAL**
SOURCE	JDA	PSCO	X	414,886	265,554	38,363	0	0	0	0	0	0	289,411	0	125,715	97,191	69,157	**1,300,276**
		CSU	101,354	X	50,871	0	0	0	0	0	0	0	0	0	0	0	0	**152,226**
		BHCE	35,611	32,883	X	0	0	0	0	0	0	0	0	0	0	0	0	**68,495**
		PRPA	298,518	0	0	X	0	0	0	0	0	0	184,336	0	0	0	0	**482,854**
	Rest of MWTG	LAP	0	0	0	0	X	0	0	0	0	0	0	0	0	0	0	**0**
		CRSP	0	0	0	0	0	X	0	0	0	0	0	0	0	0	0	**0**
		BHBE	0	0	0	0	0	0	X	0	0	0	0	0	0	0	0	**0**
		CLFP	0	0	0	0	0	0	0	X	0	0	0	0	0	0	0	**0**
		BEPW	0	0	0	0	0	0	0	0	X	0	0	0	0	0	0	**0**
		TSGT	0	0	0	0	0	0	0	0	0	X	0	0	0	0	0	**0**
	EIM	PACE	0	0	0	22,520	0	0	0	0	0	0						**22,520**
		TEPC	0	0	0	0	0	0	0	0	0	0						**0**
		AZPS	72,640	0	0	0	0	0	0	0	0	0						**72,640**
		SRP	126,602	0	0	0	0	0	0	0	0	0						**126,602**
		PNM	115,225	0	0	0	0	0	0	0	0	0						**115,225**
		TOTAL	**749,950**	**447,769**	**316,425**	**60,882**	**0**	**0**	**0**	**0**	**0**	**0**	**473,747**	**0**	**125,715**	**97,191**	**69,157**	

Table 22 is the same as Table 17 from Section III.B, re-copied here to compare with Table 21. The comparison between the two tables illustrates how the added transfer rights allow the JDA companies to export over 500,000 MWh more than in the original JDA in EIM Case.

Table 22: Simulated Annual EIM Market Transactions (MWh): JDA in EIM Case (Same as Table 17)

		SINK															
		JDA				Rest of MWTG						EIM Connections					
		PSCO	CSU	BHCE	PRPA	LAP	CRSP	BHBE	CLFP	BEPW	TSGT	PACE	TEPC	AZPS	SRP	PNM	TOTAL
SOURCE: JDA	PSCO	X	503,498	286,346	49,140	0	0	0	0	0	0	0	0	0	0	0	**838,984**
	CSU	45,020	X	50,859	0	0	0	0	0	0	0	0	0	0	0	0	**95,880**
	BHCE	14,571	34,251	X	0	0	0	0	0	0	0	0	0	0	0	0	**48,822**
	PRPA	269,227	0	0	X	0	0	0	0	0	0	184,251	0	0	0	0	**453,478**
SOURCE: Rest of MWTG	LAP	0	0	0	0	X	0	0	0	0	0	0	0	0	0	0	**0**
	CRSP	0	0	0	0	0	X	0	0	0	0	0	0	0	0	0	**0**
	BHBE	0	0	0	0	0	0	X	0	0	0	0	0	0	0	0	**0**
	CLFP	0	0	0	0	0	0	0	X	0	0	0	0	0	0	0	**0**
	BEPW	0	0	0	0	0	0	0	0	X	0	0	0	0	0	0	**0**
	TSGT	0	0	0	0	0	0	0	0	0	X	0	0	0	0	0	**0**
SOURCE: EIM	PACE	0	0	0	24,249	0	0	0	0	0	0						**24,249**
	TEPC	0	0	0	0	0	0	0	0	0	0						**0**
	AZPS	75,679	0	0	0	0	0	0	0	0	0						**75,679**
	SRP	120,776	0	0	0	0	0	0	0	0	0						**120,776**
	PNM	108,413	0	0	0	0	0	0	0	0	0						**108,413**
	TOTAL	**633,686**	**537,748**	**337,206**	**73,389**	**0**	**0**	**0**	**0**	**0**	**0**	**184,251**	**0**	**0**	**0**	**0**	

2. Natural Gas Price Sensitivity

Table 23 through Table 26 show the real-time energy transfers between areas for the cases simulated as part of the Natural Gas Price Sensitivity. The Natural Gas Price Sensitivity included simulating all four cases again with new natural gas price assumptions for the WECC. The natural gas prices used in this sensitivity are different in two ways from the prices used in the Base Cases: 1) across all of the WECC, prices are significantly higher in the Natural Gas Price Sensitivity, and 2) the natural gas price differential between Colorado and the southwest region is considerably smaller in this sensitivity (see Table 8). The effects of the change in natural gas prices are illustrated by the changes in real-time market transfers. The important conclusions from Table 23 through Table 26 are as follows:

- In the MWTG in EIM Case, there are significantly fewer real-time market transfers between the MWTG footprint and the rest of the EIM due to the smaller differential in natural gas prices between Colorado and the southwest.
- In the MWTG in EIM and the MWTG in EIS Cases, there are more real-time market transfers within the MWTG, which are driven by the higher natural gas prices in this sensitivity. The higher natural gas prices imply that some of the coal-fired resources in the MWTG footprint are frequently economic in the real-time imbalance market, which increase the overall amount of economic transfers within the MWTG.

Table 23: Simulated Annual JDA Economic Energy Transactions (MWh): Status Quo Case Natural Gas Price Sensitivity

		SINK															
		JDA				Rest of MWTG						EIM Connections					
		PSCO	CSU	BHCE	PRPA	LAP	CRSP	BHBE	CLFP	BEPW	TSGT	PACE	TEPC	AZPS	SRP	PNM	TOTAL
SOURCE – JDA	PSCO	X	14,353	5,270	3,202	0	0	0	0	0	0	0	0	0	0		**22,825**
	CSU	7,681	X	609	0	0	0	0	0	0	0	0	0	0	0		**8,289**
	BHCE	82	746	X	0	0	0	0	0	0	0	0	0	0	0		**828**
	PRPA	31,152	0	0	X	0	0	0	0	0	0	0	0	0	0		**31,152**
SOURCE – Rest of MWTG	LAP	0	0	0	0	X	0	0	0	0	0	0	0	0	0		**0**
	CRSP	0	0	0	0	0	X	0	0	0	0	0	0	0	0		**0**
	BHBE	0	0	0	0	0	0	X	0	0	0	0	0	0	0		**0**
	CLFP	0	0	0	0	0	0	0	X	0	0	0	0	0	0		**0**
	BEPW	0	0	0	0	0	0	0	0	X	0	0	0	0	0		**0**
	TSGT	0	0	0	0	0	0	0	0	0	X	0	0	0	0		**0**
SOURCE – EIM	PACE	0	0	0	0	0	0	0	0	0	0						**0**
	TEPC	0	0	0	0	0	0	0	0	0	0						**0**
	AZPS	0	0	0	0	0	0	0	0	0	0						**0**
	SRP	0	0	0	0	0	0	0	0	0	0						**0**
	PNM	0	0	0	0	0	0	0	0	0	0						**0**
	TOTAL	**38,915**	**15,099**	**5,878**	**3,202**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**		

Table 24: Simulated Annual EIM Market Transactions (MWh): JDA in EIM Case Natural Gas Price Sensitivity

		SINK															
		JDA				Rest of MWTG						EIM Connections					
		PSCO	CSU	BHCE	PRPA	LAP	CRSP	BHBE	CLFP	BEPW	TSGT	PACE	TEPC	AZPS	SRP	PNM	TOTAL
SOURCE – JDA	PSCO	X	255,764	280,901	40,743	0	0	0	0	0	0	0	0	0	0	0	**577,409**
	CSU	39,446	X	42,754	0	0	0	0	0	0	0	0	0	0	0	0	**82,200**
	BHCE	17,908	31,553	X	0	0	0	0	0	0	0	0	0	0	0	0	**49,462**
	PRPA	178,038	0	0	X	0	0	0	0	0	0	141,496	0	0	0	0	**319,534**
SOURCE – Rest of MWTG	LAP	0	0	0	0	X	0	0	0	0	0	0	0	0	0	0	**0**
	CRSP	0	0	0	0	0	X	0	0	0	0	0	0	0	0	0	**0**
	BHBE	0	0	0	0	0	0	X	0	0	0	0	0	0	0	0	**0**
	CLFP	0	0	0	0	0	0	0	X	0	0	0	0	0	0	0	**0**
	BEPW	0	0	0	0	0	0	0	0	X	0	0	0	0	0	0	**0**
	TSGT	0	0	0	0	0	0	0	0	0	X	0	0	0	0	0	**0**
SOURCE – EIM	PACE	0	0	0	31,035	0	0	0	0	0	0						**31,035**
	TEPC	0	0	0	0	0	0	0	0	0	0						**0**
	AZPS	106,558	0	0	0	0	0	0	0	0	0						**106,558**
	SRP	92,336	0	0	0	0	0	0	0	0	0						**92,336**
	PNM	84,036	0	0	0	0	0	0	0	0	0						**84,036**
	TOTAL	**518,323**	**287,318**	**323,655**	**71,778**	**0**	**0**	**0**	**0**	**0**	**0**	**141,496**	**0**	**0**	**0**	**0**	

Table 25: Simulated Annual EIM Market Transactions (MWh): MWTG in EIM Case Natural Gas Price Sensitivity

		SINK															
		JDA				Rest of MWTG						EIM Connections					
		PSCO	CSU	BHCE	PRPA	LAP	CRSP	BHBE	CLFP	BEPW	TSGT	PACE	TEPC	AZPS	SRP	PNM	TOTAL
SOURCE – JDA	PSCO	X	123,834	119,404	9,942	505,239	820,292	0	0	0	218,090	0	0	0	0	0	**1,796,801**
	CSU	290,642	X	46,310	0	0	0	0	0	0	0	0	0	0	0	0	**336,951**
	BHCE	43,530	21,034	X	0	0	0	0	0	0	20,408	0	0	0	0	0	**84,971**
	PRPA	106,829	0	0	X	0	0	0	0	0	22,347	114,908	0	0	0	0	**244,084**
SOURCE – Rest of MWTG	LAP	0	0	0	0	X	7,091	0	4,521	0	0	0	0	0	0	0	**11,612**
	CRSP	0	0	0	0	0	X	0	9,844	0	0	0	0	43,169	0	0	**53,013**
	BHBE	0	0	0	0	550	0	X	1,609	0	0	60,704	0	0	0	0	**62,862**
	CLFP	0	0	0	0	0	0	0	X	0	0	0	0	0	0	0	**0**
	BEPW	0	0	0	0	49,409	64,762	0	0	X	0	7,268	0	0	0	0	**121,438**
	TSGT	15,841	0	20,501	0	32,946	0	0	0	0	X	0	102,190	0	13,665	0	**185,144**
SOURCE – EIM	PACE	0	0	0	5,525	0	0	0	0	1,201	0						**6,726**
	TEPC	0	0	0	0	0	0	0	0	0	0						**0**
	AZPS	0	0	0	0	0	0	0	0	0	0						**0**
	SRP	68,640	0	0	0	0	0	0	0	0	0						**68,640**
	PNM	15,252	0	0	0	0	31,657	0	0	0	0						**46,909**
	TOTAL	**540,734**	**144,868**	**186,215**	**15,467**	**588,144**	**923,802**	**0**	**15,974**	**1,201**	**260,845**	**182,879**	**102,190**	**43,169**	**13,665**	**0**	

Table 26: Simulated Annual EIM Market Transactions (MWh):
MWTG in EIS Case Natural Gas Price Sensitivity

			SINK														
		JDA				Rest of MWTG						EIM Connections					
		PSCO	CSU	BHCE	PRPA	LAP	CRSP	BHBE	CLFP	BEPW	TSGT	PACE	TEPC	AZPS	SRP	PNM	TOTAL
SOURCE – JDA	PSCO	X	116,379	11,671	3,370	35,550	2,300	0	0	3,874	36,731	0	0	0	0	0	**209,876**
	CSU	39,386	X	18,444	0	0	0	0	0	0	0	0	0	0	0	0	**57,830**
	BHCE	448	1,999	X	0	0	508	0	0	0	18,286	0	0	0	0	0	**21,241**
	PRPA	108,357	0	0	X	0	0	0	18,224	11,606	139,660	0	0	0	0	0	**277,846**
SOURCE – Rest of MWTG	LAP	25,942	0	0	0	X	2,348	4,117	1,557	1,888	27,476	0	0	0	0	0	**63,328**
	CRSP	379	0	2,565	0	15	X	0	590	107	481	0	0	0	0	0	**4,138**
	BHBE	0	0	0	0	401	0	X	161	224	1,650	0	0	0	0	0	**2,437**
	CLFP	0	0	0	1,604	9,567	2,320	4,939	X	0	0	0	0	0	0	0	**18,429**
	BEPW	431	0	0	546	7,340	401	5,019	0	X	741	0	0	0	0	0	**14,479**
	TSGT	1,660	0	6,962	993	13,580	471	7,747	0	45	X	0	0	0	0	0	**31,458**
SOURCE – EIM	PACE	0	0	0	0	0	0	0	0	0	0						**0**
	TEPC	0	0	0	0	0	0	0	0	0	0						**0**
	AZPS	0	0	0	0	0	0	0	0	0	0						**0**
	SRP	0	0	0	0	0	0	0	0	0	0						**0**
	PNM	0	0	0	0	0	0	0	0	0	0						**0**
	TOTAL	**176,604**	**118,378**	**39,641**	**6,513**	**66,452**	**8,348**	**21,822**	**20,532**	**17,745**	**225,026**	**0**	**0**	**0**	**0**	**0**	

B. Simulated Real-Time Market Prices

1. Added Transmission Sensitivity

Table 27 shows the average annual simulated area load prices for the four JDA companies, and at five locations in or near the JDA footprint. The Added Transmission Sensitivity only included simulating the JDA in EIM Case, therefore the Status Quo Case prices from the Base Cases are shown in the table. The comparison of average annual prices between the Status Quo Case and the JDA in EIM Case with the added transmission rights yield similar conclusions as were discussed with respect to Table 20. Specifically, there are two key takeaways, first that prices are about $3/MWh higher in the JDA footprint due to EIM participation, and second, that membership in the EIM implies that the average annual prices in the JDA footprint are almost exactly the same across all four companies and locations. The latter results reflect the fact that we model the EIM without any hurdle rates between the JDA companies, and that there is almost no internal congestion in the JDA footprint.

Table 27: Average Annual Simulated Prices (2019$)
Added Transmission Sensitivity

	Prices ($/MWh)		Difference ($/MWh)
	Status Quo	JDA in EIM	JDA in EIM - Status Quo
Area Load Prices	[1]	[2]	[2]-[1]
PSCO	$20.13	$24.10	$3.96
CSU	$20.82	$24.10	$3.28
BHCE	$20.09	$24.09	$4.01
PRPA	$19.42	$24.10	$4.69
Locational Prices			
Ault	$23.43	$26.23	$2.80
Rawhide	$19.42	$24.10	$4.68
Midway	$20.12	$24.09	$3.97
Story	$20.14	$24.09	$3.95
Pueblo	$20.09	$24.09	$4.00

2. Natural Gas Price Sensitivity

Table 28 shows the average annual simulated real-time market prices in the Natural Gas Price Sensitivity, which includes all four cases. The important conclusions from Table 28 include:

- Average annual prices are about $5/MWh higher than in the Base Cases, which partially reflects the increase in natural gas prices and partially reflects the fact that coal is on the margin in more hours
- As in the Base Cases, average annual prices in the EIM cases are slightly higher than in the Status Quo or EIS cases.
- Participation in a regional real-time energy imbalance market cause prices within the JDA to converge, which is seen by comparing the load area price across the four JDA companies in the three EIM/EIS cases. They are separated by at most $0.02/MWh in all three EIM/EIS cases, which reflects the fact that we model the EIM and EIS without any hurdle rates between the JDA companies and that there is almost no internal congestion within the JDA footprint.

Table 28: Average Annual Simulated Prices (2019$)
Natural Gas Price Sensitivity

	Prices ($/MWh)				Difference ($/MWh)		
	Status Quo	JDA in EIM	MWTG in EIM	MWTG in EIS	JDA in EIM - Status Quo	MWTG in EIM - Status Quo	MWTG in EIS - Status Quo
Area Load Prices	[1]	[2]	[3]	[4]	[2]-[1]	[3]-[1]	[4]-[1]
PSCO	$25.44	$30.18	$29.43	$27.70	$4.75	$3.99	$2.26
CSU	$25.68	$30.19	$29.43	$27.71	$4.51	$3.75	$2.03
BHCE	$25.10	$30.19	$29.45	$27.71	$5.09	$4.35	$2.62
PRPA	$24.47	$30.19	$29.41	$27.71	$5.72	$4.94	$3.24
Locational Prices							
Ault	$28.06	$31.50	$29.41	$27.71	$3.44	$1.35	-$0.35
Rawhide	$24.48	$30.19	$29.41	$27.72	$5.72	$4.94	$3.24
Midway	$25.44	$30.19	$29.43	$27.71	$4.75	$4.00	$2.27
Story	$25.42	$30.15	$29.39	$27.67	$4.73	$3.97	$2.25
Pueblo	$25.10	$30.19	$29.45	$27.71	$5.09	$4.35	$2.61

VI. Appendix B: Technical Description of the PSO Model

For the simulations conducted in this study, we used the Power Systems Optimizer (PSO) software developed by Polaris Systems Optimization, Inc. PSO is a state-of-the-art production cost simulation tool that simulates least-cost security-constrained unit commitment and economic dispatch with a full nodal representation of the transmission system, similar to actual ISO operations. In that regard, PSO is similar to "Gridview," the simulation tool that WestConnect and WECC use for their regional transmission and generation resource planning analyses. A production cost model, like PSO, can be used as a tool to test system operation under varying assumptions, including but not limited to: generation and transmission additions or retirement, de-pancaked transmission and scheduling charges, changes in fuel costs, and jointly-optimized generating unit commitment and dispatch. PSO can be set up to produce hourly prices at every bus in the WECC and generation output for each unit in the WECC. These results can then be used to estimate changes in generation output, fuel use, production cost, or other metrics on a unit, state, utility, or regional level.

PSO has certain advantages over traditional production cost models, which are designed primarily to model controllable thermal generation and to focus on wholesale energy markets only. Recognizing modern system challenges, PSO has the capability to capture the effects on thermal unit commitment of the increasing variability to which systems operations are exposed due to intermittent and largely uncontrollable renewable resources (both for the current and future developments of the system), as well as the decision-making processes employed by operators to adjust other operations in order to handle that variability. PSO simultaneously optimizes energy and multiple ancillary services markets, and it can do so on an hourly or sub-hourly timeframe (only an hourly timeframe was used in this study).

Like other production cost models, PSO is designed to mimic ISO operations: it commits and dispatches individual generating units to meet load and other system requirements. The model's objective function is set to minimize system-wide operating costs given a variety of assumptions on system conditions (*e.g.*, load, fuel prices, *etc.*) and various operational and transmission constraints. One of PSO's most distinguishing features is its ability to evaluate system operations at different decision points, represented as "cycles," which would occur at different points in time and with different amounts of information about system conditions. Unlike some production cost models, PSO simulates trading between balancing areas based on contract-path transmission rights, which allows for a more realistic and more accurate representation of actual trading opportunities and transactions costs.

PSO uses mixed-integer programming to solve for optimized system-wide commitment and dispatch of generating units. Unit commitment decisions are particularly difficult to optimize due to the non-linear nature of the problem. With mixed-integer programming, the PSO model closely mimics actual market operations software and market outcomes in jointly-optimized competitive energy and ancillary services markets.

For the purposes of this study, we have developed the model assumptions to simulate day-ahead and real-time outcomes in three cycles as shown in Figure 3, preceded by a loss cycle. An explanation of each cycle is as follows:

- In the loss cycle, PSO calculates the marginal loss factors on the transmission system. The marginal losses affect the locational prices and the relative economics of generators.
- In the utility-specific unit commitment cycle, PSO optimizes unit commitment decisions, particularly for resources with limited operational flexibility (e.g., units that start up slowly or have long minimum online and offline periods). In this cycle, PSO determines which resources should start up to meet energy and operating reserve needs in each hour of the following day, while anticipating the needs one week ahead. While the model has the capability to address uncertainties between the day-ahead and real-time markets, we have not operated the model in such a mode. Thus, the entire simulation effort for this study is conducted with perfect foresight. This means that the unit commitment is always efficiently determined since no system changes (e.g., changes in load or generation between the day-ahead and the real-time market) are simulated that would alter the unit commitment after the day-ahead schedule is complete.
- In the utility-specific economic dispatch cycle, PSO solves for economic dispatch of resources given the unit commitment decisions made in the previous cycle. Explicit modeling of the commitment and dispatch cycles allows us to more accurately represent the preferences of individual utilities to commit local resources for reliability, but share the provision of energy around a given commitment. This consideration is captured through the use of hurdle rates on the bilateral transfers between areas. We have used adders that are higher for unit commitment in the second cycle than for generation dispatch in the third cycle.
- In the real-time market operations cycle, PSO solves for the economic dispatch and unit commitment of fast-start resources (in the EIM only) given the results of the previous three cycles as constraints. In this cycle, since no hurdle rates are represented by utilities in the same real-time energy imbalance market, PSO optimizes economic dispatch and fast-start commitment decisions together for all utilities in the market footprint.

Figure 3: Cycles Modeled in PSO

1st Model Cycle: Utility-Specific Unit Commitment

- Individual utilities optimize unit commitment
- Hurdle rates between utilities reflect hesitancy to de-commit resources to rely on purchases
- OATT fees assessed on trades between utilities
- Accounts for resources needed to provide ancillary services

2nd Model Cycle: Utility-Specific Economic Dispatch

- Individual utilities optimize dispatch and commitment of fast-start resources
- Hurdle rates between utilities reflect margins on bilateral trades
- OATT fees assessed on trades between utilities
- Transmission rights modeled for off-system sales/purchases
- Ancillary services procured for each utility or BAA

Day-Ahead Cycles for Utility-Specific Optimization

3rd Model Cycle: Real-Time Market Operations

- Regionally optimized re-dispatch of committed resources
- Regionally optimized commitment of certain fast-start units (EIM only)
- No hurdle rates between market participants
- Transfer capabilities reflect available transmission for use in the market

Real-Time Cycle for Market Optimization

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