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 Added Transmission

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.

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

NORTH AMERICA | EUROPE | ASIA-PACIFIC

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