WECC

Reliability Implications of Expanding the EIM to Include Day-Ahead Market Services: A Qualitative Assessment

WECC MIC MEA Working Group

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Executive Summary

In 2019, the California ISO (CAISO) initiated a process to explore offering its day-ahead market to entities participating in the Energy Imbalance Market (EIM). This extended day-ahead market (EDAM), if implemented, will enable Balancing Authorities (BA) outside the CAISO footprint to participate in the day-ahead wholesale energy market without requiring full integration into the CAISO BA.

WECC's mission is to ensure the reliability and security of the bulk power system (BPS) in the Western Interconnection. Markets are economic tools that can increase operational efficiencies and unlock financial benefits. That said, WECC recognizes that electricity markets may also affect reliability. The purpose of this qualitative assessment is to explore the potential reliability impacts of extending day-ahead market services to EIM participants. A work group of subject matter experts of the Market Interface Committee conducted the assessment. The report provides high-level reliability considerations that can inform future reliability evaluations of market expansion in the West.

When this assessment was conducted, no EDAM market design existed.[1] Therefore, the workgroup made assumptions about market design elements based on publicly available information. The market design described by the workgroup's assumptions is collectively referred to as the EIM + DAMS to distinguish it from the CAISO's ongoing EDAM stakeholder initiative. These assumptions are outlined in full in the report. The assessment evaluated potential reliability impacts in five areas:

1. Day-ahead operations
2. Transmission congestion
3. BA-to-BA coordination
4. Ancillary services
5. Contingency analysis

Findings

This assessment describes reliability considerations, including some potential benefits and potential challenges or risks associated with extending CAISO's day-ahead market to EIM participants. As a general matter, the potential benefits and risks are influenced by many factors, including, the size of the market footprint and the level of participation. The workgroup assumed full participation by all existing and planned EIM participants. Moreover, the reliability impacts of an EIM + DAMS will be highly dependent on implementation specifics.

[1] The assessment was concluded and the work group's draft was submitted for WECC review in March 2020.

Potential Benefits

The potential reliability benefits of an EIM + DAMS fall into three general themes: (1) coordination across a broad footprint, (2) uniform application of market tools, and (3) enhanced ability to manage variability.

Coordination across a broad footprint

Generally, electric reliability is enhanced when operations are coordinated across larger footprints. The EIM + DAMS footprint would be larger and more diverse than the individual BA footprints of the market's participants and could take advantage of the following reliability benefits:

- A larger geographic footprint, a broader pool of resources, and the use of automated processes may reduce the impact of contingencies and may improve the speed and quality of contingency response. Additional avenues to manage contingencies may include additional generation, more transmission solutions, and increased demand response solutions.
- In an EIM+DAMS, the central market operator will have visibility over all BPS elements, as well as an enhanced ability to manage any resulting congestion. This means that many of the day-ahead BA-to-BA seams issues seen today could be more effectively managed or even eliminated under an EIM + DAMS market scenario.

Uniform application of tools, information, and processes

The EIM + DAMS market operator, as well as the market's participants, will have access to an advanced set of operational tools, supported by extensive information and coordinated processes. Uniform application of these tools, information, and processes across the entire market footprint may provide several reliability benefits.

- Proactively position resources to better balance supply and demand across the footprint, which could aid congestion management, help identify and alleviate seams issues, and improve BA-to-BA coordination.
- Co-optimize all resources with ancillary services and transmission constraints simultaneously to develop day-ahead commitment plans that allow the market operator to anticipate future problems and position resources more accurately to effectively address reliability issues.
- Calculate and use the transmission system through system-wide flow-based modeling and application of locational marginal pricing (LMP)-based optimization to improve congestion management.

Enhanced Ability to Manage Variability

As VER penetration continues to increase across the West, the importance of managing operational uncertainty grows. Coordination across a diverse and broad footprint will be increasingly important. In an organized market with a larger geographic footprint like the EIM + DAMS, there are more resources available to address reliability needs, including uncertainty related to VER output.

- The variability of net load increases as VER penetrations grow. Complementary climate, weather, and load diversity may decrease net load variability. For example, weather conditions in one part of the market footprint may offset conditions in another, reducing the need for flexible resources.
- Coordinating all resources in the market footprint can decrease net load variability, and, in turn, overall flexibility (also known as balancing) needs decrease. Capturing complementary diversity in the day-ahead commitment process allows the market operator to identify potential transmission issues that could arise and can be mitigated with a coordinated commitment of resources.

Potential Risks

The workgroup also identified some issues that could present challenges or become risks. As the EDAM market design is under development, these issues represent areas that need to be addressed during that process.

Increased operational complexity

Expanding the EIM to include day-ahead market services could increase its complexity and require better coordination. Examples of increased complexity include:

- Managing different seams between organized markets.
- Ensuring reliability in a system that may operate closer to system operating limits.
- Analyzing deliverability when the provision of transmission would be voluntary.

Reduced bilateral market liquidity and the day-ahead resource sufficiency test

It is anticipated that as participants turn over their unit commitment to the day-ahead market, liquidity in the bilateral market could decline. This could affect both EIM + DAMS participants and non-participants. Specifically, there could be fewer options for bilateral purchases of power for reserves and to serve load. We assume there will be a resource sufficiency evaluation in the day-ahead time frame. The purpose of the test is to ensure each participating BA has sufficient resource capacity and flexibility to meet their BA obligations.

Gas-electric coordination

If electricity optimization and gas trading take place on different schedules in the day-ahead, EIM + DAMS participants may need to modify their operational practices and risk assessment tools to accommodate this scheduling mismatch. Otherwise, there is the potential for fuel-under procurement which could affect market participation and, if widespread, reliability.

Recommendations

This assessment provides a first step in understanding the reliability implications of expanding the EIM to include a day-ahead market. Additional analysis will require specific market design details. Based on the assessment, WECC should:

- Continue to monitor the development of the EDAM, specifically:
  - The design for transmission operations including coordination plans and agreements among and between BAs and markets (i.e., the CAISO EDAM and the Southwest Power Pool's Western Energy Imbalance Service);
  - The design for the resource sufficiency evaluation; and
  - How day-ahead market timelines could affect gas scheduling including business practices and tools that could be employed to offset potential reliability impacts.
- Continue to monitor the effectiveness of reserve requirements as market constructs are designed and operated. It is possible that market operations may encourage the BAs to carry only the required amount of reserves, which, if sufficient, will not affect reliability. However, reduced reserves carried by BAs (when day-ahead market operations begin) may require re-evaluation of reserve requirements. A reduced reserves carried by BAs is not a market design issue; the assumption is that reserve requirements would be met in an organized market.

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Overview

The California ISO (CAISO), in collaboration with EIM Participants in the Western Interconnection, has proposed to expand the capabilities of the Western Energy Imbalance Market (EIM) to include day-ahead market services (DAMS). This expansion would allow Balancing Authorities (BAs) outside CAISO to participate in the day-ahead wholesale energy market without requiring full integration into the CAISO BA. While the primary purpose of markets is to unlock economic benefits in a system, they can also affect reliability. For this reason, WECC through a Market Interface Committee (MIC) workgroup (see Appendix B), has undertaken this qualitative assessment of the reliability implications of extending the EIM to include DAMS.

This document:

- Describes day-ahead processes in the current bilateral market paradigm in the West;
- Contrasts current processes to an EIM+DAMS framework; and
- Explains how these changes could affect reliability, including a discussion of potential benefits and risks.

In late 2019, CAISO started a stakeholder process to explore extending the day-ahead market to the EIM (called EDAM).[2] At the time of this assessment, no EDAM market design proposal existed and the workgroup used only publicly available information about EDAM market design details.[3] The acronym EIM + DAMS reflects a market design represented by high-level assumptions.

This document is divided into three sections:

- Section 1 describes the scope of the report and assumptions for the market framework.
- Section 2 describes key day-ahead processes in the bilateral market, how they will change, and potential implications for reliability. Where the real-time framework is relevant, this section describes EIM processes.
- Section 3 gives a summary of the workgroup's findings and recommendations.

1 Scope and Assumptions

1.1 Assessment Parameters

The following parameters were used to guide this assessment:

- This is a qualitative assessment of the reliability impacts of expanding the EIM to include DAMS. This assessment does not provide a quantitative analysis.

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[2] Development of the EDAM market design is expected to continue through 2021. Information about CAISO's EDAM Initiative is available at: http://www.caiso.com/StakeholderProcesses/Extended-day-ahead-market.

[3] The assessment was concluded and the work group's draft was submitted for WECC review in March 2020.

- This assessment does not address the potential economic benefits of an EIM + DAMS. However, it does recognize that reliability and economic benefits can be intertwined.
- This assessment does not attempt to quantify the degree of benefits and risks identified. A more precise analysis would require specific market design details. In addition, participation in an EIM + DAMS will be voluntary and the degree of some benefits or risks would be a function of participation in the market.
- This assessment addresses the potential impacts of the EIM+DAMS on the existing EIM; however, it does not evaluate the reliability benefits and risks of the EIM itself.[4]
- While this assessment does not include an analysis of potential market design options, the impacts of a regional day-ahead market will be highly dependent on implementation specifics. So, in some cases, this assessment includes observations about potential reliability impacts if our assumptions do not, in the end, accurately describe the market that develops.

1.2 Baseline Comparison

This assessment evaluates the changes of adding DAMS for BAs that already participate in the EIM. In the day-ahead time frame, participants in the EIM outside of the CAISO operate in the bilateral market paradigm. Therefore, for the day-ahead time frame, we contrast operations in the bilateral market with those in an EIM+DAMS. In real time, participants in the EIM operate under the EIM market paradigm. To assess the impact of an EIM + DAMS on real-time operations, our baseline is the EIM, which includes the CAISO's fifteen- and five-minute markets.

1.3 Defining Risk

NERC defines a reliable electric system as one that can meet the electricity needs of end-use customers even when unexpected equipment failures or other factors reduce the amount of available electricity.[5] Today, reliability consists of three fundamental concepts:

- Adequacy: the ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
- Security (operating reliability): the ability of the electric system to withstand sudden, unexpected disturbances, such as short circuits or unanticipated loss of system components due to natural causes, physical attacks, or cyberattacks.

[4] Several reports on EIM benefits are included in Appendix C, Resources.

[5] NERC, Frequently Asked Questions (August 2013) available at: https://www.nerc.com/AboutNERC/Documents/NERC%20FAQs%20AUG13.pdf.

- Resilience: the ability of a system or its components to adapt to changing conditions and withstand and rapidly recover from disruptions.

We use the terms "reliability benefits" and "reliability risks" in a general sense. The benefits and risks identified in this paper could affect adequacy, security, or resilience, but we do not clearly draw the distinction. Similarly, while the potential reliability impacts could also affect compliance with specific reliability standards, we do not attempt to identify the impact on specific reliability standards.

1.4 EIM+DAMS Assumptions

The following is a summary of the assumptions about the EIM+DAMS used in this assessment.

Participation

- Only EIM Entities (EIM BAs) participate in an EIM+DAMS.
- Participation is voluntary at all levels. BAs elect to join and there are minimal, or no, exit fees. Resources within a BA voluntarily elect to bid into the market.
- All EIM Entities participate in the EIM+DAMS, including those that signed an implementation agreement as of June 2020. (See Figure 1.)[6]

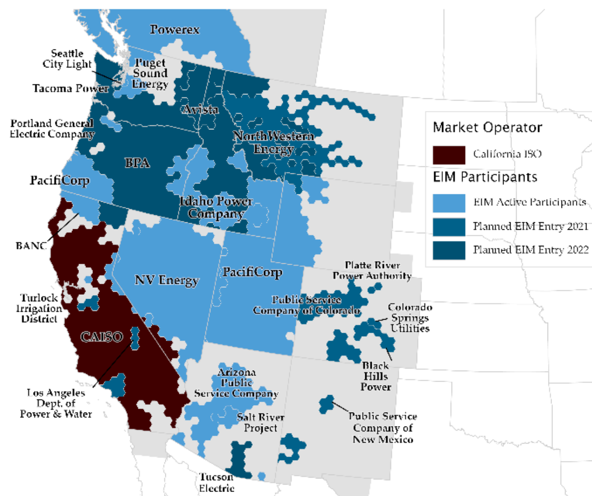

Figure 1

BA Role and Responsibilities

- Participating Entities retain their BA area boundaries, planning functions, and compliance responsibilities.
- Responsibility for integrated resource planning, resource adequacy procurement, and transmission planning and investment are unchanged; they remain with each BA and state or local regulatory authority.

Transmission

- Functional control of transmission facilities is not transferred to the market operator.
- Transmission revenue collection continues under each entity's Open Access Transmission Tariff (OATT) though the OATTs will likely be changed to align with an EIM+DAMS.
- Sufficient transmission capacity is made available to the market to satisfy reliability requirements, such as addressing congestion management, ensuring delivery of ancillary services, and maintaining resource sufficiency.

[6] Western Energy Imbalance Market webpage: https://www.westerneim.com/Pages/About/default.aspx.

Tools

- A uniform set of tools, based on CAISO's current day-ahead market, are applied across the market footprint to develop a centralized day-ahead unit commitment plan.

Ancillary Services

- Ancillary Services (AS) are offered in the market as an option for EIM+DAMS participants.
- Participation in reserve sharing groups remains an option.

Resource Sufficiency (RS)

- There is a resource sufficiency evaluation in the day-ahead time frame.

Other Markets

- An EIM+DAMS adds to or operates alongside the day-ahead bilateral market in the Western Interconnection.
- There is not a centralized capacity market; bilateral capacity trading will continue.

2 Comparison of Bilateral Market and EIM+DAMS Practices

This section describes current day-ahead practices in the bilateral markets, key changes that will take place for entities that participate in an EIM +DAMs and the potential impact these changes could have on reliability. When relevant, current practices in the EIM (real-time market) are also described. The discussion is divided into five areas:

1. General day-ahead operations
2. Transmission congestion
3. Seams management
6. Ancillary services
7. Contingency analysis

2.1 General Day-Ahead Operations

Most power entities in the Western Interconnection do not participate directly in a centralized day-ahead energy market. However, when comparing day-ahead operations in the bilateral paradigm with those in an organized market, there is little fundamental difference in the types of activities that occur. The primary difference is how these activities are performed, i.e., the tools applied and the level of coordination between and across the geographic region. The Balancing Authority (BA) typically performs balancing and reliability functions.

Day-Ahead Bilateral Market Practices

Each day, BAs use information about expected generation, load, and transmission availability to create an operating plan for the following day. The BA receives this information from operating entities in its

Balancing Authority Area (BAA). The BA uses load forecasts to determine planned load for the next day. To meet the planned load, the BA ensures all its contractually obligated and reliability-necessary units are prepared to run. If the BA determines additional units may be needed, they arrange to have them available, usually in economic order starting with the lowest cost units. Certain reliability or other binding obligations may require specific resources to be made available outside of the normal economic order. The BA integrates the selected resources and run schedules into the operating plan for the following day, along with transmission information provided by transmission operators.

The following general steps are performed by BAs or entities within the BAA in coordination with the BA in the day-ahead timeframe:

1. Develop a load forecast and determine ancillary service and reserve needs.
8. Determine resource and delivery capabilities through an outage management system (outages and derates) and Open Access Same-time Information System (OASIS).
9. Determine resource costs (e.g., current fuel supply, commodity conditions, fixed supply contracts) and develop a comparison of internal versus market energy costs including regional conditions that will affect resources (transmission availability, weather, hydro forecasts, etc.).
10. Execute a resource optimization to produce a generation commitment schedule that includes ancillary service needs.
11. Perform a reliability assessment of the resource plan.
12. Schedule generation and transmission required through OASIS and e-tagging.
13. Hand over the operating plan to the real-time operations group.

Every BA includes some optimization process in the development of its day-ahead commitment plan, though the tools, methods and sophistication vary. The goal of an optimization process is to develop the least cost unit commitment plan that meets reliability requirements. It is common for BAs to consider information and engage with entities outside their footprint when developing the day-ahead commitment plan (e.g., step 3). However, the nature and extent of this engagement varies from BA to BA.

The result is a separate day-ahead commitment plan developed by each BA operating in the bilateral market paradigm.

EIM Practices in Real-Time

The EIM is a real-time market composed of CAISO's 15- and five-minute markets.[7] In the real-time market, the market operator sends out dispatch instructions that detail at what levels offered

[7] The EIM allows BAs outside of CAISO (and entities within those BAs) to voluntarily participate in CAISO's real-time organized market without requiring full integration into the CAISO BA.

generation units will run. Before the market run, BAs that participate in the EIM submit a resource plan to CAISO based on their individual day-ahead planning process. Resource plans include:

- A base schedule (with planned hourly generation, pre-arranged interchange schedule and load forecasts);
- Energy bids (supply and demand) from participating resources;[8]
- Upward and downward available balancing capacity; and
- Reserves to meet NERC or WECC contingency reserve requirements.

The base schedule is essentially the day-ahead commitment plan for each BA. CAISO uses a sophisticated and automated optimization application, the Security Constrained Economic Dispatch (SCED), within the CAISO BAA and across the EIM footprint to make real-time dispatch decisions. However, the real-time dispatch is limited to the commitment decisions made separately by each EIM BA in the day-ahead (i.e., which units will be available for dispatch in real time).[9]

Changes in an EIM+DAMS

In an EIM+DAMS, the general duties described above do not become obsolete. However, after performing the initial resource optimization (step 4), entities would submit something similar to a resource plan to the market operator before the day-ahead market run.[10] This will not include a BA specific base schedule, as resources will be optimized across the market footprint to develop one coordinated day-ahead commitment plan. Each BA's day-ahead resource plan may include some limited information regarding specific unit outputs. However, the primary focus is on providing the market operator with the dispatchable range of resources, such as minimum and maximum expected power output availability. This is known as bid range.

Optimization

In an EIM + DAMS, the BA base schedules would be replaced by one coordinated and optimized, footprint-wide, day-ahead commitment plan. The market operator would:

- Collect all necessary resource and demand information across the market footprint;
- Analyze all bids, transmission capabilities, and resource capabilities bid in or provided to the market; and

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[8] A supply bid indicates the quantity of product a supplier will provide for a certain price; similarly, a demand bid indicates the quantity of product a buyer will purchase for a certain price. Self-schedules are also submitted. This means a buyer or seller will buy or sell a certain quantity no matter the price.

[9] The SCED is also limited by transmission provided to the market by EIM Entities for transfers across BAs.

[10] This is based on the EIM process. The EIM resource plan is over a seven-day horizon beginning on the operating day. CAISO's Business Practice Manual for the Energy Imbalance Market, V.15 (revised May 2, 2019) ("BPM for the EIM"), at 43-44.

- Determine hourly commitment schedules for the next day for all market participants using centralized unit commitment.

Participating entities would be required to submit data to the market operator, such as resource attributes and operational parameters, Variable Energy Resource (VER) forecasts, and generation and transmission outage and derate information.[11] This would give the market operator access to a more comprehensive set of data than any individual BA to develop the day-ahead commitment schedule.

The EIM + DAMS will apply a set of tools in the day-ahead time frame uniformly across multiple BA areas. (See CAISO's market analysis engine depicted in Appendix A.) The key components of the day-ahead process are the Security Constrained Unit Commitment (SCUC) optimization application, the footprint-wide Full Network Model (FNM) and flow-based transmission modeling and congestion management based on locational marginal pricing (LMP). These are explained below.

Reliability Implications

Increased Coordination

Electricity reliability can be enhanced by coordinating operations over a wider geographic footprint.[12] This is a key benefit of an EIM + DAMS. Increased coordination should be understood in combination with many of the other benefits described in this report. The following are some key examples.

The EIM + DAMS market operator would be able to see dependencies across different parts of the system that individual BAs with a more limited view may not. The EIM + DAMS market operator would have a broader wide area view than the individual participants. This would allow the market operator a holistic view of the interactions and dependencies between participants. Greater visibility of the interactions and electrical effects between and across participants may help the market operator alleviate seams issues and improve reliability. (See, for example, Transmission Congestion and BA to BA Coordination sections below.)

A larger, more diverse, geographic footprint reduces the risk of a single point of failure. A larger, more diverse geographic footprint may have more resources available to manage contingencies like generator trips or transmission outages. Such resources could include additional generation, more transmission solutions, or increased demand response options. By centrally analyzing the potential

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[11] See CAISO's Market Analysis Engine, attached as Appendix A; see also, e.g., BPM for the EIM, §7 Full Network Model; CAISO's Business Practice Manual for Market Instruments, v.58 (Updated Jan. 29, 2020), Attachment B, Master File Update Procedures.

[12] Federal Energy Regulatory Commission staff paper, Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market, at 3 (February 26, 2013), *citing* U.S. Department of Energy Secretary of Energy Advisory Board, Maintaining Reliability in a Competitive U.S. Electricity Industry: Final Report of the Task Force on Electric System Reliability, at 25 (September 29, 1998).

single points of failure across the wider footprint in the day-ahead timeframe, preparations could be arranged to respond to these potential failures more effectively through the commitment process.

A larger more closely coordinated market increases the diversity of solutions for addressing reliability issues. In an EIM + DAMS construct, reliability issues can be identified in a day-ahead timeframe and therefore addressed before real-time operations using a wider variety of resources available to the market. For example, one way to reliably integrate distributed energy resources (DER) and VER is through demand response. As difficult-to-predict VER and DER supply changes, rather than necessitating backup supply, the resulting price signals or direct load control[13] could allow load to decrease (or increase) in response to variable supply from DER and VER resources. Further, over time, in an EIM + DAMS, demand response might increase in scope, scale, type, and efficacy. As more demand response becomes available to the market, customers—aided by information technology and software advancements— have the potential to provide reliable options or substitutes potentially at a lower cost for a variety of elements in regional markets, including generation, transmission, and ancillary services.

Uniform Application of Market Tools

A regional market can provide the economies of scale needed to develop and deploy new grid tools. An EIM + DAMS would use an advanced set of tools in the day-ahead time frame and apply them uniformly across multiple BAs. In many cases, this optimization will likely be more geographically expansive, technically sophisticated, or comprehensively automated than optimization processes currently used by individual BAs.

The SCUC Optimization Application co-optimizes all resources across a wide area. The SCUC is the computer algorithm used by CAISO to produce a day-ahead commitment schedule, for each hour in the operating day, for the entire EIM + DAMS region.[14] The SCUC co-optimizes energy and ancillary services with congestion while meeting all reliability constraints, such as ramping resource and other physical transition constraints like combined cycle configuration management. Co-optimization means that the algorithm solves for multiple variables simultaneously (i.e., all resource types and ancillary services) to find the system-wide, least cost solution. The SCUC determines in the day-ahead market which resources will be turned on and determines their optimal megawatt output level. The SCED, applied in the real-time market, issues output level or dispatch instructions.[15] Generally, the dispatch signals are for resource output changes between intervals based on the need to follow the changing

[13] As used here, price signals and direct load control refer to two forms of DR.

[14] The SCUC also produces ancillary service capacity holding schedules and interchange schedules.

[15] The CAISO also issues commitment instructions for fast-start resources in the 15-minute market. Therefore, the EIM only requires EIM Entities to do unit commitment for resources with start-up times exceeding 4.5 hours.

load and other factors.[16] Very few, if any, BAs in the Western Interconnection, outside of the CAISO, co-optimize all resource types, AS and transmission constraints simultaneously. None co-optimize as extensively geographically as would the market operator over the EIM + DAMS footprint.

The EIM + DAMS Full Network Model (FNM) would provide a comprehensive result across the footprint. The CAISO's FNM[17] is a representation of the market area. All wholesale load delivery points and generating resources are identified in the FNM by nodes interconnected to each other by a network of connections that represent the transmission system. It is supplemented with commercial and operational data which includes resource attributes, equipment capabilities and topology related information provided by market participants. See Appendix A. The FNM enables the central market operator to conduct power flow analyses. These determine where power will flow on the transmission network between all generators and loads for given loading conditions and identify transmission constraints which inform the commitment and dispatch solutions.

Currently, BAs participating in the EIM maintain their own network model processes and regularly export the information to CAISO. CAISO includes each BA's information into its own FNM, which it uses to manage the EIM. With day-ahead market optimization, the EIM + DAMS FNM would extend across the geographic footprint of all participants. The resulting wide-area view may improve reliability because the market operator can determine actual transmission use, generation output, and generation availability, all in a single model. Further, a move to a flow-based evaluation of the transmission system could improve reliability across the Western Interconnection, even for those who are not participating in an organized market.

Locational Marginal Pricing (LMP). In both day-ahead and in real time, an LMP is calculated for each of the nodes in the FNM reflecting the relative value of energy at each node. The LMP is comprised of three components.[18] First is the System Marginal Price (SMP). The system demand is generally served starting with the cheapest resource bid and continues with the next cheapest bid until total demand is met. The SMP is indicative of the incremental price at which all demand has already been met and if one more MW was needed to be served. The SMP is the same price across the entire market footprint (i.e., for each node depicted in the model). Second is the Marginal Congestion Cost (MCC). If a node is unable to be served by the cheapest resource on the system (SMP) because of a transmission constraint, and instead must be served by a more expensive resource at a different location (i.e., node), the

[16] Other factors include, for example, changing interchange obligations, replace energy as needed, and adjust various resource outputs to resolve power flow issues on transmission facilities.

[17] The CAISO's network model is called the Full Network Model (FNM).

[18] In the EIM, there is also a greenhouse gas (GHG) component for sales into the CAISO by entities outside of the CAISO BA. This concept will probably continue in an EIM + DAMS, but the mechanism for GHG accounting in the day-ahead market has not yet been determined.

incremental cost to obtain that additional MW of energy represents the cost that transmission constraint is causing upon the load at that node. If no constraints are binding or influencing the dispatch of generation anywhere on the system, then the MCC will be zero at all nodes.

The third component is the Marginal Loss Component (MLC). Losses of energy occur when energy flows on the transmission system.[19] The MLC represents this energy loss and highlights that farther away generation is not as desirable as more local generation in terms of energy lost.

LMP-based pricing provides consistent, transparent, and detailed identification of reliability constraints, as compared to pricing in bilateral markets. In the bilateral paradigm, contracts, in the form of energy schedules, are arranged between resources and load. If reliability constraints arise between a resource and that load, the energy schedule is terminated and the load re-procures another resource, often at a higher cost. It may not be clear why the schedule was terminated. For example, in most cases the LSE only knows that its cost to serve demand increased.[20] Similarly, the resource only knows that its revenue was reduced or lost. If the termination persists, over time the resource may receive insufficient revenue to continue operating and the LSE may find itself not only with high costs for its customers, but potentially unable to serve those customers.

Determining the LMP at each node provides insight for all market participants into the ability of the transmission system to facilitate delivery of energy to any point. Programmatically, the LMP results from the SCUC and SCED delivering and withdrawing energy to each node in the most efficient way possible. Analyzing LMPs at a node over time, or compared to other nodes of interest, reveals detailed information that can be used to optimize the use of existing resources, identify areas where transmission enhancements or generation additions are needed to improve reliability or reduce costs.

Enhanced Ability to Manage Variability

The increase of variable energy resources (VER) on the system will likely continue, spurred by advancements in technology, improved VER economics, and energy policies of Western states or individual utilities. Generally, VERs are not "dispatchable" in the same way as traditional thermal resources. Most modern VER are technically capable of being dispatched, either up or down, under sunny or windy conditions. However, there remains uncertainty regarding overall VER resource availability (for example, during cloudy or non-windy periods). In addition, some VER owners may hesitate to dispatch down for commercial reasons. These considerations mean BAs must model and operate VERs differently.

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[19] For example, when electricity flows on power lines, a portion of that energy converts into heat, heating up the wires and dissipating into the air surrounding the wires.

[20] We recognize that LSEs can participate in different ways and some may have more insight than others through different levels of participation.

In some cases, the specific type of technology can lead to a straightforward assessment of the time and duration of additional capacity needs; an example is solar generation. Additional downward capability is needed during the time that the sun is rising and solar output is increasing and vice versa. However, what is difficult to forecast is the variability throughout the day as a cloudy weather front passes over the area. Forecasting has improved with the accumulation of wind and solar data. Many BAs have also instituted flexibility reserves, or load following reserves, an amount of capacity that move up or down quickly in response to errors in forecasts, both for load and variable generation. In this case, the BA must hold back capacity so that it can respond, if needed. In the bilateral paradigm, energy is typically sold in fixed, hourly amounts, and the BA arranges for an import of a fixed amount of energy that would offset some of its own, internal controllable generation, such as a gas generator. This frees up those controllable resources so that they are available to be used for responding to intra-hour fluctuations.

In an organized market, the central market operator performs a day-ahead analysis that combines all available resources, obligations, and constraints across the market footprint (i.e., multiple BA areas). With a larger geographic footprint there are more resources in total, a greater array of resources and a broader geographic distribution of the resources to draw from to address reliability needs including intra-hour generation variation. Through enhanced coordination the market can exploit this diversity.

Coordinating resources across a wider geographic footprint may decrease net load variability and, in turn, overall flexibility or balancing need. Net load is the total electric demand in the system minus wind and solar generation (VER). It represents the demand that must be met with other, dispatchable sources such as natural gas, hydropower, and imported electricity from outside the system. By coordinating all the resources in a wider geographic footprint, net load variability decreases and, in turn, overall flexibility needs, or balancing needs, decrease (See Figure 2).[21] The variability of the net load increases with increasing renewable energy penetration. Aggregating several transmission areas results in reduced variability.

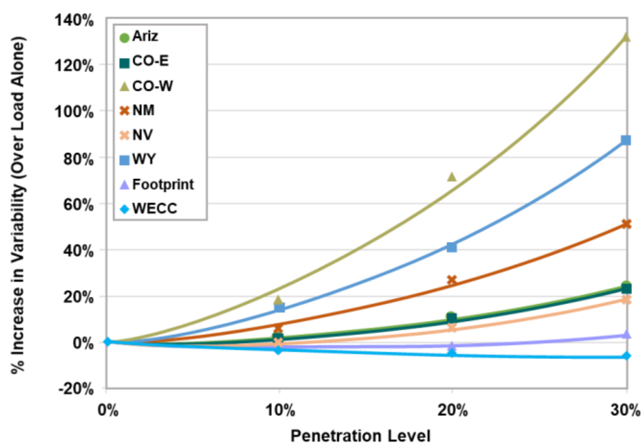

Figure 2

There are several reasons why coordination over a larger grid operating area reduces net load variability. Climate and weather diversity across a larger footprint may reduce the need for balancing.

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[21] National Renewable Energy Laboratory, Western Wind and Solar Integration Study: Executive Summary (May 2010) at 18, available at: https://www.nrel.gov/docs/fy10osti/47781.pdf.

At certain times increases in VER generation in one area (e.g., wind in the Pacific Northwest) can offset decreases in another (e.g., solar in the Desert Southwest). Similarly, the impact of combining load peaks across the wider area can reduce balancing needs, especially when sunset and sunrise do not coincide across the footprint. This complementary diversity provides inherent flexibility across large footprints.

Capturing complementary diversity in the day-ahead commitment can improve reliability. Capturing the complementary diversity can lead to a reduced need for flexible resources and identify potential transmission issues that could arise but that can be mitigated with a coordinated commitment of resources. In the absence of the coordination provided by an EIM + DAMS, the utilities in the DSW and PNW in the example above may elect to carry additional online generation during the operating day. This extra online generation can lead to power flows on the system that cannot be easily remedied without dispatching resources below their minimum online capabilities. Forcing a BA to shut down a resource to mitigate the transmission issues could put that BA in an energy deficient situation later. The centralized EIM+DAMS could identify the potential issues and determine an orderly commitment schedule that avoids these problems.

Resource Sufficiency and Bilateral Market Liquidity

Resource adequacy (RA) is a regulatory construct developed to ensure that there will be enough resources available to serve electric demand under all but the most extreme conditions. RA typically involves an evaluation of future (long-term) energy needs/forecasts and can provide appropriate incentives for siting and construction of new resources to meet those future needs. Resource sufficiency (RS) is like RA, though RS applies to a short-term time horizon, i.e., it evaluates the capacity and resource variability (INC/DEC) to meet forecasted demand in the day-ahead, hour-ahead, and real time. In a full regional transmission organization, there is typically a system-wide process for determining whether entities within the RTO market footprint will meet the total RA needs of the entire system. In the EIM+DAMS construct, each participating BA and the state or local regulatory authority continues to determine how the entities will meet their individual RA requirements within their footprint.

For the purpose of this paper, we assume there would be a RS test in the day-ahead time frame for EIM + DAMS participants, in addition to the current real-time RS evaluation.[22] While no detailed RS EIM + DAMS construct currently exists, we can look to the existing EIM RS evaluation (described below) with the expectation that similar concepts may be applied to an RS EIM + DAMS evaluation. Thus,

[22] We assume that if an EIM+DAMS participant passes the day-ahead RS test, they will still have a real-time RS evaluation. However, it will be different than that applied to EIM-only entities, because EIM+DAMS participants have already passed a day-ahead evaluation and come into the real-time market with a schedule optimized over the market footprint. EIM-only entities come into the real-time market with a BA-wide base schedule.

participating EIM + DAMS BA's should expect to demonstrate appropriate resource capacity and flexibility to meet their BAA load obligations.

Participation in an EIM + DAMS may be affected if participants feel that they are carrying an inequitable share of forward procurement. Exchanging energy to help a neighboring BA, or another participating entity is a benefit of interconnected operations and is a reliability benefit of an organized market. The purpose of an RS evaluation, performed before the EIM and EIM + DAMS market runs, is to determine whether Participating Entities are resource-sufficient, and so minimize leaning. "Leaning" occurs when an entity that is resource deficient uses the market to acquire those resources from others who have made the appropriate forward procurement of capacity and flexibility. When an entity can habitually lean on the market, it may forego forward procurement of appropriate resources. Leaning creates an inequitable situation, which, if not addressed may cause non-leaning entities to change their participation by: 1) adjusting their price of products bid into the market to a point which they believe provides adequate compensation; or 2) adjust their participation in the EIM+DAMS. Should an entity alter their participation level it has the potential to reduce the reliability benefits of the markets.

Reduction in bilateral market liquidity may affect both those participating and those not participating in the organized markets. EIM + DAMS participants will be determining the volume of generation made available to the market for each day. It is anticipated that as participants in the EIM + DAMS turn over most of their unit commitment to the day-ahead market, the liquidity and trading volume of the physical bilateral market would decline. Participating BAs would have less excess capability online for bilateral sales. Fewer trading opportunities in the bilateral market may affect both those participating in the organized markets (EIM and EIM + DAMS) and those participating only in the bilateral market.

In the EIM, reductions in liquidity have been observed between the EIM participants and other entities due in part to EIM scheduling timelines. EIM participants often complete all their hour ahead activity near the top of the prior hour (T-60'), as required by market scheduling timelines, while non-EIM participants have until 20 minutes before the hour of flow (T-20') to continue to transact. This difference in scheduling timelines has created different pools of liquidity and trading partners. If a limited number of entities decide not to participate in the DAMS portion of the market, this group would only be able to trade, day-ahead, with the other entities not in the EIM + DAMS. While an immediate reliability problem may not develop there remains a risk that the pool of non-participating organizations may not be able to meet all the reliability obligations of this group. Likewise, if an EIM or EIM + DAMS participant fails the market resource sufficiency evaluation, their options to cure the deficiency would also be limited by the reduced liquidity in the bilateral market.

EIM Entities enter the organized market in real time and must pass a real-time RS evaluation that tests transmission, balancing, capacity, and flexibility ramp sufficiency. Of these evaluations, only the capacity and flexibility ramp tests are binding for participants. In the EIM, when a participant fails this evaluation (is insufficient), they are "limited in access" to the EIM market resources for the interval in which they failed resource sufficiency evaluation. An insufficient entity may turn to the bilateral market, but that market may be much smaller than in the past. This is due in part to continued growth in EIM participation resulting in potentially fewer bilateral trading partners, and in part to the fact that resources are being committed and traded in accordance with the EIM market timelines thus removing these resources from the bilateral trading pool.

Attributes of the new EIM+DAMS RS evaluation method, once designed, could exacerbate the liquidity issues described above. These attributes include:

- The amount of RS (i.e., capacity & flexibility) required to meet day-ahead RS obligations;
- The timing of the test (i.e., how far ahead in the forward market it is applied); and
- Whether participants are limited in their access to the market for failing the day-ahead RS evaluation and whether the participant will be given a chance to cure the deficiency.

Coordination with Gas Markets

Natural gas and electric power trading and scheduling coordination have traditionally been "managed" by distinct unit commitment and gas nomination cycles. In the West, most electric trading and unit commitments follow the Preschedule Calendar produced by the WECC Market Interface Committee (MIC) and the Interchange Scheduling and Accounting Subcommittee (ISAS) standard guideline. This electric trading calendar allows for single and multiple day trading events based on weekends, first of the month transitions, and NERC holidays. Similarly, natural gas trading occurs according to its own calendar. Though similar, these calendars are not identical, and often electric and gas trading timelines do not coincide. In the bilateral paradigm, the natural gas required to fuel unit commitment does not typically trade on the same day that the unit uses the fuel nor does it coincide with a standard "next day" electric schedule. This mismatch has always introduced some level of risk for utilities, but this risk has been managed.

In an EIM + DAMS framework, if electricity optimization and gas trading take place on different schedules, Participating Entities may need to modify their operational practices and/or consider their risk tolerance to accommodate this scheduling mismatch. Entities bidding into the market need to consider implications to the gas market, and vice versa. When an electricity supplier does not know whether it will receive a day ahead award by the time it must make a decision about gas purchases, that supplier may need to evaluate the probability that its resource is "in-the-money." More generally, if the supplier believes that its resource is economic and is likely to receive a day ahead award, it may choose to purchase fuel in advance. If the supplier chooses not to pre-purchase fuel, then it may face the economic risks associated with procuring gas off-cycle (should the resource receive an award). Alternatively, the supplier could choose to self-schedule its resource in the electricity market, potentially undermining some of the optimization benefits of EIM + DAMS. Additionally, since participation in the EIM + DAMS is voluntary, the supplier could also choose not to bid the electricity from some gas plants into the market because the electricity supplier believes that it would be unable to acquire the gas off-cycle or at a price that would make the resource profitable.

There is potential for fuel under-procurement which could affect market participation and, if wide-spread, reliability. More generally, if a unit is not scheduled in the DAMS optimization, but is instead committed intra-day, because of the differing gas scheduling timeline, the entity will have to arrange to procure gas and gas transport off-cycle. Owners of firm gas transport and not scheduled by 1100 PPT will revert to non-firm transport and offered up for market use. Broadly, if intra-day gas markets are not sufficiently liquid, electricity suppliers could face challenges fulfilling unit schedules (both intra-day and day ahead). If fuel under-procurement became widespread, and if large numbers of resources became consistently unable to anticipate or adapt to day-ahead awards, there is arguably potential for a short-term reliability risk. However, as has been the case in other centralized markets and as was the case when the EIM was first implemented, it is reasonable to expect electricity suppliers to become more familiar with market operations over time. As suppliers observe how the economics of their resources compare to the economics of EIM + DAMS, they may develop more confidence to procure fuel in advance or to purchase intra-day. As noted above, the mismatch between electricity and gas scheduling timelines is not new. Nonetheless, Participating Entities may need to modify their business operations and risk assessment tools to respond to the new challenges presented by the EIM + DAMS framework.

2.2 Transmission Congestion

Transmission congestion is essentially the result of inadequate transmission capacity, which constrains electrical current from flowing. Transmission constraints can occur because of thermal, stability, or voltage limitations. They typically manifest as power flows that actually or potentially exceed a System Operating Limit (SOL).[23] Transmission congestion impedes the ability of system operators to meet system demand by blocking transmission flows, potentially preventing generation from reaching demand. Congestion is an economic issue because it can keep lower cost energy from reaching load, but it can potentially jeopardize reliability—the ability to supply the aggregate electrical demand and system energy requirements at all times.

Day-Ahead Bilateral Market Practices

Outside of the CAISO BA area, individual transmission providers and operators in each BA control the transmission. Parties use a contract path reservation method that is governed by the participating entities' OATT, which functions as a comprehensive rulebook for operating the transmission system. The contract path reservation method bases operation of the transmission system on contracts between

[23] Reliability Coordinators establish SOLs (values for MW, MVAR, amperes, frequency, or volts) to ensure the transmission system operates securely.

generation and load, including firm and non-firm transmission right priorities. In operation, transmission capacity is limited by calculated limits based on anticipated operating conditions and system configuration. These "proxy" limits estimate transmission use and are determined well ahead of the operating horizon. They are designed to limit capacity such that violations of SOLs should not occur. In real time, actual system conditions may result in more or less transmission capability being available.

One cause of transmission congestion is unscheduled loop flow.[24] In the Western Interconnection, outside the CAISO, unscheduled loop flow is managed by two means. First is the Unscheduled Flow Mitigation Plan (UFMP), which governs how flow is managed on four major transmission paths. The UFMP is a complex procedure that relies on methods like phase shifting, manual processes, and energy tag curtailments to mitigate loop flow. The UFMP is initiated when the transmission operator detects transmission congestion on a path. This procedure first allows for use of qualified controllable devices (such as phase shifting transformers) to attempt to alleviate the unscheduled flow of energy. If that process is unsuccessful, scheduled flows that are affecting the path are curtailed in a pro-rata fashion. For all other transmission paths, the transmission provider works with transmission operators to manage loop flow. This is done by curtailing transmission, redispatching generation, or using transmission loading relief procedures specified in the OATT primarily through manual intervention.

Changes in an EIM+DAMS

CAISO controls and operates transmission within its BA area. The full physical capability of transmission within the market footprint is available for use by the various real-time, intra-day, and day-ahead markets. CAISO applies a uniform transmission access charge (TAC) to load and exports across the market footprint to recover the costs to transmission owners for providing transmission. CAISO uses flow-based congestion management to commit and dispatch resources based on cost and subject to transmission limits, rather than pre-existing contracts. Flow based congestion management uses system data to analyze the actual capability of the transmission system. To manage transmission constraints, CAISO commits and dispatches resources based on their contribution to the flows over the constraints. This typically requires little manual intervention. EIM + DAMS is not a full regional transmission organization. Transmission will be provided to the market on a voluntary basis and the recovery of costs for transmission will unlikely be through a uniform TAC.

In the EIM, participating BAs are required to have delivery capability (i.e., transmission rights) to support the transfers in their Base Schedule. In both day-ahead and real time, BAs and other entities,

[24] Transmission systems are often networks, in which any two points are typically connected by more than one path. In such networks, electric power flows along the path of least electrical resistance, rather than on a path defined by contract. Therefore, unscheduled loop flow is the result of electric power flowing on a different route than was planned or expected based on transmission contract paths.

e.g., load-serving entities (LSE), procure contract path transmission rights to ensure delivery capability from resources, and transmission providers provide transmission capacity in accordance with their OATT. All resources bid into the EIM are optimized by the SCED to serve participating load. It is unlikely the resulting dispatch will match the individual Base Schedules submitted by the BAs and thus there may be unused transmission. Transmission rights are provided to the market on a voluntary basis. Typically, this includes the transmission procured by participating BAs and LSEs that support their Base Schedules and unreserved and unscheduled transmission provided by transmission providers. The extent of the market optimization of resources depends on the amount of transmission made available to the EIM.

In an EIM+DAMS, which is not a full RTO, each BA must satisfy its reliability obligations as defined by NERC Reliability Standards.[25] Each BA would demonstrate its resource sufficiency through its resource offerings (e.g., commit offers, bid range, etc.). The bid offerings must show the BA has enough resources to serve load within its footprint and any kind of uncertainty with internal resources and imports. We assume the transmission rights necessary to deliver these (internal and imported) resources to load are available for market optimization.[26] In addition, we assume the design will provide financial or other incentives for additional transmission offerings in the day-ahead time frame.

Reliability Implications

Relative to an individual BAA's forward optimization, the additional, consolidated EIM+DAMS transmission may provide increased dispatch flexibility in real time. Specifically, the increased transmission availability for market optimization could result in an improved capability to serve load after system contingencies. For example, a BA relying on an imported resource could, if that resource trips, use incremental transmission service to deliver energy to its borders from another resource. In the EIM + DAMS, the market operator would centrally procure replacement energy and ensure deliverability over available transmission, as the BA has turned over commitment authority to the market operator.

With a combined model, the market operator would likely be able to respond more effectively to sudden disturbances than would a group of separate BAs. For example, because an EIM + DAMS would allow CAISO to commit units day-ahead in anticipation of tight real-time system conditions, if such a sudden disturbance occurs the EIM+DAMS will likely be better prepared to withstand such an event than an individual BAA.

The amount of transmission available to effectively manage forward congestion will increase. An EIM + DAMS would allow not only the pooling of current EIM resources for dispatch to meet real-time

[25] NERC Reliability Standards are available at: https://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf

[26] Though this is usually the case in the EIM, it is not explicitly in the EIM design.

needs, but also the central market operator to commit additional resources, to the extent they are made available to the operator, to manage expected next-day congestion using a SCUC process. Certain resources cannot currently be committed in real time fast enough to manage real-time congestion in the EIM. Moreover, pooling bulk electrical system elements into a forward operational planning model would provide greater visibility into expected forward transmission availability. This enables the market operator to plan for the transmission of additional resources to meet expected congestion. Further, in expanding the day-ahead optimization model, the EIM + DAMS may allow operators to use counter-flows more than would otherwise exist in a single BA optimization[27] and thereby manage congestion and support scheduled flows that may otherwise need to be curtailed. Counter-flows can aid reliability by easing congestion of electric power flows in the "normal" direction.

An EIM+DAMS may reduce the amount of unscheduled flows and the need to use the UFMP. In an EIM + DAMS, procuring generating resources in the day-ahead-time frame using a flow-based model can result in more automated and efficient ways to dispatch power over the traditional contractual path approach. Doing so, would result in a more accurate system visualization (relative to the inaccurate contract path approach), and consequently fewer unscheduled flows, fewer manual curtailments, and enhanced reliability. Higher levels of flow-based power dispatch could also reduce the need for "qualified controllable devices (i.e. phase shifters) and reduce the curtailment of variable energy resources. One would expect the use of UFMP to manage unscheduled flows to decrease over time as stakeholders grow more comfortable with the consolidated, flow-based EIM+DAMS method.

Reliability benefits will correspond to the amount of transmission provided to the market and there may be less than full participation and incentives for participants to retain transmission. Because an EIM + DAMS would be a voluntary market, it is expected that some of the reliability benefits would be proportional to the amount of transmission that Participating Entities make available to the day-ahead market. Further, while not an explicit reliability benefit or risk, the retention of transmission capacity from the day-ahead market could result in increased energy price volatility in both the EIM + DAMS itself and in BAAs outside of CAISO that do not participate in the EIM + DAMS.[28]

Further, all EIM BAs may not participate at first, or at all. Therefore, even though some congestion management responsibilities might be consolidated, some congestion management practices could remain balkanized because of the BAs that are not participating. This would under-use resources across the market footprint. Finally, lumpy adoption of the EIM + DAMS framework would not only reduce

[27] Counter-flows are flows of electric power that move in the reverse direction of the "normal" or typical flow of electric power on a transmission facility.

[28] Price volatility does not directly affect reliability but may affect it indirectly by changing market participants' perceptions of the CAISO EIM + DAMS. Volatile energy prices tend to result in short-term price spikes, which could motivate new resources to enter the market, aiding reliability. However, volatile prices can at times also depress prices, leading to less resource participation and harming long run reliability.

the expected congestion management benefits, but may also discourage an individual BA from offering transmission to the EIM + DAMS as a risk reduction strategy (i.e., to ensure that it is able to manage contingencies in its area and meet its obligations under any reserve sharing agreements). Such transmission retention could be done either explicitly or implicitly (as a result of an expanded use of reliability margins in transmission line limit calculations).[29] Depending on the mechanisms used to reduce transmission offerings, other non-participating BAs may have a reduced ability to access resources to serve their load.

2.3 BA to BA Coordination

Seams are inefficiencies or barriers that occur between trading jurisdictions or transmission regions because of different practices, rules, or procedures. Seams can inhibit the economic transfer of capacity or energy and adversely affect reliability. Examples of seams issues are differences in market rules and designs, operating scheduling protocols, transmission scheduling, pricing model variation and transmission tariff service.

The following types of seams may be affected by implementation of an EIM + DAMS:

- Between participating BAs (internal seams); and
- Between EIM+DAMS participants and participants in other markets (market-to-market seams).

Each type of seam has unique characteristics that must be considered and managed.

Reliability Implications

The development of the EIM +DAMS may create new seams issues but also may address some of the existing concerns. Seams issues are common in electricity scheduling and trading but, over time, processes have been developed to overcome many of the barriers they may present.

Internal seams (between participating BAs)

The EIM+DAMS could improve BA to BA coordination. In an EIM + DAMS, the currently balkanized forward congestion management functions would be consolidated into a centralized entity (the CAISO), which would be able to combine more electrical system elements into one model, operate under common rules, and more flexibly accommodate tariff differences. With an expanded wide-area view and more detailed data, the market operator may be able to address some seams issues by recognizing interdependencies between participants. For example, unscheduled flow can result in unintended congestion in one transmission operator's territory driven by production of a generator in another transmission operator's territory. When the market operator can see across many participants, it can manage this type of congestion. This could eliminate many day-ahead seams issues , improving

[29] Set asides used on certain transmission paths or under certain conditions for emergencies or other unexpected conditions.

reliability through enhanced congestion management. The BA borders still exist but the operational constraints may be significantly relaxed.

Some may consider running the transmission system closer to reliability limits a reliability risk. On the one hand, transmission usage may increase in the course of providing additional remote resource delivery. Therefore, the system may operate closer to reliability limits on some paths, which some may consider a reliability risk. On the other hand, this may be balanced by the increased accuracy in the tools that use the transmission system and the relaxation of seams within the market footprint. Moreover, because transmission owners would continue to decide on the reliability criteria and limits needed to be built into their transmission line ratings and would choose the exact amount of transmission made available to an EIM + DAMS according to those criteria, some may not view this a significant potential reliability risk.

Market-to-market seams (between EIM+DAMS and other organized markets)

There is a risk to reliability if congestion relief processes are not properly coordinated between the market operators. With the entry of other energy imbalance markets in the Western Interconnection,[30] seams between organized markets may develop. Real-time correction of congestion is expected to continue by redispatching generation. However, when the redispatch must occur by a combination of resources in both markets, or one market must redispatch generation to correct transmission loading in the other market, proper coordination is required to avoid confusion or an inadequate response. Typically, the two markets would develop a joint operation agreement.

2.4 Ancillary Services

Day-Ahead Bilateral Market Practices

BAs are required to manage AS in their footprints. To satisfy this requirement, BAs may maintain certain operational practices, procure AS, or share responsibilities with others in a Reserve Sharing Group (RSG). See Section 2.1. Many BAs in the Western Interconnection participate in an RSG for various types of AS. For example, by sharing contingency reserves, participants in an RSG can call on assistance from the group to cover a contingency or disturbance when their own reserves are not sufficient. Contingency reserve obligations are established for the entire reserve sharing group, which may lower the obligation for individual participants.

[30] The Southwest Power Pool is developing a Western Energy Imbalance Service market for participants in the Western Interconnection. *See* Southwest Power Pool Western Energy Imbalance Service webpage: https://spp.org/weis/.

EIM Practices in Real Time

As BAs, EIM entities are responsible for procuring and managing their own AS to comply with NERC and WECC requirements. Each BA, including the CAISO BA, deploys their own reserves as they see fit to satisfy their BA obligations. EIM participants notify the real-time market operator, CAISO, where the AS are allocated as part of their base schedule submissions, and the CAISO SCED protects the upward/downward balancing capacity and contingency reserves from being dispatched to meet EIM footprint needs. Without setting aside this reserve capacity, the real-time market could elect to dispatch that capacity economically, leaving the participating BA without the reserve capacity it needs to respond to BA balancing needs.

Changes in an EIM+DAMS

CAISO offers four AS products[31] in the day-ahead and real-time markets:

1. Regulation up
14. Regulation down
15. Spinning reserve
16. Non-spinning reserve

The CAISO's market co-optimizes energy and AS, subject to transmission congestion and other security constraints. CAISO participants can get AS from the market or provide AS themselves. The CAISO procures 100% of its own AS requirements in the day-ahead market based on its load forecast. Between the day-ahead market and real-time operating horizon, circumstances can change, requiring incremental procurement of AS. This occurs under two scenarios: (1) AS requirements have changed (e.g., AS capacity has been used and needs to be replenished); or (2) a unit with an AS award in the day-ahead is unable to provide that service in real time.

If the EIM+DAMS includes AS, we assume that AS products would be offered to EIM entities on the same basis as full CAISO participants. AS are not currently traded or co-optimized in the EIM. Therefore, if AS is offered in the EIM+DAMS, it may affect both day-ahead and real-time operations. We assume that the primary benefit of co-optimizing energy with AS in an EIM-DAMS market will be economic because resources providing AS would be selected by a market algorithm on a least-cost basis,[32] but there may also be reliability benefits.

[31] In addition to the four bid-in AS products in CAISO's markets, a broader list of general AS includes, but is not limited to: Load Following Up, Load Following Down, and Primary Frequency Response. These AS are scheduled or procured differently than the bid-in products listed above, but nonetheless serve important reliability functions.

[32] However, because BAs will maintain their own AS responsibilities, there is a risk that AS procurement could be duplicated, which could lower the economic benefits.

Reliability Implications

A larger geographic footprint, broader pool of resources, and automated processes may improve the speed and quality of contingency response. For example, a larger, more diverse geographic footprint reduces the risk of a single point of failure for delivery of AS and supports more robust use of the import and export capabilities of each participating BA. Combined with the deliverability assurance of the SCUC and SCED algorithms, there is a higher likelihood of reserves being allocated to resources that are more fully deliverable for more contingencies than if the commitment was done on a BA-centric basis. The ultimate design of the EIM + DAMS AS products will be important to ensure that these potential reliability benefits are maximized.

Procuring reserves day ahead and co-optimizing energy with ancillary services proactively positions resources to respond to future supply or demand variability. Reserves are moved away from, and energy production to, locations that need more energy to reduce congestion. If the market optimization determines that AS capacity is needed as energy to resolve transmission constraints and/or satisfy the energy balance constraint, then such AS capacity can be partially or entirely converted to energy and the AS allocation relocated to other resources.

Considering that many BAs currently participate in reserve sharing groups and are likely to maintain this participation, there may be uncertainty around the actual deployment of AS. Specifically, there is a possibility that AS procurement could be duplicated and thereby eliminate the economic benefits of optimization or that instructions for actual AS deployment could conflict between CAISO and the EIM BA or reserve sharing group. As stated earlier, this is an important design element consideration for an EIM + DAMS proposal.

2.5 Contingency Analysis

Contingency analysis is a process used to simulate how the bulk power system reacts to the loss of transmission or generation resources. The analysis assumes a certain forecasted load, expected transmission network topology,[33] and generator dispatch. It then applies a series of different contingency scenarios (e.g., outage of a large generating facility or transmission line) to test the transmission system's reaction. Power systems engineers create scenarios to analyze how these credible equipment disruptions could affect transmission system reliability. These types of disruptions are typically called "N-1" or "N-2" contingencies where the system is running under normal conditions (N) and loses one facility (N-1) or two facilities simultaneously (N-2). Transmission planners and operators study these scenarios to ensure that the post-contingency (after the event) loadings on the

[33] Network topology as used here is the set of transmission facilities (e.g., transmission lines and transformers) in-service at a given time that connects generating facilities to load.

transmission system do not violate established reliability criteria such as thermal, voltage, or stability limitations.

Day-Ahead Bilateral Market Practices

Transmission operators and BAs are responsible for next-day operations planning. Transmission operators are required to perform a daily operational planning analysis to assess whether planned operations for the next day will exceed any SOLs. This daily analysis includes a contingency analysis.

EIM Practices in Real Time

The results of the next-day contingency analysis are included in the results of each EIM Entity's base schedule. In the day-ahead time frame, CAISO uses load forecast and anticipated resource base schedule data collected from EIM Entities to identify whether their base schedules might cause transmission overloads in the EIM footprint, and if so, provides advisory information to EIM BAs so they can revise their base schedules.[34] While CAISO does not currently commit and schedule generation within the EIM footprint on a day-ahead basis, CAISO seeks to ensure that the transmission system within the EIM footprint does not violate limits.

Changes in an EIM+DAMS

The CAISO's day-ahead market contingency analysis is integrated into the optimization process. (See Appendix A.) The calculated generator output levels of the SCUC process are used as an input into CAISO's AC power flow analysis engine, which uses the FNM to calculate real and reactive transmission line loadings. The AC power flow solution serves as a base case for a contingency analysis that is performed for a pre-defined and pre-determined set of "N-1" and critical "N-2" transmission outage conditions. The SCUC and AC power flow contingency analysis process is iterative (it is automatic and part of the market solution) and may need to undergo several iterations until a SCUC solution is found that does not violate SOLs. CAISO identifies expected loadings on the transmission system following a set of various contingency outages in advance of real-time operations. This enables CAISO to commit and schedule generating facilities so that the transmission system can withstand the sudden loss of transmission lines or generating facilities. Under an EIM+DAMS, the analysis would cover the entire market footprint, thus analyzing a more comprehensive set of data over a wider area than any individual BA.

Reliability Implications

CAISO's day-ahead market contingency analysis tool allows CAISO, in advance of real-time operations, to identify expected loadings on the transmission system following a set of various contingency outages. In particular, CAISO's market optimization process has an integrated day-ahead

[34] CAISO BPM for the EIM at 11.

contingency analysis tool that would be used to make unit commitment and scheduling decisions to ensure that no contingency on the contingency list causes violations of emergency transmission system limits.[35]

In an EIM + DAMS, the day-ahead contingency analyses that are currently individually employed by the EIM Entities would be complemented by CAISO's day-ahead market contingency analysis which applies an advanced market tool and considers resources and conditions across the broader market footprint. Before an operating day, CAISO will study and model anticipated demand, availability of generating facilities to serve load, and expected transmission. The CAISO's next-day contingency analysis, described above, is integrated into this modeling and would occur over the market-wide footprint using a more complete set of data that captures a wider area view than that of any individual BA.

The day-ahead market-wide contingency analysis would supplant the limited and fragmented process used in the EIM with a more streamlined process. Currently, CAISO coordinates with EIM Entities in the day-ahead time frame by reviewing their proposed base schedules to determine whether they are infeasible and would cause transmission constraints in the EIM footprint. If a base schedule is infeasible, CAISO coordinates with the EIM Entity so that it submits a revised base schedule. However, EIM Entities retain responsibility for unit commitment, therefore, the current unit commitment process may require back-and-forth between CAISO and EIM Entities to cure infeasible base schedules.

CAISO would conduct its footprint-wide analysis in addition to each BA's contingency analysis. In an EIM + DAMS, the market footprint would neither be a single consolidated BAA nor transmission operator area, and the NERC requirements for next-day operations planning will continue to apply to participants. Thus, each participating BA still needs to comply with their next day planning requirements and ensure that the unit commitment schedules for their respective areas are feasible.

The market-wide day-ahead contingency analysis may improve responses to contingency events such as severe weather. For example, if a certain BA expects a severe thunderstorm the next day, there is an increased risk of one or more contingencies resulting from a lightning strike on a specific transmission line, or other facility in that BA area. In the bilateral paradigm, the system operators in the affected BAs would commit and position generating facilities within their respective BA areas. In an EIM + DAMS, when modeling the critical contingencies, including expected severe weather conditions, the market optimization can consider all the generating facilities made available throughout the entire market footprint, while respecting available transmission and other constraints. This can result in a more optimized unit commitment and dispatch decision than would be achievable by an individual BA.

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[35] CAISO's Business Practice Manual for Managing the Full Network Model, v.18 (revised Jan. 28, 2010) ("CAISO BPM FNM") at 87. See Appendix A for more information on CAISO's Market Analysis Engine.

3 Conclusions and Recommendations

This report explores the potential reliability impacts of an EIM + DAMS in five areas: 1) general day-ahead operations; 2) transmission congestion; 3) BA-to-BA coordination; 4) ancillary services; and 5) contingency analysis. The assessment describes several reliability considerations—some potential benefits and some potential challenges or risks. We note that the degree of some benefits or risks would be a function of market participation. For example, a reduction in participation could result in a reduction or elimination of a reliability benefit.

The potential reliability benefits of an EIM+DAMS fall into the three general themes, described below.

1. ***Improved coordination across a broader geographic footprint***. This includes an expanded solution set for addressing reliability issues and accelerated deployment of new grid management tools.
2. ***Use of advanced tools in the day-ahead time frame and uniform application across multiple BAs***. Such tools include: SCUC to co-optimize energy and ancillary services while respecting transmission and reliability constraints; a full network model (i.e., flow-based modeling); and locational marginal pricing-based congestion management. Uniform application of these tools supports:
   a. An improved wide-area view by the market operator for use in developing the day-ahead commitment resulting from the central application of automated tools like the SCUC and FNM across a broader geographic footprint. This allows the market operator to anticipate future problems more accurately and to position resources to effectively address reliability.
   b. An improved response to variability resulting from the centralized application of automated tools and resource commitment over a broader geographic footprint with a larger number of resources and more diverse resource pool.
   c. Improved congestion management and relaxed impact of seams between and among BAs participating in the day-ahead market, resulting from a more accurate calculation and use of the transmission system through system-wide flow-based modeling and the application of a locational marginal pricing (LMP)-based optimization.
3. ***Better positioning and set-up for real-time operations resulting from optimized unit commitments in the day-ahead over a larger geographic footprint***. This leads to improved speed and quality of contingency response.

The Working Group also identified some issues that could present challenges or become risks. As the EDAM market design is under development, these issues represent areas that need to be addressed during that process.

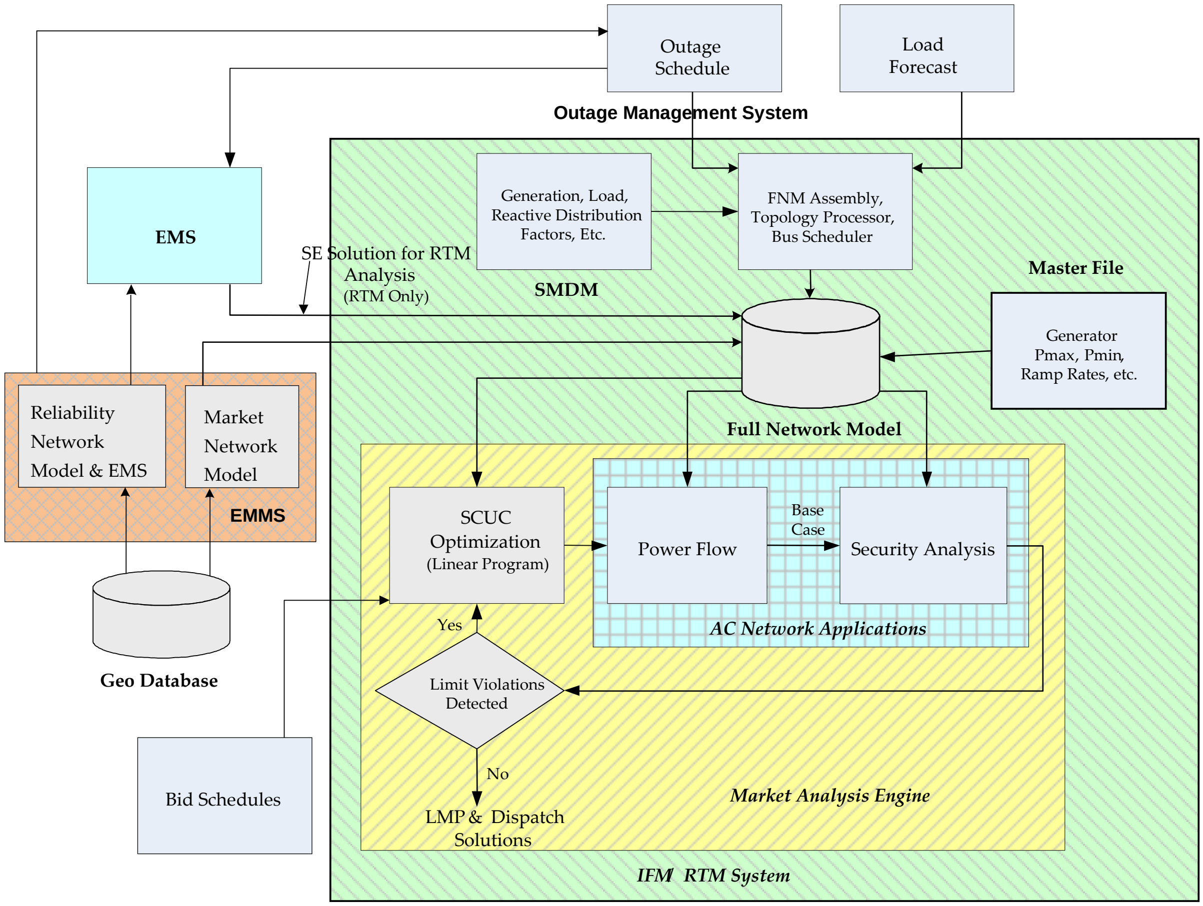
1. Additional complexity for transmission operations, which includes new challenges managing seams between organized markets and operating closer to SOLs.

2. Reduction of day-ahead liquidity in the bilateral trading market, which could affect participants in organized markets, as well as those participating only in the bilateral market.
3. Additional complexity for deliverability analysis because the provision of transmission would be voluntary. There may be an incentive for BAs to retain transmission capacity as a risk reduction strategy to preserve their own BA reliability.
4. Potential challenges in gas-electric coordination. In the day-ahead EIM framework, if electricity optimization and gas trading take place on different schedules, market participants outside of the CAISO BA may need to modify their operational practices and risk assessment tools to accommodate this scheduling mismatch. Otherwise, there is the potential for fuel under-procurement which could affect market participation and, if wide-spread, reliability.

This report is a high-level, qualitative assessment and should be viewed as the first step in understanding the reliability implications of the potential expansion of the EIM to include DAMS. A more precise analysis will require specific market design details. In terms of next steps, the Working Group recommends the following:

- WECC should continue to monitor the development of the EDAM, specifically:
  - The design for transmission operations including coordination plans and agreements among and between markets (i.e., the CAISO EDAM and the Southwest Power Pool's Western Energy Imbalance Service)
  - The design for the resource sufficiency evaluation
  - How day-ahead market timelines could affect gas scheduling including business practices and tools that could be employed to offset potential reliability impacts.
- WECC should continue to monitor the effectiveness of reserve requirements as market constructs are designed and operated. It is possible that market operations may encourage the BAs to carry only the required amount of reserves, which, if sufficient, will not affect reliability. However, reduced amount of reserves carried by BAs (when day-ahead market operations begin) could potentially require re-evaluation of reserve requirements. A reduced volume of reserves carried by BAs is not a market design issue; the assumption is that reserve requirements would be met in an organized market.

Appendix A: CAISO's Market Analysis Engine[36]



The Market Analysis Engine is used for analyzing energy and ancillary services scheduling, congestion management, intertie losses, and for calculating LMPs for the day-ahead market (IFM) and the real-time market (RTM). The first function performed by the market analysis engine is the security constraint unit commitment (SCUC). The SCUC function analyzes the bid schedule to determine the optimal generation commitment and dispatch while satisfying constraint violations. The outputs of the SCUC are an optimized dispatch for market clearing within the network, demand, and bid constraints applied, and the locational marginal prices (LMP). The optimized dispatch is used to update the injections and withdrawals of the FNM that is then solved by an AC power flow that calculates bus voltage magnitudes and phase angles from which real and reactive line flows are calculated. The AC Power Flow solution creates the base case for a contingency analysis that is performed for a pre-defined

[36] See CAISO's Market Analysis Engine, attached as Appendix A; see also, e.g., BPM for the EIM, §7 Full Network Model; CAISO's Business Practice Manual for Market Instruments, v.58 (Updated Jan. 29, 2020), Attachment B, Master File Update Procedures. CAISO FNM BPM, at 32-33

and pre-determined set of “n-1” and critical “n-2” outage conditions. This is described in section II, D of the report.

The SCUC application analyzes the generators’ bid schedules to determine the optimal generation commitment and dispatch while satisfying transmission constraint violations. The dispatch levels of the SCUC process are used as an input into CAISO’s AC power flow analysis engine, which uses the FNM to calculate real and reactive transmission line loadings. The AC power flow solution serves as a base case for a contingency analysis that is performed for a pre-defined and pre-determined set of “N-1” and critical “N-2” transmission outage conditions. An N-1 outage refers the outage of a single element such as a transmission line, transformer, or generating facility. A N-2 outage refers to the simultaneous outage of two elements (e.g., simultaneous loss of two transmission lines). The SCUC and AC power flow contingency analysis process is iterative and may need to undergo several iterations until a SCUC solution is found that does not violate SOLs. See Appendix A.

Appendix B: Working Group

The MIC, one of the three WECC standing committees, established a working group for the specific purpose of conducting this assessment. The working group is composed of MIC members from utilities, publicly administered power marketers, the CAISO, nonprofits, and semi-governmental organizations from around the Western Interconnection, as well as FERC staff. Collectively the working group includes expertise on, and experience with, bilateral markets in the West, organized markets, and electricity reliability. In addition to applying the expertise within the working group, the working group reviewed key documents and reports (many of these resources are included in Appendix C); held informational meetings and discussions with subject matter experts from organizations such as FERC, CAISO, and EIM participants; and submitted our work to the MIC and a group of specific outside experts for review and feedback.[37]

MIC Market Expansion Assessment Working Group:

Alaine Ginocchio, Western Interconnection Regional Advisory Body (co-lead)
Robert Follini, Avista (co-lead)
Andrew Meyers, Bonneville Power Administration
Angela Amos, Federal Energy Regulatory Commission*
Ben Foster, Federal Energy Regulatory Commission*
Charles Faust, Western Area Power Administration, Sierra Nevada Region
Darren Lamb, California ISO
Dillon Kolkmann, Federal Energy Regulatory Commission*
Jamie Austin, PacifiCorp
Jason Smith, Xcel Energy
Jennifer Gardner, Western Resource Advocates
Jomo Richardson, Federal Energy Regulatory Commission*
Layne Brown, WECC
Monica Taba, Federal Energy Regulatory Commission*

**The opinions and views expressed in this informational paper do not necessarily represent those of the Federal Energy Regulatory Commission, its Chairperson, or individual Commissioners, and are not binding on the Commission.*

[37] The working group solicited feedback at two key points in the process: (1) on our initial assumptions and potential benefits and risks; and (2) on a draft of the report. Summaries of these comments are on file with Alaine Ginocchio, WIRAB.

Appendix C: Resources

California Independent System Operator Corporation Fifth Replacement FERC Electric Tariff (Open Access Transmission Tariff) (effective September 28, 2019), *available at*: http://www.caiso.com/Documents/Conformed-Tariff-asof-Sep28-2019.pdf

California ISO, Business Practice Manual for the Energy Imbalance Market, Version 15 (Revised May 02, 2019), *available at*: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Energy Imbalance Market

California ISO, Business Practice Manual for Managing Full Network Model, Version 18 (Revised: January 28, 2019), *available at*: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Managing Full Network Model

California ISO, Business Practice Manual for Market Operations, Version 60 (Revised: April 8, 2019), *available at*: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market Operations

California ISO, Extending the Day-Ahead Market to EIM Entities Issue Paper (October 10, 2019), *available at*: http://www.caiso.com/InitiativeDocuments/IssuePaper-ExtendedDayAheadMarket.pdf

California ISO, Clean Energy and Pollution Reduction Act Senate Bill 350 Study Preliminary Results, Stakeholder Template (date submitted, June 22, 2016), *available at*:

EIM Entities Letter to Chair Linvill and EIM Governing Body and Chair Olsen and Board of Governors re: Extended Day-Ahead Market Principles and Elements of the EIM Entities (September 16, 2019), *available at*: http://www.caiso.com/Documents/PublicCommentLetter-EIMEntites-EDAM-Sep16-2019.pdf

Federal Energy Regulatory Commission staff paper, Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market (February 26, 2013), *available at*: https://www.westerneim.com/Documents/QualitativeAssessment-PotentialReliabilityBenefits-WesternEnergyImbalanceMarket.pdf

Federal Energy Regulatory Commission Docket No. ER08-637-000, Midwest Independent Transmission System Operator, Inc., and Transmission Owners of the Midwest Independent Transmission System Operator, Inc. Revisions to Open Access Transmission and Energy Markets Tariff to Implement the Midwest ISO's Western Markets Proposal (filed March 4, 2008) (re: Market Coordination Service Proposal).

Federal Energy Regulatory Commission Docket Nos. ER08-637-000 & 001, Comments of the Midwest Independent Transmission System Operator, Inc. (filed August 12, 2008) (responses to certain specific questions set forth in Appendix B of the FERC's June 13, 2008 Order), (re: Market Coordination Service Proposal).

Federal Energy Regulatory Commission Docket Nos. ER08-637-000 & 001, Comments of the Midwest ISO Transmission Owners. (filed August 12, 2008) (responses to certain specific questions set forth in Appendix B of the FERC's June 13, 2008 Order), (re: Market Coordination Service Proposal).

Federal Energy Regulatory Commission Docket Nos.: ER08-637-000, 001, 004 & 005, FERC Order on Market Service Proposal, 126 FERC ¶ 61,139 (Issued February 19, 2009) (re: Market Coordination Service Proposal).

Garg, Rishi, National Regulatory Research Institute, Electric Transmission Seams: A Primer, NRRI Report No. 15-03 (February 2015), available at: https://pubs.naruc.org/pub/FA86CD9B-D618-6291-D377-F1EFE9650C73.

Mariner Consulting, Why an Energy Imbalance Market Will Make the Western Interconnection More Reliable (November 16, 2012).

Milligan, M. et. al., National Renewable Energy Laboratory, Examination of Potential Benefits of an Energy Imbalance Market in the Western Interconnection (March 2013), *available at*: https://www.nrel.gov/docs/fy13osti/57115.pdf

North American Electric Reliability Corporation, ERO Reliability Risk Priorities RISC Recommendations to the NERC Board of Trustees (February 2018), available at: https://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO-Reliability-_Risk_Priorities-Report_Board_Accepted_February_2018.pdf

North American Electric Reliability Corporation, 2019 ERO Reliability Risk Priorities Report (November 2019), available at: https://www.nerc.com/comm/RISC/Documents/RISC%20ERO%20Priorities%20Report_Third_Draft_September_2019_CLEAN.pdf

North American Electric Reliability Corporation, Frequently Asked Questions (August 2013), *available at:* https://www.nerc.com/AboutNERC/Documents/NERC%20FAQs%20AUG13.pdf

North American Electric Reliability Corporation, Glossary of Terms Used in NERC Reliability Standards (Updated August 12, 2019), *available at*: https://www.nerc.com/files/glossary_of_terms.pdf

North American Electric Reliability Corporation, Reliability Standards for the Bulk Electric Systems of North America (Updated January 2, 2020), *available at*: https://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf

U.S. Department of Energy, Maintaining Reliability in the Modern Power System (December 2016), *available at*: https://www.energy.gov/sites/prod/files/2017/01/f34/Maintaining%20Reliability%20in%20the%20Modern%20Power%20System.pdf

U.S. Department of Energy, Transforming the Nation's Electricity Sector: The Second Installment of the QER, Chapter IV. Ensuring Electricity System Reliability, Security, and Resilience (January 2017) at 4-3, *available at*: https://www.energy.gov/sites/prod/files/2017/01/f34/Chapter%20IV%20Ensuring%20Electricity%20System%20Reliability%2C%20Security%2C%20and%20Resilience.pdf

WECC, Reliability Workshop Summary and Recommendations for Near-Term Priorities (April 13, 2018).