Balancing Market Opportunities in the West

How participation in an expanded balancing market could save customers hundreds of millions of dollars

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EXECUTIVE SUMMARY

The expansion of the California energy market to allow electric utilities from outside the California Independent System Operator (CAISO) footprint to participate in the real-time energy imbalance market (EIM) provides opportunities for substantial savings to ratepayers, improved reliability system-wide, and better integration of variable energy resources such as wind, solar, and hydro. These opportunities are available to all balancing authorities in the West, with systems adjacent to California the most likely initial participants.

PacifiCorp joined CAISO in the October 2014 launch of this expanded balancing market. Nevada Energy is poised to join in October 2015. Other utilities in the West are presumed to be watching closely and considering the advantages to their customers. Several studies have documented the anticipated economic savings of a large regional balancing market. They include an early E3 study in 2011, a National Renewable Energy Laboratory (NREL) follow-up study in 2013, and individual assessments by CAISO, PacifiCorp, and Nevada Energy. Our review of those studies shows that an automated dispatch (such as a security-constrained economic dispatch, or SCED) with a larger quantity of available balancing resources can save $300 million dollars annually for balancing authorities in the West, not including significant reliability benefits and variable resource integration benefits. The production cost savings attributable to various EIM scenarios and sensitivities in the NREL study are presented in Table ES-1.

Table ES-1. 2020 Production Cost Savings under EIM Case and Sensitivities, NREL

Sensitivity Cases in 2020	$MM Savings vs. BAU Case
Base case EIM (hourly dispatch)	$294
Reduced participation sensitivity (hourly dispatch)	$276
Low gas price sensitivity ($4.50/MMBtu)	$281
Faster dispatch (shift from hourly to 10-minute)	$1,312

Source: Adapted from "Summary of West-Wide Results," NREL study, pg. xviii.

To develop a dollar estimate of reliability benefits, we reviewed the FERC staff report on reliability benefits, the NERC report on the September 2011 blackout that led to cascading load drops from Arizona to San Diego, a Brattle Group study, and a London Economics Institute (LEI) paper on the value of lost load. Based on these sources, we constructed an estimate of the cost of the September 2011 blackout in the San Diego area as an illustrative example. Even if an expanded balancing market only prevented a portion of the San Diego blackout, the savings to customers would have been in the hundreds of millions of dollars for just this one event. Table ES-2 presents an estimate of the total cost of the blackout to SDG&E customers.

Table ES-2. Illustrative Example – Quantifying Impacts of the SDG&E Blackout

Quantifying the SDG&E Blackout	
Outage length	12 hours
Customers affected	1.4 million
Capacity dropped	4293 MW
Total lost load	51,516 MWh
Total cost to customers	$775 million
Residential cost	$87 million
Small C&I cost	$537 million
Large C&I cost	$151 million

Note: This table assumes that electricity was restored to half of the customers after 6 hours of the blackout and the remainder after 12 hours.

In addition to balancing market savings and potential reliability savings, an expanded balancing market will provide benefits to daily operation schedules that will need increased flexibility to integrate larger and larger quantities of variable wind, solar, and hydro generation. Experience with variable resources and improvements in forecasting have demonstrated that variable resources are reasonably predictable over a 24-48 hour period. An expanded balancing market that covers a wider geographic area provides two immediate benefits in this area: (1) smoothing of the overall output of variable resources and (2) a wider pool of traditional balancing resources to accommodate small, short-term fluctuations.

With all these advantages, the opportunity to join an expanded balancing market seems too good to pass up. State commissions can take an active role in the process by asking balancing authorities under their jurisdiction to evaluate the benefits of an expanded balancing market for their customers. Utilities in Arizona, due to their proximity to California and Nevada, are probably good candidates for participation in the expanded CAISO balancing market launched this year.

1. INTRODUCTION

There is an opportunity in the Western Interconnection to make significant improvements to the procurement of energy balancing services. Through expanding and better integrating balancing areas, balancing services can be procured at lower cost and reliability can be improved, ultimately benefitting all electricity customers.

Many system operators across the United States have achieved more efficient and reliable balancing operations through enhancing their real-time energy markets and expanding the market to serve a wide geographic area. The California Independent System Operator's (CAISO's) proposal to allow greater participation by balancing service providers in its energy imbalance market provides an opportunity for greater integration in the West that all existing balancing authorities and utilities should consider.[1] Each utility in the region should be asking, "How might my customers benefit from utilizing a larger pool of resources with improved real-time communications and sophisticated five-minute dispatch systems?"

In this paper, we examine the opportunity available to balancing area authorities in the West to participate in the newly expanded CAISO energy imbalance market (EIM). Additionally, we review the recent studies that show the likelihood of significant economic benefits and improved reliability from larger quantities and better integration of balancing resources.

In Section 2, we briefly describe the need for and the current methods of providing balancing services. We then review the CAISO application to the Federal Energy Regulatory Commission (FERC) to allow balancing area authorities and individual resource owners to participate in the CAISO EIM. We note PacifiCorp's separate analysis that convinced them to join the CAISO EIM as balancing resource participants starting in November 2014, and we summarize the recent application by Nevada Energy to join as a balancing resource participant in October 2015. The FERC approved both the CAISO tariff changes and the PacifiCorp conforming tariff changes in separate dockets in June 2014, and the Nevada Commission recently issued its decision to allow Nevada Energy to participate in the CAISO EIM next year. However, the FERC granted rehearing for various reasons in both the CAISO and PacifiCorp dockets on August 20. Although the rehearings add a level of uncertainty to the CAISO EIM, it remains the best-defined proposal for a regional energy imbalance market in the West.

In Section 3, we examine several economic benefit studies conducted over the last three years that evaluate how a broad energy imbalance market open to entities outside of California could substantially reduce overall balancing costs by accessing the lowest-cost balancing resources from numerous balancing area authorities. These studies are consistent and reinforce each other. Next, we examine the reliability benefits that participation in an EIM with a large footprint could provide, based on reports

[1] The CAISO energy imbalance market is simply an expansion of its existing real-time energy market.

produced by the North American Electric Reliability Corporation (NERC) and FERC staff in 2012 and 2013. As an illustrative example, we focus on the September 8, 2011 cascading load drops from Arizona to Southern California and portions of Mexico. We construct a quantitative analysis that estimates the economic savings that an EIM could have achieved by limiting the extent of that disruptive 2011 event.

In Section 4, we discuss the issues that state commissions will need to address to ensure the best outcomes for electricity consumers in their states. Once California, Nevada, and PacifiCorp customers in the Mountain West are engaged in a single regional balancing market, balancing authorities in adjacent states will have an obligation to seek economic benefits and improved reliability for their consumers through evaluating whether to join an EIM. We discuss how state commissions can exercise their oversight to encourage state electric utilities to take advantage of the opportunity available today.

In Section 5, we conclude that most balancing area authorities in the West would experience significant economic benefits from access to the lowest-cost balancing resources during daily real-time operation of their systems. We further conclude that, in addition to the production cost savings associated with an imbalance market, there would also be important reliability benefits from enhanced visibility of system operations across the Western grid as well as quantitative benefits from reduced or avoided load drops and outages due to contingencies on individual systems. Finally, as more variable energy resources such as wind and solar are added across the West, a broad-area EIM would be a valuable tool to assist system operators with the smooth integration of variable resources in daily operations.

Given the myriad benefits of participation in regional energy imbalance markets detailed in this paper, utilities that ignore this opportunity to reduce overall system delivery costs could risk disallowances or other regulatory penalties by their state commissions. At a minimum, the utility would have the burden of showing why they did not choose to join an expanded balancing area.

2. ENERGY IMBALANCE MARKETS

2.1. Purpose and Function

Energy imbalance services provide short-term energy supply resources necessary for balancing area authorities to use to maintain critical grid functions throughout each operating day. While day-ahead scheduling provides an initial balancing of supply resources and anticipated loads, the real-time fluctuations in actual demand and output from supply resources require grid operators to make constant adjustments in order to maintain control performance standards and adequate supply within specific NERC guidelines.[2] The adjustments may be needed for less than a minute or for up to an hour, depending on the exact mix of existing resources providing energy and the rate of change in net load.

Currently, utilities in the West generally balance supply and demand through manually dispatching generation resources, an expensive and inefficient process.[3] Further, as generation from variable resources is added to the overall mix of supply resources, the quantity of balancing services and the frequency with which these balancing resources need to respond both increase.[4] Having a large pool of balancing resources available allows for critical reliability functions to be maintained at the lowest cost.

Today, there two general approaches for grid operators to use to balance their systems. The traditional approach is to balance day-ahead dispatch schedules on an hourly basis in real time with supplemental, short-term bilateral contracts. Since the development of single-dispatch, organized markets (Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs)) in the late 1990s, the balancing of day-ahead schedules is frequently done through complex, automated dispatch algorithms based on 15-minute, and, more recently, 5-minute schedules. These scheduling programs are able to evaluate incremental offers from hundreds of resources while respecting transmission constraints and other operating issues. These programs provide a security-constrained economic dispatch (SCED) of all the available resources every five minutes. In general, the larger the footprint of the balancing authority (or multiple balancing authorities), the more efficient and reliable the dispatch.

The difference between the more manual, traditional approach and the automated, computer-based approach is mostly timing. On many days, events move slowly and both approaches work well. However, when there are sudden changes to the system (contingencies such as the loss of a generator resource or a transmission line), the manual approaches cannot match the speed of response of the SCED models. The integration of more variable resources, particularly naturally variable resources such as wind and solar, will require greater quantities of balancing services at any given moment in order to respond to sometimes instantaneous and unexpected fluctuations in generation from these resources.

Given that many larger balancing authorities—such as PacifiCorp and CAISO—have already made the switch to automated dispatch on intervals at or approaching five minutes, and that many more balancing authorities may be required to invest in automated dispatch capabilities in order to comply with FERC Order 764, the key benefit of a regional energy imbalance market in the West will be opening up a larger volume and wider variety of resources to system operators. This will enable faster, more efficient dispatch for balancing purposes, reducing dispatch from one-hour schedules to five minutes.[5]

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[2] These standards deal with maintaining voltage and frequency within specified ranges and maintaining adequate resources for peak loads, daily ramping, and reserves for contingencies.

[3] FERC Order, Docket ER14-1386, issued June 19, 2014.

[4] Orans, R., A. Olson, J. Moore, "WECC EDT Phase 2 EIM Benefits Analysis & Results (October 2011 Revision)," Energy and Environmental Economics, Inc., prepared for: Western Electricity Coordinating Council, October 11, 2011. Pgs. 8-9.

[5] FERC Order No. 764, which was originally issued on June 22, 2012, and is known as the *Integration of Variable Resources* Final Rule, requires every public utility transmission provider to offer transmission scheduling on 15-minute intervals in an attempt

In early 2010, the Western Electricity Coordinating Council (WECC) responded to growing requests to improve the ability of the Western Interconnection to efficiently manage transmission and generation as renewable penetration increases. The WECC Seams Issues Subcommittee developed the concept of a two-pronged Efficient Dispatch Toolkit that paired an energy imbalance market with an enhanced curtailment calculator.[6] This proposed Efficient Dispatch Toolkit—which did not include already established centralized dispatch operators in California or Alberta—served as the basis of the first round of cost-benefit analyses of an EIM in the West, as discussed in Section 3, below. CAISO submitted an alternative proposal for a regional EIM based on expanding the current market in California, which gained traction and eventually grew into the proposal detailed below and approved by the FERC.

2.2. Opportunity for an Expanded CAISO EIM

In February 2013, CAISO and PacifiCorp, two of the largest electricity providers in the West, entered into an agreement to establish a regional real-time energy imbalance market that would incorporate their respective balancing areas. This agreement followed a benefits study conducted by CAISO and PacifiCorp.

A year later in February 2014, CAISO filed an application with the FERC to amend its transmission tariff. The proposed amendments would provide opportunities for other balancing authority areas to participate with their own balancing resources in CAISO's current real-time energy market.

In this section, we summarize CAISO's proposed tariff changes; the companion filing by PacifiCorp amending its balancing area rules and schedules to facilitate its participation in the CAISO EIM by October 2014; and the agreement reached by Nevada Energy with CAISO to join the EIM by October 2015. Later, in Section 4 we discuss opportunities for other balancing area authorities in the West to also join and participate in a regional imbalance market.

CAISO FERC Application

In June 2014, the FERC accepted CAISO's tariff revisions to allow other balancing area authorities to participate in its real-time energy market for the purpose of providing energy imbalance services beginning October 1, 2014. The newly expanded EIM will use the existing CAISO real-time energy market

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to remove barriers to the integration of variable resources. Although the implementation date and the extent to which utilities in the West will be covered by this ruling remain uncertain, the Order is indicative of a larger trend of balancing authorities moving towards more efficient dispatch. The original Order is available at: http://www.ferc.gov/whats-new/comm-meet/2012/062112/E-3.pdf.

[6] This would improve upon existing capabilities of the curtailment responsibility calculation system, expanding to cover more transmission paths in real time. WECC Staff (2011) "WECC Efficient Dispatch Toolkit Cost-Benefit Analysis (Revised)," Western Electricity Coordinating Council, October 11, 2011.

and allow resource participation from other balancing areas over a wider geographic area. Participation will be voluntary; that is, other balancing area authorities and individual resources within those balancing authorities may participate as much or as little as they choose. Participating balancing authorities will retain their current functions and responsibilities for ensuring reliability within their area, including meeting operating reserve and capacity requirements, scheduling and managing transmission facilities, and manually dispatching resources to maintain reliable operations.

Each participating balancing area authority must enter into an implementation agreement that specifies the date that it will join the EIM, pay a modest fee for implementation costs, and adjust its own open access transmission tariffs (OATTs) as necessary. All of these arrangements will be filed with the FERC. CAISO will not charge an incremental transmission fee for use of transmission to support EIM transfers, although this policy will be reviewed after the first year of operation.[7] If a balancing area authority decides to leave the EIM, there will be no exit fee associated with that decision (the start-up fee and participation costs under the tariff will cover all incurred costs). The entity will need to provide a six-month notice of its decision to cease participation.

The CAISO EIM will require resources that serve California load to comply with relevant California greenhouse gas cap-and-trade regulations by including those compliance costs in their EIM energy bids. Local market power mitigation rules will be applied to each participating balancing area, and interties will be monitored for any necessary market power mitigation.

The approved tariff rules will create four types of EIM market participants:

1. An EIM Entity is the balancing authority and will identify all available transmission intertie capacity available to support energy flows to and from its balancing authority area on a daily basis.

2. EIM Entity Scheduling Coordinator schedules energy flows to and from the EIM as well as schedules all resources that elect not to participate in the EIM. It cannot be a scheduling coordinator for a supply resource unless it is a transmission provider and meets FERC standards of conduct.

3. An EIM Participating Resource offers its energy or load reduction into the EIM. These entities can be generation units, participating load, demand resource providers, or other resources, provided that they meet all technical requirements.

4. An EIM Participating Resource Scheduling Coordinator schedules participating resources. It cannot be an EIM Scheduling Coordinator unless it is a transmission provider and meets FERC standards of conduct.

[7] As noted above, the question of transmission access charges for EIM participants above and beyond current rates is an issue raised by transmission providers such as Deseret G&T and Tri-State G&T in the rehearing requests in FERC Dockets Nos. ER14-1386 and ER14-1578. For more information on these concerns, see: Deseret G&T rehearing request, available at: http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=13598024; and Tri-State G&T rehearing request, available at: http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=13597937

CAISO will have no role in managing other balancing area authorities' resources, transmission facilities, or maintenance outages. However, the balancing authority, through its EIM Scheduling Coordinator, must provide CAISO with day-ahead and real-time information about conditions within the balancing area, including planned and unscheduled outages.

CAISO notes that it has successfully managed and dispatched resources to date and that expanding the EIM by adding additional balancing areas would only further augment that ability, while also providing benefits to a wider geographical area. In essence, the CAISO EIM does not create a new market, just a broader, more open one.[8]

CAISO's filing letter notes that its stakeholders unanimously supported the goal of establishing an EIM that could include other balancing area authorities. Despite that support, there were numerous detailed issues that stakeholders had concerns about and these issues were noted in the filing.[9] The FERC Order addresses all those issues and in most cases dismissed them or left them for future resolution. A few of the issues will require compliance filings by CAISO.

PacifiCorp

On the same day that the FERC approved the CAISO EIM proposal, the FERC also approved a proposal from PacifiCorp to join the expanded imbalance market.[10] The utility, which serves nearly 1.8 million customers across six states in the Western Interconnect, commissioned Energy and Environmental Economics, Inc. (E3) to conduct a cost-benefit analysis of the proposed CAISO EIM specific to its company. The analysis concluded that joining the EIM would save PacifiCorp between $20 and $120 million per year as a result of lower dispatch costs, lower flexible reserve requirements, and reduced renewable energy curtailments.

The study used ABB's GridView production model to simulate changes in production costs in 2017 between a business-as-usual case and an EIM case with several alternative scenarios and sensitivities. Unlike previous cost-benefit reports that focused on an as-yet undefined imbalance market in the West (and which are discussed in Section 3), the PacifiCorp-commissioned study models a clearly defined market design and includes participation of CAISO. Additionally, the PacifiCorp study addressed concerns with earlier efforts to model an EIM by improving various components of the methodology, such as the approach to modeling hydro reserves.

Results of the PacifiCorp study rely upon a few key assumptions: amount of transmission available between CAISO and PacifiCorp that can be used in an EIM, unloaded hydro capacity contributions to flexibility reserve requirements, assumed savings from switching to nodal dispatch, and reductions of

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[8] CAISO application in Docket ER 14-1386, February 28, 2014. Page 13. Available at: http://www.ferc.gov/whats-new/comm-meet/2012/062112/E-3.pdf.

[9] Ibid, pg. 8.

[10] FERC Order, June 14, 2014, Docket No. ER14-1578.

renewable curtailment throughout the EIM. The model incorporated California's existing greenhouse gas regulations and associated dispatch costs for resources dispatched within California.[11] Even with these added environmental costs, however, results are still highly dependent upon the assumptions listed above. For instance, the authors concluded that "transmission transfer capability limits between PacifiCorp and ISO will constrain EIM benefits."[12] In fact, the study demonstrated that larger benefits could be achieved if CAISO and PacifiCorp switched to "flow-based" transmission optimization, as opposed to relying solely on pre-existing contracts.

Interestingly, and unlike a previous NREL study, the PacifiCorp study modeled dispatch across the EIM at an hourly time scale. This timescale likely significantly understates the benefits of the EIM (which operates on a sub-hourly dispatch schedule), as an earlier NREL report found that nearly $1.3 billion of savings could be achieved through a shift to a sub-hourly dispatch schedule.

Despite assuming one-time EIM start-up costs of $2.1 million[13] and annual operational costs ranging from $2-$5 million, the cost-benefit analysis demonstrated significant savings for PacifiCorp, even under the scenario with the lowest benefit. Under less conservative assumptions, and as the EIM continues to expand, the projected savings are expected to grow even further, with PacifiCorp saving hundreds of millions of dollars by joining the CAISO EIM during the first several years alone.

While the PacifiCorp study was specific to a large utility with a specific set of operating characteristics, benefits found in the PacifiCorp study offer an estimate of potential per-customer savings, given that the report merely addresses the savings associated with a single utility joining the EIM. Smaller utilities with fewer resources will certainly experience a smaller amount of overall savings than PacifiCorp, but such utilities will also incur a smaller percentage of overall annual costs. Further, as the EIM expands throughout the Western Interconnection, dispatch will become increasingly efficient and benefits will continue to grow.

Nevada Energy

Nevada Energy (NV Energy), which has proposed to become the third participant in the recently approved CAISO EIM, recently commissioned a benefits study specific to its participation in an EIM that included CAISO and PacifiCorp. The study, which was also performed by E3 with the assistance of ABB's GridView production simulation software, found that participation of NV Energy in the EIM would lead to gross incremental savings for the utility between $6 and $10 million in 2017 and between $8 and $12 million in 2022.[14] Given that NV Energy has estimated a one-time start-up cost of $11.2 million and ongoing costs of $2.6 million, it is clear that participation in the EIM is a net benefit to the company,

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[11] E3, "PacifiCorp-ISO Energy Imbalance Market Benefits," prepared for PacifiCorp and CAISO, March 13, 2013, pg. 1A, note 2.

[12] Ibid., pg. 4.

[13] WECC's assumption of EIM costs fall in the range of $1-$4 million.

[14] E3 and ABB, "NV Energy-ISO Energy Imbalance Market Economic Assessment," Prepared for NV Energy and CAISO, March 25, 2014.

leading E3 to conclude that "NV Energy's participation in the EIM provides a low-risk means of achieving operational cost savings for NV Energy."[15]

As is the case in the other studies, the results are sensitive to several key assumptions. In this case, the key assumptions include the amount of summer generation that NV Energy will be able to offer into the EIM as a summer peaking region, the efficiency of coordination among the three utilities, and the amount that CAISO is able to reduce renewable energy curtailment in California as a result of NV Energy's participation.

Nevertheless, E3's findings not only demonstrate a benefit to NV Energy, but they also confirm that "total EIM benefits can increase as new participants, such as NV Energy, join the EIM, bringing incremental load and resource diversity, real-time transfer capability utility, and flexible generation resource availability to benefit all market participants."[16]

The FERC and the Public Utilities Commission of Nevada (PUC NV) both issued orders accepting NV Energy's participation in the CAISO EIM.[17] As in the CAISO and PacifiCorp dockets before the FERC, interveners raised questions about the true costs and benefits associated with participation in the EIM, whether the modeling performed by E3 and ABB was adequate enough to approve the application, and how transmission providers would be affected by the EIM. Despite these concerns, the consensus among interveners in both the FERC and PUC NV dockets is that the EIM will be beneficial to ratepayers.

3. EIM IMPACTS IN THE WEST

3.1. Economic Benefits for Ratepayers in the Western Interconnection

Over the last three years, several cost-benefit studies and a reliability analysis have been conducted to estimate the benefits of an EIM to ratepayers across the Western Interconnection. This section summarizes the results of these studies and compares the production cost benefits of participation in the EIM to CAISO's EIM cost assumptions to provide an estimate of net benefits. Benefits from increased reliability, which are typically excluded from cost-benefit analyses, are addressed in Section 3.2, below.

Original Energy and Environmental Economics Study

In 2011, the Western Energy Coordinating Council teamed with Energy and Environmental Economics, Inc. (E3) to produce a benefits study for a proposed EIM for the West. The study developed estimated reductions in production costs through a two-phase process: first, E3 developed assumptions and the

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[15] Ibid, pg. 2.

[16] Ibid.

[17] PUCNV Docket No. 14-04024 and FERC Docket No. ER14-1729.

methodology to model the proposed EIM rules and estimate high-level savings associated with moving to centralized operation of an imbalance market; next, E3 refined the scenarios for renewable integration and EIM participation, and ultimately modeled the EIM using ABB's GridView production simulation optimization model. The results demonstrated that under a base case scenario, the EIM would lead to $141.4 million in annual savings in 2020.[18] The savings come from two main sources—improved dispatch (lower cost resources used) and reduced requirements for flexible reserves (lower quantity of resources needed). Under base case assumptions, the EIM was found to produce $42 million in savings from improved dispatch rates, and nearly $100 million in savings from reducing flexibility reserve requirements.[19] The dramatic reduction in flexibility reserve requirements stems from the ability of EIM participants to procure flexibility reserves from a wider geographic area, rather than requiring that such reserves be procured solely from within the zone where the less flexible resources, including wind and solar generation, are located.[20]

Importantly, the study did not quantify benefits from improved reliability or reduced curtailment, nor did E3 include or estimate the costs associated with implementing an EIM, which we will discuss in further detail at the end of this section.

Both of these impacts are dependent on key assumptions and methodologies used in the modeling process. For instance, due to software limitations[21] and the complexities of modeling current market inefficiencies, E3 and ABB relied upon "hurdle rates" based on 2006 power flows to "represent economic and non-economic barriers to trade across WECC interfaces" in the benchmark cases.[22] When conducting the EIM cases, E3 removed these "hurdle rates" to represent the benefits of a broader regional balancing market. By dropping the hurdle rates in the EIM scenarios, E3 effectively opened transmission boundaries to allow region-wide procurement of flexibility resources. Aggregating zones into the EIM footprint allowed for a 45 percent reduction in average flexibility reserves relative to the base case, due to the diversity of wind and solar hourly generation profiles across the EIM footprint.[23]

Sensitivity analyses demonstrated that the reduction in production costs is sensitive to many key assumptions, including varied EIM participation levels, a range of natural gas and CO_2 prices, and increasing integration of renewable generation. Increasing renewable generation, balancing authority

[18] The study uses 2010 dollars.

[19] Flexibility reserves are defined in the E3 study as dispatchable thermal and hydro resources.

[20] Orans, R., A. Olson, J. Moore, "WECC EDT Phase 2 EIM Benefits Analysis & Results (October 2011 Revision)," Energy and Environmental Economics, Inc., prepared for: Western Electricity Coordinating Council, October 11, 2011. Available at: http://www.wecc.biz/committees/EDT/EDT%20Results/E3_EIM_Benefits_Study-Phase_2_Report_RevisedOct2011_CLEAN2%5B1%5D.pdf. This document is here-in referred to as the "E3 study".

[21] For instance, E3 notes on page 47 that "Production simulation modeling does not fully capture the flexibility of hydro resources to respond to changes in market prices."

[22] E3 study, pg. 11.

[23] E3 study, pg. 23-24.

participation, or CO_2 prices were found to increase benefits, as would lower gas prices. The range of savings from some of the sensitivity runs is presented in Table 1, below.

Since many Western states are expanding their development of solar and wind resources, the improved integration of these renewable resources through an expanded balancing market is a substantial, increased benefit from the prior studies cited here. Similarly, the recent decision by WECC to raise the implied carbon price from $36 per ton to $50 per ton will significantly increase the benefits from a larger, better coordinated imbalance market.[24]

Table 1. 2020 Production Cost Savings under EIM Case and Sensitivities

Sensitivity Cases in 2020	$MM Savings vs. Benchmark Case
Base Case EIM	$141.40
Reduced Participation Sensitivity	$53.60
Low Gas Price Sensitivity ($4.50/MMBtu Henry Hub)	$226.70
High Gas Price Sensitivity ($10/MMBtu Henry Hub)	$156.60
CO_2 Price Sensitivity ($36/ton CO_2)	$232.60

Source: Adapted from E3 study, pg. 53, Table 7.

While illuminating, the E3 study suffered from several shortcomings. Altering key assumptions used in the study could produce significantly different costs and savings for an EIM in the West. For instance, E3 excluded CAISO and the Alberta Electric System Operator (AESO) from participation in a Western EIM, since these system operators already operate within a centralized market structure. However, excluding CAISO from the EIM in the benefits report may have significantly understated potential savings from an EIM, given that over one-third of the future renewable generation modeled by E3 is located within CAISO.

A few organizations expressed concern with certain aspects of the E3 methodology. For example, the Argonne National Laboratory questioned the methodology used in the E3 study for modeling various key aspects of the EIM, such as estimating current market inefficiencies across transmission lines, modeling

[24] See: WECC Technical Advisory Committee meeting minutes of August 12-13, 2014, at: https://www.wecc.biz/Administrative/140812-13_TAS_Meeting_Minutes.docx "DWG members and staff have performed an analysis to finalize the 2034 Reference Case carbon dioxide (CO2) price. Ms. Austin motioned that the group accept the recommended carbon price, average of all mid-estimate forecasts, $52.25/short ton in 2014 dollars for the 2034 Reference Case. The motion was unanimously approved. "

flexibility reserves, and using hydropower as a source of reserve capacity.[25] Later versions of cost-benefit reports by E3 and others sought to address these criticisms, refining the methodology with each iteration.

National Renewable Energy Laboratory Study

In order to expand upon the original E3 benefits study, in 2013 the National Renewable Energy Laboratory (NREL) used the assumptions from the original paper to produce a revised estimate of benefits from a different set of EIM scenarios in the West. The updated study, which was requested by the Western Interstate Energy Board (WIEB) on behalf of the PUC-EIM group, only made minimal changes to the assumptions of the base EIM case in the E3 report, but improved upon the modeling of hydropower resources and market inefficiencies, and explored alternative participation scenarios. Importantly, the NREL study maintained the assumption that excluded CAISO and AESO from participation in the EIM, as well as the future renewable energy immersion target of 8 percent of Western energy being supplied by wind and 3 percent by solar by 2020.

Unlike the E3 study, the NREL report relied on PLEXOS production cost simulation with ten-minute dispatch, nearly approximating the five-minute dispatch proposed for an EIM. In the NREL study, the savings generated by an EIM were double those in the E3 study, reaching approximately $300 million in 2020 in nearly every sensitivity study (full EIM participation, reduced EIM participation, and lower natural gas prices).[26] Overall, 21 of the 29 balancing authority areas assumed to participate in the EIM experienced savings. Additionally, the NREL study confirmed that as the EIM grows and as dispatch intervals decrease, the amount of flexibility reserves required will also fall significantly.

These savings may in fact be understated. For instance, as was the case with the E3 study, excluding CAISO and AESO removes a large source of savings both from the benefits of including existing sub-hourly dispatch capabilities as well as from greater quantities of renewables. Further, NREL assumed that even though real-time dispatch will occur on ten-minute intervals in the EIM, the hourly interchange commitment is still used for scheduling day-ahead, which, as NREL points out, "significantly reduces the EIM benefit, decoupling the savings between the schedule change and the EIM."[27]

A key finding of the NREL report is that the largest benefit stems from transitioning from hourly dispatch to ten-minute dispatch intervals. In the business-as-usual cases, the switch to faster dispatch results in $1.3 billion in savings. FERC Order 764 requires transmission operators to offer 15-minute dispatch

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[25] E3's assumptions regarding flexibility reserve requirements at various levels of wind and solar integration are based on an EnerNex study commissioned by NREL: EnerNex Corporation, "Eastern Wind Integration and Transmission Study," prepared for NREL, revised February 2011. Available at: http://www.nrel.gov/docs/fy11osti/47078.pdf.

[26] Milligan, M., et al, "Examination of Potential Benefits of an Energy Imbalance Market in the Western Interconnection," NREL, March 2013.

[27] Slide 12, Milligan, M., et al., "NREL/Plexos Analysis of the Proposed EIM in the Western Interconnection," NREL, presented to the EIM PUC Meeting, September 13, 2012.

schedules. Thus, as soon as Order 764 is implemented by Western balancing authorities, the capability to dispatch on sub-hourly schedules will exist.[28]

Given the substantial benefits associated with shifting to faster dispatch, the added benefits associated with joining an EIM, and the fact that the investment needed to implement sub-hourly dispatch will be made regardless, there is a strong case to be made for joining the CAISO EIM. And, as the Argonne critique of the E3 study pointed out, "Establishing an EIM will influence future bilateral prices and transmission flows for everyone in the [Western Interconnection] regardless of their participation in the market."[29]

3.2. Reliability Benefits of an EIM

While the studies described above focused primarily upon the production cost savings as a result of an EIM in the West, several other studies discuss the harder-to-quantify reliability benefits. For instance, reliability benefits studies attempt to answer questions such as: How much is reliability worth to different customers? And, what degree of investment will customers accept if it means improved reliability? The studies summarized below explore a range of benefits and metrics related to reliability including: differences between reliability planning calculation metrics, reliability benefits specific to the EIM, the type of reliability events that an EIM could avoid, and various estimates of the value of lost load for customers.

FERC Staff Paper

In early 2013, FERC staff produced a paper that analyzed the improved reliability that could be provided by a regional EIM and summarized qualitative benefits that they found. The FERC staff did not try to estimate quantitative benefits from an EIM. The paper identified five reliability benefits that would be provided or enhanced by a broad, regional imbalance market.[30]

The first benefit they identified was improved reliability through a security-constrained economic dispatch (SCED) across the EIM footprint. SCED is a computer-based operations program that analyzes flows across the entire system that is monitoring and organizes resource dispatch to meet loads on a 5-minute to 15-minute basis. A SCED system would replace manual dispatch decisions performed by many balancing area authorities in the West based on bilateral contracts and transmission reservations.[31]

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[28] There remains uncertainty regarding the impact of the ruling on whether or not operators must use 15-minute dispatch, or merely offer it.

[29] Argonne study, pg. 5.

[30] FERC Staff, Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market, February 26, 2013.

[31] Ibid., pg. 5-7.

Second, FERC staff analyzed enhanced situational awareness provided by an expanded view of conditions in adjacent and remote balancing areas. The entity dispatching EIM resources would need to have information about transmission system capabilities and temporary constraints (due to schedule maintenance or short-term overloads) as well as resource outages across the entire EIM footprint. FERC staff pointed to lack of situational awareness as a key contributing factor to the Southwest blackout in September of 2011 that led to cascading load drops from Arizona to San Diego, resulting in substantial financial penalties to the systems found to be responsible.[32]

Third, the FERC report focused on reduced Energy Emergency Alerts (EEAs) where a load serving entity is unable to meet its energy delivery requirements and seeks assistance from the reliability coordinator. With a SCED-based EIM, these energy imbalances could be addressed more quickly and efficiently through an automated dispatch and potentially avoid the need for an EEA. The report notes that an EIM would not effectively resolve all imbalance situations.[33]

Fourth, the FERC report covers provision of replacement reserves after a reserve sharing event expires. Balancing area authorities have reserve sharing agreements with adjacent balancing areas, but they generally expire after a specific period of time (usually 30-60 minutes). The entity required to provide replacement reserves has to implement a series of manual communications, contract paths for transmission, and E-tag approvals. An EIM with a SCED-based dispatch could schedule and deliver replacement reserves through an automated mechanism more quickly and effectively than current manual processes that exist throughout the West.[34]

Fifth, the report counts as a reliability benefit the ability to provide reliable integration of variable energy resources, such as wind and solar, that are increasing in quantity and providing challenges to system operators responsible for real-time daily operations. An EIM operating over a large geographic area can better manage variability and uncertainty of these resources. The variations of sunlight and clouds, or wind speeds, tend to average out as the balancing area expands. In addition, a larger, automated balancing area provides easier access to supplemental resources as needed through its SCED dispatch. These traditional balancing resources would be offering prices at which they would increase or decrease output to help balance the system.[35]

By providing these services and benefits, an EIM would help maintain reliable system operations to avoid outages as well as during and after times of contingency events and emergencies. The EIM would also provide faster responding replacement and supplemental reserves to make overall daily system operations more stable and reliable.

[32] Ibid., pg. 12-14.

[33] Ibid., pg. 15-16.

[34] Ibid., pg. 16-17.

[35] Ibid., pg. 17-18.

Brattle Group Study

Later in 2013, FERC commissioned a study by the Brattle Group to explore reliability requirements and economic implications of different reserve margins and reserve margin calculation methodologies. The crux of the analysis was determining differences between how utilities and system operators calculate planning reserve margins based on the standard 1-in-10 methodology. In other words, how do planning requirements differ if 1-in-10 calculations assume that a reliability event would occur one *day* in ten years or that there would be one *loss of load* event in ten years? In addition to analyzing what reliability requirements mean, the paper also attempts to quantify benefits of reliability.

Interestingly, after running the production cost optimizing Strategic Energy Risk Valuation Model (SERVM), the study found that regardless of the loss of load event calculation methodology, "the most significant factor impacting a region's planning reserve margin is the size of transmission interties."[36] Further, the report goes on to point out that interconnection to neighboring regions creates two main reliability benefits:

> First, by enabling a region to procure *firm commitment* from external resources to supply and deliver power during emergency events and, second, by creating *tie benefits* that enable the region to request neighbor assistance, if available, through non-firm imports during emergency events."[37]

An energy imbalance market has the potential to produce exactly the second type of reliability benefit and then some, as it extends beyond just emergency events to include daily imbalances and fluctuations, creating an even larger benefit for previously unconnected geographic regions.

Although the Brattle Group quickly points out that "there is no uniform approach to measuring the value of resource adequacy," its study goes on to point out the various quantifiable benefits that increased access to reliability reserves provide, "such as the ability of incremental resources to reduce the frequency of customer outages and other emergency events, moderate energy price spikes, and increase wholesale competition."[38] Further, the report explains that the true value of reliability is not necessarily captured by current reserve and planning margin mechanisms, since many utilities and system operators base requirements on physical constraints, as opposed to setting adequate and accurate prices during scarcity conditions and allowing markets to determine an appropriate level of reserves economically. Therefore, calculating the economic benefits of reliability is exceedingly tricky.

However, the Brattle Group points out that any discussion of the actual value of reliability is necessarily reliant upon assumptions about the value of lost load (VOLL). As will be discussed in further detail below, VOLL is a measure of what reliability means in economic terms to different customers, and

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[36] Pfeifenberger, J., K. Spees, K. Carden, N. Wintermantel, "Resource Adequacy Requirements: Reliability and Economic Implications," The Brattle Group, Astrape Consulting, prepared for FERC, September 2013, pg. V.

[37] Ibid., pg. 12.

[38] Ibid.,. pg. 1.

typically varies widely across customer classes and outage durations. For its study, Brattle Group uses a VOLL of $7,500 per MWh, which is directly between estimates for residential and industrial customers, at $5,000 per MWh and $15,000 per MWh, respectively.

September 2011 Case Study

On September 8, 2011, the loss of a single 500 kV transmission line in the Arizona Public Service territory led to a series of cascading power system equipment trips that caused widespread power outages affecting 2.7 million customers in the Southwest United States and parts of northern Mexico. The blackout extended as far west as San Diego, where 1.4 million customers lost power for up to 12 hours. A joint investigation by NERC and FERC (NERC report) investigated the causes of the blackout and recommended improvements to avoid future events.[39]

One of the key findings in the NERC report was that various entities responsible for daily operation of the interconnected bulk power system lacked adequate situational awareness of conditions and contingencies. In particular, operators did not have adequate real-time information about conditions on neighboring systems that might have allowed them to configure their own resources so as to avoid cascading effects of the loss of the 500 kV line. The report made three general recommendations to improve situational awareness among various operating authorities:

1. Expand visibility of external systems through date sharing to allow for better modeling of potential contingencies;
2. Improve use of real-time tools to ensure constant monitoring of both internal and external events; and
3. Improve communications among entities to help maintain situational awareness.[40]

Implementation of a region-wide energy imbalance market would help address all three recommendations. As demonstrated by proposed expansion of the CAISO real-time energy market to include PacifiCorp, internal constraints of the PacifiCorp system will need to be modeled in CAISO's security-constrained dispatch of its energy market, thus creating greater visibility of potential contingencies between the two balancing authorities. Because the CAISO energy market is dispatched on a five-minute basis in real-time, operators in both CAISO and PacifiCorp will have detailed information available about potential impacts of any real-time system changes and improved options for resolving them. Scheduling of imbalance services between the two control areas will also improve communications overall and enhance situational awareness.

Although the NERC report contained almost no discussion of EIM benefits, the FERC staff report of 2013 (discussed above) compared current approaches to addressing imbalances with a regional EIM. Without

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[39] FERC and NERC staff, "Arizona-Southern California Outages on September 8, 2011: Causes and Recommendations," April 2012.

[40] Ibid., pg. 7.

an EIM, each balancing authority is limited to resources under its direct control and economic energy purchases that can be supported with adequate transmission access and scheduling. Purchasing and scheduling economic energy purchases may be limited during an operational contingency such as sudden loss of a transmission line or generation resource. In contrast, an EIM operating on a five-minute SCED may be able to provide faster relief during a contingency.[41] The EIM would be able to dispatch energy from resources across the entire market footprint to manage flows within operating limits.[42]

Specifically, an EIM using SCED would automate identification of resources and transmission to balance load, internalize and recognize unscheduled flows, and automate the operators' ability to manage and respond to system conditions. SCED is also capable of finding and determining amounts of actual available transmission service to balance loads, rather than relying on posted reservations for transmission service that may not reflect actual system conditions.[43]

To be clear, neither the NERC report nor the FERC staff report claimed that an expanded balancing market using SCED would avoid or eliminate all imbalances and unscheduled loss of load. Many individual contingencies or multiple contingencies will not be resolved through a five-minute real-time imbalance market. However, the number of such events and the severity of the events would certainly be reduced through a coordinated imbalance market over a large region that has access to a larger number and overall quantity of resources.

Value of Lost Load

The FERC staff report discussed above provides a qualitative assessment of the reliability benefits of an EIM for the Western region. These are benefits associated with more information; more visibility of conditions in adjacent balancing areas; a large pool of balancing resources; the potential to avoid or reduce the impact of contingency events; and the ability to contain disruptions to small areas and avoid cascading outages. There are also real economic benefits of improved reliability, although attaching a dollar value is very challenging.

Determination of the quantitative (dollar) benefits of improved reliability attributable to an expanded EIM requires two initial assessments. First, what is the extent to which an EIM would completely or partially avoid involuntary load shedding? That is, how much dropped load would an expanded EIM prevent? The second assessment is: What is the appropriate dollar value to assign to dropped load in terms of both quantity of load that is lost and time that it is lost? We will return to the first assessment, for which we did not find any examples based on a literature search, after we discuss the second assessment, for which there is an abundance of discussion, but no firm conclusions.

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[41] FERC Staff paper, pg. 6.

[42] Ibid., pg. 7.

[43] Ibid., pg. 8-9.

Attempts to make calculations for the second assessment are usually described as the “value of lost load” (VOLL), and they are neither simple to construct nor is there a consensus on what those values are. A recent briefing paper prepared by the London Economics Institute (LEI) for the Electric Reliability Council of Texas (ERCOT) in June 2013 provides a comprehensive review of the current literature on VOLL as well as a macroeconomic analysis specific to Texas. For the purpose of providing some quantitative estimates of the benefits of an enhanced EIM in the West, we focus on the literature review done by LEI.[44]

VOLL estimates fall into two general categories: (1) average values that represent long-term outage events over many hours or days across a large geographical area and (2) marginal values that focus on shorter duration outages in a more limited area. Almost all VOLL studies differentiate between residential, commercial, and industrial customers; some studies even develop VOLLs for specific end uses. Seasonal timing and duration of an outage are particularly important because a loss of air-conditioning is not as important or valuable during winter as it is in summer; similarly, a loss of manufacturing capability may not be as important or valuable at night as it is during normal business hours.

Table 2 below is constructed from information in the LEI paper and shows VOLL estimates for three regions of the United States and studies done in Austria, New Zealand, Australia, and Ireland. There is a large range of estimates. However, there are consistent themes: residential VOLL is usually the lowest, followed by industrial or Large C&I, and then commercial or Small C&I. However, in Ireland industrial is the lowest and residential is the highest. We add a summary line to the table (not from the LEI paper) that eliminates the highest and lowest estimate for each customer class and then shows ranges of estimates that remain.

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[44] Julia Frayer, Sheila Keane, and Jimmy Ng, “Estimating the Value of Lost Load,” LEI, June 17, 2013.

Table 2. Summary of Value of Lost Load Estimates for Different Jurisdictions

Region/Market	System-wide VOLL	Residential	Non-Residential	
			Small C&I	*Large C&I*
US – Southwest		$0	$35,417	$8,774
US – MISO		$1,735	$42,256	$29,299
Austria		$1,544		
New Zealand	$41,269	$11,341	$77,687	$30,874
Australia - Victoria	$44,438	$4,142	$28,622	$10,457
Republic of Ireland	$9,538	$17,976	$10,272	$3,302
US – Northeast	$9,238 - $13,925			
Summary	$9,538 - $41,269	$1,544 - $11,341	$28,622 - $42,256	$8,774 - $29,299

Source: LEI (2013), pg. 8. Note: the "Summary" row excludes the maximum and minimum values in each category.

The LEI paper provides a summary of the cost of the 2003 Northeast Blackout by ICF.[45] That cascading outage led to losses of load involving eight states in the Northeast and Midwest United States and portions of Ontario, Canada. Initially, over 61,000 MW were dropped with approximately 55,000 MW restored in a day and a half. The remainder of the loads were not fully restored for two more days. ICF estimated the total cost, using a VOLL approach, as a range from $6.8 to $10.3 billion (2003 USD). ICF employed many simplifying assumptions, including an average annual cost of $93 per MWh across the entire region. There was also no differentiation for actual usage across different hours. Nonetheless, the paper does provide a range of quantitative values of a specific reliability event.

We now return to the first assessment issue: How would a broad, well-functioning EIM mitigate such an event and what would be the economic value of such mitigation? One approach would be to look at the Arizona to San Diego loss of load event in 2011 and posit that a well-functioning EIM might have prevented loss of the 500 kV line in Arizona from cascading to the San Diego balancing area.[46] Table 3 below shows the assumed MWh by customer class that would not have been lost, and then shows ranges of economic losses that would have been avoided. The economic losses are calculated using the summary high and low values for each customer class from Table 2 above.[47]

[45] LEI paper, pg. 48-50.

[46] There are many ways to construct this hypothetical. We could assume that the loss of load event would have been limited to just APS customers. We have chosen to use a less extreme assumption. We assume that an EIM with a 5-minute SCED for the entire region would have been able, during the 11 minutes it took the outage to cascade, to prevent the outage from spreading to the SDG&E service territory.

[47] For an extended description of the methodology used to build Table 3, please see the Appendix.

Table 3. Quantifying Impacts of the SDG&E Blackout

Quantifying the SDG&E Blackout	
Outage length	12 hours
Customers affected	1.4 million
Capacity dropped	4293 MW
Total lost load	51,516 MWh
Total cost to customers	$775 million
Residential cost	$87 million
Small C&I cost	$537 million
Large C&I cost	$151 million

Note: This table assumes that electricity was restored to half of the customers after six hours of the blackout and the remainder after twelve hours.

Based on these estimates, total costs that might have been avoided from a well-functioning EIM, similar to the expanded CAISO balancing market, are over three quarters of a billion dollars. This is only an illustrative estimate. Even with a five-minute SCED for a larger balancing market, the September event that began in Arizona may have cascaded to the coast of California. The key takeaway from this rough estimate is that the dollar value of avoided or reduced outages is enormous. Reliability benefits, although difficult to quantify with precision, are a significant benefit. To develop a more precise analysis one would need to identify actual loads that were disconnected and develop specific VOLL for each of those loads. It would also be important to be able to specify the hours that each load was disconnected. On the other hand, this rough estimate makes no assumptions about costs to public health and safety that may also have been incurred in the SDG&E service territory from traffic impasses, lack of emergency services, and other issues. These additional savings would be added to the savings from avoiding or lessening the outage itself.

3.3. Costs of Implementing an EIM

In 2011, WECC also commissioned a study by Utilicast to analyze the start-up and operating costs associated with a regional imbalance market. The report, which breaks costs into market operator costs and participant costs, models the same EIM analyzed in the original E3 study—a brand new market structure that runs security-constrained economic dispatch on five-minute intervals and excludes balancing authorities with currently operational markets such as CAISO and AESO. As a result of modeling an entirely new market, and excluding participation of the only balancing authorities that currently have experience in operating centralized markets, start-up and operational costs have a wide range of uncertainty. Expected start-up costs ranged from $25.6 million to $220.2 million for the market operator, while start-up costs for all market participants ranged from $41.31 million to $120.02 million for the base footprint (the West minus CAISO and AESO) and $25.52 million to $74.13 million for the smaller footprint modeled in the E3 study. For operating costs, expected incremental costs for an existing entity to operate an EIM were estimated to be $33.9 million—as opposed to $128.9 million for a brand new entity operating the market[48]—and operating costs for participants ranged from $46.46 million to $131.51 million for the base EIM footprint to $28.70 million to $81.23 million for the smaller footprint.[49]

The report concluded that the largest sources of costs for both market operator and market participants will be software improvements and increasing staff capabilities. Importantly, the majority of software costs are a result of increasing SCED abilities, which CAISO has already implemented, implying that start-up and incremental operating software costs might be even lower for a CAISO-run market.[50]

The study found that the average start-up cost for individual balancing authorities was $2.4 million, while average operating expenses would be $2.6 million.[51] These estimates, though based on a brand new market without an entirely defined structure, are remarkably similar to PacifiCorp's estimates of start-up costs and operational costs for it to participate in the existing CAISO market of $2.1 million and $2 to $5 million, respectively.[52] Further, it is worth noting that these costs for individual balancing authorities are directly influenced by "the size of the organization, its participation in other markets, and its ability to leverage existing staff and assets," as well as the overall footprint of the EIM.[53]

Asserting that actual costs of implementation of its proposed EIM would be lower than these estimates, CAISO provided additional cost estimates to the PUC-EIM Task Force in 2012.[54] CAISO concluded that implementation costs will be lower than estimates in the Utilicast report, pointing out that CAISO "would leverage its existing market and dispatch systems to provide the EIM platform," arguing further that "the ISO's existing grid management charge structure would enable EIM participants to be charged a marginal rate based on services and functionality associated only with the EIM."[55]

CAISO provided start-up and operating cost estimates of 3 cents per total MWh served and 19 cents per participating MWh for participating balancing authorities, which would cover capital investments and ongoing costs associated with software, hardware, and staffing requirements. Extrapolating based on 2012 sales data from the EIA 861 dataset confirms PacifiCorp's and Utilicast's estimates of start-up costs in the $2 million range, and operating costs of $1 to $10 million for a range of voluntary participation of 10 percent to 100 percent of served MWh.

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48 As a point of reference, Utilicast points out that CAISO's operating costs in 2010 were $163 million.

49 Utilicast (2011) "Efficient Dispatch Toolkit Cost Analysis" prepared for: Western Electricity Coordinating Council and the Efficient Dispatch Toolkit Steering Committee, April 15, 2011.

50 Ibid., pg. 16

51 Ibid., pg. 43

52 E3 PacifiCorp study pg. 9. In the E3 PacifiCorp report, these values are cited as being "based on estimates from CAISO staff."

53 Utilicast (2011), pg. 44

54 CAISO (2012), "CAISO Response to Request from PUC-EIM Task Force," March 29, 2012.

55 Ibid. pg. 5.

4. Considerations for Southwest State Regulators

With the inclusion of PacifiCorp and Nevada Energy in the expanded CAISO EIM, other utilities in the Southwest should also consider participating to provide an even larger footprint for imbalance services and capture the benefits of the EIM for their customers. The studies over the last three years that have estimated economic benefits all conclude that the benefits are substantial. The reliability benefits of reduced or avoided outages are enormous. Further, the accelerated development and integration of variable renewable resources across the Southwest increases both the need for and potential savings arising from an expanded balancing area. Utilities in the Colorado River Basin, Arizona, and New Mexico, due to their geographic proximity to California and existing interconnections, are likely to gain the most from participation in the CAISO EIM. In fact, the NREL study, which allocated benefits from an EIM to individual balancing authorities, found that utilities such as Arizona Public Service (APS), Tucson Electric Power (TEP) and Public Service Company of New Mexico (PNM) would have annual production cost savings ranging from $1 million annually for APS to $5.5 million for PNM, and $15.6 million for TEP. Salt River Project and Public Service Company of Colorado are in line for even greater savings, at $56.5 million and $92.9 million of annual production cost benefits, respectively.[56]

Each state's commission will need to evaluate the merits of participation by its utilities. It is critical, however, that such an evaluation occur. In order to protect the interests of customers, utilities should be required to evaluate the potential benefits of joining an EIM. Failure to do so may result in foregoing millions of dollars in cost savings, while experiencing lower reliability. Simply stated, it would be imprudent for a utility to choose not to join an EIM without undertaking an analysis to justify forgoing the opportunity to significantly reduce costs for customers.

4.1. Investor-Owned Utilities

In a rate case proceeding, a state commission could require the utility to conduct a cost-benefit study regarding participation in the CAISO balancing market. This would require a production cost analysis similar to the ones done most recently by E3 for PacifiCorp and Nevada Energy and discussed above. Alternatively, a state commission could rely on one of the past studies and apportion the savings to a particular utility on a load ratio share. Once the CAISO expanded market is operating successfully with PacifiCorp participation, and producing actual cost and savings data, the burden would shift even more strongly on the utility to demonstrate that non-participation is a more cost-effective and reliable option than participation. Commissions may want to explore options for both customers and shareholders to benefit from any increased off-system sales from an expanded balancing market.

Utilities that develop integrated resource plans (IRPs), such as APS and TEP in Arizona, should evaluate participation in a larger balancing authority as part of a plan to provide least-cost service to their

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[56] Milligan, M., et al., "Examination of Potential Benefits of an Energy Imbalance Market in the Western Interconnection," NREL, March 2013, Table 40, page 74.

customers. Integrated resource planning focuses on demand, supply, and infrastructure options that can be combined in various ways to meet future electricity needs of customers at the least cost. The inclusion of an evaluation of an expanded balancing market option in the IRP process, particularly in light of state policy commitments to increase the quantity of renewable resources in the supply mix, would seem to be a logical and necessary step.

4.2. Municipals and Co-Operatives

Municipals and co-operative utilities are generally not subject to the same state commission scrutiny as investor-owned utilities. Nonetheless, state commissions' approaches to regulation of investor-owned firms set a standard that public and cooperative utility boards and managements should take into consideration. Some state commissions have opportunities to provide guidance and support improvements to the operations of these utilities that are ultimately accountable to their members, a public board of directors, or municipality. Policymakers that bear responsibility for public and cooperative utilities—their board members and managers, as well as member-owners and citizens--should be asking the same questions that state regulators should be asking of investor-owned utilities:

- In light of the existing studies on balancing market costs and benefits, are there consumer benefits if our public or cooperative utility joins an expanded EIM?
- What study results show that not joining a larger EIM is a prudent decision?
- What improvements to balancing systems have been implemented pursuant to FERC Order 764, such as 15-minute energy scheduling, and do they facilitate participation in an expanded EIM?
- If our utility stays out of the EIM market, what will that decision cost each consumer?
- Has our utility commissioned a production cost model analysis to compare current balancing costs with the likely costs through an EIM?
- Are we willing to sacrifice EIM economic and reliability benefits for other reasons? What are they and how do we justify them?

As more experience is gained over the next two years with the expansion of the CAISO balancing market to include PacifiCorp and Nevada Energy, a utility decision to join a larger market may become unavoidable. Until then, state commissions should at a minimum be asking their utilities to prepare to participate, or demonstrate why participation will not be cost-effective.

5. Conclusions

Balancing authorities in the West have an opportunity to participate in an expanded energy imbalance market with more resources and a larger geographic area. This opportunity has been seized by

PacifiCorp and Nevada Energy through their commitments to join the CAISO energy market for balancing services. Other balancing authorities should also consider joining to provide less costly dispatch of resources, improved reliability during system disturbances, and better integration options for variable energy resources such as wind, solar, and hydro.

Several production cost simulations in recent years have demonstrated the economic savings available to regions, states, and individual utilities through an expanded, coordinated balancing market. The early studies examined benefits throughout the West; more recent studies have focused on specific entities (PacifiCorp and Nevada Energy) joining the CAISO energy market for balancing services.

Reliability savings are inherently difficult to quantify due to large variations between how different customer groups value energy disruptions (i.e., the "value of lost load" issue). However, even when using conservative assumptions about the actual value of avoided disruptions in electric service, the dollar impacts are enormous. To the extent that an expanded imbalance market could mitigate even a small fraction of an outage, the reliability savings for one event could easily exceed an entire year's savings of improved economic dispatch.

Our paper has not focused on variable resource integration in the West; there are many other studies that already identify the improved coordination and lower cost of using a large geographic area to average out variability in solar and wind resources. From a balancing market perspective, access to a greater quantity of traditional balancing resources will also lower the cost of addressing short-term, variable resource fluctuations. These two features of a larger, automated dispatch that are integral to an EIM are key ways to smooth out variability in daily wind, solar, and hydro output.

Every utility in the West should try to participate in a large, multi-state balancing market similar to the CAISO EIM. The economic, reliability, and integration benefits that come from the automated dispatch of a large pool of resources far outweigh short-term implementation costs. CAISO has demonstrated that adjacent balancing areas can be accommodated in its market through minimal tariff changes and without the loss of control over their other dispatch functions.

Although each state has its own specific criteria and precedent for reviewing utility decisions, they all have the authority to disallow recovery of unnecessary or imprudent expenditures. A utility that elects to not participate in a balancing market that could provide substantial savings to its customers could be found to have acted imprudently, and the excess costs could be disallowed in rates. In all proceedings there would be an evidentiary question of when a "reasonable utility" should have decided to participate in a broader balancing area. On the question of when to join an expanded balancing market, all the studies reviewed in this paper suggest that the time is now. The recent actions of PacifiCorp and Nevada Energy to participate in the CAISO balancing market provide further support for the prudence of participation by other utilities in the Southwest.

6. APPENDIX: CALCULATION OF RELIABILITY BENEFITS

Table 3 in section 3.2 of this report provides several different metrics of the benefits associated with avoiding the blackout for some customers during the September 2011 cascading outages, based on a number of assumptions carried through a multi-step calculation. The following text provides further detail regarding the quantification of these reliability benefits.

First, we assume that an expanded imbalance market might have responded to an energy imbalance on the grid quickly enough to have limited the cascading outages so as to avoid the blackout in San Diego Gas & Electric's service territory. We are not suggesting that a larger balancing market would have avoided the entire outage, nor that a larger market would always limit a cascading outage; we are just hypothesizing a more limited blackout to demonstrate the reliability savings (in dollars) that would result. Second, we assume that half of the customers and half of the megawatts were restored within 6 hours of the initial blackout, and the other half at the end of the overall 12-hour outage. Next, we split total lost energy—which we calculated as megawatts multiplied by the duration of the outage—into on-peak, shoulder, and off-peak hours, as well as into three customer classes—residential, Small C&I (or commercial), and Large C&I (or industrial). Finally, we applied the class-appropriate VOLL from Table 2 in section 3.2 to the energy lost by class, using the upper bound of the range of VOLLs during peak hours (defined as 4 PM to 6 PM), the mid-point of the range of VOLLs for shoulder hours (6 PM to 10 PM), and the minimum of the range for off-peak hours (10 PM to 4 AM).[57] The results can be seen broken down to a larger degree of detail in Table 4, below.

Table 4. Avoided Cost Estimate Calculation for the San Diego Blackout

Hours	Customers	Lost MW	Duration	Total Lost MWh	Residential		Small C&I		Large C&I		Cost of Event
					Lost MWh	***VOLL***	***Lost MWh***	***VOLL***	***Lost MWh***	***VOLL***	
	Million	*MW*	*Hours*	*MWh*	*MWh*	*$/MWh*	*MWh*	*$/MWh*	*MWh*	*$/MWh*	*Million $*
4 PM to 6 PM	1.4	4,293	2	8,586	3,267	11,341	3,444	42,256	1,875	29,299	238
6 PM to 10 PM	1.4	4,293	4	17,172	6,534	6,443	6,888	35,439	3,751	19,022	358
10 PM to 4 AM	0.7	2,147	6	12,879	4,900	1,544	5,166	28,622	2,813	8,744	180
Summary	*1.4*	*4,293*	*12*	*51,516*	*19,602*		*20,663*		*11,252*		*955*

[57] We recognize that the blackout started closer to 3:30 PM than to 4 PM, but have assumed it fully hit SDG&E's service territory by 4 PM for ease of calculations.