APS Energy Imbalance Market Participation: Economic Benefits Assessment

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Acknowledgements

Acronyms

APS   Arizona Public Service Company

BA   Balancing Authority

BAA   Balancing Authority Area

BAU   Business-as-usual

ISO   California Independent System Operator

DA   Day-ahead

EIM   Energy Imbalance Market

FERC   Federal Energy Regulatory Commission

HA   Hour-ahead

LMP   Locational Marginal Price

NVE   NV Energy

PAC   PacifiCorp

WECC   Western Electric Coordinating Council

AB32   Assembly Bill 32 – California Global Warming Solutions Act

Executive Summary

This report examines the benefits of Arizona Public Service Company's (APS) participating in the energy imbalance market (EIM) operated by the California Independent System Operator (ISO). The ISO's EIM is a regional 15- and 5-minute balancing energy market, including real-time unit commitment capability, which began operating in November 2014 with the ISO and PacifiCorp as initial participants. NV Energy will also begin participating in the EIM in Fall 2015.[1] The ISO, PacifiCorp, and NV Energy are referred to in this study as "current EIM participants"; because they are assumed to be already participating in the EIM before APS becomes a participant.[2]

This report estimates the benefits of APS's participation under a primary scenario, as well as under a range of alternative scenarios and sensitivity cases that explore how different resource changes and fuel prices could impact EIM benefits to APS. For the year 2020, participation in the EIM is estimated to create dispatch efficiency and flexibility reserve savings of $7.0 to $18.1 million per year for APS.[3] Dispatch efficiency savings were $8.9 million per year in the primary scenario, and

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[1] Puget Sound Energy (PSE) also announced in March 2015 that it intends to begin participating in the EIM in Fall 2016. The majority of this analysis for APS was completed prior to PSE's announcement, so PSE is not included as an EIM participant in this study.

[2] Throughout this report, Balancing Authorities (BAs) that participate in the EIM are described as "EIM participants". These participating BAs are referred to in the ISO's EIM Business Practice Manual and tariff as "EIM Entities."

[3] All benefits are reported in 2014 dollars.

ranged from $5.9 million to $14.9 million per year across ten alternative scenarios. Flexibility reserves savings ranged from $1.0 to $3.2 million per year.[4]

In addition, across the range of scenarios modeled, APS's participation in the EIM is estimated to produce a range of $2.2 to $8.1 million per year in incremental savings for the current EIM participants as a result of improved dispatch efficiency and reduced flexibility reserve requirements. In the primary scenario, benefits savings to current EIM participants ranged from $3.0 to $6.5 million. All incremental costs from APS's participation is expected to be recovered from APS through fixed and administrative charges, resulting in no incremental implementation costs for the current EIM participants.

To be conservative, this study's simulation modeling does not quantify potential benefits from improved dispatch in the hour-ahead (HA) and day-ahead (DA) market. We expect that information produced by participation in the real-time EIM could create learning and additional cost efficiencies in the DA and HA market for APS over time, but have not quantified those potential savings. Additionally, APS's participation in the EIM could allow APS to avoid transaction costs related to buy-sell price spreads currently incurred for market purchases and sales in bilateral 15-minute or HA trading.

This study also does not quantify potential reliability benefits tied to the increased awareness and resource control that the EIM creates. Although reliability benefits are difficult to quantify, they are important to consider qualitatively as they are likely to produce substantial benefits. A recent FERC staff report identified potential additional reliability benefits that may arise

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[4] Individual components of low range savings do not sum to total due to rounding.

from an EIM, including enhanced situational awareness, faster delivery of replacement generation after the end of contingency reserve sharing assistance, and enhanced integration of renewable resources.[5]

EIM Benefits Quantified in This Report

The EIM is a balancing energy market that optimizes generator dispatch within and between Balancing Authority Areas (BAAs) every 15 and 5 minutes.[6] By allowing BAs to pool load and generation resources, the EIM lowers total flexibility reserve requirements and minimizes curtailment of variable energy resources for the region as a whole, thus lowering costs for customers. The EIM can create value for EIM participants by: (1) using software tools to identify sub-hourly transactions that produce an optimized dispatch and minimize production costs, while respecting reliability limits (known as "Security Constrained Economic Dispatch", or "SCED"); (2) bringing this optimized dispatch down to a 5-minute interval level; (3) incorporating optimized real-time unit commitment of quick-start generation; and (4) enabling better use and compensation of flexible ramping capacity in real-time due to the diversity of loads and resources across the EIM footprint, allowing EIM participants to individually reserve a smaller amount of committed capacity for sub-hourly flexibility.

APS retained Energy and Environmental Economics, Inc. (E3) to conduct an economic study to quantify the potential benefits to APS from participation in the EIM. Energy Exemplar provided technical support to this study by running

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[5] See FERC (2013).
[6] For more information regarding the EIM, see CAISO (2014c).

sub-hourly production simulations cases using the PLEXOS production simulation modeling tool to calculate EIM benefits from dispatch cost savings. This report describes the findings of the E3 and Energy Exemplar study team.

The study evaluates benefits using an approach that builds upon E3's EIM analyses for the ISO, PacifiCorp, NV Energy, and Puget Sound Energy.[7] The analysis focuses on the incremental benefits related to APS's participation in the EIM, while assuming that the ISO, PacifiCorp and NV Energy are already "current EIM participants" in the base case. This study incorporates additional system details provided by APS to improve the accuracy of APS's generation and transmission represented in the production cost simulation.

The primary scenario in this report quantifies two categories of potential cost savings from expanding the EIM to include APS:

+ *Sub-hourly dispatch benefits*, by realizing the efficiency of optimized combined 15- and 5-minute dispatch and real-time unit commitment across APS and the current EIM footprint, compared to bilateral transactions typically done on an hourly basis under business-as-usual (BAU) practice for APS; and

+ *Reduced flexibility reserves*, by reflecting the diversity of load, wind and solar variability and uncertainty across APS and the footprint of current EIM participants.

E3's PacifiCorp-ISO EIM study included a separate benefit category, intraregional dispatch savings, which arises from PacifiCorp generators being able to be dispatched more efficiently through the ISO's automated nodal

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[7] See E3 (2013), E3 (2014), and E3 (2015).

dispatch software, reducing transmission congestion within the PacifiCorp BAAs. Based on APS's experience that there is little internal congestion within the APS system, we assumed this benefit would be small and therefore did not include it in this analysis. The PLEXOS scenarios also resulted in a reduction in renewable curtailment in the ISO region as a result of APS's participation in the EIM. Savings for this reduced renewable curtailment have been included as part of the modeled sub-hourly dispatch benefits to the current EIM participants. Renewable curtailment in the APS BA was negligible in the cases, and APS does not currently experience significant curtailment needs in its own BA.

Sub-hourly Dispatch Savings Results

We estimated the production cost benefits of APS's participation in the EIM using the PLEXOS production cost modeling software to simulate operations in the Western Interconnection for the calendar year 2020 with and without APS as an EIM participant.

As a starting point, this study used the PLEXOS database developed by PNNL for the Western Electricity Coordinating Council's (WECC) Variable Generation Subcommittee (VGS) study from 2012-13[8] and revised and as part of the NWPP Phase 1 EIM study from 2012-13.[9] Similar to those two studies, this analysis used a three-stage simulation process, including DA, HA, and real-time simulations stages to represent the different time horizons of actual power system operations. The DA and HA stages are simulated on an hourly basis. The real-time stage is simulated with a 10-minute time step and incorporates the

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[8] See Hunsacker, M., et al. (2013).
[9] See Samaan, NA, et al. (2013)

within hour variability associated with load, wind, and solar. While actual EIM operations are on a 5-minute basis, a complete and validated PLEXOS dataset for 5-minute simulation was not available at the time of this study. This study's use of 10-minute time step in the real-time stage (to make use of the WECC VGS sub-hourly dataset) produces EIM benefits results that we expect may be somewhat conservatively low, as the 10-minute time step reduces the amount of variation within the hour to a small extent, slightly moderating the need for operational flexibility that an EIM can provide. Overall, however, we expect the 10-minute time step to capture much of the real-time dispatch efficiency savings.

Based on input from APS staff, we updated the database input data for the APS BAA to improve the accuracy of system generation and transmission details in Arizona. We also implemented updates to input data for California. The primary case used updated gas prices consistent with the WECC's latest Transmission Expansion Planning Policy Committee (TEPPC) case data,[10] and the analysis also incorporates California's greenhouse gas regulations and the associated dispatch costs.

Sub-hourly dispatch savings are quantified by (1) running a real-time BAU case that holds APS net interchange (imports minus exports) with all other BAs equal to the HA interchange schedule, and (2) running an APS EIM case (starting from the same HA case) that allows APS to trade with the other EIM participants within the hour. The difference in total production cost between the two real-

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[10] See WECC, Transmission Expansion Planning (TEP) Department (2015). TEPPC data is provided for 2024. This study used gas values for the 2020 study year from the gas pricing model used to produce TEPPC data.

time cases represents the sub-hourly cost savings for all EIM participants, including APS.

Benefits are then attributed to APS and the other EIM participants based on the change in their generation cost and their net purchases and sales in real-time, priced at the transaction-weighted LMP from the model.

The dispatch savings were evaluated under a primary case and ten alternative scenarios with different assumptions regarding RPS levels in California, gas prices in the WECC, coal retirements, CO_2 prices, and EIM wheeling charges applied to real-time transactions. Scenarios were designed to test the robustness of EIM savings. They were developed based on input from APS staff to respond to categories of changes that APS believed may be plausible to occur. The table below summarizes the assumptions under each scenario. The shaded values in the table represent an assumption used for a scenario that differs from the primary scenario assumptions.

Table 1: Key Assumptions for EIM Dispatch Savings Scenarios

Scenario	CA RPS	CA CO_2 price level ($/ton)	Rest of WECC CO_2 price level ($/ton)	APS natural gas price ($ per MMBTU)	Incremental coal retirement	EIM wheeling rate ($ per MWh)
0. Primary Scenario	33%	$18	$0	$4.4	Base	$0
1. CA 40% RPS	40%	$18	$0	$4.4	Base	$0
2. WECC-wide CO_2 ($18/ton)	33%	$18	$18	$4.4	Base	$0
3. Significant WECC Coal Retirement	33%	$18	$0	$4.4	Large	$0
4. Moderate WECC coal retirement	33%	$18	$0	$4.4	Moderate	$0
5. WECC-wide CO_2 ($40/ton) plus moderate coal retirement	33%	$40	$40	$4.4	Moderate	$0
6. 30% Higher Gas Prices	33%	$18	$0	$5.7	Base	$0
7. 30% Lower Gas Prices	33%	$18	$0	$3.1	Base	$0
8. EIM wheeling cost $1/MWh	33%	$18	$0	$4.4	Base	$1
9. High CA RPS, high gas, moderate coal retirement	40%	$18	$0	$5.7	Moderate	$0
10. High CA RPS, low gas, moderate coal retirement	40%	$18	$0	$3.1	Moderate	$0

The resulting sub-hourly dispatch savings are provided in the table below. Benefits to APS resulting from participation in the EIM range from $5.9 million per year (in Scenario 7, which assumes low natural gas prices in APS and through the WECC) to $14.9 million (in Scenario 9, which includes high gas prices, a 40% RPS in California, and moderate incremental coal retirements). The primary case dispatch savings to APS were $8.9 million. Comparing scenarios

indicates that a higher RPS in California, and higher gas prices tend to have a positive impact on EIM benefits. In contrast, lower gas price assumptions (such as in Scenarios 7 and 10) reduce EIM dispatch benefits to APS because they lower the value of savings that results when the EIM improves the dispatch efficiency of gas generators. A range of coal retirement scenarios were developed to test whether EIM savings would change significantly if coal dispatch was reduced across the WECC as a result of the U.S. Environmental Protection Agency's Clean Power Plan Proposed Rule or other federal regulations restricting electric sector CO_2 emissions. These cases show slightly lower EIM savings for APS relative to the primary scenario, with the differences for these scenarios relative to the primary case typically being less than $1 million per year.

Table 2. Sub-hourly Dispatch Savings for 2020 by Scenario (2014$ million)

Scenario	Savings to APS	Savings to current EIM participants	Total sub-hourly dispatch savings
0. Primary Scenario	**$8.9**	**$1.4**	**$10.3**
1. CA 40% RPS	$12.9	$0.6	**$13.5**
2. WECC-wide CO2 ($18/ton)	$10.7	$2.9	**$13.6**
3. Significant WECC Coal Retirement	$8.3	$0.9	**$9.2**
4. Moderate WECC coal retirement	$8.0	$0.8	**$8.8**
5. WECC-wide CO2 ($40/ton) plus moderate coal retirement	$8.5	$3.0	**$11.5**
6. 30% Higher Gas Prices	$11.9	$2.2	**$14.1**
7. 30% Lower Gas Prices	$5.9	$1.9	**$7.9**
8. EIM transfer cost $1/MWh	$8.4	$2.1	**$10.6**
9. High CA RPS, high gas, moderate coal retirement	$14.9	$1.4	**$16.4**
10. High CA RPS, low gas, moderate coal retirement	$8.9	$0.7	**$9.6**

Note: Individual estimates may not sum to total benefits due to rounding.

Dispatch savings to current EIM participants range from $0.6 million to $3.0 million per year. Dispatch savings to current EIM participants include the value of a small reduction in renewable curtailment in the California ISO portion of the EIM footprint, based on an estimated replacement cost of $100/MWh for renewable energy to meet future procurement targets. This reduction to curtailment ranged from 8 to 20 GWh in across the different scenarios.

Flexibility Reserve Savings Results

This study modeled flexibility reserve benefits by analyzing coincident sub-hourly load, wind, and solar generation for each of the EIM members. Within the model, BAs not participating in the EIM are required to maintain flexibility reserves to meet 95% of the upward and downward deviations of their individual BAA's 10-minute real-time net load compared to their HA forecast. EIM participants are instead allowed to collectively meet a joint flexibility reserve requirement, which due to load and resource diversity is lower than the sum of individual BAA reserve requirements without EIM participation. APS's participation in the EIM is expected to reduce APS's flexibility reserve requirement as well as to enable an incremental reduction in flexibility reserve requirements for the current EIM participants.

In the ISO, the flexible ramping constraint provides an estimate of the market price for this ramping capability. We valued the quantity reduction in flexibility reserve requirements based on a range of historical ISO flexible ramping constraint shadow prices that were present in 2013 and 2014. The low value case uses the 2014 average price of $2.23/MWh, and the high value case uses the 2013 average flexible ramping shadow price of $6.98/MWh.

The table below summarizes the flexibility reserve savings estimated in this analysis. The results include both savings to APS as well as incremental reserve savings to the current EIM participants as a result of additional load and resource diversity of the larger EIM footprint that includes APS.

Table 3: Flexibility Reserve Savings

	Quantity reduction in flexibility reserve requirements (average MW)	Value of Flexibility Reserves Savings ($MM per year)	
		Low Case	High Case
Savings To APS	52.2	$1.0	$3.2
Incremental Savings To Current EIM Participants	83.4	$1.6	$5.1
Total Incremental Savings	135.6	$2.6	$8.3

In an average hour over the year, APS's participation in the EIM is estimated to reduce upward flexibility reserve requirements by a total 135.6 MW, a 12% reduction compared to the sum of requirements for the current EIM plus APS's individual requirement as a non-participating BA. The reduction is attributed to each EIM participant based on their relative share of standalone reserve requirements under a scenario without the EIM. For APS, the attributed diversity benefit of 52.2 MW on average represents a 28% reduction in flexibility reserves requirements compared to APS's requirements as a non-participant in the BAU case. Over the entire year, this flexibility reserve reduction produces savings to APS of $1.0 million in the low flexibility reserve value level, and $3.2 million when assuming the high flexibility reserve value.

The remaining reserve reduction of 83.4 MW is attributed to the current EIM participants, an 8% reduction relative to their requirements under the current EIM, resulting in an annual savings range of $1.6 to $5.1 million. APS is attributed a large share of total incremental savings shown in the table because the current

EIM participants are assumed to have already realized reductions in reserve requirements through the existing EIM. Thus, the table shows only the flexibility reserve reductions to those current participants that are incremental as a result of APS's participation. By contrast, the flexibility reserve savings to APS represents a full savings compared to a BAU scenario in which APS does not participate and therefore must procure reserves based on its individual BAA flexibility requirements as a standalone entity.

Summary

The estimated sub-hourly dispatch savings and flexibility reserve savings from EIM participation are together expected to be material for APS, totaling $9.9 to $12.1 million in the primary scenario. These savings to APS remain significantly positive under a robust set of fuel price levels and assumptions about renewable additions, coal retirements, and CO_2 prices. Total quantified APS EIM benefits ranged from $7.0 million to $18.1 million per year across all the scenarios evaluated. [11] This total excludes additional benefits from improved transactional efficiency in the DA or HA markets and from improved reliability, which were not quantified here but could be substantial.

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[11] Individual components of low range savings do not sum to total due to rounding.

1 Introduction

Arizona Public Service Company (APS) retained Energy and Environmental Economics, Inc. (E3) to estimate the economic benefits of APS's participation in the energy imbalance market (EIM) operated by the ISO. Energy Exemplar provided technical support by running sub-hourly production simulations cases using the PLEXOS production simulation modeling tool to calculate the dispatch cost savings category of benefits. Throughout the study process, the study team of E3 and Energy Exemplar worked closely with APS staff to refine scenario assumptions and data inputs to more accurately represent current operations on the APS system. This report details our approach for quantifying the benefits of APS's participation in the EIM and summarizes the findings of our analysis.

1.1 Structure of the Report

The remainder of this report is organized as follows:

+ **Section 2** describes the methodologies and assumptions used to estimate the benefits of APS's participation in the EIM;

+ **Section 3** presents the main results of the study;

+ **Section 4** provides the conclusions of the study.

2 Study Assumptions and Approach

2.1 Overview of Approach

The EIM, which began operating in November 2014 with the ISO and PacifiCorp as initial participants, allows Western BAs to voluntarily participate in the ISO's real-time energy market. EIM software dispatches generation across participating BAAs every 15 and 5 minutes to solve imbalances using security constrained economic dispatch (SCED), as well as commit quick-start generation every 15 minutes using security constrained unit commitment (SCUC). Each BA participating in the EIM is still responsible for meeting its own operating reserve and planning reserve requirements, and the EIM does not replace participating BAs' existing operational practices in advance of real-time.

APS's participation in the EIM is expected to produce two principal benefits resulting from changes in system operations for APS and the current EIM participants:

1. **Sub-hourly dispatch benefits**. Today, each BA outside of the EIM dispatches its own generating resources to meet imbalances within the hour, while holding schedules with neighboring BAs constant. The EIM nets energy imbalance across participating BAs, and economically

dispatches generating resources across the entire EIM footprint to manage the imbalance, resulting in operational cost savings. APS's participation in the EIM enables incremental dispatch efficiency improvements relative to the current EIM.

2. **Flexibility reserve reductions**. BAs hold flexibility reserves to balance discrepancies between forecasted and actual net load within the hour. *Load following flexibility reserves* (referred to in this report as simply "*flexibility reserves*") provide ramping capability to meet changes in net load between a 5-minute and hourly timescale.[12] By pooling load, wind, and solar output across the EIM footprint, the EIM allows participants to benefit from greater geographic diversity of forecast error and variability by reducing the quantity of flexibility reserves they require. APS's participation in the EIM would bring added load and resource diversity to the current EIM footprint, resulting in additional reserve savings.

Our general approach to estimating the benefits of APS's participation in the EIM is to compare the total cost under two cases: (1) a "business-as-usual" (BAU) case in which APS is not an EIM participant, and the operational efficiencies of the "current EIM" (including the ISO, PacifiCorp, and NV Energy)[13]

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[12] Regulating reserves, which address the need for resources to respond to changes on a sub-5 minute interval basis, are sometimes categorized in operational studies as a second type of flexibility reserve product. Since the EIM operates with 5-minute intervals, it is does not directly affect regulating reserve requirements. To be concise, all references to *flexibility reserve* in this report are related to load following reserves; *regulating reserves*, where referenced, are explicitly described by name.

[13] The ISO, PacifiCorp, and NV Energy are referred to in this study as "current EIM participants" because they are assumed to be already participating in the EIM before APS becomes a participant. NV Energy will also begin participating in the EIM in Fall 2015. Puget Sound Energy (PSE) also announced in March 2015 that it intends to begin participating in the EIM in Fall 2016. The majority of this analysis for APS was completed prior to PSE's announcement, so PSE is not included as an EIM participant in this study.

is already reflected; and (2) an "APS EIM" case in which the APS BA also participates in the EIM. The cost difference between the BAU and APS EIM cases represents the total incremental benefits of APS's participation in the EIM.

We estimate sub-hourly dispatch benefits using production simulation modeling of DA, HA, and real-time operations. The difference in WECC-wide production costs between the APS EIM simulations and the BAU simulation represents the incremental dispatch benefit for all EIM participants, including APS, as a result of APS's participation. To estimate cost savings from reduced flexibility reserve requirements, we used statistical analysis to determine the quantity of incremental flexibility reserve diversity that APS's participation would bring to the EIM, and then applied that quantity to historical flexible ramping constraint shadow prices from the ISO.

2.2 Key Assumptions

Four key modeling assumptions are important for understanding the results of this study: (1) sub-hourly dispatch; (2) real-time transmission capability; (3) hurdle rates; and (4) flexibility reserves.

2.2.1 SUB-HOURLY DISPATCH

In existing operational practice, BAs in the Western Interconnection exchange energy primarily on an hourly basis using hourly or multi-hour schedules, which require long lead times between scheduling the transaction and actual

dispatch.[14] Within the hour, each BA resolves imbalances by manually dispatching generating resources inside its BAA, without the assistance of other BAs. By contrast, the EIM optimizes dispatch of available generating resources in real-time across all of the participating BAAs using 15-minute unit commitment and 5-minute dispatch. These sub-hourly processes increase the efficiency of resolving imbalances.

This study quantifies the benefit of sub-hourly dispatch capability using a three-stage simulation process in PLEXOS consistent with the approach developed for the WECC Variable Generation Subcommittee (VGS) and refined in PNNL's Phase 1 Report for the NWPP MC Initiative. This methodology is described in detail in the PNNL report, as well as Section 2.3 below.

A PLEXOS simulation was run with hourly intervals in a DA stage, and then in an HA stage, using DA and HA forecasts of expected load, wind, and solar output. In the final stage, a real-time PLEXOS simulation is run with 10-minute intervals, using actual wind, load, and solar output for each interval. While actual EIM operations are at a 5-minute basis, a complete and validated PLEXOS dataset for 5-minute simulation was not available at the time of this study. This study's use of 10-minute time step in the real-time stage (to make use of the WECC VGS dataset) produces EIM benefits results that we expect may be somewhat conservatively low, as the 10-minute time step reduces the amount of variation within the hour to a small extent, slightly moderating the need for operational flexibility that an EIM can provide. Overall, however, we expect the 10-minute time step to capture much of the real-time dispatch efficiency savings.

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[14] The ISO and AESO are the exceptions.

During the real-time simulation, BAs not participating in the EIM must maintain a net exchange with neighboring BAs that is equal to the HA exchange level. EIM participants, on the other hand, can re-dispatch generation and exchange power with the rest of the EIM footprint during each of the 10-minute intervals, subject to transmission transfer limitations, which are discussed in Section 2.2.2 below.

In E3's prior analyses assessing the benefits of PacifiCorp and NV Energy participating in the ISO EIM, we used GridView, an hourly production cost model with input data largely based on TEPPC's 2022 Common Case. The 10-minute time-step capability of PLEXOS allows us to better represent the EIM's 5-minute dispatch interval relative to GridView's hourly time-step capability.[15]

2.2.2   REAL-TIME TRANSMISSION TRANSFER CAPABILITY

Previous studies have indicated that transmission can constrain EIM benefits by limiting the amount of power that can be transferred in real-time between EIM participants.

For the BAU case, we adopted real-time transmission transfer capability assumptions between current EIM participants from earlier EIM benefit analyses. All scenarios modeled 400 MW of capability between PacifiCorp and the ISO, and 1,500 MW of capability between the ISO and NV Energy.[16] For the APS EIM simulation, we allowed the physical limits on transmission capability

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[15] The WECC GridView database is currently developing a sub-hourly modeling capability, but this functionality and the sub-hourly data required were not available at the time of this analysis.
[16] These values are informed by capacity rights owned or controlled by the current EIM participants. Total maximum and minimum flow levels between zones in the model (including HA flow plus incremental changes in real-time) are also subject to physical transmission constraints on rated paths.

between APS and other EIM participants to constrain the maximum total transfer between these BAs for HA flow plus real-time EIM transfers.   In the model, these transmission limits included over 2,500 MW of connectivity between APS and the ISO and 600 MW between APS and PacifiCorp. The transmission topology did not include a separate trading hub zone and did not include any direct interties between APS and NV Energy, so APS to NV Energy EIM transfers would need to pass through the ISO or PacifiCorp.

2.2.3   HURDLE RATES

Within the Western Interconnection's bilateral markets, there are a number of impediments to efficient trade of energy across BAA boundaries. These include:

+ The need, in many cases, for market participants to pay for the fixed costs of the existing transmission system by redirecting or acquiring additional point-to-point transmission service in order to schedule transactions from one BAA to another;

+ The current tariff practice of requiring short-term transactions to provide real power losses for each transmission provider system that is utilized, resulting, in some cases, in multiple or "pancaked" loss requirements that are added to the fixed costs described above; and

+ Inefficiencies related to having illiquid bulk power and transmission service markets and imperfect information, such as the standard 16-hour "Heavy-Load Hour" and 8-hour "Light-Load Hour" DA trading products defined by the Western Systems Power Pool, minimum transaction quantities of 25 MW, and the bilateral nature of transaction origination and clearing.

These real-world barriers to trade are reflected in production cost simulations as "hurdle rates", $/MWh price adders applied to interfaces between BAAs. Hurdle rates inhibit power flow over transmission paths that cross BAA boundaries, and reduce economic energy exchange between BAAs.

An EIM eliminates the barriers listed above during real-time operations by performing security-constrained economic dispatch across the entire EIM footprint, allowing more efficient (i.e., lower cost) dispatch. Our production simulations in PLEXOS capture this effect by removing hurdle rates between EIM participants during the real-time simulations, while maintaining hurdle rates between non-participants. In the DA and HA simulations, hurdle rates are maintained between all BAAs, including between EIM participants.[17] We believe this is a conservative assumption regarding the expected adaptation of DA and HA markets based on information identified by the EIM. In reality, we would expect that BAs would adjust their DA and HA scheduled transactions more efficiently over time based on learning the dynamics of the real-time market results. This learning does not imply a shift away from DA and HA scheduling, but rather a more efficient and better informed selection of scheduling levels for any hour based on learning from real-time market participation. To the extent it can be realized, this opportunity for learning and improved DA and HA efficiency is a non-quantified benefit that would be additional to those quantified in this report.

Based on guidance from APS staff indicating that APS can typically send power to the ISO through the Palo Verde trading hub without incurring wheeling

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[17] This approach—to maintain hurdle rates for the DA and HA simulation and remove them in the real-time simulation run—is consistent with the methodology used by PNNL in the NWPP's MC Phase I EIM Benefit study.

charges, this study applied a hurdle rate of $0/MWh on transactions from APS to the ISO for the DA, HA, BAU and APS EIM cases. Charges for CO_2 import fees related to AB32 are still applied to energy transfers from APS to California.

For interties between the current EIM participants, hurdle rates were applied to the DA and HA cases, but removed during the real-time case runs for both the BAU and EIM scenarios. The removal of hurdles rates in real-time between current EIM participants in this analysis is consistent with the FERC-approved ISO tariff amendment associated with the EIM. One sensitivity case is used to test the impact of this assumption, by adding back in a $1/MWh wheeling charge to real-time transfers between EIM participants in the simulation. As described in the next chapter, this change has only a small downward impact on the resulting EIM benefits modeled.

2.2.4   FLEXIBILITY RESERVES

BAs hold capacity in reserve to balance discrepancies between forecasted and actual net load within the operating hour; these within-hour reserves are in addition to the spinning and supplemental reserves carried against generation or transmission system contingencies.[18] Regulating reserves automatically respond to control signals or changes in system frequency on a time scale of a few cycles up to 5 minutes. Load following reserves (referred to in this report simply as "flexibility reserves") provide ramping capability to meet changes in net load between a 5-minute and hourly timescale.

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[18] This study assumes that contingency reserves would be unaffected by an EIM, and that APS would continue to participate in its existing regional reserve sharing agreement for contingency reserves.

Higher penetrations of wind and solar increase the quantity of both regulating and flexibility reserves needed to accommodate the uncertainty and variability inherent in these resources, while maintaining acceptable BA control performance. By pooling load and resource variability across space and time, total variability can be reduced, decreasing the amount of flexibility reserves required to ensure reliable operations. This reduces operating costs by requiring fewer thermal generators to be committed and operated at less efficient set points.

Units that provide regulating reserves must respond faster than the EIM's 5-minute dispatch interval, so EIM participants are assumed here to receive no regulating reserve diversity savings as a result of participating in the EIM—savings are exclusively related to flexibility reserves that are needed for net load variations between the hourly and 5-minute level.

For this study, we used statistical analysis to estimate the reduction in flexibility reserves that would occur if APS participates in the EIM. Flexibility reserve requirements for each BA were modeled as a function of the difference between the 10-minute net load in real-time versus the HA net load schedule.

While there is currently no defined requirement for BAs to carry flexibility reserves, all BAs must carry a level of operating reserves in order to maintain Control Performance Standards (CPS) within acceptable limits, and reserve requirements will grow under higher renewable penetration scenarios. In December 2011, the ISO implemented a flexible ramping constraint in the five-minute market optimization to maintain sufficient upward flexibility in the

system within the hour.[19] Generators that are chosen to resolve a constraint are compensated at the shadow price, which reflects the marginal unit's opportunity cost. Furthermore, the ISO is in the process of introducing a flexible ramping product, which would allow economic bids to be submitted to procure upward and downward ramping capability.

The ISO's calculation of flexible ramping constraints for EIM participants is adjusted to reflect diversity of net loads for all participants, subject to transmission constraints. The ISO determines flexible ramp constraint requirements for the ISO and each EIM participant based on the aggregate load, wind, and solar resource forecasts and expected variability. By establishing the requirements based on the aggregate load and resource profiles, the benefits of diversity can be reflected in the EIM flexibility reserve requirements. The flexible ramping constraint in the EIM also compensates resources for their contribution to meeting the flexibility constraint.

2.3 Sub-hourly Dispatch Benefits Methodology

2.3.1 PRODUCTION COST MODELING

This study used PLEXOS, a sub-hourly production cost model, to estimate sub-hourly dispatch benefits in 2020. PLEXOS, like other production cost models, simulates bulk power system operations by minimizing the variable cost of operating the system subject to a number of constraints. PLEXOS includes a

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[19] See CAISO (2014d and 2014e).

three-stage sequential simulation process to model DA, HA, and real-time operations, as shown in Figure 1 below.

Figure 1. PLEXOS Three-Stage Sequential Simulation Process
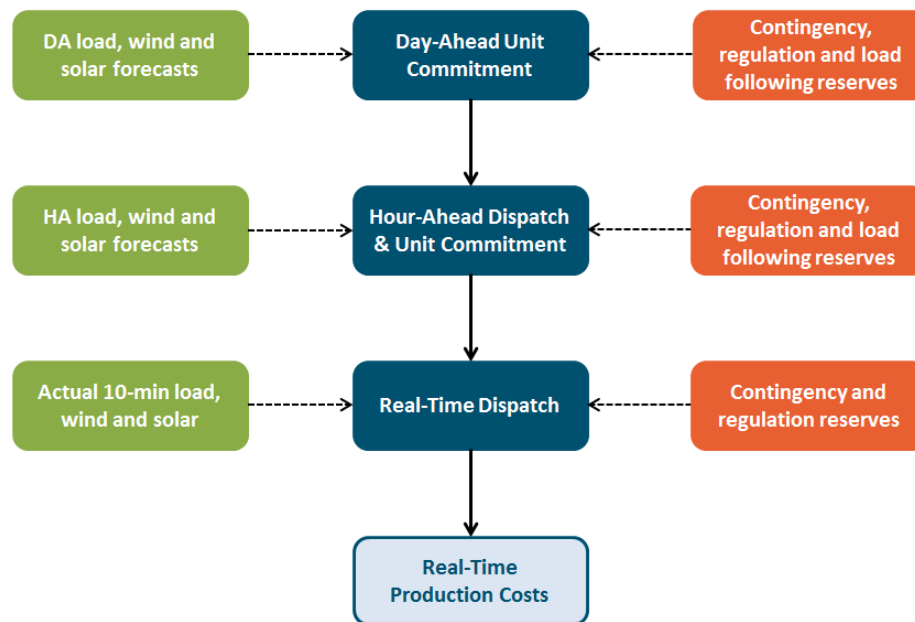
The primary purpose of the DA simulation is to generate daily unit commitment schedules for long-start units, while the HA simulation determines the HA dispatch and interchange schedules between BAs. During the real-time simulation, the "actual" load, wind, and solar data are used to generate dispatch, and flexibility reserves are "released" so that the capacity reserved from the HA simulation is allowed to serve real-time imbalances.

The DA, HA, and real-time (DA-HA-RT) sequential simulation approach allows PLEXOS to differentiate operations for BAs participating or not participating in

an EIM. When a BA is not participating in an EIM, then: (a) hurdle rates apply during the DA, HA and real-time simulations; (b) interchange is unconstrained during the DA and HA simulations; and (c) during the real-time simulation, the HA interchange schedule is locked down, resulting in the BA managing its imbalances with its own generation. In contrast, when two or more BAs are participating in an EIM, then hurdle rates on transfers between the participating BAs are removed during the real-time stage and generation from anywhere in the footprint can solve imbalances, subject to imposed transmission constraints.

This study estimated sub-hourly dispatch benefits of APS's participation in the EIM by running pairs of production cost simulations using PLEXOS. Under each simulation scenario, there is a pair of BAU and APS EIM cases. In the BAU case, APS solves its real-time imbalances with internal generation while maintaining interchange equal to the schedule from the HA simulation. Intra-hour interchange is allowed to vary to allow economic transfers between the ISO, PacifiCorp and NV Energy, reflecting the operational efficiencies of the current EIM. The APS EIM cases simulate the operations of an EIM consisting of the ISO, PacifiCorp, NV Energy and APS BAs. Hurdle rates between the BAs are removed in real-time and intra-hour interchange is allowed up to the real-time transfer capabilities specified in each scenario. The study quantifies the EIM-wide benefit of APS's participation in the EIM by measuring the reduction in production costs from the BAU case to the APS EIM case.

2.3.2   INPUT DATA

The initial dataset used for this report is the database used in analysis for the WECC VGS analysis and updated in the NWPP's Phase 1 Economic Benefit

Assessment. This dataset was built on information originally compiled for the WECC's Transmission Expansion Planning Policy Committee (TEPPC) 2020 PC0 database.

This study made the following key updates to the case:

+ **Zonal transport model**. The transmission network in PLEXOS was modeled at the zonal level rather than the nodal level. This change was made to more accurately represent commercial behavior of two BAs scheduling transactions between each other through trading hubs. Using the zonal model also significantly reduces model run time.

+ **Topology updates**. The transmission transfer capability between APS and neighboring zones was modeled according to APS's typical monthly total transmission capability. The remaining transmission topology and hurdle rate assumptions are based on the zonal model used for the ISO's 2012 Long-Term Procurement Plan (LTPP).

+ **Combustion turbine commitment during real-time**. Quick-start combustion turbines were allowed to commit and dispatch in the real-time simulations to reflect the ISO's addition of the 15-minute real-time unit commitment process for the EIM.

+ **Hydro optimization window**. The real-time simulations optimized the dispatch of flexible hydro units across a 6-hour window.

+ **Nuclear generation**. All nuclear plants throughout the WECC were modeled as must-run at their maximum capacity to avoid any unrealistic intra-hour changes in nuclear generation.

+ **Generation updates in California**. A number of select generator updates were made in the California ISO footprint, including: (1) retiring the San Onofre Nuclear Generation Station (SONGs); (2) applying the ISO's current best estimate of retirement and repowering of once-through

cooling generators by 2020; (3) updating the ISO's share of Hoover generation to match the values in the 2012 LTPP, and (4) updating the California ISO renewable resource mix to reflect a higher share of solar PV in the renewable resource portfolio and a lower share of wind resources based on current and planned additions for meeting the state's 33% RPS target by 2020. The resource mix was also adjusted to include additional rooftop PV solar in the ISO, which was not reflected in the original TEPPC model.

+ **Generation updates in APS**. APS generation in the database was updated to reflect APS planned additions of peaking units at Ocotillo, its planned retirement of a Cholla unit, as well as APS suggested revisions to operating characteristics and costs on certain APS generators. Additionally, based on information from APS indicating that APS currently does not routinely call on the Four Corners plant or its share of the Navajo plant to respond to within-hour changes, E3 held the real-time dispatch of those units equal to their hour-ahead dispatch levels during the real-time cases.

2.3.3 DISPATCH SAVINGS SCENARIOS

The dispatch savings were evaluated under a primary scenario and ten alternative scenarios with different assumptions regarding RPS levels in California, natural gas prices, coal retirements, CO_2 prices, and EIM wheeling charges on transactions. The scenarios were developed based on input from APS staff to highlight changes that APS believed both plausible to occur and also valuable to explore to test the robustness of EIM savings. Table 4 summarizes the assumptions used for each scenario modeled for calculating EIM sub-hourly benefits.

In the primary scenario, the burnertip natural gas price in the APS BA is equal to $4.4 per MMBtu, and this price is adjusted by +30% and -30% in the High Gas Price and Low Gas Price Scenarios, respectively. Natural gas prices in all other BAs throughout the WECC were adjusted by a similar percentage.

Table 4. Overview of EIM Scenario Assumptions

Scenario	CA RPS	CA CO$_2$ price level ($/ton)	Rest of WECC CO$_2$ price level ($/ton)	APS natural gas price ($ per MMBTU)	Incremental coal retirement	EIM wheeling rate ($ per MWh)
0. Primary Scenario	33%	$18	$0	$4.4	Base	$0
1. CA 40% RPS	40%	$18	$0	$4.4	Base	$0
2. WECC-wide CO$_2$ ($18/ton)	33%	$18	$18	$4.4	Base	$0
3. Significant WECC Coal Retirement	33%	$18	$0	$4.4	Large	$0
4. Moderate WECC coal retirement	33%	$18	$0	$4.4	Moderate	$0
5. WECC-wide CO$_2$ ($40/ton) plus moderate coal retirement	33%	$40	$40	$4.4	Moderate	$0
6. 30% Higher Gas Prices	33%	$18	$0	$5.7	Base	$0
7. 30% Lower Gas Prices	33%	$18	$0	$3.1	Base	$0
8. EIM wheeling cost $1/MWh	33%	$18	$0	$4.4	Base	$1
9. High CA RPS, high gas, moderate coal retirement	40%	$18	$0	$5.7	Moderate	$0
10. High CA RPS, low gas, moderate coal retirement	40%	$18	$0	$3.1	Moderate	$0

2.3.4   ATTRIBUTION OF BENEFITS TO EIM PARTICIPANTS

Total production cost savings represent the dispatch benefits to all EIM participants, including APS, as a result of APS's participation in the EIM. We attributed these benefits to APS and the current EIM participants by calculating the sum of the following components: (1) real-time generator production costs and (2) real-time imbalance costs, equal to imbalance times an EIM-wide market

clearing price. The sum of these components for a given area, such as APS, represents a proxy for the total cost to serve load, including the production costs to run local generators and the cost of importing power (or revenues from exporting power). The net change in this sum in the APS EIM case versus the BAU case represents the incremental benefit to a given participant as a result of APS's participation.

Since the EIM does not affect HA operations, there is no change in HA net import costs between the BAU and APS EIM cases. The EIM-wide market clearing price used to calculate real-time imbalance costs is the imbalance-weighted average of the participating BAs.

2.4 Flexibility Reserve Savings Methodology

The operational cost savings from reduced flexibility reserve requirements were estimated using the following methodology. First, a statistical analysis is used to estimate the quantity of flexibility reserve reductions from APS's participation in the EIM. To produce EIM annual reserve savings, this quantity reduction of flexibility reserve requirements is valued based on historical ISO flexible ramping constraint shadow prices for 2013 and 2014.

2.4.1 FLEXIBILITY RESERVE REQUIREMENT

To determine flexibility reserve requirements, we used the real-time (10-minute) and HA schedule of load, wind, and solar data developed through the WECC VGS and PNNL study. These data are used to calculate a distribution of flexibility needs (i.e., real-time net load minus the HA net load schedule). Each

BA's flexibility reserves requirement for each month and hour are calculated using a 95% confidence interval (CI), where the 2.5[th] and 97.5[th] percentiles determine the flexibility down and up requirements, respectively.[20]

For the BAU case, the flexibility requirements for the current EIM were calculated by summing the net load profiles for the ISO, PacifiCorp and NV Energy BAs before calculating the 95% CI.[21] APS's standalone requirements are calculated as a standalone entity. In the APS EIM case, flexibility requirements are calculated for the larger EIM including APS by summing the ISO, PacifiCorp, NV Energy and APS BA net load profiles. APS's EIM participation results in a "diversity benefit" that reduces total upward flexibility requirements by 135.6 MW on average.[22]

2.4.2   AVOIDED COST OF FLEXIBILITY RESERVES

To value flexibility reserve reductions, we first examined flexible ramping constraint shadow prices in the ISO for 2013 and 2014. The ISO has applied a flexible ramping constraint in the five-minute market optimization since December 2011 to maintain sufficient upward flexibility. Generators that are chosen to resolve a constraint are compensated at the shadow price, which reflects the marginal unit's opportunity cost. However, if there is sufficient capacity available, the constraint is not binding, resulting in a shadow price of zero. For 2013 the average flexible ramping constraint shadow price over all

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[20] Using the 95% confidence interval to calculate flexibility reserve requirements is consistent with the approach used in the NWPP EIM Phase 1 study.

[21] Due to diversity in forecast error and variability, the 95th percentile of aggregated real-time deviation from HA forecast for the entire EIM is a smaller level (relative to the size of the BAs) than it would be for the sum of individual EIM members.

[22] This reduction is subject to real-time transmission transfer capability limits, and cannot be larger than the transmission transfer levels between individual EIM participants and the rest of the EIM.

hours of the year was $6.98/MWh, and in 2014 the shadow price was $2.23/MWh on average.[23] Quantity reductions in *upward flexibility* requirements in 2020 are valued at the 2013 shadow price under the high flexibility reserve benefit case, and at the 2014 shadow price under the low flexibility reserve benefit case.

2.4.3   ATTRIBUTION OF FLEXIBILITY RESERVE SAVINGS

Flexibility reserve savings were attributed to APS and the current EIM participants by comparing their relative reduction in flexibility reserve requirements in the BAU case compared to the case with APS as an EIM participant. The ISO's Business Practice Manual (BPM) details how the ISO will assign flexibility reserve requirements among EIM participants. Each participating BA will be assigned a flexibility requirement equal to the BA's standalone flexibility reserve requirement (if it were not an EIM participant). This is reduced by an EIM reserve diversity factor that is equal to the combined EIM flexibility reserve requirement (which reflects diversity benefit across the EIM) divided by the sum of standalone flexibility reserve requirement quantity for all EIM participants if they were operating as standalone entities.[24]

Overall, APS's participation in the EIM provides incremental diversity to the full EIM footprint, reducing flexibility reserve requirements for current EIM participants by 83.4 MW on average, which is an 8% reduction compared to their requirements in the current EIM. APS's own flexibility reserve requirement

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[23] See CAISO (2014a). Inflated here from 2013 to 2014 dollars assuming an annual inflation rate of 2%.
[24] See CAISO (2014b).

is reduced by 52.2 MW on average, a 28% reduction from its requirements as a standalone BA.

3 Results

3.1 Benefits to APS

Table 5 below presents the annual benefits of APS's EIM participation in 2020 under each scenario. Each row displays APS's EIM sub-hourly cost savings for a particular scenario modeled in the PLEXOS simulation, the flexibility reserve requirement savings range, and the total benefits, which is the sum of sub-hourly dispatch savings plus flexibility savings.

Table 5. Annual Benefits to APS by Scenario (million 2014$)

Scenario	Sub-hourly dispatch Savings to APS	Flexibility Reserve Savings Range	Total EIM savings to APS
0. Primary Scenario	**$8.9**	**$1.0 - $3.2**	**$9.9 - 12.1**
1. CA 40% RPS	$12.9	$1.0 - $3.2 (for all scenarios)	$14.0 - 16.1
2. WECC-wide CO_2 ($18/ton)	$10.7		$11.7 - 13.9
3. Significant WECC Coal Retirement	$8.3		$9.3 - 11.5
4. Moderate WECC coal retirement	$8.0		$9.0 - 11.2
5. WECC-wide CO_2 ($40/ton) plus moderate coal retirement	$8.5		$9.6 - 11.7
6. 30% Higher Gas Prices	$11.9		$12.9 - 15.1
7. 30% Lower Gas Prices	$5.9		$7.0 - 9.1
8. EIM transfer cost $1/MWh	$8.4		$9.5 - 11.6
9. High CA RPS, high gas, moderate coal retirement	$14.9		$16.0 - 18.1
10. High CA RPS, low gas, moderate coal retirement	$8.9		$10.0 - 12.1

Note: Individual estimates may not sum to total benefits due to rounding.

The resulting EIM sub-hourly dispatch benefits to APS shown in Table 5 range from $5.9 million per year (in Scenario 7, which assumes low natural gas prices in APS and through the WECC) to $14.9 million (in Scenario 9, which includes high gas prices, a 40% RPS in California, and moderate incremental coal retirements). The primary case savings to APS were $8.9 million. Comparing scenarios indicates that a higher RPS in California, and higher gas prices tend to have a positive impact on EIM benefits. By contrast, lower gas price assumptions (such as in Scenarios 7 and 10) reduce EIM dispatch benefits to APS because they lower the value of savings that results when the EIM improves the dispatch efficiency of gas generators. A range of coal retirement scenarios were developed to test whether EIM savings would change significantly if coal dispatch was reduced across the WECC as a result of the U.S. Environmental Protection Agency's Clean Power Plan Proposed Rule or other federal regulations restricting electric sector CO_2 emissions. These cases show slightly lower EIM savings for APS relative to the primary scenario, with the differences for these scenarios relative to the primary case typically being less than $1 million per year.

The flexibility reserve savings to APS range from $1.0 to $3.2 million per year in all scenarios. The range was produced using the 52.2 MW average reduction in APS upward flexibility reserve requirements over the full year, multiplied by the ISO historical values for flexible ramping constraint shadow prices (in $/MWh) from 2014 (low case) and 2013 (high case).

3.2 Incremental Benefits to Current EIM Participants

Table 6 below presents the incremental benefit to the current EIM participants as a result of APS's participation in the EIM. In total, APS's participation is projected to create $3.0 to $6.5 million per year in incremental sub-hourly dispatch and flexibility reserves benefits for the current EIM participants under the primary scenario, and a range of total benefits from $2.2 to $8.1 million per year under the alternative scenarios.

Table 6. Annual Benefits to Current EIM Participants (million 2014$)

Scenario	Sub-hourly dispatch Savings to Current EIM Participants	Flexibility Reserve Savings Range	Total EIM savings to Current EIM Participants
0. Primary Scenario	$1.4	$1.6 - $5.1	$3.0 - 6.5
1. CA 40% RPS	$0.6	$1.6 - $5.1 (for all scenarios)	$2.2 - 5.7
2. WECC-wide CO_2 ($18/ton)	$2.9		$4.5 - 8.0
3. Significant WECC Coal Retirement	$0.9		$2.6 - 6.0
4. Moderate WECC coal retirement	$0.8		$2.4 - 5.9
5. WECC-wide CO_2 ($40/ton) plus moderate coal retirement	$3.0		$4.6 - 8.1
6. 30% Higher Gas Prices	$2.2		$3.8 - 7.3
7. 30% Lower Gas Prices	$1.9		$3.6 - 7.0
8. EIM transfer cost $1/MWh	$2.1		$3.7 - 7.2
9. High CA RPS, high gas, moderate coal retirement	$1.4		$3.1 - 6.5
10. High CA RPS, low gas, moderate coal retirement	$0.7		$2.3 - 5.8

Note: Individual estimates may not sum to total benefits due to rounding.

3.3 Results Discussion

3.3.1   DRIVERS OF SUB-HOURLY DISPATCH BENEFITS

Sub-hourly dispatch benefits are driven by a number of factors in the different scenarios modeled. EIM participation enables APS to flexibly import and export

within the hour over its interties with other EIM participants, as opposed to maintaining fixed hourly net interchange schedules as in the BAU case, and solely relying on its own resources to resolve real-time imbalances. As a result, EIM participation reduces the frequency that APS needs to start up and run its more expensive generation to respond to sub-hourly changes in load or renewable resource conditions, so APS can serve more of its load using lower cost units. Figure 2 below shows APS net exchange over a 3-day period in August for both the BAU and APS EIM case; positive values in the figure indicate outgoing energy flows from APS to other BAs. The figure illustrates how EIM participation enables APS to have a much more flexible sub-hourly net exchange than APS would have if scheduling bilaterally on a fixed hourly basis as assumed in the BAU case.

Figure 2. APS Net Exchange for Three-Day August Period

Additionally, EIM participation enables APS to import low-cost power from the other EIM participating BAAs during hours when those BAAs have lower cost

generation that becomes available in a sub-hourly time interval due to lower than expected load or higher than expected wind and solar output within the hour. The ISO BAA in particular, due to the large level of solar generation present in its system by 2020, has significant within-hour ramps and at times faces very low real-time prices or even negative prices when it would need to curtail renewable generation that it cannot use in that time to serve load. As an EIM participant, APS can provide a service and also realize cost savings during these conditions, by reducing its own internal dispatch in real-time and reducing its exports to the ISO (relative to the hour-ahead interchange schedule).

3.3.2   DRIVERS OF FLEXIBILITY RESERVE SAVINGS

The additional diversity from APS's participation in the EIM would bring an incremental 135.6 MW reduction in EIM-wide flexibility reserve requirements compared to the sum of current EIM reserve requirements plus APS standalone reserve requirements in the BAU case. The EIM assigns flexibility reserve requirements and allocates the diversity reduction among EIM participants based on their relative share of the sum of standalone reserves if each were operating without an EIM. On average, throughout the year, this methodology results in a 52.2 MW reducing in average flexibility reserve requirements for APS and an incremental 83.4 MW reserve reduction attributed to the current EIM participants.

This study values these flexibility reserve reductions based on the average historical flexible ramping constraint shadow price in the ISO. The high case uses

the 2013 historical average shadow price, which was \$6.98/MWh; the low case uses the 2014 historical average shadow price which was \$2.23/MWh.[25]

3.3.3 CONSERVATIVE ASSUMPTIONS

This study applied a number of conservative assumptions in this analysis, which could result in underestimating the benefits quantified above that would accrue to APS and to the current EIM participants. These assumptions include:

+ **Reliability-related benefits were not quantified.** The study did not quantify the potential reliability benefits tied to the increased situational awareness and resource control that the EIM will enable. Although these benefits are difficult to quantify, they are important to consider qualitatively as they are likely to produce substantial benefits.

+ **HA and DA transactions held constant**. The modeling approach conservatively assumed in the DA and HA case runs that APS's participation in the EIM would not change APS dispatch or transactional decisions relative to the BAU scenario. Over time, however, we believe as an EIM participant, APS may be able to use information obtained through more transparent awareness of the real-time market to adjust its positions more optimally in the HA and DA markets. APS's participation in the EIM could also allow APS to avoid transactions costs related to buy-sell price spreads currently incurred for market purchases and sales in bilateral 15-minute or HA trading. EIM transactions for APS would avoid such costs.

+ **Intra-regional dispatch savings were not quantified.** APS indicated that internal congestion on the APS system is usually small, so the analysis

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[25] Adjusted from 2013 to 2014 dollars.

did not endeavor to quantify if the EIM can help reduce costs or relieve problems within APS's BAA.

+ **Thermal generators were modeled with flat heat rates.** The database used in this study modeled units with a single heat rate point regardless of the unit's level of dispatch. Other databases typically use step-function incremental heat rates for thermal generators; such heat rates reflect the fact that a generator will typically have a higher average heat rate when operating at minimum dispatch levels (i.e., Pmin) compared to when operating closer to maximum output (i.e., Pmax). The EIM dispatch savings are driven by identifying efficiency opportunities to reduce dispatch of generation in one BAA and increase dispatch on a lower-cost generator located in a different participating BAA. Modeling thermal units with non-flat heat rates could produce greater variation in heat rates across generators (depending on their operating levels) and result in greater opportunities for EIM dispatch savings.

4 Conclusions

This study assessed the benefits to APS from participation in the ISO EIM, as well as the incremental savings that would accrue to the current EIM participants as a result of APS's participation. The study focused on quantifying two categories of benefits: sub-hourly dispatch savings and savings from reduced flexibility reserve requirements. The gross benefits identified are robust to a range of input assumptions regarding RPS levels in California, natural gas prices, coal retirements, CO_2 prices, and EIM wheeling charges on real-time transactions. Increased RPS levels in California would likely have an upward impact on EIM savings to APS, as it would lead to more hours in which there is value to the flexibility provided by APS generators and the ability of APS to selectively reduce real-time dispatch to bring low or zero cost energy from the other portions of the EIM.

These savings do not include a quantification of potential savings to APS from improved DA or HA market efficiency as a result of access to EIM pricing data, nor from improved reliability. The modeling approach conservatively assumed in the DA and HA case runs that APS's participation in the EIM would not change APS dispatch or transactional decisions relative to the BAU scenario. Over time, however, we believe as an EIM participant, APS may be able to use information obtained through more transparent awareness of the real-time market to adjusting its positions more optimally in the HA and DA markets. In addition, APS's participation in the EIM may allow APS to avoid transactions costs related to buy-

sell price spreads currently incurred for market purchases and sales in bilateral 15-minute or HA trading.

Finally, we did not quantify the potential reliability benefits tied to the increased situational awareness and resource control that the EIM creates. Although both of these benefits are difficult to quantify, they are important to consider qualitatively as they are likely to produce substantial benefits in addition to the savings quantified in this study.

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