Operating Reserve Reductions From a Proposed Energy Imbalance Market With Wind and Solar Generation in the Western Interconnection

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Technical Report
NREL/TP-5500-54660
May 2012

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NATIONAL RENEWABLE ENERGY LABORATORY

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Executive Summary

Our analysis considers several alternative forms of an energy imbalance market (EIM) proposed in the nonmarket areas of the Western Interconnection. The proposed EIM includes two changes in operating practices that independently reduce variability and increase access to responsive resources: balancing authority cooperation and subhourly dispatch. As proposed, the EIM does not consider any form of coordinated unit commitment; however, over time, it is possible that balancing authorities would develop formal or informal plans to coordinate unit commitment. As the penetration of variable generation increases on the power system, additional interest in coordination would likely occur. Several alternative approaches could be used, but consideration of any form of coordinated unit commitment is beyond the scope of our analysis. This report examines the benefits of several possible EIM implementations—both separately and in concert.

We calculated the need for flexibility reserve for several EIM footprints. This flexibility reserve requirement was estimated using a National Renewable Energy Laboratory method adapted from the Eastern Wind Integration and Transmission Study and is separate and distinct from contingency reserve requirements. The technique uses statistical analysis of simulated historical wind and solar generation to estimate reserve requirements at periods faster than the dispatch interval (regulation) and slower requirements (additional spin and non-spin reserve resources beyond what is needed to satisfy the contingency reserve requirement) to follow longer unforecasted changes in variable generation output. The additional flexibility reserve requirements are physically similar to, but distinct from, the existing reserves that are already required for regulation and contingencies. Each of these reserves is calculated for each hour of the year to create a dynamic reserve that can be deployed to manage forecasting errors over various time scales. Because this report assumes that contingency reserve obligations do not change with the increased use of variable generation, our discussion focuses on additional flexibility reserve throughout. Therefore, any reference to terms using *spin* or *non-spin* apply only to flexibility reserves that can be either spinning or non-spinning resources above and beyond what is needed to satisfy existing contingency reserve obligations.

We used wind data developed for the recent Western Wind and Solar Integration Study, which was managed by the National Renewable Energy Laboratory on behalf of the U.S. Department of Energy [1]. Solar data were developed by the National Renewable Energy Laboratory for the Western Electricity Coordinating Council (WECC) Transmission Expansion Planning Policy Committee (TEPPC) 2020 planning case. The scenario is defined by the TEPPC 2020 Planning Case 0, which includes approximately 8% wind and 3% solar penetration in the Western Interconnection. Although this study used the TEPPC database, it is not associated with the TEPPC process.

Both the wind and solar data sets are based on weather/cloud modeling that explicitly recognizes the temporal and geographic diversity of these resources. In effect, the load, wind power, and solar power data sets "re-create" the weather and load conditions from the year 2006 and apply them to the future year 2020, subject to various TEPPC PC0 assumptions. This approach is state-of-the-art in providing high-quality, simulated time series of wind power and solar power plants that have not yet been built.

Our analysis finds a reduction in required flexibility reserve is made possible by an EIM if it is implemented over the entire areas of the Western Interconnection not currently participating in regional markets. Figure i illustrates the impact of the full-footprint implementation of an EIM on reserves. The business-as-usual (BAU) case represents the current operational paradigm, with limited coordination among balancing authorities. The solid bars show the average hourly reserve deployment, and the whiskers show the maximum and minimum reserve levels over the course of the year for the BAU and EIM cases. Total average regulation is cut from 1669 MW for the BAU case to 1076 in the footprint EIM, while total flex spin and flex non-spin reserves are reduced from 5359 MW to 3083 MW. The figure shows the reserve detail for the footprint EIM compared with the BAU case. The average reserve is reduced 35%–46%.

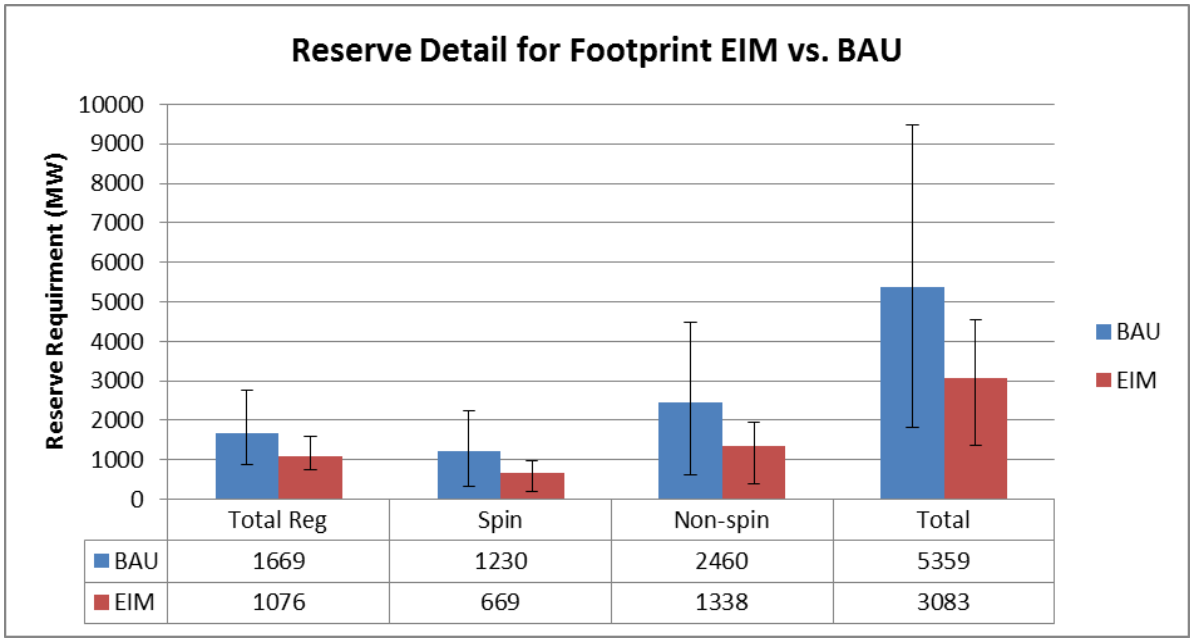


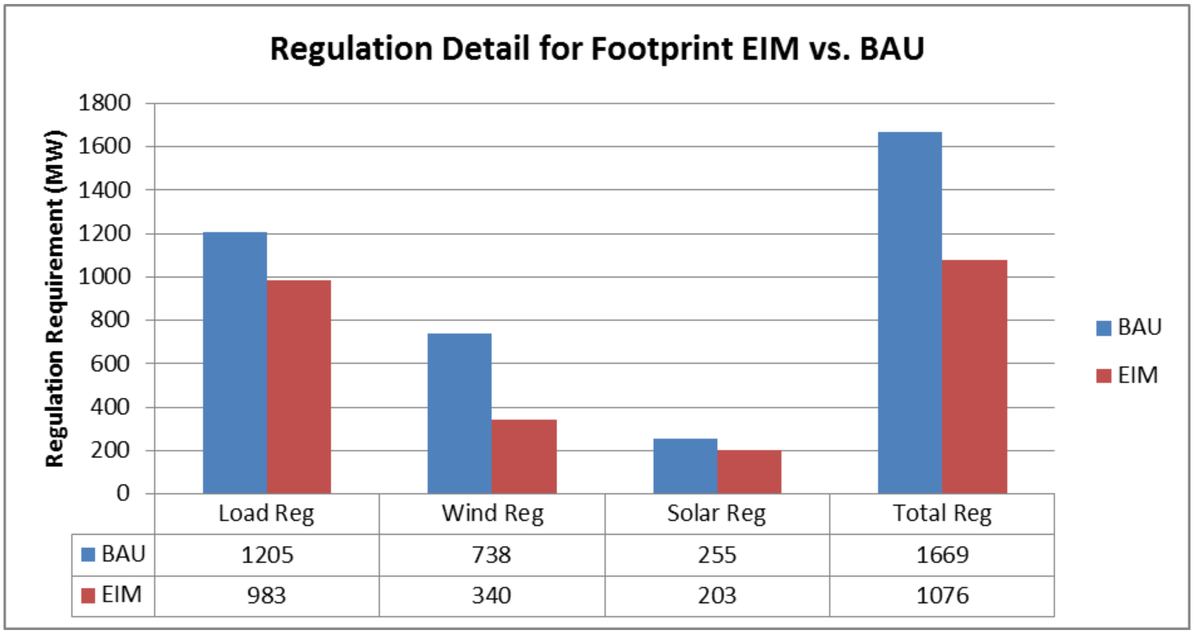
Figure i. The EIM reduces reserve targets by 35%–46%, on average

Table i shows the maximum reductions—ranging from a 42% maximum reduction in regulation to a 56% maximum reduction in spin and non-spin—in each flex reserve type.

Table i. Reduction in Maximum Flexibility Reserve Values

	BAU	EIM	Reduction
Total Regulation	2765	1607	42%
Spin	2236	977	56%
Non-Spin	4472	1955	56%
Total	9473	4539	52%

Total regulation is made up of three components: load, wind, and solar. The relationship among these components is shown in Figure ii. Total regulation is the square root of the sum of the squares of the individual components because they are assumed uncorrelated in the regulation timeframe. Load regulation is the largest contributor to total regulation, but the most significant savings for the EIM occur for the wind component, which is reduced by 54%. Solar impact on regulation is significantly smaller than that of wind, but that is because wind energy penetration is 8% and solar energy penetration is 3% in the TEPPC 2020 case.



	Load Reg	Wind Reg	Solar Reg	Total Reg
BAU	1205	738	255	1669
EIM	983	340	203	1076

Figure ii. Contributions of load, wind, and solar to average total regulating reserves

Calculating the reduction in total system flexibility reserve requirements that results from increased aggregation is relatively straightforward (as is measuring the benefits once the wind and solar generation is installed); allocating the savings to the individual participants is not as easy. To enable individual balancing authorities to assess the effect of the EIM on their reserves, it is necessary to calculate the balancing authority flexibility reserve needs in the aggregated case. This means that some form of allocation method is needed. We describe several allocation approaches, including incremental allocation, proportional allocation, and vector allocation. We define a very broad notion of "fairness" based on prior work that we use as a framework for discussing the alternative forms of allocation of reserves. We find that incremental and proportional allocations, although possessing some potentially attractive characteristics and simplicity, may result in reserve allocations that do not respect our simple, and hopefully noncontroversial, notions of fairness. Evaluating the reserve reduction potential of the EIM for any particular entity or balancing authority requires the use of some allocation, either implicitly or explicitly.

We also apply general reserve pricing to estimate the potential cost savings of each reserve type by balancing authority and for the market footprint. These estimates are not intended to be precise because we use the same pricing for all balancing authorities and at all times. We find that the full-footprint implementation of the EIM—which comprises the entire Western Interconnection, excluding the California Independent System Operator and Alberta Electric System Operator market areas—would result in savings of approximately $103 million/year because of less flexibility reserve deployment. This benefit is reduced to approximately $77 million/year if the Bonneville Power Administration and Western Area Power Administration, the federal power marketing administrations in the West, do not participate in the EIM.

We also apply this analysis to an alternative renewable energy scenario from the Western Wind and Solar Integration Study that uses a 30% annual wind energy penetration. We find that the reserve benefit for the entire footprint is approximately $221 million, which is reduced to $144 million without the participation of Bonneville Power Administration and Western Area Power Administration.

Our savings estimates are imprecise but provide an order-of-magnitude estimate of benefits. More importantly, this provides a glimpse at how the benefits might be allocated across the participants in the EIM. These results also show the overall sensitivity of the benefits (both in terms of megawatts of reserve and monetized benefits) to the penetration of variable generation. This analysis also shows the danger of relying on specific point estimates of the benefits of the EIM because the difference in results obtained from alternative penetrations is large.

Flexibility reserve requirements are not explicitly specified for each balancing authority area, but they are implicit in the operating reliability requirements for balancing. Each balancing authority must carry enough reserves to meet Control Performance Standard (CPS) 1, CPS 2, and Disturbance Control Standard requirements. Balancing authorities differ in their risk tolerance, and different balancing authorities may elect to carry different reserves to compensate for the same level of variability. One balancing authority may carry enough reserves to maintain a CPS 2 score of 98%, for example, while another may carry fewer reserves because it is comfortable with a 92% CPS 2 score. (Ninety percent or better is required.) For the purposes of this report, and to calculate the specific savings that result from the EIM, it is necessary to assume a common level of risk tolerance and a common reserve criterion to apply to each balancing authority, which we do inside the context of the reserve method discussed in this report. In reality, participation in the EIM and aggregating variability will always reduce the required reserves regardless of the individual balancing authority's risk tolerance.

Our analysis focuses only on the ramping and flexibility reserve impacts of the EIM. We do not consider or evaluate production costs, nor do we consider the cost of establishing the EIM or operating the EIM. The flexibility reserve calculations in this report also do not consider transmission limitations that might affect the delivery of an EIM transaction across congested transmission interfaces. The flexibility reserves that we calculate here were used as inputs to the WECC benefit study [2] and are also input to production simulation modeling under way using the Plexos production simulation model through a partnership between the National Renewable Energy Laboratory and Energy Exemplar. Both the WECC and Plexos analyses incorporate transmission constraints into the production simulation. The flexibility reserve calculations in this report establish the need for these reserves, and the production simulation provides a means to evaluate whether the demand for energy and reserves can be met.

Acknowledgments

The National Renewable Energy Laboratory project team would like to thank Heidi Pacini at Western Electricity Coordinating Council for her contributions to this work and the numerous reviewers from stakeholders in the Western Interconnection.

List of Abbreviations and Acronyms

AVA	Avista
AZPS	Arizona Public Service
BA	balancing authority
BAA	balancing authority area
BAU	business as usual
BCTC	British Columbia Transmission Corp.
BPA	Bonneville Power Administration
CHPD	Public Utility District No. 1 of Chelan County
CPS	Control Performance Standard
DOPD	Public Utility District No. 1 of Douglas County
E3	Energy and Environmental Economics Inc.
EIM	energy imbalance market
EPE	El Paso Electric
ERCOT	Electric Reliability Council of Texas
GCPD	PUD No. 1 of Grant County
GW	gigawatt
IID	Imperial Irrigation District
IPC	Idaho Power Corp.
ISO	independent system operator
ISO-NE	Independent System Operator – New England
LDWP	Los Angeles Department of Water and Power
MISO	Midwest Independent Transmission System Operator
NREL	National Renewable Energy Laboratory
NTTG	Northern Tier Transmission Group
NWE	Northwest Energy
PACE	Pacificorp East
PACW	Pacificorp West
PC	Planning Case
PGE	Portland General Electric
PNM	Public Service Company of New Mexico
PSCO	Public Service Company of Colorado
PSE	Puget Sound Energy
SCL	Seattle City Light
SMUD	Sacramento Municipal Utility District
SPP	Sierra Pacific Power
SRP	Salt River Project
TEP	Tucson Electric Power
TEPPC	Transmission Expansion Planning Policy Committee
TID	Turlock Irrigation District
TPWR	Tacoma Power
VG	variable generation
WACM	Western Area Power Administration – Colorado Missouri Region
WALC	Western Area Power Administration – Lower Colorado Region
WAPA	Western Area Power Administration

WAUW	Western Area Power Administration – Upper Great Plains West
WECC	Western Electricity Coordinating Council
WWSIS	Western Wind and Solar Integration Study

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1 Introduction

The anticipated increase in variable generation (VG) in the Western Interconnection over the next several years has raised concerns about maintaining system balance, especially in smaller balancing authority areas (BAAs).[1] Given renewable portfolio standards in the West, it is possible that more than 50 gigawatts (GW) of wind capacity will be installed by 2020. Significant quantities of solar generation are likely to be added as well. The consequent increase in variability that must be managed by the conventional generation fleet and responsive load makes it attractive to consider ways in which balancing authorities (BAs) can pool their variability and response resources to take advantage of geographic and temporal diversity and increase overall operational efficiency.

Several approaches, each of which involves alternative levels of operational coordination beyond what is done today, could be taken to implement this type of variability pooling. A full pooling of variability could potentially result in fully coordinated unit commitment, after blending load, solar, and wind forecasts. Closer to real time, economic dispatch could be implemented across the entire electrical footprint. An alternative to this fully coordinated operational case is using the existing practice for unit commitment, which is largely uncoordinated among BAs, in most cases, but allows for economic dispatch over a wide area.

Our analysis considers several alternative forms of an energy imbalance market (EIM) proposed in the non-market areas of the Western Interconnection. The proposed EIM includes two changes in operating practices that independently reduce variability and increase access to responsive resources: BA cooperation and subhourly dispatch. As proposed, the EIM does not consider any form of coordinated unit commitment; however, over time, it is possible that BAs would develop formal or informal coordination plans. This report examines the benefits of several possible EIM implementations, both separately and in concert.

Our analysis focuses only on the ramping and flexibility reserve impacts of the EIM. We do not consider or evaluate production costs, nor do we consider the costs to establish the EIM or operate the EIM. The flexibility reserve calculations in this report also do not consider transmission limitations that might affect the delivery of an EIM transaction across congested transmission interfaces. The flexibility reserves that we calculate here were used as inputs to the Western Electricity Coordinating Council (WECC) benefit study and are also input to production simulation modeling under way using the Plexos production simulation model through a partnership between the National Renewable Energy Laboratory (NREL) and Energy Exemplar. Both the WECC and Plexos analyses incorporate transmission constraints into the production simulation. The flexibility reserve calculations in this report establish the need for these reserves, and the production simulation provides a means for evaluating whether the demand for energy and reserves can be met.

Because this report assumes that contingency reserve obligations do not change with the increased use of VG, our discussion focuses on additional flexibility reserves throughout. Therefore, any reference to terms using *spin* or *non-spin* apply only to flexibility reserves that can be either spinning or non-spinning resources above and beyond what is needed to satisfy existing contingency reserve obligations.

Table 1 describes the ancillary services referenced in this report (adapted from [6]). Both contingency reserves and flexibility reserves use regulating, spinning, and non-spinning resources. Flexibility reserves are in addition to contingency reserves.

[1]Balancing the same variable renewable generation penetration percentage is more difficult for numerous small BAAs than for fewer large BAAs because variability partially cancels as BAA size increases while access to flexible resources continues to increase.

Table 1. Ancillary Service Descriptions

<table>
<tr><th rowspan="2">Service</th><th colspan="5">Service Description</th></tr>
<tr><th>Response Speed</th><th>Duration</th><th>Cycle Time</th><th>Market Cycle</th><th>Price Range (Average/Max) $/MWh</th></tr>
<tr><td colspan="6">Normal Conditions</td></tr>
<tr><td rowspan="2">Regulating Reserve</td><td colspan="5">Online resources, on automatic generation control, that can respond rapidly to system operator requests for up and down movements; used to track the minute-to-minute fluctuations in system load and correct for unintended fluctuations in generator output to comply with CPS 1 and 2</td></tr>
<tr><td>~1 min</td><td>Minutes</td><td>Minutes</td><td>Hourly</td><td>33–60#
300–620</td></tr>
<tr><td rowspan="2">Load Following or Fast Energy Markets</td><td colspan="5">Similar to regulation but slower; bridge between the regulation service and the hourly energy markets</td></tr>
<tr><td>~10 min</td><td>10 min to hours</td><td>10 min to hours</td><td>Hourly</td><td>-</td></tr>
<tr><td colspan="6">Contingency Conditions</td></tr>
<tr><td rowspan="2">Spinning Reserve+</td><td colspan="5">Online resources, synchronized to the grid, that can increase output or decrease consumption immediately in response to a major generator or transmission outage and can provide full response within 10 min to comply with the North American Electric Reliability Corp Disturbance Control Standard</td></tr>
<tr><td>Seconds to <10 min</td><td>10–120 min</td><td>Hours to days</td><td>Hourly</td><td>6–27
60–2000</td></tr>
<tr><td rowspan="2">Non-Spinning Reserve*+</td><td colspan="5">Same as spinning reserve but need not respond immediately; resources can be offline but still must be capable of fully responding within the required 10 min</td></tr>
<tr><td><10 min</td><td>10–120 min</td><td>Hours to days</td><td>Hourly</td><td>1–4
10–2000</td></tr>
<tr><td rowspan="2">Replacement or Supplemental Reserve</td><td colspan="5">Same as non-spinning reserve but with a 30–60 min response time; used to restore spinning and non-spinning reserves to their pre-contingency status</td></tr>
<tr><td><30 min</td><td>2 hours</td><td>Hours to days</td><td>Hourly</td><td>1–2
4–244</td></tr>
</table>

#Up and down regulation prices for California and ERCOT are combined to facilitate comparison with the full-range prices of New York and other regions.

*In this analysis, non-spinning reserve is considered to be a 30-min service.

+The flexible reserves defined in this report are in addition to reliability reserves using the same names.

This study extends the analysis by King et al. [10] that quantifies the flexibility reserve requirements for several implementations of the EIM. The prior study used the wind energy penetration assumptions for a 35% renewable penetration scenario from the Western Wind and Solar Integration Study but used only the wind energy at a 30% penetration. This study uses the approximately 8% wind and 3% solar penetration assumptions from the WECC Transmission Expansion Planning Policy Committee (TEPPC) 2020 Planning Case 0 (PC0).

The NREL method uses a technique for estimating flexibility reserve requirements adapted from the Eastern Wind Integration and Transmission Study. This technique uses statistical analysis of simulated historical wind and solar generation to estimate reserve requirements at periods faster than the dispatch interval (regulation) and slower requirements (spin and non-spin reserves) to follow longer unforecasted changes in VG output.

The method is used to calculate the reserve requirements for a business-as-usual (BAU) case and compares those results with calculations for several EIM implementations to estimate the savings in reserves resources.

WECC engaged E3 (Energy and Environmental Economics Inc.) to perform a study using a production cost modeling approach to estimate the production cost savings that would be realized with EIM implementation. This study also used the WECC TEPPC 2020 PC0 assumptions. The E3 analysis used the NREL reserve results (described herein) that consist of one time series for each reserve type, hourly, for the full year, as input to production cost simulations that were carried out using the Gridview production simulation model. The E3 study uses the reduced reserve requirements for the EIM to calculate the value of energy savings due, in part, to those reduced requirements.[2]

Figure 1 shows the relationship between the methods and data presented here and production cost modeling studies that are used to simulate the total savings from the implementation of an EIM. The boxes on the left show the process used to develop the flexibility reserves described in this report, and the boxes on the right show how those results are integrated into production cost simulations. Because Gridview and Plexos both incorporate the WECC TEPPC 2020 PC0 assumptions, transmission is explicitly considered in the production simulations. The flexibility reserves calculated in this report describe the need for those reserve products, and the production simulation provides a way to evaluate the operation of the power system and how the flexibility reserve can be delivered.

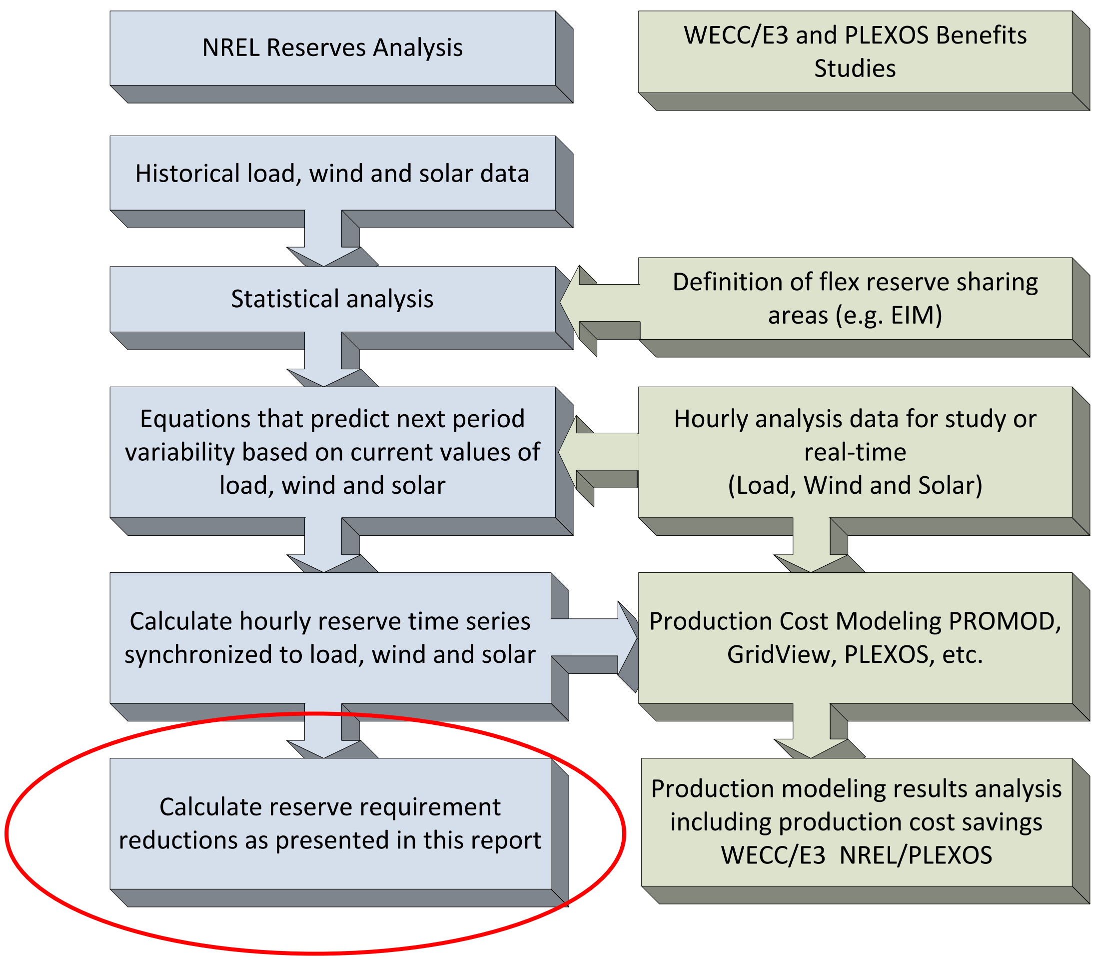

Figure 1. Relationship between reserve calculations and production cost studies

[2]The E3 study provides a point estimate of the benefits of the EIM. It is based on a single scenario. The actual benefits of the EIM would accrue through time and depend heavily on the level of wind and solar generation, along with other assumptions about the remaining components of the power system and the modeling. Interested readers are referred to [13].

2 Data

We used wind data from the recent Western Wind and Solar Integration Study, which was managed by NREL on behalf of the U.S. Department of Energy [1]. Solar data were developed by NREL for the WECC TEPPC 2020 planning case. The scenario is defined by TEPPC 2020 PC0, which includes approximately 8% wind and 3% solar penetration in the Western Interconnection.

Both the wind and solar data sets are based on weather/cloud modeling that explicitly recognizes the temporal and geographic diversity of these resources. In effect, the load, wind power, and solar power data sets "re-create" the weather and load conditions from the year 2006 and apply them to the year 2020, subject to the various TEPPC PC0 assumptions. This approach is state-of-the-art in providing high-quality, simulated time series of wind and solar power plants that have not been built.

The 2006 time series wind data set was paired with the 2006 time series load data so that the common weather impacts on load and wind would be consistent. We aggregated the data into subregional footprints: Columbia Grid, Northern Tier Transmission Group (NTTG), WestConnect, and British Columbia. Other areas within the Western Interconnection (California and Alberta) were not modeled because markets are already in place in those areas and they likely would not participate in the initial EIM analyzed in this report.[3]

2.1 Wind Production Data

3TIER developed a large wind speed and wind power database using a numerical weather prediction model applied to the West. Because the model allows the re-creation of the weather at any time or space, wind speed data were sampled every 10 min for a 3-year period on a 2-km spatial resolution at representative hub heights for modern wind turbines. The resulting data set does a good job of capturing the chronological behavior and geographical diversity of the wind that would occur at locations around the West. The high-resolution data set was then used to construct the various wind scenarios.

The numerical weather prediction model of the Western Interconnection contained geographic and temporal seams that were not possible to resolve. This resulted in unrealistic wind energy ramps near the temporal boundaries, which occurred every 3 days. To make the reserves and ramping analysis complete, a continuous annual record was needed, so a method to smooth those ramps below statistical significance was required. To do this, the wind data were analyzed in detail surrounding the anomalies.

The anomalies occurred at approximately the same time, 3 p.m., every third day starting with the first day of data for all wind plants in the data set. Anomalous data were seen up to 3 hours before this time and 3 hours after—a side effect of the blending of model runs done by the wind data contractor. These anomalous data caused 10-min ramps more than double that seen anywhere else in the data sets. Figure 2 shows a scatter plot of 10-min interval changes verses the interval number out of a 3-day period. The red dots show where the anomalous data are found. The spikes near 90 on the X axis show the peak interval changes. The similar time, 3 p.m., on the second and third days are near 230 and 380 and do not show similar peaks.

The time range in which the anomalies occurred and the magnitude characteristics were observed. Statistics for similar time periods not affected were computed. Several moving average filters were designed to push the magnitude of the anomalies below a threshold consistent with statistics from the nonaffected times. The blue dots show the results of the filtering. Although some artifacts of the filtering are observed, the overall shape of the envelope is similar to the same time on the second and third days of the sequence.

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[3] If seams coordination between the EIM with the California ISO and the Alberta ISO allows for real-time border price convergence, the benefits calculated herein would likely increase.

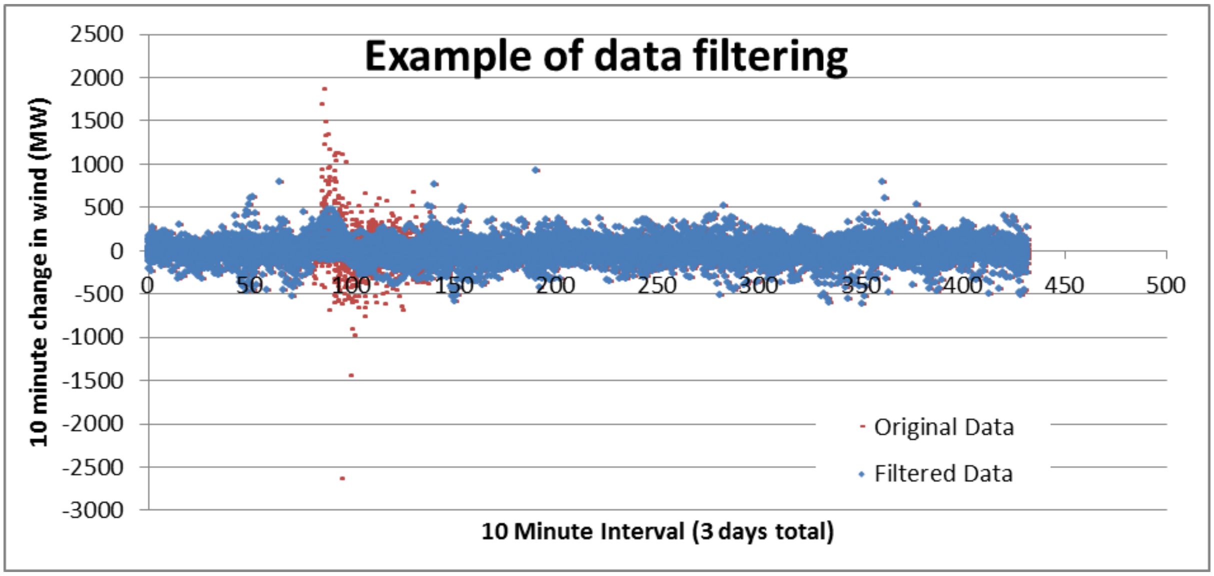


Figure 2. Example correction of the third-day anomaly in the Western Wind and Solar Integration Study wind data set

2.2 Solar Data

Solar data for this study were developed at NREL using satellite-based irradiance data, as described in Orwig [11]. The model produced data for multiple solar technologies, including fixed photovoltaic panels, one-axis tracking photovoltaic panels, and concentrating solar power plants.

The solar data were developed at spatial resolution of 10 km and temporal resolutions of 1, 10, and 60 min for the year 2006. The data were calculated for 1488 grid locations that correspond to Western renewable energy zones. At each of the retained locations, output for nominal 50-MW photovoltaic and 100-MW concentrating solar power plants were calculated at each time interval for the entire year.

TEPPC 2020 PC0 solar locations were mapped to the NREL data. These locations were then used to generate 1-hour resolution regional profiles. These profiles were eventually disaggregated back to the original solar locations to allow the generation of 10-min resolution data compatible with the methods used in the analysis reported here.

2.3 Load Data

Load time series data from 2006 were provided by WECC for each of the load zones in the Western Interconnection. The load data were taken from the TEPPC 2020 PC0 case and reflect forecasted load conditions for the year 2020 based on the load shapes from 2006.

To provide adequate temporal resolution to observe diversity effects and match the resolution of the wind data, 10-min data were synthesized from hourly load data. The intra-hour variability was statistically characterized using multiple high-resolution data sets from BPA and some Eastern Interconnection BA sources. These data sets ranged from 5- to 10-min sampling resolution for BAs ranging from about 2000 MW up to 15,000 MW. The size range was chosen to cover the range of the subset of WECC-member BAs used in the broader analysis discussed later in this report.

2.4 BAAs and Regional Modeling

This study modeled portions of the Western Interconnection not already covered by a market structure. Table 2 shows the BAAs considered as part of the study as well as subregional groupings used for subregional implementations of EIM operations. BAs that do not contain load were not considered for this evaluation.

Table 2. BAAs and Subregional Groups Considered in This Study

Columbia Grid	
	Avista (AVA)
	Bonneville Power Administration (BPA)
	Public Utility District No. 1 of Chelan County (CHPD)
	Public Utility District No. 1 of Douglas County (DOPD)
	Public Utility District No. 1 of Grant County (GCPD)
	Puget Sound Energy (PSE)
	Seattle City Light (SCL)
	Tacoma Power (TPWR)
Northern Tier Transmission Group	
	Idaho Power Corp. (IPC)
	Northwest Energy (NWE)
	Pacificorp East (PACE)
	Pacificorp West (PACW)
	Portland General Electric (PGE)
WestConnect	
	Arizona Public Service (AZPS)
	El Paso Electric (EPE)
	Imperial Irrigation District (IID)
	Public Service Company of New Mexico (PNM)
	Public Service Company of Colorado (PSCO)
	Sacramento Municipal Utility District (SMUD)
	NV Energy [Sierra Pacific Power (SPP), Nevada Power (NEVP)]
	Salt River Project (SRP)
	Tucson Electric Power (TEP)
	Turlock Irrigation District (TID)
	WAPA - Colorado Missouri Region (WACM)
	WAPA - Lower Colorado Region (WALC)
	WAPA - Upper Great Plains West (WAUW)
California Other	
	Los Angeles Department of Water and Power (LDWP)
Canada	
	British Columbia Transmission Corp. (BCTC)

Figure 3 shows a map of the reduced BAA structure considered for this study. The color of the BAA name indicates to which subregional group it belongs. Orange indicates Columbia Grid, light blue is NTTG, white is WestConnect, and black is BCTC and LDWP.

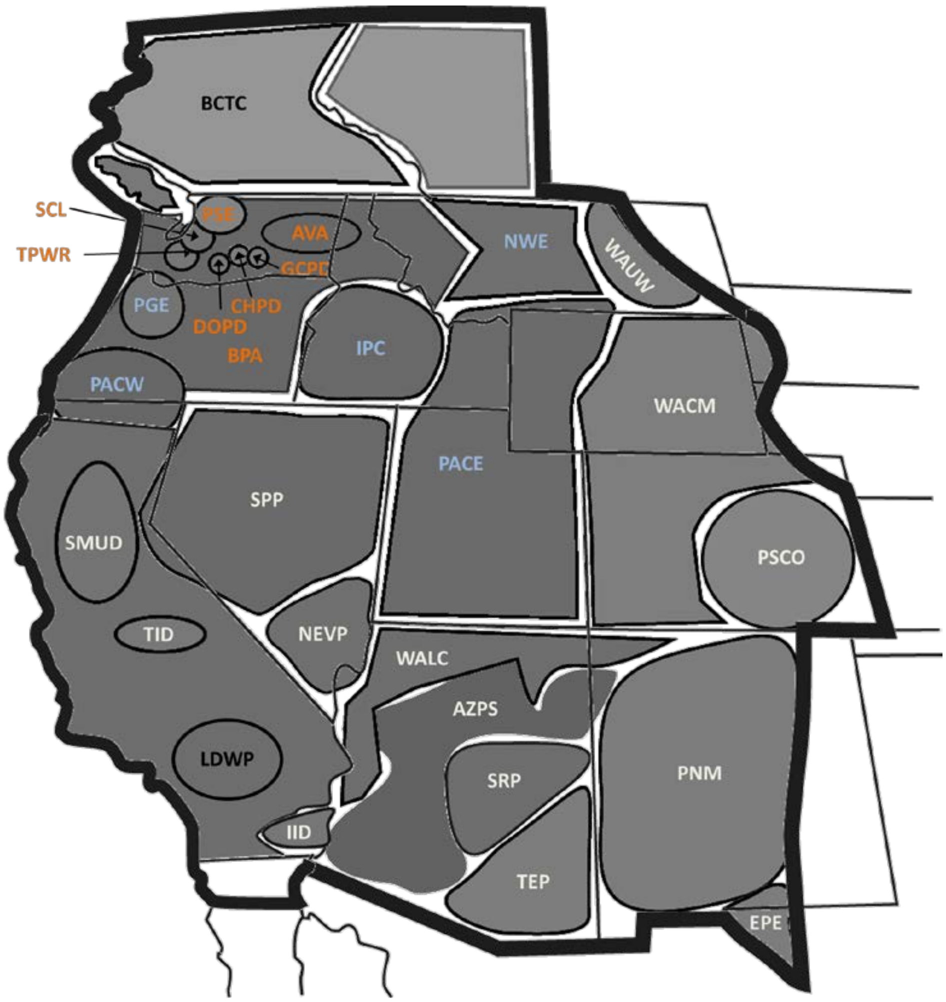


Figure 3. WECC BAA map with subregional groups

3 Overview of the Proposed EIM and Efficient Dispatch Toolkit[4]

In the Western Interconnection, areas outside of California and Alberta do not have a common energy market, although there is bilateral transaction activity in the region. In addition, a joint initiative (www.nttg.biz) provides low-cost, bilateral products that include the intra-hour transaction accelerator platform and the dynamic scheduling system. Stakeholders in the Western Interconnection are investigating an efficient dispatch toolkit that would achieve many of the benefits of a large-scale energy market but without a coordinated unit commitment or regulation market.

The proposed efficient dispatch toolkit would use two primary tools. An enhanced curtailment calculator, which can prioritize and allocate transmission service curtailments based on service priority for power flow impacts on the grid, would evaluate tagged and untagged flows. (Most deliveries inside balancing areas are not tagged.) The enhanced curtailment calculator would pass relevant curtailment information to the second tool: the EIM.

The EIM uses a security-constrained economic dispatch to provide two functions:

[4] This section is adapted from [9].

- Balancing service: This service redispatches generation every 5 min to maintain the balance between generation and load. For deliveries scheduled in advance, the effect is that the market supplies deviations from schedules in generator output and errors in load schedules.
- Congestion redispatch service: This redispatches generation to relieve overload constraints on the grid. Information provided to the EIM from the enhanced curtailment calculator ensures correct allocation of the costs of redispatch service.

Federal Energy Regulatory Commission Pro Forma Tariff Schedules 4 (energy imbalance) and 9 (generation imbalance) provide the approach used by the WECC BAs for balancing services. The proposed EIM replaces part of the BA services and results in a "virtual consolidation" because of a wide-area security-constrained economic dispatch that covers imbalances. The congestion redispatch service is new to the nonmarket portions of the Western Interconnection.

The EIM design includes a feature different from most regional markets in the United States in which internal resources are subject to a "must offer" requirement. Instead, the default operating assumption is that each market participant provides sufficient resources to cover its own obligations (as is the case today) and the regional economic dispatch is provided by any resource that voluntarily offers responsive capability and which is cleared by the security-constrained economic dispatch process. Most transmission service deliveries would continue to use traditional reserved transmission service, but the EIM would not use pre-reserved transmission. Instead, the EIM flow would receive the lowest transmission service curtailment priority. By this mechanism, EIM flows would not displace reserved transmission service.

Unlike other regional markets in which transmission service for market delivery is provided under a regional network service tariff, the EIM flows would pay an imputed service compensation after the fact to participating transmission providers. At this stage of development of the efficient dispatch toolkit, the specific terms for the transmission service revenue target and revenue allocation among participating transmission providers have not been established.

The EIM function adds some operational steps to the practices used in the Western Interconnection today. Functionally, the operating steps for the proposed EIM track closely with the operating process established in the Southwest Power Pool in its Energy Imbalance Service Market. Figure 4 illustrates the timeline for operation of the proposed efficient dispatch toolkit.

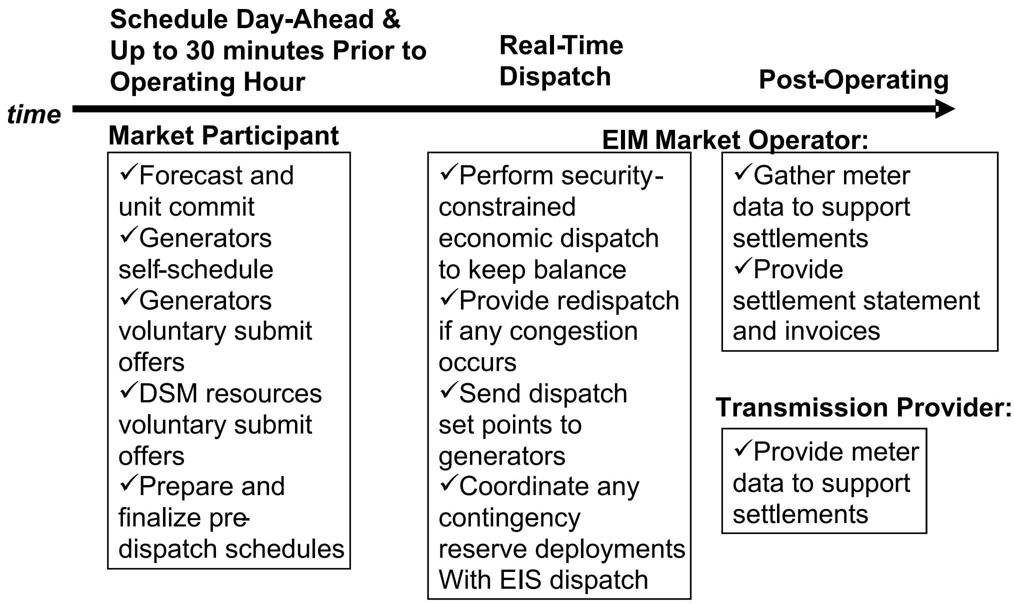


Figure 4. Operation timeline for the EIM toolkit

Figure 5 shows the sequence of taking the system data, calculating the expected conditions and required set points for the next interval, communicating those set points to generators and responsive loads, and then responsive resources moving to the new set points—all in 10 min.

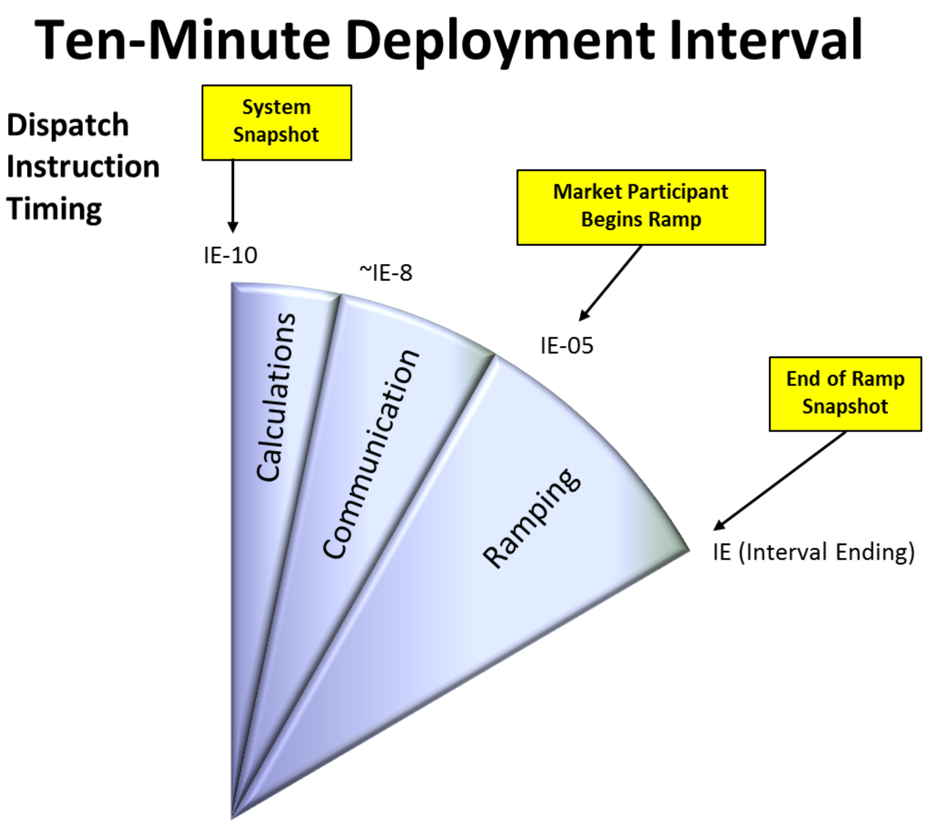


Figure 5. EIM schedule for calculating dispatch set points and moving generation within 10 min

Figure 6 shows how continuously repeating the process shown in Figure 5 results in meeting a new system dispatch point every 5 min, based on information that is only 10 min old.

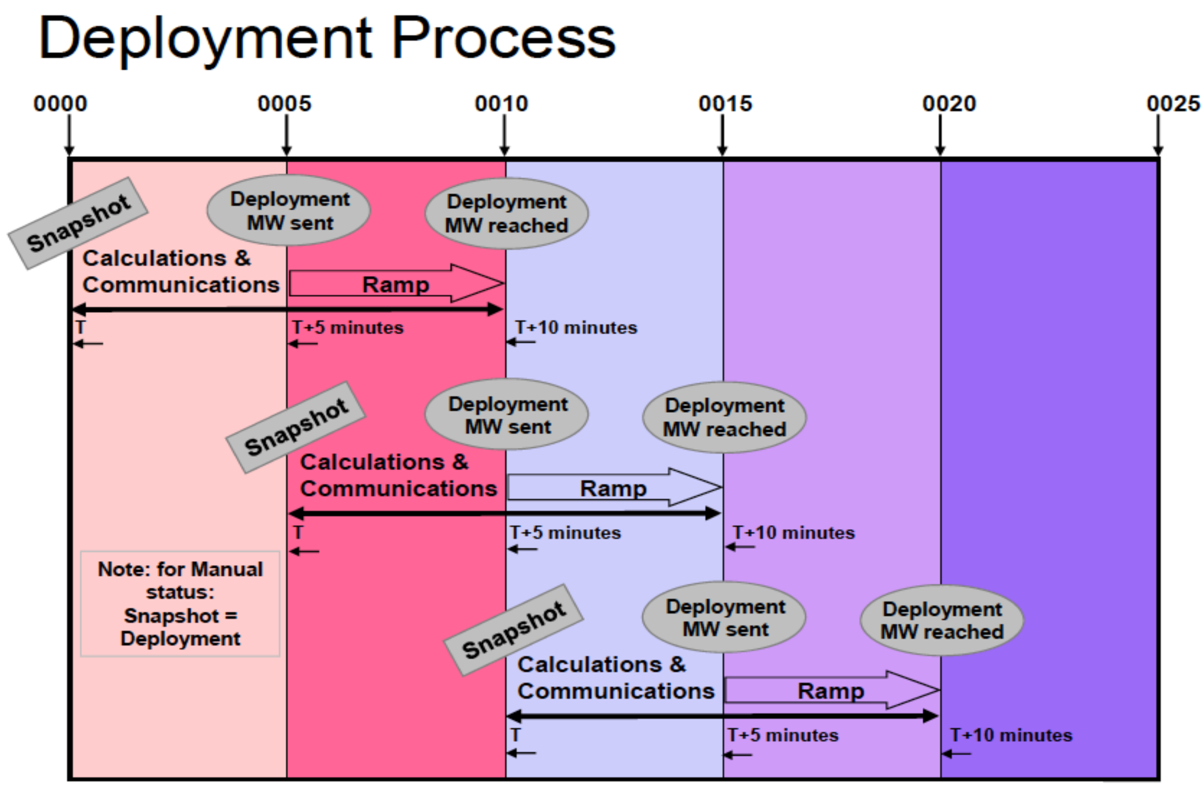


Figure 6. EIM repeats the calculations and unit ramping every 5 min based on system snapshots that are only 10 min old

The EIM would effectively implement some aspects of a virtual BAA across the Western Interconnection. (California and Alberta would not be included because they already have energy markets.[5]) Imbalances would be netted out, much as they would be in a single BAA. As proposed, the EIM does not result in a coordinated unit commitment, nor does it pool regulation, which remains a service at the local BA level. However, the netting of energy imbalance, which would include impacts of load and wind, is expected to be significant.

Figure 7 illustrates the concept, with each of the small bubbles representing a single BAA. The arrows between the BAAs indicate bilateral tagged energy flows that would not be precluded in the EIM. However, under the EIM, only the footprint net imbalance must be managed, resulting in less net variability within the local BAAs and less required ramping across the footprint.

[5] EIM benefits would increase if the California ISO and/or Alberta Electric System Operator coordinated with the EIM.

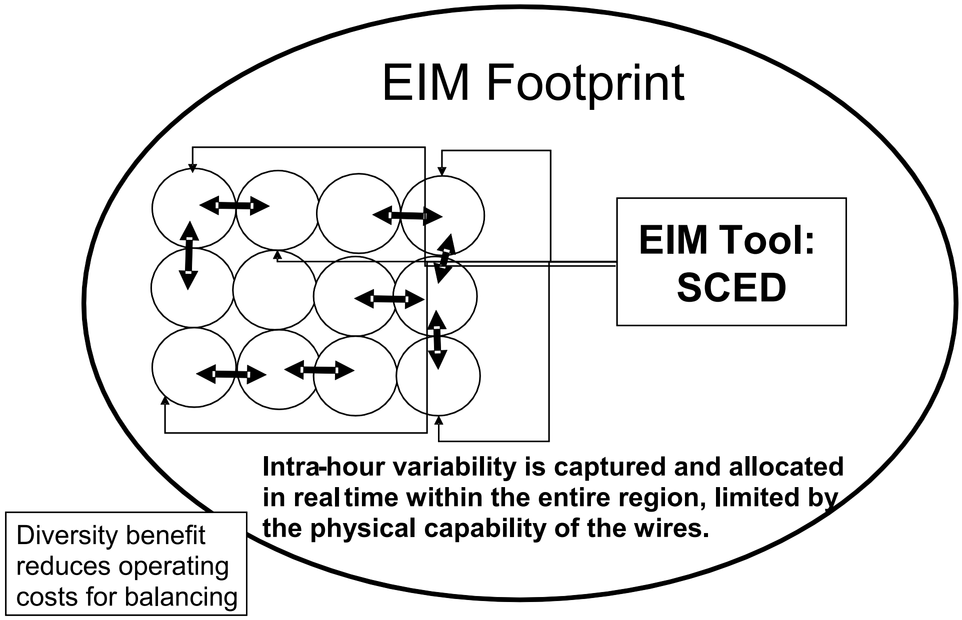


Figure 7. The EIM would effectively pool variability within the operating footprint, similar to a single BAA

4 Analysis Methods

4.1 Reserve Analysis

The increased variability and uncertainty from wind and solar power causes an increase in flexibility reserve requirements that can be provided by some combination of flexible generation and responsive load.[6] Our reserve categories are discussed in more detail in [4].This flexibility reserve is separate and distinct from contingency reserves. Flexibility reserve is discussed in more detail in this section and encompasses both generation and responsive load that may be available to help manage wind and load variability. This reserve is calculated dynamically and is a function of the time-synchronized anticipated variability of the wind and solar power and the load. A method was developed to estimate the increased requirements for regulation with wind variability in the Eastern Wind Integration and Transmission Study [4] and King et. al [10]. The Eastern Wind Integration and Transmission Study method focused on fast dispatch updates of 10 min or faster.

Short-term variability is challenging because it is difficult to anticipate the scheduling changes and fluctuations that must be covered with reserves. In a system with 10-min or faster markets or dispatch updates, a common approach is to forecast a flat value for wind output for the next interval based on the past 10–20 min.[7] This method is known as *persistence forecasting*. The wind varies on that time scale, and an understanding of how it will vary during the forecast interval is needed. Figure 8 illustrates how the forecast error is calculated for 10-min dispatch. The forecast error is the difference between the actual data and the forecast value.

[6]We note that wind power plants do not constitute a contingency because of the relatively slow rate at which wind power changes compared with a unit tripping offline.
[7]The short-term load trend can be forecast somewhat more accurately, but the load regulation movement cannot.

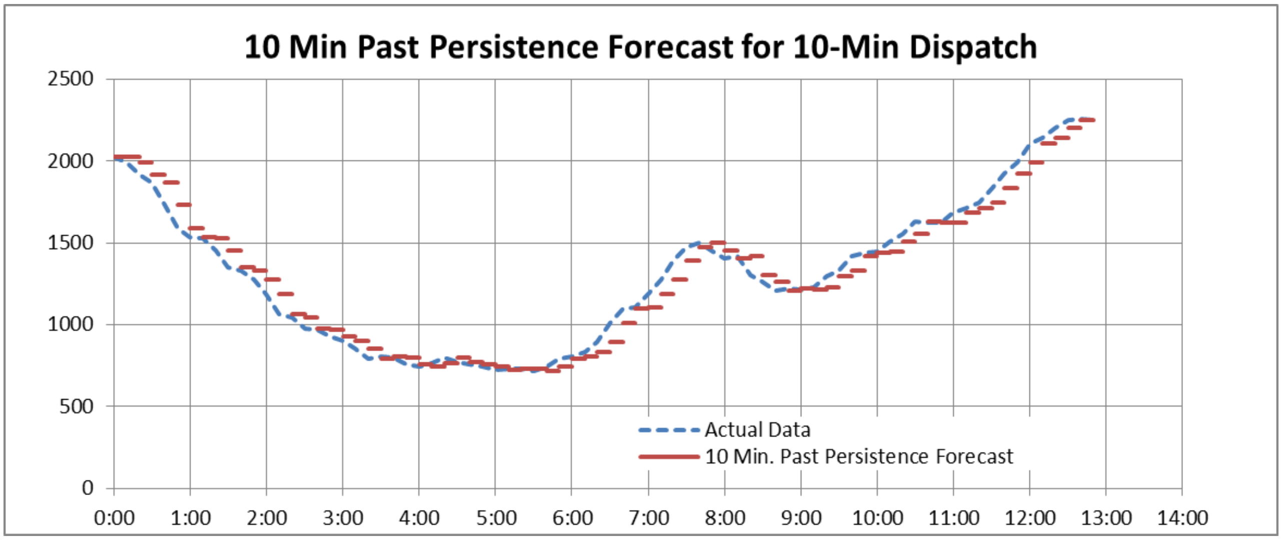


Figure 8. Forecast for 10-min dispatch

With a statistical approach based on detailed wind, solar, and load and forecast data, an estimate of the required reserves can be calculated based on the standard deviation or other variability metric derived from the data.

For our purposes, the flexibility reserve requirements are broken into three classes by the types of resources required to fulfill them.

1. Regulation is required to cover fast changes within the forecast interval. These changes can be up or down and can happen on a minute-to-minute time scale up to the re-dispatch timing for the system. Regulation requires resources on automatic generation control.
2. Spinning reserve is required to cover larger, less frequent variations that are primarily due to longer-term forecast errors. Spinning reserve is provided by resources (generation and responsive load) that are spinning and can respond within 10 min. These resources do not necessarily require automatic generation control.
3. Non-spinning and supplemental reserves are used to cover large, slower-moving, infrequent events such as unforecasted ramping events. Non-spinning reserve can be made available within 10 min and can come from quick-start resources and responsive load. Supplemental reserves can be made available within 30 min.

Note that these additional reserves are separate and distinct from the reserves the power system already requires to address load variability and contingencies. The names are the same (regulation, spinning reserve, and non-spinning reserve) because the same types of resources are required to provide flexibility reserves and contingency reserves. The flexibility reserves are distinct because they address the variability and uncertainty of wind and solar generation (aggregated with load variability and uncertainty) instead of responding to conventional generation contingencies. Large wind and solar ramp events are similar to conventional contingencies in that they are large and infrequent. They are different because they are slower. Similar resources can fulfill both needs and come from the same resource pool (conventional generation and responsive load), but our analysis does not consider the use of contingency reserves to provide flexibility reserves. Flexibility reserves are in addition to contingency reserves. The added spinning and non-spinning flexibility reserves address the wind and solar ramps.

Longer-term (an hour and longer) forecast errors can be dealt with by bringing additional generation on line, which is done via the unit commitment process. Faster-responding spinning and non-spinning reserves are required to bridge from the time when it becomes evident to the system operator that a large, slow ramping event is unfolding until the additional resources are available. The use of slower-responding reserves would reduce reserve costs, but this benefit has not been quantified.

Unless specifically stated elsewhere in this report, all of our references to the term *reserves* are intended to apply to flexibility reserve. We do not discuss contingency reserves further, and the flexibility reserve that is the focus of our analysis is separate and distinct from contingency reserves.

The variability of wind plant output is a function of its production level.[8] The Eastern Wind Integration and Transmission Study method assumes that the short-term variability in wind plant output, and thus short-term forecast error, is a normally distributed value over a large geographic footprint. Through analysis, an equation can be written for the standard deviation (sigma) of variability that varies with production level. That equation is derived by analyzing wind production data over some long period of time (a year or more) and calculating the standard deviation for the variability in various ranges of wind output. This approach does use the simplifying assumption that the data are normally distributed. The underlying data have been shown to be slightly non-normal, with more events in the tails than would be predicted by a normal distribution [12]. Figure 9 shows an example of this function.

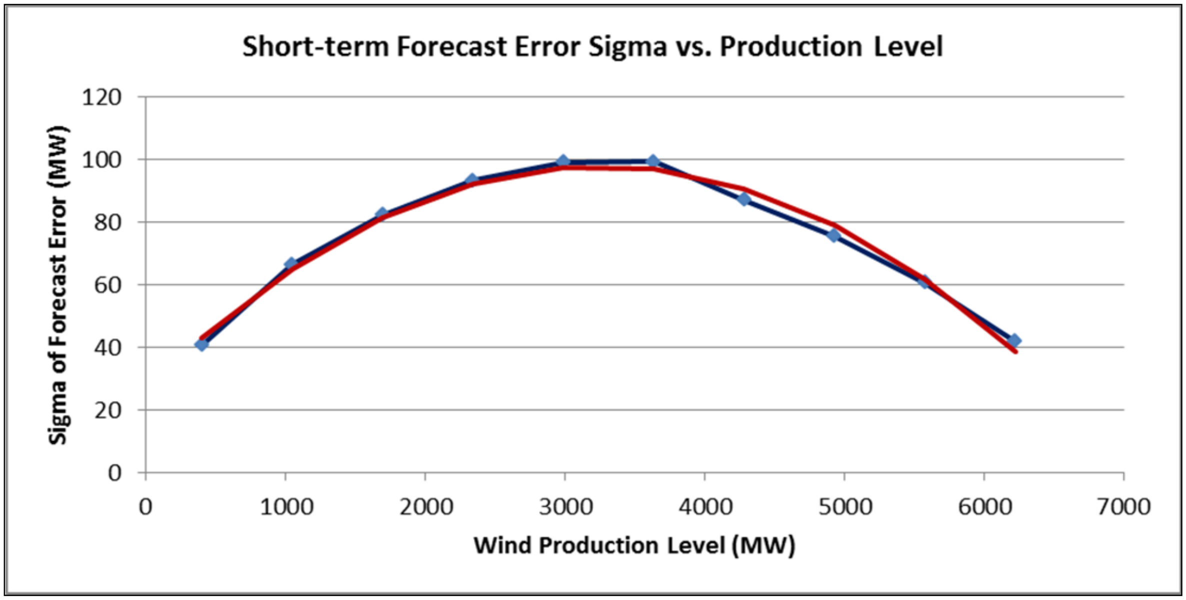


Figure 9. Short-term forecast error sigma as a function of wind production level

The curve fit polynomial shown as the smoothed line, in this example, is shown in Equation 1.

Equation 1. Sample calculation of hourly wind standard deviation

$$\sigma_{WST}\,(Hourly\ Wind) = \ -6.72E-06\ \cdot (Hourly\ Wind)^2 + 0.0437\ \cdot (Hourly\ Wind) + 26.74$$

A similar procedure can be used to obtain an equation that describes the short-term variability of solar output as a function of production level.

The equations are used to calculate the standard deviation (sigma) of the wind and solar power for each hour. A component to cover load variability is calculated as a fixed percentage of the hourly load. That fixed percentage is calculated based on the load size in the BAA as described in the Data section above and is

[8]The minute-to-minute variability has been shown to be uncorrelated between individual wind plants [4]. This results in only a small contribution to regulation requirements and is neglected in this method.

calculated to cover 1 sigma of the load variability. The wind, solar, and load components are scaled to 3 sigma and combined as the square root of the sum of the squares, as shown in Equation 2. This provides us with a common level of implicit risk for each BAA and is similar to maintaining a high Control Performance Standard (CPS) 2 score.

Equation 2. Calculation of intra-hour regulation requirement

$$Total\ Regulation\ Requirement\ (With\ Wind\ and\ Solar) = 3 \cdot \sqrt[2]{\left(\frac{1.5\%\ Hourly\ Load}{3}\right)^2 + (\sigma_{WST}\ (Hourly\ Wind))^2 + (\sigma_{SST}(Hourly\ Solar))^2}$$

The 3-sigma approach estimates reserve values that will cover 99.7% of all short-term variability for normal distributions; for non-normal distributions, adjustments can be made accordingly. Some analysis has indicated that using the normality assumption and 3 sigma yields approximately 99% coverage with actual data. Larger multiples of sigma—for example, 4 or 5—would cover additional events. Analysis of the distribution of events shows that a multiplier of 5 catches all events seen in the database for larger aggregation areas. This component must be covered by regulation-like reserves under automatic generation control.

The component of regulation that is due to VG, referred to here as *flex reserves*, can be isolated from the load regulation. This concept has been used in studies in which the load regulation is calculated and evaluated separately from the VG component. This component must also be covered with resources under automatic generation control.

Equation 3. Calculation of intra-hour "flex only regulation" requirement

$$Flex\ Only\ Regulation\ Requirement\ (With\ Wind\ and\ Solar) = 3 \cdot \sqrt[2]{(\sigma_{WST}\ (Hourly\ Wind))^2 + (\sigma_{SST}(Hourly\ Solar))^2}$$

In general, the analysis in this report uses the total regulation component shown in Equation 2. When "flex only reserves" are used, it will be clearly noted.

An additional uncertainty component related to hour-ahead wind forecasting error was calculated as part of the Eastern Wind Integration and Transmission Study method. This component is calculated in a similar manner to the short-term forecast error described above using an equation to describe the standard deviation of hour-ahead forecast error. Figure 10 shows the development of the equation for hour-ahead forecast error standard deviation.

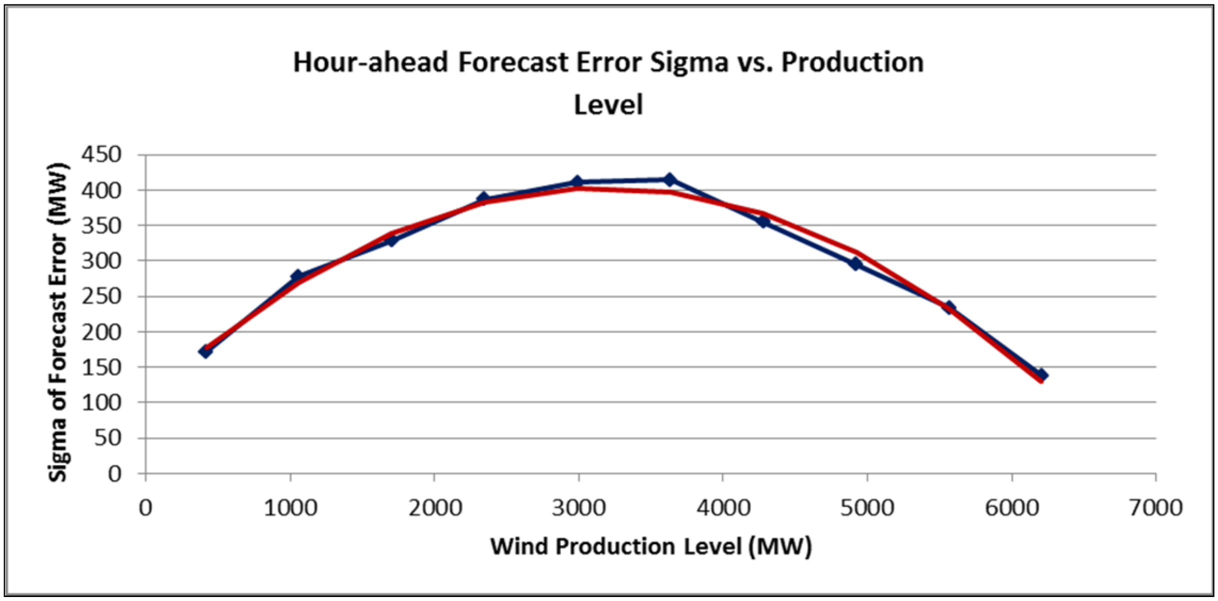


Figure 10. Hour-ahead forecast error sigma as a function of wind production level

The curve fit polynomial shown as the smoothed line, in this example, is shown in Equation 4.

Equation 4. Sample calculation of hour-ahead wind standard deviation

$$\sigma_{HAWind}(Hourly\ Wind) = \ -2.985E-05\ \cdot (Hourly\ Wind)^2 + 0.1895\ \cdot (Hourly\ Wind) + 103.2$$

With that equation, the expected sigma for the forecast error is calculated based on the previous hour's production (persistence forecast). A similar equation can be derived for the solar hour-ahead forecast error using the same procedure.

These components help ensure the system is positioned with enough maneuverability to cover the probable forecast error and divided as 1 sigma assigned to spinning reserves and 2 * sigma assigned to non-spin/supplemental reserves. Equation 5 shows the function for the spinning reserves. The equation for non-spinning/supplemental reserves is the same except that 2 * sigma is used. As before, adjustments can be made for non-normal distributions. Analysis of the available data shows that a total of 5 sigma would capture all events in the data set, which implies a CPS 2 score of 100%.

Equation 5. Calculation of spinning reserve requirement

$$\begin{aligned} &Spinning\ Requirement\ (Hour - Ahead\ Forecast\ Error) \\ &\qquad = \sqrt{\sigma_{HAWind}(Previous\ Hour\ Wind)^2 + \ \sigma_{HASolar}(Previous\ Hour\ Solar)^2} \end{aligned}$$

Finally, to find the total reserve requirement, each of these three components—regulation, spin, and non-spin—are added arithmetically.

This analysis must be performed for each region or aggregation of regions studied. For instance, in the base or BAU case, each BA within the study footprint is responsible for managing the variability within its boundaries. These calculations are performed on the data specific to each BAA, including the VG production profiles. These profiles are based on the time series of load and wind and solar production aggregated from individually modeled plants and thus fully represent the geographic and temporal diversity of their BAAs. The results of this analysis are 8760 hour vectors of flex regulation, flex spin, and flex non-spin reserves for each BAA that reflect the variability in the BAA load and VG data.

When the EIM is analyzed, the VG for each of the BAAs included in the EIM is aggregated by combining the time series for the resources. Again, the geographic and temporal diversity of the data are preserved. The calculations shown in this section are performed based on the aggregated data, and a different set of flex reserve vectors are obtained that reflect the variability of the combined or aggregated regions. As will be shown later, the effect of aggregating the VG is to reduce the overall variability of the combined regions. This directly leads to lower aggregate reserve requirements.

Both conventional contingencies and the increased variability and uncertainty associated with wind and solar generation increase the need for responsive reserves. Because the response requirements are similar in terms of speed, frequency, and duration, they are expressed in terms of the same set of required reserves: regulation, spinning reserve, non-spinning reserve, and supplemental reserve. The same resources can supply services for either need. That does not mean that dedicated contingency reserves would be used to respond to wind variability or uncertainty. It does mean that wind variability and uncertainty results in an increased need for the same *types* of reserves—spinning and non-spinning—that are required for contingency response. Our analysis does not evaluate contingency reserves, nor do we consider whether resources that provide one type of reserve can be activated to provide another type of reserve. The issue of whether reserve types can be shared among uses is under discussion in several forums, and we do not take a position on this issue. For the analysis in this report, we do not reduce the contingency reserve margin nor deploy contingency reserve to manage the increased variability and uncertainty of wind and solar.

4.2 Ramp Analysis

We followed a similar approach as Milligan and Kirby [3] and King et al. [10] in developing 1-hour ramp-reduction estimates based on the chronological wind and load data available for this study. BAAs that are operated without coordination may have ramps simultaneously occurring in opposite directions. With coordinated operations, such as would be available with the EIM, some of this ramping requirement—and therefore generator and responsive load ramping—could be reduced or eliminated. Similarly, different BAAs can experience peak ramping requirements during different hours or on different days. By combining ramping across the EIM, all participants realize a reduction in ramping reserve requirements.

This analysis was performed in several steps. Individual BAA 1-hour ramps were partitioned into positive and negative ramps, and these were separately combined into estimates of the up-ramps and down-ramps that would be met if the systems were to operate separately (without the EIM). The wind, solar, and load data were then pooled into a single hypothetical BA, and the ramp requirements were recalculated. Ramp savings were calculated by chronologically subtracting the total up-ramps and down-ramps of the individual BAAs from the similar ramps for the combined areas. Figure 11 shows an example of the results for this analysis for an arbitrary week for a sample area.

Contingency Reserves and Ramping Reserves

Contingency reserves and ramping reserves share a number of similarities but also a few differences. The power system maintains a series of contingency reserves in sufficient quantity to ensure it will be able to maintain the generation-load balance even if a large generator or transmission line suddenly fails. These reserves are made up of generating capacity held back from the energy supply and responsive load available to respond.

Contingency reserves are time-synchronized. Spinning reserve begins responding immediately, while non-spinning reserve is fully deployable within 10 minutes, and supplemental operating reserve is typically available within 30 minutes. For our purposes, both non-spin and supplemental reserves must be available in 30 minutes. An important characteristic of these contingency reserves is that they are used relatively infrequently (every few days as opposed to every hour) because contingency events are relatively infrequent. Consequently, the cost to stand ready to respond is more important than the response cost itself. A fast-start combustion turbine may be an economic source of non-spinning reserve even if it has a relatively high fuel cost.

Wind ramping requirements are similar to conventional contingency requirements in that large wind ramp events are relatively rare. The standby costs are often more important than the response costs, just as with conventional contingency reserves.

Wind ramps differ from conventional contingencies both in event speed and duration. A large generator can trip and remove 1000 MW from the power system in a cycle. Because of geographic diversity, even a fast, large wind ramp will take an hour or more to drop 1000 MW. This means that non-spinning and supplemental operating reserves (instead of spinning reserves) can often be used for wind ramps. Wind ramp events are also longer than conventional contingency events. North American Electric Reliability Corp. standards require BAs to restore their contingency reserves within 105 minutes of an event, and they typically restore their reserves much more quickly [6]. Slower wind ramps may require longer reserve deployments.

The important point is that wind ramps require the same *types* of responsive resources as conventional contingencies. Reserves may or may not be sharable between contingencies and wind ramps. The issue is still being investigated. This analysis is agnostic to that point and assumes there is no sharing. Partial sharing may be economic and reliable. Contingency-like reserves, however, are used for wind ramps because they are much lower-cost than alternatives such as regulation.

Table 3 presents annual average prices for regulation and contingency reserves from five regions for 2011. Spinning reserve is only 15%–73% of the cost of regulation, while non-spinning reserve is 5%–38%. These are the annual average hourly prices paid for each ancillary service in dollars for 1 MW of ancillary service capacity for 1 hour. It seems likely that additional reserves, with similar characteristics, will have similar prices and similar price relationships.

Table 3. Ancillary Service Prices From Five Regions Show Contingency Reserves Are Much Less Expensive Than Regulation

	California (Reg = up+dn)	ERCOT (Reg = up+dn)	New York	New England (Reg + "mileage")	MISO
	2011 Annual Average $/MWh				
Regulation	**16.1**	**31.3**	**11.8**	**7.16**	**10.8**
Spin	**7.2**	**22.9**	**7.4**	**1.04**	**2.8**
Non-Spin	**1.0**		**3.9**	**0.39**	**1.2**
Replacement		**11.8**	**0.1**	**0.25**	

Note: The California Independent System Operator and MISO do not provide replacement reserve markets. These values are derived from OASIS ancillary services data or communications directly with the ISOs.

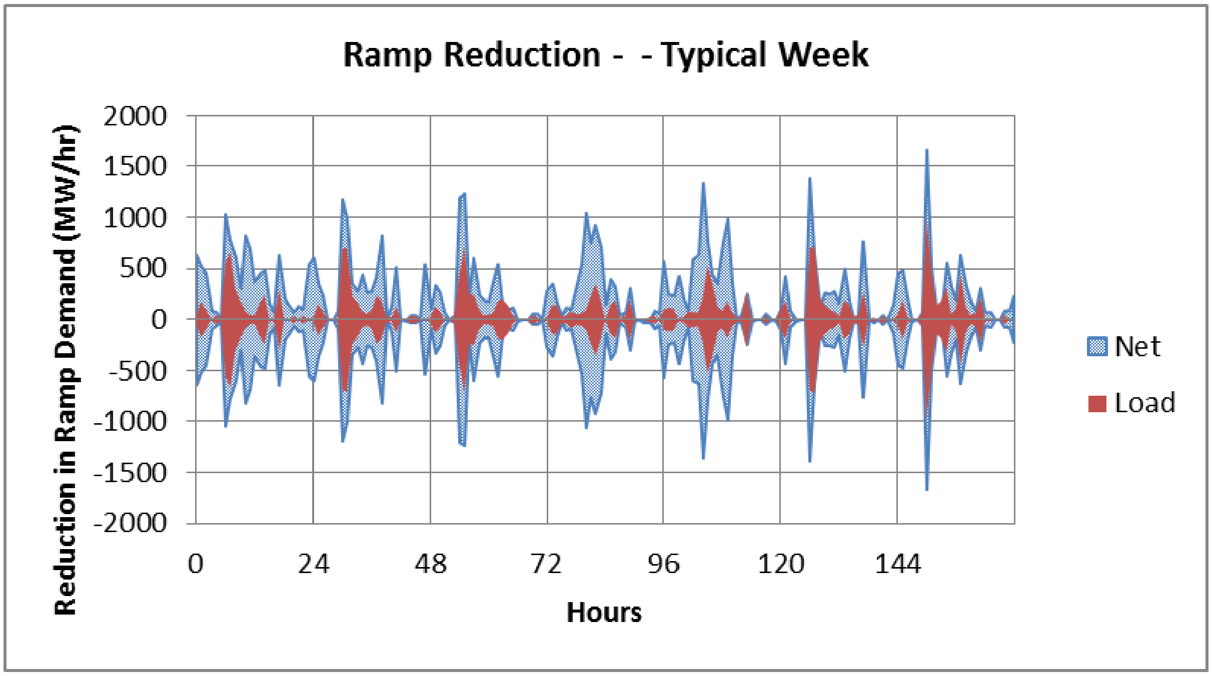


Figure 11. Example of effect of EIM on 1-hour ramps

The red trace shows the reduction in load ramps, and the blue shows the reduction for net load (load – wind – solar). For this sample week, the maximum net load ramp savings is approximately 1600 MW around Hour 150 for the BAAs. The symmetric nature of the graph is because of the simultaneous savings of +1600 MW and -1600 MW at the hour in question.

By tallying the hourly ramp savings over the entire year, we can create a plot that describes the frequency at which ramps of various magnitudes occur. Figure 12 shows that for our sample EIM footprint.

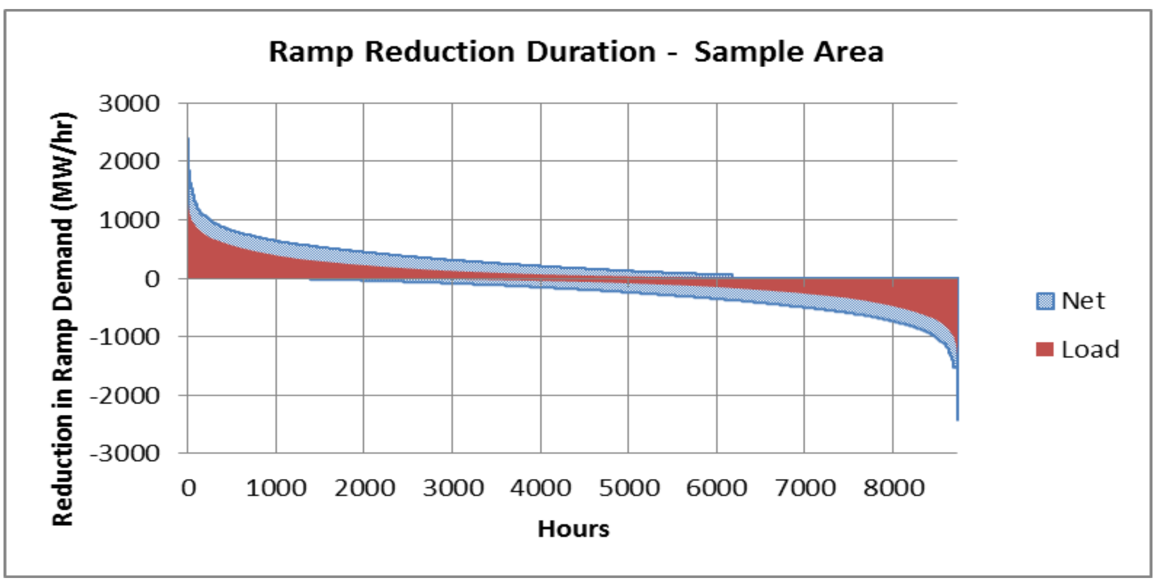


Figure 12. Example of annual ramp savings duration plot

Figure 12 shows that the reduction in net ramp is more than 1000 MW, symmetrically up and down, for approximately 250 hours per year. The peak net ramp reduction is about 2400 MW.

4.3 Allocation of Reserves and Reserve Savings to EIM Participants

Calculating the reduction in total system reserve requirements that results from increased aggregation (combining more load, wind, and solar generation within a balancing footprint) is relatively straightforward (as is measuring the benefits once the wind and solar generation are installed); allocating the savings to individual participants is not as easy. So that individual BAs can assess the impact of the EIM on their reserve savings, it is necessary to calculate the BAA reserve needs in the aggregated case. This means some form of allocation method is needed. This section is motivated by the desire to explore some of the characteristics of simple allocation methods so their behavior and properties can be better understood.

The physical act of coordinating scheduling and dispatch among BAAs, or fully combining them, results in a specific physical outcome. *Allocating* the resulting reduction in flexibility reserve requirements is a policy choice that does not have a single, unique, physical solution. Instead, there are many possible allocation choices. The nonlinear nature of reserves that provide the aggregation benefit also creates the allocation difficulty. A number of allocation methods that at first appear appealing turn out to have undesirable characteristics. We describe one method with appealing properties of "fairness" that avoids the shortcomings of other methods. Because we are attempting to allocate flexibility reserves, which are substantially different from contingency reserves, our method likely differs significantly from approaches used in existing reserve sharing groups. We also note that, under the proposed EIM, there is no proposed method to allocate flexibility reserves among participants; therefore, we are unable to precisely estimate flexibility reserve allocations that would be in effect under the EIM.

One clerical problem needs to be addressed first. Reserve requirements are not explicitly specified for each BAA, but they are implicitly addressed via required balancing/reliability metrics. Each BA must carry enough reserves to meet CPS 1, CPS 2, and Disturbance Control Standard requirements. BAs differ in their risk tolerance, and different BAs may elect to carry different amounts of reserves to compensate for the same level of variability. One BA may carry enough reserves to maintain a CPS 2 score of 98%, for example, while another may carry fewer reserves because it is comfortable with a 92% CPS 2 score. (Ninety percent or better is required.) For the purposes of this report, and to calculate the specific savings that result from the EIM, it is necessary to assume a common level of risk tolerance and a common reserve criterion to apply to each BA. In reality, participation in the EIM and aggregating variability will always reduce the required reserves, regardless of the individual BA's risk tolerance. Note, too, that this discussion does not address if the source or sink BA is responsible for the cost of carrying reserves. The discussion is written as though the source and sink are the same BAA, which seems reasonable without knowledge of the specific case. Actual implementation of the allocation method can easily account for the desired allocation of responsibility.

4.3.1 A Working Definition of Fairness

To facilitate the discussion that follows, we describe a general notion of fairness. Our definition is not intended to be prescriptive; however, a few simple principles can help guide our discussion. We adapt these from Milligan et al. [12]. To help motivate this discussion, we briefly describe the notion of cost causation and relate that to our simplified notion of fairness.

Some utilities have worked to quantify the impact wind energy has on the operational cost of the power system. (Not much work has been done in this area for solar energy, which reflects its slower pace of development.) There is general agreement that wind energy increases the levels of variability and uncertainty that must be managed by the power system operator. In addition, there is broad recognition that these impacts increase operational cost.[9] A prerequisite for calculating integration cost is the principle of cost causation. If a generator imposes a cost on the system, then it may be financially responsible for mitigating this cost. Conversely, if the generator does not impose a cost, then it should not be assessed a payment. Two corollaries can be derived from these simple principles:

1. Horizontal consistency: Two entities that have the same (or similar) variability and uncertainty in power system operation should be allocated the same (or similar) level of reserve.
2. Vertical consistency: If one entity has less variability and uncertainty than another entity, then it should receive a smaller reserve allocation. A corollary is that if Entity A and Entity B start with the same reserve allocation and then B adds significant wind and/or solar generation, then A's reserve level should not increase (whereas B's should).

These ideas can easily be adapted to reserves analysis:

1. If an entity increases the reserve requirement for the whole, it is *fair* if its reserve obligation increases.
2. If an entity decreases the reserve requirement for the whole, then *fairness* dictates that its reserve obligation be reduced.
3. If an entity has no change in the variability or uncertainty that provide the basis for the need for reserves, the principle of *fairness* implies that its reserve obligation should not change

In the discussion that follows, we use this loose definition of fairness and avoid specific recommendations on allocation of reserves. Instead, our objective is to point out some interesting, and potentially important, issues regarding some rather simple allocation methods and some possible unintended consequences of these methods.

4.3.2 Alternative Allocation Methods Produce Different Results

To illustrate the benefits and complexity of aggregation, we will examine a hypothetical set of BAAs[10] (A–K) that require 100 MW of regulation each when they balance on their own. Later, we will extend this example to spinning, non-spinning, and supplemental reserves. For simplicity, assume that the regulation requirements are identical for each BAA and are completely independent. These assumptions are not necessary, and the math works out for all of the allocation methods discussed for BAAs of differing sizes and when there is some correlation. However, these simple assumptions make the examples easier to follow. We will also examine three subregions (X, Y, and Z) that are each composed of several of the BAAs.

Table 4 shows how aggregating individual BAAs into three subregions and a single region reduces the physical regulation burden—the greater the aggregation, the greater the benefit.

[9]There is some disagreement among experts about whether the cost impact of one generator, or type of generator, can be accurately calculated because of the highly nonlinear nature of operation and cost. We ignore that issue in this discussion. Interested readers can consult Milligan et al. [12].
[10]These concepts apply equally well to individual loads and generators and combinations of loads, generators, and BAAs.

Table 4. Physical Benefits of Aggregation

BA	Actual Regulation (MW)	Sub Region	Aggregate Regulation (MW)	Region	Aggregate Regulation (MW)
A	100	X	224	Total Footprint	332
B	100				
C	100				
D	100				
E	100				
F	100	Y	200		
G	100				
H	100				
I	100				
J	100	Z	141		
K	100				
Sum	1100		565		332

The members of subregion X reduce their collective regulation burden by 55% when they cooperate. Members of subregion Y save 50%, and members of subregion Z save 29%. Regional cooperation would reduce the regulation burden by 70%. These physical savings can be directly measured as changes in the area control error (ACE) variability of each of the collections.

How should these savings be allocated? There is no single technically correct answer. Different allocation methods have different properties and provide different results under different conditions. One fundamental principle is that the sum of the allocated amounts should equal the total physical requirement. If the balancing is on a regional basis for all 11 BAAs, for example, then the sum of the regulation amounts allocated to each of the 11 BAAs should equal 332 MW because that is all the regulation that is physically required.

4.3.3 Incremental Allocation

BAA K could offer to join BAA J in the formation of Subregion Z. BAA K could offer to fully protect BAA J and supply all of the extra regulation required when BAA K joined. BAA J would be held completely harmless. BAA J would continue to supply 100 MW of regulation, while BAA K would supply the extra 41 MW required to maintain reliability in Subregion Z.

Clearly, incremental allocation of regulation requirements is not fair when two similarly situated entities are combined, but it can be a reasonable allocation method under other circumstances. A regulatory commission might, for example, determine that it is in the public interest to allocate the incremental regulation burden to a new industrial enterprise if there were significant job creation or tax benefits. The BA customers would be no worse off, and the subregion would gain economic benefits.

Allocating the regulation burden among BAAs on an incremental basis has the very undesirable effect of assigning different amounts to otherwise identical entities based solely on the order that the entities join the aggregation. This would result in the violation of the principle of horizontal consistency. Table 5 shows how an incremental allocation would work if all 11 BAAs were aggregated sequentially. BAA A would see no benefits from regional cooperation, while BAA K would see its regulation requirement drop by 85%. Note that the incremental allocation did result in meeting the total regional requirement of 332 MW. It is only the allocation among individuals that is problematic.

Table 5. Incremental Regulation Allocation Treats Identical Entities Differently

BA	Actual Regulation (MW)	Incremental Regulation Allocation (MW)
A	100	100
B	100	41
C	100	32
D	100	27
E	100	24
F	100	21
G	100	20
H	100	18
I	100	17
J	100	16
K	100	15
Sum	1100	332

4.3.4 Proportional Allocation

Allocating regulation benefits proportionally based on the BAAs' standalone regulation requirements at first appears to be very fair. If the total regulation requirements are reduced by 70%, then one could simply reduce each BAA's regulation assignment by 70%. What could be fairer? Unfortunately, because of the nonlinear nature of the physical aggregation benefit, proportional allocation places a disproportionate burden on the smaller entities. This becomes clear when subregions are considered, which we evaluate below.

Proportional allocation does work when all the individuals are the same size, as shown in Table 6. The left side of the table shows that each BAA is allocated an equal share, 30 MW, of the regional regulation burden. The right side shows that each BAA is allocated an equal share of *its* subregional regulation burden (assuming that the subregions do not aggregate together into an aggregate region). BAAs A–E have less regulation burden than BAAs F–I and BAAs J and K. This is reasonable because there are greater physical benefits for larger aggregations.

The proportional allocation breaks down if the subregions aggregate, as shown in Table 7. The physical regulation requirement drops by 41% from 565 MW to 332 MW (the same as on the left side of Table 6). That reduction is proportionately allocated to each of the subregions based on the subregions' regulation requirements. It only becomes apparent that this may not be the desired outcome when the subregional regulation allocations are further allocated to the individual BAAs. BAAs A–E are allocated a 26-MW regulation burden, while BAAs F–I are allocated a 29-MW regulation burden, and BAAs J and K are allocated a 42-MW regulation burden. Even though balancing is on a regional level and all 11 BAAs are identical, they get allocated different regulation requirements based on an arbitrary listing of the BAAs in subregions in the calculation. The amount of regulation allocated to each BAA depends on any intermediate subgrouping of the BAAs. Had BAAs A–J been grouped together first and had BAA K been considered last, the proportional regulation allocation would have been even more disproportionate, with BAAs A–J supplying 25 MW each and BAA K supplying 80 MW. This, too, violates the principle of horizontal consistency. Note again that, in all cases, the regulation allocation adds up to the 332 MW that is physically required by the aggregate region doing the balancing.

Table 6. Proportional Allocation at First Appears To Work Well

Regional Aggregation				Sub-Regional Aggregation				
BA	Actual Regulation (MW)	Proportional Regulation Allocation (MW)		BA	Actual Regulation (MW)	Sub Region	Aggregate Regulation (MW)	Proportional Allocation Within the Sub-region (MW)
A	100	30		A	100			45
B	100	30		B	100			45
C	100	30		C	100	X	224	45
D	100	30		D	100			45
E	100	30		E	100			45
F	100	30		F	100			50
G	100	30		G	100	Y	200	50
H	100	30		H	100			50
I	100	30		I	100			50
J	100	30		J	100	Z	141	71
K	100	30		K	100			71
Sum	1100	332		Sum	1100		565	565

Table 7. Proportional Allocation Fails When Subregions Aggregate and for Different Sizes of BAAs

Regional Aggregation of Sub-Regions							
One Set of Sub-regions						*Another Set*	
Sub Region	Actual Aggregate Regulation (MW)	Proportional Sub-regional Regulation Allocation (MW)	BA	Proportional Allocation Within the Sub-region (MW)		BA	Proportional Allocation Within the Sub-region (MW)
			A	26		A	25
			B	26		B	25
X	224	131	C	26		C	25
			D	26		D	25
			E	26		E	25
			F	29		F	25
Y	200	117	G	29		G	25
			H	29		H	25
			I	29		I	25
Z	141	83	J	42		J	25
			K	42		K	80
Sum	565	332		332			332

4.3.5 Vector Allocation

Regulation requirements can be allocated such that the allocation does not depend on the number or order of subaggregations. Any number of individual entities (loads, generators, BAAs, etc.) can be disaggregated. Subaggregations can be reordered and redefined without affecting the regulation allocated to other entities.

An allocation method developed by one of us has this appealing property [7].[11] The method has been verified and used by numerous utilities to analyze the regulation burdens imposed by individual loads and subaggregations of loads. The method appropriately handles any amount of correlation between the individual BAAs. The method accommodates a mix of individually allocated entities and subaggregations.

The vector allocation method requires one to know only the reserve requirement of the total system, the reserve requirement of the individual BAA, and the reserve requirement of the system without that BAA.

Equation 6. Allocation of reserve requirements

$$\sigma_{i\_allocation} = \frac{\left(\sigma_{Total}^2 + \sigma_i^2 - \sigma_{Total-i}^2\right)}{2 * \sigma_{Total}}$$

Where:

σ_{Total} is the total system regulation requirement
σ_i is the standalone regulation requirement of entity i
$\sigma_{Total\text{ - }i}$ is the regulation requirement of the total system without entity i
$\sigma_{i\_allocation}$ is the regulation requirement allocated to entity i

Table 8 shows the vector allocation results when every BAA is allocated its regulation burden, when three subregions are allocated their regulation burdens, and when an alternate pair of subregions is allocated its regulation burdens. The individual BAAs are then allocated their share of the subregions' regulation burden. Note that the regulation allocated to each subregion and each BAA is always the same, regardless of how other BAAs are subaggregated. Only a change in the physical aggregation itself will change the allocation.

Table 8. The Vector Allocation Results Do Not Depend on Subaggregation or Order

Individual BA			*Sub-Region*				*Alternate Sub-Region*			
BA	**Actual Regulation (MW)**	**Vector Allocation (MW)**	**Sub Region**	**Actual Regulation (MW)**	**Vector Allocation (MW)**	**Individual BA in Sub Region**	**Sub Region**	**Actual Regulation (MW)**	**Vector Allocation (MW)**	**Individual BA in Sub Region**
A	100	30	X	224	151	30	A-J	316	302	30
B	100	30				30				30
C	100	30				30				30
D	100	30				30				30
E	100	30				30				30
F	100	30	Y	200	121	30				30
G	100	30				30				30
H	100	30				30				30
I	100	30				30				30
J	100	30	Z	141	60	30				30
K	100	30				30	K	100	30	30
Sum	1100	332		565	332	332		416	332	332

4.3.6 BAAs of Different Size

When two BAAs with identical regulation requirements join, it appears intuitively obvious that each should be allocated an equal share of the net regulation requirement (absent a compelling societal reason to use incremental allocation). It is not nearly as obvious what the regulation allocation should be in the much more usual case when the standalone regulation requirements of multiple BAAs differ. The results shown

[11]The method is based on similarities between regulation allocation and the MW/MVAR/MVA relationship.

above provide some insight into what a "fair" allocation is for entities with different standalone regulation requirements. Subregions X, Y, and Z have different standalone regulation requirements (224, 200, and 141 MW, respectively). Although the sizes cannot be compared easily based on the megawatt regulation requirements, they can be compared because we know why the megawatt requirements differ: Each subregion is composed of a different number of otherwise identical BAAs. So although it is not immediately obvious that subregion Y is twice the size of subregion Z based on their standalone regulation requirements, it is obvious based on subregion Y being composed of four identical BAAs while subregion Z is composed of two identical BAAs. It then makes intuitive sense that the fair allocation of the regional regulation requirement for subregion Y should be twice the allocation of subregion Z. The vector allocation method has the unique property of providing a "fair" allocation. This is in keeping with the principle of vertical consistency, in which the entity that consumes more regulation also provides more regulation.

5 Impact of Energy Imbalance Markets on Reserves and Ramping

Per-unit wind and solar variability are reduced with increased geographic diversity, which reduces the level of reserves needed to compensate for that variability. Forecast errors are also reduced by diversity [7].

5.1 Alternative Market Scenarios

We analyzed a large number of possible market footprints and variations on participation levels based on discussions with WECC. Although the EIM may cover all of the nonmarket areas of the interconnection, there may instead be subregional implementations of the market that correspond to the subregional transmission planning groups (or other alternative footprints that we do not address), which include Columbia Grid, WestConnect, and NTTG. For our study, we did not include wind in British Columbia because no wind data were available. Federal power marketing administrations such as BPA and Western Area Power Administration (Western or WAPA) may not participate in the EIM because of potential institutional constraints.[12] We therefore constructed cases that excluded these entities as variations from the all-inclusive participation cases. The full footprint includes all of the Western Interconnection except for Alberta and the California Independent System Operator market areas of California.

The proposed EIM would operate at the 5-min level, possibly aggregating energy settlements to hourly (similar to the 5-min markets currently operated by the Pennsylvania-New Jersey-Maryland Interconnection, Midwest Independent Transmission System Operator [MISO], New York Independent System Operator, Independent System Operator-New England, Electric Reliability Council of Texas [ERCOT], and California Independent System Operator); however, our analysis evaluated alternative dispatch intervals of 10 min because of data limitations. As discussed in [5], faster markets improve access to generation that may be available to alter its output, whereas slower markets restrict units on economic dispatch so that they cannot respond to demand changes within the dispatch period. Our 10-min analysis therefore understates the benefits of the actual 5-min EIM.

5.2 Variability Analysis

Larger operating footprints improve the ability of the system to respond to variability [2, 3]. This occurs for two reasons:

1. Pooling of variability of loads and wind generation increases diversity, which reduces the overall per-unit variability.

2. A broader resource mix increases ramping capability linearly.

[12] It is also possible that a version of EIM, or an improved interface between EIM and non-EIM areas, may eventually be extended to include all of the Western Interconnection.

The result is that aggregation provides an increased ability to manage variability, which itself is reduced with aggregation. This principle can be applied to many facets of power system operation and is one driver for the formation of reserve-sharing pools that reduce the total contingency reserves needed to maintain reliability. The full footprint in our analysis includes all of the Western Interconnection except for Alberta and California Independent System Operator areas of California.

Table 9. Summary of Load, Wind, and Solar Data Variability

	Footprint	West Connect	NTTG	Columbia Grid	LADWP	BCTC
# of BAAs	29	14	5	8	1	1
Load						
Max Non-Coincident	123720	57240	24644	23645	6778	11393
Max Coincident	110504	55251	22843	22933	6778	11393
Avg	71631	31292	14969	14464	3712	7194
Min Coincident	50577	21866	10284	10005	2172	5091
Min Non-Coincident	46404	20003	9628	9511	2171	5091
Wind						
Max Non-Coincident	18749	5510	4571	8083	585	
Max Coincident	15641	4949	4357	8077	585	
Average	5859	1672	1618	2359	210	
Non-Coincident CF	31%	30%	35%	29%	36%	
Coincident CF	37%	34%	37%	29%	36%	
Solar						
Max Non-Coincident	4546	4205	20	0	321	
Max Coincident	4375	4052	20	0	321	
Average	1250	1172	4	0	74	
Non-Coincident CF	27%	28%	20%	0%	23%	
Coincident CF	29%	29%	20%	0%	23%	
Total VG (Wind and Solar)						
Max Non-Coincident	23116	9601	4584	8083	848	
Max Coincident	18105	8393	4357	8077	848	
Average	7108	2843	1622	2359	285	
Non-Coincident CF	31%	30%	35%	29%	34%	
Coincident CF	39%	34%	37%	29%	34%	
VG Penetration						
Max BAA in Area	300%	300%	82%	126%	34%	
Max Coincident	28%	31%	36%	69%	34%	
Energy	10%	9%	11%	16%	8%	

VG penetration is the ratio of annual VG-produced energy to total generation.

Figure 13 shows the peak load and VG coincidence for all of the Western Interconnection and the three subregions. Aggregation provides a host of benefits for load as well as for VG. Aggregation reduces the peak capacity requirements for load alone. Coincident peak load is 11% lower for the overall footprint than the sum of the non-coincident peak loads that each BAA must support on its own.

Aggregation also benefits VG. Peak Western Interconnection wind is reduced by 20% through aggregation. Footprint VG capacity factor increases by 7% with aggregation. Aggregating VG also reduces the maximum wind penetration. One BAA in WestConnect (Imperial Irrigation District) has a maximum 10-min wind penetration of 300%, which is reduced to a maximum of 31% for the aggregated WestConnect and a maximum 28% for the aggregated footprint.

A detailed table showing the VG for each BAA can be found in Appendix B.

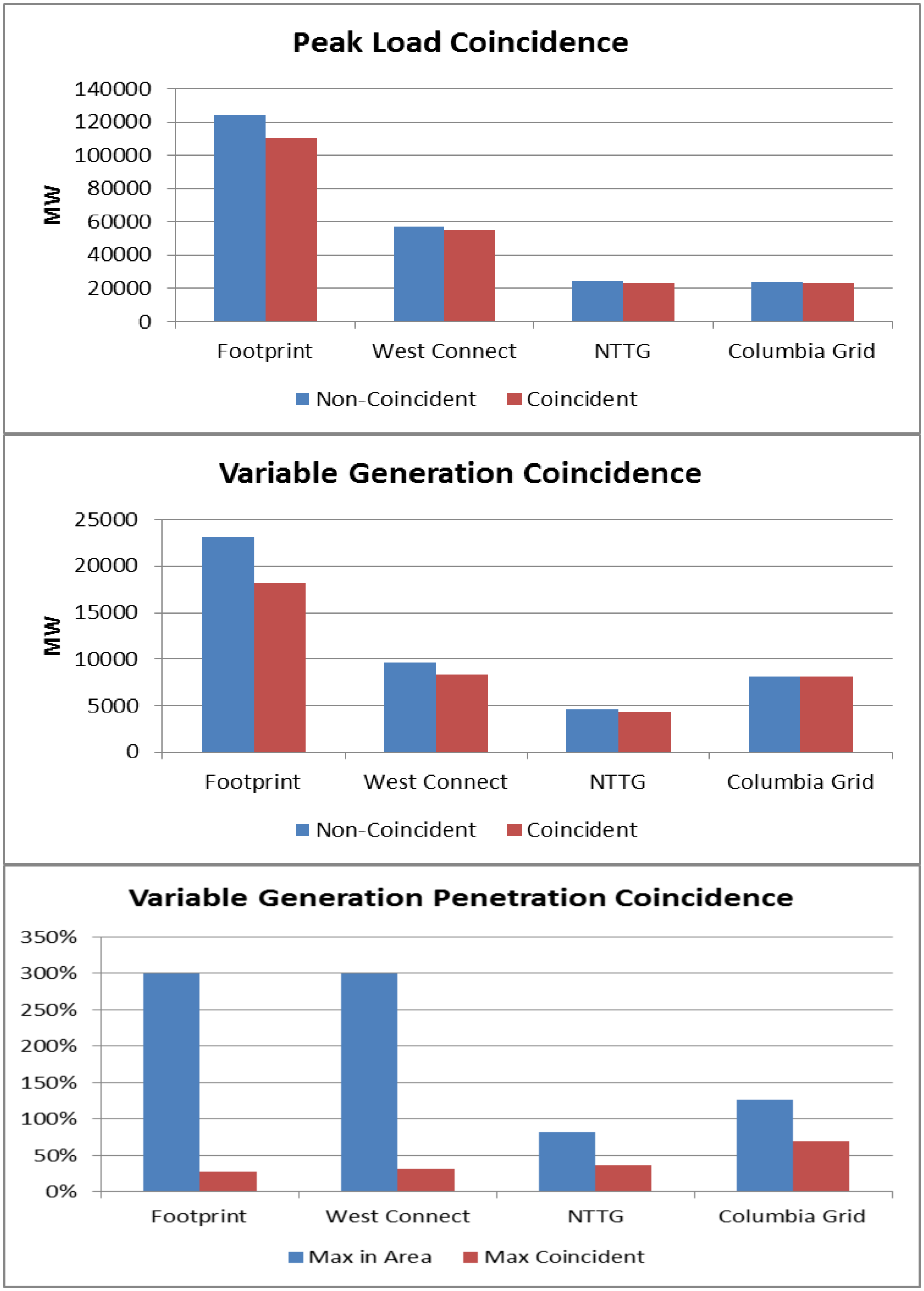


Figure 13. Coincidence of VG, load, and hourly penetration

5.3 Footprint EIM Scenario – Base Case

The base scenario for our analysis compares the footprint-wide EIM with the BAU case. The footprint-wide EIM includes all of the BAAs included in the study cooperating to manage that variability.

For the purposes of this report, the BAU case is defined as follows. Each BA is responsible for balancing the variability, both load and VG, within its borders as defined by WECC TEPPC 2020 PC0. In all cases, we assume that all BAs dispatch every 10 min, even in the BAU. The BAAs included in the footprint are defined in Section 2.4.

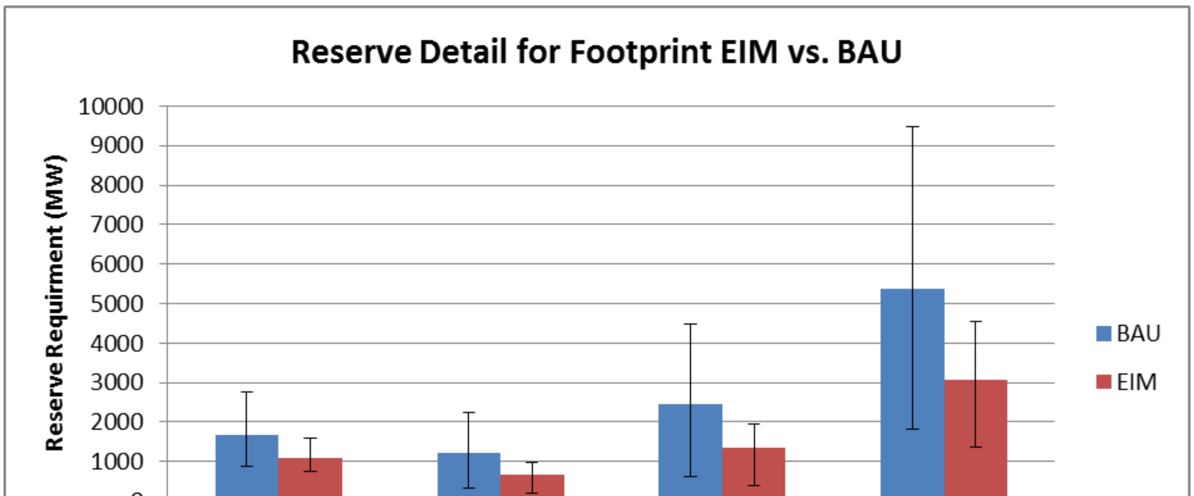
Existing reserve sharing groups are not relevant to this analysis because those reserve sharing groups are defined only for contingency reserves, not flexibility reserves. No assumptions are made about deliverability of reserves in this analysis. Production simulation models can verify if the aggregate reserves that result from these calculations can be delivered around the system as required.

5.3.1 Flexibility Reserves

As described in Section 4, Analysis Methods, three categories of reserve requirements were calculated for the footprint EIM and BAU scenarios. Figure 14 shows the comparison of the regulation, spin, and non-spin/supplemental reserves. The whiskers show minimum and maximum values, and the bar shows the average value of all hours of the year.

For each category of reserves, the requirement is reduced 35%–46%, depending on type. Total regulation is cut from 1669 MW for the BAU case to 1076 in the footprint EIM, while total reserves are reduced from 5359 MW to 3083 MW.

Table 10 shows that the reduction in maximum values seen is substantially larger.



	Total Reg	Spin	Non-spin	Total
BAU	1669	1230	2460	5359
EIM	1076	669	1338	3083

Figure 14. Comparison of reserve requirements for footprint EIM and BAU

Table 10. Reduction in Reserves Maximum Values

	BAU	EIM	Reduction
Total Regulation	2765	1607	42%
Spin	2236	977	56%
Non-Spin	4472	1955	56%
Total	9473	4539	52%

As described earlier, total regulation is made up of three components: load, wind, and solar. The relationship among these components is shown in Figure 15. The total regulation is the square root of the sum of the squares of the individual components because these components are uncorrelated. Load regulation is the largest contributor to total regulation, but the most dramatic savings for the EIM are seen for the wind component, which is reduced by 54%.

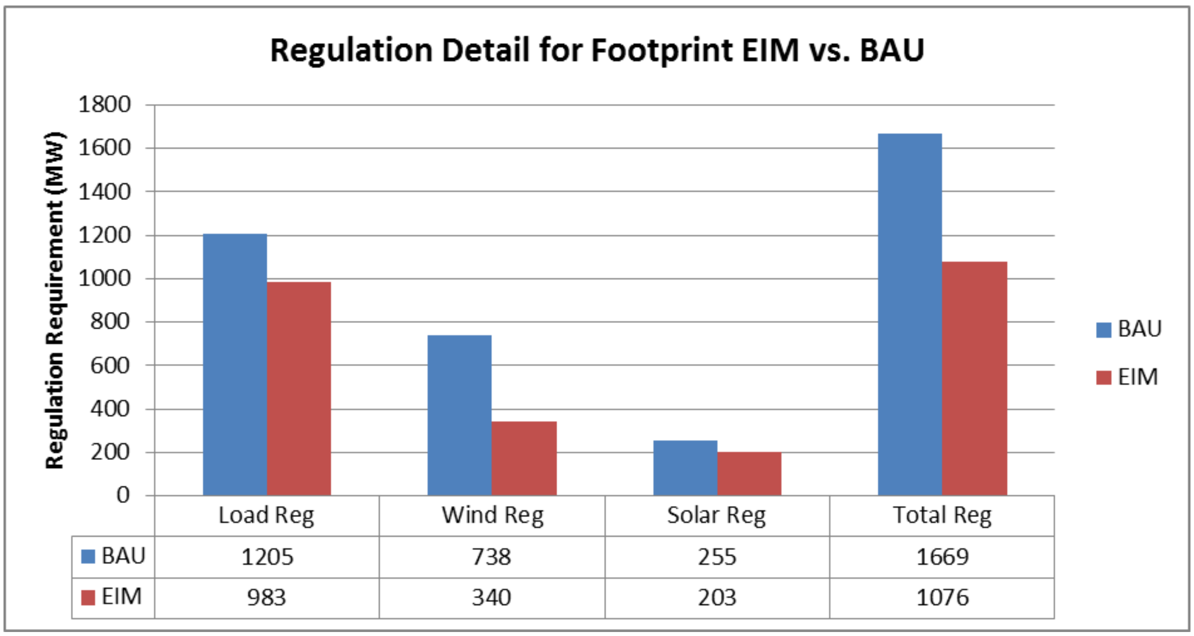


Figure 15. Detail of regulation components for footprint EIM

To understand how often various amounts of reserves are required, we developed regulation and total reserves duration plots. Total reserves are the sum of the total regulation, spin, and non-spin requirements. Figure 16 shows total reserves duration for the BAU and footprint-wide EIM case. The black line shows the saving in total reserves that are realized when the footprint EIM is implemented. The plot shows the large decrease in the overall requirements but particularly for the large, infrequent tails events.

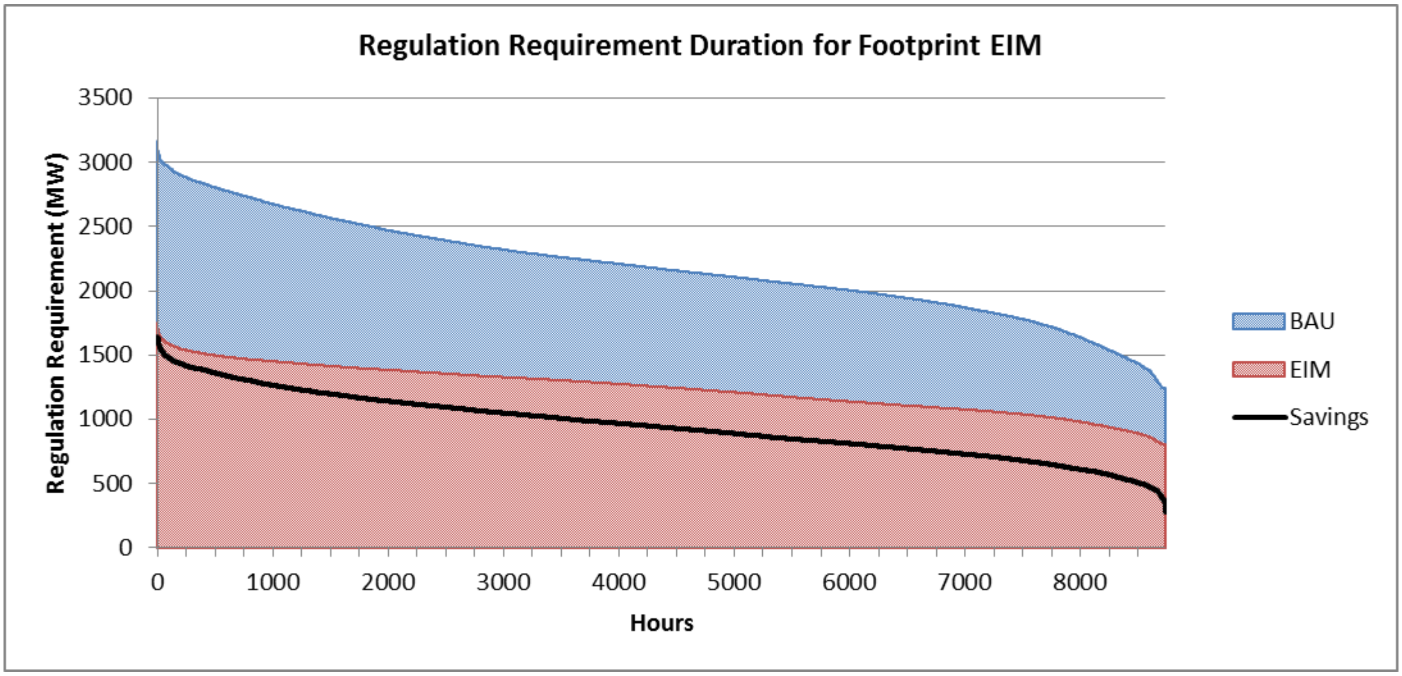


Figure 16. Comparison of footprint-wide EIM and BAU total reserve requirement

Interestingly, the total reserve requirement for the large aggregation is flatter and lower than when reserves are supplied for each BAA individually. The same pattern is seen for regulation for the scenario regions, as show in Figure 17.

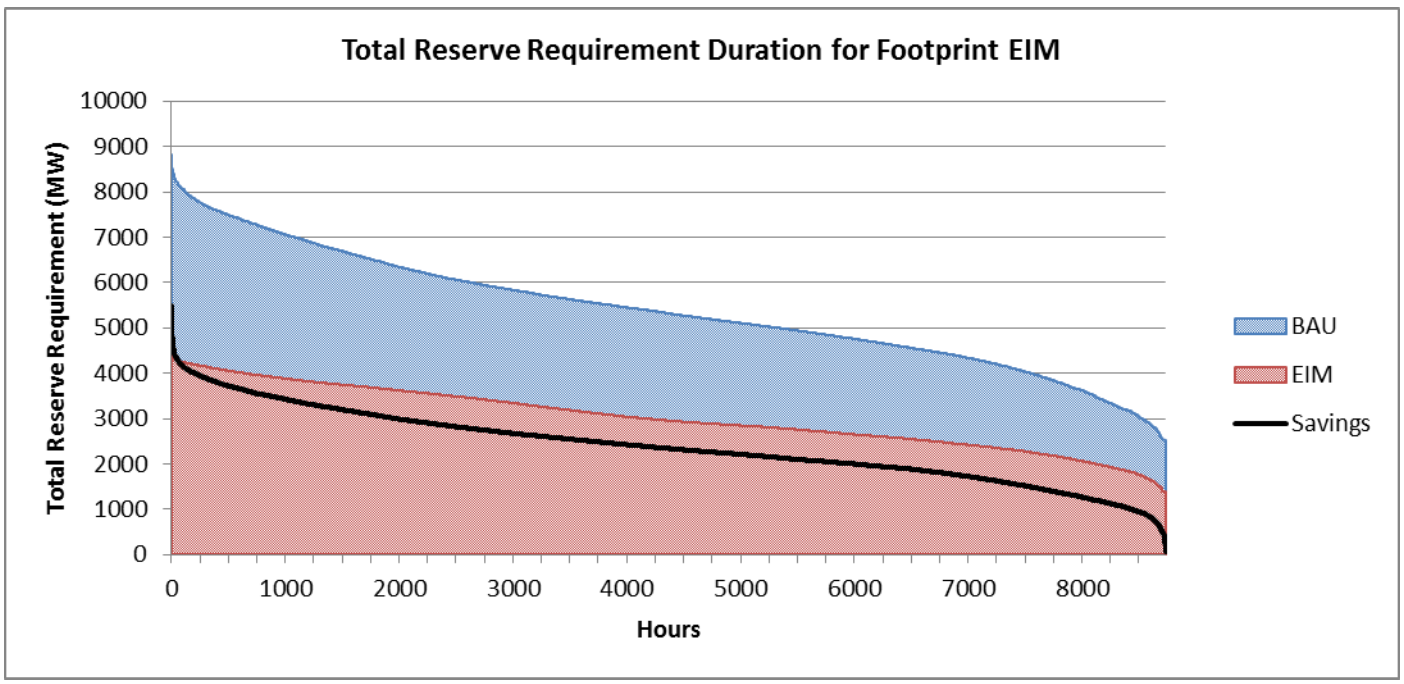


Figure 17. Reduction in total regulation reserve requirements by implementing a footprint-wide EIM

5.3.2 Ramp Demand Reduction

The reduction in variability implies that the need for ramping will be reduced under the various coordination approaches. We followed a similar approach as E3 [2], Milligan and Kirby [3], and King et al. [10] in developing ramp-reduction estimates based on the chronological wind, solar, and load data available for this study. The approach calculates hourly individual area ramp requirements, separating up-ramp and down-ramp demand for load alone and for net load (load minus wind and solar). Balancing areas that operate without coordination may simultaneously have ramps in opposite directions. With coordinated operations, such as would be available with the EIM, some of this ramping requirement, and therefore generator ramping, could be reduced or eliminated.

Figure 18 illustrates the concept for a sample 1-week period. This graph assumes that the EIM would operate across the entire footprint. As shown in the graph, there is a benefit even without any wind because of the load diversity. However, as also shown in the graph, there is a much larger ramp saving at a high wind penetration rate, largely because a high wind penetration will cause a significant increase in ramping demand for many hours of the year and the greater geographic diversity in wind ramps as compared with load ramps.

Figure 19 shows a duration plot for the load and net ramp savings for the entire year (8760 hours). For 248 hours per year, the savings in net ramp exceed 1000 MW. It averages about 275 MW for the year. Load ramp savings over the year average about 144 MW. Again, the effect of aggregation on wind and solar ramp savings is clearly higher than for load alone.

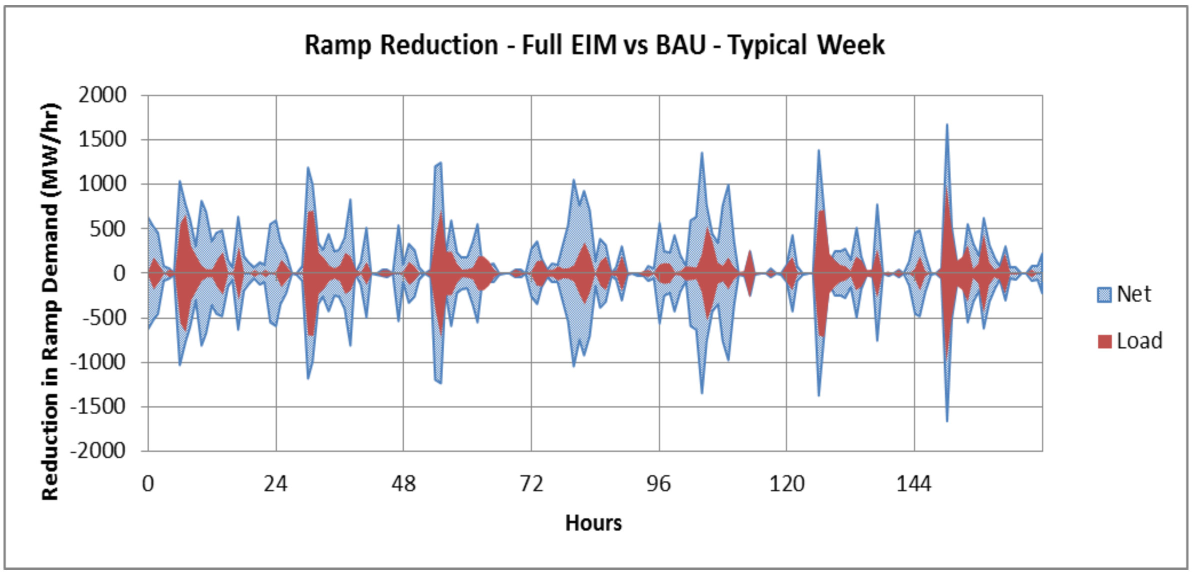


Figure 18. Footprint-wide ramping that can be eliminated by the EIM for a sample 1-week period

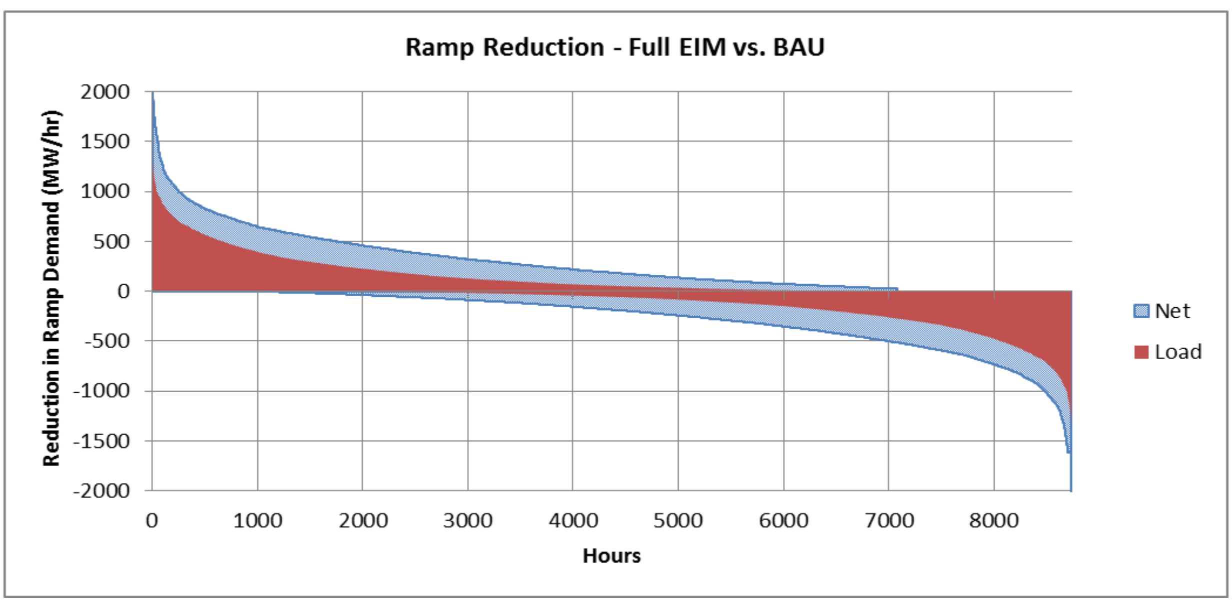


Figure 19. Frequency and magnitude of annual ramping reductions

5.3.3 Allocation of Reserves to Participants

We next applied the allocation procedure discussed in Section 4.3 to the regulation and total reserve requirements for the footprint EIM. This procedure allocates the reserve requirements for various classes of reserves to the areas participating in the EIM based on each area's contribution to variability. Average total reserve requirements are the arithmetic sum of regulation, spinning, and non-spinning components.

The savings for any particular participant are influenced by the diversity that area lends to the aggregate area. An area with a relatively small amount of wind can see a disproportionate savings if that area adds to the diversity of the overall area and lowers overall variability. An area with a large proportion of wind and/or solar energy can experience relatively little savings if its wind/solar resources have a small impact on the overall variability, as happens when a single area dominates the VG. Further, an area with both wind and solar can contribute even more to the overall diversity because the wind and solar variabilities are not correlated at short time frames.

Another factor in the savings for each BA is the VG penetration for that area. As penetration increases, there is a tendency for the savings to also increase. This is primarily because of the relatively low diversity of load variability across the study footprint. Because the load and VG components are combined as root sum squares, the higher load component will dominate the regulation and the savings until VG penetration reaches higher levels.

Finally, the size of the of the overall EIM relative to the size of the participating BAs has a direct influence on the savings seen by each participant. Large aggregation areas maximize the diversity of both load and VG, which, in turn, increases the savings seen by all.

The results for the full EIM compared with the BAU case are shown in Figure 20 for both total reserves and regulation. Based on this allocation method, the average savings is about 47% for total reserves and 42% for total regulation.

The largest BAAs see greatest absolute savings, while smaller BAAs with significant VG penetration can see higher percentage reductions. BAAs with little or no VG see the smallest savings. Tabular data for these charts can be found in Appendix A in Table 24.

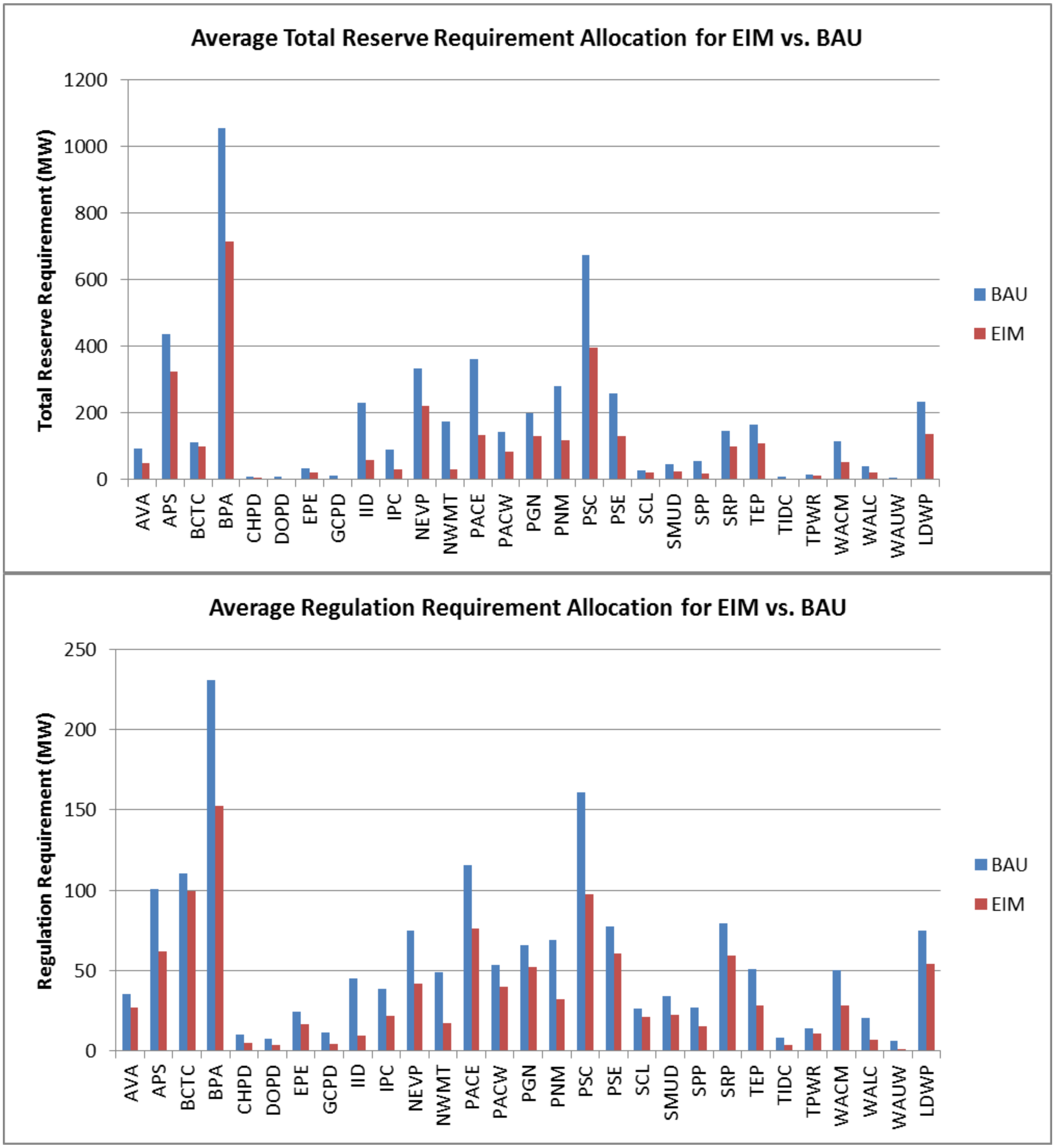


Figure 20. Allocation of reserves in the full-footprint EIM

We also calculated the value of the reserve savings by assuming a price for each class of reserves. The assumed prices are shown in Table 11. These prices are typical for these services in various parts of the country and are derived from Table 3 as rough averages for the three classes. We acknowledge that these prices may not be representative for some areas; however, we provide additional information in the appendices that allow individual BAs to assess their own benefits using the reserve reductions calculated herein and their own reserve pricing.

Table 11. Prices Assumed for Valuing Reserve Savings

Reserve	Price $/MW-hour[13]
Regulation	$12.00
Spin	$6.00
Non-Spin	$1.00

By applying the values in Table 11 to the reserve savings for full-footprint EIM, we find a total savings of about $103 M. Table 12 shows the allocation of these savings to each of the BAAs participating in the EIM. Note that the values are in millions of dollars.

Table 12. Value of Annual Flexibility Reserve Savings by BAA for Footprint EIM ($M)

BAA	Regulation	Spin	Non-Spin	Total
AZPS	$4.08	$1.27	$0.42	$5.77
AVA	$0.90	$0.62	$0.21	$1.72
BCTC	$1.18	$0.00	$0.00	$1.18
BPA	$8.22	$4.44	$1.48	$14.14
CHPD	$0.53	$0.00	$0.00	$0.53
DOPD	$0.40	$0.00	$0.00	$0.40
EPE	$0.83	$0.05	$0.02	$0.90
GCPD	$0.76	$0.00	$0.00	$0.76
IID	$3.70	$2.38	$0.79	$6.87
IPC	$1.75	$0.74	$0.25	$2.73
LDWP	$2.17	$1.37	$0.46	$3.99
NEVP	$3.47	$1.38	$0.46	$5.30
NWE	$3.36	$1.92	$0.64	$5.91
PACE	$4.17	$3.32	$1.11	$8.60
PACW	$1.43	$0.78	$0.26	$2.47
PGE	$1.41	$0.96	$0.32	$2.68
PNM	$3.92	$2.14	$0.71	$6.77
PSCO	$6.68	$3.72	$1.24	$11.63
PSE	$1.79	$1.91	$0.64	$4.34
SCL	$0.59	$0.00	$0.00	$0.59
SMUD	$1.25	$0.20	$0.07	$1.51
SPP	$1.27	$0.46	$0.15	$1.89
SRP	$2.07	$0.50	$0.17	$2.74
TEP	$2.39	$0.54	$0.18	$3.11
TID	$0.49	$0.00	$0.00	$0.49
TPWR	$0.31	$0.00	$0.00	$0.31
WACM	$2.29	$0.72	$0.24	$3.25
WALC	$1.43	$0.12	$0.04	$1.59
WAUW	$0.53	$0.00	$0.00	$0.53
Total	$63.34	$29.52	$9.84	$102.70

[13]Ancillary service prices are often given as dollars per megawatt-hour because there is no energy content inherent in the reserves.

5.4 Subregional EIM Scenario Results

Results in the previous section show how reserves are affected when the entire study footprint operates as a single EIM. We also evaluated the effect of operating three distinct subregional EIMs from the same regional footprint. These subregional footprints are defined in Section 2.4.

5.4.1 Columbia Grid EIM

Columbia Grid was evaluated as a standalone EIM with all the members participating and also with BPA not participating (Section 5.6.1). Figure 21 shows the net reserve requirement reduction results for Columbia Grid with all the members participating in the EIM.

Reserve reductions for the Columbia Grid EIM are relatively modest compared with the full footprint and other subregional EIMs. This is primarily due to the relatively high correlation among wind sites in the footprint, with approximately 83% of the nameplate (measured as maximum zonal output, not actual machine nameplate) located in the BPA.[14] This dilutes much of the advantage of aggregating the wind across the subregional EIM.

Total regulation is reduced by 20% for each of the Columbia Grid BAs operating independently. Total reserves are reduced from 1476 MW to 1263 MW, or about 14%.

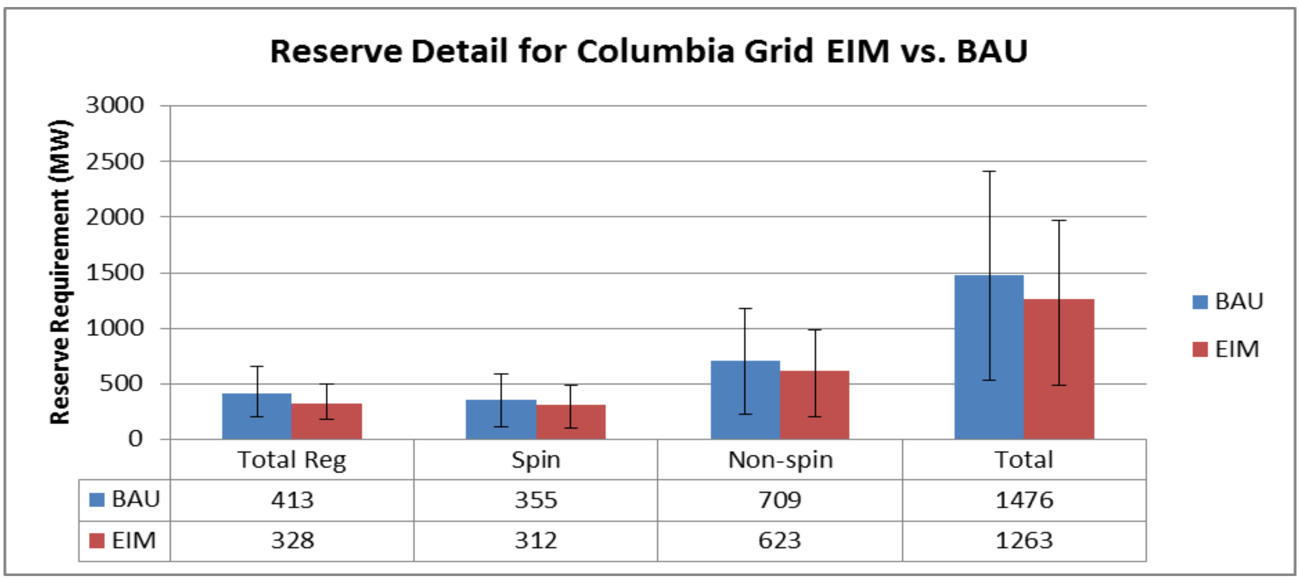


Figure 21. Net reserve savings for Columbia Grid EIM

Figure 22 shows the load and net load ramp savings from implementing the subregional EIM. The savings are relative to ramping that would be seen in the same set of BAAs without the EIM.

For net ramps, the maximum up-ramp reduction is about 20% and down-ramp is about 25%. Ramping energy or average ramp saving is about 8.3%, and the savings exceed 250 MW/hr for at least 130 hours per year. The average ramp is reduced by 27 MW. For load ramps, the maximum up-ramp reduction is 13% and down is 8%. The average ramp savings is about 3%, or 8 MW, and the savings exceed 100 MW/hr for at least 46 hours per year.

[14]We note that BPA does not calculate a dynamic reserve for wind energy and uses a different approach, as presented here.

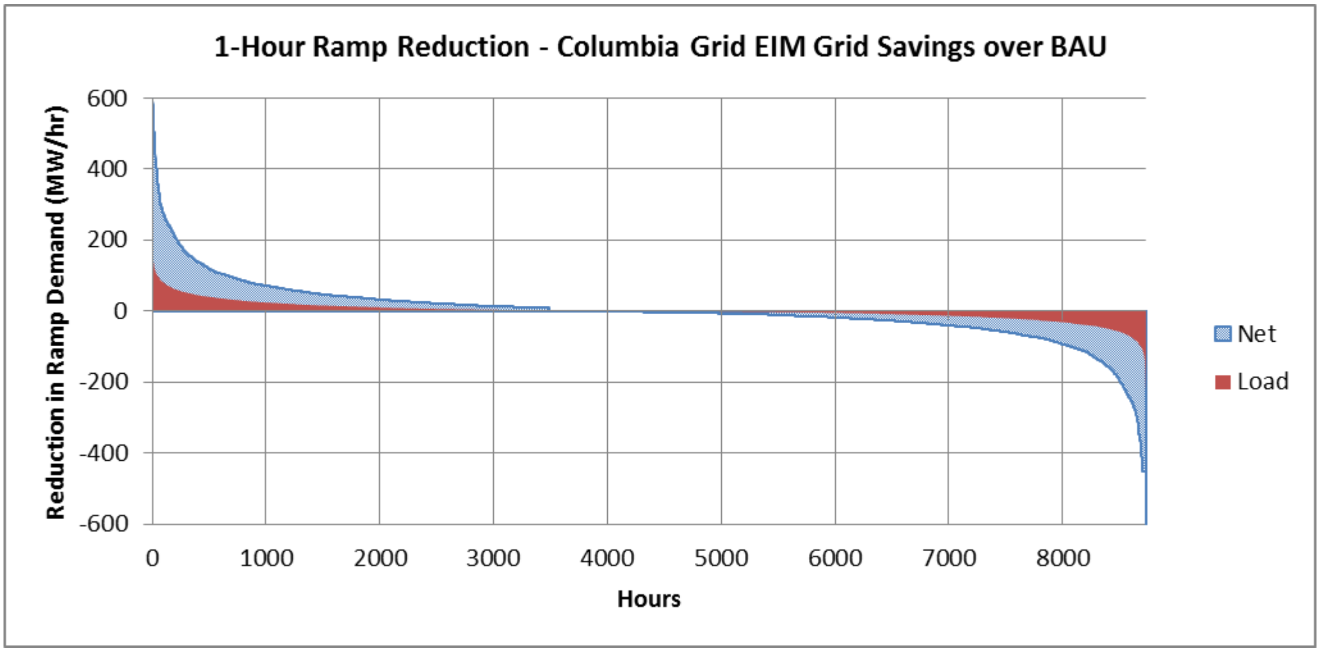


Figure 22. Columbia Grid EIM 1-hour ramp savings

Figure 23 shows the ramp savings for a typical week. The net savings are much larger than the load only because the load in Columbia Grid is highly correlated and the wind is less so, making net ramp reductions greater in magnitude.

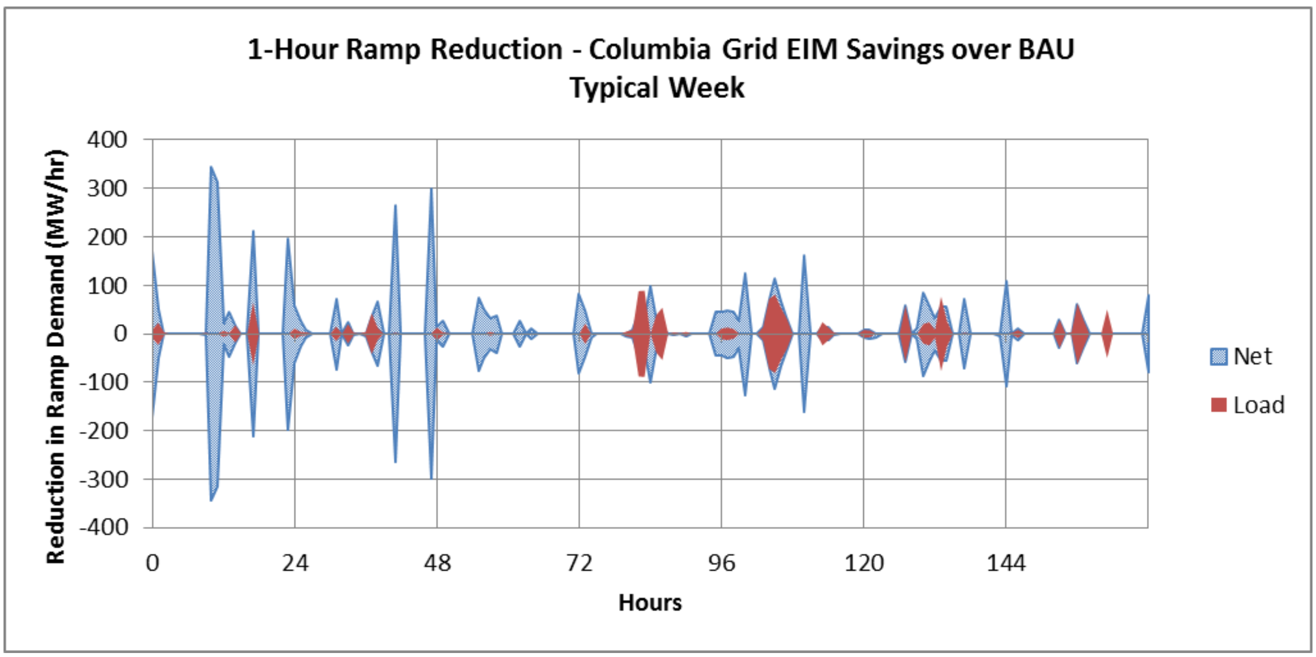


Figure 23. Columbia Grid EIM ramp savings over a typical week

Figure 24 shows the allocation of average total reserves and average regulation for the Columbia Grid EIM. The method for calculating these allocations is discussed in Section 4.3.

BPA dominates the Columbia Grid for load, VG, and variability. This leads to relatively small savings for BPA in the EIM because the diversity effects from the EIM aggregation are small. BPA saves about 41 MW of total reserve, on average, and about 12 MW of regulation. PSE sees larger savings in absolute terms—97 MW total reserves and 21 MW of regulation, on average—because PSE has a relatively large load (approximately half of BPA) but a significant amount of VG that adds to the diversity of the EIM.

There is also a reduction for Avista of 36 MW of total reserves, on average, and 12 MW of regulation. There is no VG in the remaining BAAs, so all the reduction in reserves is due to load aggregation effects. If load were not included in the calculations, their portion of the reserves would be zero, so savings would be zero. Tabular data for this table can be found in Appendix A in Table 25.

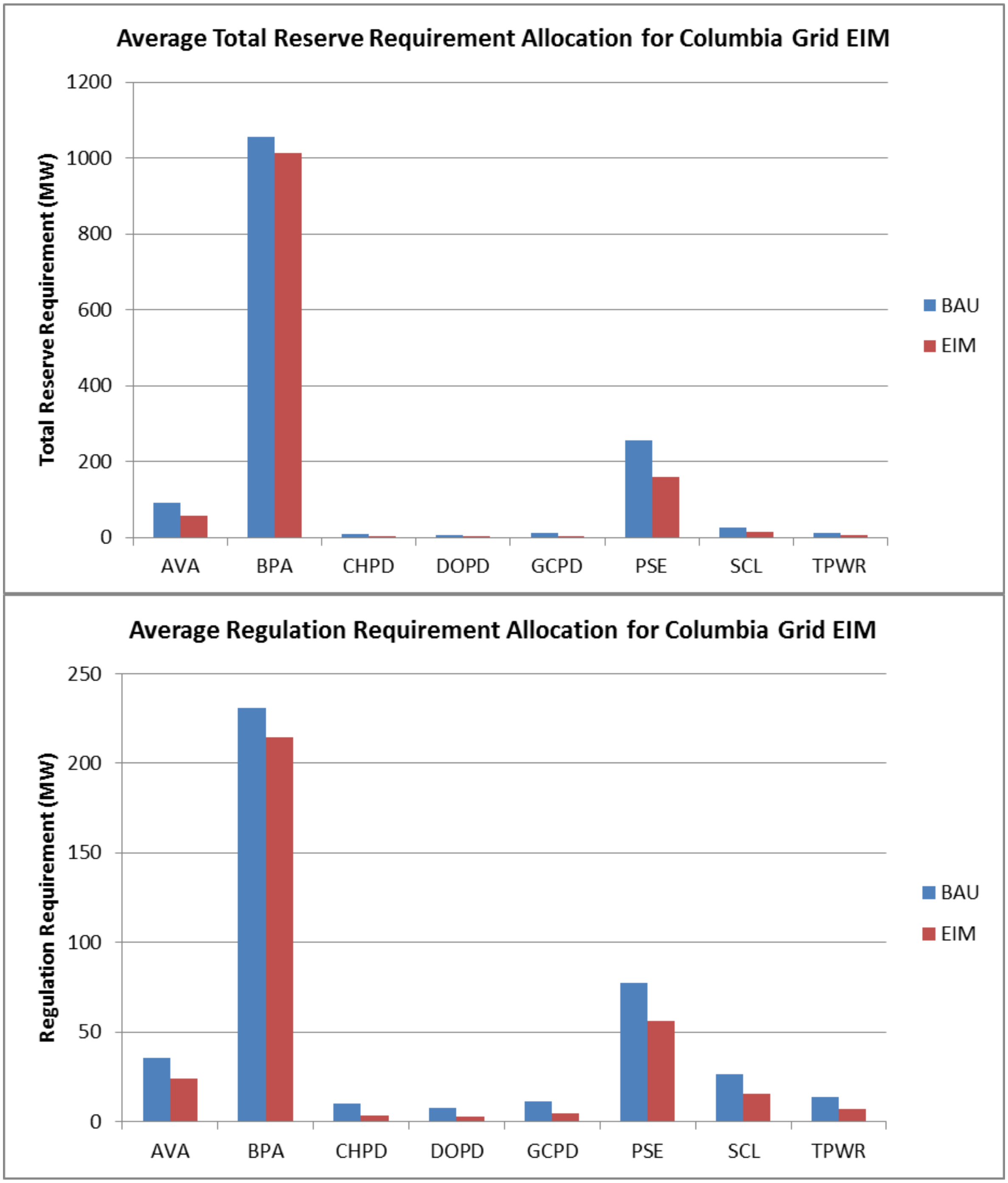


Figure 24. Allocation of reserves in the Columbia Grid EIM

The value of the reserve savings was calculated using the prices shown in Table 11. These reserve savings are shown in Table 13 for each BA participating in the EIM. The total savings for the Columbia Grid EIM is approximately $12 million. Note that the values are in millions of dollars.

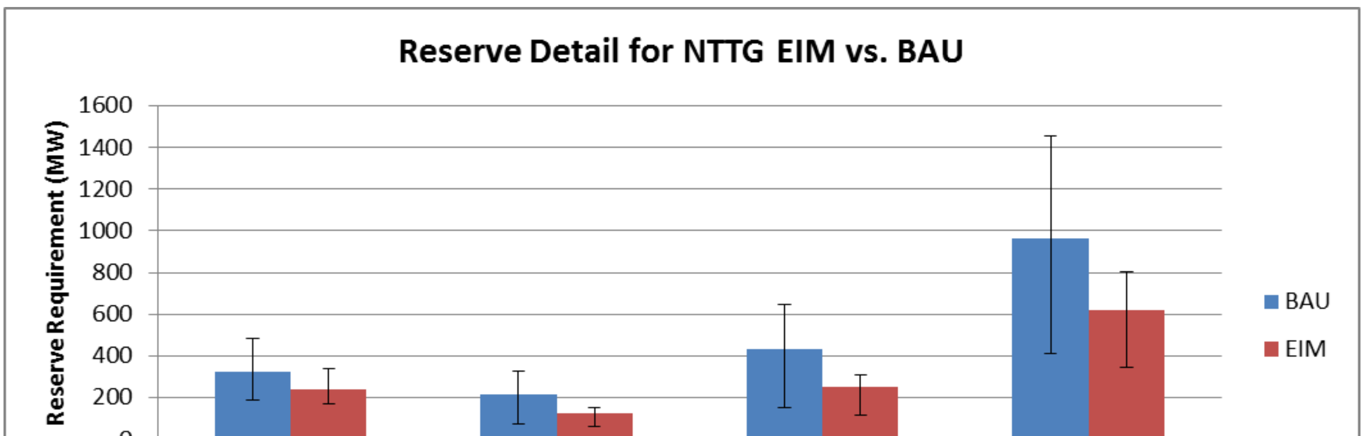
Table 13. Value of Annual Reserve Savings for Columbia Grid EIM ($M)

BAA	Regulation	Spin	Non-Spin	Total
AVA	$1.22	$0.42	$0.14	$1.78
BPA	$1.75	$0.44	$0.15	$2.34
CHPD	$0.69	$0.00	$0.00	$0.69
DOPD	$0.50	$0.00	$0.00	$0.50
GCPD	$0.72	$0.00	$0.00	$0.72
PSE	$2.24	$1.32	$0.44	$4.00
SCL	$1.16	$0.00	$0.00	$1.16
TPWR	$0.69	$0.00	$0.00	$0.69
Total	$8.97	$2.18	$0.73	$11.88

5.4.2 NTTG EIM

NTTG was evaluated as a separate subregional EIM. Figure 25 shows the net reserve requirement reduction results for NTTG with all the members participating in the EIM.

For NTTG, the savings are more substantial because of additional diversity in the wind resources in the subregion. The wind is spread across a large area without large concentrations. The net regulation requirement is reduced from 497 MW, on average, to 338 MW—a 32% reduction. Average total net reserves are reduced from 1744 MW to 1191 MW—also a 32% reduction.



	Total Reg	Spin	Non-spin	Total
BAU	322	215	429	966
EIM	240	126	251	617

Figure 25. Net reserve reductions for NTTG EIM

Figure 26 shows the load and net load ramp savings from implementing the subregional EIM. The savings are relative to ramping that would be seen in the same set of BAAs without the EIM.

For net ramps, the maximum up-ramp reduction is about 20% and down-ramp is about 17%. Ramping energy or average ramp savings is about 9%. The average ramp is reduced by 26 MW. For load ramps, the maximum up-ramp reduction is 15% and down is 13%. The average ramp savings is about 5%, or 11 MW.

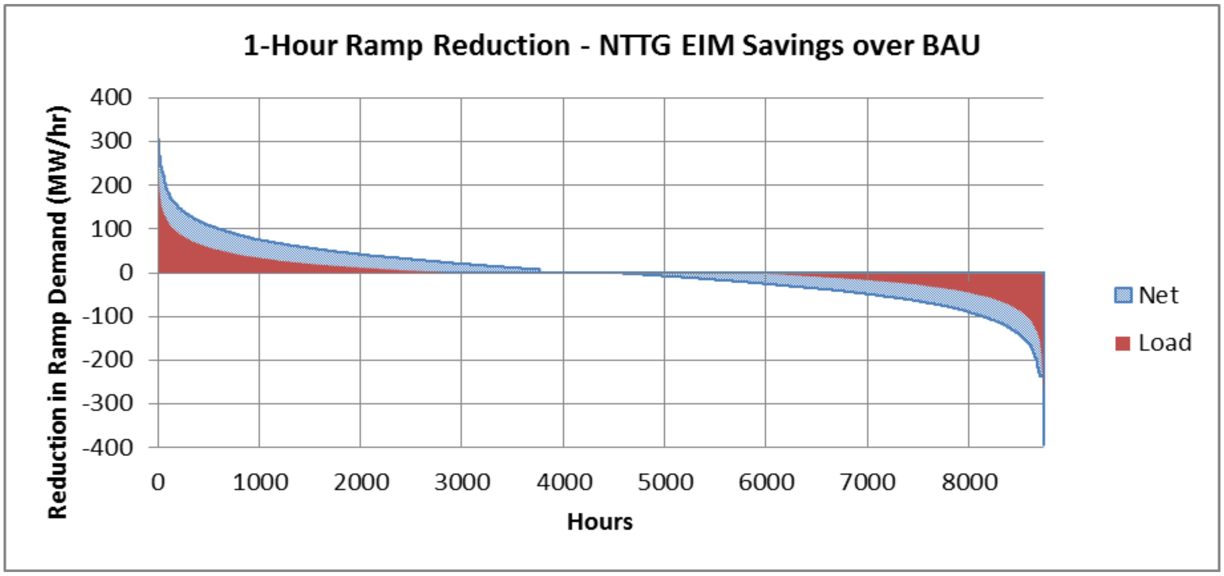


Figure 26. NTTG EIM 1-hour ramp savings

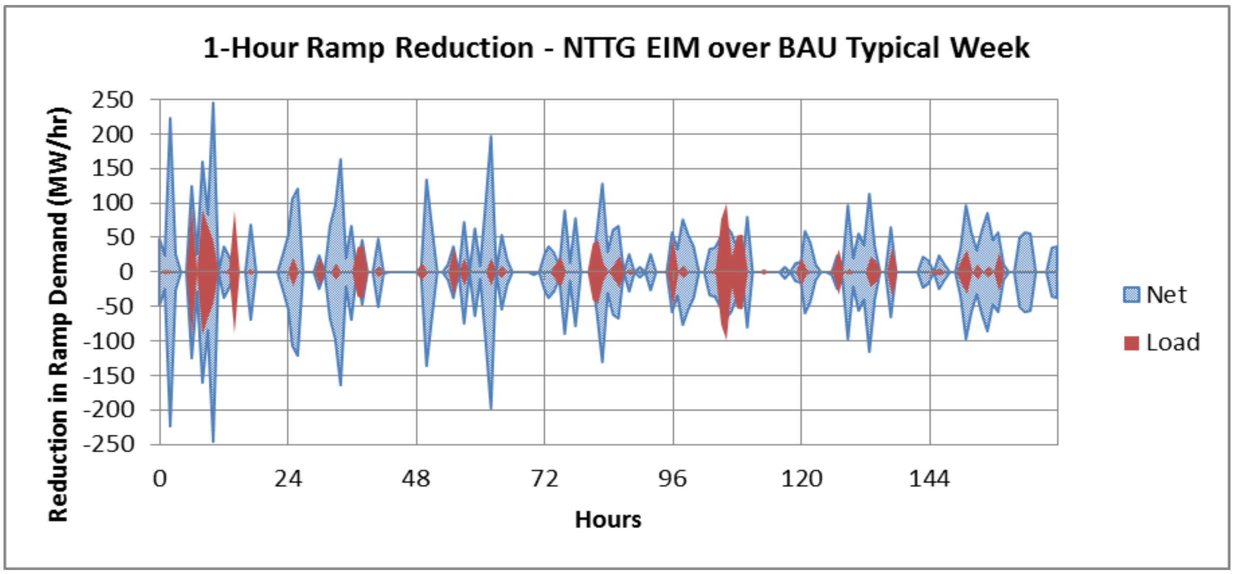


Figure 27. NTTG EIM ramp savings over a typical week

The allocation of average total reserves and average total regulation is shown in Figure 28. This figure compares the allocation for the BAU case with the NTTG subregional EIM case.

The relationship among BAA characteristics, size of the EIM, and resulting EIM reserve savings is complex. Small BAAs can have a disproportionately large effect on the aggregate if they add geographic diversity. Large BAAs with low diversity in their VG can see a disproportionately small effect on aggregate diversity because they dominate the aggregate diversity. One example is PACE, which experiences an 81-MW reduction (17%), while NWE—with a small load and high penetration—experiences a reduction of 94 MW (55%) in average total reserves. PACW and PGE show a similar, substantial reduction in both total reserves (~38%) and total regulation (~20%), as their size and VG penetration are similar. IPC sees a large percentage decrease in both total reserves and regulation because it contributes to the diversity of the EIM even with a low penetration of wind.

Tabular data for these graphs can be found in Appendix A in Table 26.

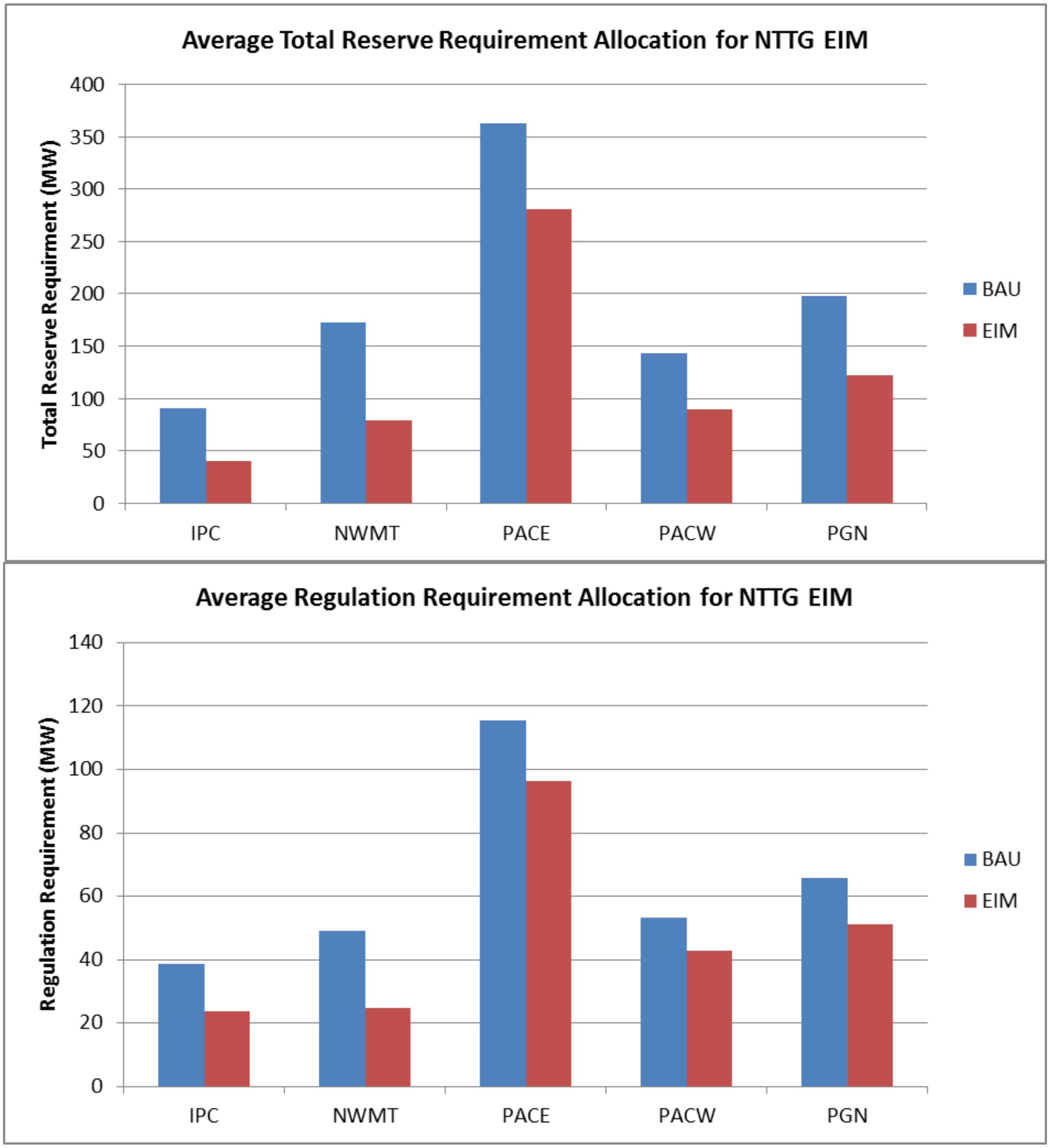


Figure 28. Allocation of reserves for NTTG EIM

The value of the reserve savings was calculated using the prices shown in Table 11. These reserve savings are shown in Table 14 for each BA participating in the EIM. The total savings for the NTTG EIM is approximately $15 million. Note that the values are in millions of dollars.

Table 14. Value of Annual Reserve Savings in NTTG EIM ($M)

BAA	Regulation	Spin	Non-Spin	Total
IPC	$1.57	$0.62	$0.21	$2.39
NWE	$2.54	$1.21	$0.40	$4.15
PACE	$2.03	$1.04	$0.35	$3.42
PACW	$1.09	$0.74	$0.25	$2.08
PGE	$1.53	$1.06	$0.35	$2.95
Total	$8.77	$4.66	$1.55	$14.99

5.4.3 WestConnect EIM

WestConnect was evaluated as a separate EIM with all the members participating and also with three subregions of WAPA not participating (Section 5.6.3). Figure 29 shows the net reserve requirement reduction results for WestConnect with all the members participating in the EIM.

Of the three subregional EIM implementations modeled, WestConnect realizes the greatest benefits both in absolute and relative terms. This is due to the large load and footprint of the subregion and high geographic diversity of the wind resources. Total regulation is reduced from 749 MW for the BAs operating independently to 496 MW for the EIM—a 34% reduction. Total reserve requirements are reduced from 2572 MW to 1823 MW for the EIM—a 29% reduction.

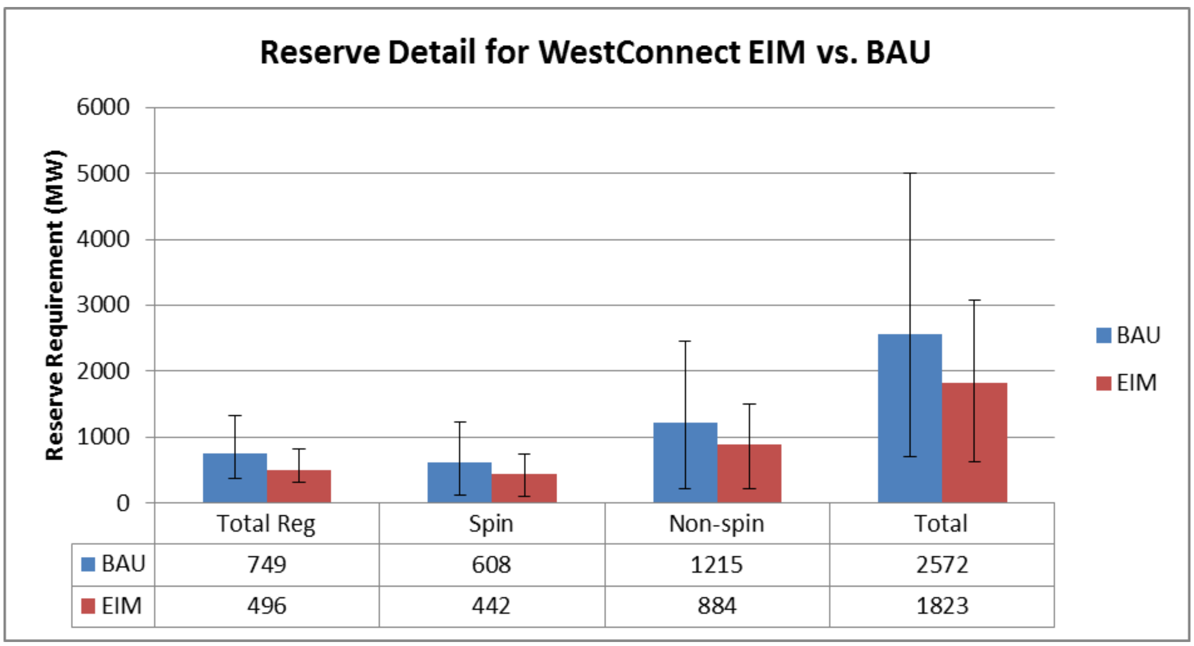


Figure 29. WestConnect EIM net reserve reductions

Figure 30 shows the load and net load ramp savings from implementing the subregional EIM. The savings are relative to ramping that would be seen in the same set of BAAs without the EIM.

For net ramps, the maximum up-amp reduction is about 21% and down-ramp is about 19%. Ramping energy or average ramp saving is about 18%. The average ramp is reduced by 117 MW. For load ramps, the maximum up-ramp reduction is 17% and down is 19%. The average ramp savings is about 9% or 56 MW.

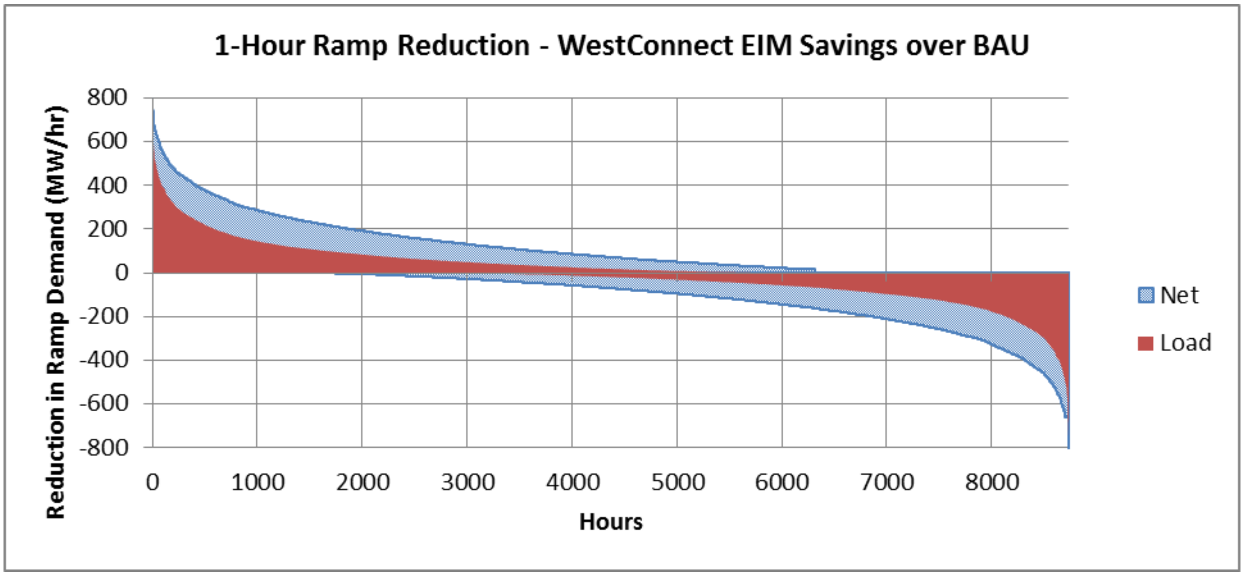


Figure 30. WestConnect EIM 1-hour ramp savings

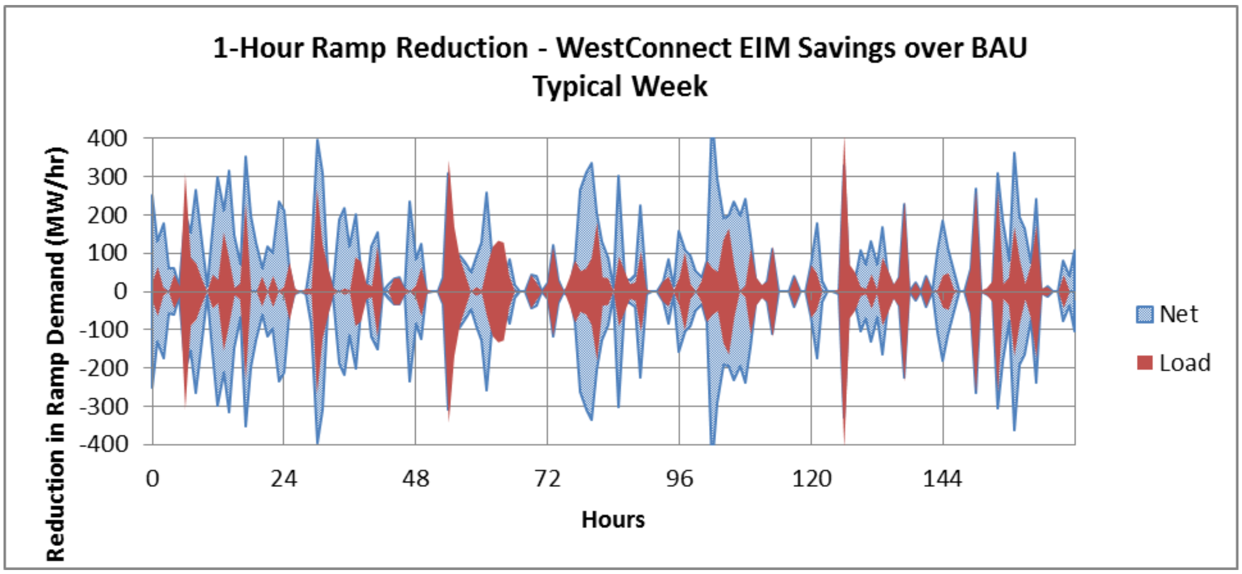


Figure 31. WestConnect EIM ramp savings over a typical week

The BAA allocation of average total reserves and average total regulation for the WestConnect subregional EIM is shown in Figure 32. The WestConnect subregional EIM has enough participants so that no one participant exceeds 20% of the total load, so no one BAA dominates the others.

In VG penetration however, PSCO has about 40% of the total in both wind and solar. With this penetration of VG, we might expect PSCO to see relatively small savings. However, the VG in PSCO is made up of both wind and significant solar, giving those combined resources comparatively low variability.

AZPS, on the other hand, sees relatively smaller reductions because its VG is highly correlated and low penetration compared with PSCO.

Tabular data for these graphs can be found in Appendix A in Table 27.

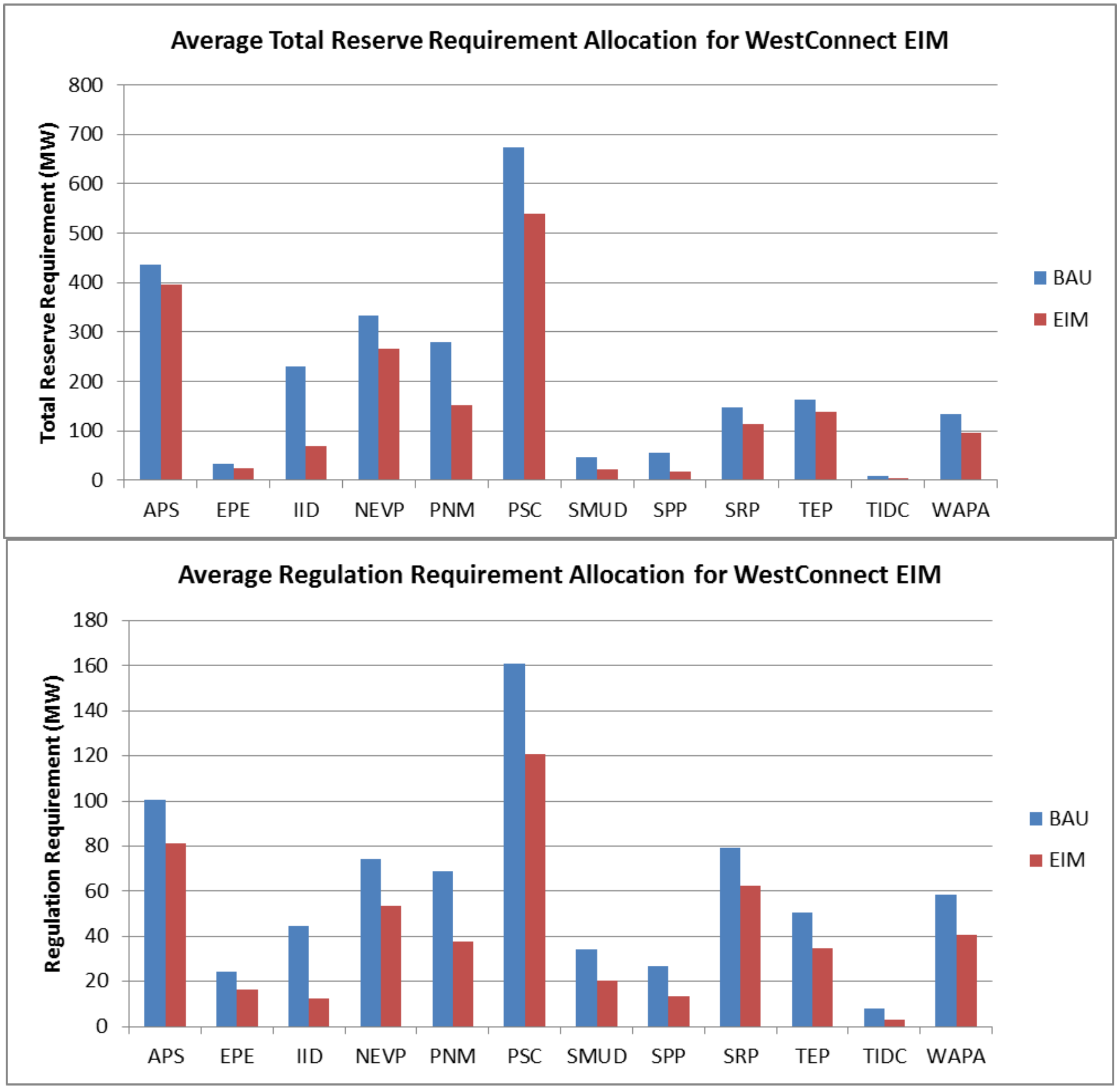


Figure 32. Allocation of reserves for WestConnect EIM

The value of the reserve savings was calculated using the prices shown in Table 11. These reserve savings are shown in Table 15 for each BAA participating in the EIM. The total savings for the WestConnect EIM is approximately $36 million. Note that the values are in millions of dollars.

Table 15. Value of Annual Reserve Savings for WestConnect EIM ($M)

BAA	Regulation	Spin	Non-Spin	Total
AZPS	$2.03	$0.37	$0.12	$2.52
EPE	$0.88	$0.01	$0.00	$0.90
IID	$3.39	$2.21	$0.74	$6.34
NEVP	$2.20	$0.84	$0.28	$3.32
PNM	$3.30	$1.66	$0.55	$5.51
PSCO	$4.22	$1.60	$0.53	$6.36
SMUD	$1.46	$0.20	$0.07	$1.73
SPP	$1.44	$0.45	$0.15	$2.04
SRP	$1.77	$0.30	$0.10	$2.17
TEP	$1.65	$0.17	$0.05	$1.87
TID	$0.51	$0.00	$0.00	$0.51
WAPA	$1.90	$0.34	$0.11	$2.35
Total	$24.76	$8.17	$2.72	$35.64

5.5 WECC TEPPC EIM Study Phase 2 EIM and Reduced Footprint With Flex-Only Regulation

WECC performed an independent study to understand the benefits of EIM implementation using chronological production cost modeling techniques. NREL was asked to provide the reserve requirement calculation to this effort. The GridView reserve model, as developed for the WECC study carried out by E3, was developed using a separate calculation for the load regulation, so a new class of reserve was defined to cover just the VG portion of what we have defined as regulation for this study. This component is called the flex-only regulation and is defined in Equation 3 in Section 4.1. The spin and non-spin components of reserves are as defined in Equation 5.

The flex reserve requirements were calculated for the full-Western Interconnection footprint as defined in Section 2.4. The flex requirements differ from the regulation requirement used elsewhere in this analysis because there is no load component included in this flex reserve calculation. Figure 33 shows the flex regulation-based reserve requirements for the footprint EIM. The data in this chart can be compared to Figure 14, which shows the reserve requirements for the same EIM definition with load regulation included.

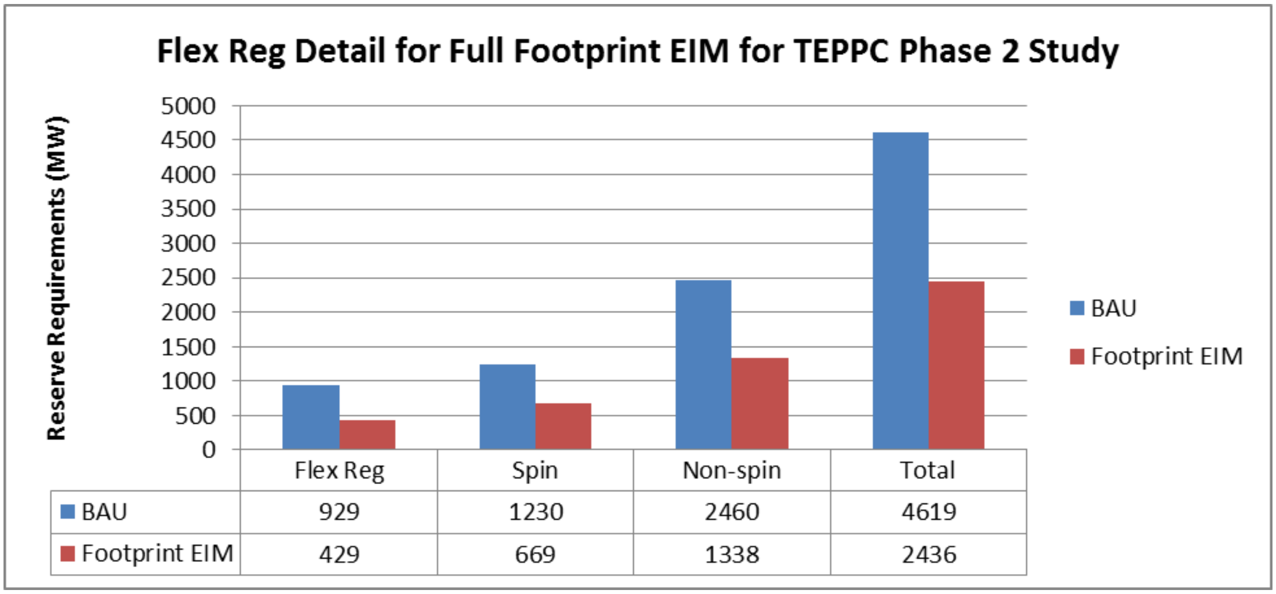


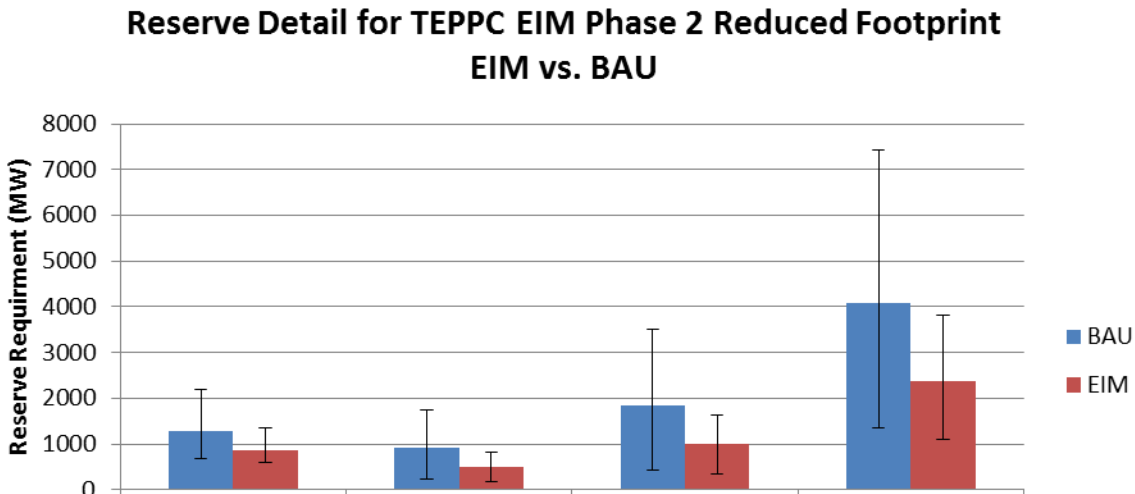
Figure 33. Flex-only regulation and total requirements for footprint EIM

When the model was developed, a new reduced-footprint EIM was defined that is close to, but not quite the same as, the scenario that excluded BPA and WAPA. The difference is that the municipal and public utility district entities that are embedded in BPA were also excluded from the EIM.

Table 16. BAAs Included in the TEPPC Phase 2 Reduced Footprint Scenario

BAAs in Reduced Footprint	
Avista	Pacificorp West
Arizona Public Service	Portland General Electric
British Columbia	Public Service of New Mexico
El Paso Electric	Public Service of Colorado
Imperial Irrigation District	Puget Sound Energy
Idaho Power Corp.	Sacramento Municipal Utility District
LA Department of Water and Power	Sierra Pacific Power
Nevada Power	Salt River Project
Northwest Energy	Tucson Electric Power
Pacificorp East	Turlock Irrigation District

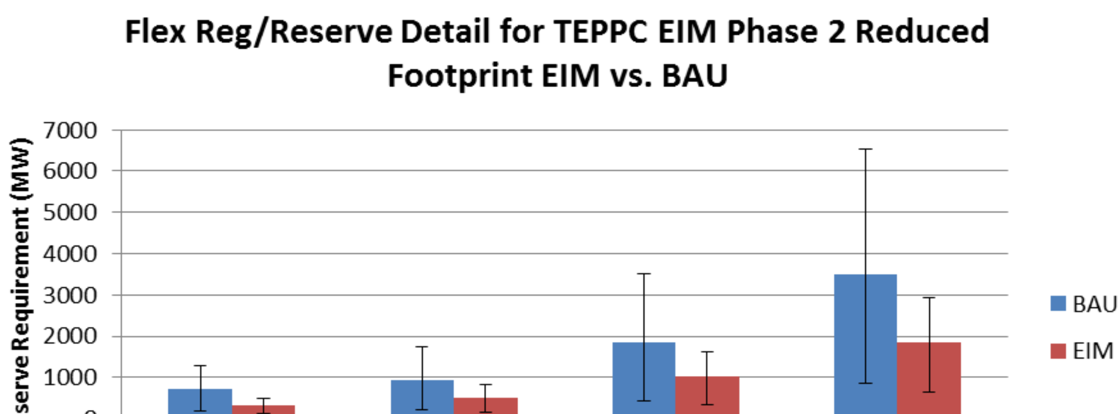
The reserve data were calculated using both the method used in this study and the flex reserves from the TEPPC EIM Phase 2 study. Figure 34 shows the results using load regulation as part of the total regulation calculation, as was done in all earlier analyses in this report.



	Total Reg	Spin	Non-spin	Total
BAU	1293	926	1853	4072
EIM	862	508	1017	2387

Figure 34. Average reserves for reduced footprint with load regulation component included

The flex reserves are the regulation requirement to cover the in-the-hour movements of VG only and do not include load regulation. The total regulation values used throughout this report include a load component, as defined in Section 4.1.



	Flex Reg	Spin	Non-spin	Total
BAU	705	926	1853	3484
EIM	321	508	1017	1846

Figure 35. Average reserves for reduced footprint using flex-only regulation with no load component

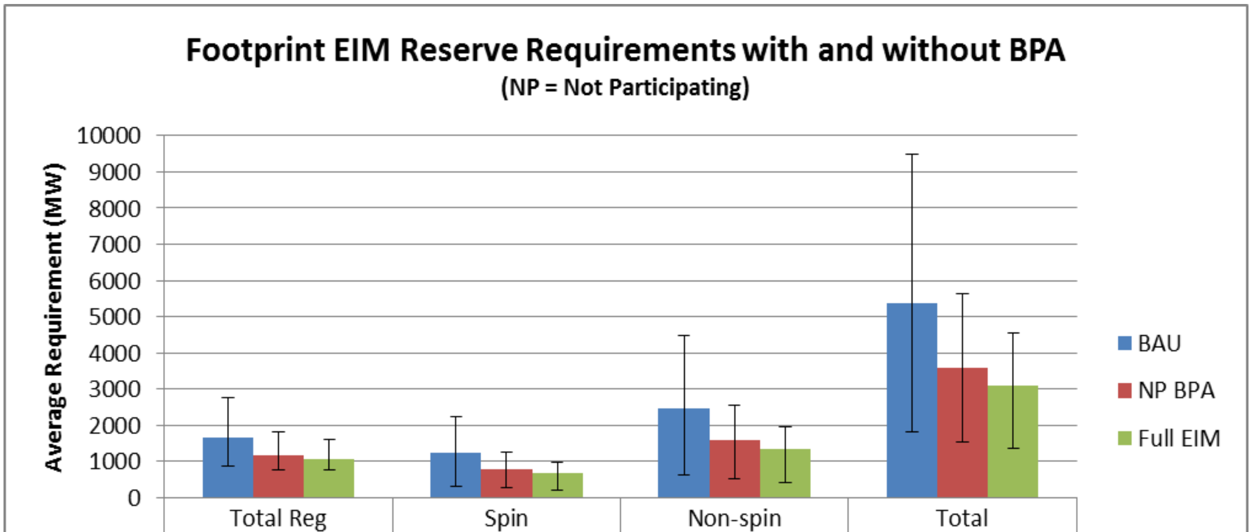
5.6 Results With BPA and WAPA Not Participating in EIM

One of the important elements of this work was to understand the effect of nonparticipation of BAs with large VG production on the EIM implementations. To do this, cases were run with BPA and WAPA managing their net load variability independently of the EIMs. When a BA does not participate, it obviously cannot reduce its own reserve requirements, but it also impacts the savings for the remaining participants.

5.6.1 BPA Not Participating in Footprint EIM

The footprint EIM case was evaluated with BPA not participating. Without BPA, there is still a significant reduction in reserves, as shown in Figure 36. This chart compares the BAU case with the full EIM and the EIM with BPA not participating. The bar labeled “NP BPA” includes the standalone requirements for BPA added to the footprint EIM requirements (without BPA participating) so the total requirements across the study area can be compared. The bars show the average requirements, and the whiskers show the minimum and maximum values. The effect on reserve requirements for the EIM's remaining participants is investigated below.

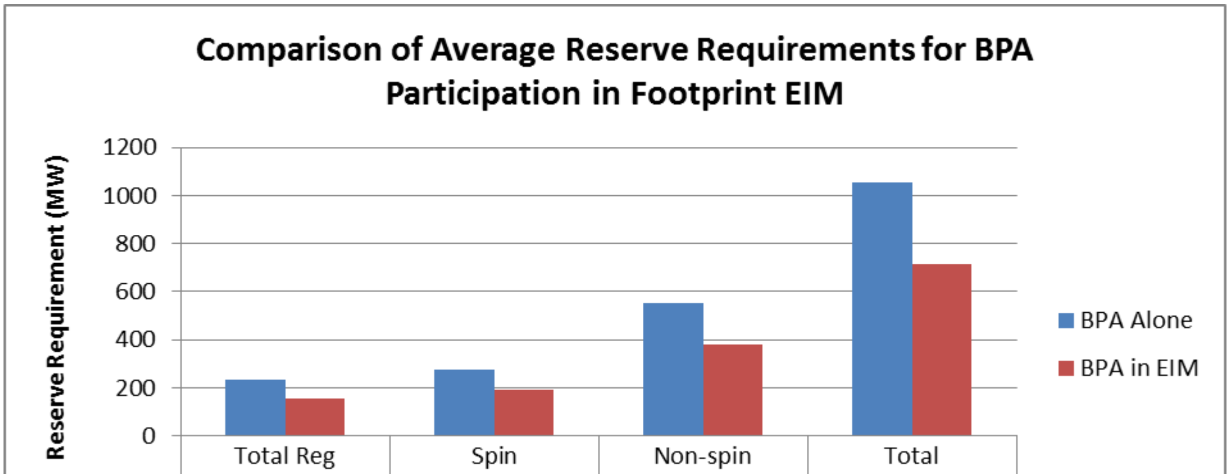
There is a reduction in benefit to the total footprint reserve requirements when a large BA such as BPA does not participate. The average total reserve requirement rises from 3083 MW for the full EIM with BPA to 3570 MW without BPA. However, there are still savings compared with the BAU, and most of the full EIM benefit is captured.



	Total Reg	Spin	Non-spin	Total
BAU	1669	1230	2460	5359
NP BPA	1174	799	1597	3570
Full EIM	1076	669	1338	3083

Figure 36. Reserve requirement for footprint EIM with and without BPA participation

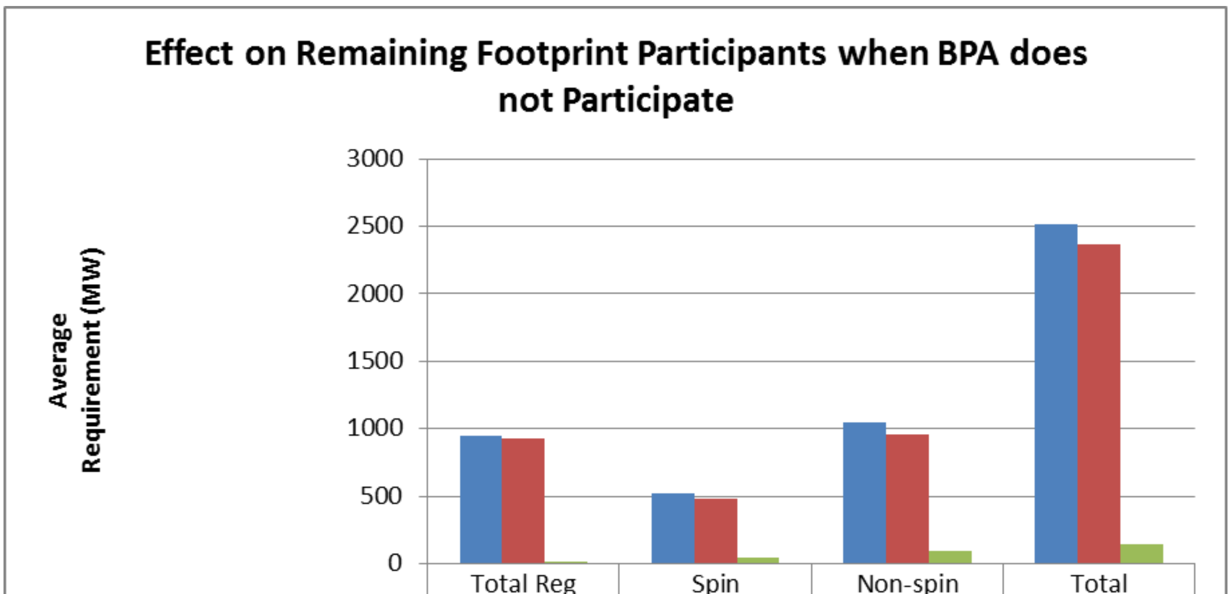
When a region does not participate, it will not receive the benefits of the EIM. For BPA, the difference between participating and not participating is shown in Figure 37. The reserve requirements for the case with BPA participating are calculated using the allocation method detailed in Section 4.3 and shown in Figure 20. The differences between the bars are the potential savings BPA receives from the footprint EIM. The potential savings are approximately 33% for each class of reserves.



	Total Reg	Spin	Non-spin	Total
BPA Alone	231	275	550	1056
BPA in EIM	153	191	381	714

Figure 37. BPA's reserve requirements are reduced if it participates in the EIM

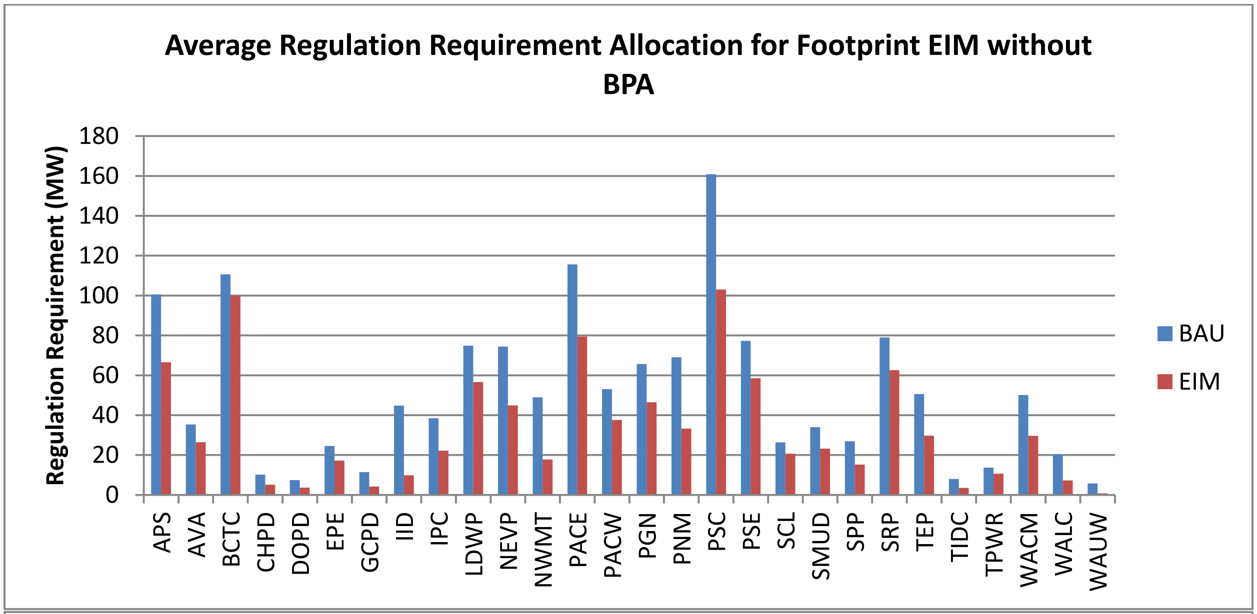
The savings for the rest of the EIM participants are affected by the participation of other BAs also. The effect for the remaining participants is much smaller than for BPA. Figure 38 shows that the lost savings when BPA does not participate are modest relative to the overall requirement, although they do add up to 145 MW of savings in total reserves.



	Total Reg	Spin	Non-spin	Total
Req for rest of footprint, BPA Not Participating	943	524	1047	2514
Req for rest of footprint BPA Participating	924	478	957	2369
Savings Not Realized	19	45	91	145

Figure 38. Summary of reserves for footprint EIM with and without BPA

The BA allocation of average total reserves and average total regulation for the footprint EIM without BPA is shown in Figure 39. Tabular data for this figure can be found in Appendix A in Table 28.



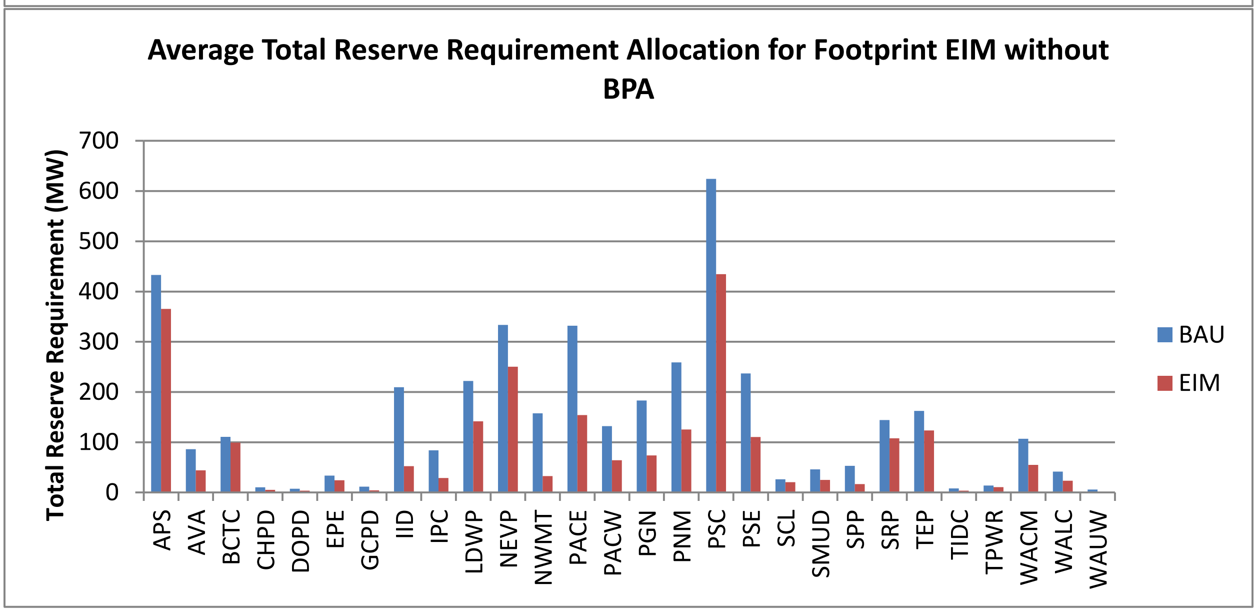


Figure 39. Allocation of reserve savings for footprint EIM without BPA participation

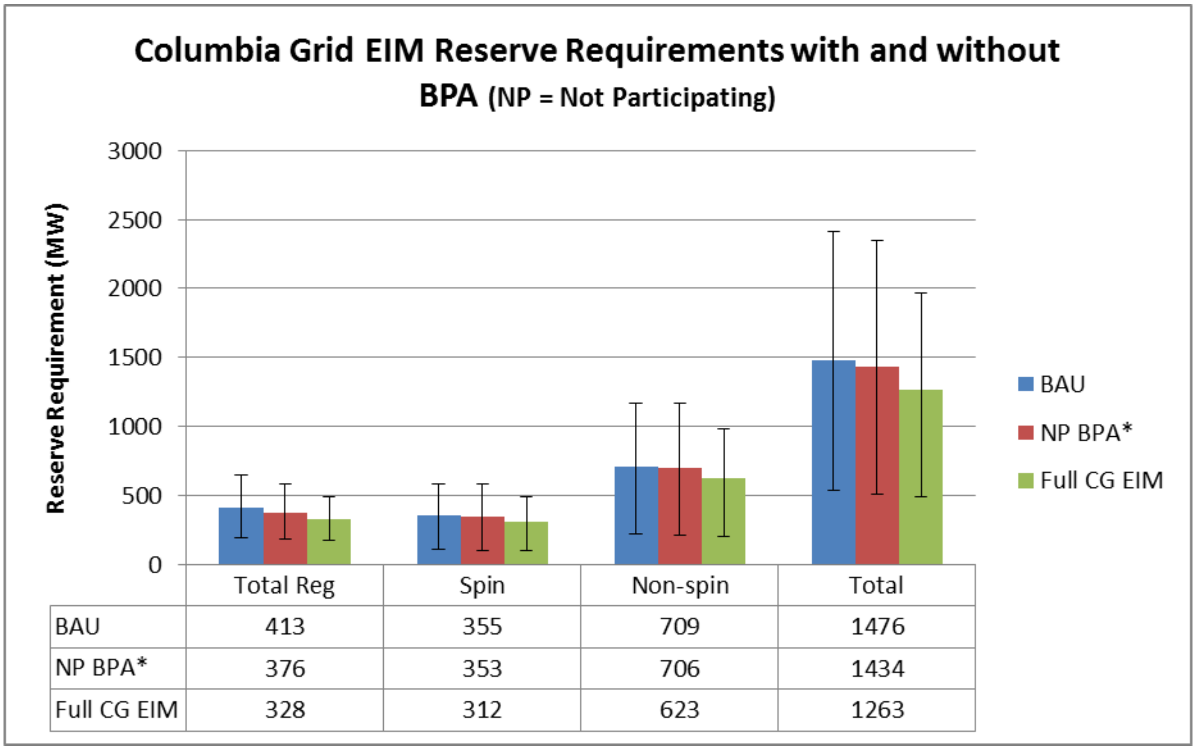
The value of these savings can be calculated using the price assumptions shown in Table 11. The resulting values are shown in Table 17. Note that the values are in millions of dollars and do not include costs to operate or participate in the EIM.

Table 17. Value of Annual Reserve Savings for Footprint EIM Without BPA ($M)

BAA	Regulation	Spin	Non-Spin	Total
AZPS	$3.57	$0.60	$0.20	$4.37
AVA	$0.94	$0.58	$0.19	$1.71
BCTC	$1.12	$0.00	$0.00	$1.12
CHPD	$0.53	$0.00	$0.00	$0.53
DOPD	$0.40	$0.00	$0.00	$0.40
EPE	$0.76	$0.04	$0.01	$0.81
GCPD	$0.76	$0.00	$0.00	$0.76
IID	$3.67	$2.09	$0.70	$6.45
IPC	$1.71	$0.68	$0.23	$2.62
LDWP	$1.92	$1.09	$0.36	$3.37
NEVP	$3.11	$0.93	$0.31	$4.35
NWE	$3.28	$1.63	$0.54	$5.45
PACE	$3.80	$2.47	$0.82	$7.10
PACW	$1.63	$0.91	$0.30	$2.84
PGE	$2.01	$1.57	$0.52	$4.11
PNM	$3.76	$1.69	$0.56	$6.01
PSCO	$6.08	$2.18	$0.73	$8.99
PSE	$1.97	$1.87	$0.62	$4.46
SCL	$0.60	$0.00	$0.00	$0.60
SMUD	$1.14	$0.18	$0.06	$1.37
SPP	$1.23	$0.43	$0.14	$1.81
SRP	$1.73	$0.35	$0.12	$2.19
TEP	$2.19	$0.31	$0.10	$2.61
TID	$0.48	$0.00	$0.00	$0.48
TPWR	$0.32	$0.00	$0.00	$0.32
WACM	$2.15	$0.55	$0.18	$2.88
WALC	$1.38	$0.09	$0.03	$1.49
WAUW	$0.53	$0.00	$0.00	$0.53
Total	$53	$20	$7	$80

5.6.2 BPA Not Participating in Columbia Grid Subregional EIM

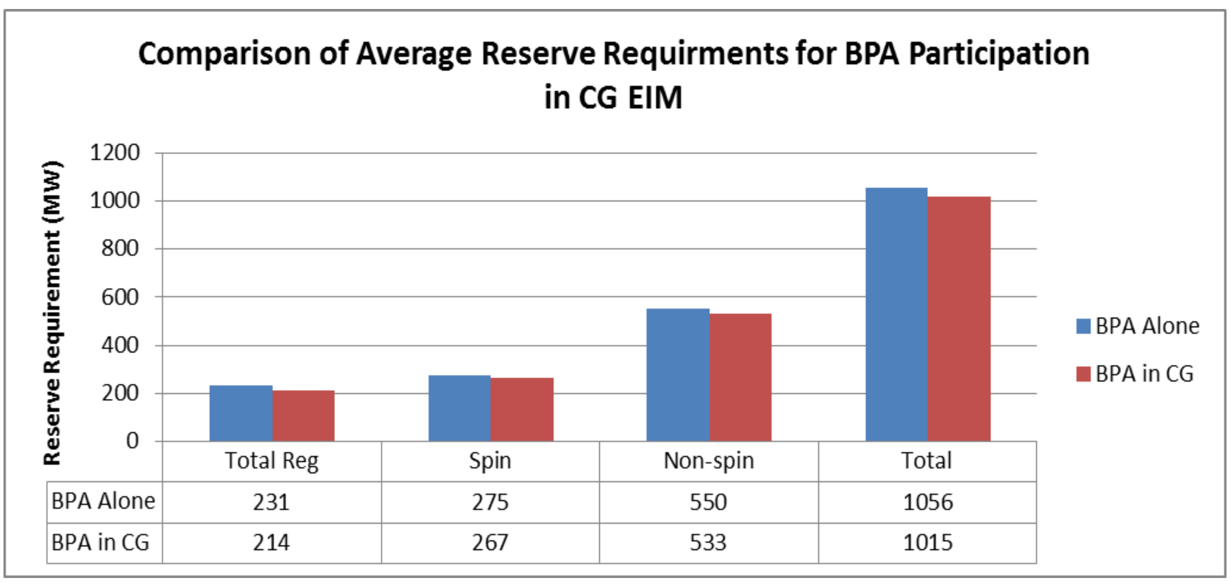
As we saw with the full Columbia Grid EIM in Section 5.4.1, the savings are somewhat less than those for the other EIMs relative to the total size. BPA dominates with around 45% of the average load and around 81% of the total average wind in Columbia Grid. Removing BPA from the EIM further reduces the savings, as shown in Figure 40. Note that the bar labeled "NP BPA*" includes the standalone requirement for BPA added to the Columbia Grid EIM without BPA requirement to allow comparison of values across the complete Columbia Grid.



	Total Reg	Spin	Non-spin	Total
BAU	413	355	709	1476
NP BPA*	376	353	706	1434
Full CG EIM	328	312	623	1263

Figure 40. Net average reserve requirements for Columbia Grid EIM with and without BPA

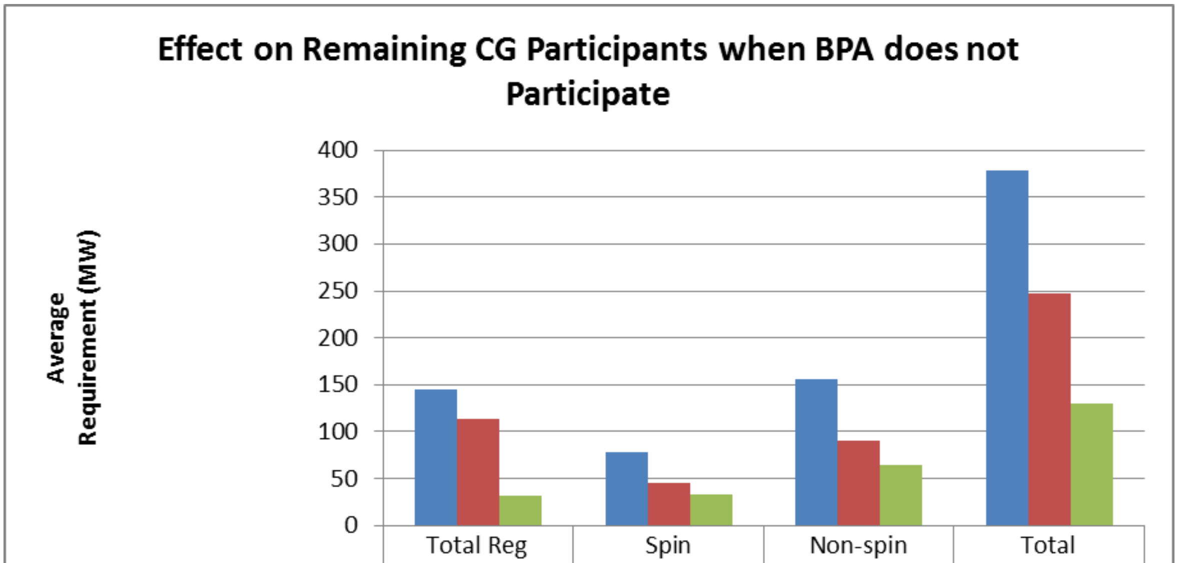
Figure 41 shows the effect on BPA for participation in the Columbia Grid subregional EIM. These savings are small because BPA dominates the VG in the EIM. Note that the allocation for BPA is calculated using the method described in section 4.3 .



	Total Reg	Spin	Non-spin	Total
BPA Alone	231	275	550	1056
BPA in CG	214	267	533	1015

Figure 41. Effects of BPA not participating in EIM on BPA requirements

Without BPA, the remaining participants in the EIM still enjoy savings but significantly less than with BPA. Figure 42 compares the requirements for the BAAs included in the EIM with and without BPA's participation. BPA requirements are not included in the bars. The unrealized savings are shown in the right-most bar.



	Total Reg	Spin	Non-spin	Total
Req for rest of CG, BPA Not Participating	145	78	155	378
Req for rest of CG, BPA Participating	114	45	90	248
Savings Not Realized	31	33	65	130

Figure 42. Effect on CG EIM participants when BPA does not participate

5.6.3 WAPA Not Participating in Footprint EIM

The full-footprint EIM was also evaluated with WAPA regions not participating. The three WAPA regions in the model represent approximately, on average, 5% of the load, 2% of the wind, and 0.5% of the solar modeled in the footprint EIM. With these proportions, the impact of the WAPA regions on the EIM is not very significant.

Figure 43 compares the BAU case requirements with those for the EIM both with and without WAPA participating. The bar labeled "NP WAPA" contains the standalone requirements for WAPA added to the footprint EIM requirements so that the total requirements across the study area can be compared. The bars are the average value, and the whiskers are minimum and maximum values. As shown, the impact on total reserve requirements for the entire footprint including WAPA is relatively small, with only a 90-MW (3%) difference between WAPA participating in the EIM or not. The majority of the savings for the EIM are intact without WAPA.

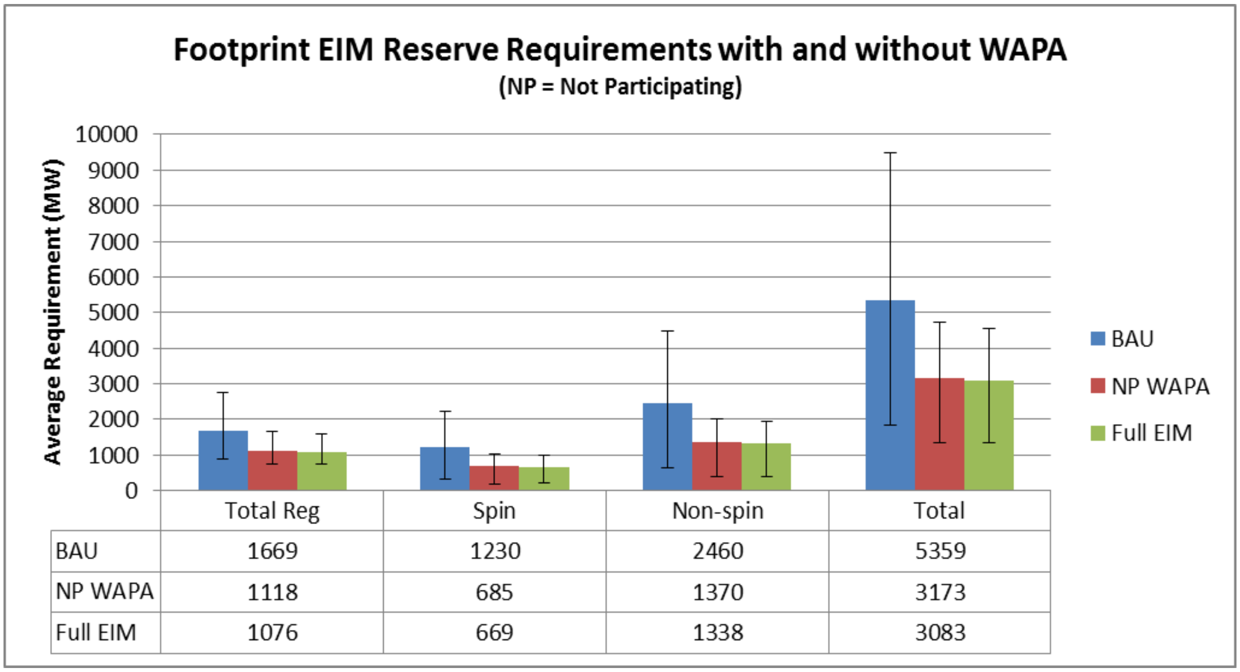


Figure 43. Reserve requirements for footprint EIM with and without WAPA participation

Next, we examined the effect on WAPA's reserve requirements of not participating in the footprint EIM. Figure 44 compares WAPA's reserve requirements in and out of the EIM. In relative terms, the unrealized savings are quite significant. For total reserves, the savings could be 60 MW, or 45%. The allocation of reserves for WAPA in the EIM is calculated using the method described in Section 4.3.

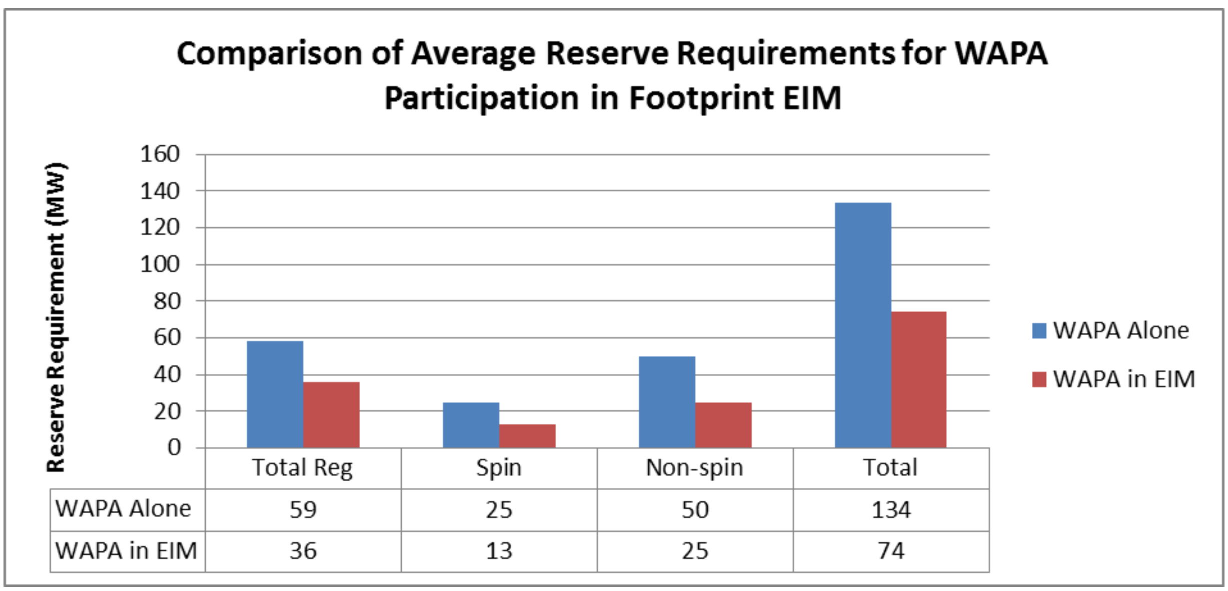


Figure 44. Effects of WAPA not participating in footprint EIM on WAPA requirements

WAPA's participation in the Footprint EIM has little effect on the other participants in the EIM. This is because of the low percentages of load, wind, and solar in WAPA. These savings are in the low single digits for all classes of reserves. Figure 45 shows the effect of WAPA nonparticipation.

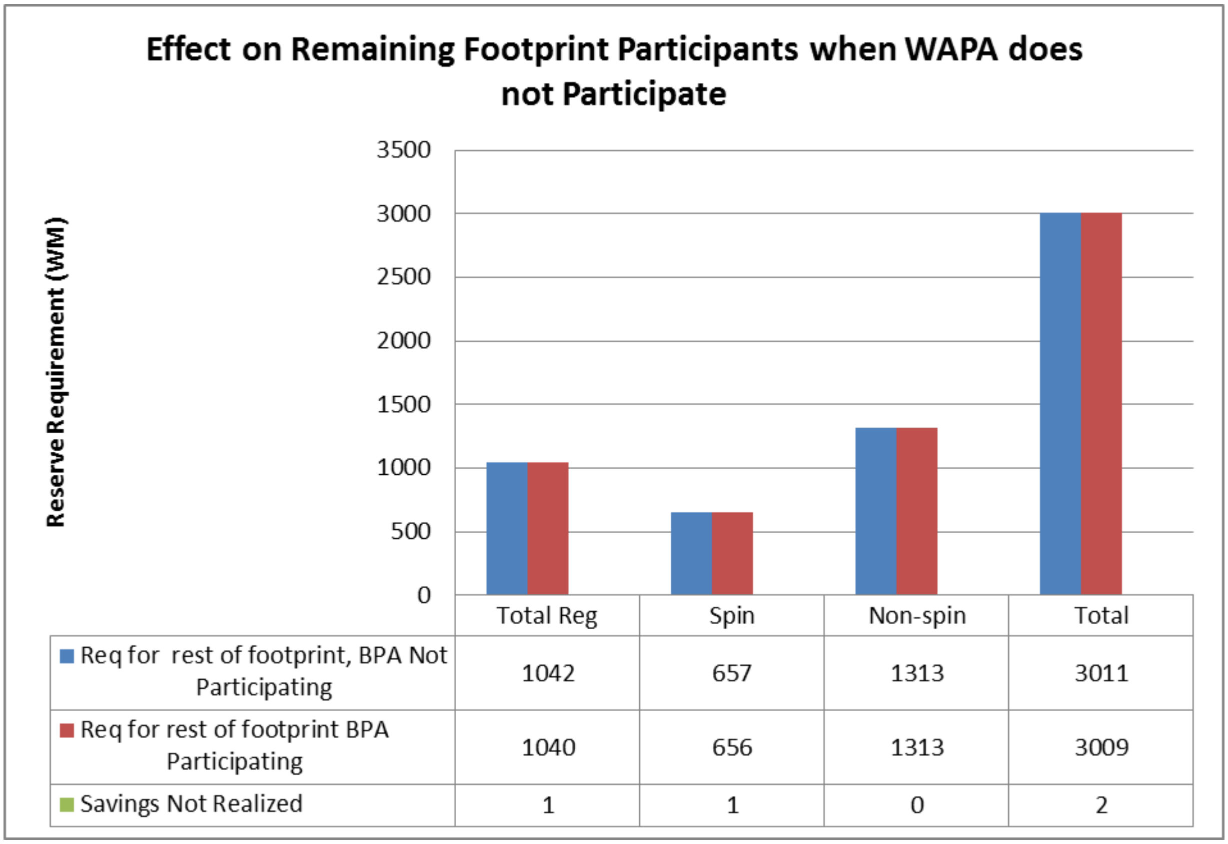
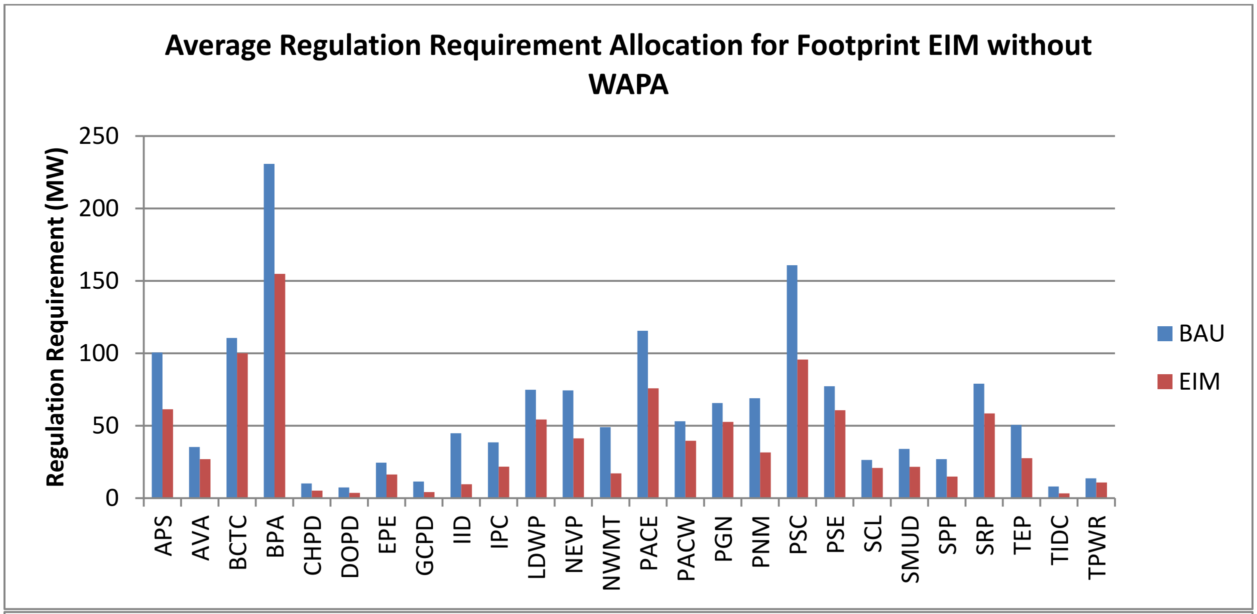


Figure 45. Effect of WAPA not participating in footprint EIM

The BAA allocation of average total reserves and average total regulation for the footprint EIM without WAPA can be seen in Figure 46. Tabular data for this figure can be found in Appendix A in Table 29.



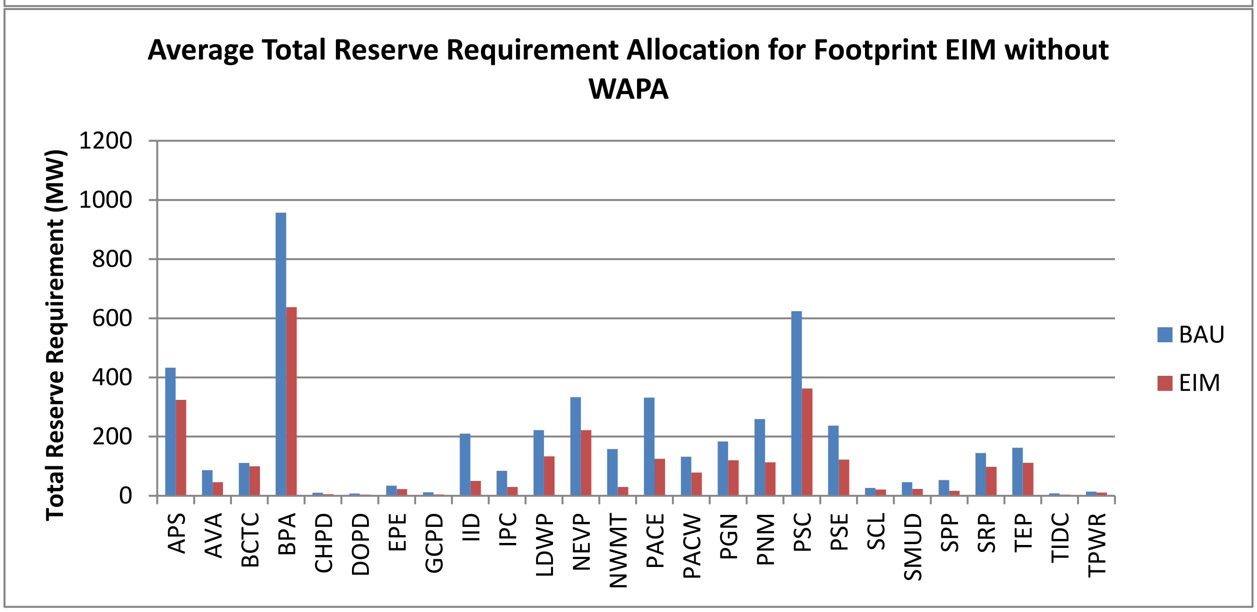


Figure 46. Allocation of reserve savings for footprint EIM without WAPA participation

The value of these savings can be calculated using the price assumptions shown in Table 11. The resulting values are shown in Table 18. Note that the values are in millions of dollars.

Table 18. Value of Annual Reserve Savings for Footprint EIM Without WAPA ($M)

BAA	Regulation	Spin	Non-Spin	Total
AZPS	$4.11	$1.20	$0.40	$5.71
AVA	$0.89	$0.56	$0.19	$1.64
BCTC	$1.12	$0.00	$0.00	$1.12
BPA	$7.99	$4.27	$1.38	$13.64
CHPD	$0.53	$0.00	$0.00	$0.53
DOPD	$0.40	$0.00	$0.00	$0.40
EPE	$0.85	$0.06	$0.02	$0.93
GCPD	$0.76	$0.00	$0.00	$0.76
IID	$3.70	$2.13	$0.72	$6.55
IPC	$1.76	$0.66	$0.22	$2.64
LDWP	$2.16	$1.18	$0.40	$3.74
NEVP	$3.48	$1.34	$0.45	$5.27
NWE	$3.35	$1.70	$0.56	$5.61
PACE	$4.18	$2.89	$0.98	$8.05
PACW	$1.41	$0.71	$0.24	$2.36
PGE	$1.37	$0.87	$0.29	$2.54
PNM	$3.93	$1.89	$0.63	$6.45
PSCO	$6.85	$3.27	$1.13	$11.25
PSE	$1.75	$1.71	$0.57	$4.03
SCL	$0.57	$0.00	$0.00	$0.57
SMUD	$1.30	$0.19	$0.06	$1.55
SPP	$1.27	$0.43	$0.14	$1.84
SRP	$2.16	$0.45	$0.15	$2.75
TEP	$2.41	$0.49	$0.16	$3.07
TID	$0.49	$0.00	$0.00	$0.49
TPWR	$0.31	$0.00	$0.00	$0.31
Total	$59	$26	$9	$94

5.6.4 WAPA Not Participating in WestConnect Subregional EIM

We also evaluated the effect WAPA nonparticipation would have on a WestConnect subregional EIM. The three WAPA regions modeled constitute 11% of the load, 8% of the wind, and 1% of the solar modeled in WestConnect.

Figure 47 shows the reserve requirements for the WestConnect subregional EIM with and without WAPA compared with the BAU case. Note that the bar labeled “NP WAPA*” includes the standalone requirements for WAPA added to the WestConnect EIM without WAPA so that total requirements for the complete WestConnect can be compared. The bars show the average requirements, and the whiskers show the minimum and maximum values.

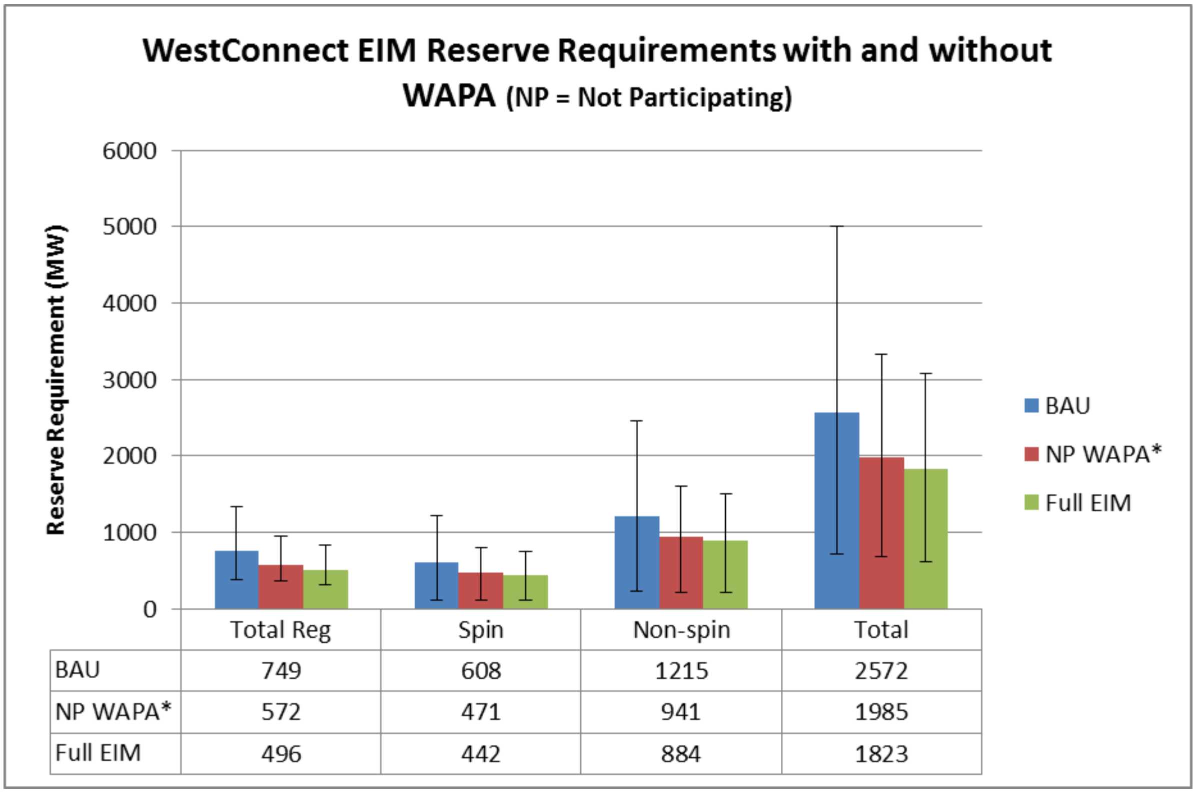


Figure 47. Reserve requirements for WestConnect EIM with and without WAPA participation

Although WAPA sees no benefit when it does not participate, it is interesting to compare the standalone requirements with WAPA's allocation of requirements in the full EIM to see how much savings WAPA would forgo by not participating. Figure 48 compares these values and shows that WAPA potential savings, although modest in absolute numbers, are appreciable as a percentage of its total requirement at about 28%.

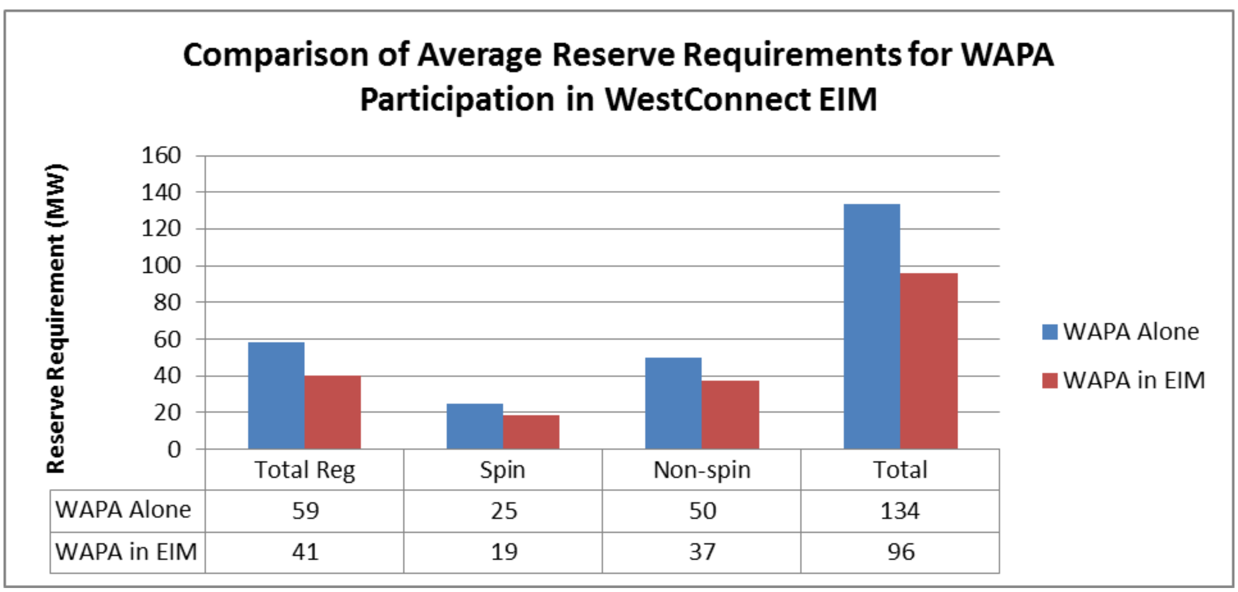
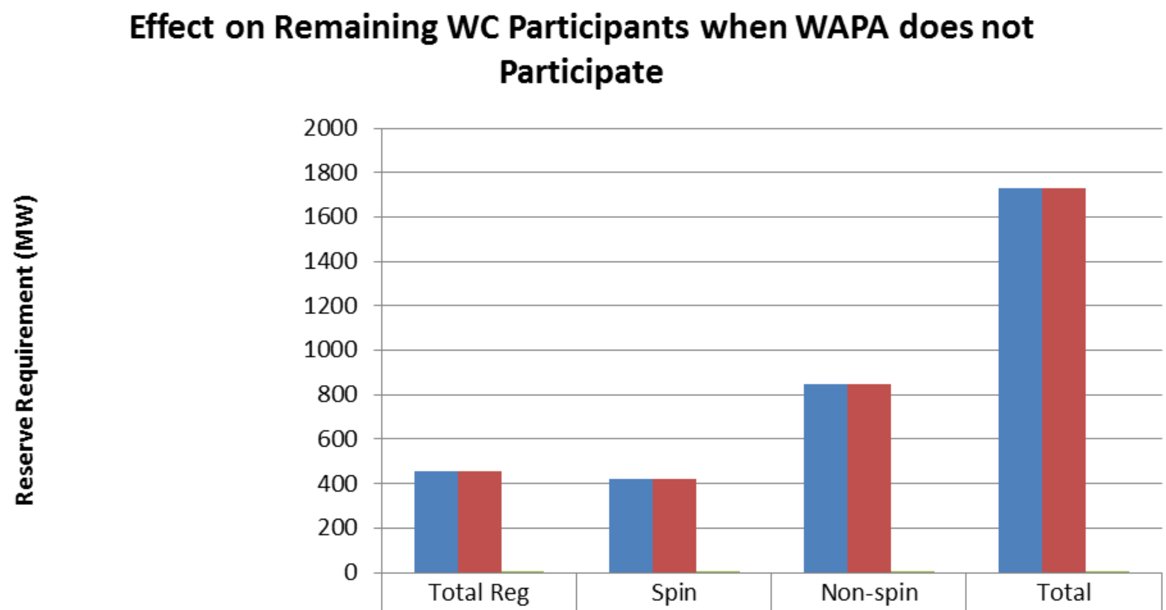


Figure 48. Effect of WAPA participation in WestConnect EIM on WAPA reserve requirements

Although there are impacts on the BAs in the WestConnect subregional EIM when WAPA does not participate, those impacts are quite small—in the single digits. Figure 49 shows the impact.

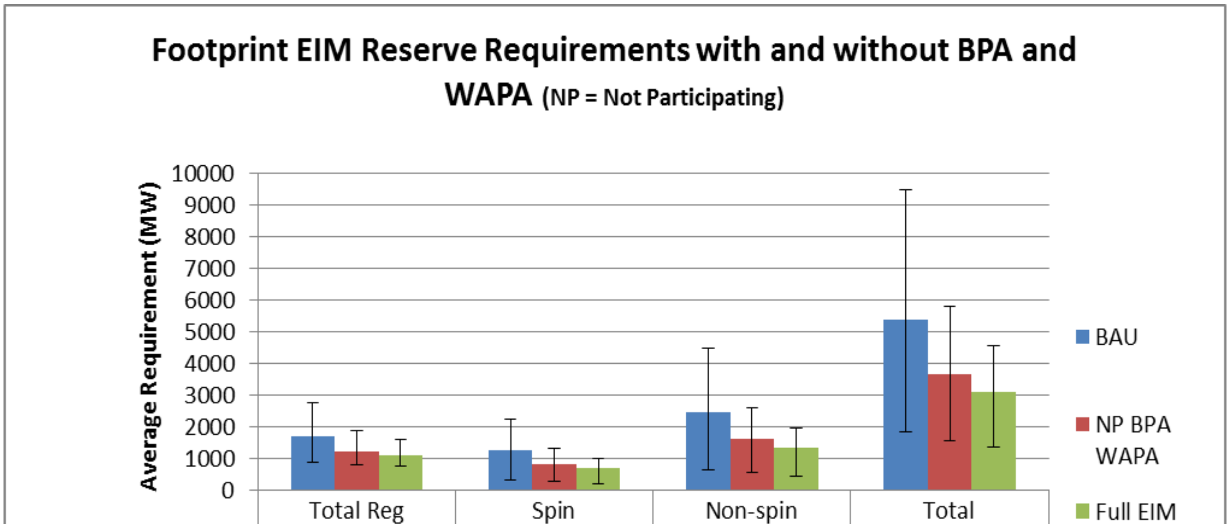


	Total Reg	Spin	Non-spin	Total
Req for Rest of WC WAPA Not Participating	458	424	848	1730
Req for Rest of WC, WAPA Participating	456	424	847	1727
Savings Not Realized	2	0	1	3

Figure 49. Effect of WAPA not participating in WestConnect subregional EIM

5.6.5 BPA and WAPA Not Participating

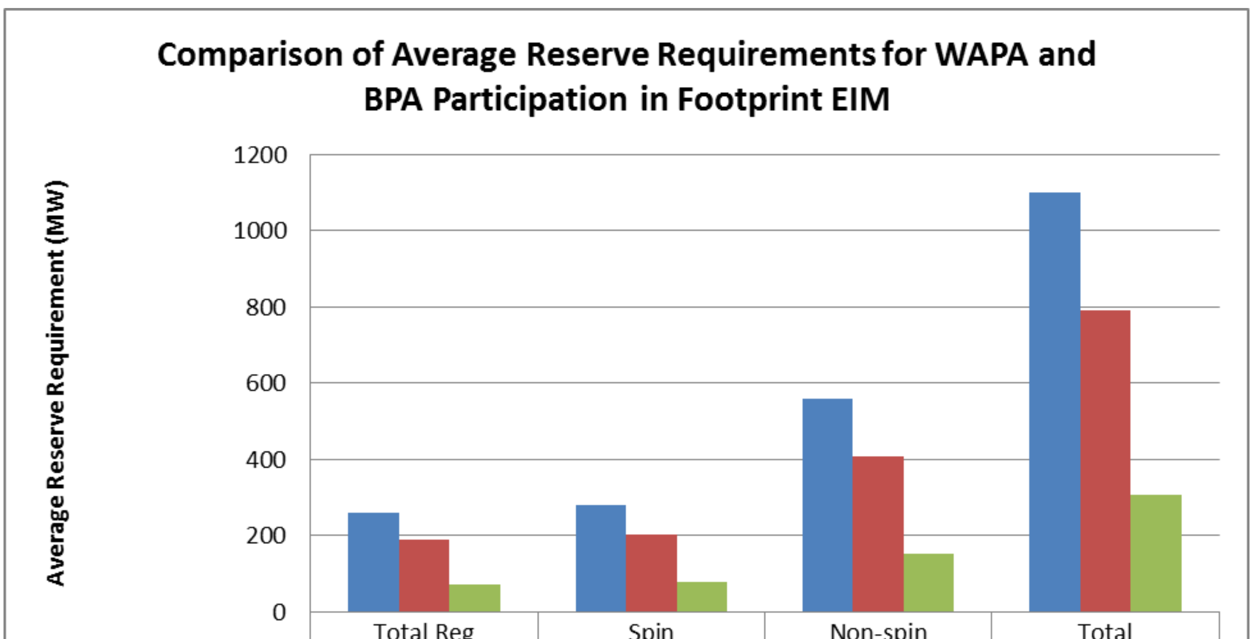
The case in which neither BPA nor WAPA participate in a footprint-wide EIM was also evaluated. These BAAs represent a significant portion of the wind in the entire footprint, with approximately 35% of the total wind resource modeled. Figure 50 shows reserve requirements for the footprint with these two BAAs not participating in the EIM. The bar labeled “NP BPA WAPA” contains the standalone requirements for WAPA and BPA added to the footprint EIM requirements so that the total requirements across the study area can be compared. The bars are the average value, and the whiskers are minimum and maximum values. Although we can see a definite reduction in requirements of the EIM, there still are significant savings for the remaining participants in the EIM.



	Total Reg	Spin	Non-spin	Total
BAU	1669	1230	2460	5359
NP BPA WAPA	1213	812	1624	3649
Full EIM	1076	669	1338	3083

Figure 50. Reserve savings for footprint EIM without BPA or WAPA participation

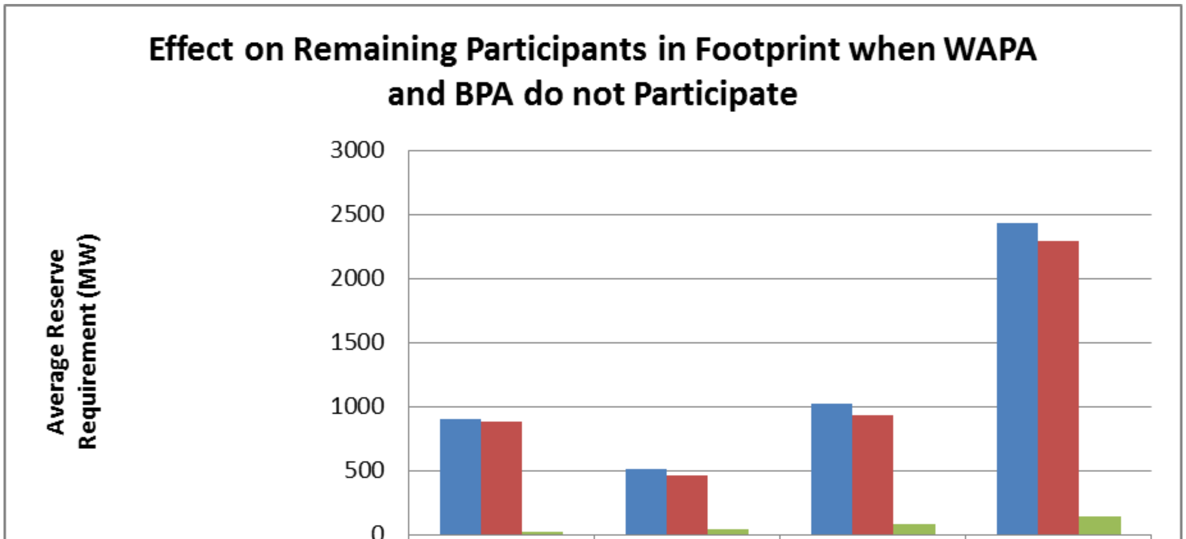
The savings with BPA and WAPA participating in the footprint EIM are roughly the sum of the savings for the individual BAAs seen in the previous two sections. Figure 51 shows a summary of the average reserves for BPA and WAPA both in and out of the footprint EIM.



	Total Reg	Spin	Non-spin	Total
WAPA/BPA Alone	260	280	560	1100
WAPA/BPA in EIM	190	203	407	792
Savings Not Realized	70	77	153	308

Figure 51. Summary of reserves for WAPA and BPA alone and in footprint EIM

Figure 52 shows a summary of the reserve requirements for the footprint EIM with and without BPA and WAPA. This shows a relatively small impact on the participants of the EIM when BPA and WAPA do not participate.



	Total Reg	Spin	Non-spin	Total
Req for Rest of FP WAPA/BPA Not Participating	906	508	1017	2432
Req for Rest of FP WAPA,BPA Participating	886	466	931	2291
Savings Not Realized	20	42	86	141

Figure 52. Effect on remaining footprint EIM participants with and without BPA and WAPA

Figure 53 shows the allocation of average total reserves and average regulation for the footprint EIM without participation of BPA and WAPA. The method for calculating these allocations is discussed in Section 4.3. Tabular data for this figure can be found in Appendix A in Table 30.

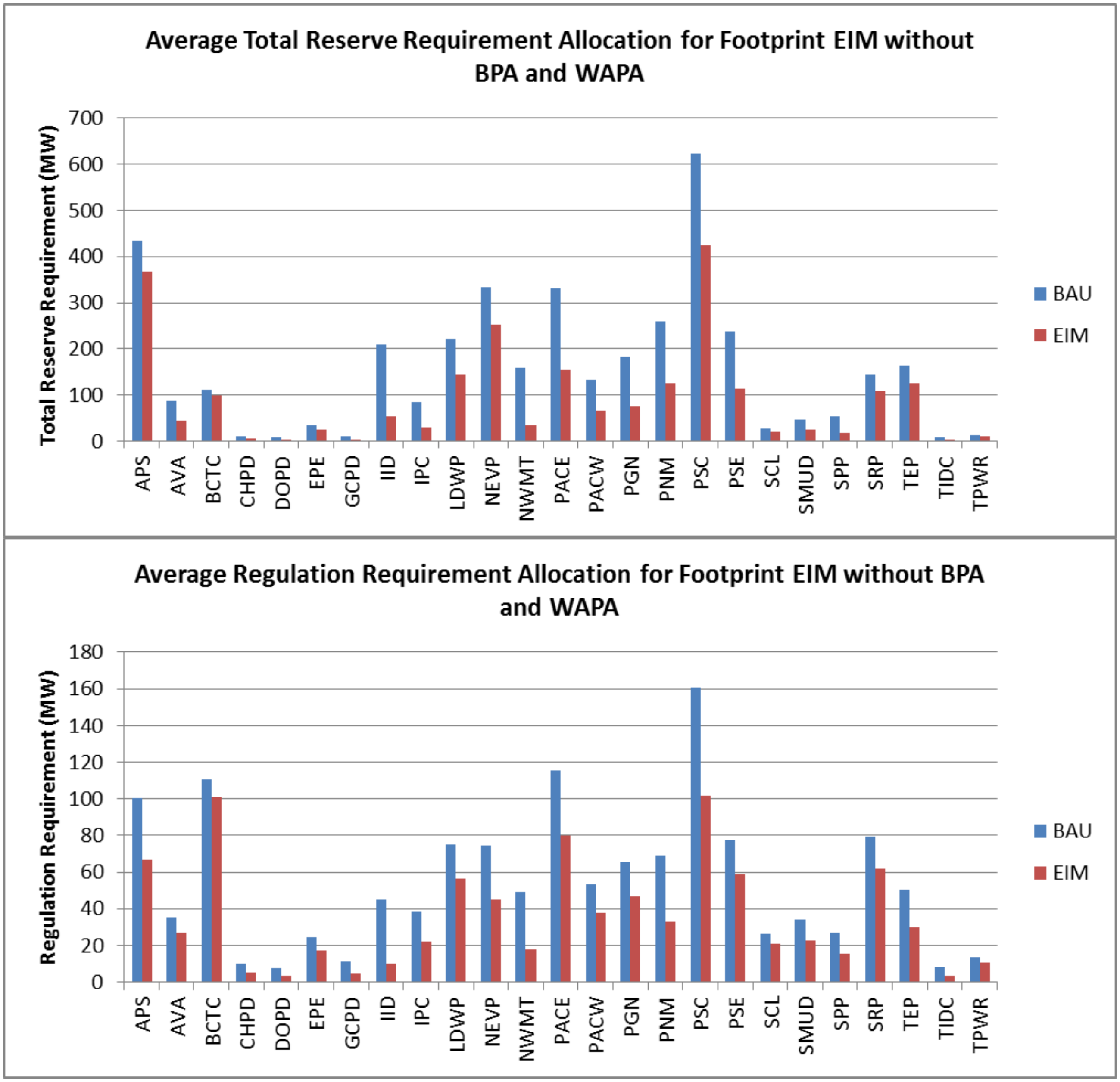


Figure 53. Allocation of reserves in footprint EIM without BPA and WAPA participation

The value of the reserve savings was calculated using the prices shown in Table 11. These reserve savings are shown in Table 19 for each BA participating in the EIM. The savings for this footprint are approximately $77 M. By comparison, the full-footprint savings for the BAs included in this reduced footprint are approximately $83 M. This indicates that the nonparticipation of BPA and WAPA costs the remaining participants about $6 M in potential savings.

Table 19. Value of Annual Reserve Savings for Footprint EIM Without BPA and WAPA ($M)

BAA	Regulation	Spin	Non-Spin	Total
AZPS	$3.59	$0.62	$0.21	$4.42
AVA	$0.92	$0.61	$0.21	$1.74
BCTC	$1.03	$0.00	$0.00	$1.03
CHPD	$0.53	$0.00	$0.00	$0.53
DOPD	$0.40	$0.00	$0.00	$0.40
EPE	$0.78	$0.04	$0.01	$0.84
GCPD	$0.75	$0.00	$0.00	$0.75
IID	$3.66	$2.23	$0.74	$6.64
IPC	$1.72	$0.75	$0.25	$2.73
LDWP	$1.92	$1.17	$0.39	$3.48
NEVP	$3.10	$0.92	$0.31	$4.33
NWE	$3.27	$1.82	$0.61	$5.70
PACE	$3.77	$2.77	$0.92	$7.47
PACW	$1.61	$0.97	$0.32	$2.90
PGE	$1.99	$1.71	$0.57	$4.26
PNM	$3.77	$1.89	$0.63	$6.28
PSCO	$6.25	$2.67	$0.89	$9.81
PSE	$1.93	$1.97	$0.66	$4.55
SCL	$0.58	$0.00	$0.00	$0.58
SMUD	$1.18	$0.20	$0.07	$1.45
SPP	$1.22	$0.46	$0.15	$1.83
SRP	$1.79	$0.39	$0.13	$2.30
TEP	$2.20	$0.31	$0.10	$2.62
TID	$0.48	$0.00	$0.00	$0.48
TPWR	$0.31	$0.00	$0.00	$0.31
Total	$48.74	$21.49	$7.17	$77.40

6 Comparison With a 30% Wind Energy Penetration

Comparing these results with the earlier Western Wind and Solar Integration Study 30% wind energy scenario [10], savings are significantly less for the 8% wind/3% solar case, as we would expect. Said another way, the EIM benefits would grow significantly with increasing penetrations of wind and solar energy. The Western Wind and Solar Integration Study scenario has nearly three times the VG (all wind) than the TEPPC 2020 PC0 case. The footprint EIM reserve reductions (in average megawatts) ranged from 51% to 54% for the Western Wind and Solar Integration Study scenario and from 35% to 42% for the TEPPC 2020 PC0 scenario. Table 20 shows a summary of the results from the earlier Western Wind and Solar Integration Study analysis. It is clear from these two studies that the reserve savings are very sensitive to the level of wind and/or solar build-out represented by the study.

Table 20. Summary of Results From Western Wind and Solar Integration Study Data Analysis: Average Megawatts

		Footprint EIM		Subregional EIM	
	BAU	EIM	Reduction	EIM	Reduction
Regulation	2440	1198	51%	1547	37%
Spin	2096	969	54%	1420	32%
Non-Spin	4192	1938	54%	2840	32%
Total	8729	4105	53%	5807	33%

We also calculated the value of the reserve reductions by using the vector allocations described in Section 4.3 to each class of reserve and applying the prices in Table 11 to the savings. The values in Table 21 are the results of these calculations. This shows that, for the 30% wind penetration case, a total of $221 million/year could be saved with the implementation of the EIM. This table can be compared with Table 12 for TEPPC 11% penetration data, where the potential EIM reserve savings were found to be $103 million/year.

Table 21. Estimated Value of Annual Reserve Savings for Western Wind and Solar Integration Study Data Analysis Full EIM Case ($M)

BAA	Regulation	Spin	Non-Spin	Total
AVA	$2.87	$1.59	$0.53	$4.99
AZPS	$16.99	$8.50	$2.83	$28.32
BCTC	$2.59	$0.00	$0.00	$2.59
BPA	$17.39	$10.25	$3.42	$31.05
CHPD	$1.19	$0.54	$0.18	$1.91
COPD	$0.97	$0.00	$0.00	$0.97
DOPD	$0.49	$0.00	$0.00	$0.49
EPE	$1.32	$0.48	$0.16	$1.96
GCPD	$2.57	$1.23	$0.41	$4.21
IID	$0.72	$0.09	$0.03	$0.83
IPC	$5.68	$3.76	$1.25	$10.69
NEVP	$3.81	$1.81	$0.60	$6.23
NWEA	$3.00	$1.55	$0.52	$5.07
PACE	$11.29	$7.73	$2.58	$21.60
PACW	$4.34	$2.41	$0.80	$7.56
PGE	$2.31	$0.70	$0.23	$3.24
PNM	$9.48	$6.11	$2.04	$17.62
PSCO	$7.72	$4.90	$1.63	$14.25
PSE	$1.35	$0.10	$0.03	$1.48
SCL	$0.86	$0.00	$0.00	$0.86
SMUD	$4.84	$2.77	$0.92	$8.54
SPP	$6.39	$3.75	$1.25	$11.39
SRP	$2.96	$0.55	$0.18	$3.69
TEP	$1.53	$0.00	$0.00	$1.53
TID	$0.88	$0.18	$0.06	$1.12
TPWR	$0.62	$0.00	$0.00	$0.62
WACM	$11.68	$7.09	$2.36	$21.13
WALC	$1.56	$0.74	$0.25	$2.54
WAUW	$3.17	$1.27	$0.42	$4.87
Total	$130.57	$68.09	$22.70	$221.36

These calculations were also carried out for the Western Wind and Solar Integration Study 30% scenario with BPA and WAPA not participating in the EIM. Table 22 shows the allocated savings for each participating BA. These data can be compared with the TEPPC 11% case shown in Table 19, where the potential savings were $77 million/year. Regardless of wind power and solar power penetration, the results show a significant reduction in benefits without the participation of the power marketing administrations, including WAPA and BPA; and of course, the administrations receive no additional benefit from the EIM if they do not participate.

Table 22. Estimated Value of Annual Reserve Savings for Western Wind and Solar Integration Study Data Analysis EIM Case Without BPA and WAPA

BAA	Regulation	Spin	Non-Spin	Total
AVA	$2.82	$1.61	$0.54	$4.96
AZPS	$14.22	$4.41	$1.47	$20.10
BCTC	$2.19	$0.00	$0.00	$2.19
CHPD	$1.20	$0.46	$0.15	$1.81
COPD	$0.96	$0.00	$0.00	$0.96
DOPD	$0.49	$0.00	$0.00	$0.49
EPE	$1.25	$0.37	$0.12	$1.74
GCPD	$2.55	$1.15	$0.38	$4.09
IID	$0.66	$0.09	$0.03	$0.79
IPC	$5.51	$3.40	$1.13	$10.04
NEVP	$3.48	$1.66	$0.55	$5.69
NWEA	$2.99	$1.65	$0.55	$5.19
PACE	$9.96	$5.77	$1.92	$17.66
PACW	$4.22	$2.36	$0.79	$7.37
PGE	$2.16	$0.63	$0.21	$3.00
PNM	$9.05	$5.34	$1.78	$16.17
PSCO	$7.28	$4.64	$1.55	$13.46
PSE	$1.21	$0.12	$0.04	$1.37
SCL	$0.80	$0.00	$0.00	$0.80
SMUD	$4.69	$2.73	$0.91	$8.33
SPP	$6.20	$3.48	$1.16	$10.83
SRP	$2.62	$0.53	$0.18	$3.33
TEP	$1.41	$0.00	$0.00	$1.41
TID	$0.86	$0.17	$0.06	$1.08
TPWR	$0.60	$0.00	$0.00	$0.60
Total	$89.36	$40.57	$13.52	$143.46

7 Conclusions

This report examines several alternative implementations of the proposed EIM in the nonmarket areas of the Western Interconnection. We adapt the reserves method from the Eastern Wind Integration and Transmission Study to analyze the implications of these alternative market structures on the flexibility reserve requirements for the EIM and its participants. This method is extended to include solar generation. Although we use standard deviation as the variability metric, our approach could easily be adapted to non-normal distributions. We also adapt a vector allocation method for allocation of variability to the participants of the EIM. This method possesses characteristics that lead to a fair allocation of reserves.

Our analysis focuses only on the ramping and flexibility reserve impacts of the EIM. We do not consider or evaluate production costs, nor do we consider the costs to establish or operate the EIM. The flexibility reserve calculations in this report do not consider transmission limitations that might affect the delivery of an EIM transaction across congested interfaces. The flexibility reserves that we calculate here were used as inputs to the WECC benefit study and are also input to production simulation modeling, using the Plexos production simulation model, currently under way through a partnership between NREL and Energy

Exemplar. Both the WECC and Plexos analyses incorporate transmission constraints into the production simulations. The flexibility reserve calculations in this report establish the need for these reserves, and the production simulation provides a means of evaluating whether the demand for energy and reserves can be met.

The proposed EIM includes two independent beneficial changes in operating practices: subhourly scheduling and inter-BA coordination. Half of the load in the country is served in regions with 5-min markets. This includes PJM, MISO, ERCOT, New York Independent System Operator (NYISO), Independent System Operator – New England, and California Independent System Operator. It is therefore likely that there are no real technical barriers to implementing 5-min scheduling in the rest of the Western Interconnection, too. Inter-BA cooperation has been practiced for decades with contingency reserve sharing pools and energy transactions. The EIM simply extends this concept through an automated imbalance market.

Based on our analysis, we conclude that full participation of all BAs would result in maximum benefit across the interconnection—as much as a 46% reduction in requirements for some reserve classes. Lesser participation levels (which include subregional implementations of the EIM) and several exclusions (BPA and Western) will still improve on the BAU case but will fail to achieve the maximum benefit of the full-participation scenario, especially for the nonparticipants.

Table 23 shows a summary of the reserve savings, comparing the footprint EIM and the subregional EIM with the BAU case. The subregional EIM implementation results in 10% less savings across the complete study footprint.

Table 23. Summary of EIM Benefits to Footprint and Subregional EIM Implementations

	BAU (MW)	Footprint EIM			Subregional EIM		
		EIM (MW)	Reduction Over BAU (MW)	% Savings	EIMs (MW)	Reduction Over BAU (MW)	% Savings
Total Regulation	1669	1076	592	35%	1250	419	25%
Spin	1230	669	561	46%	933	297	24%
Non-Spin	2460	1338	1122	46%	1865	594	24%
Total	5359	3083	2275	42%	4048	1311	24%

The participating BAs will capture 70% to 90% of the benefits of reduced reserves if BPA or WAPA are unable to participate, but the excluded BA will forgo a 44% (for WAPA) or 32% (for BPA) savings in a footprint EIM. We recognize there may be various institutional impediments to a full EIM implementation, but the results of our analysis suggest that potential participants should undertake a careful cost-benefit analysis to determine whether it may be economically efficient to implement institutional changes that can help move toward a full EIM implementation. Expanding the EIM to the full Western Interconnection may be possible in the future and would result in additional savings.

Realizing that our cost benefits are order-of-magnitude and depend on how the reserve obligations and deployment would be allocated under the EIM, our analysis points out some important insights. The reserve reduction, along with the reserve cost savings, depend on the level of market participation and the size of the footprint, along with the penetration of VG. Because the future build-out of wind power and solar power facilities is unknown, reliance on a single-point estimate of the EIM benefit may not provide a robust view of the potential benefit of the EIM.

Finally, we note that the proposed EIM does not consider coordinated unit commitment. We believe that, over time, participants will conclude that some form of coordinated commitment will achieve additional savings, although additional analysis would be needed to determine these impacts. Partial coordination of unit commitment may occur naturally as participants learn to anticipate what generation is likely to be available from other BAAs tomorrow through the EIM and then incorporate those expectations into their own unit commitment. Participants may engage in bilateral contracts to add certainty to those expectations. Firm transmission may be necessary to fully capture the benefits of coordinated unit commitment.

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Appendix A: Reserve Savings Data Tables

This appendix provides the source reserve savings data for the reserve values calculations referenced in this report. Table 11 provides the hourly prices used for value calculations in this report. Other price assumptions can be evaluated using these tables by multiplying the average hourly savings given by the assumed price for each service and then by 8760 to annualize. The total savings can be calculated as the sum of savings for regulation, spin, and non-spin categories.

Table 24 shows the average hourly megawatt reserve savings allocated to each BAA in the full EIM footprint. These values were calculated by applying the vector allocation method described in Section 4.3 to the participants of the EIM and subtracting the EIM allocated values from the before-EIM allocated values. These values where used to calculate the value data in Table 12.

Table 24. Average Hourly Reserve Savings for TEPPC Full EIM Case (MW)

BAA	Regulation	Spin	Non-Spin	Total
AZPS	39	24	48	112
AVA	9	12	23	44
BCTC	11	0	0	12
BPA	78	85	169	342
CHPD	5	0	0	5
DOPD	4	0	0	4
EPE	8	1	2	11
GCPD	7	0	0	7
IID	35	45	90	172
IPC	17	14	28	59
LDWP	21	26	52	99
NEVP	33	26	52	113
NWE	32	37	73	142
PACE	40	63	126	229
PACW	14	15	30	58
PGE	13	18	36	68
PNM	37	41	81	160
PSCO	64	71	141	278
PSE	17	36	73	126
SCL	6	0	0	6
SMUD	12	4	8	23
SPP	12	9	18	38
SRP	20	9	19	48
TEP	23	10	20	54
TID	5	0	0	5
TPWR	3	0	0	3
WACM	22	14	27	63
WALC	14	2	5	21
WAUW	5	0	0	5

Table 25 shows the average reserve megawatt hourly savings for the Columbia Grid EIM case with full participation. These values were used to calculate the data in Table 13.

Table 25. Average Hourly Reserve Savings for Columbia Grid EIM Case

BAA	Regulation	Spin	Non-Spin	Total
AVA	12	8	16	36
BPA	17	8	17	41
CHPD	7	0	0	7
DOPD	5	0	0	5
GCPD	7	0	0	7
PSE	21	25	50	97
SCL	11	0	0	12
TPWR	7	0	0	7

Table 26 shows the average reserve megawatt hourly savings for the NTTG subregional EIM case with full participation. These values were used to calculate the data in Table 14.

Table 26. Average Hourly Reserve Savings for NTTG EIM Case

BAA	Regulation	Spin	Non-Spin	Total
IPC	15	12	23	50
NWE	24	23	46	94
PACE	19	20	39	81
PACW	10	14	28	53
PGE	15	20	41	76

Table 27 shows the average reserve megawatt hourly savings for the WestConnect subregional EIM case with full participation. These values were used to calculate the data in Table 15.

Table 27. Average Hourly Reserve Savings for WestConnect EIM Case

BAA	Regulation	Spin	Non-Spin	Total
AZPS	19	7	14	40
EPE	8	0	1	9
IID	32	42	84	161
NEVP	21	16	32	69
PNM	31	32	63	127
PSCO	40	31	61	134
SMUD	14	4	8	26
SPP	14	9	17	40
SRP	17	6	12	35
TEP	16	3	6	25
TID	5	0	0	5
WAPA	18	6	13	38

Table 28 shows the average reserve megawatt hourly savings for the TEPPC footprint EIM case without BPA participation. These values were used to calculate the data in Table 17.

Table 28. Average Hourly Reserve Savings for TEPPC EIM Case Without BPA (MW)

BAA	Regulation	Spin	Non-Spin	Total
AZPS	34	11	23	67
AVA	9	11	22	42
BCTC	11	0	0	11
BPA	5	0	0	5
CHPD	4	0	0	4
DOPD	7	1	1	10
EPE	7	0	0	7
GCPD	35	40	79	157
IID	16	13	26	55
IPC	18	21	41	81
LDWP	30	18	35	83
NEVP	31	31	62	125
NWE	36	47	94	178
PACE	16	17	35	68
PACW	19	30	60	109
PGE	36	32	64	134
PNM	58	42	83	190
PSCO	19	36	71	126
PSE	6	0	0	6
SCL	11	3	7	21
SMUD	12	8	16	36
SPP	16	7	13	36
SRP	21	6	12	39
TEP	5	0	0	5
TID	3	0	0	3
TPWR	20	10	21	52
WACM	13	2	3	18
WALC	5	0	0	5

Table 29 shows average megawatt hourly savings for the TEPPC footprint EIM case without WAPA participation. These values were used to calculate the data in Table 18.

Table 29. Average Hourly Reserve Savings for TEPPC EIM Case Without WAPA (MW)

BAA	Regulation	Spin	Non-Spin	Total
AZPS	39	23	46	109
AVA	8	11	21	41
BCTC	11	0	0	11
BPA	76	81	157	319
CHPD	5	0	0	5
DOPD	4	0	0	4
EPE	8	1	2	11
GCPD	7	0	0	7
IID	35	41	82	159
IPC	17	12	25	54
LDWP	21	22	45	89
NEVP	33	26	51	111
NWE	32	32	64	128
PACE	40	55	112	207
PACW	13	13	27	54
PGE	13	17	33	63
PNM	37	36	72	146
PSCO	65	62	129	262
PSE	17	33	65	114
SCL	5	0	0	6
SMUD	12	4	7	23
SPP	12	8	16	36
SRP	21	9	17	46
TEP	23	9	19	51
TID	5	0	0	5
TPWR	3	0	0	3

Table 30 shows the megawatt hourly savings for the EIM implementation if BPA and WAPA do not participate. These values were used to calculate the values in Table 19.

Table 30. Average Hourly Reserve Savings for TEPPC Full EIM Case Without BPA and WAPA (MW)

BAA	Regulation	Spin	Non-Spin	Total
AZPS	34	12	24	69
AVA	9	12	24	44
BCTC	10	0	0	11
CHPD	5	0	0	5
DOPD	4	0	0	4
EPE	7	1	2	10
GCPD	7	0	0	7
IID	35	42	85	166
IPC	16	14	29	59
LDWP	18	22	45	85
NEVP	30	18	35	82
NWE	31	35	69	136
PACE	36	53	106	195
PACW	15	19	37	71
PGE	19	32	65	117
PNM	36	36	72	145
PSCO	59	51	102	220
PSE	18	37	75	132
SCL	6	0	0	6
SMUD	11	4	7	23
SPP	12	9	17	38
SRP	17	7	15	39
TEP	21	6	12	39
TID	5	0	0	5
TPWR	3	0	0	3

Appendix B: VG Penetration by BAA

BAA	Load			Wind			Solar			Total VG			VG Penetration	
	Min (MW)	Avg (MW)	Max (MW)	Avg (MW)	Max (MW)	CF (%)	Avg (MW)	Max (MW)	CF (%)	Avg (MW)	Max (MW)	CF (%)	Avg (%)	Max (%)
AZPS	2550	4100	8410	58	173	34%	371	1293	29%	429	1464	29%	10%	46%
AVA	1041	1715	2882	105	323	32%	0	0	0%	105	323	32%	6%	28%
BCTC	5091	7194	11393	0	0	0%	0	0	0%	0	0	0%	0%	0%
BPA	4748	6577	10377	1909	6693	29%	0	0	0%	1909	6693	29%	29%	126%
CHPD	323	464	719	0	0	0%	0	0	0%	0	0	0%	0%	0%
DOPD	100	244	466	0	0	0%	0	0	0%	0	0	0%	0%	0%
EPE	794	1215	2135	0	0	0%	9	44	22%	9	44	22%	1%	4%
GCPD	352	592	877	0	0	0%	0	0	0%	0	0	0%	0%	0%
IID	231	537	1243	219	857	26%	0	0	0%	219	857	26%	47%	300%
IPC	1280	2233	4043	101	330	31%	0	0	0%	101	330	31%	5%	20%
LDWP	2171	3712	6778	210	585	36%	74	321	23%	285	848	34%	8%	25%
NEVP	1893	3224	6603	0	0	0%	281	835	34%	281	835	34%	8%	36%
NWE	864	1307	1875	298	833	36%	0	0	0%	298	833	36%	23%	82%
PACE	4685	6387	10548	814	1973	41%	0	0	0%	814	1973	41%	13%	38%
PACW	1311	2361	3904	174	630	28%	2	9	18%	176	635	28%	8%	42%
PGE	1488	2681	4294	230	805	29%	2	11	18%	232	813	29%	9%	47%
PNM	1346	1846	2886	269	749	36%	76	257	30%	345	1001	35%	19%	62%
PSCO	3859	5651	9339	886	2880	31%	242	1000	24%	1128	3782	30%	20%	74%
PSE	1829	3010	5365	345	1067	32%	0	0	0%	345	1067	32%	12%	54%
SCL	766	1243	1924	0	0	0%	0	0	0%	0	0	0%	0%	0%
SMUD	1305	2111	4802	19	104	18%	0	0	0%	19	104	18%	1%	6%
SPP	1060	1453	2155	40	150	26%	0	0	0%	40	150	26%	3%	13%
SRP	2610	4599	8800	38	127	30%	62	165	38%	100	290	35%	2%	8%
TEP	1123	1877	3677	12	50	25%	106	494	22%	119	543	22%	6%	38%
TID	215	358	793	0	0	0%	0	0	0%	0	0	0%	0%	0%
TPWR	352	618	1035	0	0	0%	0	0	0%	0	0	0%	0%	0%
WACM	2586	3388	4678	131	420	31%	6	30	20%	137	444	31%	4%	15%
WALC	409	860	1591	0	0	0%	17	87	20%	17	87	20%	2%	14%
WAUW	22	72	128	0	0	0%	0	0	0%	0	0	0%	0%	0%