THE STATE-LED MARKET STUDY

ROADMAP *Technical Report*

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About the Study and Roadmap

The U.S. Department of Energy awarded the State Energy Offices of Utah (lead recipient), Idaho, Colorado, and Montana (sub-recipients) a State Energy Program Competitive award (FOA-0001644) to facilitate a state-led assessment of organized market options in the West. The goal of the project was to provide Western states with a neutral forum, and neutral analysis, to evaluate generic market expansion options while enhancing regional dialog on the matter. A project "Lead Team" was formed to provide input and help guide the study process. The Lead Team was composed of representatives from the grant recipient states and from other Western states that elected to participate (Arizona, California, New Mexico, Nevada, Oregon, Washington, and Wyoming). Additionally, public stakeholder meetings were held on a quarterly basis to provide project updates and solicit stakeholder feedback. Energy Strategies was selected as the technical consultant to perform the study.

The study work culminated in a final "Roadmap," which is organized into two companion reports:

1. The Technical Report, which provides states with an independent, neutral, and state-specific technical evaluation of potential market outcomes that consider both services offered and footprint alternatives; and
2. The Market and Regulatory Review Report, which evaluates how different potential market structures might facilitate achievement of each state's energy policy objectives and how the market constructs may impact state jurisdiction in key areas.

Acknowledgments

The project team thanks the Western Interstate Energy Board for providing logistical support for several of the project's public stakeholder meetings.

Disclaimers

This publication was prepared based on Energy Strategies' independent study work—sponsored by the Utah Office of Energy Development (OED), sub-recipient states, and the U.S. Department of Energy—and is provided as is with no guarantees of accuracy. There are no warranties or guarantees, express or implied, relating to this work, and neither Energy Strategies, OED, sub-recipient states, Lead Team members, or the U.S. Department of Energy are liable for any damages of any kind attributable to the use of this Roadmap or other project materials. The Roadmap does not represent the views of OED, sub-recipient states, Lead Team members, or the U.S. Department of Energy or their employees.

Technical Report Contents

Notes

- All dollar values in the report are presented in 2018 dollars unless otherwise noted.
- Rounding explains apparent errors in whole number results presented in the text and tables.

1. Executive Summary

Study Background

Most of the nation's demand for electric energy is served by regional transmission organizations (RTOs) or independent system operators (ISOs) that coordinate the balancing of generation and load across multiple utility operating areas, ensuring a system optimized for economics and reliability. These entities control, coordinate, and monitor the electric transmission system in their jurisdictions as neutral, independent authorities under Federal regulation. In the Western United States, only a portion of California's system[1] is managed through one of these organizations—most of the remaining transmission in the West is managed by nearly 40 balancing authorities that rely on inflexible power schedules, bilateral transactions negotiated by buyer and sellers, and a contract path transmission network to facilitate the delivery of resources to load.

The West does, however, have the benefit of existing and planned real-time-only markets – or Energy Imbalance Markets (EIM) – including the Western EIM operated by the California Independent System Operator (CAISO) and the Southwest Power Pool (SPP) Western Energy Imbalance Service Market (WEIS). These markets have demonstrated the scale of benefits organized market frameworks could achieve, generating hundreds of millions of dollars of benefits while providing only a subset of the services typically provided by an RTO or ISO.

Over the years preceding and during this State-Led Market Study, proposals for new Western energy markets included proposals for new RTOs, expanded footprints of existing RTOs, new day-ahead energy markets, and market structures that help facilitate the sharing of capacity resources. Options are continually presented and considered by utilities, as Western states seek to better understand potential benefits, impacts, and tradeoffs of these options. The historic success of the West's real-time markets piqued interest in expanding wholesale markets in both geographic scope and services.

This study, which was funded through a U.S. Department of Energy State Energy Program Competitive Grant awarded to the state energy offices in Utah, Idaho, Colorado, and Montana, had the goal of helping Western states evaluate generic market expansion options while enhancing regional dialog on the matter. Prior to this project, states had little or incomplete information around potential market options. This study filled an important gap by providing a forum for states to independently and jointly evaluate the options and impacts associated with regional market options, while remaining agnostic to the entities that may ultimately provide such services.

The primary goal of the technical modeling portion and this report – which is accompanied by a sister report entitled the Market and Regulatory Review – is to provide states with an independent, neutral, and state-specific technical evaluation of potential market outcomes that considers both services offered and footprint alternatives. These market configurations were selected by Western states to help answer a set of outstanding questions around market formation in the West. In doing so, the study

[1] And a very small portion of Nevada.

considered operational implications of new market formation in the 2020 and 2030 timeframe, including an evaluation of capacity and operational related benefits that could accrue under future market scenarios selected by the states representatives that participated in the project.

Study Setup

The study evaluated real-time, day-ahead, and RTO/ISO markets across a series of potential market footprints. The study leveraged production cost modeling to simulate the operations of the Western grid in 2020 and the 2030 timeframes, attempting to emulate how the system might dispatch generators and utilize transmission under hypothetical market frameworks. By comparing the operational costs of a "business-as-usual" Status Quo scenario with a series of cases designed to represent future market alternatives, the study was able to estimate annual operational benefits associated with new market formation.

Market Constructs Considered in Study

EIM/Real-Time Market

- ✓ Centrally optimized real-time dispatch – *Day-ahead unit commitment not optimized across market participants*
- ✓ Individual transmission tariffs
- ✓ Limited transmission dedicated to real-time market
- ✓ Balancing Authority Area (BAA) boundaries and associated reliability obligations retained
- ✓ Transmission providers retain operational control of transmission

Day-Ahead Market (DAM)

- ✓ Centrally optimized real-time and **day-ahead energy market**
- ✓ Individual transmission tariffs
- ✓ Limited transmission dedicated to market **at assumed rate** (other transactions must pay tariff rate for transmission)
- ✓ BAA boundaries and associated reliability obligations retained
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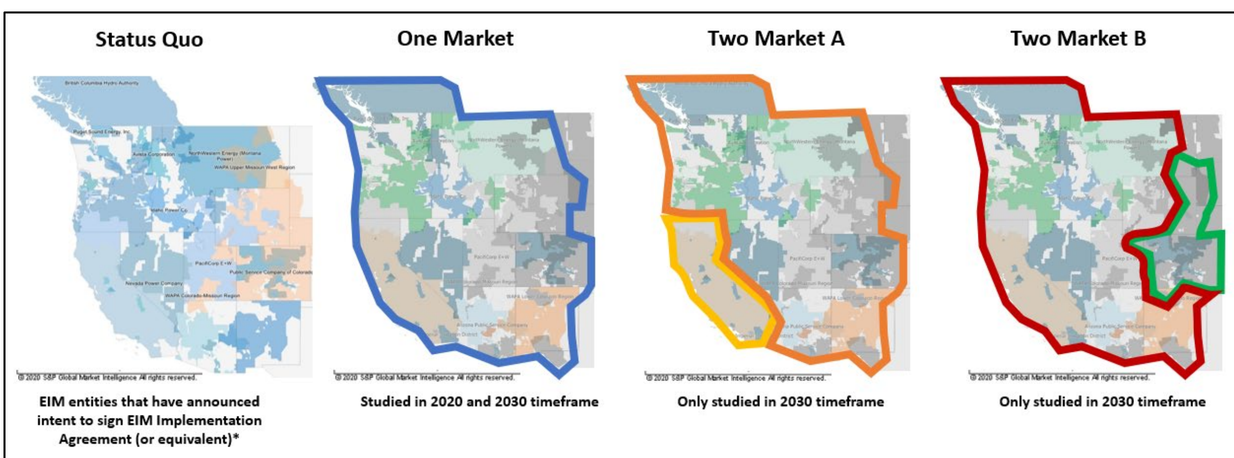
RTO

- ✓ Centrally optimized real-time and day-ahead energy market
- ✓ **Joint transmission tariff** for participants in a given footprint
- ✓ Transmission used **up to reliability limit**
- ✓ BAA boundaries and reliability obligations **consolidated**
- ✓ **Joint transmission planning** and cost allocation
- ✓ Transmission providers **transfer operational control** of transmission

Market Footprints Considered in Study



In addition to the operational benefit analysis, the study evaluated the degree to which new markets could help avoid the procurement or construction of capacity resources by capturing load diversity savings among market participants. In addition to evaluating these benefits, ongoing administrative costs for the market configurations were estimated, helping to add context to the benefit estimates. Importantly, numerous quantifiable and unquantifiable benefits and costs were excluded from the analysis, which was not designed as a "net benefit" study for any given state, utility, or the region.

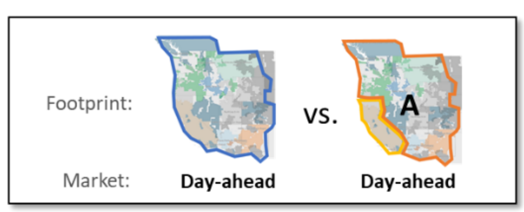
Key Findings

The Western states leading the project developed a series of study-driving questions which were communicated to the contractor via a "Modeling and Analysis Request" document at the onset of the project. In response, a series of market scenarios were evaluated to estimate the benefits and costs described above. Details regarding the questions and responsive analysis, along with supporting assumptions and methodologies, can be found in the body of this document.

Below is a summary of the issues investigated and the findings supported by this study.

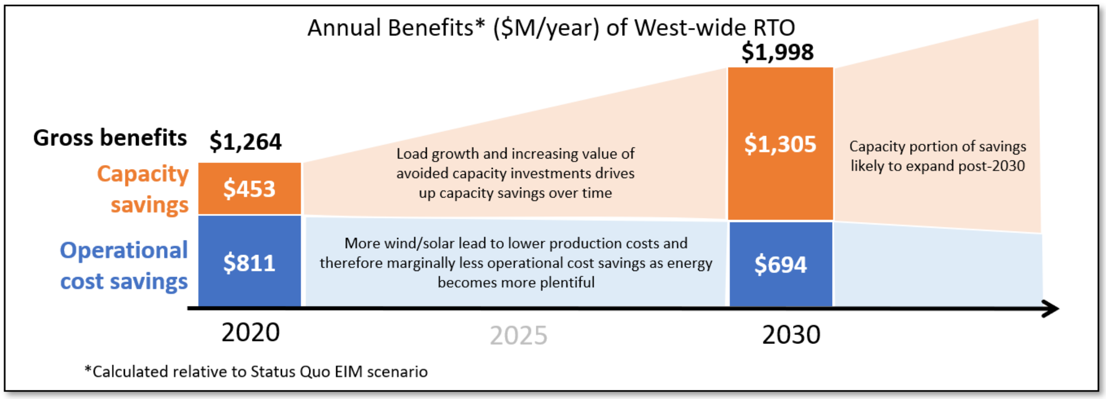
1. ***Expanding current and planned real-time-only markets to include day-ahead market services could result in West-wide annual gross savings of up to $642 million. Such a day-ahead market would involve a day-ahead unit commitment and dispatch optimization and overall market framework that could facilitate significant load diversity savings. However, if these load diversity savings cannot be realized, operational benefits of the transition to a day-ahead market are forecasted to be a more modest $47 million per year. The ongoing administrative cost of such a day-ahead market is estimated at $76 – 226 million per year.***

2. ***The geographic scope – or footprint – of a future day-ahead market could significantly impact benefits achieved. A West-wide day-ahead market could result in $747 million per year of gross benefits, while an outcome with two separate day-ahead market footprints could produce a***



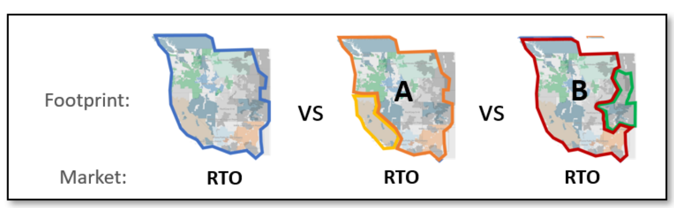
measurably lower $501 million per year of gross benefits.

3. ***The RTO framework is expected to provide increasing levels of gross benefits over time. In the present day, an "overnight" RTO could generate as much as $1.3 billion of benefits annually. However, by 2030, this benefit estimate grows to nearly $2 billion per year. By 2030, capacity savings make up the majority of the overall RTO benefits quantified in this study.***



4. ***Relative to the day-ahead market construct, the RTO framework is expected to provide superior gross benefits. The gross benefits of the RTO are estimated at $2 billion per year, with between $187 – 513 million per year of ongoing administrative costs. The day-ahead construct produces, on the high end, $747 million per year of gross benefits, with estimated ongoing costs of $85 – 254 million per year. While the RTO is likely to be more expensive to implement and is not without regulatory and political challenges, the regional benefits significantly surpass the high-end day-ahead market estimates, even after considering the different costs required to administer the two markets. And the RTO construct offers more certainty that load diversity (capacity) savings can be achieved, while market design will be critical to capturing these savings in a day-ahead market.***

5. ***To assess how RTO benefits changed based on the geographic footprint of the market, the study included three potential RTO configurations. The West-wide RTO market resulted in greater benefits than the two alternative footprints, which were referred to as Two Market A and Two Market B. The West-wide footprint resulted in $569 million greater benefits than Two Market A, and $187 million of greater benefits than Two Market B. Since the costs for market administration were held constant (e.g., operator agnostic), each market construct had the same range of potential ongoing administrative costs, which supports the conclusion that larger markets help to increase system-wide benefits.***



6. ***The study assumed a relatively conservative transmission buildout. To assess how market benefits might change in response to a larger transmission buildout, a sensitivity was run in which several generic high-voltage upgrades were added to the Western system and the Status Quo Real-time, One Market RTO, and Two Market B RTO configurations. The results showed $113 million, $90 million, and $81 million greater operational savings, respectively. These results indicate that the benefits of regional markets are bolstered by transmission expansion. However, these results are <u>not</u> a comprehensive benefits assessment of these incremental transmission projects as many categories of transmission benefits are unquantified in this market study. In addition, the capital costs of the conceptual transmission upgrades were not accounted for in the study. Therefore, the results only demonstrate the additional market related benefits that may accrue in response to additional transmission development.***

7. ***Finally, to understand how market benefits were impacted under a future with a West-wide carbon price, a $41 per metric ton carbon adder was applied to emitting units (while leaving California's carbon price framework unchanged). The results show that RTO benefits are lower under a future with a West-wide carbon price as compared to a future in which no such West-wide carbon price is implemented. Due to the carbon price, operational benefits of the One Market RTO fell by $205 million per year. Similarly, the operational benefits of the Two Market A and Two Market B RTO configurations were $266 million and $105 million per year lower with the carbon price. However, since the carbon price had no impact on the capacity savings of the RTO construct, the total benefits of the RTO constructs with the carbon price were not significantly different that the total benefits without the carbon price.***

In addition to the high-level regional findings, above, the study produced state-level benefit results that, while not sufficient to weigh any specific market proposals, should be useful for states when considering current and future market options. Notably, the benefits outlined above were not distributed equally among the Western states.

The table below presents the sum of the Western states' gross benefits for each market configuration studied, including sensitivities. The benefits are broken out by adjusted production cost savings and capacity savings and are contrasted by an estimated range of potential ongoing market administration costs. All values are annual values for the 2030 study horizon and are calculated relative to the Status Quo Real-time/EIM market configuration scenario.

Gross Benefits of All Study Scenarios

	2030 Scenarios (Footprint + Market Construct)	Total Benefits	= APC Savings	+ Capacity Savings	Admin Cost Range	Carbon Emissions	Curtailments
Core Case	Status Quo Real-time/EIM	$0	$0	$0	$0 - 0	194	2.87%
	Status Quo Day-ahead	$643	$47	$596	$77 - 226	194	2.71%
	One Market Day-ahead	$747	$95	$652	$85 - 254	193	2.62%
	One Market RTO	$1,998	$694	$1,305	$187 - 513	191	1.63%
	Two Market A Day-ahead	$501	$85	$416	$85 - 254	194	2.79%
	Two Market A RTO	$1,430	$598	$831	$187 - 513	192	1.89%
	Two Market B RTO	$1,811	$589	$1,223	$187 - 513	191	1.65%
Sensitivity	One Market RTO *Carbon*	$1,793	$489	$1,305	$187 - 513	159	1.47%
	Two Market A RTO *Carbon*	$1,163	$332	$831	$187 - 513	160	1.76%
	Two Market B RTO *Carbon*	$1,706	$484	$1,223	$187 - 513	161	1.45%
	Status Quo Real-time/EIM *Transmission*	$107	$107	$0	$0 - 0	193	2.47%
	One Market RTO *Transmission*	$2,089	$784	$1,305	$187 - 513	190	1.39%
	Two Market B RTO *Transmission*	$1,892	$670	$1,223	$187 - 513	190	1.43%

Values are in $2018 and million/year and are calculated relative to Status Quo Real-time/EIM — *Million short tons* — *% RE generation*

Details describing each of the 2030 scenario can be found in the body of the report. In addition to state-level benefit results, to help assess the operational implications of the various market configurations, the body of this report contains summaries indicating how generation dispatch, renewable curtailments, carbon emissions, and transmission congestion may be impacted by market formation.

While not a detailed net benefits analysis of a specific and well-developed market option, the findings for the study, at a regional level, generally support the case for new and expanded energy markets in the West. None of the market configurations produced high-end ongoing cost estimates that exceeded the high-end benefit estimates. This was especially the case for market scenarios that featured large footprints with many services, such as the RTO configurations. When the footprint is maximized and resources, loads, and transmission are all optimized within the same market framework, significant benefits for the West can accrue. However, at the same time, the study found that market-enabled load diversity caused major capacity savings to accrue, and there are non-market options that may be capable of achieving some of these capacity benefits, such as a regionally coordinated capacity program that is coupled with an operational program.

2. Introduction

The Utah Office of Energy Development, in partnership with the state energy offices in Colorado, Idaho, and Montana, received a grant from the U.S. Department of Energy to facilitate a state-led assessment of organized energy market options across the Western U.S. The project is referred to as *Exploring Western Organized Market Configurations: A Western States' Study of Coordinated Market Options to Advance State Energy Policies*[2] or the "State-Led Market Study." The objective of the project was to facilitate a neutral forum, and neutral analysis, for Western states to independently and jointly evaluate the options and impacts associated with new or more centralized wholesale energy markets. Eleven Western states participated in the project, including: Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming. The representatives from these states that participated in the project are referred to as the "Lead Team."

This Technical Report summarizes the technical modeling portion of the State-Led Market Study. The report details the analytical methods and assumptions used to estimate the benefits of generic real-time, day-ahead, and RTO/ISO market constructs across hypothetical market footprints.[3] The study relied heavily on a production cost or "dispatch" model that was used to simulate the transmission network and power system operations of the Western power grid to assess potential operational benefits posed by new markets. An analysis of historical hourly load data was also performed to estimates how the market configurations could result in the need to construct fewer capacity resources due to load diversity benefits. In addition to estimating market benefits, the study also provides insight related to market-driven impacts to green-house gas (GHG) emissions, generation dispatch, renewable curtailment, and transmission utilization. The report includes an *Appendix* that covers topics not addressed in the body of this report.

Background

A wide range of wholesale market options have been proposed and continue to be discussed in the West.[4] The term "market configuration" was created during this project to describe the various market options analyzed in this study, as they vary in terms of footprint and scope of energy market offerings. Some proposals focus on extending the day-ahead unit commitment and dispatch functionality of an existing ISO/RTO to other areas, while other proposals involve standardization for exchanging capacity needed for resource adequacy purposes or expanding existing real-time energy markets. There are also market configurations of interest to Western state representatives involved in this project that may not have been previously proposed that should be considered. While the study sought to cast a wide net

[2] This project was originally entitled: *A Western State's Strategic Roadmap for the Coordination and Control of Electric Transmission to Advance Affordable, Reliable Energy.* But it has been renamed to better reflect the changed landscape of Western market development efforts since the original grant application was compiled.
[3] The terms ISO and RTO are used interchangeably within the context of this study.
[4] From the time the initial grant application for this project was submitted (in January 2018) until today, the landscape of proposed market options has shifted significantly. A variety of market options are being discussed and reviewed with far more options on the table than just RTO formation or expansion.

and evaluate many different combinations of market construct and footprints, it was not possible to consider every viable market option.

Study Principles

At the onset of the project, the Lead Team established several guiding principles that were considered in the technical evaluation of the various market configurations, including:

1. **Consideration of Existing and Planned Markets –** The modeling approach acknowledges the presence and plans for existing markets in the West. Given that the Western EIM is already operating in much of the West and that the WEIS is also operational, the focus of this project was on the incremental benefits and considerations associated with new market reforms, such as day-ahead market development, consolidation of transmission tariffs, and development of an RTO (across varying footprints). For this reason, the study features a Status Quo scenario that accounts for all planned or announced participants in the Western EIM and WEIS.[5] At the same time, the study recognizes that real-time market participation is voluntary and not a permanent commitment by current and future utilities. For this reason, the study also estimates incremental benefits associated with other organized market configurations, even if those configurations include footprints or market services that differ from those in the Status Quo scenario.

   The following table summarizes the assumed Status Quo market footprints and the associated market services for the 2020 and 2030 study timeframe. It shows which, if any, markets the West's 39 balancing areas (BAs) are assumed to participate in within the two study timeframes, 2020 and 2030, for the Status Quo scenario.

Figure 1: Assumed Status Quo Market Participation by Balancing Area

Balancing Areas	2020		2030	
	Western EIM	SPP WEIS	Western EIM	SPP WEIS
CAISO	✓		✓	
PacifiCorp	✓		✓	
NV Energy	✓		✓	
Puget Sound Energy	✓		✓	
Arizona Public Service	✓		✓	
Portland General Electric	✓		✓	
Idaho Power	✓		✓	
Powerex	✓		✓	
SMUD (BANC Phase 1)	✓		✓	
Seattle City and Light	✓		✓	
Salt River Project	✓		✓	

[5] Entities that had announced their intention to join the EIM by the end of 2019 were included in the EIM footprint. Thus, entities such as BPA and PNM were included as part of the EIM market for 2030 studies.

Balancing Areas	2020		2030	
	Western EIM	SPP WEIS	Western EIM	SPP WEIS
LADWP			✓	
PNM			✓	
BANC (BANC Phase 2)			✓	
WAPA-Sierra Nevada			✓	
Northwestern Energy			✓	
TID			✓	
Avista			✓	
Tucson Electric Power			✓	
Tacoma Power			✓	
BPA			✓	
PSCO			✓	
WACM & WAUW				✓

All entities that announced plans to join the Western EIM or the SPP WEIS as of January 2020 were assumed to participate in those markets in the 2030 Status Quo scenario. Only active market participants as of the end of 2020 were included in the market footprints for the 2020 Status Quo scenario.

2. **Reflect Achievement of State Energy Policy –** The study assumes a resource mix that reflects statutorily approved and relevant state public utility commission adopted state energy policy. To the extent possible, resource portfolios and power trading constructs were made consistent with these state policies.[6] In addition, cities, municipalities, and certain utilities in the West have voluntary commitments toward cleaner generation fleets. In these instances, modeling assumptions sought to reasonably reflect achievement of most (but not all) of these voluntary goals, accounting for the fact that the commitments are indeed voluntary and may not be met. The following clean energy target assumptions were used to develop the 2030 models. These policies were sourced from information provided by the Lead Team, which is summarized in an appendix to the Market and Regulatory Review (the companion report to this).

[6] Including modeling that reflects the carbon price attributed to imports into the state of California and other similar programs.

Figure 2: 2030 Clean Energy or Renewable Portfolio Standard (RPS) Targets

State	2030 Target (% of annual energy)
Arizona	38% RPS
California	60% RPS
Colorado	31% RPS
Idaho	55% Clean
Montana	18% Clean
Nevada	50% RPS
New Mexico	50% RPS
Oregon	27% RPS
Utah	31% Clean
Washington	80% Clean
Wyoming	No RPS

Omitted from this list are state policies that require a specific greenhouse gas (GHG) reduction, such as Colorado's mandate for 80% GHG reduction by 2030. Since the models used in the study cannot capture these reduction targets as a constraint, the assumed resource portfolio was developed based on resource plans developed the by utilities subject to the GHG standards. Therefore, to the extent utilities in these states are planning to add renewables and other clean energy resources to meet GHG reduction targets, those resources and their operational effects are captured in the study.

Finally, tote that the resource mix was held constant across all market configurations analyzed. Therefore, benefits in this analysis are attributable solely to the market services and not to changes in the resource mix.

3. **Major New Transmission as a Sensitivity –** The Lead Team requested that major new high-voltage transmission upgrades in the West not yet approved be *excluded* from the modeling. This required a process to determine which lines should be deemed "approved" based on explicit and reasonable replicable criteria related to financing, permitting, and other thresholds. Given the significant impact that major transmission upgrades can have on system operations, evaluating benefits of organized market configurations absent this infrastructure is important to project participants. A list of the major proposed transmission projects included in the study is provided in *Section 4 Modeling Assumptions*.

   The Lead Team was also interested in a sensitivity study in which major incremental transmission additions are included in modeling. The intention of modeling incremental transmission is not to associate the benefits of transmission buildout with one market structure or another, but rather was to see how operational benefits change with the addition of more transmission. Significant new transmission additions could have large impacts on projected costs/benefits of regional markets. Finally, because of this market-centric study framework, the

cost of new transmission projects was not considered in the analysis. An overview of the assumed transmission buildout is provided under the *Technical Work Plan* section, below.

4. **Market Provider Agnostic –** The study focuses on the qualities and benefits of different options and does not specifically evaluate details of each proposal and potential market service providers. The project's Market and Regulatory Review – which accompanies this technical report – focuses on the pros and cons and qualities of different market options in supporting several state policy priorities but does not provide a single ranking of market options nor providers of market services. The ambiguous naming convention assigned to each market scenario considered in the technical portion of this project purposefully excludes any mention of a specific market provider (aside from those markets that already exist, such as the Western EIM). In addition, since the study is not focused on the details of market design, generalized techniques were used in the simulation of energy markets. In some cases, the need to generalize the performance of certain market constructs could lead the study to overestimate or underestimate the results as compared to a similar study evaluating a specific market proposal with market design details.

5. **No Work Duplication –** The Lead Team requests that work plans not include analyses of areas where there has already been recent and meaningful work performed in the region. Two examples are market governance and reliability coordinator implications.

The above study principles were used in developing the technical study program, which is covered later in this section.

Key Questions

By combining market constructs and footprints into market configurations across the two study timeframes, the technical modeling performed in this study was able to address a series of key questions developed by the Lead Team. The Lead Team developed these questions to guide the study. Below is a summary of the questions followed by an overview of the study timeframe, market footprints, and market constructs.

Question 1: Assuming no change in market footprints from the Status Quo, what benefits are expected by adding day-ahead energy market services to the West's real-time markets?

The study was able to address this important question because the Status Quo 2030 scenarios assume current and planned levels of real-time market participation. By retaining the same market participant footprints but enhancing the simulated market to include day-ahead functionality, the study evaluated state-level and aggregate benefits of this incremental market service.

Question 2: Assuming a day-ahead market forms, how do the benefits of two market footprints compare with a single market footprint?

This question investigates how the benefits of day-ahead markets change based on the market footprint. The Lead Team developed a market configuration scenario in which two day-ahead markets operate in parallel (and adjacent to each other), which was compared with a future in which the West operates under a single-day ahead market.

Question 3: What is the trajectory of benefits for a West-wide RTO?

The study is positioned to address this question because of several factors. First, the study featured two study horizons – 2020 and 2030 – which allows it to estimate how benefits of a consolidated Western RTO market may grow over time. Second, the study captures the operational implications of the West's changing resource mix over the upcoming years, which means market benefits are adjusted for this important variable. Finally, the study estimates only *incremental* benefits from a current and future Status Quo. Since real-time market participation will be expanded by 2030 (beyond what is in place today), the study captures a realistic view of what incremental benefits a system-wide RTO may offer.

Question 4: How do the benefits of a West-wide RTO compare with a West-wide day-ahead market?

By including 2030 scenarios in which the West forms a single RTO and one in which the West forms a single day-ahead market, the study draws conclusions about the relative benefits of these two market configurations.

Question 5: How are the benefits of an RTO impacted by market footprints?

The Lead Team also developed scenarios that assume two Western RTOs operate in parallel to each other. The benefits of these two scenarios are compared and are also benchmarked against a future in which a single RTO forms to provide insights into this question.

Question 6: How do operational benefits change if more transmission is built?

The 2030 Status Quo scenario assumed a conservative buildout of the future grid to not overestimate market benefits. To answer this question, a transmission sensitivity was developed in which several high-voltage transmission projects are added to the Western system. Market configurations were re-run with this transmission overlay to determine how production cost-related market benefits change when more transmission is built.

Question 7: How sensitive are RTO configurations to a Federal or West-wide carbon pricing regime?

The 2030 Status Quo scenario assumes that California is the only Western state with a carbon allowance program for the electric sector. To assess how market benefits might change if a broader Federal or West-wide carbon pricing regime was implemented, a number of the market scenarios were modified by adding a $41/metric ton carbon price across the West (while keeping California's carbon and import rate unchanged), which has the effect of increasing the

marginal energy cost of emitting generators in the West (especially those with high emission rates) and reducing overall system emissions.

Technical Work Plan

The Contractor developed, and the Lead Team approved, a Technical Modeling Work Plan document as a part of the State-Led Market Study to define how the modeling analysis would be performed to address the questions listed above. The following sections, which address study years, market configurations, and sensitivities, are excerpts from the *Technical Work Plan*.

Study Years

The analysis considered two study years. The year 2020 was designed to represent the present-day system and was selected to ground the analysis based on easily agreed to study assumptions. The year 2030 was evaluated as a longer-term horizon, capturing changes in system conditions due to the implementation of energy policies, new or retired generation, fuel price changes, load growth, and new transmission, among other variables. Importantly, the 2020 and 2030 study years feature different status quo representations of real-time market participation since some utilities will join the Western EIM and the SPP WEIS after 2020. In addition, through sensitivity studies (addressed below) the year 2030 provided the opportunity to assume varying amounts of transmission build.

Market Constructs

It was not possible to evaluate every organized market configuration. However, after significant discussion, three market structures emerged and were selected by the Lead Team for assessment. The three structures are (1) new or expanded real-time markets, (2) a new day-ahead market that retains individual transmission owner transmission tariffs, and (3) a new day-ahead market with a regional transmission tariff (i.e., an RTO). In this Technical Report the three market types evaluated in this study are referred to as "market constructs" and, more specifically, "real-time," "day-ahead," and "RTO" markets. Short descriptions of the features that were assumed for each market are outlined in the figure below.

Figure 3: Features of Market Constructs

EIM/Real-Time Market

- ✓ Centrally optimized real-time dispatch – *Day-ahead unit commitment not optimized across market participants*
- ✓ Individual transmission tariffs
- ✓ Limited transmission dedicated to real-time market
- ✓ Balancing Authority Area (BAA) boundaries and associated reliability obligations retained
- ✓ Transmission providers retain operational control of transmission

Day-Ahead Market (DAM)

- ✓ Centrally optimized real-time and **day-ahead energy market**
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RTO

- ✓ Centrally optimized real-time and day-ahead energy market
- ✓ **Joint transmission tariff** for participants in a given footprint
- ✓ Transmission used **up to reliability limit**
- ✓ BAA boundaries and reliability obligations **consolidated**
- ✓ **Joint transmission planning** and cost allocation
- ✓ Transmission providers **transfer operational control** of transmission

The study was set up to analyze and explore differences among these market constructs and the Status Quo system in which real-time energy market participation occurs based on known plans and announcements. Figure 4 below summarizes key assumptions used to simulate the real-time, day-ahead, and RTO market constructs analyzed in this study effort. Additional details regarding the modeling of each market construct are covered in *Section 3 Analytical Approach*.

Figure 4: Summary of Assumptions for Market Constructs

Assumption	Market Construct		
	Real-time	**Day-ahead**	**RTO**
Real-time intra-market trading costs	No cost for market transactions	$3/MWh for market transactions above real-time market-levels (which are $0/MWh)	No cost for all transactions
Day-ahead intra-market trading costs	Tariff rate + $4	$3/MWh for market transactions	No cost for all transactions
Real-time trading costs for market exports and out-of-market transactions	Tariff rate + $2	Tariff rate + $2	Tariff rate + $2 (exports only)
Day-ahead trading costs for market exports and out-of-market transactions	Tariff rate + $4	Tariff rate + $4	Tariff rate + $4 (exports only)
Transmission available for in-market transactions	~15% of inter-area transfer capability for real-time transactions	~70% of inter-area transfer capability for day-ahead transactions, 15% for real-time	100% of inter-area transfer capability for day-ahead and real-time transactions
CAISO export limit	Real-time: 7,000 MW Day-ahead: 2,000 MW	Real-time: No limit Day-ahead: No limit, except for 2 Market A which has 7,000	Real-time: No limit Day-ahead: No limit, except for 2 Market A which has 7,000
Operating reserves	BA and reserve sharing group obligations retained		BAs consolidated and reserves held across market footprint
Flexibility reserves	BA-level constraint based on sub-hourly demand and wind/solar volatility and forecast error		BAs consolidated and reserves held across market footprint

Study Footprints

The Western Interconnection is home to 39 BAs. As of the date that data was collected for this study, nineteen of these BAs participate or plan to participate in the Western EIM. Those entities that plan to join the Western EIM in 2021 or later were included in Western EIM for the Status Quo footprint in the 2030 study year but not the 2020 study year. These entities have an asterisk in the table below. The SPP WEIS was assumed to include two BAs by the 2030 study period, and no BAs in 2020 since the market was not yet operational. Market participation announcements made after December 2019 are not reflected in the Status Quo case in the study.

Figure 5: Market Footprints

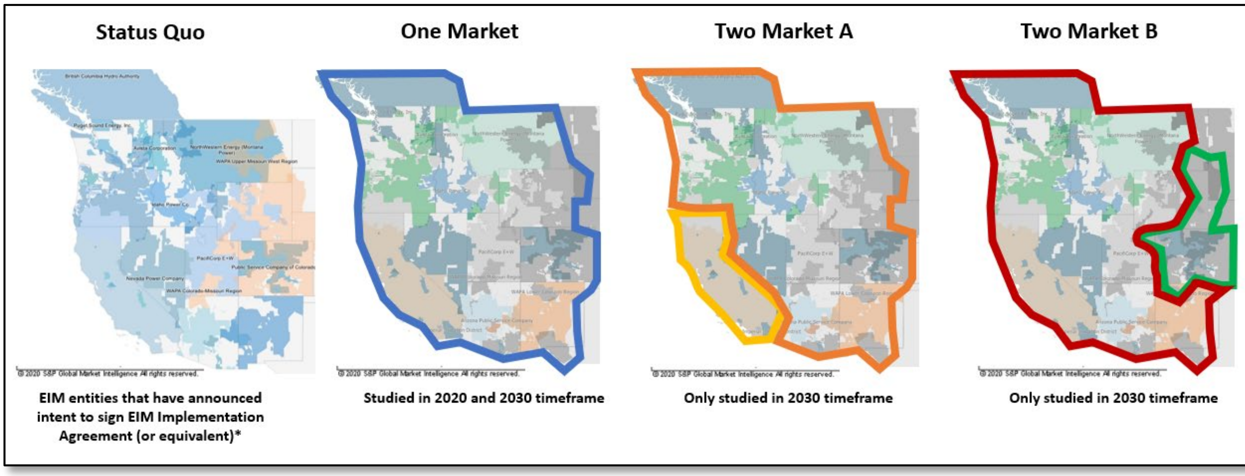
Status-Quo	One Market	Two Market A	Two Market B
CAISO	All WECC Balancing Areas (excluding AESO)	Footprint A1	Footprint B1
PacifiCorp		CAISO	PSCo
NV Energy		BANC	WACM
Puget Sound Energy		TID	WAUW
Arizona Public Service		LADWP	Footprint B2
Portland General Electric		IID	All *remaining* WECC Balancing Areas (excluding AESO)
Idaho Power		Footprint A2	
Powerex		All *remaining* WECC Balancing Areas (excluding AESO)	
SMUD (BANC Phase 1)			
Seattle City and Light			
Salt River Project			
LADWP*			
PNM*			
BANC* (BANC Phase 2)			
WAPA-Sierra Nevada*			
Northwestern Energy*			
TID*			
Avista*			
Tucson Electric Power*			
Tacoma Power*			
BPA*			
PSCO*			
Separate Market for WACM & WAUW*			

**Entities that plan to join the Western EIM in 2021 or later and were included in Western EIM for the Status Quo footprint in the 2030 study year but not the 2020 study year*

The One Market footprint assumed all Western BAs consolidate into a single market footprint, except for AESO, which was assumed to continue to operate its own market in all scenarios. The Two Market A scenario has a footprint that includes all California BAs (Footprint A1) and a footprint that includes the rest of the West (Footprint A2). Two Market B has a footprint that includes BAs from the eastern side of the system (Footprint B1) and a footprint with the rest of the Western BAs (Footprint B2). As outlined

below, the above market constructs were overlaid on these footprints to form a series of market configurations. A summary map presenting these footprints is also below.

Figure 6: Market Footprints



Market Configurations

The lists below outline the market configurations evaluated in the 2020 and 2030 study years.[7] Three market configurations were evaluated for the 2020 study year:

1) Status Quo Real-time only (EIM) – Current market footprints with real-time market operations
2) One Market Real-time only (EIM) – West-wide market footprint with real-time market operations
3) One Market RTO – West-wide market footprint with consolidated RTO tariff

Seven market configurations were studied for the 2030 study year:

1) Status Quo Real-time only (EIM) – Current market footprints with real-time market operations
2) Status Quo Day-ahead – Current market footprints expanded to day-ahead market
3) One Market Day-ahead – West-wide footprint with day-ahead market
4) One Market RTO – West-wide footprint with consolidated RTO tariff
5) Two Market A RTO – Both markets operating under consolidated RTO tariffs
6) Two Market A Day-ahead – Both markets operating under day-ahead market
7) Two Market B RTO – Both markets operating under consolidated RTO tariffs

The market configurations in the list above were referred to as the "core studies" during the project as they were designed to answer most of the questions that motivated the project.

[7] The naming of each study case is based on a footprint - market construct naming nomenclature.

Sensitivities

The study included two sensitivities. Their details and assumptions are described below.

Impact of transmission expansion

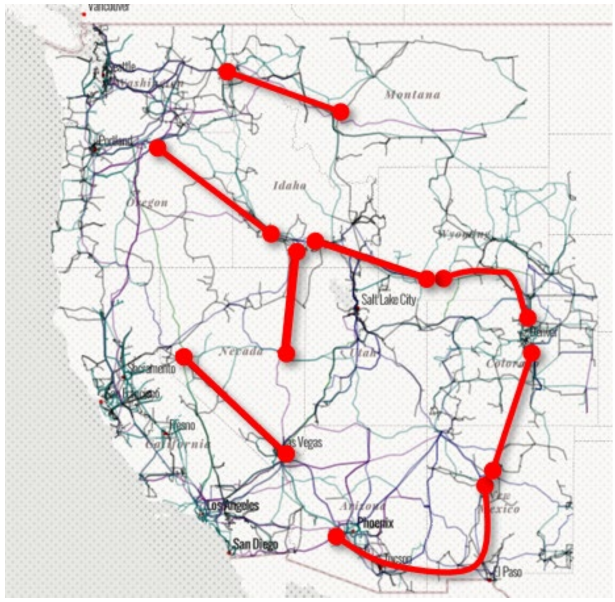
This sensitivity explores how market benefits change if major transmission upgrades, beyond what was included in the core studies, are placed into service before 2030.[8] Since small changes to the transmission system were unlikely to impact the study results, the study assumed a relatively large buildout that could occur by 2030 or beyond. The buildout was developed with the following goals in mind:

- Provide additional transmission capacity between the Intermountain/Pacific Northwest region and the Desert Southwest markets
- Better integrate Colorado into the rest of the Western system with new capacity
- Add transmission to enhance the connection between New Mexico and Desert Southwest markets
- Increase the potential for exports out of Montana

In some cases, real transmission projects previously or currently under development inspired the buildout designed to achieve the above objectives. However, the buildout – outlined in the figure below – does not represent a comprehensive transmission plan nor a preference for a given set of proposed projects and projects were modeled generically and do not represent the exact characteristics of the projects that inspired them.

[8] Notably, the core cases already include the following transmission upgrades: Gateway South, Gateway West Segment D.2, Ten West Link, and other lower voltage projects under-construction or previously approved.

Figure 7: Assumed Transmission Build for Sensitivity

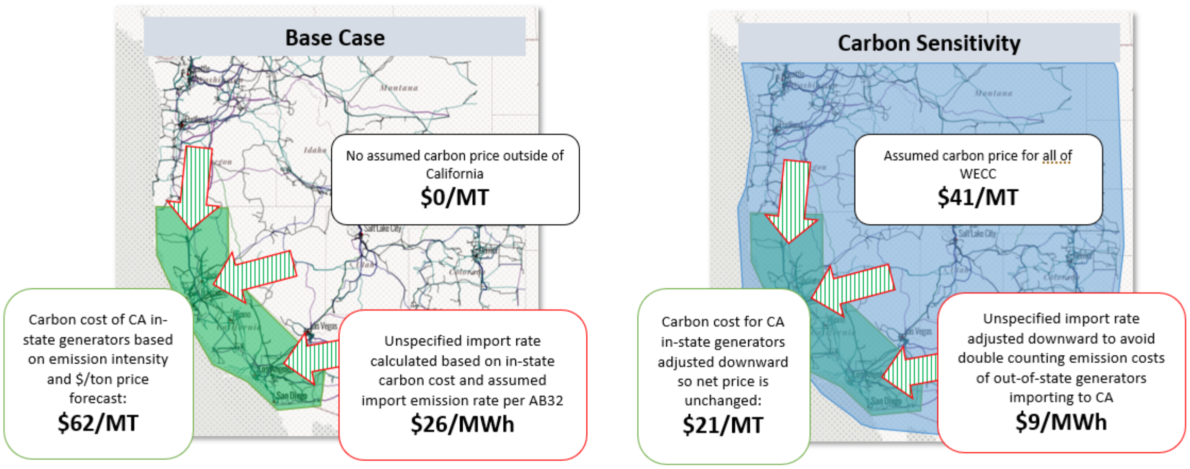


Impact of regional carbon price

The intent of the carbon sensitivity study was to determine how RTO market benefits might be impacted by implementation of a federal carbon price. The study's core scenarios assumed that California was the only state with carbon policy that requires emitting generators to procure allowances based on their emissions. For California, an allowance price of $62/metric ton in 2030 was modeled as carbon adder that impacts the marginal cost required to dispatch an emitting generator located in the state and applicable to imports into the state (based on a default emission factor). The carbon sensitivity assumes that a federally mandated or regionally consistent carbon price is implemented across the Western states. The price was assumed to be $41/metric ton, which is an average 2030 carbon price based on a survey of 11 recently completed integrated resource plans (IRPs) performed by Western utilities. This price was applied to emitting generators in the Western Electricity Coordinating Council (WECC) footprint and California, with adjustments to California generators to ensure that there was not a net reduction to the gross California carbon price (i.e., the higher $62/metric ton price is retained and not replaced by the lower price that applies to the rest of the West).

The visual below demonstrates the modeling approach and how the unspecified emission rate for imports into California was adjusted downward to ensure double penalizing did not occur.

Figure 8: Carbon Sensitivity Modeling



CA in-state/specified resources:	**$62/MT**	$21/MT + $41/MT = **$62/MT**
CA imports:	**$62/MT** ($26/MWh)	$21/MT ($9/MWh) + $41/MT = **$62/MT**
WECC system adder:	**$0/MT**	**$41/MT**

3. Analytical Approach

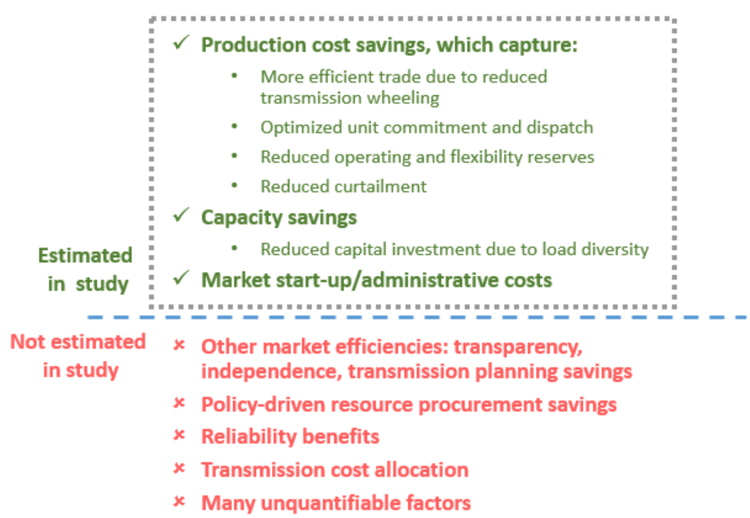
This section addresses the analytical approach used to model the market configurations and estimate their benefits. The first two subsections address the production cost modeling software tool and the primary benefit metric used in estimating operational benefits – adjusted production cost (APC). The next subsection details the method used to estimate capacity savings due to load diversity. Finally, several study limitations that add important context to the study and its results are reviewed.

Overview and Study Design

The primary goal of the study was to assess both state-level and regional benefits of the various market configurations. To achieve this goal, the study calculated the relative benefits of how one market configuration performed relative to another. To provide the results at a state-level, benefits were calculated at the BA level and then allocated to individual states within a BA on a load weighted basis. This approach was necessary given the interest in understanding likely market impacts at a state-level, even though system operations generally do not consider state boundaries.

The study assessed a subset of potential benefits that can be offered by markets and took a conservative approach to benefit inclusion and quantification. In terms of the categories of benefits considered, the study focused on operational and capacity savings that may accrue due to new regional markets. As outlined in the figure below, several qualitative and quantitative impacts associated with markets were not quantified in the study.

Figure 9: Market Benefits and Costs Captured in Study



Modeling Tool

Energy Strategies used ABB's GridView™ production simulation software to simulate grid operations and energy markets in the Western Interconnection for 2020 and 2030 study years. In an hourly timestep, the model performs a least-cost security constrained unit commitment and dispatch based on a detailed "nodal" representation of the power system, which includes representation of substations, transformers, transmission lines, and transmission interfaces. The tool was used to generate results

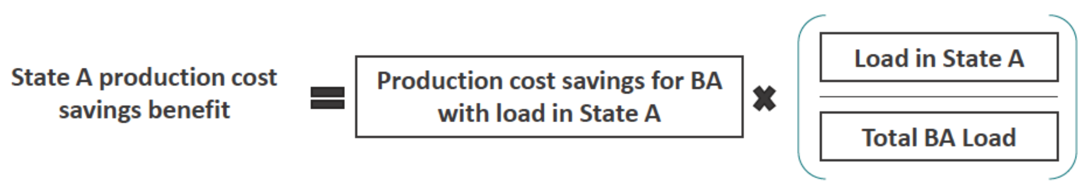
estimating the production cost (or variable power costs) required to serve load during the study year. To assess the operational performance of the various market constructs, model input assumptions such as transmission wheeling rates between BAs, reserve requirements, and market footprints were adjusted.

In addition to generating results related to the operational cost implications of the market configurations, the tool was used to provide insight related to changes in GHG emissions, generation mix, renewable curtailment, transmission congestion, and transmission utilization. For additional detail regarding the modeling scope and the GridView™ model, please see *Appendix D*.

Adjusted Production Cost

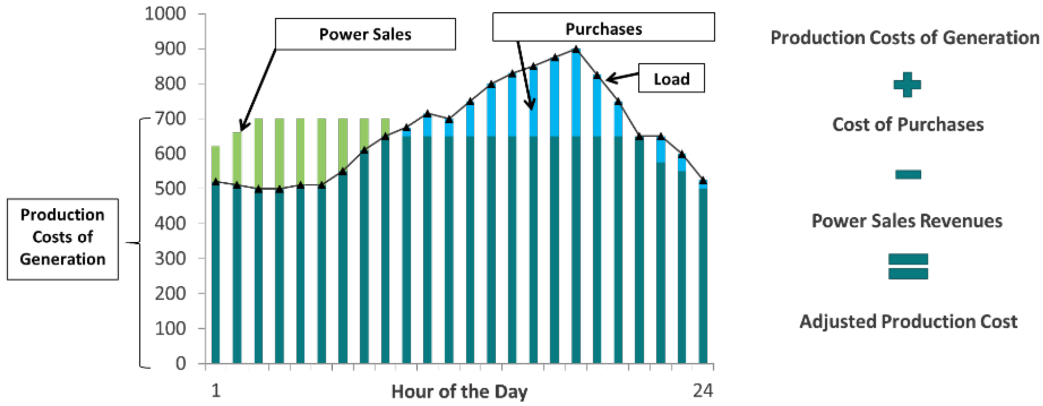
APC estimates the net costs for a given area to produce, buy, and sell power. The metric is commonly used in market benefit studies as it accounts for the trade benefits between buyers and sellers. This study calculates APC on a BA basis and then sums the costs at the state level. For BAs that have load in multiple states, BA-based APC are allocated to states on a load ratio basis, consistent with the equation in Figure 10 below.

Figure 10: Allocation of APC from BAs to States



APC is calculated for a BA as the variable production costs of generation plus the cost of power purchases less the revenue from power sales. Variable production costs represent the cost to produce power and include fuel costs, start-up costs, and variable operations and maintenance (O&M) costs for generation within or contracted by the BA. The costs of purchases are calculated hourly based on the BAs net short position multiplied by the load-weighted locational marginal price (LMP) for the BA. Revenues from power sales are estimated hourly as the net long position of the BA multiplied by the generation-weighted LMP for the area. These three cost and revenue terms are tabulated hourly based on simulation results for the given BA, as demonstrated in the figure below, and are summed across the study period to calculate the BA's APC.

Figure 11: Adjusted Production Cost Calculation



Since one of the primary purposes of this project was to provide Western states information about how market options impact individual states, a calculation of state-level benefits is required. Reduction in APC from one market configuration compared to another represents a cost savings – or benefit – for a particular state. By comparing changes in state-level APCs among market configurations, the study estimates how states might experience operational benefits from various market configurations. Results from this analysis are presented in *Section 6 Operational Benefits*.

Capacity Benefit Analysis Methodology

In addition to operational benefits, estimated through the APC methodology described above, the study estimated capacity savings that may accrue due to future market configurations. Savings are conservatively estimated in this study based on load diversity benefits alone. Resource diversity benefits or reductions in gross planning reserve margin requirements were not accounted for in the analysis and would lead to additional benefits. The more conservative load diversity capacity benefits savings estimated in this study vary by market construct and footprint.

Load Diversity

Load diversity occurs when individual BA peak loads occur at different times. This causes their coincident – or combined – peak load for the combined footprint to be less than the sum of the non-coincident or individual BA peak loads. Load diversity benefits are most pronounced when the non-coincident peaks for each BA occur during different seasons (such as summer vs. winter peaking), but savings can also accrue even if BA non-coincident peaks occur at different hours during the same peak day.

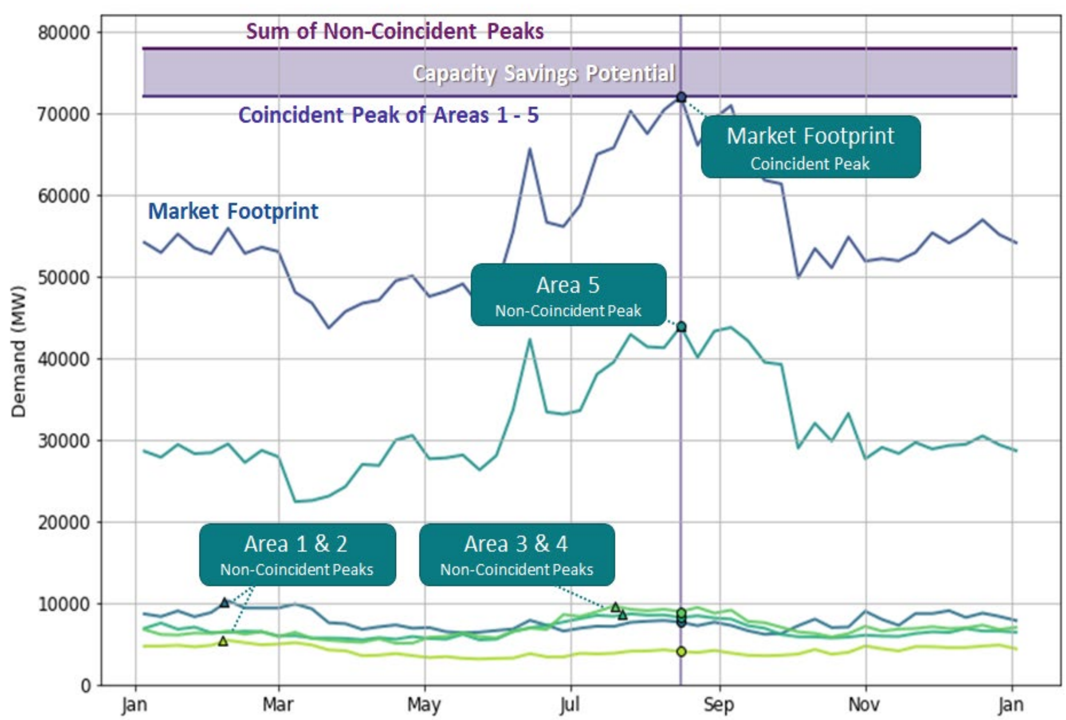
In the absence of any coordination of BA peak demand, resource adequacy obligations in place today generally require each BA (or utility)[9] to build or contract for resources to meet individual system loads plus a planning reserve margin. With a coordinated (or consolidated) system, the BAs/utilities can plan capacity to meet the combined peak load, adjusting for local capacity needs that may exist because of

[9] While, today in the West, resource adequacy obligations are generally imposed at the utility level, this study focused on quantifying peak demand needs at the BA level, given better load data availability at the BA level.

transmission constraints.[10] By planning for a system-wide peak instead of individual BA peaks, individual BAs and the system may be able to avoid the procurement or construction of capacity resources. This avoided cost is what this study considers to be load diversity benefits and represent the benefits classified as capacity savings in this study.

This load diversity concept is demonstrated in the example below in which the capacity savings are estimated as the difference between the coincident and non-coincident demand of a hypothetical footprint with five BAs. For simplicity of demonstration, the study does not apply a planning reserve margin in this example.

Figure 12: Historical Peak Demand (MW) for Five BAs in a Conceptual Footprint Used to Demonstrate Load Diversity Concept

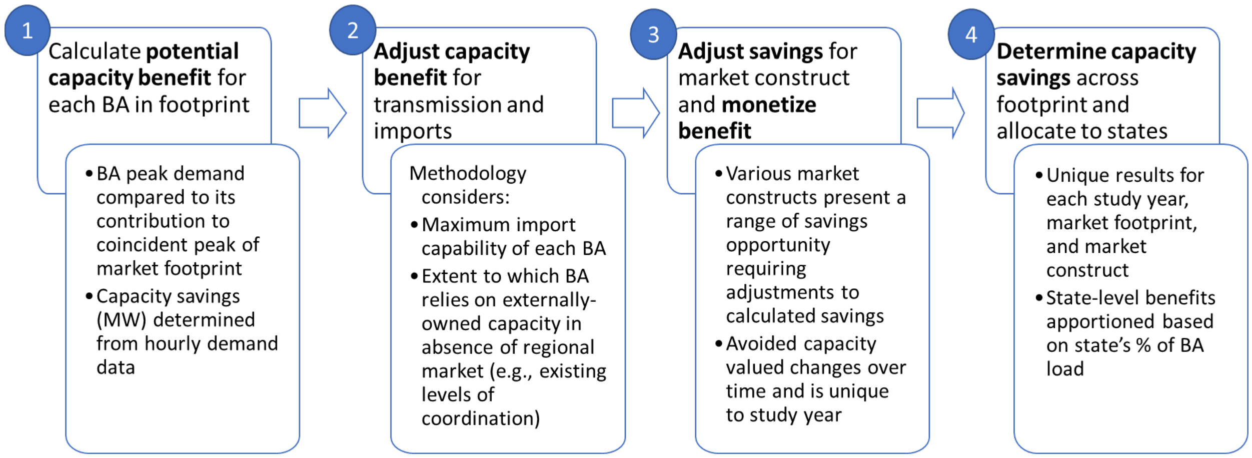


Method and Key Assumptions

The method used to estimate BA-level capacity savings is described in this section. The approach is summarized in the flow chart below.

[10] Such constraints may limit a BAs ability to rely on imports from a neighbor, thereby reducing its potential load diversity benefits.

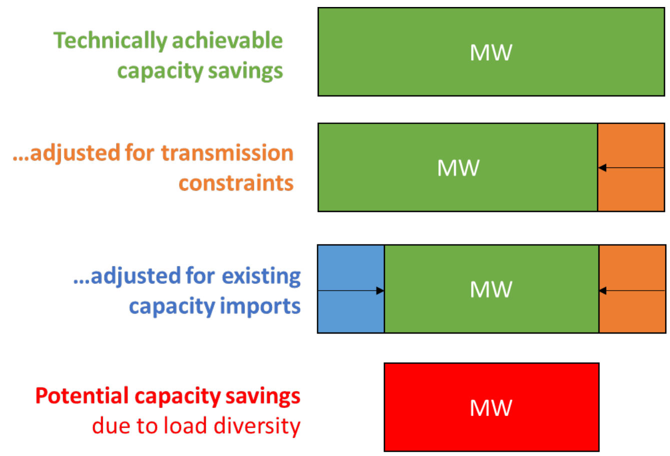
Figure 13: Capacity Savings Methodology



The approach starts by calculating the theoretical maximum capacity savings for each individual BA in each market footprint. This was done by comparing the peak demand plus reserve requirements for each BA to the coincident peak of the combined market footprint load. Historical hourly demand data from 2019 and planning reserve margins sourced from IRPs or state planning processes were used for this calculation. The study conservatively assumed that planning reserve margins were constant and did not decrease due to market expansion or changes in the resource mix.

In the second step, the theoretical maximum amount of capacity benefits for each BA was adjusted to account for transmission constraints that may limit the ability of the BA to rely on imported capacity. Depending on the BA, this analysis relied on either published maximum import capability data, WECC Path ratings, or data collected from WECC powerflow models. After estimating a maximum import capability for each BA, IRPs and other contractual data sourced from industry databases were used to estimate the degree to which import capability was already being utilized by external resources to provide capacity to the area. This step is important because an import limitation that limits diversity benefits amounts to a local capacity requirement for each BA, which is necessary for maintaining system reliability and serves to limit the amount of capacity benefits a given area can realize. Figure 14, below, demonstrates how technically achievable capacity savings for a given BA in a market footprint were adjusted for transmission constraints and transmission commitments by existing or planned imports.

Figure 14: Adjusting Capacity Benefits for Transmission Limits and Existing Coordination/Imports



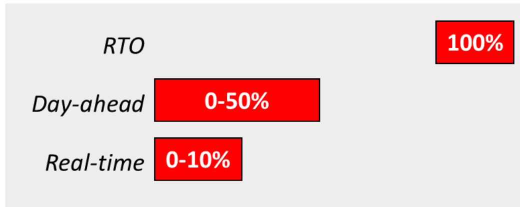
The third step considers that different market constructs are likely to lead to different levels of capacity savings based on their service offerings and organizational structures. For example, an RTO is likely to enable far greater capacity savings than a real-time energy market, because it more freely allows power to transact in the day-ahead timeframe. The study assumes that:

- In **RTO scenarios**, **100% of calculated load diversity benefits** can be realized by the BA participating in the market. This is because RTOs generally provide the resource adequacy framework and necessary market product offerings that allow participants to capture the full benefit of load diversity.
- **The day-ahead market construct can result in a realized savings range of 0-50%** of technically achievable load diversity benefits, recognizing that day-ahead markets may not achieve any capacity savings and that status quo planning requirements may continue for some time even after the formation of a day-ahead market. However, the study recognizes that enhanced price discovery, resource pooling, and coordinated access to transmission could cause changes to reliability requirements and resource coordination that allow some amount of load diversity-related capacity benefits to be obtained.
- **Real-time only markets are unlikely to result in significant capacity savings**, though it is possible they may result in some capacity-based savings. The assessment assumes real-time markets can achieve between 0-10% of load diversity benefits. It is possible that increased access to the markets' real-time imports that support reliability may, over time, lead to slight changes in amounts of reserves held, although this outcome has not been clearly demonstrated and is not the focus of this study. However, all else being equal, the capacity needs of a system that has enhanced ability to respond to real-time variation and imbalances – such as what is facilitated in real-time market – will require marginally less capacity than an equivalent system that lacks this capability and real-time coordination.

The approach to diversity saving estimates for each market construct is summarized in Figure 15 below. The study adopted a bookend approach for day-ahead and real-time markets so stakeholders

can draw their own conclusions about what level of achievable load diversity benefits is most appropriate for these market constructs.

Figure 15: Achievable Benefits as a Percentage of Load Diversity Savings



This final step in quantifying the load-diversity benefits in this study is to take the market-adjusted amount of annual capacity savings, in terms of MWs demand, and monetize the saving through an assumed $/kW-year avoided capacity cost. The study assumes that the avoided cost of capacity changes over time in recognition of evolving load-resource balance conditions in the West. The study year 2020 capacity value estimate assumes that no generation investment can be avoided, but BAs could have not entered capacity contracts and/or market purchases. For this reason, capacity is valued at $40/kW-year in 2020 based roughly on average bilateral contract information from the California market. For the 2030 study year, the value of capacity in the West in assumed to increase, as taking advantage of load diversity benefits may allow for the avoidance of new generation investment. Therefore, the analysis assumes a net cost of new entry (Net CONE) proxy of $110/kW-year for the value of capacity in 2030.[11] The assumptions and sources are outlined in Figure 16 below.

Figure 16: Value of Avoided Capacity

Year	Capacity Cost	Source
2020	$40/kW-year	Based on 2018 CEC Resource Adequacy Report for 2020 capacity
2030	$110/kW-year	Net CONE proxy value

Hypothetical NGCC CONE	$150/kW-year	CEC - Estimated Cost of New Utility Scale Generation in California: 2018 Update
Estimated Net Revenue	$40/kW-year	CAISO - 2018 DMM Annual Report
Estimated Net CONE	**$110/kW-year**	

[11] The Net CONE calculation represents the cost of new entry less estimated revenues from energy and ancillary service markets. A Net CONE value is used in this analysis as a proxy for any type of generation that can provide capacity value and is technology agnostic.

The resulting BA-level capacity benefits were then allocated to states on a load-share basis for those BAs covering more than one state. Results from this capacity savings analysis are presented in *Section 5 Capacity Benefits*.

Ongoing Market Costs

Markets have costs associated with their ongoing administration that are important to consider alongside the potential benefits the market might provide. This study does not seek to provide a "net" benefit analysis for these market options. The study also does not capture all factors that may contribute to the costs of new or expanded markets. For example, certain market participants are likely to require communication and IT upgrades to enable their resources to participate in a new market. Estimating the need and cost for this type of new equipment or additional headcount is beyond the scope of this study. Thus, the high-level cost estimates contained below were limited to a range of costs that might be associated with the market operator providing ongoing services.

Consistent with the estimated *incremental* benefits approach, the study estimates *incremental* ongoing costs of the market configurations considered in the study. The ongoing costs for each market construct were developed based on historic market operator costs, input from market operators, and proposed costs for new market proposals. A high-end and low-end range costs were developed to reflect uncertainty surrounding potential providers and the economies of scale that might be realized. The high-end cost estimates conservatively do not incorporate any economies of scale that would be expected with larger market footprints, so the high-end costs are likely higher than what might be realized. Additionally, since the study is operator agnostic, developing representative market operator costs that are consistent among the study footprints is in line with the study's principle of not evaluating specific market providers.

All costs are presented in 2018 dollars, consistent with benefit results. The per-unit cost assumptions are provided below, along with a summary of the source used to derive the estimates. These costs apply to all MWh of load within a relevant market footprint and, thus, may not directly line up with the reported administrative costs for certain markets that only apply costs to transactions that occur within the market itself.

Figure 17: Per-unit Market Cost Assumptions

Market Construct	Low-Cost Estimate ($/MWh)	High-Cost Estimate ($/MWh)	Sources
Real-time (EIM)	$0.01	$0.21	Low-end based on Western EIM and high-end based on SPP WEIS for current footprint
Day-ahead	$0.15	$0.45	Based on an assessment of a range of CAISO charge codes that might apply and estimated transactions that might occur in market
RTO	$0.33	$0.90	Low-end costs are based on SPP proposal for MWTG while high-end costs are from FERC metrics report for the CAISO system

The above per-unit costs were applied to each market footprint that required incremental/new ongoing market services. The calculated $/year costs for each market footprint are summarized in the figures below.

Figure 18: Estimated Market Administration Costs of 2020 Market Configurations

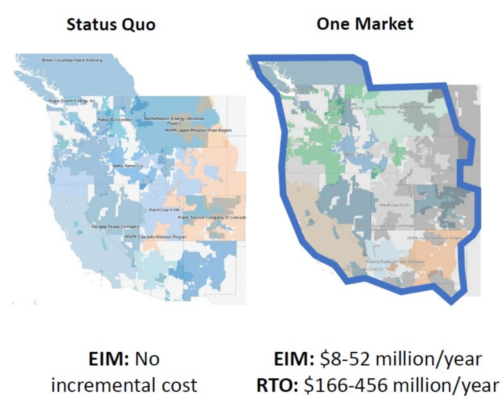
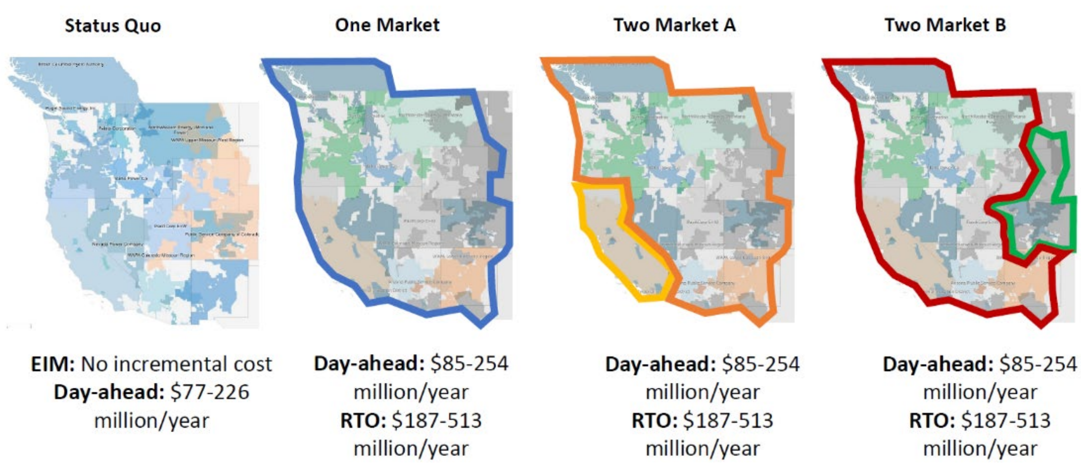


Figure 19: Estimated Market Administration Costs of 2030 Market Configurations



Study Limitations

The tool and modeling approach have limitations that will cause the study to not capture all benefits and costs associated with a given market configuration. Important study limitations include:

- The tool does not reflect all market intervals that occur in actual market operations. For example, the tool does not perform an intra-hour dispatch, which means it does not capture benefits of optimizing generation dispatch and load imbalance within the operating hour. This will cause the study to fail to capture certain benefits associated with certain market configurations.
- The tool assumes perfect foresight between the day-ahead unit commitment and real-time market dispatch – there are no changes in load or renewable generation due to variability and forecast uncertainty, which will also result in the study not capturing certain market benefits (mainly those associated with resource diversity).
- Generator operational assumptions are "generic" and not unit-specific, which means the model may not capture all the benefits associated with coordinated market dispatch.[12]
- Modeling does not reflect all long-term or legacy transmission agreements, although it attempts to capture transmission dedicated to "remote" resources. An example of a remote resource is a resource dedicated to servicing load in one BA but is physically located in another. The approach used for this study attempts to identify all such occurrences and make adjustments to transmission modeling based on the assumption that remote units likely have dedicated legacy or long-term transmission arrangements that exempt them from point-to-point transmission service wheeling charges.
- The tool assumes that the entire system is dispatched centrally to minimize costs, and that BAs and market participants are perfectly competitive, meaning they always willingly trade with neighbors if system economics support transactions.[13] Especially in today's bilateral market, this is generally not the case, but the model does not approximate the current inefficient system operations; in effect, this means there are certain benefits associated with coordinated commitment and dispatch that may not be captured in the modeling exercise.[14]
- Modeling assumes normal weather conditions and does not account for transmission outages, operational de-rates, gas supply reliability issues, or other "black swan" events. Coordinated markets can help the system "ride through" such reliability events, and this benefit is not included in the analysis.
- The tool does not endogenously model resource retirement or investment decisions – these are input assumptions determined outside of the modeling framework.

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[12] For example, ramp rates of all units are not known individually and are based on unit-type data.
[13] The modeling also assumes that generators submit cost-based market bids.
[14] Note that the inefficiencies of the current system can be approximated through the use of "frictional adders" to transmission wheeling rates. As discussed more below, this study incorporated these adders to seek to capture some of the inefficiencies that exist in the bilateral market that occurs in the West today.

- The tool does not fully capture bilateral transmission markets, contract path scheduling, and trading blocks for transacting bilateral power – although it approximates these factors in certain instances.
- The tool does not replicate exact market structures (e.g., a replication of CAISO's actual market features like convergence bidding or virtual bidding).
- The tool is focused only on the electric sector and must be fed certain assumptions such as GHG prices, GHG price application, and gas prices. These assumptions were sourced from varying reputable data.

Ideally, the model would have been used to study every year between 2020 and 2030. However, the tool is comprised of advanced algorithms and large databases and, as a result, it can take as long as a day to run a single study (not to mention the time it takes to set-up, process, and analyze the volumes of study results). Also, building and validating model datasets is a manual and time intensive effort. For these reasons, the modeling was limited to two study years and not all combinations of market configurations and sensitivities were evaluated.

Despite these limitations, caveats, and ability to capture only certain market benefits, GridView™ – and other production cost models like it – can produce valuable insight related to market expansion; the tool reasonably reflects market fundamentals, policy implications, and highly technical operational and transmission constraints across the power system. The market simulations produced as a part of this study will help the Western states better understand how various market configurations might impact the operations and economics of the Western wholesale electric system.

4. Modeling Assumptions

The study required input assumptions to populate a model that simulates Western grid operations in the 2020 and 2030 study years under various market constructs. In summarizing these assumptions, the report categorizes them as System Assumptions and Market Modeling Variables. The types of modeling assumptions that fall into these categories are summarized in the Figure 20 below.

Figure 20: Summary of Modeling Assumptions

System Assumptions	Market Modeling Variables
Demand	Transmission/Trading Costs
Generation Supply	Transmission Availability
Fuel Prices	Ancillary Services
Thermal Unit Parameters	Export Limits
Transmission Topology	
GHG Prices	
Held constant in all studies[15]	**Vary across studies based on market construct and footprint**

System Assumptions are held constant in the evaluation of all market configurations while Market Modeling Variables are adjusted across the study cases to best represent the market construct. This ensures that the study is isolating the impact of new energy markets.

A detailed description of each of the above assumptions is provided in *Appendix B and C*.

5. Capacity Benefits

Regional market expansion has the potential to drive material capacity benefits for the West. Without coordination of each BA's resource adequacy needs, each area must build or contract resources to meet their own peak demand. However, since individual BAs demand peak at different times of the day and seasons of the year, there is an opportunity for markets and other forms of regional coordination to reduce the gross capacity requirement across the footprint of market/program, which can translate to savings for BAs, utilities, and states. New regional energy markets can facilitate the planning and operations of a coordinated system that allows resource capacity across the region to meet the consolidated system peak. This means the procurement or construction of capacity resources can be avoided under a regional energy market relative to the status quo. The sharing of resources through regional coordination outside of an organized market can also lead to decreased capacity needs on the system.

[15] Sensitivity studies adjusted GHG prices, transmission topologies, and fuel prices

The capacity savings analysis presented below estimates the magnitude of capacity savings for the various 2020 and 2030 market configurations considered in this study. The methodology used to perform the capacity benefit analysis is outlined above in the analytical approach (*Section 3*). Note that the capacity benefit analysis was not adjusted for the sensitivity cases and those cases simply relied on the capacity benefits results of the core cases. This is a conservative assumption for the transmission expansion sensitivity, which would likely have increased import capability between certain regions and, thus, may have higher capacity benefits savings.

Results Summary

The table, below, summarizes the capacity benefits in MW, by state, estimated for the 2020 timeframe for the two market configurations considered. The values in the table represent the MWs of "pure" capacity resources that, based on the methods used in this study, can be assumed to be avoided due to the implementation of the given market configuration.

Figure 21: 2020 Load Diversity Benefits (MW)

State	One Market EIM	One Market RTO
Arizona	93	927
California	173	1,727
Colorado	87	866
Idaho	65	652
Montana	34	338
Nevada	45	449
New Mexico	65	655
Oregon	110	1,099
Utah	49	492
Washington	392	3,918
Wyoming	20	198
Total	**1,132**	**11,321**

The 2020 analyses assumed an avoided capacity cost of $40/kW-year. This value is less than the cost it would take to construct a new capacity resource as the study assumes that in the 2020 horizon only contracts for existing capacity resources can be avoided since resources cannot be "unbuilt" in the present-day. Additionally, the study assumes that the One Market EIM configuration would present a range of savings that are between 0% and 10% of the technical maximum of load diversity benefits. The One Market RTO configuration is assumed to generate the technical maximum level of savings. The per-year estimated load diversity benefits are shown below, by state, in Figure 22.

Figure 22: 2020 Capacity Savings ($M/year)

State	One Market EIM		One Market RTO
	Low End	High End	
Arizona	$0	$4	$37
California	$0	$7	$69
Colorado	$0	$3	$35
Idaho	$0	$3	$26
Montana	$0	$1	$14
Nevada	$0	$2	$18
New Mexico	$0	$3	$26
Oregon	$0	$4	$44
Utah	$0	$2	$20
Washington	$0	$16	$157
Wyoming	$0	$1	$8
Total	**$0**	**$45**	**$453**

In 2020, annual capacity savings for the RTO scenario are $453 million per year, while the high-end of the One Market EIM scenario are $45 million per year. Based on the assumptions, the low-end savings for the One Market EIM configuration assumes no capacity benefit savings are realized and, thus, are zero.

Load diversity benefits, in MW, as calculated for each 2030 market configuration are presented below.

Figure 23: 2030 Load Diversity Benefits (MW)

State	Status Quo Day-ahead	One Market Day-ahead	One Market RTO	Two Market A Day-ahead	Two Market A RTO	Two Market B RTO
Arizona	511	534	1067	137	274	1067
California	823	864	1727	665	1331	1727
Colorado	377	444	888	444	888	142
Idaho	398	398	796	320	639	796
Montana	164	164	327	14	28	327
Nevada	229	229	459	55	109	459
New Mexico	290	318	636	40	80	636
Oregon	577	577	1153	350	700	1153
Utah	250	254	508	42	83	508
Washington	1717	2042	4084	1670	3340	4084
Wyoming	79	107	213	43	86	213
Total	**5,414**	**5,930**	**11,860**	**3,779**	**7,557**	**11,114**

These MWs of diversity benefits are translated to capacity savings results for the 2030 study year in the table below. Again, the range of savings for the day-ahead market construct was assumed to be 0% of technical potential for the low end, and 50% of the net technical potential benefit on the high end. As was the case in the 2020 analysis, the RTO construct is assumed to be able to achieve 100% of the potential savings.

Figure 24: 2030 Capacity Savings ($M/year)

State	Status Quo Day-ahead		One Market Day-ahead		One Market RTO	Two Market A Day-ahead		Two Market A RTO	Two Market B RTO
	Low End	High End	Low End	High End		Low End	High End		
Arizona	$0	$56	$0	$59	$117	$0	$15	$30	$117
California	$0	$91	$0	$95	$190	$0	$73	$146	$190
Colorado	$0	$41	$0	$49	$98	$0	$49	$98	$16
Idaho	$0	$44	$0	$44	$88	$0	$35	$70	$88
Montana	$0	$18	$0	$18	$36	$0	$2	$3	$36
Nevada	$0	$25	$0	$25	$50	$0	$6	$12	$50
New Mexico	$0	$32	$0	$35	$70	$0	$4	$9	$70
Oregon	$0	$63	$0	$63	$127	$0	$38	$77	$127
Utah	$0	$28	$0	$28	$56	$0	$5	$9	$56
Washington	$0	$189	$0	$225	$449	$0	$184	$367	$449
Wyoming	$0	$9	$0	$12	$23	$0	$5	$9	$23
Total	**$0**	**$596**	**$0**	**$652**	**$1,305**	**$0**	**$416**	**$831**	**$1,223**

There are several takeaways from these results. First, the RTO market constructs achieved the greatest level of capacity savings. This result is a product of (1) the assumptions regarding the achievable level of capacity benefits made in performing the analysis, and (2) that the RTO market configurations feature broad footprints that include BAs that peak at different times of day and seasons of the year. Second, the West-wide RTO has the greatest capacity benefit at $1.3 billion per year, which is driven by the system-wide market footprint that drives up diversity benefits. The Two Market B configuration is close behind, however, as it has a similar footprint that did not sacrifice significant diversity. Two Market A, which has California and the rest of the West operating in two parallel markets, loses significant capacity benefits due to the loss of load diversity caused, primarily, by removing California's loads from the rest of the Western system demand.

Similar observations are made for the day-ahead market configurations, where the most consolidated system achieves the greatest savings (up to $652 million per year). The Two Market A footprint (with California in one market and the rest of the West in another) has materially lower high-end benefits because California and the rest of the West are no longer able to share load diversity savings. Notably, under the day-ahead construct, the Status Quo market footprint achieves $180 million per year greater capacity savings than the Two Market A footprint.

At the state-level, note that all states achieve zero or positive capacity savings in all market configurations. In addition, all states have savings greater than $10 million per year under the One Market RTO construct. In general, California, Arizona, Washington, and Oregon accrue relatively higher gross capacity savings in most constructs because (1) these states have relatively large loads so the potential for material diversity benefits exists, and (2) the demand during the system coincident peak was significantly lower than the non-coincident peak demand for the state. The impact of shifting coincident peaks was most significant for winter peaking states in the Northwest.

These capacity benefit results for 2020 and 2030 are combined with the operational benefits presented in the next section to estimate of the gross benefits of each market configuration. The combined benefits analysis is summarized in the *Findings* section.

6. Operational Benefits

One of the primary purposes of the study was to perform production cost modeling to estimate relative operational benefits of the various market configurations selected by the Lead Team. The primary metric used to estimate operational savings that could accrue due to market expansion is APC, as summarized in *Section 3*. APC savings results for each state and market construct are presented in this section, along with additional study results that include overviews of changes in generation dispatch, carbon emissions, and transmission congestion. The section presents these results for the cores studies as well as the sensitivities.

Adjusted Production Cost Benefits

Annual APC savings for the 2020 study timeframe are presented in the table below. These savings are calculated relative to the Status Quo scenario, which was designed to represent current levels of market participation in 2020.[16]

Figure 25: 2020 APC Savings ($M/year)

State	One Market Real-time		One Market RTO	
	Savings	% Change	Savings	% Change
Arizona	$42	2.9%	$173	12.0%
California	$18	0.4%	$234	5.8%
Colorado	$13	1.5%	$60	6.5%
Idaho	$7	2.3%	$26	8.0%
Montana	-$3	-1.7%	$7	4.2%
Nevada	-$3	-0.4%	$5	0.6%
New Mexico	$9	2.5%	$26	7.6%
Oregon	-$1	-0.1%	$62	11.3%
Utah	-$5	-0.9%	$28	5.2%
Washington	$23	3.1%	$168	22.9%
Wyoming	$4	1.9%	$21	9.6%
Total	**$105**	**1.0%**	**$812**	**8.0%**

The results show that when holding the market footprint constant (e.g., single West-wide system), the RTO construct provides approximately eight times greater operational benefits than a real-time-only market. Notably, most state-level changes in APC are not significant in the upward or downward direction in the case where the real-time market's footprint is expanded from the Status Quo to include the full West. Due to the complexity of the modeling methods and the APC metric itself, it is difficult to track exactly why these small changes in APC occur. The larger and more material savings are

[16] Note that market participation assumptions were based on information on market plan available no later than December 2019.

representative of efficiencies that are gained because of the new market, meaning the state's BAs can buy more power at lower costs, sell more power at higher prices, or some combination of the two that allow it to more cost effectively serve loads.

Similar results for the 2030 market constructs are presented below. The 2030 APC savings are calculated relative to the 2030 Status Quo real-time market configuration.

Figure 26: 2030 APC Savings ($M/year)

State	Status Quo Day-ahead		One Market Day-ahead		One Market RTO		Two Market A Day-ahead		Two Market A RTO		Two Market B RTO	
	Savings	%	Savings	%	Savings	%	Savings	%	Savings	%	Savings	%
Arizona	($11)	-0.5%	($12)	-0.5%	$59	2.7%	($4)	-0.17%	$42	1.9%	$58	2.7%
California	$63	1.8%	$74	2.1%	$288	8.3%	$51	1.46%	$169	4.9%	$272	7.9%
Colorado	$3	0.3%	$27	2.7%	$62	6.2%	$26	2.54%	$69	6.8%	($6)	-0.6%
Idaho	$2	0.3%	$1	0.1%	($8)	-1.5%	($1)	-0.26%	($0)	0.0%	($5)	-1.0%
Montana	$1	0.5%	$1	0.2%	$10	4.2%	($1)	-0.37%	$11	4.7%	$6	2.7%
Nevada	($13)	-1.9%	($12)	-1.8%	($5)	-0.8%	$0	0.01%	$28	4.1%	($5)	-0.8%
New Mexico	$1	0.3%	$3	0.9%	$43	12.5%	$7	2.05%	$44	12.8%	$41	12.1%
Oregon	$1	0.2%	$3	0.5%	$80	13.9%	$3	0.57%	$83	14.4%	$80	13.9%
Utah	$3	0.5%	$9	1.7%	$43	8.5%	$9	1.74%	$45	8.8%	$34	6.8%
Washington	($4)	-0.4%	($3)	-0.2%	$102	9.7%	($9)	-0.89%	$89	8.4%	$104	9.8%
Wyoming	$2	0.6%	$5	2.0%	$19	7.8%	$5	1.98%	$20	7.9%	$10	3.8%
Total	**$47**	**0.4%**	**$95**	**0.9%**	**$694**	**6.4%**	**$85**	**0.8%**	**$598**	**5.5%**	**$589**	**5.4%**

Again, the One Market RTO configuration resulted in the highest savings at $694 million per year. The two other RTO configurations had comparable results, with savings of $598 million per year for the Two Market A configuration, and $589 million per year for the Two Market B configuration. The three day-ahead market configurations all had savings below $100 million per year.

The APC savings results for the 2030 sensitivities are presented below.

Figure 27: 2030 APC Savings - Sensitivities ($M/year)

State	Carbon Sensitivity						Transmission Sensitivity					
	One Market RTO		Two Market A RTO		Two Market B RTO		Status Quo Real-time		One Market RTO		Two Market B RTO	
	Savings	%	Savings	%	Savings	%	Savings	%	Savings	%	Savings	%
Arizona	$107	5%	$151	7%	$99	5%	($5)	0%	$50	2%	$51	2%
California	$489	14%	$290	8%	$444	13%	$8	0%	$288	8%	$271	8%
Colorado	($89)	-9%	($63)	-6%	($61)	-6%	$4	0%	$67	7%	$1	0%
Idaho	($199)	-39%	($194)	-38%	($186)	-36%	$18	4%	$3	1%	$5	1%
Montana	($132)	-57%	($128)	-55%	($132)	-57%	$8	4%	$20	9%	$14	6%
Nevada	$218	32%	$166	24%	$195	29%	$11	2%	$2	0%	($1)	0%
New Mexico	$12	4%	$18	5%	$13	4%	$2	1%	$41	12%	$40	12%
Oregon	$142	25%	$163	28%	$142	25%	$10	2%	$89	15%	$86	15%
Utah	($14)	-3%	($21)	-4%	($5)	-1%	$9	2%	$48	10%	$40	8%
Washington	$19	2%	$14	1%	$35	3%	$38	4%	$153	15%	$146	14%
Wyoming	($65)	-26%	($62)	-25%	($60)	-24%	$4	2%	$22	9%	$14	6%
Total	**$489**	**5%**	**$332**	**3%**	**$484**	**5%**	**$107**	**1%**	**$784**	**7%**	**$670**	**6%**

For the Carbon Sensitivity, the results show that the One Market RTO configuration still accrues the greatest APC savings, although Two Market B RTO is only $5 million behind. Two Market A RTO sees APC savings of 3.1%.

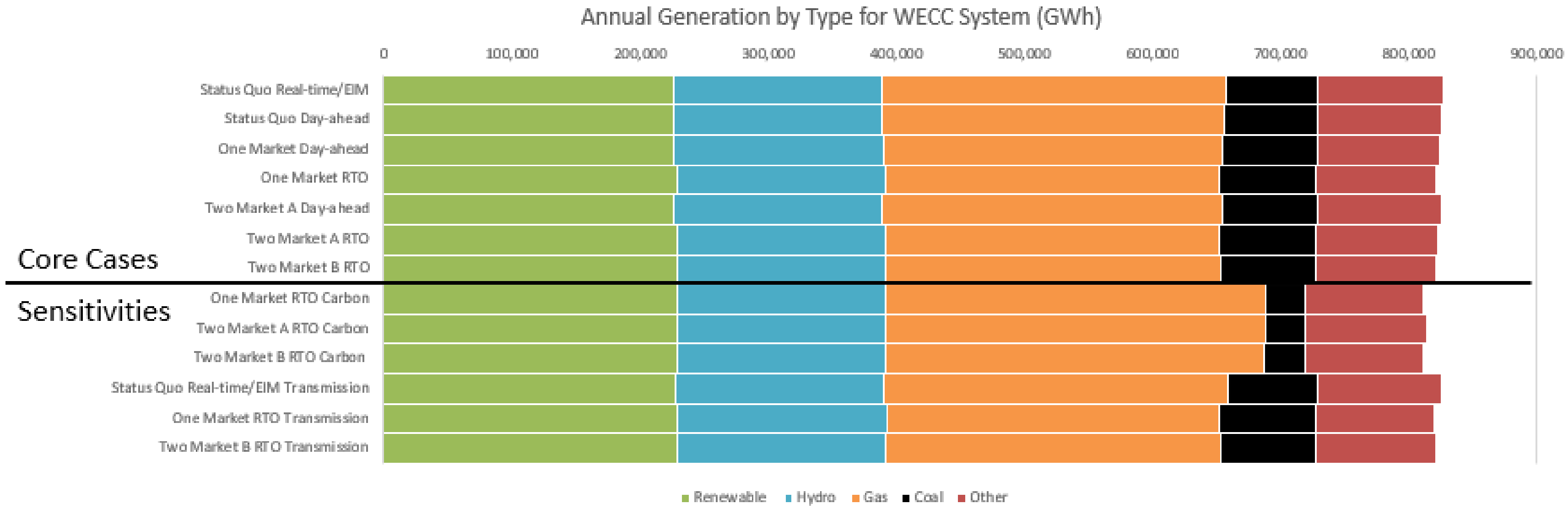
The Transmission Sensitivity caused higher operational savings in the three market configurations studied. Adding the transmission projects caused the APC of the Status Quo Real-time configuration to fall by 1% or $107 million per year. Savings in the One Market RTO and Two Market B RTO configurations were 7.3% and 6.2%, respectively.

Other study results

In addition to the production cost savings addressed above, the study reports metrics related to GHG emissions, generation, renewable curtailment, congestion costs, and flows/utilization of transmission paths.

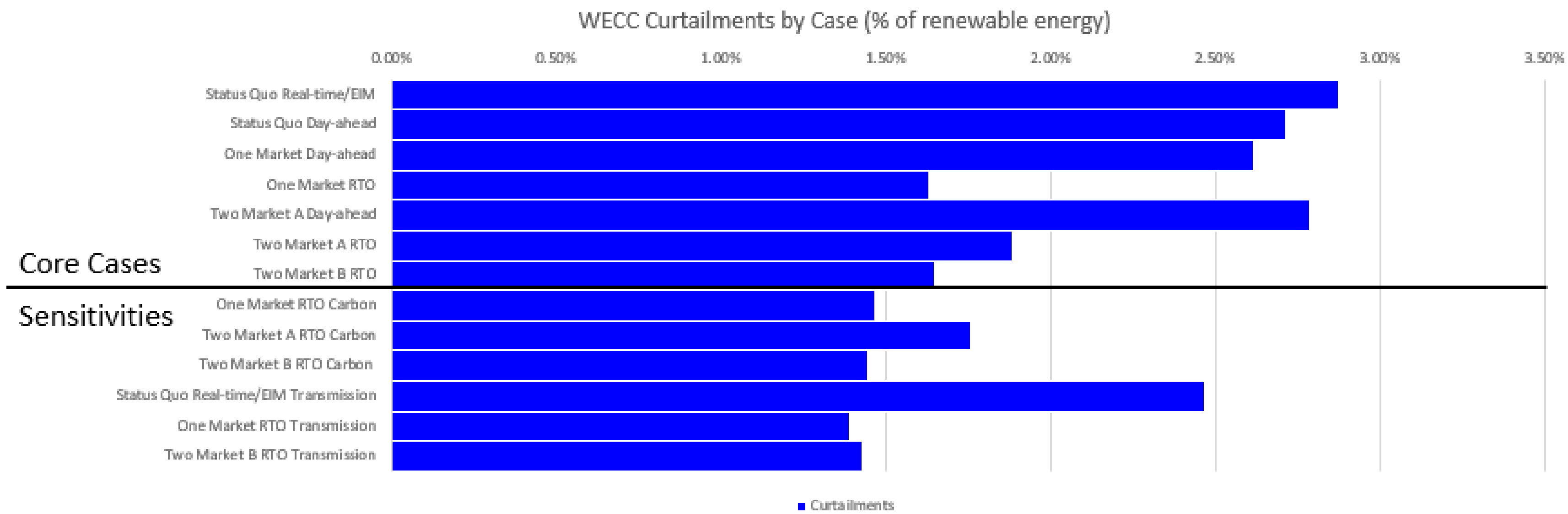
The generation dispatch results for the WECC system, below, demonstrate that the market configurations cause relatively small changes in system wide dispatch. The exception is the carbon sensitivities, which caused a material shift from coal to gas.

Figure 28: Generation Dispatch Results



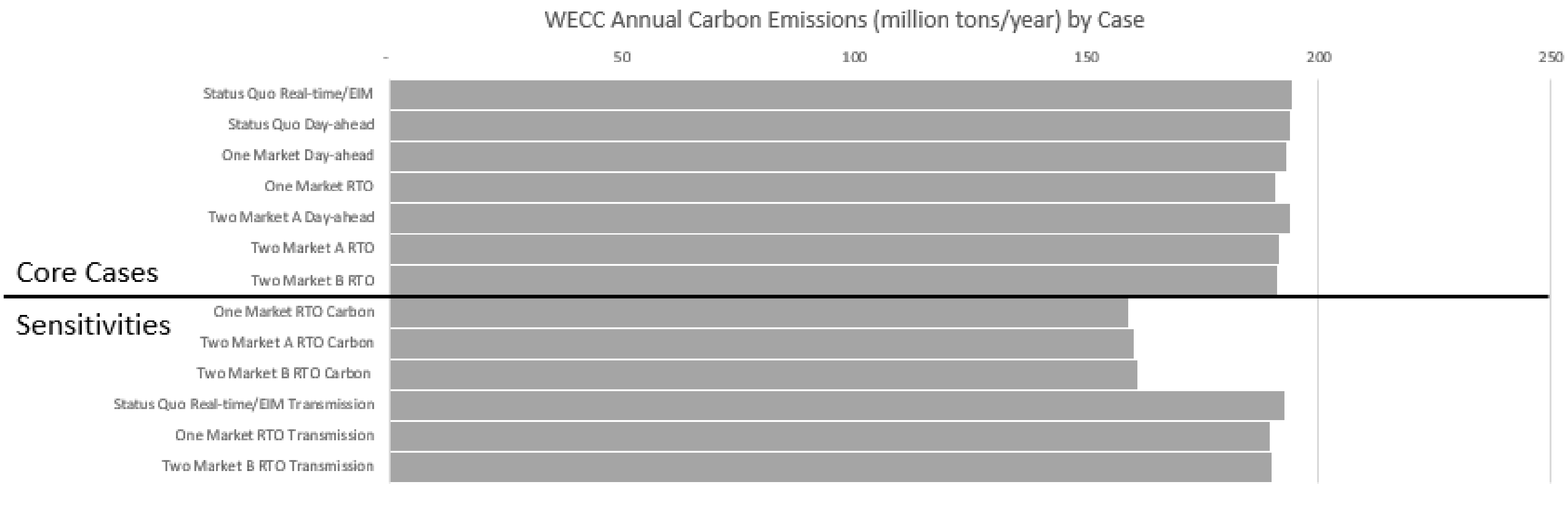
The RTO construct was the most effective at mitigation renewable curtailments, as demonstrated below.

Figure 29: Renewable Curtailment Results



The RTO construct also resulted in the least carbon emissions, although varying the market construct was not as effective at reducing carbon emissions as was the addition of the West-wide carbon price in the carbon sensitivity.

Figure 30: Carbon Emission Results



Finally, transmission path utilization varied among the studies, but there were no outliers in terms of a certain market configuration causing extreme amounts of new congestion or utilization.

Figure 31: Key Transmission Path Utilization Rates (2030 Studies)

				2030 SQ RT_EIM		2030 SQ DA		2030 1Mkt DA		2030 1Mkt RTO		2030 2Mkt A DA		2030 2Mkt A RTO		2030 2Mkt B RTO	
Path	**Path Name**	**Direction**	**States**	**U75**	**U99**	**U75**	**U99**	**U75**	**U99**	**U75**	**U99**	**U75**	**U99**	**U75**	**U99**	**U75**	**U99**
P03	P03 Northwest-British Columbia	S→N	WA→BC	1.2%	0.0%	1.1%	0.0%	1.1%	0.0%	4.2%	0.0%	1.2%	0.0%	4.5%	0.0%	4.4%	0.0%
P06	P06 West of Hatwai	E→W	ID→WA	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
P08	P08 Montana to Northwest	E→W	MT→ID/WA	14.5%	6.8%	14.6%	6.4%	14.9%	7.3%	15.3%	7.5%	14.9%	6.8%	16.6%	8.5%	15.7%	7.4%
P19	P19 Bridger West	E→W	WY→ID	6.0%	0.0%	6.0%	0.0%	4.9%	0.0%	4.4%	0.0%	5.3%	0.0%	4.4%	0.0%	8.2%	0.0%
P32	P32 Pavant-Gonder InterMtn-Gonder 230 kV	E→W	UT→NV	10.1%	4.1%	11.5%	5.7%	12.8%	6.3%	19.3%	11.1%	9.8%	3.5%	9.0%	3.8%	15.7%	8.8%
P36	P36 TOT 3	N→S	WY/NE→CO	0.1%	0.0%	0.1%	0.0%	0.9%	0.0%	2.5%	0.0%	1.0%	0.0%	2.5%	0.0%	0.7%	0.0%
P39	P39 TOT 5	W→E	CO	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	0.1%	0.0%	0.1%	0.0%
P46	P46 West of Colorado River (WOR)	E→W	NV/AZ→CA	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
P47	P47 Southern New Mexico (NM1)	N→S	AZ→NM	0.7%	0.0%	0.8%	0.1%	1.3%	0.1%	6.6%	1.3%	1.1%	0.1%	4.4%	0.8%	6.6%	1.3%
P48	P48 Northern New Mexico (NM2)	NW→SE	NM	0.1%	0.0%	0.1%	0.0%	0.1%	0.0%	0.5%	0.0%	0.1%	0.0%	0.3%	0.0%	0.8%	0.0%
P49	P49 East of Colorado River (EOR)	E→W	AZ→NV/CA	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
P65	P65 Pacific DC Intertie (PDCI)	N→S	OR/WA→CA	26.1%	9.7%	25.1%	9.6%	25.0%	9.3%	30.1%	11.1%	25.7%	9.9%	21.3%	6.9%	30.5%	11.1%
P66	P66 COI	N→S	OR→CA	0.5%	0.0%	0.7%	0.0%	0.5%	0.0%	2.3%	0.2%	0.7%	0.0%	0.5%	0.0%	2.2%	0.2%

7. Findings

This section reviews the findings of the study, based on an assessment of the gross combined operational and capacity savings as well as the consideration of potential market administration costs. It also provides more in-depth findings based on the "key questions" that the technical assessment set out to answer.

Combined Gross Benefits

The table below presents the sum of the Western states' gross benefits for each market configuration studied, including sensitivities. The benefits are broken out by APC savings and capacity savings and are contrasted by an estimated range of potential ongoing market administration costs. All values are annual values for the 2030 study horizon and are calculated relative to the Status Quo Real-time scenario.

Figure 32: Combined Gross Benefits of all Scenarios

	2030 Scenarios (Footprint + Market Construct)	Total Benefits	=	APC Savings	+	Capacity Savings	Admin Cost Range	Carbon Emissions	Curtailments
Core Case	Status Quo Real-time/EIM	$0		$0		$0	$0 - 0	194	2.87%
Core Case	Status Quo Day-ahead	$643		$47		$596	$77 - 226	194	2.71%
Core Case	One Market Day-ahead	$747		$95		$652	$85 - 254	193	2.62%
Core Case	One Market RTO	$1,998		$694		$1,305	$187 - 513	191	1.63%
Core Case	Two Market A Day-ahead	$501		$85		$416	$85 - 254	194	2.79%
Core Case	Two Market A RTO	$1,430		$598		$831	$187 - 513	192	1.89%
Core Case	Two Market B RTO	$1,811		$589		$1,223	$187 - 513	191	1.65%
Sensitivity	One Market RTO *Carbon*	$1,793		$489		$1,305	$187 - 513	159	1.47%
Sensitivity	Two Market A RTO *Carbon*	$1,163		$332		$831	$187 - 513	160	1.76%
Sensitivity	Two Market B RTO *Carbon*	$1,706		$484		$1,223	$187 - 513	161	1.45%
Sensitivity	Status Quo Real-time/EIM *Transmission*	$107		$107		$0	$0 - 0	193	2.47%
Sensitivity	One Market RTO *Transmission*	$2,089		$784		$1,305	$187 - 513	190	1.39%
Sensitivity	Two Market B RTO *Transmission*	$1,892		$670		$1,223	$187 - 513	190	1.43%

Values are in $2018 and million/year and are calculated relative to Status Quo Real-time/EIM — *Million short tons* — *% RE generation*

These regional-level results were used to inform the responses to the Lead Team's key questions, as provided in the next section. Detailed state-level results are provided in *Appendix E*.

Key Questions

The technical portion of the State-Led Market Study was designed to answer a series of questions derived by the Lead Team. The broad range of questions reflect the highly uncertain nature of future market outcomes in the West. The answers derived through the study are intended to help shed light on how market development scope and footprint may impact the West so state policy makers and regulators can develop informed perspectives on regional market matters that may come before them.

Question 1: Assuming no change in market footprints from the Status Quo, what benefits are expected by adding day-ahead energy market services to the West's real-time markets?

In recent years there have been proposals to expand existing real-time-only markets to include day-ahead market services. Such a market would include a day-ahead unit commitment and dispatch optimization that would involve a much greater volume energy transactions than what is observed in today's real-time markets. Modeling results indicate that transitioning to a day-ahead market while retaining the Status Quo market footprint in 2030 could drive up to $643 million per year of savings for Western states. $47 million of these annual benefits is based on operational savings, while the

remainder is attributed to the potential to achieve load diversity benefits, which help avoid the construction of new capacity resources. If the market does not enable such capacity savings, gross benefits of the day-ahead market will be substantially compromised. Finally, as demonstrated in Figure 33, if the high-end capacity savings are achieved, each Western state is estimated to realize positive gross benefits that, when aggregated, exceed the estimated ongoing costs of a new day-ahead market.

Figure 33: 2030 Status Quo Day-ahead Annual Benefits ($M)

2030 Status Quo Day-ahead Annual Benefits

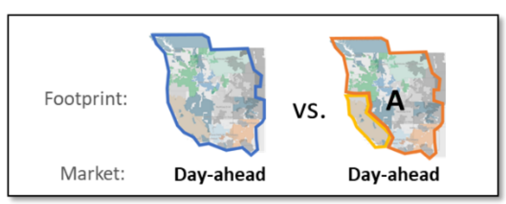
State	APC Benefit ($M)	Capacity Benefit ($M)	Total Benefit ($M)	
AZ	($11)	$56	$45	
CA	$63	$91	$153	
CO	$3	$41	$44	
ID	$2	$44	$45	
MT	$1	$18	$19	
NM	$1	$32	$33	
NV	($13)	$25	$12	
OR	$1	$63	$64	
UT	$3	$28	$30	
WA	($4)	$189	$184	Estimated Ongoing Cost
WY	$2	$9	$10	
TOTAL	**$47**	**$596**	**$642**	$76-226

In addition to the annual savings above, the addition of a day-ahead market to the already anticipated real-time market footprints could reduce emissions (0.3% reduction) as well as curtailments (6% reduction).

This study made numerous assumptions regarding the form and function of a hypothetical day-ahead market. For instance, the study assumed that a relatively conservative amount of transmission would be available for market transactions, and that those transactions would incur a $3/MWh charge. Representing detailed market design for such a complicated market is well beyond the scope of this assessment. Thus, alternative market modeling approaches should be expected to yield different levels of benefits.

Question 2: Assuming a day-ahead market forms, how do the benefits of two market footprints compare with a single market footprint?

To answer this question, the study compared a day-ahead market construct covering the Status Quo footprint to two alternative day-ahead footprints: one in which the entire Western system operates within a single day-ahead market, and one market configuration (Two Market A) in which California BAs operate in one market while a separate, day-ahead market composed of all other BAs in the West also operates in parallel.



The study estimates that the West-wide day-ahead market could result in as much as $747 million per year of benefits, while the dual market scenario results in only $501 million per year of savings.

Therefore, the consolidated, single market footprint leads to $247 million per year of additional savings. The primary reason the West-wide system has greater benefits than the Two Market A footprint, in this case, is because the West-wide market captures load diversity benefits that are sacrificed in the Two Market A scenario.

Figure 34: Difference in 2030 Day-Ahead Market Annual Benefits ($M): One Market less Two Market A

Difference in Annual Benefits: 2030 One Market Day-ahead - 2030 Two Market A Day-ahead

State	APC Benefit ($M)	Capacity Benefit ($M)	Total Benefit ($M)	
AZ	($8)	$44	$36	
CA	$23	$22	$45	
CO	$1	$0	$1	
ID	$2	$9	$11	
MT	$1	$16	$18	
NM	($4)	$31	$27	
NV	($12)	$19	$7	
OR	($1)	$25	$24	
UT	($0)	$23	$23	
WA	$7	$41	$48	Estimated Ongoing Cost
WY	$0	$7	$7	
TOTAL	$10	$237	**$247**	$0

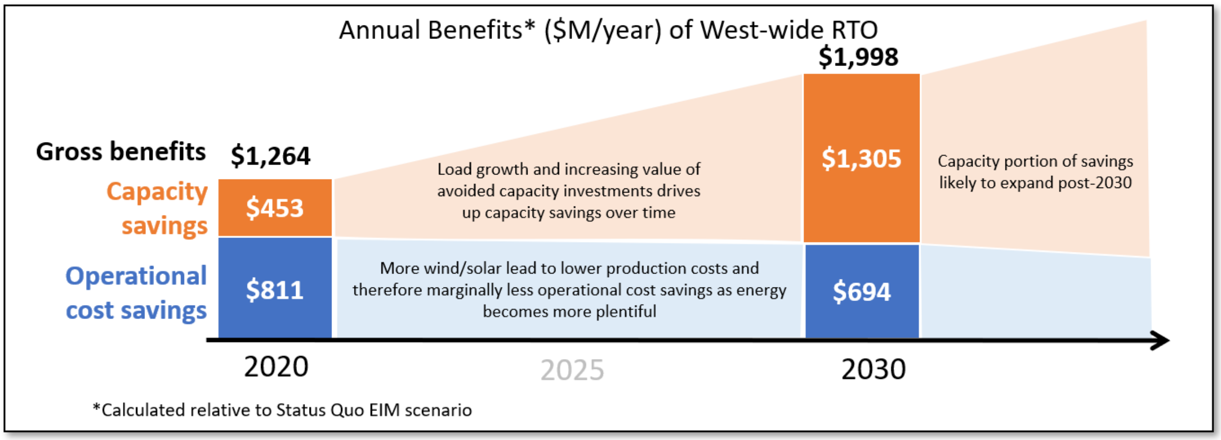
The above analysis assumed that the day-ahead construct achieves capacity benefits at the high-end estimated in the study. If low end (0%) capacity savings are achieved, the operational benefits of the two market footprints are relatively comparable.

Question 3: What is the trajectory of benefits for a West-wide RTO?

The study assumes that the RTO market structure is the more regionally optimized and efficient because (1) there are no transmission wheel costs for transactions within the RTO footprint, (2) all transmission capacity in the footprint is available for market transactions, (3) operating reserves can be met with generators across the entire market footprint, and (4) flexibility reserves are calculated and met with generation across the entire market footprint. In addition, the study assumes that the RTO construct achieves 100% of the technically feasibility load diversity benefits. This question is designed to investigate how these assumptions impact RTO market benefits on today's system (2020) and on the system of the future (2030), and how those benefits compare.

To reflect how gross RTO benefits are expected to evolve over time, Figure 35, below, shows the gross benefits estimated for the One Market (West-wide) RTO market configuration in the 2020 and 2030 study horizon.

Figure 35: West-wide RTO Trajectory of Benefits



The 2020 results show that, relative to the Status Quo, a West-wide RTO could result in nearly $1.3 billion of annual savings. 65% of these savings are attributable to operational efficiencies of the RTO market, and the remainder represent the estimated capacity benefits. By 2030, the study suggests that these proportions could reverse. Gross benefits increase to nearly $2 billion per year, and capacity savings make up 65% of the total while operational benefits account for the rest.

The increase in capacity benefits over time is explained by the higher load levels in 2030, and the higher valuation of avoided capacity. In the near term (i.e., 2020), investment in capacity resources cannot be avoided, so the study assumes a lower cost for avoided capacity. However, in the long term, capacity savings from load diversity – which total more than 11 GW in the One Market RTO configuration – allows for generation investment to be fully avoided, which drives a higher valuation for the unbuilt capacity.

The decrease in operational benefits over time observed in the RTO market construct is due to shifts in the West's resource mix, including the increasing prevalence of low-cost energy resources. By 2030, the study assumes that nearly 60% of the West's resource mix is made up of zero-emission resources such as wind, solar, hydro, and nuclear. With such high volumes of low- or no-cost energy on the grid, the efficiencies gained from optimized market dispatch are slightly muted as compared with efficiencies that can be realized on today's system, which has more thermal resources and therefore a more diverse set of marginal energy costs to economize.

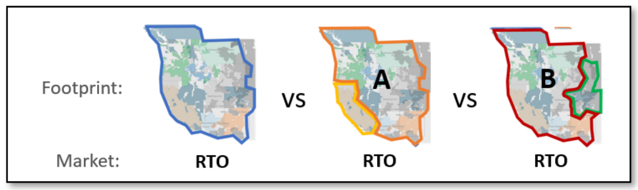
Question 4: How do the benefits of a West-wide RTO compare with a West-wide day-ahead market?

The day-ahead and RTO market constructs and their relative performance was a core issue for the study. To lay the groundwork for such a comparison, the study featured 2030 scenarios in which (a) the West forms a single-footprint RTO, and (b) one in which the West forms a single-footprint day-ahead market. Results estimate that a West-wide RTO will produce roughly three times the gross annual benefits that might be realized under a day-ahead market with the same footprint, in the case where the day-ahead market is able to realize the high end of capacity benefits savings. The gross benefits of the RTO are

estimated at $2 billion per year, with between $187 – 513 million per year of ongoing administrative costs. The day-ahead construct produces, on the high end, $747 million per year of gross benefits, with estimated ongoing costs of $85 – 254 million per year. While the RTO is likely more expensive to implement – and faces regulatory and political challenges – the regional benefits significantly surpass the high-end day-ahead market estimates, even after taking into account the expected ongoing costs required to administer the two markets. Additionally, if a day-ahead market is not able to realize any capacity benefits savings, then the RTO will provide orders of magnitude more benefits to the West ($95 million for a day-ahead market that does not achieve capacity savings, relative to nearly $2 billion for an RTO that is assumed to achieve capacity savings).

Question 5: How are the benefits of an RTO impacted by market footprints?

Three RTO market configurations were evaluated to assess how benefits changed based on the geographic footprint of the RTO. While the modeling approach may not capture all seams issues that might exist between two RTO markets operating in parallel, the study found that the West-wide RTO market resulted in greater benefits than the two alternative footprints: Two Market A and Two Market B. The West-wide footprint resulted in $569 million greater benefits than Two Market A, and $187 million of greater benefits than Two Market B. Since the costs for market administration are based on cost per MWh and the amount of load in an RTO is constant between the different scenarios, each market construct had the same total ongoing administrative costs. The same range of administrative costs for these different market configurations is consistent with the desire for the study to be market operator agnostic.



Of the two configurations that assume parallel operation for two markets with market-to-market seams, the Two Market B configuration outperformed Two Market A by $381 million per year. This was largely due to the greater capacity savings that arose from having a more diverse footprint the fully integrates the Northwest and Southwest loads. Two Market A did not achieve this level of capacity savings as California was not integrated with the rest of the core Western footprint.

In terms of curtailments and carbon emissions, the three RTO constructs performed comparably, although the West-wide footprint was slightly better at reducing emissions and integrating renewables.

Question 6: How do operational benefits change if more transmission is built?

The core cases in the study assumed a relatively conservative transmission buildout based on the application of a development screening criteria designed to evaluate the certainty of planned transmission projects. To assess how market benefits might change in response to a larger transmission buildout, several generic high-voltage upgrades were added to the Western system, and the Status Quo Real-time, One Market RTO, and Two Market B RTO configurations were re-run.

With the new transmission projects in place, the markets achieved higher production cost savings as the added transmission facilitated access to low-cost generation and helped to reduce transmission losses.

The Status Quo Real-time market had $113 million greater operational benefits with the transmission in place, and the system experienced fewer curtailments and emissions. The One Market RTO and Two Market B cases had similar results as they had $90 million and $81 million per year of additional savings, respectively, with the additional transmission overlay in place.

These results indicate that the benefits of regional markets are bolstered by larger transmission buildouts. It is likely that these results are conservative in terms of estimating the benefits driven by new transmission as they do not account for how the new transmission upgrades may enable more sharing of resources across the system and therefore assist in greater levels of load diversity benefits and do not capture other benefits that may be offered by transmission expansion.

Question 7: How sensitive are RTO configurations to a Federal or West-wide carbon pricing regime?

To understand how market benefits accrued under a future with a West-wide carbon price, a $41 dollar per metric ton carbon adder was applied to thermal units in the Western states, adjustments were made to the assumed California carbon modeling framework, and the three RTO market configurations were re-run as a sensitivity. The results show that RTO benefits are lower with a West-wide carbon price. Operational benefits of the One Market RTO fell by $205 million per year. Similarly, the operational benefits of the Two Market A and Two Market B RTO configurations were $266 million and $105 million per year lower with the carbon price. The reduced operational benefits are likely driven by adding additional costs to many generators in the West, which reduces the spread between low- and high-cost generators and, thus, the potential for more economic dispatch across the West, is reduced in a scenario which has a carbon price across the West.

Importantly, the carbon price was assumed to have no impact on the capacity savings of the RTO construct, which is where most benefits accrue in 2030. Therefore, *total* benefits of the RTO constructs with the carbon price were not significantly different that the total benefits without the carbon price.

The carbon price also had the expected effect of reducing emissions. In reaction to the carbon price, carbon emissions fell by 22% in the One Market RTO configuration, 17% in the Two Market A configuration, and 21% in the Two Market B configuration. By placing a cost on carbon emissions, the simulation sought out the most cost-effective dispatch after considering the implied cost of emissions from the thermal fleet. By shifting generation from coal to gas, emissions fell.

Observations

In addition to findings above, which are in direct response to the key questions that motivated this State-Led Market Study, several additional observations were formed in response to the study's results:

- **The regional economic case for new/expanded markets is supported by the technical findings of the study:** At the regional level, there were not any market configurations in which the high-end ongoing incremental cost estimates to operate these markets eclipsed the high-end gross benefits estimated in this study. While actual market participation and development decisions

require a more detailed evaluation, this study's regionally focused findings demonstrate that from an economic perspective regional markets are likely to present savings.

- **Bigger is still better:** Gross benefits results for the various market configurations considered support the perspective that bigger (in terms of footprint) and more comprehensive (in terms of services) markets are best suited to maximize benefits for the most Western states. The study found that all states tended to benefit when footprints were broadened, resources were shared, and transmission barriers and operational constraints were removed.

- **Alternative types of regional coordination could help achieve capacity benefits estimated in the study:** Study results demonstrate the economic benefits (in the form of capacity savings) can accrue when regional markets help to achieve load diversity benefits. However, these capacity savings could also be achieved under even the most limited market frameworks so long as the proper capacity sharing and operational programs are in place.

- **Energy-rich future:** Given the rapidly evolving resource mix in the West, the study suggests that, over time, operational/dispatch savings from new regional markets are likely to decrease relative to present-day savings. However, integration benefits, reliability benefits, capacity savings from resource and load diversity, among a host of other benefit drivers will replace and likely exceed any lost energy benefits driven by an evolving resource mix.

- **State-level metrics:** Observed reductions in regional production costs across all market footprints and constructs suggests that new and expanded markets generally lead to more efficient operations and use of the transmission system. However, at the state-level, the APC metric, which considers power prices, purchases/sales, and net long/short positions, is complicated to calculate, and indicates that not all states may realize operational savings. Another uncertainty is the consideration that utilities may implement hedging or other trading strategies to minimize potential downsides, and these actions cannot be captured in the study. Ultimately, targeted BA- or state-by-state studies of actual market proposals – versus the genericized options considered herein – are the best tool to determine if the benefits of new markets are likely to exceed their cost.

8. Appendix

A. Load Forecasts

Figure 36: Summary of BA Peak and Energy Demand, Inclusive of Reductions from Projected EE and DG

Balancing Area	Annual Energy (GWh)			Peak (Non-coincident in MWs)		
	2020	2030	CAGR (%)	2020	2030	CAGR (%)
AESO	86,220	96,335	1.1%	12,005	13,241	1.0%
AVA	12,941	13,681	0.6%	2,199	2,360	0.7%
AZPS	29,724	36,820	2.2%	7,026	8,563	2.0%
BANC	17,148	18,085	0.5%	4,428	4,931	1.1%
BCHA	63,726	65,681	0.3%	10,905	12,204	1.1%
BPAT	56,050	69,279	2.1%	10,275	12,897	2.3%
CFE	14,971	22,031	3.9%	2,929	4,301	3.9%
CHPD	1,844	1,972	0.7%	463	497	0.7%
CISO	214,893	207,680	-0.3%	43,849	47,852	0.9%
DOPD	1,813	2,182	1.9%	386	464	1.8%
EPE	8,548	10,409	2.0%	1,985	2,218	1.1%
GCPD	5,379	10,592	7.0%	846	1,496	5.9%
IID	3,681	3,805	0.3%	1,067	1,175	1.0%
IPCO	17,103	19,494	1.3%	3,670	4,842	2.8%
LDWP	26,910	35,362	2.8%	6,212	7,961	2.5%
NEVP	37,361	34,463	-0.8%	8,292	9,325	1.2%
NWMT	12,666	13,186	0.4%	1,961	2,070	0.5%
PACE	48,838	52,933	0.8%	8,685	11,259	2.6%
PACW	20,779	22,341	0.7%	3,874	4,016	0.4%
PGE	20,627	22,453	0.9%	3,787	3,870	0.2%
PNM	14,005	14,750	0.5%	2,581	2,987	1.5%
PSCO	47,964	51,670	0.7%	9,640	10,814	1.2%
PSEI	29,658	25,773	-1.4%	5,431	5,204	-0.4%
SCL	9,484	8,968	-0.6%	1,797	1,582	-1.3%
SRP	30,351	39,103	2.6%	7,347	9,444	2.5%
TEPC	12,640	17,275	3.2%	3,525	3,502	-0.1%
TIDC	2,705	2,455	-1.0%	643	647	0.1%
TPWR	4,866	4,888	0.0%	937	914	-0.2%
WACM	22,657	28,183	2.2%	3,925	4,514	1.4%
WALC	9,538	8,922	-0.7%	1,919	1,764	-0.8%
WAUW	827	841	0.2%	159	161	0.1%

B. System Assumptions

Demand

BA annual peak and energy demand assumptions were input into the model for the 2020 and 2030 study years. Energy and demand assumptions for 2020 were based on 2019 actual hourly BA loads

sourced from the U.S. Energy Information Administration (EIA) EIA-861 data and therefore include the effects of energy efficiency and distributed generation. For the 2030 study year, CAISO area load assumptions were based on the California Energy Commission's (CEC's) 2019 IEPR "mid-mid" forecast, which assumes "mid" levels of energy efficiency savings and a "mid" level of distributed generation. The CEC forecast also includes forecasted load growth from vehicle electrification. For remaining Western BAs, 2030 load assumptions were based on 2030 WECC Anchor Data Set (ADS) assumptions, which are sourced from 2019 WECC Loads and Resource forecasts submitted by WECC BAs. Assumptions regarding energy efficiency and distributed generation were consistent with the 2030 WECC ADS for BAs outside of California. The load assumption data is summarized in *Appendix A.*

Generation Supply

The 2020 generation supply was based on generators operating in the Western Interconnection as of December 31, 2019. This generation supply database was informed by EIA-860 data as well as the S&P Global Market Intelligence database of generators.

The 2030 generation supply was built starting from the 2020 system, adjusting the generation fleet based on:

- Generators under construction;
- Announced or anticipated generator retirements;
- New renewable generation required for public policy or clean energy goals;
- Forecasted levels of energy storage; and
- Forecasted deployment of other generating resources.

Most of the data to achieve the above objectives was sourced from the 2028 and 2030 WECC ADS generator databases as well as data from the California Public Utilities Commission (CPUC) 2019-2020 Reference System Plan. Generator plans from several, recent IRPs were considered and reconciled with the above databases to develop the 2030 generation forecast.

Wind and Solar Modeling

Wind and solar generation profiles were developed for the study based on data from the NREL Wind and Solar Integration National Datasets (WIND and SIND, respectively). These datasets include historical production estimates for thousands of existing and viable future wind and solar site locations across the study footprint.

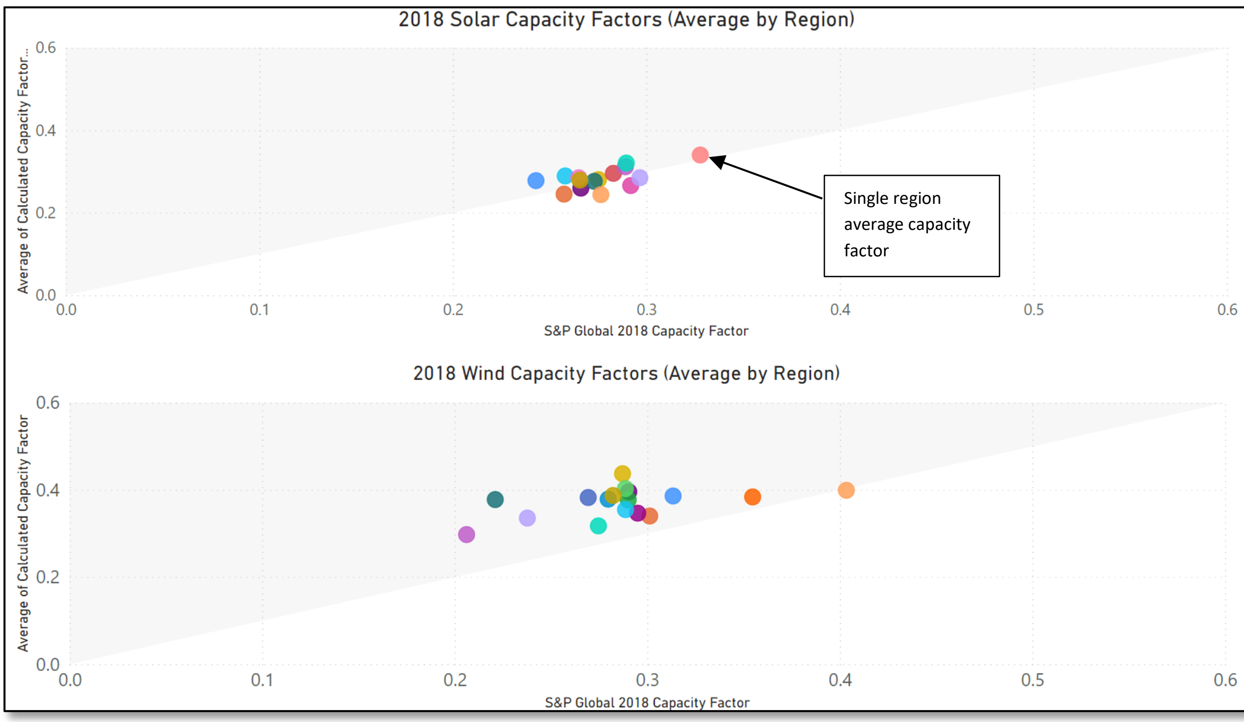
Per-unit production profiles in this study were developed based on a "nearest neighbor" approach similar to techniques presented in other studies using NREL WIND and SIND datasets.[17] In this approach, each wind or solar unit in the production cost model was matched with one or more of its nearest WIND or SIND sites based on latitude and longitude. In compiling profiles for wind units, off-shore WIND sites and sites beyond 100km from the unit location were excluded from this aggregation. A 100m hub height

[17] Midcontinent Independent System Operator Renewable Integration Impact Assessment

was assumed for all wind units in the study. Solar profiles taken from SIND were altered to exhibit an inverter loading ratio of 1.4.

Wind and solar profiles created for existing units with EIA codes were validated by comparing the simulated capacity factor to historical capacity factors sourced from S&P Global for 2018. This capacity factor comparison indicated a reasonable level of error – with a nearly 1:1 match for solar, but a slight overestimation of capacity factor for wind units in the study.[18]

Figure 37: Calculated vs. Historical Solar and Wind Capacity Factors



Coal Retirements

A forecast of coal retirements for 2030 was developed for the study. The Lead Team assisted with the identification and validation of announced or planned coal retirements, including recommending that certain plants scheduled for retirement in late 2030 be assumed to be retired for the duration of the 2030 study year. The primary data sources for identifying coal plant retirements were public announcements from generator owners, utility resource plans, and data submitted to WECC or the EIA. The retired capacity was replaced in the model with the best-available information on resource plans for each owner, as generally sourced from IRPs. The table below summarizes the retired units and the assumed dates. While developing a realistic and accurate perspective on future coal retirements is

[18] The overestimation in capacity factor for wind units is likely caused by the assumption of 100m hub height in the NREL WIND database.

important to the study, since the resource mix was held constant throughout the market configurations, no single unit retirement is likely to material impact the study findings. Based on this list, the study assumed that nearly 13 GW of coal would be retired by 2030.

Figure 38: Coal Retirement Assumptions

Plant Name	Owner	Capacity (MW)	Retirement Year
Centralia 1	TransAlta	670	2020
Boardman	PGE, Idaho power	601	2020
Cholla 4	PacifiCorp	380	2020
Escalante	Tri-State	247	2020
North Valmy 1	NV Energy, Idaho Power	254	2021
Comanche 1	PSCo	325	2022
San Juan 1 & 4	PNM, TEP, other municipalities	847	2022
Martin Drake	Colorado Springs Utilities	208	2023
Jim Bridger 1	PacifiCorp, Idaho Power	531	2023
Comanche 2	PSCo	335	2025
Cholla 1	APS	116	2025
Cholla 3	APS	271	2025
North Valmy 2	NV Energy/Idaho Power	290	2025
Naughton 1 & 2	PacifiCorp	357	2025
IPP	Multi (UT and CA municipals)	1,800	2025
Craig 1	Tri-State, SRP, PRPA, PacifiCorp, PSCo	428	2025
Centralia 2	TransAlta (contract with PSE)	670	2025
Dave Johnston 1-4	PacifiCorp	760	2027
Springerville 1	TEP	387	2027
Jim Bridger 2	PacifiCorp, Idaho Power	527	2028
Craig 2	Tri-State, SRP, PRPA, PacifiCorp, PSCo	670	2028
Colstrip 3	See (1)	740	2029
Craig 3	Tri-State	601	2029
Hayden 1-2	PSCo, PacifiCorp, SRP; See (3)	380	2029
Rawhide 1	Platte River Power Authority	280	2029
Ray Nixon Power Plant	Colorado Springs Utilities	208	2029
	Total Retirements by 2030	**12,883 MW**	

State Energy Policy

The different energy policy priorities and goals for each state participating in the study were considered in developing the generation portfolios for the study. For those states that had an approved renewable portfolio or clean energy standard, the study included an analysis to confirm that appropriate amounts of renewable/clean energy were included in the resource portfolios to ensure that generation levels were in-line with state energy policy requirements. A list of the policies considered in the study, as developed by the Lead Team in 2019, is included in an appendix to the State-Led Market Study's Market and Regulatory Review (which is a companion report to this one). Nine of the states involved in this project have renewable energy requirements or goals. Additionally, five of the states participating in this project are aggressively pursuing a zero-carbon electricity supply, through legislation or regulation: California, Colorado, New Mexico, Nevada, and Washington. All these states had significant legislation

directing energy policy pass within the last few years. This reflects the extremely dynamic nature of this project and state energy policy goals. The study sought, to the greatest extent possible, to capture the state energy policies that were in place at the time the generation portfolios were developed.

Distributed Generation

Distributed Generation (DG) constituted behind-the-meter rooftop solar PV and were forecasted based on the NREL Regional Energy Deployment System (ReEDS) study, with the state-level ReEDS data applied to BAs based on their share of each state's load. The so-called "Mid-Mid" PV generation of the most recent CEC's Integrated Energy Policy Report (IEPR) was used for the DG forecast in the CAISO investor-owned utility territories.

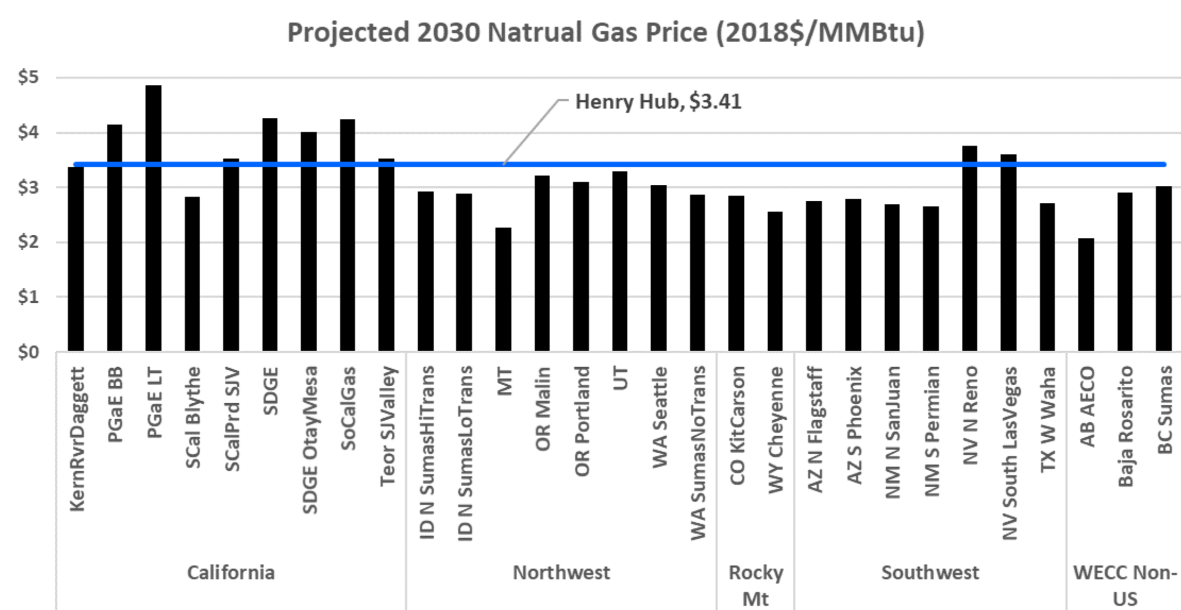
Fuel Prices

Fuel price assumptions can impact the variable cost of thermal generators, which impact their economics, energy prices, and the APC calculation. Since much of the load in the West is served by gas-fired plants, gas prices can have an outsized effect on results of market benefit analyses. Similarly, coal prices impact the marginal cost of coal units and therefore can also impact study results.

For natural gas, Henry Hub gas price forecasts were converted to burner tip pricing using West-wide assumptions from the CEC 2019 IEPR. For the 2020 study scenarios a Henry Hub price of $2.64/MMBTU in 2018$ was assumed based on the CEC's NAMGAS Model published October 2019.

The forecasted 2030 Henry Hub average price was $3.41/MMBTU in 2018$. Burner tip prices for the 2030 studies are summarized by Figure 39, below.

Figure 39: Burner Tip Natural Gas Prices for the 2030 Studies



Coal prices were held constant for both 2020 and 2030 studies. Price estimates were based on data submitted to WECC that was intended to be integrated into the 2030 ADS. The forecasted prices were based on EIA-923 submittals for 2017-2019, with an assumed 25% pricing discount to account for the inflexibility of the coal fuel supply, which often are tied to fixed take-or-pay contracts. This price forecast aligns with the current EIA Annual Energy Outlook 2019 price forecasts. Average coal prices for the 2020 and 2030 studies are summarized in Table 40 below.

Figure 40: Coal Prices for the 2020 and 2030 Studies

Generator or Zone	Price (2018$/MMBtu)
Alberta	$1.20
Apache	$1.88
AZ	$1.52
Battle_River	$1.20
Boardman	$1.59
Bonanza	$1.39
CA_South	$2.83
Centennial_Hard	$0.96
Centralia	$1.83
Cholla	$1.53
CO_East	$0.95
CO_West	$1.58
Colstrip	$0.96
Comache	$0.95
Coronado	$1.80
Craig	$1.56
Dave_Johnston	$0.67
Dry_Fork	$0.47
Escalante	$1.59
Four_Corners	$1.94
Hayden	$1.58
Hunter	$1.23

Generator or Zone	Price (2018$/MMBtu)
Huntington	$1.35
ID	$1.93
Intermountain	$1.52
Jim_Bridger	$1.93
Laramie_River	$0.73
Martin_Drake	$1.06
Naughton	$1.52
Neil_Simpson	$0.60
Nixon	$1.06
NM	$1.60
Pawnee	$0.84
Rawhide	$0.91
San_Juan	$1.28
Springerville12	$1.20
Springerville34	$1.55
Sunnyside	$1.35
UT	$1.30
Valmy	$2.04
WY_PRB	$0.68
WY_SW	$1.81
Wygen	$0.59
Wyodak	$0.82

All other fuel prices – such as oil, biofuels, and uranium – were consistent with the 2030 WECC ADS for in the 2020 and 2030 studies. Based on prior modeling experience these prices have little impact to study results because these plants are either very high cost or very low cost, which means the fuel price has little impact on their dispatch and relative operational costs between scenarios.

Thermal Unit Parameters

Certain thermal operational parameters were updated in this study based on data resulting from an InterTech report commissioned by WECC.[19] Start-up costs, unit ramp rates, and minimum up/down times were made consistent with data published in that report, on a unit category basis. In addition, the study leveraged historical average variable O&M rates for those thermal units mapped to the S&P Global database of generators. Aside from these updates, which were intended to improve the accuracy of the assumed thermal unit variable costs, the dataset was consistent with the WECC ADS.

Transmission Topology

Transmission topology refers to the transmission lines, transformers, substation, and other electrical facilities that make up the transmission grid. For the 2020 study, the topology of the transmission system was based on a WECC-published power flow case that was adjusted by removing projects planned to be in-service after the end of 2020. Therefore, no new or incremental transmission projects beyond what was planned for or already operational during 2020 were included in the 2020 study cases.

The 2030 study required a representation of incremental transmission projects and upgrades. The study included regionally significant (i.e., >230 kV) incremental transmission projects that met one or more of the following criteria:

1) Are currently under physical construction; or
2) Have been granted a Certificate of Public Convenience and Necessity, a Certificate of Environmental Compatibility, or similar, by the transmission provider's relevant regulatory body(ies); or
3) Have been approved by an ISO board of directors; or
4) Are planned to be in-service *prior* to 2024 and are included in an approved or acknowledged action plan or near-term plan (as applicable) associated with a utility IRP.[20]

The following projects met one or more of these criteria and were included in the 2030 study model:

- Gateway West D.2 (Aeolus - Bridger) 500-kV
- Gateway South (Aeolus - Mona) 500-kV
- Delaney-Colorado River (TenWest Link) 500-kV
- Mesa 500 kV Substation Project
- Round Mountain / Gates Reactive Support

In addition to these major upgrades, transmission upgrades below 200-kV were included on the basis that these upgrades are required for reliability and are required to maintain a reasonable electrical

[19] InterTek Update of Reliability and Cost Impacts of Flexible Generation on Fossil-fueled Generators for Western Electricity Coordinating Council
[20] This criterion is only applicable in instances when integrated resource planning processes include specific transmission projects.

connection between the higher- and lower-voltage (i.e., sub transmission or distribution) systems. In addition to modeling individual transmission elements, modeling included representation of WECC path rating definitions and certain operational nomograms.

GHG Prices

California is the only Western state that has an enacted cap-and-trade carbon policy that influences the economic commitment, dispatch, and import of power generation. In this study, California's GHG policy was represented consistently with what was assumed in the development of the CPUC 2019 Reference System Plan (which was based on Low Trajectory in the 2019 IEPR Preliminary Nominal Carbon Price Projections).[21] The assumed values for 2020 and 2030 are summarized in Figure 41, below.

Figure 41: California GHG Policy Modeling

Study Year	Carbon Price (2018$/metric ton CO2e)	Unspecified Import Rate (2018$/MWh)
2020	$18.65	$7.98
2030	$62.15	$26.60

The carbon price applies to all carbon-emitting generation physically within California ("in-state") as well to imported resources from out-of-state (though the emissions rate varies depending on whether the import is resource specific or not). The cost adder for each generator is calculated by the model based on the CO_2 emission rate of the in-state and specified out-of-state generating units. Other market imports into California that are "unspecified" are subject to the unspecified import rate. This rate is calculated based on the average emission rate of a gas-fired combined-cycle plant.[22]

C. Market Modeling Variables

This section addresses assumptions critical to estimating the operational benefits of the market configurations at issue in this study. Transmission/trading costs were adjusted for each market construct to represent the cost required to transfer power between BAs. Since certain market constructs are likely to provide a limited amount of transfer capability for in-market transactions between BAs, the study made assumptions to represent this limitation. In addition, operational reserves, including spinning contingency reserves, regulation/load following reserves, and frequency response obligations, were represented in the operational modeling and were adjusted to represent the various market constructs and footprints.

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[21] 2019 Reference System Plan and CARB price projections source: https://efiling.energy.ca.gov/GetDocument.aspx?tn=227328&DocumentContentId=58424

[22] Special modeling is used to represent imports from BPA. These imports are assigned a much lower import rate, which applies to a finite set of energy.

By adjusting the above variables within the production cost model, the study sought to reasonably represent the operational impacts of real-time, day-ahead, and RTO market constructs to make comparisons of each market configuration's relative benefits.

The following sections detail modeling variables that were adjusted to represent each market configuration.

Transmission/Trading Costs

Assumptions for the transmission wheeling rate, or transaction cost, for each of the three different market types are described in Figure 42 below.[23] Certain market constructs allow transmission wheeling rates between BAs to be removed or reduced, which helps drive more efficient and optimized system operations.

Figure 42: Summary of Wheeling Rate Modeling for Market Structures

Market construct[24]	Intra-market exchange		Export from market footprint	
	Real-time	Day-ahead	Real-time	Day-ahead
Real-time Market (EIM)	No wheeling rate	Tariff rate	Tariff rate of wheel-out transmission provider	
Day-ahead Market	Estimated market rate ($3/MWh) applied to transfers above real-time market transfer levels (which are $0/MWh) and tariff rate applied to transfers that exceed assumed day-ahead market transfer limits		Tariff rate of wheel-out transmission provider	
RTO	No wheeling rate or market rate for all transactions		Tariff rate of wheel-out transmission provider	

This study assumes that bilateral transactions are those transfers that occur between BAs outside of or bordering the given market construct. Under this paradigm, to transfer resources across multiple systems transmission rates are "pancaked," which can prevent the most economical resources from serving load. The study assumed each transmission provider's non-firm transmission rate as the

[23] This study uses the terminology "wheeling rate" to refer to tariff-based transmission rates associated with the provision of transmission service. We refer to "hurdle rates" between areas as a modeling assumption that can include wheeling rates or other transaction costs, such as implied costs associated with modeling imports for a carbon/GHG program.

[24] Bilateral transactions will continue in most market structures (with the exception of the RTO), though their percentage of total transactions will vary, decreasing as the market moves from real-time to day-ahead optimization. Bilateral transactions will be modeled using the tariff rate as the wheeling rate for bilateral transfers between BAs or markets.

cost/wheeling rate associated with bilateral transactions. Bilateral transactions are assumed to continue to occur in the day-ahead and real-time market constructs when flows between areas exceed the MWs set aside to facilitate in-market transactions.

For those bilateral transactions that occur outside of the market construct, cost adders over and above the non-firm rate were included as a modeling proxy to capture administrative costs and the need for trading margins for these transactions. These adders are commonly used to help emulate the "friction" that occurs in bilateral transactions, i.e., a trading margin representing the price differential at which neighboring areas are willing to make a trade. For this work, a $4/MWh commitment adder was included, and a $2/MWh dispatch adder to all tariff-based bilateral transactions. Approximately $1/MWh charge represents administrative costs applicable to both adders, a $1/MWh charge represents the required trading margin applicable to both adders, and a $2/MWh adder for commitment decisions was assumed based on the idea that under a bilateral market it is less likely the unit commitment decisions will be influenced by bilateral trades unless there is a significant economic upside (e.g., >$2/MWh).

To represent operations of the real-time-only market, BAs included in the market footprint were assumed to have access to transmission that allows them to freely transact real-time power across BA borders. As such, the generation dispatch was optimized (up to the market transmission limits) without considering transmission costs between the areas within the market. This transmission is assumed to be "free" for real-time transactions. However, day-ahead unit commitment still considers tariff-based wheeling rates. Power exports to BAs outside of or bordering the given market footprint were subject to the bilateral tariff rate wheeling charges for both real-time and day-ahead transactions. The modeling approach used to emulate real-time markets in this study is similar to but not in exact alignment with how the Western EIM and WEIS markets currently operate.

The day-ahead market modeling approach assumes that real-time dispatch and day-ahead commitment are both subject to the same "estimated market rate," which was assumed to be $3/MWh in this study for all day-ahead market configurations.[25] To ensure the study captured only incremental benefits of the day-ahead market structure, in the real-time horizon intra-market transactions were allowed to occur for $0/MWh up to the real-time market transfer limit. Above that limit, the $3/MWh fee was applied for intra-market transactions up until the day-ahead market transfer limit. Any transactions above the day-ahead market transfer limit were then charged the prevailing tariff rate, resulting in a three-tiered transmission rate model in the real-time. Similarly, in the day-ahead timeframe, the $3/MWh rate applied to all transactions up to the day-ahead transfer limit, and any transactions above this level were charged the full tariff rate, resulting in a two-tiered rate model for the day-ahead timeframe. As with the real-time market, exports out of the market footprint were subject to wheeling rates based on the

[25] For context, the EIM Entities, in performing their EDAM Feasibility Study, estimated a $3/MWh hurdle rate.

location of the exporting resource, the area to which power is flowing, and prevailing non-firm tariff rates for the sending BA.

For the RTO configuration, the study assumed that BAs are consolidated (within the market footprint) and as such there will be no transmission hurdles for real-time and day-ahead transactions within the market footprint. Exports from the RTO market footprint were charged the transmission tariff rate of the BA from which the market export occurs.

Changes in transmission rates across these various configurations (and footprints) was a significant driver in determining operational benefits and efficiencies of the market configurations.

Transmission Availability

The study also required assumptions around how much transmission capacity (between BAs) was available in the model for the market transactions at the rates specified above. This transmission capacity assumption is important to the determination of the study results. Consider that the Western EIM has access to only certain amounts of transmission over which to optimize energy dispatch in real-time. If the study were to assume that 100% of transmission was available for the market, it would run the risk of overstating the benefits of the Western EIM and understating the benefits of incremental market services. For this reason, the study attempted to reasonably estimate the amount of transmission capacity available for each market, recognizing that there is no means to accurately predict the exact MWs that are likely to be available in yet-to-be proposed or evolving markets or even under operational markets (like the EIM) where actual transmission available to the market changes frequently. The table below summarizes the assumptions used to estimate the area-to-area transfer capability set aside for each market construct.

Figure 43: Summary of Transmission Capacity Availability for Market Structures

Market Construct	Transmission Availability for Market Transactions
Real-time only (EIM)	• The amount of "free" transmission available to the real-time market was based on an assessment of historic averages of transmission availability in the Western EIM. The assessment showed that, on average, the amount of transmission available for real-time transfers was about 15% of the inter-area transfer capacity. Historical averages of transfer capability were used for participants for which data existed while future participants were assigned the 15% average value. • To seek to replicate the SPP WEIS, the maximum transfer capability between WACM and WAUW BAs was assumed as the real-time transfer limits.

Market Construct	Transmission Availability for Market Transactions
Day-ahead	• Day-ahead transfer limits on in-market transactions was assumed to be approximately 70% of the maximum observed physical flow in the simulation or the historic/anticipated real-time market transfer capability, whichever was greater. • Incremental transfers (above real-time market levels) were available for use at a $3/MWh wheeling rate.
RTO	• All day-ahead and real-time transmission capacity is assumed available for in-market transactions (which do not incur a wheeling rate).

CAISO Net Export Limits

The WECC and CAISO production cost models typically represent a "CAISO Net Export Limit," which is a BA-level constraint that is placed on exports from the CAISO system. The constraint limits the MWs of power the CAISO can send to neighboring regions. The basis for this assumption is that in today's market the CAISO cannot export an unlimited amount of power – typically mid-day excess solar – as neighboring areas are not willing or able to accept exports above a certain level given that they must keep some amount of their own generators online to meet local reliability and resource sufficiency requirements. Therefore, the CAISO export limit serves as a constraint that is more limiting than the physical capabilities of the transmission system. Figure 44 below summarizes the export limits for the CAISO system for the day-ahead and real-time intervals for each of the study's market configurations analyzed in 2020 and 2030. The CAISO export limit is an important assumption, as it can impact estimated renewable curtailments and the benefits of market expansion.

Figure 44: CAISO Export Limit Assumptions

Study Year	Market Configuration	Day-ahead Export Limit (MW)	Real-time Export Limit (MW)
2020	Status Quo: Real-time only (EIM)	5,000	5,000
	One Market: Real-time only (EIM)	5,000	5,000
	One Market: RTO	No Limit	No Limit
2030	Status Quo: Real-time only (EIM)	2,000	7,000
	Status Quo: Day-ahead	No Limit	No Limit
	One Market: Day-ahead	No Limit	No Limit
	One Market: RTO	No Limit	No Limit
	Two Market A: RTO	No Limit	No Limit
	Two Market A: Day-ahead	7,000	7,000
	Two Market B: RTO	No Limit	No Limit

The assumptions above were informed by an analysis of historical CAISO net interchange data. The CAISO also provided feedback and technical presentations to help inform the assumptions. Ultimately, the study assumed a 5,000 MW export limit in the day-ahead and real-time horizons for the real-time-

only (EIM) 2020 configurations.[26] This export constraint was eliminated under the 2020 One Market RTO configuration on the basis that the market would provide willing buyers for all exported power.

For 2030, the Status Quo Real-time configuration the study assumes that in the day-ahead horizon no more than 2,000 MWs can be exported from the CAISO, and no more than 7,000 MW can be exported in the real-time horizon. For all remaining 2030 studies the export constraint was assumed to be eliminated, except for the Two Market A Day-ahead configuration. In the Two Market A Day-ahead scenario, the BAs in California are consolidated into a single market, while the rest of the West operates another market. To reflect the potential for seams along these markets, a 7,000 MW CAISO export limit was assumed for both the real-time and day-ahead operating horizons.

Reserve Requirements

The reserves included in the production cost modeling include spinning reserves, regulation and load following reserves, and frequency response reserves. Non-spinning reserves were not explicitly modeled.[27] In modeling these reserve requirements, GridView™ sets aside generating capacity within a given footprint sufficient to meet the hourly reserve requirement, subject to eligible units' ramping rates, which vary by technology type.

Spinning reserves make up a portion of "contingency reserves" and are needed to respond quickly (~10 minutes) after a reliability event. Regulation reserves automatically balance supply and demand, minute to minute, while load following reserves help to accommodate intra-hour ramps and forecast error (~15 minutes). Finally, frequency response reserves help ensure that the system maintains 60 Hz frequency by quickly responding to large outages or disturbances.

Contingency Reserves (Spinning Reserves)

Modeling of spinning reserves in WECC production cost models is typically done in tiers to best capture the sharing of reserves across the system. Under the Status Quo, the total hourly reserve requirement is carried at the reserve sharing group level, as applicable to a given BA, with sub-constraints layered on at the BA-level ensure that a portion of the total reserves are carried locally at the participating BA level. Consistent with BAL-002-WECC-2, the spinning reserve requirement is set to 3% of hourly load for a given reserve sharing group area. For the Northwest Reserve Sharing Group (which was modified to include new entrants that joined during Fall 2019), each BA in the group must meet 25% of the 3% reserve standard locally (which equates to 0.75% of their hourly load). In the Southwest Reserve Sharing

[26] Guidance and analysis provided by the CAISO suggests that in 2020 it would have been reasonable to model a minimum day-ahead import constraint of 1,000 MWs. However, the model did not react will to this import constraint and therefore, the study effectively removed any import minimum by reverting to the 5,000 MW export limit. The 5,000 MW day-ahead export limit was consistent with work performed by the EIM entities in the EDAM Feasibility Assessment (2019), as well as the CPUC 2018-2019 IRP.

[27] We omit non-spinning reserves based on the assumption that there is sufficient quick-start generation on the system to provide this service. Non-spinning reserves can be held by generation that is not online so long as it can start-up within the required timeframes.

Group area, the 3% hourly reserve requirement of all load in the sharing group is layered on top of a requirement that each BA in the group meet 90% of the total requirement (or 2.7% of hourly load) locally. These modeling methods are generally consistent with the WECC ADS.

The above spinning reserve modeling approach was adopted for the real-time and day-ahead market constructs based on the assumption that Western BAs would be retained, and each would continue to be responsible for meeting their spinning reserve requirements. For the RTO scenarios, BA consolidation is assumed to occur and as such, the spinning reserve requirement was consolidated and carried by the entire market footprint. For the single market RTO scenario, the total system was required to meet a 3% reserve requirement.

Regulation and Load Following Reserves (Flexibility Reserves)

For the status quo, real-time, and day-ahead market scenarios, load following and regulation reserves are calculated and carried at the balancing area level. These scenarios do not assume BA consolidation and thus, the obligation for carrying regulation and load following reserves do not vary for these market constructs.

Under the RTO scenarios, load following and regulation is calculated assuming balancing area consolidation (for the given market footprint) and are carried by the entire market, thereby capturing the diversity of load and renewables under a wider geographic footprint. As explained more below, due to this geographic diversity, the required amount of total reserves under the RTO scenarios is less than the reserves required under the status quo, real-time, and day-ahead scenarios.

Regulation and load following reserve shapes were developed and modeled in the production cost model according to a statistical methodology adapted from NREL and ABB studies.[28, 29, 30] Flexibility reserve shapes were developed to account for variability in net load and forecast uncertainty related to non-dispatchable resources in each market footprint.

Figure 45: Summary of Flexibility Reserve Calculations

Reserve	Calculation
Regulation	$MAX(\sqrt{(1\%\ load)^2 + (Wind\ reqt)^2 + (PV\ reqt)^2},$ $Max\ 20\ minute\ Net\ Load\ Ramp\ within\ hour),$

[28] E. Ela, M. Milligan, B. Kirby, "Operating reserves and variable generation," NREL, August 2011.
[29] E. Ibanez, G. Brinkman, M. Hummon, and D. Lew, "A Solar Reserve Methodology for Renewable Energy Integration Studies Based on Sub-Hourly Variability Analysis," NREL, August 2012.
[30] E. Ela, B. Kirby, E. Lannoye, M. Milligan, D. Flynn, B. Zavadil, and M. O'Malley, "Evolution of Operating Reserve Determination in Wind Power Integration Studies," NREL, March 2011.

Load Following	$MAX(\sqrt{(1\%\ load)^2 + (Wind\ reqt)^2 + (PV\ reqt)^2},$ $Max\ 20\ minute\ Net\ Load\ Ramp\ within\ Hour)$

To develop flexibility reserves for this study, sub-hourly (5-minute) production profiles were compiled from NREL's WIND and SIND datasets for the study region. Hour-ahead forecast data was compiled for solar units, interpolated to a sub-hourly time resolution, and synchronized with PV production data. A 10-minute-ahead persistence forecast was used to approximate the error associated with hour-ahead wind forecasts.

While sub-hourly forecast error was used directly in the regulation reserve calculation, these sub-hourly error values were aggregated to an hourly average for the load-following reserve calculation to represent reserve requirements over a longer time interval.

For each study footprint, the hour-ahead forecast errors from all wind and solar units were aggregated to the appropriate level. A "rolling horizon" method was used to statistically characterize each day's forecast error with same-time-of-day data for +/- 15 days. The data from this 30-day horizon were statistically characterized via a normal distribution from which confidence intervals of forecast error were calculated (95% for regulation reserves and 70% for load following reserves). These confidence intervals represent the wind and solar PV requirements in Figure 45. The 20-minute ramp requirement of a footprint's net load was implemented as a "lower bound" on flexibility reserves such that the system held adequate flexibility reserves in all hours of the simulation.

The various levels of market footprint aggregation shown in Figure 46 indicate the inverse relationship between market footprint size and cumulative flexibility reserve requirements held across the study area.

Figure 46: Max and Average Flexibility Reserves for 2030 & (2020) Footprints

Reserve Footprint and Market Scenario	Cumulative Average Load Following (aMW)	Cumulative Average Regulation (aMW)	Max Load Following (MW)	Max Regulation (MW)
Sum of BAs (Real-time and Day-ahead)	5,177 (2,776)	3,738 (1650)	22,182 (8,838)	11,911 (4,396)
One-Market RTO	3,260 (1,791)	2,090 (1,166)	19,370 (7,445)	10,055 (3,811)
Sum of 2 Mkt A RTO (Sum of A1 and A2)	3,536	2,391	19,910	10,324
Sum of 2 Mkt B RTO (Sum of A1 and A2)	3,672	2,394	19,986	10,298

Figure 47: Cumulative Status Quo RT Flexibility Reserves (2030)

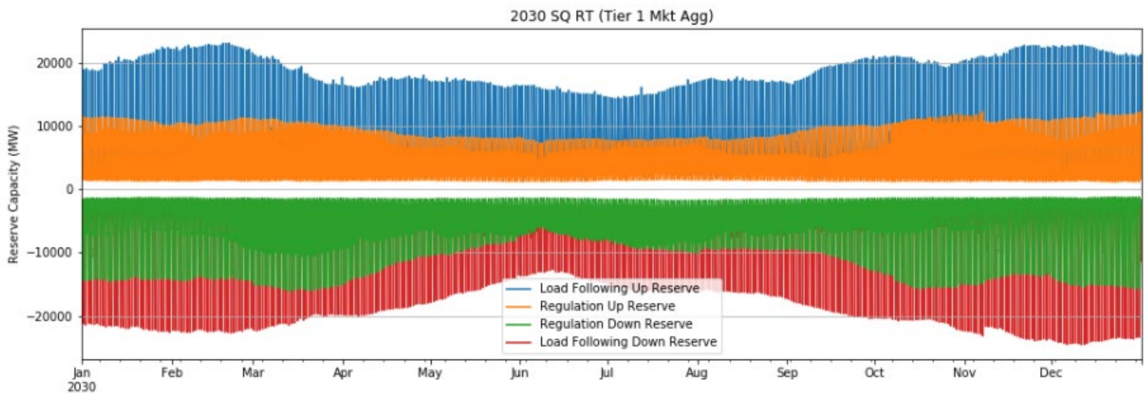
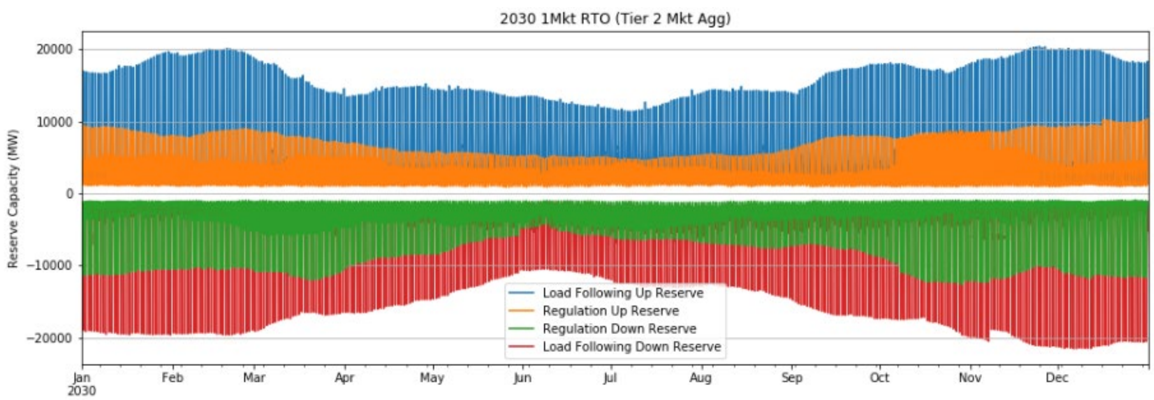


Figure 48: Cumulative One Market RTO Flexibility Reserves (2030)



Frequency Response

Frequency response is a measure of the system's ability to recover after the most severe disturbance in the system. NERC, through its Frequency Response Annual Analysis (FRAA) in support of NERC Reliability Standard BAL-003-1, recommendations the interconnection frequency response obligation (FRO) for each of the four electrical Interconnections of North America. This NERC requirement mandates that BAs ensure resources provide sufficient headroom to cover a portion of the interconnection's frequency response obligation. Modeling this obligation in the State-Led Market Study required assumptions around the total frequency response requirement for WECC, how that requirement is divided among geographic areas under different market configurations, and what resources can contribute to the constraint. NERC's 2019 FRAA was used to define the Western interconnection FRO at 2,506 MW based on the net of the Resource Contingency Protection Criteria and Credit for Load Resources.[31] The details of the modeling approach and allocation of the FRO to market footprints and BAs is covered in the table below. Throughout the market configurations, 50% of the frequency response obligation for the system

[31] NERC 2019 Frequency Response Analysis Report

is assumed to be met by hydro and renewable resources, leaving the 1,253 MW obligation to be met by the remaining responsive resources on the system.

Figure 49: Frequency Response Obligation (FRO) Assumptions

<table>
<tr><th>Study Year</th><th>Market Configuration</th><th>Assumed FRO Obligation</th></tr>
<tr><td>2020</td><td>Status Quo: Real-time only (EIM)</td><td rowspan="2">• 770 MWs of FRO allocated to CAISO based on Palo Verde share, with 50% of assumed to be met by hydro and renewables and the other 50% met by dispatchable thermal resources and batteries in the simulation.
• Remaining 1,736 MW allocated to BAs on load-share basis. 50% (868 MW) of calculated BA-level constraint required to be met by headroom provided by dispatchable thermal and battery resources; remainder was assumed to be met by hydro and renewables.</td></tr>
<tr><td>2020</td><td>One Market: Real-time only (EIM)</td></tr>
<tr><td>2020</td><td>One Market: RTO</td><td>• 1,253 MW requirement met by headroom from dispatchable thermal and battery resources across the One Market footprint, remainder not modeled explicitly and was assumed to be met by system hydro and renewable resources.</td></tr>
<tr><td>2030</td><td>Status Quo: Real-time only (EIM)</td><td rowspan="4">• 770 MWs of FRO allocated to CAISO based on Palo Verde share, with 50% of assumed to be met by hydro and renewables and the other 50% met by dispatchable thermal resources and batteries in the simulation.
• Remaining 1,736 MW allocated to BAs on load-share basis. 50% (868 MW) of calculated BA-level constraint required to be met by headroom provided by dispatchable thermal and battery resources; remainder was assumed to be met by hydro and renewables.</td></tr>
<tr><td>2030</td><td>Status Quo: Day-ahead</td></tr>
<tr><td>2030</td><td>One Market: Day-ahead</td></tr>
<tr><td>2030</td><td>Two Market A: Day-ahead</td></tr>
<tr><td>2030</td><td>One Market: RTO</td><td>• 1,253 MW requirement met by headroom from dispatchable thermal and battery resources across One Market footprint, remainder not modeled explicitly and was assumed to be met by system hydro and renewable resources.</td></tr>
<tr><td>2030</td><td>Two Market A: RTO</td><td rowspan="2">• 1,253 MW requirement divided among the market footprints on a load-share basis, except for CAISO's assumed 770 MW obligation.
• 50% of the resulting obligation calculated for each footprint was required to be met by headroom from dispatchable thermal and battery resource within a given footprint.</td></tr>
<tr><td>2030</td><td>Two Market B: RTO</td></tr>
</table>

Generator Contribution

Select generators were able to contribute to the reserves represented as a constraint in the simulation. In each case, the contribution of each generator was limited by its ramp rate and relative responsiveness within the timeframe required for the specific reserve. The modeling framework did not evaluate the ability of solar and wind to explicitly provide "headroom" type services (e.g., regulation up), though recent studies have demonstrated their ability to provide these services and they may be increasingly important in the future. While these resources may provide these ancillary services in the future, their ability to do so was not the focus of this study.

Figure 50: Generator Contribution

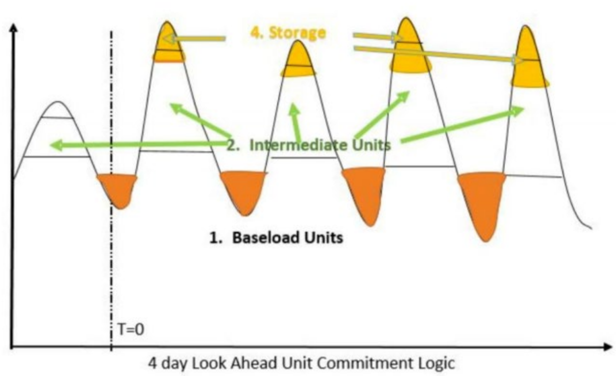
Ancillary Service or Reserve	What Can Contribute
Spinning Reserve, Regulation Up, & Load Following Up	• Coal, natural gas, and other gas-fired thermal generators • Hydro and storage resources
Regulation Down & Load Following Down	• Coal, natural gas, and other gas-fired thermal generators • Hydro and storage resources • Wind and solar resources
Frequency Response	• Coal and natural gas thermal generators • Storage resources

D. Modeling Tool

The GridView™ model, similar to other production cost models, is designed to simulate an electricity market's commitment and dispatch of individual generating units to meet loads, subject to various system operational requirements and transmission constraints. The model's "objective function" – or the "goal" of the optimization algorithm – is to minimize system-wide operational costs for the entire Western Interconnection subject to modeling inputs and constraints. Therefore, modeling results are heavily influenced by input assumptions such as load levels, generation capacity, fuel prices, and thousands of operational and transmission constraints. Economic factors such as the cost to transfer power between BAs, in the form of transmission wheeling rates and (when applicable) GHG costs, will also substantially impact study results.

The tool's optimization algorithm works by first estimating marginal transmission losses across the system. Next, it performs an hourly unit commitment, which seeks to minimize the cost to meet load and ancillary services for sequential operating hours. Generator minimum up/down times, start-up costs, fuel costs, and other operational parameters are all important factors in the unit commitment modeling, which determines which generating units are most economical to start up and which should be shut down. Leveraging the model's "look ahead" functionality allows the commitment decisions to be made based on 24- to 168-hour forecasts of system operations, which helps to more accurately model hydro operations, storage resources performance, and unit commitment of thermal resources with long minimum up/down times.[32]

Figure 51: GridView™ Look-ahead Logic[33]



Once the unit commitment plan is set for a given hour, the model performs the economic dispatch optimization in which it seeks to minimize the dispatch production cost of all generation subject to operational limits, transmission constraints, and the previously established unit commitment plan. The

[32] Minimum up/down times refers to operational constraints for generators that, once online (or offline), must remain in that state for a given amount of time.
[33] Source: https://www.wecc.org/Administrative/PMWG%20Meeting%20Discussion%20January%202018%20Final.pdf

economic dispatch decision considers the heat rate of thermal units, operational limitations of generators (e.g., Pmin/Pmax, ramp rate), weather-based output of renewable generation, and operational costs such as fuel costs, variable O&M, applicable transmission wheeling rates, emission costs, and startup costs.

While this modeling allows the tool to achieve its primary purpose, which is to simulate market operations, it does have limitations, which were addressed in the body of the report.

E. Summary of State-level Combined Benefit Results

2030 Core Studies

2030 Status Quo Day-ahead Annual Benefits

State	APC Benefit ($M)	Capacity Benefit ($M)	Total Benefit ($M)	
AZ	($11)	$56	$45	
CA	$63	$91	$153	
CO	$3	$41	$44	
ID	$2	$44	$45	
MT	$1	$18	$19	
NM	$1	$32	$33	
NV	($13)	$25	$12	
OR	$1	$63	$64	
UT	$3	$28	$30	
WA	($4)	$189	$184	Estimated Ongoing Cost
WY	$2	$9	$10	
TOTAL	**$47**	**$596**	**$642**	$76-226

2030 One Market Day-ahead Annual Benefits

State	APC Benefit ($M)	Capacity Benefit ($M)	Total Benefit ($M)	
AZ	($12)	$59	$47	
CA	$74	$95	$169	
CO	$27	$49	$76	
ID	$1	$44	$44	
MT	$1	$18	$19	
NM	$3	$35	$38	
NV	($12)	$25	$13	
OR	$3	$63	$66	
UT	$9	$28	$37	
WA	($3)	$225	$222	Estimated Ongoing Cost
WY	$5	$12	$17	
TOTAL	**$95**	**$652**	**$747**	$85-254

2030 One Market RTO Annual Benefits

State	APC Benefit ($M)	Capacity Benefit ($M)	Total Benefit ($M)	
AZ	$59	$117	$176	
CA	$288	$190	$478	
CO	$62	$98	$160	
ID	($8)	$88	$80	
MT	$10	$36	$46	
NM	$43	$70	$113	
NV	($5)	$50	$45	
OR	$80	$127	$207	
UT	$43	$56	$99	
WA	$102	$449	$552	Estimated Ongoing Cost
WY	$19	$23	$43	
TOTAL	$694	$1,305	**$1,998**	$187-513

2030 Two Market A Day-ahead Annual Benefits

State	APC Benefit ($M)	Capacity Benefit ($M)	Total Benefit ($M)	
AZ	($4)	$15	$11	
CA	$51	$73	$124	
CO	$26	$49	$74	
ID	($1)	$35	$34	
MT	($1)	$2	$1	
NM	$7	$4	$11	
NV	$0	$6	$6	
OR	$3	$38	$42	
UT	$9	$5	$13	
WA	($9)	$184	$174	Estimated Ongoing Cost
WY	$5	$5	$10	
TOTAL	**$85**	**$416**	**$501**	$85-254

2030 Two Market A RTO Annual Benefits

State	APC Benefit ($M)	Capacity Benefit ($M)	Total Benefit ($M)	
AZ	$42	$30	$72	
CA	$169	$146	$315	
CO	$69	$98	$167	
ID	($0)	$70	$70	
MT	$11	$3	$14	
NM	$44	$9	$53	
NV	$28	$12	$40	
OR	$83	$77	$160	
UT	$45	$9	$54	
WA	$89	$367	$456	Estimated Ongoing Cost
WY	$20	$9	$29	
TOTAL	$598	$831	$1,430	$187-513

2030 Two Market B RTO Annual Benefits

State	APC Benefit ($M)	Capacity Benefit	Total Benefit	
AZ	$58	$117	$176	
CA	$272	$190	$462	
CO	($6)	$16	$9	
ID	($5)	$88	$82	
MT	$6	$36	$42	
NM	$41	$70	$111	
NV	($5)	$50	$45	
OR	$80	$127	$207	
UT	$34	$56	$90	
WA	$104	$449	$553	Estimated Ongoing Cost
WY	$10	$23	$33	
TOTAL	$589	$1,223	$1,811	$187-513

2030 Sensitivities

2030 One Market RTO Carbon Annual Benefits

State	APC Benefit ($M)	Capacity Benefit ($M)	Total Benefit ($M)	
AZ	$107	$117	$224	
CA	$489	$190	$679	
CO	($89)	$98	$8	
ID	($199)	$88	($111)	
MT	($132)	$36	($96)	
NM	$12	$70	$82	
NV	$218	$50	$269	
OR	$142	$127	$269	
UT	($14)	$56	$42	
WA	$19	$449	$469	Estimated Ongoing Cost
WY	($65)	$23	($41)	
TOTAL	$489	$1,305	$1,793	$187-513

2030 Two Market A RTO Carbon Annual Benefits

State	APC Benefit ($M)	Capacity Benefit ($M)	Total Benefit ($M)	
AZ	$151	$30	$181	
CA	$290	$146	$436	
CO	($63)	$98	$34	
ID	($194)	$70	($124)	
MT	($128)	$3	($125)	
NM	$18	$9	$26	
NV	$166	$12	$178	
OR	$163	$77	$240	
UT	($21)	$9	($12)	
WA	$14	$367	$382	Estimated Ongoing Cost
WY	($62)	$9	($52)	
TOTAL	$332	$831	$1,163	$187-513

2030 Two Market B RTO Carbon Annual Benefits

State	APC Benefit ($M)	Capacity Benefit ($M)	Total Benefit ($M)	
AZ	$99	$117	$216	
CA	$444	$190	$634	
CO	($61)	$16	($46)	
ID	($186)	$88	($99)	
MT	($132)	$36	($96)	
NM	$13	$70	$83	
NV	$195	$50	$246	
OR	$142	$127	$269	
UT	($5)	$56	$51	
WA	$35	$449	$484	Estimated Ongoing Cost
WY	($60)	$23	($36)	
TOTAL	$484	$1,223	$1,706	$187-513

2030 One Market RTO Transmission Annual Benefits

State	APC Benefit ($M)	Capacity Benefit ($M)	Total Benefit ($M)	
AZ	$50	$117	$167	
CA	$288	$190	$478	
CO	$67	$98	$165	
ID	$3	$88	$90	
MT	$20	$36	$56	
NM	$41	$70	$111	
NV	$2	$50	$52	
OR	$89	$127	$215	
UT	$48	$56	$104	
WA	$153	$449	$603	Estimated Ongoing Cost
WY	$22	$23	$46	
TOTAL	$784	$1,305	$2,089	$187-513

2030 Status Quo EIM Transmission Annual Benefits

State	APC Benefit ($M)	Capacity Benefit ($M)	Total Benefit ($M)	
AZ	($5)	$0	($5)	
CA	$8	$0	$8	
CO	$4	$0	$4	
ID	$18	$0	$18	
MT	$8	$0	$8	
NM	$2	$0	$2	
NV	$11	$0	$11	
OR	$10	$0	$10	
UT	$9	$0	$9	
WA	$38	$0	$38	**Estimated Ongoing Cost**
WY	$4	$0	$4	
TOTAL	**$107**	**$0**	**$107**	**0**

2030 Two Market B RTO Transmission Annual Benefits

State	APC Benefit ($M)	Capacity Benefit ($M)	Total Benefit ($M)	
AZ	$51	$117	$169	
CA	$271	$190	$461	
CO	$1	$16	$17	
ID	$5	$88	$93	
MT	$14	$36	$50	
NM	$40	$70	$110	
NV	($1)	$50	$50	
OR	$86	$127	$213	
UT	$40	$56	$96	
WA	$146	$449	$596	**Estimated Ongoing Cost**
WY	$14	$23	$38	
TOTAL	$670	**$1,223**	**$1,892**	**$187-513**