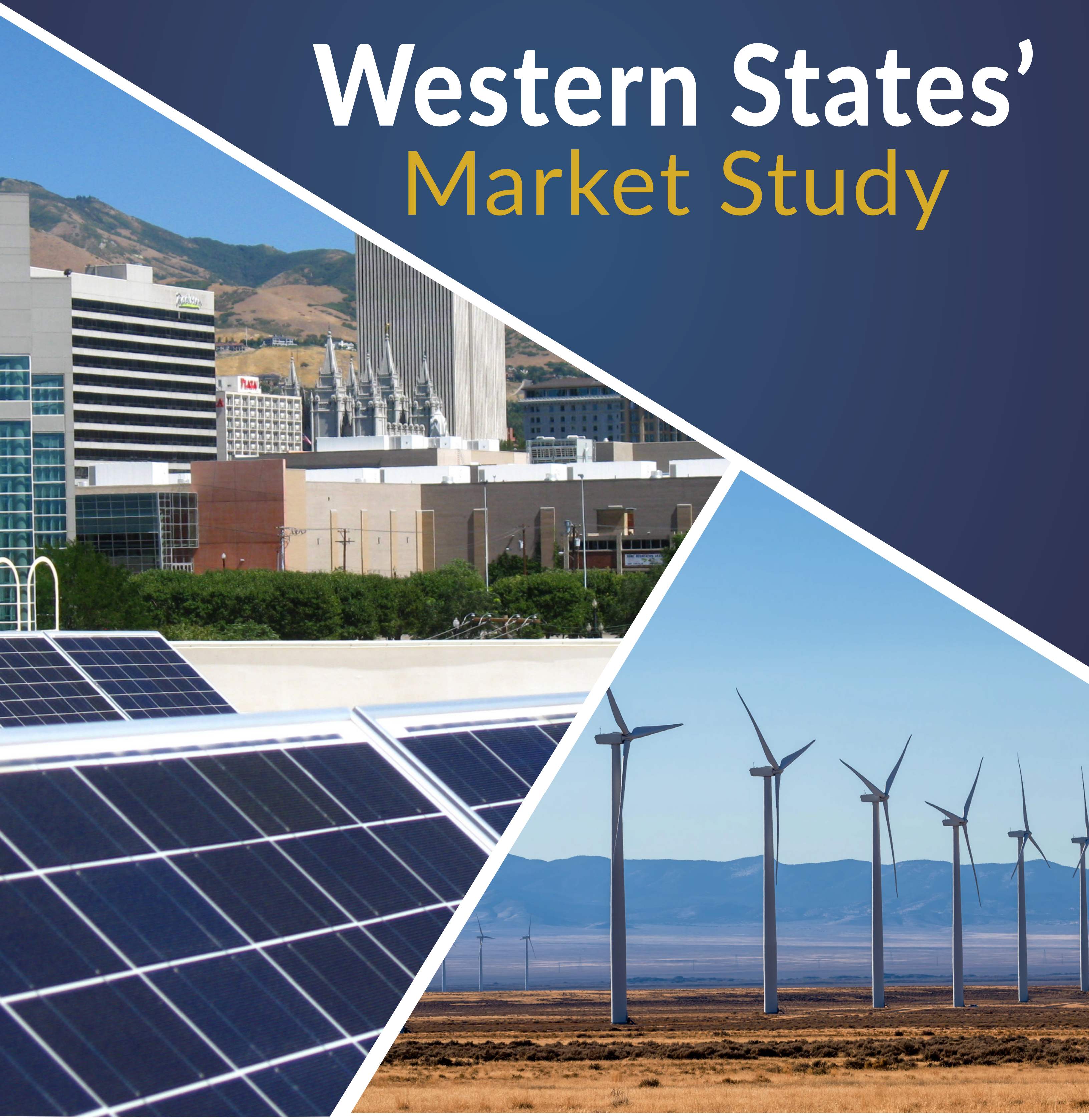
Western States' Market Study



UTAH OFFICE OF
ENERGY DEVELOPMENT

The West's evolving electricity markets are a critical component of our nation's infrastructure, as they have been for roughly a century. We are pleased to add this new study, *Exploring Western Organized Market Configurations: A Western States' Study of Coordinated Market Options to Advance State Energy Policies*, to the list of resources available to help policy makers find solutions to the challenges today's resources and needs present.

This report is the product of invaluable work from partners across the West and was made possible by a generous grant from the United States Department of Energy to Utah (lead recipient), Idaho, Colorado, and Montana (sub-recipients). Eleven western states provided representatives for a lead team that guided the formulation, conduct, and report of the study. Energy Strategies, a Salt Lake City-based consultancy, was our technical partner, performing the modeling, evaluations, and report preparation necessary to the project.

Careful readers will notice the study provides a neutral analysis of wholesale market structures in the West and presents discussion of the tradeoffs inherent in broader organized markets. Noting that wider market structures can more efficiently dispatch resources in a way that could generate west-wide savings, the study also acknowledges the governance tradeoffs, via a qualitative guide for states, that can come with fuller participation in regional transmission organizations. Understanding these points is key to understanding electricity markets in the West.

As with any study, this study's conclusions are heavily dependent on its chosen assumptions. The study is transparent about these assumptions and inputs, which were jointly formulated by the lead team and Energy Strategies. Utilities in the West operate in different climates—natural, economic, and regulatory—and study findings pertinent to one entity might make little difference for another. The study also does not address the specific costs of participation in a region wide market. Nevertheless, regardless of one's assumptions, the study identifies key sensitivities pertinent to any conversation about broadening electricity markets.

While commentators often refer to Western electricity markets as "balkanized," cooperation is the norm in the West. Whether, and when, that cooperation might lead to a broader regional transmission organization is an open question, one that will be informed by this study's results and the ongoing efforts of utilities, regulators, and policy makers in the diverse Western states. Whatever form that cooperation takes in the future, we are confident it will lead to greater efficiencies, increased understanding, and improved living conditions for Westerners. We are grateful to have contributed this study to the conversations well underway throughout the West and are hopeful for a bright and prosperous future.

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THE STATE-LED MARKET STUDY

ROADMAP *Market and Regulatory Review 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.

Market and Regulatory Review Report Contents

1. Introduction and Background

The Utah Governor's Office of Energy Development (OED) received a grant, in partnership with the State Energy Offices of Idaho, Colorado, and Montana, from the U.S. Department of Energy to facilitate a state-led assessment of organized electricity market options. The project is referred to as Exploring Western Organized Market Configurations: A Western States' Study of Coordinated Market Options to Advance State Energy Policies[1] or the "State-Led Market Study." The objective of the "State-Led Market Study*"* was to facilitate a neutral forum, and neutral analysis, for Western States to independently and jointly evaluate options and impacts associated with new or more centralized wholesale electricity markets and their footprints.

The project is composed of two primary pieces of work:

- Technical Modeling (which is summarized in the companion "Technical Report"); and
- Market and Regulatory Review

This document comprises the Market and Regulatory Review and includes the Market Factor Scorecards, which **evaluate how different potential wholesale market structures might facilitate achievement of each state's energy policy objectives**. The Market Factor Scorecards are based on two primary overarching state energy policy priorities, which were identified based on a review of participating state's key energy policies conducted in 2019. For each of the two overarching state energy policy objectives, several metrics/factors are assessed for each market construct, resulting in the "scorecards" included in this report. The report also includes a scorecard for how each market construct might impact the retention of state regulatory authority. While retaining state regulatory authority is not an explicit state policy preference, it has the potential to impact a state's ability to implement its other energy policy priorities and, thus, has been included in this report as a scorecard for ease of review by states and policy makers. Additionally, this report includes an appendix (Appendix 1) that provides findings based on research and analysis on likely approvals required for each market construct, as requested by the Lead Team.[2] This report and appendices comprise the final work products for the "Market and Regulatory Review" stream of work for this project.

2. Overview of Market Constructs and Assumptions

To perform the Market and Regulatory Review, it is first necessary to provide some definitions around each of the market constructs that will be evaluated. The more technical aspects and key modeling

[1] 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.
[2] The Lead Team is made up of up to two state representatives from the Lead State (Utah), grant sub-recipient states (Colorado, Idaho, and Montana), and from other Western states that have elected to participate (Arizona, California, New Mexico, Nevada, Oregon, Washington, and Wyoming). The Lead Team oversaw and guided this study effort and has been responsible for making key decisions during the project.

assumptions for each market are reviewed in the Technical Report which accompanies this document. But the key assumptions regarding these market constructs, which are likely to impact how each market construct does, or does not, contribute to achievement of the metrics for each overarching state policy objective, are reviewed here for the four different electricity market constructs that are assessed herein.

These market constructs are generalized and are intended to, at a high-level, capture qualities and benefits of different market options. Thus, it is important to understand that these generic market constructs will not, and are not intended to, capture the finer details of individual markets operated by different service providers. Consistent with the direction provided by the Lead Team in the Modeling and Analysis Request ("Request"), the Market and Regulatory Review does not specifically evaluate details of each market services proposal nor of potential market providers. Consequently, there may be differences in the underlying assumptions regarding a market construct and what is ultimately proposed or implemented by a particular market services provider.[3]

To support the Market and Regulatory Review, certain assumptions needed to be made about the underlying components of each of the market constructs. Table 1, below, outlines key assumptions regarding market constructs that are important for this assessment. A brief written overview of the market construct precedes the more detailed table of key assumptions regarding these markets.

Bilateral Market

A bilateral market is a market construct with no centralized, organized optimization of energy transactions. Trades of electricity occur "bilaterally" between two counterparties. This market construct generally has individual transmission tariffs and does **not** include Security Constrained Economic Dispatch (SCED).[4] This type of market construct is often characterized by fragmented operational responsibilities and multiple Balancing Authorities (BAs). The "bilateral only" market construct, still exists in some areas of the West (namely, those that are not yet participating in a real-time electricity market).

Real-Time Market

A real-time market is an electricity market that settles—determines the price—for time periods of one hour or less during the day of delivery.[5] In a real-time market, day-ahead unit commitment is not optimized across participants and non-real-time transactions continue to occur bilaterally. Examples of real-time markets include the Western Energy Imbalance Market (EIM) operated by the California Independent System Operator (CAISO) and the Western Energy Imbalance Service (WEIS) operated by the Southwest Power Pool (SPP).

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[3] For instance, the Day-Ahead Market construct evaluated in this study may or may not be consistent with the ultimate market design developed as part of the ongoing Extended Day-Ahead Market (EDAM) initiative.
[4] SCED determines the most economic dispatch of resources across the grid, taking into account constraints on the system and is generally utilized by organized wholesale electricity markets.
[5] FERC.gov

Day-Ahead Market

The concept of a day-ahead market outside of the construct of a formal Independent System Operator (ISO) or Regional Transmission Organization (RTO)[6] has been contemplated, but to date, has not been implemented in the U.S. Generally, it is expected that a day-ahead market would entail centrally optimized day-ahead unit commitment and real-time dispatch, but participants would continue to administer their own transmission tariffs and transmission planning functions and would retain operational/functional control over their transmission systems. A similar concept was proposed by the (now) Midcontinent Independent System Operator (MISO) in 2008[7] and is currently being contemplated by both the CAISO and the SPP.[8]

Regional Transmission Organization

An RTO or ISO is typically a non-profit organization that is tasked with ensuring reliability and optimizing electrical supply and demand bids for wholesale power in its footprint. ISO and RTO formation was primarily proposed, developed, and enhanced through various orders of the Federal Energy Regulatory Commission (FERC).[9] RTOs and ISOs do not own generation or transmission, but they do perform a variety of tasks including managing transmission and energy flows across the market footprint, performing transmission planning within the market footprint, ensuring reliable operation of the grid, and managing wholesale energy market transactions and cash flows within the market. Examples of ISOs/RTOs include CAISO, SPP, MISO, and PJM Interconnection.

The various market constructs are further summarized in Table 1, below.

[6] The terms ISO and RTO are under interchangeably within the context of this study.
[7] FERC Docket No. ER08-637
[8] CAISO is developing the EDAM through an ongoing stakeholder initiative and SPP is discussing a "Markets+" concept.
[9] Including FERC Orders 888, 889, and 2000

Table 1

Organized Market Type	Bilateral Market	Real-Time Market	Day-Ahead Market	RTO
Centrally optimized dispatch	No central optimization of electricity trades	Centrally optimized real-time dispatch; day-ahead unit commitment **not** optimized across participants	Centrally optimized real-time dispatch and day-ahead unit commitment	
Transmission tariffs	Individual transmission tariffs			Joint transmission tariff for participants in a given footprint
Transmission dedicated to market	Transmission rights required for all bilateral sales/purchases	Limited transmission dedicated to the market (other transactions must explicitly pay for transmission)		Transmission used up to reliability limit
Transmission Planning	Local transmission planning remains with individual transmission providers; regional planning and interregional coordination under Order 1000 remain as they are today			Joint transmission planning by RTO for full footprint for reliability, economic and public policy purposes; some lower voltage transmission planning remains at the local level (as is typical in RTOs)[10]
Operational/Functional Control of Transmission	Remains with individual transmission providers			RTO has operational/functional control of transmission
Reliability Obligations and Balancing Authority Boundaries	As they are today			RTO has primary reliability obligations; BAs are consolidated
Ancillary-Service Co-Optimization	No ancillary service co-optimization	Can, but does not have to, include ancillary service co-optimization and provision		Includes ancillary service co-optimization and provision in the market
Resource Adequacy Implications[11]	Addressed by individual regulators; no market requirement	Market addresses intra-hour resource sufficiency, but does not impact long-term resource adequacy planning and processes	Market addresses day-ahead resource sufficiency, but does not impact long-term resource adequacy planning and processes	Market will include its own longer-term resource adequacy requirements that must be achieved (states may have more stringent requirements, though states' exact roles will depend on the governance structure)

[10] ISOs/RTOs generally perform transmission planning and manage transmission flows across transmission of a certain voltage threshold. Transmission below that voltage threshold may be referred to as "distribution" and will continue controlled by and have local reliability planning performed by the applicable transmission owner. For instance, Southern California Edison's (SCE) transmission of 200 kV or higher is under CAISO's operational control and considered transmission, while most facilities between 50 kV – 200 kV are under SCE's control.
[11] A Resource Adequacy program could be added to the non-RTO market constructs, but the addition of such a program is not explicitly considered as a "part" of these markets.

Organized Market Type	Bilateral Market	Real-Time Market	Day-Ahead Market	RTO
Transparent Access to Market & Operational Information	Very little access to information, what is available is generally aggregated	Transparent access to pricing information for real-time transactions and transmission in the market	Transparent access to pricing information for day-ahead and real-time transactions and transmission in the market	Transparent access to pricing information for day-ahead and real-time transactions and transmission in the market
Ability for Large Commercial/Industrial Consumers to Enter into Power Agreements with Preferred Resource Types (outside of a utility green tariff program)	Unlikely (inability for resource to easily sell its output in a bilateral market)	Unlikely (resource can only easily sell its output in the real-time market)	Possible (resource can easily sell its output in the day-time market and trading hubs likely to be established)	Highly likely (resources can easily sell output to the RTO as we have seen in SPP, MISO, etc.)
Retail Choice	No change to existing retail choice programs and traditional, vertically-integrated utility service provision is assumed under these market structures (as retail choice is a separate policy consideration from market constructs)			

3. Overarching State Energy Policy Priorities

As part of the completion of the Request document in 2019, the Lead Team and the Contractor compiled a list of Western state key energy policy priorities and regulations. This list is included in this report, for reference, as Appendix 2. This review of state energy policy priorities suggested that participating Western states generally have two, high-level primary energy policy objectives:

1. Increased use of clean energy technologies[12]; and
2. Reliable, affordable provision of energy to consumers.

These two overarching energy policy priorities are ***not*** mutually exclusive, and many states are pursuing both policy priorities simultaneously. Some states may lean more towards one overarching goal or the other. Because each state may differently weight these two policy priorities, a Market Factor Scorecard has been produced for each of these two policy priorities. This is intended to allow states to individually consider their respective weighting of each policy priority in evaluating energy market constructs and how those might assist in meeting that state's energy policy priorities.

Although not explicitly a state energy policy priority, states also indicated an interest in the impacts of market constructs on state jurisdiction in key areas. At the request of the Lead Team, an additional scorecard regarding the ability to retain state regulatory authority over key jurisdictional elements under different market constructs was developed and is included in this report. This scorecard can help states assess how markets might impact their state jurisdiction over electricity related matters, which may contribute to a state's ability to successfully implement its energy policy priorities.

Each state likely prioritizes these three "goals" differently. And it should be reiterated that the three market factor scorecards are *not* mutually exclusive. Outlining how different wholesale market constructs are likely to contribute to these three goals will allow states to make their own value judgements between these different priorities and how each wholesale market construct might affect their individual objectives.

4. Market Factor Scorecard Overview and Analysis[13]

For each of the three different energy policy "goals" that make up the three Market Factor Scorecards, a set of metrics was developed. The metrics are individual elements which may contribute to achieving

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[12] For purposes of this effort, clean energy technologies are generally defined as those electricity technologies which have low or no greenhouse gas (GHG) emissions and would include renewable resources such as wind, solar, storage, hydroelectric, geothermal, and other low/no GHG electricity resources.
[13] The Lead Team and Contractor wish to acknowledge and express appreciation to Jennifer Chen and the Nicholas Institute for Environmental Policy Solutions for outlining a logical and useful approach to assessing wholesale market options and how they contribute to state policy goals. The March 2020 paper entitled *Evaluating Options for Enhancing Wholesale Competition and Implications for the Southeastern United States* provided an inspiration for the approach utilized in these Market Factor Scorecards.

the broader energy policy goals. The metrics were developed by the Contractor in coordination with the Lead Team and were deemed the appropriate key metrics to assess for each overarching goal.

A ranking key was developed and utilized to rank how each of the market constructs might facilitate (or not facilitate) achievement of the individual metrics within each of the three market factor scorecards. A key to the rankings can be found in the table below. Some metrics received a "ranking range," to help account for the high degree of nuance and variables associated with some of the metrics.

It is important to be mindful that the following scorecards represent generalized scores that are based on simplified assumptions regarding market design. Invariably, the specifics of market designs, governance structures, and participating entities could have significant impacts on the scores and associated benefits.

Rankings for the Market Factor Scorecards	
Icon	**Meaning**
Excellent	Market construct is expected to substantially support achievement of this metric
Very Good	Market construct is expected to mostly support achievement of this metric
Good	Market construct is expected to somewhat support achievement of this metric
Fair	Market construct is expected to minimally support achievement of this metric
Poor	Market construct is not expected to support achievement of this metric
**Note that multiple icons may be utilized to illustrate how a market construct contributes to the relevant metric, depending on the outcome of the assessment.*	

5. Increased Use of Clean Energy Technologies Market Factor Scorecard

This section outlines the metrics that were used to help assess whether a market construct is likely to contribute to the overarching goal of *increasing use of clean energy technologies*. This energy policy priority was evident in review of Western state energy policies, as many states have Renewable Portfolio Standards (RPSs) or other goals designed to increase the use of clean energy technologies across the grid. And, thus, it was determined a market factor scorecard would be helpful to understand how each market construct might help achieve *Increased Use of Clean Energy Technologies*. Six metrics were identified as important to helping achieve this overarching policy goal and the following subsections discuss how each market construct was ranked at helping achieve these metrics.

Efficient grid operation which allows low (and zero) marginal cost resources to be dispatched and reduces overall costs of integrating clean electricity technologies

Ability of Market Construct to Support Increased Use of Clean Energy Technologies	**Bilateral**	**Real-Time**	**Day-Ahead**	**RTO**
Efficient grid operation which allows low (and zero) marginal cost resources to be dispatched and reduces overall costs of integrating clean energy technologies	*Fair*	*Good*	*Very Good*	*Excellent*

Many of the states (or portions thereof) that make up the Western Interconnection have ambitious renewable and/or clean energy goals. To maximize production of these technologies, a market construct should promote efficient grid operation and dispatch zero and low marginal cost resources (such as wind and solar). Market constructs can also support increased use of clean energy technologies by reducing the costs associated with integrating these technologies onto the grid. The use of SCED, which is used in organized market constructs, can help ensure that low and zero marginal cost resources are dispatched. The more time horizons SCED is utilized on, the more likely low and zero marginal cost resources are to be utilized. Additionally, the fewer hurdles there are to dispatching these resources across the footprint, the more likely they are to be dispatched.

Bilateral: A bilateral only market construct generally involves individual BAs optimizing generation within their own footprint (or remote generation to which they have associated transmission rights). Other generation, including low and zero marginal cost clean energy resources are typically only utilized if their costs, including transmission wheeling costs necessary to access them, are lower than other options available. Locating and transacting for generation from other parties in the bilateral construct can be a rather manual process. With the 39 BAs and 63 transmission providers in the Western

Interconnection,[14, 15] a bilateral market likely misses opportunities to utilize low or zero marginal cost clean energy resources and increases curtailment of these resources relative to other market constructs. Additionally, integrating these resources across 39 different areas is unlikely to reduce integration costs and likely causes such costs to be higher than they would be if optimization and resource sharing occurred across a larger footprint. ***Thus, a bilateral market is ranked as "fair" in achieving this metric.***

Real-Time: A real-time market helps to improve the dispatch and utilization of low and marginal cost resources and reduces their curtailment by utilizing SCED for real-time transactions. For example, as a result of being able to share, in real-time, resources' output across a larger footprint, the Western EIM has seen, since 2015, 1,400,055 MWh in avoided curtailments in the CAISO's footprint, with an associated avoided emissions of 599,144 metric tons of CO_2.[16] The centralized dispatch and optimization of resources and ability to share resources across the footprint of a real-time market should also decrease the costs of integrating clean energy technologies. Compared to the day-ahead and RTO market constructs, a real-time market is limited in its ability to accomplish these things because not all generation in the footprint is necessarily participating in the market, the ability to centrally optimize is only in real-time, and there is a limited amount of transmission available to the market. ***Thus, a real-time market is "good" at promoting efficient grid operation, including dispatching low and zero marginal cost resources and reducing costs of integrating clean energy resources.***

Day-Ahead: A day-ahead market further increases the ability to support efficient grid operation beyond what is offered by a real-time market. This occurs in several ways, first, from the likely increased availability of free (or low cost) transmission within the market. This allows more sharing of free and low marginal cost resources across the footprint. Additionally, the ability to make unit commitment decisions on a day-ahead basis across a larger footprint should allow additional zero or low marginal cost energy to be utilized more fully and should further reduce curtailments of clean energy technologies. For instance, an Arizona gas plant may not need to be committed if that utility can count on exports of California solar at key hours. And the California solar may have otherwise been curtailed, due to the Arizona gas plant being online, had it not had the opportunity to serve the needs of the Arizona entity. ***A day-ahead market is ranked as "very good" at achieving this metric. Its actual ability to do so will depend on market design and the amount of generation and transmission committed to the market. As generation and transmission in the market increases, a day-ahead market will begin to converge with the benefits an RTO offers for this metric.***

RTO: Of these market constructs, an RTO is expected to provide the greatest ability to achieve efficient grid operation, which allows zero and low marginal cost resources to be dispatched and reduces overall costs of integrating clean energy. An RTO best facilitates achievement of this metric because it generally

[14] Western Electricity Coordinating Council (WECC): Western Interconnection Balancing Authorities Map
[15] NERC: Compliance Registry Activity Report (April 2, 2021 – May 14, 2021)
[16] CAISO: Western EIM Quarterly Benefits Report, Q1 2021

optimizes all generation in the footprint (outside of self-schedules[17]) and can utilize all available transmission, which may be limited in other market constructs. Integration of these resources, including the ancillary services to support them, can be co-optimized with the dispatch of zero and low marginal cost energy resources. ***Thus, a real-time market is "excellent" at promoting efficient grid operation, including dispatching low and zero marginal cost resources and reducing costs of integrating clean energy resources.***

Lower barriers to access new generation in high-quality renewable resource locations

Ability of Market Construct to Support Increased Use of Clean Energy Technologies	Bilateral	Real-Time	Day-Ahead	RTO
Lower barriers to access new generation in high-quality renewable resource locations	*Poor*	*Poor*	*Good*	*Excellent*

States seeking to increase the use of clean energy technologies may be interested in accessing new renewable resources located in the West's highest quality resource areas. These locations, where high-capacity factor resources (such as wind and solar) are located are often remote from load centers and may be remote from the states that seek to access them. For clarity, this metric is focused on access to ***new generation***. It also does not attempt to account for all the nuances in individual state policies that may come into play as states seek access to new clean energy resources in various locations across the West (e.g., delivery requirements for state RPSs). These individual state requirements will be important considerations for each state in considering discrete market proposals but, at a high-level, such requirements are not instrumental to achieving the overarching policy goal of increasing use of clean energy technologies, which is evaluated in this scorecard. Thus, the rankings of the market constructs are based on the general ability to lower barriers to accessing new generation in high-quality resource locations.

Bilateral: As discussed above, a bilateral market requires the utilities interested in accessing remote generation to acquire transmission (or repurpose existing transmission rights) to those areas. Under a bilateral market, this can create challenges in accessing new generation in high-quality renewable resource locations by increasing the transmission costs to reach those areas, frequently including the pancaking of transmission rates. Additionally, the bilateral construct that exists in the West generally

[17] Self-scheduling occurs when a market participant commits a resource to provide energy in an hour regardless of whether the market operator would have dispatched the resource. The resource becomes a price taker for the output which is self-scheduled into the market.

relies on the contract path methodology[18] for using transmission rights, which reduces the number of resources that can be accommodated on a fixed amount of transmission capacity compared to approaches used in organized market constructs. ***Therefore, a bilateral market is ranked as "poor" in lowering barrier to access <u>new</u> generation in high-quality renewable resource locations.***

<u>Real-Time:</u> A real-time market does not substantially change the ability for load serving entities to access ***new*** generation in high-quality renewable resource locations. The addition of new renewable generation resources generally requires a long-term agreement to purchase the resource's output. And while a real-time market may increase the use of renewable generation that is already on the system, a real-time market has not been demonstrated to address the underlying bilateral market barriers that exist for new, remote, renewable resource development. A real-time market does not, for instance, eliminate transmission rate pancaking or the use of the contract path methodology of determining transmission availability on a ***long-term*** basis. ***Thus, a real-time market is ranked the same as a bilateral market, "poor," at achieving this metric.***

<u>Day-Ahead:</u> The degree to which a day-ahead market will help achieve this metric is highly dependent on how that day-ahead market is designed. It is plausible that a day-ahead market could be designed in a manner that can reduce some of the barriers to new, remote, renewable resource development that exist in a bilateral or real-time market. A day-ahead market may, for instance, include an ability for participating entities to "trade" resource qualities, as is being conceptualized in the CAISO's Extended Day-Ahead Market (EDAM) resource sufficiency evaluation framework, and the market design which enables these trades may help eliminate some of the transmission-related barriers to accessing new, remote generation resources that exist in a bilateral or real-time market. A day-ahead market could also be designed in a manner that transitions long-term transmission rights into financial transmission rights, allowing increased use of transmission capacity and increasing the amount of resources that can rely on a given quantity of transmission capacity. However, regardless of market design, it is important to note that these features would likely be part of a "voluntary" market, which may make long-term contracting that relies on the market's structure riskier than it would be in a market construct with more long-lasting participation decisions (such as an RTO). ***Thus, a day-ahead market may be "good" at facilitating access to <u>new</u> high-quality renewable resources with actual market design specifics potentially increasing or decreasing the market's effectiveness on this metric.***

<u>RTO:</u> Of these market constructs, an RTO can provide the most ability to lower barriers to access new generation in high-quality renewable resource locations. Assuming that the high-quality renewable resource locations are within the RTO footprint, an RTO should eliminate the barrier of rate pancaking for all available transmission – providing increased economic access to new, remote renewable

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[18] The North American Energy Standards Board (NAESB) defines a contract path as a predetermined Transmission Service electrical path between contiguous Transmission Service Providers established for scheduling and commercial settlement purposes that represents the continuous flow of electrical energy between the parties to a transaction. See NAESB Business Practices.

resources. An RTO should also effectively eliminate the use of the contract path methodology, resulting in an increased ability to accommodate renewable resources on a given amount of transmission capacity. Additionally, in contrast to the other market constructs, an RTO includes centralized transmission planning across the footprint, which may be more likely than other market constructs to result in the development of new transmission across a footprint large enough to access high-quality renewable resource locations and deliver them to large load centers.[19] ***Thus, an RTO is ranked as "excellent" at lowering barriers to new generation in high-quality renewable resource locations.***

Opportunities for clean electricity resources to be added to the grid (e.g., direct customer access to renewable/clean resource power purchase agreements)

Ability of Market Construct to Support Increased Use of Clean Energy Technologies	**Bilateral**	**Real-Time**	**Day-Ahead**	**RTO**
Opportunities for clean electricity resources to be added to the grid (e.g., direct customer access to renewable/clean resource power purchase agreements)	*Good*	*Good*	*Very Good*	*Excellent*

States which seek to increase the use of clean energy technologies are likely interested not only in achieving their own state renewable/clean energy goals, but also in helping facilitate the clean energy goals of municipalities, corporations, universities, and other entities. This can be achieved through a variety of different mechanisms including utility green energy tariffs, which are optional programs offered by utilities and approved by State Public Utility Commissions (PUCs or "State Commissions") that allow larger commercial and industrial customers to buy bundled renewable electricity from a specific project (or set of projects) through a special utility tariff rate.[20]

In any of the market constructs evaluated in this report, utilities can offer green energy tariffs to different types of consumers. This happens in the West today (with and without a real-time market in place) and should continue to be available under a day-ahead or RTO market construct. For instance,

[19] Non-RTO market constructs are more reliant on individual utility transmission plans (which generally cover smaller footprints) and on FERC Order 1000 regional planning and interregional coordination. There has been some recent criticism of Order 1000's effectiveness, especially with respect to interregional planning. See, for instance,: Utility Dive: 'No compelling reason not to': Former FERC chairs, commissioners call for federal transmission overhaul

[20] Examples of utility green tariffs include: Rocky Mountain Power's Utah Schedules 32, Schedule 34, and Public Service Company of New Mexico's Green Energy Rider.

Rocky Mountain Power is working with various municipalities in Utah to create a green energy tariff that will allow these municipalities to achieve 100% clean energy goals.[21] This is in addition to other green tariffs available to larger customers of Rocky Mountain Power's in Utah.

Corporate renewable buyers in other regions of the country have also increasingly signed creative power purchase agreements (PPAs) to facilitate the achievement of their goals and increase the quantity of renewable resources on the electrical grid. One popular construct is a virtual PPA,[22] which allows a customer or set of customers to facilitate the addition of new renewable generation to the grid. A simplified way of describing these contracts is that the renewable energy owner sells its output into a liquid energy market and the customer either pays some additional amount above the market price to achieve the contracted price or is paid by the renewable energy developer if the market revenue is above the contract price.[23] These types of constructs, however, require a liquid market (with many buyers and sellers and comparatively lower transaction costs) for the renewable project to sell into. An RTO market provides this type of liquid market. This may be part of the reason that roughly 80% of corporate PPAs have taken place in these types of markets.[24]

This metric evaluates how each market construct might help increase the opportunities for consumers to meet their own clean energy goals through green tariffs and/or providing opportunities for virtual PPAs or other transactions.

Bilateral: As explained above, green tariffs can be used to meet the needs of consumers interested in clean energy goals, creating opportunities to add clean energy resources to the grid. However, other options that can be utilized in highly liquid markets are limited by the illiquidity and rigidity in transaction structure, and transmission delivery requirements of bilateral markets. In some areas of a bilateral market construct, large customers may have "direct access" to the wholesale market, which could enable the customer to select a portfolio of clean energy resources, but those opportunities are rather limited in the Western Interconnection today.[25] ***Thus, a bilateral market is ranked as "good" at achieving this metric as some options are available, but there are not as many opportunities for consumers to add clean electricity resources to the grid as there are with other market constructs.***

Real-Time: Similar to the bilateral market, under a real-time energy market, green tariffs can be used to meet consumer's clean energy goals and add clean resources to the grid. Real-time markets are unlikely to significantly open other avenues of direct consumer access to clean resources as real-time markets

[21] See, for instance: Utah 100 Communities

[22] Virtual PPAs are also sometimes known as financial or synthetic PPAs, a contract for differences, or a fixed-for-floating swap.

[23] A summary and informative graphic can be found at EPA.gov.

[24] See the quote from the Renewable Energy Buyers Alliance in Utility Dive: Google, GM, other REBA members push to expand organized wholesale markets to spur renewables.

[25] As a reminder, this assessment is not evaluating any changes to direct access/customer choice policies, which is a separate consideration from the different organized market constructs.

are voluntary. The voluntary nature of real-time markets creates a risk that market participation could be ended in the midst of a resource's useful life, and this risk likely makes financing of any long-term agreement that relies on the market very challenging. Real-time markets are also generally not designed to accommodate the full output of new resources being sold directly into the market. ***Thus, like a bilateral market, a real-time market is ranked as "good."***

Day-Ahead: Depending on the market design, the addition of a day-ahead market may help expand new contracting opportunities, like virtual PPAs, for consumers seeking to add clean energy resources to the grid. However, the currently envisioned voluntary nature of a day-ahead market, may make the achievement of this type of long-term contracting structure a challenge under this market construct, just as it is under a real-time market. The day-ahead market is still ranked slightly above the bilateral and real-time market for facilitating achievement of this metric, because it is likely to open additional possibilities for clean energy resources to be added to the grid to meet consumers' clean energy goals, including by likely increasing the ability of resources, including clean energy resources, to utilize the existing transmission system. ***Thus, a day-ahead market is ranked as "very good."***

RTO: An RTO market construct, because of the liquid and certain nature of the market, offers the additional ability to facilitate virtual PPAs, increasing this market construct's ability to achieve the metric of offering expanded opportunities for clean energy resources to be added to the grid. RTO regions have seen significant growth in virtual PPA constructs, which has led to substantial additions of clean resources to the grid. ***Therefore, the RTO construct received an "excellent" ranking in this metric.***

Provides financing opportunities and a variety of revenue stream opportunities for clean electricity technologies

Ability of Market Construct to Support Increased Use of Clean Energy Technologies	**Bilateral**	**Real-Time**	**Day-Ahead**	**RTO**
Provides financing opportunities and a variety of revenue stream opportunities for clean electricity technologies	*Fair*	*Good*	*Very Good*	*Excellent*

States that wish to increase the use of clean energy technologies can help achieve that goal through enhancing financing opportunities and providing additional revenue streams to clean energy technologies, which may help bring more clean energy resources online. Creating new opportunities to finance the construction of clean energy projects, such as the ability to enter into virtual PPAs (as discussed in the prior metric), can help bring additional clean energy technologies online. Additionally, if more revenue stream opportunities are created, this may help finance additional projects and/or may reduce the cost of clean energy technologies, helping increase their deployment. While it may be true that many of these additional revenue streams would generally be retained by the counterparty to the PPA (and not the clean energy resource itself), the addition of new revenue streams may open up additional development paths for these resources.

This metric evaluates the ability of different market constructs to support new financing opportunities and to provide more revenue streams, as this may be one way to enhance development of clean energy resources.[26]

Bilateral: As discussed in the prior metric, in a bilateral market, the primary financing mechanism for development of new clean electricity resources is a PPA with a utility and/or with a customer (generally through a utility's green tariff). Under a bilateral market, financing new resources utilizing a virtual PPA is not nearly as accessible as it is in other market constructs given that the bilateral market is fairly illiquid and often includes rather rigid trading structures (for instance, the bilateral market often transacts in "blocks" such as a 16-hour on-peak block of energy). These rigid trading structures may be difficult for clean energy technologies to transact around. Revenue streams for clean energy resources in a bilateral market are often limited to the PPA price and, generally, there are not easily accessible revenue streams for other services that might be provided by clean energy technologies to reduce their cost or help increase financing opportunities. ***Thus, a bilateral market is ranked as "fair" in achieving this metric.***

Real-Time: Financing opportunities in a real-time market are unlikely to be significantly changed from a bilateral market. Financing of clean energy project based solely on liquidating energy into a voluntary, real-time market appears unlikely. However, a real-time market can provide opportunities to sell incremental real-time output at market prices. Real-time markets might also include some ancillary service components, which could offer limited additional revenue streams to clean energy resources, potentially helping improve their economics. The existence of a real-time market could also include the potential for resources to sell into the real-time market after the expiration of the original PPA. ***Thus, a real-time market is ranked as "good."***

Day-Ahead: A day-ahead market is generally expected to include the same financing opportunities for clean energy technologies as a bilateral or real-time market. However, financing based on liquidation of a resource's energy is expected to be more likely in a day-ahead market construct than in a real-time market – though the actual ability to do so will ultimately depend on the specifics of the day-ahead market design. Furthermore, day-ahead markets are more likely to include additional ancillary service components, which may offer additional revenue streams for clean energy resources – potentially

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[26] To be clear, this metric is not exclusively focused on "merchant" opportunities for these resources. A "merchant" is a generation resource which does not have a PPA with an offtaker and, instead, is financed based on a plan to rely on revenue from the wholesale market. This metric is simply focused on increasing financing opportunities and revenue streams available to clean energy resources (whatever those may be). It is possible some of these market structures would make "merchant" projects more viable, but that is not central to the rankings of the market constructs for this metric.

including revenue for provision of reserves and frequency response. There is also a greater potential for capacity-based revenue sources in a day-ahead market. The addition of potential revenue streams in a day-ahead market may create more financing opportunities and/or may provide revenue streams that could decrease costs of clean energy technologies under this market construct. ***A day-ahead market is, therefore, ranked as "very good."***

RTO: The RTO construct appears to offer the greatest number of potential financing opportunities and a variety of revenue stream opportunities for clean electricity technologies. As discussed above, RTOs provide the clearest path for financing new projects through the use of virtual PPAs. Furthermore, depending on market design, a full suite of day-ahead, real-time, and ancillary service revenue streams are expected to be available under an RTO construct. RTOs also can, though they do not have to, provide capacity-based revenue streams with a joint resource adequacy construct or other capacity mechanism.[27] ***Given the potential financing opportunities that open up in this construct and higher likelihood of new revenue streams that could reduce total cost of clean energy resources, the RTO construct received a score of "excellent" on this metric***.

Economically facilitates emissions reduction goals/requirements via market signals

Ability of Market Construct to Support Increased Use of Clean Energy Technologies	Bilateral	Real-Time	Day-Ahead	RTO
Economically facilitates emissions reduction goals/requirements via market signals	*Fair*	*Good*	*Very Good*	*Excellent*

States with a policy objective to increase use of clean electricity technologies may sometimes also have a goal of reducing greenhouse gas (GHG) emissions from the electricity sector (or economy-wide). For instance, California has a cap-and-trade program to reduce GHG emissions across the economy in addition to its RPS and clean energy goals. Under the cap-and-trade program generators that emit GHG and are located inside of California include, in their energy bid price, the cost of purchasing allowances necessary to comply with the cap-and-trade program and cover their emissions.[28] By including the costs of emission allowances in bids, the market can consider the costs of the associated GHG emissions and help economically facilitate achievement of the state policy.. Various market constructs may be able to

[27] Capacity payments might also occur in other market construct but are generally more likely to come to fruition in an RTO and may also be more likely to provide capacity payments to renewable energy and certain types of demand response technologies.
[28] Imports into California must also comply with the cap-and-trade program and are required to submit GHG allowances for their emissions.

assist in economically reducing emissions via market signals, though the extent to which they do so depends on whether there is central optimization in the market and how many transactions are centrally (and economically) optimized.

All electricity market constructs, from bilateral to RTO, must contend with the specifics of state emission reduction goals, the interconnected nature of the transmission system, GHG accounting challenges, and differences between state policies. State programs to reduce GHG emissions from the electricity sector can be challenging to implement in any electricity market construct, as tracking electricity transactions across states can present difficulties, market optimizations/transactions are generally not designed to assign generation output to a specific load, and states are likely to have different GHG reduction goals, programs, and associated rules. Therefore, state coordination will be critical in any efforts to resolve potential GHG accounting issues in various organized market constructs.[29]

While acknowledging the complications of GHG accounting and reconciling individual state policies, this metric is **not** focused on the nuances of individual state GHG accounting frameworks and, instead, is aimed at assessing whether, the market construct is capable of economically facilitating the reduction of GHGs through the addition of GHG emissions costs into generation optimization decisions (e.g., market signals). Economically achieving emissions reductions goals under a market construct that is not centrally optimized is least likely to help facilitate low-cost achievement of the emissions reduction goal. As centrally optimized dispatch increases, the ability to economically achieve emission reduction goals should also increase, as the central optimization can account for the costs associated with GHG emission allowances or potentially include a constraint to achieve a GHG goal. The *ability* of a market to use economic signal to efficiently reduce GHG emissions is the primary focus of this metric and subsequent rankings.

Bilateral: Simply put, the lack of central optimization of generation dispatch in a bilateral market is unlikely to result in the most economic outcome for achieving emissions reductions goals through market signals. However, bilateral market participants still take costs into account in making transaction decisions and, thus, a GHG price may provide some market signals to help economically facilitate GHG reductions. However, the economic impacts of those decisions will not be centrally optimized. ***Thus, a bilateral market is ranked as "fair."***

Real-Time: The increased central optimization of real-time bids that occurs in a real-time market can facilitate more economic achievement of emissions reductions goals than a bilateral market construct. However, a real-time market construct is less likely to economically facilitate GHG reductions via market signals than a day-ahead or RTO construct due to the relatively small number of transactions that are part of the real-time market's central optimization. Bilateral transactions outside the real-time market will generally occur the same as they would in a bilateral market. ***A real-time market is ranked as***

[29] The Center for the New Energy Economy WIRED GHG Accounting Working Group Report provides more information on the challenges around individual state programs GHG accounting frameworks.

"good" at economically facilitating GHG emissions reductions via market signals, as it represents an improvement over a bilateral market construct with the addition of central optimization for real-time transactions.

Day-Ahead: Under a day-ahead market construct additional transactions become centrally optimized allowing the market to consider the emissions impacts, and associated costs, of emission intensive resource start-ups (for instance), while also optimizing a larger number of transactions through a centralized platform. Central optimization of day-ahead and real-time bids within the market can facilitate more economic achievement of emissions reductions goals with more transactions being centrally optimized. However, not all transactions are expected to flow through the market in a day-ahead market and some bilateral/outside the market transactions would remain and may not be as efficient as achieving GHG reductions through market signals than those transactions that occur within the market. ***Thus, a day-ahead market is ranked as "very good."***

RTO: With more transactions included in the market and centrally optimized under an RTO, economic achievement of emission reductions goals through market signals is more likely to be achieved in an RTO than under the other market constructs. Though some self-scheduling will likely occur in the RTO, it is expected those transactions will be fewer than self-schedules plus outside market transactions in a day-ahead market construct and, thus, an RTO would represent an improvement in utilizing market signals to efficiently reduce GHG emissions. ***Therefore, in this metric, the RTO construct was scored "excellent" for its ability to economically facilitate GHG reductions via market signals.***

Transparent and timely information on pricing, resource operations, and emissions

Ability of Market Construct to Support Increased Use of Clean Energy Technologies	**Bilateral**	**Real-Time**	**Day-Ahead**	**RTO**
Transparent and timely information on pricing, resource operations, and emissions	*Fair*	*Good*	*Very Good*	*Excellent*

States that are seeking to increase use of clean energy technologies can benefit from the provision of information on a timely basis. Transparent and timely information on electricity pricing, resource operations, and GHG emissions can help inform additional policies or actions that the state may be able to take to further its clean energy goals. Each of the four market constructs offer different levels of transparency on electricity pricing, resource operations, and emissions information. The expected availability and timeliness of this information is used to rank the market constructs for this metric.

Bilateral: A bilateral market offers some transparency into pricing, resource operations, and emissions, but generally through a less centralized party than a market operator and/or on a less timely basis than might be observed in the other market constructs. Market prices, for instance, are generally only report at limited locations (such as trading hubs) and provide aggregated and averaged information (e.g., weighted average price, high price, low price, volume). Furthermore, information on resource operations and emissions becomes available in a bilateral market, but typically only through means outside of the market construct itself, such as required reporting by the Energy Information Administration (EIA) or the Environmental Protection Agency (EPA). And the information that is made available may not always be delivered in the timeliest fashion (relying on monthly or yearly reporting requirements, for instance). A bilateral market, therefore, offers minimal transparency into pricing and often delayed reporting of other information on resource operations and/or emissions. ***Thus, the bilateral market was scored "fair."***

Real-Time: In addition to the information that is made available in bilateral markets, more granular and current information on real-time prices at a variety of locations is generally released in a timely manner in a real-time market, increasing price transparency through this market construct. Though some resource operations and emissions information may be available from the market operator, it will generally continue to come from other sources as it does in a bilateral market. In a real-time market, information is generally provided regarding transmission congestion, which represents an improvement over the bilateral market. ***Thus, a real-time market is ranked as "good" under this metric.***

Day-Ahead: Compared to a real-time market, day-ahead market is expected to provide timely access to both day-ahead and real-time prices at more locations, since more generation resources are expected to actively bid into the market (creating new pricing nodes that may be less likely to be reported in a real-time market). Additionally, the day-ahead market may provide increased information on resource operations and, potentially, emissions on a timely basis from the market operator. It also anticipated that information regarding transmission congestion would be made available in a timely fashion under a day-ahead market. ***Thus, a day-ahead market is ranked as "very good."***

RTO: Given that an RTO would generally require resource participation and bidding (or self-scheduling), across the footprint, there would likely be additional pricing transparency into more locations under this market construct than under any of the other options. Similar to the day-ahead market construct, an RTO may provide additional information on resource operations and, potentially, emissions. It is also anticipated that information regarding transmission congestion would be made available in an RTO construct. Furthermore, FERC Order 844 requires RTOs to report uplift payments and resource commitment decisions, among other items. Though different RTOs have different policies on the release of operational data and the timing of such releases, of these market constructs, an RTO is anticipated to provide the most transparent and timely access to information. ***An RTO is, therefore, ranked as "excellent."***

Summary Scorecard for Increased Use of Clean Energy Technologies

In sum, this scorecard sought to assess how the various market constructs may contribute to increasing the use of clean energy technologies by assessing six different metrics. Generally, across all six metrics, moving toward more centrally optimized dispatch increases the score of a given market construct. In particular, the day-ahead and RTO constructs are more likely to promote more efficient dispatch, allow for new financing opportunities, provide enhanced market signals, and increase transparency around pricing, operations, and emissions. That said, it should be noted again that the scorecard represents generalized assumptions regarding each market construct, and actual benefits of a proposed market will be dependent on its ultimate design.

Summary Market Factor Scorecard for Increased use of Clean Energy Technologies

Increased Use of Clean Energy Technologies	Bilateral	Real-Time	Day-Ahead	RTO
Efficient grid operation which allows low (and zero) marginal cost resources to be dispatched and reduces overall costs of integrating clean energy technologies	Fair	Good	Very Good	Excellent
Lower barriers to access new generation in high-quality renewable resource locations	Poor	Poor	Good	Excellent
Opportunities for clean electricity resources to be added to the grid (e.g. direct customer access to renewable/clean resource power purchase agreements)	Good	Good	Very Good	Excellent
Provides financing opportunities and a variety revenue stream opportunities for clean electricity technologies	Fair	Good	Very Good	Excellent
Economically facilitates emissions reduction goals/requirements via market signals	Fair	Good	Very Good	Excellent
Transparent and timely information on pricing, resource operations, and emissions	Fair	Good	Very Good	Excellent

6. Reliable, Affordable Provision of Energy to Consumers Market Factor Scorecard

This section outlines the metrics that were used to help assess whether a market construct is likely to contribute to the overarching goal of *Reliable, Affordable Provisions of Energy to Consumers*. Many Western state energy policies included, explicitly or implicitly, goals of providing reliable and affordable electricity. This market factor scorecard is intended to help states assess how each market construct might support the provision of affordable, reliable energy. Eight metrics were identified as important to helping achieve this overarching policy goal, as discussed in the subsequent subsections.

The following subsections provide additional detail and nuance around how the study arrived at each score and discusses some of the caveats associated with the scores. Please see the companion Technical Report for a quantification of on how the various market constructs (over different hypothetical market footprints) are expected to impact adjusted production costs on a state-by-state basis.

Efficient grid operation which reduces costs and increases flexibility of transactions

Ability of Market Construct to Support Reliable, Affordable Provision of Energy to Consumers	**Bilateral**	**Real-Time**	**Day-Ahead**	**RTO**
Efficient grid operation which reduces costs and increases flexibility of transactions	*Fair*	*Good*	*Very Good*	*Excellent*

States with policies aimed at reliable, affordable provisions of energy to consumers may be interested in ensuring efficient operation of the grid which reduces costs. To a certain extent, this metric is captured in this project's technical studies and results, which include quantification of adjusted production cost savings on a state-by-state basis for a variety of different market configurations. However, the structure of the production cost modeling tool, approximates in some instances, but does not fully capture bilateral markets including the operational realities of contract path scheduling and transactional inflexibility associated with standard trading blocks[30] for transacting bilateral power. The production cost model, therefore, tends to overestimate the flexibility that is available outside of an organized wholesale market and, thereby, may potentially underestimate the benefits of organized market constructs. This metric builds on the quantification of benefits associated with efficient grid operations

[30] The bilateral market often trades in blocks of power (e.g., 16-hour on-peak and 8-hour off-peak blocks), but that trading rigidity is not reflected in the modeling of bilateral trades in the production cost model.

included in the Technical Report by addressing, from a qualitative perspective, market constructs' ability to support efficient grid operations, flexible transactions, and reduced costs.

Bilateral: In a bilateral market, individual BAs optimize generation in their footprint, and there is a relatively manual process of determining the optimal generation to dispatch. Generally, resources external to the BA footprint (or to the utility in question) are only used if the price plus the transmission wheeling costs (which can be pancaked if they cross multiple transmission providers) are economic. This approach does not facilitate the minimization of generation costs on the system. Furthermore, transmission usage to facilitate trades in a bilateral market is generally limited by the contract path method of determining transmission availability. Finally, under a bilateral market construct, many transactions are limited to "block" trades, and parties interested in transacting may need to do so for periods for which they would not choose to. For instance, in a bilateral construct, an entity may wish to purchase additional energy only for an hour or two of the day but may have to transact for the full 16-hour on-peak period in order to ensure power deliveries during the hour or two of need. ***Given these factors, a bilateral market is ranked as "fair" in achieving this metric.***

Real-Time: A real-time market can eliminate or reduce transmission wheeling rates and rate pancaking for transactions that occur within the market and on the amount of transmission that is available to the market. The real-time construct provides the ability for BAs to use some external generation without wheeling or pancaking of transmission rates, thereby increasing efficiency. Outside of the real-time construct, longer-term trades continue bilaterally (with limited flexibility and most "block" trades). However, real-time trades add flexibility and efficiency across the market footprint. ***Thus, a real-time market is ranked as "good" as it represents an improvement over a bilateral market.***

Day-Ahead: Transactions in a day-ahead construct can be centrally and economically optimized and it is assumed there will be more transmission available to a day-ahead market than a real-time construct (but less so than in an RTO). The day-ahead market opens up the ability for participating entities to plan to use external generation in a day-ahead timeframe with the potential for reduced wheeling or pancaking of transmission rates associated with those transactions. Additionally, a day-ahead market would provide greater flexibility in transactions on a day-ahead basis, with more frequent (i.e., hourly plus intrahour) trades taking place via the market optimization, reducing the need to rely on inflexible block trades. ***Given these factors, a day-ahead market is ranked as "very good."***

RTO: Of all the market constructs, an RTO offers the highest level of flexibility for hourly and intrahour transactions and enables the greatest ability to eliminate transmission wheeling/pancaking across the most transactions. In an RTO, the vast majority of transactions are expected to be centrally and economically optimized by the market operator, utilizing the capability of the transmission system up to its reliability limits and transitioning from contract path methodology to more full utilization of the transmission system with use of financial transmission rights. Furthermore, BA consolidation allows for maximum sharing of ancillary services across the footprint, which is expected to reduce costs. ***Given all of this, an RTO is ranked as "excellent" with respect to achieving efficient grid operations with reduces costs and increases flexibility of transactions.***

Ability to unlock the full potential of existing generation (lowering costs) and decrease generation capital costs/investments

Ability of Market Construct to Support Reliable, Affordable Provision of Energy to Consumers	**Bilateral**	**Real-Time**	**Day-Ahead**	**RTO**
Ability to unlock full potential of existing generation (lowering costs) and to decrease generation capital costs/investments	*Poor*	*Fair*	*Good*	*Very Good*

This metric is focused on the relative efficiencies that market constructs can bring, reducing costs and increasing reliability, from more efficient use of existing ***generation*** and their ability to reduce the need for future ***generation*** investments. The subsequent metric focuses on efficiencies related to the transmission system.

A system that can optimize existing generation in an economic manner and reduce the chances of curtailing low or zero marginal cost energy will perform well under this metric. Additionally, market constructs that allow for pooling of reserves and sharing of resources across a broader footprint can also help reduce the need to build new generation resources and thus will also score well under this metric. The Technical Report for this project includes quantification of potential capacity savings under different market constructs. Securing capacity savings is less certain under the non-RTO market constructs, as it is only the RTO which has been clearly demonstrated to take advantage of load diversity and reduce planning reserve margin requirements. Thus, these rankings build on the quantification of capacity savings in the Technical Report by considering qualitative factors as well.

Bilateral: Bilateral markets, with pancaked transmission rates, use of contract path methodology, and generation optimization taking place at the individual BA level, are most likely to require curtailments of low and zero marginal cost generation resources. Therefore, this market construct fails to unlock the full potential of existing generation on the system. Furthermore, in a bilateral market, unlocking external generation is often limited due to transmission wheeling cost barriers. Seams and lack of coordination between BAs also increase the need to hold extra generation in reserve, to achieve reliability standards and/or to meet longer-term planning reserve margins. As such, higher reserve margins tend to be necessary to maintain reliability in a bilateral market construct, which may increase the need for new generation investments relative to other market constructs. Generation investments may also be less efficient, as they are less likely to have been coordinated/optimized across neighboring areas. ***Therefore, a bilateral market is ranked as "poor" at unlocking the full potential of existing generation and decreasing the need for future generation investments.***

Real-Time: The real-time market construct unlocks additional generation capabilities by introducing bidding opportunities in real-time via introduction of a real-time SCED. For a real-time market, SCED optimization is generally limited to 5-10% of transactions; therefore, much of the generation system remains optimized in the same manner as in a bilateral market. Real-time markets, like the EIM, have shown they can reduce curtailments, helping to unlock the potential of the existing generation system. In the real-time market construct, individual BAs still hold reserves and are responsible for ensuring reliability in their area. Though, some optimization and sharing does occur in real-time, planning reserve margins in a real-time market are expected to be substantially similar to bilateral markets. As with a bilateral market, a real-time market is less likely than more comprehensive organized market constructs to reduce the need for new generation investment.[31] And as with a bilateral market, generation investments are less likely to be coordinated with neighboring areas than they may be in other market constructs. ***For these reasons, a real-time market is scored as "fair."***

Day-Ahead: The day-ahead market construct is expected to further unlock the capabilities of existing generation and increase generation optimization with generation bidding opportunities existing in both the real-time and day-ahead time horizons. However, the ability to unlock generation potential will be limited to that which is bid into the voluntary market and the generation fleet can only be optimized on the amount of transmission which is made available to the market. Furthermore, it is assumed that some transactions will take place outside the market and, thus, not all generation will be optimized via SCED in a day-ahead market construct. In the day ahead market construct, the market may optimize ancillary services, reducing the reserve needs for individual BAs. A day-ahead market can also offer the ability to decrease future generation investments, via capturing load diversity benefits, but the extent to which generation investments can be reduced is highly dependent on the specifics of market design.[32] In this type of a market, it is still less likely than under an RTO that new generation investment will be coordinated across a large area. But it is possible there may be somewhat more coordination of new generation investments than in a bilateral or real-time market construct, as the potential for reduced wheeling costs should incent the siting of generation investments in more efficient areas. ***Thus, a day-ahead market is ranked as "good" as it is an improvement over real-time in achieving this metric but is unlikely to be as effective as an RTO in reducing the need for new generation investments.***

RTO: RTOs are generally excellent at optimizing and unlocking the full potential of the generation that is bid into the market. That said, experience has shown that some resources will self-schedule in an RTO and, therefore, their full potential (and/or the lowest cost generation solution) may not be unlocked. An RTO is assumed to have access to the full transmission system for optimization, which increases the ability to unlock generation potential under this market construct. An RTO can reduce the need for new generation resources to be built (i.e., reducing generation investment) by allowing for resource and load

[31] In the companion, Technical Report associated with this study, the real-time market construct was evaluated as having 0-10% of the capacity cost savings potential that might be available under an RTO.
[32] Thus, the day-ahead market construct was evaluated as having 0-50% capacity cost savings of an RTO in the Technical Report.

diversity to be shared across the footprint. Securing these savings is more likely in an RTO than in other market constructs given the shared Resource Adequacy frameworks of an RTO.[33] ***An RTO is ranked as "very good" for unlocking existing generation and reducing future generation investment costs. An excellent ranking was not provided given that self-scheduling can prevent full optimization of the generation fleet.***

Ability to unlock full potential of existing transmission system (lowering costs) and to decrease transmission capital costs/investments

Ability of Market Construct to Support Reliable, Affordable Provision of Energy to Consumers	Bilateral	Real-Time	Day-Ahead	RTO
Ability to unlock full potential of existing transmission system (lowering costs) and to decrease transmission capital costs/investments	*Fair*	*Good*	*Very Good*	*Excellent*

This metric is similar to the prior metric but is focused on the transmission system. It evaluates how market constructs can both unlock the full potential of the existing transmission system and also decrease transmission capital costs/investments that may be necessary to provide reliable electric service. Efficient use of the existing transmission system can provide both affordability and reliability benefits. Decreasing the need for future transmission investments (or decreasing their costs) can support the more affordable provision of energy to consumers. Additionally, transmission planning over a larger footprint, and with more competitive bidding of transmission projects can help reduce the total cost of transmission that consumers will bear. Market constructs that provide for efficient use of the existing transmission system, provide opportunities to reduce the need for investments in the transmission system, and provide avenues to reduce costs when transmission investments are necessary will rank well under this metric.

Bilateral: In the bilateral construct, transmission system capacity may go unused due to both wheeling costs and the contract path methodology preventing full use of the existing transmission system. However, in the West, real-time, operational use of the transmission system (including under a bilateral market) may be allowed up to reliability limits under the new paradigm for Path Operations, which enhances how this market construct can unlock the full capabilities of the existing transmission

[33] The Technical Report assumed RTOs could capture 100% of the calculated load diversity benefits that could be realized through planning sufficient to meet a coincident peak as compared to planning to meet a non-coincident peak.

system.[34] Despite increased operational efficiencies under a bilateral market construct, the contract path methodology used to determine availability of longer term uses/sales on the existing transmission system in a bilateral is inefficient for those longer term uses. Therefore, the bilateral market has the potential to necessitate additional investments in the transmission system when contract paths that are desired for contractual use become constrained. When investments in new transmission are needed under a bilateral market, they may be less efficient than under other market constructs, as they are less likely to be coordinated with neighboring areas and unlikely to be subject to competitive bidding requirements.[35] ***Thus, a bilateral market is ranked as "fair" for this metric.***

Real-Time: A real-time market is similar to bilateral for this metric but has the potential to use the existing transmission system more efficiently and to reduce the need for new transmission investments. A real-time energy market can increase efficient use of the existing transmission system, but only for transactions that occur within the real-time market. Nevertheless, this might help reduce congestion on the system and could, theoretically, defer the need to invest in additional transmission infrastructure. As in the bilateral construct, when investments in new transmission are needed they may be less efficient as they are less likely to be coordinated with neighboring areas and they continue to be less likely to be subject to competitive bidding requirements. ***A real-time market is ranked as "good."***

Day-Ahead: In a day-ahead market construct, the use of the existing transmission system and the impact on future transmission investments are highly dependent on market design. For instance, the market design will likely determine to what extent the market incorporates financial transmission rights to increase the efficient use of the existing transmission system. Regardless of ultimate market design, it is reasonable to expect some use of the contract path methodology for transmission availability/sales (or holding back of certain amounts of transmission for bilateral uses) will continue in a day-ahead market. This would serve to limit efficient long-term use of the transmission system as compared to a market where all transmission capacity is available to for use in the market optimization. Under a day-ahead market, joint transmission planning across the footprint is not assumed. Thus, new transmission is still unlikely to be fully coordinated across the footprint of a day-ahead market and new transmission investment remains less likely to be subject to competitive bidding requirements (similar to a bilateral or real-time market). ***A day-ahead market is ranked as "very good" as it is a significant improvement over a real-time market but is unlikely to unlock the most efficient use of the transmission system nor to reduce future transmission investment needs in the same manner as an RTO, which includes coordinated transmission planning and, more frequently, results in competitive bidding for large transmission projects.***

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[34] See the following for more information on the "New Paradigm for Path Operations":
WECC: New Paradigm for Path Operations Report

[35] Though FERC Order 1000 regional and interregional transmission planning activities occur in bilateral markets, to date, they have not demonstrated an ability to drive coordinated transmission investments across the West nor, outside of the CAISO, to facilitate competitive bidding of transmission investments.

RTO: Financial transmission rights, elimination of rate pancaking/wheeling costs, and the use of SCED in an RTO generally lead to efficient use of the full capabilities of the existing transmission system up to reliability limits. This efficient use of the transmission system generally results in a reduced need for new transmission projects and investments compared to other methods market constructs. Furthermore, future investments may be more efficient with transmission jointly planned by the independent RTO, with more frequent competitive solicitations utilized to reduce transmission investment costs. Though this metric is focused on unlocking existing potential and decreasing capital investments, it is worth noting that, under an RTO, cost allocation of new transmission investments, and allocation of existing transmission costs across the footprint, may benefit or harm individual states or entities depending on its design. Transmission cost allocation issues should be evaluated by states within RTO market design effort and should take into account specific circumstances. ***An RTO is ranked as "excellent" at achieving this metric, but special consideration should be paid to addressing and evaluating transmission cost shifts and transmission cost allocation under this market construct.***

General ability to support reliable operations

Ability of Market Construct to Support Reliable, Affordable Provision of Energy to Consumers	Bilateral	Real-Time	Day-Ahead	RTO
General ability to support reliable operations	*Good*	*Very Good*	*Very Good*	*Excellent*

Market constructs, and the associated tools utilized in those market constructs, can be valuable in supporting reliability of the electric system. A number of analyses have been performed to evaluate how markets can contribute to reliable operations. Several assessments were reviewed for this project and were relied upon to rank how market constructs contribute to this metric. Readers interested in additional details on reliability benefits of markets are encouraged to review the following materials, in addition to many others that may be available, as the detailed findings from other assessments will not be repeated here:

- Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market; *Federal Energy Regulatory Commission staff paper;* February 26, 2013.
- Reliability Implications of Expanding the EIM to Include a Day-Ahead Market Services: A Qualitative Assessment; *WECC MIC MEA Working Group;* September 2020.

Bilateral: Bilateral markets can, and do, achieve reliable operations, though, reliability may become more challenging under this construct in the future as the resource mix evolves and the need to share variability across a large footprint increases. Bilateral markets generally lack a SCED to manage generation and energy flows and instead utilize a number of more manual processes. Overall, in a bilateral market there is relatively little automation of processes, including in responding to system contingencies. The addition of automated tools and consolidated operational responsibilities may improve reliability or deliver reliable operations at a lower cost in a bilateral market. During system events, in a bilateral market resources are dispatched manually; moreover, their ability to serve load may be limited by the availability of transmission reservations and could be hampered by the lack of centralized information on generation availability. In a bilateral market construct, multiple parties have operational/reliability responsibilities within a relatively small geographic footprint, and imbalances and resource integration take place on the individual BA level (though trades can take place to facilitate these needs, they are less coordinated). ***A bilateral market can offer good reliable operations but there is room for improvement. Thus, a bilateral market is ranked as "good."***

Real-Time: A real-time market provides additional situational awareness and new information on generation availability/ dispatch across a wider footprint, both of which can support reliability. The addition of a real-time SCED enhances reliability by managing generation in a manner that can help alleviate transmission constraints and, under this market construct, generation is more likely to be able to be dispatched to take advantage of physical transmission capability as compared to bilateral markets that require securing a transmission reservation. Increased automation of processes may also take place in a real-time construct (though some processes are likely to remain less automated). For example, SCED can automate the resolution of imbalances and support resource integration over a larger footprint. Additionally, while multiple parties retain operational responsibility under this market construct, there tends to be greater coordination through the market operator, enhancing reliability. ***Given the reliability benefits offered by a real-time market, it is ranked as "very good."***

Day-Ahead: Additional information on generation availability and dispatch in a day-ahead market construct can be useful in supporting reliable operations. Furthermore, moving to a day-ahead market may provide opportunities for increased automation of processes and the addition of shared tools across the market footprint. For example, the use of SCED for day-ahead unit commitment enhances reliability by managing generation and helping relieve transmission constraints in advance of real-time operations, leaving the grid better positioned/set-up for reliable outcomes in real-time operations. Similar to the real-time market multiple parties still retain operational responsibility, but there is greater coordination through the market operator, enhancing reliability. ***Like a real-time market, a day-ahead market is ranked as "very good" at supporting reliable operations, though, it does offer some enhanced benefits over a real-time market.***

RTO: An RTO offers very similar overall reliability benefits to a day-ahead market but may include a few additional reliability-based benefits. For example, it is generally expected that, under an RTO, more generation will be offered into the market, which may help the system be better positioned to achieve reliable outcomes than when not all of the generation on the system is participating in the market, as may be more likely in a day-ahead market. An RTO also consolidates operational responsibilities compared to the other market constructs, which may enhance reliability. An RTO includes BA consolidation, which likely provides the best ability to resolve imbalances, increase automation, meet reserve requirements, and support resource integration over larger footprint. ***Thus, an RTO is ranked as "excellent" at supporting reliable operations, though it is recognized that RTOs are not immune from reliability challenges.***

Visibility into electric system conditions to improve reliability

Ability of Market Construct to Support Reliable, Affordable Provision of Energy to Consumers	Bilateral	Real-Time	Day-Ahead	RTO
Visibility into electric system conditions to improve reliability	*Fair*	*Good*	*Very Good*	*Excellent*

In addition to a general ability to support reliable operations, market constructs can provide enhanced visibility into electric system conditions which can help facilitate reliable outcomes. This section evaluates the ability of market constructs to provide enhanced visibility into system operations to support reliability. Visibility to operators is most important to improving reliability, and will be the key focus of the rankings under this metric, but there may be tangential benefits to providing some level of visibility to non-operators. Thus, both audiences are considered under this metric, but the primary focus is on ensuring a wide and complete view of system conditions to system operators.

Bilateral: Visibility into system conditions can be somewhat limited in a bilateral market, which has the potential to hinder reliable operations in some instances. Under this market construct, the Reliability Coordinator will likely have the most visibility into system conditions across a wide area. Individual BAs and transmission providers may have, somewhat limited, visibility for generation resources and transmission systems beyond their service areas. For non-operators, there is generally little visibility into system conditions and what information is available can be inconsistent and difficult to locate. ***Thus, bilateral markets are ranked as "fair."***

Real-Time: A real-time market can enhance visibility into system conditions and increase situational awareness with the addition of a market operator along with SCED and other tools. The Reliability Coordinator continues to have the widest area view, just as in a bilateral market, but under a real-time market there is increased visibility to the market operator. The addition of the real-time market, and its associated rules, provide the market operator with more insights into transmission availability and increased information on generator operations and availability. Non-operators are also expected to have increased visibility through disclosure of additional information by the market operator, though the market operator may only report on a subset of information on system conditions relative to more expanded market constructs. ***A real-time market is ranked as "good."***

Day-Ahead: A day-ahead market further enhances visibility into system conditions, including enhancing the visibility of expected system conditions on a day-ahead basis. Under a day-ahead market, there is expected to be increased visibility of generator information and other transmission-related data to the market operator (and potentially to some other participants as well). The ability to review generator and transmission information on a day-ahead basis can enhance reliability by providing operational entities with additional time to react to potential reliability risks. Non-operators are also expected to get increased visibility of system conditions through disclosure of additional information by the market operator. ***Therefore, a day-ahead market is ranked as "very good" in providing enhanced visibility into system conditions.***

RTO: An RTO generally offers substantial visibility into system conditions for market operators, given the associated requirements of the market, and RTOs can provide increased situational awareness. Under an RTO, the Reliability Coordinator function continues to have a wide area view. An RTO includes the consolidation of BAs, which leads to more centralized operational and reliability responsibilities, which may improve overall visibility to the market operator across the system. Also, the addition of a mid-term reliability construct (e.g., resource adequacy requirements or capacity market) may serve to increase visibility into reliable operations in the longer term. In an RTO, non-operators are expected to get increased visibility of system conditions through the disclosure of additional information by the market operator. ***Thus, an RTO is ranked as "excellent."***

Transparent and timely information available to regulators, consumer advocates and other stakeholders

Ability of Market Construct to Support Reliable, Affordable Provision of Energy to Consumers	Bilateral	Real-Time	Day-Ahead	RTO
Transparent and timely information available to state PUCs consumer advocates and other stakeholders	*Fair*	*Good*	*Very Good*	*Excellent*

In order to provide reliable, affordable provision of energy, it is important that parties tasked with protecting customers have access to transparent and timely information to support their efforts. State PUCs and consumer advocates can be more effective in ensuring affordability and reliability for consumers if they have transparent and timely access to information. This section evaluates how different market constructs contribute to providing timely and transparent information on system operation, market prices, and more.

Bilateral: Bilateral markets generally do not provide a large degree of transparent and timely information to key stakeholders. For instance, bilateral market prices generally are only reported at limited locations (such as trading hubs) with aggregated and averaged trading information reported. Thus, there is a limited ability for regulators, consumer advocates and stakeholders to access bilateral trade data and it may not be provided in the most timely manner. Of course, information on bilateral trades can be requested via regulatory processes for regulated utilities, but is unlikely to be provided in a timely manner via those processes. In a bilateral market, resource and transmission related information typically comes not as a result of the market construct but due to other reporting requirements (e.g., EIA and Western Electricity Coordinating Council). Additionally, it can be difficult to obtain information on transmission flows and utilization within a bilateral market. ***Thus, a bilateral market is ranked as "fair" in providing timely and transparent information to key stakeholders.***

Real-Time: In addition to the information available in bilateral markets, more granular and timely information on real-time prices at a variety of locations is provided under a real-time market structure. Some resource operations and transmission flows information may be provided by the market operators, but significant amounts of information on resource operations and transmission will likely continue to come from other (non-market) sources, as is true in a bilateral market. ***A real-time market is ranked as "good."***

Day-Ahead: A day-ahead market would likely provide timely access to day-ahead and real-time prices at more locations (as more generation resources are expected to actively bid into a day-ahead market than might participate in a real-time market). A day-ahead market may also provide additional, timely information on resource operations to key stakeholders. Generally, it is expected that a day-ahead market would provide more transparency into transmission flows and utilization than a bilateral or real-time market. ***Thus, a day-ahead market is ranked as "very good."***

RTO: Given that an RTO would generally require resource participation in the market, there would likely be additional pricing transparency into more locations and additional information on resource operations than in a day-ahead market. Additionally, it is expected that information on transmission flows and utilization would be available to PUCs, consumer advocates and other stakeholders on a timely basis, as is generally seen in other RTOs. RTOs also have other reporting requirements, such as those imposed by Order 844. ***Therefore, an RTO is ranked as "excellent" In achieving this metric.***

Long-term mechanisms to support a system with adequate electric resources

Ability of Market Construct to Support Reliable, Affordable Provision of Energy to Consumers	Bilateral	Real-Time	Day-Ahead	RTO
Long-term mechanisms to support a system with adequate electric resources	*Fair*	*Good*	*Good*	*Very Good*

This metric is focused on whether market constructs provide mechanisms that can support reliability in the longer-term. For instance, a market construct that includes resource adequacy measures that extend out one year or more may help support longer-term reliable operations by providing insights into potential reliability concerns and a window of time to address them. There are different mechanisms to support reliable operations in the longer-term that can be implemented under these various market constructs. The benefits of adequate resources across a larger footprint are also considered in these rankings.

While the market constructs evaluated as part of this project may provide longer-term mechanisms to support adequate resources, it should be noted that non-market mechanisms may be separately developed to achieve this metric. For instance, the Northwest Power Pool (NWPP) is currently developing a Resource Adequacy Program. That program may be able to be implemented in a bilateral, real-time, or day-ahead market construct and the addition of such a program could increase the rankings for those market constructs.

Bilateral: Within a bilateral market, mechanisms to support long-term resource adequacy are generally facilitated through individual utility resource plans and the requirements can vary. Long-term adequacy is met by utilities relying on their own generation, generation purchased through PPAs, and through bilateral market purchases (sometimes referred to as "front office transactions"). Generally, there are no overarching long-term reliability requirements on a systemwide basis nor is there a regional entity responsible for overseeing the ability of the larger system, as a whole, to achieve resource adequacy.[36] Absent regional coordination on resource adequacy, there is a potential for load serving entities to rely on the same underlying resources in order to meet their future needs, which could present a reliability challenge. The potential for exposure to high market prices in a bilateral market during tight system conditions can serve as an incentive for load serving entities to develop adequate resources to meet their longer-term needs. ***A bilateral market is ranked as "fair" though this ranking could be increased with the addition of a regional resource adequacy program to a bilateral market.***

Real-Time: Long-term resource adequacy in a real-time market construct is expected to be handled in the same manner as it is a bilateral market. However, mechanisms to ensure sufficiency in the real-time market may provide additional incentives to ensure longer-term adequacy, as market participants may seek to avoid any penalties (financial or otherwise) that would be applied for failing resource sufficiency requirements. As in a bilateral market, there is potential for high real-time prices to provide incentives for entities to ensure they have adequate supplies in the longer-term. ***Thus, a real-time market is***

[36] As noted above, some entities are working through the NWPP to develop a voluntary, regional program to address regional resource adequacy. This program is not yet fully implemented but is in development. Its addition to the bilateral, real-time, or day-ahead construct would likely increase the rankings of those market constructs under this metric.

ranked slightly above a bilateral market as "good." A real-time market's ranking on this metric would increase with the addition of a regional resource adequacy program.

Day-Ahead: Long-term adequacy in a day-ahead market construct is expected to be handled in the same manner as it is a bilateral or real-time market. Like a real-time market, there is a potential for market rules around resource sufficiency to provide additional incentives to ensure longer-term adequacy. And the potential for high prices, and the impacts of failing the market's resource sufficiency test, may also provide incentives for maintaining adequate supplies in the longer-term. ***A day-ahead market is ranked the same as a real-time market with a "good" ranking. As with a bilateral or real-time market, a day-ahead market's ranking on this metric would increase with the addition of a regional resource adequacy program.***

RTO: RTOs generally include a systemwide resource adequacy metric/planning reserve margin to support mid- to long-term reliability objectives. Depending on market design, an RTO may have capacity market or other backstop procurement authority to support longer-term resource adequacy. However, reliability issues have persisted in RTOs and there are challenges associated with various mechanisms used to support longer-term adequacy in RTOs. ***Given the improvement over real-time and day-ahead markets and the recognition of reliability issues persisting in some RTOs despite longer-term programs, an RTO is ranked as "very good" in providing long-term mechanisms to support system adequacy.***

Increased opportunities for cost-effective demand-side resource participation

Ability of Market Construct to Support Reliable, Affordable Provision of Energy to Consumers	Bilateral	Real-Time	Day-Ahead	RTO
Increased opportunities for cost-effective demand-side resource participation	*Fair*	*Good*	*Very Good*	*Excellent*

Providing opportunities for cost-effective demand-side resource participation in the markets can support both reliability and affordability to consumers. Demand-side resource participation in markets can reduce the load that must be served during stressed system conditions, increasing reliability. A high-profile example of this is the reductions in load that were achieved in the CAISO footprint during the summer 2020 heatwave. In the midst of these 2020 events, there were concerns that there may be a resource deficiency of up to 4,400 MW on August 17th and 18th; however, a statewide mitigation effort and consumer conservation prevented the need for any rotating outages on those days.[37, 38] Demand-side resources can also prevent the need to build additional generation facilities and can, therefore, serve to promote affordability for consumers. This section evaluates how each market construct can support increased opportunities for cost-effective demand-side resources.

Bilateral: In a bilateral market, there may be some opportunities for demand-side resource participation. For instance, utilities may enter into interruptible load agreements with utility providers. Utilities may also offer a variety of programs to help shift load, such as Rocky Mountain Power's Cool Keeper program. But, these types of opportunities for demand-side resource participation are generally not widely available to all demand-side resource types or across all areas. Additionally, in order for a utility to obtain state PUC approval for a demand-side resource program in a bilateral market, the proposal may need to rely on historical events and prices to justify the program's cost-effectiveness; however, an evaluation based primarily on historical data may not fully capture the program's value during high price periods if those periods are not sufficiently reflected in the historical data. ***A bilateral market is, therefore, ranked as "fair."***

Real-Time: A real-time market construct can generally accommodate demand-side resource participation, but whether such participation options are enabled will generally depend on market design and the decisions of individual participants. For instance, at least one EIM Entity that participate in the CAISO's Western EIM enables load, curtailable demand and other demand-side resource services to become EIM Participating Resources and bid into the market. However, many others do not allow this type of participation. ***Thus, a real-time market may increase some opportunities for cost-effective use of demand-side resources but the extent to which that occurs will depend on market design and, therefore, real-time market is ranked as "good."***

Day-Ahead: A day-ahead market construct can generally accommodate demand-side resource participation within the market, but similar to the real-time construct, whether it is enabled will likely depend on market design and individual participant decisions. As a day-ahead market is likely subject to increased FERC oversight, it is more likely to have requirements associated with demand-response participation across all participants than a real-time market might have. ***Thus, while exact opportunities will depend on market design, a day-ahead market is expected to increase opportunities for demand-side resource participation over a real-time market, and is, therefore, ranked as "very good."***

RTO: Several FERC Orders are aimed at ensuring demand-side resources can participate in an RTO (including Order 719, 745, 841, and 2222 for distributed energy resources). Issued in 2008, Order 719 opened organized wholesale markets to the participation of demand response resources, allowing large industrial customers to be compensated at wholesale rates. A subsequent order, Order 745, allowed demand response resources to participate in both energy and ancillary service markets, and in 2011,

[37] CAISO: Briefing on System Operations Presentation
[38] CAISO: Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave

FERC issued Order 841, opening organized wholesale markets to storage resources.[39] Following up on Order 841, Order 2222 expanded opportunities for distributed energy resources to participate alongside traditional resources in wholesale markets by allowing distributed energy resources to aggregate to satisfy minimum size and performance requirements that they might not meet individually.[40] ***Given the opportunities provided for demand-side resources in an RTO, it ranked as "excellent."***

Summary Scorecard for Reliable, Affordable Provision of Energy to Consumers

In conclusion, this scorecard assesses how the four market constructs may help contribute to the *Reliable, Affordable Provision of Energy to Consumers*. Similar to the *Increased Use of Clean Energy Technologies* scorecard, moving toward more centrally optimized markets generally increases the scores across the individual metrics – but again, achieving those potential benefits in practice will depend on the details of an individual market's design. An RTO appears best situated to achieve the various metrics that contribute to *Reliable, Affordable Provision of Energy to Consumers*. However, the RTO construct was not "excellent" at achieving every metric within this scorecard. Given the potential for generation to self-schedule in an RTO and the continued challenges with long-term mechanisms for achieving adequate resources, the RTO construct was ranked as "very good" at supporting two metrics that address those issues within this scorecard.

[39] S&P Global Market Intelligence: FERC clarifies order on distributed energy, launches demand response inquiry
[40] FERC News Release: FERC Addresses Demand Response Opt-Out for Certain DER Aggregations

Summary Market Factor Scorecard for Reliable, Affordable Provision of Energy to Consumers

Ability of Market Construct to Support Reliable, Affordable Provision of Energy to Consumers	Bilateral	Real-Time	Day-Ahead	RTO
Efficient grid operation which reduces costs and increases flexibility of transactions	*Fair*	*Good*	*Very Good*	*Excellent*
Ability to unlock full potential of existing generation (lowering costs) and to decrease generation capital costs/investments	*Poor*	*Fair*	*Good*	*Very Good*
Ability to unlock full potential of existing transmission system (lowering costs) and to decrease transmission capital costs/investments	*Fair*	*Good*	*Very Good*	*Excellent*
General ability to support reliable operations	*Good*	*Very Good*	*Very Good*	*Excellent*
Visibility into electric system conditions to improve reliability	*Fair*	*Good*	*Very Good*	*Excellent*
Transparent and timely information available to state PUCs, consumer advocates and other stakeholders	*Fair*	*Good*	*Very Good*	*Excellent*
Long-term mechanisms to support a system with adequate electric resources	*Fair*	*Good*	*Good*	*Very Good*
Increased opportunities for cost-effective demand-side resource participation	*Fair*	*Good*	*Very Good*	*Excellent*

7. Retain State Regulatory Authority on Key Jurisdictional Elements Market Factor Scorecard

In addition to scorecards evaluating how market constructs would contribute to meeting Western states' two overarching goals—increased clean energy technology use and providing affordable and reliable energy to consumers—stakeholders requested an evaluation of how market constructs might impact key elements of state jurisdiction. While not an overarching state policy goal, the ability to retain state authority on certain elements is a crucial piece of market expansion discussions, and as such, is addressed in this section. There is inherent difficulty in ranking the impacts to state authority, while broadly considering the range of potential market designs that might arise from any of the market constructs. Thus, the assessment of state authority issues was not originally envisioned as a "scorecard" and was originally proposed to take the form of a written summary. However, the *Retain State Authority on Key Jurisdictional Elements* scorecard was created as a result of stakeholder feedback indicating that having this assessment provided in the market factor scorecard format would enhance ease of review for state participants and stakeholders.

It is important to caution that the rankings in this scorecard on state authority are *not* based on an in-depth review of federal and state statutes and administrative codes across the West. Each state (and specifics of an individual market formation) will invariably have unique circumstances, rules, and regulations. And an in-depth review of state-by-state nuances was outside of the scope of the Market and Regulatory Review's Work Plan. Furthermore, in any scenario, the retention of state authority is a highly nuanced issue, which depends on the position of individual states and utilities and, perhaps most importantly, the specifics of a market's design. These nuances cannot be fully captured in the simplified format of the scorecard that is intended to provide generalized information and is not evaluating a specific market proposal's impact on a specific utility and state. As such, the *Retain State Regulatory Authority on Key Jurisdictional Elements* scorecard includes several "ranges" of rankings in order to help reflect the nuance, uncertainty, and diversity of potential outcomes associated with retention of state authority and market development.

These ranges of state authority apply not only to various degrees of organized wholesale markets, but also to a bilateral market framework. As the Lead Team noted during meetings over the course of the project, even under a bilateral market, states may not have as much practical authority over certain elements of electric utilities' business actions as state statutes would suggest. It has been noted that, even in a bilateral market construct, the interconnected nature of the electric system as well as the fact that some utilities serve load in multiple states and/or partner with other utilities on power projects can, in practice, serve to limit the authority a state has over regulated electric utilities under the state's jurisdiction. For instance, states that regulate PacifiCorp effectively share certain elements of their authority with other states and must coordinate and work with those other states through the Multi-State Process (MSP).

Finally, when reviewing the ranking for the metrics in the *Retain State Authority on Key Jurisdictional Elements* scorecard, it should be noted that the rankings are intended to capture *practical implications* of market formation on the authority of a single state, rather than to exclusively focus on the potential legal implications or changes to a state's authority. For instance, from a legal perspective, states generally do not give up any authority over ratemaking activities due to a utility electing to participate in any of these forms of wholesale markets. However, from a practical perspective, there may be some change in a state's ability to fully exert its authority, with fewer inputs and assumptions that can be easily challenged in a ratemaking process. At the request of the Lead Team, these scorecards are intended to capture not just the strictly legal implications of market formation, but also the practical implications and their effect on a state's authority.

Special Considerations and Best Practices

In addition to the *Retain State Authority on Key Jurisdictional Elements* taking the form of a scorecard, stakeholder feedback also requested the inclusion of "best practices" for states as they engage in discussions around the development of various market constructs. While not an exhaustive or detailed list, this section reviews historical examples of state engagement in organized market development that may provide insight into potential best practices and special considerations for states as they contemplate future market proposals.

Specifically, the Lead Team identified the following areas as important for state engagement, particularly around RTO formation, each of which is discussed in more detail below.

- Informed engagement by a State Commission in the planning, decisions, and governance of an organized market
- Careful state PUC consideration of conditions of approval requests by jurisdictional utilities to join an organized market
- Comprehensive review of the impacts of proposals to unbundle state PUC regulated rates

Informed engagement by a State Commission in the planning, decisions, and governance of an organized market

Informed engagement by a State Commission in the planning, decisions, and governance of organized markets was identified as an overarching best practice for states, which can help states retain stronger authority over many elements of jurisdiction that may be important in achieving their energy policy objectives. At the outset of market expansion proposals, states often have the opportunity to participate in market design and development processes.[41] Such early engagement by states can help shape the ultimate design, benefits, and, importantly, influence the ongoing role for states within a market construct. State participation in market proposal development can help promote the inclusion of

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[41] In addition to participating in these processes, when an RTO is being contemplated, state PUCs will also generally have an opportunity to consider applications for a utility to join the RTO. And, as discussed more in the following subsections, states can utilize that approval process to help ensure some of these best practices are implemented by the RTO.

provisions that preserve state authority over matters presently regulated by the states and potentially build out a special role for states in RTO governance. In some markets, relatively robust ongoing state engagement has been facilitated through regional state committees.

For example, SPP's Regional State Committee (RSC) is composed of regulatory commissioners from participating states. SPP's bylaws confer certain authorities and responsibilities within the governance of SPP to the RSC, including specific authority over transmission cost allocation, financial transmission rights, planning for remote resources, and regional resource adequacy.[42, 43]

When the RSC reaches a decision on the areas under its authority, SPP will file the methodology with FERC pursuant to Section 205 of the Federal Power Act.[44] However, SPP is not prohibited from filing its own related proposal(s) on these issues. Thus, within SPP the RSC is referred to as having "Section 205 filing rights" for transmission cost allocation and resource adequacy proposals.

Additionally, Section 7.3 of the SPP bylaws makes clear that nothing in the formation of SPP as an RTO is intended to diminish jurisdiction or authority of any other regulatory body, and any regulatory agency with utility rates or services jurisdiction over a member of the RTO reserves the right to exercise all lawful means available to protect its existing jurisdiction and authority.[45]

Another example of an RTO with a regional state committee that provides meaningful opportunity for state engagement in an RTO is MISO, with its Organization of MISO States (OMS). OMS was established to represent the interests of state and local utility regulators in the MISO territory. The OMS consists of 17 members across 15 states and the Canadian province of Manitoba. The organizational structure of the OMS is composed of an executive director, staff, and a board made up of a commissioner from each member state. Additionally, MISO's bylaws allow for "associate membership," which is open to state agencies covering issues related to energy planning, environmental issues, and consumer advocacy.[46]

As part of the agreement for Entergy to join MISO (discussed below and in Appendix 1), the OMS was granted Section 205 filing rights complementary to those held by RTOs and transmission owners. As such, if 66% of OMS' voting members concur, the OMS can request that MISO file an "OMS Alternative"

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[42] SPP: History of the Regional State Committee for SPP, 2021
[43] SPP: Bylaws See Section 7.2.
[44] Section 205 of the Federal Power Act tasks FERC with ensuring that rates for transmission and electricity under its jurisdiction are "just and reasonable and not unduly preferential." A mechanism FERC utilizes to fulfill this responsibility is requiring certain entities that it regulates to submit a filing requesting FERC's approval for proposed rates. The ability to submit such a filing with FERC is known as "Section 205 filing rights." Transmission owners and regional grid operators typically hold Section 205 filing rights, and as illustrated by the examples in the body of this text, some regional state committees in organized markets have acquired complementary Section 205 filing rights for certain discrete elements. Please see FERC 101 and NRDC Issue Brief: Making Sense of Potential Western ISO Governance Structures: The Role of States.
[45] SPP: Bylaws, First Revised Volume No. 4
[46] MISO: Bylaws

proposal with FERC. That said, MISO is not required to make the filing. Should MISO not file the OMS Alternative, the OMS may intervene in the FERC proceeding. The transmission owners' agreement makes clear that no aspect of OMS' complementary filing rights diminishes the Section 205 filing rights of MISO or its member owners. However, some contend that the existence of enhanced influence for OMS has proved effective at influencing outcomes in MISO processes related to cost allocation.[47]

MISO's tariff provisions also provide states with significant retained authority over resource adequacy. Recently, there have been ongoing discussions in MISO to understand and clarify the relevant tariff provisions related to states setting their own resource adequacy requirements for utilities under a state's jurisdiction. In sum, within MISO state authorities can set planning reserve margins (but not local reliability requirements or local clearing requirements). States can designate which entities are subject to their jurisdiction, and MISO would incorporate the state-set planning reserve margin into the jurisdictional load-serving entity's planning resource margin requirements. Notably, under the current tariff provisions, states could set not only a higher reserve margin than the MISO standard, but *may also set a lower reserve margin*, thereby, providing significant discretion to individual states on resource adequacy matters within MISO. [48]

As illustrated by the examples above, regional state committees, particularly when coupled with complementary Section 205 filing rights, can be an effective avenue to enhance states' influence in an RTO. State engagement in the development or modification of RTO tariff provisions can also provide individual states with significant authority, such as the authority provided to individual states on resource adequacy within MISO, even if those areas of authority are not directly included in the regional states committee's scope. As states contemplate the inclusion of a regional states committee within a potential RTO construct, they may also wish to explore options and implications around the committee's membership eligibility, voting rights, funding structures, and the committee's organizational structure to ensure the committee best serves the needs of the states. And, on a going forward basis, states should actively engage in a regional states committee to best support retention of state authority.[49, 50]

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[47] NRDC Issue Brief: Making Sense of Potential Western ISO Governance Structures: The Role of States

[48] MISO: Tariff Provisions Pertaining to State Authorities Establishing Requirements

[49] There are other "best practices" not specifically covered here to provide states with resources to assist in continuing informed engagement in a regional states committee. While some of the funding/structure for these additional resources may come from with the construct of the market, it is likely that others may need to come from the state itself.

[50] Beyond regional state committees with Section 205 filing rights, opportunities for state influence in RTOs can also be possible through intervening in proceedings at FERC in support of, or in opposition to, a filing. Furthermore, states can also influence market decisions through engaging in general stakeholder initiatives and participating in various committees or working groups within an RTO. For example, there is an Independent State Agencies Committee (ISAC) in PJM, which is a voluntary, stand-alone committee that consists of members from regulatory and other state agencies from within PJM's service territory. The ISAC is an independent committee that is not controlled or directed by PJM, the PJM Board of Managers or PJM members. The purpose of the ISAC is

Careful state PUC consideration of conditions of approval requests by jurisdictional utilities to join an organized market

As market expansion proposals materialize, a crucial point for states to exert influence is in the careful state PUC consideration of conditions for approval in response to requests from jurisdictional utilities to join an organized market. In general, it is the practice of a utility turning over operational/functional control of transmission to a market operator which will trigger the greatest degree of state regulatory involvement in market participation decisions.[51] This implies that states are likely to have a relatively higher degree of engagement in the approval processes when a utility is seeking to join an RTO as opposed to a market formation in which operational/functional control of transmission facilities is retained by the utility, as is assumed to be the case for both real-time and day-ahead market constructs. States can utilize the approval process for modifications to operational control to place conditions upon which a utility may join or continue participation in a market.

These conditions have been used in the past to help secure or enhance the role of states within an organized market. For example, in order to join MISO, Entergy was required to file an application, for approval to transfer operational control of its transmission assets to the MISO RTO, in each state where it delivered electricity to customers: Arkansas,[52] Louisiana,[53] Mississippi,[54] and Texas.[55] All four state commissions gave their approval subject to conditions, including conditions around expanding or retaining the role of the states within the MISO construct. Therefore, it was through the state PUC approval process for Entergy to join MISO that the states were able to increase their involvement in key market design elements of the MISO RTO. A small subset of the conditions set in the states' orders include:

- State PUCs orders indicated that Entergy needed state PUC approval to exit MISO, and that the relevant state PUCs could also direct Entergy to exit MISO.
- The Arkansas PUC ordered that the OMS must have "legally recognized responsibility" for determining regional proposals regarding transmission planning and cost allocation and directing MISO to construct transmission upgrades and choosing the approach to be utilized for assessing resource adequacy.
- The Arkansas and Texas PUCs ordered that the Entergy Regional State Committee (a multi-state committee in existence prior to Entergy's proposed entrance into MISO) retain the same

to provide PJM with inputs and scenarios for transmission planning studies (except public policy requirements, which are provided individually by the state). See PJM.com.

[51] As an example, please see Laws Relating to the Public Utility Commission of Oregon.

[52] Arkansas Public Utility Commission, Docket No. 10-011-U, Order No. 68

[53] Louisiana Public Service Commission, Order No. U-32148

[54] Mississippi Public Service Commission, Docket 2011-UA-376

[55] Public Utility Commission of Texas, Docket No. 40346

governance authority in MISO during the transition period (including the ability to act on transmission planning and cost allocation issues by majority vote).

- The Arkansas PUC instructed Entergy to file a detailed report, after a five-year transition period, providing historical and projected net benefits of MISO membership; any significant changes in FERC RTO policies, rules or regulations, MISO requirements, Day 2 market conditions, or other regulatory or market structure components; and an estimate of costs to exit MISO after end of the five-year transition period.

To summarize, careful state PUC consideration of potential conditions for approval of market participation proposals can help maximize ongoing state authority within market constructs and, thus, is considered a "best practice" for states wishing to retain as much regulatory authority as possible upon the implementation of new or expanded markets.

Comprehensive review of the impacts of proposals to unbundle state PUC regulated rates

The process of joining an organized market construct does not legally change the authority of state PUCs over retail electric rates. However, certain market constructs may lend themselves to utilities, or other stakeholders, seeking to unbundle certain elements of retail rates, such as unbundling the transmission component. If these unbundling proposals are implemented, they could impact state authority over retail electric rates and, thus, require careful consideration by state PUCs.

FERC has jurisdiction over unbundled costs of retail transmission in interstate commerce (and thus over wholesale transmission rates), but most states retain authority for bundled retail rates and, thus, what transmission costs are recovered in retail electric rates. This construct generally remains regardless of the market construct that is in place. It is important to note that decisions around bundled rates can have a significant effect on a state's authority over transmission cost recovery determinations, and it is a decision that can be made independent of the market construct.

States can also pre-emptively address concerns around loss of state authority over transmission rates and cost recovery by including conditions in relevant orders for utilities under their jurisdiction to join a market. The Arkansas, Louisiana, and Texas PUC orders approving Entergy's participation in MISO indicated that Entergy could not unbundle transmission or make changes to transmission service for retail ratemaking without the PUC's approval, thereby helping to preserve their respective authority over transmission costs in retail rates and retail rates themselves when Entergy joined MISO.

Undertaking a comprehensive review of the impacts of any proposals to unbundle state PUC regulated rates is an important best practice for states and can also be addressed preemptively, as was done by Arkansas, Louisiana, and Texas, to help preserve state authority over transmission costs and overall retail electric rates.

Conclusion

In sum, informed state engagement throughout the process of proposed market expansion is a best practice that can enhance states' ongoing influence and potentially improve outcomes associated with market formation. States can play a crucial role in shaping discussions around the development of market expansion proposals and in crafting an ongoing role for states through an influential regional state committee. To the extent that market proposals culminate in utilities seeking state PUC approval to join a market, PUCs have an opportunity to carefully evaluate the proposal and set forth conditions of approval for market participation, reaffirming the important role of states in potential market expansion. And states can carefully consider any proposals that may come before them to unbundle retail electric rates in a manner that may reduce state jurisdiction over these costs. Some states have even explicitly stated that transmission cannot be unbundled, and changes to transmission ratemaking, without state PUC approval. These various "best practices" can be evaluated and, where appropriate, utilized to help improve a state's market experience and the retention of state authority within a market construct.

Scorecard to Retain State Regulatory Authority on Key Jurisdictional Elements

This section outlines the metrics that were used to help assess whether a market construct is likely to allow states to *Retain Regulatory Authority on Key Jurisdictional Elements.* While retention of state authority is not an explicit state energy policy priority, retaining state authority may be important to ensure states have the tools necessary to achieve their energy policy objectives. This scorecard, more so than the prior two, is highly dependent on the specifics of individual state and utility situations as well as specifics of a market's design and thus this scorecard includes a range of rankings for each market construct.

The following sections provide additional detail and nuance around how the study arrived at the range of scores and highlights some of the potential caveats associated with the scores. As noted above, within this simplified scorecard, it is impossible to capture all the nuances of each individual state's position, the position of each regulated utility, and the specifics of a particular market's design. The use of ranges of scores is intended to help reflect some of the inherent uncertainty and different situations that may exist. Market design, including utilizing some of the best practices discussed in the preceding section, can help improve a market's relative ranking for retention of state authority. For instance, providing a strong role for states in areas of resource adequacy and transmission cost allocations, can help improve the ranking of a market construct such as an RTO.

Ability for state to retain authority over resource adequacy

Ability of Market Construct to Retain State Regulatory Authority on Key Jurisdictional Elements	**Bilateral**	**Real-Time**	**Day-Ahead**	**RTO**
Ability for state to retain authority over resource adequacy	*Good – Excellent*	*Good – Excellent*	*Good – Very Good*	*Poor – Good*
	As it exists today, the interconnected nature of the Western grid, including complexities around regulation of multi-state utilities, may limit the practical impact of state authority over resource adequacy. Market development, up to and including an RTO, can provide similar levels of "good" state authority, provided the market design includes best practices for informed engagement and authority of a Regional State Committee over resource adequacy matters. One individual state's ability to affect overall change on resource adequacy will depend on the market's governance, design and make -up.			

Outside of an RTO construct, state commissions generally have jurisdiction over resource adequacy requirements of the utilities they regulate, often via an integrated resource planning (IRP) process. Through this process, states generally determine the planning reserve margin utilities should use in their planning processes as well as the way that individual resource types and/or individual resources contribute to meeting needs. RTO constructs generally require a more coordinated set of requirements for resource adequacy, including a market wide planning reserve margin. RTOs can be designed to include strong state committees which may have varying levels of authority over resource adequacy. This metric evaluates how the role of a state on resource adequacy may change under the different market constructs.

Bilateral: In a bilateral market, state PUCs generally have jurisdiction over resource adequacy requirements of the utilities they regulate, often via an IRP process. This construct can provide the state authority over resource adequacy of utilities under their jurisdiction, which could be considered "excellent." However, for utilities that operate across multiple states, there may be practical limitations on an individual state's authority over resource adequacy. In this situation state authority may be, effectively, shared with other states. Thus, for some states in a bilateral market construct, their individual authority over resource adequacy decisions must already, in effect, be coordinated and shared with other states, which may be seen as an individual state having "good" authority over resource adequacy. Additionally, the potential for regional resource adequacy programs (such as the program under development by the NWPP) could have a practical impact on state authority over resource adequacy and could be developed under a bilateral market construct. It should also be noted that utilities that are not state regulated may have resource adequacy decisions made by their governing bodies (and not the state). ***Thus, a bilateral market may provide states with "good," "very good," or "excellent" authority over resource adequacy depending on the specifics associated with the state and its regulated utilities.***

Real-Time: There are no changes to the legal authority of states over resource adequacy through the implementation of a real-time energy market. Real-time markets may have resource sufficiency requirements which prevent real-time energy flows from being maximized in certain situations when an entity is not self-sufficient. These rules may marginally influence state decisions around resource adequacy, but do not impact state authority over resource adequacy. Similar to the bilateral market, for utilities that operate across multiple states, there may be practical limitations on individual state authority over resource adequacy which may be, effectively, shared with other states, and regional resource adequacy programs may impact state authority. And the implementation of a regional resource adequacy program may affect a state's practical authority over resource adequacy in a real-time market construct. ***Thus, like a bilateral market, a real-time market may provide states with "good," "very good," or "excellent" authority over resource adequacy depending on the specific situation of the state and utilities operating in the state.***

Day-Ahead: Implementation of a day-ahead market is not expected to significantly change the legal authority of states over resource adequacy as compared to a bilateral or real-time market. The practical impacts to state authority over resource adequacy in a day-ahead market will depend on the design of the market. It is expected that day-ahead markets would be designed, to the extent possible, to limit their practical impact on state jurisdiction. However, a day-ahead market may have capacity and resource requirements embedded in the market design in order to prevent "leaning" within the market construct and to help ensure each participant could be self-sufficient. These types of requirements could have a marginal to meaningful impact on state resource adequacy decisions, though, they are generally not expected to impact state's legal authority over resource adequacy matters. ***Thus, a day-ahead market may provide states with "good" or "very good" authority over resource adequacy. An "excellent" ranking was not included for the day-ahead market to reflect the impact that market-wide capacity and resource requirements to transact in the market may have on states' practical authority over resource adequacy decisions.***

RTO: In an RTO, states' ability to retain authority over resource adequacy greatly depends on market design, including whether a capacity market exists or whether a regional states committee has been given a strong role on resource adequacy. Some RTOs demonstrate that, with the right governance structure, a group of states can retain significant authority over resource adequacy in an RTO (e.g., SPP and MISO); but, even under these structures, individual states must share that authority with other states that participate in the RTO through the governance of the regional states committee. Thus, an individual state may have a limited ability to influence resource adequacy decisions if they are in the minority. Other RTOs with weaker state roles and/or RTOs that include organized capacity markets have demonstrated that states can lose some control over resource adequacy within an RTO. ***Thus, depending on market design, an RTO may provide states with "poor," "fair," or "good" authority over resource adequacy. A "good" ranking is generally in line with the practices utilized in SPP and MISO and, under these constructs, states that have "good" authority over resource adequacy in the bilateral or real-time market may have similar authority in an RTO.***

Ability for state to retain authority over the resource mix of utilities it regulates

Ability of Market Construct to Retain State Regulatory Authority on Key Jurisdictional Elements	**Bilateral**	**Real-Time**	**Day-Ahead**	**RTO**
Ability for state to retain authority over the resource mix of utilities it regulates	*Good – Excellent*	*Good – Excellent*	*Good – Excellent*	*Fair – Very Good*
	As it exists today, the interconnected nature of the Western grid, including complexities around regulation of multi-state utilities and generation units with multiple owners, may serve as limitations on the practical authority states have over the resource mix of regulated utilities. Market development, up to and including an RTO, can provide similar levels of state authority over the resource mix, though market prices and market rules may impact resource mix decisions. The addition of market elements that are more likely to affect resource mix decisions (such as inclusion of a capacity market) can serve to reduce state's practical authority over the resource mix. States can improve their market experience by participating in market design and discouraging market elements that would serve to impact a state's practical authority over the resource mix.			

This metric evaluates how the role of a state in determining the resource mix may change under the different market constructs. Through state resource mix requirements, such as RPSs and clean energy standards, many Western states have exerted authority over the resource mix of electric utilities that operate within the state, in some cases whether those utilities are regulated by a state PUC or not. Additionally, state PUCs generally can exert jurisdiction over electric resource mix decisions of the utilities they regulate through a number of mechanisms including an IRP process and an ability to approve or deny cost recovery for resource investments of regulated utilities. In the case where utilities operate across multiple states, there may be practical limitations on an individual state PUC's authority over the resource mix, regardless of the market construct that utility operates within. This occurs because decisions by other states can impact the resource mix of the utility as a whole. Even when a utility operates in a single state, and is regulated by the state PUC, there can be practical limitations on a state's authority over the utility's resource mix in instances when the utility may jointly own a piece of power plant with other entities and must coordinate with those other entities on decisions related to resource retirement or extension of the useful life. In other words, the interconnected nature of the electrical grid across multiple state boundaries can serve as a practical limitation on state's authority over the resource mix of regulated utilities, regardless of the market construct in effect.

The implementation of organized wholesale market constructs does not change a state's legal authority over the resource mix of the utilities it regulates nor affect a state's legal ability to implement resource mix requirements, such as clean energy standards or RPSs. States' regulatory oversight over resource planning does not change under a real-time, day-ahead, or RTO construct. However, increased coordination with other states under these market constructs and the increased number of transactions settling through an organized wholesale market can impact economics of different resource types, which may have a practical effect of changing the economics of different resource types. This may, in turn, impact resource mix decisions. This secondary impact was considered in the rankings of market constructs in achieving this metric.

For instance, the application of certain market designs, such as an organized capacity market, can have a significant impact on the economics of different resource types. Recent controversy over PJM's capacity market rules helps demonstrate this point. In an effort to address concerns regarding price suppression in its capacity market, in 2018, PJM proposed to expand its Minimum Offer Price Rule (MOPR) by raising the price floor for new state-subsidized resources. In 2019, FERC directed PJM to expand the MOPR to apply to most resources receiving state subsidies.[56] States expressed concerns related to the potential impacts the rule could have on their state resource mix.[57] In comments filed with FERC, 45 state legislators indicated the MOPR could potentially affect their ability to achieve state policy goals and requested the MOPR be eliminated.[58] PJM has since proposed a more limited application of the MOPR and is expected to file a new proposal with FERC in the summer of 2021.[59] While, at this juncture, a capacity market seems unlikely to be implemented in a future organized market construct in the West, it is still important to consider the impacts of these types of market designs on state authority over the resource mix, as consideration of different market design options can help states understand the range of potential outcomes associated with a given market construct.

Bilateral: As discussed above, in a bilateral market, state commissions generally have jurisdiction over resource mix decisions through IRP processes and cost recovery determinations. States can legislate resource mix requirements, such as clean energy standards. But, when utilities operate across multiple states or share ownership in a large generating resource with other utilities, individual states may functionally share decisions on major resource retirements or additions with other states. In these situations, even a bilateral market construct can present practical limitations on a state's authority over the resource mix***. Thus, a bilateral market may provide, "good," "very good," or "excellent" authority over the resource mix of regulated utilities, depending on the specifics of the individual state and utility at hand.***

Real-Time: There are no changes to the authority of states over the resource mix with the addition of a real-time energy market. While real-time markets may include requirements to prevent "leaning" (e.g., resource sufficiency requirements), real-time transactions are a relatively small portion of overall transactions. This implies that real-time market resource sufficiency requirements are unlikely to have a meaningful practical impact on states' decisions around future resources/the resource mix. ***Thus, a real-time market earns a range of rankings consistent with the bilateral market of: "good," "very good," or "excellent."***

Day-Ahead No significant changes are expected to the authority of states over the resource mix from implementation of a day-ahead market. Day-ahead market requirements to prevent "leaning" may have

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[56] FERC Docket Nos. EL16-49-000 & EL18-178-000 (Consolidated)
[57] Utility Dive: FERC move to raise PJM capacity market bids shows "clear bias" against new, clean generation: Glick
[58] FERC Docket No. AD21-10-000
[59] Utility Dive: PJM proposes to end FERC MOPR policy that raised prices for state-subsidized resources and Utility Dive: PJM Board approved new MOPR plan in effort to placate states, FERC.

a marginal impact on state decisions are the future resource mix, but those requirements are not expected to impact a state's authority regarding resource mix decisions. However, the increased reliance on market prices, and the larger number of transactions settled at the market's prices, may have a greater impact on resource mix decisions than in a bilateral or real-time market construct. Yet these factors that differ in a day-ahead market are not expected to be significant enough to substantively change the range of rankings for a day-ahead market. ***Thus, a day-ahead market has a range of rankings consistent with the bilateral and real-time markets of: "good," "very good," or "excellent."***

RTO: Legally, there is no change in state authority over resource mix decisions due to the implementation of an RTO market construct, but there may be practical implications to individual state authority that result from market rules and requirements. RTO market requirements have an increased potential to affect future resource decisions and may provide greater ties between resource mix decisions of a given state and other states within the market footprint. Additionally, in an RTO, the vast majority of transactions are expected to be settled at market prices. Thus, market prices, and resulting economics, may have a greater practical impact on resource mix decisions than in other market construct. RTOs may also be more likely than other market construct to have market components, such as a capacity market, that impact the economics of individual resource types, though these elements are not a component of many RTO market designs. Thus, an RTO may have a greater practical impact on resource mix decisions than other market constructs. ***An RTO is ranked as "fair," "good," or "very good," for retaining state authority over resource mix decisions. The actual impact will depend on the RTO's design and a state's specific situation. An RTO design which includes a capacity market would end up at the bottom of this range with a "fair" ranking, while an RTO that does not include a capacity market and provides a strong role for states on issues that impact the resource mix may be "very good."***

Ability for state to retain authority over transmission planning and prudence/cost recovery for transmission investments

Ability of Market Construct to Retain State Regulatory Authority on Key Jurisdictional Elements	**Bilateral**	**Real-Time**	**Day-Ahead**	**RTO**
Ability for state to retain authority over transmission planning and prudence/cost recovery for transmission investments	*Good – Very Good*	*Good – Very Good*	*Good – Very Good*	*Fair – Good*
	As it exists today, states have various roles in transmission planning (with FERC-jurisdictional utilities adhering to FERC transmission planning Orders such as Order 890 and 1000), but states generally retaining siting authority for transmission. FERC has jurisdiction over rates and services for electric transmission in interstate commerce, but most states continue to determine how transmission costs are (or are not) passed on into retail electric rates. Market development, up to and including an RTO, can provide similar levels of "good" state authority over transmission planning and cost allocation, provided the market includes best practices for informed engagement and authority of a Regional State Committee over transmission -related matters.			

This metric focuses on a state's practical ability to retain authority over transmission planning decisions and cost recovery for transmission investments in different market structures. States have various roles in transmission planning decisions across the different market constructs evaluated in this report. Additionally, even under an RTO construct where significant amounts of transmission planning occur at the RTO level, individual utilities often retain authority for planning of facilities below a certain voltage and those plans serve as an input into regional planning efforts. FERC-jurisdictional utilities must comply with various FERC transmission planning requirements, including local planning requirements in Order 890 and regional planning and interregional coordination requirements in Order 1000. There can be different ways that states are involved in those processes,. In general, states retain (regardless of the market construct) authority over bundled retail electric rates. Those bundled retail rates include a transmission component, which may be influenced by the FERC regulated interstate wholesale transmission rate. But, states with bundled retail service determine the allowed recovery of transmission costs holistically, i.e., starting with transmission rate base, while recognizing and incorporating the pass-through of wholesale transmission credits and expenses, which are transacted at FERC regulated rates.

This metric reviews how each market construct might impact an individual state's authority over transmission planning and transmission cost recovery decisions. It is important to note that the biggest impact to a state's authority over transmission cost recovery determinations is a decision that can be made independent of the market construct: the decision to allow for unbundling of the transmission component from retail electric rates. This decision, if made, could allow FERC-approved interstate wholesale transmission rates to be passed through to retail customers without state oversight. But many states continue to have bundled retail electric rates under an RTO market construct and in some instances, such as some states approving Entergy's participation in MISO, the states have proactively prohibited the unbundling of transmission rates without explicit PUC approval.

Bilateral: In a bilateral market construct, utilities must comply with FERC transmission planning requirements (e.g., Order 890 and 1000) and states have varying roles in those planning processes.[60] Many states PUCs, or other state agencies, have some form of transmission permitting or Certificate of Public Convenience and Necessity (CPCN) authority that can be leveraged to influence transmission planning activities. FERC has jurisdiction over unbundled costs of retail transmission in interstate commerce (and thus over wholesale transmission rates), but most (though not all) states retain authority for bundled retail rates and what transmission costs are approved to be recovered in retail electric rates within their state. ***Thus, a bilateral market may offer "good" or "very good" ability for a***

[60] For example, NorthernGrid is a transmission planning association that facilitates regional transmission planning in the Northwest and Intermountain West and facilitates compliance with FERC requirements, including Orders 890 and 1000. NorthernGrid has a number of committees, including an Enrolled Parties and States Committee (EPSC). Each state may appoint up to two representatives and an alternate for each representative to the EPSC. EPSC members participate in the planning processes and provide study scope contributions and comments on the plans.

state to retain authority over transmission planning and transmission cost recovery. These rankings recognize that there is an important role for FERC in defining transmission planning requirements and in reviewing and approving wholesale transmission rates for interstate commerce,[61] along with a role for FERC defined transmission planning processes, but that states retain important tools that provide them with significant authority over transmission planning and cost recovery.

Real-Time: No substantive changes to transmission planning or transmission cost recovery are expected when transitioning from a bilateral market to a real-time market. ***Thus, like a bilateral market, a real-time market may provide states with "good" or "very good" authority over transmission planning and transmission cost recovery.***

Day-Ahead: Just like a real-time market, the implementation of a day-ahead market is not expected to bring any changes to an individual state's authority over transmission planning and transmission cost recovery. A day-ahead market is not assumed to include joint transmission planning; thus, transmission planning and siting authority in a day-ahead market is expected to be the same as under a bilateral or real-time market. ***A day-ahead market, like both the bilateral and real-time markets, may provide states with "good" or "very good" authority over transmission planning and transmission cost recovery.***

RTO: An RTO would perform regional transmission system planning and interregional coordination. This has the potential to decrease state involvement in transmission planning relative to other market constructs, but whether that occurs or not depends in large part on market design and the role that is given to states with respect to transmission planning activities. Transmission cost allocation rules for pricing transmission service occur at the RTO-level, but state ability to influence those rules will depend on market design and the role that is provided to a state committee on transmission cost allocation issues. Though it is not a given, there is a possibility for unbundling transmission rates under this market construct, which would give FERC authority over transmission component of retail rates. However, many states that have not unbundled transmission rates under an RTO and, thus, such an outcome is not a necessary outcome of RTO development in a state. Additionally, transmission permitting/CPCN authority is unlikely to change due to RTO formation (or RTO market design), providing at least "fair" authority for states on transmission build decisions in their state. ***Thus, depending on market design an RTO may provide "fair" or "good" or "very good" authority over transmission planning and transmission cost recovery. An RTO with a strong role for states in transmission planning and cost allocation decisions would help move this market construct to the "very good" rating.***

[61] FERC: An Overview of the Federal Energy Regulatory Commission and Federal Regulation of Public Utilities

Ability for state to retain authority over retail electric rates

Ability of Market Construct to Retain State Regulatory Authority on Key Jurisdictional Elements	**Bilateral**	**Real-Time**	**Day-Ahead**	**RTO**
Ability for state to retain authority over retail electric rates	*Good – Excellent*	*Good – Very Good*	*Good – Very Good*	*Fair – Good*
	The interconnected nature of the Western grid, including complexities around regulation of multi-state utilities, may serve to limit the practical authority a state has over retail electric rates, even when the state has full legal authority over these matters. Market development should not change the legal authority of states over retail electric rates. Though as more inputs into the ratemaking process come from a market, a state's ability to challenge costs may be diminished in practice. Market constructs, up to an RTO, can provide strong state authority on retail electric rates. States can improve their market experience through strong engagement in the market processes and through careful consideration of any proposals to unbundle retail rates.			
Recall, this assessment assumes no changes to retail choice programs and traditional, vertically-integrated utility service provision for most of the West is generally assumed under all of these market structures.				

This metric is focused on how the development of various market constructs might affect a state's authority over retail electric rates. At the outset it is crucial to note that, regardless of the market construct, the rates, terms, and conditions for sales of electricity to end users (i.e., retail sales) are state jurisdictional and market constructs, in and of themselves, do not change the legal authority states have over retail electric rates for utilities that are state regulated. Accordingly, from a purely legal perspective, each market construct could be rated as "excellent" for this metric. But there are practical realities that may impact the degree to which states have meaningful ability to change or significantly modify retail rates. Those practical realities were considered in this assessment and the rankings of each market construct on state authority over retail rates.

Additionally, under a bilateral market construct, states that regulate utilities which operate across multiple states may find that their individual state authority over retail electric rates is somewhat limited due to cost sharing agreements between the states in which the utility operates or other factors. In organized wholesale markets, as the scope of services expands, a greater share of ratemaking inputs will likely come directly from market costs and market revenues. State regulators may have very little *practical* ability to affect these inputs that come directly from the market or to find them imprudent to include in retail electric rates. The following rankings take these practical factors into consideration in evaluating a state's ability to retain authority over retail electric rates, rather than exclusively focusing on the legal changes over retail rate jurisdiction.

Bilateral: In the bilateral market construct, state PUCs have authority over the determination of bundled retail electricity rates for utilities under their jurisdiction. It is possible, though unlikely, under this market structure that a state may unbundle retail electric rates, for instance unbundling the transmission component. If this were to happen, the state would likely simply pass through FERC-approved wholesale transmission rates to retail customers. But, absent this type of unbundling, states would holistically have authority for retail rate determination for utilities under their jurisdiction. In this market construct, there may be practical limitations on an individual state's authority when one or more regulated utilities in the state operates over multiple states. ***Thus, a state's practical authority over retail electric rates in a bilateral market may be "good," "very good," or "excellent" depending on the state's situation and the composition of the utilities it regulates.***

Real-Time: In a real-time market, state PUCs retain authority over the determination of bundled retail electricity rates, as they do in a bilateral market and the caveats discussed for a bilateral market apply to a real-time market as well. Even though a state's authority over retail rates is unchanged from a bilateral market, market revenues and costs associated with the real-time market may make rate setting more complex for state regulatory agencies and, potentially, harder to challenge, can be seen as marginally impacting a state's authority. ***Thus, a real-time market may provide state's "good" or "very good" authority over retail electric rates.***

Day-Ahead: In the day-ahead construct, as with bilateral and real-time, state PUCs continue to retain authority over the determination of bundled retail electricity rates and the caveats discussed for those markets are expected to apply to a day-ahead market as well. With more transactions occurring through the market in a day-ahead market construct, market revenues and costs are more important to the process of ratemaking and may be harder to challenge even though a state's legal authority is unchanged from bilateral market. ***Consistent with a real-time market, a day-ahead market is ranked as "good" or "very good." Though, it should be recognized that the additional transactions occurring in a day-ahead market may have a marginal impact on states' authority over retail rates relative to a real-time market, this is still captured in the good-very good range.***

RTO: Under an RTO construct, state PUCs retain authority over the determination of bundled retail electricity rates as they do in other market constructs. "Unbundling" of retail rates (most notably having the potential to result in FERC jurisdiction over transmission costs that are passed through to retail customers) is possible, but it is a separate issue from the creation of an RTO. In an RTO, it is potentially more difficult for states to disallow or challenge certain costs (e.g., transmission, resource adequacy-related) if they are involved in decisions around these costs at the RTO level (or even if they are not) and more inputs and assumption some directly from the RTO. ***Thus, an RTO may provide "fair" or "good" state authority over retail electric rates as the practical impact on state authority has the potential to be more than in other market constructs.***

Ability for states to be involved in the process of obtaining approval to participate in the market construct

Ability of Market Construct to Retain State Regulatory Authority on Key Jurisdictional Elements	Bilateral	Real-Time	Day-Ahead	RTO
Ability for states to be involved in the process of obtaining approval to participate in the market construct	*Fair*	*Good – Very Good*	*Good – Very Good*	*Excellent*
	State approval of market participation is almost certainly required for an RTO, while varying degrees of state approval may be necessary for other market constructs. States can utilize the approval process to place conditions on a decision to enter a market, which can help improve state retention of jurisdiction in the other metrics within this scorecard.			

Lead Team participants were interested in understanding, at a high-level, the regulatory approval processes that would be required to implement each market construct and how states might be involved in these approval processes. Appendix 1 provides a high-level overview of the regulatory approval processes that are expected for each market type and demonstrates that an RTO is more likely to trigger necessary state PUC approval than some of the other market constructs. This metric focuses, specifically, on how states can be involved in the approval process for regulated utilities seeking to implement each market construct. This metric was important to include in this scorecard as, when state approval is required for a utility to join a market construct, states can use that approval process as a tool to help improve the market's design and ensure a strong state role on the key jurisdictional areas discussed in the preceding metrics. The importance of the approval process for market participation and the consideration of conditions of approval was discussed in the "Special Considerations and Best Practices" section of this report.

Bilateral: Generally, there is no approval needed to participate in bilateral trading or be a part of a bilateral market construct. States can review bilateral trading costs for prudence and can review and approve utility risk policies around market trading activities. But, generally, states are not involved in the process of approving participation in a bilateral market. ***Thus, a state's authority over the approval process to participate in bilateral markets is ranked as "fair."***

Real-Time: As states seek to join a real-time market, the level of state involvement in the approval process for joining the market depends on the individual state, its statutes, and administrative codes (which were not reviewed in detail for this project). A review of the history of approval processes for real-time markets generally demonstrated relatively little state involvement in the initial approval process for real-time market participation. Most approvals for real-time market participation have come from FERC, though some states have approved or otherwise been involved in real-time energy market decisions (see Appendix 1 for additional details). Additionally, PUC groups (such as the PUC EIM group) were involved in early EIM filings that were filed at FERC. But their involvement was limited, like other stakeholders, to intervening, commenting, and protesting in the FERC approval processes. States may be able to affect real-time market participation decisions through denial of real-time market implementation costs, though this would generally occur after the fact. ***Thus, a state's authority over the approval process to participate in a real-time market may be deemed "good" in instances where no state dockets are required to implement the market, but the state can be involved in the FERC approval process as an intervenor. For states that have statues and administrative codes that do require some sort of state review prior to participation, the ranking is deemed "very good."***[62]

Day-Ahead: There is still significant uncertainty around what the regulatory approval process for a day-ahead market might look like, given that there is not a clear, pre-existing design model for this type of market. But given that functional/operational control of transmission facilities will not be turned over in a day-ahead market, state PUC approval of this market construct is expected to be rather limited and very similar to a real-time market. ***Thus, just like a real-time market, a state's authority over the approval process to participate in a day-ahead market may be deemed "good" or "very good," depending on the specific requirements for review an individual state has.***

RTO: Regulated utilities seeking to turn over functional control of transmission facilities to an RTO generally need to obtain approval from state PUCs.[63] State PUCs can (and frequently have) placed conditions on the ability of a regulated utility to join a market as part of that approval process. As illustrated in the "Special Considerations and Best Practices" section and Appendix 1, these conditions have been used to enhance states' authority within RTO constructs (on elements such as transmission planning and cost allocation). ***Thus, a state's authority over the approval process to participate in an RTO is deemed "excellent," as regulated utilities generally require state approval before they can turn over functional control of transmission to the RTO. And conditions for approval that a state may include can be utilized as a tool to help increase state authority over other items.***

Summary Scorecard for Retaining State Regulatory Authority on Key Jurisdictional Elements

While it would be impossible for the summary scorecard above to capture all the nuances of each individual state's position, the position of each regulated utility, and the specifics of a market's design, the scorecards and "Special Considerations and Best Practices" in this section are intended to serve as tools for states as they consider the various potential outcomes associated with market proposals. Similar to the state policy goals scorecards above, it should be noted thoughtful market design can significantly influence a market's relative ranking.

[62] An excellent ranking was not utilized here because, even where state approval was initially deemed necessary by the utility to join a real-time market, in one instance when such approval was not secured from the state PUC, there was still thought to be a path forward for participation in that market. However, to join an RTO and turn over operational/functional control of transmission, there is far more certainty that state approval is necessary prior to a utility joining the market.
[63] As an example, please see Laws Relating to the Public Utility Commission of Oregon.

Summary Market Factor Scorecard for Retain State Regulatory Authority on Key Jurisdictional Elements

<table>
<tr><th>Ability of Market Construct to <u>Retain State Regulatory Authority on Key Jurisdictional Elements</u></th><th>Bilateral</th><th>Real-Time</th><th>Day-Ahead</th><th>RTO</th></tr>
<tr><td rowspan="2">Ability for state to retain authority over resource adequacy</td><td><u>Good – Excellent</u></td><td><u>Good – Excellent</u></td><td><u>Good – Very Good</u></td><td><u>Poor – Good</u></td></tr>
<tr><td colspan="4">As it exists today, the interconnected nature of the Western grid, including complexities around regulation of multi-state utilities, may limit the practical impact of state authority over resource adequacy. Market development, up to and including an RTO, can provide similar levels of "good" state authority, provided the market design includes best practices for informed engagement and authority of a Regional State Committee over resource adequacy matters. One individual state's ability to affect overall change on resource adequacy will depend on the market's governance, design and make-up.</td></tr>
<tr><td rowspan="2">Ability for state to retain authority over the resource mix of utilities it regulates</td><td><u>Good – Excellent</u></td><td><u>Good – Excellent</u></td><td><u>Good – Excellent</u></td><td><u>Fair – Very Good</u></td></tr>
<tr><td colspan="4">As it exists today, the interconnected nature of the Western grid, including complexities around regulation of multi-state utilities and generation units with multiple owners, may serve as limitations on the practical authority states have over the resource mix of regulated utilities. Market development, up to and including an RTO, can provide similar levels of state authority over the resource mix, though market prices and market rules may impact resource mix decisions. The addition of market elements that are more likely to affect resource mix decisions (such as inclusion of a capacity market) can serve to reduce state's practical authority over the resource mix. States can improve their market experience by participating in market design and discouraging market elements that would serve to impact state's practical authority over the resource mix.</td></tr>
<tr><td rowspan="2">Ability for state to retain authority over transmission planning and prudence/cost recovery for transmission investments</td><td><u>Good – Very Good</u></td><td><u>Good – Very Good</u></td><td><u>Good – Very Good</u></td><td><u>Fair – Good</u></td></tr>
<tr><td colspan="4">As it exists today, states have various roles in transmission planning (with FERC-jurisdictional utilities adhering to FERC transmission planning Orders such as Order 890 and 1000), but states generally retaining siting authority for transmission. FERC has jurisdiction over rates and services for electric transmission in interstate commerce, but most states continue to determine how transmission costs are (or are not) passed on into retail electric rates. Market development, up to and including an RTO, can provide similar levels of "good" state authority over transmission planning and cost allocation, provided the market includes best practices for informed engagement and authority of a Regional State Committee over transmission-related matters.</td></tr>
<tr><td rowspan="2">Ability for state to retain authority over retail electric rates</td><td><u>Good – Excellent</u></td><td><u>Good – Very Good</u></td><td><u>Good – Very Good</u></td><td><u>Fair – Good</u></td></tr>
<tr><td colspan="4">The interconnected nature of the Western grid, including complexities around regulation of multi-state utilities, may serve as limitations on the practical authority a state has over retail electric rates, even when they have full legal authority over these matters. Market development should not change the legal authority of states over retail electric rates. Though as more inputs into the ratemaking process come from a market, a state's ability to challenge costs may be diminished in practice. Market constructs, up to an RTO, can provide strong state authority on retail electric rates. States can improve their market experience through strong engagement in the market processes and through careful consideration of any proposals to unbundle retail rates.</td></tr>
<tr><td rowspan="2">Ability for states to be involved in the process of obtaining approval to participate in the market construct</td><td><u>Fair</u></td><td><u>Good – Very Good</u></td><td><u>Good – Very Good</u></td><td><u>Excellent</u></td></tr>
<tr><td colspan="4">State approval of market participation is almost certainly required for an RTO, while varying degrees of state approval may be necessary for other market constructs. States can utilize the approval process to place conditions on a decision to enter a market, which can help improve state retention of jurisdiction in the other metrics within this scorecard.</td></tr>
</table>

8. Conclusion

This report has reviewed the three Market Factor Scorecards developed as part of the State-Led Market Study. These scorecards evaluated how different potential wholesale market structures might facilitate the achievement of each state's energy policy objectives. The scorecards and their associated metrics were developed based on two primary overarching Western state energy policy priorities and on how different market constructs might enable states to retain jurisdiction over key elements that may impact achievement of state energy policy priorities. The three scorecards assessed in this report were:

1. Increased use of clean energy technologies
2. Reliable, affordable provision of energy to consumers
3. Ability to retain state regulatory authority over key jurisdictional elements

The two overarching energy policy priorities (numbers one and two above) are *not* mutually exclusive, and many states are pursuing both policy priorities simultaneously. Some states may lean more towards one overarching goal or the other. Ultimately, it is up to the states to individually consider their respective weighting of each policy priority in considering energy market constructs and how those might assist in meeting that state's energy policy priorities. States will also need to review the specifics of any market proposal that comes before them, as different market designs may influence and change the generic rankings included in these scorecards.

States can also employ these scorecards to consider the potential impact on state regulatory authority of the various market constructs and how those impacts might be weighed against achieving a state's energy policy goals. As with the overarching energy policy priorities, it is ultimately up to each state to weight and prioritize the anticipated benefits of a market construct with the potential impacts to state authority. The Lead Team also identified several ways that states can improve their market experiences and retain authority, particularly under an RTO market construct. The specifics of a market proposal, and of an individual state's existing position, will be important for states to consider in evaluating how a specific proposal might impact state authority.

In sum, the scorecards provided generalized information regarding the potential achievement of overarching state policy goals and potential impacts to state authority. As such, the scorecards are intended to serve as a high-level tool of directional indicators for states as they individually and jointly evaluate options around their energy futures, but states will need to conduct more detailed analyses to evaluate specific market proposals that may come before them.

9. Appendix

A. Overview of Approval Processes

Appendix A Contents

Background

During the course of the project, the Lead Team indicated an interest in understanding, at a high-level, the differences in potential state and federal regulatory approval processes needed for each market construct. In response to that request, this Appendix reviews, at a high and generalized level, the regulatory processes that may be required at the state and federal level to implement a:

- Real-time market
- Day-ahead market
- Regional Transmission Organization (RTO) or Independent System Operator (ISO)

It is important to note that this assessment is **not** based on an in-depth review of federal and state statutes and administrative codes. Each state (and specifics of an individual market formation) will invariably have unique circumstances, rules, and regulations, but an in-depth review of state-by-state nuances was outside of the scope of the Market and Regulatory Review's Work Plan. In lieu of a state-by-state legal assessment, this high-level review relied primarily on historical examples of instances where these various market constructs were successfully implemented or were sought to be implemented.

Additionally, the reader should be aware that approval processes and the bodies involved in those approval processes will vary depending on the regulatory jurisdiction of the potential market participant. There is a mix of structures in the Western Interconnection, from investor-owned utilities (IOUs) to publicly owned utilities and power marketing administrations, among others. Non-IOUs will generally have less state involvement and will instead seek approval for market participation (of various forms) from their Board or administrator. However, organized markets generally involve Federal Energy Regulatory Commission (FERC) review and approval. [64] Entrance into an RTO or ISO generally requires regulated utilities to seek state Public Utility Commission (PUC) approval.

The subsequent sections of this Appendix include a high-level overview of market approval processes as well as several historical examples of these processes and state regulatory involvement.

Overview of Potential State Involvement in Approval Processes

The overview table below and subsequent historical examples are provided as illustrative examples of potential areas for state involvement in the approval or other processes associated with different organized market constructs. The state involvement outlined in the table, and the subsequent examples, are not necessarily required or applicable in all instances.

[64] Sections 201, 205, and 206 of the Federal Power Act gives FERC the power to regulate rates, terms, and conditions of wholesale sales of electric energy in interstate commerce, including all practices affecting such rates, terms, and conditions.

Potential Areas of State Involvement in Approval Processes		
Real-Time Market	**Day-Ahead Market**	**RTO or ISO**
• Participating in market policy and tariff design processes • Intervening in FERC process • Requiring cost-benefit analyses be submitted to the PUC • Imposing conditions to join a real-time market or for cost recovery of market implementation-related costs • Requiring PUC approval to join real-time market (based on historical experience this is less likely to be required in most cases)	• Participating in market policy and tariff design processes • Intervening in FERC process • Requiring cost-benefit analyses be submitted to the PUC • Imposing conditions to join a day-ahead market or for cost recovery of market implementation-related costs • Requiring PUC approval to join day-ahead market (similar to a real-time market this is less likely to be required in most cases)	• Participating in market policy and tariff design processes • Intervening in FERC process • Requiring cost-benefit analyses to be submitted to the PUC • PUC imposing conditions to join an RTO or for cost recovery of market implementation-related costs • Requiring PUC approval to join an RTO (expected to be necessary in most cases due to the utility turning over operational control of transmission to the RTO)

Real-Time Electricity Market

To assess the general regulatory approval processes for implementation of a real-time electricity market, the Market and Regulatory Review included a review of the processes undertaken at the state and federal levels to initiate and expand the Western Energy Imbalance Market (EIM) and a review of the approval processes for Southwest Power Pool's (SPP's) Western Energy Imbalance Service (WEIS) market.

Given that real-time electricity markets generally do not entail the transfer of operational/functional control of transmission facilities, the approval processes for implementing such markets tend to be concentrated at the federal level. This is because the relevant tariff provisions enabling the market are generally FERC-jurisdictional, and/or are implemented under the market operator's existing governance and tariff structure. However, there are some instances where, given specific state requirements, State PUCs were involved in different pieces of approval or review of a decision by a regulated utility to join a real-time market.

The following subsections provide a high-level overview of selected components of the research conducted related to approval processes for real-time energy markets. Based on that research, the list below illustrates the *generalized* process for real-time market participation approval (again recognizing that individual states, utilities, and market structures will have unique variations from this generalized approval process). These steps generally follow some type of cost/benefit assessment and an announcement regarding the decision to form the market or for a new participant to join.

General Process for Real-Time Market Participation Approval

- Implementation and cost allocation agreement filed with FERC for approval
    - Sometimes this is done concurrently with the tariff filing
- Market policy developed by market operator:
    - Proposed market policy and tariff language developed by the market operator
        - Typically including one or more stakeholder processes
        - Approved through a market operator's existing processes (e.g., stakeholder committee structure and Board)
            - May or may not include involvement from state regulatory agencies, depending on market operator governance structure
    - Section 205 filing on tariff modifications/market design made by the market operator at FERC
- Tariff changes developed by individual participants
    - Necessary transmission tariff changes and policies developed via stakeholder process
    - Section 205 filing on tariff modifications made by the transmission service provider at FERC (or with another regulator)

Western EIM

This review included a look back at the processes used to initially establish the EIM and the process for subsequent participants. It also assessed several examples where state regulators were involved in the decision to join the EIM, either through a formal state regulatory docket or through involvement in a group of state regulators.

Initial EIM Implementation

The West's discussion of implementing a real-time energy market can be traced back to efforts to study a real-time market as part of the Efficient Dispatch Toolkit, which was being discussed at the Western Electricity Coordinating Council (WECC). That effort effectively culminated with a cost-benefit analysis and associated white-paper on risks, governance, and costs. Through these efforts, and efforts of a group of PUC commissioners that formed, called the PUC-EIM Group, several cost-benefit analyses were performed regarding a real-time energy market in the West. In 2012, the California Independent System Operator (CAISO) responded to a request from the PUC-EIM Group and put forward a proposal to establish the Western EIM.[65] Following that proposal, PacifiCorp announced its intention to join the EIM, which effectively kicked off the various regulatory and stakeholder processes to bring the EIM into operation.

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[65] CAISO: CAISO Response to Request from PUC-EIM Task Force

CAISO filed an EIM Implementation Agreement at FERC which outlined the costs PacifiCorp would pay to the CAISO to implement PacifiCorp's participation in the market. The Implementation Agreement also affirmed key principles such as structure of market rules and oversight, provided a framework to resolve differences, and outlined a process for obtaining stakeholder input. [66]

As part of the process of implementing the market, the CAISO also initiated a process to develop a governance structure for the EIM. While this Appendix is not focused on governance-related issues, it is worth mentioning that, as part of the EIM's governance structure, the Body of State Regulators (BOSR) was created to provide a forum for state regulators to learn about the Western EIM, EIM Governing Body, and related ISO developments and to express a common position on CAISO stakeholder processes and EIM issues.

Stakeholder processes were also undertaken at both CAISO and PacifiCorp to develop the tariff provisions and policies necessary to establish the operation of the EIM. Various stakeholders, including states, participated in the CAISO and PacifiCorp stakeholder processes. The CAISO hosted a stakeholder process to develop tariff changes to implement the EIM, which were approved by the CAISO Board of Governors before making their way to FERC for approval.[67] PacifiCorp also initiated its own stakeholder process to develop tariff changes needed in its Open Access Transmission Tariff (OATT) to implement the new market. These tariff changes were filed with FERC for approval before the market became operational.[68] For PacifiCorp's initial entrance into the EIM, formal state PUC approval was not deemed necessary or obtained in any of the states that PacifiCorp operates in.

Additions of New EIM Entities

After the initial EIM was operational, similar regulatory approvals were needed for each new participant, including filing of an EIM Implementation Agreement with FERC outlining the costs the participant would pay and the milestones associated with each payment to the market operator (CAISO). Each participant has also updated its tariff to facilitate the EIM, typically utilizing a stakeholder process and then filing with the appropriate regulatory body (which is FERC for FERC-jurisdictional entities), effectively the same as the initial PacifiCorp process, though some key policy elements had been determined through the regulatory approval processes that allowed PacifiCorp and CAISO to establish the EIM.

Additionally, as the EIM has grown, the CAISO stakeholder process has addressed EIM design and made modifications to the EIM. These types of stakeholder processes continue, including a recently initiated stakeholder process to establish a new "EIM Sub-Entity scheduling role" to address settlement provisions that were requested by potential participants.

[66] CAISO: PacifiCorp EIM Implementation Agreement
[67] FERC Docket No. ER14-1386-000
[68] FERC Docket No. ER14-1578-000

Examples of State Involvement in Decisions to Join the Western EIM

As demonstrated from the high-level review of the approval processes necessary for the EIM, the regulatory approval processes have been primarily at the CAISO and FERC level. Initial implementation of the EIM did not require approval of state PUCs that regulate PacifiCorp, though, the approval of EIM-related costs eventually came before those bodies for approval.

In some instances, cost approvals may happen earlier in market formation. An example of this is the Arizona Corporation Commission authorizing an accounting order to record and defer operations and maintenance costs associated with the implementation phase of Tucson Electric Power joining the EIM with certain conditions.[69] The Order also directed Tucson Electric Power to submit an annual compliance filing summarizing its deferred costs, annual revenues, and associated savings from its EIM membership.

However, there have been some instances in which state PUCs have been more involved in the process of implementing the EIM or approving a regulated utility's participation in it. A few examples are outlined below.

Example #1 of State Regulatory Involvement in EIM Approval: Nevada PUC Approval of NV Energy's EIM Participation

In addition to the "standard" stakeholder process and FERC filing processes outlined above, NV Energy filed for approval to join the EIM via an amendment to the Integrated Resource Plan (IRP) for each of its operating entities. This type of filing was necessary in Nevada because it constituted a modification to the Energy Supply Plan (ESP) for NV Energy's operating utilities. The EIM was a new strategy for optimizing assets within the ESP and thus a filing was made at the Nevada PUC to modify the ESPs of the operating companies.

NV Energy requested that the PUC find the amendment for EIM participation and supply optimization prudent pursuant to NAC 704.9494(3). The PUC found that it was in the public interest to grant the application and found that participating in the EIM was prudent so long as the benefits of participation exceeded NV Energy's costs.[70] Thus, state regulatory approval for participation in the EIM was deemed necessary in this instance for NV Energy based on the Nevada Administrative Code requirements.

Example #2 of State Regulatory Involvement in EIM Approval: Oregon PUC Required a Cost-Benefit Analysis of the EIM

The Oregon Public Utilities Commission (OPUC), in approving Portland General Electric (PGE's) 2013 IRP, directed a "comprehensive cost-benefit analysis of joining the PacifiCorp-CAISO EIM."[71] PGE was directed to conduct this comprehensive analysis by June 30, 2015, and to present the results at a

[69] Arizona PUC Docket No. E-01933A-20-0039
[70] Nevada PUC Docket No. 14-04024
[71] Oregon PUC Order 14415

Commissioner workshop. OPUC outlined several different benefit types that must be included in the analysis.

Following completion of the analysis, PGE decided to join the CAISO EIM and moved forward with the general approval processes described above. Thus, the OPUC may have played a role in moving a participant towards a market solution, even though the PUC did not, and was not required to, formally approve a decision to for PGE to participate in the EIM.

Example #3 of State Regulatory Involvement in EIM Approval: Commission Cost Recovery Approval Sought by Public Service Company of New Mexico (PNM)

In August of 2018, after making an announcement of its intention to join the Western EIM in 2021, PNM filed an Application for Commission Order Governing the Accounting Treatment of Costs Related to Joining the Western EIM with the New Mexico Public Regulation Commission (NMPRC). In December 2018, the NMPRC issued a favorable order,[72] which, among other things approved carrying costs for PNM's expenses to join the EIM (with costs based on debt rates, rather than a weighted-average cost of capital) and created a regulatory asset for expenses incurred to integrate and join the EIM (to be adjudicated in a future rate case).

However, the Albuquerque Bernalillo County Water Utility Authority sought a rehearing, asserting the Commissioners did not have sufficient time to consider the issues before a decision was made. Subsequently, the NMPRC (which included newly seated members) issued an Order vacating the December 2018 order and granting a rehearing.

After the rehearing, the Commission issued an order in March 2019, which did not oppose PNM's entry into the EIM but also did not provide the ratemaking treatment that PNM had originally sought for EIM-related costs. The order on rehearing declined PNM's request to find "it is reasonable for PNM to join the EIM and expend the necessary funds to do so" and clarified that all EIM-related ratemaking issues would be deferred to a future rate case. The order on rehearing granted authority to create a regulatory asset to record the implementation costs incurred to join the EIM. It also required PNM to submit:

- Annual reports of PNM's EIM costs and savings
- Quarterly CAISO benefit reports
- Copies of all executed contracts with CAISO

Despite the less favorable order, which did not explicitly find that it was reasonable for PNM to join the EIM, PNM nevertheless moved forward with EIM implementation, including signing an EIM Implementation Agreement with CAISO in 2019. PNM began participating in the EIM on April 1, 2021.

[72] New Mexico PUC Docket No. 18-00261-UT

Thus, the NMPRC was involved in reviewing PNM's decision to join the EIM and laid out requirements for what must be filed with the NMPRC. But, in this instance, PNM was able to move forward with EIM participation without explicit state "approval" to participate in the market.

WEIS Market

Initial WEIS Implementation

The WEIS, similar to the EIM, began with a proposal[73] from the potential market operator, SPP. SPP established December 2019[74] as the deadline for entities to express interest in participation in WEIS and execute a Western Joint Dispatch Agreement to facilitate market development. From there, SPP began working with interested entities and hosting various committee meetings to develop the market rules and prepare for a filing at FERC to approve the market structure and tariff. In early 2020, the proposed WEIS Tariff, Western Joint Dispatch Agreement, and Western Markets Executive Committee Charter (WMEC) were filed with FERC.[75]

In general, most of the entities[76] seeking to join WEIS were not subject to PUC-jurisdiction over their rates. No state legislature or individual PUC required the entities to obtain their approval to join the WEIS.

The Colorado PUC did, however, file intervention and comment on SPP's WEIS Tariff. The Colorado PUC expressed concerns with the governance structure of WEIS and the allocation of administrative costs and encouraged FERC to instruct SPP to revise and clarify their proposal to include "meaningful state participation and avoid unintended cost allocation burdens."[77] More specifically, the Colorado PUC was concerned that:

- The WMEC is comprised solely of representatives that are not independent from market participants
- There is potential for disproportionate voting power
- The opportunity for state commissions to provide meaningful input to the WMEC is limited

Though SPP's initial WEIS tariff filing was rejected by FERC, that rejection did not center around the concerns raised by the Colorado PUC. And, following a revised filing that addressed the areas of deficiencies identified by FERC, SPP's revised WEIS tariff filing received FERC approval.[78] The revised filing did not include any additional avenues for state participation as those were not deemed necessary

[73] SPP: Proposal for the SPP WEIS
[74] SPP: WEIS Implementation Milestones
[75] FERC Docket Nos. ER20-1059 & FERC ER20-1060
[76] Historically, Colorado, Nebraska, New Mexico and Wyoming did not exercise rate-regulation over Tri-State, though, in recent years, Colorado and New Mexico exercised rate jurisdiction in (Tristate.coop). In August 2020, FERC indicated it has exclusive jurisdiction over Tri-State's rates (FERC Docket No. EL20-16-001).
[77] FERC Docket No. ER20-1059
[78] FERC Order Nos. ER21-3-000 & ER21-4-000

for the WEIS to be "just and reasonable." Thus, in the currently operating WEIS, state participation is enabled through "state liaisons" comprised of one commissioner from each state with generation or load participating in the WEIS. The state liaisons serve in an advisory capacity on the WMEC. SPP officially launched the WEIS in February 2021, and no state PUC approvals or assessments were necessary for implementation of that particular market and set of market participants.

Day-Ahead Electricity Market

The concept of a day-ahead electricity market outside of the construct of a formal ISO or RTO has been contemplated, but never actually implemented, in the U.S. Thus, it is difficult to know with certainty, the regulatory approval processes that might be required for such a market construct. Furthermore, regulatory approval processes for a day-ahead market would likely depend on the details of the market design, the composition of market participants, and on individual state statutes and administrative codes.[79]

Despite this uncertainty, an example of a historical day-ahead market proposal may provide some insight into possible regulatory processes for this type of market, should it be proposed in the future. In 2008, the Midcontinent Independent System Operator (MISO)[80] proposed to develop and implement a day-ahead electricity market referred to as "Market Services." This section briefly reviews that proposal and what is known about the approval processes that were pursued for its creation; however, it should be noted that the MISO proposal and circumstances surrounding it may be substantially different than a day-ahead market proposal that may be developed for the West. This section also briefly considers a potential Western Day-Ahead Market and what approval processes might be required for such a market, recognizing that there is very little certainty at this time given the lack of specifics on a day-ahead proposal and market design.

MISO's Day-Ahead Market Service Proposal

In March of 2008, MISO submitted for FERC approval a proposed new "Module F "to their Open Access Transmission and Energy Markets Tariff; the module described new services that MISO intended to offer, which included a Market Service. The Market Service would provide "access to MISO's energy and ancillary services markets to the footprints of those taking Market Service."[81] But, similar to the real-time market construct evaluated in this study, individual participants would continue to administer their own tariff and transmission planning and would retain control over their transmission system. Thus, this market was as close to a "day-ahead" market construct as has previously been formally proposed in the U.S. and considered by FERC.

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[79] As a reminder a review of individual state statues and administrative codes is outside of the scope of this review.
[80] At the time this proposal was made, MISO was known as the Midwest Independent System Operator.
[81] FERC Docket Nos. ER08-637-000, ER08-637-001, ER08-637-004, & ER08-637-005

MISO highlighted that the benefits of this market in making its filing with FERC. However, in the February 2009 final order,[82] FERC rejected the Market Services proposal, determining the potential benefits of the Market Service proposal did not outweigh the potential adverse impacts or long-term costs. FERC noted the proposal may create an incentive for current members to leave MISO in favor of the Market Service offering, which could create rate pancaking and would remove MISO's operational control from some areas. FERC expressed concern that this proposal could "adversely" impact the efficiency of the wholesale markets and could prevent transmission owners from joining MISO as full members and "institutionalize the seam." Lastly, FERC also found the proposal could cause negative impacts on MISO's ability to address reliability and operational issues or eliminate residual discrimination in transmission services. Thus, this proposal was never fully implemented.

State Involvement in MISO's Market Service Proposal at FERC

This review sought to evaluate the role of state PUCs, energy offices and other state agencies in the development and consideration of the MISO Market Service proposal. A search was conducted to seek to identify any state-level proceedings on the Market Service proposal or state PUC involvement in the development of this market construct. Outreach to MISO staff was also conducted as part of this effort to inquire about the proposal and state involvement in its development. The Market Service proposal is nearly 15 years old, and it is possible that a state docket or involvement was overlooked in this review. But, outside of the FERC docket in which some states intervened, no definitive state PUC dockets or examples of state participation in the development of the Market Service proposal were identified.

Within the FERC docket seeking approval of this market, joint intervention and comments were filed by the Indiana Utility Regulatory Commission and the Indiana Office of the Utility Consumer Counselor. These entities generally supported MISO's Market Service Proposal and expected the overall impact of the proposal would reduce costs to MISO customers by spreading administrative costs across a wider footprint, among other benefits. Although they generally supported the proposal, they expressed concern regarding the ability for new entities to participate in the MISO on more flexible terms than when the original transmission owners joined MISO; thus, they noted that there could be undue discrimination between the original transmission owners and the new participants. They recommended approval of the Market Service proposal subject to a "short-term condition of no more than a few years, at the end of which it could be revisited."[83]

Based on the review conducted as part of this effort, it appears that, for the Market Service proposal, state participation was limited to intervention and comment within the FERC proceeding.

Potential for State Involvement in a Western Day-Ahead Market

This subsection very briefly opines on the possible regulatory processes that might be requires to stand up a potential future Western day-ahead market and for state-regulated utilities to facilitate their

[82] FERC Docket Nos. ER08-637-000, ER08-637-001, ER08-637-004, & ER08-637-0059
[83] FERC Docket No. ER08-637-000

entrance into such a market. Currently, an initiative is underway (though on hold) at CAISO to develop an approach to extend participation in the day-ahead market to EIM entities in a framework similar to the existing EIM approach for the real-time market. This is known as the Extended Day-Ahead Market (EDAM). However, many of the specifics around that market's design are yet to be determined and, thus, there is significant uncertainty around what a potential day-ahead market may entail and what approvals would be required for it to move forward.

Based on discussions with some entities involved with the evaluation and design of EDAM, it appears the approval processes to join a day-ahead market would likely be comparable to the EIM. Similar to the EIM, operational control would not be turned over upon joining the EDAM. Therefore, it is possible, some states may not require any regulatory approvals to join the EDAM while others may require processes similar to those required for joining the EIM. The same would likely be true of any other day-ahead market proposal proposed in the west, such as the "Markets+" concept that SPP has begun work on. But the specifics of the approvals for a future day-ahead market will, of course, depend on the market structure, design, and its participants.

Regional Transmission Operator Market

ISOs and RTOs grew out of FERC Orders Nos. 888/889 where the Commission suggested the concept of an ISO as one way for existing power pools to satisfy the requirement of providing non-discriminatory access to transmission. In Order No. 2000, the Commission encouraged utilities to join RTOs which, like an ISO, would operate the transmission systems and develop innovative procedures to manage transmission equitably. While major sections of the country operate under more traditional market structures, two-thirds of the nation's electricity load is served in RTO regions.[84]

Of the market formations discussed in this Appendix, the RTO market construct would likely require the highest degree of state involvement in the approval processes, given the transfer of operational control and typical state requirements for state regulated utilities to obtain state PUC approval to effectuate such a transfer.[85] Based on historical examples, the general regulatory processes required to join an RTO or ISO, involves the approval of the relevant state commission(s) and FERC approval of the RTO transmission tariff facilitating integration. A high-level, *generalized* process is outlined below. However, recall that individual states, utilities, and market structures will have unique variations from this generalized process. Additionally, these steps often follow a cost/benefit analysis on ISO/RTO participation.

General Process for an Entity to Join an RTO

- Policy and tariff development initiatives
    - Tariff approval through RTO stakeholder process and at RTO board

[84] FERC: Market Assessments – Electric Power Markets
[85] As an example, please see Laws Relating to the Public Utility Commission of Oregon.

  - Tariff filed with FERC for approval via a Section 205 filing by the RTO
- Signed Transmission Owner Agreement (or equivalent) between transmission owning entity seeking to join the market and the RTO
  - Approval by RTO board
  - Filed at FERC for approval
- Filing for "transfer of control" approval and "public interest determination" with relevant state PUCs (for state regulated entities seeking to join the market)
  - PUCs typically addressed a monitoring plan, transition cost allocation plan, RTO exit authority, responsibility for reliability, RTO governance, and commission jurisdiction, among other things, within these dockets

Entergy's Entrance into MISO

In April 2011, Entergy announced its intention to join the MISO RTO with an anticipated integration date of December 2013. This section reviews, at a high-level, some elements of the various state approval processes that were necessary for Entergy to join the MISO RTO.

In order to join MISO, Entergy was required to file an application, for approval to transfer operational control of its transmission assets to the MISO RTO, in each state where it delivered electricity to customers: Arkansas,[86] Louisiana,[87] Mississippi,[88] and Texas.[89] All four state Commissions gave their approval, subject to conditions, including conditions around expanding or retaining the role of the states under an RTO construct. Below is a short selection of some of the conditions set forth in the states' Orders.

- The Arkansas PUC ordered that the Organization of MISO States—which is the self-governing organization with a board comprising a commissioner from each Member state with regulatory jurisdiction over entities participating in MISO—must have "legally recognized responsibility" for the following regulatory activities:
  - Determining regional proposals regarding transmission planning and cost allocation; and
  - Directing MISO to construct transmission upgrades and choosing the approach to be utilized for assessing resource adequacy.
- The Arkansas and Texas PUCs ordered that the Entergy Regional State Committee (ERSC) retain the same governance authority in MISO during the transition period (including the ability to act on transmission planning and cost allocation issues by majority vote).
  - After the five-year transition period, the Arkansas PUC instructed Entergy to file a detailed report providing:
    - Historical and projected net benefits of MISO membership;

[86] Arkansas PUC Docket No. 10-011-U, Order No. 68
[87] Louisiana PUC Order No. U-32148
[88] Mississippi PUC Docket No. 2011-UA-376
[89] Texas PUC Docket No. 40346

- Any significant changes in FERC RTO policies, rules or regulations, MISO requirements, Day 2 market conditions, or other regulatory or market structure components; and
- Estimate of costs to exit MISO after end of the five-year transition period.

- The Texas PUC also ordered MISO to file with FERC to expand the retail representation of the Advisory Committee to include a retail regulator from the ERSC and to create a new retail regulatory committee that reports directly to the Board of Directors of MISO.
- Arkansas, Louisiana, and Texas orders indicated that Entergy could not unbundle transmission or make changes to transmission service for retail ratemaking without the PUC's approval.
- The state PUCs indicated that Entergy needed state PUC approval to exit MISO and state PUCs could also direct Entergy to exit MISO.

On April 19, 2012, FERC approved the proposed tariff revisions of MISO to facilitate the integration of Entergy as a member of the RTO, which included changes to address the relevant conditions states put on Entergy's entrance into the market.[90] Entergy's entrance into MISO demonstrates the role of states in the approval process to join an RTO and highlights some of the conditions for approval that have been used by states in the past.

Conclusion

This Appendix sought to shed light on areas of potential state involvement in the approval processes for different market construct primarily by reviewing several historical examples of approval processes. As illustrated by the examples herein, states may have several opportunities to participate in regulatory approval processes for market implementation as entities seek to participate in various markets. Turning over operational/functional control of transmission facilities is only expected to occur in an RTO, and it is this action which triggers the highest degree of expected state regulatory involvement in the process for joining the market. But some state PUCs have required approval and set conditions for real-time market participation and could be expected to do the same with a future day-ahead market.

Again, it is important to note that this Appendix was **not** based on an in-depth review of federal and state statutes and administrative codes. Each state, market formation, and participating entity will have its own unique circumstances, rules, and regulations. Nonetheless, this Appendix may serve as a high-level tool for Western states as they independently and jointly consider options and make decisions around their energy futures.

[90] FERC Docket No. ER12-480-000

Appendix B. Summary of Participating State Energy Policy Priorities and Key Regulations

The information in the following table was compiled in September 2019 and was utilized by the Lead Team during the project development phase. Please note that the table has **not** been updated since its original compilation and reflects state energy policy priorities as of 2019.

State	State Energy Policy Priorities [as of September 2019]
Arizona	• RPS of 15% by 2025 • Arizona's last Master Energy Plan was drafted in 2013 and approved by former Governor Brewer in 2014[91] • Governor Ducey believes in the benefits of Arizona's balanced energy portfolio, and that market forces — including those that have driven down the cost of natural gas — make additional climate-change regulation unnecessary for the electricity sector[92]

California	• SB 100
	  ○ Procurement of electricity products from eligible renewable energy resources: 25% of retail sales by 12/31/2016; 33% by 12/31/2020; 44% by 12/31/2024; 52% by 12/31/2027; 60% by 12/31/2030
	  ○ Eligible renewable energy resources and zero-carbon resources to supply 100% of all retail sales of electricity to California end-use customers and 100% of electricity procured to serve all state agencies by 12/31/2045. [the 100% policy]
	  ○ The CPUC, CEC and CARB shall issue a joint report to the Legislature by 1/1/2021, and at least every four years thereafter, that includes the following:
	    ▪ A review of [the 100% policy] focused on technologies, forecasts, then-existing transmission, and maintaining safety, environmental and public safety protection, affordability, and system and local reliability
	    ▪ An evaluation identifying the potential benefits and impacts on system and local reliability associated with achieving [the 100% policy]
	    ▪ An evaluation identifying the nature of any anticipated financial costs and benefits to electric, gas, and water utilities, including customer rate impacts and benefits
	    ▪ The barriers to, and benefits of, achieving [the 100% policy].
	    ▪ Alternative scenarios in which [the 100% policy] can be achieved and the estimated costs and benefits of each scenario

[91] National Association of State Energy Officials State Energy Plan Repository: emPOWER Arizona
[92] Arizona Central: Where Arizona Candidates Stand on Climate Change, Water Issues, and Heat-Related Deaths

	• SB 350
	  ○ Double energy efficiency by 2026 relative to the AAEE in 2016 IEPR.
	  ○ Reduce emissions of GHG to 40% below 1990 levels by 2030 and to 80% below 1990 levels by 2050
	• AB 32 & SB 32
	  ○ Reduce GHG emissions to 1990 levels by 2020
	  ○ Reduce GHG emissions to 40 percent below 1990 levels by 2030
	• Other goals
	  ○ Reduce methane and hydrofluorocarbon (HFC) refrigerants to 40 percent below 2013 levels by 2030 (SB 1383).
	  ○ 5 million ZEVs on the road by 2030 as well as a network of 200 hydrogen refueling stations ad 250,000 electric vehicle charging stations, including 10,000 direct current (DC) fast chargers by 2025 (Executive Order B-48-18)
	  ○ Achieve carbon neutrality (zero-net GHG emissions) by 2045 and maintain net negative emissions thereafter (Executive Order B-55)
	  ○ Reduce GHG emissions in residential and commercial buildings to 40 percent below 1990 levels by January 1, 2030 (AB 3232), which will require building electrification
	  In addition, California is the first state to require rooftop solar on new homes under new building standards that go into effect on January 1, 2020

Colorado	• Colorado has a 30% by 2020 RPS for investor-owned utilities • HB19-1261 established statewide goals to reduce 2025 GHG emissions from the 2005 baseline by at least 26% by 2025, 50% by 2030, and 90% by 2050[93] ○ These are economy-wide (not just the electric sector) and include various GHG, not just carbon dioxide • SB19-236 directed Xcel Energy to file a Clean Energy Plan that will reduce GHG emissions 80% below 2005 levels by 2030, and 100% by 2050 • SB19-236 also directs the Public Utilities Commission to explore whether utilities should join a regional transmission organization or an energy imbalance market[94] • Governor Polis, who took office in 2019, has an administration goal of 100% renewable electricity by 2040
Idaho	• Idaho's last energy plan was completed in 2012 and includes objectives of ensuring secure, reliable, and stable energy and maintaining low-cost supply • In 2019, Governor Little noted that *"through the free market and innovations at the Idaho National Laboratory, Idaho will continue to expand opportunities for clean and affordable energy for our citizens and the world"*[95]

[93] Colorado Legislature: House Bill 19-1261
[94] Colorado Legislature: Senate Bill 19-236
[95] Idaho Press: Full text of Gov. Little's State of the State and budget address

	• Though no Idaho legislation or regulation required this, two of Idaho's major investor-owned utilities (Idaho Power and Avista) are pursuing 100% clean energy goals by 2045
Montana	• Montana has a 15% RPS[96] • On July 1, 2019, Governor Bullock created the Montana Climate Solutions Council and announced that Montana would join the US Climate Alliance ○ The Council shall provide recommendations and strategies for the State of Montana to reduce greenhouse gas emissions • Governor Bullock released a blueprint for Montana's Energy Future in 2016 ○ The plan includes support for energy infrastructure development, the existing RPS, solar and wind power development, carbon capture technologies, and energy efficiency[97]
Nevada	• In 2019, Nevada passed legislation (SB 358) which establishes an RPS of 50% by 2030 for retail electric customers and sets a goal of 100% zero-carbon electricity by 2050. • Also in 2019, Nevada passed legislation (SB 254) that establishes state GHG emission reduction targets of 28 percent below 2005 levels by 2025, 45 percent by 2030 and net zero, or near net zero, emissions by 2050. • Governor Sisolak joined Nevada to the US Climate Alliance in March of 2019.
New Mexico	• In 2019, New Mexico passed the Energy Transition Act (SB 489) which establishes New Mexico's pathway to a zero-carbon electric industry, by creating an RPS of 40% by 2025, 50% by 2030, and 80% by 2040 for investor-owned utilities ○ Investor-owned utilities must also reach a 100% clean energy standard by 2045 ○ Co-ops must achieve the RPS requirements and must also meet the 100% clean standard by 2050[98] • Governor Lujan Grisham seeks to make New Mexico a leader in fighting climate change • The 2019 legislative session also resulted in updated Energy Efficiency standards for utilities (HB 291)[99]
Oregon	• In 2016, Oregon passed legislation (SB 1547) that established a 50% RPS for investor-owned utilities by 2040, with additional interim goals, and separate goals for smaller utilities • SB 1547 also eliminated coal as a resource for electric utilities by 2030[100] • Governor Brown's vision for energy policy is that *"Oregon has a strong, innovative, and inclusive economy that achieves the state's climate emissions*

[96] *Note: In 2021, HB 576 repealed Montana's RPS*
[97] Governor Bullock: Blueprint for Montana's Energy Future *Note: This webpage is no longer active.*
[98] New Mexico Senate Bill 489
[99] New Mexico House Bill 291
[100] Oregon Senate Bill 1547

	goals through a complementary set of policies, including a least-cost, market-based GHG emissions pricing program"[101]
Utah	• In 2008, Utah established a 20% by 2025 RPS mandate, if cost effective (SB 202) • In 2019, Utah passed HB 411, the Community Renewable Energy Act, which allows for communities served by PacifiCorp's Rocky Mountain Power to move to 100% net renewable energy[102] • Governor Herbert's administration supports strategic infrastructure and ensuring value for Utahns, and champions an "all of the above" energy policy[103] ○ Specifically, "*It is the policy of the state that Utah shall have adequate, reliable, affordable, sustainable, and clean energy resources*"[104]
Washington	• Washington has an older RPS of 15% by 2020 • Washington's SB 5116 passed in the 2019 session and will transition Washington to 100% clean energy for its electricity supply ○ Under the legislation, coal-fired resources are prohibited for electric utilities as of 2026 ○ By 2030, 80% of all sales of electricity to Washington retail electric customers must be from non-emitting or renewable resources, and 100% by 2045 ○ Between 2030 and 2045, utilities have a requirement to be GHG neutral, so if the utility is still relying on natural-gas, diesel, and wood fired resources for up to 20% of retail sales, compliance may be met through alternative compliance measures specified in the law[105]
Wyoming	• Wyoming's last energy plan was completed in 2013[106] • Senate File 159, which passed in 2019, requires utilities (e.g., PacifiCorp's Rocky Mountain Power) to attempt to sell coal plants rather than retire them ○ Furthermore, the utility is required to buy back power from the purchaser, and the bill guarantees cost recovery from the utility's Wyoming customers for those costs[107] • Governor Gordon promises to ensure "responsible development" of Wyoming's natural resources and to make Wyoming a "leader in advanced energy technologies including Carbon Capture and Storage"[108]

[101] Oregon Climate Agenda: A Strong, Innovative, Inclusive Economy While Achieving State Climate Emissions Goals
[102] Utah House Bill 411
[103] Governor Herbert Administration Utah Office of Energy Development: Energy Policy Solutions *Note: This webpage is no longer active.*
[104] Utah State Energy Policy
[105] Washington Senate Bill 5116
[106] National Association of State Energy Officials State Energy Plan Repository: Wyoming
[107] Wyoming Senate Bill 159
[108] Governor Gordon Website: Issues

THE STATE-LED MARKET STUDY

ROADMAP *Technical Report*

Prepared by:

Energy Strategies, Project Contractor

July 30, 2021

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

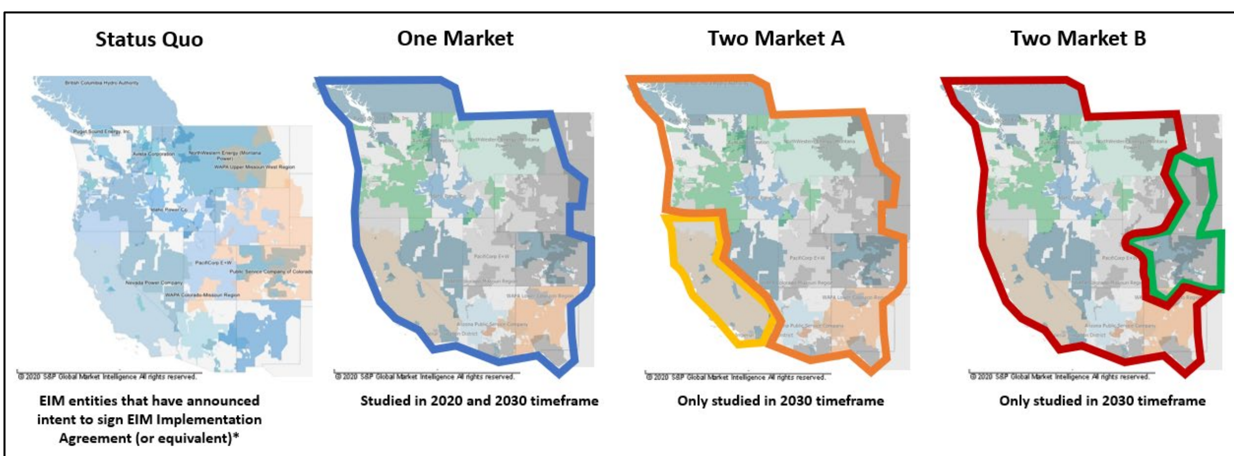
Day-Ahead Market (DAM)

- ✓ 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
- ✓ Transmission providers retain operational control of transmission

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.

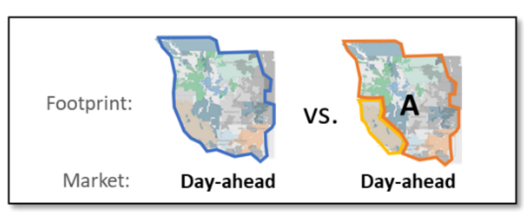
Key Findings

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.

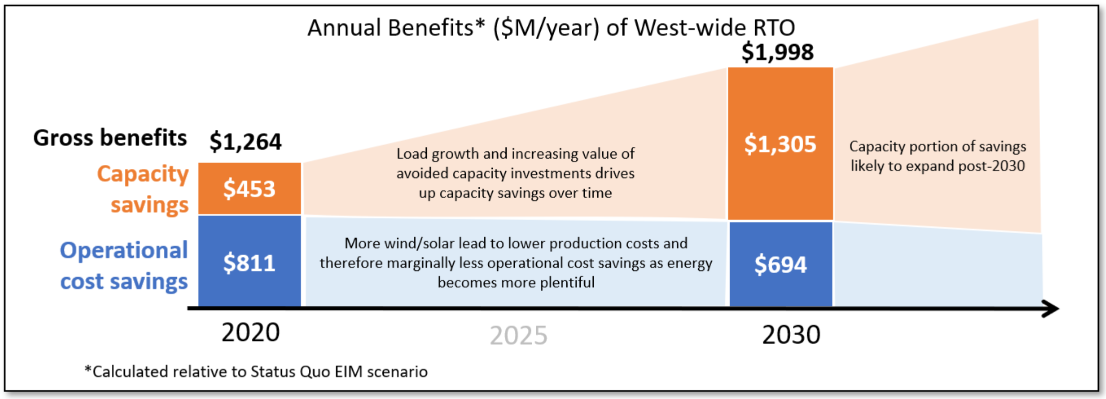
1. ***Expanding current and planned real-time-only markets to include day-ahead market services could result in West-wide annual gross savings of up to $642 million. Such a day-ahead market would involve a day-ahead unit commitment and dispatch optimization and overall market framework that could facilitate 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***



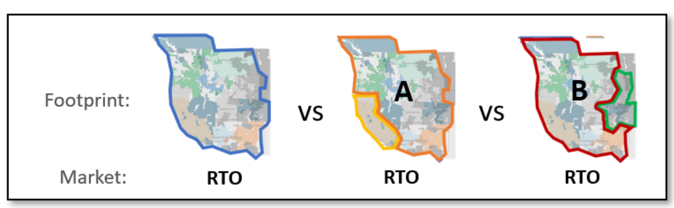
measurably lower $501 million per year of gross benefits.

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 not 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%
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*

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**
- ✓ 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
- ✓ Transmission providers retain operational control of transmission

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

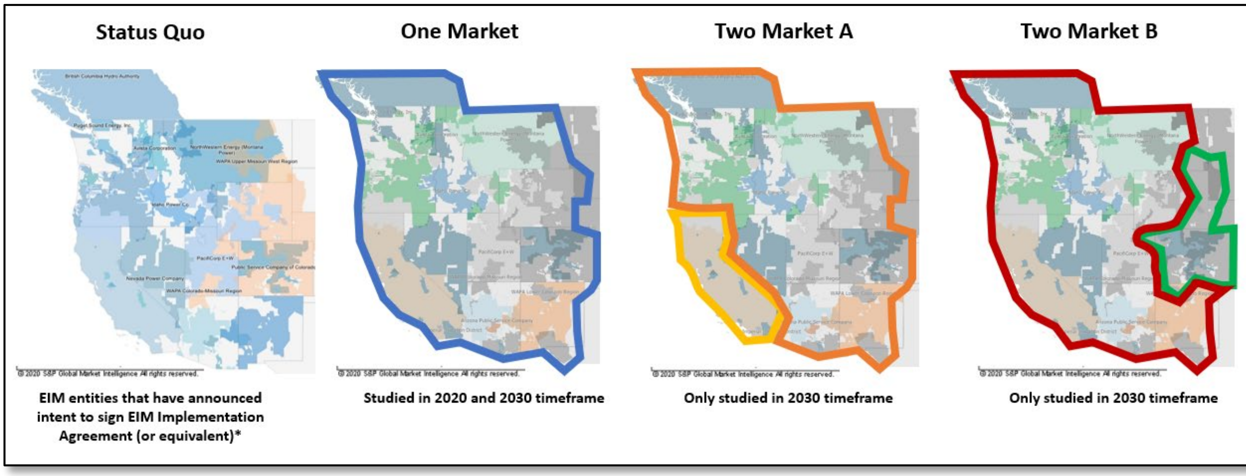
The Western Interconnection is home to 39 BAs. As of the date that data was collected for this study, nineteen of these BAs participate or plan to participate in the Western EIM. Those entities that plan to join the Western EIM in 2021 or later were included in Western EIM for the Status Quo footprint 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.

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[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

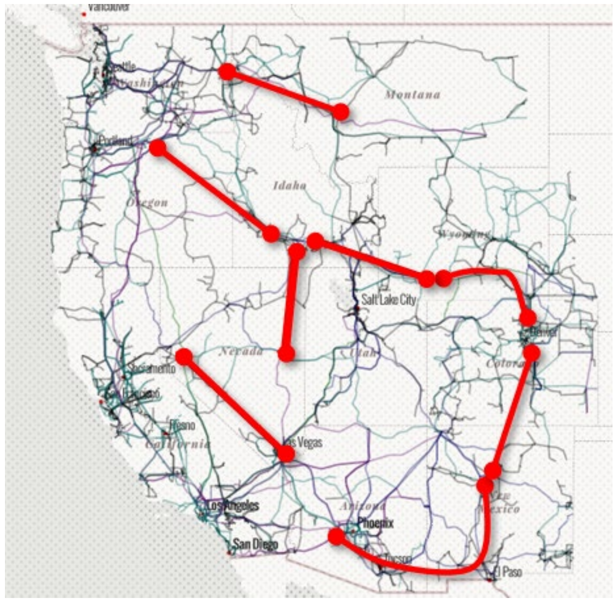
This sensitivity explores how market benefits change if major transmission upgrades, beyond what was included in the core studies, are placed into service before 2030.[8] Since small changes to the transmission system were unlikely to impact the study results, the study assumed a relatively large buildout 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

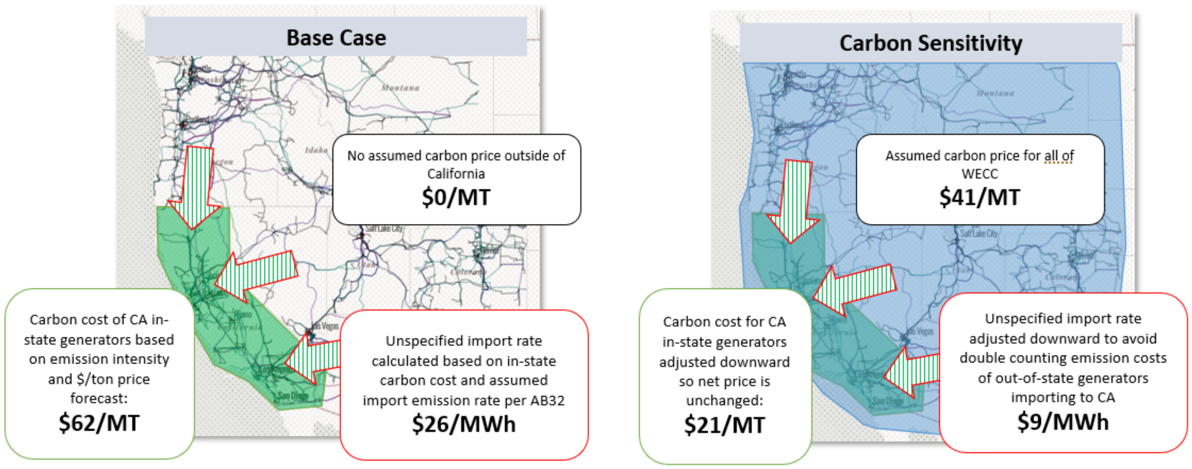


Impact of regional carbon price

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

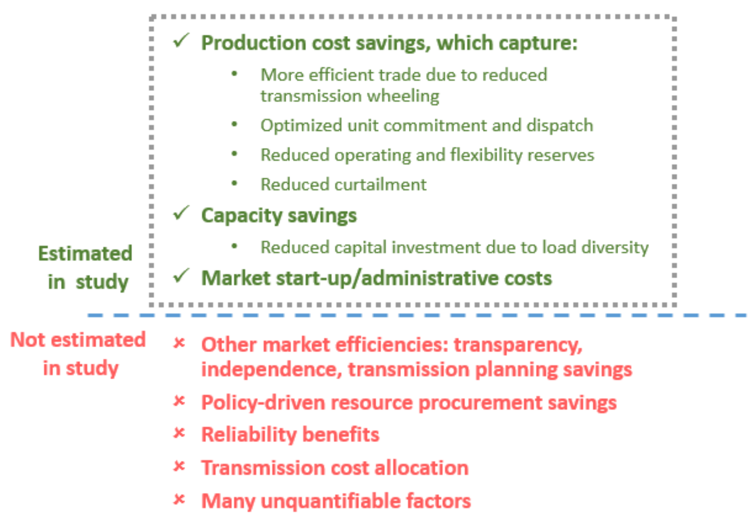
This section addresses the analytical approach used to model the market configurations and estimate their benefits. The first two subsections address the production cost modeling software tool and the primary benefit metric used in estimating operational benefits – adjusted production cost (APC). The 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

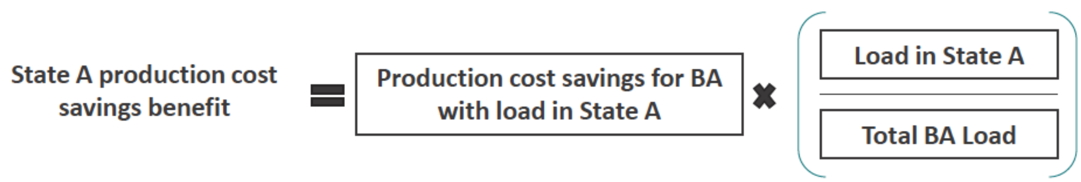
Energy Strategies used ABB's GridView™ production simulation software to simulate grid operations and energy markets in the Western Interconnection for 2020 and 2030 study years. In an hourly timestep, the model performs a least-cost security constrained unit commitment and dispatch based on a detailed "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

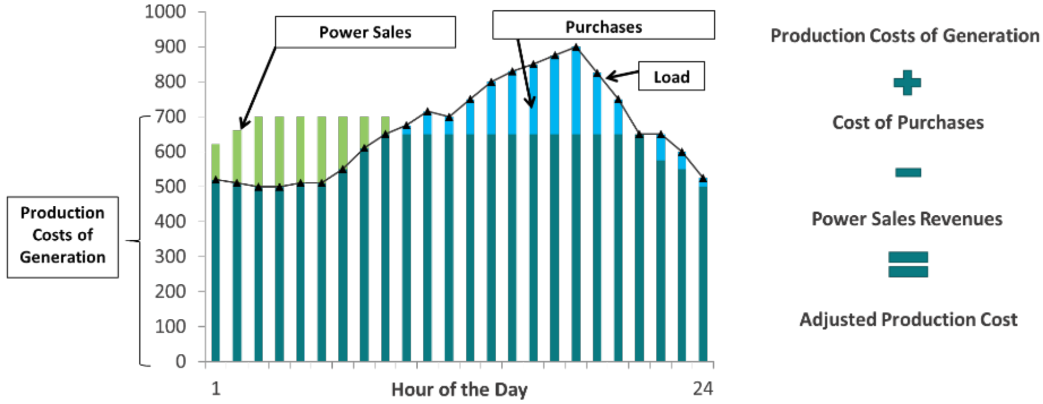
APC estimates the net costs for a given area to produce, buy, and sell power. The metric is commonly used in market benefit studies as it accounts for the trade benefits between buyers and sellers. This study calculates APC on a BA basis and then sums the costs at the state level. For BAs that have load 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.

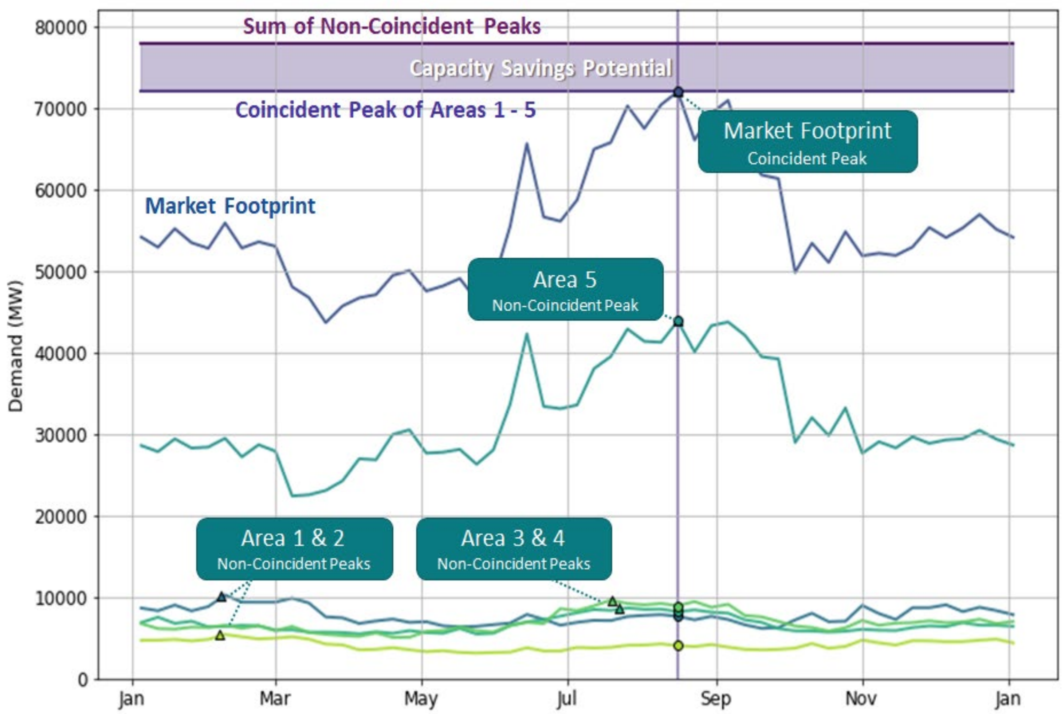
In the absence of any coordination of BA peak demand, resource adequacy obligations in place today generally require each BA (or utility)[9] to build or contract for resources to meet individual system loads plus a planning reserve margin. With a coordinated (or consolidated) system, the BAs/utilities 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

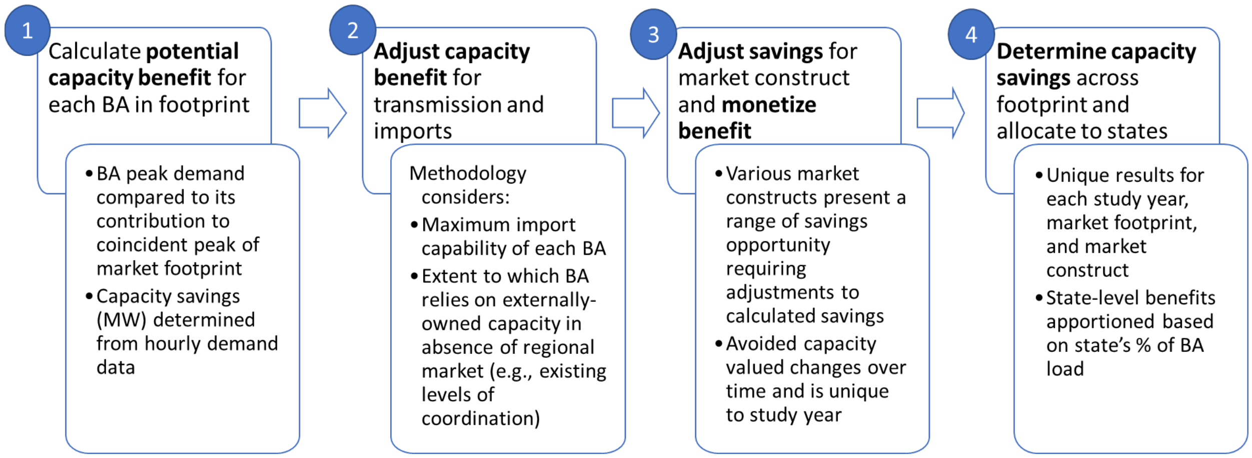


Method and Key Assumptions

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.

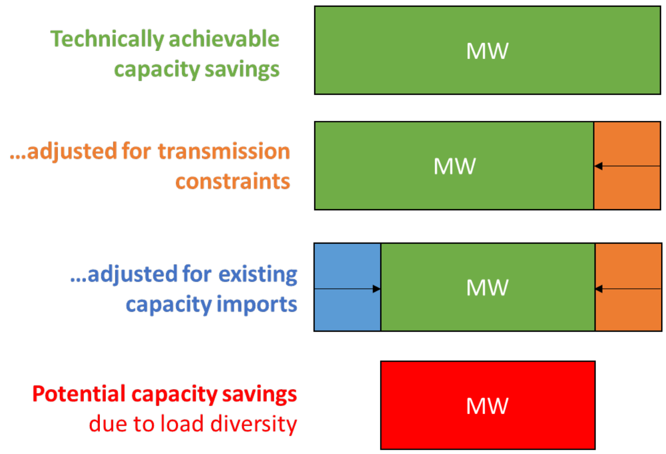
Figure 13: Capacity Savings Methodology



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

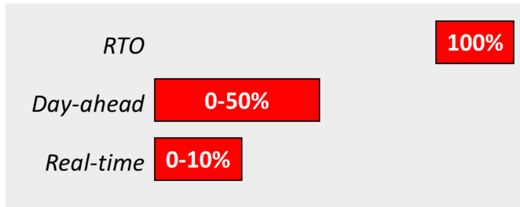


The third step considers that different market constructs are likely to lead to different levels of capacity savings based on their service offerings and organizational structures. For example, an RTO is likely to enable far greater capacity savings than a real-time energy market, because it more freely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

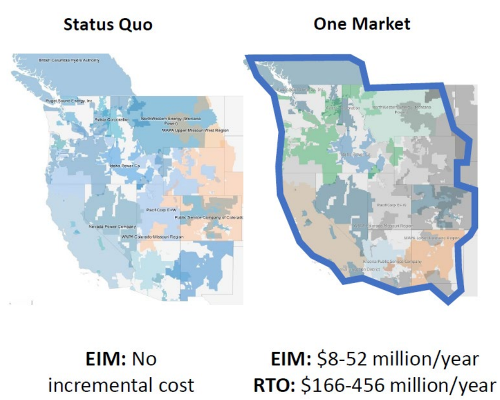
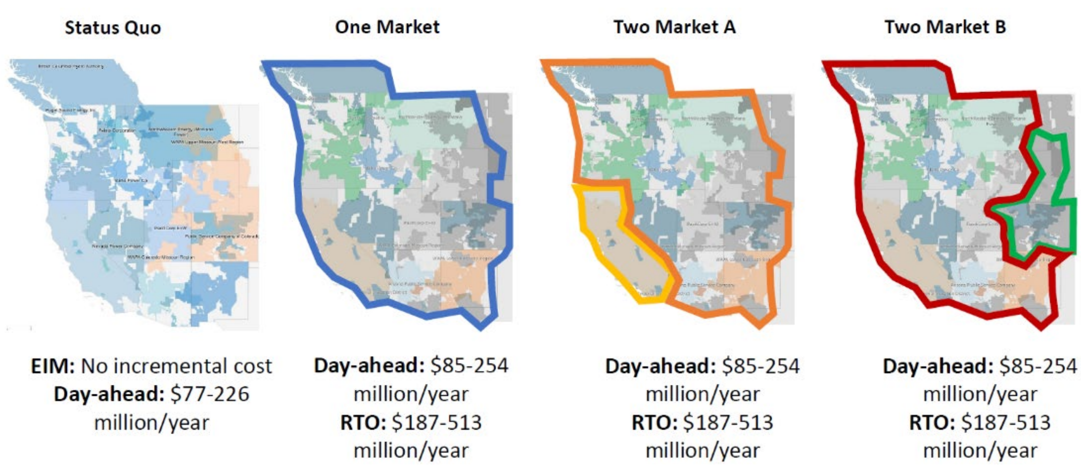


Figure 19: Estimated Market Administration Costs of 2030 Market Configurations



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.

[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%.

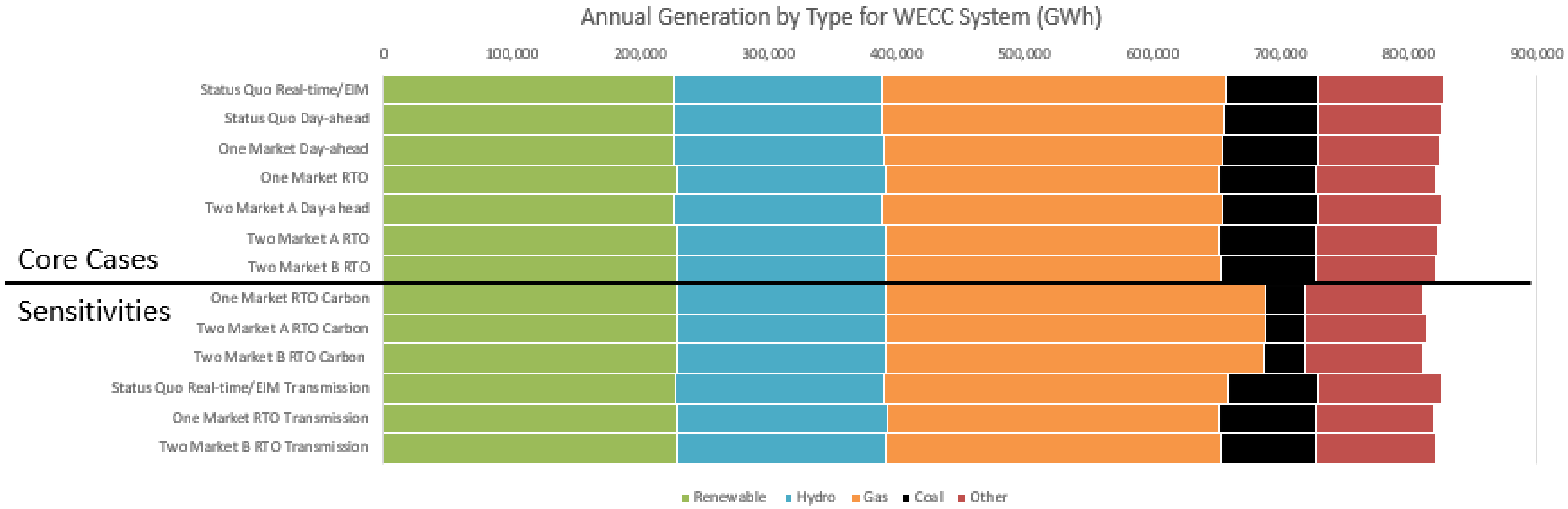
The Transmission Sensitivity caused higher operational savings in the three market configurations studied. Adding the transmission projects caused the APC of the Status Quo Real-time configuration to fall by 1% or $107 million per year. Savings in the One Market RTO and Two Market B RTO configurations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

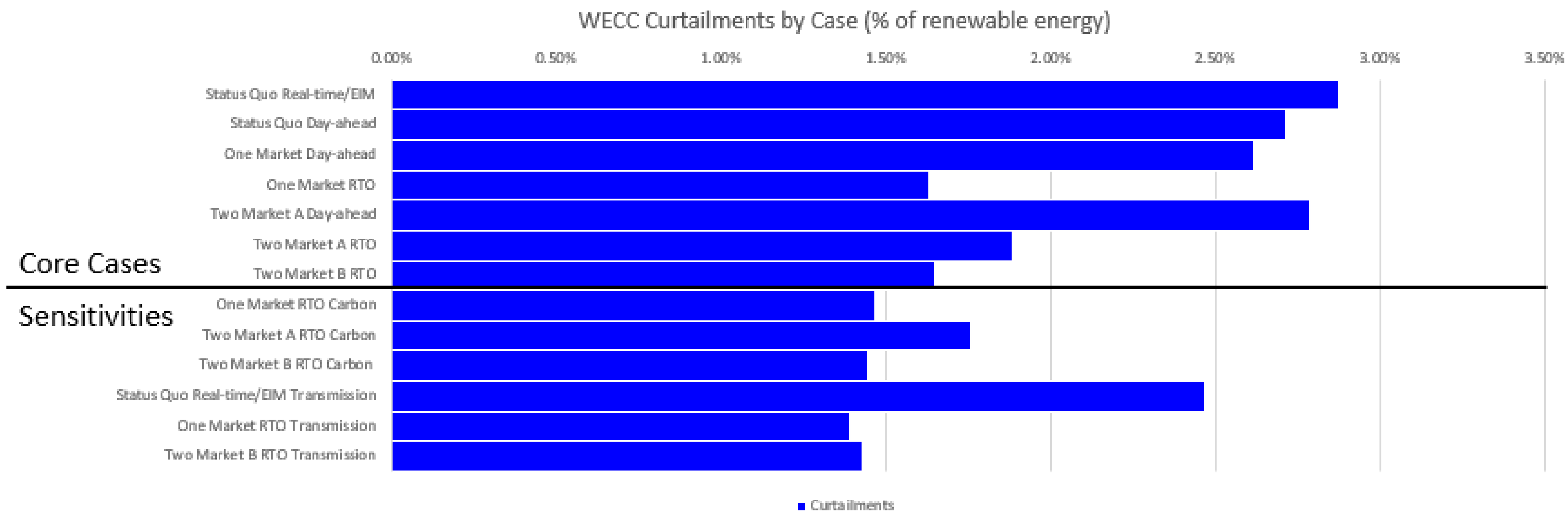
The generation dispatch results for the WECC system, below, demonstrate that the market configurations cause relatively small changes in system wide dispatch. The exception is the carbon sensitivities, which caused a material shift from coal to gas.

Figure 28: Generation Dispatch Results



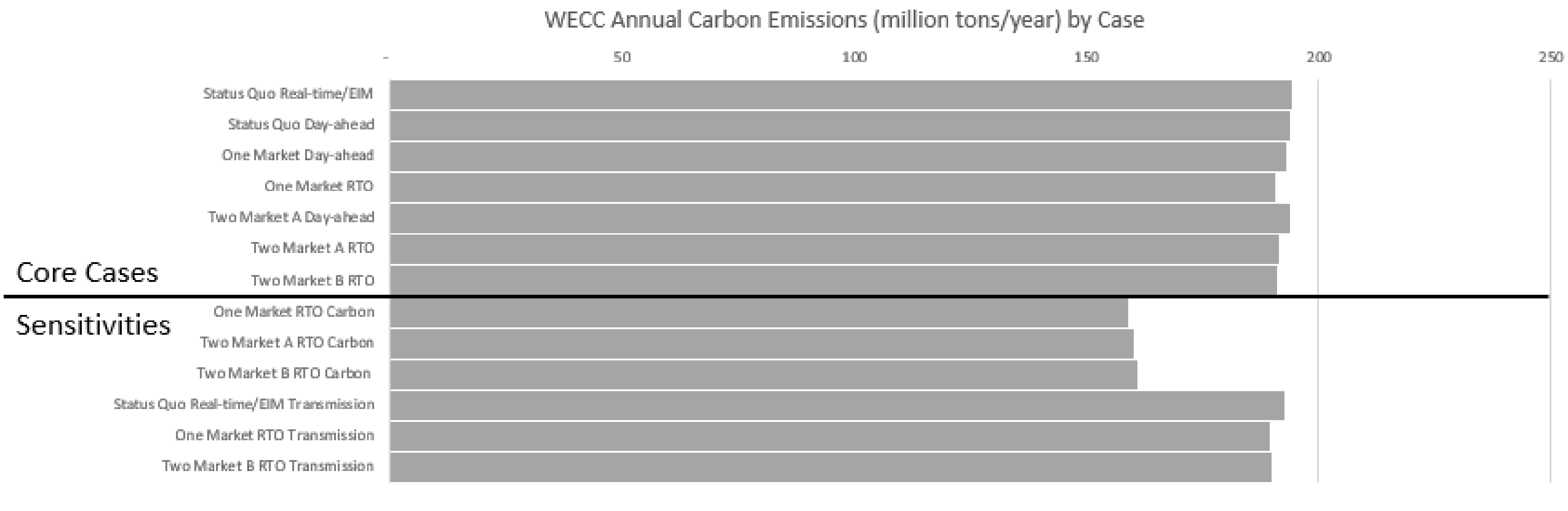
The RTO construct was the most effective at mitigation renewable curtailments, as demonstrated below.

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_BM		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%
	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*

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

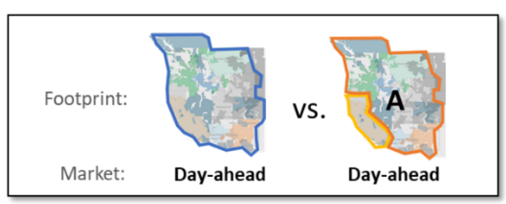
State	APC Benefit ($M)	Capacity Benefit ($M)	Total Benefit ($M)	
AZ	($11)	$56	$45	
CA	$63	$91	$153	
CO	$3	$41	$44	
ID	$2	$44	$45	
MT	$1	$18	$19	
NM	$1	$32	$33	
NV	($13)	$25	$12	
OR	$1	$63	$64	
UT	$3	$28	$30	
WA	($4)	$189	$184	Estimated Ongoing Cost
WY	$2	$9	$10	
TOTAL	**$47**	**$596**	**$642**	$76-226

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

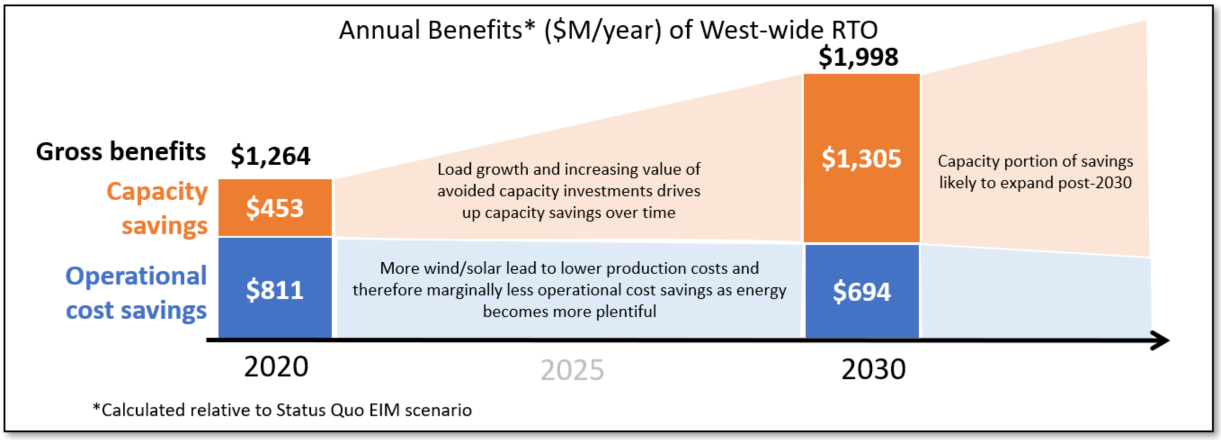
The above analysis assumed that the day-ahead construct achieves capacity benefits at the high-end estimated in the study. If low end (0%) capacity savings are achieved, the operational benefits of the two market footprints are relatively comparable.

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.

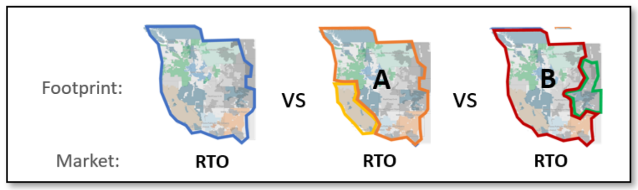
The decrease in operational benefits over time observed in the RTO market construct is due to shifts in the West's resource mix, including the increasing prevalence of low-cost energy resources. By 2030, the study assumes that nearly 60% of the West's resource mix is made up of zero-emission resources 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.

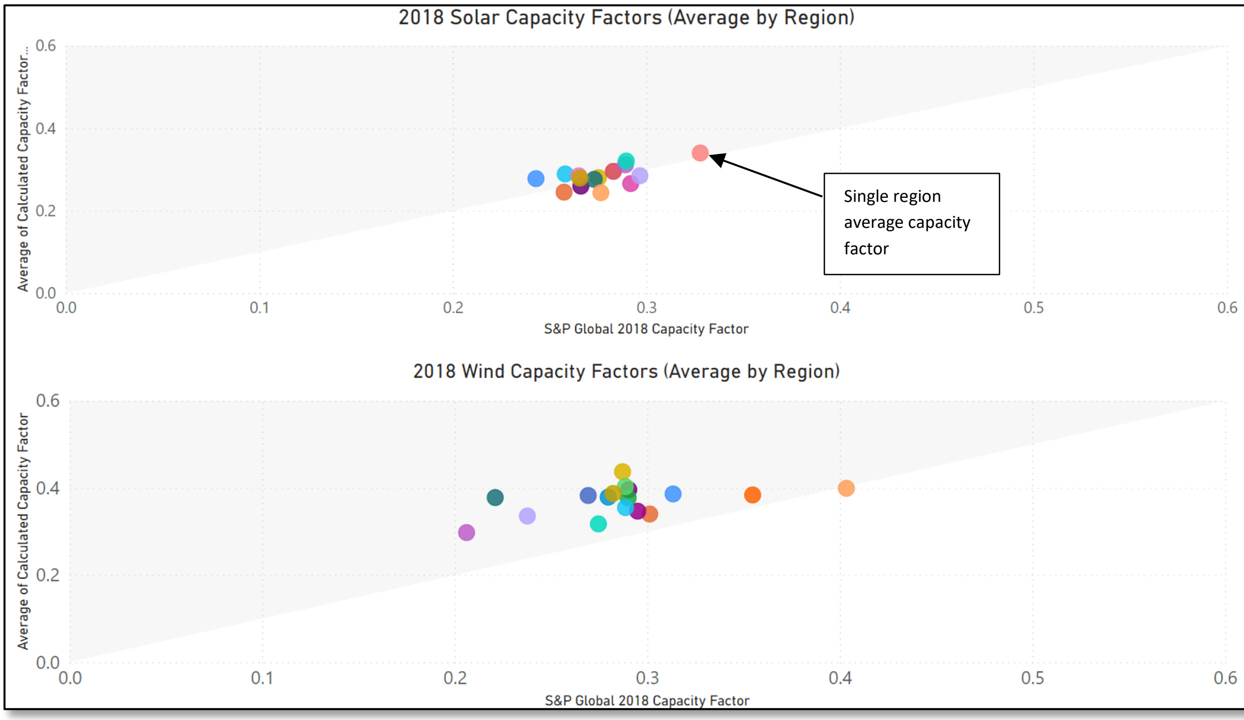
Per-unit production profiles in this study were developed based on a "nearest neighbor" approach similar to techniques presented in other studies using NREL WIND and SIND datasets.[17] In this approach, each wind or solar unit in the production cost model was matched with one or more of its nearest WIND 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.

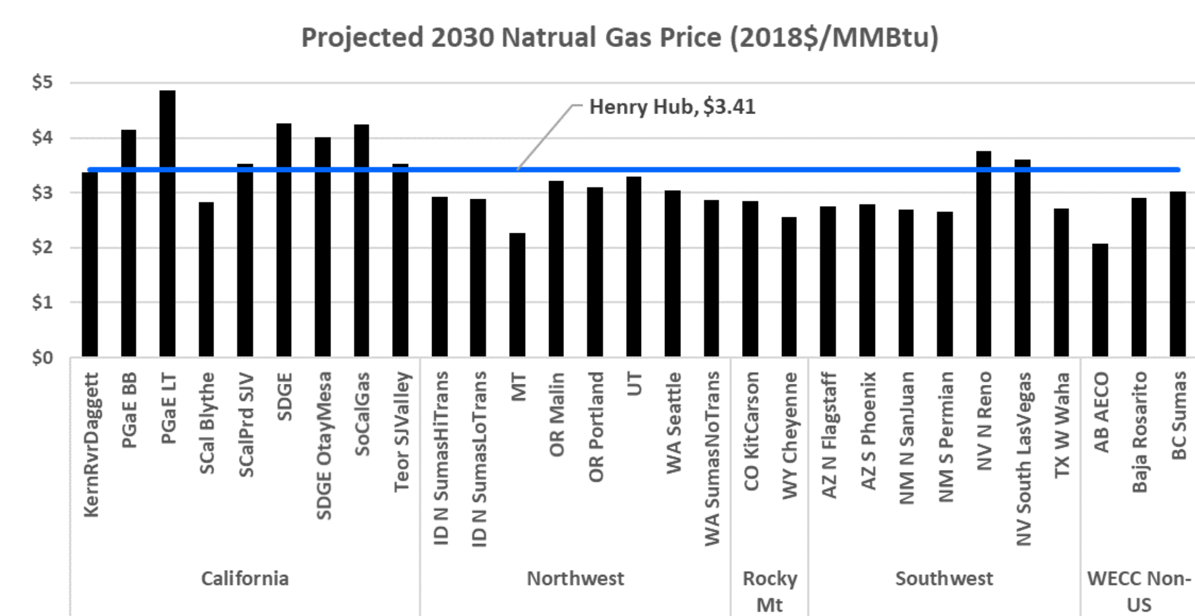
Fuel Prices

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

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[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)

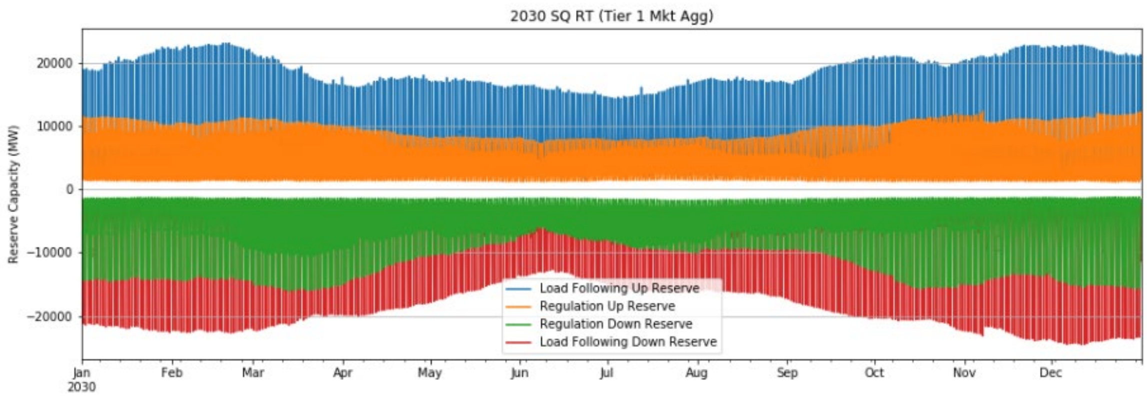
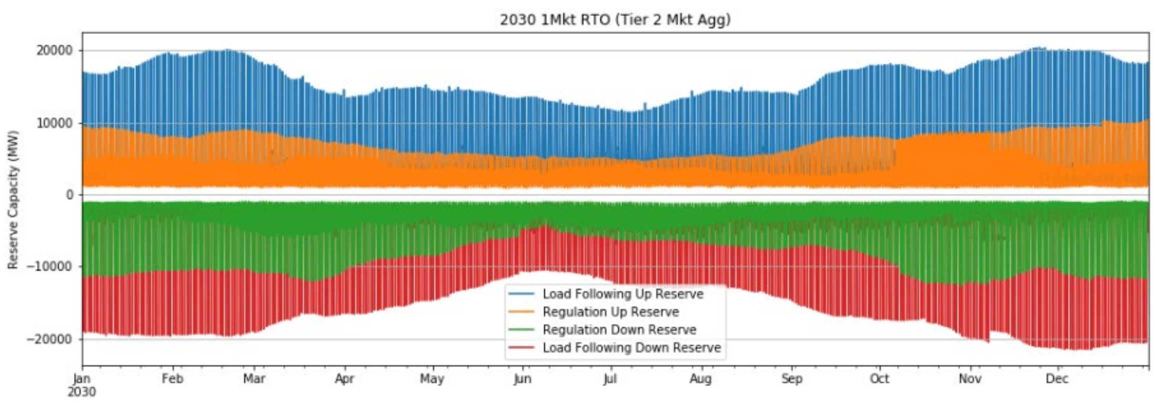


Figure 48: Cumulative One Market RTO Flexibility Reserves (2030)



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

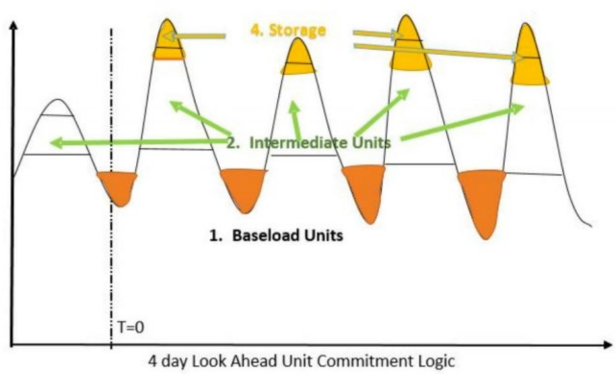
Ancillary Service or Reserve	What Can Contribute
Spinning Reserve, Regulation Up, & Load Following Up	• Coal, natural gas, and other gas-fired thermal generators • Hydro and storage resources
Regulation Down & Load Following Down	• Coal, natural gas, and other gas-fired thermal generators • Hydro and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

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[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**
WY	$4	$0	$4	**Cost**
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**
WY	$14	$23	$38	**Cost**
TOTAL	$670	**$1,223**	**$1,892**	**$187-513**