Decision No. C21-0755

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 19M-0495E

IN THE MATTER OF THE COMMISSION’S IMPLEMENTATION OF §§ 40-2.3-101 AND 102, C.R.S., THE COLORADO TRANSMISSION ACT.

COMMISSION DECISION DETERMINING MARKET PARTICIPATION IS IN THE PUBLIC INTEREST

Mailed Date: December 1, 2021
Adopted Date: November 12, 2021

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I. BY THE COMMISSION

A. Statement
   1. On September 17, 2019, the Public Utilities Commission (Commission) opened this proceeding pursuant to the Colorado Transmission Coordination Act of 2019, §§ 40-2.3-101
and 102, C.R.S. (CTCA). The CTCA directs the Commission to investigate the costs and benefits resulting from electric utility participation in energy imbalance markets (EIMs), regional transmission organizations (RTOs), power pools, or joint tariffs. The statute set deadlines for four specific Commission actions:

- **January 1, 2020** – “The commission shall open a proceeding to investigate the potential costs and benefits” associated with market participation.
- **July 1, 2021** – “The commission shall hold a hearing for public comment to consider the information received during the commission’s investigation…”
- **December 1, 2021** – “The commission shall issue a decision determining whether electric utilities participating in [an electricity market] is in the public interest.”
- **July 1, 2022** – If the Commission determines that market participation is in the public interest, the Commission “shall direct electric utilities to take appropriate actions and conduct such proceedings as the commission deems appropriate to pursue participation in an energy imbalance market, regional transmission organization, power pool, or joint tariff.”

2. During the course of this investigation, the Commission has received and considered numerous stakeholder comments, engaged an outside consultant to complete a quantitative modeling study, reached out to regional thought leaders on these issues, and considered many other reports, studies, and analyses on market participation. On June 24, 2021, the Commission held a hearing for public comment to consider the information received through this proceeding.

3. After thorough consideration of the information learned through our investigation, we find that participation in regional electricity markets has the potential to provide significant value to customers through operating cost savings. However, we also find that market participation, especially participation in an RTO, raises substantial concerns involving governance, resource adequacy, transmission interconnection queue management, emissions tracking, and transmission planning and cost allocation.
4. By this Decision, we determine that participation in an EIM, RTO, power pool, or joint tariff is generally in the public interest. This determination does not extend to participation in a specific market, however, and any analysis of the costs, benefits, and public interest associated with participation in a specific market will occur through a separate proceeding.

5. We direct Staff of the Commission (Staff) to prepare a Notice of Proposed Rulemaking (NOPR) by June 1, 2022, that proposes new rules setting forth filing requirements for utilities to join and participate in a market.

6. Additionally, we adopt the Report on the Commission’s Investigation of Wholesale Market Alternatives for the State of Colorado under the Colorado Transmission Coordination Act, attached to this Decision as Attachment 1.

B. Background

7. The CTCA directs the Commission to investigate the costs and benefits to electric utilities, other generators, and Colorado electric utility customers resulting from electric utility participation in EIMs, RTOs, power pools, or joint tariffs. Electric utilities are defined in § 40-1-103(2)(a), C.R.S., to include “[e]very cooperative electric association, or nonprofit electric corporation or association, and every other supplier of electric energy, whether supplying electric energy for the use of the public or for the use of its own members.” The CTCA directs the Commission to consider the impact of these four different market constructs on retail and wholesale electricity rates for both participating and non-participating entities, transmission rates, the commitment and dispatch of generation, operating costs, reserve requirements, renewable integration, and regional infrastructure investment.
8. The Commission opened this Proceeding on September 17, 2019. In late 2019, stakeholders submitted an initial round of comments primarily addressing how the Commission should evaluate various costs and benefits associated with markets. Consistent with the CTCA’s directives and stakeholder feedback, the Commission contracted with and directed Siemens Power Technologies International (Siemens) in the preparation of quantitative modeling and analysis (Siemens Quantitative Study). The Siemens Quantitative Study was completed and filed in this Proceeding on June 11, 2021. On June 24, 2021, the Commission held a hearing for public comment to consider the information learned in this Proceeding. Stakeholders then submitted another round of comments on July 16, 2021, specifically addressing the Siemens Quantitative Study and recent market developments. Following the completion of the Siemens Quantitative Study, the hearing for public comment, and the second round of stakeholder comments, Staff prepared the Report on the Commission’s Investigation of Wholesale Market Alternatives for the State of Colorado under the Colorado Transmission Coordination Act, which includes much of the discussion and analysis in this Decision, and which is attached to this Decision as Attachment 1.

9. In the Decision opening this Proceeding, the Commission solicited comment on definitions of various market options. Based on the comments received from stakeholders, we believe the definitions proposed by Public Service Company of Colorado (Public Service) in its initial comments are appropriate, and we therefore use the following definitions in our discussion of this investigation:

**Power Pool:** A Power Pool is a group of utilities that combine or consolidate electric generation services. Such services can include, but are not limited to, reserve sharing, joint dispatch, energy imbalance, outage coordination, and

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1 See Decision No. C19-0756.
resource adequacy. A power pool can be administered either by an independent party or by one of the participating entities.

**Joint Tariff:** A Joint Tariff is a construct wherein two or more transmission providers create a single Open Access Transmission Tariff with a single transmission provider responsible for administering transmission service across the combined footprint.

**Energy Imbalance Market (EIM):** An Energy Imbalance Market refers to a real-time bulk power trading market that allows participants to buy and sell unscheduled energy using available/unscheduled transmission. An EIM incorporates Security Constrained Economic Dispatch (SCED) whereby generating resources are dispatched on a least cost basis subject to transmission constraints on a five-minute granularity.

**Regional Transmission Organization (RTO):** A Regional Transmission Organization refers to an independent electric transmission operator that provides wholesale transmission services to more than one provider of electric services. An RTO incorporates centralized real-time dispatch and day ahead unit commitment with a joint transmission tariff. An RTO also consolidates reliability obligations, transmission planning and cost allocation, and transfers operational control of the transmission system to the system operator. “RTOs also typically administer markets for ancillary services (such as contingency and regulating reserves), function as reserve sharing groups, coordinate seams with neighboring footprints, and provide mechanisms for hedging congestion cost exposure.

**Extended Day Ahead Market (EDAM):** The EDAM is an initiative conceptualized by the California Independent System Operator (CAISO) and Western EIM entities to extend the benefits of the EIM to the day-ahead market. EDAM would enable day-ahead unit commitment and dispatch across the participating footprint but would not encompass transfer of operational control or any planning responsibilities to the CAISO.²

10. Since this Proceeding was opened, numerous developments have occurred that are relevant to our consideration of the costs and benefits of organized electricity markets. For one, the various proposals, plans, and operations of markets in the Western Interconnect have developed further. In December 2019, Public Service, Black Hills Colorado Electric, LLC, Platte River Power Authority, and Colorado Springs Utilities (CSU), announced they would join the California Independent System Operator’s (CAISO’s) Western EIM (WEIM). However, in

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² Initial Comments of Public Service Company of Colorado in Proceeding No. 19M-0495E, pp. 3-5.
May 2021, CSU announced it would join Southwest Power Pool’s (SPP’s) Western Energy Imbalance Service (WEIS) instead, and Public Service announced a pause in its plan to join the WEIM. SPP’s WEIS was announced in September 2019 and is currently operating with three regions from the Western Administration Power Authority (WAPA) and five other utility members, including Tri-State Generation and Transmission Association, Inc. In November 2020, WEIS members committed to evaluating participation in the SPP RTO, and in July 2021, the SPP Board approved policy-level terms and conditions for expansion of the SPP RTO in the Western Interconnect. In addition to expansion of the SPP RTO, SPP proposes to develop a “Markets Plus” bundle of services that would include day-ahead commitment and dispatch without full RTO membership. Similarly, CAISO is attempting to develop its Extended Day-Ahead Market (EDAM) with a goal to launch in 2024.

11. Additionally, a number of western utilities have announced the “Western Markets Exploratory Group” (WMEG) which is “exploring the potential for a staged approach to new market services, including day-ahead energy sales, transmission system expansion, and other power supply and grid solutions consistent with existing state regulations.” And, the Northwest Power Pool has been working since 2019 to design and implement a regional resource adequacy construct -- the Western Resource Adequacy Program.

12. On June 24, 2021, Senate Bill 21-072 (SB 72) was signed into law. SB 72 requires that “transmission utilities,” except municipally owned utilities and power authorities, join an “organized wholesale market” on or before January 1, 2030. The statute defines a “transmission utility” as a wholesale electricity supplier or transmitter that owns and operates

transmission lines of 100 kV or greater, and an “organized wholesale market” (OWM) as an RTO or ISO that is “established for the purpose of coordinating and efficiently managing the dispatch and transmission of electricity among public utilities on a multistate or regional basis” and which meets ten specified characteristics.\(^4\) SB 72 allows the Commission to waive or delay the requirement to join an OWM if: (a) the Commission has determined that the utility has made all reasonable efforts to comply but there is no viable and available OWM; and (b) the Commission has determined that requiring the utility to join an OWM is not in the public interest based on the Commission’s evaluation of appropriate factors.\(^5\)

13. Finally, the Federal Energy Regulatory Commission (FERC) recently signaled it will consider broad reforms to various transmission issues. In its Advanced Notice of Proposed Rulemaking, published on July 27, 2021, FERC identified potential areas for reform, including regional transmission planning, cost responsibility and cost allocation, generator interconnection funding and changing how grid network upgrades are assessed, generation interconnection queues, and oversight of transmission planning and spending.

\(^4\) As set forth at § 40-5-108(1)(a), C.R.S., an OWM: (1) is approved by FERC; (2) effects separate control of transmission facilities from control of generation facilities; (3) implements, to the extent reasonably possible, policies and procedures designed to minimize pancaked transmission rates within Colorado; (4) improves, to the extent reasonably possible, service reliability within Colorado; (5) is of sufficient scope or otherwise operates to substantially increase economical supply options for customers; (6) has a structure of governance or control that is independent of ownership and operation of the transmission facilities; (7) improves emission reduction and customer savings benefits to Colorado customers from operating within the Western Interconnection without significantly impairing actions taken by public utilities to meet the emission-reduction goals of § 25-7-102, C.R.S., and § 40-2-125.5, C.R.S.; (8) has an inclusive and open stakeholder process; (9) includes all transmission and generation resources approved, acquired, or constructed and in service by 2030 to meet the emission reduction requirements of § 25-7-102, C.R.S., and § 40-2-125.5, C.R.S.; and (10) is capable of planning for improved efficiency of use, future expansion, and consideration of all options for meeting transmission needs, providing effective cost allocation, maintaining reliability, ensuring transmission access, minimizing system congestion, and addressing transmission constraints.

\(^5\) § 40-5-108(2)(a), C.R.S.
C. Discussion

1. Quantitative Analysis of Costs and Benefits

14. The Commission retained Siemens to conduct a quantitative study on the costs and benefits to electric utilities, other generators, and Colorado electric utility customers of alternative organized wholesale electricity market structures. Market structures considered include those employed by RTOs/ISOs, EIMs, state or regional power pools, and joint transmission tariffs. The market footprints and modeling timeframes chosen were responsive to stakeholder comments recommending consideration of multiple footprints, looking both east and west, and evaluating a long timeframe. Several commenters also noted the importance of an evaluation that considered the impact of market participation in meeting the State’s emissions and decarbonization goals. The Siemens Quantitative Study evaluated the impacts of market participation on many of the components identified in the CTCA including the impacts on:

    a) **Both participating and non-participating retail and wholesale Colorado electric service providers:** The Siemens Quantitative Study modeled all electric generation in the State of Colorado including investor-owned utilities, municipalities, co-operatives, and public power. Siemens evaluated four potential participation scenarios based on market footprint: 1) All of Colorado joins a WECC-wide market; 2) All of Colorado joins an SPP-West market; 3) Colorado is split whereby the PSCo Balancing Authority entities join the WECC market and the WAPA Balancing Authority joins the SPP-West market; and 4) All of Colorado participated in a regional power pool along with other Mountain West Transmission Group members.

    b) **Wholesale Electric Energy Rates:** The analysis included modeling of the resulting wholesale electric energy rates over the modeling time horizon from 2020 through 2040 for each market construct.

    c) **Transmission Rates:** The modeling includes transmission rates that represent wheeling charges between transmission zones. The transmission rates are included in the analysis as a part of the cost of imports, as they represent payments to existing Transmission Owners (TOs) for wheeling across their transmission systems. For the RTO and Joint Tariff/Power Pool (JTPP) cases,

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6 The study was filed into this Proceeding on June 11, 2021.
the hurdle rates within the RTOs or Power Pool are zero reflecting members’ use of the joint transmission system.

d) **Retail Electric Energy Rates for Both Participating and Nonparticipating Colorado retail electric service providers:** Retail electric energy rates are dependent on the specific wholesale energy market and the regulatory processes through which costs and savings attributable to market participation would be reflected in retail rates.

e) **Commitment and Dispatch of Generation and Real-time Dispatch Optimization of Energy and Ancillary Services:** Generator unit commitment and dispatch was optimized for each market construct and footprint based on the market services included. The RTO and Power Pool market cases included full optimization of real-time dispatch and day-ahead unit commitment. The imbalance market cases included only optimization of the real-time energy market.

f) **Reserve Margin Requirements:** For all market constructs, minimum planning reserve margin requirements were enforced, but were not a main driver of Colorado’s capacity expansion plan. The reserve margins for each of the market constructs follow similar trajectories, but have slight variations depending on Colorado’s capacity expansion plan. In general, Colorado is well above its minimum reserve margin requirement for all market constructs.

g) **Short-term and Long-term Operational Costs:** The analysis of each market structure included modeling of the annual operating and investment costs for each year over the modeling time horizon from 2020 through 2040.

h) **Regional infrastructure investment in response to growth in demand for electric energy or changes in energy production:** Modeling includes the Long Term Capacity Expansion optimization for each of the market constructs modeled. Imbalance market constructs reflect the same capacity expansion as the reference case.

i) **Operating Reserve Procurement:** The Long-Term Capacity Expansion performed for the RTO Market Cases reflect the benefits from sharing resource adequacy requirements, Planning Reserve Margin, and operating reserve margins.

j) **Renewable Energy Resource Interconnection and Integration:** Interconnection and renewable integration was included in the Siemens analysis.
15. Siemens performed capacity expansion and unit commitment and dispatch modeling for several combinations of market constructs and market footprints:

<table>
<thead>
<tr>
<th>Case #</th>
<th>Description</th>
<th>Day Ahead Market</th>
<th>RT Imbalance Market</th>
</tr>
</thead>
<tbody>
<tr>
<td>1A &amp; 1B</td>
<td>CO Reference</td>
<td>CO utility-level</td>
<td>Colorado JDA</td>
</tr>
<tr>
<td>1A &amp; 2B</td>
<td>CO + WEIM</td>
<td>CO utility-level</td>
<td>WEIM</td>
</tr>
<tr>
<td>1A &amp; 4B</td>
<td>CO + WEIS</td>
<td>CO utility-level</td>
<td>WEIS</td>
</tr>
<tr>
<td>1A &amp; 6B</td>
<td>CO + Split WEIM/WEIS</td>
<td>CO utility-level</td>
<td>Split WEIM/WEIS</td>
</tr>
<tr>
<td>3A &amp; 3B</td>
<td>WECC RTO</td>
<td>WECC RTO</td>
<td>WECC RTO</td>
</tr>
<tr>
<td>5A &amp; 5B</td>
<td>SPP RTO</td>
<td>SPP RTO</td>
<td>SPP RTO</td>
</tr>
<tr>
<td>7A &amp; 7B</td>
<td>Split RTO</td>
<td>Split RTO</td>
<td>Split RTO</td>
</tr>
<tr>
<td>8A &amp; 8B</td>
<td>Joint Tariff/Power Pool</td>
<td>JTPP</td>
<td>JTPP</td>
</tr>
</tbody>
</table>

16. In all cases, the modeling assumed that Colorado achieves its goals of carbon reduction from a 2005 baseline: 80 percent reduction by 2030 and 90 percent reduction by 2040 (representing the path to 100 percent reduction by 2050). The RTO cases consisted of annual modeling through 2040 while the imbalance and JTPP cases consisted of snapshots for 2025, 2030, and 2035 with interpolation of results in between the snapshot years.

17. The Siemens Quantitative Study results demonstrate that markets can provide savings through operational and investment efficiencies and provided information about the comparative savings associated with different constructs and footprints. In particular, the results show that EIM savings represent about 1 percent of the total State revenue requirement (including fuel, operational costs, and return of and on capital), and RTO savings represent about
4 to 5 percent of the total State revenue requirement. These results are summarized in the table below.

<table>
<thead>
<tr>
<th>Case #</th>
<th>Market Construct</th>
<th>NPV of Total Costs ($2019M)</th>
<th>Savings vs. Ref.</th>
<th>Levelized Annual Savings ($2019M)</th>
<th>Total % Savings</th>
<th>Avg. Total % Savings</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 Sens</td>
<td>Reference</td>
<td>$26,564</td>
<td>$25,677</td>
<td>$888</td>
<td>$92</td>
<td>1.6%</td>
</tr>
<tr>
<td>2</td>
<td>WEIM</td>
<td>$25,901</td>
<td>$173</td>
<td>$663</td>
<td>$69</td>
<td>1.2%</td>
</tr>
<tr>
<td>4</td>
<td>WEIS</td>
<td>$26,076</td>
<td>$253</td>
<td>$488</td>
<td>$50</td>
<td>0.9%</td>
</tr>
<tr>
<td>6</td>
<td>Split WEIM/WEIS</td>
<td>$26,064</td>
<td>$252</td>
<td>$500</td>
<td>$52</td>
<td>0.9%</td>
</tr>
<tr>
<td>3</td>
<td>WECC RTO</td>
<td>$24,337</td>
<td>$173</td>
<td>$2227</td>
<td>$230</td>
<td>4.0%</td>
</tr>
<tr>
<td>5</td>
<td>SPP RTO</td>
<td>$24,095</td>
<td>$223</td>
<td>$2,469</td>
<td>$255</td>
<td>4.5%</td>
</tr>
<tr>
<td>7</td>
<td>Split RTO</td>
<td>$24,637</td>
<td>$254</td>
<td>$1,927</td>
<td>$199</td>
<td>3.5%</td>
</tr>
<tr>
<td>3 Sens</td>
<td>WECC + TX Sens</td>
<td>$23,518</td>
<td>$173</td>
<td>$3,046</td>
<td>$315</td>
<td>5.5%</td>
</tr>
<tr>
<td>5 Sens</td>
<td>SPP + TX Sens</td>
<td>$23,497</td>
<td>$223</td>
<td>$3,067</td>
<td>$317</td>
<td>5.6%</td>
</tr>
<tr>
<td>7 Sens</td>
<td>Split + TX Sens</td>
<td>$24,190</td>
<td>$223</td>
<td>$2,374</td>
<td>$245</td>
<td>4.3%</td>
</tr>
<tr>
<td>8</td>
<td>JTPP</td>
<td>$26,099</td>
<td>$223</td>
<td>$465</td>
<td>$48</td>
<td>0.8%</td>
</tr>
</tbody>
</table>

18. The study demonstrates that in obtaining the savings above, greater market integration and more market services are more impactful than the specific market footprint. The Net Present Value (NPV) of EIM savings ranged from $488 million to $663 million, depending on the footprint, while the NPV of RTO savings ranged from $1,927 to $2,469 million, depending on the footprint. Even the least economic RTO option delivered approximately three times more benefits than the most economic EIM option. Further, the split RTO footprint provided the least benefit of the RTO options, but the difference was not large. Additionally, the geographically smaller JTPP option produced benefits similar in scale to the benefits produced by the EIM options despite the provision of more market services such as day ahead unit commitment. In all market constructs, additional transmission interconnection led to significant operational savings.

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19. The study also demonstrates that a larger footprint leads to more savings. Even with the greater services provided by the JTPP market construct (i.e., day ahead unit commitment), the smaller market size led to lower savings ($465 million) versus even the EIM cases ($488 million for the least beneficial EIM).

20. Through this Proceeding, we also considered *The State-Led Market Study -- Exploring Western Organized Market Configurations: A Western States’ Study of Coordinated Market Options to Advance State Energy Policies* (State-Led Study), which was funded by the Department of Energy (DOE) and in which Staff and the Colorado Energy Office participated.\(^8\) Similar to the Siemens Quantitative Study, the State-Led Study evaluated real-time (imbalance) and RTO markets (and in addition, a Day-Ahead market modeled after CAISO’s EDAM proposal) across several western footprints. Unlike the Siemens Quantitative Study, the State-Led Study only examined two time periods (2020 and 2030), did not assume achievement of Colorado’s carbon reduction goals, and used a different methodology to examine capacity (investment) savings.

21. Nevertheless, the State-Led Study produced similar overall findings: all organized markets studied would produce savings compared to the status quo, but the greater the level of market integration (RTO compared to Day-Ahead compared to imbalance) and the larger the market footprint, the greater the savings. The State-Led Study report presented market savings in the context of adjusted production cost and in addition, for the Day-Ahead and RTO cases, as calculated capacity investment savings attributable to load diversity across the footprint. To show savings metrics comparable to those presented above for the Siemens Quantitative Study report,

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\(^8\) The study’s first technical report and accompanying Market and Regulatory Review scorecard were filed in this proceeding on September 27, 2021.
the table below presents savings allocated to Colorado as a percentage of the assumed Colorado electric utility revenues of approximately $5.7 billion.

Table 3 – DOE/State-Led Study Savings Results for Colorado

<table>
<thead>
<tr>
<th>Case</th>
<th>Annual Savings ($mil)</th>
<th>% Savings</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020 WECC-wide IM</td>
<td>13</td>
<td>0.2%</td>
<td></td>
</tr>
<tr>
<td>2030 WECC-wide Day Ahead</td>
<td>76</td>
<td>1.3%</td>
<td>Using top end of capacity savings range</td>
</tr>
<tr>
<td>2030 WECC-wide RTO</td>
<td>160</td>
<td>2.8%</td>
<td></td>
</tr>
<tr>
<td>2030 2 Market A RTO</td>
<td>167</td>
<td>2.9%</td>
<td>WECC divided into 2 markets: 1. CAISO and 2. Rest of WECC</td>
</tr>
<tr>
<td>2030 2 Market B RTO</td>
<td>10</td>
<td>0.2%</td>
<td>WECC divided into 2 markets: 1. MWTG and 2. Rest of WECC</td>
</tr>
</tbody>
</table>

22. While these savings appear lower than those calculated by the Siemens Quantitative Study, the overall conclusions regarding the role of market integration level and geographic scope remain the same. Also, as noted above, the State-Led Study examined a shorter timeframe and did not assume Colorado achieved the 80 percent by the 2030 carbon dioxide reduction target. Both of those factors would likely tend to reduce the resulting savings produced by the study in comparison to the Siemens analysis.

23. The State-Led Study also examined certain qualitative market attributes using a scorecard approach. For example, the Market and Regulatory Review discussed the ability of each market construct to “Support Increased Use of Clean Energy Technologies” using several metrics such as efficient grid operation and transparent pricing. In general, markets with limited
integration rated only fair to good on these measures while RTOs were rated as excellent. The report provides detailed descriptions explaining the basis for these ratings.

Figure 1 – DOE/State-Led Study Summary Market Factor Scorecard for Increased use of Clean Energy Technologies

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

24. Many other market studies have been conducted in recent years by or on behalf of utilities and other entities in the West. Stakeholders identified a number of these studies for consideration, pointing out that they all found cost savings from organized markets compared to a bilateral market status quo. For example, joint commenters Western Resource Advocates, Western Grid Group, and Natural Resources Defense Council provided a table listing six different market studies (including two performed for Mountain West Transmission Group) and described the modeled savings from each (see Table 4 below). They also pointed out that in the
case of the CAISO WEIM, the actual benefits (as calculated by CAISO) have far exceeded the savings predicted by modeling.

Table 4 – Recent Regional Energy Market Benefit Studies

<table>
<thead>
<tr>
<th>Study</th>
<th>Market Type</th>
<th>Summary of Results</th>
</tr>
</thead>
<tbody>
<tr>
<td>CAISO-PAC EIM Benefits Study (2014)</td>
<td>EIM</td>
<td>With only CAISO and PacifiCorp participating in an EIM, annual benefits (in the form of dispatch savings) range from $21,129 million. Benefits to date have far exceeded these initial predicted ranges.</td>
</tr>
<tr>
<td>SB 350 Study (2016)</td>
<td>ISO</td>
<td>A Western Interconnection-wide CAISO market (minus WAPA and BPA), could provide benefits to California ratepayers in the range of $1-1.5 billion per year by 2030. Quantified benefits include savings from reduced capital investments for RPS-related procurement; reduced production, purchase, and sales costs for electricity; and reduced capital investments from regional load diversification.</td>
</tr>
<tr>
<td>MWTG Gross Benefits Study (2016)</td>
<td>RTO</td>
<td>MWTG utilities are anticipated to realize $88 million per year in production cost savings by eliminating rate pancaking within their footprint and by participating in SPP’s RTO.</td>
</tr>
<tr>
<td>MWTG DC Intertie Study (2017)</td>
<td>RTO</td>
<td>Benefits to both MWTG utilities and SPP range from $117.7-28.8 million by forming an integrated market through an RTO and dispatching the four DC ties using the market clearing process.</td>
</tr>
<tr>
<td>Western EIM Benefits Report (2019)</td>
<td>EIM</td>
<td>CAISO’s latest EIM Benefits Report finds gross benefits, realized through more efficient economic dispatch, of $801.07 million since 2014. It also quantifies economic benefits attributable to avoided renewable curtailment within the CAISO footprint of 418,031 eq. tons of CO₂ reductions.</td>
</tr>
<tr>
<td>EDAM Feasibility Assessment (2019)</td>
<td>EDAM</td>
<td>The Brattle Group estimated total production cost savings in the range of $119,227 million per year when the EIM’s participating utilities move from real-time only operations to day-ahead operations, including hourly trading, day-ahead transmission availability, and day-ahead unit commitment. Assessment acknowledges potential environmental benefits, including reduced renewables curtailment, but does not quantify these benefits.</td>
</tr>
</tbody>
</table>

25. In addition to the Siemens Quantitative Study and the State-Led Study described above, the Commission considered several recent studies of direct relevance to Colorado. These included: Vibrant Clean Energy’s study on behalf of Holy Cross Energy and the Intermountain Rural Electric Association studying EIM options for Colorado; Brattle Group’s study on behalf of Colorado’s Joint Dispatch Agreement (JDA) members assessing EIM participation; Brattle Group’s study on behalf of SPP studying benefits of the WEIS and RTO Participation; and CAISO’s quarterly EIM benefits reports. Consistent with the reports for the Siemens Quantitative Study and the State-Led Study, these studies showed that market participation...
lowers overall operational and investment costs. In addition, the level of savings increased with greater market integration and larger footprints.

2. Concerns Identified with Organized Markets

26. While quantitative modeling suggests that more integrated market constructs result in higher net benefits, there are other aspects of market participation that need to be considered. Our investigation has identified a number of important concerns, including the role of state Commissions in planning activities, appropriate methods to account for greenhouse gas (GHG) emissions across a region with varying environmental objectives, and the management of transmission interconnection queues.

27. One consideration is the administrative fees associated with market participation, which can be significant. Generally, larger markets have higher overall administration fees, but lower per-megawatt costs. The table below, copied from the Revised Narrative of the JDA Entities’ Comparative Analysis of the SPP WEIS and CAISO WEIM, lists one estimate of the costs of RTO Market Administration.9

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9 Page 18 of Revised Attachment A Narrative filed by PSCo on February 5, 2020 in Proceeding No. 19M-0495E.
Table 5 – JDA Entities’ Estimated Costs of RTO Market Administration

<table>
<thead>
<tr>
<th>Entity</th>
<th>2019 Peak Load (MW)</th>
<th>2020 Cost ($Millions)</th>
<th>Cost/MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>NY-ISO</td>
<td>32,392</td>
<td>$168</td>
<td>$ 5,186</td>
</tr>
<tr>
<td>SPP</td>
<td>50,662</td>
<td>$174</td>
<td>$ 3,435</td>
</tr>
<tr>
<td>CAISO</td>
<td>46,526</td>
<td>$187</td>
<td>$ 4,019</td>
</tr>
<tr>
<td>ISO-NE</td>
<td>22,224</td>
<td>$201</td>
<td>$ 9,044</td>
</tr>
<tr>
<td>ERCOT</td>
<td>74,820</td>
<td>$268</td>
<td>$ 3,582</td>
</tr>
<tr>
<td>PJM</td>
<td>151,358</td>
<td>$296</td>
<td>$ 1,956</td>
</tr>
<tr>
<td>MISO</td>
<td>125,000</td>
<td>$368</td>
<td>$ 2,944</td>
</tr>
<tr>
<td>Colorado Estimates</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO in SPP</td>
<td>10,000</td>
<td>$34</td>
<td>$ 3,435</td>
</tr>
<tr>
<td>CO in CAISO</td>
<td>10,000</td>
<td>$40</td>
<td>$ 4,019</td>
</tr>
</tbody>
</table>

28. EIM administrative fees are estimated to be substantially lower than RTO administrative costs. For example, Public Service and the other JDA Entities estimated the annual administrative cost for Public Service’s Balancing Authority in the WEIM would be about $450,000 and in the WEIS would be about $3.4 million, or lower if the WEIS expanded to additional members with additional load (which has occurred since this estimate).\(^{10}\) In addition, the cost to withdraw from an imbalance market ranges from zero (if implementation fees are paid upfront) to the remaining share of implementation charges, if spread out over several years. In either case, the cost commitment is low and would not be expected to be a barrier to exit.

29. Another consideration is market participation’s impact on resource adequacy. Although organized markets can and do contribute to electric system reliability by providing a wide-area view and appropriate information sharing between the market operator and the reliability coordinator, recent events have provided reminders that RTOs are not immune from significant reliability concerns, particularly related to resource adequacy. The most recent

\(^{10}\) See Revised Attachment A Narrative at 4-5.
NERC Summer Reliability Assessment showed an elevated or high risk of insufficient operating reserves in several RTO regions, including CAISO, MISO, and ERCOT. In addition, SPP issued a Resource Alert in June 2021 due to outages, high loads, and wind forecast uncertainty.

30. The way in which markets manage their transmission interconnection queues should also be considered. Some RTOs do not currently have a mechanism for allocating scarce interconnection access to flow benefits back to customers. Developers that obtain access to scarce interconnection resources are free to obtain hedging contracts from national companies and are not subject to any competitive process for the benefit of local customers. The result of these practices is that the interconnection queue in the State of Colorado is substantially more efficient than in a number of the large RTOs.

31. Another consideration is emission tracking in organized markets, or lack thereof. Many of the benefits of market participation arise because of more inter-state trading and the accompanying operational efficiencies. While accounting for emissions from importing and exporting energy is an issue even in the primarily bilateral market structure currently in place, this concern goes hand in hand with integrated markets. It is the trading and sharing of resources that drive the operating cost savings that are the backbone of the benefits attributable to market participation.

32. Currently, there is no national GHG policy and the state-level policies in the West vary widely. Accounting for GHG emissions from imports and exports matters to the overall demonstration of achieving Colorado’s goals. Without a comprehensive approach to GHG accounting, the potential for emissions leakage is real and significant. GHG leakage occurs when generation that produces GHG emissions shifts away from states with relatively strict GHG
reduction targets and towards states with less strict target as utilities located in the “strict” states change operations to meet state GHG goals.

33. Yet another consideration is transmission planning and cost allocation. When a transmission-owning utility places its existing facilities under a joint tariff, these facilities are included in a zone ("pricing zone") that contributes to the zone’s revenue requirement. The pricing zone design of the joint tariff can directly impact customer transmission rates. The de-pancaking of the system can create new cost implications depending on the zonal rate structure deployed within the joint tariff. As demonstrated by the Mountain West Transmission Group negotiations, the issue of establishing transmission zones can involve significant cost shifting amongst utilities for existing transmission assets, potentially requiring mitigation with impacts to ultimate transmission rates. Allocation of transmission costs, particularly for regional transmission projects, can be contentious because benefits of transmission accrue unevenly. A line, for example, transmitting electricity from generation in one state, across another state, and serving load in a third state clearly benefits the state with load served, also benefits the state where generation is located, but provides no obvious benefit to the state crossed.

34. Transmission cost allocation is intertwined with transmission planning. FERC Order 1000 therefore included reform of cost allocation, noting that it is necessary for each public utility transmission provider, whether an ISO/RTO or non-ISO/RTO, to include in its Open Access Transmission Tariff a method(s) for allocating costs of new regional and interregional transmission in a plan. FERC emphasized that all benefits of new transmission facilities need to be accounted for in order to fairly allocate costs, while acknowledging that determination of benefits (and beneficiaries) is difficult. Depending on the cost allocation policies for new transmission established by the RTO, an individual utility can be required to pay
transmission costs for projects in other areas of the footprint. This occurs when costs of individual utility projects are assigned to all transmission zones in an RTO.

35. Finally, governance of a market is an essential consideration. The development of market rules and tariffs that guide a market’s operations is shared among stakeholders, boards of directors, specific market committees, and ultimately, FERC and the courts. FERC requires a baseline level of RTO/ISO responsiveness to stakeholders. For example, FERC Order No. 719 requires that the policies of RTOs and ISOs meet four “responsiveness” criteria: inclusiveness, fairness in balancing diverse interests, representation of minority positions, and ongoing responsiveness. However, the amount and significance of input that stakeholders, boards of directors, and committees can provide, and the way in which that input is used to develop market rules, depends on the specific market. A market’s governance is especially important when contemplating participation in an RTO or ISO, as compared to participation in an EIM, which would have less market integration and fewer impacts on state planning processes.

36. Generally, stakeholders in RTOs and ISOs are grouped by sector, such as transmission owners, electric generators, end-use customers, marketers and/or brokers, public power entities, consumer advocates, and environmental groups. These membership types and the associated application requirements and membership criteria are defined by market operating agreements or bylaws. Some RTOs and ISOs have stakeholder processes that are open to nonmembers, or have low fees for membership. Others, such as SPP, require that an entity be a member to participate in market rule and tariff development processes, and have membership fees that may be barriers to participation by non-governmental organizations and consumer advocates.
37. Typically, each sector receives a voting interest in the governance process of the market, and individual votes are split among the sector members. In addition to providing votes, stakeholders participate in market governance through stakeholder committees and working groups that assist in the development of market rules. RTOs and ISOs often allow for some participation of nonvoting members, such as state public utility commissions, which are often allowed to attend meetings and provide opinions on stakeholder proposals.

D. Findings and Conclusions

38. Based on the Siemens Quantitative Study, the State-Led Study, and the other quantitative modeling studies of various market constructs and footprints that we reviewed, the Commission finds that regional markets have the potential to provide significant benefits to customers through operating cost and infrastructure investment savings. These benefits increase as the level of market integration and services increases such that EIMs provide more benefit than bilateral markets, Day-Ahead markets provide more benefits than EIMs, and RTOs provide more benefits than Day-Ahead markets. In addition, larger markets result in more significant savings. A market must be large enough for the trading and reserve sharing opportunities to produce sufficient benefits.

39. Additionally, the Siemens Quantitative Study, as well as the other quantitative analyses we considered in this Proceeding, demonstrate that greater geographic market integration allows for higher renewable penetration at a lower cost. If Colorado’s electric utilities participated in a regional market, especially an RTO, it is likely that cost savings would occur and a large geographically diverse market would support greater renewable penetration, helping the State to meet its renewable energy targets while maintaining reliable service.
40. However, our recognition of the potential benefits associated with market participation comes with substantial underlying concerns. Market participation brings the possibility of adverse impacts on the State’s robust resource planning and interconnection queue processes, and raises additional issues such as emissions tracking, transmission planning and cost allocation, and subjecting Colorado’s utilities and consumers to decision-making processes that may not be as robust, open, or transparent as Colorado’s current stakeholder processes. Market participation also presents serious questions of changes to our authority and State authority generally. These concerns are heightened when considering participation in an RTO. Conversely, we find that EIMs and Day-Ahead markets have the potential to provide benefits that are still significant, while raising fewer concerns than RTOs.

41. Weighing both the probable benefits attributable to market participation and our substantial concerns with such participation, we determine that participation in an organized market, including an EIM, RTO, power pool, or joint tariff, is generally in the public interest if certain concerns involving governance, access to scarce interconnection, transmission expansion, and resource adequacy can be appropriately addressed. As such, this determination does not extend to participation in a specific market. Any analysis of the costs, benefits, and public interest associated with participation in a specific market by a specific utility will occur through a separate future proceeding.

42. We recognize that Colorado’s utilities are already joining EIMs and are contemplating participation in RTOs/ISOs, some well in advance of SB 72’s 2030 deadline to join an OWM. As utilities move towards greater regional integration, regulatory filings will be necessary to address issues such as tariff changes. We believe a rulemaking would be the proper forum for utilities and stakeholders to further engage with the Commission on what filings and
reporting may be appropriate. We anticipate that such a rulemaking would provide utilities and
the Commission with guidance on how to address and analyze the concerns with market
participation identified during this investigation.

43. Therefore, to provide an appropriate process to consider the costs, benefits, and
public interest considerations associated with participation in a particular market, and to begin
implementation of requirements contained in SB 72, we direct Staff to prepare a NOPR by
June 1, 2022 that would address filing requirements for utilities to join and participate in an
organized market. Such a NOPR should encompass, potentially among others, the following
items in its scope:

1. Whether and when transmission utilities should be required to file an
application with the Commission to join and participate in an organized
market based on their unique circumstances.

2. Requirements for such an application to address the Commission’s
concerns with market participation, including the concerns identified by the
Commission in its investigation in Proceeding No. 19M-0495E.

3. Requirements for addressing required changes to tariffs or other processes,
including, where applicable: Energy Commodity Adjustment rules;
recovery of administrative market fees; utility retention of demonstrated net
present value savings attributable to market participation; market trading
rules; and transmission planning processes.

4. Requirements for annual reporting on market activities consistent with
SB 72’s requirement to demonstrate reasonable efforts to comply with the
statute’s mandate to join an OWM.

5. Process for a transmission utility to seek a waiver of SB 72’s requirement
to join an OWM.

6. Whether certain proposed rules should be specific to investor-owned
utilities and whether separate rules should be implemented for municipal
utilities or cooperative utilities.

44. Finally, we adopt the Report on the Commission’s Investigation of Wholesale
Market Alternatives for the State of Colorado under the Colorado Transmission Coordination
Act, attached to this Decision as Attachment 1. This report should be distributed to persons
deemed appropriate by the Commission and the Commission’s Advisory Staff, including Colorado State legislators and other utility commissions.

II. ORDER

A. The Commission Orders That:

1. The Commission determines that electric utility participation in an energy imbalance market, regional transmission organization, power pool, or joint tariff is generally in the public interest.

2. Advisory Staff of the Commission is directed to prepare a Notice of Proposed Rulemaking by June 1, 2022, consistent with the discussion above.

3. The Commission adopts the Report on the Commission’s Investigation of Wholesale Market Alternatives for the State of Colorado under the Colorado Transmission Coordination Act, attached to this Decision as Attachment 1.

4. This Decision is effective upon its Mailed Date.
B. ADOPTED IN COMMISSIONERS’ DELIBERATIONS MEETING

November 12, 2021.

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

JOHN GAVAN

MEGAN M. GILMAN

Commissioners