UNITED STATES OF AMERICA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of an Investigation into		
Implementing Changes to the Renewable	)	
Energy Standard and the Newly Created Carbon	)	PUC Docket No. E999/CI-23-151
Free Standard under	)	
Minnesota Statute § 216B.1691		

COMMENTS
OF
DR. KATHLEEN SPEES AND DR. LONG LAM

March 19, 2025

CONTENTS

Introduction

We, Dr. Kathleen Spees and Dr. Long Lam, were retained by Great River Energy (GRE) to review and independently assess evidence related to different clean energy compliance standards in the context of a Minnesota Public Utilities Commission (MN PUC or Commission) proceeding to address implementation questions related to the state's Renewable Energy Standard (RES) and the Carbon Free Standard (CFS).[1]

We were asked by GRE to offer to the MN PUC our independent assessment of an hourly versus annual clean energy compliance standard, in consideration of the following evidence submitted by interveners:

- Minnesota Department of Commerce (MN DOC) submitted "Comments of the Minnesota Department of Commerce" ("MN DOC Comments")[2];
- Minnesota Clean Energy Organizations (MN CEOs) submitted "Initial Comments of the Clean Energy Organizations" ("MN CEOs Comments")[3]; and
- Midwest Renewable Energy Tracking System (M-RETS) submitted "Comments on behalf of the Midwest Renewable Energy Tracking System" ("M-RETS Comments")[4].

Specifically, GRE requested that we provide an assessment of the economic implications and other implementation considerations associated with hourly energy matching as the clean energy compliance standard; review and analyze the results from the existing body of research comparing hourly energy matching to annual matching; and estimate the potential costs and effectiveness of the different clean energy compliance standards. We also summarize recent developments in temporally granular and locationally granular greenhouse gas (GHG) emissions accounting and tracking in other jurisdictions, which may offer insights as Minnesota policymakers consider data needs over the coming years.

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1 Minnesota Public Utilities Commission, Notice of Comment Period and Updated Timeline, Docket Number E-999/CI-23-151, October 31, 2024.

2 Minnesota Department of Commerce, Comments of the Minnesota Department of Commerce, Docket Number E-999/CI-23-151, January 29, 2025 (hereinafter MN DOC Comments).

3 The Clean Energy Organizations, Initial Comments of the Clean Energy Organizations, Docket Number E-999/CI-23-151, January 29, 2025. (hereinafter MN CEOs Comments).

4 M-RETS, Comments on Behalf of the Midwest Renewable Energy Tracking System, Docket Number E-999/CI-23-151, January 29, 2025 (hereinafter M-RETS Comments).

Dr. Kathleen Spees is an economic consultant at The Brattle Group, where she focuses on bulk electricity system reliability, electricity market design, and energy policy in the context of clean energy transition. She has conducted economic, reliability and modeling analysis of decarbonization transition for utilities, policymakers, and market operators across more than a dozen jurisdictions across Canada, the US, and internationally.[5] She earned her PhD in Engineering and Public Policy and MS in Electrical and Computer Engineering from Carnegie Mellon University, and a BS in Mechanical Engineering and Physics from Iowa State University.

Dr. Long Lam specializes in the development and implementation of decarbonization strategies and in the design and analysis of clean energy policy. His work for governments and large companies with net-zero commitments and for regulated utilities, market operators, and regulators focuses on: emissions reduction strategies and implementation program development for entities pursuing large-scale decarbonization; granular accounting of Scope 2 emissions and clean energy procurement, including defining future-ready contractual arrangements and policies; and development and analysis of pathways for an orderly clean energy transition. He earned his PhD and MS in Engineering and Public Policy from Carnegie Mellon University, and a BS in Mechanical Engineering from the Massachusetts Institute of Technology. We prepared the below comments with support from Brattle Senior Energy Analysts Natalie Northrup and Audrey Yan.

[5] As examples of our prior work related to assessments of clean energy procurements and compliance standards, see:

Kathleen Spees, Long Lam, and Kala Viswanathan, *Assessment of Studies on US Hydrogen Tax Credits and Potential Takeaways for Scope 2 Guidance*, Prepared for the Greenhouse Gas Protocol. November 21, 2024.

Kathleen Spees, Samuel Newell, Johannes Pfeifenberger, Joe DeLosa III, Linquan Bai, Ragini Sreenath, Ivy Yang, *Illinois Renewable Energy Access Plan 2024*, Prepared for the Illinois Commerce Commission, May 30, 2024.

Kathleen Spees, John Tsoukalis, Long Lam, *Greenhouse Gas and Clean Energy Accounting Methodology Catalog*, Prepared for WEST Associates, June 2023.

Kathleen Spees, Joe DeLosa III, Linquan Bai, John Higham, *New England Forward Clean Energy Market*, Prepared for the Massachusetts Department of Energy Resources, January 2023.

Kathleen Spees, Samuel Newell, Joe DeLosa III, *Alternative Resource Adequacy Structures for New Jersey*, Prepared for New Jersey Board of Public Utilities Staff, June 2021.

I. Executive Summary

A temporally and locationally granular understanding of the grid and its role in the clean energy transition is increasingly essential as Minnesota and the Midcontinent System Operator (MISO) continue to integrate more wind and solar resources. Given the intermittent nature of electricity generation from these renewable energy resources, it is important to assess their output profiles and contributions to resource adequacy, reliability, and Minnesota's GHG emissions reduction efforts. In this context, it makes sense that some stakeholders call for hourly energy procurement as the clean energy compliance standard in this docket. However, managing the energy transition effectively and efficiently requires a greater focus on the nuances of reliability requirements, transmission congestion, and regional markets. Doing so will help establish a clean energy pathway that is reliable, affordable, and strategically positioned to maximize the benefits of a regional marketplace.

In this report, we find that:

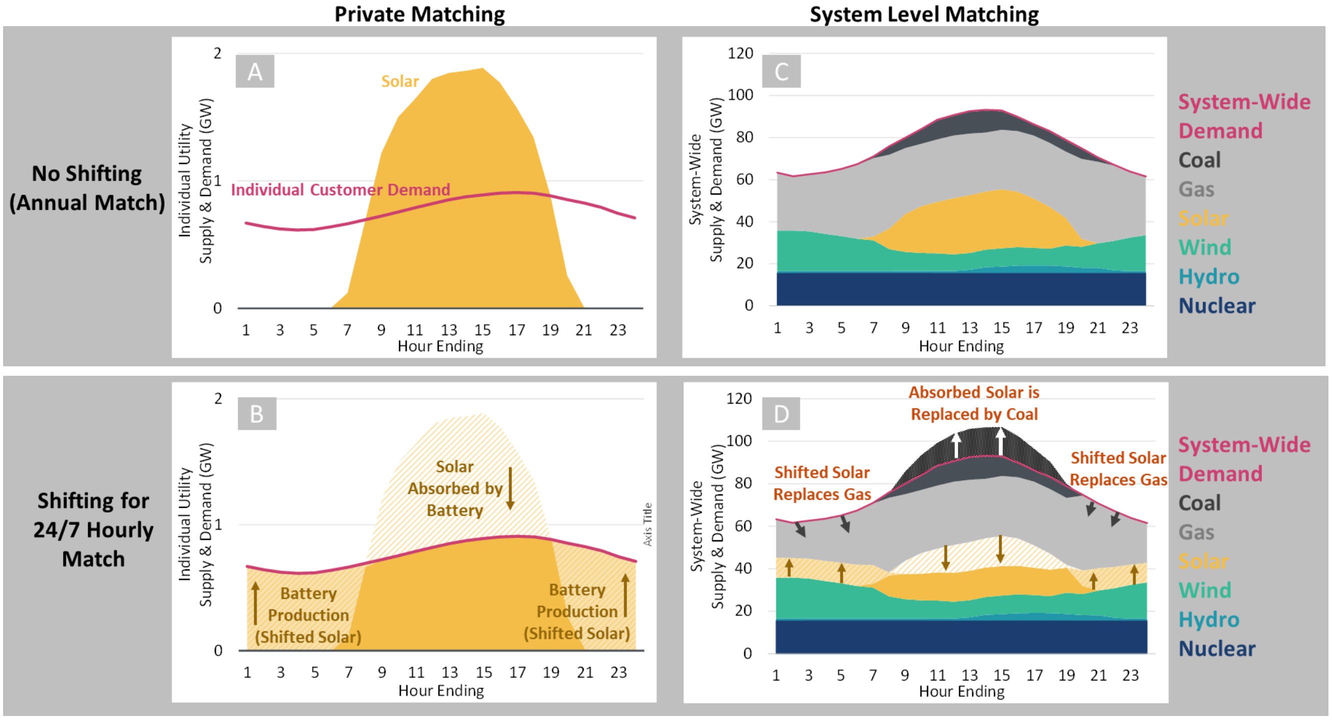
- **Private hourly energy matching is more expensive than annual matching**, both on an absolute basis and a $/MWh basis. Prior studies conducted for different geographies and system conditions show hourly energy matching costs in the range of $1–255/MWh more than annual matching. Pursuing hourly energy matching means that clean energy must be procured across all hours of the year, including at times of low wind and solar output. Because of the mismatch in demand profile and renewable energy generation profile, a substantial over-procurement volume of new renewable and storage resources would be needed to achieve 100% hourly energy matching. We conducted an indicative cost estimate in the Minnesota context and find that the potential cost of hourly matching with renewables may be approximately $43–260/MWh more than annual matching, depending on scenario assumptions such as the availability and cost of an hourly market for Renewable Energy Certificates (RECs) that may reduce compliance cost.
- **Private hourly energy matching may or may not accomplish more GHG emissions reductions than annual matching**. The emissions outcome is driven more by broader system conditions than by the nature of the matching standard. The specific resources used to meet demand for electricity, their economics, and the grid transmission topography at any given hour are all important factors in determining whether hourly energy matching would result in lower system emissions. Prior studies show that hourly energy matching is not meaningfully more effective than annual matching in jurisdictions with an aggressive clean energy policy like a strong renewable portfolio standard or a strong clean energy standard.

- **Hourly energy matching is not an effective solution to the reliability, deliverability, and risk management challenges** that will need to be tackled as Minnesota pursues and implements the state's CFS, and as MISO continues to improve its resource adequacy framework. An hourly energy matching standard does not address (and in some cases exacerbates) these challenges, because it poses the dual problem of over-constraining the flexibility that utilities and consumers have for meeting Minnesota's clean energy goals, while at the same time being too divorced from the realities of reliability, transmission constraints, and costs that govern real-world grid operations and market transactions.
- **Developments in other states and markets demonstrate that more effective solutions are in development** for measuring net GHG emissions associated with storage resources and market purchases from the regional transmission organization (RTO).

The challenges of an hourly matching standard all stem from the same central flaw of enforcing a standard upon a metric that is not, on its own, useful or valuable. An hourly matched portfolio of supply and demand is not inherently more cost-effective, more reliable, or lower-emitting than an annually matched clean energy portfolio. For example, Figure 1 below illustrates how pursuing hourly energy matching may inadvertently lead to more GHG emissions than annual matching. An individual customer or a stylized utility using a storage system to shift its solar generation from the daytime hours (Panel A) to later PM (Panel B) to achieve 100% energy matching at every hour throughout the day. However, when taking a system-wide view of GHG emissions, it would be counterproductive in this example for this customer to shift their renewable output. This is because the solar generation that would naturally displace carbon-intensive electricity from coal plants during daytime hours (Panel C) is shifted to displace lower-emitting natural gas generation in the other hours (Panel D). In addition, each MWh of shifted renewable output is subject to approximately 15–20% efficiency losses through the battery charge-discharge cycle. The outcome of shifting the solar to align with demand is to produce more GHG emissions compared to allowing the solar to be absorbed into the grid under its natural output profile.[6]

[6] We note that it is equally easy to construct examples where shifting the renewables would cause fewer emissions to be produced. Whether shifting to match demand causes more or less emissions depends on the specifics of the resource in question and on broader market conditions.

FIGURE 1: PRIVATE HOURLY MATCHING CAN LEAD TO HIGHER SYSTEM EMISSIONS



Source and Notes: Stylized demand and generation are modeled after the demand and resource mix on a MISO summer day. The shifted profiles in panels B and D reflect the stylized generation mix if a battery was used to store and re-dispatch solar to fully meet the Minnesota share of MISO system load.

Optimally planning and dispatching resources to meet deep decarbonization standards requires a more nuanced view of grid operations than is offered by an hourly energy matching strategy. Utilities will most affordably manage clean transition if they carefully consider the economic and reliability value signalled on a time-varying basis through the energy, ancillary, and capacity markets, including the locationally differentiated prices that align with transmission system capability. To most meaningfully understand the GHG abatement value of alternative resources and dispatch choices, Minnesota policymakers and utilities can begin by reviewing the progress that MISO and other RTOs have made in providing more accurate, timely, and comprehensive GHG tracking and measurements. As clean energy integration progresses, increasingly granular GHG accounting data will be needed to meet growing policy and customer demands. Ongoing enhancements in temporal and locational granularity in grid GHG emissions data can then be increasingly accounted for and considered, alongside market signals of economic value and reliability needs, to inform the most effective decarbonization measures.

II. Background and Context

Minnesota in 2023 established a carbon free standard.[7] The CFS requires each electric utility to procure electricity from carbon-free energy (CFE) sources to meet the following milestones:

- By 2030: for public utilities, 80 percent "of the electric utility's total retail electric sales to retail customers in Minnesota” must be procured from CFE technologies; and 60 percent for other electric utilities;
- By 2035: 90 percent for all electric utilities;
- By 2040: 100 percent for all electric utilities.[8]

The CFS targets are incremental to the state’s RES, which requires electric utilities to generate or procure electricity from renewable energy sources to meet 55 percent of total retail electrical sales by 2035.[9] Tasked with the implementation of the new CFS, the MN PUC has requested input on several topics, including the measurement and tracking criteria and standards as well as the treatment of RECs and net market purchases in CFS.[10]
Several intervenors have submitted comments in response to the PUC’s request. The MN DOC recommends that the Commission require all electric utilities to comply with the CFS requirements on an hourly basis (e.g., 24×7 clean energy matching) instead of an annual basis. Under the DOC’s recommendation, compliance with the 100 percent CFS would require the electric utilities in the state to procure CFE to match 100 percent of demand in every hour of the year. Notably, the DOC’s recommended interim and final targets depart from those in statutes:

- **By 2030:** Annual matching of 80 percent for public utilities, and 60 percent for other electric utilities (same as in statute);
- **By 2035:** Hourly matching of 80 percent for public utilities, and 60 percent for other electric utilities;
- **By 2040**: Hourly matching of 90 percent for all electric utilities; and

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7 Minnesota Department of Commerce, Governor Walz Signs Bill Moving Minnesota to 100 Percent Clean Energy by 2040, February 7, 2023.

8 Minnesota Statute § 216b.1691 subdivision 2g. The statutes also specify interim targets of 80 percent for public utilities and 60 percent for other electric utilities by 2030, and 90 percent for all electric utilities by 2035.

9 Eligible renewable energy technologies include solar, small existing hydro (less than 100 MW), new large hydro, hydrogen produced from these technologies, and certain biomass technologies.

10 Minnesota Public Utilities Commission, Notice of Comment Period and Updated Timeline, Docket Number E-999/CI-23-151, October 31, 2024.

- **By 2045**: Hourly matching of 100 percent for all electric utilities.[11]

In addition, the DOC recommends that if a utility relies on market purchases to fulfill its CFS obligations, whether on an hourly or annual basis, it would be required to purchase Energy Attribute Certificates (EACs) to match the carbon-free share of those purchases.[12] Further, the DOC proposes that all EACs retired for CFS compliance should originate from the Midwest region or meet interregional delivery requirements as specified in the Section 45V of the US Clean Hydrogen Fuel Credit production tax credit (PTC). The DOC further cites the 45V tax credit guidance in its endorsement of an hourly energy matching requirement.

The MN CEOs recommend that the MN PUC should require utilities to disclose the types of bundled and unbundled RECs used for CFS compliance and report the compliance level that would be achieved by using time-stamped RECs.[13] The MN CEOs state that doing so would better inform how carbon-free generation aligns with utilities' hourly electricity demand profiles. In addition, M-RETs recommends that the Commission prevent the double counting of RECs and mandate that the regulated entities claiming renewable or clean electricity consumption to use RECs, alternative energy credits (AECs), or the Commission's preferred EAC to substantiate their claims.[14]

GRE is concerned that measuring performance against the CFS targets using a 24×7 clean energy matching standard would be more restrictive than the annual matching standard as required by current law. Further, GRE is concerned that a 24×7 matching requirement would be more costly to customers and introduce implementation challenges, without offering commensurate policy or other benefits. To inform this proceeding, GRE asked for this analysis to summarize available evidence on the relative performance of annual matching versus hourly energy matching on dimensions of cost and performance in avoiding GHG emissions, as well as to address other points made on the asserted benefits of 24×7 matching.

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[11] MN DOC Comments.

[12] EACs is a broad category of certificates that verify the generation of electricity from clean or low-carbon resources. RECs refers to a specific type of EAC, primarily used in the US, in compliance markets (e.g., for meeting Renewable Portfolio Standards) and voluntary clean energy procurement programs. In this report, we use both terms interchangeably.

[13] MN CEO Comments.

[14] M-RETS Comments.

III. Economic Implications and Limitations of Hourly Matching

A. Relevant Definitions of Hourly Energy Matching

In general, hourly energy matching refers to the matching of electricity generation to consumer consumption on 24×7 hourly basis. Proponents usually envision two primary variations:

- ***Private matching***, where an entity's CFE supply is required to meet or exceeds its demand on an hourly, entity-specific basis; and
- ***Hourly REC trading***, where individual entities must similarly match their hourly supply and demand, but where time-stamped RECs can be purchased or sold to address hourly imbalances.

The purchased clean energy and hourly RECs would typically originate from the same region where the electricity is consumed.

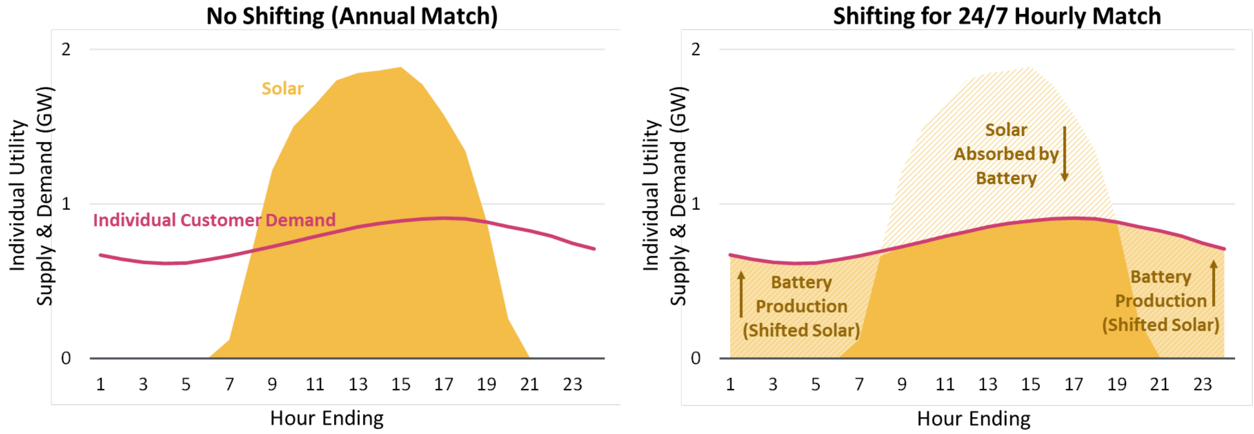
Figure 2 below illustrates this concept. Similar to the example customer in the MN DOC Comments, a stylized electric utility sources energy from a solar power plant.[15] The solar facility's output fully meets the utility's electricity demand on a volumetric basis over the day, and so fulfills the obligations of a traditional annual CFE matching standard. When solar generation exceeds electricity demand, the utility can sell that excess generation to the RTO market (and purchase from the market or rely on other generation resources during the shortfall hours).

To achieve hourly energy matching, however, the utility would need to deploy an energy storage system to store surplus solar energy generated during the daytime and discharge that energy during periods of lower solar generation, reflected by the hashed yellow area.[16] The utility could also address the shortfall in each hour by purchasing time-stamped RECs generated in that hour, or engage with customers to change their consumption patterns. Any renewable supply shifted via battery storage would also be affected by approximately 15–20% round-trip efficiency losses that would need to be made up for.

[15] MN DOC Comments, p. 10.

[16] This example is similar to the one shown in Figure 1 in the MN DOC Comments.

FIGURE 2: HOURLY ENERGY MATCHING REQUIRES SHIFTING RENEWABLE GENERATION TO MATCH ELECTRICITY CONSUMPTION THROUGHOUT THE DAY



Source and Notes: Stylized demand and generation are modeled after the demand and resource mix on a MISO summer day.

Hourly energy matching as a concept carries an intuitive appeal, especially when one imagines a simple, islanded power system without transmission limitations. In such a system, storage technologies can be deployed to shift clean energy generation to align with demand and to manage fluctuations in renewable output. However, as discussed below, this simplicity is misleading, as it fails to consider the broader implications of 24×7 matching within real-world power grid operations. In many cases, attempting to shift supply to match demand can have the unintended and counter-productive effect of increasing overall emissions.

Indeed, a key challenge with hourly energy matching as a strategy to reduce GHG emissions is that it focuses on the wrong metric. Requiring a utility or a group of entities operating in a larger power system to match their CFE supply to their own demand on an hourly basis may create better-aligned supply and demand profiles, but the measurement itself is not directly tied to GHG emissions policy objectives. Further, hourly energy matching does not inherently advance other key objectives such as maintaining grid reliability and minimizing costs. Moreover, despite its strict temporal enforcement, hourly energy matching lacks locational granularity, which means that it cannot account for the patterns of transmission system constraints that govern efficient energy market dispatch and trade.

B. Misalignment with GHG Emissions Goals

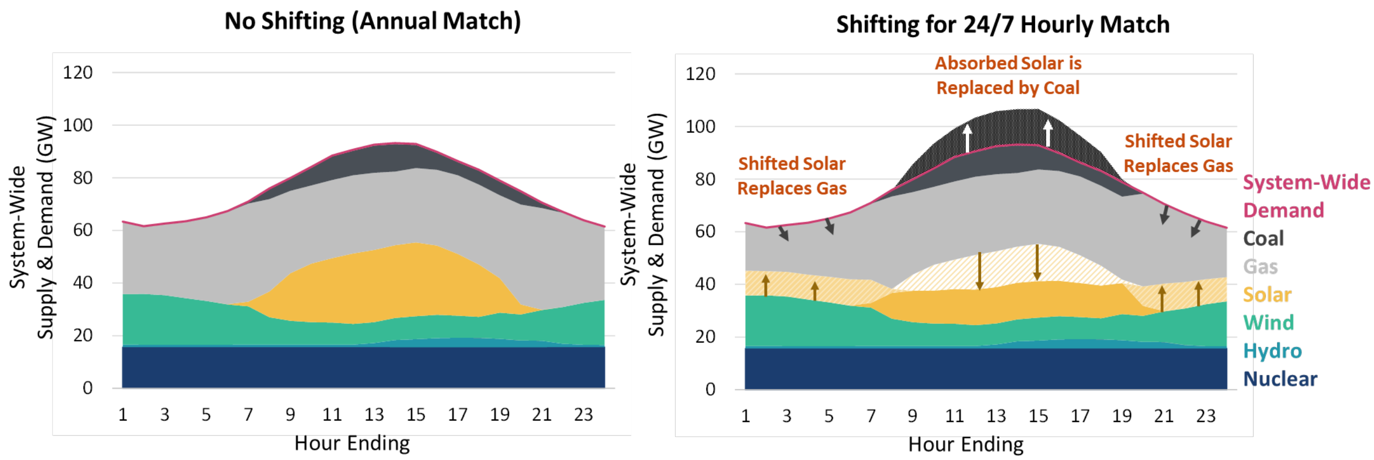
Hourly energy matching can inadvertently result in increases in GHG emissions, depending on system conditions. Whether the shifting required to meet an hourly matching standard displaces or causes more GHG emissions depends on the conditions of the broader power grid, and so the GHG implications cannot be evaluated by looking at one customer or utility in isolation.

Consider the same utility described above, but in the context of the broader power system in Figure 3 below. Under an annual matching standard, the utility would sell its surplus solar generation into the market during daylight hours, with the surplus solar supply displacing whatever resource is marginal in the RTO power market (coal on this example day). During nighttime hours, the solar resource is not producing power, and the utility must purchase power from the marginal resource in the RTO power market (natural gas in this example). Over the course of the day, the utility's imbalances of power interact with the broader market such that the surpluses displace coal generation, while the deficits are filled by natural gas.

Under an hourly energy matching standard, the utility would store its excess solar generation rather than selling it. The stored energy would then be discharged in the late evening and early morning hours, displacing some gas generation. However, this behavior ultimately leads to more system-wide GHG emissions. This is because coal generation is ramped up to fill in the supply gap in the daytime hours when excess solar generation is stored. Further, the utility loses 15–20% of the stored solar generation due to round-trip efficiency losses during charging and discharging. Considering the combined effects of round-trip efficiency losses and shifting from hours when coal is marginal to when gas is marginal, each MWh of solar power that is shifted results in 564 kg additional GHG emissions.[17] This outcome runs counter to how the utility would operate and optimize a battery if the goal is to reduce system-wide GHG emissions. Operating a battery system in this way would also conflict with the utility's objective of maximizing the battery's economic and reliability value by dispatching optimally in response to energy and ancillary market prices.

[17] This ratio considers the difference in emissions rates of coal at 958 $kgCO_2e/MWh$ times 1.2 MWh, which after shifting and 20% efficiency losses can displace only 1 MWh of natural gas from a CT at a rate of 585 $kgCO_2e/MWh$. Emissions rates are calculated from the US Environmental Protection Agency (EPA), Emissions Factors for Greenhouse Gas Inventories, September 12, 2023 and the US EIA Electric Power Annual, Table 8.2: Average Tested Heat Rates by Prime Mover and Energy Source, 2023.

FIGURE 3: A DAY WHEN SHIFTING FOR HOURLY ENERGY MATCHING INCREASES SYSTEM-WIDE GHG EMISSIONS



Source and Notes: Stylized demand and generation are modeled after the demand and resource mix on a MISO summer day.

This example describes only one type of day and was selected to illustrate the potential for counterproductive outcomes that can occur with hourly energy matching. The frequency and emissions impacts of such scenarios depend on the system context and time horizon (short term versus long term). In this example, coal is the marginal resource during the solar generation hours, and gas, a less carbon-intensive resource, is the marginal resource in the other hours. As we discuss later in the report, which fuel is the marginal resource at any given time depends on fuel prices, transmission constraints, and levels of renewable energy output. The net emissions impacts of hourly matching will also change in a dynamic fashion along with system conditions and patterns of supply, demand and transmission. However, the underlying issue that the example highlights arises primarily because private hourly energy matching is executed based on one individual entity's electricity demand profile, whereas emissions impacts depend on the characteristics of the aggregate system supply and demand for clean energy as well as prevailing transmission constraints.

The extent to which an hourly matching approach increases or decreases GHG emissions is a product of system conditions, the level of adoption of hourly matching on a market-wide basis, and the prominence of transmission constraints that may limit the simultaneous deliverability of matched supply and demand.

C. Misalignment with Reliability Needs

An hourly energy matching approach would encourage the selection and operation of resources that align closely with an entity's demand profile, but there is no reason to believe that the hourly matched portfolio would offer superior reliability value. For example, achieving 100% hourly matching would require utilities to deploy their storage or load-shifting technologies to match a load profile. Operating batteries and demand response in this way would substantially diminish their reliability value by diverting these flexible clean resources away from a more natural dispatch profile that would prioritize the provision of ancillary services and maximize production in dispatch intervals with the highest energy prices. These highest-price intervals offer strong signals for when the system is approaching supply shortfall and reliability value is at a premium. Maximizing availability and output in these same tight intervals is also what contributes to resource adequacy value for capacity resources. In other words: a battery that is maximizing its reliability and resource adequacy value should be balancing against the variability and uncertainties of the system-wide net supply-demand balance and may have a complex and highly variable charging and discharging profile that has little or no relationship to the utility customers' demand profile.

Reliability is a complex and evolving issue that is continuously monitored and managed by utilities, state regulators, and MISO through ongoing processes that update resource adequacy definitions and ancillary service requirements. These reliability needs vary across multiple timescales, from sub-minute contingency responses to 5-minute to multi-hour balancing and ramping, as well as seasonal and long-term planning horizons. To effectively manage reliability needs throughout the clean energy transition, MISO and utilities will need to carefully consider how grid reliability needs are changing and what resources will be the most robust sources of reliability services over the relevant asset life. One of MISO's core organizational priorities is to actively and continuously update its approaches to measuring and managing reliability needs on the operating and planning timeframes. For example, MISO's *Reliability Imperative* and *Attributes Roadmap* documents sketch out a suite of reforms that MISO plans to pursue in the ancillary services markets, resource adequacy construct, and to better leverage the capabilities of batteries and other emerging technologies.[18]

In the planning timeframe, the reliability value of resources is most accurately measured considering the capacity accreditation value under the resource adequacy construct codified in MISO's Tariff Module E.[19] To more reliably and accurately manage resource adequacy needs, the MISO capacity construct has been undergoing substantial reforms including transitioning from an annual construct to a four-season construct and applying ongoing revisions to more

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18 MISO, *Reliability Imperative*, and *Attributes Roadmap*, December 2023.

19 MISO Tariff, Module E-1 – Resource Adequacy and Module E-2 – Resource Adequacy, March 2025.

accurately measure resources accredited capacity value.[20] For example, recent modeling enhancements have resulted in Effective Load Carrying Capability (ELCC) ratings that are materially changing compared to prior more simplified approaches, and that are subject to substantial going-forward uncertainty due to both rule changes and anticipated changes to system conditions (see Table 1 below).[21] MISO's resource adequacy definitions and requirements will continue to evolve as the system operator determines methods to cost-effectively accommodate more electricity demand and integrate greater volume of renewable energy resources in the future.

Over the coming decades, effective resource planning will require utilities to proactively track these ongoing reforms and prioritize the development and retention of resources that can provide the needed reliability attributes. A utility's resource plan will have to ensure sufficient supply to reliably serve net peak demand during coincident peak times in each of the four seasons, including accounting for total supply requirements and a portion that must be located in the same Local Resource Zone. In this context of system transition and change, MISO's resource adequacy and ancillary markets will define reliability needs and should drive planning and operational choices. Any efforts to pursue hourly matching in ways that deviate from these system reliability signals would work to degrade reliability and/or increase costs.

[20] For description and approval of the seasonal resource adequacy construct and accreditation reforms, see Federal Energy Regulatory Commission (FERC), Order Accepting Proposed Tariff Revisions Subject to Condition, 85 FERC ¶ 61,141, August 31, 2022.

[21] For previous proposed capacity accreditation for Planning Year 2028—2029, see MISO, Market Redefinition: Accreditation Reform, February 28, 2024.

TABLE 1: MISO PROPOSED ACCREDITATION USING DIRECT LOSS OF LOAD METHOD

Season	Scenario	Battery	Coal	Gas	Gas CC	Hydro	Nuclear	Pumped Storage	Run of River	Solar	Wind
	Early	99%	73%	61%	72%	88%	79%	65%	100%	1%	7%
Spring	*Even loss*	99%	74%	61%	72%	88%	79%	66%	100%	1%	7%
	Blended	99%	73%	61%	72%	88%	79%	65%	100%	1%	7%
	Early	81%	90%	84%	91%	97%	93%	97%	100%	2%	6%
Summer	*Even loss*	83%	90%	84%	91%	97%	93%	97%	100%	3%	6%
	Blended	81%	90%	84%	91%	97%	93%	97%	100%	3%	6%
	Early	70%	80%	81%	85%	91%	86%	76%	100%	0%	8%
Fall	*Even loss*	75%	80%	80%	84%	91%	85%	75%	100%	1%	8%
	Blended	72%	80%	80%	84%	91%	85%	75%	100%	1%	8%
	Early	39%	78%	84%	95%	93%	91%	80%	100%	0%	12%
Winter	*Even loss*	61%	79%	84%	96%	93%	91%	80%	100%	0%	11%
	Blended	56%	79%	84%	96%	93%	91%	81%	100%	0%	11%

Source and Note: MISO, LOLE Modeling Enhancements Storage Modeling, November 6, 2024.

D. Misalignment with Transmission System Capability

Guidance for hourly energy matching requirements, including guidance for the 45V tax credit, generally requires that the procured renewable energy and the associated demand be located within the same grid region. Such guidance implicitly assumes the procured energy is always deliverable to demand location, i.e., there are no transmission constraints. This assumption ignores the reality of how the grid operates across different locations and timescales, including the critical role that the nodal power markets play to optimally schedule power flows across the transmission system and manage congestion costs.

Transmission system capability and limitations are critical factors informing resource siting decisions and operating profiles. MISO has faced increasing transmission congestion in recent years due to the rapid growth in wind and solar energy. As of 2023, wind and solar reached close to 47.5 GW in capacity, or about a fifth of total generation capacity.[22] Looking forward, MISO estimates that to meet regional policy goals, member states will need to add about 343 GW of new resources by 2043, primarily consisting of wind, solar, and battery storage.[23] To facilitate this transition, MISO has launched a comprehensive transmission framework to guide multi-billion-dollar investments in the transmission system, so that renewable generation from wind- and solar-regions can be moved to demand centers.[24]

22 S&P Global. Historical & Future Power Plant Capacity. Retrieved March 6, 2025.

23 See MISO, *2024 Regional Resource Assessment: A Reliability Imperative Report*, January 2025.

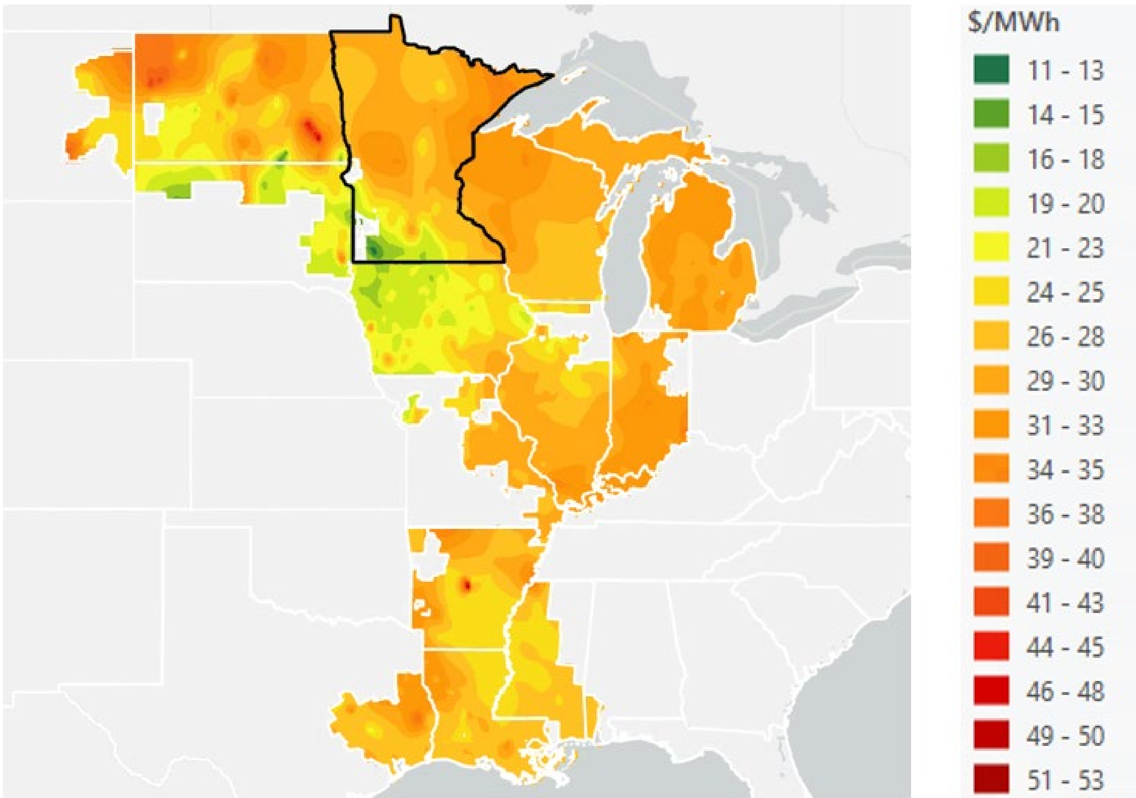
24 Wilson, Michelle, Building a Stronger Future: MISO Leads the Charge on a Comprehensive Investment in Transmission Infrastructure, MISO, September 18, 2024. .

An effective utility planning strategy must account for the anticipated availability of transmission to deliver supply to demand, the potential for exposure to transmission-driven resource curtailments, and the potential for congestion cost exposures. These factors are increasingly affecting the deliverability of supply to customers in Minnesota, as new patterns of transmission constraints are emerging along with expansions in wind and solar deployment. In southwest Minnesota, for example, wind and solar are clustered in locations with insufficient transmission to deliver all generation to demand centers. Due to the high correlation in generation across nearby wind or solar plants, these clusters become saturated with renewable generation in certain hours. When this occurs, the renewable generation does not displace fossil generation in those hours (and may have to be curtailed), diminishing the overall GHG emissions reduction value.

Figure 4 below illustrates how transmission constraints across MISO manifest as price differentials across different locations. There is a high concentration of wind deployment in southwest Minnesota, and neighboring portions of Iowa and South Dakota, with transmission limitations that prevent full deliverability to demand centers. As a result, the annual average locational marginal price (LMP) in those locations is lower relative to LMPs in the rest of Minnesota and other MISO zones. These transmission limitations are evident in the LMP differential between southwest Minnesota, where many wind and solar projects are sited, and demand centers such as Minneapolis. If supply is sourced in these low-price locations to serve demand in higher-priced locations, it exposes the customers to the risks of resource curtailments and congestion costs (i.e., LMP differences between supply and demand).

To manage such transmission limitations, a typical utility strategy would be to make go-forward siting decisions in locations that have less congestion exposure. Even if resource siting decisions have already been made, the utility may still be able to reduce curtailment and congestion exposures for example by adding a battery to an existing renewable resource and shifting output to times when transmission limits are not binding (i.e., when LMPs are higher). In fact, one of the central benefits of participating in a large regional RTO market is that RTO dispatch and pricing signals will naturally leverage the capability of individual resources to most effectively utilize available transmission and compensate for transmission limits with optimally scheduled purchases and sales. To pursue hourly matching of supply and demand, a utility may have to implement resource dispatch decisions that deviate from this economically optimized schedule, which would result in higher exposure to congestion costs.

FIGURE 4: LOCATIONAL MARGINAL PRICING VARIATION ACROSS MISO
2024 Annual Average LMP



Source and Notes: RT LMPs pulled from around 3,700 MISO price nodes from Hitachi Energy Velocity Suite for 2024. Data shown represents annual average LMPs in nominal $/MWh

Because hourly matching of supply with demand does not account for the realities of transmission congestion, it has the potential to induce renewables shifting that exacerbates congestion costs. For similar reasons, hourly energy matching in the presence of transmission congestion can also increase emissions. A recent study focusing on PJM and ERCOT found that demand that is 100% hourly matched through load-shifting often results in substantial net operational emissions and in some cases even higher emissions relative to the annual matching strategy due to intra-regional transmission constraints.[25] In other words, shifting supply (or demand) to accomplish hourly-match profiles does not mean that net emissions in any particular hour are made to be zero. This is because energy is not uniformly deliverable throughout an RTO, as transmission congestion plays a crucial role in determining the emissions impact of different clean energy compliance standards.

Figure 5 below illustrates how an hourly energy matching requirement can lead to higher congestion costs and emissions when considering the profile of transmission constraints over a

[25] Sofia, Sarah and Dvorkin, Yury, *Carbon Impact of Intra-Regional Transmission Congestion*, October 14, 2024.

typical day. Consider a scenario where a utility serving Minneapolis has solar generation assets in the southwestern part of the state. At noon on July 26, 2024 (left panel), the LMP differential between the demand location and the generation location is minimal, indicating relatively unconstrained energy flow. In contrast, at 10 PM on the same day (right panel), the LMP at the generation location is negative, and much lower than that at the demand center, indicating the presence of transmission constraints.[26] Under annual matching, the utility would sell all of its solar generation at noon, an economic decision that maximizes the resource's economic value and that limits the utility's exposure to congestion costs.

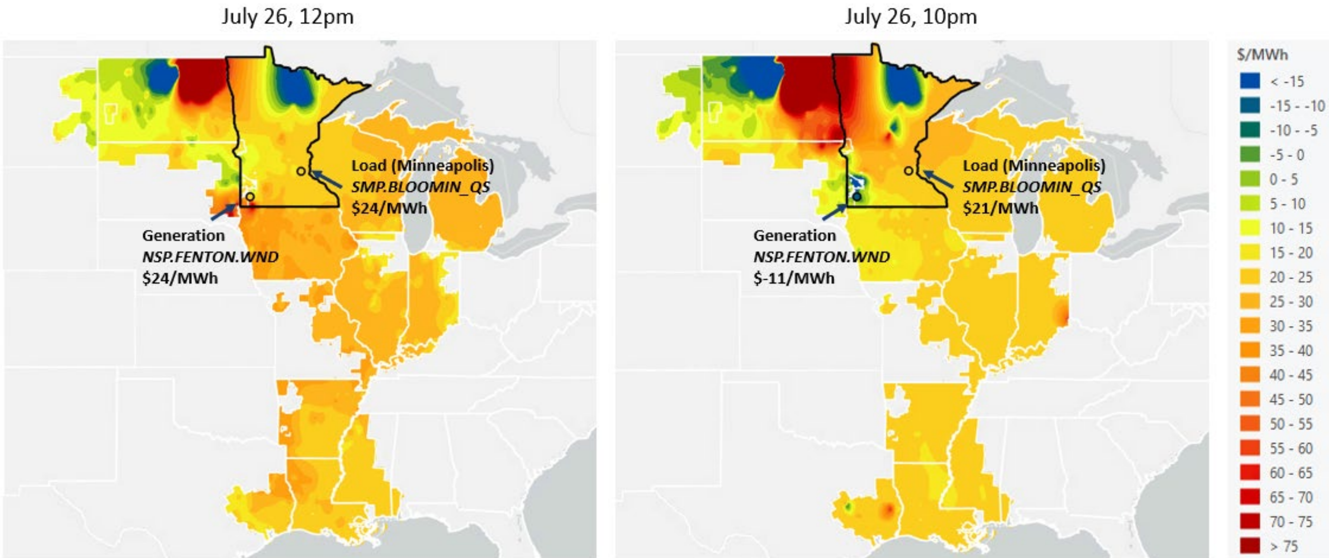
Under hourly energy matching, however, the utility would be required to store its excess solar generation at noon and discharge the stored energy at 10 PM to match the demand profile. This approach exacerbates the transmission congestion in the evening hours, increases congestion cost exposure, and reduces the solar project's effectiveness in cutting GHG emissions. If all of the solar generation, including generation in excess of demand, were used at noon, it would displace fossil fuel generation in that hour (as indicated by the higher LMPs).[27] Instead, storing and discharging the energy at 10 PM results in exacerbating a local surplus of power in nighttime hours when additional clean energy injections can only be absorbed if other renewables are curtailed (as evidenced by negative LMPs). Further, this charging and discharging pattern would result in 15-20% inefficiency losses and would cause the utility to lose revenue by shifting production to the lower LMP at 10 PM instead of at the higher LMP at noon.

This example highlights how rigid hourly energy matching requirements, when implemented without accounting for real-time grid conditions and transmission constraints, can inadvertently lead to both increased emissions and higher costs. The effectiveness of any clean energy compliance standard depends not only on the system-wide conditions and average and marginal emissions profile, as discussed above, but also on the local marginal emissions rate.

[26] Using LMP is a proxy for transmission constraints, we assume that electricity is deliverable from a high-LMP location to a low-LMP location. The European Commission adopts a similar assumption in the context of defining renewable hydrogen, where deliverable electricity is delivered from a high-price areas to a low-price area. See European Commission. "Commission sets out rules for renewable hydrogen". Feb 13, 2023, paragraph 12. This test can be reformulated using locational marginal emissions as well.

[27] LMP and LME are correlated because both are influenced by the marginal generator that sets the electricity price and emissions intensity at a specific location on the grid. If the marginal generator is a fossil fuel plant, both LMP and LME tend to be high due to fuel costs and emissions intensity. If the marginal generator is a renewable resource, LME is zero while LMP can vary based on transmission constraints and demand. Grid congestion, renewable deployment level, time and location are all factors that affect LMPs and LMEs.

FIGURE 5: HOURLY ENERGY MATCHING WOULD REQUIRE SHIFTING RENEWABLE ENERGY GENERATION TO A TRANSMISSION-CONSTRAINT HOUR
MISO LMP on July 26, 2024



Source and Notes: RT LMPs pulled from around 3,700 MISO price nodes from Hitachi Energy Velocity Suite for 2024.

IV. Evidence from Prior Studies: Cost and Effectiveness of Hourly versus Annual Matching

Debates over the advantages and disadvantages of different clean energy procurement strategies and compliance standards have attracted considerable interest in recent years. The debates reached a wider audience in 2023, when the US Treasury was finalizing regulations for the 45V tax credit, a key incentive for hydrogen development. Around the same time, the Greenhouse Gas Protocol (GHGP) launched a multi-year effort to update its Scope 2 Guidance, which describes how private companies should tabulate and report their emissions associated with power consumption in their investor reports. In its review of Scope 2 guidance, the GHGP is reviewing how to appropriately account for emissions associated with clean energy procured from the market is one of the central focus areas.[28] To contribute to these discussions and

[28] In short, under the GHGP Scope 2 guidance, companies report their emissions using the location-based method and the market-based method. Under the former method, the reporting company can rely on the emissions intensity of the electricity grid where operations and energy consumption occur. The latter method estimates emissions associated with energy procurement by accounting for contractual instruments such as clean energy attribute certificates and power purchase agreements (PPA), as well as an electricity supplier's specific emissions rates. For more information, see WRI, GHG Protocol Scope 2 Guidance, 2014.

inform the broader discussions of climate policy and clean energy procurement strategies, stakeholders have commissioned and undertaken a number of studies, including:

- Giovanniello et al., *The Influence of Additionality and Time-Matching Requirements on the Emissions from Grid-Connected Hydrogen Production*, Nature Energy, 2024 ("MIT Study"), funded by the Future Energy Systems Center, an industry research consortium at the MIT Energy Initiative;
- He et al., *Paths to Carbon Neutrality A Comparison of Strategies for Tackling Corporate Scope II Carbon Emissions*, Tabors Caramanis Rudkevich/Meta, 2023 ("TCR Study"), funded by Meta Platforms, Inc.;
- Olson et al., *Consequential Impacts of Voluntary Clean Energy Procurement*, E3, 2024 ("E3 Study"), funded by Meta Platforms, Inc.; and
- Xu et al., *System-Level Impacts of Voluntary Carbon-Free Electricity Procurement Strategies*, Joule, 2024 ("Princeton 2024 Study"), funded by a grant from Google and by the Princeton Zero-Carbon Technology Consortium, which is supported by unrestricted gifts from GE, Google, ClearPath, and Breakthrough Energy.[29]

The studies vary substantially in their findings with respect to GHG abatement effectiveness of hourly versus annual energy matching.[30] Though these studies differ in design and purpose, their findings when taken as a whole do offer some common findings that we report here. They do not definitively establish the superiority from a carbon perspective of any single clean energy procurement strategy or over others in all circumstances.

For example, the TCR Study examines the cost-effectiveness of hourly and annual clean energy procurement strategies, as well as comparing these options to the authors' preferred approach of a marginal emissions strategy. Under a marginal emissions procurement strategy, the customer would seek to procure clean energy that is injected to the grid at whatever time and place is anticipated to displace the greatest GHG emissions from other fossil supply, with marginal emissions displacement measured on an hourly basis. The customer does not seek to match hourly supply with hourly demand, but instead seeks to accomplish the greatest possibly reduction of GHGs for each MWh of clean energy procured. The study finds that while all voluntary procurement strategies lead to large displacement of GHG emissions, the hourly energy matching strategy results in more avoided emissions than the annual matching strategy

29 A working paper version was published as Xu et al., *System-Level Impacts of 24×7 Carbon-Free Electricity Procurement*, 2021.

30 For an assessment of a subset of these studies (i.e., the BCG study, the MIT study, and the TCR study), please see Spees et al., *Assessment of Studies on US Hydrogen Tax Credits and Potential Takeaways for Scope 2 Guidance*, prepared for the Greenhouse Gas Protocol, 2024

as well as the marginal emissions matching strategy. However, hourly matching is the most cost-intensive strategy because it requires a much greater level of clean energy procurement. (See below for a discussion on cost implications.)

The TCR Study accounts for emissions impacts associated with changes to dispatch and considering a fixed resource mix. It does not consider long-run effects, or changes in system-wide emissions due to a marginal shift in demand. Such long-run effects include structural and investment impacts from power plant additions and retirements.

Accounting for these long-run effects, the MIT Study finds that hydrogen development under the hourly energy matching strategy results in lower system emissions. Similarly, the Princeton Study finds that hourly energy matching as a voluntary clean energy procurement strategy leads to lower overall emissions compared to the annual matching. The weaker performance of the annual matching strategy is largely attributed to the fact that that strategy can be satisfied by using existing clean energy resources or using clean energy resources that would be built anyway thanks to favorable economics without driving additional clean energy deployment. Under annual matching, renewables (or their environmental attribute certificates) are reshuffled to serve the voluntary CFE demand instead of serving other parts of the economy. As a result, states and consumers without clean energy mandates may be more likely to extend their reliance on existing and new fossil fuel resources to meet electricity demand in sectors that do not require clean power. However, these findings are not consistent across all scenarios.

The GHG advantages of temporal matching diminish or disappear in the presence of grid decarbonization policies, such as a binding RPS or a CFS. For example, according to the Princeton Study, assuming that an 80% clean energy standard is in place and 10% of commercial and industrial customers are participating in voluntary procurement, there is virtually no difference in system emissions between annual matching and hourly matching at 92% level in California. Hourly matching beyond the 92% level drives greater emissions reduction than annual matching, but at much greater costs (see discussion below).[31] The E3 Study, which focuses on the impacts of voluntary clean energy procurement in California, reports similar findings. California policy specifies incremental milestones toward 100% GHG-free energy generation by 2045 (Senate Bills 100 and 1020) and 80% economy-wide GHG emissions reduction below 1990 levels by 2050 (Assembly Bill 32). In the presence of the

[31] Similarly, the paper finds that with an 80% clean energy standard, no significant difference in system emission between annual matching and hourly matching at 90% level for Wyoming and Colorado (see Figure S25 in the Supplemental Information). In a working paper version of the paper, the authors report similar findings for PJM without the assumption that an RTO-wide clean energy standard is in place. See Xu et al., *System-Level Impacts of 24×7 Carbon-Free Electricity Procurement*, Princeton ZERO lab, 2021.

California's clean energy policy, both annual and hourly energy matching strategies drive additional clean energy generation and result in lower system emissions.[32,33]

All studies conclude that hourly energy matching is more costly than annual matching, though the magnitude of this cost difference varies substantially. A key driver of these higher costs is the mismatch between variable renewable generation and demand profiles. Achieving a 100% hourly match requires deploying a larger volume of renewable resources and storage than what would be needed under annual matching. As summarized in Figure 6 below, across all studies, the cost of energy in an hourly energy matching approach is $1-255/MWh higher than in an annual matching approach. Regarding the cost of emissions abatement, hourly matching generally costs $2-332 per tonne of CO_2 equivalent (tCO_2e) more. In a few scenarios, the Princeton Study and the MIT Study find that annual matching has a higher abatement cost, primarily because the but-for scenario already has a sufficiently high renewable penetration that annual matching can be accomplished by utilizing unbundled RECs that would otherwise have remained unclaimed/unused (so the annual matching approach has a negligible impact on system emissions).

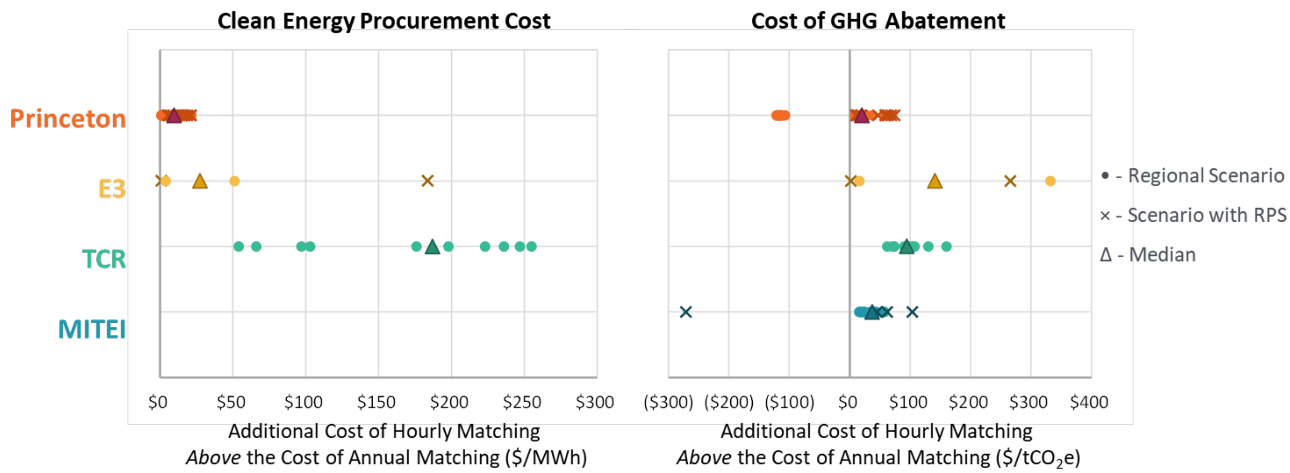
In addition, the E3 and TCR Studies find that costs escalate further if deliverability requirements are highly restrictive, such as mandating on-site generation. Allowing flexibility when implementing matching requirements can help reduce the costs associated with 24×7 clean energy procurement. The authors examine how flexibility can be created through adjustments to procurement strategies such as deploying energy storage; operating loads flexibly; selling excess renewable generation; concentrating clean energy dispatch during the power system's highest-emitting hours; and building excess renewable capacity relative to an annual energy matching volume. The costs of hourly matching can also be reduced under market-wide approaches, where hourly net demand and supply are pooled into an hourly REC or clean energy certificate market. Instead of each entity sourcing its own clean energy without broader considerations and system-optimized interactions with the rest of the market as is the case in

[32] The US Treasury recognizes these dynamics in its 45V tax credit regulations, which consider clean energy procured in states with stringent clean energy policy to be additional. See Federal Register, Credit for Production of Clean Hydrogen and Energy Credit, January 10, 2025.

[33] In addition, the notion that clean energy resources would be built anyway because of their favorable economics (e.g., declining costs, tax incentives through the Inflation Reductio Act) has been challenged. Long-term offtake contracts are needed to finance most new clean energy projects, especially as resources with zero marginal cost are added to the grid, bringing down energy prices and worsening project economics. *See* Beiter, P. et al. *The Enduring Role of Contracts for Difference in Risk Management and Market Creation for Renewables*. *Nat Energy* **9**, 20–26, 2024.

the private matching approach, pooling demand and supply for clean energy could reduce the resulting volume of renewable over-procurement and reduce the joint costs.[34]

FIGURE 6: HOURLY MATCHING IS MORE EXPENSIVE THAN ANNUAL MATCHING



Sources and Notes: Modeling scenarios with an assumed RPS or clean energy standard are represented with an ×, scenarios where the base case has no existing clean energy policies are represented with a •, and the median value is reported with a Δ. Scenario cost data is from the Princeton 2024, E3 Study, TCR Study, and MIT Study. MIT study data updated from more recent results under the "compete" framework and without PTC results.

The importance of deliverability in the context of clean energy procurement is widely recognized.[35] However, none of the studies we reviewed examines this dimension adequately. The studies model and assess large market regions, assuming deliverability is achieved so long as the procured renewable supply is located in the same region as demand. But in real-world power systems, deliverability is more complex. As discussed above, transmission constraints play an important role in determining the effectiveness of each compliance standard in reducing GHG emissions. Further, the ability to deliver energy between any two locations within the same state can vary throughout the day. The assumptions made in these studies are appropriate given their main objectives of quantifying GHG emissions and costs, but they also mean that the study results are less helpful in informing the more granular realities of grid operations that utilities will have to account for in planning for deep decarbonization.

[35] For example, the US Treasury specifies that deliverability is one of the "important guardrails to ensure that hydrogen producers' electricity use can be reasonably deemed to reflect the emissions associated with the specific generators from which the EACs were purchased and retired." See Credit for Production of Clean Hydrogen and Energy Credit. Vol. 89, No. 7, Federal Register, page 2254. See also Miller et al., *Where Matters: Integrating Deliverability into Voluntary Clean Energy Market Boundaries*, prepared by Singularity Energy and The Brattle Group for Google LLC, 2023

V. Potential Costs and Effectiveness of Annual versus Hourly Matching in Minnesota

To assess the potential costs and efficacy of hourly matching compared to annual matching in Minnesota, we conducted an analysis comparing the two options under recent historical market conditions. Consistent with the literature, we find that pursuing hourly energy matching in Minnesota would be more expensive than annual matching under a range of scenarios and sensitivity assumptions. In our analysis, we assume that a customer or utility pursues annual or hourly matching to serve a representative 1 MW of demand by procuring generation from a portfolio of wind and solar resources.

Under annual matching, we assume that hourly supply and demand imbalances are managed through RTO market purchases and sales. Under hourly matching, we compare differences in outcomes depending on whether hourly imbalances are managed through alternative strategies of over-building supply, building and operating battery storage, or utilizing an hourly REC market. Relative to annual matching, we find that achieving 100% hourly matching by doubling the size of the same resource portfolio and adding a semi-optimized large battery is $260/MWh more expensive. Using a more right-sized portfolio of wind, solar, and a typical 4-hour storage system reduces the incremental costs of hourly matching, but only achieves about 87% hourly matching. Relying on time-stamped RECs to achieve 100% hourly matching can also bring down procurement costs, but it is still $32/MWh more expensive than annual matching. Because there is not a sufficiently liquid hourly REC market in MISO today from which we could derive hourly REC prices, we developed an indicative hourly REC price profile for the purpose of our analysis (though we acknowledge that prevailing prices in such a market may deviate substantially from what we have assumed).

There may be additional strategies that utilities and customers may utilize to reduce the cost of hourly matching beyond what we have estimated, but regardless of these strategies the outcome would be higher costs to meet a more restrictive compliance mandate compared to annual matching. Beyond the higher costs, this analysis further illustrates the more central problem that hourly matching incurs higher costs without delivering on the hypothesized benefits. Applying the concept inside the realities of real market conditions illustrates why hourly matching does not advance other goals of decarbonization, reliability, managing market risk exposures and managing transmission constraints. There are other, better, signals one must chase in order to advance those objectives.

A. Locational Marginal Emissions in Minnesota and Surrounding Areas

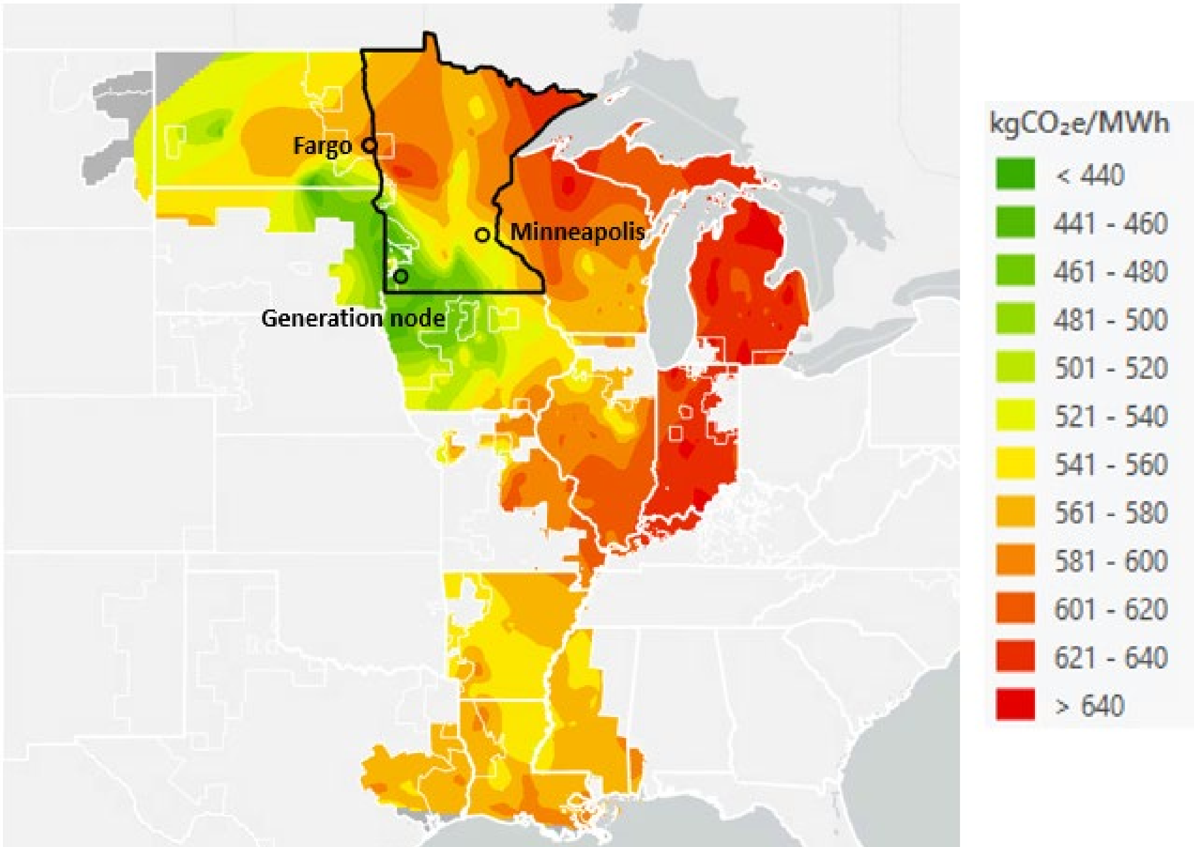
To estimate emissions impacts, we rely on 2024 locational marginal emissions (LME) data from REsurety for MISO.[36] The LME measures the kilograms of carbon emissions avoided per megawatt-hour (MWh) of clean energy injected into the electric grid at a specific location and time. Similar to LMPs, LMEs are calculated at each power system node by identifying the marginal resource(s) that would have otherwise been producing electricity but for the renewable energy injection into the grid at that location and time.[37] The nodal LME metric (in kg/MWh) is analogous to LMP (in $/MWh) in that both measure the incremental impact of injecting or withdrawing one more MWh of energy from the grid in a specific location, considering the marginal supply resource(s) that would need to be ramped up to supply that incremental demand (or ramped down to accommodate more supply).

Figure 7 below presents the average LME for MISO in 2024. Across the Midwest, LMEs are higher in Michigan, Indiana, southern Illinois, and northern Wisconsin compared to other areas in the MISO footprint. Renewable resources sited in these areas would displace more emissions from fossil generation than those in regions with lower LMEs, such as Iowa, a state with a high level of wind deployment and where more renewable curtailments already occur. Within Minnesota, northern areas exhibit higher LMEs than the southwestern part of the state, where there is a high concentration of renewable energy projects. Therefore, a new renewable project located in the southwestern part of the state would have a lower emissions abatement value, especially if renewable generation in that area would be produced during times when other renewables are already curtailed. The North-South LME disparity also highlights a transmission limitation affecting the state, indicating insufficient transmission capacity to move renewable generation out of the southwest.

[36] REsurety, Locational Marginal Emissions (LMEs), accessed March 11, 2025.

[37] David Oates and Kathleen Spees, *Locational Marginal Emissions: A Force Multiplier for the Carbon Impact of Clean Energy Programs*, REsurety, March 2023, and PJM, Marginal Emissions Rate – A Primer

FIGURE 7: LOCATIONAL MARGINAL EMISSIONS VARY ACROSS LOCATION
2024 MISO Average LME



Source and Notes: Locational marginal emissions pulled for approximate 1,800 nodes from REsurety's LME database. Data shown represents annual average LMEs in $kgCO_2e/MWh$.

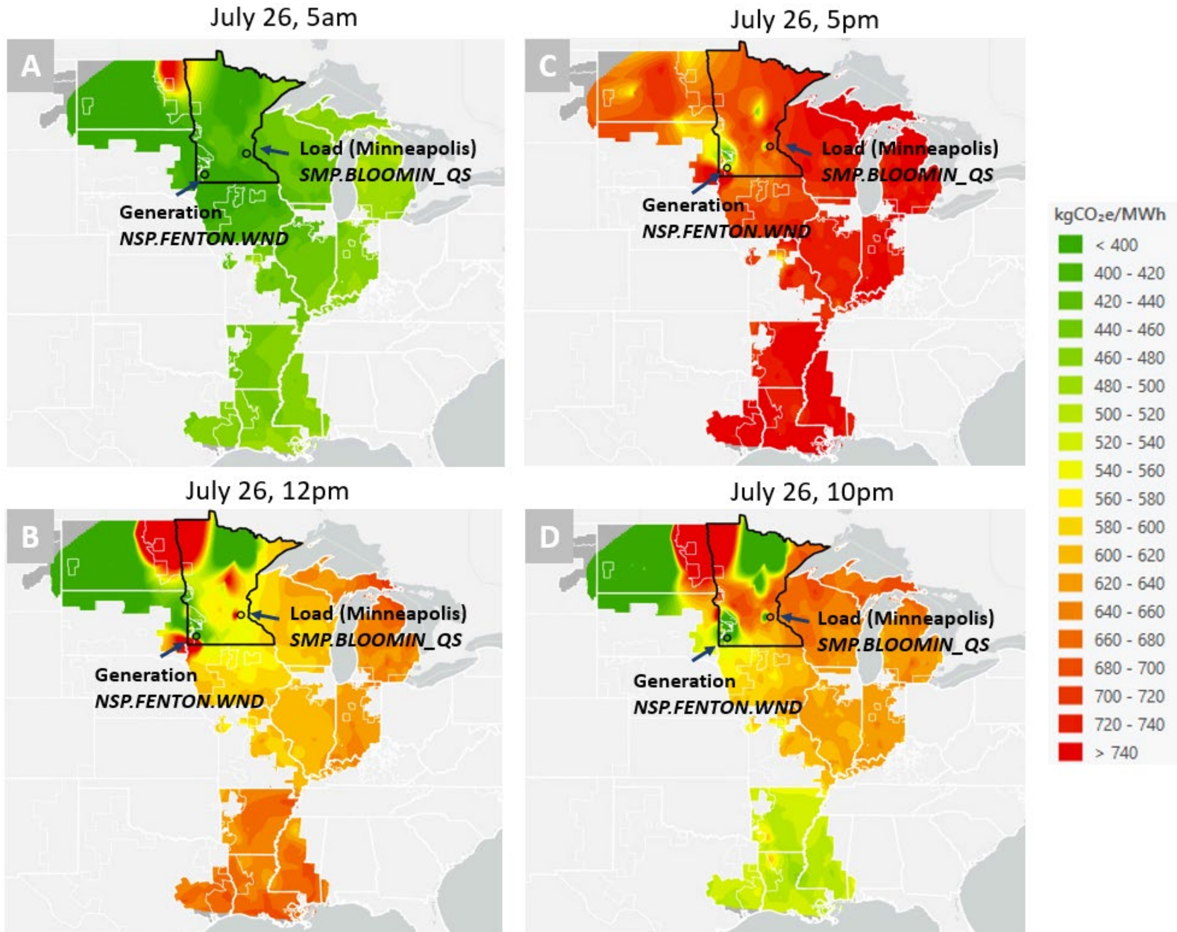
In addition to location, LMEs also vary over time. For example, Figure 8 below compares snapshots of MISO-wide LMEs across different four different hours all on the same day July 26, 2024. The LME in the Minneapolis area is low at 5 AM, higher at noon, and much higher at 5PM before decreasing in the evening hour. Accordingly, the carbon abatement value of a renewable project located in the Minneapolis area would change throughout the day, even if that project had constant output. For that reason, differences in generation profiles can produce substantial differences in the GHG abatement value. For example, in one location a solar resource may provide more GHG abatement value than wind (e.g. if the increased output during on-peak hours allows the output to focus on more GHG-intensive peak hours); while in a different location wind may offer more GHG abatement value (e.g., if the flatter output profile of wind means that it is less susceptible to curtailments during on-peak hours when insufficient power can be delivered over the available transmission system).

Beyond serving as an indicator of carbon abatement value, LMEs can help inform siting decisions that aim to maximize carbon abatement benefits. There is a correlation between LMPs and LMEs, though the strength of this correlation is strongest and most reliable when renewable generation is curtailed on the margin. For example, a comparison of MISO's average LMPs (Figure 4) and average LMEs (Figure 7) shows that areas with low LMPs (e.g., Iowa, southwest Minnesota, eastern South Dakota) also tend to experience low LMEs. Conversely, areas with high LMPs tend to have higher LMEs because the marginal generators in these areas are often fossil-fuel-fired power plants.[38] Because of this correlation, LMPs (particularly low and negative LMPs) can be used as a proxy for LMEs in evaluating deliverability and optimizing siting decisions, ensuring that generation from newly developed clean energy resources can reach demand centers. To improve the GHG abatement value of planning decisions, LMEs can be used to screen out locations where adding more renewable resources would exacerbate grid congestion, thereby helping to align the interests of investors and power system operators.

[38] To provide more nuance on this point: the correlation between LMP and LME is strong when considering the difference between fossil resources as marginal compared to renewable resources being marginal. However, the correlation between LMP and LME is weaker and may be in the opposite direction considering only the subset of hours when fossil resources are marginal. This is because coal and natural gas resources' operating and fuel costs are similar and vary substantially depending on fuel prices. For example, when natural gas prices are high, coal is lower-cost than gas, and hence lower-price hours are more coal-intensive on the margin. When natural gas prices are low, the low-price hours typically have gas on the margin. It is also common for coal and gas resources to be intermixed in the supply curve and so LMP during fossil hours, in which case the determination of which resource is marginal at a particular time is less predictable in advance and is most accurately determined by the RTO as a function of market dispatch.

FIGURE 8: LOCATIONAL MARGINAL EMISSIONS VARY ACROSS TIME

MISO LME on Jul 26, 2024 at 5am (A), 12PM (B), 5PM (C), and 10PM (D)



Source and Notes: Locational marginal emissions pulled for approximate 1,800 nodes from REsurety's LME database. Data shown represents hourly LMEs in $kgCO_2e/MWh$.

B. Method for Evaluating Impacts of Hourly Energy Matching in Minnesota

To assess the cost and emissions impacts of the different clean energy compliance standards, we reviewed emissions and cost outcomes across five cases:

1. **No Matching**: We assume that a stylized utility located in Minneapolis with peak demand of 1 MW would purchase energy from market at its nodal LMP to meet customers' demand for electricity. The utility's demand profile mirrors that of MISO in 2024.[39]

[39] MISO load data from EIA. https://www.eia.gov/electricity/wholesalemarkets/data.php?rto=miso. Nodal data from Hitachi Energy Velocity Suite for 2024 for SMP.BLOOMIN_QS (Minneapolis).

2. **Annual Matching:** We assume the same utility procures generation from a portfolio of wind and solar photovoltaic (PV) power plants located in southwest MN (see Figure 8 above). The renewables are sized to match 100% of the utility's electricity demand on an annual basis with equal capacity split between wind and solar. The incremental cost is the levelized cost of energy of the solar and wind plants multiplied by their respective generation and is net of the revenue received from RTO energy sales.[40] In addition, the utility would continue to pay for energy consumption at the hourly LMP (same as in the No Matching case above and in all hourly matching cases below). The differences in output versus demand profile, combined with the differences in LMP at the renewable and demand node together make up the congestion costs (or net cost of RTO market balancing) that we account for in our analysis.
3. **Hourly Energy Matching with Renewables and a 4-Hour Battery:** The same utility would procure generation from a portfolio of wind, solar, and storage to match its energy consumption on an hourly basis. The solar and wind plants have the same capacity as those the Annual Matching case to start and are then sized up to accounting for the battery's round-trip efficiency of 85%. The 4-hour battery has a capacity of 1,000 kW (around 50% of assumed combined wind + solar capacity). Fully charged initially, the battery discharges when generation is less than demand, and charges up when generation is greater than demand and when storage capacity is available (i.e., the battery is operated to accomplish demand matching and is not operated in an economically optimized fashion relative to LMPs). Incremental costs are calculated as in the Annual Matching case.[41]
4. **100% Hourly Energy Matching with Renewables and a Semi-Optimized Battery:** The same utility would procure generation from a portfolio of wind, solar, and storage to match its energy consumption on an hourly basis. The wind + solar portfolio size is twice as large as that in the Annual Matching case. The utility also adds an 8-hour storage duration, whose power capacity is sized to achieve 100% hourly matching across all hours of the year. The battery only charges from the wind + solar system. Charging behavior is similar to the battery in Case 3.
5. **100% Hourly Energy Matching with Time-Stamped RECs**: The utility has the same portfolio of wind and solar resources as in the Annual Matching case and purchases hourly RECs for

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[40] We assume the wind and solar resource portfolio is located at node NSP.FENTON.WND. Wind and solar generation profiles are from EIA. Levelized technology costs are from NREL Annual Technology Baseline, modified for an 8% nominal discount rate assumption, 30-year life, and with production tax credit. Costs are taken for class 6 wind resources and class 8 solar resources from NREL, consistent with southwest Minnesota. Generation profiles are sourced from Renewables.ninja 2024 capacity factor data.

[41] For battery system cost, we use data from NREL ATB for utility-scale battery levelized using a 15-year life and 8% discount rate.

to make up for any hourly clean energy shortfalls. The utility can also sell hourly REC surpluses at times of excess supply. To develop a reasonable profile of prices that may prevail in an hourly REC market, we assume that these hourly prices would be driven by the hourly balance of renewable supply minus hourly demand as measured on a regional basis. We assume that prices would be at one of three levels, depending on net supply conditions: (1) "surplus renewable hours" we assume would have zero price for RECs, with these hours identified during Minnesota Hub curtailment hours (defined as the 20% of lowest LMP hours); (2) "standard price" for during most hours; and "premium price" during scarcity hours when the system-wide renewable supply is lowest compared to hourly demand.[42] The total incremental costs are the costs as in the Annual Matching case plus the net REC costs. (RECs can also be sold at zero price, standard price, and premium price based on when the excess generation occurs.)

TABLE 2: SUMMARY OF CLEAN ENERGY PROCUREMENT UNDER DIFFERENT STRATEGIES

Case	Demand Characteristics	Clean Energy Resource/Instrument	Total Costs
1. No Matching	1-MW demand located in Minneapolis with same profile as MISO system's consumption profile	N/A	= Energy Purchased at Demand Location
2. Annual Matching	Same as (1) above	Wind + Solar (50/50 equal installed capacity)	= Levelized Wind cost × Wind MWh Generation + Levelized Solar cost × Solar MWh Generation + Energy Purchased at Load Location — Energy Sales at Gen Location
3. Hourly Matching with 4-Hour Battery	Same as (1) above	Wind + Solar as in (2), but sized to compensate for storage efficiency loss + 1,000 kW 4-hour battery	Same as in (3) above
4. 100% Hourly Matching with Battery	Same as (1) above	Wind + Solar sized 2x larger than (2) + 8-hr Battery (3,300 kW)	*Same as in (2)* + Levelized Battery Costs + Net Energy Sales from Battery
5. 100% Hourly Matching with Time-Stamped RECs	Same as (1) above	Wind + Solar as in (2) + Time-Stamped RECs for clean energy shortfall hours	*Same as in (2)* + REC costs – Revenues from REC Sales

42 Standard price of RECs is assumed to be the cost of doing annual matching. Scarcity hours are hours in which the utility's renewable generation is less than hourly REC demand. We estimate the utility's hourly REC demand by multiplying the ratio of historical 2024 compliance (RPS) and voluntary demand for RECs in MISO to total MISO load by the utility's hourly load. We estimate the premium associated with RECs generated during scarcity hours by calculating the additional cost of renewable buildout that would be needed for the utility to reach 100% hourly matching relative to annual matching costs. Premium REC price is about $300/REC. Voluntary REC demand from NREL, 2023 Voluntary Green Power Procurement. Zonal prices from US Energy Information Administration, Wholesale Electricity Market Data by RTO, 2024.

Table 2 summarizes the five cases, including demand characteristics, clean energy resources or instruments used under each compliance standard, and the associated costs.

We calculate the marginal emissions abatement accomplished in each case following Equation 1 below. In the case where the utility purchases hourly RECs to comply with 100% hourly matching, we only account for the avoided emissions thanks to the procured wind and solar generation. We do not include the avoided or incurred emissions associated with RECs purchase and sales.

In all cases, we report two cost metrics for each compliance standard:

- \$/MWh: the cost of procured clean energy resources or clean energy instruments (e.g., RECs) divided by the total demand for electricity (MWh), such that the resulting \$/MWh metric is reported as a net delivered cost to customers (on top of the costs that would be incurred in Case 1 that does not have any clean energy requirement)
- \$/tCO_2e: the carbon abatement cost, calculated by dividing the incremental cost of clean energy procurement costs (e.g., procuring wind + solar, or RECs) relative to the No Matching case by the total avoided emissions.

EQUATION 1: MARGINAL EMISSIONS ABATEMENT IMPACT CALCULATION

$$Marginal\ Emissions\ Impact = \sum_{h=1}^{8760} Supply_h \times LME_{S,i}$$

Where:

Marginal Emissions Impact (tCO_2e) = Total annual emissions avoided by procured renewable supply
LME (tCO_2e/MWh) = Locational marginal emissions in each hour *h* at the Supply location *S*
Supply (MWh) = Supply in each hour *h*, including renewable generation and battery discharge

C. Costs and Emissions Outcomes

Costs and emissions results can be seen for the five cases in Table 3 below. As described above, costs for each of the matching scenarios are calculated relative to the No Matching base case. The cost of annual matching is approximately \$34/MWh above the cost of doing nothing, reflecting the cost premium of building the selected renewable portfolio relative to the expected receipts from energy sales. Note that these incremental costs for annual matching are likely on the higher end of what could be accomplished by a robust utility planning exercise that fully optimizes resource selection, siting that aims to avoid congestion risk, and resources' seasonal resource adequacy value. In our more simplified analysis against historical market prices, we have not attempted to fully optimize on these dimensions and instead adopted in our study design a simplified 50/50 wind and solar resource mix located away from the demand center, and do not attempt to account for capacity or other resource values. We apply these same assumptions across all study cases in order to provide a common basis upon which to compare the cost and GHG implications of hourly matching strategies.

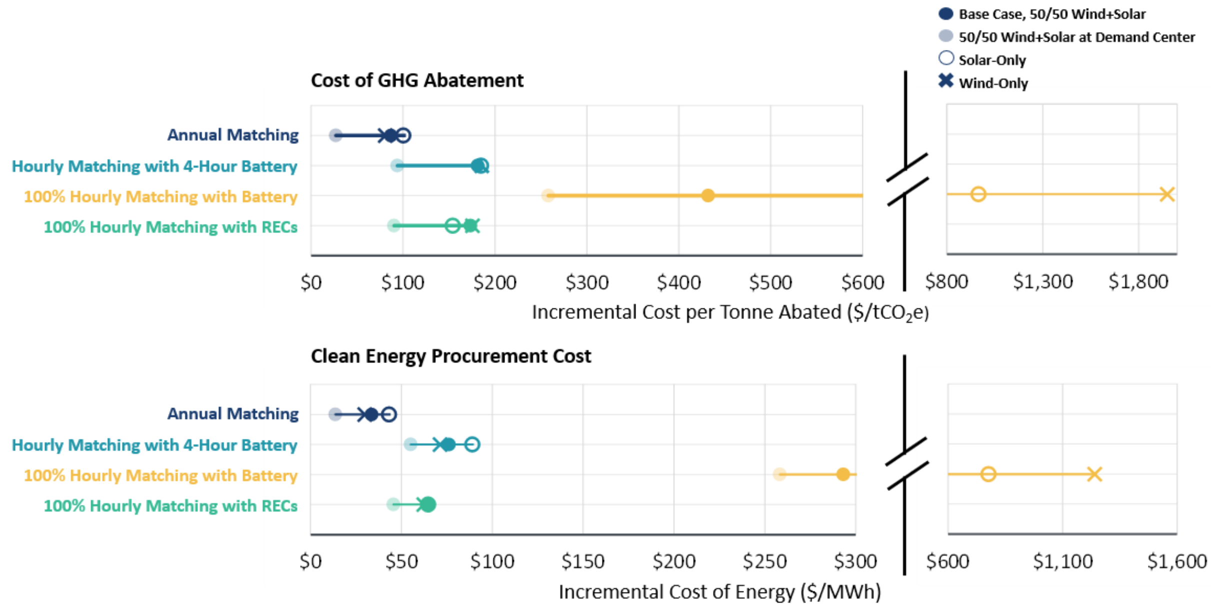
The cost and abatement value of matching change based on both the renewable portfolio's location and composition. In the base case, we assume the generator is located in an area with a much higher concentration of renewable generation but not close to the demand center. Because of the high concentration of renewable generation, LMPs are also frequently low or negative during hours where the procured renewables are generating. Emissions impact and cost outlook may improve if the generator is sited near the demand center with higher LMEs and LMPs. Similarly, emissions impact and cost outlook may improve if the procured clean energy portfolio tends to generate in hours that are not already saturated with renewables (e.g., a solar + wind portfolio in a solar-dominated system). Utilities with more diverse geographic and generation portfolios can take advantage of these factors.

TABLE 3: COSTS OF ANNUAL AND HOURLY MATCHING ACROSS CASES

	Case	**% Annual Matching**	**% Hourly Matching**	**Matching Cost** *($/MWh)*	**Abatement Cost** *($/t$CO_2$e)*
1	No Matching	0%	0%	N/A	N/A
2	Annual Matching	100%	74%	$34	$87
3	Hourly Matching with 4-Hour Battery	118%	87%	$76	$181
4	100% Hourly Matching with Battery	200%	100%	$293	$432
5	100% Hourly Matching with Time-Stamped RECs	126%	100%	$65	$173

To explore these factors, we examine three sensitivity cases: a solar-only portfolio, a wind-only portfolio, and a 50-50 wind and solar portfolio placed at the demand center (co-location). These produced a range of cost results, as can be seen in Figure 9 below. If the utility follows an hourly energy matching approach instead of an annual matching one, the costs of meeting the CFS are uniformly higher across all cases we examined, as summarized in Table 3 above and Figure 9 below. Across all cases and sensitivities, we find that hourly matching would cost approximately $21-1,210/MWh more on a delivered customer cost basis or approximately $54-1,868/t$CO_2$e more.

FIGURE 9: RANGE OF ANNUAL AND HOURLY MATCHING COSTS FROM SENSITIVITY ANALYSES



The cost of annual matching is subject to moderate variation depending on both renewable location and portfolio. In the case of co-located renewable generation, the cost of annual matching (and hourly matching) is lower because moving the procured resource portfolio from an area that is saturated with renewable deployment to a demand center boosts both revenues from energy sales as well as emissions impacts. However, constructing renewable projects close to a demand center is usually more expensive, and this analysis does not reflect those higher construction costs. The cost of annual matching with an all-wind portfolio is generally slightly cheaper than with an all-solar or mixed portfolio on a dollar per MWh basis.

Across all cases, there is a much larger range of different costs for hourly matching. The reasons driving the substantial range of potential costs also reveal certain underlying dynamics and economic challenges that utilities would face if pursuing alternative strategies for fulfilling an hourly matching mandate. The detailed volume and cost components for the base case across the five matching strategies are summarized in Table 4 below. The specific factors affecting net costs of alternative hourly matching approaches (Cases 3-5) include:

- **Hourly Matching with Renewables + 4-Hour Battery (Case 3):** A portfolio of wind, solar, and 4-hour battery can achieve around 87% hourly matching at a cost of $76/MWh in the base case. In this scenario, we do not enforce 100% hourly matching; instead, we simply operate the battery to maximize hourly matching and observe what level of hourly matching is achieved. The incremental cost above the annual matching cost of around $43/MWh in the base case largely reflects the additional investment cost of building the additional battery. This incremental cost is slightly higher for an all-solar system, as the cost per MWh of energy is generally higher for solar than for wind or a mixed system. While this strategy only results in a moderate increase in matching cost, it also only achieves an additional 13% hourly matching relative to an annually matched, 50-50 wind and solar system without a battery. As we will describe, achieving 100% hourly matching solely with owned renewable and battery resources will require much higher incremental costs.

- **100% Hourly Matching with Renewables + Battery (Case 4):** 100% hourly matching with owned resources is the most expensive, at \$320/MWh, or about \$260/MWh more expensive than annual matching in the base case. A moderately sized battery in Case 3 contributes an about 13% increase in hourly matching score at an already substantial cost, but imposing a 100% hourly matching requirement, a 26% increase over what would be achieved by the annually matched system, incurs nearly ten times the matching cost as the annually matched system in this case. To achieve 100% hourly matching in an isolated system such as the one modeled, the battery needs to be oversized to compensate for multi-day stretches of low renewable generation. In fact, the modeled cost of matching for a wind-only system is the highest of all the sensitivity cases because of a month-long lull in wind generation in 2024 that the battery is forced to compensate for. In reality, the extra cost of using the battery to meet an hourly energy matching requirement is not warranted by the additional volume of GHG emissions reduction and does not improve system-wide reliability. Indeed, it would be better to operate the battery in response to MISO dispatch and reliability needs. If the goal is to build and operate batteries to avoid emissions, then that goal should be reflected in policy by imposing a $\$/tCO_2e$ cost, instead of using hourly matching as an intermediary mechanism. Given the high costs, utilities may be better off pursuing alternative measures to reduce GHG emissions before committing to 100% hourly matching. The last 10-15% emissions reduction needed to achieve net zero can be achieved more cost-effectively through decarbonization measures such as energy efficiency and load flexibility. It is important to note that while these results indicate that pursuing hourly matching with a wind, solar, and storage portfolio is considerably more expensive than achieving annual matching using only wind and solar, in practice, more renewable-plus-storage projects are being developed, reflecting their economic advantages over standalone wind or solar deployment. The higher costs observed in this analysis result from optimizing the battery system for maximum hourly matching rather than for revenue generation or emissions reduction. In addition, batteries are often deployed to mitigate or avoid costly interconnection expenses associated with infrastructure upgrades, and these costs are not accounted for in this analysis.
- **100% Hourly Matching with Time-Stamped RECs (Case 5):** Achieving 100% hourly matching at lower costs is possible by partially or fully relying on time-stamped RECs purchased from

the market. Our analysis indicates that 100% hourly matching with RECs is around $65/MWh, or $32/MWh more expensive than annual matching, similar to what others have previously reported.[43] However, REC prices would be influenced by market liquidity. If only a few buyers were to participate in the hourly REC market, prices would likely be low. If a large number of buyers competed for time-stamped RECs, prices could surge during scarcity hours. At the same time, in that scenario, market forces would likely drive investment in additional resources to increase REC supply. We do not capture these market dynamics in our analysis.

We caveat these findings with the broad statement that the findings are indicative, and the values we estimate would vary substantially with different modeling parameters or if conducted on a forward-looking rather than backward-looking basis. For these reasons, the results should be understood to provide a meaningful description and comparison of the differences in costs between annual and hourly matching variations under a common set of study assumptions, but should not be interpreted as a prediction of the absolute value of alternative strategies under future market conditions.

[43] The Princeton study reports similar finding, where the cost premium of hourly energy matching in California where RECs can be traded is about $27-40/MWh, depending on how much of the market participates in hourly matching.

TABLE 4: DETAILED COST AND EMISSIONS RESULTS FOR ANNUAL AND HOURLY MATCHING

		No Matching	Annual Matching	Hourly Matching with 4-Hour Battery	100% Hourly Matching with Battery	100% Hourly Matching with Time-Stamped RECs
Market Prices on a Cost to Utility Basis						
Cost of Energy at Load	*($/MWh)*	$26.92	$26.92	$26.92	$26.92	$26.92
Cost of Solar	*($/MWh)*	$0	$15.45	$18.26	$30.91	$15.45
Cost of Wind	*($/MWh)*	$0	$18.82	$22.24	$37.64	$18.82
Cost of Curtailment	*($/MWh)*	$0	$0	$3.02	$8.24	$1.04
Cost of Battery	*($/MWh)*	$0	$0	$39.91	$232.16	$0
Cost of RECs	*($/MWh)*	$0	$0	$0	$0	$38.76
Revenues from Generation	*($/MWh)*	$0	$0.71	$4.40	$10.27	$2.14
Revenues from Battery Discharge	*($/MWh)*	$0	$0	$2.84	$5.51	$0
Revenue from RECs	*($/MWh)*	$0	$0	$0	$0	$7
Procurement Volumes						
Total Load	*(MWh)*	5,438	5,438	5,438	5,438	5,438
Total RECs Procured	*(MWh)*	0	0	0	0	1,397
Total Solar Generation	*(MWh)*	0	1,534	1,813	3,069	1,534
Total Wind Generation	*(MWh)*	0	3,904	4,613	7,808	3,904
Uncurtailed Solar Generation	*(MWh)*	0	1,534	1,680	2,746	1,485
Uncurtailed Wind Generation	*(MWh)*	0	3,904	4,149	6,501	3,747
Total Renewable Curtailment	*(MWh)*	0	0	597	1,630	207
Total Battery Charge	*(MWh)*	0	0	581	835	0
Total Battery Discharge	*(MWh)*	0	0	491	707	0
Total RECs Sold	*(MWh)*	0	0	0	0	1,190
All-In Costs						
Total Cost per MWh Demand	*($/MWh)*	$26.92	$60.49	$103.10	$320.09	$92.14
Incremental Cost Relative to No Matching	*($/MWh)*	NA	**$33.57**	**$76.18**	**$293.17**	**$65.22**
Emissions Impact						
Total Load Hourly Matched	*(MWh)*	0	4,042	4,753	5,437	5,438
% Annual Matching	*(%)*	0	100%	107%	170%	122%
% Hourly Matching	*(%)*	0	74%	87%	100%	100%
Emissions Avoided from Generation	*(tonne)*	0	2,103	2,285	3,691	2,045
Emissions Avoided per Unit Generation	*(tonne/MWh*	0	0.39	0.39	0.40	0.31
Cost per Tonne Abated	*($/tonne)*	NA	**$86.80**	**$181.30**	**$432.01**	**$173.47**

VI. Developments in GHG Emissions Tracking in Other States and RTO Markets

The complexity of real-time power grid operations is an ever-increasing challenge that utilities and policymakers will have to manage throughout clean energy transition. Tracking and managing these realities at all timeframes will become increasingly critical, considering timeframes down to 5-minute dispatch intervals and considering transmission limitations at the nodal level. However, hourly matching is not an effective means to measure or manage these challenges. The central problem with hourly matching is that it measures the wrong thing. There is no inherent reliability, cost, or GHG abatement value that is measured or managed by hourly matching, so there is no reason to anticipate that it would perform better than annual matching on any of these dimensions of performance. In fact, hourly matching is inherently worse than annual matching, to the extent that it would induce decisions and operations that run contrary to the economic and reliability signals issued via RTO market dispatch.

Annual matching by itself also does not inherently encapsulate or advance all of these policy objectives, but it has the substantial advantage of being simpler and more flexible than hourly matching. That flexibility afforded by annual matching means that utilities have the ability to pursue additional clean energy in ways that minimize their net cost of supply. Minimizing net supply costs in the context of a broad regional marketplace also has the indirect benefits of: (a) maximizing the resource portfolio's reliability value (by maximizing economic value relative to peak energy prices, ancillary service value, and capacity accreditations); (b) managing around and avoiding transmission limits (by incorporating anticipated nodal prices in siting decisions and assessing the economics of co-located storage to address curtailment risks and costs); and (c) to a lesser extent, improving decarbonization performance, to the extent that nodal prices are correlated with emissions abatement value.

It is on this last point regarding decarbonization value where we observe an informational and signaling gap in current RTO market structures, since the value that Minnesota, other states, and many other customers place on avoiding emissions is not internalized in market prices. However, as states and customers more prominently raise this concern, MISO and other US RTOs are beginning to fill that gap with more extensive and valuable data on GHG emissions. The RTOs are the natural entity to provide this information, considering that only the RTO has the comprehensive grid data needed to provide transparency into GHG emissions in a broad regional marketplace that spans many states and utility areas.

Over the coming years, we anticipate there will be increasing opportunities for utilities, customers, the MN PUC and other state policymakers to leverage ongoing advancements in GHG measurement and accounting by MISO to inform policy and resource decisions. The MN PUC is also well-positioned to clarify and articulate to MISO its priorities for what GHG data are most needed and on what timeframe, considering that MISO has already signalled its intent to substantially expand its support for issuing GHG data and considering its track record of incorporating the priorities of other states such as Illinois into its GHG data support plan.[44]

These efforts can offer a more accurate and timely means of assessing emissions, allowing for a state-wide and system-wide perspective rather than focusing solely on the net production or consumption of an individual entity in a given hour. Below is a snapshot of what RTOs across the country are doing to enhance the breadth, granularity, and timeliness of GHG emissions data, which demonstrates the scope of GHG and clean energy tracking and support needs may be available:

- **MISO**: Provides a publicly available dashboard that can be used to review hourly average emissions (generation-based total and average emissions) for the entire RTO.[45] MISO also provides 5-minute, system-wide marginal and average emissions rates data on a near-real-time basis.[46] The RTO is in the process of developing more locationally granular data support including nodal, 5-minute marginal emissions rates and nodally-traced average emissions rates.[47]
- **PJM Interconnection (PJM)**: Publishes marginal GHG emissions rates, with 5-minute, nodal-level granularity, aligned with the real-time energy markets.[48] Policymakers in Illinois, District of Columbia, and New Jersey are beginning to leverage these data to shape policies and incentive structures, including optimizing renewable energy and transmission investments, incentivizing batteries for optimal operations, and assessing GHG benefits of electric vehicles charging.[49]

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44 Illinois Commerce Commission, Renewable Energy Access Plan, Section V.B.1, May 30, 2024.

45 MISO, MISO Grid Emissions Map, accessed March 2025.

46 Ibid.

47 MISO, MISO's Emissions Estimates Initiative, July 2024. The GHG "flow tracing" approach that MISO will use to calculate nodal, 5-minute GHG emissions rates is the node-specific consumption-based average emissions rates (i.e., for granular Scope 2, location-based accounting. The flow-tracing approach tracks GHGs produced by fossil plants at each generator node where injected to the power system, and tracks GHG emissions across each transmission element before depositing the emissions in proportion to physical withdrawals.

48 PJM, Five Minute Marginal Emission Rates, accessed March 10, 2025.

49 Illinois Commerce Commission, Renewable Energy Access Plan, Section V.B.1; New Jersey Board of Public Utilities, Storage Incentive Program; and Public Service Commission of the District of Columbia, Strategic Electrification Roadmap.

- **Independent System Operator of New England (ISO-NE)**: Publishes marginal and average system-wide emissions rates, which are aggregated at various timescales (annual, monthly, on/off peak).[50] Currently, each New England state uses the same REC tracking system, New England Power Pool Generation Information System (NEPOOL-GIS), to track resource attributes but each determines its own methodology for calculating the residual grid mix relevant for tracking progress toward state compliance goals.[51]
- **New York Independent System Operator (NYISO) New York**: Provides consumption-based average emissions rates for two areas within the state.[52] NYISO also provides implied day-ahead and real-time marginal emissions rates for all energy market zones.
- **Southwest Power Pool (SPP)**: As part of its Market+ initiative (with a market targeted go-live date in 2027), SPP will include in its market a mechanism to integrate GHG-pricing adders into seller offer prices and assign the MW of generation associated with imports to states with GHG pricing or cap-and-trade programs.[53] In addition, SPP is developing a "GHG Tracking and Reporting Program", which will offer comprehensive resource tracking and attributional GHG accounting mechanisms to support reporting entities in meeting their GHG emissions obligations. These reports will be tabulated from hourly system-wide market and operations data. GHG reports will allow utilities to claim their self-supply (owned or contracted) resources; will assign GHG emissions associated with any net supply or sales to other entities; and will account for any net RTO market purchases at the residual grid mix rate.
- **California ISO**: The CAISO has for a decade published an emissions dashboard on the current GHG emissions intensity of generation serving the CAISO Balancing Authority Area (BAA), as a function of California's GHG Cap and Trade program history. The dashboard reports current and historical emissions within the state of California and imports from the Western Energy Imbalance Market, including total emissions, average emissions rate, and emissions by resource type. [54] CAISO also publishes an hourly, monthly, and annual data and reports covering California emissions.[55] The CAISO recently started publishing an average emissions rate report which covers the WEIM footprint and provides the emissions intensity

[50] ISO-NE, Environmental and Emissions Reports, 2025.

[51] State policymakers recognize the challenges posed by inconsistent GHG measurement and allocation approaches and the benefits that would be shared from a commonly accepted approach. For example, see Rhode Island Commissioner Dr. Abigail Anthony, "Bigger meals require better receipts: A call for coordinated greenhouse gas emissions tracking," *Utility Dive*, July 12, 2023.

[52] NYISO, Day-Ahead and Real-Time Implied Marginal Emission Rates (IMER), accessed March 2025.

[53] SPP, Market+ GHG Task Force, 2025.

[54] CAISO, Today's Outlook "Emissions", accessed March 2025.

[55] CAISO, Greenhouse gas emissions tracking reports.

of WEIM transfers into California.[56] The CAISO also publishes GHG shadow prices and the GHG component of nodal power prices for each market interval.[57] The CAISO is currently undertaking efforts within its GHG Coordination Working Group to expand its support for states and members pursuing decarbonization goals, including a GHG reporting program (similar to what SPP Markets+ has proposed) and the potential to expand in-market dispatch support for states with GHG policy goals.[58]

As MISO and Minnesota advance toward higher clean energy integration and deeper decarbonization, developments in other markets may offer valuable insights and strategies worth considering. Indeed, more system operators offering increasingly granular GHG accounting data in response to growing demand from policymakers and customers. Even though hourly clean energy procurement requirements may be too restrictive and can inadvertently lead to counter-productive results, we anticipate greater temporal and locational granularity will be needed for more accurate GHG accounting and reporting. The importance and relevance of more accurate and granular GHG accounting will grow, as standard-setting bodies refine criteria for high-quality Scope 2 reporting. Accurate GHG accounting will also be needed to highlight the challenges presented by deep decarbonization and offer insights into the how policymakers and utilities to pursue decarbonization reliably and at the lowest cost to consumers.

[56] CAISO, WEIM average emissions rate report.

[57] CAISO, Nodal market prices and GHG shadow pricing data from OASIS, accessed March 2025.

[58] CAISO, California ISO - Greenhouse gas coordination working group; CAISO, *Greenhouse Gas Coordination: Discussion Paper: Recommendations for Policy Development.* September 16, 2024; and CAISO Accounting and Reporting Issue Paper – GHG Coordination, December 20, 2024.

VII. Certification

We hereby certify that we have read the filing signed and know its contents are true as stated to the best of our knowledge and belief. We possess full power and authority to sign this filing.

Respectfully Submitted,

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March 19, 2025