April 16, 2025

Will Seuffert
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: Comments of the Minnesota Department of Commerce
Docket No. E-999/CI-23-151

Dear Mr. Seuffert:

Attached are the supplemental comments of the Minnesota Department of Commerce (Department) in the following matter:

> In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon Free Standard under Minn. Stat. § 216B.1691

The Investigation was initiated by the Minnesota Public Utilities Commission (Commission) on April 28, 2023.

The Department recommends **annual compliance matching, hourly matching analysis in integrated resource plans, a geographic preference, and energy attribute certificate requirements for all compliance claims,** and is available to answer any questions the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ Dr. SYDNIE LIEB
Assistant Commissioner of Regulatory Analysis

SL/AZ/ad
Attachment

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Acronyms and Abbreviations

AEC	alternative energy certificate
AMI	advanced metering infrastructure
CCS	carbon capture and sequestration
CFA	carbon-free allocator
CFS	Carbon-free Standard
DLOL	Direct Loss of Load
DSES	Distributed Solar Energy Standard
EAC	energy attribute certificate
EETS	Eligible Energy Technology Standard
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
LRR	Local Reliability Requirement
LMP	locational marginal price
LCFS	Low Carbon Fuel Standard
MISO	Midcontinent Independent System Operator
M-RETS	Midwest Renewable Energy Tracking Systems
PPA	power purchase agreement
REC	renewable energy certificate
RES	Renewable Energy Standard
SES	Solar Energy Standard

COMMERCE DEPARTMENT

Before the Minnesota Public Utilities Commission

Supplemental Comments of the Minnesota Department of Commerce

Docket No. E-999/CI-23-151

I. INTRODUCTION

The Minnesota Legislature created the carbon-free standard (CFS) with the passage of H.F. 7, which requires Minnesota electric utilities to reach 100% carbon-free electricity by 2040 and tasks the Minnesota Public Utilities Commission (Commission) with the implementation of the standard. The Commission laid out a series of proceedings to implement the standard in its July 7, 2023 *Notice of Docket Process and Timeline*,[1] and the current proceeding is the third round, which focuses on CFS compliance.[2]

In these supplemental comments, the Department provides further analysis of the four-year environmental attribute certificate (EAC) shelf-life, hourly matching, geographic preference, and net market purchases.

II. PROCEDURAL BACKGROUND

The following procedural history outlines relevant Commission action to the current proceeding.

March 19, 2010	The Commission issues its *Order Clarifying Criteria and Standards for Determining Compliance Under Minn. Stat. § 216B.1691* in Docket No. E-999/CI-03-389.[3]
July 7, 2023	The Minnesota Legislature signs H.F. 7 into law, which created the CFS and amended Minn. Stat. § 216B.1691 to increase the Renewable Energy Standard (RES), also known as the Eligible Energy Technology Standard (EETS), to 55 percent by 2035.[4]
July 7, 2023	Commission issues its *Notice of Docket Process and Timeline* which set comment period dates for changes to RES and Solar Energy Standard (SES; Round 1), new and amended terms (Round 2), CFS compliance (Round 3), and the off ramp process (Round 4).[5]

[1] *Notice of Docket Process and Timeline*, July 7, 2023, (eDockets) 20237-197301-01 at 2, (hereinafter "Notice of Docket Process and Timeline").
[2] , *Notice of Comment Period and Updated Timeline*, October 31, 2024, (eDockets) 202410-211486-01, (hereinafter "Notice").
[3] *In the Matter of Detailing Criteria and Standards Measuring an Electric Utility's Good Faith Efforts in Meeting the Renewable Energy Objectives Under Minn. Stat. 216B. 169, Order Clarifying Criteria and Standards for Determining Compliance Under Minn. Stat. § 216B.1691*, March 19, 2010, Docket No. E-999/CI-03-869, (eDockets) 20103-48177-01, (hereinafter "March 19, 2020 Order").
[4] *See* H.F. 7.
[5] Notice of Docket Process and Timeline.

December 6, 2023	The Commission issues its order for Round 1 of comments. The Commission orders that a hydroelectric facility greater than 100 MW and built before February 8, 2023 qualifies for compliance with the RES. The Commission also states that renewable energy certificates (RECs) are eligible for use in the year of generation and for four years following the year of generation.[6]
April 12, 2024	The Commission issues its order for Round 1.5 of comments.[7]
June 28, 2024	The Department submits its comments for Round 2.[8]
October 31, 2024	The Commission issues its Notice of Comment for the current proceeding.
November 7, 2024	The Commission issues its *Order Initiating New Docket and Clarifying "Environmental Justice Area"* which created the Docket No. E-999/CI-24-352 to further record development on partial compliance and the application of fuel life-cycle analysis.[9]
January 29, 2025	The Department files its initial comments in the current proceeding.[10]
March 19, 2025	The Department files its reply comments in the current proceeding.[11]

Topics open for comment:

- When and how should utilities report preparedness for meeting upcoming CFS requirements?
- By which criteria and standards should the Commission measure an electric utility's compliance with the CFS?
- What considerations should the Commission take into account regarding the double counting of Renewable Energy Credits (RECs) to meet multiple requirements?
- How should net market purchases be counted towards CFS compliance?
- Are there other issues or concerns related to this matter?

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[6] *Order Clarifying Implementation of Changes to Minn. Stat. § 216B.1691 and Directing Additional Comment Period*, December 6, 2023, Docket No. E-999/CI-23-151, (eDockets) 202312-201019-01, Order Point 6, at 9, ("hereinafter December 6, 2023 Order").
[7] *Order Clarifying Implementation of Changes to Minn. Stat. § 216B.1691*, April 12, 2024, Docket No. E-999/CI-23-151, (eDockets) 20244-205306-01, (hereinafter "April 12, 2024 Order").
[8] Minnesota Department of Commerce, Comments, June 28, 2024, (eDockets) 20246-208098-01, (hereinafter "Department June 28, 2024 Comments").
[9] *Order Initiating New Docket And Clarifying "Environmental Justice Area,"* November 7, 2024, Docket Nos. E999/CI-23-151 and E-999/CI-24-352, (eDockets) 202411-211701-01, (hereinafter "November 7, 2024 Order").
[10] Minnesota Department of Commerce, Initial Comments, January 19, 2025, (eDockets) 20251-214567-01, (hereinafter "Department Initial Comments").
[11] Minnesota Department of Commerce, Reply Comments, March 19, 2025, (eDockets) 20253-216562-01, (hereinafter "Department Reply Comments").

The Minnesota Department of Commerce (Department) submits its reply comments in the context of multiple related proceedings, including the newly created Docket No. E-999/CI-24-352,[12] which has implications for how partial compliance and market purchases are measured and reported for CFS compliance. In addition, the fourth round of comments in the current docket concerns the "Off Ramp Process," which will discuss modifications to the Commission's March 19, 2010 Order in Docket No. E999/CI-03-869.[13] The Commission's March 19, 2010 Order also includes criteria and standards related to measurement and achievement,[14] which makes it difficult to separate relevant topics open for comment in each proceeding. The Department addresses overlaps with other proceedings, and describes these concerns in relevant areas of Section III.

III. DEPARTMENT ANALYSIS

A. WHEN AND HOW SHOULD UTILITIES REPORT PREPAREDNESS FOR MEETING UPCOMING CFS REQUIREMENTS?

The Department has no additional comments on this notice topic.

B. BY WHICH CRITERIA AND STANDARDS SHOULD THE COMMISSION MEASURE AN ELECTRIC UTILITY'S COMPLIANCE WITH THE CFS?

B.1. Criteria and Standards for the Measurement of CFS Compliance

B.1.1. Four Year Shelf Life Recission

B.1.1.1 Recission of 4-Year Shelf-Life Legal Arguments

In its Initial Comments, the Department recommended:

> The Department recommends that the Commission rescind its order points 1 and 3 from its December 18, 2007 Order in Docket Nos. E-999/CI-04-1616 and E999/CI-03-869 and modify order point 6 of the Commission's December 6, 2023 Order in Docket E-999/CI-23-151 to remove "All renewable energy credits generated from such facilities will be eligible for use in the year of generation and for four years following the year of generation." These orders will be rescinded/modified effective January 1, 2030.[15]

[12] *See* November 7, 2024 Order, at Order Point 1.
[13] Notice of Docket Process and Timeline at 2.
[14] *See* Section I. Issues 1, 2, and 4 and Order Points 1, 2, and 7-10, March 19, 2020 Order at 3 and 11-12.
[15] Department Initial Comments at 11.

Several commenters raise legal concerns with the Department's recommendation to end the four-year shelf-life for RECs. Basin Electric states:

> First, the Department requests the Commission rescind its December 18, 2007 Order establishing a four-year shelf-life for RECs. This request 17 years later does not meet the Commission's standard for reconsideration under Minn. Stat. § 216B.27 and Minn. R. 7829.3000 nor is it grounded in good public policy.[16] [citations omitted]

The Northern States Power Company, dba Xcel Energy (Xcel)[17] and Great River Energy (GRE)[18] similarly echo the deviation from established precedent.

Central Municipal Power Agency/Services (CMPAS) makes a procedural argument. CMPAS states:

> The full text of MPUC's Order Point 6 indicates it applies to the Renewable Energy Standard (now the "EETS"). This order point does not mention the CFS. The Department's recommendation is outside the scope of this docket, which is limited to CFS compliance, and should be rejected.
>
> Moreover, the use of renewable energy credits for RES (EETS) compliance was already decided by the Commission in this very same docket. As such, the Department's request to change an order point related to RES compliance in a comment intended to address CFS compliance is contradictory and confusing for utilities who are seeking clarification on how to comply with the new legislative standards.[19] [citation omitted]

The language used in the Commission's December 18, 2007 order suggests that its shelf-life decision was not intended to be permanent. The order was issued to establish "initial" protocols for trading RECs. In addressing the shelf life of RECs, the order outlines the different shelf-life proposals submitted by the parties then states: "The Commission considers a four-year shelf life, added to the year of generation, *as a good place to start this process*."[20] (Emphasis added.) And in rejecting the utilities' recommendation for an indefinite shelf life, the Commission stated that it, "at present does not believe

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[16] Basin Electric Power Cooperative, Reply Comments, March 19, 2025, (eDockets) 20253-216605-01 at 2, (hereinafter "Basin Electric Reply Comments).

[17] Northern States Power Company, dba Xcel Energy, Reply Comments, March 19, 2025, (eDockets) 20253-216596-01, at 11, (hereinafter "Xcel Reply Comments").

[18] Great River Energy, Reply Comments, March 19, 2025, (eDockets) 20253-216616-01, at 19, (hereinafter "GRE Reply Comments").

[19] Central Municipal Power Agency/Services, Initial Comments, March 19, 2025, (eDockets) 20253-216602-01 at 9, (hereinafter "CMPAS Reply Comments").

[20] *In the Matter of a Commission Investigation into a Multi-State Tracking and Trading System for Renewable Energy Credits and In the Matter of Detailing Criteria and Standards for Measuring an Electric Utility's Good Faith Efforts in Meeting the Renewable Energy Objectives Under Minn. Stat. §216B.1691, Order Establishing Initial Protocols for Trading Renewable Credits*, December 18, 2007, Docket Nos. E-999/CI-04-1616 and E999/CI-03-869, (eDockets) 4872137.

that to be an advisable course" and would "not at this juncture" adopt such a recommendation.[21] Note that the December 18, 2007 order was the second of three orders issued by the Commission in Docket Nos. E-999/CI-04-1616 and E999/CI-03-869 to satisfy its statutory obligation to establish a program and protocols for trading RECs. The third order—which established procedures for retiring RECs—concluded by stating that the procedures would be "subject to modification in the light of future experience in implementing the Minnesota renewable energy objective and standards."[22]

The deadlines cited by Basin Electric in Minn. Stat. § 216B.27 and Minn. R. 7829.3000 are for requests to reconsider decisions when a party believes the decision was wrong at the time it was made. The Department does not suggest that the four-year shelf life has been inappropriate since its adoption. Rather, the Department contends that the duration of the shelf life should be reconsidered in light of the fact that this is no longer the start of the renewable-energy-standard process. When the Commission ordered the four-year shelf life in 2007, both Minnesota's and national renewable-energy standards were a fraction of what they are now, and the Commission and parties had comparatively little experience in implementing those standards. As explained in greater detail below, technological developments and our increased understanding of and experience with renewable energy warrants reconsidering the shelf-life duration to ensure the protocols and standards for banking credits and best suited to implementing and achieving the State's carbon-free standard.

B.1.1.2 Recission of 4-Year Shelf-Life—Other Arguments

In its Reply Comments, GRE states:

> If the Commission eliminates the ability for utilities to bank RECs/AECs beyond the current year of generation, it could have significant consequences for utility compliance with both the Minnesota RES and the CFS. For almost two decades, utilities have relied on a year-of-generation plus four-year REC banking construct to strategically manage RECs by balancing years and periods of high renewable generation with future compliance obligations. Removing this flexibility would be tantamount to a regulatory rug pull - removing well-established compliance strategies that utilities have been planning around, and potentially incurring tens of millions of dollars in lost value by rendering previously banked RECs worthless. This cost to consumers in the loss of existing assets and value and the future cost of lost flexibility could be significant. This is not to mention the market impacts of the forced liquidation of existing assets,

[21] *Id.*
[22] *In the Matter of a Commission Investigation into a Multi-State Tracking and Trading System for Renewable Energy Credits and In the Matter of Detailing Criteria and Standards for Measuring an Electric Utility's Good Faith Efforts in Meeting the Renewable Energy Objectives Under Minn. Stat. §216B.1691, Minnesota Public Utilities Commission, Third Order Detailing Criteria and Standards for Determining Compliance Under Minn. Stat. §216B.1691 and Setting Procedures for Retiring Renewable Energy Credits*, December 14, 2008, Docket Nos. E-999/CI-04-1616 and E999/CI-03-869, (eDockets) 5659148.

> and the loss of market power by utilities attempting to divest currently held RECs, which the market and counterparties would understand to be worthless in the future to the utilities, who would lose nearly all negotiating position.[23]

Xcel states that the Department does not justify why it recommends a recission of the four-year shelf-life.[24]

The rationale to eliminate the four-year shelf-life is simple. Seventeen years ago, the renewable energy industry was in its infancy, and faced significantly greater uncertainty in expected generation for a number of reasons, including novel technology and potential equipment failures, inexperience with the operation and maintenance of equipment, and limited modeling capabilities. The novelty of renewable generation warranted, at that time, increased flexibility to meet state renewable energy goals. All of these conditions have now been ameliorated, and while weather uncertainty still exists, the challenges of variable renewables can be appropriately planned. Given the significant change in the availability of renewable energy generation and the maturity of these technologies, it would be absurd to maintain the same shelf life of RECs in 2025 as was originally adopted in 2007.

The recission of the four-year shelf-life is a first step towards more granular time constraints on renewable energy generation, which requires utilities to better match generation to load. As the Department stated in its Initial Comments,[25] matching generation to load offers lower market price exposure for ratepayers, which is disincentivized by the significant non-temporal allowance of the four-year shelf-life. The Carbon Solutions Group (CSG) formally supports the Department's recommendation to better match generation to load.[26]

GRE's criticism of the four-year shelf-life decision is a misleading characterization of the Department's position. GRE's Reply Comments appear to indicate that the four-year shelf-life will be rescinded upon the Commission's decision in the current proceeding, which is not the Department's recommendation. In fact, GRE has years to plan the acquisition or sale of its EACs before the compliance year 2030 begins, which should not result in forced liquidations or reduced market power unless GRE waits until 2030 to sell any excess generated EACs. However, GRE's comments mask a different reality than the utility currently faces. In GRE's most recent integrated resource plan (IRP), the Department stated: "[d]ata provided by GRE in response to Information Request No. 3 shows that without market purchases and RECs, GRE falls short of the 60 percent standard by 1.2 percent in 2030. Also, GRE falls short by over 11 percent between 2035 and 2037, when the standard increases to 90 percent."[27] As

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[23] GRE Reply Comments at 12.
[24] Xcel Reply Comments at 11.
[25] Department Initial Comments at 10.
[26] Carbon Solutions Group, LLC, Reply Comments, March 19, 2025, (eDockets) 20253-216369-01 at 25, (hereinafter "CSG Reply Comments").
[27] *In the Matter of Great River Energy's 2023–2037 Integrated Resource Plan*, Minnesota Department of Commerce, Comments, August 8, 2023, Docket No. ET-2/RP-22-75, (eDockets) 20238-198066-01 at 46.

the Department discusses in Section III.D, net market purchases cannot be relied upon for CFS compliance, but GRE can meet its compliance requirement with unbundled EAC retirements. While GRE added a 300 MW wind procurement to its updated plan,[28] this procurement is not expected to close the 11 percent compliance gap in 2035. In order to reach its 2035 compliance goal, GRE requests to rely on older vintage EACs ahead of its 90 percent CFS compliance goal in 2035. The result is that in real time, GRE, without further actions to close its generation gap or additional unbundled EAC purchases, will not physically retire enough EACs to meet 90 percent of its load in 2035. Effectively, reliance on older vintage EACs delays GRE's CFS compliance in real-time power flows. The Department does not support this outcome.

The Department understands the goal of renewable portfolio standards and the CFS is to accelerate investment in renewable and carbon free resources. This goal is not achieved through compliance with unbundled EACs. The generation gap highlighted above should incentivize GRE to engage in more robust generation and transmission planning to meet the compliance goals of the CFS on time. For these reasons, the Department is not persuaded to change its position.

B.1.1.3 Final Recommendation

The Reply Comments submitted by the CSG highlight one omission in the Department's recommendation:

> While far less granular, and thus credible, than hourly matching, 1-year banking ensures that the cycle of carbon-free generation and procurement is occurring anew year-over-year. This means that carbon-free claims in 2030 will be closer to the reality of 2030 carbon-free generation and procurement, rather than 2030 CFS compliance reports potentially representing a 5-year-lag in carbon-free investment, development, generation, and delivery to Minnesotans.[29]

The Department's recommendation is silent on any banking period after the recission of the Commission's orders. The Department agrees with the CSG, and recommends a one-year banking for EACs to replace the four-year EAC banking period that is currently practiced. The Department withdraws its previous recommendation, and makes a new recommendation:

The Department recommends that the Commission modify order points 1 and 3 from its December 18, 2007 Order in Docket Nos. E-999/CI-04-1616 and E999/CI-03-869 and modify order point 6 of the Commission's December 6, 2023 Order in Docket E-999/CI- 23-151 to remove "All renewable energy credits generated from such facilities will be eligible for use in the year of generation and for four

[28] *In the Matter of Great River Energy's 2023–2037 Integrated Resource Plan*, Great River Energy, Reply Comments, October 2, 2023, Docket No. ET-2/RP-22-75, (eDockets) 202310-199331-01 at 3.
[29] CSG Reply Comments at 25.

years following the year of generation," and replace the language with "All renewable energy credits generated from such facilities will be eligible for use in the year of generation and for one year following the year of generation." These orders will be modified effective January 1, 2030.[30]

B.1.2. Hourly Matching

In its Initial Comments, the Department recommended:

> The Department recommends the Commission order the following total retail electric sales matching requirements for electric utilities by the end of the year indicated:
>
> - 2030: Annual matching of 80 percent for public utilities; 60 percent for other electric utilities
> - 2035: Hourly matching of 80 percent for public utilities; 60 percent for other electric utilities
> - 2040: Hourly matching of 90 percent for all electric utilities
> - 2045: Hourly matching of 100 percent for all electric utilities.[31]

The Department's recommendation for hourly matching produced a lively debate from nearly all commenters. The Department notes hourly matching support from the Center for Environmental Advocacy (MCEA) and the Sierra Club,[32] and the Center for Resource Solutions (CRS).[33] The Department notes dissent from the GRE, Rochester Public Utilities, Connexus Energy, CMPAS, Missouri River Energy Services (MRES), Minnkota Power Cooperative, Basin Electric, Minnesota Municipal Utilities Association, Minnesota Municipal Power Agency, East River Electric, Minnesota Rural Electric Association, Otter Tail Power Company (OTP), Xcel Energy, Sothern Minnesota Municipal Power Agency, and ALLETE Minnesota Power (collectively, the "Aligned Utilities").[34] Additional parties in dissent outside of the Aligned Utilities include Laborers' International Union of North America

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[30] Department Initial Comments at 11.
[31] *Id*.
[32] The Minnesota Center for Environmental Advocacy, the Sierra Club, and Fresh Energy, Reply Comments, March 19, 2025, (eDockets) 20253-216592-01 at 1.
[33] CSG Reply Comments at 17.
[34] Great River Energy, Rochester Public Utilities, Connexus Energy, Central Municipal Power Agency/Services, Missouri River Energy Services, Minnkota Power Cooperative, Basin Electric Power Cooperative, Minnesota Municipal Utilities Association, Minnesota Municipal Power Agency, East River Electric, Minnesota Rural Electric Association, Otter Tail Power Company, Xcel Energy, Sothern Minnesota Municipal Power Agency, and ALLETE Minnesota Power, Reply Comments, March 19, 2025, (eDockets) 20253-216574-01 at 1, (hereinafter "Aligned Utilities Reply Comments").

Minnesota and North Dakota (LIUNA)[35] and the Operating Engineers Local 49 and North Central States Regional Council of Carpenters (IUOE 49 & NCSRCC) joint comments.[36]

In the below subsections, the Department addresses each of the concerns raised in dissent.

B.1.2.1 Hourly Matching Legal Arguments

The Aligned Utilities' Reply Comments legal criticism is the most pertinent of the legal issues raised. The Aligned Utilities state:

> Nothing in the applicable statute, Minn. Stat. § 216B.1691, suggests that the Legislature intended to fundamentally change compliance from an annual to an hourly basis. The Legislature had the opportunity to make such a change and chose not to. Any suggestion that the Legislature intended hourly accounting is not supported by the express statutory text or decades of precedent for determining RES compliance.
>
> Legislature had the opportunity to make such a change and chose not to. Any suggestion that the Legislature intended hourly accounting is not supported by the express statutory text or decades of precedent for determining RES compliance. The Department erroneously asserts that the Commission has broad authority under Minn. Stat. § 216B.1691, Subd. 2d(a) to require hourly matching for CFS compliance. That provision authorizes the Commission to issue necessary orders "detailing the criteria and standards" to measure compliance with the CFS, but it does not authorize the Commission to change the annual compliance approach established by the Legislature in favor of an hourly approach that the Legislature did not reference or allude to anywhere in the statute.[37] [citation omitted]

In this criticism, the Aligned Utilities reference annual compliance requirements in Minn. Stat. § 216B.1691, subd. 2a (the EETS),[38] Minn. Stat. § 216B.1691, subd. 2g (the CFS), and Minn. Stat. § 216B.1691, subd. 2d(b)(2)(i) and (ii) (the partial compliance clauses).

[35] Laborers' International Union of North America Minnesota and North Dakota, Reply Comments, March 19, 2023, (eDockets) 20253-216624-01 at 1, (hereinafter "LIUNA Reply Comments").
[36] Operating Engineers Local 49 and North Central States Regional Council of Carpenters, Reply Comments, March 19, 2023, (eDockets) 20253-216594-01 at 1, (hereinafter "IUOE 49 & NCSRCC Reply Comments").
[37] Aligned Utilities Reply Comments at 2-3.
[38] Also referred to as the Renewable Energy Standard (RES).

LIUNA[39] and IUOE 49 & NCSRCC[40] both support the Joint Utilities' assertion about statutory intent during CFS drafting negotiations. Xcel offers additional clarification about statutory intent and permissibility:

> We disagree with the Department's expansive interpretation. Applying Minnesota law for discerning legislative intent, the Department's proposed extension to hourly tracking is inconsistent with Legislative intent and improperly expands the authority granted to the Commission. Minnesota Statutes Section 645 legislates the framework to be used when interpreting statutory provisions. The Statute states: "[e]very law shall be construed, if possible, to give effect to all its provisions." Minnesota Supreme Court also confirms that it will "read a statute as a whole and give effect to all its provisions" and rejects arguments or interpretations that omit statutory language.[41] [citations omitted]

In addition, Connexus claims that the Commission is tasked only with the issuance of necessary orders:

> Minn. Stat. § 216B.1691 Subd. 2d. (a) states the following:
>
> The commission shall issue necessary orders detailing the criteria and standards used to: (1) measure an electric utility's efforts to meet the standards under subdivisions 2a, 2f, and 2g; and (2) determine whether the utility is achieving the standards.
>
> Statute here groups the three standard obligations together: 2a (Eligible Energy Technology Standard), 2f (Solar Energy Standard), and 2g (Carbon-Free Standard). This points to a common mechanism to measure efforts to meet all three standards. Annual matching of eligible generation to total retail electric sales at the corresponding percentage required for each year is already a valid compliance mechanism for EETS and SES, and there is no language in statute that could reasonably be interpreted to require a new compliance mechanism due to the passage of the CFS. Since hourly matching is not necessary for compliance, we urge the Commission to reject the Department's recommendation in this matter.[42]

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[39] LIUNA Reply Comments at 1-2.
[40] IUOE 49 & NCSRCC Reply Comments at 1-2.
[41] Xcel Reply Comments at 5.
[42] Connexus Energy, Reply Comments, March 19, 2025, (eDockets) 20253-216595-01 at 2, (hereinafter "Connexus Reply Comments).

CMPAS claims that hourly matching will treat EACs differently:

> An hourly matching requirement for CFS compliance will systematically make EACs from some types of carbon-free generation more valuable than others. Carbon-free energy that comes from more dispatchable resources, such as nuclear and reservoir hydro, etc, will become more economically valuable because it can be targeted to hours in which non-dispatchable carbon free energy, such as solar and wind, is in shortage and demand in an hourly EAC trading platform will be higher for these hours. Conversely, in hours when there is more solar and wind production than needed for matching an hourly load, the remaining EACs receive no credit and cannot be used for CFS compliance.
>
> The Department or other parties may counter that storage resources could be coupled with wind and solar resources to target their output for the more economically valuable hours, similar to dispatchable, clean firm generation. This strategy still gives less credit to solar and wind EACs because of energy losses involved with charging and discharging batteries, which still results in conflict with Minn. Stat § 216B.1691 Subd. 4(a).
>
> A CFS matching requirement that systematically provides more economic benefits to some types of EACs than others and reduces the amount of credit EACs from other technologies being counted is in direct conflict with Minn. Stat § 216B.1691 Subd. 4(a). Those utilities who don't have future access to the most "valuable" EACs – such as nuclear (which cannot currently be built in Minnesota) or hydrogen-fired generation (which would require a significant infrastructure update)– are at risk of having a more difficult path to compliance than other utilities.[43]

The Department disagrees that its recommendation for hourly matching is impermissible under the CFS statute. First, contrary to the assertion made by the Aligned Utilities and Xcel, the Department does not propose that compliance be determined on an hourly basis. Under the Department's recommendation, the total amount of electricity generated from a carbon-free technology that a utility must generate or procure will still be determined on an annual basis using a utility's total retail electric sales to retail customers in Minnesota for a given year, as required by Minn. Stat. § 216B.1691, subd. 2g. Thus, the amount of carbon-free electricity needed to satisfy the CFS will be determined in the same manner as has been done for the RES and EETS—by calculating the percentage identified in the relevant provisions of Minn. Stat. § 216B.1691 of a utility's total annual retail sales to retail customers in Minnesota. As the Aligned Utilities observe, hourly matching is method of "accounting," and the Department concludes that hourly matching is therefore an appropriate method to "measure an

[43] CMPAS Reply Comments at 7-8.

electric utility's efforts" to satisfy the CFS that may be implemented by the Commission in its order establishing the criteria and standards to be used for compliance.

The Department also notes that the adoption of the CFS was itself a dramatic and intentional evolution from the established renewable-energy standards. Prior to the adoption of the CFS, the EETS required each electric utility to generate or procure 25 percent of its total retail electric sales from an eligible energy technology by 2025, or 30 percent by 2020 for utilities that owned a nuclear generating facility as of January 1, 2007.[44] The decision to adopt the CFS and require 100 percent of electricity to be generated or procured from carbon-free technologies by 2040 plainly demonstrates the legislature's intent to take a progressive approach to accelerate its renewable-energy goals. The use of hourly matching to measure CFS compliance serves that purpose.

Additionally, the Department disagrees with Connexus' narrow interpretation of the authority granted to the Commission under Minn. Stat. § 216B.1691, 2d(a). The plain language of the statue permits the Commission to issue "orders detailing the criteria and standards" to be used to measure compliance, which on its face contemplates the Commission issuing multiple orders with multiple standards. As noted above, the adoption of the CFS marked an intentional increase in Minnesota's renewable-energy goals, and created a new focus on decarbonization. It is therefore necessary for the Commission to issue orders to implement that new standard focusing on decarbonization, and as the Department noted in its Initial Comments, hourly matching is an effective means to promote and achieve decarbonization.

Finally, the Department rejects CMPAS' argument that hourly matching will treat EACs differently based on the type of carbon-free generation. Pursuant to Minn. Stat. § 216B.1691, subd. 4(a), the program for trading renewable energy credits "must treat all eligible energy technology equally and shall not give more or less credit to energy based on […] the technology with which the energy was generated." An hourly matching construct would not give more or less credit based on the technology used; all technologies will receive an equal amount of credit based on the amount of energy generated, which is different from EAC retirement. The statute does not require that credits attributable to different technologies cost the same, or that there is purchaser for every available credit. Connexus' substantive arguments therefore fall outside the scope of what is required by Minn. Stat. § 216B.1691, subd. 4(a). Energy storage is not an Eligible Energy Technology, although hydrogen generated from Eligible Energy Technologies is an Eligible Energy Technology. Counter to CMPAS' claim, it is essential to only consider EAC equality at the time of generation—and not at retirement. For example, if 70 percent of the primary energy in hydrogen is lost, and hydrogen receives the full EACs retired to generate the hydrogen, effectively the hydrogen would be assigned approximately three EACs for only one EAC worth of generation, which would lead to an absurd result. CMPAS' claim of zero EACs for generation that is unclaimable is similarly refuted by existing practice. For example,

[44] Minn. Stat. § 216B.1691, subd. 2a(a)-(b) (2022).

Minnesota Power, in its current IRP, identifies that the utility was 50 percent renewable in 2020,[45] yet the EETS is only 25 percent, which means that half of all of Minnesota Power's EACs are ineligible for EETS compliance, and receive no credit under CMPAS' example. This practice has not been problematic to date, and there is no reason to suggest that hourly matching would trigger a new statutory compliance problem.

B.1.2.2 Hourly Matching Logistical Concerns

In its Reply Comments, CMPAS expressed a number of concerns about the logistics of hourly matching. First, CMPAS claims that the Department's recommendations would invalidate its contracts:

> CMPAS members have and continue to seek and enter into long-term PPAs for wind power, solar, hydro power, and nuclear power, as well as long term contracts for fixed amounts of MISO market energy and unbundled RECs. Many of these contracts have and will provide RECs or carbon-free energy that would be invalidated in 2030 by one or more of the Department's proposals. Invalidating purchases CMPAS is already obligated to make on behalf of its members penalizes CMPAS for having proactively made long-term carbon-free purchase commitments, forcing CMPAS members to purchase carbon-free energy twice - the annual RECs and carbon-free energy they are already contractually obligated to purchase in their long-term contracts and additional hourly EACs to comply with CFS.[46] [citations omitted]

Second, CMPAS claims that hourly matching would create carbon accounting problems:

> CMPAS does not believe that purchasing carbon-free energy twice is a good policy outcome for ratepayers. Given the detailed carbon accounting and residual mix examples provided by other stakeholders in Initial Comments, CMPAS also believes that the Department's recommendations are likely to result in inaccurate carbon accounting for the state of Minnesota as well as EETS and CFS compliance results that are not directly comparable since CMPAS will continue to use RECs from its long term contracts for EETS compliance regardless of whether they qualify for the CFS.[47]

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[45] *In the Matter of Minnesota Power's 2025-2039 Integrated Resource Plan*, Minnesota Power, Integrated Resource Plan, March 3, 2025, Docket No. E015/RP-25-127, (eDockets) 20253-215986-11 at pdf page 6.
[46] CMPAS Reply Comments at 3.
[47] *Id.*, at 4.

Third, CMPAS claims that hourly matching would discourage power purchase agreements (PPAs) because PPA suppliers do not currently supply hourly EAC data:

> Many independent power producers ("IPPs") are not aware of hourly attribute tracking, much less obligated to accommodate transitions to hourly RECs or AECs in their current or future contracts. While utilities can wait years for many IPPs to develop these capabilities, they lose out on the ability to contract with qualifying resources in the near-term that will still be in operation in 2035, when the Department proposes hourly matching to start. In contrast, owners of generation are free to control when they begin hourly AEC tracking for all of their resources.[48] [citation omitted]

Fourth, CMPAS claims that it cannot force its PPA contractors to use storage:

> Utilities with PPAs, particularly those who are partial off-takers of a larger central plant, have limited ability to force IPPs to add storage, which the Department has emphasized in its comments as a potentially CFE-compliant clean firm resource– at existing transmission interconnections. In contrast, owners of generation can control the commitment to, size, timing, and the interconnection type (for capacity accreditation) of storage additions.[49]

Fifth, CMPAS claims that many PPAs have provisions to supply replacement energy in resources fail to meet minimum performance standards:

> Many PPAs have provisions requiring developers to supply replacement energy, capacity, and/or RECs if contracted generation resources fail to meet minimum performance standards.
>
> - It is unknown how these types of contract provisions would work in with an hourly matching paradigm. For example, would some minimum performance standards in PPAs now need to be hourly? If minimum performance standards in PPAs remain based on annual performance, how will Sellers obtain replacement EACs to meet their obligations?

[48] *Id*.
[49] *Id.*, at 5.

- Similarly, it is unclear how performance standards can be enforced if non-utility sellers cannot access the hourly trading platform alluded to in the Department's Initial Comments.[50]

Finally, CMPAS concludes by stating that all of the above concerns would unduly discourage PPA procurements:

> The compliance risks posed by the Department's hourly matching requirement may cause many utilities to pursue ownership rather than PPAs as a means of comply with CFS. CMPAS believes that would be a poor policy outcome because the law should not be implemented in a way that favors a single resource acquisition method for CFS compliance, particularly one that may not be feasible for all utilities, or that may itself disincentivize new third party generation development that often relies on PPAs to drive financeability. To achieve the best policy outcome, the law should allow utilities to comply with CFS and count carbon free energy through a myriad of ways.[51]

MRES states that its IRP software does not support hourly matching.

> In addition to being contrary to the plain language of the statute and legislative intent, the Department's proposal would be extremely difficult to implement. MRES' resource planning software is not capable of modeling hourly renewable energy certificates ("RECs"), making MRES unable to incorporate hourly matching into its Integrated Resource Plan ("IRP"). MRES is not aware of any other resource planning software capable of incorporating hourly matching constraints in the models to demonstrate CFS compliance. Without tools like the planning software to robustly test alternative resource options, it is difficult if not impossible to estimate the costs of implementing what the Department has proposed.
>
> Even if resource planning software supported hourly matching in the models, it would become a very time intensive and administratively burdensome effort to demonstrate CFS compliance. All electric utilities, including small municipal electric utilities that do not file an IRP but otherwise are required to demonstrate CFS compliance, would be subject to the increased costs for CFS compliance that would result from an hourly matching requirement. This is inconsistent with the Legislature's directive

[50] *Id*.
[51] *Id*.

> to the Commission to protect against undesirable economic impacts on Minnesota utility ratepayers.[52] [citation omitted]

Finally, Basin Electric states that the Department's recommendations are in the Midcontinent Independent System Operator (MISO), and would be problematic for its Southwest Power Pool (SPP) generation:

> Second, the Department's hourly proposal is based on the MISO market. While most of Basin Electric's Minnesota Cooperative members are in the MISO market the renewable generation that Basin Electric currently owns and Operates is primarily within SPP. In addition to the hourly data and overall market purchase roadblocks that come with the Department's proposal, this mismatch between MISO and SPP would require significant compliance costs to track and match generation in non-MISO region to load that sinks in MISO. The Department's recommendation runs contrary to the requirement that the Commission must establish a REC program that "must treat all eligible energy technology equally and shall not give more or less credit to energy based on the state where the energy was generated or the technology with which the energy was generated." Requiring Basin Electric to track its hourly generation in MISO would restrict the use of RECs to comply with the CFS and the RES.[53]

First, the Department addresses CMPAS' claims that hourly matching would invalidate its contracts that only require hourly reporting and would force CMPAS to procure energy twice. The Department is not convinced that this is a legitimate concern. The additional data required to substantiate hourly matching is a marginal addition to the data currently supplied under Minn. Stat. § 216B.1691, subd. 3(a)(9)(ii), which requires the generation date. The data is generated on a meter, which is time stamped, and is readily available for export, should any party request such information. No physical or software modifications are necessary to generate these data. It would simply be a change in practice to upload a different EAC data format to generate EACs within a system such as M-RETS. The assertion that CMPAS would have to procure EACs twice because a generator does not have to provide data it already owns in a different format is not a valid concern. Should CMPAS' concerns be realized, appropriate exemptions are possible to assuage this unlikely scenario.

Second, the Department addresses CMPAS' claim that hourly matching would create accounting problems, particularly for residual mix accounting. In fact, the opposite of CMPAS' claims is true. Serialized EACs with additional time data can only assist in accounting because there is additional data to ensure that the same EAC has not been entered twice. The bigger problem is EACs that do not have

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[52] Missouri River Energy Services, Reply Comments, March 19, 2025, (eDockets) 20253-216597-01 at 2-3, (hereinafter "MRES Reply Comments").
[53] Basin Electric Reply Comments at 2.

time data, however this issue is not a material hinderance to residual mix accounting. Finally, the Department does not recommend residual mix accounting because the process is unnecessary and is administratively burdensome.

Third, the Department addresses CMPAS' concern that hourly matching would discourage PPAs. The Department refers to its response to CMPAS' first concern.

Fourth, the Department addresses CMPAS' concern that it cannot force its PPA contractors to add storage. While storage is one solution to achieve hourly matching, and is likely the ideal choice, surplus interconnections are not the only way to add storage. A utility can install standalone storage or contract for storage outside of its existing PPA contracts. Further, storage may also be welcomed by PPA contractors, particularly if it is adequately compensated and allows the contractor to avoid curtailments.

Fifth, the Department addresses CMPAS' concern about minimum replacement standards and replacement energy. This concern is the most legitimate raised by CMPAS. Minimum performance standards and replacement energy are both highly relevant to hourly matching. The most appropriate solutions are true-up EAC procurements and exemptions for replacement energy that cannot meet hourly reporting standards.

Sixth, the Department addresses MRES' concerns about access to hourly matching software and the administrative burden of hourly matching. First, in Section B.1.2.4, the Department discusses Xcel's hourly matching methodology in EnCompass, which is simple to implement and is nothing more than an extra sensitivity by the enforcement of a 100% carbon-free electricity renewable portfolio standard.[54,55] It is likely that the software used by MRES is capable of this functionality, although the Department discusses the potential value of more complex modeling considerations in Section B.1.2.4 that may warrant the addition of features that are not currently available in modeling software.

Finally, the Department addresses Basin Electric's concerns about EACs within SPP and the unequal treatment of EACs from outside MISO. While Basin Electric presents its argument under a statutory framework of equal treatment of EACs under Minn. Stat. § 216B.1691, subd. 4(a), the underlying problem is simply a misunderstanding of the mechanics of hourly matching. Under current practice, utilities are allowed to use EACs from anywhere in the country, even in SPP, to demonstrate CFS compliance. While Basin Electric would need to report its MISO load for hourly matching purposes, it would not need to report its MISO or SPP generation to demonstrate CFS compliance. Basin Electric would simply need to generate or purchase EACs on an approved registry and retire the time stamped EACs to match its MISO load. This system does not deviate from how Basin Electric currently reports its SPP generation for EETS compliance, except for the hourly temporal shift.

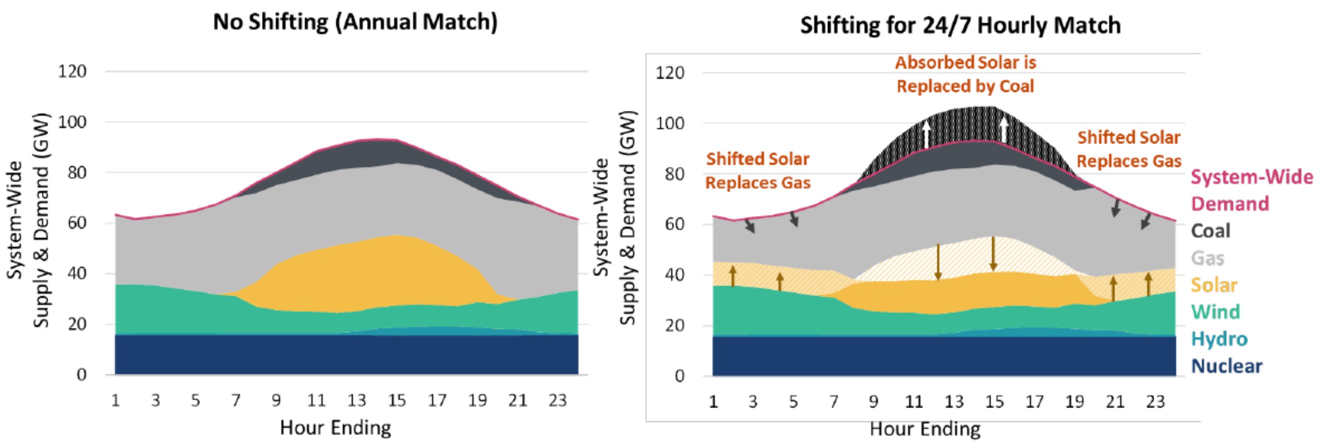
[54] See Department Supplemental Comments - Appendix A.
[55] The portfolio standard requirement can be relaxed to less than 100% to generate more affordable scenarios.

B.1.2.3 Hourly Matching Environmental Concerns

The Brattle Group and CMPAS[56] both claim that hourly matching may, in some cases, lead to more emissions. First, CMPAS cites a McKinsey & Company report that appears to indicate that hourly matching would be less effective at reducing emissions than optimizing battery dispatch at the grid level, based on the results of a capacity expansion model.[57]

Second, the Brattle Group discusses how battery charging can increase emissions because if solar is stored when a coal plant is below its maximum dispatch, it may trigger the coal plant to ramp up generation and offset lower emission gas later in the day. The Brattle Group presents the following figure to illustrate the concept:

Figure 1: Brattle Group Illustration of How Battery Charging Can Induce Additional Coal Generation



Source: GRE Reply Comments – Appendix A – Figure 3[58]

The Brattle Group also states that battery storage suffers from efficiency losses of 15-20%, which further reduces emissions if battery storage is not otherwise necessary.[59] The Brattle Group also describes how transmission constraints may lead to increased emissions if load is shifted:

> 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

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[56] CMPAS Reply Comments at 5-6.
[57] *Id*.
[58] Great River Energy, Reply Comments, March 19, 2025, (eDockets) 20253-216616-02, at 11, (hereinafter "GRE Reply Comments – Appendix A").
[59] *Id*., at 10.

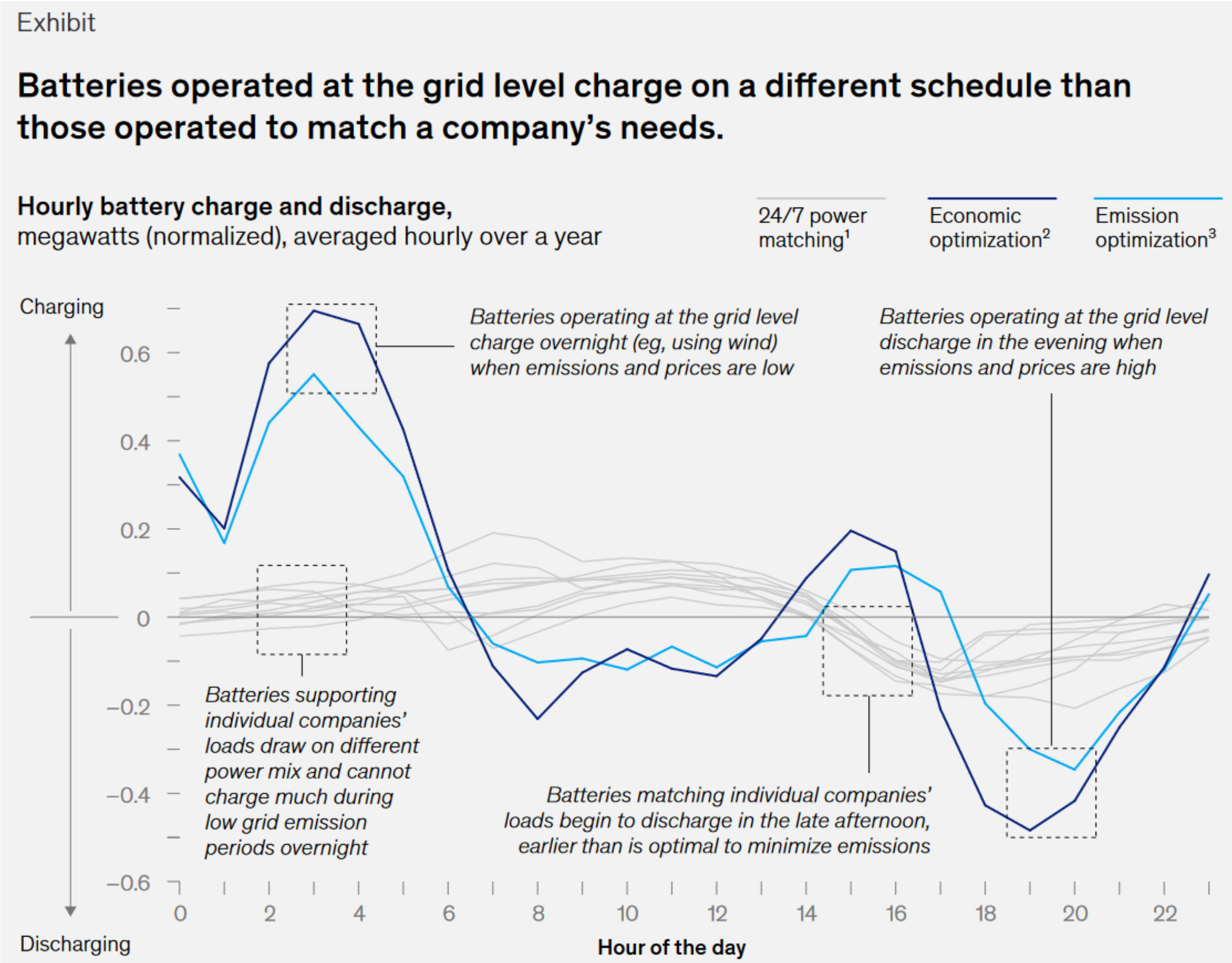
> results in substantial net operational emissions and in some cases even higher emissions relative to the annual matching strategy due to intra-regional transmission constraints. In other words, shifting supply (or demand) to accomplish hourly-match profiles does not mean that net emissions in any particular 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.[60] [citation omitted]

Finally, the Brattle Group presents an analysis that shows that Annual Matching scenario would reduce emissions by 2,103 MT CO_2, and its "Partial Hourly Matching with a 4-Hour Battery" scenario will reduce emissions by 2,285 MT CO_2, 100% Hourly Matching With a Battery will reduce emissions by 3,691 MT CO_2, and 100% Hourly Matching With Time-Stamped RECs will reduce emissions by 2,045 MT CO_2.[61]

First, the Department addresses CMPAS' statement that hourly matching may increase emissions. The McKinsey Report utilizes data from ten companies,[62] and employs the McKinsey Battery Dispatch Model,[63] which does not appear to be a capacity expansion model as stated by CMPAS. Regardless, the report shows the following figure to explanation why grid dispatch lowers emissions more than hourly matching, which is shown in Figure 2.

[60] *Id.*, at 16.
[61] *Id.*, at 35.
[62] Adam Barth, Humayun Tai, and Jesse Noffsinger. *Rethinking your company's clean-power strategy*. McKinsey & Company, (February 2025). At 3, (hereinafter "McKinsey Report"). Available at: https://www.mckinsey.com/industries/electric-power-and-natural-gas/our-insights/rethinking-your-companys-clean-power-strategy#/
[63] McKinsey Report at 4.

Figure 2: McKinsey Report Showing Battery Dispatch Optimization to Reduce Emissions



Source: McKinsey Report[64]

The grey lines represent the charging shapes of the ten companies' profiles, while the purple line is economically optimized dispatch, and the blue line is emissions optimized dispatch. The shallowness of the grey lines indicates that that battery does not fully charge and discharge at the times of highest marginal emissions, and therefore the 24/7 power matching scenarios do not reduce emissions as much as the more grid following scenarios. CMPAS states: "[g]iven that this report was only released five weeks before these Reply Comments, it is clear that hourly matching for a single company, much less an entire state, is still an emerging concept that needs comprehensive study before it is implemented as a requirement of CFS."[65] However, the contents of the report directly contradict CMPAS' assertion. Hourly matching at a company level is fundamentally different than hourly matching for an entire utility. Just one example illustrates why CMPAS' claim is inaccurate. Corporate load is just one component of utility load. After all of a corporation's employees go home and turn on all of their

[64] Ibid., at 4.
[65] CMPAS Reply Comments at 5-6.

appliances at night and generate the nightly peak, corporate load goes down. A battery will reduce emissions if it can prevent a gas plant from ramping up generation while the corporate load goes down at night, and charges, in this example, on abundant, zero-emission wind power. The McKinsey Report shows that energy arbitrage lowers emissions much better when the battery is able to follow large system load, like that of a utility, and not like that of a corporation.

Second, the Department addresses the Brattle Group's statements about the marginal unit, battery efficiency loss, and transmission constraints. As a preliminary matter, the Department does not advocate for dispatch out of the MISO merit order, and thus any energy storage solutions that may assist in hourly matching are all expected to dispatch economically. The Department is mindful of transmission constraints, and discusses these constraints with regard to hourly matching in the next section. Battery efficiency losses amount to reduced emissions, as correctly articulated by the Brattle Group, but only to the extent that generation is not otherwise curtailed, which as discussed in the next section, is already a significant problem for Minnesota. Despite the Brattle Group's critiques, its analysis shows a significant emissions reduction from hourly matching compared to annual matching, with the Annual Matching scenario showing a savings of 2,103 MT CO_2, and the 100% hourly matching scenario showing a savings of 3,691 MT CO_2. In addition, the "short-run" method of analysis employed by the Brattle Group has been shown to overestimate marginal emissions increases, and thus underestimates emissions reductions from the displacement of fossil fuel generation discussed above. For example, Ricks et al. (2024) explain:

> By definition, short-run marginal emissions rates estimate how changes in electricity consumption would affect total grid emissions, exclusively considering impacts on the operations of the grid as it exists at some specific moment in time. Crucially, they neglect how the project would influence the structural evolution of the grid, i.e., the deployment and retirement of capital assets, such as electric generators and transmission lines. In other words, short-run marginal emissions rates are incomplete descriptions of the consequences of consuming or producing electricity.
>
> […]
>
> More recently, Gagnon and Cole (2022) used a capacity expansion model (which simulates the structural evolution of the electricity system) to assess the emissions impacts of various electricity sector interventions, and likewise found that short-run marginal emissions rates systematically overestimated the emissions induced by load, often quite significantly, in large part because the short-run analysis methods' omission of induced

> structural change tends to ignore the role of new-build renewable generators in meeting new electricity demand.[66]

Finally, forthcoming analysis from the Princeton University Zero Lab[67] demonstrates carbon savings if hourly matching is enforced in MISO North, and emissions reductions are significantly higher if matching is enforced within Minnesota, consistent with utility self-build. The Princeton Hourly Matching Study states:

> A 100% matching requirement with MISO North boundaries mitigates up to 5 MMT CO_2/yr systemwide in 2045 (see Table 1), equivalent to roughly a quarter of Minnesota's total emissions from in-state generation today. This impact requires greater investment in a clean portfolio that provides the reliability necessary to displace fossil emissions, leading to cost premiums of up to $10/MWh for consumers in 2045 (or roughly 8% of the current average Minnesota retail rate).[68]

Despite claims that hourly matching could increase emissions under certain circumstances, no commenter presents evidence that hourly matching will increase emissions. To the contrary, each hourly matching emissions study demonstrates that hourly matching can significantly reduce emissions; however, the cost of hourly matching is another topic of discussion, which is addressed below in the next section.

B.1.2.4 Hourly Matching Cost Concerns

Nearly all commenting parties raised cost concerns with regard to the Department's hourly matching recommendation. Most notably, the Aligned Utilities list several reasons why costs could be problematic, which mostly center on competition.[69] The Aligned Utilities cite the Department's Initial Comments and reiterate the same concern expressed by the Department,[70] which states:

> As renewable resources become a larger share of MISO's fuel mix, times of low EAC generation may be coincident with more systematic shortages of EAC generation, and therefore prices may spike during these times. While the Department desires to incentivize utilities to continue to match hourly retail sales during times of higher prices in order to meet the

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[66] Ricks, W., Gagnon, P., & Jenkins, J. D. (2024). Short-run marginal emission factors neglect impactful phenomena and are unsuitable for assessing the power sector emissions impacts of hydrogen electrolysis. *Energy Policy*, *189*, 114119. Available at: https://www.sciencedirect.com/science/article/abs/pii/S0301421524001393
[67] To be submitted in supplemental comments. See Department Supplemental Comments - Appendix B. Wilson Rick and Jesse Jenkins. *Policy Memo: Impacts and Feasibility of an Hourly-Matched Clean Electricity Standard in Minnesota*. Princeton University: Zero Lab, (April 14, 2025), (hereinafter "Princeton Hourly Matching Study").
[68] *Id.*, at 3.
[69] Aligned Utilities Reply Comments at 4.
[70] *Id*., at 3.

> recommended hourly matching standard, it is equally important not to subject ratepayers to undue financial burden.
>
> The Department intends to present criteria and standards for the off-ramp process in Comment Round 4 that implement ratepayer protections, such that ratepayers are not required to pay for EACs during times of abnormally high prices, including the provenance of the EAC.[71]

The Aligned Utilities additionally reference the immaturity of EAC trading markets,[72] as described in the Department's Initial Comments.[73] In this regard, the Aligned Utilities are concerned that there is not sufficient time to plan for hourly matching compliance, and that EAC markets may not have sufficient liquidity to provide EACs during scarce hours.[74] In addition, if scarce EACs are available, the Aligned Utilities are concerned that the price may be prohibitively high.[75]

Cost concerns from the Aligned Utilities also include competition from voluntary hourly markets, which may additionally drive up prices, without a clear benefit.[76]

Two utilities express concerns about uneconomic dispatch. The Brattle Group claims that reliability may be compromised if resources are dispatched uneconomically,[77] which may also increase curtailments.[78] OTP claims that out-of-merit-order dispatch may violate the Independent Market Monitor's (IMM) rules on physical and economic withholding.[79] GRE comments on MISO out-of-merit-order dispatch:

> The Department appears to imply that if the cost of an hourly REC/AEC becomes prohibitively expensive during a time of low renewable generation resulting in a need for dispatchable capacity, carbon-free capacity resources - such as a hydrogen combustion turbine (HCT) - may become the preferable option in MISO's dispatch decision. This example is true, but it further illustrates how an hourly matching construct would increase costs for Minnesota ratepayers. A utility may be compelled to artificially lower its HCT offer in the MISO market if the cost to operate the HCT is less than the cost to operate a CT which requires a corresponding

[71] Department Initial Comments at 20-21.
[72] Aligned Utilities Reply Comments at 4.
[73] Department Initial Comments at 12-13.
[74] Aligned Utilties Reply Comments at 3-5.
[75] *Id*., at 4.
[76] *Id*.
[77] GRE Reply Comments, Appendix A at 11-13.
[78] *Id.*, at 15.
[79] Otter Tail Power Company, Reply Comments, March 19, 2023, (eDockets) 20253-216587-01 at 3.

> hourly REC/AEC. As a result, both offer strategies will ensure the unit operates uneconomically and both will negatively impact ratepayers.[80]

CMPAS states its concern with the administrative and cost burden of compliance with the Department's recommendations:

> We appreciate that much of the focus in the Initial Comments has been on Integrated Resource Plan ("IRP") modeling. However, there are also utilities providing electricity to Minnesotans who meet the more expansive definition of an "electric utility" under Minn. Stat. § 216B.1691 subd. 1(d).
>
> Just because these utilities are too small to file IRPs does not mean they are immune from the costs of compliance with the criteria and standards determined in this docket for measuring CFS compliance. Quite the contrary, these generally smaller utilities are precisely the utilities likely to experience economic hardship if the Commission opts for standards that are overly complex and impractical.
>
> CMPAS recognizes that the Commission will decide on off-ramps in the forthcoming fourth round of comments. However, CMPAS agrees with the Department that Notice Topic 2 pertains both to Minn. Stat. § 216B.1691 subd. 2d(a) and subd. 2d(b)(1), the latter of which requires the Commission to include standards and criteria that "protect against undesirable impacts on the reliability of the utility's system and economic impacts on the utility's ratepayers and that consider technical feasibility". CMPAS is therefore alarmed by the Department's own statement in this round that "economic impacts of the CFS will be studied in an electric utility's IRP." This statement suggests that the potential economic impact of CFS compliance on Minnesota's small utilities hardly merits acknowledgment, let alone consideration.[81] [citation omitted]

CMPAS additionally raises concerns about the MISO transmission planning process, and any marginal costs that may be necessary to build out additional transmission.[82] Xcel raises similar marginal transmission cost concerns.[83]

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[80] GRE Reply Comments at 13-14.
[81] CMPAS Reply Comments at 12-13.
[82] CMPAS Reply Comments at 6.
[83] Xcel Reply Comments at 9.

Most notably, Xcel and the Brattle Group submit analyses which claim that hourly compliance will increase ratepayer costs. The Brattle Group presents the following scenario analysis results for annual vs hourly matching:

Table 1: Brattle Group Summary of Hourly Matching Modeling Results

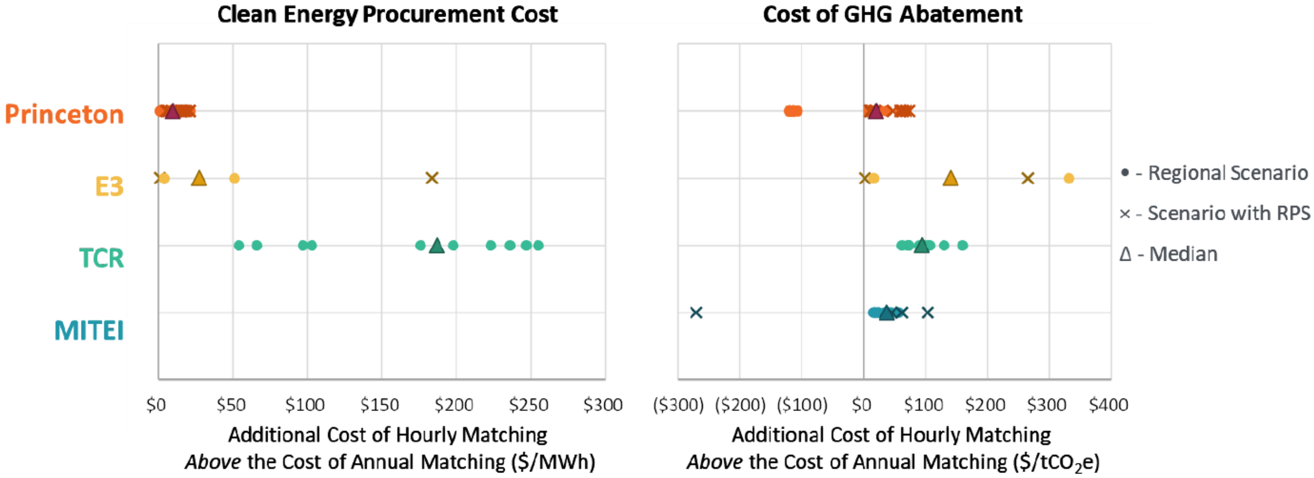
		No Matching	Annual Matching	Hourly Matching with 4-Hour Battery	100% Hourly Matching with Battery	100% Hourly Matching with Time-Stamped RECs
Market Prices on a Cost to Utility Basis						
Cost of Energy at Load	*($/MWh)*	$26.92	$26.92	$26.92	$26.92	$26.92
Cost of Solar	*($/MWh)*	$0	$15.45	$18.26	$30.91	$15.45
Cost of Wind	*($/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**

Source: GRE Reply Comments – Appendix A – Table 4[84]

[84] GRE Reply Comments – Appendix A at 35.

The Brattle Group presents additional literature sources about the cost of hourly matching, which all show increased costs associated with hourly matching:

Figure 3: Brattle Group Summary of Literature About Hourly Matching Costs



Source: GRE Reply Comments – Appendix A – Figure 6[85]

Xcel presents its own analysis in EnCompass:

> Until recently, the Company was collaborating with the GSA to develop a voluntary customer program for customers interested in securing one hundred percent carbon free energy on an hourly basis. As part of the analysis undertaken to develop a potential program, the Company considered the impact of serving the GSA load in our service territory on an hourly basis. To conduct this analysis, the Company used the Encompass model and assumptions from our IRP to evaluate the impact of serving the GSA load in our service territory with carbon-free energy on an hourly basis.
>
> Based on a similar approach used for the GSA analysis, to evaluate the Department's proposal we conducted an analysis of the impacts of an hourly matching requirement by modeling a scenario in Encompass that requires all of our Minnesota load to be served by carbon-free energy on an hourly basis by 2040. We enforced this constraint consistent with the legislation by requiring an interim requirement of 80 percent carbon-free by 2030 and 90 percent carbon-free by 2035. We allowed the Encompass model to optimize resource additions, including solar, wind, and storage to meet these constraints. Consistent with the analysis conducted in collaboration with the GSA, a 100 percent carbon-free energy requirement

[85] *Id.*, at 22.

> results in significantly increased costs and an overbuild of resources. In order to meet the 2040 goal, our analysis shows that we would need to add an incremental 17,700 MWs of battery storage and over 4,000 MW of incremental solar resources, both which would require significant acreage, above the amount included in our recently approved IRP. As a result, in 2040 the revenue requirement associated with this overbuild of resources would be over 60 percent higher than the costs included in our IRP without providing additional energy or capacity benefits for our customers. These resources would go beyond our actual system needs and transmission and infrastructure costs would be in addition to this. Such a requirement would have significant impacts on customer rates. More analysis of the potential rate impacts of an hourly requirement should be undertaken to fully understand the impact to customers before implementation of an hourly matching compliance methodology.
>
> The implementation of hourly matching, given the lack of any hourly REC and/or AEC trading markets, would force the deployment of existing storage technology at a high price, rather than waiting for cost-effective alternate storage and clean firm generation options that are not broadly available or cost-effective today. We would already be including additional clean firm resources and storage at a greater scale in our resource plans if they were cost-effective. These additional overbuilt storage costs would increase rates borne by our customers.[86]

First, the Department addresses the Aligned Utilities concerns about competition. The CSG provides an excellent description of why hourly EAC markets will generally not be necessary for most hourly matching:

> It is also important to explicitly note that 24/7 hourly REC matching does not necessarily equate to a utility having to literally procure a new batch of RECs every hour, on the hour, of every day of every year. In other words, it is unlikely a utility would be procuring 100% of its hourly RECs in real-time on a currently non-existent 24/7 REC spot market. Rather, the utility would likely continue to engage either bilaterally with generators, through third-party over-the-counter ("OTC") REC brokerages, or to a lesser extent via marketer-to-marketer transactions on existing exchanges, in order to secure forward contracts for RECs at certain hours. A forward contract for hourly RECs would not only reduce administrative strain for utility buyers but the approach should also de-risk hourly REC procurement by stabilizing against price volatility. Generally speaking, forward contracts would likely

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[86] Xcel Reply Comments at 9-10.

> buttress Minnesota ratepayers from price spikes in a wholly new hourly REC market. These forward contracts, to the Department's prior point, would still need to be premised on accurate hourly load projections, which could be determined by assessing AMI data and other analytical toolsets as part of the IRP process, as per the recommendation of the Department. That said, mis-projections or other compliance shortfalls in forward contract procurement would necessitate spot purchases for the difference—those spot purchases would still be likely procured bilaterally or through an OTC broker for the near future, rather than on a novel, real-time hourly exchange.
>
> As such, a brand-new centralized REC exchange for hourly trading is not necessary for CFS-compliant hourly trading to occur. However, hourly transactions do need to be premised on effective trading functionality on tracking systems such as M-RETS. Therefore, CSG respectfully disagrees with the Department's statement: "The Department recognizes that while tracking mechanisms exist for hourly EACs, a market trading solution currently does not yet appear to exist." Rather, it appears that the opposite is true. The key challenge is creating an effective hourly search function and an efficient re-batching process for hourly REC allocations within the tracking system itself.
>
> This all said, CSG reiterates its support of the Department's proposal for the hourly tracking of RECs. Furthermore, CSG does believe that the present logistical challenges facing hourly trading will be overcome and that hourly REC accounting will be widely available in the coming years.[87] [citations omitted]

The Princeton Hourly Matching Study demonstrates that a $300/MWh cost cap reduces the marginal cost of firm hourly matching from $20/MWh to $13/MWh, which results in 98.5% hourly matching and an emissions reduction of 16 million metric tons (MMT)/yr,[88] which most closely resembles Xcel's analysis to self-build generation. While these responses do not fully address the breadth of the Aligned Utilities' concerns, particularly regarding competition from voluntary hourly EAC purchases, the responses provide a sufficient basis to alleviate the majority of the concerns addressed, and additional cost containment solutions are available.

Second, the Department addresses the Brattle Group and GRE's concerns with uneconomic dispatch. While the Department stated in its Initial Comments that non-merit order dispatch is possible in the

[87] CSG Reply Comments at 18-19.
[88] Id., at 6.

MISO market, the Department did not state that this outcome is in any way expected by the Department. Instead, the Department stated:

> Nothing in the CFS precludes a utility from maintaining or building additional CFS-ineligible generation, for example, in order to meet MISO capacity requirements. Such resources will be dispatched according to the MISO merit order, which penalizes higher-variable cost resources such as future carbon-free hydrogen combustion turbines, for example. Even when all Minnesota utilities achieve 100% carbon-free electricity, all generation, including CFS-ineligible generation will be dispatched by MISO to meet grid capacity needs. If sufficient carbon-free capacity does not exist at any one time, and as discussed above, there is no guarantee that carbon-free capacity will be dispatched by MISO to meet of all Minnesota's capacity needs. Instead, the likely outcome is that if utilities do not possess sufficient carbon-free capacity, or if the carbon-free capacity is too expensive to routinely dispatch in the MISO merit order, MISO will dispatch lower cost CFS-ineligible resources external to utility-owned or -operated resources to meet Minnesota's capacity needs. The Department notes that, in the MISO dispatch process utilities can require MISO dispatch to occur out of economic merit order. This anomaly currently happens for some coal plants, for example.[89] [citation omitted]

To be clear, the Department does not encourage or expect dispatch outside of the MISO merit order to meet hourly matching requirements. This nuance appears to be lost by the majority of commentors in this section, who erroneously infer that the Department's recommendation for hourly matching is monolithic and that every effort must be made to ensure compliance with the hourly standard without consideration of tradeoffs. The Department's comments highlight how the challenge of meeting hourly compliance is enhanced by the MISO merit order dispatch system.

Third, the Department addresses CMPAS' concern that the administrative burden of hourly matching compliance is not considered by the Department, particularly for smaller utilities. The Department is aware of the administrative challenges faced by smaller utilities, and understands that compliance requirements will affect larger utilities much differently than the smallest Minnesota utilities. In order to address this potential inequity, the Commission may determine that it is appropriate to grant exemptions or extensions to hourly matching requirements for smaller utilities—and particularly those that do not meet the definition of a utility under Minn. Stat. § 216B.2422, subd. 1(b) or those that are not required to file an IRP under Minn. Stat. § 216B.2422, subd. 2b.

Fourth, the Department addresses CMPAS' and Xcel's concerns over increased transmission costs and planning needs compared to annual matching. These concerns are valid and warrant further

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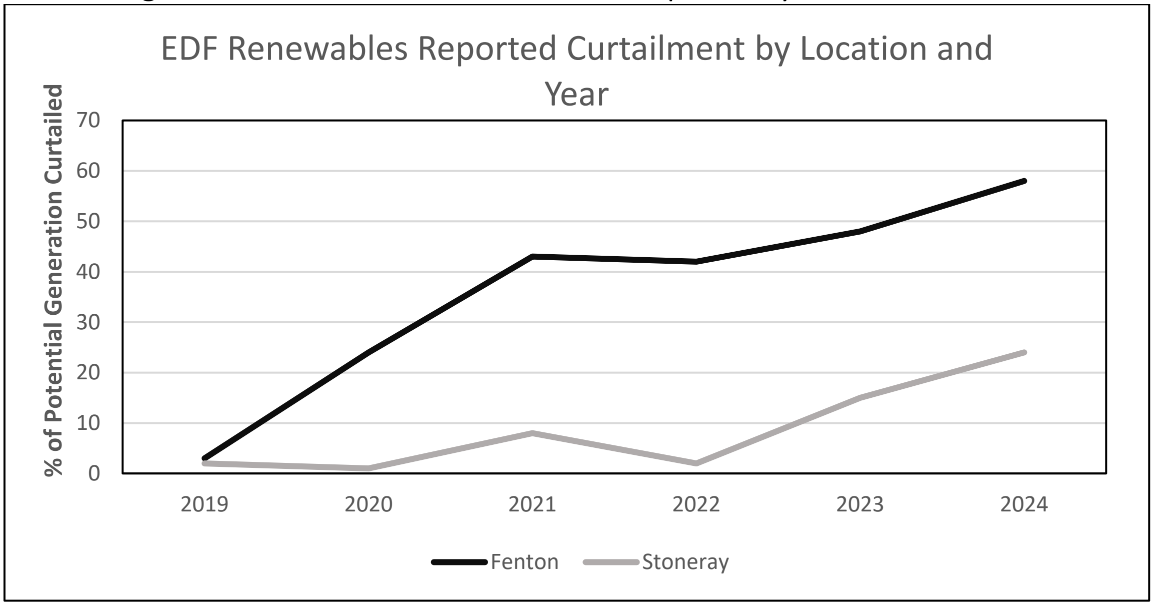
[89] Department Initial Comments at 6.

consideration, but appear to ignore the inherent tradeoff between curtailment, energy storage, and increased transmission. Less transmission is needed if the utilization of transmission lines is increased by energy storage. With proper market incentives, energy storage purchases energy at lowest cost hours when curtailments are likely, and discharges at the highest cost hours when curtailment is less likely. The absence of energy storage fosters an environment where similar renewable resources in similar geographies are more likely to co-generate and induce curtailments when transmission resources are insufficient. There is an appropriate balancing that needs to take place to properly analyze the optimal utilization of energy storage and generation that factors in transmission planning. Transmission planning is primarily performed in MISO, however, Docket No. E999/CI-24-316 demonstrates that MISO processes can lead still to significant curtailments, while net benefits for ratepayers are unclear.[90] There may be opportunities to engage further consider transmission and generation planning in existing processes.

Fifth, the Department addresses the Brattle Group's modeling results. While the Brattle Group describes some of its assumptions, the data provided is not sufficient to recreate the analysis presented. The Brattle Group cities several studies that show that hourly matching is more expensive than annual matching, and the Brattle Group's analysis presented in the study shows a marginal cost increase of $259.60/MWh relative to the annual matching scenario, which is significantly higher than the three other median results presented in Figure 3. The Brattle Group chooses an interesting baseline LMP for its cost analysis of renewable resources. The Brattle Group states: "[w]e 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)."[91] Figure 8 shows the location to be the NSP.FENTON.WND node in 2024.[92] In Docket No. No. E999/CI-24-316 NSP.FENTON.WND was identified as the epicenter of curtailment in Minnesota with short term 2024 transmission construction congestion exacerbating curtailments in an already congested area.[93] Figure 4 shows how extreme curtailments were at the NSP.FENTON.WND node in 2024, which reached nearly 60% curtailment in the partial 2024 dataset submitted.

[90] *In the Matter of the Investigation into Transmission-Curtailment Matters, Drivers, and Potential Solutions to Limitations Resulting from the Nobles County Substation*, Minnesota Department of Commerce, Supplemental Comments, December 3, 2024, Docket No. E999/CI-24-316, (eDockets) 202412-212623-02, at 6-37 (hereinafter "Department Supplemental Comments on SW Minnesota Curtailment Investigation").
[91] GRE Reply Comments – Appendix A at 27-28.
[92] *Id.*, at 28.
[93] Department Supplemental Comments on SW Minnesota Curtailment Investigation at 6-21.

Figure 4: Wind Generation Curtailment Reported by EDF Renewables[94]



Source: Data From EDF Renewables Initial Comments at 3.[95]

Binding constraints[96] in the FENOCH area, which contains Fenton, skyrocketed from 0.8% of five-minute increments in 2022 to 16.3% of five-minute increments in 2024.[97] While the Brattle Group states that it is aware of congestion in Southwest Minnesota,[98] the selected location and year are both extreme examples of potential renewable generation in Minnesota. The modeling bias presented undermines the legitimacy of the remainder of the analysis, particularly given that the full study analysis and methodology is not published. It is not surprising that the utilization of the worst-case LMPs in Minnesota would result in a significantly higher marginal cost of CFS compliance under any scenario presented, or compared to Brattle's literature review. In addition, the base case, which assumes 100% market purchases and no CFS compliance, is completely unrealistic for the majority of load in Minnesota, which cannot source anywhere near 100% of its power from the MISO market without matching generation. This assumption therefore artificially inflates the reported marginal annual compliance cost that is over twice as high as the base case.[99] A more realistic base case would be a new combined cycle gas plant, which Lazard's 2024 Levelized Cost of Energy Analysis reports to cost between $45/MWh and $108/MWh, with a midpoint of $76.5/MWh,[100] compared to $29.5/MWh

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[94] 2024 data is reported up to 10/10/2024.
[95] *In the Matter of the Investigation into Transmission-Curtailment Matters, Drivers, and Potential Solutions to Limitations Resulting from the Nobles County Substation*, Initial Comments, October 23, 2024, Docket No. E999/CI-24-316, (eDockets) 202410-211265-01, at 5.
[96] These are constraints that MISO reports. Additional curtailments happen in the economic bidding process, which are induced by low LMPs.
[97] Data reported up to November 19, 2024. See Table 3. Department Supplemental Comments on SW Minnesota Curtailment Investigation at 18.
[98] GRE Reply Comments – Appendix A at 15.
[99] The base case reports a cost of $26.92 / MWh and the annual compliance case reports a cost of $60.49/MWh. See Table 1.
[100] Lazard. *Lazard Levelized Cost of Energy +*. (June 2024). At 9. Available at: https://www.lazard.com/media/xemfey0k/lazards-lcoeplus-june-2024-_vf.pdf

for land based wind and $46.8/MWh for utility PV from the NREL Annual Technology Baseline used by the Brattle Group.[101] The Department can critique additional modeling choices, but this initial analysis is sufficient to discount the value of the analysis presented by the Brattle Group. While the Department does not refute the general conclusions of the Brattle Group's analysis, the results do not appear to have sufficient validity to serve as a valuable prediction of ratepayer costs. The analysis does however setup a more substantive and realistic discussion about Xcel's modeling results, which is an example of cost modeling that could come before the Commission.

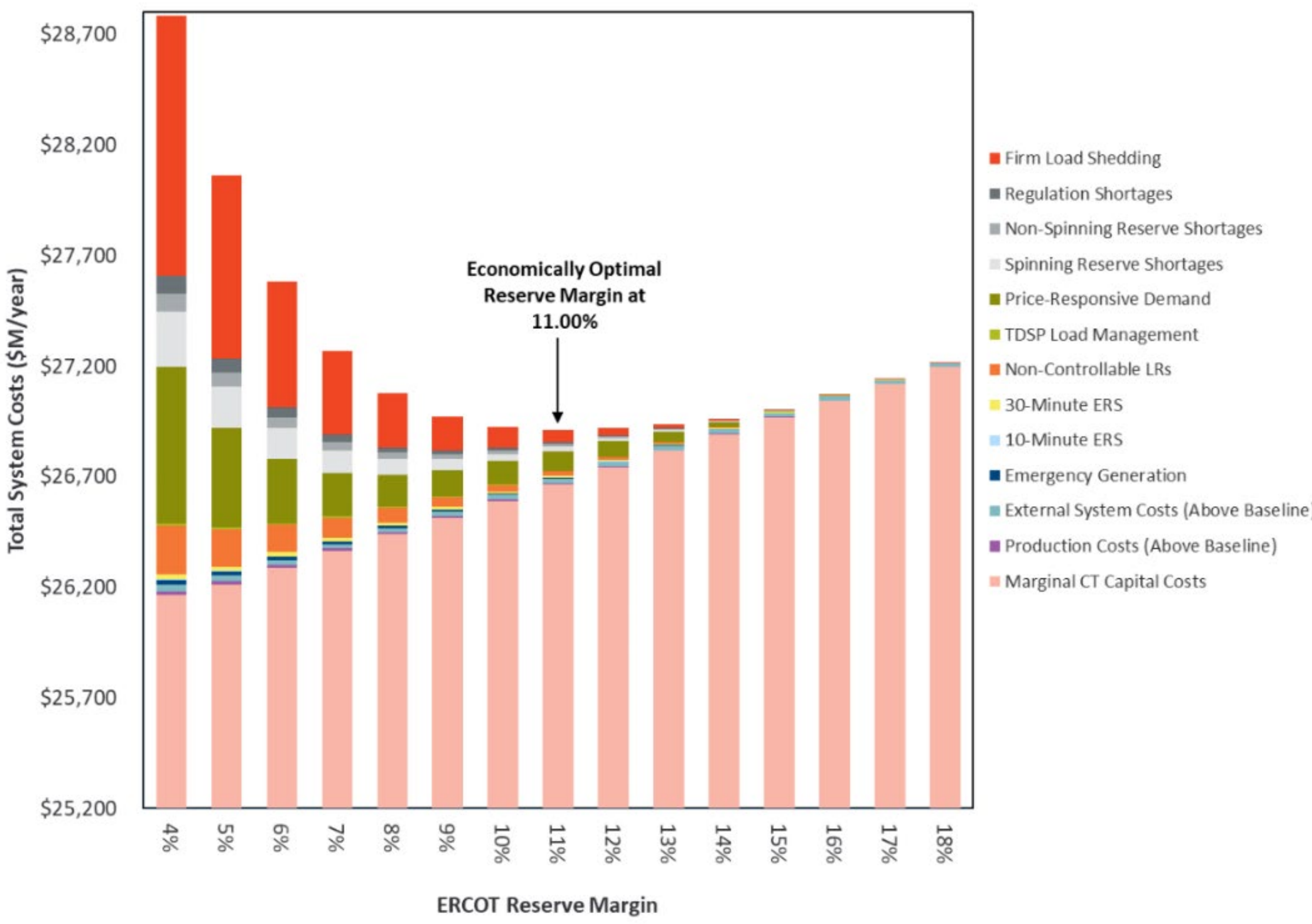
Sixth, the Department addresses Xcel's EnCompass modeling results. As a preliminary matter, the Department notes that Xcel submits processed EnCompass run data without submitting any supporting materials, which is highly unusual. The Department submitted three information requests to Xcel on April 1, 2025 and received Xcel's response on April 11, just three business days before the comment submission deadline.[102] The Department obtained Xcel's EnCompass files, but does not have sufficient time to verify and test Xcel's assumptions. The Department may provide a detailed discussion of Xcel's modeling results in a late filed supplemental filing, or discuss its response at the forthcoming Agenda Meeting. Information Request 3 states:

> On pages 9-10 of Xcel's reply comments, Xcel describes the results of an hourly matching modeling process performed in EnCompass. Please provide a description of all EnCompass inputs that were modified from Xcel's recently approved Settlement Agreement plan in Docket No. E002/RP-24-67 that are necessary to enforce the hourly matching constraints described in Xcel's reply comments.
>
> Response:
>
> The only modification made within the EnCompass model for this exercise from the Settlement Agreement EnCompass model run was the creation of a renewable portfolio standard (RPS) Program. Within EnCompass, an RPS Program is an allowance program that allows a user to set a constraint determining what percentage of system generation is provided by certain resources – in this case, zero carbon-emitting resources. The RPS Program was only applied to the Minnesota load within the NSP System. The input file for this modification, "Input_Step_RPS Program_rnwb_nuc.xlsx", has been provided as part of the Attachment A files for the Department's IR No. 1.[103]

[101] National Renewable Energy Laboratory. *Annual Technology Baseline*. U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy. (2024). Available at: https://atb.nrel.gov/electricity/2024/index
[102] See Department Supplemental Comments - Appendix A.
[103] See Department Supplemental Comments - Appendix A.

Based on the results submitted by Xcel, hourly matching will increase ratepayer costs by "60 percent higher than the costs included in our IRP without providing additional energy or capacity benefits for our customers."[104] Xcel's model appears to be enforced at 100% compliance for all hours, which treats CFS compliance as stricter constraint than reliability. Reliability planning uses a standard, such as such as a one-in-ten year loss of load expectation (LOLE), which allows EnCompass to relax the constraint once the standard is met, if added capacity no longer provides a lowest cost option. Similar to reliability planning, the higher the reliability standard is set, the higher the system costs become to plan for an increasingly unlikely event, which is what Xcel refers to as an "overbuild of resources." Figure 5 shows the capital cost vs. reliability tradeoff that is optimized in reliability planning:

Figure 5: Cost VS Reliability Tradeoff



Source: Lawrence Berkeley National Laboratory[105]

[104] Xcel Reply Comments at 9-10.

[105] JP Carvallo. *The Value of Lost Load – Concepts, methods, and applications*. Lawrence Berkely National Laboratory, (September 27, 2024). Available at: https://cdn.misoenergy.org/20240927%20ERSC%20WG%20Item%2003%20The%20Value%20of%20Lost%20Load649514.pdf

Figure 5 shows that as the capital cost increases, shown in the very bottom bar, all other adverse reliability metrics above the bottom bar decrease. However, there is an optimal point at which reliability balances with system costs, which is shown above at a reserve margin of 11 percent. A similar relationship exists with hourly matching and the optimization of societal costs, which includes operating costs and emissions reductions. As a higher share of utility load is matched with additional, or different zero-carbon resource portfolios, carbon reduction is expected to increase. As the Department states in its Initial Comments, better matching of generation to load reduces market exposure, which is another benefit of hourly matching.[106] The Department expects that there is a significant system overbuild in Xcel's model, because a large number of resources are built to serve an energy need that may occur for a few hours per year or even less frequently, similar to how the most expensive capacity resources are not utilized except during emergency grid conditions. This example does not imply that overbuilt resources will not be utilized in the MISO market, but Xcel's model clearly indicates that the cost of the additional resources will not be appropriately offset by MISO market structures, which likely includes significant curtailments.

EnCompass optimizes for the lowest system operating costs under specified constraints, such as Xcel's 100 percent hourly matching constraint. However, the social cost of carbon is added after the model has been optimized, unless carbon is included as a regulatory cost that affects the dispatch of resources. Regulatory costs of carbon are regularly included in IRPs, but an optimized EnCompass capacity expansion model that uses the regulatory cost of carbon in a production cost run will not yield an accurate social cost of carbon, because the regulatory cost is included in resource dispatch. Instead, a regulatory cost of carbon capacity expansion run needs to remove the regulatory cost of carbon in the production cost run to simulate real world dispatch conditions, because there is no regulatory cost of carbon in Minnesota utilities' generation offer bids. Even when a regulatory cost of carbon is used in the manner described, EnCompass still does not optimize the social cost of carbon because the model optimizes for revenue requirements, which potentially leaves room for marginal improvements to find the optimal social cost.

Hourly matching is a different way to approach the problem of the optimization of the social cost of carbon. Hourly matching attempts to reduce emissions by avoiding energy generation buildout needed to match load. Thus, fewer CFS-ineligible resources are required and thus built to match utility load, independent of reliability requirements. While this process can obviously lead to increased costs, as Xcel modeling shows, the hourly matching constraints can be relaxed such that a certain number of hours do not need to be served by utility-owned or operated infrastructure, which the Princeton Hourly Matching Study refers to as a "circuit breaker." In addition to the circuit breaker, an EAC market can be simulated in EnCompass with a cost cap to provide EACs during unserved hours, unless the cost of EACs is above the cost cap. EAC markets ensure that utilities do not have to significantly overbuild their systems because EACs can be purchased instead. The Princeton Hourly Matching Study in fact assumes an EAC cost of $0 because of the natural evolution of renewable energy in MISO, which

[106] Department Initial Comments at 10.

supplies so many excess EACs above state compliance requirements that the cost is effectively $0. This assumption demonstrates that in the future, the majority of hours in a year can be supplied with zero or low cost EACs to meet hourly compliance needs, which is why the study finds zero marginal cost of hourly matching in the Midwest region. Conversely, the study also finds *zero marginal emissions reductions*, because utilities can purchase excess EACs at low cost from existing facilities, which does not marginally decrease emissions or incentivize new generation. Therefore, emissions reductions beyond the natural MISO changing resource mix can only be anticipated when utilities plan their systems to not be fully reliant on unbundled EACs for compliance. Xcel's modeling represents an extreme example, which is similar to the "In-State Only" policy scenario in the Princeton Hourly Matching Study. The Princeton "Midwest Region" represents the opposite end of the spectrum, where no additional buildout is necessary because of excess low cost EACs available within MISO. Somewhere between the modeling that Xcel presents and the Princeton "Midwest Region" policy scenario exists a socially optimal solution that balances capital and operating expenses with social costs, and there is reason to infer that hourly matching may yield socially optimal results that are not contemplated in existing IRP practice. For example, hourly matching can induce zero carbon buildout without the modification of dispatch costs, which may offer more market-realistic outcomes compared to the regulatory cost of carbon example described earlier.

The Department is also not convinced that an EAC cost of $0 is an appropriate planning assumption for Minnesota utilities. For example, the CEOs discuss the multi-state allocation and MISO export problems with CFS compliance, with their Recommendations 1A, 1B, 1D, and 1E.[107] These recommendations seek to capture the "Midwest Region" excess EAC problem that dissuades utilities from buildings new generation because they can source free or low cost EACs from outside of their Minnesota ratepayer funded territory. Multi-state utilities like Xcel and OTP can simply move EACs from their non-Minnesota ratepayer funded assets in states with no renewable standards, and apply these EACs to meet the CFS, which makes these utilities appear Carbon-free on paper for doing nothing to change their generation, at least in regard to the EACs reallocated to Minnesota. The CEOs take aim at Xcel's multi-state allocation formula presented in the utility's most recent IRP,[108] but this criticism reveals a more important concern. In the Department's Initial Comments in Xcel's most recent IRP, the Department stated:

> As it is, Xcel's proposed plan demonstrates compliance with the CFS solely by applying a Minnesota-specific allocator to the Company's system-wide carbon-free generation; Xcel claims that a certain amount of carbon-free generation physically located in other states will be re-allocated to Minnesota. As a result, Xcel's plan can include fossil fuel resources and still meet the CFS goals because Xcel is able to allocate enough carbon generation from other states that it equals or exceeds all of Minnesota's

[107] The Minnesota Center for Environmental Advocacy, the Sierra Club, and Fresh Energy, Initial Comments, January 29, 2025, (eDockets) 20251-214613-01 at 20, (hereinafter "CEOs Initial Comments").
[108] *Id.*, at 4-5.

> retail load. It is unclear to the Department exactly how this allocator was calculated, but jurisdictional allocators are often based on a percentage of retail sales.
>
> […]
>
> The Department recommends that Xcel clarify in Reply Comments how it calculated its Minnesota-allocated Generation.[109]

Xcel never replied to the Department's request because the Settlement Agreement[110] was reached before Xcel submitted its reply comments. There is little record development on the issue of jurisdictional allocation. While the topic of jurisdictional allocation can be resolved quickly, the issue of cost allocation is thornier. With its Recommendation 1, the CEOs argue that Minnesota ratepayers should have to pay for EACs from utility-owned non-Minnesota ratepayer funded assets to incentivize buildout of assets to serve Minnesota load.[111] This exercise is inherently beneficial for ratepayers in other states, but highlights a potential free rider problem where EACs are not appropriately compensated. While the cost of EACs may indeed be zero in the future, the current value of EACs in MISO is far from zero.[112,113] If hourly matching is to be considered in earnest, any model should include some level of EAC purchases at some cost. Again, IRPs do not model outside EAC purchases, and indeed if they do, a possible outcome of low to zero cost EACs could be new gas buildout accompanied by EAC purchases, which is not a desirable outcome with regard to the State's energy goals. Currently, EnCompass will solve to meet any feasible compliance constraint, including the annual CFS compliance goals, by selecting new generation to meet the compliance goal. The Department does not think the existing annual standard needs to be relaxed with the potential introduction of EACs into EnCompass models, but should cost containment become problematic, increased reliance on EAC purchases is preferable to a delay of the CFS. However, the Department's primary interest in EAC value and purchases within IRPs is to study how appropriate EAC price incentives can both lower costs compared to new generation buildout, as well as appropriately incentivize new market participation to serve currently low EAC generation hours. The Department is interested in studying hourly EAC costs within EnCompass to reduce the large compliance costs that Xcel presents in its Reply Comments. The Department is however aware that A) EnCompass may require upgrades to accommodate this request,

[109] *In the Matter of Xcel Energy's 2024-2040 Integrated Resource Plan*, Minnesota Department of Commerce, Initial Comments, August 12, 2024, Docket No. E002/RP-24-67, (eDockets) 20248-209394-02, at 85.
[110] In the Matter of Xcel Energy's 2024-2040 Upper Midwest Integrated Resource Plan, Northern States Power Company, dba Xcel Energy, Comments in Support of Settlement Agreement, October 25, 2024, Docket No. E002/RP-24-67, (eDockets) 202410-211354-03.
[111] CEOs Initial Comments at 20.
[112] Adam Wilson and Tony Lenoir. *US renewable energy credit market size forecast to approach $40B by 2033*. S&P Global. (February 13, 2024). Available at: https://www.spglobal.com/market-intelligence/en/news-insights/research/us-renewable-energy-credit-market-size-forecast-to-approach-40b-by-2033
[113] Amy Chiang. U.S. renewable energy market: Pricing trends and projections for PPAs. 3 Degrees. (February 10, 2023). Available at: https://3degreesinc.com/insights/us-renewable-energy-market-pricing-trends-and-projections/

which is possible, and B) that further study on EAC markets is necessary to develop costs that could be modeled within EnCompass.

Finally, hourly matching also necessitates a more thorough analysis of the stochastic nature of renewable energy generation. The deterministic modeling currently performed in IRPs can easily miss random weather events that are not captured in a fixed generation profile, even if the model is based on historical data. The increasing reliance on variable generation necessitated by the CFS warrants further examination as to whether stochastic modeling may be appropriate in some application in IRPs. EnCompass can perform Monte Carlo simulations to generate random draws of variable renewable generation to give a probabilistic assessment of generation, which would help utilities better plan for off years and would better inform hourly modeling.

B.1.2.5 Final Hourly Matching Recommendations

The Department does not know the optimal strategy to generate the greatest societal cost savings, but the Department presents a comprehensive argument why the existing practice may not be socially optimal. Xcel,[114] CMPAS,[115] and Google[116] each recommend to varying extents that more analysis of hourly matching is necessary prior to its implementation. The record demonstrates that additional analysis of hourly matching and related issues in IRPs is warranted for further analysis. CMPAS further states that any such analysis should not delay the implementation of the annual matching CFS requirement,[117] and the Department agrees with CMPAS. The Department withdraws its recommendation for hourly matching as a compliance requirement. In addition, the Department withdraws the following recommendations:

- B.1.2.2.1. The Department recommends the Commission order the following total retail electric sales matching requirements for electric utilities by the end of the year indicated:
  - 2030: Annual matching of 80 percent for public utilities; 60 percent for other electric utilities
  - 2035: Hourly matching of 80 percent for public utilities; 60 percent for other electric utilities
  - 2040: Hourly matching of 90 percent for all electric utilities
  - 2045: Hourly matching of 100 percent for all electric utilities.

- B.1.2.4.1. The Department recommends the Commission order the Department to submit an annual compliance report that outlines the status of EAC markets and provides potential options to implement hourly EAC trading for electric utilities.

[114] Xcel Reply Comments at 9.
[115] CMPAS Reply Comments at 13-14.
[116] Google LLC, Reply Comments, March 19, 2025, (eDockets) 20253-216589-01 at 2-3.
[117] CMPAS Reply Comments at 14.

- B.1.2.4.2 The Department recommends the Commission order a new docket be opened in 2029, which shall determine the requirements necessary to facilitate the sales and purchases of hourly EACs.

- B.2.4. The Department recommends that the Commission order that hourly matching achievement for electric utilities be determined by the calculation of the total number of hours for which total retail electric sales are matched by EACs, as compared to the hourly matching standard for that year.

- E.1. The Department recommends the Commission order the Commissioner of Commerce to seek authority from the Commissioner of Management and Budget to incur costs for specialty services to provide reports on the status of EAC markets and to propose a suite of solutions that would facilitate hourly EAC trading for electric utilities.

In addition, the Department modifies the following recommendation as follows:

- B.1.2.2.2. The Department recommends the Commission order ~~a 2030 to 2034~~ CFS compliance true up period of three months after the conclusion of the reporting year.

The Department maintains its recommendation to require utilities to study hourly matching in IRPs:

- B.1.2.3. The Department recommends the Commission order all integrated resource plans where the utility uses a capacity expansion model to incorporate hourly matching constraints in the models to demonstrate CFS compliance.

In the wake of these withdrawals, there is a need for further analysis on a number of topics discussed previously. The Department concludes that a separate comment period is not sufficient in scope, nor collaborative enough to address the multitude of issues that could stimulate hourly matching, or which could improve emissions reductions within IRPs without hourly matching. A stakeholder workgroup is necessary to discuss, model, iterate, and develop conclusions about the role of hourly matching or other additions to IRPs and CFS compliance. The Department continues to assert that the Commission has the authority to order hourly matching compliance. Any recommendations that may result from the stakeholder workgroup will help to further justify or refute hourly matching in IRPs or in CFS compliance, however the Department expects the workgroup to develop best practices in hourly matching, but the workgroup will not relitigate the Department’s recommendation for hourly matching requirements in IRPs.

The Department recommends the Commission order the creation of a Commission-led stakeholder workgroup that is tasked with the analysis, development, testing, and recommendation of best practices for the optimization of societal costs as they pertain to:

A. ***Hourly matching for CFS compliance;***
B. ***Methodologies to implement hourly matching scenario requirements in integrated resource plans;***

C. ***The integration of transmission constraints in integrated resource plans;***
D. ***The integration of energy attribute certificates and allocation thereof in integrated resource plans;***
E. ***Stochastic modeling of variable renewable generation into integrated resource plans; and***
F. ***The co-optimization of transmission and generation resources.***

B.1.3. EAC Purchase Region

In its Initial Comments, the Department recommended:

> The Department recommends that the Commission order that all EACs retired to demonstrate CFS compliance be generated within the Midwest Region, as defined by 26 CFR Ch. I, Sch. A, § 1.45V-4 Paragraph (d)(2)(ix), or meet the 45V requirements for interregional delivery, as defined by 26 CFR Ch. I, Sch. A, § 1.45V-4 Paragraph (d)(3)(iii)(B).[118]

With an awareness that REC purchases from the Midwest region may not always be possible, the Department stated:

> The Department notes that it may not always be possible to purchase RECs from the Midwest region. The Department intends to discuss appropriate off-ramps in the Round 4 comment period, but recommends regional compliance as the standard to meet before exemptions are granted.[119]

MRES responds to the Department's recommendation:

> The Department's proposal is contrary to both the plain language and intent of Minn. Stat. § 216B.1691. Minn. Stat. § 216B.1691, subd. 4(b) clearly states in lieu of generating or procuring energy directly to satisfy the CFS, a utility may utilize RECs allowed under a Commission-approved program. This provision expressly grants utilities the option to meet the CFS by utilizing renewable energy attributes that are separate and distinct from the energy. To treat RECs (or EACs) as only being counted for CFS compliance when the attributes are bundled with deliverable energy runs counter to how RES compliance has been determined for nearly two decades. The Legislature could have, but chose not to, create a requirement that the energy associated with a REC also be deliverable to the Midwest region of MISO. Instead, the Legislature's decision to have the CFS subject to the same statutory provisions as the EETS with respect to RECs underscores the Legislature's intent to not impose a requirement for

[118] Department Initial Comments at 14.
[119] Department Initial Comments at 14.

> deliverability into MISO. Finally, requiring deliverability directly contravenes the Legislature's directive that the Commission "shall facilitate the trading of renewable energy credits between states."
>
> Further, requiring delivery of the energy associated with the RECs into the MISO Midwest footprint would unduly burden entities that have built renewable facilities outside MISO. MRES' Pierre Solar Project and Brookings Solar Project (currently under construction) are both located in South Dakota within the Southwest Power Pool footprint. It is not financially feasible for MRES to purchase transmission service between SPP and MISO for these solar energy projects. MRES believes the RECs associated with the energy produced from these projects should count toward CFS compliance, just as they currently count toward compliance with the EETS. Otherwise, to impose a deliverability requirement not found in statute would be contrary to Minn. Stat. § 216B.1691, subd. 4 that allows one REC to be used to:… satisfy both the carbon-free energy standard obligation under subdivision 2g and either the renewable energy standard obligation under subdivision 2a or the solar energy standard obligation under subdivision 2f, if the credit meets the requirements of each subdivision.[120] [citations omitted]

Basin Electric makes a similar argument about generation in SPP with no transmission access, and additionally cites Minn. Stat. § 216B.1691, subd. 4(a) compliance concerns.[121] Minn. Stat. § 216B.1691, subd. 4(a) states "[t]he program must treat all eligible energy technology equally and shall not give more or less credit to energy based on the state where the energy was generated or the technology with which the energy was generated." CMPAS also cites the same concern about Minn. Stat. § 216B.1691, subd. 4(a) compliance.[122]

CMPAS explains that utilities will plan around meeting exemptions to the proposed standard, which will increase the complexity and administrative burden of compliance through the exemption process.[123] CMPAS also presents Table 1 in its Reply Comments, which is shown in Table 2 below:

[120] MRES Reply Comments at 3-4.
[121] Basin Electric Reply Comments at 2-3.
[122] CMPAS Reply Comments at 9-10.
[123] *Id*., at 8.

Table 2: CMPAS' Response to the Department's Geographic Recommendation

Reason a Utility Would Retire EACs from Generation Located Outside of the Midwest Region	Had the utility initially contracted for physical delivery of energy from a carbon-free resource?	Considered by the Department in Initial Comments?
The utility is one of several utilities who contract for physical energy from a set of large generators of the same type in various locations. Since it is not always possible to tell exactly which generator has delivered the actual, physical energy to each utility, the generator owner provides RECs from any of generators to any of the utilities. Example: Power from Western Area Power Administration (WAPA) hydropower reservoir dams.	Yes	Unclear[12]
The utility has traded more expensive EACs originating from its contracted renewable or carbon-free generation in the Midwest Region with less expensive EACs originating from generation in a different location.	Yes	No
The utility has a PPA with a counterparty for EACs bundled with physical energy from a specific carbon-free generator in the Midwest Region. The PPA counterparty has failed to deliver at contractual minimum levels and provides the utility with replacement energy from the MISO Market and unbundled EACs from a different location outside the Midwest Region.	Yes	No
The utility truly does not have physical delivery for any energy from a renewable or carbon free resource in the Midwest Region.	No	Yes

Source: CMPAS Reply Comments at 10.

Taken together, the reply comments from MRES, Basin Electric, and CMPAS provide a compelling narrative to reject the Department's recommendation. While there are additional modifications that could be applied to address many of the issues raised by these parties, the Minn. Stat. § 216B.1691, subd. 4(a) compliance concern is the most compelling, even in spite of the Department's proposed exemption process. Based on these comments, the Department withdraws its recommendation.

The geographic issue, however, is not resolved with the Department's withdrawal of its recommendation. The CSG raises a conflicting concern, with regard to Minn. Stat. § 216B.1691, subd. 9(a).[124] The statute requires that the Commission "take all reasonable actions within the commission's statutory authority to ensure this section is implemented in a manner that maximizes net benefits to

[124] CSG Reply Comments at 15-16.

all Minnesota citizens," which includes jobs,[125] and air emissions[126] that are particularly Minnesota-specific.

CSG's comment highlights that Minn. Stat. § 216B.1691, subd. 4 and Minn. Stat. § 216B.1691, subd. 9 are in conflict with one another because of the push for equal treatment of RECs and a geographic preference. The Department concludes that subdivision 4 must take precedence over subdivision 9, consistent with reply comments submitted by MRES, Basin Electric, and CMPAS, however subdivision 9 must still be addressed.

None of the three prior Commission orders in the present docket devote any discussion to subdivision 9 compliance. The Commission's November 7, 2024 Order references subdivision 9 only once, and simply references the statute's existence: "MRES noted that Minn. Stat. § 216B.1691, subd. 9, directs the Commission to take all reasonable actions within its authority to implement the statute to maximize net benefits."[127] While the Commission issued orders on reporting requirements under Minn. Stat. § 216B.1691, subd. 3(a)(5-7), which includes labor and environmental reporting,[128] the Commission did not address Minn. Stat. § 216B.1691, subd. 9 compliance in its December 6, 2023 Order. This lack of discussion is contrasted by the significant concurrent revisions to subdivision 9 with the passage of H.F. 7 and the CFS. The language included in subdivision 9 does not strictly require a compliance component, but strongly suggests that local benefits should be considered. The absence of a compliance requirement puts into question how net benefits for Minnesota citizens can be maximized without explicit consideration somewhere. Finally, the Department finds that a formal compliance requirement is supported by Minn. Stat. § 216B.1691, subd. 2(b)(1), which requires the Commission to issue necessary orders to "protect against undesirable impacts on the reliability of the utility's system and economic impacts on the utility's ratepayers and that consider technical feasibility." The Minnesota Legislature clearly articulated its concerns about undesirable economic impacts in subdivision 9, and thus the Department concludes that a Commission order on subdivision 9 is justified.

The Department concludes that a geographic preference is the most appropriate mechanism to address the dissenting parties' concerns, as well as to address subdivision 9. An EAC geographic preference was ordered in Docket No. G-008/M-23-215 in the Commission's October 9, 2024 Order.[129] The Commission required that CenterPoint Energy include a geographic preference in its Pilot C renewable natural gas (RNG) EAC competitive bidding process:

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[125] Minn. Stat. § 216B.1691, subd. 9(a)(1),(2), and (4).
[126] Minn. Stat. § 216B.1691, subd. 9(a)(5).
[127] Minnesota Public Utilities Commission, Order Initiating new Docket and Clarifying "Environmental Justice Area", November 7, 2024, (eDockets) 202411-211701-01, at 8.
[128] See order points 8-10. Minnesota Public Utilities Commission, Order Clarifying Implementation of Changes to Minn. Stat. § 216b.1691 and Directing Additional Comment Period, December 6, 2023, (eDockets) 202312-201019-01.
[129] *In the Matter of CenterPoint Energy's Natural Gas Innovation Plan*, Minnesota Public Utilities Commission, Order Approving Natural Gas Innovation Plan With Modifications, October 9, 2024, (eDockets) 202410-210845-01, (hereinafter "October 9, 2024 Order").

> The Commission modifies Pilot C such that the express geographic preferences are as follows:
>
> a. RNG interconnected with CenterPoint's Minnesota distribution system;
>
> b. RNG within Minnesota; and
>
> c. RNG in neighboring regions.[130]

There are two relevant venues by which a geographic preference could apply. As referenced in the above order point, the procurement of physical energy assets or power purchase agreements (PPAs) in a competitive bidding process is the most appropriate venue to consider subdivision 9 compliance. There are additional circumstances whereby a noncompetitive procurement may take place, such as in an IRP or a negotiated bilaterial contract. The economic and environmental benefits considered under subdivision 9 are inherently derived from physical assets, however the economic contribution of EACs to physical asset cash flow is also relevant. While it is not appropriate to disallow utilities to procure assets or EACs from outside Minnesota, it is appropriate to require utilities to demonstrate how net benefits for Minnesota citizens are maximized for all procurements that involve bundled and unbundled EACs necessary to demonstrate Minn. Stat. § 216B.1691 compliance.

The Department recommends the Commission order all procurements of physical assets, PPAs, and any other contract that involves EACs necessary to meet Minn. Stat. § 216B.1691 compliance requirements be subject to the following geographic preference reporting requirements at the time the procurement decision is proposed:

- ***A. <u>Procurements Within Minnesota</u>:***
  1. ***The number of EACs expected to be procured each year.***
- ***B. <u>Procurements in Counties or Municipal Divisions Bordering Minnesota</u>:***
  1. ***The number of EACs expected to be procured each year.***
  2. ***The state and county or municipal division and country of procurement.***
- ***C. <u>Procurements in the MISO territory of Non-Border Counties of North Dakota, South Dakota, Iowa, Wisconsin, and Manitoba</u>:***
  1. ***The number of EACs expected to be procured each year.***
  2. ***The state and county or municipal division and country of procurement.***
  3. ***Explanation of any technical, cost, or other constraints that preclude a procurement under A. or B.***
  4. ***Explanation of any local benefits including jobs, tax revenue, other economic factors, air quality, and environmental justice considerations that will not be received by Minnesota ratepayers.***

[130] See Order Point 3 of the October 9, 2024 Order.

D. *<u>Procurements in all Other Locations</u>:*

1. ***The number of EACs expected to be procured each year.***
2. ***The state and county or province of procurement.***
3. ***Discounted cash flow that demonstrates why a procurement under A., B., or C. is financially harmful to Minnesota ratepayers.***
4. ***Technical analysis of why there is insufficient transmission, siting, or unbundled EAC availability under A., B., or C.***
5. ***Quantification of any local benefits including jobs, tax revenue, direct and indirect economic factors, air quality, and environmental justice considerations that will not be received by Minnesota ratepayers.***

The logic behind the proposed recommendation is to increase the required due diligence to justify why Minnesota citizens should not directly receive benefits from CFS compliance.

A., which involves procurements within Minnesota, provides the greatest benefits to Minnesota ratepayers because all of the benefits are accrued in Minnesota. There is no need to justify how benefits have been maximized for Minnesotans if the procurement is within Minnesota.

B., which involves procurements in counties that border Minnesota, still provides substantial benefits to Minnesota ratepayers because employment and air quality benefits can still reasonably be expected to be received by Minnesota ratepayers. Although some jobs and tax revenues will be received by bordering states, there is not a need to justify why EAC generation in these locations is justified.

C., which involves procurements within the MISO territory of bordering states and Canada not included in B., requires a semi-formal justification process to explain why Minnesota ratepayers are less likely to realize the majority of benefits from CFS compliance. All generators under C. participate in the MISO market, and therefore influence wholesale electricity prices paid by Minnesota ratepayers. Similarly, employment and air quality may still be realized by Minnesota ratepayers, albeit at a diminished rate. Reporting under C. requires utilities to contemplate and explain why Minnesota ratepayers are better off siting generation further away from Minnesota. Jobs, tax revenue, economic benefits, air quality, and environmental justice considerations are significantly diminished, under C., so there should be justifiable economic or technical constraints that offset the loss of local benefits. The Department chooses the word "explanation" for C. to indicate that a discussion of unrealized benefits in Minnesota is necessary, such as bid price comparison, lost tax revenues, unrealized direct and indirect jobs, or expected MWh of generator displacement. However, the justification process expected is semi-formal, such that industry averages or other readily available materials can be used to explain why generation in C. is preferable or technically infeasible compared to A. and B.

D., which involves procurements in all other locations, requires a formal justification process to explain why Minnesota ratepayers are likely to realize little to no benefits from CFS compliance. Some of the locations in D. are still within the MISO territory, and thus impact wholesale electric rates, and much of the generation in D. is not within MISO. It is not expected that any employment and air quality benefits will be realized in D, which is the key differentiating factor between C. and D. Reporting under D. requires utilities to formally quantify why Minnesota ratepayers should be expected to receive no local benefits. Under D., utilities are expected to perform the highest degree of due diligence. Formal discounted cash flows and a technical analysis are required to demonstrate why generation assets used for CFS compliance cannot be located in A., B., or C., or would otherwise be significantly less expensive such that local benefits cannot justify a higher price. This analysis also requires a formal quantification of employment, air quality, and environmental justice benefits that will not be realized from the procurement, which includes direct and indirect economic benefits.

The Department understands that unbundled EAC procurements cannot supply all of the data required under C.3, C.4, D.3, D.4, and D.5 because of data availability constraints. However, EAC revenues flow to the geographic location of the generator and make up a fractional share of the generator revenue. Therefore, unbundled EAC contracts should report on the fractional share of local benefits to the extent that data is available to report.

C. WHAT CONSIDERATIONS SHOULD THE COMMISSION TAKE INTO ACCOUNT REGARDING THE DOUBLE COUNTING OF RENEWABLE ENERGY CREDITS (RECS) TO MEET MULTIPLE REQUIREMENTS?

The Department has no additional comments on this notice topic.

D. HOW SHOULD NET MARKET PURCHASES BE COUNTED TOWARDS CFS COMPLIANCE?

In Reply Comments, GRE,[131] MRES,[132] and Connexus[133] raise an issue of statutory compliance with Minn. Stat. § 216B.1691, subd. 2d.(b)(ii). These commentors assert that EACs are incompatible with the plain language reading of the statute, which states:

> (2) require the commission to allow for partial compliance with subdivision 2g from:
>
> […]
>
> (ii) an electric utility's annual purchases from a regional transmission organization net of the electric utility's sales to the regional transmission organization, but only for the percentage of annual net purchases that is carbon-free, which percentage the commission must calculate based on

[131] GRE Reply Comments at 8.
[132] MRES Reply Comments at 4.
[133] Connexus Reply Comments at 2-3.

> the regional transmission organization's systemwide annual fuel mix or an applicable subregional fuel mix.

Notably, the CSG[134] and CRS[135] discuss why RECs are necessary to prevent double counting at length, and were discussed in the Department's Reply Comments.[136] Despite these excellent justifications to use RECs, the commenting parties continue to assert that RECs cannot be required for net market purchase partial compliance. For this reason, it is helpful to use a real-world example to illustrate the request that the commenters make. On October 9th, 2024, the Commission approved CenterPoint Energy's (CPE) Natural Gas Innovation Act (NGIA) Petition,[137] which included $46,521,911 for the purchase of renewable natural gas (RNG) environmental attributes.[138] Similar to RECs, the RNG environmental attributes represent the environmental claim, and are separated from the physical energy. CPE's Petition estimated environmental attribute costs that ranged from $16-50/Dth, while the physical gas is expected to sell around $3/Dth.[139] In CPE's lowest attribute cost example, the environmental attributes comprise 84 percent of the total cost of the gas. The significantly higher cost of RNG is accepted by the RNG market because the environmental attributes allow the purchaser to claim an emissions reduction upon the retirement of the environmental attributes. Without the sale of environmental attributes, these RNG projects would stand no chance of being financed.

If the dissenting parties' request is granted, then it would be appropriate to question the need for ratepayers to pay $46,521,911 in marginal costs when CPE could buy the physical gas at $3/Dth and still claim the emissions reduction. The same logic extends to REC purchases. If utilities do not have to pay to claim the environmental benefits, then the value of the environmental attributes would be diminished. This diminished value damages the financial viability of any project that relies on environmental attributes for its financing, regardless of whether the environmental attribute is for RNG or carbon-free power.

The above example illustrates a key oversight of the commenters' request for what the CSG refers to as "double claiming."[140] Minn. Stat. § 216B.1691, subd. 1(b) defines "Carbon-free" as "a technology that

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[134] Initial Comments in their entirety. Carbon Solutions Group, LLC, Initial Comments, January 29, 2025, (eDockets) 20251-214606-01.
[135] Initial Comments in their entirety. Center for Resource Solutions, Initial Comments, January 29, 2025, (eDockets) 20251-214651-01 at 8, (hereinafter "CRS Initial Comments")
[136] Department Reply Comments at 18-20.
[137] October 9, 2024 Order.
[138] See Table 2 "RNG Produced from Ramsey & Washington County Organic Waste" and "Renewable Natural Gas RFP Purchase" in the revised portfolio. *In the Matter of the Company's First Natural Gas Innovation Act ("NGIA") Innovation Plan*, CenterPoint Energy, Reply Comments, March 15, 2024, Docket No. G-008/M-23-215, (eDockets) 20243-204399-04, at 32.
[139] For example, CenterPoint Energy's Natural Gas Innovation Act (NGIA) petition anticipated environmental attribute prices of $16 – 50 / Dth, as compared to conventional natural gas prices that typically average around $3 / MMBtu (Source: US Energy Information Administration – Henry Hub Natural Gas Spot Price). See Table 9. *In the Matter of A Petition by CenterPoint Energy for Approval of its First Natural Gas Innovation Plan,* Minnesota Department of Commerce, Initial Comments, January 17, 2024, Docket No. G008/M-23-215,(eDockets) 20241-202261-02.
[140] CSG Reply Comments at 4-6.

generates electricity without emitting carbon dioxide." The ownership and retirement of a REC allows a utility to claim the environmental attributes associated with the electricity purchase. Without the right to claim the environmental attributes, a utility cannot meet the statutory definition of Carbon-free electricity through net market purchases alone. Instead, the power is what the CSG refers to as "null power." The entire compliance structure of Minn. Stat. § 216B.1691 relies on the core principle that an eligible energy technology or carbon-free generator is only substantiated through the ownership and retirement of EACs. There is no reason to deviate from this practice. The commenters' interpretation of statute would therefore lead to an absurd result.

Finally, if the Commission is not persuaded by these arguments, there is one additional statutory conflict with the utility's request for double claiming. In order to implement both the EETS/CFS, and net market purchase double claiming, the statute would require two separate definitions of "Carbon-free" electricity. The existing definition of "Carbon-free" explicitly refers to the environmental attributes of electricity by its reference to carbon dioxide. Carbon dioxide is not sold in MISO wholesale power markets, which is why the statutory definition of "Carbon-free" explicitly refers to attributes and not physical electricity in isolation. Therefore, attributes must be either retained by the generating party or sold separately from the cost of electricity. The implementation of double claiming requires a separate definition of "Carbon-free," that may mirror the definition of "eligible energy technology," which does not rely on environmental attributes to define statutory eligibility. The alternative definition would bypass the ownership of EACs to substantiate CFS compliance and would allow for double claiming based on physical electricity generation, such as a MISO subregional mix, rather than the environmental attributes of electricity. Even if a second definition of "Carbon-free" is adopted, the Commission currently substantiates the EETS and its statutory definition through EACs. Further, if physical electricity generation is required for CFS compliance under a singular alternate definition of "Carbon-free," then effectively unbundled RECs cannot be used for Minn. Stat. § 216B.1691 compliance, which violates Minn. Stat. § 216B.1691, subd. 4. Because the Commission cannot adopt two separate definitions of the same statute, double claiming is not statutorily permissible.

There is one statutorily compliant possibility to derive some carbon-free electricity from net market purchases without REC purchases and retirements. In its Initial Comments, CRS provides an explanation of how residual mix accounting works.[141] CRS states:

> A residual mix represents generation and emissions that remain after specified power purchases have been allocated. Residual mix calculations verified through retirement of RECs, therefore, creates an indelible record tracking the attributes of carbon-free electricity from generation to consumption and ensuring those attributes are claimed exclusively by a single owner.[142] [citation omitted]

[141] CRS Initial Comments at 8-11.
[142] *Id.*, at 9.

This system would allow utilities to claim carbon-free power only after all other claims have been subtracted from the power mix, which may result in no unclaimed EACs, or so few residual EACs that the carbon-free percentage of the power mix would essentially be meaningless for CFS compliance. Because residual mix accounting relies on EAC retirements, it would be prudent for the Commission to adopt the Department's recommendation to rescind the four-year shelf life of EACs to expedite the residual mix accounting process.

It is important to understand that if the Commission adopts residual mix accounting, there would be a need to hire a contractor that can perform the annual residual accounting after the compliance year, which would require substantial involvement from all Minnesota utilities to report to the contractor which RECs are owned and retired in the reporting year. This process may take several months to complete, and utilities may still need to purchase additional EACs after the residual accounting for the reporting year is complete, particularly because both net market purchases and the residual mix are unknown in the compliance year. The purchase of EACs after the determination of the residual mix may also require several months to complete. It is possible that residual mix accounting could delay CFS compliance determinations by an entire year to allow all parties to claim any residual EACs and then retire and then report necessary EACs to fully meet CFS compliance requirements.

The administrative burden of the proposed process does not appear to be worth the potential revelation that there may be no residual RECs available to claim at all. Therefore, the easiest compliance pathway is to adopt the Department's recommendation:

> The Department recommends the Commission order:
>
> > A. Net market purchases shall only be quantified for CFS compliance when the carbon-free share of the systemwide annual fuel mix or an applicable subregional fuel mix is necessary to demonstrate CFS compliance.
> >
> > B. EACs must be purchased in the first three months of the subsequent reporting year for the carbon-free share of the systemwide annual fuel mix or an applicable subregional fuel mix that is necessary to demonstrate CFS compliance.

E. ARE THERE OTHER ISSUES OR CONCERNS RELATED TO THIS MATTER?

The Department has no additional comments on this notice topic.

IV. DEPARTMENT RECOMMENDATIONS

Based on analysis of Minn. Stat. § 216B.1691 and the information in the record, the Department has prepared recommendations, which are provided below. The recommendations correspond to the subheadings of Section III from the Department's Initial Comments.

A. WHEN AND HOW SHOULD UTILITIES REPORT PREPAREDNESS FOR MEETING UPCOMING CFS REQUIREMENTS?

- A.1. The Department recommends the Commission order electric utilities to begin to report CFS compliance in 2029 for generation year 2028.
- A.2. The Department recommends that any decisions regarding modifications to the existing REC tracking system be made in Docket No. E-999/CI-24-352.

B. BY WHICH CRITERIA AND STANDARDS SHOULD THE COMMISSION MEASURE AN ELECTRIC UTILITY'S COMPLIANCE WITH THE CFS?

- B.1.1.1. The Department recommends the Commission order electric utilities to report all sales and purchases of EACs at the time interval required for CFS matching.
- B.1.1.2 The Department recommends the Commission order electric utilities to report all hourly Minnesota retail electric sales.
- B.1.2.1.1. The Department recommends the Commission order hourly matching for CFS compliance for electric all electric utilities.
- B.1.2.1.2. The Department recommends that the Commission modify order points 1 and 3 from its December 18, 2007 Order in Docket Nos. E-999/CI-04-1616 and E999/CI-03-869 and modify order point 6 of the Commission's December 6, 2023 Order in Docket E-999/CI- 23-151 to remove "All renewable energy credits generated from such facilities will be eligible for use in the year of generation and for four years following the year of generation," and replace the language with "All renewable energy credits generated from such facilities will be eligible for use in the year of generation and for one year following the year of generation." These orders will be modified effective January 1, 2030.
- B.1.2.2.1. The Department recommends the Commission order the creation of a Commission-led stakeholder workgroup that is tasked with the analysis, development, testing, and recommendation of best practices for the optimization of societal costs as they pertain to:
  A. Hourly matching for CFS compliance;
  B. Methodologies to implement hourly matching scenario requirements in integrated resource plans;
  C. The integration of transmission constraints in integrated resource plans;
  D. The integration of energy attribute certificates and allocation thereof in integrated resource plans;
  E. Stochastic modeling of variable renewable generation into integrated resource plans; and
  F. The co-optimization of transmission and generation resources.

- B.1.2.2.2 The Department recommends the Commission order a CFS compliance true up period of three months after the conclusion of the reporting year.

- B.1.2.3. The Department recommends the Commission order all integrated resource plans where the utility uses a capacity expansion model to incorporate hourly matching constraints in the models to demonstrate CFS compliance.

- B.1.3. The Department recommends the Commission order:
  A. EACs be issued equivalent to metered generation on a per MWh basis;
  B. A single REC be issued for all generation that may be retired to demonstrate both EETS and CFS compliance;
  C. A carbon-free allocator, which defines the percentage of CFS eligible generation, must be used for any generation facility that is partially CFS compliant;
  D. For all generation made in a CFS partial compliant facility that is also eligible for the EETS, metered generation in A. shall be:
     - Multiplied by C. to determine the whole number of RECs to issue that are fully eligible for both the EETS and CFS;
     - Multiplied by one minus C. to determine the whole number of RECs to issue that are only eligible for the EETS;
  E. For all generation made in a CFS partial compliant facility that is not eligible for the EETS, metered generation in A. shall be multiplied by C. to determine the whole number of AECs to issue that are only eligible for the CFS; and
  F. The methodology to determine the carbon-free allocation shall be decided in Docket No. E-999/CI-24-352.

- B.6. The Department recommends that all decisions made regarding criteria and standards to measure a utility's partial compliance with the CFS be made in Docket No. E-999/CI-24-352.

- B.7. The Department recommends the Commission order CFS and RES compliance measurement to factor in line losses to determine compliance with each standard.

C. WHAT CONSIDERATIONS SHOULD THE COMMISSION TAKE INTO ACCOUNT REGARDING THE DOUBLE COUNTING OF RENEWABLE ENERGY CREDITS (RECS) TO MEET MULTIPLE REQUIREMENTS?

- None.

D. HOW SHOULD NET MARKET PURCHASES BE COUNTED TOWARDS CFS COMPLIANCE?

- D.1. The Department recommends that all decisions made regarding criteria and standards to measure a utility's net market purchases be made in Docket No. E-999/CI-24-352.

- D.2. The Department recommends the Commission order:
  A. Net market purchases shall only be quantified for CFS compliance when the carbon-free share of the systemwide annual fuel mix or an applicable subregional fuel mix is necessary to demonstrate CFS compliance.
  B. EACs must be purchased in the first three months of the subsequent reporting year for the carbon-free share of the systemwide annual fuel mix or an applicable subregional fuel mix that is necessary to demonstrate CFS compliance.

E. ARE THERE OTHER ISSUES OR CONCERNS RELATED TO THIS MATTER?

- E.1. The Department recommends the Commission order the Commissioner of Commerce to seek authority from the Commissioner of Management and Budget to incur costs for specialty services to provide auditing of all CFS reports for up to three years

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Xcel Energy		Information Request No.	3
Docket No.:	E999/CI-23-151		
Response To:	Minnesota Department of Commerce		
Requestor:	Ari Zwick, Steve Rakow, Sydnie Lieb		
Date Received:	April 1, 2025		

Question:
Topic: Hourly Constraint Modeling Assumptions
Reference(s): Xcel Reply Comments, Pages 9-10

On pages 9-10 of Xcel's reply comments, Xcel describes the results of an hourly matching modeling process performed in EnCompass. Please provide a description of all EnCompass inputs that were modified from Xcel's recently approved Settlement Agreement plan in Docket No. E002/RP-24-67 that are necessary to enforce the hourly matching constraints described in Xcel's reply comments.

Response:

The only modification made within the EnCompass model for this exercise from the Settlement Agreement EnCompass model run was the creation of a renewable portfolio standard (RPS) Program. Within EnCompass, an RPS Program is an allowance program that allows a user to set a constraint determining what percentage of system generation is provided by certain resources – in this case, zero carbon-emitting resources. The RPS Program was only applied to the Minnesota load within the NSP System. The input file for this modification, "Input_Step_RPS Program_rnwb_nuc.xlsx", has been provided as part of the Attachment A files for the Department's IR No. 1.

Preparer:	Jared K. Nelson
Title:	Director
Department:	Energy Supply and Market Modeling
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Date:	April 11, 2025

PRINCETON UNIVERSITY

ZERO LAB

Zero-carbon Energy Systems Research and Optimization Laboratory

POLICY MEMO

Impacts and Feasibility of an Hourly-Matched Clean Electricity Standard in Minnesota

Wilson Ricks and Jesse D. Jenkins
Princeton University | April 14, 2025

Executive Summary

- **A proposed requirement to evaluate compliance with Minnesota's 100% carbon-free electricity law on an hourly basis is likely to be feasible.**
- **Tighter regional boundaries on qualifying clean power reduce emissions and increase costs.**
- **Hourly matching is made easier by long-duration energy storage and creates an early market for this technology.**

Introduction

In 2023, the state of Minnesota passed a law requiring all local electric utilities to provide 100% carbon-free electricity to Minnesota customers by 2040. As with many similar state-level clean electricity standard (CES) policies, Minnesota utilities will be required to demonstrate compliance by procuring and retiring "energy attribute certificates" (EACs) representing individual units of qualifying clean generation. However, many important details of the law's implementation have yet to be determined.

One key emerging question is whether utilities should be required to procure EACs from generation that is correlated in both time and space with their customers' electricity demand and that could by extension be reasonably understood to have physically met Minnesotans' electric power needs. Temporal and spatial matching requirements are an emerging gold standard for claims to consumption of clean electricity, and such requirements were recently adopted by the US federal government in a rulemaking governing the use of carbon-free electricity for subsidized clean hydrogen production.

In recent comments submitted to the Minnesota Public Utilities Commission, the Minnesota Department of Commerce recommended that the PUC require utilities to match the clean generation they procure on an hourly basis with their retail electric sales in order to demonstrate compliance with the 100% CES law. The DOC proposed the following escalating matching requirements:

- **By 2035**, an hourly matching requirement of 80% for public utilities and 60% for other utilities;
- **By 2040**, an hourly matching requirement of 90% for all utilities; and
- **By 2045**, an hourly matching requirement of 100% for all utilities.

In addition, the DOC proposed that all EACs used to meet this requirement must be sourced from within the Midwest grid region defined in federal clean hydrogen production regulations, equivalent to the northern half of the Midwest Independent System Operator's territory (see Figure 1). In this policy memo we examine both the feasibility and impacts of DOC's proposal, as well as the implications of potential variations on the proposed policy.

Princeton University's Zero-carbon Energy systems Research and Optimization Laboratory conducts research to improve decision-making and accelerate rapid, affordable, and effective transitions to net-zero carbon energy systems. The ZERO Lab improves and applies optimization-based modeling tools and methods to understand complex macro-scale energy systems and uses these tools to evaluate and optimize emerging low-carbon energy technologies and generate decision-relevant insights to guide national and sub-national jurisdictions in transitioning to net-zero emissions energy systems. Prof. Jesse D. Jenkins is the Principal Investigator. For more, see http://zero.lab.princeton.edu

Approach

We used the GenX electricity system optimization model to evaluate the emissions, resource procurement, and consumer cost impacts of an hourly matching requirement for Minnesota's electric utilities following the DOC's proposed schedule. GenX is an open-source system planning model that optimizes investments and operations (at hourly resolution) to minimize the cost of delivered power, subject to physical and policy constraints. In doing so it simulates the expected behaviors of both competitive markets and system planners, making it a useful tool for assessing the expected impacts of electricity sector policy interventions. GenX is capable of operating with high temporal resolution, and has been used in the past in multiple peer-reviewed studies examining the impacts of hourly-matched clean electricity procurement in the context of both federal clean hydrogen subsidy rules and corporate carbon accounting.

In this study we use GenX to model the evolution of the electricity sector from the present day through 2045 across four five-year planning periods. In each planning period we model the operations of the system at hourly resolution across 30 representative weeks, which are selected from seven weather years of demand and generation data. The model is capable of tracking energy held in storage across this entire seven-year period, a key feature permitting accurate modeling of multi-day energy storage resources. We use 30 model zones to represent the US Eastern Interconnection – the larger synchronous grid of which Minnesota is a part – including four zones representing the state of Minnesota itself (see Figure 1).

To model the DOC's proposed hourly matching requirement, we implement a constraint requiring that enough qualifying carbon-free energy be sourced from within a specified spatial boundary to match the required portion of Minnesota electricity demand across the required number of hours. Qualifying carbon-free resources are assumed to include biomass, hydropower, in-state nuclear, wind, solar, and any qualifying energy stored and then discharged from batteries. Technologies eligible for new deployment in our central scenarios include wind, solar, batteries, gas, and nuclear, and costs are adopted from the National Renewable Energy Laboratory's Annual Technology Baseline 2024.

We model three hypothetical sets of spatial boundaries on qualifying EACs to assess the influence of this potential policy lever on outcomes of interest. These three boundaries are shown in Figure 1, and are here referred to as:

- **Midwest**, equivalent to the region of the same name defined in the US DOE's Transmission Needs Study and federal clean hydrogen regulations, and consisting of the MISO North and MISO Central grid regions;
- **MISO North**, a tighter geographic boundary based on the MISO region of the same name, and roughly covering the states of North Dakota, Minnesota, and Iowa; and
- **In-State Only**, a case where all demand must be matched with generation in Minnesota.

Figure 1: Illustration of three potential sets of spatial boundaries for qualifying EACs used for hourly matching of clean electricity in Minnesota, outlined in bold and overlaid on a map of the 30-zone model of the US Eastern Interconnection used in this study.

We also recognize that intermediate fractional hourly matching requirements like those included in the DOC proposal (e.g. 90%) can have multiple possible interpretations. One such interpretation is that a 90% matching target requires matching 90% of demand in every hour of the year. A second interpretation is that a 90% matching target simply requires matching 90% of all demand in a year without any restrictions on which particular hours are or are not matched. We refer to these interpretations as **"firm"** matching and **"flexible"** matching, respectively (see Figure 2 for illustrations), and model both in this study.

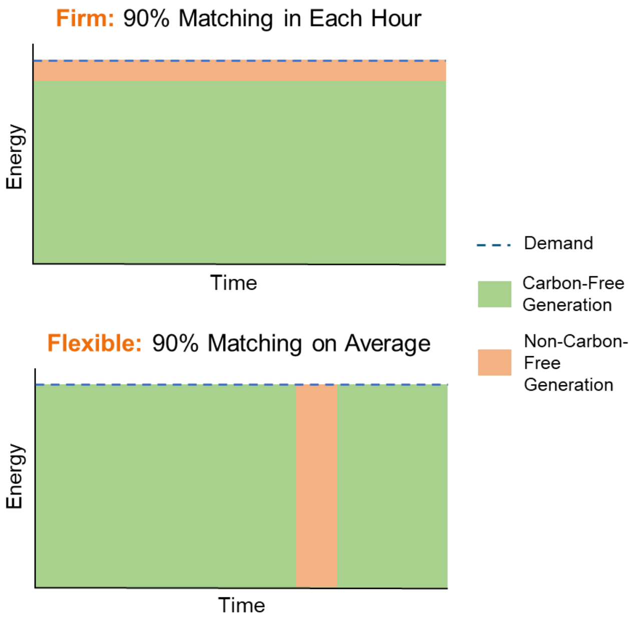

Figure 2: Stylized illustration of two potential implementations of a fractional hourly matching requirement (in this case 90%). In the flexible case, it is possible for demand in some hours to be entirely unmatched as long as 90% is matched on average over the year.

We assess the impacts and feasibility of different potential implementations of an hourly matching requirement in Minnesota by comparing model outcomes in 2035, 2040, and 2045 to a baseline scenario where Minnesota's carbon-free electricity standard is implemented similarly to other state CES policies, i.e. via annual matching of EACs. We focus on two primary metrics of interest: **impacts on emissions** and **impacts on consumer electricity costs** in Minnesota. We calculate emissions impacts by comparing total emissions in the entire Eastern Interconnection model to those observed in the baseline case, recognizing that there may be knock-on emissions impacts that extend beyond the borders of the matching region due to the interconnected nature of electricity grids and markets. We calculate weighted average electricity costs for Minnesota consumers by extracting energy prices, capacity prices, annual EAC prices for conventional CES and RPS programs, and hourly EAC prices for hourly programs from the model. Because the GenX only optimizes generation and transmission expansion, it is assumed that costs for distribution and existing transmission are identical across cases.

Findings

Compliance with the DOC's proposed escalating hourly matching requirement and regional boundaries is feasible at no excess cost under baseline assumptions. Due to the large spatial extent of the Midwest regional boundary and the relatively large amount of qualifying clean energy development projected within this boundary, even a 100% hourly matching requirement is technically feasible under our baseline assumptions at no excess cost. Figure 3 shows a comparison between Minnesota's hourly electricity demand and the hourly stacked generation from qualifying clean energy technologies within the Midwest region in 2045 without any hourly matching requirement (i.e., those deployed based on economic viability alone), illustrating sufficient availability of qualifying power in all hours. A 100% hourly matching requirement could thus be met at no excess cost in this scenario if Minnesota utilities are able to effectively acquire the necessary EACs through markets and would therefore also bring no additional benefits beyond the baseline (see Table 1). Larger impacts may be possible if real-world renewable deployment is less than the modeled baseline, in which case Minnesota's policy could drive deployments that would not have occurred otherwise.

Using MISO North as the boundary for qualifying clean power increases both the impact and cost of an hourly matching requirement. In scenarios where MISO North is used as the regional boundary on qualifying clean electricity, the emissions impact of an hourly matching requirement becomes significant. A 100% matching requirement with MISO North boundaries mitigates up to 5 MMT CO_2/yr systemwide in 2045 (see Table 1), equivalent to roughly a quarter of Minnesota's total emissions from in-state generation today. This impact requires greater investment in a clean portfolio that provides the reliability necessary to displace fossil emissions, leading to cost premiums of up to \$10/MWh for consumers in 2045 (or roughly 8% of the current average Minnesota retail rate).

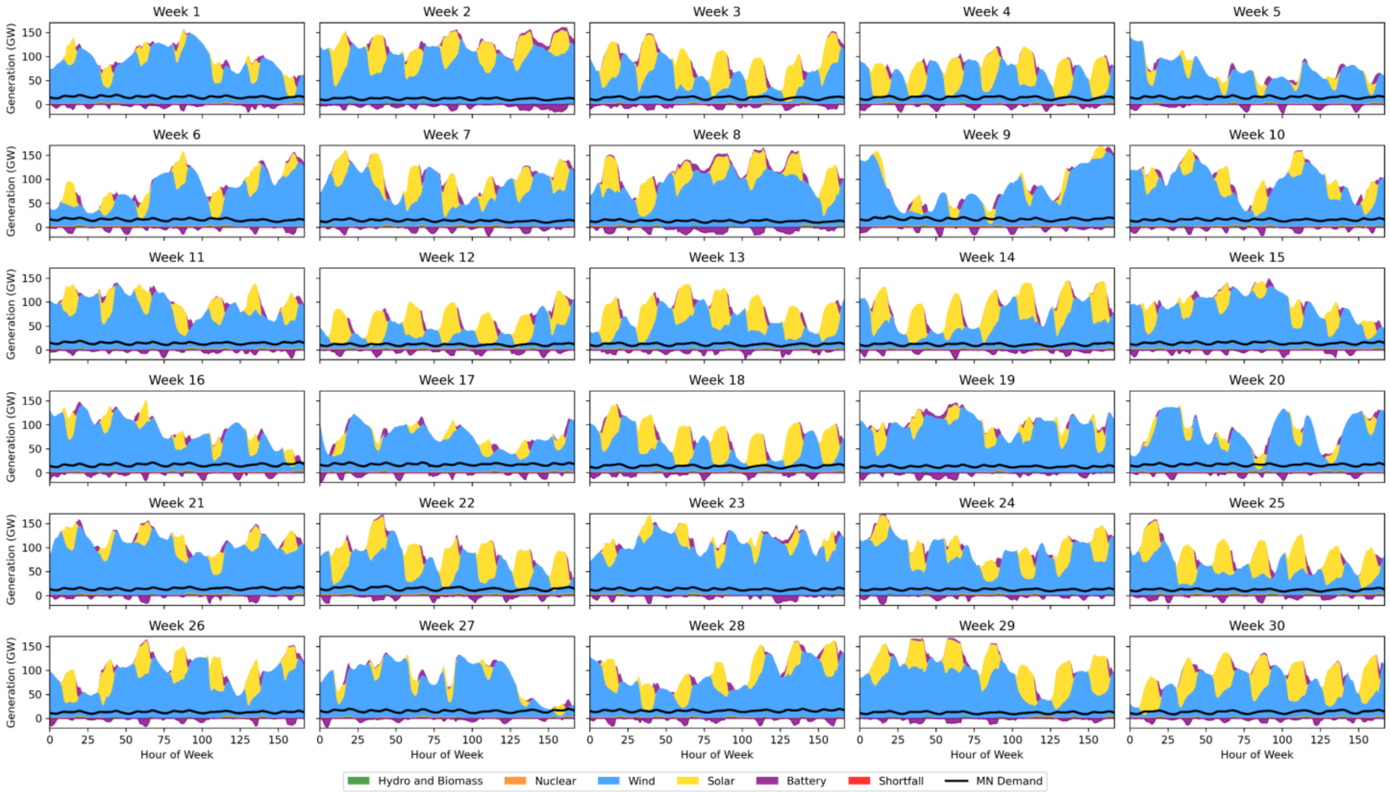

Figure 3: Stack plot showing Minnesota's hourly electricity demand alongside qualifying clean generation and storage charging within the Midwest regional boundary across 30 representative weeks in the baseline modeled scenario in 2045. If Minnesota utilities are able to trade for the necessary hourly EACs, compliance with a 100% hourly matching requirement becomes trivial.

Policy Scenario						
Matching Interpretation	**"Firm" Hourly Requirement**			**"Flexible" Hourly Requirement**		
Regional Boundary	**Midwest Region**	**MISO North**	**In-State Only**	**Midwest Region**	**MISO North**	**In-State Only**
Impact on Consumer Cost Compared to Baseline ($/MWh)						
2035	**+0**	**+2**	**+12**	**+0**	**+0**	**+0**
2040	**+0**	**+3**	**+18**	**+0**	**+0**	**+0**
2045	**+0**	**+10**	**+33**	**+0**	**+11**	**+39**
Impact on Grid Emissions Compared to Baseline (MMT CO_2/yr)						
2035	**-0**	**-6**	**-23**	**-0**	**-0**	**-0**
2040	**-0**	**-5**	**-28**	**-0**	**-0**	**-0**
2045	**-0**	**-5**	**-24**	**-0**	**-3**	**-18.5**

Table 1: Consumer cost and emissions impacts of different potential implementations of an hourly matching requirement in Minnesota. Both metrics are reported as changes relative to a baseline case where no hourly matching requirement exists. Bulk electricity costs for Minnesota consumers in the baseline case (non-inclusive of distribution costs and existing transmission costs, which are not modeled) are $30/MWh in 2035, $28/MWh in 2040, and $34/MWh in 2045.

An In-State Only requirement for qualifying clean power leads to substantial emissions reductions, but at a more significant cost premium. As shown in Table 1, the cost premium of requiring 100% hourly matching with in-state clean resources only could exceed $30/MWh if only wind, solar, and lithium-ion batteries are available for deployment. However, this policy can also mitigate more than 20 MMT CO_2/yr of emissions under baseline assumptions. While a 100% in-state requirement may not be compatible with Minnesota statute, this is the scenario most likely to fully mitigate the state's reliance on fossil generation of any kind. The magnitude of the emissions abatement observed suggests that the requirement has a significant impact on out-of-state emissions as well.

An hourly matching requirement with tighter regional boundaries requires greater investment, in renewables and (especially) storage. As shown in Figure 4, compliance with "firm" matching targets and MISO North or In-State Only boundaries (top and middle, respectively) requires deployment of more renewables and storage than in the baseline scenario. Changes in renewable capacity vary, with the MISO North scenarios for example deploying less solar and more wind than the baseline. The most consistent change in outcomes is a much greater emphasis on battery storage, and especially battery *energy* capacity and duration.

Hourly matching with tight geographic boundaries creates a key early market for multi-day storage technologies, and the availability of these technologies reduces consumer costs. In a scenario where we model an In-State Only 100% hourly matching requirement and include a long-duration storage technology with relatively high power capacity costs ($2000/kW), low round-trip efficiency (42%), and very low energy capacity costs ($20/kWh) as a new-build option in the model, this technology is deployed to help meet the hourly matching requirement (Figure 4, bottom). The Minnesota policy thus [creates an early market](#) for this technology, which does not see uptake in the absence of the hourly matching requirement. Long-duration storage can be critical for cost-effectively eliminating fossil generation, and here cuts the cost premium of 100% in-state hourly matching in half from $33/MWh to $17/MWh (see Table 2 column 1).

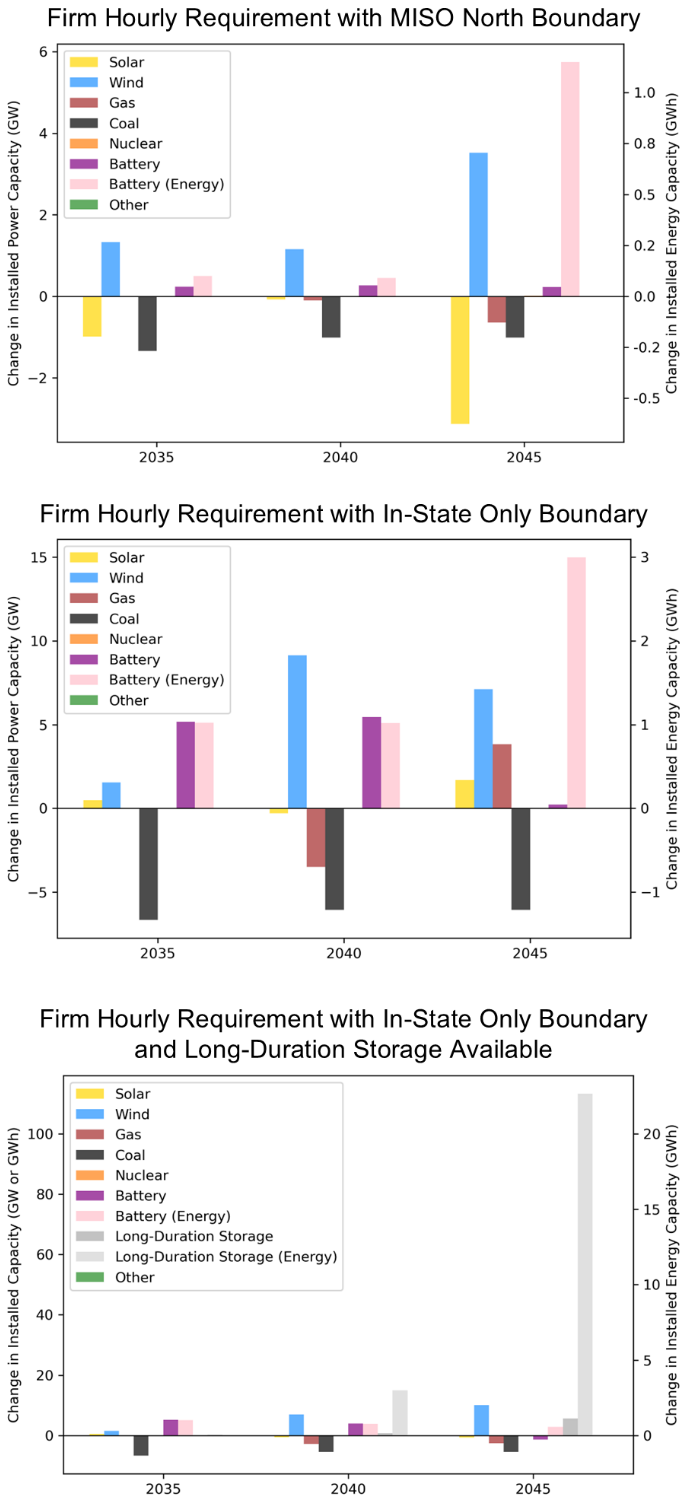

Figure 4: Changes in technology deployment compared to the baseline scenario, organized by year for three scenarios with "firm" hourly matching policies: one with a MISO North boundary and two with In-State Only boundaries, the latter of which includes a long-duration storage technology as a procurement option. Generating capacity changes are given in GW, and storage energy capacity changes are given in GWh.

"Firm" hourly matching requirements drive more and earlier impact than "flexible" ones. "Flexible" hourly matching requirements where utilities can pick and choose which hours they do or do not match lead to effectively no emissions impact until the matching requirement hits 100%, even with the tightest geographic boundaries (see Table 1). This is due to an abundance of qualifying clean power in the vast majority of hours. They also generally lead to greater consumer costs in 2045, as investments have been made in previous modeled periods that are not optimal for 100% hourly matching. These outcomes may be attributable in part to the structure of the model, which does not have foresight into future stages when planning for a given stage (e.g. it does not know that it will have to deliver 100% hourly matching in 2045 when designing a system that can achieve 90% in 2040). If utilities plan investments proactively and do not face policy uncertainty, the differences between the firm and flexible requirement cases may be reduced.

A circuit-breaker mechanism could constrain costs (and impact). In a scenario where we model the most restrictive version of an hourly matching policy (firm, with In-State Only boundaries) but allow utilities to avoid compliance at a cost of $300/MWh, the consumer cost impact in 2045 falls by more than $20/MWh on average to $13/MWh (see Table 2 column 2). The emissions impact of the policy is also reduced in this case, but not by as much as cost. When the breaker mechanism is utilized, the effective hourly matching rate in 2045 is still 98.5% and emissions fall by 16 MMT/yr.

A policy with wide spatial boundaries can still drive impact *if* neighboring states adopt similar policies. In a case where we model the Midwest regional boundary but assume that Illinois and Michigan also adopt hourly matching policies identical to Minnesota's, both the impact and cost of hourly matching using this boundary increase substantially due to competition for clean power in key hours (Table 2 column 3).

Outcomes can vary moderately depending on technology cost and fuel price assumptions. As shown in Table 2, columns 4 and 5, the impacts of an hourly matching requirement on consumer electricity prices and emissions can vary depending on assumed values for uncertain parameters like the cost of renewable energy resources and fossil fuels.

Policy Scenario					
Description	**In-State Only with Long-Duration Storage**	**In-State Only with a Circuit-Breaker**	**Midwest Region with Illinois and Michigan**	**MISO North Region with High Wind, Solar and Storage Costs**	**MISO North Region with High Fossil Fuel Prices**
Impact on Consumer Cost Compared to Baseline ($/MWh)					
2035	+12	+3	+4	+6	+2
2040	+16	+9	+2	+0	+3
2045	+17	+13	+16	+6	+11
Impact on Grid Emissions Compared to Baseline (MMT CO_2/yr)					
2035	-23	-11	-24	+4	+1
2040	-24	-16	-19	+3	-8
2045	-25	-16	-35	-3	-9

Table 2: Consumer cost and emissions impacts of an hourly matching requirement in Minnesota under different variations of our central cases. All of the examples shown here assume a "firm" hourly matching requirement. Bulk electricity costs for Minnesota consumers in the baseline high renewable cost case are $34/MWh in 2035, $33/MWh in 2040, and $37/MWh in 2045. Electricity costs in the baseline high fuel price case are $30/MWh in 2035, $29/MWh in 2040, and $34/MWh in 2045.

For example, in a case where we use costs for wind, solar, and batteries taken from the National Renewable Energy Laboratory's "conservative" cost projections, we observe moderate increases in grid emissions in 2035 and 2040 followed by a moderate decrease in 2045. While hourly matching increases systemwide clean generation in these cases, we observe that in the early stages it reduces the buildout of *new* gas-fired power plants, which in turn displaces less coal power than in the baseline. This secondary gas-to-coal effect highlights the limitations of policies focused exclusively on increasing clean generation and could be mitigated by supplemental policies that seek to hasten the retirement of coal plants. In a scenario where we assume higher prices for all fossil fuels, hourly matching achieves larger emissions reductions in later stages than in our central cases.

Summary

There are several policy levers that could be used to adjust both the climate impact and manage the consumer cost premium of an hourly matching requirement for carbon-free power in Minnesota. Based on our modeling, **the most important of these levers is likely to be the geographic boundary** placed on qualifying carbon-free electricity. If the Minnesota DOC's proposed Midwest boundary is adopted, our analysis suggests that an hourly matching requirement will be quite easy to meet but will have little-to-no impact on emissions. It should be noted that if real-world renewable energy deployment lags behind the pace suggested by our modeled baseline scenario, Minnesota's policy as an important and impactful backstop even under these loosest requirements. Outcomes could also change if there is significant demand for hourly EACs in the Midwest region from other sources, including federally subsidized hydrogen producers, corporate voluntary action, or policies in neighboring states. In the absence of additional demand for hourly-matched clean power, **tighter regional boundaries on procurement can increase both the cost and emissions benefits of an hourly matching policy**. Both cost and impact are moderate when a MISO North boundary is used, and become more significant when only use of in-state clean resources is permitted. **The implementation of a circuit-breaker mechanism that establishes a maximum compliance price for utilities can help significantly constrain costs** in cases where they become excessive. **Availability of multi-day energy storage technologies (or other advanced clean firm resources like advanced nuclear or geothermal) can also reduce the cost of matching the most difficult hours**, and in turn an hourly matching policy in Minnesota could be an important demand driver for these technologies.

Our results also suggest that intermediate matching targets which drive toward the long-run goal of 100% matching are necessary to minimize costs and maximize impact. **A "Flexible" hourly matching requirement that allows utilities to pick and choose the hours they match is incredibly easy to comply with in a wind-rich state like Minnesota**, and can also create path dependencies where the resource investments made in the 2030s are not necessarily consistent with a long-run goal of 100% hourly matching. **By contrast, a "firm" hourly matching requirement aligns near-term investments better with long-run goals, drives impact even in early years, and creates an earlier demand-pull for advanced technologies like long-duration energy storage.** Additionally, because complete hourly matching with deliverable clean power will eventually be necessary to truly eliminate Minnesota's reliance on climate-warming sources of power, a policy that intentionally drives toward this goal from the start is likely the best way to deliver on the state's promise to use 100% carbon-free electricity.

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Supplemental Comments

Docket No. E999/CI-23-151

Dated this **16th** day of **April 2025**

/s/Sharon Ferguson

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62	Stacy	Dahl	sdahl@minnkota.com	Minnkota Power Cooperative, Inc.		5301 32nd Ave S Grand Forks ND, 58201 United States	Electronic Service		No	23-151Official
63	Michael	Daley	mdaley@carbonsolutionsgroup.com	Carbon Solutions Group LLC		2045 W Grand Ave. Ste B PMB #58751 Chicago IL, 60612 United States	Electronic Service		No	23-151Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
64	Lorene	Damsits	lorened@cmpasgroup.org	Central MN MPA		459 S Grove St Blue Earth MN, 56013 United States	Electronic Service		No	23-151Official
65	Lisa	Daniels	lisadaniels@windustry.org	Windustry		201 Ridgewood Ave Minneapolis MN, 55403 United States	Electronic Service		No	23-151Official
66	Miyah	Danielson	miyahdanielson@fdlrez.com	Fond du Lac Band of Lake Superior Chippewa		1720 Big Lake Road Cloquet MN, 55720 United States	Electronic Service		No	23-151Official
67	Chris	Davis	christopher.davis@state.mn.us		Department of Commerce	Suite 280 85 Seventh Place East St. Paul MN, 55101-2198 United States	Electronic Service		No	23-151Official
68	Rob	Davis	rob@mrets.org	M-RETS		60 S 6th Street Suite 2800 Minneapolis MN, 55402 United States	Electronic Service		No	23-151Official
69	Jason	Decker	jason.decker@llojibwe.net	Leech Lake Band of Ojibwe		190 Sailstar Drive NW Cass Lake MN, 56633 United States	Electronic Service		No	23-151Official
70	James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	23-151Official
71	Bobby	Deschampe	robertdeschampe@grandportage.com	Grand Portage Band of Lake Superior Chippewa		PO Box 428 Grand Portage MN, 55605 United States	Electronic Service		No	23-151Official
72	Curt	Dieren	curt.dieren@dgr.com	L&O Power Cooperative		1302 S Union St Rock Rapids IA, 51246 United States	Electronic Service		No	23-151Official
73	Kami	Diver	kamidiver@fdlrez.com	Fond du Lac Band of Lake Superior Chippewa		1720 Big Lake Road Cloquet MN, 55720 United States	Electronic Service		No	23-151Official
74	Becky	Dobbs	bdobbs@grenergy.com			null null, null United States	Electronic Service		No	23-151Official
75	J.	Drake Hamilton	hamilton@fresh-energy.org	Fresh Energy		408 St Peter St Ste 350 Saint Paul MN, 55101 United States	Electronic Service		No	23-151Official
76	Shane	Drift	sdrift@boisforte-nsn.gov	Bois Forte Band of Chippewa		Bois Forte Tribal Government 5344 Lakeshore Drive Nett Lake MN, 55772 United States	Electronic Service		No	23-151Official
77	Jeremy	Duehr	jduehr@fredlaw.com	Fredrikson & Byron, P.A.		60 S Sixth St Ste 1500 Minneapolis MN, 55402-4400 United States	Electronic Service		No	23-151Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
78	Adam	Duininck	aduininck@ncsrcc.org	North Central States Regional Council of Carpenters		700 Olive Street St. Paul MN, 55130 United States	Electronic Service		No	23-151Official
79	Kristin W	Duncanson	kw.duncanson@gmail.com			57746 Highway 30 Mapleton MN, 56065 United States	Electronic Service		No	23-151Official
80	Wally	Dupuis	wallydupuis@fdlband.org	Fond du Lac Band of Lake Superior Chippewa		1720 Big Lake Road Cloquet MN, 55720 United States	Electronic Service		No	23-151Official
81	Kevin	Dupuis, Sr.	kevindupuis@fdlrez.com			Reservation Business Committee 1720 Big Lake Rd Cloquet MN, 55720 United States	Electronic Service		No	23-151Official
82	Brian	Edstrom	briane@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota St Ste W1360 Saint Paul MN, 55101 United States	Electronic Service		No	23-151Official
83	Jamie	Edwards	jamie.edwards@millelacsband.com	Mille Lacs Band of Ojibwe		43408 Oodena Drive Onamia MN, 56358 United States	Electronic Service		No	23-151Official
84	Kristen	Eide Tollefson	healingsystems69@gmail.com	R-CURE		28477 N Lake Ave Frontenac MN, 55026-1044 United States	Electronic Service		No	23-151Official
85	Betsy	Engelking	betsy@nationalgridrenewables.com	National Grid Renewables		8400 Normandale Lake Blvd Ste 1200 Bloomington MN, 55437 United States	Electronic Service		No	23-151Official
86	Michael	Fairbanks	michael.fairbanks@whiteearth-nsn.gov	White Earth Reservation Business Committee		PO Box 418 White Earth MN, 56591 United States	Electronic Service		No	23-151Official
87	John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance		2720 E. 22nd St Institute for Local Self-Reliance Minneapolis MN, 55406 United States	Electronic Service		No	23-151Official
88	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101-2198 United States	Electronic Service		No	23-151Official
89	Terri	Finn	terri.goggleye@llojibwe.net			null null, null United States	Electronic Service		No	23-151Official
90	Mike	Fiterman	mikefiterman@libertydiversified.com	Liberty Diversified International		5600 N Highway 169 Minneapolis MN, 55428-3096 United States	Electronic Service		No	23-151Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
91	Christine	Fox	cfox@itasca-mantrap.com	Itasca-Mantrap Coop. Electric Assn.		PO Box 192 Park Rapids MN, 56470 United States	Electronic Service		No	23-151Official
92	Lucas	Franco	lfranco@liunagroc.com	LIUNA		81 Little Canada Rd E Little Canada MN, 55117 United States	Electronic Service		No	23-151Official
93	Ronald J.	Franz	ronald.franz@dairylandpower.com	Dairyland Power Cooperative		3200 East Ave S PO Box 817 La Crosse WI, 54602-0817 United States	Electronic Service		No	23-151Official
94	Nathan	Franzen	nathan@nationalgridrenewables.com	Geronimo Energy, LLC		8400 Normandale Lake Blvd Ste 1200 Bloomington MN, 55437 United States	Electronic Service		No	23-151Official
95	Gary	Frazer	gfrazer@mnchippewatribe.org	Minnesota Chippewa Tribe		PO Box 217 Cass Lake MN, 56633 United States	Electronic Service		No	23-151Official
96	Barb	Freese	bfreese@mncenter.org	Minnesota Center for Environmental Advocacy		1919 University Ave W Ste 515 Saint Paul MN, 55104-3435 United States	Electronic Service		No	23-151Official
97	Christopher	Friez	christopher.friez@nacco.com	NACCO Natural Resources/North American Coal		918 E. Divide Ave., Suite 200 Bismarck ND, 58501 United States	Electronic Service		No	23-151Official
98	Stacey	Fujii	sfujii@grenergy.com	Great River Energy		12300 Elm Creek Boulevard Maple Grove MN, 55369-4718 United States	Electronic Service		No	23-151Official
99	Jessica	Fyhrie	jfyhrie@otpco.com	Otter Tail Power Company		PO Box 496 Fergus Falls MN, 56538-0496 United States	Electronic Service		Yes	23-151Official
100	Edward	Garvey	garveyed@aol.com	Residence		32 Lawton St Saint Paul MN, 55102 United States	Electronic Service		No	23-151Official
101	Benjamin	Gerber	ben@mrets.org	Midwest Renewable Energy Tracking System		60 South Sixth Street Suite 2800 Minneapolis MN, 55402 United States	Electronic Service		No	23-151Official
102	David P.	Geschwind	dp.geschwind@smmpa.org	Southern Minnesota Municipal Power Agency		500 First Avenue SW Rochester MN, 55902 United States	Electronic Service		No	23-151Official
103	Shannon	Geshick	shannon.geshick@state.mn.us	Minnesota Indian Affairs Council (MIAC)		null null, null United States	Electronic Service		No	23-151Official
104	Allen	Gleckner	gleckner@fresh-energy.org	Fresh Energy		408 St. Peter Street Ste 350 Saint Paul MN, 55102 United States	Electronic Service		No	23-151Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
105	Jenny	Glumack	jenny@mrea.org	Minnesota Rural Electric Association		11640 73rd Ave N Maple Grove MN, 55369 United States	Electronic Service		No	23-151Official
106	Julie	Goehring	julie@redriverbasincommission.org			708 70 Ave NW Moorhead MN, 56560 United States	Electronic Service		No	23-151Official
107	Todd J.	Guerrero	todd.guerrero@kutakrock.com	Kutak Rock LLP		Suite 1750 220 South Sixth Street Minneapolis MN, 55402-1425 United States	Electronic Service		No	23-151Official
108	Tessa	Haagenson	tessa.haagenson@connexusenergy.com	Connexus Energy		14601 Ramsey Blvd NW Ramsey MN, 55303 United States	Electronic Service		No	23-151Official
109	Jeffrey	Haase	jhaase@grenergy.com	Great River Energy		12300 Elm Creek Blvd Maple Grove MN, 55369 United States	Electronic Service		No	23-151Official
110	Hal	Halpern	halhalpern@clpower.com	Cooperative Light & Power		1554 Hwy 2 P0 Box 69 Two Harbors MN, 55616 United States	Electronic Service		No	23-151Official
111	Jeremy	Hamilton	jhamilton@uppersiouxcommunity-nsn.gov	Upper Sioux Community		Upper Sioux Community PO Box 147 Granite Falls MN, 56241 United States	Electronic Service		No	23-151Official
112	David A.	Hansen	hansen@federatedrea.coop	Federated Rural Electric Association		77100 U.S. Highway 71 PO Box 69 Jackson MN, 56143 United States	Electronic Service		No	23-151Official
113	James	Hartson				59931 300th Street Waltham MN, 55982 United States	Paper Service		No	23-151Official
114	Amy	Hastings	amyh@uppersiouxcommunity-nsn.gov	Upper Sioux Community		5722 Travers Lane PO Box 147 Granite Falls MN, 56241 United States	Electronic Service		No	23-151Official
115	Erik	Hatlestad	erik@cureriver.org			117 1st St Montevideo MN, 56265 United States	Electronic Service		No	23-151Official
116	Kim	Havey	kim.havey@minneapolismn.gov	City of Minneapolis		350 South 5th Street, Suite 315M Minneapolis MN, 55415 United States	Electronic Service		No	23-151Official
117	Philip	Hayet	phayet@jkenn.com	J. Kennedy and Associates, Inc.		570 Colonial Park Drive Suite 305 Roswell GA, 30075-3770 United States	Electronic Service		No	23-151Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
118	Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association		4300 220th St W Farmington MN, 55024 United States	Electronic Service		No	23-151Official
119	Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors		413 Wacouta Street #230 St.Paul MN, 55101 United States	Electronic Service		No	23-151Official
120	Jessy	Hennesy	jessy.hennesy@avantenergy.com	Avant Energy		220 S. Sixth St. Ste 1300 Minneapolis MN, 55402 United States	Electronic Service		No	23-151Official
121	Kristin	Henry	kristin.henry@sierraclub.org	Sierra Club		2101 Webster St Ste 1300 Oakland CA, 94612 United States	Electronic Service		No	23-151Official
122	Benjamin	Hertz	bhertz@bepc.com	Basin Electric Power Cooperative		1717 E Interstate Ave Bismarck ND, 58503 United States	Electronic Service		Yes	23-151Official
123	Holly	Hinman	holly.r.hinman@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	23-151Official
124	Joe	Hoffman	ja.hoffman@smmpa.org	SMMPA		500 First Ave SW Rochester MN, 55902-3303 United States	Electronic Service		No	23-151Official
125	Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.		445 Etna Street Ste. 61 St. Paul MN, 55106 United States	Electronic Service		No	23-151Official
126	Ronald	Horman	rhorman@redwoodelectric.com	Redwood Electric Cooperative		60 Pine Street Clements MN, 56224 United States	Electronic Service		No	23-151Official
127	Rick	Horton	rhorton@minnesotaforests.com	Minnesota Forest Industries		324 West Superior Street 903 Medical Arts Building Duluth MN, 55802 United States	Electronic Service		No	23-151Official
128	Robbie	Howe	robbie.howe@llojibwe.net	Leech Lake Band of Ojibwe		190 Sailstar Drive NW Cass Lake MN, 56633 United States	Electronic Service		No	23-151Official
129	John	Ihle	ljihle@rrt.net	PlainStates Energy LLC		27451 S Hwy 34 Barnesville MN, 56514 United States	Electronic Service		No	23-151Official
130	Annie	Jackson	cheryl.jackson@whiteearth-nsn.gov	White Earth Nation		White Earth Tribal Headquarters 35500 Eagle View Road Ogemo MN, 56569 United States	Electronic Service		No	23-151Official
131	Faron	Jackson, Sr.	faron.jackson@llojibwe.net			190 Sailstar Drive NW Cass Lake	Electronic Service		No	23-151Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						MN, 56633 United States				
132	Casey	Jacobson	cjacobson@bepc.com	Basin Electric Power Cooperative		1717 East Interstate Avenue Bismarck ND, 58501 United States	Electronic Service		No	23-151Official
133	Justin	Jahnz	justin.jahnz@ecemn.com	East Central Energy		412 Main Ave N Braham MN, 55006 United States	Electronic Service		No	23-151Official
134	Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law		2950 Yellowtail Ave. Marathon FL, 33050 United States	Electronic Service		No	23-151Official
135	Nathan	Jensen	njensen@otpco.com	Otter Tail Power Company		215 S. Cascade St. Fergus Falls MN, 56537 United States	Electronic Service		No	23-151Official
136	Kevin	Jensvold	kevinj@uppersiouxcommunity-nsn.gov	Upper Sioux Community		PO Box 147 Granite Falls MN, 56241-0147 United States	Electronic Service		No	23-151Official
137	Annette	Johnson	annette.johnson@redlakenation.org	Red Lake Nation		15484 Migizi Drive Red Lake MN, 56671 United States	Electronic Service		No	23-151Official
138	Jody	Johnson	jody.johnson@piic.org	Prairie Island Indian Community		5636 Sturgeon Lake Rd Welch MN, 55089 United States	Electronic Service		No	23-151Official
139	Johnny	Johnson	johnny.johnson@piic.org	Prairie Island Indian Community		5636 Sturgeon Lake Road Welch MN, 55089 United States	Electronic Service		No	23-151Official
140	Richard	Johnson	rick.johnson@lawmoss.com	Moss & Barnett		150 S. 5th Street Suite 1200 Minneapolis MN, 55402 United States	Electronic Service		No	23-151Official
141	Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	23-151Official
142	Nate	Jones	njones@hcpd.com	Heartland Consumers Power		PO Box 248 Madison SD, 57042 United States	Electronic Service		No	23-151Official
143	Nick	Kaneski	nick.kaneski@enbridge.com	Enbridge Energy Company, Inc.		11 East Superior St Ste 125 Duluth MN, 55802 United States	Electronic Service		No	23-151Official
144	Veda	Kanitz	vmkanitz@gmail.com			null null, null United States	Electronic Service		No	23-151Official
145	Jenny	Kartes	jkartes@arrowhead.coop	Arrowhead Electric Cooperative, Inc.(P)		PO Box 39 5401 W Hwy 61 Lutsen MN, 55612 United States	Electronic Service		No	23-151Official

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146	David	Kempf	dkempf@grenergy.com	Great River Energy		12300 Elm Creek Blvd Maple Grove MN, 55369 United States	Electronic Service		No	23-151Official
147	William	Kenworthy	will@votesolar.org			1 South Dearborn St Ste 2000 Chicago IL, 60603 United States	Electronic Service		No	23-151Official
148	Becky	Kern	bkern@bepc.com	Basin Electric Power Cooperative		1717 E Interstate Ave Bismarck ND, 58501 United States	Electronic Service		Yes	23-151Official
149	Samuel B.	Ketchum	sketchum@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	23-151Official
150	Nazir	Khan	nazir@mnejtable.org	Minnesota Environmental Justice Table		2720 E 22nd St Minneapolis MN, 55406 United States	Electronic Service		No	23-151Official
151	Hudson	Kingston	hudson@curemn.org			PO Box 712 Ely MN, 55731 United States	Electronic Service		No	23-151Official
152	Kate	Knuth	kate.knuth@gmail.com			2347 14th Terrace NW New Brighton MN, 55112 United States	Electronic Service		No	23-151Official
153	Frank	Kohlasch	frank.kohlasch@state.mn.us		Minnesota Pollution Control Agency	520 Lafayette Rd N. St. Paul MN, 55155 United States	Electronic Service		No	23-151Official
154	Brian	Kolbinger	brian@beckertownship.org	Becker Township Board		PO Box 248 12165 Hancock St Becker MN, 55308 United States	Electronic Service		No	23-151Official
155	Seth	Koneczny	st.koneczny@smmpa.org	SMMPA		500 First Avenue, SW Rochester MN, 55902-3303 United States	Electronic Service		No	23-151Official
156	Brian	Krambeer	bkrambeer@mienergy.coop	MiEnergy Cooperative		PO Box 626 31110 Cooperative Way Rushford MN, 55971 United States	Electronic Service		No	23-151Official
157	Randy	Kramer	rlkramer89@gmail.com	Water and Soil Resources Board		42808 Co. Rd. 11 Bird Island MN, 55310 United States	Electronic Service		No	23-151Official
158	Allen	Krug	allen.krug@xcelenergy.com	Xcel Energy		414 Nicollet Mall-7th fl Minneapolis MN, 55401 United States	Electronic Service		No	23-151Official
159	Kay	Kuhlmann	teri.swanson@ci.red-wing.mn.us	City Of Red Wing		315 West Fourth Street Red Wing MN, 55066 United States	Electronic Service		No	23-151Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
160	Brenda	Kyle	bkyle@stpaulchamber.com	St. Paul Area Chamber of Commerce		401 N Robert Street Suite 150 St Paul MN, 55101 United States	Electronic Service		No	23-151Official
161	Therese	LaCanne	tlacanne@grenergy.com	Great River Energy		12300 Elm Creek Blvd Maple Grove MN, 55369 United States	Electronic Service		No	23-151Official
162	Matthew	Lacey	mlacey@grenergy.com	Great River Energy		12300 Elm Creek Boulevard Maple Grove MN, 55369-4718 United States	Electronic Service		No	23-151Official
163	Becky	Lammi	cityclerk@ci.aurora.mn.us	City of Aurora		16 W 2nd Ave N PO Box 160 Aurura MN, 55705 United States	Electronic Service		No	23-151Official
164	Carmel	Laney	carmel.laney@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	23-151Official
165	Arthur	LaRose	arthur.larose@llojibwe.net	Leech Lake Band of Ojibwe		190 Sailstar Drive NW Cass Lake MN, 56633 United States	Electronic Service		No	23-151Official
166	Robert L	Larsen	robert.larsen@lowersioux.com	Lower Sioux Indian Community		PO Box 308 39527 Reservation Highway 1 Morton MN, 56270 United States	Electronic Service		No	23-151Official
167	Emily	Larson	elarson@duluthmn.gov	City of Duluth		411 W 1st St Rm 403 Duluth MN, 55802 United States	Electronic Service		No	23-151Official
168	James D.	Larson	james.larson@avantenergy.com	Avant Energy Services		220 S 6th St Ste 1300 Minneapolis MN, 55402 United States	Electronic Service		No	23-151Official
169	Mark	Larson	mlarson@meeker.coop	Meeker Coop Light & Power Assn		1725 Highway 12 E Ste 100 Litchfield MN, 55355 United States	Electronic Service		No	23-151Official
170	Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.		8300 Norman Center Drive Suite 1000 Bloomington MN, 55437 United States	Electronic Service		No	23-151Official
171	Rachel	Leonard	rachel.leonard@ci.monticello.mn.us	City of Monticello		505 Walnut St Ste 1 Monticello MN, 55362 United States	Electronic Service		No	23-151Official
172	Dan	Lesher	dlesher@grenergy.com	Great River Energy		12300 Elm Creek Blvd Maple Grove MN, 55369 United States	Electronic Service		No	23-151Official
173	Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota Street, Suite W1360	Electronic Service		No	23-151Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						St. Paul MN, 55101 United States				
174	Jesse	Levine	jesse_levine@afandpa.org			1101 K St NW Suite 700 Washington DC, 20005 United States	Electronic Service		No	23-151Official
175	Amy	Liberkowski	amy.a.liberkowski@xcelenergy.com	Xcel Energy		414 Nicollet Mall 7th Floor Minneapolis MN, 55401-1993 United States	Electronic Service		No	23-151Official
176	Eric	Lindberg	elindberg@mncenter.org	Minnesota Center for Environmental Advocacy		1919 University Avenue West Suite 515 Saint Paul MN, 55104-3435 United States	Electronic Service		No	23-151Official
177	Eric	Lipman	eric.lipman@state.mn.us		Office of Administrative Hearings	PO Box 64620 St. Paul MN, 55164-0620 United States	Electronic Service		Yes	23-151Official
178	Michelle	Lommel	mlommel@grenergy.com	Great River Energy		12300 Elm Creek Blvd Maple Grove MN, 55369 United States	Electronic Service		No	23-151Official
179	Bob	Long	rlong@larkinhoffman.com	Larkin Hoffman (Silicon Energy)		1500 Wells Fargo Plaza 7900 Xerxes Ave S Bloomington MN, 55431 United States	Electronic Service		No	23-151Official
180	Nicole	Luckey	nluckey@invenergyllc.com	Invenergy LLC		1 S. Wacker Suite 1800 Chicago IL, 60606 United States	Electronic Service		No	23-151Official
181	Susan	Ludwig	sludwig@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	23-151Official
182	Robert	Lunder	robert.lunder@mdu.com	Montana-Dakota Utilities (ET)		400 N 4th St Bismark ND, 58501 United States	Electronic Service		No	23-151Official
183	Alice	Madden	alice@communitypowermn.org	Community Power		2720 E 22nd St Minneapolis MN, 55406 United States	Electronic Service		No	23-151Official
184	Scott	Magnuson	smagnuson@bpu.org	Brainerd Public Utilities		8027 Highland Scenic Rd Baxter MN, 56425 United States	Electronic Service		No	23-151Official
185	Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC		961 N Lost Woods Rd Oconomowoc WI, 53066 United States	Electronic Service		No	23-151Official
186	Emily	Marshall	emarshall@lourismarshall.com	Miller O'Brien Jensen, PA		120 S. 6th Street Suite 2400 Minneapolis MN, 55402 United States	Electronic Service		No	23-151Official

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187	Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc		414 Nicollet Mall 7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	23-151Official
188	Gregg	Mast	gmast@cleanenergyeconomymn.org	Clean Energy Economy Minnesota		4808 10th Avenue S Minneapolis MN, 55417 United States	Electronic Service		No	23-151Official
189	Shena	Matrious	shena.matrious@millelacsband.com	Mille Lacs Band of Ojibwe		43408 Oodena Drive Onamia MN, 56349 United States	Electronic Service		No	23-151Official
190	Daryl	Maxwell	dmaxwell@hydro.mb.ca	Manitoba Hydro		360 Portage Ave FL 16 PO Box 815, Station Main Winnipeg MB, R3C 2P4 Canada	Electronic Service		No	23-151Official
191	Tim	McCarthy	tim.mccarthy@siouxvalleyenergy.com	Sioux Valley Southwestern Electric Cooperative, Inc. d/b/a Sioux Valley Energy		null null, null United States	Electronic Service		No	23-151Official
192	Scot	McClure	scotmcclure@alliantenergy.com	Interstate Power And Light Company		4902 N Biltmore Ln PO Box 77007 Madison WI, 53707-1007 United States	Electronic Service		No	23-151Official
193	April	McCormick	aprilm@grandportage.com	Grand Portage Band of Lake Superior Chippewa		PO Box 428 Grand Portage MN, 55605 United States	Electronic Service		No	23-151Official
194	Jess	McCullough	jmccullough@mnpower.com	Minnesota Power		30 W Superior St Duluth MN, 55802 United States	Electronic Service		No	23-151Official
195	Sara G	McGrane	smcgrane@felhaber.com	Felhaber Larson		220 S 6th St Ste 2200 Minneapolis MN, 55420 United States	Electronic Service		No	23-151Official
196	Natalie	McIntire	natalie.mcintire@gmail.com	Wind on the Wires		570 Asbury St Ste 201 Saint Paul MN, 55104-1850 United States	Electronic Service		No	23-151Official
197	Harvey	McMahon	hmcmahon@otpco.com	Otter Tail Power Company		215 South Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	23-151Official
198	Taylor	McNair	taylor@gridlab.org			668 Capp Street San Francisco CA, 94110 United States	Electronic Service		No	23-151Official
199	Ronald	Meier	rmeier@mcleodcoop.com	Mcleod Cooperative Power		3515 11th St East Glencoe MN, 55336 United States	Electronic Service		No	23-151Official
200	Melanie	Mesko Lee	melanie.lee@burnsvillemn.gov	City of Burnsville		100 Civic Center Parkway Burnsville	Electronic Service		No	23-151Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						MN, 55337-3867 United States				
201	Peder	Mewis	pmewis@cleangridalliance.org	Clean Grid Alliance		570 Asbury St. St. Paul MN, 55104 United States	Electronic Service		No	23-151Official
202	Joseph	Meyer	joseph.meyer@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Bremer Tower, Suite 1400 445 Minnesota Street St Paul MN, 55101-2131 United States	Electronic Service		No	23-151Official
203	Valentina	Mgeni	valentina.mgeni@piic.org	Prairie Island Indian Community		Prairie Island Indian Community 5636 Sturgeon Lake Road Welch MN, 55089 United States	Electronic Service		No	23-151Official
204	Cole W.	Miller	cole.miller@shakopeedakota.org	Shakopee Mdewakanton Sioux Community		Shakopee Mdewakanton Sioux Community 2330 Sioux Trail NW Prior Lake MN, 55372 United States	Electronic Service		No	23-151Official
205	Stacy	Miller	stacy.miller@minneapolismn.gov	City of Minneapolis		350 S. 5th Street Room M 301 Minneapolis MN, 55415 United States	Electronic Service		No	23-151Official
206	David	Moeller	dmoeller@allete.com	Minnesota Power			Electronic Service		No	23-151Official
207	Dalene	Monsebroten	dalene.monsebroten@nmpagency.com	Northern Municipal Power Agency		123 2nd St W Thief River Falls MN, 56701 United States	Electronic Service		No	23-151Official
208	Sarah	Mooradian	sarah@curemn.org	CURE		117 South 1st Street Montevideo MN, 56265 United States	Electronic Service		No	23-151Official
209	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	23-151Official
210	Travis	Morrision	travis.morrison@boisforte-nsn.gov	Bois Forte Band of Chippewa		Bois Forte Tribal Government 5344 Lakeshore Drive Nett Lake MN, 55772 United States	Electronic Service		No	23-151Official
211	David	Morrison, Sr.	david.morrison@boisforte-nsn.gov	Bois Forte Band of Chippewa		Bois Forte Tribal Government 5344 Lakeshore Drive Nett Lake MN, 55772 United States	Electronic Service		No	23-151Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
212	Evan	Mulholland	emulholland@mncenter.org	Minnesota Center for Environmental Advocacy		1919 University Ave W Ste 515 Saint Paul MN, 55101 United States	Electronic Service		No	23-151Official
213	Alan	Muller	alan@greendel.org	Energy & Environmental Consulting		1110 West Avenue Red Wing MN, 55066 United States	Electronic Service		No	23-151Official
214	Sonny	Myers	smyers@1854treatyauthority.org	1854 Treaty Authority		4428 Haines Rd Duluth MN, 55811-1524 United States	Electronic Service		No	23-151Official
215	Ben	Nelson	benn@cmpasgroup.org	CMMPA		459 South Grove Street Blue Earth MN, 56013 United States	Electronic Service		No	23-151Official
216	Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment		212 3rd Ave N Ste 560 Minneapolis MN, 55401 United States	Electronic Service		No	23-151Official
217	Deb	Nelson	dnelson@grenergy.com	Great River Energy		12300 Elm Creek Blvd Maple Grove MN, 55369 United States	Electronic Service		No	23-151Official
218	David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	23-151Official
219	Duane	Ninneman	duane@cureriver.org	Clean Up the River Environment		117 South 1st St Montevideo MN, 56265 United States	Electronic Service		No	23-151Official
220	Michael	Noble	noble@fresh-energy.org	Fresh Energy		408 Saint Peter St Ste 350 Saint Paul MN, 55102 United States	Electronic Service		No	23-151Official
221	Rolf	Nordstrom	rnordstrom@gpisd.net	Great Plains Institute		2801 21ST AVE S STE 220 Minneapolis MN, 55407-1229 United States	Electronic Service		No	23-151Official
222	Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company		200 1st Street SE PO Box 351 Cedar Rapids IA, 52406-0351 United States	Electronic Service		No	23-151Official
223	M. William	O'Brien	bobrien@mojlaw.com	Miller O'Brien Jensen, P.A.		120 S 6th St Ste 2400 Minneapolis MN, 55402 United States	Electronic Service		No	23-151Official
224	Ric	O'Connell	ric@gridlab.org	GridLab		2120 University Ave Berkeley CA, 94704 United States	Electronic Service		No	23-151Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
225	Joseph	OBrien	joey.obrien@lowersioux.com			39527 Highway 1 Morton MN, 56270 United States	Electronic Service		No	23-151Official
226	Matthew	Olsen	molsen@otpco.com	Otter Tail Power Company		215 South Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	23-151Official
227	Russell	Olson	rolson@hcpd.com	Heartland Consumers Power District		PO Box 248 Madison SD, 57042-0248 United States	Electronic Service		No	23-151Official
228	Debra	Opatz	dopatz@otpco.com	Otter Tail Power Company		215 South Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	23-151Official
229	Mikayla	Osterman	mosterman@otpco.com	Otter Tail Power Company		215 S Cascade St PO Box 496 Fergus Falls MN, 56537 United States	Electronic Service		No	23-151Official
230	Jamie	Overgaard	jovergaard@minnkota.com	Minnkota Power Cooperative, Inc.		5301 32nd Ave S Grand Forks ND, 58201 United States	Electronic Service		No	23-151Official
231	Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office		1110 West Avenue Red Wing MN, 55066 United States	Electronic Service		No	23-151Official
232	Gregory	Padden	gpadden@grenergy.com	Great River Energy		12300 Elm Creek Blvd Maple Grove MN, 55369 United States	Electronic Service		No	23-151Official
233	Jessica	Palmer Denig	jessica.palmer-denig@state.mn.us		Office of Administrative Hearings	600 Robert St N PO Box 64620 St. Paul MN, 55164 United States	Electronic Service		No	23-151Official
234	Marsha	Parlow	mparlow@grenergy.com	Great River Energy		12300 Elm Creek Blvd Maple Grove MN, 55369 United States	Electronic Service		No	23-151Official
235	Priti	Patel	ppatel@grenergy.com	Great River Energy		12300 Elm Creek Blvd Maple Grove MN, 55369-4718 United States	Electronic Service		No	23-151Official
236	Gerad	Paul	gpaul@minnkota.com	Minnkota Power Cooperative		5301 32nd Ave S Grand Forks ND, 58201 United States	Electronic Service		No	23-151Official
237	Earl	Pendleton	earl.pendleton@lowersioux.com	Lower Sioux Indian Community		39527 Highway 1 Morton MN, 56270 United States	Electronic Service		No	23-151Official
238	Mary Beth	Peranteau	mperanteau@fredlaw.com	Fredrikson & Byron, P.A.		44 East Mifflin Street Suite 1000 Madison WI, 53703 United States	Electronic Service		No	23-151Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
239	Thom	Petersen	thom.petersen@state.mn.us		Minnesota Department of Agriculture	625 North Robert St Saint Paul MN, 55155 United States	Electronic Service		No	23-151Official
240	Luke	Peterson	luke.peterson@hpuc.com	Hibbing Public Utilities Commission		1902 Sixth Ave E Hibbing MN, 55746 United States	Electronic Service		No	23-151Official
241	Neil	Peterson	info@nclucb.org	Northern Counties Land Use Coordinating Board		null null, null United States	Electronic Service		No	23-151Official
242	DONNA	PICKARD	dpickard@aladdinsolar.com	Genie Solar Support Services		1215 Lilac Lane Excelsior MN, 55331 United States	Electronic Service		No	23-151Official
243	Gordon	Pietsch	gpietsch@grenergy.com	Great River Energy		12300 Elm Creek Blvd. Maple Grove MN, 55369-4718 United States	Electronic Service		No	23-151Official
244	Joe	Plumer	joe.plumer@redlakenation.org	Red Lake Nation		15484 Migizi Drive Red Lake MN, 56671 United States	Electronic Service		No	23-151Official
245	J.	Porter	greg.porter@nngco.com	Northern Natural Gas Company		1111 South 103rd St Omaha NE, 68124 United States	Electronic Service		No	23-151Official
246	Kevin	Pranis	kpranis@liunagroc.com	Laborers' District Council of MN and ND		81 E Little Canada Road St. Paul MN, 55117 United States	Electronic Service		No	23-151Official
247	Robert	Prescott	bob.prescott@lowersioux.com	Lower Sioux Indian Community		39527 Highway 1 Morton MN, 56270 United States	Electronic Service		No	23-151Official
248	David	Raatz	draatz@bepc.com	Basin Electric Power Cooperative		1717 East Interstate Avenue Bismarck ND, 58501 United States	Electronic Service		No	23-151Official
249	John C.	Reinhardt		Laura A. Reinhardt		3552 26th Ave S Minneapolis MN, 55406 United States	Paper Service		No	23-151Official
250	Victoria	Reinhardt	victoria.reinhardt@co.ramsey.mn.us	Partnership on Waste and Energy		Ramsey County Board Office 15 W. Kellogg Blvd., Ste. 220 St. Paul MN, 55102 United States	Electronic Service		No	23-151Official
251	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		Yes	23-151Official
252	Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy		26 E Exchange St, Ste 206 St. Paul MN,	Electronic Service		No	23-151Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						55101-1667 United States				
253	John	Richards	johnrichards@nweco.com	Northwestern Wisconsin Electric Company		104 S. Pine St. Grantsburg WI, 54840 United States	Electronic Service		No	23-151Official
254	Susan	Romans	sromans@allete.com	Minnesota Power		30 West Superior Street Legal Dept Duulth MN, 55802 United States	Electronic Service		No	23-151Official
255	Stephan	Roos	stephan.roos@state.mn.us		Minnesota Department of Agriculture	625 Robert St N Saint Paul MN, 55155-2538 United States	Electronic Service		No	23-151Official
256	Alan	Roy	alan.roy@whiteearth-nsn.gov	White Earth Nation		White Earth Tribal Headquarters 35500 Eagle View Road Ogema MN, 56569 United States	Electronic Service		No	23-151Official
257	Bill	Rudnicki	bill.rudnicki@shakopeedakota.org	Shakopee Mdewakanton Sioux Community		Shakopee Mdewakanton Sioux Community 2330 Sioux Trail NW Prior Lake MN, 55372 United States	Electronic Service		No	23-151Official
258	Nathaniel	Runke	nrunke@local49.org			611 28th St. NW Rochester MN, 55901 United States	Electronic Service		No	23-151Official
259	Zachary	Ruzycki	zruzycki@grenergy.com	Great River Energy		12300 Elm Creek Boulevard Maple Grove MN, 55369 United States	Electronic Service		No	23-151Official
260	Robert K.	Sahr	bsahr@eastriver.coop	East River Electric Power Cooperative		P.O. Box 227 Madison SD, 57042 United States	Electronic Service		No	23-151Official
261	Todd	Sailer		Minnetonka Power Cooperative		5301 32nd Ave. S Grand Forks ND, 58201 United States	Paper Service		No	23-151Official
262	Miranda	Sam	miranda.sam@lowersioux.com	Lower Sioux Indian Community		39527 Reservation Highway 1 PO Box 308 Morton MN, 56270 United States	Electronic Service		No	23-151Official
263	Joseph L	Sathe	jsathe@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	23-151Official
264	Adam	Savariego	adams@uppersiouxcommunity-nsn.gov	Upper Sioux Community		5722 Travers Lane PO Box 147 Granite Falls MN, 56241 United States	Electronic Service		No	23-151Official
265	John	Saxhaug	john_saxhaug@yahoo.com			3940 Harriet Ave	Electronic Service		No	23-151Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						Minneapolis MN, 55409 United States				
266	Jean	Schafer	jeans@bepc.com	Basin Electric Power Cooperative		1717 E Interstate Ave Bismarck ND, 58501 United States	Electronic Service		No	23-151Official
267	Jeff	Schneider	jeff.schneider@ci.red-wing.mn.us	City of Red Wing		315 West 4th Street Red Wing MN, 55066 United States	Electronic Service		No	23-151Official
268	Kay	Schraeder	kschraeder@minnkota.com	Minnkota Power		5301 32nd Ave S Grand Forks ND, 58201 United States	Electronic Service		No	23-151Official
269	Kathleen	Schuler	keschuler47@gmail.com			1520 10th Ave S #2 Minneapolis MN, 55404 United States	Electronic Service		No	23-151Official
270	Robert H.	Schulte	rhs@schulteassociates.com	Schulte Associates LLC		1742 Patriot Rd Northfield MN, 55057 United States	Electronic Service		No	23-151Official
271	J.P.	Schumacher	jps@mrenergy.com	Missouri River Energy Services		null null, null United States	Electronic Service		No	23-151Official
272	Kevin	Schumacher	kevin@mrets.org	Midwest Renewable Energy Tracking System		null null, null United States	Electronic Service		No	23-151Official
273	Ronald J.	Schwartau	rschwartau@noblesce.com	Nobles Electric Cooperative		22636 U.S. Hwy. 59 Worthington MN, 56187 United States	Electronic Service		No	23-151Official
274	Christine	Schwartz	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall FL 7 Minneapolis MN, 55401-1993 United States	Electronic Service		No	23-151Official
275	Douglas	Seaton	doug.seaton@umwlc.org	Upper Midwest Law Center		8421 Wayzata Blvd Ste 300 Golden Valley MN, 55426 United States	Electronic Service		No	23-151Official
276	Dean	Sedgwick	sedgwick@itascapower.com	Itasca Power Company		PO Box 455 Spring Lake MN, 56680 United States	Electronic Service		No	23-151Official
277	Jessie	Seim	jessie.seim@piic.org	Prairie Island Indian Community		5636 Sturgeon Lake Rd Welch MN, 55089 United States	Electronic Service		No	23-151Official
278	Darrell	Seki, Sr.	dseki@redlakenation.org			15484 Migizi Drive Red Lake MN, 56671 United States	Electronic Service		No	23-151Official
279	Will	Seuffert	will.seuffert@state.mn.us		Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul MN, 55101 United States	Electronic Service		Yes	23-151Official
280	Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates		7400 Lyndale Ave S Ste 190 Richfield MN,	Electronic Service		Yes	23-151Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						55423 United States				
281	Bria	Shea	bria.e.shea@xcelenergy.com	Xcel Energy		414 Nicollet Mall Minneapolis MN, 55401 United States	Electronic Service		No	23-151Official
282	Andrew R.	Shedlock	andrew.shedlock@kutakrock.com	Kutak Rock LLP		60 South Sixth St Ste 3400 Minneapolis MN, 55402-4018 United States	Electronic Service		No	23-151Official
283	Doug	Shoemaker	dougs@charter.net	Minnesota Renewable Energy		2928 5th Ave S Minneapolis MN, 55408 United States	Electronic Service		No	23-151Official
284	Beth	Smith	bsmith@greatermankato.com	Greater Mankato Growth		1961 Premier Dr Ste 100 Mankato MN, 56001 United States	Electronic Service		No	23-151Official
285	Joel	Smith	jsmith@mnchippewatribe.org	Minnesota Chippewa Tribe		PO Box 217 Cass Lake MN, 56633 United States	Electronic Service		No	23-151Official
286	Joshua	Smith	joshua.smith@sierraclub.org			85 Second St FL 2 San Francisco CA, 94105 United States	Electronic Service		No	23-151Official
287	Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.		76 W Kellogg Blvd St. Paul MN, 55102 United States	Electronic Service		No	23-151Official
288	Nizhoni	Smith	nizhoni.smith@lowersioux.com	Lower Sioux Indian Community		PO Box 308 39527 Reservation Highway 1 Morton MN, 56270 United States	Electronic Service		No	23-151Official
289	Trevor	Smith	trevor.smith@avantenergy.com	Avant Energy, Inc.		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	23-151Official
290	Roger	Smith, Sr.	rogermsmithsr@fdlrez.com			1720 Big Lake Road Cloquet MN, 55720 United States	Electronic Service		No	23-151Official
291	Beth	Soholt	bsoholt@cleangridalliance.org	Clean Grid Alliance		570 Asbury Street Suite 201 St. Paul MN, 55104 United States	Electronic Service		No	23-151Official
292	Anna	Sommer	asommer@energyfuturesgroup.com	Energy Futures Group		PO Box 692 Canton NY, 13617 United States	Electronic Service		No	23-151Official
293	Marie	Spry	mariespry@grandportage.com			PO Box 428 Grand Portage MN, 55605 United States	Electronic Service		No	23-151Official
294	Mark	Spurr	mspurr@fvbenergy.com	International District Energy Association		222 South Ninth St., Suite 825 Minneapolis	Electronic Service		No	23-151Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						MN, 55402 United States				
295	LeRoy	Staples Fairbanks III	leroy.fairbanks@llojibwe.net	Leech Lake Band of Ojibwe		190 Sailstar Drive NW Cass Lake MN, 56633 United States	Electronic Service		No	23-151Official
296	Russ	Stark	russ.stark@ci.stpaul.mn.us	City of St. Paul		Mayor's Office 15 W. Kellogg Blvd., Suite 390 Saint Paul MN, 55102 United States	Electronic Service		No	23-151Official
297	Byron E.	Starns	byron.starns@stinson.com	STINSON LLP		50 S 6th St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	23-151Official
298	Cary	Stephenson	cstephenson@otpco.com	Otter Tail Power Company		215 South Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		Yes	23-151Official
299	Mark	Strohfus	mstrohfus@grenergy.com	Great River Energy		12300 Elm Creek Boulevard Maple Grove MN, 55369-4718 United States	Electronic Service		No	23-151Official
300	James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	23-151Official
301	Samuel	Strong	sam.strong@redlakenation.org	Red Lake Nation		15484 Migizi Drive Red Lake MN, 56671 United States	Electronic Service		No	23-151Official
302	Kent	Sulem	ksulem@mmua.org			3131 Fernbrook Ln N Ste 200 Plymouth MN, 55447-5337 United States	Electronic Service		No	23-151Official
303	Timothy	Sullivan	tsullivan@whe.org	Wright Hennepin Coop. Electric Assn.		6800 Electric Drive PO Box 330 Rockford MN, 55373 United States	Electronic Service		No	23-151Official
304	David	Sunderman	daves@benco.org	BENCO (DUPLICATE)		PO Box 8 Mankato MN, 56002-0008 United States	Electronic Service		No	23-151Official
305	Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine		225 S 6th St Ste 3500 Capella Tower Minneapolis MN, 55402-4629 United States	Electronic Service		No	23-151Official
306	Randy	Synstelien	rsynstelien@otpco.com	Otter Tail Power Company		215 S Cascade St Fergus Falls MN, 56537 United States	Electronic Service		No	23-151Official
307	Camille	Tanhoff	kamip@uppersiouxcommunity-nsn.gov	Upper Sioux Community		5722 Travers Lane PO BOX 147 Granite Falls MN, 56241 United States	Electronic Service		No	23-151Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
308	Mikayala	Thompson	mmthompson@otpco.com	Otter Tail Power Company		null null, null United States	Electronic Service		No	23-151Official
309	Tim	Thompson	tthompson@lrec.coop	Lake Region Electric Cooperative		PO Box 643 1401 South Broadway Pelican Rapids MN, 56572 United States	Electronic Service		No	23-151Official
310	Stuart	Tommerdahl	stommerdahl@otpco.com	Otter Tail Power Company		215 S Cascade St PO Box 496 Fergus Falls MN, 56537 United States	Electronic Service		Yes	23-151Official
311	Pat	Treseler	pat.jcplaw@comcast.net	Paulson Law Office LTD		4445 W 77th Street Suite 224 Edina MN, 55435 United States	Electronic Service		No	23-151Official
312	Lise	Trudeau	lise.trudeau@state.mn.us		Department of Commerce	85 7th Place East Suite 500 Saint Paul MN, 55101 United States	Electronic Service		No	23-151Official
313	Caralyn	Trutna	carrie@uppersiouxcommunity-nsn.gov	Upper Sioux Community		Upper Sioux Community P.O. Box 147 Granite Falls MN, 55372 United States	Electronic Service		No	23-151Official
314	Jackie	Van Norman	jvannorman@grenergy.com	Great River Energy		12300 Elm Creek Blvd Maple Grove MN, 55369 United States	Electronic Service		No	23-151Official
315	Analeisha	Vang	avang@mnpower.com			30 W Superior St Duluth MN, 55802-2093 United States	Electronic Service		Yes	23-151Official
316	Adrian	Varga	avarga@actcommodities.com	ACT Commodities		437 Madison Ave New York City NY, 10022 United States	Electronic Service		No	23-151Official
317	Sam	Villella	sdvillella@gmail.com			10534 Alamo Street NE Blaine MN, 55449 United States	Electronic Service		No	23-151Official
318	Julie	Voeck	julie.voeck@nee.com	NextEra Energy Resources, LLC		700 Universe Blvd Juno Beach FL, 33408 United States	Electronic Service		No	23-151Official
319	Amelia	Vohs	avohs@mncenter.org	Minnesota Center for Environmental Advocacy		1919 University Avenue West Suite 515 St. Paul MN, 55104 United States	Electronic Service		Yes	23-151Official
320	Michael	Volker	mvolker@eastriver.coop	East River Electric Power Coop		211 S. Harth Ave Madison SD, 57042 United States	Electronic Service		No	23-151Official
321	Toni	Volkmeier	toni.volkmeier@state.mn.us	MPCA		520 Lafayette Rd. N. St. Paul MN, 55155 United States	Electronic Service		No	23-151Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
322	Trent	Waite	twaite@grenergy.com			null null, null United States	Electronic Service		No	23-151Official
323	Laurance R	Waldoch	larrywaldoch@gmail.com	Attorney		2597 Parkview Dr Saint Paul MN, 55110 United States	Electronic Service		No	23-151Official
324	Greg	Wannier	greg.wannier@sierraclub.org	Sierra Club		2101 Webster St Ste 1300 Oakland CA, 94612 United States	Electronic Service		No	23-151Official
325	Roger	Warehime	roger.warehime@owatonnautilities.com	Owatonna Municipal Public Utilities - Gas		208 S Walnut Ave PO BOX 800 Owatonna MN, 55060 United States	Electronic Service		No	23-151Official
326	Cynthia	Warzecha	cynthia.warzecha@state.mn.us	Minnesota Department of Natural Resources		500 Lafayette Road Box 25 St. Paul MN, 55155-4040 United States	Electronic Service		No	23-151Official
327	Carol	Westergard	cwestergard@otpco.com	Otter Tail Power Company		215 S Cascade St Fergus Falls MN, 56537 United States	Electronic Service		No	23-151Official
328	Heather	Westra	heather.westra@piic.org	Prairie Island Indian Community		5636 Sturgeon Lake Rd Welch MN, 55089 United States	Electronic Service		No	23-151Official
329	Paul	White	paul.white@prcwind.com	Project Resources Corp./Tamarac Line LLC/Ridgewind		618 2nd Ave SE Minneapolis MN, 55414 United States	Electronic Service		No	23-151Official
330	Steve	White	steve.white@llojibwe.net	Leech Lake Band of Ojibwe		190 Sailstar Drive NW Cass Lake MN, 56633 United States	Electronic Service		No	23-151Official
331	Cody	Whitebear	cody.whitebear@piic.org	Prairie Island Indian Community		5636 Sturgeon Lake Road Welch MN, 55089 United States	Electronic Service		No	23-151Official
332	John	Williams	jwilliams@grenergy.com	Great River Energy		12300 Elm Creek Blvd Maple Grove MN, 55369 United States	Electronic Service		No	23-151Official
333	Laurie	Williams	laurie.williams@sierraclub.org	Sierra Club		Environmental Law Program 1536 Wynkoop St Ste 200 Denver CO, 80202 United States	Electronic Service		No	23-151Official
334	Virgil	Wind	virgil.wind@millelacsband.com	Mille Lacs Band of Ojibwe		43408 Oodena Drive Onamia MN, 56359 United States	Electronic Service		No	23-151Official
335	Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine		225 South Sixth Street, Suite 3500 Minneapolis MN, 55402 United States	Electronic Service		No	23-151Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
336	Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company		200 First St SE Cedar Rapids IA, 52401 United States	Electronic Service		No	23-151Official
337	Sara	Wolff	sara@mnipl.org			710 Linwood Avenue St Paul MN, 55105 United States	Electronic Service		No	23-151Official
338	Tim	Wulling	t.wulling@earthlink.net			1495 Raymond Ave. Saint Paul MN, 55108 United States	Electronic Service		No	23-151Official
339	Laurie	York	laurie.york@whiteearth-nsn.gov	White Earth Reservation Business Committee		PO Box 418 White Earth MN, 56591 United States	Electronic Service		No	23-151Official
340	Kurt	Zimmerman	kwz@ibew160.org	Local Union #160, IBEW		2909 Anthony Ln St Anthony Village MN, 55418-3238 United States	Electronic Service		No	23-151Official
341	Emily	Ziring	eziring@stlouispark.org	City of St. Louis Park		5005 Minnetonka Blvd St. Louis Park MN, 55416 United States	Electronic Service		No	23-151Official
342	Patrick	Zomer	pat.zomer@lawmoss.com	Moss & Barnett PA		150 S 5th St #1200 Minneapolis MN, 55402 United States	Electronic Service		No	23-151Official