MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	**April 23, 2026**	**Agenda Item 1*** **
Company	All Electric Utilities	
Docket No.	E-999/CI-23-151	
	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	
Issues	• What clarifications, if any, should the Commission make regarding carbon-free standard off-ramps under Minn. Stat. § 216B.1691, subd. 2b? • Should the Commission provide an extended credit duration for certain small wind resources or other similarly situated projects? • Are there any other issues the Commission should address?	
Staff	Danielle Winner	danielle.winner@state.mn.us 651-539-1084

✓ **Relevant Documents**

	Date
Docket No. E-999/CI-23-151	
Comments, Minnesota Large Industrial Group (MLIG)	August 2, 2023
Comments, MLIG	June 28, 2024
Comments, MLIG	January 29, 2025
Order, Minnesota Public Utilities Commission (MPUC or Commission)	September 16, 2025
Compliance Filing, Central Municipal Power Agency/Services (CMPAS)	October 15, 2025
Comments, Minnesota Power	October 27, 2025
Comments, Central Municipal Power Agency/Services	October 28, 2025

✓ **Relevant Documents**	**Date**
Comments, Department of Commerce –Division of Energy Resources (DOC DER, Department, or Dept)	October 28, 2025
Comments, Great River Energy	October 28, 2025
Comments, Otter Tail Power (OTP or Otter Tail)	October 28, 2025
Comments, Northern States Power Company d/b/a Xcel Energy	October 28, 2025
Reply Comments, Minnesota Center for Environmental Advocacy and Sierra Club (collectively, the Clean Energy Organizations or CEOs)	November 18, 2025
Reply Comments, CMPAS	November 18, 2025
Comments, MLIG	November 18, 2025
Reply Comments, Minnesota Power	November 18, 2025
Reply Comments, Xcel Energy	November 18, 2025
Letter of Clarification, Department	December 4, 2025
<u>Docket No. E-999/CI-03-869</u>	
Order, Commission	March 19, 2010
Order, Commission	June 1, 2004
<u>Docket No. E-999/CI-11-852</u>	
Order, Commission	January 6, 2015

Table of Contents

EXECUTIVE SUMMARY

When the Carbon-Free Standard ("CFS") was introduced into the Renewable Energy Objectives statute ("REO Statute") (Minn. Stat. § 216B.1691) in 2023, it was accompanied by amendments to other parts of the REO Statute. These amendments included changes to Minn. Stat. § 216B.1691, subd. 2b., which concerns modification or delay of a standard, colloquially referred to as "off-ramps." The Commission's most recent order concerning off-ramps was made in 2010 in Docket No. E-999/CI-03-869 and was specific to the Renewable Energy Standard ("2010 Order").

The Commission may wish to update that 2010 Order to accommodate the 2023 statutory changes. The Commission must therefore determine:

- Should Commission's off-ramp guidance from the 2010 Order apply to the CFS?
- Do the 2023 statutory changes necessitate any changes to the 2010 Order?
- Should the Commission issue a new order that supersedes the 2010 Order **(Decision Option 2)** or simply state that the 2010 Order applies to the CFS **(Decision Option 1)**?

Commenters also brought up issues beyond the 2010 Order. Great River Energy discussed potential cost-benefit analysis considerations in any future off-ramp requests. Minnesota Large Industrial Group ("MLIG") requested utilities provide additional cost- and rate-impact information in their Integrated Resource Plan ("IRP") filings.

Finally, Central Minnesota Power Agency/Services ("CMPAS") requested the Commission to expand the scope of its extended credit duration ("extended shelf life") approved in its August 7, 2025 Order in Docket No. E-999/CI-23-151. The Commission must determine whether the extended shelf life should apply to credits from CMPAS's specified projects.

BACKGROUND

I. CFS Docket Procedural History

House File No. 7 became effective on February 7, 2023, amending Minn. Stat. § 216B.1691, the REO Statute. These amendments included changes to Minnesota's existing Renewable Energy Standard ("RES") and the introduction of the state's Carbon-Free Standard.

The REO Statute requires the Commission to issue the necessary orders that 1) detail the criteria and standards used to measure an electric utility's efforts to meet the RES (now known as the Eligible Energy Technology Standard, or "EETS"), Solar Energy Standard ("SES"), Distributed Solar Energy Standard ("DSES"), and CFS; and 2) determine whether the utility is achieving these standards.

To address these statutory changes, the Commission initiated the instant Docket No. E-999/CI-23-151, *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 ("CFS Docket"). Staff divided the proceedings into a series of four rounds; Table 1 shows the current timeline of these proceedings.

Table 1. Carbon-Free Standard Docket Rounds of Comment

Round	Content	Comment Period Date	Agenda Meeting Date	Order Date
1	Changes to RES and SES	Initial: Aug 2, 2023 Reply: Aug 18, 2023	Oct 19, 2023	Dec 6, 2023
1.5	Additional clarifications: changes to RES and SES	Initial: Jan 19, 2024 Reply: Feb 7, 2024	Mar 14, 2024	Apr 12, 2024
2	New and Amended Terms	Initial: June 28, 2024 Reply: July 24, 2024	Sept 26, 2024	Nov 7, 2024
2.5	Request for Reconsideration and Clarification of Nov 7, 2024 Order	Petition: Nov 27, 2024 Answers: Dec 9, 2024	Jan 16, 2025	Jan 23, 2025
3	CFS Compliance	Initial: Jan 29, 2025 Reply: Mar 19, 2025 Supp: Apr 16, 2025	July 17, 2025	Order 1: Aug 7, 2025 Order 2: Sept 16, 2025
3.5	Request for Reconsideration on September 16, 2025 Order	Petition: Oct 16, 2025 Answers: Oct 27, 2025	Nov 20, 2025	Order: Nov 24, 2025
4	Off Ramp Process	Initial: Oct 28, 2025 Reply: Nov 18, 2025	April 23, 2025	

In Round 1, the Commission's December 6, 2023 Order:

- Specified which electric utilities are subject to the Renewable Energy Objectives under the revised statute;
- Directed the Executive Secretary to open an additional comment period to develop the record on specific remaining questions ("Round 1.5");
- Clarified certain reporting requirements;
- Specified how utilities becoming subject to Minn. Stat. § 216B.1691 or becoming no longer subject to Minn. Stat. § 216B.1691 should notify the Commission; and
- Made provisions concerning large hydroelectric facilities and utilities with members or customers in the Western Area Power Administration.

In Round 1.5, the Commission's April 12, 2024 Order clarified certain remaining questions from Round 1.

In Round 2, the Commission's November 7, 2024 Order:

- Delegated authority to the Executive Secretary to initiate a new proceeding to develop a life-cycle analysis framework for complex fuels such as biomass, renewable natural gas, and solid waste as they relate to the CFS;[1]
- Clarified that environmental justice areas should align with census tracts; and
- Determined that further record development was needed concerning partial compliance due to net market purchases but gave provisional guidance.

In Round 2.5, the Commission's January 23, 2025 Order denied a Petition for Clarification and Reconsideration made by the Clean Energy Organizations (comprising the Sierra Club and the Minnesota Center for Environmental Advocacy).

In Round 3, the Commission issued two orders. The Commission's August 7, 2025 Order incentivizes utilities to capitalize on federal production and investment tax credits by: 1) allowing an extended shelf life of Renewable Energy Credits for expedited projects, and 2) requiring each utility that files a resource plan to make a compliance filing detailing the utility's efforts to respond to Public Law No. 119-21 (restricting access to federal tax credits for renewable energy facilities) and ways the Commission can help mitigate negative impacts of the law.[2] The Commission's September 16, 2025 Order:

- Specified that Renewable Energy Credits ("RECs"), Alternative Energy Credits ("AECs"), and Environmental Attribute Credits ("EACs") may be used to demonstrate compliance with the CFS;
- Affirmed that RECs, AECs, and EACs have a four-year shelf life;
- Specified how net market purchases should be calculated and clarified that credits need not be retired to substantiate net market purchases;
- Made specific preparedness and compliance reporting requirements; and
- Allowed that resource plan-filing utilities may incorporate into their plans one or more sensitivities involving hourly matching to achieve the CFS.

In Round 3.5, the Commission's November 24, 2025 Order denied a Petition for Reconsideration made by Carbon Solutions Group.

---

[1] The Commission opened Docket No. E-999/CI-24-352, *In the Matter of a Commission Investigation into a Fuel Life-Cycle Analysis Framework for Utility Compliance with Minnesota's Carbon-Free Standard* (the "LCA docket"). The Commission met to discuss this docket on January 15, 2026; an order is forthcoming.

[2] On October 15th, 2025, utilities made these filings. Commission Staff summarized the results of these filings in a memorandum filed on February 3, 2026.

For Round 4, Staff issued a Notice of Comment on September 12, 2025 concerning the following topics:

- In light of the statutory changes made by H.F. No. 7, are any additional clarifications necessary regarding the off-ramp process outlined in the Commission's March 19, 2010 Order in Docket No. E-999/CI-03-869?
- Are there other issues or concerns related to this matter?

The following commenters provided either Comments or Reply Comments concerning off-ramps:

- Clean Energy Organizations ("CEOs," comprising Minnesota Center for Environmental Advocacy and Fresh Energy)
- Department of Commerce, Division of Energy Resources ("Department" or "DOC DER")
- Great River Energy
- Minnesota Large Industrial Group ("MLIG")
- Minnesota Power
- Otter Tail Power ("OTP" or "Otter Tail")
- Northern States Power d/b/a Xcel Energy ("Xcel")

A. CMPAS Request

As noted above, the Commission's August 7, 2025 Order allows an extended shelf life for credits generated from expedited projects and required utilities that file resource plans to describe how the Commission can help mitigate the negative effects of Public Law No. 119-21.

Central Municipal Power Agency/Services ("CMPAS") asked the Commission to provide an incentive for keeping Minnesota's small, older wind farms operating.[3] CMPAS's specific request is discussed in Section VI below.[4] On October 17, 2025, Staff issued a Notice of Comment on the following topics related to CMPAS's request, asking commenters to provide feedback in Round 4:

- Should the Commission approve Central Municipal Power Agency/Service's request for extended duration of Environmental Attribute Credits associated with certain wind projects?
- Are there other similar circumstances in which extended credit duration would incentivize CFS-obligated utilities to procure resources in the near term, rather than waiting for a future compliance date?

[3] Central Municipal Power Agency/Services Filing (October 15, 2025) (hereinafter "CMPAS Request").

[4] CMPAS initially made this request as part of a Request for Amendment of the August 7th, 2025 Order, but subsequently withdrew its Request. In Briefing Papers filed before the withdrawal of the Request, Staff noted that this was an entirely new issue which needs full record development and a comment period for other utilities and stakeholders to meaningfully analyze and respond.

- Are there other issues or concerns related to this matter?

In response to Staff's Notice, only CMPAS provided comment.

II. Off-Ramps Statute and 2023 Statutory Changes

Minn. Stat. § 216B.1691, subd. 2b concerns modification or delay of the standard, colloquially referred to as "off-ramps." This subdivision was introduced in 2007 and amended in the 2023 statutory changes to House File No. 7.

Broadly, the 2023 changes to the off-ramps subdivision:

- Explicitly applied the subdivision to the EETS, SES, and CFS (subds. 2a, 2f, and 2g, respectively);
- Added three new provisions the Commission must consider in determining whether an off-ramp is in the public interest (environmental costs, environmental justice areas, and beneficial electrification);
- Defined beneficial electrification; and
- Specified additional factors the Commission must consider when evaluating an off-ramp request related to transmission constraints.

Specifically, the 2023 statutory amendments to the off-ramps subdivision were as follows:

> Subd. 2b. Modification or delay of standard.
> (a) The commission shall modify or delay the implementation of a standard obligation under subdivision 2a, 2f, or 2g, in whole or in part, if the commission determines ~~it~~ that modifying or delaying the standard obligation is in the public interest ~~to do so~~. The commission, when ~~requested~~ evaluating a request to modify or delay implementation of a standard, must consider:
>
> (1) the impact of implementing the standard on its customers' utility costs, including the economic and competitive pressure on the utility's customers;
>
> (2) the environmental costs that would be incurred as a result of a delay or modification, based on the full range of environmental cost values established in section 216B.2422, subdivision 3;
>
> ~~(2)~~ (3) the effects of implementing the standard on the reliability of the electric system;
>
> ~~(3)~~ (4) technical advances or technical concerns;
>
> ~~(4)~~ (5) delays in acquiring sites or routes due to rejection or delays of necessary siting or other permitting approvals;
>
> ~~(5)~~ (6) delays, cancellations, or nondelivery of necessary equipment for construction or commercial operation of an

eligible energy technology facility;

~~(6)~~ (7) transmission constraints preventing delivery of service; ~~and~~

~~(7)~~ (8) other statutory obligations imposed on the commission or a utility~~.~~;

(9) impacts on environmental justice areas; and

(10) additional electric load from beneficial electrification and the greenhouse gas emissions savings associated with those loads as compared to serving the load with nonelectric energy sources.

For the purposes of this paragraph, "beneficial electrification" means the substitution of electricity for a fossil fuel, provided that the substitution meets at least one of the following conditions without adversely affecting either of the other two, as determined by the commission:

(i) saves a consumer money over the long run compared with continued use of the fossil fuel;

(ii) enables an electric utility to better manage the electric utility's electric grid network; or

(iii) reduces negative environmental impacts of fuel use, including but not limited to statewide greenhouse gas emissions.

(b) The commission may modify or delay implementation of a standard obligation under paragraph (a), clauses (1) to ~~(3)~~ (4), only if it finds implementation would cause significant rate impact, requires significant measures to address reliability, or raises significant technical issues. The commission may modify or delay implementation of a standard obligation under paragraph (a), clauses ~~(4)~~ (5) to ~~(6)~~ (7), only if it finds that the circumstances described in those clauses were due to circumstances beyond an electric utility's control and make compliance not feasible.

(c) When evaluating transmission capacity constraints under paragraph (a), clause (7), the commission must consider whether the utility has:

(1) taken reasonable measures that are under the utility's control and consistent with the utility's obligations under local, state, and federal laws and regulations, and the utility's obligations as a member of a regional transmission organization or independent system operator, to acquire sites, necessary permit approvals, and necessary equipment to develop and construct new transmission lines or upgrade existing transmission lines to transmit electricity generated by eligible energy technologies; and

(2) taken all reasonable operational measures to maximize cost-effective electricity delivery from eligible energy technologies in advance of transmission availability.

~~(b)~~ (d) When considering whether to delay or modify implementation of a standard obligation, the commission must give due consideration to a preference for electric generation through use of eligible energy technology and to the achievement of the standards set by this section.

~~(c)~~ (e) An electric utility ~~requesting~~ that requests a modification or delay ~~in~~ to the implementation of a standard must file a plan to comply with ~~its~~ the electric utility's standard obligation ~~in~~ as part of the same proceeding ~~that it is requesting~~ in which the electric utility requests the modification or delay.[5]

III. 2010 Order

After the 2007 statutory changes, the Commission re-initiated proceedings in Docket No. E-999/CI-03-869, *In the Matter of Detailing Criteria and Standards for Measuring a Utility's Good Faith Efforts in Meeting the Renewable Energy Objectives Under Minn. Stat. § 216B.1691*, eventually issuing its March 19, 2010 *Order Clarifying Criteria and Standards for Determining Compliance Under Minn. Stat. § 216B.1691* ("2010 Order"). The 2010 Order was specific to the RES, the only REO Standard in place at that time.[6] The 2010 Order did not add to the statutory requirements but clarified how the Commission interpreted the statute.

In regards to off-ramps,[7] the 2010 Order clarified the following:

- An off-ramp request may be filed at any time.
- Existing proceedings—such as Safety, Reliability, and Service Quality Reports ("SRSQs"), IRPs, transmission reports, and rate and rider proceedings—are the best vehicles to track how implementing the CFS will affect a utility's rate and reliability.
- Utilities not subject to IRPs may file voluntary rate impact information with their biennial RES compliance reporting.
- Any utility filing an off-ramp request should explain why the RES cannot be met with REC purchases.

---

[5] Laws of Minnesota 2023, Chapter 7, modifying Minn. Stat. §216B.1691, subd. 2b.

[6] Staff is unaware of any subsequent orders regarding SES or DSES off-ramps.

[7] In addition to off-ramps, the 2010 Order considered how to account for Western Area Power Administration ("WAPA") sales and how the Commission should interpret years between statutory compliance years. *In the Matter of Detailing Criteria and Standards for Measuring a Utility's Good Faith Efforts in Meeting the Renewable Energy Objectives Under Minn. Stat. § 216B.1691*, ORDER CLARIFYING CRITERIA AND STANDARDS FOR DETERMINING COMPLIANCE UNDER MINN. STAT. § 216B.1691, Docket No. E-999/CI-03-869, Ordering Paragraphs 1-3 (March 19, 2010) (hereinafter "2010 Order").

Specifically, the 2010 Order states in relevant part:

> 4. The Commission clarifies that a petition to modify or delay a Renewable Energy Standard may be filed at any time.
>
> 5. Any petition to modify or delay a Renewable Energy Standard shall include the following information: (a) a discussion of the reasons for concluding that compliance cannot be achieved by buying Renewable Energy Credits; (b) a plan for future compliance, as required under Minn. Stat. § 216B.1691, subd. 2b (c); and (c) the time frame within which the petitioner requests Commission action.
>
> 6. Petitions to modify or delay any Renewable Energy Standard shall comply with the service and filing requirements of Minnesota Rules 7829.1300 and, at least initially, follow the procedural track set forth in Minnesota Rules 7829.1400.
>
> 7. The Commission clarifies that it will use the proceedings and methods discussed in section V of this order to track the rate and reliability effects of the Renewable Energy Objectives and Standards. The Commission will accept voluntary filings on the rate impact of the Renewable Energy Objectives and Standards in the biennial compliance reports filed by utilities not required to file resource plans.
>
> 8. The Commission clarifies that it favors forward-looking, long-term cost information when analyzing the rate impacts of the Renewable Energy Objectives and Standards but will not preclude other types of cost information from being presented by the parties.
>
> 9. The Commission clarifies that intervenors in a resource plan proceeding who request information related to the rate impact of future compliance with the Renewable Energy Standards are making a reasonable request for information under Minn. Rules, part 7843.0300, subp. 8, and that utilities must promptly respond.
>
> 10. The Commission clarifies that it will evaluate compliance with the Renewable Energy Standards on a case-by-case basis, but will also consider the factors set forth below:
>
> a. The factors articulated in its June 1, 2004 [sic] order for evaluating compliance with the Renewable Energy

> Objectives.
> b. Whether the utility brought the noncompliance to the attention of the Commission in a timely manner.
> c. Whether Renewable Energy Credits are available for purchase, and at what price.

Staff notes that Ordering Paragraph 7 refers to "the proceedings and methods discussed in section V of this order" as the best vehicles to track rate and reliability impacts for RES compliance. Those proceedings and methods include resource plans, rate cases, certificate of need applications, purchased power contract approval proceedings, renewable energy and transmission rider approval requests.[8]

Staff notes that Ordering Paragraph 10.a. refers to "factors … for evaluating compliance" articulated in the Commission's June 1, 2004 *Initial Order Detailing Criteria and Standards for Determining Compliance with Minn. Stat. § 216B.1691 and Requiring Customer Notification by Certain Cooperative, Municipal, and Investor-Owned Distribution Utilities*.[9] These articulated factors can be found in Ordering Paragraphs 11A-H of the June 1, 2004 Order; they were established prior to the adoption of the RES and were specifically meant to help evaluate a utility's "good faith efforts" towards meeting renewable energy objectives.

DISCUSSION

IV. 2010 Order

Broadly, commenters support applying the provisions set forth in the 2010 Order to the CFS, arguing that the Order provides reasonable guidance while preserving flexibility. The Department stated that, to its knowledge, the existing process has been sufficient to maintain statutory compliance with the REO standards.[10]

A. Timing of Filing (Ordering Paragraph 4)

Xcel Energy suggested the following redline edit to Ordering Paragraph 4:

> 4. The Commission clarifies that a petition to modify or delay a ~~Renewable Energy~~ Standard under Minn. § Stat. 216B.1691 may be filed at any time.[11]

---

[8] 2010 Order, p. 9.

[9] INITIAL ORDER DETAILING CRITERIA AND STANDARDS FOR DETERMINING COMPLIANCE WITH MINN. STAT. § 216B.1691 AND REQUIRING CUSTOMER NOTIFICATION BY CERTAIN COOPERATIVE, MUNICIPAL, AND INVESTOR-OWNED DISTRIBUTION UTILITIES, Docket No. E-999/CI-03-869, Ordering Paragraph 11 (June 1, 2004) (hereinafter "2004 Order").

[10] Department of Commerce, Division of Energy Resources Comments, p. 3 (October 28, 2025) (hereinafter "Department Comments").

[11] Northern States Power Company d/b/a Xcel Energy Comments, Attachment B, p. 1 (October 28, 2025) (hereinafter "Xcel Comments").

(Decision Option 3)

While commenters were generally not opposed to the clarification that off-ramp requests may be filed at any time, many agreed that a resource plan proceeding is the best place to file a petition to modify or delay a standard. OTP noted that the statute does not preclude the Commission from evaluating requests filed at other times.[12]

Minnesota Power specifically recommended that modification and delay requests made outside of a resource planning process should be reserved for those caused by the reasons established in Minn. Stat. § 216B.1961, subd. [2b (5-8)],[13] namely:

> (5) delays in acquiring sites or routes due to rejection or delays of necessary siting or other permitting approvals
> (6) delays, cancellations, or nondelivery of necessary equipment for construction or commercial operation of an eligible energy technology facility
> (7) transmission constraints preventing delivery of service
> (8) other statutory obligations imposed on the commission or a utility

Minnesota Power reasoned that these considerations may be less predictable and more likely to occur outside of IRP evaluation periods.[14] Minnesota Power's recommendation is reflected in **Decision Option 4.**

CEOs supported Minnesota Power's recommendation and further recommended that if a utility requests an off-ramp outside of an IRP, it should be required to explain why non-compliance was not foreseen in its IRP.[15] **(Decision Option 5)**

While CEOs were generally supportive of IRPs as the appropriate proceeding in which to request an off-ramp, they asked the Commission to reject off-ramp requests made years in advance of a compliance deadline. CEOs argued a Commission approval of an off-ramp years in advance would "undercut Minnesota's CFS by allowing a utility to prematurely stop even trying to achieve compliance."[16] CEOs did not specify how far in advance of a compliance deadline would be an acceptable timeline for off-ramp requests and did not make a formal recommendation on this count.

1. Staff Analysis

Staff agrees that Xcel's recommended edits to Ordering Paragraph 4 provide clarity and that

---

[12] Otter Tail Power Company Comments, pp. 3-4 (October 28, 2025) (hereinafter "OTP Comments").
[13] Minnesota Power cited Subd. 2a, but the correct citation appears to be Subd. 2b. Minnesota Power Comments, PDF p. 3 (October 28, 2025) (hereinafter "Minnesota Power Comments").
[14] Minnesota Power Comments, PDF p. 3.
[15] Minnesota Center for Environmental Advocacy and Sierra Club, collectively "Clean Energy Organizations" Comments, p. 8 (November 18, 2025) (hereinafter "CEOs Comments").
[16] CEOs Comments, p. 9.

Minnesota Power and CEOs' recommendations appear reasonable.

To CEOs' concern regarding a premature off-ramp request, Staff notes that the Five-Year Action plan appears to be a natural and reasonable cutoff for keeping requests close to compliance years. Furthermore, if a utility's IRP happens to be filed five years ahead of a compliance year, the Commission may choose to decline a request, knowing that it may have the opportunity to review another plan by that utility in the intervening years. However, since the record has not been developed on this front, Staff recommends that if the Commission wishes to specify a timeframe in which off-ramp requests are made, it should ask commenters about their positions at the Agenda Meeting.

B. Contents of Filing (Ordering Paragraph 5)

Minnesota Power[17] and Xcel[18] both noted that the Commission's September 16, 2025 Order in this proceeding permits the use of Alternative Energy Credits and equivalent Environmental Attribute Credits to be retired to demonstrate compliance with the CFS. Both utilities recommended the Commission incorporate language reflecting these other credits in Ordering Paragraph 5.

Minnesota Power provided the following redline edits:

> 5. Any petition to modify or delay a Renewable Energy Standard shall include the following information: (a) a discussion of the reasons for concluding that compliance cannot be achieved by buying Renewable Energy Credits, Alternative Energy Credits, equivalent carbon free attributes allowed by statute or Commission order (i.e. the carbon free percentage of the utility's annual net market purchases); (b) a plan for future compliance, as required under Minn. Stat. § 216B.1691, subd. 2b (c); and (c) the time frame within which the petitioner requests Commission action.[19]
> **(Decision Option 6)**

Xcel provided the following redline edits:

> 5. Any petition to modify or delay a ~~Renewable Energy~~ Standard under Minn. Stat. § 216B.1691 shall include the following information: (a) a discussion of the reasons for concluding that compliance cannot be achieved by buying Renewable Energy Credits, Alternative Energy Credits, or equivalent Environmental

[17] Minnesota Power Comments, PDF p. 7.
[18] Xcel Comments, p. 4.
[19] Minnesota Power Comments, PDF p. 7.

> Attribute Credits, where applicable; (b) a plan for future compliance, as required under Minn. Stat. 216B.1691, subd. 2b (~~e~~e); and (c) the time frame within which the petitioner requests Commission action.[20]
> **(Decision Option 7)**

1. Staff Analysis

Staff agrees that adding other types of credits and qualifying carbon-free attributes into Ordering Paragraph 5 would provide clarity. Staff notes that this language should also be inclusive of the Solar Energy Standard, and so suggests adding "Solar Renewable Energy Credits."

Staff recommends a hybrid of Minnesota Power's and Xcel's language:

> 5. Any petition to modify or delay a ~~Renewable Energy~~ Standard under Minn. Stat. § 216B.1691 shall include the following information: (a) a discussion of the reasons for concluding that compliance cannot be achieved by buying Renewable Energy Credits, Solar Renewable Energy Credits, Alternative Energy Credits, Environmental Attribute Credits, or equivalent attributes allowed by statute or Commission order (such as the carbon-free percentage of the utility's annual net market purchases), where applicable; (b) a plan for future compliance, as required under Minn. Stat. 216B.1691, subd. 2b (~~e~~e); and (c) the time frame within which the petitioner requests Commission action.
> **(Staff Decision Option 8)**

C. Procedural Requirements of Filing (Ordering Paragraph 6)

Minnesota Power,[21] Otter Tail Power,[22] and Xcel provided general support for Ordering Paragraph 6.

Xcel provided the following redline edits:

> 6. Petitions to modify or delay any ~~Renewable Energy~~ Standard under Minn. Stat. § 216B.1691 shall comply with the service and filing requirements of Minnesota Rules 7829.1300; and~~, at least initially,~~ follow the procedural track set forth in Minnesota Rules

[20] Xcel Comments, Attachment B, p. 1.

[21] Minnesota Power stated that "Order Point 6 requires no clarification," which Staff interprets to mean that Minnesota Power supports leaving Ordering Paragraph 6 as is. Minnesota Power Comments, PDF p. 7.

[22] OTP Comments, p. 4.

7829.1400.
(Decision Option 9)

CEOs recommended that, following an off-ramp request, 1) the comment period be extended to sixty days and 2) the reply comment period be extended to thirty days. This is opposed to the thirty-day comment/ten-day reply period in Minnesota Rules 7829.1400. To justify their recommendation, CEOs note the importance of off-ramp requests, the many statutory factors that must be considered, and the potential need for significant information regarding available compliance alternatives when an off-ramp request occurs outside an IRP, including new modeling.[23] CEOs' recommendation is reflected in **Decision Option 10**.

MLIG stated that some parties' initial comments appear to imply that only utilities could bring petitions for delay, but MLIG believes the process is open to anyone impacted by the CFS.[24]

1. Staff Analysis

Staff agrees that Xcel's recommended edits to Ordering Paragraph 6 provide clarity. Staff also agrees with CEOs that the many statutory factors and the potential need for new modeling may warrant an extended comment/reply period.

Although the Commission's 2010 Order did not specify which parties may file an off-ramp Petition, Staff notes that this was part of the record at the time. Ordering Paragraph 6 refers to Minn. Rules 7829.1300 (Miscellaneous Filings) and Minn. Rules 7829.1400 (Commission Action on Miscellaneous Filings; Comments), both of which contemplate non-utility parties making such filings. Provided the party filing an off-ramp petition meets the requirements of these rules, Staff finds no reason why a non-utility party would be barred from filing a request. In other words, Staff considers Ordering Paragraph 6 to adequately address who may file an off-ramp petition; however, the Commission may wish to provide further clarity.

D. Tracking Rate and Reliability Impacts (Ordering Paragraph 7)

Commenters generally agreed that existing proceedings are the best place in which to track rate and reliability effects of implementing the CFS. However, Minnesota Large Industrial Group requested additional cost and rate impact information be provided in resource plan proceedings; this is discussed further in Section V.B. below.

The Department stated that it agrees with the Commission's logic in its 2010 Order concerning the rate impacts of meeting the RES,[25] offering the following quote:

> [R]esource plan proceedings generally offer the best opportunity to examine the utility-specific rate impact of meeting the

[23] CEOs Comments, p. 10.
[24] Minnesota Large Industrial Group Comments, p. 3 (November 18, 2025) (hereinafter "MLIG 2026 Comments").
[25] Department's October 28, 2025 Comments, p. 4.

> Renewable Energy Standards. These proceedings are designed to provide detailed, long-term cost comparisons between different resource mixes; in theory they are ideally suited for gauging the rate impacts of resource choices resulting from legislative mandates. There is therefore no generalized need to establish separate procedural track for monitoring the rate impact of the Renewable Energy Standards.[26]

The Department further pointed out that the Commission's 2010 Order lists a number of other opportunities for rate impacts to be discussed: rate cases, certificate of need applications, purchased power contract proceedings, and renewable energy and transmission rider approval requests.[27] The Department concluded that the Commission, the Department, and interested stakeholders would be best able to monitor rate impacts of CFS compliance in these same dockets, and that no additional proceeding need be established.[28]

The Department agreed with the Commission's 2010 Order discussion that concluded that reliability issues are best monitored through the biennial transmission filings, the annual reliability reporting requirements of Minn. Rules Chapter 7826 (SRSQ reports), and regional reliability organizations.[29] The Department further clarified that the resource adequacy component of reliability is best handled through dockets such as IRPs.[30] Therefore, the Department concluded that the Commission, the Department, and interested stakeholders would be best able to monitor the reliability impacts of compliance with the CFS in these dockets, and in collaboration with regional reliability organizations, and no additional proceeding need be established at this time.[31]

Minnesota Power recommended the Commission clarify the Order Point 7 language by removing references to the 2010 Order, and instead clearly define the IRP as the preferred proceeding in which a utility shall report rate impacts, reliability, and technical challenges caused by standards compliance.[32] Minnesota Power did not provide preferred language, so Staff provides the following interpretation of Minnesota Power's recommendation:

> 7. The Commission clarifies that Integrated Resource Plans are the preferred ~~it will use the~~ proceedings ~~and methods discussed in section V of this order~~ to track ~~the~~ rate impacts, ~~and~~ reliability, and technical challenges caused by compliance with the ~~effects of the~~ Renewable Energy Objectives and Standards. The Commission will accept voluntary filings on the rate impact of the Renewable Energy

[26] 2010 Order, p. 9.
[27] Department October 28, 2025 Comments, p. 4, referencing Commission's 2010 Order, p. 9.
[28] Department October 28, 2025 Comments, p. 5.
[29] Department Comments, pp. 4-5.
[30] Department Comments, p. 5.
[31] Department Comments, p. 5.
[32] MP Comments, PDF page 4.

> Objectives and Standards in the biennial compliance reports filed by utilities not required to file resource plans.
> **(Decision Option 11)**

Xcel recommended removing Ordering Paragraph 7 entirely, but was not opposed to leaving it in, should the Commission wish to retain the additional clarity concerning procedures and expectations.[33]

1. Staff Analysis

Staff finds Minnesota Power's proposed amendments to be reasonable.

No commenter addressed the second component of the Commission's Ordering Paragraph 7, namely that the Commission will accept voluntary filings on the rate impact of the Renewable Energy Objectives and Standards in the biennial compliance reports filed by utilities not required to file resource plans.

The Commission's 2010 Order provided the following discussion on this topic:

> While five of the sixteen utilities subject to the Standards do not file resource plans, because their customer numbers within the state are too low, the Commission, the [Department], and interested stakeholders will continue to monitor their rates, will accept voluntary filings on rate impact in the annual filings detailing their compliance with the Standards, and will of course examine rate impact information submitted in any petition to modify or delay any obligation under the Renewable Energy Standards. These safeguards are adequate at present and can be supplemented should the need arise.

Staff is unaware of any such voluntary filings being made. Further, if a need has arisen that has warranted supplementing the existing process, no commentor has mentioned it.

E. Cost Information (Ordering Paragraph 8) and Reasonableness of Intervenors (Ordering Paragraph 9)

Both Minnesota Power and Xcel recommended removing Ordering Paragraphs 8 and 9.[34] Minnesota Power reasoned that those paragraphs are redundant because a utility's IRP filing already includes forward-looking long-term cost information for the analysis of potential rate impacts caused by compliance with applicable standards.[35] Minnesota Power further argued that as utilities already provide rate impact outlook in IRPs, providing stakeholders with a

---

[33] Xcel Comments, p. 6.

[34] Minnesota Power Comments, PDF pp. 4-5; Xcel Comments, p. 6.

[35] Minnesota Power Comments, PDF p. 4.

centralized source of information for evaluating the financial implications of compliance and a clear process for request rate impact information; therefore, MP argued, this requirement is redundant.[36]

1. Staff Analysis

The Commission adopted Ordering Paragraphs 8 and 9 in response to a cost and rate impact discussion in the 2010 proceeding brought up by the Chamber of Commerce and Large Industrial Group. As part of this discussion, the Chamber of Commerce recommended requiring utilities filing resource plans to file a "reference case" scenario based on the assumption that the Renewable Energy Objectives and Renewable Energy Standards had not been enacted.[37] In response, utilities noted that it would be too difficult to retroactively analyze the cost impacts of complying with the RES/REO. This is discussed further in Section V.B. below. Should the Commission wish to maintain these Ordering Paragraphs, this is reflected in **Decision Options 12 and 13.**

F. Compliance with the Standards (Ordering Paragraph 10)

Xcel noted that it did not consider Ordering Paragraph 10 to be about off-ramps, but instead about compliance and non-compliance; in fact, Xcel clarified that as long as a utility has appropriately filed for a delay or modification, that utility is in compliance.[38]

Minnesota Power recommended the following redline edits to Ordering Paragraph 10.

> 10. The Commission clarifies that it will evaluate compliance with the Renewable Energy Standards on a case-by-case basis, but will also consider the factors set forth below:
>
> ~~a. The factors articulated in its June 4, 2004 order for evaluating compliance with the Renewable Energy Objectives.~~
>
> b. Whether the utility brought the noncompliance to the attention of the Commission in a timely manner.
>
> c. Whether Renewable Energy Credits, Alternative Energy Credits, or equivalent carbon free attributes allowed by statute or Commission order are available for purchase, and at what price.[39]
>
> **(Decision Option 14)**

[36] Minnesota Power Comments, PDF p. 5.
[37] 2010 Order, p. 9.
[38] Xcel Comments, p. 2.
[39] Minnesota Power Comments, PDF p. 6.

1. Staff Analysis

Staff has reviewed the June 1, 2004 Order and agrees with Minnesota Power that it is specific to a utility's "good faith efforts" to meet the Renewable Energy Objectives; once compliance became measured by REC retirement, these "articulated factors" were no longer the primary means of evaluating utility compliance with the statute. Therefore, it may be reasonable for the Commission to remove 10.a. as suggested by Minnesota Power. Staff cautions, however, that removing reference to these articulated factors may erase institutional knowledge concerning evaluation tools the Commission might employ outside of basic questions of compliance.

Should the Commission wish to move forward with Minnesota Power's recommended changes, Staff suggests the following amendments to bring the language into alignment with its recommended changes to Ordering Paragraph 5:

> 10. The Commission clarifies that it will evaluate compliance with any ~~the Renewable Energy~~ Standard~~s~~ under Minn. Stat. § 216B.1691 on a case-by-case basis, but will also consider the factors set forth below:
>
> ~~a. The factors articulated in its June 4, 2004 order for evaluating compliance with the Renewable Energy Objectives.~~
>
> ~~b.~~ a. Whether the utility brought the noncompliance to the attention of the Commission in a timely manner.
>
> ~~c.~~ b. Whether Renewable Energy Credits, Solar Renewable Energy Credits, Alternative Energy Credits, equivalent Environmental Attribute Credits, or equivalent carbon-free attributes allowed by statute or Commission Order, where relevant, are available for purchase, and at what price.
>
> **(Staff Decision Option 15)**

V. Additional Off-Ramp Considerations

A. Cost-Benefit Analysis

Great River Energy did not make any formal recommendations, but argued that "[t]he key policy question is how to determine that costs of compliance materially exceed the benefits of incremental carbon-free deployment."[40] To this end, Great River Energy offered a number of considerations that could inform a future cost-benefit discussion. These are summarized in the following table.

[40] Great River Energy Comments, p. 2 (October 28, 2025) (hereinafter "Great River Energy Comments").

Table 2. Great River Energy's List of Cost Considerations

Cost Category	Specific Consideration
Ratepayer Affordability and Economic Impact	• Rate increases relative to inflation or median-income growth • Disproportionate burden on low- and moderate-income households, renters, or customers lacking access to distributed energy resources • Alignment with energy justice principles, so as to minimize energy insecurity, energy burden, or force trade-offs between essential needs and electricity • Regional economic impacts, including effects on small businesses and large industrial employers
System Reliability and Resource Adequacy	• Impacts on reserve margins and the ability to cost-effectively meet MISO planning requirements • Reliability risks during extreme-weather events, with reduced dispatch flexibility • Timing mismatches between renewable additions and the availability of firm, carbon-free replacements • Risk of accelerated thermal retirements before proven alternatives are available
Implementation and Infrastructure Costs	• MISO interconnection and queue-congestion factors that delay renewable deployment • Cost and market-readiness of emerging technologies that remain unproven or uneconomic at scale
Broader Societal and Environmental Trade-Offs	• Land-use and siting impacts on Minnesota's rural and tribal communities • Environmental-justice implications when renewable-infrastructure burdens, including location, shift to specific geographies, demographics, or socioeconomic groups
Energy Burden	• The share of disposable household income devoted to electricity as a measure of energy burden and vulnerability within a utility's service territory

Otter Tail did not respond specifically to Great River Energy but included a similar discussion. Otter Tail stated that it believes that requests for modification and delay need not be strictly limited to the explicit statutory factors the Commission must consider, but could also include compelling developments, such as challenges driven by catastrophic events such as natural disasters.[41]

CEOs were critical of Great River Energy's comments, noting that to grant an off-ramp request, the Commission must first determine that granting the request is in the public interest, and that

[41] OTP Comments, p. 4.

the off-ramps statute explicitly outlines a number of factors the Commission must consider when making such a determination.[42] CEOs further noted that if customer costs, reliability, or technical issues are the main reason for a delay or modification, the Commission must then consider a second factor, which is whether denying the request would cause a significant rate impact.[43] In other words, delaying or modifying a standard for customer costs, reliability, or technical issues requires a two-part standard: 1) it must be in the public interest and 2) it must cause a significant rate impact. CEOs concluded that "[t]o the extent that GRE's comments suggest that the standard for granting an off-ramp request is simply whether the incremental cost of compliance exceeds the incremental benefits of compliance, that proposal would violate the statute and should be rejected."[44]

Additionally, CEOs note that Great River Energy's list does not include other factors identified in statute that are required for the Commission to consider when determining whether a request is in the public interest.[45]

As a result of this discussion, CEOs recommended that the Commission do the following:

1. Affirm that cost-based off-ramp requests will be assessed pursuant to Minn. Stat. § 216B.1691, subd. 2b(a) and (b), requiring the Commission to determination whether compliance "would cause significant rate impact" and whether an off-ramp would be "in the public interest." **(Decision Option 16)**

2. Decline to adopt a detailed list of factors it will consider when assessing off-ramp requests, or if it does adopt such a list, expand it to require information on all relevant considerations already specified by law and Commission order. **(Decision Option 17)**

1. Staff Analysis

Staff appreciates the delineation between costs increases and rate impacts; simply because a cost increases, it does not follow that the increase would result in a significant rate impact.

Staff also agrees that while the Commission is bound by the statutory provisions, the Commission has broad authority in how it chooses to weigh the statutory factors in determining whether to grant an off-ramp request. Staff does not believe a decision option on this topic is necessary at this time; instead, such a determination would be more appropriately discussed at the time of a future off-ramp request.

---

[42] CEOs Comments, p. 2.
[43] CEOs Comments, p. 3.
[44] CEOs Comments, p. 3.
[45] CEOs Comments, p. 4.

B. Rate Impacts

Minnesota Large Industrial Group made a series of recommendations to track costs and rates in IRP filings.[46] MLIG made these same recommendations at different stages in these CFS proceedings;[47] however, Staff specified in its July 7, 2025 Briefing Papers that more record development was needed in Round 4 of the CFS.[48]

MLIG recommended that the Commission require utilities to file in their IRPs:

1. The average current rate for each customer class as of the year of the IRP filing. **(Decision Option 18a)**

2. Projected rate increases (in dollars and percentages) by customer class for each year of the five-year IRP action plan. **(Decision Option 18b)**

3. The net present value of the utility's revenue requirement (PVRR) over the life of the IRP action plan, under various scenarios, while separately identifying the environmental costs. **(Decision Option 18c)**

MLIG has previously offered the following justification for these recommendations: "…the production and presentation of rate impacts is rarely uniform across utility dockets, and the Commission should carefully develop the 'uniform reporting system' required in Minn. Stat. §216B.1691, Subd. 2e."[49]

MLIG previously offered an example of how its recommendation 3 could be reported, citing a table made by the Department in 2022:[50]

Table 3. Staff Re-creation of Department's total cost results for each Boswell retirement scenario, as cited by MLIG

NPV Plan Costs ($Millions)	StatusQuo	PrefPlan	Early3	Early4	FastExit
Revenue Requirement	$8,062	$8,128	$8,151	$8,227	$8,329
Externalities	$2,022	$1,901	$1,897	$1,857	$1,709
Revenue Requirement + Externalities (Total Plan Cost)	$10,084	$10,030	$10,048	$10,084	$10,038

[46] MLIG 2026 Comments, pp. 1-2.

[47] See Minnesota Large Industrial Group Comments, pp. 5-7 (August 2, 2023) (hereinafter "MLIG 2023 Comments"); Minnesota Large Industrial Group Comments, pp. 4-5 (June 28, 2024) (hereinafter "MLIG 2024 Comments); MLIG Comments (January 29, 2025).

[48] Staff Briefing Papers, p. 32 (July 7, 2025).

[49] MLIG 2024 Comments, p. 4.

[50] MLIG 2023 Comments, p. 7.

MLIG further requested that the Commission require utilities to file the following in their IRPs:

> 4. A reference case scenario, detailing the least cost plan, from a ratepayer impact perspective, for meeting the CFS by 2040, even if the intermediate benchmarks for 2030 and 2035 set out in Minn. Stat. § 216B.1691, Subd. 2g(1) and (2) are missed; **(Decision Option 18d)** and
>
> 5. A reference case scenario, detailing the least cost plan, from a ratepayer impact perspective, to meet the CFS by 2050, which were goals incorporated in recent resource planning dockets of Xcel Energy and Minnesota Power. **(Decision Option 18e)**

MLIG specifies that in recommendations 4 and 5, "from a ratepayer impact perspective" means "exclusive of the various modeling assumptions built into statute."[51] Staff interprets this to mean without environmental and regulatory (i.e., Social Cost of Carbon) costs.[52]

In support of recommendations 4 and 5, MLIG has previously offered the following justification:

> These two reference case scenarios would give the Commission and intervening parties the information they need to understand the utility's preferred plan versus other possible plans, with the ability to evaluate (i) the least cost way of meeting the carbon free target by 2040, independent of whether the intermediate targets are met; and (ii) the cost premium for achieving the carbon free target ten years earlier than the Commission determined was reasonable in two recent resource plans. [footnote omitted] Furthermore, by including these scenarios, which exclude the influence of various modeling assumptions, the Commission will understand how the modeling assumptions influence the utility's preferred plan.[53]

As part of these reference case requirements, MLIG requests that the Commission provide utilities and customers with some expectation as to what is a "reasonable" cost increase, to provide a target or range of costs that are acceptable and in the public interest to achieve compliance with the 2040 legislation. MLIG argues that this information would 1) provide guidance to utilities and customers as they prepare their IRPs and budgets, and 2) allow the Commission to determine in future proceedings whether the actual costs of approved IRPs

---

[51] MLIG 2026 Comments, p. 2, Footnotes 2-3.

[52] Recall that the Commission's "regulatory" costs estimate the cost of a theoretical carbon dioxide tax, while the Commission's "environmental" costs estimate the externality costs of other pollutants.

[53] MLIG 2024 Comments, pp. 5-6.

were reasonable, or whether the pace of investments needs to be slowed to maintain affordability.[54]

1. Staff Analysis

Staff notes that MLIG referred to a "uniform reporting system" in subdivision 2e. This subdivision contained 2023 statutory amendments that have not been addressed in these CFS proceedings:

> Subd. 2e. Rate impact of standard compliance; report.
>
> Each electric utility must submit to the commission and the legislative committees with primary jurisdiction over energy policy a report containing an estimation of the rate impact of activities of the electric utility necessary to comply with this section. In consultation with the Department of Commerce, the commission shall determine a uniform reporting system to ensure that individual utility reports are consistent and comparable, and shall, by order, require each electric utility subject to this section to use that reporting system. The rate impact estimate must be for wholesale rates and, if the electric utility makes retail sales, the estimate shall also be for the impact on the electric utility's retail rates. Those activities include, without limitation, energy purchases, generation facility acquisition and construction, and transmission improvements. ~~An initial report must be submitted within 150 days of May 28, 2011. After the initial report,~~ A report must be updated and submitted as part of each integrated resource plan or plan modification filed by the electric utility under section 216B.2422. The reporting obligation of an electric utility under this subdivision expires December 31, ~~2025, for an electric utility subject to subdivision 2a, paragraph (a), and December 31, 2020, for an electric utility subject to subdivision 2a, paragraph (b)~~ 2040.

The Commission took up subdivision 2e. requirements in Docket No. E-999/CI-11-852, *In the Matter of Utility Renewable Energy Cost Impact Reports Required by Minnesota Statutes Section 216B.1691, Subd. 2e*, and on January 6, 2015 issued its *Order Establishing Uniform Reporting System for Estimating Rate Impact of Minn. Stat. § 216B.1691* ("2015 Rate Impacts Order"). The 2015 Rate Impacts Order does not appear to have been updated since that time.

Staff notes that the 2015 Rate Impacts Order specifically refers to the Renewable Energy Standard and the Solar Energy Standard, but subdivision 2e. applies to all REO Standards. Therefore, the Commission may wish to revisit its 2015 Rate Impacts Order to determine

[54] MLIG 2024 Comments, pp. 5-6.

whether anything needs to be updated to ensure that parties can apply it to the CFS.

Pursuant to subdivision 2e., utilities file rate impact reports with their IRPs. Staff reviewed the most recent rate impact reports filed by Great River Energy, Minnesota Power, Otter Tail Power, and Xcel, and has provided them as Attachment A to these Briefing Papers. They appear to show projected rate increases by customer class over the next five years, under the utility's preferred action plan. It is unclear to Staff how the information provided in these reports is different from MLIG's recommendations 1 and 2.

Staff notes that recommendations 4 and 5 relate to the Commission's Ordering Paragraph 8 (forward-looking data) and Ordering Paragraph 9 (intervenors making reasonable requests) from the 2010 Order. In the 2010 proceeding, both the Chamber of Commerce and the Large Industrial Group requested that additional rate and cost information be provided in IRPs; the Chamber of Commerce specifically requested a modeling scenario that would identify the cost of meeting the RES. The Commission's discussion noted the following:

> [The utilities] stated their willingness to provide forward-looking cost comparisons between different resource choices, including, when relevant, resource choices that could require delay or modification of their Renewable Energy Standard obligations. They cautioned against being required to provide backward-looking data, however, saying that attempting to reconstruct hypothetical past costs quickly becomes speculative and onerous.[55]
>
> …
>
> The Commission concurs with the [Department] that forward-looking, long-term cost information is the most probative, reliable, and helpful in gauging the rate impacts of the Renewable Energy Standards. Both the Standards and the utility initiatives undertaken to meet them are long-term projects whose costs and rate impact must be examined primarily in the future and in the long term. While the costs of past projects, undertaken or forgone, may have some relevance - and parties should not be precluded from introducing such evidence - the Commission concurs with the utilities that compelling them to develop and produce such cost information carries costs and risks that normally exceed its value.[56]

To this point, Staff notes that there is a limitation to the usefulness of examining the cost of meeting REO standards, as the true cost of compliance would necessitate a backwards-looking analysis. That being said, a forward-looking analysis examining the modification or delay of the

[55] 2010 Order, p. 9.

[56] 2010 Order, pp. 9-10.

CFS could be beneficial. Staff notes that the Department was not opposed to examining a delay of the CFS, but recommended a five-year delay be examined instead of a ten-year delay.[57] **(Decision Option 18f)**

In regards to MLIG's recommendation 3—and to an extent, any of MLIG's recommendations—it is unclear whether an Order Point is necessary when Information Requests in the relevant proceedings should suffice. In fact, this appears to have been the conclusion of the Commission during the 2010 Order, where the discussion concerns Ordering Paragraph 9 states:

> The Commission will therefore clarify that intervenors in a resource plan proceeding who request information related to the rate impact of future compliance with the Renewable Energy Standards are making a reasonable request for information under Minn. Rules 7843.0300. Utilities must respond to these requests completely and under the time frames set by rule. Further, the Commission urges all parties not to lose sight of the fact that utilities always have the burden of proof to demonstrate that any cost they seek to recover from ratepayers is just and reasonable, whatever the nature of the cost.[footnote omitted]
>
> With these clarifications, the Commission sees no need at present to establish additional filing or reporting requirements on the rate impact of the Renewable Energy Standards.

Staff concludes that if MLIG has found the existing Ordering Paragraph 9 to be insufficient to support its work in IRP proceedings, it has not sufficiently explained this to the Commission it its recommendations. The Commission may wish to ask MLIG to further justify its requests.

Staff appreciates MLIG bringing these matters to the Commission's attention. Staff concludes that, should the Commission wish to pursue MLIG's recommendations, it would not be unreasonable to do so. However, Staff recommends that the Commission revisit its 2015 Rate Impacts Order to ensure that the Commission's guidance sufficiently encompasses all REO Standards. A decision option on this may not be warranted, but if the Commission wishes to provide clear direction, Staff offers **Staff Decision Option 19.**

C. Social Cost of Carbon

Part of the record was devoted to discussing the role of the Social Cost of Carbon ("SCC") in the context of CFS off-ramps. Initially, the Department noted two new provisions the Commission must consider in evaluating whether an off-ramp request is in the public interest—namely, environmental costs and beneficial electrification. The Department specified that because Minn. Stat. § 216B.2422, subd. 3(a), requires the Commission to quantify and establish a range

[57] Department of Commerce, Division of Energy Resources Comments, p. 16 (March 19, 2025).

of environmental costs associated with each method of electricity generation, the Commission has established the SCC, which is applied in IRP proceedings to quantify environmental costs.[58] The Department stated, "[t]herefore, the SCC should establish the maximum amount that should be paid to satisfy compliance requirements" and that "the Commission…may find that a value below the SCC cost is reasonable."[59]

Multiple parties interpreted the Department's discussion to mean that the Commission should establish an upper cost limit, beyond which the cost of compliance is too great. CEOs recommended rejecting establishing a limit beyond which the cost of compliance would be too great.[60] MLIG recommended that the Commission delay action on this topic until a more complete record can be established.[61] Minnesota Power argued that the SCC should not be used as the primary cost cap metric for evaluating the potential need for modification of delay of CFS compliance.[62] In response to the Department's comments, Xcel stated that it believes the Commission should retain flexibility in how to evaluate petitions and not establish caps or thresholds for modification.[63]

Otter Tail did not respond to the Department's comment, but included a discussion similarly noting the importance of evaluating petitions on a case-by-case basis.[64] OTP noted that in some cases, many small factors may justify a delay or modification whereas in other cases, a single overriding factor (such as cost impact) may be enough.[65] OTP also noted that it would be reasonable for the Commission to consider a modification or delay in instances where a utility has achieved substantial compliance, but incremental units required for full compliance carries disproportionate costs.[66]

The Department responded to those concerned that it did not make a recommendation.[67]

1. Staff Analysis

Staff's understanding is that the Department's objective was to point out that these new statutory provisions are sufficiently addressed through the current SCC process. Commenters appear to generally favor evaluating off-ramp petitions on a case-by-case basis, without the use of thresholds or caps. A decision option on this topic does not appear to be warranted.

---

[58] Department Comments, p. 6.
[59] Department Comments, p. 6.
[60] CEOs Comments, p. 6.
[61] MLIG Comments, p. 4.
[62] Minnesota Power Comments, PDF p. 2.
[63] Northern States Power Company d/b/a Xcel Energy Reply Comments, p. 2 (November 8, 2025) (hereinafter "Xcel Reply Comments").
[64] OTP Comments, p. 4.
[65] OTP Comments, p. 4.
[66] OTP Comments, p. 4.
[67] Department of Commerce, Division of Energy Resources Reply Letter, p. 2 (December 4, 2025) (hereinafter "Department Reply Letter").

VI. CMPAS Request

As noted above, the Commission's August 7, 2025 Order allowed for extended credit duration for certain expedited projects. Specifically, the Commission ordered:

> 2. Prospectively, if a utility meets its obligations under the Renewable Energy Objectives of Minn. Stat. § 216B.1691 using Renewable Energy Credits, Alternative Energy Credits, or equivalent Environmental Attribute Credits from a facility that —
>
> A. began construction after July 4, 2026, and was placed in service by December 31, 2027, or
>
> B. began construction before July 5, 2026, and was placed in service within four years after construction began,
>
> then those credits will not expire until four years after generation, and in no event before January 2034.

The Commission's intent in adopting the extended credit duration was to incentivize utilities to capitalize on expiring federal production and investment tax credits by getting projects into the ground quickly:

> Federal tax credits have helped developers finance the construction of various projects used to meet the Renewable Energy Objectives' requirements, but this has changed with the passage of Public Law No. 119-21 (the Act). Among other things, the Act restricts access to various federal tax credits and other incentives for building carbon-free sources of electricity. For example, prior law established that a developer building a solar- or wind-powered generator might qualify for federal production tax credits or investment tax credits, provided that the project was placed in service within four years after construction began. Under the new law, a developer that begins building a solar- or wind-powered generator after July 4, 2026, must place the generator in service before 2028 to qualify for these tax credits.
>
> These changes alter the context in which Minnesota law and Commission decisions have sought to advance state policy. To ensure that Minnesota ratepayers and utilities make maximum benefit of federal incentives while they last, the Commission will take the following actions.
>
> …
>
> Second, to provide added incentive to develop carbon-free facilities that may qualify for federal tax credits, the Commission

> will extend the period for which a utility may use the RECs/AECs/EACs generated from qualifying new solar- or wind-powered facilities to comply with the Renewable Energy Objectives.[68] *[footnotes omitted]*

As noted previously, this Order also required IRP-filing utilities to make a compliance filing. The Commission asked these utilities to address, in relevant part, what supportive actions the Commission or other state regulatory bodies could take to mitigate the harms arising from recent changes to federal energy policy.[69]

Although it is not an IRP-filing utility, CMPAS filed a response to this topic. In its filing, CMPAS requested that the extended credit duration terms be applied to certain smaller, older wind facilities. Specifically, CMPAS sought extended credit duration for smaller, older wind facilities meeting the following criteria:

> A. smaller than 20 MW; and
> B. was originally placed in service prior to 2008; and
> C. has had at least one of the substantial actions extending its lifetime completed by December 31, 2027:
> a. is repowered, or
> b. has a battery energy storage system installed, or
> c. is acquired by a utility specifically for the purpose of serving end-use customers, or
> d. enters into a new power purchase agreement with a term exceeding 10 years.[70]
> **(Decision Option 20)**

From Staff's understanding, CMPAS has an opportunity to renew or begin new Power Purchase Agreements ("PPAs") with small, locally-owned wind farms. However, many of these wind farms are at the ends of their useful lives, meaning that these facilities might be forced to retire very soon.[71] CMPAS is facing a number of situations in order to pursue tax credits for these facilities.

First, federal tax credits are available if older wind is repowered, but in order for repowering to be financially viable for CMPAS's members, any PPA would need to be long-term—at least 10 years in duration.[72] From Staff's understanding, CMPAS is arguing that an extended credit duration would help incentivize its members to enter into longer PPAs, thus enabling

---

[68] ORDER EXTENDING CREDIT DURATION FOR EXPEDITED PROJECTS AND REQUIRING FILINGS, Docket No. E-999/CI-23-151, pp. 2-3 (August 7, 2025) (hereinafter "August 7, 2025 Order").

[69] August 7, 2025 Order, pp. 2-3.

[70] CMPAS Request, p. 4.

[71] CMPAS Request, p. 4.

[72] CMPAS Request, p. 6.

repowering and helping its members qualify for tax credits.

In some cases, however, technical issues prevent repowering to the degree required for federal tax credits. CMPAS notes that some of the original manufacturers may no longer be in business or may no longer operate in the United States.[73] Alternatively, the original construction of the wind turbines could make it difficult to repower, as they were designed and built before certain MISO design requirements.[74] Some repowering could also require transmission upgrades or could be in highly congested areas where a developer might de-prioritize repowering investments.[75] From Staff's understanding, CMPAS is arguing that an extended credit duration would help incentivize its members to pursue costly technological upgrades where possible.

An alternative option to qualify for tax credits could be to add storage; CMPAS states that if it pursues storage and qualifies for tax credits, it should be eligible for extended credit duration.[76] However, CMPAS also notes that sometimes the terms for the older PPAs do not permit storage to be added.[77] CMPAS stated that the Commission's August 7, 2025 Order does not appear to contemplate storage, only wind and solar.[78]

CMPAS cites a number of reasons it is choosing to pursue smaller, older wind, including the following:

- The high cost of new wind, partially due to MISO interconnection queue times and supply chain constraints.[79]
- Interest in supporting local Minnesota-owned individuals and small companies, both the wind farms themselves and the companies that service and insure them.[80]
- The appeal of smaller wind farms for smaller utilities such as CMPAS's members:[81]
    - CMPAS notes that many of its members may have peak demands of 5 MW or less; many of the existing older wind farms are less than 20 MW, whereas new greenfield wind farms owned by independent power producers are larger than 100 MW.
    - Smaller utilities don't necessarily have the customer base to absorb contracts for substantially larger resources than their load.
    - The business model of smaller utilities revolves around serving their communities, not serving as large net exporters into the MISO market.

---

[73] CMPAS Request, p. 6.
[74] CMPAS Request, p. 6.
[75] CMPAS Request, pp. 6-7.
[76] CMPAS Request, p. 7.
[77] CMPAS Request, p. 7.
[78] CMPAS Request, p. 7.
[79] CMPAS Request, pp. 4-5.
[80] CMPAS Request, p. 5.
[81] CMPAS Request, p. 5.

CMPAS later clarified that it did not have any concerns about meeting the CFS, and that if needed, it would purchase unbundled RECs or EACs for compliance.[82]

The Department did not take a position on CMPAS's request.[83] No other commenters provided comment.

A. Staff Analysis

CMPAS's situation is complicated. Broadly, CMPAS's main concern appears to be that the Commission's extended credit duration contemplated only new facilities, not old facilities being repowered or adding storage. Further, CMPAS has multiple issues where it or its members will be attempting to pursue tax credits, but little guarantee of actually receiving tax credits.

At some parts of its request, CMPAS appears to be asking for extended credit duration to help it pursue tax credits; at other parts, CMPAS appears to be asking for extended credit duration to make up for *not being able to* pursue tax credits. Staff notes that although the latter of these was not the purpose of the original Order, it is still in keeping with the Commission's compliance filing topics, which asked about supportive actions the Commission could take, generally.

For instances where CMPAS is able to qualify for expiring tax credits from a repower, Staff sees no reason why it shouldn't also be entitled to an extended credit duration.

However, the Commission should consider how it would treat credit duration if the facility is able to qualify for tax credit from added storage. From Staff's understanding, the added storage facility would receive the tax credits, but the RECs receiving extended duration would be those from the associated wind facility. CMPAS states that the wind would directly be powering the storage, but it is unclear to Staff if this would always be the case, either with CMPAS or with other similarly situated utilities.

Notably, CMPAS's proposed language appears to encompass both facilities that eventually do receive a tax credit and those that don't; for example, CMPAS recommendation C.d. (the facility enters into a new PPA with a term exceeding 10 years) would not necessarily result in a tax credit. It may be that the extended term would mean a utility pursues a tax-credit-qualifying repower, but not necessarily. Therefore, the Commission must decide: should these types of smaller wind repowers be incentivized generally, or should the incentive apply only in cases where the facility qualifies for a tax credit?

Finally, Staff is generally concerned that CMPAS's request may be too specific concerning the facilities.

---

[82] Central Municipal Power Agency/Services Comments, p. 3 (October 28, 2025) (hereinafter "CMPAS Comments").
[83] Department Comments, p. 6.

- Potentially, CMPAS's proposed language could close itself out of some unforeseen situation wherein it was able to secure a tax credit for these facilities.
- The Commission may receive other requests for extended credit duration for similarly situated but technically different facilities.
- The Commission would be incentivizing only old wind repowers and leave out other potentially valuable resources.

To address these concerns, Staff specifically sought comment on whether commenters were aware of other similar situations that may warrant an extended credit duration. Again, no one provided comment on these issues.

Staff concludes that it would be reasonable for the Commission to approve CMPAS's request for instances in which it is pursuing a tax credit for repowering. Should the Commission wish to incentivize old wind repowers generally, or incentivize old wind with battery storage added, it should proceed with caution.

DECISION OPTIONS

Instructions: DO 1 allows the Commission to simply apply the 2010 Order to all REO Standards without any updates. It is a standalone item and should not be chosen alongside DOs 2-18. DOs 2-18 would allow the Commission to update the old Order based on recommendations from the record; if selected, the Commission would be issuing a new Order that would supersede the 2010 Order.

1. Ordering Paragraphs 4-10 of the Commission's March 19, 2010 Order in Docket No. E-999/CI-03-869 apply to all REO Standards.

OR

2. Ordering Paragraphs 4-10 of the Commission's March 19, 2010 Order in Docket No. E-999/CI-03-869 are superseded by the decisions in this order.

Timing of Filing

3. The Commission clarifies that a petition to modify or delay a ~~Renewable Energy~~ Standard under Minn. § Stat. 216B.1691 may be filed at any time.
(Xcel)

4. Modification and delay requests made outside of a resource planning process should be reserved for those caused by the reasons established in Minn. Stat. § 216B.1691, subd. 2b (5-8).
(Minnesota Power, CEOs)

5. If a modification or delay request is made outside of an IRP by an IRP-filing utility, the request should explain why the need for a modification or delay was not foreseen in its IRP.
(CEOs)

Contents of Filing

6. Any petition to modify or delay a Renewable Energy Standard shall include the following information: (a) a discussion of the reasons for concluding that compliance cannot be achieved by buying Renewable Energy Credits, Alternative Energy Credits, equivalent carbon free attributes allowed by statute or Commission order (i.e. the carbon-free percentage of the utility's annual net market purchases); (b) a plan for future compliance, as required under Minn. Stat. § 216B.1691, subd. 2b (c); and (c) the time frame within which the petitioner requests Commission action.
(Minnesota Power)

OR

7. Any petition to modify or delay a ~~Renewable Energy~~ Standard under Minn. Stat. § 216B.1691 shall include the following information: (a) a discussion of the reasons for concluding that compliance cannot be achieved by buying Renewable Energy Credits, Alternative Energy Credits, or equivalent Environmental Attribute Credits, where applicable; (b) a plan for future compliance, as required under Minn. Stat. 216B.1691, subd. 2b (~~c~~e); and (c) the time frame within which the petitioner requests Commission action.
(Xcel)

OR

8. Any petition to modify or delay a ~~Renewable Energy~~ Standard under Minn. Stat. § 216B.1691 shall include the following information: (a) a discussion of the reasons for concluding that compliance cannot be achieved by buying Renewable Energy Credits, Solar Renewable Energy Credits, Alternative Energy Credits, Environmental Attribute Credits, or equivalent attributes allowed by statute or Commission order (such as the carbon-free percentage of the utility's annual net market purchases), where applicable; (b) a plan for future compliance, as required under Minn. Stat. 216B.1691, subd. 2b (~~c~~e); and (c) the time frame within which the petitioner requests Commission action.
(Staff Proposed)

Procedural Requirements of Filing

9. Petitions to modify or delay any ~~Renewable Energy~~ Standard under Minn. Stat. § 216B.1691 shall comply with the service and filing requirements of Minnesota Rules 7829.1300; and~~, at least initially,~~ follow the procedural track set forth in Minnesota Rules 7829.1400.
(Xcel)

10. Following a request for delay or modification of a Standard, the comment period will be extended to sixty days and the reply comment period will be extended to thirty days.
(CEOs)

Tracking Rate and Reliability Impacts

11. The Commission clarifies that Integrated Resource Plans are the preferred ~~it will use the~~ proceedings ~~and methods discussed in section V of this order~~ to track ~~the~~ rate impacts, ~~and~~ reliability, and technical challenges caused by compliance with the ~~effects of the~~ Renewable Energy Objectives and Standards. The Commission will accept voluntary filings on the rate impact of the Renewable Energy Objectives and Standards in the biennial compliance reports filed by utilities not required to file resource plans.
(Staff Interpretation of Minnesota Power recommendation)

Cost Information and Reasonableness of Intervenors

12. The Commission clarifies that it favors forward-looking, long-term cost information when analyzing the rate impacts of the Renewable Energy Objectives and Standards but will not preclude other types of cost information from being presented by the parties.
(Original 2010 Order language)

13. The Commission clarifies that intervenors in a resource plan proceeding who request information related to the rate impact of future compliance with the Renewable Energy Standards are making a reasonable request for information under Minn. Rules, part 7843.0300, subp. 8, and that utilities must promptly respond.
(Original 2010 Order language)

Compliance with the Standards

14. The Commission clarifies that it will evaluate compliance with the Renewable Energy Standards on a case-by-case basis, but will also consider the factors set forth below:
~~a. The factors articulated in its June 4, 2004 order for evaluating compliance with the Renewable Energy Objectives.~~
b. Whether the utility brought the noncompliance to the attention of the Commission in a timely manner.
c. Whether Renewable Energy Credits, Alternative Energy Credits, or equivalent carbon free attributes allowed by statute or Commission order are available for purchase, and at what price.
(Minnesota Power)

OR

15. The Commission clarifies that it will evaluate compliance with any ~~the Renewable Energy~~ Standard~~s~~ under Minn. Stat. § 216B.1691 on a case-by-case basis, but will also consider the factors set forth below:
~~a. The factors articulated in its June 4, 2004 order for evaluating compliance with the Renewable Energy Objectives.~~
~~b.~~ a. Whether the utility brought the noncompliance to the attention of the Commission in a timely manner.
~~c.~~ b. Whether Renewable Energy Credits, Solar Renewable Energy Credits, Alternative Energy Credits, equivalent Environmental Attribute Credits, or equivalent carbon-free attributes allowed by statute or Commission Order, where relevant, are available for purchase, and at what price.
(Staff Proposed)

Cost-Benefit Analysis

16. The Commission will assess cost-based requests to modify or delay a Standard pursuant to Minn. Stat. § 216B.1691, subd. 2b(a) and (b), will and determine whether compliance "would cause significant rate impact" and whether an off-ramp would be "in the public interest."
(CEOs)

17. The Commission declines to adopt a list of factors to consider when assessing off-ramp requests.
(CEOs)

Rate Impacts

18. In their IRPs, IRP-filing utilities shall provide:
    a. The average current rate for each customer class as of the year of the IRP filing.
    b. Projected rate increases (in dollars and percentages) by customer class for each year of the five-year IRP action plan.
    c. The net present value of the utility's revenue requirement (PVRR) over the life of the IRP action plan, under various scenarios, while separately identifying the environmental costs
    d. A reference case scenario, detailing the least cost plan, from a ratepayer impact perspective, for meeting the CFS by 2040, even if the intermediate benchmarks for 2030 and 2035 set out in Minn. Stat. § 216B.1691, subd. 2g(1) and (2) are missed.
    e. A reference case scenario, detailing the least cost plan, from a ratepayer impact perspective, to meet the CFS by 2050.
    f. A reference case scenario, detailing the least cost plan, from a ratepayer impact perspective, to meet the CFS by 2045.

    (MLIG supports 18a-e, Department not opposed to 18f)

19. The Commission delegates to the Executive Secretary authority to begin proceedings to review its January 6, 2015 *Order Establishing Uniform Reporting System for Estimating Rate Impact of Minn. Stat. § 216B.1691* from Docket No. E-999/CI-11-852 to ensure the Order adequately covers all REO Standards.
(Staff Proposed)

CMPAS Request

20. The extended credit duration from the Commission's August 7, 2025 Order shall also apply to wind facilities meeting the following criteria:

    A. smaller than 20 MW; and
    B. was originally placed in service prior to 2008; and
    C. has had at least one of the substantial actions extending its lifetime completed by December 31, 2027:
        a. is repowered, or
        b. has a battery energy storage system installed, or
        c. is acquired by a utility specifically for the purpose of serving end-use customers, or
        d. enters into a new power purchase agreement with a term exceeding 10 years.

    (CMPAS)

ATTACHMENT A:

RECENT RATE IMPACT ANALYSES

Appendix J - RES Rate Impact Report

Appendix J serves as Great River Energy's (GRE) Renewable Energy Standard (RES) Rate Impact Report to the Minnesota Public Utilities Commission (PUC) as required by Minn. Stat. § 216B.1691, subd. 2e (Docket No. E999/CI-11-852). This report serves as GRE's compliance with PUC's January 6, 2015 Order Establishing Uniform Reporting System for Estimating Rate Impact of Minn. Stat. § 16B.1691 ("Order"), in addition to the language and objectives of the statute.

The Order outlines the objectives that must be met in the RES Rate Impact Report as follows:

- In the utility's next filing, analyze costs for the period 2005 until the last reported year. (Order Point 2A.1).
- Analyze costs from the year following the last reported year, and for the following 15 years. (Order Point 2A.2).
- Include all facilities used to comply with the Renewable Energy Standard ("RES") and the Solar Energy Standard ("SES"), regardless of when the facilities were constructed. (Order Point 2B).
- Calculate direct costs to include payments under power purchase agreements and revenue requirements associated with utility-owned renewable energy projects. (Order Point 2C).
- Provide a narrative discussion about the impact that adding generators powered by renewable sources may have had on the utility's indirect costs, such as the cost for ancillary services and base load cycling. (Order Point 2D).
- Include transmission costs for transmission improvements created exclusively for the purpose of gaining access to electricity from renewable resources, as well as the percentage directly attributable to compliance with the RES and SES. Additionally, for multi-purpose transmission providing access to renewable resources include a narrative estimating the costs and portion the

utility would allocate to the cost of gaining access to renewable resources. (Order Point 2E.1 & 2E.2).

- Calculate savings arising from avoiding energy and capacity costs that the utility would have incurred directly in the absence of the RES and SES. (Order Point 2F.1 & 2F.2).
- Calculate savings arising from avoiding costs (past and future) that the utility would have incurred indirectly in the absence of the RES and SES to include costs of sulfur dioxides ("SO_2") and oxides of nitrogen ("NO_x") permits required under Title IV of the Federal Clean Air Act, and expected future emission compliance costs, including costs of SO2 and NOx permits, as well as the range of compliance cost values for carbon dioxide ("CO_2") set by the Commission under Minn. Stat. § 216H.06. (Order Point 2G.1 & 2G.2).
- Report estimated annualized and estimated levelized costs. (Order Point 2H).
- Calculate separately the rate impacts of complying with the RES and the SES. (Order Point 2I.1 & 2I.2).
- Calculate the ultimate rate impact of Minn. Stat. § 216H.1691 to reflect the fact that renewable energy comprises only a fraction of a utility's total energy costs, and consequently most of a utility's energy costs are unaffected by the RES and SES. (Order Point 2J.1).
- Calculate additional modifications as are agreed upon by the Department of Commerce – Division of Energy Resources and the commentors. (Order Point 2J.2).

In response to the Minnesota Public Utilities Commission Order Establishing Uniform Reporting System for Estimating Rate Impact of Minnesota Statute § 216B.1691, Great River Energy provides Table 1, analyzing the costs and rate impacts for the 2005 – 2016 historic time period and Table 2, analyzing the projected costs and rate impacts for the 2017 – 2032 time period. Table 3 includes the levelized historic and

future RES costs. Only Renewable Energy Standard (RES) costs were analyzed, no Solar Energy Standard costs were analyzed.

RES Rate Impacts

Table 1 - Historic RES Rate Impact

RES Generation	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Total RES Generation (GWh)	113	401	432	808	996	1,069	1,458	1,569	1,566	1,686	1,607	1,564
RES Generation Costs												
PPA Generation Costs (millions)	$ 3.49	$ 10.76	$ 11.86	$ 29.36	$ 39.70	$ 42.71	$ 57.54	$ 62.68	$ 63.06	$ 67.31	$ 66.12	$ 66.57
RES Transmission Costs (millions)	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.61	$ -	$ -	$ -	$ -	$ -
Total RES Costs (millions)	$ 3.49	$ 10.76	$ 11.86	$ 29.36	$ 39.70	$ 42.71	$ 58.15	$ 62.68	$ 63.06	$ 67.31	$ 66.12	$ 66.57
RES Costs ($/MWh)	$ 30.78	$ 26.80	$ 27.47	$ 36.33	$ 39.88	$ 39.97	$ 39.87	$ 39.94	$ 40.26	$ 39.93	$ 41.15	$ 42.56
Avoided Energy Costs Due to RES												
Avoided Energy Costs (millions)	3.13	10.83	13.00	27.44	27.68	33.64	41.68	42.62	50.90	62.17	37.60	34.20
Avoided Capacity Costs (millions)	$ 0.85	$ 0.44	$ 1.12	$ 2.09	$ 1.45	$ 1.97	$ 2.35	$ 2.19	$ 2.27	$ 2.27	$ 2.24	$ 2.26
Avoided Transmission Costs (millions)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Avoided Emsission (millions)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Avoided Costs (millions)	3.98	11.27	14.12	29.52	29.13	35.61	44.03	44.81	53.17	64.44	39.84	36.45
Total Avoided Costs ($/MWh)	35.13	28.06	32.70	36.54	29.25	33.32	30.19	28.56	33.94	38.23	24.79	23.30
Market Revenues												
Total Market Revenues (millions)	$ 5.76	$ 17.41	$ 21.61	$ 37.70	$ 22.25	$ 24.93	$ 24.24	$ 22.71	$ 29.70	$ 33.85	$ 20.29	$ 21.81
Net RES Costs (RES Costs - Market Revenues)												
Net Total Costs (millions)	$ (2.28)	$ (6.65)	$ (9.75)	$ (8.34)	$ 17.46	$ 17.78	$ 33.91	$ 39.96	$ 33.36	$ 33.46	$ 45.83	$ 44.76
Total Costs												
Total RES Premium / Discount (millions)	$ (6.26)	$ (17.92)	$ (23.87)	$ (37.87)	$ (11.67)	$ (17.83)	$ (10.12)	$ (4.85)	$ (19.81)	$ (30.98)	$ 5.99	$ 8.30
Total RES Premium / Discount ($/MWh)	$ (55.21)	$ (44.63)	$ (55.28)	$ (46.87)	$ (11.72)	$ (16.68)	$ (6.94)	$ (3.09)	$ (12.65)	$ (18.38)	$ 3.73	$ 5.31
Annualized RES Rate Impacts												
Total Member Sales (GWh)	11,455	11,455	11,455	11,455	11,455	11,455	11,455	11,455	11,455	11,455	11,455	11,455
Rate Impact ($/MWh)	**$ (0.55)**	**$ (1.56)**	**$ (2.08)**	**$ (3.31)**	**$ (1.02)**	**$ (1.56)**	**$ (0.88)**	**$ (0.42)**	**$ (1.73)**	**$ (2.70)**	**$ 0.52**	**$ 0.72**
Rate Impact (c/kWh)	**$ (0.05)**	**$ (0.16)**	**$ (0.21)**	**$ (0.33)**	**$ (0.10)**	**$ (0.16)**	**$ (0.09)**	**$ (0.04)**	**$ (0.17)**	**$ (0.27)**	**$ 0.05**	**$ 0.07**

Table 2 - Projected Future RES Rate Impact

RES Generation	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total RES Generation (GWh)	1,673	1,664	1,637	1,637	1,284	1,274	1,239	1,239	1,239	1,239	1,033	533	883	1,234	1,935	2,635
RES Generation Costs																
PPA Generation Costs (millions)	$ 71.50	$ 71.81	$ 71.47	$ 72.06	$ 63.61	$ 63.73	$ 62.65	$ 63.24	$ 63.85	$ 64.47	$ 55.16	$ 32.82	$ 49.18	$ 65.94	$ 99.61	$ 134.00
RES Transmission Costs (millions)	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total RES Costs (millions)	$ 71.50	$ 71.81	$ 71.47	$ 72.06	$ 63.61	$ 63.73	$ 62.65	$ 63.24	$ 63.85	$ 64.47	$ 55.16	$ 32.82	$ 49.18	$ 65.94	$ 99.61	$ 134.00
RES Costs ($/MWh)	$ 42.75	$ 43.15	$ 43.66	$ 44.02	$ 49.54	$ 50.03	$ 50.57	$ 51.05	$ 51.54	$ 52.04	$ 53.40	$ 61.59	$ 55.68	$ 53.45	$ 51.49	$ 50.85
Avoided Energy Costs Due to RES																
Avoided Energy Costs (millions)	$ 42.71	41.18	39.76	39.64	31.21	32.00	31.94	33.85	36.06	38.14	33.82	18.43	32.64	49.92	88.60	133.85
Avoided Capacity Costs (millions)	$ 2.26	$ 1.81	$ 3.04	$ 4.76	$ 4.56	$ 6.70	$ 6.51	$ 6.59	$ 6.63	$ 6.72	$ 6.84	$ 3.96	$ 5.79	$ 7.66	$ 11.36	$ 15.28
Avoided Transmission Costs (millions)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Avoided Emsission (millions)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Avoided Costs (millions)	$ 44.96	$ 42.99	$ 42.80	$ 44.40	$ 35.78	$ 38.70	$ 38.45	$ 40.44	$ 42.70	$ 44.86	$ 40.66	$ 22.40	$ 38.43	$ 57.58	$ 99.96	$ 149.13
Total Avoided Costs ($/MWh)	$ 26.88	$ 25.83	$ 26.15	$ 27.12	$ 27.87	$ 30.38	$ 31.04	$ 32.64	$ 34.46	$ 36.21	$ 39.36	$ 42.03	$ 43.50	$ 46.67	$ 51.67	$ 56.59
Market Revenues																
Total Market Revenues (millions)	$ 28.79	$ 28.85	$ 28.09	$ 28.52	$ 22.29	$ 21.57	$ 21.03	$ 21.35	$ 21.67	$ 21.99	$ 22.32	$ 7.78	$ 16.73	$ 25.68	$ 43.20	$ 61.25
Net RES Costs (RES Costs - Market Revenues)																
Net Total Costs (millions)	$ 42.71	$ 42.97	$ 43.37	$ 43.54	$ 41.31	$ 42.16	$ 41.62	$ 41.90	$ 42.18	$ 42.47	$ 32.84	$ 25.04	$ 32.45	$ 40.26	$ 56.41	$ 72.76
Total Costs																
Total RES Premium / Discount (millions)	$ (2.25)	$ (0.02)	$ 0.57	$ (0.86)	$ 5.54	$ 3.46	$ 3.17	$ 1.46	$ (0.51)	$ (2.39)	$ (7.81)	$ 2.64	$ (5.98)	$ (17.32)	$ (43.55)	$ (76.37)
Total RES Premium / Discount ($/MWh)	$ (1.35)	$ (0.01)	$ 0.35	$ (0.53)	$ 4.31	$ 2.71	$ 2.56	$ 1.18	$ (0.41)	$ (1.93)	$ (7.56)	$ 4.96	$ (6.77)	$ (14.04)	$ (22.51)	$ (28.98)
Annualized RES Rate Impacts																
Total Member Sales	11,505	11,455	11,267	11,337	11,369	11,436	11,503	11,574	11,638	11,706	11,774	11,848	11,913	11,983	12,054	12,129
Rate Impact ($/MWh)	**$ (0.20)**	**$ (0.00)**	**$ 0.05**	**$ (0.08)**	**$ 0.49**	**$ 0.30**	**$ 0.28**	**$ 0.13**	**$ (0.04)**	**$ (0.20)**	**$ (0.66)**	**$ 0.22**	**$ (0.50)**	**$ (1.45)**	**$ (3.61)**	**$ (6.30)**
Rate Impact (c/kWh)	**$ (0.02)**	**$ (0.00)**	**$ 0.01**	**$ (0.01)**	**$ 0.05**	**$ 0.03**	**$ 0.03**	**$ 0.01**	**$ (0.00)**	**$ (0.02)**	**$ (0.07)**	**$ 0.02**	**$ (0.05)**	**$ (0.14)**	**$ (0.36)**	**$ (0.63)**

Table 3 - Levelized RES Costs, Revenues and Rate Impacts

Levelized RES Generation	**Historical**	**Future**
Total RES Generation (GWh)	1,106	1,399
Levelized RES Generation Costs	**Historical**	**Future**
PPA Generation Costs (millions)	$ 59.80	$ 45.59
RES Transmission Costs (millions)	$ 0.07	$ -
Total RES Costs (millions)	$ 59.87	$ 45.59
RES Costs ($/MWh)	$ 51.05	$ 49.38
Levelized Avoided Costs Due to RES	**Historical**	**Future**
Avoided Energy Costs (millions)	$ 44.16	$ 29.85
Avoided Capacity Costs (millions)	$ 2.47	$ 4.14
Avoided Transmission Costs (millions)	$ -	$ -
Avoided Emissions Costs (millions)	$ -	$ -
Total Avoided Costs (millions)	$ 46.63	$ 34.00
Total Avoided Costs ($/MWh)	$ 42.91	$ 23.86
Levelized Market Revenues	**Historical**	**Future**
Total Market Revenues (millions)	$ 32.39	$ 17.37
Levelized RES Net Costs	**Historical**	**Future**
Total Net Costs (millions)	$ 27.48	$ 28.21
Levelized RES Premium/Discount	**Historical**	**Future**
Total RES Premium / Discount (millions)	$ (19.15)	$ (5.78)
Total RES Premium / Discount ($/MWh)	$ (30.11)	$ (2.81)
Levelized RES Rate Impacts	**Historical**	**Future**
Total Company Sales	11,289.14	11,655.66
Rate Impact ($/MWh)	$ (1.67)	$ (0.48)
Rate Impact (¢/kWh)	$ (0.17)	$ (0.05)

Direct Costs

GRE's direct costs reflect power purchase agreement payments and revenue requirements for owned facilities. GRE considered many direct costs in this analysis, which included the contract rate paid to the wind developer as part of the power purchase agreements (PPA) that we hold, the avoided market energy costs and avoided market capacity costs associated with the energy and capacity of the PPA projects, and the market revenues that we receive from the projects.

Using the direct costs, GRE determined the total RES net costs, inclusive of the PPA generation costs minus the market revenues associated with those projects, compared to the avoided energy and capacity costs. If the PPA generation costs and associated market revenues were smaller than the avoided energy and capacity costs, there was a net rate benefit. Conversely, if the PPA generation costs and associated market revenues were larger than the avoided energy and capacity costs, then there was a net rate cost.

Overall the RES can be seen to provide a very small net total rate benefit in both the historic and future periods in the levelized analysis.

Indirect Costs

The January 6, 2015 Order in Docket No. E999/CI-11-852 discussed the indirect costs of adding variable generation, such as base load cycling and ancillary services. Section 5 of GRE's 2018-2032 Integrated Resource Plan filing outlines the changing Midcontinent Independent System Operator (MISO) energy market as a result of the increasing penetration of wind resources.

In response to low power market prices, the decision was made to identify actions at Coal Creek Station that could make generation more flexible, and avoid periods of low prices. This complex undertaking was compounded by the fact that the obligation of providing steam limited the original capability of the units to load

follow, plant staff made minor control modifications to automatically transfer the steam customer to different sources along the extraction path. The change has allowed the two units to effectively ramp across the full capable range, allowing turndown during weak pricing periods and ramping based on real-time market signals in the MISO region.

Operating flexibly, however, is fundamentally different than the historic primary directive of a baseload coal plant. As a result, GRE has been conducting testing to determine the effects of operating in such a way. We have not quantified the impacts of long-term flexible operation and increased ramping. More time is needed under flexible operations to place a cost or benefit on cycling. We do believe that the changes at Coal Creek Station are very likely to result in greater than historic operations and maintenance costs for the plant.

Ancillary services costs in the MISO market are difficult to quantify as attributable to RES compliance and have not been included in our analysis. GRE has not identified any impacts or costs associated with ancillary services as a direct result of the RES.

Permitting and Emission Costs

All of the historic projects considered in this cost analysis were pursued solely for compliance with the RES. Wind generation required to meet the RES going forward was included in the future RES Rate Impact calculation to represent both a resource need and a compliance pathway for a future RES change.

No permitting and emission costs were included in the analysis, as the PUC Order discusses the matter and includes on Page 12 of the Order, the statement "- except to the extent that § 216B.1691 causes a utility to need fewer permits."

In this case, all projects were pursued solely for RES compliance and do not therefore represent a scenario in which a decision of generation type was made to select wind over gas, or another type of generation resource. The presupposition that an addition of wind resources in this RES analysis supplants the investment in a different type of generating resource, thereby avoiding permitting and emissions costs associated with that technology may not be accurate. In GRE's case, we would not have added a

different type of generation in the absence of the wind projects we procured for RES compliance, therefore making any comparison to cost savings from permits or emissions costs a false equivalent.

Transmission Costs

2011 is the only year that GRE realized transmission costs directly related to RES facilities. Transmission costs are typically borne by the wind developer, recovered as a development cost and reflected in their power purchase price. With the exception of one year in the historical data, we consider all transmission costs for future RES projects inclusive in the contract price of that resource. We assume also that no transmission costs are assigned to avoided energy and capacity, as those costs come directly from the market, and not from a replacement resource that may add transmission costs to our system.

Summary

Under the PUC approved Uniform Reporting System methodology for estimating RES rate impacts, GRE experiences only minor rate impacts in both the historical and forward looking analyses.

APPENDIX L: COST IMPACT ANALYSIS BY CUSTOMER CLASS

A. Introduction

Under Minn. Stat. § 216B.1691, subd. 2e., electric utilities must submit to the Minnesota Public Utilities Commission ("Commission") a report containing an estimation of the rate impact of their resource plans. As part of the Commission's review of a utility's resource plan, it must evaluate the plan's ability to "keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints."[1] In 2011, the Commission ordered Minnesota Power (or the "Company") to include a "cost impact analysis by customer class" in its next resource plan.[2] The Company complied with this order point by including the cost impact analysis by customer class in its subsequent integrated resource plans. This Appendix is included to provide that information for this 2025-2039 Integrated Resource Plan ("2025 IRP"). For purposes of this analysis, the terms "cost impact" and "rate impact" are assumed to have the same meaning. It should be noted that these are estimated impacts and thus may not correspond with actual revenue requirements or rates that the Commission sets for various rate classes in the future. In addition, numerous assumptions have been made in both the calculation methodology and the input variables, and these assumptions naturally cause imprecision in the estimates. Long-term resource planning is inherently inexact and therefore causes additional uncertainty in the resulting rate impacts. Thus, the numbers estimated here should be used as guideposts on rate impact rather than viewed or used as determinative calculations on customer power costs.

This Appendix provides detail on the estimated rate impacts of the Company's power supply plan for the next five years, which includes actions from prior approved IRPs and the recommended plan in the 2025 IRP,[3] referred to in this Appendix as the "5 Year Power Supply Plan." Specifically, this Appendix discusses the following items:

- Calculation of Plan Power Supply Costs
- Calculation of Base Rates
- Calculation of Rate Impacts
- Minimizing Customer Rate Impacts

B. Calculation of Plan Power Supply Costs

The estimated rate impacts are based on the revenue requirement outputs from the 2025 IRP long-term planning model. These outputs are referred to as the "IRP Power Supply Costs." The first step in estimating the rate impacts by customer class is to calculate the annual incremental power supply cost of the 5 Year Power Supply Plan for the years 2025 to 2029, compared to the 2025 power supply costs.[4] The 2025 power supply costs are subtracted from the annual power supply cost of the 5 Year Power Supply Plan for 2025 to 2029 to determine the incremental power supply cost relative to 2025. The estimated rate impacts by customer class are therefore calculated relative to the 2025 Base Rates, which are discussed in the next section.

The incremental 5 Year Power Supply Plan power supply costs are separated into two categories: power supply costs and solar costs. The power supply costs are allocated to

[1] Minn. R. 7843.0500, subp. 3.
[2] *In the Matter of Minnesota Power's 2010-2024 Integrated Resource Plan*, Docket E-015/RP-09-1088, Order Accepting Resource Plan and Requiring Compliance Filings (May 6, 2011).
[3] The 5 Year Power Supply Plan does not include the NTEC project for estimating cost impacts.
[4] The 2025 Plan is described in Appendix K: Detailed Analysis Section.

jurisdiction and customer class as described below. The solar costs are divided by the projected non-exempt energy usage to obtain the solar cost rate in accordance with state statute.[5]

After the incremental power supply costs of the 5 Year Power Supply Plan for 2025 to 2029 are determined, these costs are allocated to the Minnesota jurisdiction and to customer classes based on projected revenue requirement allocators for 2025 to 2029. The allocators are based on the total revenue apportionment to the Minnesota jurisdiction and to each retail customer class in Minnesota Power's last retail rate case.[6] The annual allocators are projected assuming perfect annual rate making that follows the fully allocated class cost-of-service study. In other words, the 2024 test year rate case relationships between jurisdictional and class revenue apportionment and jurisdictional and class energy usage are assumed to remain constant, thus allowing those relationships (ratios) to be used to estimate the allocators using the forecasted energy usage by jurisdiction and customer class from Minnesota Power's 2024 Annual Electric Utility Forecast Report (see Appendix A). The 5 Year Power Supply Plan incremental power supply costs are then divided by the projected energy usage by customer class to obtain the 5 Year Power Supply Plan incremental power supply cost rates by customer class.

The 5 Year Power Supply Plan incremental power supply cost rates and the solar cost rates are then added by customer class to obtain the total adjusted 5 Year Power Supply Plan incremental power supply cost rates by customer class.

C. Calculation of Base Rates

As mentioned above, the estimated rate impacts by customer class are calculated relative to Minnesota Power's 2025 Base Rates. The starting point to estimate the 2025 Base Rates is the 2024 test year rate case final approved rate design, sales, and revenue schedule from Minnesota Power's 2024 test year rate case.[7] The estimated average rates customers will pay in 2025 for Minnesota Power's Renewable Resources Rider, Transmission Cost Recovery Rider, and the Capacity Revenue and Expense Adjustment are added to the 2024 test year base rates. Lastly, an estimated 2025 Fuel and Purchased Energy ("FPE") Adjustment and an estimated 2025 average Conservation Program Adjustment ("CPA") rate are added to arrive at the estimated 2025 Base Rates.[8] The 2025 FPE Adjustment and CPA rate are estimated by comparing the 2024 rates in Minnesota Power's last rate case to the 2025 budgeted costs expected to be incurred through the FPE and in the new CPA rate expected to be implemented in 2025.

D. Calculation of Rate Impacts

The 5 Year Power Supply Plan incremental cost rates by customer class from 2025 to 2029 are divided by the estimated 2025 Base Rates to determine the estimated percent increase in rates. The 5 Year Power Supply Plan incremental cost rates by customer class from 2025 to 2029 are then multiplied by the projected average monthly billing units by customer class to estimate the average dollar per month increase by customer class. As shown in Table 1, the 5 Year Power

[5] Pursuant to Minn. Stat. § 216B.1691, subd. 2f(f), retail electric sales to certain large power customers (iron mining and paper and wood product manufacturing) are excluded for the purposes of calculating a utility's total retail sales for purposes of the Solar Energy Standard.

[6] *In the Matter of the Application of Minnesota Power for Authority to Increase Electric Service Rates in the State of Minnesota*, Docket E-015/GR-23-155, Order Accepting and Adopting Agreement Setting Rates (Nov. 25, 2024).

[7] *In the Matter of the Application of Minnesota Power for Authority to Increase Electric Service Rates in the State of Minnesota*, Docket E-015/GR-23-155, Minnesota Power Compliance Filing, Schedule 12 (Dec. 20, 2024).

[8] The CPA factor is not applied to Large Power customers that have obtained exemptions from Conservation Improvement Program charges.

Supply Plan incremental power supply costs change from 2025 to 2029 would be expected to increase the average Residential rate by about two percent Compound Annual Growth Rate ("CAGR"). That is equivalent to an increase of $2.53 per month compared to 2025 Base Rates for Residential customers. The impact to the average Large Power rate would be an annual increase of about a two percent from 2025 to 2029. That is equivalent to an increase of $122,302 per month.

Table 1. Estimated Average Rate Impacts of 2025 Plan Relative to 2025 Projected Base Rates

Rate Class Impacts[9]	2026	2027	2028	2029	2026 – 2029 CAGR
Residential (average rate, cents/kWh)	14.961	14.961	14.961	14.961	
Increase (cents/kWh)	0.277	1.058	1.839	1.472	
Increase (%)	1.85%	7.07%	12.29%	9.84%	2.37%
Average Impact ($ / month)	$1.90	$7.24	$12.64	$10.10	
General Service (average rate, cents/kWh)	15.005	15.005	15.005	15.005	
Increase (cents/kWh)	0.278	1.060	1.844	1.475	
Increase (%)	1.85%	7.07%	12.29%	9.83%	2.37%
Average Impact ($ / month)	$6.95	$26.41	$45.97	$36.40	
Large Light & Power (average rate, cents/kWh)	11.584	11.584	11.584	11.584	
Increase (cents/kWh)	0.218	0.823	1.429	1.146	
Increase (%)	1.88%	7.11%	12.33%	9.89%	2.39%
Average Impact ($ / month)	$437.78	$1,616.59	$2,756.65	$2,147.10	
Large Power (average rate, cents/kWh)	8.937	8.937	8.937	8.937	
Increase (cents/kWh)	0.160	0.634	1.109	0.885	
Increase (%)	1.80%	7.09%	12.41%	9.90%	2.39%
Average Impact ($ / month)	$94,071	$371,582	$600,104	$489,207	
Lighting (average rate, cents/kWh)	45.778	45.778	45.778	45.778	
Increase (cents/kWh)	0.779	3.034	5.388	4.362	
Increase (%)	1.70%	6.63%	11.77%	9.53%	2.30%
Average Impact ($ / month)	$1.08	$4.19	$7.43	$5.97	
Average Weighted Increase (cents/kWh)	0.192	0.746	1.298	1.035	
Avg Weighted Increase (%)	1.82%	7.09%	12.33%	9.82%	2.37%

[9] Average current rates are 2025 estimates. These estimates are based on 2024 base rates from Minnesota Power's last rate case, Docket No. E-015/GR-23-155, with 2025 estimated cost recovery rider rates and the estimated 2025 FPE and CPA factor added. The CPA factor is not applied to Large Power Class.

E. Minimizing Customer Rate Impacts

Minnesota Power has been working hard to reduce the rate impacts of capital projects needed to support its *Energy**Forward*** strategy and compliance with state renewable and carbon free energy requirements. As discussed in Section V of the IRP, Minnesota Power has identified opportunities to capitalize on Production Tax Credits ("PTCs") and Investment Tax Credits ("ITCs"). The Company has also been aggressively pursuing state and federal funding opportunities. To date, Minnesota Power has secured $78.10 million in state and federal funding to support capital projects needed to maintain reliability of transmission and hydroelectric infrastructure. As shown in Table 2, the Company has applied for over $261 million in funding since 2023. Federal funding opportunities are highly competitive, and the Company is proud to share that it has been awarded approximately 30 percent of the funding it has pursued.

Table 2. Minnesota Power's State and Federal Funding Opportunities

Status	Funding Opportunity	Project(s) Supported	Type	Request (In Millions)
Awarded	GRIP I (TA2)	HVDC Modernization	Grant	$50.00
Appropriated	MN Legislative appropriation	HVDC Modernization	Grant	$15.00
Awarded	MN State Competitiveness Fund	HVDC Modernization	Grant	$10.00
Awarded	Section 247 - applications (2)	Scanlon Gates; Blanchard #1	Incentive Payment	$3.10
			Total Awarded --->	**$78.10**
Drafting	Rural and Remote	Burnett Substation/FDL	Grant	$47.00
Not Selected	GRIP II (TA2) - concept paper	HVDC AC Interconnection	Grant	$50.00
Not Selected	GRIP II (TA1) - application	Resilience & Preparedness Project	Grant	$50.00
Not Selected	NEVI	DCFC Installation - Duluth	Grant	$0.77
Not Selected	NEVI	DCFC Installations - Hinckley	Grant	$0.78
Not Selected	Section 247 - applications	Scanlon Unit 2	Incentive Payment	$0.63
Not Selected	Carbon Management	Biomass Capture Study	Grant	$1.50
Not Selected	Energy Storage	GridStar Flow Battery Demonstration	Grant	$30.00
Not Selected	Industrial Decarbonization	Mine Truck Electrification	Grant	$25.00
Not Selected	GRIP II (TA1) - concept paper	HVDC 900 MW Line Upgrade	Grant	$25.00
			Total Not Selected --->	**$183.68**
7 Concept Paper submissions (5 – Encouraged to submit full application)			**Total Requested --->**	**$261.78**
12 Application submissions (4 – Awarded; 8 – Not Selected; 0 – Pending)			**Award Rate --->**	**30%**
22 Letters of Support provided to ther entities seeking governmnet funding			**Total Supporting --->**	**$1,004**

Additionally, the Company has provided 22 letters of support for other entities seeking over $1 billion in total funding. Projects the Company has provided support for and that have been awarded funding include:

- The City of Duluth's application to the United States Department of Energy ("DOE") Energy Future grant program
- Minnesota's Climate Pollution Reduction Grant, Coalition Proposal for Equitable Residential Decarbonization - City of Duluth Partnership
- Center for Energy and Environment, Minnesota Advanced Energy Codes Partnership; DOE's Resilient and Efficient Codes Implementation initiative
- University of North Dakota's Carbon Ash Project
- Moving Greater MN forward
- Hydrogen Hub (regional)
- Minnesota Green Iron Project

- City of Duluth Geothermal project; DOE Heating and Cooling Grant; Community Geothermal Heating and Cooling Design and Deployment
- United States Department of Transportation Advanced Transportation Technologies and Innovation ("ATTAIN") Grant - Grand Rapids, Minnesota Autonomous Rural Transit Initiative (goMARTI) expansion
- LNKP 156 DOE Technical Assistance (DOE Local Energy Action Program ("LEAP") Grant)
- Bois Forte Tribal Government Electrifying Tribal Communities
- Minnesota Industrial Transformation Initiative ("MITI")

Minnesota Power will continue to monitor state and federal funding opportunities as they become available, as well as PTC and ITC availability, to reduce overall rate impacts as it implements actions identified in its IRPs. The Company looks forward to continued collaboration with regional and state partners to identify and secure funding to support our shared energy goals.

A number of RECs should be banked, only as long as Otter Tail has surplus RECs to bank for contingencies and future use. Once a jurisdiction is required to purchase RECs for REO/RES compliance, it does not make sense to purchase RECs simply to maintain a bank balance, unless it is expected that RECs will not be available for purchase in the future or if a particularly economic REC purchase opportunity arises.

While the prior discussion identifies the various purposes for banking RECs, the current Otter Tail situation becomes very simple. All RECs in the Minnesota jurisdiction that qualify for compliance in Minnesota should be banked as long as there is not a risk of those RECs exceeding the allowable shelf life for MN compliance.

In all cases, the oldest RECs possible should be used for compliance as newer RECs will tend to have a higher value and a longer remaining shelf life for MN compliance.

In summary:

- All MN jurisdiction RECs eligible for MN compliance should be banked.
- Wherever possible, non-eligible jurisdictional RECs should be swapped between MN and the Dakotas to make optimum use of these RECs (which are all non-wind), for compliance purposes.
- All surplus Dakotas jurisdiction RECs should be sold.

5. RES/SES Rate Impacts

As ordered by the Minnesota Commission, each utility that files a Resource Plan must calculate the cost of complying with Minn. Stat. §216B.1691. Utilities are required to do the following:

- Analyze costs for the period 2005 until the last reported year.
- Analyze costs from the year following the last reported year, and for the following 15 years.
- Include all facilities used to comply with the Renewable Energy Standard and the Solar Energy Standard, regardless of when the facilities were constructed.
- Calculate direct costs to include payments under power purchase agreements and revenue requirements associated with utility-owned renewable energy projects.

- Provide a narrative discussion about the impact that adding generators powered by renewable sources may have on the utilities indirect costs, such as the cost for ancillary services and base load cycling.
- Include transmission improvement costs.
- Calculate Energy and Capacity savings arising from avoiding costs that the utility would have incurred directly in the absence of the RES and SES.
- Calculate past and future emission compliance savings arising from avoiding costs that the utility would have incurred indirectly in the absence of the RES and SES.
- Report estimated annualized and estimated levelized costs.
- Calculate the costs of complying with the RES and SES separately.
- Calculate the ultimate rate impact of Minn. Stat. §216B.1691 to reflect the fact that renewable energy comprises only a fraction of a utility's total energy costs, and consequently most of a utility's energy costs are unaffected by the RES and SES.

Table 2
Past RES Rate Impacts

RES Generation	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total RES Generation (GWh)	95.4	79.3	83.2	307.3	648.1	735.6	818	750	658	902.5	839.3	873.2	899.5	824.1	784.7	815.9
RES Generation Costs																
PPA + Owned Generation Costs (millions)	$2.6	$2.2	$2.3	$13.0	$20.7	$28.4	$26.9	$27.3	$27.2	$31.3	$31.0	$30.7	$28.5	$29.0	$28.3	$28.5
RES Transmission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total RES Costs (millions)	$2.6	$2.2	$2.3	$13.0	$20.7	$28.4	$26.9	$27.3	$27.2	$31.3	$31.0	$30.7	$28.5	$29.0	$28.3	$28.5
RES Costs ($/MWh)	$27.25	$27.74	$27.64	$42.30	$31.94	$38.61	$32.89	$36.40	$41.34	$34.68	$36.92	$35.19	$31.63	$35.24	$36.00	$34.88
Avoided Costs Due to RES																
Avoided Energy Costs (millions)	$4.5	$3.5	$4.3	$14.8	$16.3	$20.6	$20.3	$16.0	$18.6	$30.9	$18.4	$17.7	$20.7	$22.5	$18.0	$13.5
Avoided Capactiy Costs (millions)	$0.4	$0.2	$0.3	$1.0	$1.4	$0.5	$0.4	$0.4	$1.1	$0.5	$0.8	$1.5	$1.9	$2.1	$2.9	$2.7
Avoided Transmission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Avoided Emission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total Avoided Costs (millions)	$4.9	$3.7	$4.6	$15.8	$17.7	$21.1	$20.7	$16.4	$19.7	$31.5	$19.3	$19.1	$22.6	$24.6	$21.0	$16.2
Total Avoided Costs ($/MWh)	$51.68	$47.13	$55.33	$51.42	$27.27	$28.65	$25.24	$21.85	$29.95	$34.87	$22.95	$21.89	$25.14	$29.81	$26.70	$19.86
Total RES Premium/Discount (millions)	($2.3)	($1.5)	($2.3)	($2.8)	$3.0	$7.3	$6.2	$10.9	$7.5	($0.2)	$11.7	$11.6	$5.8	$4.5	$7.3	$12.3
Total RES Premium/Discount ($/MWh)	($24.43)	($19.39)	($27.69)	($9.12)	$4.67	$9.96	$7.64	$14.55	$11.39	($0.19)	$13.97	$13.30	$6.49	$5.44	$9.30	$15.02
Annualized RES Rate Impacts																
Total Company Sales (GWh)	3903	3988	4118	4215	4248	4284	4303	4216	4449	4684	4597	4723	4784	4967	4997	4780
Rate Impact ($/MWh)	($0.60)	($0.39)	($0.56)	($0.66)	$0.71	$1.71	$1.45	$2.59	$1.68	($0.04)	$2.55	$2.46	$1.22	$0.90	$1.46	$2.56
Rate impact (¢/kWh)	(0.06)	(0.04)	(0.06)	(0.07)	0.07	0.17	0.15	0.26	0.17	(0.00)	0.26	0.25	0.12	0.09	0.15	0.26

Table 3
Past SES Rate Impacts

SES Generation	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total SES Generation (GWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SES Generation Costs																
PPA + Owned Generation Costs (millions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SES Transmission Costs (millions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total SES Costs (millions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SES Costs ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avoided Costs Due to SES																
Avoided Energy Costs (millions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avoided Capactiy Costs (millions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avoided Transmission Costs (millions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avoided Emission Costs (millions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Avoided Costs (millions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Avoided Costs ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total SES Premium/Discount (millions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total SES Premium/Discount ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Annualized SES Rate Impacts																
Total Company Sales (GWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rate Impact ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rate impact (¢/kWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table 4
Future RES Rate Impacts

RES Generation	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Total RES Generation (GWh)	1484	1584	1595	1899	1897	2323	2336	2291	2300	2292	2287	2329	2324	2322	2335
RES Generation Costs															
PPA + Owned Generation Costs (millions)	$29.0	$33.2	$33.7	$44.6	$44.8	$60.1	$60.6	$59.5	$60.0	$60.0	$60.0	$57.8	$58.0	$58.3	$58.8
RES Transmission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total RES Costs (millions)	$29.0	$33.2	$33.7	$44.6	$44.8	$60.1	$60.6	$59.5	$60.0	$60.0	$60.0	$57.8	$58.0	$58.3	$58.8
RES Costs ($/MWh)	$19.56	$20.99	$21.11	$23.51	$23.61	$25.89	$25.94	$25.99	$26.08	$26.19	$26.25	$24.83	$24.96	$25.09	$25.19
Avoided Costs Due to RES															
Avoided Energy Costs (millions)	$41.6	$44.4	$41.7	$41.2	$41.6	$54.5	$58.0	$60.8	$63.8	$67.1	$69.5	$68.9	$70.6	$76.9	$83.6
Avoided Capactiy Costs (millions)	$0.2	$0.2	$2.3	$6.2	$7.4	$7.5	$7.6	$7.7	$7.8	$7.8	$7.9	$8.1	$8.2	$8.0	$8.2
Avoided Transmission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Avoided Emission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total Avoided Costs (millions)	$41.8	$44.6	$44.0	$47.4	$49.0	$62.0	$65.6	$68.5	$71.6	$74.9	$77.5	$76.9	$78.9	$84.9	$91.7
Total Avoided Costs ($/MWh)	$28.17	$28.18	$27.58	$24.98	$25.85	$26.69	$28.10	$29.90	$31.15	$32.68	$33.88	$33.04	$33.93	$36.57	$39.29
Total RES Premium/Discount (millions)	($12.8)	($11.4)	($10.3)	($2.8)	($4.2)	($1.9)	($5.0)	($9.0)	($11.7)	($14.9)	($17.5)	($19.1)	($20.8)	($26.7)	($32.9)
Total RES Premium/Discount ($/MWh)	($8.61)	($7.19)	($6.48)	($1.47)	($2.24)	($0.81)	($2.16)	($3.91)	($5.07)	($6.49)	($7.63)	($8.21)	($8.97)	($11.49)	($14.10)
Annualized RES Rate Impacts															
Total Company Sales (GWh)	5361	5328	5333	5363	5394	5450	5479	5480	5477	5479	5481	5483	5484	5485	5486
Rate Impact ($/MWh)	($2.38)	($2.14)	($1.94)	($0.52)	($0.79)	($0.34)	($0.92)	($1.63)	($2.13)	($2.72)	($3.19)	($3.49)	($3.80)	($4.86)	($6.00)
Rate impact (¢/kWh)	(0.24)	(0.21)	(0.19)	(0.05)	(0.08)	(0.03)	(0.09)	(0.16)	(0.21)	(0.27)	(0.32)	(0.35)	(0.38)	(0.49)	(0.60)

Table 5
Future SES Impacts

SES Generation	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Total SES Generation (GWh)	0	104	104	416	415	415	416	416	416	416	416	519	519	520	521
SES Generation Costs															
PPA + Owned Generation Costs (millions)	$0.0	$4.1	$4.1	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0
SES Transmission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total SES Costs (millions)	$0.0	$4.1	$4.1	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0
SES Costs ($/MWh)	$0.00	$39.29	$39.29	$36.07	$36.07	$36.07	$36.07	$36.07	$36.07	$36.07	$36.07	$28.85	$28.85	$28.84	$28.85
Avoided Costs Due to SES															
Avoided Energy Costs (millions)	$0.0	$3.1	$2.9	$11.6	$11.7	$11.9	$12.6	$13.5	$14.1	$14.9	$15.5	$19.8	$20.3	$22.2	$24.0
Avoided Capactiy Costs (millions)	$0.0	$0.0	$0.0	$1.0	$1.2	$1.2	$1.3	$1.3	$1.3	$1.3	$1.3	$1.3	$1.4	$1.4	$1.4
Avoided Transmission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Avoided Emission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total Avoided Costs (millions)	$0.0	$3.1	$2.9	$12.6	$12.9	$13.1	$13.8	$14.8	$15.4	$16.2	$16.8	$21.1	$21.7	$23.6	$25.4
Total Avoided Costs ($/MWh)	$0.00	$29.99	$27.94	$30.29	$31.07	$31.58	$33.27	$35.51	$37.02	$38.89	$40.34	$40.64	$41.77	$45.34	$48.78
Total SES Premium/Discount (millions)	$0.0	$1.0	$1.2	$2.4	$2.1	$1.9	$1.2	$0.2	($0.4)	($1.2)	($1.8)	($6.1)	($6.7)	($8.6)	($10.4)
Total SES Premium/Discount ($/MWh)	$0.00	$9.30	$11.35	$5.78	$5.01	$4.49	$2.80	$0.56	($0.95)	($2.82)	($4.28)	($11.80)	($12.92)	($16.49)	($19.94)
Annualized SES Rate Impacts															
Total Company Sales (GWh)	5361	5328	5333	5363	5394	5450	5479	5480	5477	5479	5481	5483	5484	5485	5486
Rate Impact ($/MWh)	$0.00	$0.18	$0.22	$0.45	$0.39	$0.34	$0.21	$0.04	($0.07)	($0.21)	($0.32)	($1.12)	($1.22)	($1.56)	($1.89)
Rate impact (¢/kWh)	0.00	0.02	0.02	0.04	0.04	0.03	0.02	0.00	(0.01)	(0.02)	(0.03)	(0.11)	(0.12)	(0.16)	(0.19)

Table 6
Levelized RES Rate Impacts

Levelized RES Generation	Historic	Future
Total RES Generation (GWh)	632	2106

Levelized RES Generation Costs		
PPA + Owned Generation Costs (millions)	$40.6	$22.1
RES Transmission Costs (millions)	$0.0	$0.0
Total RES Costs (millions)	$40.6	$22.1
RES Costs ($/MWh)	$64.24	$10.50

Levelized Avoided Costs Due to RES		
Avoided Energy Costs (millions)	$30.2	$32.3
Avoided Capactiy Costs (millions)	$1.9	$3.3
Avoided Transmission Costs (millions)	$0.0	$0.0
Avoided Emission Costs (millions)	$0.0	$0.0
Total Avoided Costs (millions)	$32.1	$35.6
Total Avoided Costs ($/MWh)	$50.74	$16.91

Total RES Premium/Discount (millions)	$8.5	($13.5)
Total RES Premium/Discount ($/MWh)	$13.50	($6.42)

Levelized RES Rate Impacts		
Total Company Sales (GWh)	4454	5438
Rate Impact ($/MWh)	$1.92	($2.49)
Rate impact (¢/kWh)	0.19	(0.25)

Table 7
Levelized SES Rate Impacts

Levelized SES Generation	Historic	Future
Total SES Generation (GWh)	-	374

Levelized SES Generation Costs		
PPA + Owned Generation Costs (millions)	-	$7.2
SES Transmission Costs (millions)	-	$0.0
Total SES Costs (millions)	-	$7.2
SES Costs ($/MWh)	-	$19.12

Levelized Avoided Costs Due to SES		
Avoided Energy Costs (millions)	-	$7.0
Avoided Capactiy Costs (millions)	-	$0.6
Avoided Transmission Costs (millions)	-	$0.0
Avoided Emission Costs (millions)	-	$0.0
Total Avoided Costs (millions)	-	$7.6
Total Avoided Costs ($/MWh)	-	$20.33

Total SES Premium/Discount (millions)	-	($0.5)
Total SES Premium/Discount ($/MWh)	-	($1.21)

Levelized SES Rate Impacts		
Total Company Sales (GWh)	-	5438
Rate Impact ($/MWh)	-	($0.08)
Rate impact (¢/kWh)	-	(0.01)

Indirect Costs

As a member of the Midcontinent Independent System Operator, Inc. (MISO), Otter Tail is required to offer its generation units into the day-ahead energy market. Recently, energy prices have been very low due to the addition of renewable resources as well as low fuel costs for existing thermal units. Up until 2020, Otter Tail offered in its co-owned baseload thermal units as "must-run" units to prevent them from cycling on and off with fluctuating energy prices. This means that if the day-ahead price of energy dips below the cost of the unit, the unit will still clear at minimums in order to keep the unit online. Because these units stay online regardless of energy prices, there is no increase in cycling charges. In April 2020, the owners of Big Stone Plant agreed to a methodology to allow the operation of Big Stone Plant to be offered into the MISO/Southwest Power Pool (SPP) markets on an economic dispatch basis. This methodology includes weekly, bi-weekly, or as-needed meetings with all Co-Owners (Otter Tail, Montana-Dakota Utilities Co., and NorthWestern Energy) to review the economic dispatch or self-commitment status of Big Stone Plant. For the time periods agreed to by the Co-Owners, this unit is offered into the market economically meaning the day-ahead energy price has to be higher than the unit's cost for long enough to justify bringing the unit online. As a result, it could be argued that this unit cycles more because of the additional renewable resources on the system. The Co-Owners of Coyote Station have developed the capability to offer the plant under an economic offer. As with Big Stone Plant, each Coyote Co-Owner maintains the contractual right to request self-commitment. At the time of this filing, one of the plant's Co-Owners, not Otter Tail, has requested ongoing self-commitment. As a results, the plant has not been offered into the market on an economic dispatch basis.

In terms of ancillary services, Otter Tail has not identified any impacts which can be attributed to the implementation of the RES requirements so far. That being said, as the amount of renewable resources increases, so does the need for ancillary services. Eventually there will be a tipping point where the amount of renewable resources increases and the amount of available spinning reserves decreases to a level which causes the cost of ancillary services to rise.

Avoided Permitting and Emission Cost Impacts

All historical avoided permitting and emission costs are factored in when calculating the avoided energy and capacity costs. For the future avoided carbon dioxide ($CO_{2)}$ costs, Otter Tail used the Commission approved value of \$15.00/ton CO_2 penalty starting in 2025.

Transmission Costs

For the purpose of simplifying our modeling, all transmission costs for future RES/SES projects are built into the project energy price. It is also assumed that all avoided energy and capacity costs (both past and future) will be purchased from the market resulting in no added transmission costs.

6. Summary

The following strategy is being used to optimize the usage of RECs:

- Otter Tail allocates RECs from resources used to serve all customers based on a monthly energy allocation.
- Otter Tail banks all MN jurisdiction RECs which are eligible for MN compliance to be used for current and future REO/RES compliance.
- Otter Tail swaps MN jurisdiction RECs which cannot be used for MN compliance but can be used for Dakotas compliance for Dakotas jurisdiction RECs which cannot be used for ND or SD compliance but can be used for MN compliance. Equivalent monetary value will be maintained for all swaps.
- Otter Tail expects to transfer enough Dakotas RECs to Minnesota, as necessary, to maintain a bank balance for MN REO/RES compliance, but without risking shelf life expiration of RECs for compliance purposes.
- Otter Tail sells the surplus ND and SD allocated RECs.
- Otter Tail evaluates opportunities to purchase/use lower value RECs for compliance and banking, while selling higher value RECs. All benefits and costs flow to customers.
- When possible, sell higher value MN RECs and acquire older and lower value Dakotas RECs for compliance in MN. MN REC sales revenues, net of replacement purchase costs, will be treated in accordance with MN Commission Orders. Dakotas REC revenues from sales to the MN jurisdiction will be treated in accordance with the Commission Orders in those two states.
- The oldest RECs possible should be used for compliance or for sales in order to keep the REC inventory as fresh as possible and at as high a value as possible.
- Seek opportunities to sell wind generation energy either with or without RECs if lower cost replacement energy purchases can be made to reduce energy costs.

CHAPTER 6 – CUSTOMER RATE AND COST IMPACTS

I. INTRODUCTION

Minn. R. 7843.0500, subp. 3, requires that the Minnesota Public Utilities Commission evaluate resource plans on, among other things, their ability to "keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints." In this chapter we present rate and bill impacts of our Preferred Plan for our Residential, Commercial, and Industrial customer classes.[1] Overall, our Preferred Plan results in an estimated annual rate increase of 0.5 percent for Minnesota customers, which is less than the expected national average increase of 2.1 percent for electricity prices.

Producing a detailed analysis of rate impacts in a resource planning process with long time horizons is challenging due to the potential changes in our rates and resource needs over time. Factors that can impact the estimated rate impacts in the planning period include generation ownership structure, tax treatment, regulatory decisions, large customer load additions, changes in customer class allocations, and others. The simplifying assumptions made in both the calculation methodology and the input variables mean that these estimated impacts may not align with the actual rates set by the Commission for various customer classes in the future. We caution that this information should not be interpreted as directly comparable to the customer rate impact information we would provide as part of a rate case filing.

Our customer cost impact analysis shows that the Preferred Plan does not materially increase costs for our customers. The Preferred Plan results in an estimated average annual increase in retail rates of 0.9 percent across our system, compared to the Reference Case results of 0.7 percent and the EIA forecasted national average electricity rate increase of 2.1 percent. In other words, we can achieve significant CO_2 emissions reductions, with cost impacts that are less than half of the expected national average increase in electricity prices. Both the Reference Case and the Preferred Plan are designed to meet the Company's clean energy goals, and state policy objectives. As shown below, our Preferred Plan maintains affordability and reliability while continuing our trend of carbon reduction benefits relative to our Reference Case.

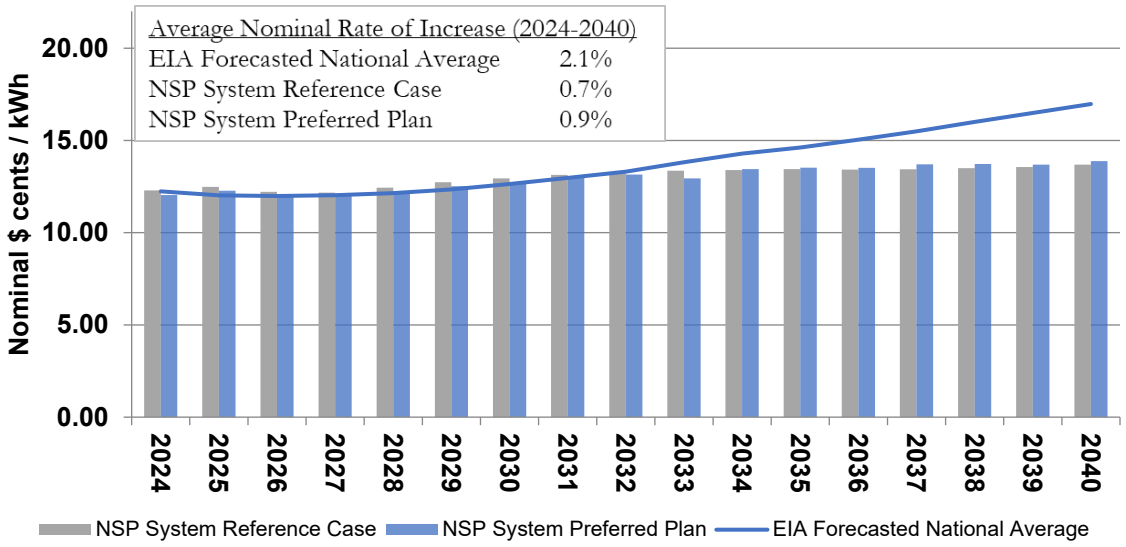
A. Preferred Plan Average Nominal Cost Comparison to National Average

We begin by showing our Reference Case and Preferred Plan's average nominal cost as compared to the national average as forecasted by the Energy Information

[1] See *In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy*, Order Approving Plan with Modifications and Establishing Requirements for Future Filings, MN PUC Docket No. E-002/RP-19-368, Order Point 18 (April 15, 2022).

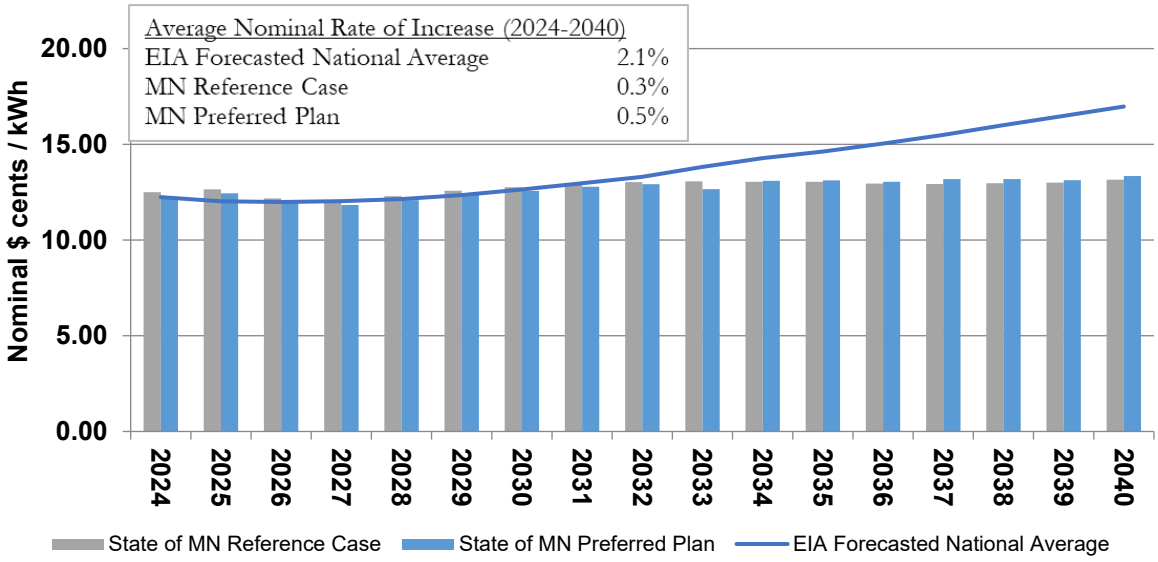
Administration. To show the cost impact of our proposal over the long-term, we provide a compound average growth rate (CAGR) comparison of our Preferred Plan compared to the national average nominal cost CAGR for the NSP System in Figure 6-1, and Minnesota in Figure 6-2, below. As can be seen in these figures, our Preferred Plan remains lower than the national average.

Figure 6-1: Average Nominal Cost Comparison NSP System



* *Notes: National energy cost forecast from Energy Information Administration (EIA) Annual Energy Outlook 2023, Table Energy Supply, Disposition, Prices and Emissions – Reference Case. End use prices, all sector average.*[2] The Preferred Plan and Reference Plan lines include the costs of Solar Rewards*Community.

Figure 6-2: Average Nominal Cost Comparison State of Minnesota



The results above indicate that the CAGR for average rates is higher for the Preferred Plan than for the Reference Case. To be clear, however, this should not be interpreted to mean that the Reference Case is more beneficial to customers than the Preferred

Plan. The CAGR simply measures the growth rate from one end point to another, in this case the average rate in 2024 versus the average rate in 2040. The Preferred Plan average rate in 2024 begins at a slightly lower point than in the Reference Case, and ends slightly higher in 2040, resulting in a higher growth rate. In contrast, the PVRR analysis takes into account each year of the annual revenue requirement stream, and not just the end points in 2024 and 2040. As discussed earlier in this filing, the Preferred Plan results in a lower PVRR than the Reference Case, making the Preferred Plan the overall least cost option for our customers.

The results in Figures 6-1 and 6-2 also show that the Minnesota CAGR is lower than the NSP system average CAGR for the time period of 2024 through 2040. This is due to the way each CAGR is calculated. The annual NSP system average rates are calculated as the annual revenue requirement for the entire NSP system divided by NSP system sales. The annual Minnesota rates are calculated the same way using the jurisdictional revenue requirement and the jurisdictional annual sales forecast. Since Minnesota sales are forecasted to grow more quickly than the NSP average, they make up a larger portion of the total NSP sales mix in 2040 than they do in 2024. Therefore, the average rates in 2040 (and thereby the CAGR to reach those rates) for Minnesota are lower than for the NSP system as a whole.

II. REVENUE REQUIREMENTS FORECAST METHODOLOGY

To calculate the long-term rate impacts of the Preferred Plan as compared to the Reference Case, we first developed a forecast of revenue requirements for the Reference Case. This forecast leverages retail revenue requirements from the Company's most recent rate case test years approved by each Commission in our five jurisdictions: Minnesota,[3] North Dakota,[4] South Dakota,[5] Wisconsin,[6] and Michigan[7] to create an NSP System revenue requirement for 2024. We identified annual costs through the end of the planning period (2040) using the CAGR of generation and fuel costs from the EnCompass model Reference Case. This approach avoids speculation

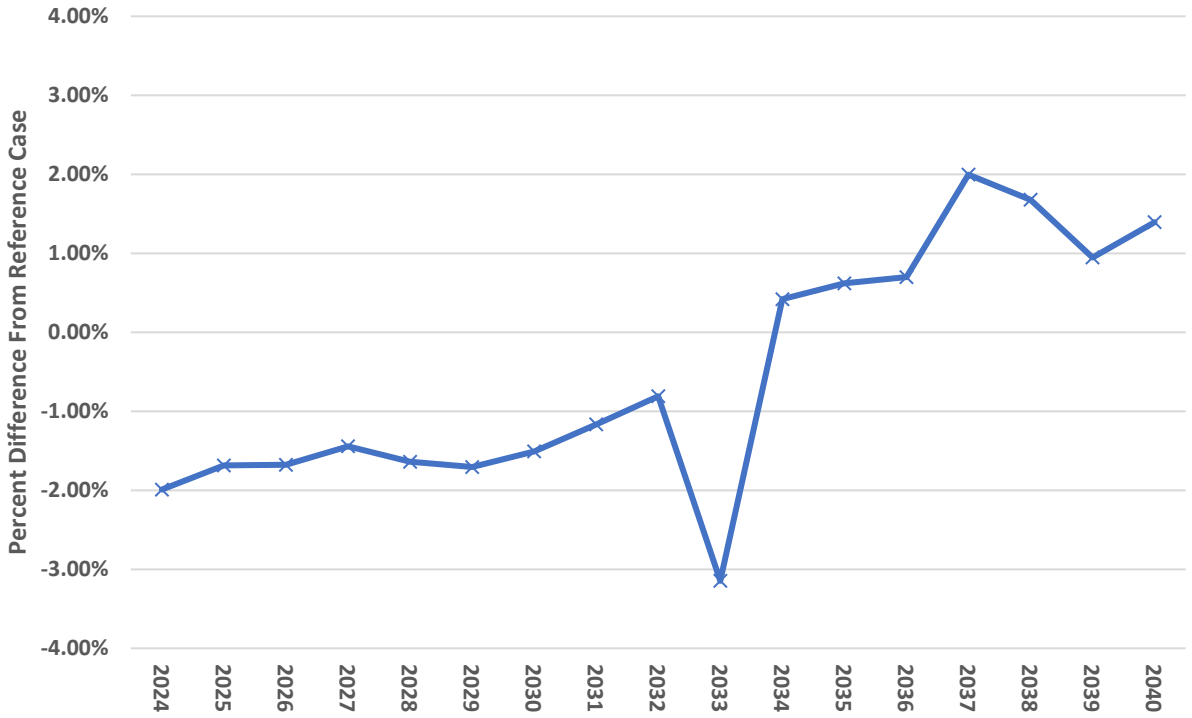
[2] *See* U.S. Energy Information Administration - EIA - Independent Statistics and Analysis The EIA's Annual Energy Outlook was published in 2023.
[3] *In the Matter of the Application of Northern States Power Company, dba Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota*, Findings of Fact, Conclusions, and Order, MN PUC Docket No. E-002/GR-21-630 (July 17, 2023).
[4] *Northern States Power Company 2021 Electric Rate Increase Application*, Order on Settlement, Case No. PU-20-441 (August 18, 2021).
[5] *In the Matter of the Application of Northern States Power DBA Xcel Energy for Authority to Increase Its Electric Rates*, Order Granting Joint Motion for Approval of Settlement Stipulation; Order Approving Refund Plan, Docket No. EL22-017 (June 8, 2023).
[6] *Application of Northern States Power Company-Wisconsin for Authority to Adjust Electric and Natural Gas Rates,* Final Decision, 4220-UR-126 (December 20, 2023).
[7] *Id.*

on areas of the business not related to resource planning and modeling, while still using the detailed generation-related information from the EnCompass model to create a "business as usual" long term rate projection.

To determine the revenue requirement impact of the Preferred Plan, we identified the differential in annual expenses and capital spend of the Preferred Plan compared to the Reference Case Encompass model results. This annual differential was added to the annual Reference Case revenue requirements to create the Preferred Plan annual revenue requirements.

Figure 6-3 below illustrates the estimated revenue requirement impacts of the Preferred Plan compared to the Reference Case over the planning period, while Figure 6-4 localizes the impacts to Minnesota.

Figure 6-3: Annual Percent Change in Revenue Requirements (2024-2040)
Preferred Plan Compared to Reference Case
NSP System

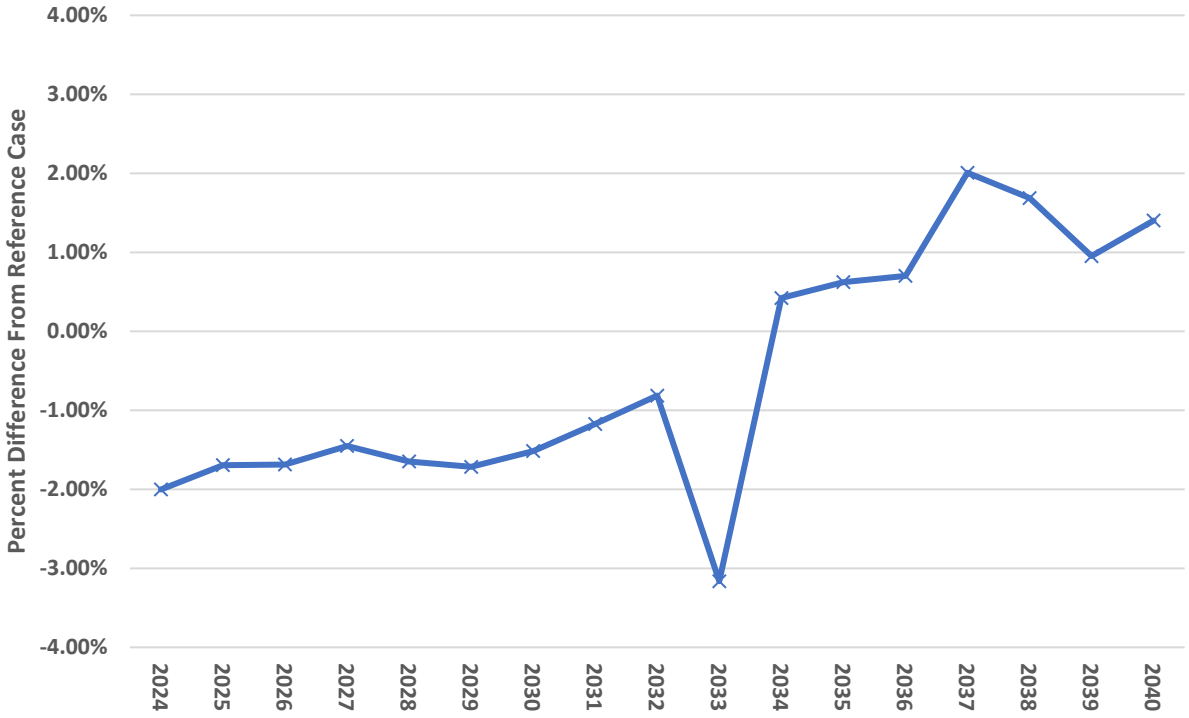


The annual revenue requirements for the Reference Case and Preferred Plan were jurisdictionalized using allocators from the Company's 2022-2024 Minnesota Electric Rate Case (Docket No. E-002/GR-21-630). Table 6-1 and Figure 6-4 below provide the estimated impact of the Preferred Plan for Minnesota.

Table 6-1: Estimated Incremental Impact of Preferred Plan State of Minnesota – All Customers

Year	Reference Case Revenue Req ($000)	Incremental Impact of Preferred Plan ($000)	Preferred Plan Revenue Req ($000)	Incremental Impact (%)
2024	$3,537,894	-$70,821	$3,467,074	-2.00%
2025	$3,628,567	-$61,488	$3,567,079	-1.69%
2026	$3,721,563	-$62,756	$3,658,808	-1.69%
2027	$3,816,943	-$55,396	$3,761,547	-1.45%
2028	$3,914,768	-$64,499	$3,850,268	-1.65%
2029	$4,015,099	-$68,867	$3,946,232	-1.72%
2030	$4,118,002	-$62,422	$4,055,580	-1.52%
2031	$4,223,542	-$49,503	$4,174,039	-1.17%
2032	$4,331,788	-$35,259	$4,296,529	-0.81%
2033	$4,442,807	-$140,536	$4,302,271	-3.16%
2034	$4,556,672	$19,193	$4,575,865	0.42%
2035	$4,673,454	$29,110	$4,702,565	0.62%
2036	$4,793,230	$33,664	$4,826,895	0.70%
2037	$4,916,076	$98,679	$5,014,755	2.01%
2038	$5,042,070	$85,061	$5,127,131	1.69%
2039	$5,171,293	$49,226	$5,220,520	0.95%
2040	$5,303,828	$74,393	$5,378,222	1.40%

Figure 6-4: Annual Percent Change in Revenue Requirements (2024-2040)
Preferred Plan Compared to Reference Case
State of Minnesota



III. KEY DRIVERS

The major inflection points in the delta of revenue requirements (and rates) are driven by the differences in the set of resources that comprise the Preferred Plan and Reference Case; these points coincide with differences in the retirement dates for Prairie Island. Compared to the Reference Case, the Preferred Plan results in lower cost through 2033 due to the extension of Prairie Island and corresponding reduction in depreciation expense. The Prairie Island extension results in fewer resources added in 2033, including the offset of a firm dispatchable addition, compared to the Reference Case, and therefore lower costs reflected in the downward spike in 2033 reflected in Figures 6-3 and 6-4 above. The slightly higher costs in 2034 and beyond reflect the relative costs associated with the Prairie Island extension and the costs of resources added in the Reference Case after Prairie Island retires based on our assumptions for generic resource additions. The generic resource additions are modeled assuming a levelized cost over the life of the asset.

IV. ESTIMATED ANNUAL RATE IMPACTS

After determining the revenue requirement of the Reference Case and the incremental impacts from the Preferred Plan, we determined customer class revenue requirement impacts using cost allocation principles described below. We calculated rate impacts in $ per kWh by dividing each customer class's revenue requirement in each year by the annual forecasted sales.

Figure 6-5 and 6-6 provide the incremental rate impacts of the Preferred Plan for retail customers and by customer class, respectively.

Figure 6-5: Incremental Rate Impact of Preferred Plan State of Minnesota – All Customers

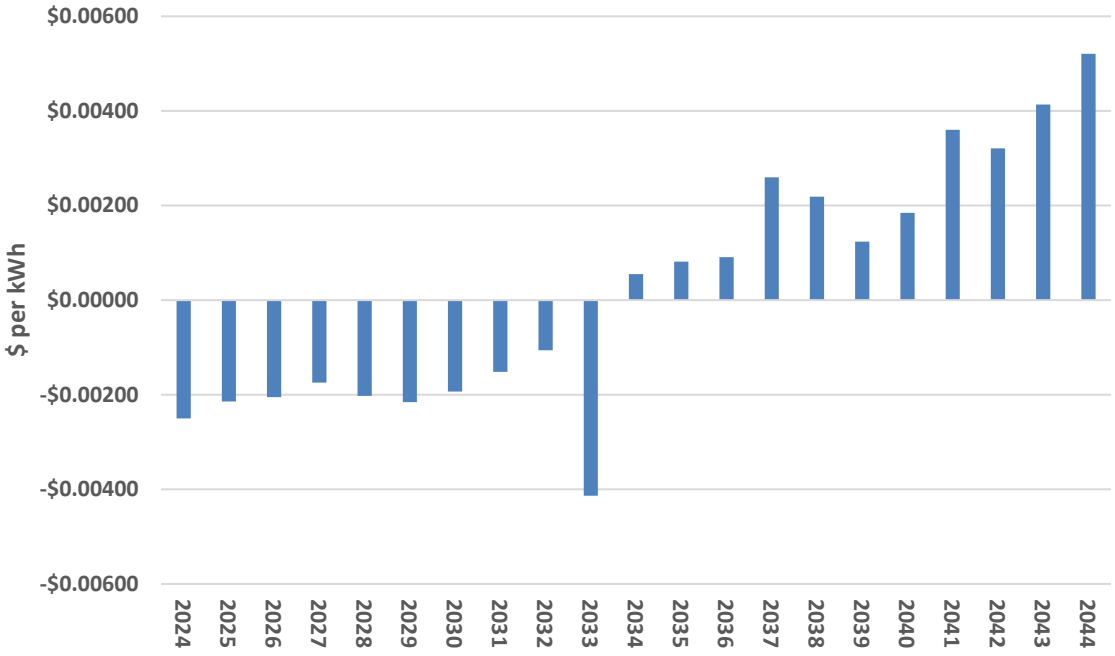
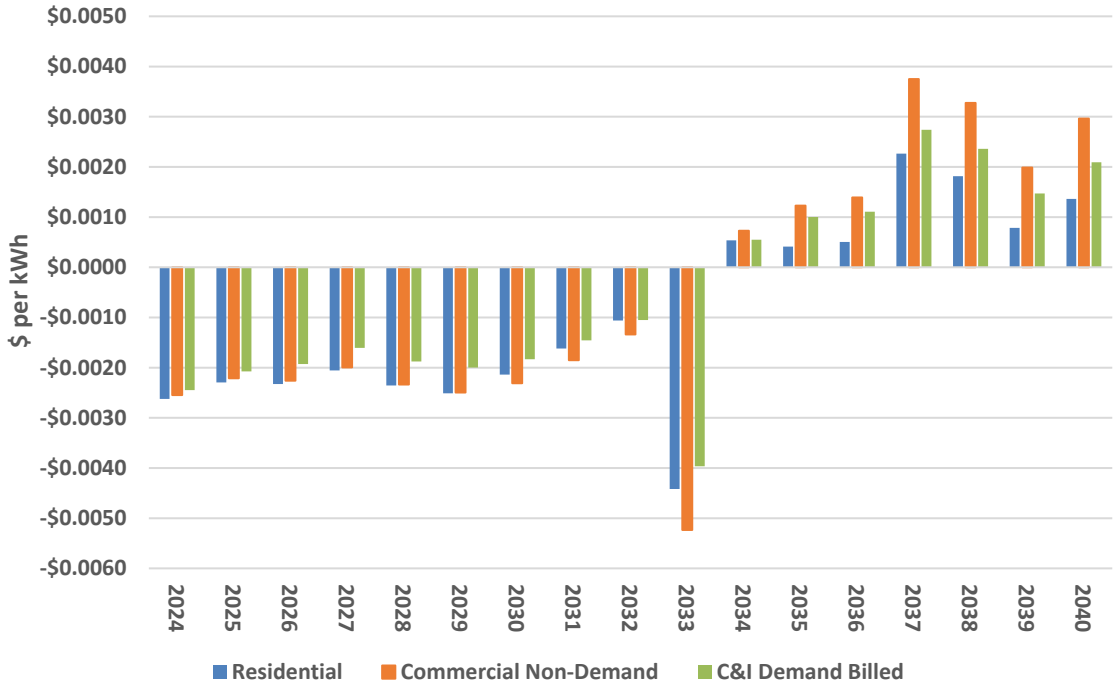


Figure 6-6: Incremental Rate Impact of Preferred Plan by Customer Class – State of Minnesota



As noted above, we determine customer class revenue requirement impacts of the Preferred Plan by allocating incremental costs to customer classes for each year in the planning period (2024-2040). To do this, we apply ratemaking treatments to expense items for each generation resource type that is impacted by the 2024 Plan. Items include fuel costs and purchased energy, fixed O&M, variable O&M, and the revenue requirement associated with capital investments.

Costs for fuel, purchased energy, and variable O&M are allocated to customer classes using the E8760 energy allocator approved in our most recent Minnesota rate case, as provided below:[8]

Table 6-2: E8760 Energy Allocator

MN	Residential	Commercial Non-Demand	C&I Demand	Lighting
100.00%	31.69%	2.94%	65.03%	0.35%

The E8760 allocator is calculated by taking the forecast hourly load for each of the 8,760 hours of the test year for each customer class, then weighting the hourly load by the forecasted hourly marginal energy cost in each respective hour.

Fixed O&M and the revenue requirement related to capital investments are split into energy-related and capacity/demand-related components using the Company's plant stratification analysis approved in our most recent Minnesota rate case.[9] We provide the plant stratification analysis for each plant type below:

[8] See Docket No. E002/GR-21-630, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Findings of Fact, Conclusions, and Order , (July 17, 2023).
[9] *Id.*

Table 6-3: Stratification Analysis by Plant Type

Plant Type	Replacement Value $/kW	Capacity Ratio	Capacity/Demand Percentage	Energy Percentage
Combustion Turbine	$1,026	$1,026 / $1,026	100.0%	0.0%
Fossil	$2,458	$1,026 / $2,458	41.8%	58.2%
Nuclear	$5,109	$1,026 / $5,109	20.1%	79.9%
Wind	$11,262	$1,026 / $11,262	9.1%	90.9%
Solar	$3,736	$1,026 / $3,736	27.5%	72.5%

The plant stratification approach begins by comparing the replacement cost of each type of generation plant (fossil, nuclear, etc.) to the replacement cost of a Combustion Turbine (CT). CTs are 100 percent capacity/demand-related since they are the generation source with the lowest capital cost and the highest operating cost. For each generation type, the percent of total generation costs that exceeds the cost of a CT peaking plant are classified as being energy related. These costs are in excess of the capacity/demand-related portion, and as such, were not incurred to obtain capacity, but rather to obtain lower cost energy.

After fixed O&M costs and the capital-related revenue requirement originating from each type of generation plant are split into capacity-related and energy-related components based on the percentages shown in Table 6-3 above, those costs that have been classified as being energy-related are allocated to customer class using the E8760 energy allocator provided in *part 1* above.

The capital costs that have been classified as being capacity- or demand-related are allocated to customer class using the D10S capacity allocator utilized in our most recent rate case.[10] The D10S allocator is simply each customer class's load that is coincident with the NSP system peak load. We provide the D10S customer class allocator percentages below:

Table 6-4: D10S Capacity Allocator

MN	Residential	Commercial Non-Demand	C&I Demand	Lighting
100.00%	39.55%	2.77%	57.68%	0.00%

[10] *Id.*

V. ESTIMATED NEAR-TERM RATE IMPACTS

Table 6-5 below provides a more detailed view of near-term estimated rate impacts for Minnesota customer classes.

Table 6-5: Preferred Plan Minnesota Estimated Rate Impacts by Customer Class per Year

Rate Class Impacts	2024	2025	2026	2027	2028	2029	2030	Comp'd Incr/Yr
Residential (avg rate, ¢/kWh)	15.467¢	15.248¢	15.607¢	15.961¢	16.192¢	16.456¢	15.911¢	N/A
Cumul Increase (¢/kWh)		-0.219	0.140	0.494	0.725	0.989	0.444	N/A
Cumulative Increase (%)		-1.42%	0.90%	3.19%	4.69%	6.39%	2.87%	0.47%
$ Impact/Month, @ 650 kWh		($1.42)	$0.91	$3.21	$4.71	$6.43	$2.89	N/A
Sm Non-Dmd (avg rate, ¢/kWh)	14.501¢	14.301¢	14.672¢	15.122¢	15.522¢	15.949¢	16.743¢	N/A
Cumul Increase (¢/kWh)		-0.200	0.171	0.621	1.021	1.448	2.242	N/A
Cumulative Increase (%)		-1.38%	1.18%	4.28%	7.04%	9.99%	15.46%	2.43%
$ Impact/Month, @ 1,000 kWh		($2.00)	$1.71	$6.21	$10.21	$14.48	$22.42	N/A
Demand (avg rate, ¢/kWh)	10.879¢	10.447¢	9.739¢	9.477¢	9.706¢	9.953¢	10.331¢	N/A
Cumul Increase (¢/kWh)		-0.432	-1.141	-1.403	-1.173	-0.927	-0.548	N/A
Cumulative Increase (%)		-3.97%	-10.48%	-12.89%	-10.79%	-8.52%	-5.04%	-0.86%
$ Impact/Month, @ 37,500 kWh		($162.01)	($427.72)	($526.04)	($440.02)	($347.47)	($205.45)	N/A
Street Ltg (avg rate, ¢/kWh)	26.983¢	26.673¢	27.082¢	27.690¢	28.200¢	28.681¢	29.236¢	N/A
Cumul Increase (¢/kWh)		-0.310	0.099	0.708	1.217	1.698	2.254	N/A
Cumulative Increase (%)		-1.15%	0.37%	2.62%	4.51%	6.29%	8.35%	1.35%
$ Impact/Month, @ 60 kWh		($0.19)	$0.06	$0.42	$0.73	$1.02	$1.35	N/A

Using the methodologies described above, the incremental costs in the last year of the period (2030) for the Preferred Plan would be expected to have the following impacts:

- Residential rate increases by about 0.47 percent on a compounded annual basis through 2030, equivalent to a total increase of $2.89 per month above the current rate level;
- Commercial rate increases by about 2.43 percent on a compounded annual basis through 2030, equivalent to a total increase of $22.42 per month above the current rate level; and
- Industrial rate decreases by about 0.86 percent on a compounded annual basis through 2030, equivalent to a total decrease of $205.45 per month below the current rate level.

As noted above, this is not intended to be a prediction of what rate or bill increases will actually be over this time (which will be impacted by numerous factors, including,

among other things, the specific costs of actual generation additions rather than generic assumptions used here, non-generation related costs, actual sales growth, and cost allocation decisions). Instead, this is intended to serve as an indicative look at the incremental rate and monthly bill impacts of the modeling results for the Preferred Plan.

VI. RATE IMPACTS OF STANDARD OBLIGATIONS

Each electric utility must submit to the Commission a report containing an estimation of the rate impact of activities necessary to comply with Minn. Stat. § 216B.1691, subd. 2e. The report must be updated and submitted as part of each integrated resource plan or plan modification filed under section Minn. Stat.§ 216B.2422.

We have been adding cost-effective renewable resources to our system to reduce emissions consistent with the analysis in our resource plans and acquisitions. Our analysis in the 2024 Plan considers the costs and impacts of the renewable additions but does not require any additions to meet our standard obligations. Therefore, our standard obligations do not impact our rates. For further details please see Appendix N: Standard Obligations.

VII. CONCLUSION

Based on the totality of these metrics, we believe that our Preferred Plan keeps customers' bills and rates as lows as practicable while continuing our transition to a carbon-free system. As we continue our transition to a carbon-free system, we remain committed to being the energy provider of choice for our customers, and keeping rates low is a key part of that commitment.