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2025 WIND CURTAILMENT REPORT

I. INTRODUCTION

The Commission's April 4, 2006 Order regarding curtailment payments to wind developers (Docket No. E999/AA-04-1279) requires the Company to provide in future Annual Automatic Adjustment of Charges (AAA) reports a projection of wind generation curtailment costs given existing and planned wind-generated energy purchases and transmission system needs. The Commission's June 12, 2019 Order in Docket No. E999/CI-03-802 approved the disposition of AAA reporting requirements as agreed to by the Company and the Department. The Company and the Department agreed that curtailment reporting could be reformatted to provide support for increased curtailment, in addition to providing detailed curtailment data by unit and by curtailment code.

Below we summarize the Company's experience regarding wind curtailment payments and provide a discussion of the drivers for increased wind curtailment payments during the 2025 reporting year as compared to the 2025 forecast. Part C, Attachment 2 shows detailed curtailment payments by unit and by curtailment code, in compliance with the Commission's February 6, 2008 Order in Docket Nos. E,G999/AA-06-1208 and E002/M-04-1970 *et al.*

We most recently discussed and provided an estimate of potential curtailment payments and the assumptions used to develop our 2026 curtailment forecast in our May 1, 2025 Petition and July 30, 2025 Reply Comments in Docket No. E002/AA-25-63. We will provide an estimate of 2027 curtailment payments, including forecast assumptions, in our 2027 Fuel Forecast Petition to be filed by May 1, 2026.

System conditions and wind project development are very dynamic and actual curtailment may vary from what is projected in this report. The Company will continue to participate in discussions regarding transmission planning and operations to identify needs and work to manage future costs. We will continue to refine and gather information for use in future updates to be submitted with subsequent fuel true-up and forecast reports.

II. CURTAILMENT OVERVIEW

The Company again expects that wind curtailment from Power Purchase Agreement (PPA) facilities will occur in the foreseeable future, and 2025 curtailment can be attributed to regional and localized congestion resulting from the lack of sufficient

transmission capacity to accommodate the large concentration of wind facilities in Minnesota, North Dakota, South Dakota, and Iowa. The transmission capacity required to deliver the wind is often further reduced by transmission outages.

The Company is making significant efforts to reduce the impact of congestion, and therefore curtailment, by sponsoring transmission upgrades that can be completed in the near term, upgrading substation equipment where that is the limiting element on a transmission line, prioritizing repairs on transmission facilities that impact congestion, optimizing transmission outages to limit duration along with scheduling outages during periods of lower wind when possible.

Another factor that contributed to higher curtailment at Company PPA facilities is the status of a wind project's Production Tax Credit (PTC). Projects without PTCs are curtailed before projects with PTCs since they are a higher priced resource.[1] The lack of PTCs is a significant factor related to Company curtailments since a number of PPA projects do not have PTCs and are reducing the curtailment on other area projects regardless of the owner.

The Company, along with MISO and other area utilities, have taken a number of steps to create additional transmission capacity to reduce wind curtailment and congestion. These steps include the development the CapX2020 transmission projects (CapX2020), Huntley – Wilmarth 345 kV line, the MISO Multi-Value Projects (MVPs), and the Brookings – Lyon County 345 kV second circuit. The Company has also worked with the Grid North Partners,[2] to complete a number of transmission improvement projects[3] that are specifically designed to reduce congestion and curtailment.

Work has begun on the MISO Long-Range Transmission Planning (LRTP) Tranche 1 and Tranche 2 projects designed to enable reliable and economic delivery of energy in the future with lower-carbon resources. The LRTP projects will create additional transmission capacity for new generating resources and positively impact curtailment.

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[1] Projects with PTCs are bid into the market at a negative value since the owner will lose the PTC if curtailed while projects without PTCs are bid in at zero dollars.
[2] The Grid North Partners include Central Municipal Power Agency/Services, Dairyland Power Cooperative, Great River Energy, Minnesota Power, Missouri River Energy Services, Otter Tail Power Company, Rochester Public Utilities, Southern Minnesota Municipal Power Agency, WPPI Energy, and Xcel Energy.
[3] https://www.startribune.com/minnesota-utilities-spending-130-million-to-improve-wind-energy-transmission-great-river-energy-xcel/600308291/

The LRTP Tranche 1 projects have projected in-service dates of 2028-2030. The LRTP Tranche 2 projects have projected in-service dates of 2032-2034.

MISO identifies wind facilities that can be controlled through Automatic Generation Control[4] as Dispatchable Intermittent Resources (DIR), which provide better management of the wind resources. Under this system, a number of existing PPA wind facilities that are capable of operating as DIR, along with all new wind facilities, are registered with MISO as DIR. DIR facilities are given set point instructions every five minutes and rely on Automated Generation Control (AGC) technology, which automatically controls wind project output. DIR allows wind generators to be operated more like traditional generating facilities and, as a result, MISO is able to more quickly and accurately respond to system conditions.

Table 1 shows the current PPA wind facilities associated with this report that are registered and operate as DIR.

Table 1
DIR PPA Facilities

Wind Project	MW
Big Blue	36
Cisco	8
Crowned Ridge 1	200
Dakota Range 3	150
Fenton	200
Glen Ullin Wind	106
MinnDakota	150
Moraine II	50
Odell	200
Prairie Rose	200
Valley View	10
Zephyr	30
Total	1,340

[4] MISO requires all new intermittent resources, including non-dispatchable facilities that are being repowered, to be fully dispatchable. The Company has contracts with a number of PPA Facilities that are not dispatchable.

MISO manages generation, including DIR generation, in the Real Time market which is described on the MISO website as the following:

> The Real-Time Market is a continuous process for balancing supply and demand at least-cost while recognizing current operating conditions. This includes any deviations from the day-ahead plan as a result of unanticipated and unhedged congestion due to unexpected changes. The Real Time Market dispatches the least-cost generation resources to satisfy system demand without overloading the transmission network.
>
> MISO uses the Security Constrained Economic Dispatch (SCED) algorithm to provide co-optimized clearing solutions in the Real-Time Market. The objective of the Security Constrained Economic Dispatch (SCED) algorithm is to minimize cost while meeting forecasted demand, scheduled interchange, and operating reserves requirements, which are subject to transmission congestion and other system limitations. SCED produces Balanced injections and withdrawals, congestion management solutions, and LMP and MCP. The SCED runs every five minutes during the Operating Hour to establish the dispatch instruction for generation resources. SCED produces Resource Energy Dispatch Targets, Dispatch target information vis setpoint instructions, RT LMP and RT MCP. MISO sends out a five-minute dispatch target to each resource and repeats throughout the Operating Day.

1. Curtailment Procedures

MISO performs a 10-minute forecast every five minutes which is used as the maximum limit for the wind farm in the Unit Dispatch System. MISO sends five-minute dispatch instructions to DIR wind farms. When LMP drops below the offer price of the DIR unit, the farm is automatically dispatched down. The setpoint is sent to the DIR wind farm, and the facility is automatically curtailed. Both PTC and non-PTC DIR wind farms are managed by MISO through automatic control, and these facilities are required to comply with the MISO cost signals. Failure to comply would expose the Company to Revenue Sufficiency Guarantee (RSG) charges. More curtailment occurs at non-PTC wind farms.

2. Real Time Binding Constraints

Real time binding constraints are the transmission facilities that are identified in the SCED that would overload in anticipation of the next contingency. The SCED would send setpoint instruction to redispatch generation to eliminate the constraint.

A number of factors result in real time binding constraints which cause curtailment, including: 1) the oversubscription of the transmission system resulting in more wind generation than the transmission system can accommodate; 2) the relationship between wind and load levels where more curtailment will occur during periods of higher wind and lower load; 3) planned and emergency transmission outages required for construction, maintenance or repair activities; and 4) wind generation projects going into service before all required transmission facilities are completed.

Real Time Binding Constraints (RTBCs) can have regional impacts on multiple generating facilities located in a larger area or localized impacts on specific generating facilities located in a specific area. Individual transmission outages can impact both regional and/or localized Constraints. The most frequent 2025 real time binding constraints impacting the Company owned and PPA facilities are listed in Table 2 below.

Note: the Company has worked to identify binding constraints that are likely to occur going forward and have been implementing plans to mitigate these constraints. The mitigation plans are designed to cost effectively reduce both curtailment and congestion. These plans were discussed in detail in our December 22, 2021 compliance filing in Docket No. E002/AA-21-295

Table 2
2025 Real Time Binding Constraints

Constrained Facility Name*	Constraint Name	Contingency Description	State	Hours
[PROTECTED DATA BEGINS				

PROTECTED DATA ENDS]

*Table 2 shows the hours that a specific transmission facility was impacted by multiple binding constraints. For example, The Murphy Creek – Hayward 161 kV line was impacted by ten (10) separate constraints for a total of 861 hours.

Constrained Facility Name	Constraint Name	Contingency Description	State	Hours
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Constrained Facility Name	Constraint Name	Contingency Description	State	Hours
[PROTECTED DATA BEGINS				

PROTECTED DATA ENDS]

Constrained Facility Name	Constraint Name	Contingency Description	State	Hours
[PROTECTED DATA BEGINS				

PROTECTED DATA ENDS]

Constrained Facility Name	Constraint Name	Contingency Description	State	Hours
[PROTECTED DATA BEGINS				

PROTECTED DATA ENDS]

Table 3 lists the transmission outages that negatively impacted regional or localized RTBCs and contributed to the curtailment. The outages, which were both planned and unplanned, were required to support area road construction, to allow maintenance or repair activities, to allow upgrades to existing transmission facilities or construction of new regional transmission facilities and supported new generator interconnections.

Table 3
2025 Transmission Outages

REQUEST ID	COMPANY	KV	FROM_STATION	TO_STATION	Start	End
1-27550549	GRE, NSP	345	WILMART 8S24 BRKR		12/22/2024	1/27/2025
1-27622093	GRE, NSP	345	CRANDAL	WILMART	3/2/2025	3/7/2025
1-27556019	GRE, NSP	345	CHUB_LK	HELENAMN	3/31/2025	4/4/2025
1-27678554	GRE, NSP	345	WILMART 8S24 BRKR		4/22/2025	5/1/2025
1-27705309	GRE, NSP	345	CRANDAL	WILMART	5/16/2025	5/19/2025
1-27230919	GRE, NSP	345	CHUB_LK	HELENAMN	5/19/2025	9/18/2025
1-26988772	MDU	230	MERRICRT	WISHEK	5/19/2025	7/2/2025
1-27646528	ITC_MW, NSP	345	LKFLNSP	LAKEFLD	5/27/2025	5/30/2025
1-27714169	GRE, NSP	345	HELENAMN	HAMPTNSP	5/31/2025	7/13/2025
1-27646521	NSP	345	CRANDAL	LKFLNSP	6/1/2025	6/6/2025
1-27637715	GRE, NSP	345	HELENAMN	SHEASLK	6/4/2025	6/18/2025
1-27695523	NSP	115	BUFFRID	YANKEE	6/9/2025	6/16/2025
1-27379922	NSP	115	BUFFRID	PIPESTN	6/16/2025	8/8/2025
1-27695529	NSP	115	BUFFRID	YANKEE	6/16/2025	7/18/2025

REQUEST ID	COMPANY	KV	FROM_STATION	TO_STATION	Start	End
1-27230957	GRE, NSP	345	CHUB_LK	HAMPTNSP	6/30/2025	9/3/2025
1-27623680	NSP	345/115	BRKNGCO TR10		7/7/2025	7/22/2025
1-27714169	GRE, NSP	345	HELENAMN	HAMPTNSP	7/13/2025	9/6/2025
1-27753984	MDU	230	MERRICRT	WISHEK	7/21/2025	12/17/2025
1-27747868	GRE, NSP	345	HELENAMN	SHEASLK	8/4/2025	8/15/2025
1-27730734	NSP	115	LKYNKTN	BUFFRID	8/4/2025	8/8/2025
1-27781280	NSP	345	CRANDAL	LKFLNSP	8/25/2025	9/12/2025
1-27714169	GRE, NSP	345	HELENAMN	HAMPTNSP	9/6/2025	9/22/2025
1-27184302	GRE, NSP	345	SHERCO	BENTON3	9/30/2025	10/14/2025
1-27184302	GRE, NSP	345	SHERCO	BENTON3	10/14/2025	12/18/2025
1-27793356	NSP	115	PIPESTN	SPLIT_R	11/3/2025	11/18/2025

The amount of wind generation interconnected to the transmission system has a significant impact on congestion and curtailment – especially if it is placed in-service prior to the completion of the necessary transmission upgrades. The Company is aware of 2,319 MW of wind generating projects in Minnesota, North Dakota, South Dakota, and Iowa that have gone into service since 2024, or that may go into service in the next few years. The wind generation is shown in Table 4. All of these wind projects will be registered and operated as DIRs.

Table 4
Wind Generation In-service and Planned

Company	MW	Location	In-Service Dates
Alliant Energy	550	IA	2027-2028
Great River Energy	1,159	MN/ND	2026-2028
Minnesota Municipal Power Agency	160	MN	2027
Minnesota Power	200	MN	2027
Other	250	ND	2026
Total	2,319		

The required transmission upgrades for the planned wind projects may not all be in-service at the time the projects begin producing energy. In addition, a number of the projects are using surplus interconnection service at existing generating facilities which means they will not be required to install additional transmission facilities. These projects will impact real-time wind generation on the NSP System.

III. TRANSMISSION SYSTEM IMPROVEMENTS

Since 1994, wind energy resources have been the dominant factor in determining the need for transmission infrastructure improvements in southwestern Minnesota. To meet this need, the Company, often in cooperation with other utilities, has planned, engineered, and constructed a number of projects designed to increase the transmission capacity in that area. Table 5 lists historic southwest Minnesota projects that were developed by the Company.

Table 5
Southwest Minnesota Wind Projects

Transmission Project	Transmission Owner	In-Service Date
425 MW Wind Transmission Expansion Project	Xcel Energy	December 2006
825 MW Wind Transmission Expansion Project	Xcel Energy	June 2008
Buffalo Ridge Incremental Generation Outlet (BRIGO)	Xcel Energy	December 2009

Table 6 lists the CapX2020 transmission projects that were developed by the Company and other area utilizes which have provided additional transmission capacity on the Minnesota transmission system.

Table 6
CapX2020 Transmission Projects

Transmission Project	Transmission Owner	In-Service Date
Brookings County - Southeast Twin Cities 345 kV Line	Xcel Energy, Great River Energy	March 26, 2015
Fargo North Dakota - Northwest Twin Cities 345 kV Line	Xcel Energy, Great River Energy	April 2, 2015
Southeast Twin Cities - La Crosse, Wisconsin 345 kV Line	Xcel Energy, SMMPA and non-MISO	September 16, 2016

Table 7 lists the MISO Multi-Value Projects (MVP) that were developed by the Company and other area utilities. The MVPs were constructed to expand and enhance the region's transmission system, reduce congestion, provide access to affordable energy sources, and meet public policy requirements including renewable energy mandates.

Table 7
MVP Projects

Transmission Project	Transmission Owner	In-Service Date
Big Stone South to Brookings County 345 kV Line	Otter Tail Power Company, Xcel Energy	September 8, 2017
Lakefield Jct. - Winnebago - Winco - Kossuth County & Obrien County - Kossuth County - Webster 345 kV Line	MidAmerica Energy, ITC Midwest	September 27, 2018
North La Crosse - North Madison	American Transmission Company, Xcel Energy	December 12, 2018
Winco to Hazleton 345 kV Line	MidAmerica Energy, ITC Midwest	July 18, 2019
Ellendale to Big Stone South 345 kV Line	Otter Tail Power Company, Montana Dakota Utilities	February 5, 2019
Cardinal - Hickory Creek 345 kV Line	American Transmission Company, ITC Midwest	September 27, 2024

Table 8 lists other projects that that were, or are being, developed by the Company and other area utilities that were specifically designed to reduce congestion and curtailment. The Huntley – Wilmarth 345 kV line was constructed as a Market Efficiency Project (MEP) under the MISO MTEP process.

Table 8
Other Transmission Projects

Transmission Project	Transmission Owner	Planned/Actual In-Service Date
Huntley – Wilmarth 345 kV line	Xcel Energy, ITC Midwest	December 1, 2021
Brookings County – Lyon County 345 kV line second circuit	Grid North Partners	September 23, 2024
Helena – Chub Lake – Hampton Corner 345 kV line second circuit	Grid North Partners	Summer/Fall 2025
Installation of a new Forman 230/115 kV transformer	Otter Tail Power Company/ Xcel Energy	September 15, 2025

MISO has approved the LRTP Tranche 1 and LRTP Tranche 2.1 projects which are designed to expand and enhance the region's transmission system, reduce congestion, provide access to affordable energy sources, and meet public policy requirements including renewable energy mandates. Tables 9 and 10 list the LRTP Tranche 1 and

LRTP Tranche 2.1 projects, both of which will have a positive impact on the Minnesota transmission system including curtailment.

Table 9
LRTP Tranche 1 Projects

Transmission Project	Transmission Owners	Planned In-Service Date
Jamestown – Ellendale 345 kV	MDU, OTP	2028
Big Stone South - Alexandria – Big Oaks 345 kV	Minnesota Power, Great River Energy, Otter Tail Power, Missouri River Energy Services	2030
Iron Range - Benton County –Big Oaks 345 kV	Minnesota Power, Great River Energy	2030
Wilmarth - North Rochester – Tremval 345 kV	ATC, Dairyland Power, Xcel Energy	2028
Tremval - Eau Claire - Jump River 345 kV	ATC, Xcel Energy	2028
Tremval - Rocky Run – Columbia 345 kV	ATC, Xcel Energy	2029

Table 10
LRTP Tranche 2.1 Projects

Transmission Project	Transmission Owners	Planned In-Service Date
Bison – Alexandria 345 kV	Minnesota Power, Great River Energy, Otter Tail Power, Missouri River Energy Services, Xcel Energy	2032
Maple River – Cuyuna 345 kV	Great River Energy, Otter Tail Power, Minnesota Power	2033
Iron Range – Arrowhead 345 kV	Minnesota Power, Alliant Energy	2032
Big Stone South – Brookings County – Lakefield Junction. 765 kV	Xcel Energy, Otter Tail Power, ITC Midwest	2034
Lakefield Junction – East Adair 765 kV	ITC Midwest, MidAmerican Energy Company	2034
Lakefield Junction – Pleasant Valley – North Rochester 765 kV	Xcel Energy, Great River Energy, ITC Midwest	2034
Pleasant Valley – North Rochester – Hampton Corner 345 kV	Xcel Energy, Dairyland Power, Rochester Public Utilities, Southwest Minnesota Municipal Power Agency	2032

Transmission Project	Transmission Owners	Planned In-Service Date
North Rochester – Columbia 765 kV	Xcel Energy, Dairyland Power, American Transmission Company	2034

IV. WIND GENERATION AND CURTAILMENT

Chart 1 shows planned and installed Company-owned and PPA wind generation facilities throughout the NSP service territory on an incremental and cumulative basis.

Chart 1

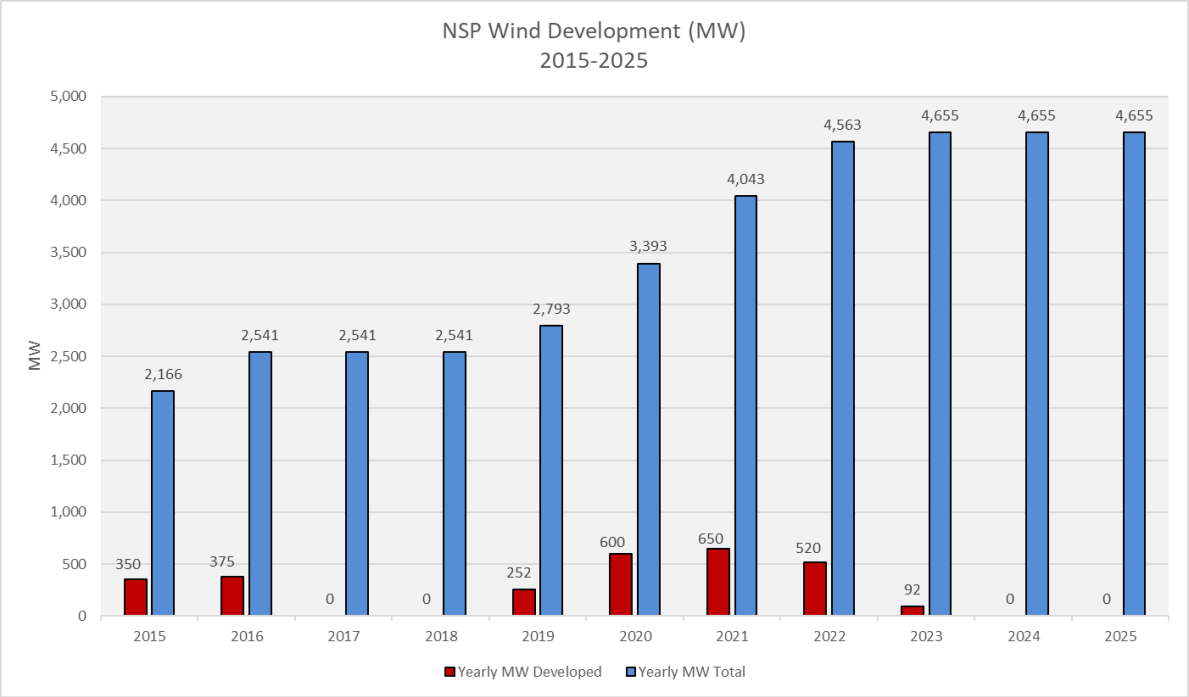


Chart 2 shows the comparison between total wind energy produced and the wind energy curtailed from the projects for 2025.[5] Chart 2 shows that wind curtailment is small compared to the total wind generation delivered. Chart 3 provides similar data for Company-owned wind facilities, as requested by the Department of Commerce in Information Request No. DOC-15 in Docket No. E002/AA-22-179.

Wind curtailment, as a tool to manage wind generation volumes when necessary, has had the positive benefit of facilitating a large amount of wind resources to be added to the system, which may not otherwise have been possible.

[5] Part C, Attachment 2.

Chart 2

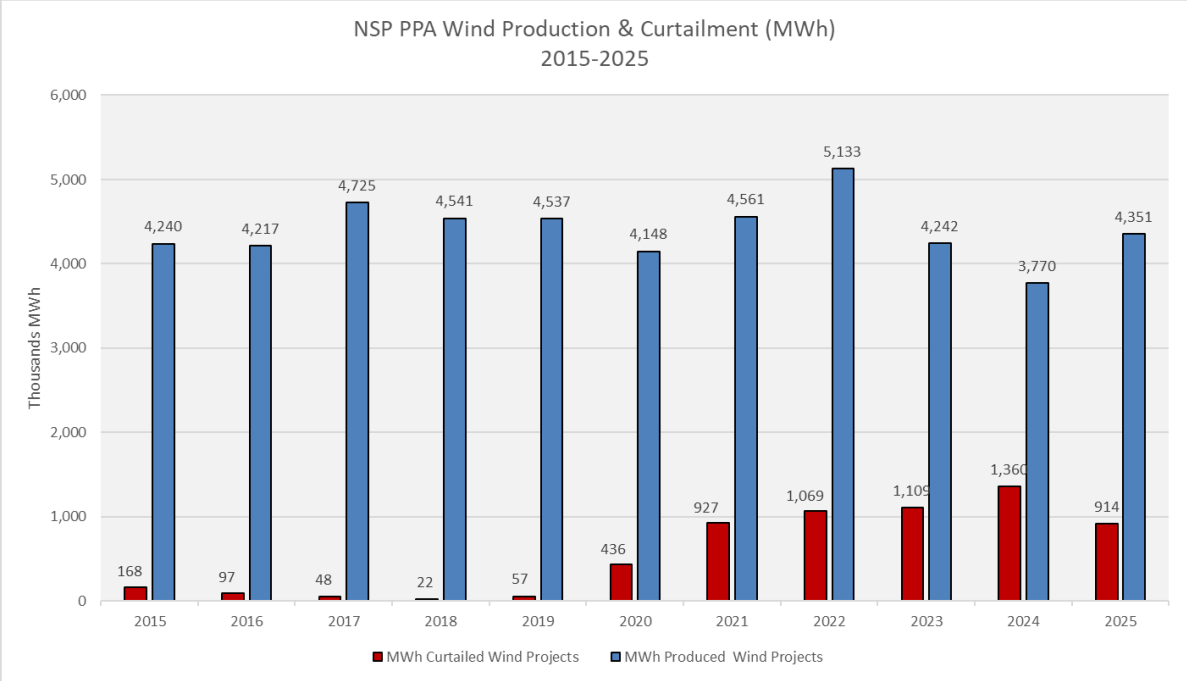
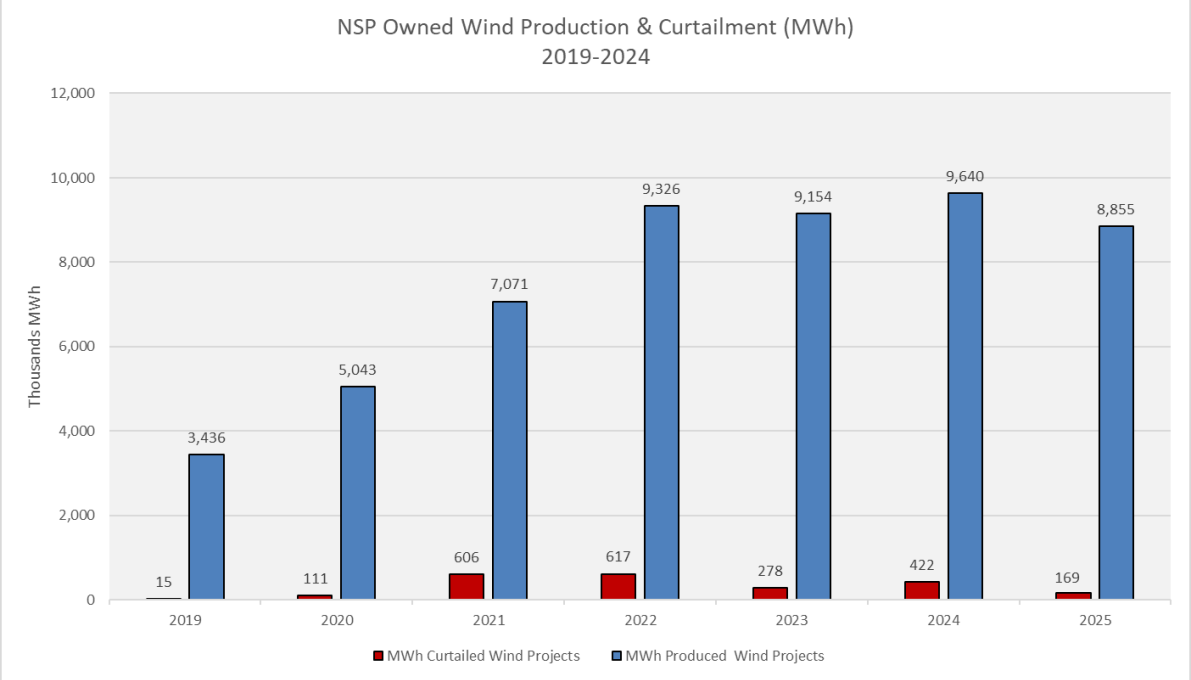


Chart 3



The 2025 PPA Wind Curtailment in summarized in Table 11.

Table 11
2025 PPA Wind Curtailment MWh and Costs

	MWh	Costs
Curtailment	913,981	$37,704,245

It is important to note that of the $34,453,068 in total curtailment costs, the vast majority of these costs are associated with the contractual energy price of the PPAs. These are contractually obligated sunk costs which are not economically relevant to the decision to curtail the generation from a wind facility.[6]

1. Curtailment Mitigation Efforts

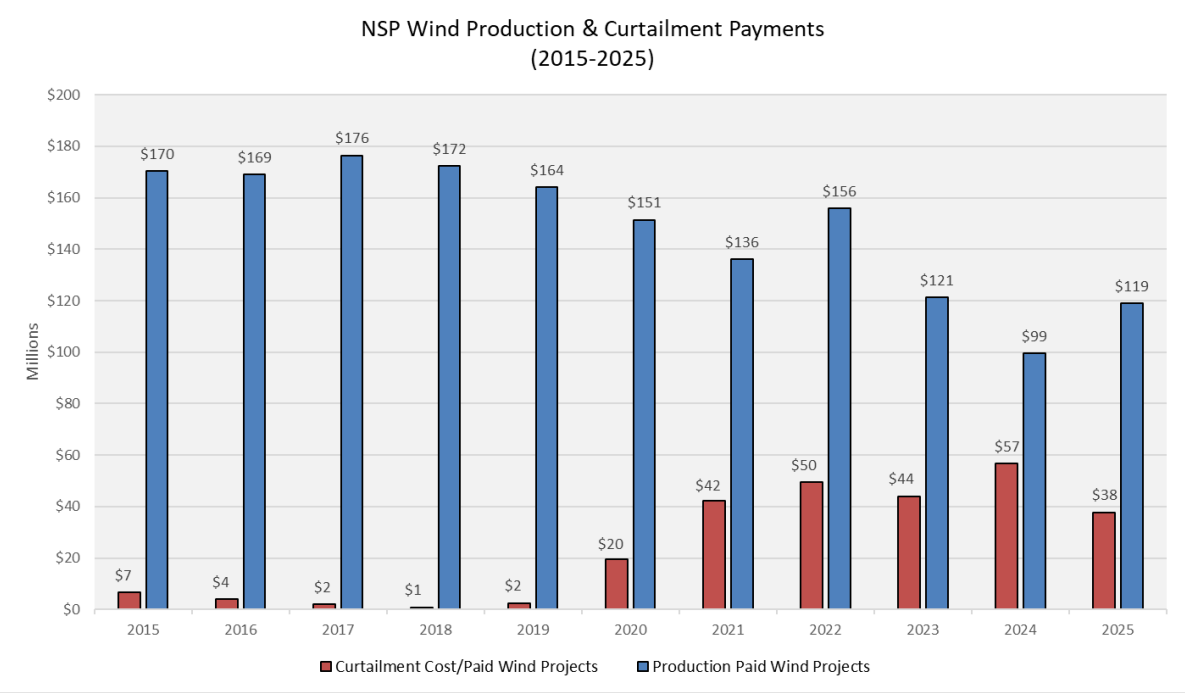
The Company has been working to schedule transmission outages to minimize curtailment for a number of years – performing multiple outages at the same time and scheduling these activities during times when wind is normally at its lowest levels – typically the summer months in the NSP service territory. While Xcel Energy attempts to plan outage work with this principle in mind, this is not always possible. Summer months are also high load months and transmission outages may not be possible due to load serving needs.

V. WIND PRODUCTION AND CURTAILMENT PAYMENTS

Chart 4 shows the corresponding production and curtailment costs for 2015 through 2025.[7] As with wind generation produced and curtailed, paid curtailment is a small portion of total cost of wind generation on the system.

[6] The PPA contract language can generally be described as "take or pay" in which NSP must pay for the wind energy that could be produced, regardless of whether it is actually produced or if it is curtailed.
[7] The data for 2023-2025 is shown in Part C, Attachment 2.

Chart 4



In the past, the Company provided estimates of future potential curtailment payment estimates in the AAA Report. However, these estimates are now provided in our Annual Fuel Forecast Petitions filed on May 1.

VI. ADDITIONAL COMPLIANCE ITEMS RELATED TO CURTAILMENT

As noted above, Part C, Attachment 2 shows detailed curtailment payments by unit and by curtailment code, in compliance with the Commission's February 6, 2008 Order in Docket Nos. E,G999/AA-06-1208 and E002/M-04-1970 *et al.* We provide curtailed MWh for Company owned wind facilities in Attachment 2a.

In compliance with Order Point 5 of the Commission's November 9, 2023 Order in Docket No. E002/AA-23-153, we provide detail about assumed versus actual wind capacity factors with and without curtailment for the Company's owned wind facilities in Attachment 2b.

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Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - 2025 Total

Docket No. E002/AA-24-63
True-Up Report
Part C, Attachment 2

	Date Paid		Wind Production Delivered		Lost Production		
Production Month	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Total Xcel Energy Paid
Jan-23			393,539.81	11,685,951.91	31,307.96	1,193,237.63	$ 12,879,189.54
Feb-23			457,372.21	12,714,269.78	105,822.35	4,515,463.23	$ 17,229,733.01
Mar-23			401,518.34	11,177,949.13	126,969.66	5,145,929.23	$ 16,323,878.36
Apr-23			401,450.67	11,239,143.01	233,339.64	8,885,901.35	$ 20,125,044.36
May-23			356,283.30	10,473,135.98	107,749.67	4,332,169.82	$ 14,805,305.80
Jun-23			229,902.24	6,547,246.80	25,986.97	1,131,588.32	$ 7,678,835.12
Jul-23			227,960.97	5,997,173.58	14,721.14	620,226.20	$ 6,617,399.78
Aug-23			301,707.75	8,590,910.10	40,692.28	1,443,504.63	$ 10,034,414.73
Sep-23			292,808.25	8,774,907.11	50,288.45	1,817,959.89	$ 10,592,867.00
Oct-23			349,930.24	10,155,505.00	157,767.04	6,422,597.84	$ 16,578,102.84
Nov-23			406,121.36	11,715,734.21	141,409.42	5,708,258.93	$ 17,423,993.14
Dec-23			423,265.51	12,255,617.97	72,952.92	2,819,767.57	$ 15,075,385.54
Total-23			4,241,860.65	$ 121,327,544.58	1,109,007.47	$ 44,036,604.64	$ 165,364,149.22
Jan-24			383,644.55	11,108,778.02	47,795.53	2,254,689.27	$ 13,363,467.29
Feb-24			384,473.64	10,793,881.34	113,601.92	4,876,651.16	$ 15,670,532.50
Mar-24			437,376.69	12,586,350.20	155,102.91	6,430,104.06	$ 19,016,454.26
Apr-24			415,747.68	11,444,758.63	254,803.14	10,754,594.43	$ 22,199,353.06
May-24			369,513.96	10,183,267.83	114,534.36	4,740,964.90	$ 14,924,232.73
Jun-24			338,987.62	9,448,978.75	77,713.51	3,249,051.12	$ 12,698,029.87
Jul-24			230,601.03	6,585,254.14	26,487.60	997,192.36	$ 7,582,446.50
Aug-24			284,339.87	7,831,133.08	49,436.60	1,932,488.10	$ 9,763,621.18
Sep-24			308,802.80	9,033,604.76	175,558.60	7,252,089.06	$ 16,285,693.82
Oct-24			409,599.24	11,455,676.63	154,204.55	6,210,591.33	$ 17,666,267.96
Nov-24			369,971.25	10,251,884.60	123,166.40	5,218,216.92	$ 15,470,101.52
Dec-24			402,308.10	11,405,907.28	67,560.81	2,693,304.33	$ 14,099,211.61
Total-24			4,335,366.42	$ 122,129,475.26	1,359,965.93	$ 56,609,937.04	$ 178,739,412.30
Jan-25			511,083.39	13,957,468.84	105,925.11	4,535,580.86	$ 18,493,049.70
Feb-25			438,766.46	13,009,419.20	47,160.92	1,858,950.27	$ 14,868,369.47
Mar-25			486,592.56	14,094,751.09	113,274.29	4,795,007.62	$ 18,889,758.71
Apr-25			441,292.17	12,533,364.53	147,644.55	6,075,050.80	$ 18,608,415.33
May-25			362,828.25	10,113,454.30	80,451.59	3,299,008.27	$ 13,412,462.57
Jun-25			311,641.28	9,081,551.52	67,711.20	2,773,339.01	$ 11,854,890.53
Jul-25			277,500.55	8,054,700.24	13,798.91	504,046.34	$ 8,558,746.58
Aug-25			261,423.38	7,472,365.44	13,580.12	560,298.43	$ 8,032,663.87
Sep-25			277,484.22	7,857,014.13	48,152.45	1,919,307.20	$ 9,776,321.33
Oct-25			475,698.79	13,844,979.15	115,546.60	4,615,905.04	$ 18,460,884.19
Nov-25			402,117.35	12,174,747.20	85,401.58	3,516,574.38	$ 15,691,321.58
Dec-25			486,975.73	15,276,143.72	75,333.30	3,251,176.94	$ 18,527,320.66
Total-25			4,733,404.11	$ 137,469,959.36	913,980.60	$ 37,704,245.16	$ 175,174,204.52

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 3 (MISO)

Production Month	Date Paid		Wind Production Delivered		Lost Production		Total Xcel Energy Paid
	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	
Jan-23			300,505.52	7,621,749.84	31,307.96	1,193,237.63	$ 8,814,987.47
Feb-23			422,223.84	10,826,162.18	105,822.35	4,515,463.23	$ 15,341,625.41
Mar-23			369,946.99	9,401,623.12	126,969.66	5,145,929.23	$ 14,547,552.35
Apr-23			363,859.87	9,149,165.33	233,339.64	8,885,901.35	$ 18,035,066.68
May-23			307,407.89	8,291,640.27	107,749.67	4,332,169.82	$ 12,623,810.09
Jun-23			205,105.68	5,435,189.30	25,986.97	1,131,588.32	$ 6,566,777.62
Jul-23			178,833.06	4,648,049.48	14,721.14	620,226.20	$ 5,268,275.68
Aug-23			268,723.55	7,159,598.34	40,692.28	1,443,504.63	$ 8,603,102.97
Sep-23			257,892.62	7,291,080.65	50,288.45	1,817,959.89	$ 9,109,040.54
Oct-23			321,211.47	8,591,181.45	157,767.04	6,422,597.84	$ 15,013,779.29
Nov-23			374,994.07	10,034,452.42	141,409.42	5,708,258.93	$ 15,742,711.35
Dec-23			351,691.40	10,153,037.71	72,952.92	2,819,767.57	$ 12,972,805.28
Total-23			3,722,395.95	$ 98,602,930.09	1,109,007.47	$ 44,036,604.64	$ 142,639,534.73
Jan-24			358,885.38	9,870,717.08	47,795.53	2,254,689.27	$ 12,125,406.35
Feb-24			295,642.22	8,070,136.35	113,601.92	4,876,651.16	$ 12,946,787.51
Mar-24			326,546.19	9,105,916.09	155,102.91	6,430,104.06	$ 15,536,020.15
Apr-24			383,385.78	9,727,944.33	254,803.14	10,754,594.43	$ 20,482,538.76
May-24			344,243.04	8,848,454.37	114,534.36	4,740,964.90	$ 13,589,419.27
Jun-24			299,562.25	7,799,661.84	77,713.51	3,249,051.12	$ 11,048,712.96
Jul-24			203,240.57	5,439,568.57	26,487.60	997,192.36	$ 6,436,760.93
Aug-24			247,872.70	6,343,095.70	49,436.60	1,932,488.10	$ 8,275,583.80
Sep-24			260,518.10	6,987,923.71	175,558.60	7,252,089.06	$ 14,240,012.77
Oct-24			350,578.51	9,006,617.41	154,204.55	6,210,591.33	$ 15,217,208.74
Nov-24			323,761.40	8,217,332.95	123,166.40	5,218,216.92	$ 13,435,549.87
Dec-24			375,638.80	10,047,540.84	67,560.81	2,693,304.33	$ 12,740,845.17
Total-24			3,769,874.94	$ 99,464,909.24	1,359,965.93	$ 56,609,937.04	$ 156,074,846.28
Jan-25			449,454.00	11,425,359.36	105,925.11	4,535,580.86	$ 15,960,940.22
Feb-25			413,174.96	11,617,764.12	47,160.92	1,858,950.27	$ 13,476,714.39
Mar-25			453,445.60	12,298,363.06	113,274.29	4,795,007.62	$ 17,093,370.68
Apr-25			383,170.23	10,032,261.10	147,644.55	6,075,050.80	$ 16,107,311.90
May-25			340,158.49	8,863,749.84	80,451.59	3,299,008.27	$ 12,162,758.11
Jun-25			280,591.83	7,737,872.04	67,711.20	2,773,339.01	$ 10,511,211.05
Jul-25			257,739.59	7,143,255.08	13,798.91	504,046.34	$ 7,647,301.42
Aug-25			241,335.01	6,556,698.66	13,580.12	560,298.43	$ 7,116,997.09
Sep-25			248,891.40	6,621,664.41	48,152.45	1,919,307.20	$ 8,540,971.61
Oct-25			446,492.14	12,231,872.14	115,546.60	4,615,905.04	$ 16,847,777.18
Nov-25			376,642.12	10,735,148.64	85,401.58	3,516,574.38	$ 14,251,723.02
Dec-25			460,354.10	13,815,492.29	75,333.30	3,251,176.94	$ 17,066,669.23
Total-25			4,351,449.46	$ 119,079,500.74	913,980.60	$ 37,704,245.16	$ 156,783,745.90