2023 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 2023 reporting year as compared to the 2023 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 2024 curtailment forecast in our May 1, 2023 Petition and July 31, 2023 Reply Comments in Docket No. E002/AA-23-153. We will provide an estimate of 2025 curtailment payments, including forecast assumptions, in our 2025 fuel forecast Petition to be filed by May 1, 2024.

II. CURTAILMENT OVERVIEW

The Company again expects that some level of wind curtailment from Power Purchase Agreement (PPA) facilities will occur in the foreseeable future. The reasons driving the curtailment have shifted from primarily local transmission constraints on NSP's transmission system in southwest Minnesota to regional transmission system congestion on the MISO system. The regional congestion, which results in negative LMP, was again the largest driver of curtailment during this reporting period. Additionally, the nature of transmission congestion is accentuated by the large concentration and increased level of wind facility operations in Minnesota, North Dakota, South Dakota, and Iowa.

Significant transmission improvements in southwestern Minnesota and the region, such as the CapX2020 transmission projects (CapX2020), the Huntley – Wilmarth 345 kV line, and all but one of the MISO Multi-Value Projects (MVPs)[1] are now in-service and will positively impact curtailment by reducing local and regional congestion.

The Grid North Partners,[2] which includes the Company and other area utilities, are moving forward on transmission improvement projects[3] that have or will go into service in the next couple of years that are specifically designed to reduce congestion and curtailment. However, the Company still believes curtailment in this area will continue to occur because of more regional congestion and the resulting negative LMP in the MISO energy market, along with transmission outages required for construction, maintenance or repair activities and wind generation projects going into service before all required transmission facilities are completed and likely generation oversubscription of the transmission system.

MISO has approved the Long-Range Transmission Planning (LRTP) Tranche 1 projects which were 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. The LRTP Tranche 1 projects projected in-service dates of 2029-2030.

To better manage regional congestion, MISO and the industry utilize 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.

[1] The owners of the Cardinal – Hickory Creek 345 kV line, which is the last MVP under construction, expect that the line will be completed and placed in service by June 2024. https://www.cardinal-hickorycreek.com/joint-news-release-eastern-half-of-cardinal-hickory-creek-transmission-line-energized/
[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/

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

The federal Production Tax Credit (PTC), which provides tax benefits to wind generating plants, is connected with increases in wind curtailment, since wind projects are often put into service to meet PTC eligibility requirements even though the necessary transmission upgrades were not completed. The Company is aware of 7,150 MW of new wind generation in Minnesota, North Dakota, South Dakota, and Iowa that have recently gone into service, or are expected to go into service in the next couple years. This includes 2,025 MW of Company-owned and PPA wind. Table 2 shows planned wind developments by NSP and other regional companies. All of these wind developments will be registered and operated as DIRs.

Table 2
Wind Generation Additions[4]

Company	MW	Location	In-Service Dates
Alliant Energy	1,150	IA	2019-2021
Great River Energy	1448	ND	2020-2025
MidAmerican[5]	2,216	IA	2019-2021
Minnesota Municipal Power Agency	111	MN	2021
Minnesota Power	250	MN	2020
Northern States Power	2,026	ND, SD, MN	2019-2022
Otter Tail Power	150	ND	2020
Total	7,351		

The required transmission upgrades for these wind projects will not all be in-service at the time the projects begin producing energy. A number of transmission facilities that were identified in the interconnection studies as overloaded, along with MTEP related transmission facilities were, or will be, taken out of service and rebuilt. This has, and will continue to have, a negative effect on LMP pricing in the MISO energy market and will continue to 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 3 shows historic southwest Minnesota projects that increased the available transmission outlet in that area.

[4] The wind repowering projects being developed by NSP are not included in this list.
[5] MidAmerican has proposed a renewable energy development project called Wind Prime which would add 2,042 MW of new wind generation in Iowa. It is unclear at this time when the projects will go into service.

Table 3
Southwest Minnesota Wind Limits

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

The Company also participated in the development of three CapX2020 transmission projects, all of which have gone into service and are helping reduce wind curtailment on the NSP system. Table 4 lists the CapX2020 transmission projects.

Table 4
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

In addition to the transmission projects discussed above, a number of other new transmission infrastructure projects have been placed in service, including the Huntley – Wilmarth 345 kV line, and all but one of the Multi-Value Projects (MVP). The Cardinal – Hickory Creek 345 kV Line will be the last MVP to go into service with an expected in-service date of June 2024.[6] The Huntley – Wilmarth line, which went into service on December 1, 2021, was classified as a Market Efficiency Project (MEP) under the MTEP process and was installed to improve congestion. The MVPs were 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. The completion of the MVP projects, particularly the ones listed in Table 5, have had, or will have, a positive impact on Company-owned and PPA wind facilities.

[6] The Cardinal - Hickory Creek 345 kV MVP line is scheduled to go into service in June 2024.[7] Part C, Attachment 2.

Table 5
MVP Projects

Transmission Project	Transmission Owner	Planned/Actual 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	June 2024

One of the design goals for the North La Crosse – North Madison and Cardinal – Hickory Creek 345 kV Lines was to increase the transmission export capacity from Iowa and Minnesota into the 345 kV system in Wisconsin that connects to the Milwaukee and Illinois load centers.

The Grid North Partners have identified nineteen (19) transmission upgrades, which when they go into service in the next two years, will provide positive benefits for congestion and curtailment. The upgrades include installing second circuits on the Brookings County – Lyon County and the Helena – Hampton Corner 345 kV lines. In addition, Otter Tail Power Company and Northern States Power Company coordinated an upgrade to Forman Substation which includes installation of a new Forman 230/115 kV transformer with a Fall 2024 in-service date.

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

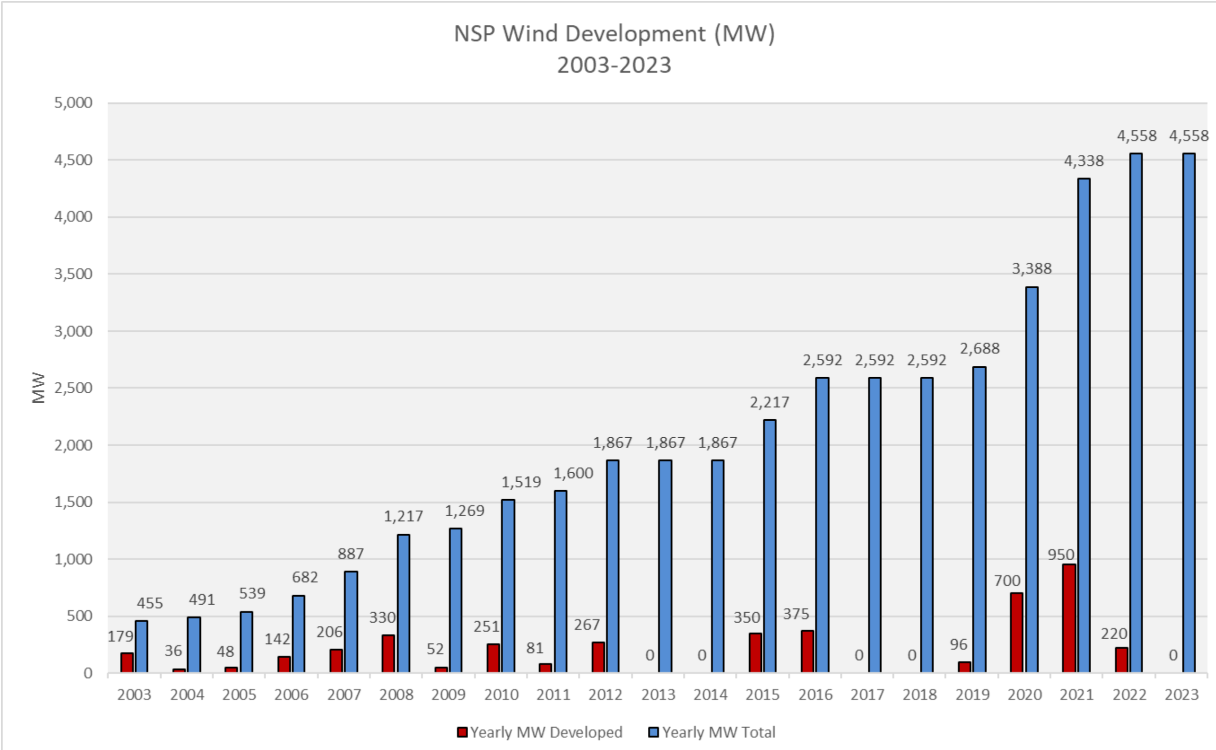
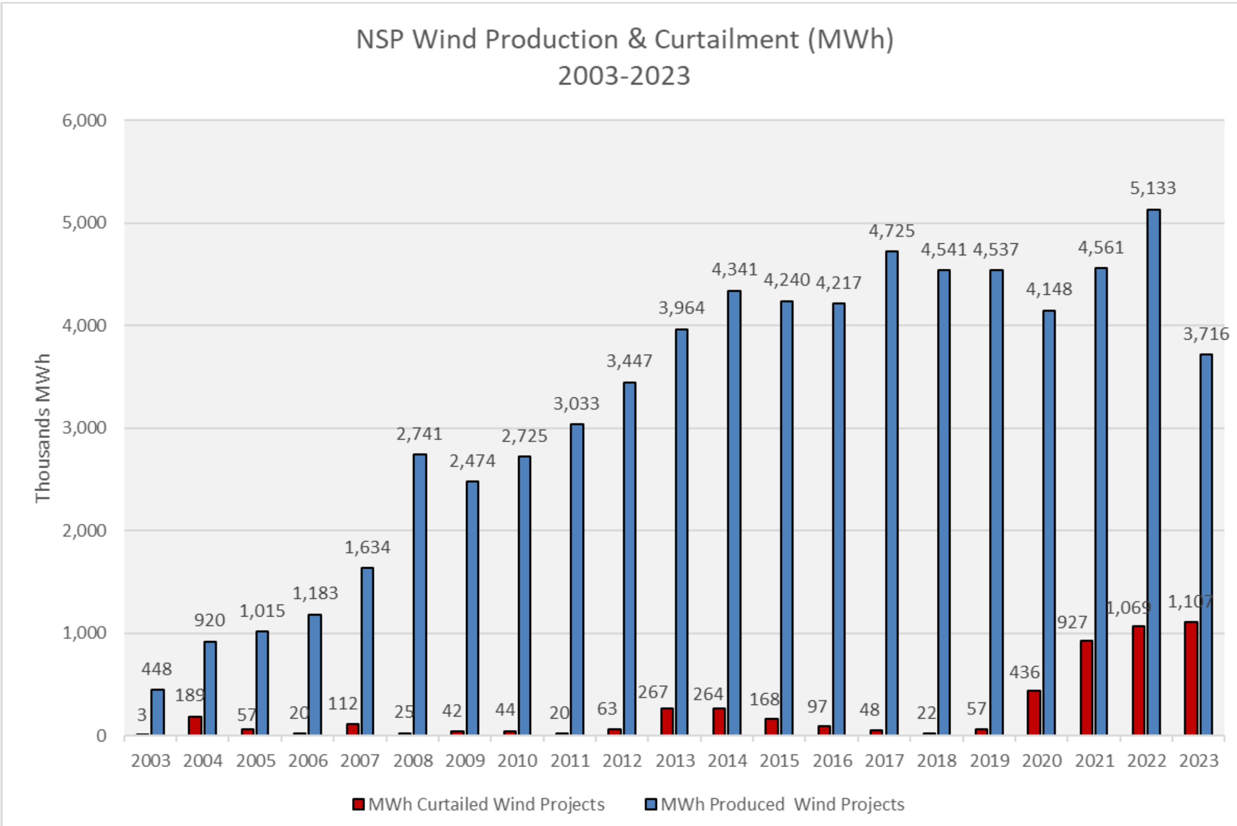


Chart 2 shows the comparison between total wind energy produced and the wind energy curtailed from the projects through December 2023.[7] Despite the lead/lag time associated with generation and transmission development, Chart 2 shows that wind curtailment is small compared to the total wind generation delivered.

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 would not otherwise have been possible.

[7] Part C, Attachment 2.

Chart 2



The 2023 Curtailment in summarized in Table 6.

Table 6
2023 Wind Curtailment MWh and Costs

	MWh	Costs
Curtailment	1,107,395	$43,944,695

It is important to note that of the $43,944,695 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 farm.[8]

The Company typically has broken up curtailment into two categories to better explain the reasons for the curtailment and its cause. The two categories were Transmission Curtailment and DIR Curtailment. Transmission Curtailment was specifically related to situations where local transmission-related outages impacted

[8] 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.

wind projects. DIR Curtailment was considered curtailment that was not caused by local transmission outages, or where transmission outages did not impact a specific wind farm. This breakdown was more informative when the curtailment was primarily related to local transmission constraints on NSP's transmission system in southwest Minnesota. Curtailment identified as Transmission Curtailment has been declining over the past number of years and is currently almost entirely related to regional transmission congestion on the MISO system, Transmission Curtailment costs in this reporting period continue to be relatively small compared to DIR Curtailment, as shown in Table 7 below:

Table 7: 2023 Wind Curtailment Breakdown

Type	Curtailment (MWh)
Economic	1,054,805
Transmission Related	52,590
Total	1,107,395

Compared to the breakdown between these curtailment types, the Company believes that it will be more informative to provide details on the drivers of regional congestion as measured by the Real Time Binding Constraints which are used to manage congestion in the MISO Real Time Market along with a discussion on transmission outages that occurred during the year.

> *Per the MISO website, 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 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. The most frequent real time binding constraints in the NSP area are listed in Table 7.[9]

[9] Area includes Minnesota, North Dakota, South Dakota, Iowa and Wisconsin.

Table 8
2023 Real Time Binding Constraints

Constraint Name	Contingency Description	State	Hours
BASE_FENOCH		MN	874.1
OTP23100_MORRISOT_MORRIGRANT 11_1_1	HANKINSON-WAHPETON 230+WAHPETN TR2	MN	793.0
Forman_230_115_TR1_flo_Hankinson_Wahpeton_230kV	HANKINSON-WAHPETON 230+WAHPETN TR2	ND	681.9
NSP34102_ALMA2_ALMAWABAC16_1_1	BRIGGS ROAD - NORTH ROCHESTER 345	MN	492.2
PVLYGRE_BYRON2_161kV_flo_PVLY NSP_BYRON2_345kV	BYRON-PLEASANT VALLEY 345	MN	377.3
NSP34011_SWAN_LK_SWAN_WILMA11_1_1	HELENA-SHEAS LAKE 345	MN	339.3
NSP34011_MURPHYCR_MURPHHAYWA16_1_1	HELENA-SHEAS LAKE 345	MN	320.2
BASE_CHBGEN		MN	285.4
Ellendal_AberdeenJct_115kV_flo_TwinBrooks_BigSto	TWIN BROOKS - BIG STONE SOUTH 345	ND	281.2
NSP34X15_NOBLES_TR9_TR9	NOBLES 345/115 TR10	MN	280.8
NSP34X28_EAU_CLA_TR9_TR9	EAU CLAIRE 345/161 T10	WI	266.9
Bigston_Brownsvalley_230_FLO_Ellenda_Twinbrooks_	ELLENDALE - TWIN BROOKS 345	SD	243.3
Helena_ScottCounty345Kv_Flo_ChubLake_Helena345Kv	CHUB LAKE-HELENA 345 (0960)	MN	216.7
NSP34011_LIME_CK_LIME_BARTO16_1_1	HELENA-SHEAS LAKE 345	IA	216.1
Watertn_345_230_XF_FTLO_Hawkn_Lk_Lyon_Co_345kV	LYON CO - HAWKS NEST LAKE 345	SD	211.3
Bigstone_BrownsVally_230kV_flo_Oaks_Ellenda_230k	ELLENDALE-OAKES 230	SD	200.9
BASE_BRIGEN		MN	187.4
Adams_BeaverCreek_161kV_flo_BriggsRd_NorthRoches	BRIGGS ROAD - NORTH ROCHESTER 345	MN	156.1
Hampton_BlueLake_345Kv_Flo_ScottCounty_Helena_34	SCOTT CO - HELEN 345	MN	126.4

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.

Table 9 lists the transmission outages that the Company has identified as having the most impact on the area binding constraints and the resulting curtailment. The outages were required for reasons including construction required for regional transmission upgrades and generator interconnection required upgrades along with regular maintenance or repair activities.

Table 9
2023 Significant Transmission Outages

Outage Request ID	Company	KV	From Station	To Station	Actual Start	Actual End	Length (Days)
1-26500578	ATC, NSP	345	EAU_CLA	ARPIN	1/4/2023	3/2/2023	58
1-26846701	MDU, OTP	345	ELLENDL2	TWINBRKS	2/7/2023	2/15/2023	9
1-26889661	NSP, WAUE	345	SPLT_RT	NOBLES	2/24/2023	3/1/2023	6
1-26915352	NSP	115	LKYNKTN	BUFFRID	3/17/2023	3/23/2023	7
1-26815940	OTP	230	FORMAN	HANKSON	5/15/2023	6/21/2023	38
1-26815940	OTP	230	FORMAN	OAKES	5/15/2023	6/21/2023	38
1-27017147	NSP	345/ 115	NOBLES TR9		6/22/2023	8/17/2023	57
1-26992506	NSP, WAUE	345	SPLT_RT	NOBLES	7/31/2023	8/10/2023	11
1-26862828	NSP	115	CHARAMB	FENTON	8/15/2023	9/14/2023	31
1-26657195	NSP	345	EAU_CLA	KING	9/6/2023	10/26/2023	51
1-27034922	NSP	115	CHARAMB	PIPESTN	10/2/2023	10/25/2023	24
1-26958239	OTP	345	DEUELCO	ASTORIA	10/30/2023	11/3/2023	5
1-26958241	OTP	345	BSSOUTH	DEUELCO	11/6/2023	11/7/2023	2
1-26958243	NSP, OTP	345	ASTORIA	BRKNGCO	11/8/2023	11/8/2023	1

Binding Constraints that can be attributed to transmission outages:

- The BASE_FENOCH[10] binding constraint was the result of Split Rock – Nobles 345 kV, Nobles 345/115 kV TR9 and Chanarambie – Fenton 115 kV outages.
- The Alma – Wabaco 161 kV binding constraint was the result of King – Eau Claire 345 kV and the Eau Claire – Arpin 345 kV outages.

[10] FENOCH refers to generation limitations on wind generation interconnected to the Fenton, Nobles and Chanarambie substations.

- The Eau Claire 345/161 kV TR9 binding constraint (NSP34X28_EAU_CLA _TR9_TR9) was the result of the Eau Claire – Arpin 345 kV outage.
- The BASE_CHBGEN[11] and BASE_BRIGEN[12]binding constraint were the result of the Chanarambie – Fenton 115 kV outage.

Binding Constraints that were made worse by transmission outages:

- The Forman 230/115 kV TR1 binding constraint (Forman_230_115_TR1_flo_ Hankinson_Wahpeton_230kV) occurred more often during the Ellendale – Twin Brooks 345 kV outage, however, the constraint also occurred during periods where they were no outages that would directly explain the constraint. The non-outage related constraints were likely related to the oversubscription of the transmission system. Note: Forman 230/115 kV transformer is being upgraded with an expected in-service date of Fall 2024.
- The Ellendale – Aberdeen Jct. biding constraint (Ellendal_AberdeenJct_115kV _flo_TwinBrooks_BigSto) occurred primarily during the Oaks – Forman and Forman – Hankinson 230kV line outages; however, the constraint also occurred during periods where they were no outages that would directly explain the constraint. The non-outage related constraints were likely related to the oversubscription of the transmission system.

Binding Constraints (localized) that cannot be directly attributed to transmission outages:

- The Morris – Grant County 115 kV binding constraint (OTP23100_MORRISOT _MORRIGRANT11_1_1) cannot be directly attributed to any specific outage or outages. The constraint was likely related to combination of factors, including regional generation dispatch, and oversubscription of the transmission system. Note: Morris – Grant County 115 kV is one of the nineteen facilities being upgraded by the Grid North Partners.
- The Nobles 345/115kV TR9 binding constraint (NSP34X15_NOBLES_TR9 _TR9), Big Stone – Browns Valley 230kV (Bigston_Brownsvalley_230_FLO _Ellenda_Twinbrooks), Watertown 345/230 kV TR (Watertn_345_230_XF _FTLO_Hawkn_Lk_Lyon_Co_345kV), and Big Stone – Browns Valley 230kV (Bigstone_BrownsVally_230kV_flo_Oaks_Ellenda_ 230k) are localized

[11] CHBGEN refers to generation limitations on wind generation interconnected to the Chanarambie substation.
[12] BRIGEN refers to generation limitations on wind generation interconnected to the Buffalo Ridge substation.

constraints that cannot be directly attributed to any specific outage or outages. The constraints were likely related to combination of factors including oversubscription of the transmission system in the areas around the project.

Binding Constraints (Regional) that cannot be directly attributed to transmission outages:

- The Pleasant Valley – Byron 161kV (PVLYGRE_BYRON2_161kV_flo_ PVLYNSP_ BYRON2_ 345kV), Swan Lake – Wilmarth (NSP34011_SWAN _LK_SWAN_ WILMA11_1_1), Murphy – Creek – Hayward 161kV (NSP34011_MURPHYCR _MURPHHAYWA16_1_1), Helena – Scott County 345 kV (Helena_ScottCounty 345Kv_Flo_ChubLake_Helena345Kv), Lime Creek – Barton 161 kV (NSP34011_LIME_CK_LIME_BARTO16_1_1), (Adams – Beaver Creek 161 kV (Adams_BeaverCreek_161kV_flo_ BriggsRd_NorthRoches), and Hampton Corner – Blue Lake 345 kV (Hampton_BlueLake_345Kv_Flo_ScottCounty_Helena_34) are regional constraints that cannot be directly attributed to any specific outage or outages. The constraints were likely related to a combination of factors including the relationship between wind and load levels where more curtailment will occur during periods of higher wind and lower load.

3. Curtailment Mitigation Efforts

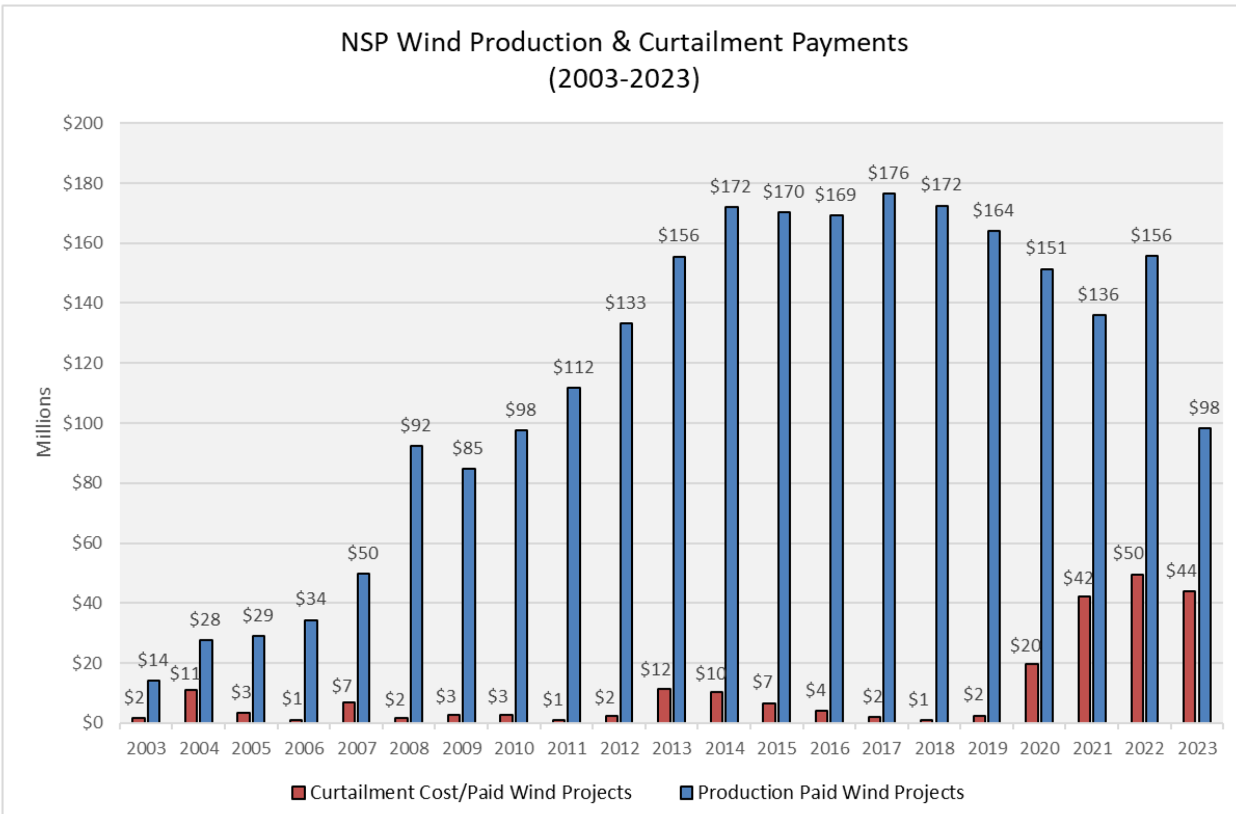
The Company has been working to schedule transmission outages to minimize curtailment for a number of years –performing multiple outages at the same time and scheduling these activities during times when wind is normally at its lowest levels – typically the summer months in the NSP service territory. 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.

The Company has worked to identify binding constraints that are likely to occur going forward and are implementing plans to mitigate these constraints. The mitigation plans will be 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.

V. WIND PRODUCTION AND CURTAILMENT PAYMENTS

Chart 3 shows the corresponding production and curtailment costs for 2003 through 2023.[13] As with wind generation produced and curtailed, paid curtailment is a very small portion of total cost of wind generation on the system.

Chart 3



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, which is filed on May. The Company is projecting future curtailment will occur because of regional congestion and the resulting negative LMP in the MISO energy market, along with transmission outages required for construction, maintenance or repair activities and wind generation projects going into service before all required transmission facilities are completed.

Significant transmission improvements in southwestern Minnesota and the region such as the CapX2020 transmission projects (CapX2020), the Huntley – Wilmarth, Grind North Partner upgrades, and all but one of the MISO Multi-Value Projects

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13 The data for 2021-2023 is shown in Part C, Attachment 2.

(MVPs)[14] are now in-service and will positively impact curtailment by reducing local congestion. However, the Company anticipates that wind generation curtailment and associated payment to vendors will continue to occur over the coming years because of regional congestion and the resulting negative LMP in the MISO energy market, along with transmission outages required for construction, maintenance, or repair activities and wind generation projects going into service before all required transmission facilities are completed and likely generation oversubscription of the transmission system. System conditions and wind project development are very dynamic and actual curtailment may vary from that 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.

The Company continues to utilize initiatives to reduce curtailment. Examples include, where possible, scheduling transmission activities which can impact curtailment during low wind months. The Company is also working to identify binding constraints that are likely to occur going forward and are implementing plans to mitigate these constraints.

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.

[14] The Cardinal - Hickory Creek 345 kV MVP line is scheduled to go into service in June 2024.

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - 2023 Total

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-21			415,276.96	12,790,075.17	55,813.10	2,807,900.43	$ 15,597,975.60
Feb-21			299,731.39	9,077,653.32	33,081.74	1,494,249.98	$ 10,571,903.30
Mar-21			454,702.83	13,823,194.08	102,918.72	4,570,158.12	$ 18,393,352.20
Apr-21			452,040.18	13,764,354.19	95,559.76	4,295,598.08	$ 18,059,952.27
May-21			378,818.38	11,076,185.38	83,722.64	3,810,012.94	$ 14,886,198.32
Jun-21			279,425.87	8,220,002.13	53,729.94	2,451,113.61	$ 10,671,115.74
Jul-21			254,534.12	6,964,756.60	19,170.23	842,853.61	$ 7,807,610.21
Aug-21			334,103.43	9,296,401.87	45,423.20	2,027,854.35	$ 11,324,256.22
Sep-21			365,006.51	10,674,869.41	90,261.00	4,036,330.17	$ 14,711,199.58
Oct-21			374,769.54	10,876,269.01	127,250.80	5,717,621.97	$ 16,593,890.98
Nov-21			475,572.96	14,208,437.64	117,907.39	5,371,503.97	$ 19,579,941.61
Dec-21			477,025.60	15,228,791.71	102,492.38	4,738,764.29	$ 19,967,556.00
Total-21			4,561,007.76	$ 136,000,990.51	927,330.92	$ 42,163,961.52	$ 178,164,952.03
Jan-22			486,114.99	15,421,309.72	133,508.58	6,145,798.49	$ 21,567,108.21
Feb-22			502,705.35	14,769,300.19	108,559.97	4,988,995.72	$ 19,758,295.91
Mar-22			514,652.57	15,019,353.70	92,798.08	4,318,981.66	$ 19,338,335.36
Apr-22			530,699.02	15,996,139.35	214,574.54	9,782,194.55	$ 25,778,333.90
May-22			366,916.47	11,262,896.97	109,890.35	5,166,458.68	$ 16,429,355.65
Jun-22			350,175.92	10,518,548.04	63,910.23	3,115,800.38	$ 13,583,670.96
Jul-22			301,204.95	8,932,747.36	33,917.25	1,645,347.40	$ 10,529,413.05
Aug-22			313,056.66	9,541,612.85	17,553.49	841,351.23	$ 10,382,964.08
Sep-22			363,404.50	11,401,827.49	58,496.79	2,698,650.21	$ 14,100,477.70
Oct-22			456,771.15	13,490,974.69	89,873.45	4,187,674.83	$ 17,678,649.52
Nov-22			520,187.11	15,784,594.96	99,216.95	4,491,208.90	$ 20,275,803.86
Dec-22			429,825.87	13,875,252.48	47,946.35	2,182,658.21	$ 16,057,910.69
Total-22			5,135,714.56	$ 156,014,557.80	1,070,246.02	$ 49,565,120.26	$ 205,480,318.89
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	49,521.10	1,774,220.77	$ 10,549,127.88
Oct-23			349,930.24	10,155,505.00	157,120.66	6,385,763.52	$ 16,541,268.52
Nov-23			406,071.27	11,712,085.22	141,210.53	5,696,922.71	$ 17,409,007.93
Dec-23			423,291.87	12,257,537.96	72,952.92	2,819,767.57	$ 15,077,305.53
Total-23			4,241,836.91	$ 121,325,815.58	1,107,394.86	$ 43,944,694.98	$ 165,270,510.56

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

	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-21			286,239.78	8,608,971.51	55,813.10	2,807,900.43	$ 11,416,871.94
Feb-21			207,036.82	5,238,392.38	33,081.74	1,494,249.98	$ 6,732,642.36
Mar-21			313,731.84	7,958,889.42	102,918.72	4,570,158.12	$ 12,529,047.54
Apr-21			359,879.41	10,295,738.72	95,559.76	4,295,598.08	$ 14,591,336.80
May-21			335,682.76	9,476,493.54	83,722.64	3,810,012.94	$ 13,286,506.48
Jun-21			244,634.08	6,801,152.64	53,729.94	2,451,113.61	$ 9,252,266.25
Jul-21			188,634.61	4,407,043.28	19,170.23	842,853.61	$ 5,249,896.89
Aug-21			279,344.49	7,183,597.10	45,423.20	2,027,854.35	$ 9,211,451.45
Sep-21			317,149.99	8,632,740.85	90,261.00	4,036,330.17	$ 12,669,071.02
Oct-21			322,379.24	8,637,684.25	127,250.80	5,717,621.97	$ 14,355,306.22
Nov-21			409,323.89	11,381,625.18	117,907.39	5,371,503.97	$ 16,753,129.15
Dec-21			413,313.74	12,568,403.16	102,492.38	4,738,764.29	$ 17,307,167.45
Total-21			3,677,350.63	$ 101,190,732.03	927,330.92	$ 42,163,961.52	$ 143,354,693.55
Jan-22			421,262.70	12,660,937.24	133,508.58	6,145,798.49	$ 18,806,735.73
Feb-22			444,805.98	12,491,211.87	108,559.97	4,988,995.72	$ 17,480,207.59
Mar-22			449,872.63	12,203,323.15	92,798.08	4,318,981.66	$ 16,522,304.81
Apr-22			449,668.29	12,480,199.83	214,574.54	9,782,194.55	$ 22,262,394.38
May-22			331,572.70	9,590,629.65	109,890.35	5,166,458.68	$ 14,757,088.33
Jun-22			325,296.09	9,173,049.08	63,910.23	3,115,800.38	$ 12,288,849.46
Jul-22			281,795.31	7,914,911.18	33,917.25	1,645,347.40	$ 9,560,258.58
Aug-22			294,801.09	8,576,613.16	17,553.49	841,351.23	$ 9,417,964.39
Sep-22			330,882.88	9,722,738.22	58,496.79	2,698,650.21	$ 12,421,388.43
Oct-22			422,570.65	11,865,164.82	89,873.45	4,187,674.83	$ 16,052,839.65
Nov-22			403,573.57	10,362,753.12	99,216.95	4,491,208.90	$ 14,853,962.02
Dec-22			398,971.69	12,150,842.70	47,946.35	2,182,658.21	$ 14,333,500.91
Total-22			4,555,073.57	$ 129,192,374.02	1,070,246.02	$ 49,565,120.26	$ 178,757,494.28
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			251,765.26	6,941,821.07	49,521.10	1,774,220.77	$ 8,716,041.84
Oct-23			321,211.47	8,591,181.45	157,120.66	6,385,763.52	$ 14,976,944.97
Nov-23			374,994.07	10,034,452.42	141,210.53	5,696,922.71	$ 15,731,375.13
Dec-23			351,691.40	10,153,037.71	72,952.92	2,819,767.57	$ 12,972,805.28
Total-23			3,716,268.59	$ 98,253,670.51	1,107,394.86	$ 43,944,694.98	$ 142,198,365.49