COMMERCE DEPARTMENT

May 1, 2024 **PUBLIC DOCUMENT**

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

RE: **PUBLIC Comments of the Minnesota Department of Commerce**
Docket No. E999/CI-19-704

Dear Mr. Seuffert:

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

> In the Matter of an Investigation into Self-Commitment and Self-Scheduling of Large Baseload Generation Facilities.

The Department recommends that the Minnesota Public Utilities Commission (Commission) **accept the filings**. The Department is available to answer any questions that the Commission may have in this matter.

Sincerely,

/s/ DR. SYDNIE LIEB
Assistant Commissioner of Regulatory Affairs

SR/ar
Attachment

COMMERCE DEPARTMENT

Before the Minnesota Public Utilities Commission

PUBLIC Comments of the Minnesota Department of Commerce

Docket No. E999/CI-19-704

I. INTRODUCTION

A. PROCEDURAL HISTORY

On November 13, 2019, the Minnesota Public Utilities Commission (Commission) issued its Order Accepting 2017-2018 Electric Reports and Setting Additional Requirements (2019 Order) in Docket No. E999/AA-18-373. In the 2019 Order the Commission included the following Order Points:

> 8. Minnesota Power, Otter Tail, and Xcel shall submit an annual compliance filing analyzing the potential options for seasonal dispatch generally, and potential options and strategies for utilizing "economic" commitments for specific coal-fired generating plants. The utilities shall include a specific explanation of barriers or limitations to each of these potential options, including but not limited to technical limits of the units and contract requirements (shared ownership, steam offtake contracts, minimum fuel supply requirements, [sic] (shared ownership, steam offtake contracts, minimum fuel supply requirements, etc.) as relevant, on March 1, 2020, and each year thereafter.
> 9. The Commission will open an investigation in a separate docket and require Minnesota Power, Otter Tail, and Xcel to report their future self-commitment and self- scheduling analyses using a consistent methodology by including fuel cost and variable O&M costs, matching the offer curve submitted to MISO [Midcontinent Independent System Operator, Inc.] energy markets.
> 10. In the investigation docket, Minnesota Power, Otter Tail, and Xcel shall provide stakeholders with the underlying data (work papers) used to complete their analyses, in a live Excel spread sheet, including, at a minimum, the data points listed below for each generating unit, with the understanding that this may include protected data.

On November 8, 2023, the Commission issued its *Order Accepting Annual Filings and requiring Additional Filing* which accepted as adequate and meeting the filing requirements the March 1, 2023 filings of Northern States Power Company doing business as Xcel Energy (Xcel), Minnesota Power, an operating division of ALLETE, Inc. (Minnesota Power or MP) and Otter Tail Power Company (Otter Tail or OTP) covering January 1, 2022 to December 31, 2022.

On March 1, 2024, OTP, MP, and Xcel made their fifth Annual Compliance filings covering January 1, 2023 to December 31, 2023. Xcel's report provided data regarding Allen S. King Generating Station (King), Monticello Nuclear Generating Station (Monticello), Prairie Island Nuclear Generating Station

(Prairie Island) units 1 and 2; and Sherburne County Generating Station (Sherco) units 1, 2, and 3.[1] Minnesota Power's report provided data regarding Boswell Energy Center (Boswell) units 3 and 4.[2] Otter Tail's report provided data regarding the Big Stone Plant (Big Stone) and Coyote Station (Coyote).[3]

Table 1 below shows the ownership arrangements for Big Stone and Coyote.

Table 1. OTP Unit Ownership Arrangements

Utility	Big Stone Ownership Share	Coyote Ownership Share	ISO Membership
Otter Tail Power Company	53.9%	35.0%	MISO
Montana Dakota Utilities	22.7%	25.0%	MISO
NorthWestern Energy	23.4%	10.0%	SPP
Minnkota Power Cooperative	0.0%	30.0%	MISO

On April 2, 2024, the Commission issued its *Notice of Comment Period* (Notice). The Notice stated that the following topics are open for comment:

- Are the March 1, 2024 filings by the utilities, as updated March 29, 2024 by Xcel Energy, adequate and in compliance with prior Commission orders?
- What conclusions can be drawn from the data filed by the utilities in conjunction with what has been learned earlier in this investigation?
- How should the Commission use the information provided by the utilities in this docket going forward?
- Should the Commission order any further analysis for future reports, or any additional reports by the utilities?
- Are there other issues or concerns related to this matter?

Below are the comments of the Minnesota Department of Commerce (Department) regarding the issues specified in the Notice.

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[1] Regarding Sherco unit 3, Southern Minnesota Municipal Power Agency (SMMPA) owns 41 percent and Xcel owns the remainder. SMMPA serves 18 municipal electric utilities in Minnesota.
[2] Regarding Boswell unit 4, WPPI Energy owns 20 percent and Minnesota Power owns the remainder. WPPI Energy serves 51 cooperative and municipal electric utilities.
[3] Note that NorthWestern Energy provides electric and/or natural gas services to 349 cities in the western two-thirds of Montana, eastern South Dakota and central Nebraska. Montana-Dakota Utilities is a subsidiary of MDU Resources Group, Inc., a company providing retail natural gas and/or electric service to parts of Montana, North Dakota, South Dakota and Wyoming. Minnkota Power Cooperative serves as operating agent for the Northern Municipal Power Agency; Northern Municipal Power Agency actually owns the share of Coyote and serves 12 municipal electric utilities in eastern North Dakota and northwestern Minnesota.

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B. MISO MARKET BACKGROUND

1. Capacity Market Operations

For purposes of this proceeding there are two stages to MISO's market construct. The first stage is the Planning Resource Auction (PRA), an annual capacity auction. According to MISO, the PRA is a way for market participants to meet resource adequacy (capacity) requirements. Resources that either clear the annual PRA—stage 1 of MISO's market—must be offered into MISO's energy market, which is stage 2 of the market process. This must-offer requirement does not allow utilities to de-commit. In other words, once a unit is cleared in the PRA, the utility cannot make a unit unavailable to MISO for dispatch, on a seasonal basis or otherwise, except for when the unit is on mechanical outage, overhaul, testing, etc.

2. Energy Market Operations

The 2019 Order described the operations of MISO's energy market, stage 2 of the market process, as follows:

> MISO markets identify the supply of electric generation available throughout the MISO regions, and the anticipated (and, in real time, the actual) demand for electricity in each area, selecting generators for dispatch in a manner designed to minimize overall costs to the system while meeting reliability requirements. MISO unit commitment is the process that determines which generators (and other resources) will operate to meet the upcoming need. MISO scheduling and dispatch sets the hourly output for each committed resource, using simultaneously co-optimized Security Constrained Unit Commitment and Security Constrained Economic Dispatch to clear and dispatch the energy and reserve markets.
>
> A market participant—that is, anyone registered for participation in MISO markets—can specify the production cost of its generator, and MISO will refrain from dispatching the resource until market prices meet or exceed that level, again, subject to reliability requirements. But under some circumstances a participant will prefer to commit its generator to be available for MISO dispatch ("self-commit"), and unilaterally set the generator's output level ("self-schedule"), accepting whatever market price results rather than waiting.

MISO's energy market has both a day ahead (DA) market and a real time (RT) market.[4] Essentially, the DA market is a forward market for energy and operating reserves. Transactions in the DA market occur

[4] Information on how MISO's markets work is available in the Learning Center on MISO's website.

the day before the operating day. The DA market creates binding results for next operating day and sets the DA locational marginal prices (LMP).

Transactions in the RT market occur throughout the operating day. Essentially, the RT market is a spot market for energy and operating reserves. The RT market balances supply and demand under actual system conditions, dispatches the least cost resources every five minutes, and thus provides transparent economic signals, especially RT LMPs.

3. MISO Market Structure Changes

MISO is currently pursuing demand-side capacity market changes, referred to as a downward-sloped or reliability-based demand curve.[5] In addition, MISO is pursuing supply-side capacity market changes, referred to as direct-loss of load accreditation reform.[6] The capacity market changes have the potential to impact this proceeding by changing how often the units involved in this proceeding clear in the capacity market.

MISO is also pursuing an update to the Value of Lost Load (VOLL). The VOLL is currently $3,500/MWh and has not changed since 2009. Several items in MISO's tariffs are connected to VOLL and MISO is considering changes to some of these relationships.[7] Changes to VOLL are not expected to be filed with FERC until later in 2024.

II. DEPARTMENT ANALYSIS

A. COMMITMENT AND DISPATCH DATA

1. Commitment Data

As stated in the 2019 Order, unit commitment is the first step in MISO's energy market and determines which generators (and other resources) will operate to meet the demand. The units involved in this proceeding generally use a commitment status of Economic, Must Run, or Outage. Table 2a below summarizes the commitment data for each unit in 2023.

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[5] See Federal Energy Regulatory Commission (FERC) Docket No. ER23-2997.
[6] See Federal Energy Regulatory Commission (FERC) Docket No. ER24-1638.
[7] For example, the LMP cap is set at VOLL and the Operating Reserve Demand Curve (ORDC) is linked to VOLL.

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Table 2a. Distribution of Commitment Status in 2023 (Hours)

	(a)	(b) = (a)/(h)	(c)	(d) = (c)/(h)	(e)	(f) = (e)/(h)	(g)	(h) = (a) + (c) + (e) + (g)
	Economic (hours)	Economic %	Must Run (hours)	Must Run %	Outage (hours)	Outage %	Other (hours)	Total (hours)
Big Stone	[TRADE SECRET DATA HAS BEEN EXCISED]							
Coyote								
Boswell 3	[TRADE SECRET DATA HAS BEEN EXCISED]							
Boswell 4								
King	[TRADE SECRET DATA HAS BEEN EXCISED]							
Sherco 1								
Sherco 2								
Sherco 3								
Monticello								
Prairie Island 1								
Prairie Island 2								
COAL TOTAL	16,194	23.1%	36,558	52.2%	17,328	24.7%	0	70,080

Table 2b shows a summary of the commitment data for the coal units since 2019, the first full year for this proceeding.

Table 2b. Summary of Commitment Status for Coal Units, 2019-2023 (Hours)[8]

	(a)	(b) = (a)/(h)	(c)	(d) = (c)/(h)	(e)	(f) = (e)/(h)	(g)	(h) = (a) + (c) + (e) + (g)
COAL TOTAL	Economic (hours)	Economic %	Must Run (hours)	Must Run %	Outage (hours)	Outage %	Other (hours)	Total (hours)
2019	5,681	10.8%	38,160	72.6%	8,719	16.6%	0	52,560
2020	12,953	18.4%	47,601	67.7%	6,509	9.3%	3,209	70,272
2021	15,382	21.9%	38,139	54.4%	12,681	18.1%	3,878	70,080
2022	19,742	28.2%	36,069	51.5%	13,874	19.8%	395	70,080
2023	16,194	23.1%	36,558	52.2%	17,328	24.7%	0	70,080

Table 2b shows that, on average, use of the Must Run designation during the commitment process has decreased substantially; from around 70 percent the first two years to a little over 50 percent the last three years.

2. Dispatch Data

As stated in the 2019 Order, dispatch is the second step in MISO's energy market and sets the hourly output for each committed resource. Data on uneconomic DA dispatch for the individual units subject to this proceeding is available in Table 3a . The following definitions apply to the data presented in Table 3a:

- Total DA Dispatch—sum of the MWh Cleared in the Day Ahead Market for all hours;
- Total Uneconomic DA Dispatch—sum of the MWh Cleared in the Day Ahead Market for hours where the DA LMP was less than Unit Fuel Cost plus Unit Variable O&M Cost; and
- Uneconomic DA Dispatch Minimum—sum of the Minimum MW Level the unit can be dispatched at in the Day Ahead market for hours where the DA LMP was less than Unit Fuel Cost plus Unit Variable O&M Cost.

[8] Data taken from prior Department comments in this proceeding, except 2019, which was calculated from the data provided in the utilities' 2020 filings. Note that OTP's 2020 filing did not provide commitment data for 2019 and thus OTP's units are excluded from Table 2b.

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Table 3a. Distribution of Dispatch Status by Unit in 2023 (MWh)

	(a)	(b)	(c)	(d) = (c)/(a)	(e) = (b)-(c)	(f) = (e)/(a)	(g) = (d)+(f)
Unit	**Total DA Dispatch**	**Total Uneconomic DA Dispatch**	**Uneconomic DA Dispatch Minimum**	**Percent Uneconomic DA Minimum**	**Uneconomic DA Dispatch Above Minimum**	**Percent Uneconomic DA Above Minimum**	**Percent Uneconomic DA Dispatch**
Boswell 3	**[TRADE SECRET DATA HAS BEEN EXCISED]**						
Boswell 4							
Big Stone	**[TRADE SECRET DATA HAS BEEN EXCISED]**						
Coyote							
King	**[TRADE SECRET DATA HAS BEEN EXCISED]**						
Sherco 1							
Sherco 2							
Sherco 3							
Monticello							
Prairie Island 1							
Prairie Island 2							
COAL TOTAL	13,466,748	4,297,101	2,954,284	21.9%	1,342,817	10.0%	31.9%

Table 3b shows a summary of the dispatch data for the coal units since the proceeding began.

Table 3b: Summary of Dispatch Status for Coal Units, 2019-2023 (MWh)[9]

	(a)	(b)	(c)	(d) = (c)/(a)	(e) = (b)-(c)	(f) = (e)/(a)	(g) = (d)+(f)
Calendar Year	**Total DA Dispatch**	**Total Uneconomic DA Dispatch**	**Uneconomic DA Dispatch Minimum**	**Percent Uneconomic DA Minimum**	**Uneconomic DA Dispatch Above Minimum**	**Percent Uneconomic DA Above Minimum**	**Percent Uneconomic DA Dispatch**
2019	18,117,211	8,039,070	6,027,191	33.3%	2,011,879	11.1%	44.4%
2020	14,943,438	5,825,575	4,641,341	31.1%	1,184,234	7.9%	39.0%
2021	15,974,270	3,075,470	2,260,695	14.2%	814,774	5.1%	19.3%
2022	16,975,300	2,788,773	1,956,519	11.5%	832,254	4.9%	16.4%
2023	13,466,748	4,297,101	2,954,284	21.9%	1,342,817	10.0%	31.9%

Table 3b shows that, consistent with less usage of the Must Run designation during the commitment process, uneconomic DA dispatch has decreased substantially; from 39 to 44 percent of total dispatch the first two years to between 16 and 32 percent of total dispatch the last three years. In addition, the majority of the uneconomic DA dispatch is associated with the DA minimum. From this data the Department concludes that the utilities continue to keep uneconomic dispatch below the levels prior experienced prior to the Commission's investigation in late 2019.

B. ECONOMIC OUTCOMES

The Department notes that the economic outcomes discussed here appear to be largely driven by the LMPs. Table 4 shows the LMPs at the Minnesota hub to illustrate the different prices faced by the units over time. Table 4 shows that LMPs were substantially higher in 2021 and 2022 than the other years, driving a greater number of hours of operating at a net benefit in those years.

Table 4: Minnesota Hub LMPs[10]

Year	Average Price	Average Off-Peak Price	Average On-Peak Price
2018	$26.57	$23.02	$30.65
2019	$21.97	$19.06	$25.31
2020	$17.58	$14.71	$20.84
2021	$36.63	$30.77	$43.37
2022	$44.10	$35.12	$54.47
2023	$28.75	$22.49	$35.99

[9] Data for 2019 was calculated from the files provided at that time; the data for 2020 to 2022 was taken from prior Department comments, and the data for 2023 was calculated from the utilities' most recent filings.
[10] While Table 4 shows real time LMPs, over a long duration real time LMPs are comparable to day ahead LMPs since real time LMPs converge to the day ahead LMPs.

1. Minnesota Power

Table 5a below shows the number of hours MP's units operated at a net benefit or net cost during 2023.

Table 5a: 2023 Hours at Net Benefit/Breakeven/Net Cost for MP

Unit	Net Benefit	Breakeven	Net Cost	TOTAL
Boswell 3	5,707 65%	948 11%	2,105 24%	8,760 100%
Boswell 4	3,858 44%	2,161 25%	2,741 31%	8,760 100%

Table 5b summarizes the historical data for Boswell 3 and Table 5c summarizes the historical data for Boswell 4.

Table 5b: Boswell 3—History of Hours at Net Benefit/Breakeven/Net Cost[11]

Year	Net Benefit	Breakeven	Net Cost	TOTAL
2018-2019	49.3%	22.1%	28.6%	100.0%
2020	30.8%	9.2%	60.1%	100.0%
2021	73.2%	13.0%	13.8%	100.0%
2022	74.1%	12.1%	13.8%	100.0%
2023	65.1%	10.8%	24.0%	100.0%

[11] The first filings covered the period July 1, 2018 to December 31, 2019. For this section the Department did not re-calculate the data to show a single year.

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Table 5c: Boswell 4—History of Hours at Net Benefit/Breakeven/Net Cost

Year	Net Benefit	Breakeven	Net Cost	TOTAL
2018-2019	52.3%	11.6%	36.1%	100.0%
2020	31.1%	11.3%	57.6%	100.0%
2021	84.6%	2.0%	13.4%	100.0%
2022	57.3%	27.9%	14.8%	100.0%
2023	44.0%	24.7%	31.3%	100.0%

Tables 5b and 5c show that both Boswell units had fewer hours at net benefit and more hours at net cost than in the prior two years, consistent with the LMPs.

1. Otter Tail

Table 6a below shows the number of hours OTP's units operated at a net benefit or net cost during 2023.

Table 6a: 2023 Hours at Net Benefit/Breakeven/Net Cost for OTP[12]

Unit	Net Benefit	Breakeven	Net Cost	TOTAL
Big Stone	2,191 25%	2,015 23%	4,554 52%	8,760 100%
Coyote (with Production Cost)	5,767 66%	794 9%	2,199 25%	8,760 100%
Coyote (with Total Production Cost)	3,344 38%	794 9%	4,622 53%	8,760 100%

Table 6b summarizes the historical data for Big Stone and Tables 6c and 6d summarize the historical data for Coyote.

[12] The difference between "Production Cost" and "Total Production Cost" is that total production cost includes what is classified as "Remaining Unit Fuel Cost." The remaining unit fuel costs are fixed costs associated with fuel. The utilities with such fixed fuel costs provide two sets of analysis to comply with the Commission's January 11, 2021 order in this proceeding, which required: "If a utility excludes any fuel costs from its MISO offer curves, the utility should also provide an analysis that includes all fuel costs, including those currently treated as fixed costs due to contractual terms."

Table 6b: Big Stone—History of Hours at Net Benefit/Breakeven/Net Cost

Year	Net Benefit	Breakeven	Net Cost	TOTAL
2018-2019	44.1%	16.7%	39.2%	100.0%
2020	15.6%	23.2%	61.2%	100.0%
2021	26.9%	34.9%	38.3%	100.0%
2022	37.5%	25.4%	37.1%	100.0%
2023	25.0%	23.0%	52.0%	100.0%

Table 6c: Coyote—History of Hours at Net Benefit/Breakeven/Net Cost With Production Cost

Year	Net Benefit	Breakeven	Net Cost	TOTAL
2018-2019	63.6%	23.0%	13.4%	100.0%
2020	44.0%	6.2%	49.8%	100.0%
2021	61.5%	11.6%	26.9%	100.0%
2022	62.1%	23.0%	14.9%	100.0%
2023	65.8%	9.1%	25.1%	100.0%

Table 6d: Coyote—History of Hours at Net Benefit/Breakeven/Net Cost With Total Production Cost

Year	Net Benefit	Breakeven	Net Cost	TOTAL
2018-2019	63.6%	23.0%	13.4%	100.0%
2020	8.8%	6.2%	85.0%	100.0%
2021	36.8%	11.6%	51.6%	100.0%
2022	54.2%	22.8%	23.0%	100.0%
2023	38.2%	9.1%	52.8%	100.0%

Table 6b shows that Big Stone has a persistently high number of hours operating at a net cost. Table 6c shows that, using the as bid or Production Cost data, Coyote generally has fewer hours operating at a net cost than Big Stone. As with MP, OTP's data is broadly consistent with the trends in LMPs.

2. Xcel

Table 7a below shows the number of hours Xcel's units operated at a net benefit or net cost during 2023.

Table 7a: 2023 Hours at Net Benefit/Breakeven/Net Cost for Xcel

Unit	Net Benefit	Breakeven	Net Cost	TOTAL
King	1,281 15%	6,432 73%	1,047 12%	8,760 100%
Sherco 1	3,907 45%	2,439 28%	2,414 28%	8,760 100%
Sherco 2	1,494 17%	5,938 68%	1,328 15%	8,760 100%
Sherco 3	2,897 33%	3,971 45%	1,892 22%	8,760 100%
Monticello (with Production Cost)	7,662 87%	1,022 12%	76 1%	8,760 100%
Prairie Island 1 (with Production Cost)	6,758 77%	1,727 20%	275 3%	8,760 100%
Prairie Island 2 (with Production Cost)	6,273 72%	2,229 25%	258 3%	8,760 100%
Monticello (with Total Production Cost)	7,519 86%	1,022 12%	219 3%	8,760 100%
Prairie Island 1 (with Total Production Cost)	6,443 74%	1,727 20%	590 7%	8,760 100%
Prairie Island 2 (with Total Production Cost)	5,885 67%	2,229 25%	646 7%	8,760 100%

Tables 7b to 7h summarize the historical data Xcel's generating units.

Table 7b: King—History of Hours at Net Benefit/Breakeven/Net Cost

Year	Net Benefit	Breakeven	Net Cost	TOTAL
2018-2019	37.8%	0.0%	62.2%	100.0%
2020	18.0%	0.0%	82.0%	100.0%
2021	27.7%	64.6%	7.7%	100.0%
2022	28.7%	0.0%	71.3%	100.0%
2023	14.6%	73.4%	12.0%	100.0%

Table 7c: Sherco 1—History of Hours at Net Benefit/Breakeven/Net Cost

Year	Net Benefit	Breakeven	Net Cost	TOTAL
2018-2019	42.5%	18.4%	39.2%	100.0%
2020	43.6%	21.0%	35.4%	100.0%
2021	49.2%	36.5%	14.4%	100.0%
2022	65.5%	16.2%	18.4%	100.0%
2023	44.6%	27.8%	27.6%	100.0%

Table 7d: Sherco 2—History of Hours at Net Benefit/Breakeven/Net Cost

Year	Net Benefit	Breakeven	Net Cost	TOTAL
2018-2019	48.1%	19.2%	32.7%	100.0%
2020	36.3%	34.7%	29.0%	100.0%
2021	56.1%	25.5%	18.4%	100.0%
2022	58.6%	28.5%	12.9%	100.0%
2023	17.1%	67.8%	15.2%	100.0%

Table 7e: Sherco 3—History of Hours at Net Benefit/Breakeven/Net Cost

Year	Net Benefit	Breakeven	Net Cost	TOTAL
2018-2019	48.5%	7.8%	43.7%	100.0%
2020	46.0%	32.3%	21.7%	100.0%
2021	46.2%	32.0%	21.8%	100.0%
2022	51.8%	32.4%	15.8%	100.0%
2023	33.1%	45.3%	21.6%	100.0%

Tables 7c through 7 e show that Xcel’s Sherco units have the same trend as MP’s Boswell units where breakdown of hours into net benefit/net cost tracks the increases and decreases in average LMPs.

Table 7f: Monticello—History of Hours at Net Benefit/Breakeven/Net Cost With Total Production Cost[13]

Year	Net Benefit	Breakeven	Net Cost	TOTAL
2018-2019	93.8%	6.1%	0.1%	100.0%
2020	96.1%	0.0%	3.9%	100.0%
2021	89.6%	9.1%	1.3%	100.0%
2022	96.6%	0.9%	2.5%	100.0%
2023	85.8%	11.7%	2.5%	100.0%

Table 7g: Prairie Island 1—History of Hours at Net Benefit/Breakeven/Net Cost With Total Production Cost

Year	Net Benefit	Breakeven	Net Cost	TOTAL
2018-2019	92.8%	6.4%	0.8%	100.0%
2020	84.2%	7.5%	8.4%	100.0%
2021	96.0%	0.0%	4.0%	100.0%
2022	90.7%	2.1%	7.1%	100.0%
2023	73.6%	19.7%	6.7%	100.0%

Table 7h: Prairie Island 2—History of Hours at Net Benefit/Breakeven/Net Cost With Total Production Cost

Year	Net Benefit	Breakeven	Net Cost	TOTAL
2018-2019	95.4%	4.2%	0.4%	100.0%
2020	92.5%	0.0%	7.5%	100.0%
2021	88.7%	7.6%	3.7%	100.0%
2022	97.4%	0.0%	2.6%	100.0%
2023	67.2%	25.4%	7.4%	100.0%

Tables 7f through 7h show that Xcel's nuclear units tend to have relatively few hours operating at a net cost regardless of fluctuations in the average LMP.

3. Summary

Overall, the data show the Commission's proceeding appears to have had an impact in reducing the use of must run designation during commitment and on uneconomic dispatch for the coal units. However, the changes in the LMPs appear to be the driving factor in the net benefit/net cost outcome rather than the details of the commitment and dispatch process.

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[13] Even with consideration of total production costs (which are larger than production costs) Xcel's nuclear units operate at a net benefit most hours. Thus, to reduce the number of tables production cost data is not presented.

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C. IMPACT ON OUTAGE RATE

The Commission's November 17, 2022 Order at Point 7b required the utilities to provide the equivalent forced outage rates (EFOR) to be tracked over time for each unit. The Department proposed this requirement to track the operating conditions of the units and identify impacts of additional wear and tear. Flexible operations put more stress on steam piping; headers; and superheater, reheating, and waterwall tubing. The calculation of EFOR is defined in the North American Electric Reliability Corporation (NERC) GADS Data Reporting Instructions[14] as follows:

$$\textbf{EFOR} = \frac{\textbf{FOH + EFDH}}{\textbf{FOH + SH + Synchronous Condensing Hours + Pumping Hours + EFDHRS}} \textbf{ x 100\%}$$

Where:

- FOH – Forced outage hours;
- EFDH – Equivalent forced derated hours;
- SH – Service hours; and
- EFDHRS - Equivalent forced derated hours during reserve shutdowns.

Tables 8 to 11 show the EFOR data from the two filings made since the data was required.

Table 8: MP EFOR Data

Month	Boswell 3		Boswell 4	
	2022	2023	2022	2023
January	[TRADE SECRET DATA HAS BEEN EXCISED]			
February				
March				
April				
May				
June				
July				
August				
September				
October				
November				
December				
Average				

[14] NERC Generating Availability Data System (GADS) Data Reporting Instructions, Effective January 1, 2023 Appendix F at F-9. Accessed at: https://www.nerc.com/pa/RAPA/gads/DataReportingInstructions/GADS_DRI_2023.pdf

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Table 9: OTP EFOR Data

Month	Big Stone 2022	Big Stone 2023	Coyote 2022	Coyote 2023
January	[TRADE SECRET DATA HAS BEEN EXCISED]			
February				
March				
April				
May				
June				
July				
August				
September				
October				
November				
December				
Average				

Table 10: Xcel Coal EFOR Data

Month	King 2022	King 2023	Sherco 1 2022	Sherco 1 2023	Sherco 2 2022	Sherco 2 2023	Sherco 3 2022	Sherco 3 2023
January	[TRADE SECRET DATA HAS BEEN EXCISED]							
February								
March								
April								
May								
June								
July								
August								
September								
October								
November								
December								
Average								

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Table 11: Xcel Nuclear EFOR Data

Month	Monticello 2022	Monticello 2023	Prairie Island 1 2022	Prairie Island 1 2023	Prairie Island 2 2022	Prairie Island 2 2023
January	[TRADE SECRET DATA HAS BEEN EXCISED]					
February						
March						
April						
May						
June						
July						
August						
September						
October						
November						
December						
Average						

At this time insufficient data has accumulated to draw any conclusions regarding impacts of flexible dispatch on EFOR.

D. IMPACT ON EMISSIONS

The Commission's December 1, 2021 Order at Point 8 a required utilities to provide carbon dioxide emissions data for each unit. The Commission's November 17, 2022 Order at Point 7a extended this requirement by requiring the utilities to provide avoided carbon dioxide emissions due to economic commitment, using the Department's recommended method. Tables 12 and 13 show the overall emissions and the avoided emissions available in this proceeding.

Table 12: Carbon Dioxide Emissions Data

Unit	Emissions (short tons) in 2021	Emissions (short tons) in 2022	Emissions (short tons) in 2023
Boswell Unit 3	2,543,828	2,604,917	2,464,473
Boswell Unit 4	2,636,159	2,618,437	2,574,516
Big Stone	2,066,415	2,390,422	2,094,916
Coyote	3,058,364	2,787,970	3,209,506
King	1,545,215	1,385,510	1,094,107
Sherco Unit 1	3,051,380	3,955,004	3,205,467
Sherco Unit 2	3,898,059	3,416,090	1,390,671
Sherco Unit 3	2,224,536	2,423,237	1,925,692
Total	21,023,956	21,581,587	17,959,348

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Table 13: Avoided Carbon Dioxide Emissions Data

Unit	Avoided Emissions (short tons) in 2022	Avoided Emissions (short tons) in 2023
Boswell Unit 3	2,087	27,632
Boswell Unit 4	-	-
Big Stone	24,033	65,346
Coyote	-	4,482
King	476,869	1,728,499
Sherco Unit 1	69,911	405,743
Sherco Unit 2	66,640	463,488
Sherco Unit 3	119,360	107,850
Total	758,900	2,803,040

At this time insufficient data has accumulated to draw any firm conclusions regarding impacts of flexible dispatch on carbon dioxide emissions. However, based tables 12 and 13, we can conclude that flexible dispatch may have the potential to decrease emissions, 3.5 percent of actual emissions from these coal plants were avoided in 2022 due to flexible operations. This increased to 15.6 percent in 2023.

E. BEST-CASE AND WORST-CASE ANALYSIS

In accordance with Order Point 8.a of the Commission's December 1, 2021 order, the utilities came up with the best-case and worst-case potential for economic commitment for each plant. The Department proposed this requirement to track the progress that utilities make as they transition their units to greater economic commitment over time.

MP considered two operational scenarios for its units:

1. A worst-case scenario where its units were set to must run all year.
2. A best-case scenario where its units were set to Economic Dispatch all year. Due to the need for supplemental heat Boswell 4 was set to economic dispatch for April to October and December 2024 and must run during the other months. For 2025 and 2026 Boswell 4 was set to economic dispatch for all months.[15]

Similar to last year's filing Otter Tail calculated net benefits for three scenarios:

1. Self-Commitment–OTP assumed its share of the plant was self-committed whenever the unit was not in an outage. The Department would categorize this as Benchmark 1 (worst case).
2. Economic one–Otter Tail share is assumed to be independently committable and dispatchable: OTP assumed it can independently dispatch its generation share economically. The Department would categorize this as Benchmark 2 (best scenario).

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[15] See Table 9 of MP's March 1, 2024 compliance filing.

3. Economic two– Otter Tail share constrained by unavoidable self-commitment: OTP assumed it can dispatch its generation share economically unless it is forced to self-commit. The Department would categorize this as Benchmark 3.

Xcel considered two scenarios for its plants:

1. Worst Case Scenario: Assume the unit runs with Must Run commitment outside of historic outages.
2. Best Case Scenario: Assumes all existing constraints, such as outages and nondiscretionary must-runs of the units but allow the units to be economically committed all other hours.

This analysis is proving to be of little value. For several units the actual net benefit is outside of the best case/worst case range. In addition, some units are reporting the net benefits of the worst case are greater than the net benefits of the best case. Both of these outcomes happened last year as well.[16]

F. CURTAILMENT

The utilities reported curtailment data for 2023 as follows:

- Minnesota Power—**[TRADE SECRET DATA HAS BEEN EXCISED]**
- Otter Tail—**[TRADE SECRET DATA HAS BEEN EXCISED]** and
- Xcel—**[TRADE SECRET DATA HAS BEEN EXCISED]**

The historic data on curtailment is summarized in Table 14.

Table 14: Historic Curtailment Percentage

Utility	2020	2021	2022	2023
MP	**[TRADE SECRET DATA HAS BEEN EXCISED]**			
OTP				
Xcel				

Overall, Xcel and MP experienced curtailment similar to last year while OTP's curtailment dropped significantly from last year.

[16] See the Department's May 31, 2023 comments for details.

III. DEPARTMENT RECOMMENDATION

The Department recommends the Commission accept as adequate and meeting the filing requirements the March 1, 2024 filings of Xcel, Minnesota Power, and Otter Tail.