COMMERCE DEPARTMENT

April 30, 2025 **PUBLIC DOCUMENT**

Will Seuffert
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 Petitions were filed by Minnesota Power, Xcel Energy, and Otter Tail Power Company by March 3, 2025.

The Department recommends **accepting the utilities' reports** and is available to answer any questions the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ Sydnie Lieb, Ph.D.
Assistant Commissioner, Department of Regulatory Affairs

SR/ad
Attachment

Before the Minnesota Public Utilities Commission

PUBLIC Comments of the Minnesota Department of Commerce

Docket No. E999/CI-19-704

I. INTRODUCTION

The Minnesota Public Utilities Commission (Commission) has issued orders directing Minnesota Power (MP), Otter Tail Power Company (OTP), and Northern States Power Company d/b/a Xcel Energy (Xcel) to make annual compliance filings containing an analysis of the impacts of self-committing and self-scheduling their generators in the Midcontinent Independent System Operator, Inc.'s (MISO) energy market, including the annual difference between production costs and corresponding prevailing market prices.[1,2] The annual compliance filings are due March 1 of each year.[3]

II. PROCEDURAL BACKGROUND

By March 3, 2025	MP[4], OTP[5], and Xcel[6] filed their annual compliance filings, containing data regarding the impacts of self-committing and self-scheduling their generators.
March 6, 2025	The Commission issued its *Notice of Comment Period* (Notice) regarding the utilities' annual compliance filings.[7]

[1] *In the Matter of the Review of the 2016-2017 Annual Automatic Adjustment Reports for All Electric Utilities* and *In the Matter of the Review of the 2017-2018 Annual Automatic Adjustment Reports for All Electric Utilities*, *Order Accepting 2016-2017 Reports and Setting Additional Requirements*, February 7, 2019, Docket Nos.E999/AA-17-492 and E999/AA-18-373, (eDockets) 20192-150080-01 at Order Point 4.

[2] *In the Matter of the Review of the 2017-2018 Annual Automatic Adjustment Reports for All Electric Utilities, Order Accepting 2017-2018 Reports and Setting Additional Requirements*, November 13, 2019, Docket No.E999/AA-18-373, (eDockets) 201911-157516-01 at Order Points 8, 9, and 10, (Hereinafter "2019 Order").

[3] Note that the filings made in March 2024 have not yet been acted upon by the Commission.

[4] *In the Matter of an Investigation into Self-Commitment and Self-Scheduling of Large Baseload Generation Facilities*, MP, Annual Compliance Filing, March 3, 2025, Docket No. E999/CI-19-704, (eDockets) 20253-216006-04 (Hereinafter "MP Report").

[5] *In the Matter of an Investigation into Self-Commitment and Self-Scheduling of Large Baseload Generation Facilities*, OTP, Annual Compliance Filing, February 27, 2025, Docket No. E999/CI-19-704, (eDockets) 20252-215820-02, 20252-215820-04, and 20252-215820-06 (Hereinafter "OTP Report").

[6] *In the Matter of an Investigation into Self-Commitment and Self-Scheduling of Large Baseload Generation Facilities*, Xcel, 2024 Annual Report, March 3, 2025, Docket No. E999/CI-19-704, (eDockets) 20253-216008-01, 20253-216008-03, 20253-216008-05, and 20253-216008-08 (Hereinafter "Xcel Report").

[7] *In the Matter of an Investigation into Self-Commitment and Self-Scheduling of Large Baseload Generation Facilities*, Notice of Comment Period, March 6, 2025, Docket No. E999/CI-19-704, (eDockets) 20253-216124-01.

According to the Notice the following topics are open for comment:

- Are the March 1, 2025 filings by the utilities, 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?

III. DEPARTMENT ANALYSIS

A. MISO MARKET BACKGROUND

A.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.[8] Resources that clear in 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.

A.2. Energy Market Operations

MISO's energy markets identify both the supply of electric generation available throughout the MISO regions, and the anticipated (and, in the real-time market, the actual) demand for electricity in each area. Generators are selected 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 for electricity. 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.

MISO's energy market has both a day ahead (DA) market and a real time (RT) market.[9] Essentially, the DA market is a forward market for energy and operating reserves. Transactions in the DA market occur the day before the operating day. The DA market creates binding results for next operating day and sets the DA locational marginal prices (LMP).

[8] See MISO PRA Website
[9] Information on how MISO's markets work is available in the Learning Center on MISO's website.

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.

A participating generation owner can specify the operating parameters—including 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. However, 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 awaiting economic dispatch by MISO.

The concern in this proceeding is that the utilities may over-use self-commitment and self-scheduling, which results in higher costs for ratepayers.

B. COMPLETENESS REVIEW

The first topic open for comment is "Are the March 1, 2025 filings by the utilities, adequate and in compliance with prior Commission orders?"

The Department reviewed the annual compliance filings and notes two items. First, the Commission's December 1, 2021 Order required the utilities to include "Plant startup conditions (e.g. cold, warm, or hot)."[10] While MP included certain information, the Department recommends MP include a column in the annual Excel spreadsheet that indicates whether each start was cold, warm, or hot. Both Xcel and OTP met this Order requirement in their respective compliance filings.

Second, the Commission's November 17, 2022 Order required:

> Xcel to provide, in future reports, instances when greater economic commitment led to lost revenue. If there were such instances, the utility should describe its strategy to weigh those lost revenues with the environmental benefits of lower emissions.[11]

The Department was unable to locate this information. The Department recommends Xcel, in reply comments, indicate where information regarding instances when greater economic commitment led to lost revenue is located or provide the information.

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[10] *In the Matter of an Investigation into Self-Commitment and Self-Scheduling of Large Baseload Generation Facilities*, Commission, *Order Accepting Reports and Setting Additional Requirements*, December 1, 2021, Docket No. E999/CI-19-704, (eDockets) 202112-180308-01.
[11] *In the Matter of an Investigation into Self-Commitment and Self-Scheduling of Large Baseload Generation Facilities*, Commission, Order, November 17, 2022, Docket No. E999/CI-19-704, (eDockets) 202211-190727-01.

C. ANALYSIS OF THE DATA

The Department begins by noting that OTP's units are co-owned with other utilities in multiple RTOs, making commitment and dispatch decisions somewhat complicated.[12] Table 1 below shows the ownership arrangements for Big Stone and Coyote.

Table 1. OTP Unit Ownership Arrangements[13]

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

C.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 2024.

[12] OTP Report at 3-4.
[13] OTP Report at 4.

Table 2a. Distribution of Commitment Status in 2024 (Hours)[14]

	(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	[TRADE SECRET DATA HAS BEEN EXCISED]							
Monticello								
Prairie Island 1								
Prairie Island 2								
COAL TOTAL	12,203	19.8%	38,571	62.7%	10,714	17.4%	0	61,488

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

[14] MP Report at Attachments 1 and 2, OTP Report at Attachments 2 and 3, Xcel Report at Attachments A and B.

Table 2b. Summary of Commitment Status for Coal Units, 2019-2024 (Hours)[15, 16]

	(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**
2024	**12,203**	**19.8%**	**38,571**	**62.7%**	**10,714**	**17.4%**	**0**	**61,488**

Table 2b shows that, on average, use of the Must Run designation during the commitment process has decreased; from around 70 percent the first two years to a little over 50 percent the next three years. However, for 2024 the use of must run increased to a little over 60 percent.

C.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.

[15] *In the Matter of an Investigation into Self-Commitment and Self-Scheduling of Large Baseload Generation Facilities*, Department, Comments, June 8, 2020, Docket No. E999/CI-19-704, (eDockets) 20206-163795-02. Department, Comments, April 30, 2021, Docket No. E999/CI-19-704, (eDockets) 20214-173727-02. Department, Comments, May 2, 2022, Docket No. E999/CI-19-704, (eDockets) 20225-185438-02. Department, Comments, May 31, 2023, Docket No. E999/CI-19-704, (eDockets) 20235-196234-02. Department, Comments, May 1, 2024, Docket No. E999/CI-19-704, (eDockets) 20245-206285-02 (Collectively, "Prior Department Comments")
[16] Note that 2019 data was calculated from the information 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 for 2019.

Table 3a. Distribution of Dispatch Status by Unit in 2023 (MWh)[17]

<table>
<tr><th></th><th>(a)</th><th>(b)</th><th>(c)</th><th>(d) = (c)/(a)</th><th>(e) = (b)-(c)</th><th>(f) = (e)/(a)</th><th>(g) = (d)+(f)</th></tr>
<tr><th>Unit</th><th>Total DA Dispatch</th><th>Total Uneconomic DA Dispatch</th><th>Uneconomic DA Dispatch Minimum</th><th>Percent Uneconomic DA Minimum</th><th>Uneconomic DA Dispatch Above Minimum</th><th>Percent Uneconomic DA Above Minimum</th><th>Percent Uneconomic DA Dispatch</th></tr>
<tr><td colspan="8"></td></tr>
<tr><td>Boswell 3</td><td colspan="7" rowspan="2">[TRADE SECRET DATA HAS BEEN EXCISED]</td></tr>
<tr><td>Boswell 4</td></tr>
<tr><td colspan="8"></td></tr>
<tr><td colspan="8"></td></tr>
<tr><td>Big Stone</td><td colspan="7" rowspan="2">[TRADE SECRET DATA HAS BEEN EXCISED]</td></tr>
<tr><td>Coyote</td></tr>
<tr><td colspan="8"></td></tr>
<tr><td colspan="8"></td></tr>
<tr><td>King</td><td colspan="7" rowspan="2">[TRADE SECRET DATA HAS BEEN EXCISED]</td></tr>
<tr><td>Sherco 1</td></tr>
<tr><td>Sherco 2</td><td colspan="7"></td></tr>
<tr><td>Sherco 3</td><td colspan="7" rowspan="4">[TRADE SECRET DATA HAS BEEN EXCISED]</td></tr>
<tr><td>Monticello</td></tr>
<tr><td>Prairie Island 1</td></tr>
<tr><td>Prairie Island 2</td></tr>
<tr><td colspan="8"></td></tr>
<tr><td>COAL TOTAL</td><td>11,951,183</td><td>5,229,761</td><td>3,510,505</td><td>29.4%</td><td>1,719,256</td><td>14.4%</td><td>43.8%</td></tr>
</table>

[17] MP Report at Attachments 1 and 2, OTP Report at Attachments 2 and 3, and Xcel Report at Attachments A and B.

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)[18]

	(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%	814,775	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%
2024	11,951,183	5,229,761	3,510,505	29.4%	1,719,256	14.4%	43.8%

Table 3b shows that uneconomic DA dispatch returned to the level experienced in the first two years. In addition, a significant portion of the uneconomic DA dispatch is associated with uneconomic dispatch above the DA minimum. From this data the Department concludes that the utilities on average have regressed to the levels experienced prior to the Commission's investigation in late 2019.

C.3. Economic Outcomes

The Department notes that in past years the economic outcomes appear to have been largely driven by 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 operation at a net benefit in those years.

Table 4: Minnesota Hub LMPs[19]

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
2024	$27.40	$22.95	$32.54

[18] MP Report at Attachments 1 and 2, OTP Report at Attachments 2 and 3, Xcel Report at Attachments A and B and Prior Department Comments.

[19] 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.

C.3.1. MP

Table 5a below shows the number of hours MP's units operated at a net benefit or net cost during 2024.

Table 5a: 2023 Hours at Net Benefit/Breakeven/Net Cost for MP[20]

Unit	Net Benefit	Breakeven	Net Cost	TOTAL
Boswell Unit 3	3,730 42%	2,812 32%	2,242 26%	8,784 100%
Boswell Unit 4	4,093 47%	472 5%	4,219 48%	8,784 100%

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[21, 22]

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%
2024	42.5%	32.0%	25.5%	100.0%

Table 5c: Boswell 4—History of Hours at Net Benefit/Breakeven/Net Cost[23]

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%
2024	46.6%	5.4%	48.0%	100.0%

Tables 5b and 5c show that both Boswell units had a greater percentage of hours at net cost than in the prior three years, consistent with the 2024 LMPs which were lower than the 2021 to 2023 LMPs.

[20] MP Report at Attachments 1 and 2.
[21] 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.
[22] See Table 5a and Prior Department Comments.
[23] See Table 5a and Prior Department Comments.

C.3.2. OTP

Table 6a below shows the number of hours OTP's units operated at a net benefit or net cost during 2024.

Table 6a: 2024 Hours at Net Benefit/Breakeven/Net Cost for OTP[24, 25]

Unit	Net Benefit	Breakeven	Net Cost	TOTAL
Big Stone	2,041 23%	1,239 14%	5,504 63%	8,784 100%
Coyote (with Production Cost)	4,078 46%	1,034 12%	3,672 42%	8,784 100%
Coyote (with Total Production Cost)	2,205 25%	1,034 12%	5,545 63%	8,784 100%

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

Table 6b: Big Stone—History of Hours at Net Benefit/Breakeven/Net Cost[26]

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%
2024	23.2%	14.1%	62.7%	100.0%

Table 6c: Coyote—History of Hours at Net Benefit/Breakeven/Net Cost With Production Cost[27]

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%
2024	46.4%	11.8%	41.8%	100.0%

[24] 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."
[25] OTP Report at Attachments 2 and 3.
[26] See Table 6a and Prior Department Comments.
[27] See Table 6a and Prior Department Comments.

Table 6d: Coyote—History of Hours at Net Benefit/Breakeven/Net Cost With Total Production Cost[28]

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%
2023	25.1%	11.8%	63.1%	100.0%

As with MP, Tables 6b to 6d show that OTP's units had a greater percentage of hours at net cost than in the prior three years, consistent with the LMPs.

C.3.3. Xcel

Table 7a below shows the number of hours Xcel's units operated at a net benefit or net cost during 2024.

Table 7a: 2024 Hours at Net Benefit/Breakeven/Net Cost for Xcel[29]

Unit	Net Benefit	Breakeven	Net Cost	TOTAL
King	953 11%	7,350 84%	481 5%	8,784 100%
Sherco 1	3,949 45%	2,812 32%	2,023 23%	8,784 100%
Sherco 2	Retired			
Sherco 3	3,551 40%	1,810 21%	3,423 39%	8,784 100%
Monti (Production Cost)	8,529 97%	190 2%	65 1%	8,784 100%
Prairie Island 1 (Production Cost)	5,413 62%	3,148 36%	223 3%	8,784 100%
Prairie Island 2 (Production Cost)	6,798 77%	1,711 19%	275 3%	8,784 100%
Monticello (Total Production Cost)	8,331 95%	190 2%	263 3%	8,784 100%
Prairie Island 1 (Total Production Cost)	5,087 58%	3,148 36%	549 6%	8,784 100%
Prairie Island 2 (Total Production Cost)	6,436 73%	1,711 19%	637 7%	8,784 100%

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

[28] See Table 6a and Prior Department Comments.
[29] Xcel Report at Attachments A and B.

Table 7b: King—History of Hours at Net Benefit/Breakeven/Net Cost[30]

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%
2024	10.8%	83.7%	5.5%	100.0%

Table 7c: Sherco 1—History of Hours at Net Benefit/Breakeven/Net Cost[31]

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%
2024	45.0%	32.0%	23.0%	100.0%

Table 7d: Sherco 2—History of Hours at Net Benefit/Breakeven/Net Cost[32]

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%
2024	Retired			

Table 7e: Sherco 3—History of Hours at Net Benefit/Breakeven/Net Cost[33]

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%
2024	40.4%	20.6%	39.0%	100.0%

Tables 7b through 7e show that Xcel's coal units have no consistent result in terms of percentage of operating at a net benefit or net cost in 2024 compared to prior years.

Table 7f: Monticello—History of Hours at Net Benefit/Breakeven/Net Cost

[30] See Table 7a and Prior Department Comments.
[31] See Table 7a and Prior Department Comments.
[32] See Table 7a and Prior Department Comments.
[33] See Table 7a and Prior Department Comments.

With Total Production Cost[34, 35]

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%
2024	94.8%	2.2%	3.0%	100.0%

Table 7g: Prairie Island 1—History of Hours at Net Benefit/Breakeven/Net Cost With Total Production Cost[36]

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%
2024	57.9%	35.8%	6.3%	100.0%

Table 7h: Prairie Island 2—History of Hours at Net Benefit/Breakeven/Net Cost With Total Production Cost[37]

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%
2024	73.3%	19.5%	7.3%	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.

C.3.4. 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, for many units 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.

C.4. Impact on Outage Rate

[34] 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.
[35] See Table 7a and Prior Department Comments.
[36] See Table 7a and Prior Department Comments.
[37] See Table 7a and Prior Department Comments.

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[38] as follows:

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

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 filings made since the data was required.

Table 8: MP EFOR Data[39]

Month	BEC3			BEC4		
	2022	2023	2024	2022	2023	2024
January	[TRADE SECRET DATA HAS BEEN EXCISED]					
February						
March						
April						
May						
June						
July						
August						
September						
October						
November						
December						
Average						

[38] 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
[39] MP Report at Attachments 1 and 2

Table 9: OTP EFOR Data[40]

Month	Big Stone Plant 2022	Big Stone Plant 2023	Big Stone Plant 2024	Coyote Station 2022	Coyote Station 2023	Coyote Station 2024
January						
February						
March						
April						
May						
June						
July	**[TRADE SECRET DATA HAS BEEN EXCISED]**					
August						
September						
October						
November						
December						
Average						

Table 10: Xcel Coal EFOR Data[41]

Month	King 2022	King 2023	King 2024	Sherco 1 2022	Sherco 1 2023	Sherco 1 2024	Sherco 3 2022	Sherco 3 2023	Sherco 3 2024
January									
February									
March									
April									
May									
June									
July	**[TRADE SECRET DATA HAS BEEN EXCISED]**								
August									
September									
October									
November									
December									
Average									

[40] OTP Report at 15.
[41] Xcel Report at Attachment E.

Table 11: Xcel Nuclear EFOR Data[42]

Month	Monticello			Prairie Island 1			Prairie Island 2		
	2022	2023	2024	2022	2023	2024	2022	2023	2024
January	[TRADE SECRET DATA HAS BEEN EXCISED]								
February									
March									
April									
May									
June									
July									
August									
September									
October									
November									
December									
Average									

The Department is unable to draw any conclusions regarding EFOR from this data.

C.5. 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[43]

Unit	2021	2022	2023	2024
Boswell Unit 3	2,543,828	2,604,917	2,464,473	1,617,259
Boswell Unit 4	2,636,159	2,618,437	2,574,516	2,688,734
Big Stone	2,066,415	2,390,422	2,094,916	2,210,266
Coyote	3,058,364	2,787,970	3,209,506	2,942,752
King	1,545,215	1,385,510	1,094,107	654,948
Sherco Unit 1	3,051,380	3,955,004	3,205,467	2,841,521
Sherco Unit 2	3,898,059	3,416,090	1,390,671	Retired
Sherco Unit 3	2,224,536	2,423,237	1,925,692	2,319,249
Total	21,023,956	21,581,587	17,959,348	15,274,730

[42] Xcel Report at Attachment E.
[43] MP Report at 10, OTP Report at 12, and Xcel Report at 10.

Table 13: Avoided Carbon Dioxide Emissions Data[44]

Unit	2022	2023	2024
Boswell Unit 3	2,087	27,632	33,972
Boswell Unit 4	-	-	-
Big Stone	24,033	65,346	90,400
Coyote	-	4,482	4,012
King	476,869	1,728,499	2,205,256
Sherco Unit 1	69,911	405,743	97,336
Sherco Unit 2	66,640	463,488	Retired
Sherco Unit 3	119,360	107,850	141,625
Total	758,900	2,803,040	2,572,601

Based tables 12 and 13, the Department concludes that flexible dispatch is resulting in a decrease in emissions. Avoided emissions equal about 3.5 percent of actual emissions in 2022. This percentage increased to 15.6 percent in 2023 and 16.8 percent in 2024.

C.6. Best-case and Worst-case Analysis

In accordance with Order Point 8.a of the Commission's December 1, 2021 order, the utilities developed a 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.

Since the reporting of this metric has started, the analysis has proven to be of little value. Over the years there are instances where the actual net benefit is outside of the best case/worst case range. In addition, some units have reported the net benefits of the worst case are greater than the net benefits of the best case. Therefore, the Department does not address this information in these comments and recommends the best case/worst case reporting requirement be discontinued.

C.7. Curtailment

The utilities reported curtailment data for 2024 as follows:

- MP—**[TRADE SECRET DATA HAS BEEN EXCISED]**
- OTP—**[TRADE SECRET DATA HAS BEEN EXCISED]**
- Xcel—**[TRADE SECRET DATA HAS BEEN EXCISED]**

[44] MP Report at 10, OTP Report at 18, and Xcel Report at 10.

The historic data on curtailment is summarized in Table 14.

Table 14: Historic Curtailment Percentage[45]

Utility	Curtailment Percentage 2020	2021	2022	2023	2024
MP	[TRADE SECRET DATA HAS BEEN EXCISED]				
OTP					
Xcel					

Overall, the utilities experienced high curtailment in the past year.

D. CONCLUSIONS FROM THE DATA

The second topic open for comment is "What conclusions can be drawn from the data filed by the utilities in conjunction with what has been learned earlier in this investigation?"

Based upon the analysis above the Department concludes that:

- Table 3b shows that the percent of uneconomic DA dispatch has increased substantially the last two years. Table 3b also shows that the percent uneconomic DA dispatch above minimum has reached a new high in 2024.
- Tables 5b and 5c show that MP's Boswell units have operated at a higher percentage of hours at net cost in 2024 than in the prior 3 years. Tables 6b and 6c show the same for OTP's units. The equivalent data for Xcel's units shows some at a high level (Sherco 3) and others relatively low (King) for 2024.
- Tables 8 to 11 do not show a clear trend in the utilities' EFOR data for 2024.
- Table 13 shows that the avoided carbon dioxide emissions for 2024 are substantial.
- Table 14 shows the utilities experienced high levels of curtailment in 2024.

Overall, the Department recommends that the Commission accept the utilities' reports

E. USE GOING FORWARD

The third topic open for comment is "How should the Commission use the information provided by the utilities in this docket going forward?"

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[45] MP Report at Attachment 3, OTP Report at Attachment 7, Xcel Report at Attachment F, and Prior Department Comments.

The Department recommends that the Commission use the information provided in this proceeding to ensure that the utilities do not engage in practices that increase costs unnecessarily.

F. FURTHER ANALYSIS

The fourth topic open for comment is "Should the Commission order any further analysis for future reports, or any additional reports by the utilities?"

The Department does not recommend any further analysis or reporting.

IV. DEPARTMENT RECOMMENDATIONS

Based on analysis of the information in the record this year and in prior years, the Department has prepared recommendations, which are provided below. The recommendations correspond to the subheadings of Section III above.

B. COMPLETENESS REVIEW

- The Department recommends Xcel, in reply comments, indicate where information regarding instances when greater economic commitment led to lost revenue is located or provide the information.

C. ANALYSIS OF THE DATA

- The Department recommends the best case/worst case reporting requirement be discontinued.

D. CONCLUSIONS FROM THE DATA

- The Department recommends that the Commission accept the utilities' reports.