414 Nicollet Mall
Minneapolis, Minnesota 55401

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March 1, 2023

—VIA ELECTRONIC FILING—

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

RE: ANNUAL TRUE-UP COMPLIANCE REPORT
2022 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES
DOCKET NO. E002/AA-21-295

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Annual True-Up and Compliance Report for the fuel forecast and monthly fuel cost charges approved for the 2022 calendar year. This Report also includes compliance items required to be included in the Company's Electric Annual Automatic Adjustment of Charges Reports.

Please note that portions of our Petition and attachments are marked as "Not Public." Certain data is considered to be "not public data" pursuant to Minn. Stat. §13.02, Subd.9, and is "Trade Secret" information pursuant to Minn. Stat. §13.37, subd. 1(b) as this data derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use.

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document, and served copies of the summary on the parties on the attached service lists.

If you have any questions regarding this filing, please contact Rebecca Eilers at 612-330-5570 or rebecca.d.eilers@xcelenergy.com or me at 612-330-7681 or lisa.r.peterson@xcelenergy.com.

Sincerely,

/s/

LISA R. PETERSON
DIRECTOR, REGULATORY PRICING AND ANALYSIS

Enclosures
cc: Service Lists

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STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE 2022 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES

DOCKET NO. E002/AA-21-295

ANNUAL TRUE-UP REPORT

OVERVIEW

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this Annual Fuel Forecast True-Up Report which provides a comparison of the approved 2022 fuel forecast to 2022 actuals. This report is submitted in compliance with the various Orders issued in Docket No. E999/CI-03-802 which implemented Fuel Clause Reform and provides various other compliance items required to be filed in the Company's Electric Annual Automatic Adjustment of Charges Report (AAA).[1]

The Company's 2022 actual fuel expense was $950.2 million, or $100.8 million higher than our approved forecast of $849.4 million. The actual average fuel cost of $33.55 per MWh was 6.6 percent higher than the authorized rate of $31.47 per MWh. However, actual fuel cost collections were $891.0 million due to higher than forecast Minnesota jurisdictional sales. Furthermore, Minnesota fuel collections were adjusted through a mid-year rate surcharge, resulting in an additional $62.9 million of collections from July through December. Therefore total Minnesota fuel collections were $954.0 million versus total actual fuel expense of $950.2 million, resulting in over-collected fuel costs of $3.8 million.

The significant drivers for increased costs between our 2022 forecast and actuals were:

1. higher congestion cost from the MISO market than forecast;
2. increased fuel cost for gas generation due to higher gas prices;

[1] Orders dated December 17, 2017, December 12, 2018, and June 12, 2019.

3. increased fuel cost for coal generation in response to higher gas prices and resulting market LMPs; and
4. increased costs for PPA wind generation

Higher market LMPs also led to greater than forecast asset-based sales volumes and revenues, which also increased volume of generation from both gas and coal generators. In addition, actual FTR revenues were greater than forecast. Asset-based sales and FTR revenues served to offset some of the increased costs for 2022. We review these drivers and mitigating factors in detail in section II-D.

In this report, we provide details of the variance between forecast and actuals, discuss the prudency of our management of fuel costs in 2022, propose to implement true-up factors by class in September 2023 to return $3.8 million of over-collected costs to customers in one month, and provide various additional compliance reports.

2022 ANNUAL TRUE-UP REPORT

I. DESCRIPTION AND PURPOSE OF FILING

A. Background

On December 19, 2017, the Commission issued its ORDER APPROVING NEW ANNUAL FUEL CLAUSE ADJUSTMENT REQUIREMENTS AND SETTING FILING REQUIREMENTS in Docket No. E999/CI-03-802 (December 19 Order) which requires a utility's fuel rates to be set in a rate case or an annual fuel clause adjustment filing unless a utility can show a significant unforeseen impact. The Order specifies that these filings should include complete documentation supporting the proposed fuel rates, including information on Power Purchase Agreements (PPAs), estimates of costs for each type of fuel, and the proportion of each type of fuel, along with a complete description of any model used to develop the proposed $/MWh fuel rates, including but not limited to the identification and justification of the inputs and formulas used for all fuel types, and fully documented sales forecasts.

The December 19 Order also requires utilities to report annually the actual $/MWh fuel costs in each month by fuel type (including identification of costs from specific power purchase agreements) and compare the annual revenue based on the fuel rates set by the Commission with annual revenues based on actual costs for the year. Each utility will refund any over-collections and show prudence of costs before allowing recovery of under-collections. If annual revenues collected ($/MWh) are higher than total actual costs, the utility must refund the over-collection through a true-up mechanism. If annual revenues collected are lower than total actual costs, the utility must show why it is reasonable to charge the higher costs (under-collections) to ratepayers through a true-up mechanism. In this true-up report, the Company reports that the 2020 annual revenues collected were lower than total actual costs, and therefore we show why it is reasonable to charge the higher costs.

The Commission's December 12, 2018 Order in the same docket (December 12 Order) established January 1, 2020 as the implementation date for Fuel Clause Reform and also ordered that the forecast year be a calendar year. Each utility is required to file its Annual Fuel Forecast Petition in a separate docket.

The Commission's June 12, 2019 Order (June 12 Order) in the same docket set forth a procedural schedule for the various filings, reviews, approvals, and implementation of the various components Annual Fuel Forecast process and approved the disposition of reporting items that are required to be included in Electric AAA Reports per Minn. Rules and past Commission Orders.[2]

The Commission's December 2, 2021 Order in Docket No. E002/AA-21-295 approved the Company's fuel forecast and resulting monthly rate factors by customer class for calendar year 2022. The Commission's July 5, 2022 Order in Docket No. E002/AA-20-417 approved 2021 true-up factors by customer class, which adjusted the approved rates for the months of September through December 2022. In addition, no party objected to the Company's May 19, 2022 adjustment proposal filed in Docket No. E002/AA-21-295, therefore we implemented a $61.0 million increase to fuel costs which increased the rate factors by customer class for the months of July through December 2022.

B. Procedural Schedule

Under the procedural schedule detailed in Appendix A of the June 12 Order, Comments on the true-up reports are due on April 15, Reply Comments are due on May 2, and Response Comments are due on May 15. A Commission Order is expected by August 2 to allow utilities to provide customers notice of true-up rate factors 30 days before implementation on September 1.

[2] See Part F, Attachment 5 of this Report for a compliance matrix detailing the various compliance items included in this report.

II. 2022 FORECAST VERSUS ACTUALS COMPARISON

A. Summary

The Company's 2022 actual fuel expense was $950.2 million, or $100.8 million higher than our approved forecast of $849.4 million. The actual average fuel cost of $33.55 per MWh was 6.6 percent higher than the authorized rate of $31.47 per MWh. However, actual fuel cost collections were $891.0 million due to 4.9 percent higher than forecast Minnesota jurisdictional sales. Furthermore, Minnesota fuel collections were adjusted through a mid-year rate surcharge, resulting in an additional $62.9 million of collections from July through December. Therefore total Minnesota fuel collections were $954.0 million versus total actual fuel expense of $950.2 million, resulting in over-collected fuel costs of $3.8 million.

Table 1 below summarizes the 2022 forecast to actuals comparison.

**Table 1: 2022 Fuel Cost and Revenue Comparison Summary
MN Jurisdiction**

	Actual (000s)	Forecast (000s)	Variance (000s)	Variance (%)
Total FCA Costs	$950,221	$849,447	$100,774	11.9%
MWh Sales	28,318,349	26,988,335	1,330,013	4.9%
FCA Cost in $/MWh	$33.55	$31.47	$2.08	6.6%
Fuel Collections	$891,041	$849,447	$41,594	4.9%
Mid-Year Adjustment Collections	$62,934			
(Over) Under Recovery	($3,753)			

We provide more detailed analysis of variances between the forecast and actuals for the primary components of fuel costs later in this report.

B. Management of 2022 Fuel Costs and Prudency of True-Up Proposal

2022 was another challenging year for fuel recovery under the new fuel recovery mechanism. Beginning with rising natural gas prices in September 2021, just following our July 2021 Reply Comments filing, and continuing throughout the year, pressures arose that led to significantly higher costs than forecast. Natural gas prices stayed higher than forecast throughout most of the year, leading to higher fuel costs than forecast for the year. As a result of high gas prices, coal generation ran more than forecast, and resulted in higher than forecast costs for coal generation. Given high natural gas prices, increased coal generation served as an offset, resulting in lower overall costs for customers than alternative forms of generation.

Another pressure that drove costs much higher than forecast was substantially higher costs from congestion. Recall that Locational Marginal Prices consist of three components: system energy cost (which varies for each market interval but is constant across the MISO footprint for that interval), congestion costs, and losses. Put simply, congestion costs are a signal that transmission capacity in the market is constrained. Congestion costs saw step increases in April 2021 and again in September 2021, and remained high throughout 2022. In-servicing of new projects, such as the Huntley-Wilmarth transmission line in December 2021, provided some relief to further step increases in congestion costs; however, costs still ended the year much higher than forecast in our July 2021 Reply Comments, the forecast approved in this docket. Congestion was high in MISO due to substantial additions of renewable energy, concentrated in certain wind-rich regions of MISO. Additions of generation have outpaced transmission capacity, limiting the ability to transport lower-cost wind generation to load zones in MISO, instead leaving higher priced resources to set marginal market prices. On-going transmission work in MISO to bring new lines, such as Huntley-Wilmarth, into service and actions such as reconfigurations and dynamic line ratings may help mitigate some of the congestion in the near term. However, additional investment in transmission will likely be necessary to address congestion over the longer term.

Throughout all these events, we were able to manage our generation fleet successfully and reliably, with outstanding nuclear plant performance evidenced by low nuclear forced outage rates. This led to substantial revenues from asset-based sales to MISO that contributed a significant offset to higher fuel and congestion costs. In addition, greater than forecast revenues from FTRs provided a partial offset to high congestion costs realized in 2022. The rise in natural gas prices, in addition to rising congestion in MISO, were events the Company could not have forecast in July 2021 when our Reply Comments established rates for 2022 fuel recovery.

Although the Company's year-end results reveal over-collection of $3.8 million, this reflects $62.9 million in additional fuel surcharges implemented as a mid-year adjustment to fuel rates beginning in July 2022. At that time, the Company projected that year-end under-recovery could exceed $100 million. Subsequently, gas prices and congestion costs moderated slightly and did not continue to increase to higher levels. In addition, FTR and asset- based sales revenues provided a greater offset to higher costs than we anticipated.

Because 2022 under-recovery was recovered through the surcharge we implemented in July, leading to a slight over-recovery by year-end, and because the Company managed our diverse generation fleet through very challenging circumstances to provide high availability that led to significant offsets to higher costs, we believe our proposal to refund the over-collected 2022 fuel costs is reasonable, and we request the Commission approve a true-up for that amount.

C. Proposed True-Up Rate Factors

We propose to refund $3.8 million in the September 2023 Fuel Cost Charge (FCC). The proposed monthly true-up factors by customer class are shown in Part A, Attachment 3 and Part A, Attachment 5.

To determine the proposed true-up factors by customer class, we compare the 2022 forecasted Minnesota cost to the actual cost, which includes the mid-year rate adjustment. This monthly amount, further divided by the Minnesota jurisdiction MWh sales subject to the Fuel Clause Adjustment, yields the true-up per unit cost for each month. This per unit cost multiplied by the Fuel Adjustment Factor (FAF) ratio determines the proposed class true up factors. The proposed class refund will be added to the September 2023 FCC. We provide the proposed tariff sheet reflecting the proposed true-up rates as Part A, Attachment 9. We propose to update the Company web site with the true-up factors by August 1, 2023, or upon issuance of the Commission's Order, to provide customers 30 days' notice of the rate change. Monthly fuel rates are presented at the following link: https://www.xcelenergy.com/company/rates_and_regulations/rates/rate_riders.

Pursuant to the Commission Order dated July 5, 2022 in Docket No. E002/AA-20-417, the Commission authorized the Company to recover the 2021 under-collection of $81.8 million over twelve months beginning with the September 2022 FCC. As shown in Part A, Attachment 5, the Company has recovered $28.9 million during the last 4 months in 2022. The over- or under-recovery of the $81.8 million true-up will be determined when the final monthly recovery is completed in August 2023. The Company will submit a filing in late September in Docket No. E002/AA-20-417 to address the final true-up amount for 2021. If no objections are received from other parties within 30 days, the Company will implement the final true-up by adjusting the November 2023 FCC factor accordingly.

D. Detailed Variance Explanations

Part A, Attachment 1 of this report summarizes the year-end results by providing a comparison of forecast to actuals by fuel cost component, including the variance amount. Below we describe variances between the forecast and actuals for the primary components of fuel costs.

i. Company-Owned Hydro Generation

The Company-owned hydro generation forecast was based on a 30-year annual historical average of hydro generation for NSP System plants. There is no cost for hydro generation in the model because it's a fuel free resource.

Figure 1: Hydro Forecast to Actuals

	2022 ($000)			2022 GWh			2022 $/MWh		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
Hydro	0	0	0	848	933	(85)	$0.00	$0.00	$0.00

Company-owned hydro facilities experienced lower than normal water flows in 2022, which resulted in less hydro generation than forecast. Less hydro generation than forecast increased generation from other fuel types.

ii. Company-Owned Wind Generation

To forecast wind generation the forecast model incorporates individual hourly profiles of each NSP-owned project based on historical data for projects with at least twelve months of operational data. For new projects that did not yet have annual data, the profiles were based on turbine technology, plant design, and localized weather data.

Figure 2: Company-Owned Wind Forecast to Actuals

	2022 ($000)			2022 GWh			2022 $/MWh		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
Owned Wind	0	0	0	9,361	8,328	1,033	$0.00	$0.00	$0.00

Actual 2022 Company-owned wind generation was greater than forecast primarily due to improved wind resources relative to forecast. There is no cost for wind generation in the model because it is a fuel free resource. Higher wind generation than forecast reduced generation from other fuel types and contributes to lower costs.

iii. Company-Owned Coal Generation

Coal prices are forecast based on coal purchases under contract and rail contracts in effect at the time of filing. Any coal requirements that are not under contract are forecast based on spot market prices. The coal forecast includes key modeling parameters, such as operating capacity and heat rate, based on capabilities of the individual plants. Planned maintenance for each unit, as well as forced outage rates based on historical data and expected plant conditions going forward, are included in the forecasted coal rates. We discuss detailed outage data in more detail later in this report.

Figure 3: Company-Owned Coal Forecast to Actuals

	2022 ($000)			2022 GWh			2022 $/MWh		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Coal	$242,848	$138,083	$104,766	9,524	5,867	3,657	$25.50	$23.54	$1.96

Actual coal generation in 2022 was greater than forecast. This was due to higher gas prices that led to stronger LMP and greater market sales making coal more economical for generation. Also, the 2022 forecast assumed seasonal operations of two coal units, that could not occur following a ruling by MISO's Independent Market Monitor (IMM), which further contributed to greater generation from coal than forecast. The increase in coal generation is the primary driver to higher coal costs than forecast. A secondary driver is higher cost for coal fuel delivered to the plants. Some of the increase was driven by coal purchases made after our July 30, 2021 Reply Comments that were priced higher than assumed. Coal prices were higher in response to natural gas prices that had already begun to rise by the Fall of 2021.

iv. Company-Owned Wood/RDF Generation

The wood/refuse-derived fuel (RDF) forecast includes key modeling parameters, such as operating capacity and heat rate, based on capabilities of the individual plants. Planned maintenance for each unit, as well as forced outage rates based on historical data and expected plant conditions going forward, are included in the forecasted wood/RDF rates. We discuss detailed outage data in more detail later in this report.

Figure 4: Company-Owned Wood/RDF Forecast to Actuals

	2022 ($000)			2022 GWh			2022 $/MWh		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Wood/ RDF	9,781	9,392	389	513	442	71	$19.05	$21.23	-$2.18

Actual 2022 Company-owned wood/RDF cost was slightly higher than forecast due to increased generation, but the $/MWh declined due to lower fuel costs.

v. Company-Owned Natural Gas Generation

The Company-owned natural gas forecast includes key modeling parameters, such as operating capacity and heat rate, based on capabilities of the individual plants. Planned maintenance for each unit, as well as forced outage rates based on historical data and expected plant conditions going forward, are included in the natural gas forecast. We discuss outage data in more detail later in this report.

Natural gas fuel prices are forecast based on New York Mercantile Exchange (NYMEX) futures prices for natural gas at the Ventura hub at the time of our July 30, 2021 Reply Comments filing. Costs for transport of natural gas to each specific plant are based on the Company's transport and delivery contracts in place at the time we made our filing.

Figure 5: Company-Owned Natural Gas Forecast to Actuals

	2022 ($000)			2022 GWh			2022 $/MWh		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Owned Gas	263,681	161,071	102,610	4,381	4,695	(313)	$60.19	$34.31	$25.88

The Company used natural gas futures prices in July 2021 for our Reply Comments filing. Subsequent to that filing, natural gas prices began to rise significantly in the Fall of 2021 and remained elevated throughout 2022. Higher natural gas prices resulted in greater costs for natural gas generation despite lower generation than forecast.

vi. Company-Owned Nuclear Generation

The Company-owned nuclear forecast includes key modeling parameters, such as monthly operating capacity, based on the capability of each individual unit. Planned maintenance for each unit, as well as forced outage rates based on historical data and expected conditions going forward, are included in the forecasted nuclear rates. Forecasted nuclear fuel price is based on the Company's existing nuclear fuel contracts at the time the forecast was filed.

Figure 6: Company-Owned Nuclear Forecast to Actuals

	2022 ($000)			2022 GWh			2022 $/MWh		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Nuclear	117,174	115,474	1,700	14,696	14,599	97	$7.97	$7.91	$0.06

Actual Company-owned nuclear generation experienced better-than-forecast performance in 2022 due to continued strong performance from our nuclear fleet. The investments we have made in our nuclear plants over the past several years have provided benefit. Since January 2019 (through December 2022), Monticello has operated at an average capacity factor of more than 93 percent, including 98.6 percent in 2020 and 98.0 percent in 2022, both non-refueling years. In that same timeframe, Prairie Island achieved a combined average capacity factor of 96 percent, including a 99.8 percent on Unit 1 in 2021 and 99.9 percent on Unit 2 in 2022, both non-refueling years. Part C, Attachments 4 and 5 provide details on actual outages in 2021, including a comparison of forecast to actual outage costs by unit.

vii. Purchased Natural Gas Generation

The purchased natural gas forecast includes key modeling parameters, such as operating capacity and heat rate, based on capabilities of the individual plants or according to terms specified in the individual Power Purchase Agreements (PPAs). Planned maintenance for each unit based on the overhaul schedule provided by the PPA counterparty, as well as forced outage rates based on historical data and expected plant conditions going forward, are included in the PPA natural gas forecast.

Figure 7: Purchased Natural Gas Forecast to Actuals

	2022 ($000)			2022 GWh			2022 $/MWh		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
Gas PPAs	155,596	94,913	60,673	2,495	3,212	(717)	$62.36	$29.55	$32.81

The Company used natural gas futures prices in July of 2021 for our July 30, 2021 Reply Comments filing. Subsequent to that filing, natural gas prices began to rise significantly in the Fall of 2021 and remained elevated throughout 2022. Higher natural gas prices resulted in greater costs for natural gas generation despite lower generation than forecast.

viii. Purchased Solar Generation (PPAs)

Each solar PPA is modeled in the forecast with hourly profiles for each project. These profiles are based on historical results from projects with operational data, and prices are based on the terms of each contract.

Figure 8: Solar PPAs Forecast to Actuals

	2022 ($000)			2022 GWh			2022 $/MWh		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
Solar PPAs	48,621	47,827	795	788	767	21	$61.71	$62.38	-$0.67

Actual 2022 PPA solar costs were slightly higher than forecast due greater generation than forecast.

ix. Purchased Solar Generation (Community Solar Gardens)

The community solar gardens (CSG) program forecast includes expectations of future growth based on current applications for gardens seeking to participate in the program. We identified current projects to anticipate in-service dates and estimate project completion (in capacity) by month and year. We also forecast additional applications based on a three-year historical average (removing outliers) to help account for our future pipeline of projects. The program is modeled as one entity rather than individually by garden. The assumed price for the program is based on historical price data, incorporating the Applicable Retail Rate (ARR) and Value of Solar (VOS) vintage rates for projects forecasted to be in-service in 2021.

The market cost of energy from the solar gardens generation is determined based on the assumed Locational Marginal Price (LMP) in the simulation. This cost is shared with all jurisdictions in the NSP system. The cost of the program above market is direct assigned to Minnesota customers.

Figure 9: Community Solar Gardens Forecast to Actuals

	2022 ($000)			2022 GWh			2022 $/MWh		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
CSG Market	99,994	38,884	61,110						
CSG Above Market	84,036	161,853	(77,816)						
Total CSG	184,030	200,737	(16,707)	1,404	1,577	(173)	$131.12	$127.29	$3.83

Costs for community solar gardens (CSGs) were lower than forecast due primarily to lower generation from CSGs than assumed in our July 30, 2022 Reply Comments. Partially offsetting the cost decrease due to lower generation was higher CSG rates driven by a higher ARR than we had assumed in our Reply. The higher ARR was driven by higher actual fuel costs, the interim rate increase in 2022, and the Company's riders, including the Renewable Energy Standard (RES) Rider.

See Part C, Attachments 8-10 for more details about actual CSG above-market costs and total number of gardens and subscriptions.

x. Purchased Wind Generation

The wind PPA forecast reflects the hourly profiles for each individual project. For existing PPAs, profiles are based on historical data. For new PPAs, the profiles are based on turbine technology, plant design, and localized weather data. The price for each wind PPA is based on the terms of each contract. Projects for which the Company can allow MISO to curtail output are modeled as curtailable projects, using a 5-year historical average for curtailment costs. Those for which curtailment is not allowed are modeled as non-curtailable projects.

Figure 10: Wind PPAs Forecast to Actuals

	2022 ($000)			2022 GWh			2022 $/MWh		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Wind PPAs	244,613	215,351	29,261	6,470	6,688	(218)	$37.81	$32.20	$5.61

Actual purchased wind generation was less than forecast due to higher wind curtailment than assumed in the forecast. Some of the increase in curtailment was offset by improved wind resources relative to forecast. Wind PPA costs were higher than forecast because of greater curtailment costs than assumed in our Reply forecast, in addition to greater available PPA wind generation due to improved wind resource. See Part C, Attachments 1 and 2 for more details regarding wind curtailment.

xi. Purchased Generation – Other

PPAs that do not fit within one of the prior three categories (primarily small hydro PPAs, the remaining biomass PPA, and the PPA with Manitoba Hydro) are modeled based on historical generation (for the small hydro PPAs) or according to their contract terms (for the biomass and Manitoba Hydro PPAs). Price is determined based on contract terms or based on historical prices with assumed escalation.

Figure 11: Other PPAs Forecast to Actuals

	2022 ($000)			2022 GWh			2022 $/MWh		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Other PPAs	190,655	192,847	(2,182)	2,220	2,351	(131)	$85.90	$82.03	$3.87

Actual 2022 costs for other purchased generation were slightly lower than forecast due to lower generation volumes from this mix of other PPA contracts.

xii. Market Purchases and Sales

For forecasting purposes, the PLEXOS simulation can purchase energy from a simulated MISO market if that source of supply results in lower cost than utilization of one of the NSP system dispatchable resources. In addition, the model forecasts asset-based sales opportunities into the MISO market after system native requirements are fulfilled. This is done through an hourly dispatch simulation based on projected hourly market prices that represent LMP for the NSP system. The sum of these quantities plus the MISO charges represent the equivalent MISO Day 2 and Day 3 costs for the Forecast.

Figure 12: Net MISO Costs and Revenues

	2022 ($000)			2022 GWh		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Net MISO	($178,121)	($40,700)	($137,421)	(10,951)	(6,674)	(4,277)

Due to congestion, net MISO revenue was lower, despite higher than forecast asset-based sales into MISO. Higher than forecast LMPs led to greater volume and revenue from asset-based sales, but these sales were made from higher cost generation due to higher fuel prices and limited ability to transport energy from the Company's renewable resources. In addition, higher market LMPs resulted in greater costs for market purchases from MISO than forecast.

Table 2 below compares the 2022 forecast to actuals by primary MISO charge type.

Table 2: MISO Charge Type Forecast to Actuals ($000s)

Category	Actual	Forecast	Variance
Congestion	$287,010	$118,750	$168,260
FTR	($130,758)	($36,032)	($94,727)
Incremental Transmission losses	$30,863	($6,612)	$37,475
RSG/RNU	$7,599	$6,966	$633
ASM	($5,541)	($1,852)	($3,690)
MISO Charges TOTAL	$189,172	$81,221	$107,951

We provide additional MISO charge details in Part B, Attachments 1-14. In addition, we discuss system congestion in Part B, Attachment 1 and within our wind curtailment report provided as Part C, Attachment 1.

Table 3 compares the 2022 forecast to actual Asset-Based Margins.

Table 3: Actual 2022 Asset-Based Margins($ millions)

	Revenue	Cost	Margin
Forecast	135.8	87.3	48.5
Actuals	564.4	376.1	188.3
Variance	428.6	288.8	139.8

Asset-Based margins were higher than forecast consistent with the increase in revenues from asset-based sales into MISO as previously discussed. Higher LMP was the primary driver to higher volumes of asset-based sales as the Company's low cost resource portfolio was heavily relied on by MISO throughout the year. Higher fuel costs for natural gas and coal throughout the year led to a lower increase in margins than the increase in revenues as shown in Table 3.

xiii. Retail Sales

The Minnesota sales forecast used in the 2022 Fuel Forecast was developed in July 2021. Actual Minnesota retail sales in 2022 were 28,994,858 MWh, compared with the 2022 sales forecast of 28,201,969 MWh, resulting in a sales-to-forecast variance of 792,889 MWh.[3] As summarized in Table 4 below, contributing factors to the forecast variance include: lower than expected savings from demand side management (DSM) programs,[4] slightly higher than anticipated load additions from commercial and industrial customers (C&I), increased sales due to weather, lower than forecast Combined Heat and Power (CHP) generation, greater than anticipated distributed solar generation, and other non-specified factors. In summary, DSM and weather impacts were the largest contributors to the forecast variance.

[3] Sales for Renewable*Connect and WindSource programs are excluded from these figures in the fuel clause mechanism.

[4] This forecast included a sizable "over achievement" adjustment based on a 3-year historical average of achieved savings, which resulted in a fairly aggressive DSM outlook.

Table 4: Sales-to-Forecast Variance in 2022 (MWh)

	2022 Minnesota Jurisdiction
Jul 2022 Cal Mth Sales Forecast	28,201,969
Actual 2022 Cal Mth Sales	28,994,858
Actual Sales Variance from Forecast	792,889
Contribution to Forecast Variance:	
DSM Forecast Variance	661,166
C&I Load additions/reductions	**[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**
2022 Weather Impact	305,862
CHP Forecast Variance	**[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**
Solar Forecast Variance	(97,962)
Other Factors	(152,944)
Total	792,889

E. Other Items Impacting Total Fuel Cost

i. Costs Excluded from Fuel Costs

Part A, Attachment 3 provides monthly details of the direct assigned WindSource and Renewable*Connect amounts for 2022, which are excluded from total fuel costs.

ii. Solar Energy Standard Exclusion

The Commission's January 16, 2018 Order in Docket No. E002/M-17-425 approved the Company's plan for crediting Solar Energy Standard (SES)-related costs back to SES-exempt customers and to annually recover this amount from the Company's customers through the riders through which solar costs are charged.[5] The 2021 annual FCA recovery of $831,268 is shown in Part A, Attachment 2, line 46, the month the excluded customers were issued their bill credit.[6] The amount is also included in the "Other Adjustments" line on Part A, Attachment 1. This charge was not included in the original forecast given the small amount and in order to include only the exact amount after it is known.

[5] The Fuel Clause Adjustment (FCA) and Renewable Development Fund (RDF) Riders.

[6] The Company provided this amount in the June 1, 2022 SES Exclusion Annual Report filed in Docket No. E002/M-17-425.

iii. Saver's Switch Discount Recovery

The Saver's Switch discount is applied during the months of June through September, and therefore our 2022 true-up shows these amounts for those months in our detailed monthly actuals report shown in Part A, Attachment 2, line 47. The amount is also included in the "Other Adjustments" line on Part A, Attachment 1. This charge was not included in the original forecast given the small amount and in order to include only the exact amounts after they are known.

IV. REPORTING IN COMPLIANCE WITH MINNESOTA RULES

This filing contains information provided in response to the annual reporting requirements specified in the following rule sections:

7825.2800 Policies and Actions
7825.2810 Annual Report of Automatic Adjustment Charges
7825.2820 Annual Auditor's Report
7825.2830 Annual Five-Year Projection
7825.2840 Annual Notice of Reports Availability

A. 7825.2800 Annual Reports: Policies and Actions

Part D, Attachments 1-10 include information and supporting data in compliance with the following topics listed in Minn. Rule 7825.2800:

- Procurement Policies
- Dispatching Policies and Procedures
- Fuel Supply
- Conservation Policy
- Other Actions

The Commission's June 12, 2019 Order approved a rule variance requiring this information to be submitted by March 1 each year with the Annual True-Up filing.

B. 7825.2810 Annual Report: Automatic Adjustment of Charges

Minn. Rule 7825.2810 requires the following information:

- Base Cost of Fuel

- Billing Adjustment Amounts Charged Customers for Each Month
- Total Cost of Fuel Delivered to Customers
- Revenue Collected from Customers for Energy Delivered
- Monthly Fuel Cost Charge

The Commission's June 12, 2019 Order approved a rule variance requiring this information to be submitted by March 1 each year with the Annual True-Up filing.

1. Base Cost of Fuel

The Commission's November 5, 2019 Order in Docket No. E999/CI-03-802 approved the Company's proposed changes to the base cost of energy. The Company will no longer recover energy-related costs via a base costs of energy. For electric rate case filings, a representative level of test year fuel expense and revenues will be set using the most recent fuel expense forecast filed in the Annual Fuel Forecast docket. Our tariff sheets have been updated to reflect these changes.

As required by the Order, the Company has included in our 2022 test year rate case application a demonstration that the proposed base rates exclude Fuel Clause-Adjustment-related costs.[7]

2. Monthly Fuel Cost Charges

See Part A, Attachment 8 for the monthly fuel cost charges implemented in 2022.

C. 7825.2820 Annual Auditor's Report

The Annual Auditor's Report is provided as Part E, Attachment 2.

The Commission's March 20, 2002 Order in Docket Nos. E002/M-01-1953 and E,G999/AA-02-950 approved the Company's proposed method to separate, for accounting purposes, the costs and effects of financial instruments purchased to meet the needs of retail electric or natural gas ratepayers from the financial instruments purchased to mitigate price risk in the Company's non-jurisdictional wholesale electric sales activity. The Commission's Order also required the Company to submit a written request that its external auditors specifically examine these transactions in preparation of the auditor's report, to be submitted with the Company's 2001-2002 electric and natural gas AAA reports submitted September 1, 2002. The Company continues to annually provide such a written request to its external auditors. Part E,

[7] Docket No. E002/GR-21-630

Attachment 1 is a copy of the letter that was sent to facilitate the independent audit by Deloitte & Touche LLP.

Additional audit reporting requirements included in the Commission's July 21, 2017 Order in the 2015 AAA Report proceeding (Docket No. E999/AA-15-611) are discussed in the letter outlining audit requirements that was sent to the auditor.

D. 7825.2830 Annual Five-Year Projection

The monthly five-year projection of fuel cost by energy source for the period of 2023-2027 was provided as part of the Company's May 2, 2022 fuel forecast for calendar year 2023. The monthly five-year projection of fuel cost by energy source for the period of 2024-2028 will be provided as part of the Company's May 1, 2023 fuel forecast for calendar year 2024.

E. 7825.2840 Annual Notice of Reports Availability

Minn. Rule 7825.2840 requires utilities to provide notice of the availability of the reports defined in parts 7825.2800 to 7825.2830 to all intervenors in the utility's two previous general rate cases. In compliance with this rule, the Company is providing notice to all intervenors in our 2015 and 2021 electric rate cases who have requested to remain on the docket service lists.

V. OTHER COMPLIANCE ITEMS

Please see the Table of Contents for a complete list of attachments provided in compliance with a variety of Commission Orders in various dockets.

CONCLUSION

Xcel Energy respectfully requests the Commission approve our 2022 Annual True-Up Report, our proposal to refund $3.8 million in over-recovered fuel costs for the 2022 calendar year, and the Electric AAA reporting requirements included in this report.

Dated: March 1, 2023

Northern States Power Company

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Northern States Power Company
Electric Utility - State of Minnesota
Comparison of Actual Fuel and Purchased Power Costs to Filed Forecast

	2022 ($000)	
MN Jurisdiction Fuel Collections	$891,041	
MN Jurisdiction Fuel Costs	$950,221	
(Over)/Under Recovery (Deferred to Balance Sheet)	**$59,181**	**Receivable**
Collections via Mid-Year Rate Adjustment	$62,934	
Net (Over)/Under Recovery	**($3,753)**	**Net Liability**

	2022 ($000)				2022 GWh			2022 $/MWh		
	Actual	Forecast (1)	Variance	% Variance	Actual	Forecast (1)	Variance	Actual	Forecast (1)	Variance
Coal	$242,848	$138,083	$104,766		9,524	5,867	3,657	$25.50	$23.54	$1.96
Wood/RDF	8,951	9,392	(441)		513	442	71	$17.43	$21.23	-$3.80
Natural Gas & Oil	264,511	161,071	103,440		4,381	4,695	(313)	$60.38	$34.31	$26.06
Wind, Solar, Hydro		0	0		10,209	9,267	943	$0.00	$0.00	$0.00
Nuclear Fuel	117,174	115,474	1,700		14,696	14,599	97	$7.97	$7.91	$0.06
Total Fuel	$633,483	$424,020	$209,464	49.4%	39,324	34,869	4,455	$16.11	$12.16	$3.95
Purchased Energy	733,489	301,672	431,817		7,485	6,140	1,345	$97.99	$49.13	$48.86
Purchased Energy (Solar)	48,316	47,827	489		788	767	21	$61.32	$62.38	-$1.06
Community Solar*Gardens	184,347	200,737	(16,390)		1,403.55	1,577.00	(173)	$131.34	$127.29	$4.05
Purchased Energy (Wind)	244,613	215,351	29,261		6,470	6,688	(218)	$37.81	$32.20	$5.61
MISO Market Charges	(990)	81,221	(82,211)							
Total Purchased Power	$1,209,774	$846,808	$362,966	42.9%	16,146	15,172	975	$74.92	$55.82	$19.11
Less Sales Revenue	($564,368)	($135,833)	($428,535)		(13,721)	(7,251)	(6,470)	**$41.13**	**$18.73**	**$22.40**
Less Costs Direct Assigned (2)	(124,383)	(197,845)	73,462							
Net System Costs	**$1,154,506**	**$937,149**	**$217,357**	**23.2%**	41,749	42,790	**(1,040)**	**$27.65**	**$21.90**	**$5.75**
Net System Mwh Sales	**39,689,014**	**38,081,074**	**1,607,940**	**4.2%**						
System Cost in $/Mwh	**$29.09**	**$24.61**	**$4.48**	**18.2%**						
MN Jurisdictional Fuel Cost	***$824,270***	***$664,597***	***$159,673***							
Direct Assigned Costs:										
Solar Gardens - Above Market Cost	99,883	161,853	(61,970)							
Biomass Termination Costs	22,906	22,998	(92)							
Net Direct Assigned Costs	**$122,789**	**$184,850**	**($62,061)**	**-33.6%**						
MN Direct Assigned	***$122,789***	***$184,850***	***($62,061)***							
SES Exemption	***831***		***831***							
Saver Switch	***2,331***		***2,331***							
Total MN Jurisdiction FCA Costs	**$950,221**	**$849,447**	**$100,774**	**11.9%**						
MN Jursdiction Mwh Sales	**28,318,349**	**26,988,335**	**1,330,013**	**4.9%**						
MN Jurisdiction FCA Cost in $/MWh	**$33.55**	**$31.47**	**$2.08**	**6.6%**						

(1) As filed with the MPUC in July 2021
(2) Community Solar Garden, Windsource, Renewable Connect

Northern States Power Company
Electric Utility - State of Minnesota
2022 Fuel, Purchased Power and Other Costs

	($000)	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	2022 Total
	Owned Generation													
	Fossil Fuel													
1	Coal	$31,882	$21,690	$15,339	$5,195	$6,027	$23,008	$32,297	$29,570	$14,247	$16,713	$16,651	$30,229	$242,848
2	Wood/RDF	$352	$722	$588	$540	$837	$862	$1,002	$1,081	$740	$1,331	$775	$951	$9,781
3	Natural Gas CC	$16,162	$18,189	$13,306	$13,993	$13,279	$22,419	$26,333	$32,992	$24,435	$12,703	$8,604	$14,707	$217,122
4	Natural Gas & Oil CT	$1,489	$859	$650	$512	$2,572	$6,694	$8,691	$9,821	$6,343	$3,162	$2,814	$2,953	$46,559
5	Total Fossil Fuel 1+2+3+4	$49,886	$41,459	$29,883	$20,239	$22,715	$52,983	$68,323	$73,464	$45,765	$33,909	$28,843	$48,840	$516,310
6	Hydro	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7	Wind	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Nuclear Fuel	$9,634	$9,312	$10,231	$9,991	$10,136	$10,018	$10,345	$10,336	$9,940	$8,213	$8,822	$10,194	$117,174
9	Total Fuel 5+6+7+8	$59,520	$50,772	$40,114	$30,230	$32,851	$63,001	$78,668	$83,800	$55,705	$42,122	$37,665	$59,035	$633,483
	Purchased Energy													
10	LT Purchased Energy (Gas)	$11,568	$6,378	$5,032	$7,667	$10,488	$16,752	$22,644	$25,463	$17,102	$9,456	$7,874	$15,163	$155,586
11	LT Purchased Energy (Solar)	$1,872	$2,946	$4,152	$3,960	$5,393	$6,826	$6,382	$5,526	$5,154	$3,671	$1,798	$954	$48,633
12	Community Solar*Gardens	$8,014	$11,620	$15,627	$13,644	$19,409	$22,929	$22,164	$21,705	$20,080	$16,110	$7,849	$4,880	$184,030
13	LT Purchased Energy (Wind)	$23,938	$23,095	$22,653	$22,319	$22,842	$17,301	$13,433	$13,797	$17,655	$21,634	$24,794	$21,152	$244,613
14	LT Purchased Energy (Other)	$12,965	$9,020	$14,664	$10,627	$19,115	$20,694	$19,306	$21,086	$19,845	$13,773	$14,342	$15,229	$190,665
15	Total Purchased Energy 10+11+12+13+14	$58,357	$53,058	$62,127	$58,216	$77,246	$84,501	$83,928	$87,576	$79,836	$64,645	$56,657	$57,379	$823,527
16	ST Market Purchase	$10,793	$8,127	$10,367	$7,956	$14,068	$17,578	$12,144	$10,084	$27,330	$13,248	$5,083	$9,994	$146,773
17	Asset Based Sales Revenues (Market Sales)	($56,191)	($41,182)	($26,479)	($28,347)	($26,562)	($66,082)	($69,845)	($77,361)	($54,424)	($35,050)	($25,377)	($57,467)	($564,368)
18	Net Market Cost 16+17	($45,398)	($33,055)	($16,112)	($20,391)	($12,494)	($48,504)	($57,701)	($67,277)	($27,094)	($21,801)	($20,294)	($47,473)	($417,595)
19	MISO Cost	$23,523	$27,373	$20,701	$42,432	$16,995	$12,237	$15,303	$18,498	$14,433	$19,832	$18,142	$10,004	$239,474
20	Net MISO D2 and ASM Cost 18+19	($21,875)	($5,682)	$4,589	$22,041	$4,501	($36,267)	($42,398)	($48,779)	($12,660)	($1,969)	($2,152)	($37,469)	($178,121)
21	**Total System Cost 9+15+20**	$96,002	$98,148	$106,831	$110,488	$114,598	$111,235	$120,198	$122,597	$122,881	$104,798	$92,169	$78,944	$1,278,889
22	Less Solar Gardens - Above Market Cost	($6,717)	($6,326)	($11,526)	($7,826)	($11,106)	($9,437)	($8,518)	($6,921)	($10,682)	($10,093)	($7,026)	($3,726)	($99,903)
23	Less WindSource	($1,315)	($2,340)	($1,188)	($1,919)	($1,249)	($904)	($1,284)	($1,571)	($1,591)	($1,583)	($1,912)	($1,333)	($18,190)
24	Less Renewable*Connect	($577)	($492)	($598)	($476)	($507)	($407)	($574)	($586)	($516)	($544)	($505)	($509)	($6,291)
25	Total Costs Direct Assigned 22+23+24	($8,609)	($9,157)	($13,313)	($10,221)	($12,862)	($10,748)	($10,376)	($9,078)	($12,789)	($12,220)	($9,443)	($5,568)	($124,383)
26	**Net System Costs 21+25**	$87,394	$88,990	$93,518	$100,267	$101,736	$100,488	$109,822	$113,520	$110,092	$92,578	$82,726	$73,376	$1,154,506
	Calendar Month MWh Sales													
27	Total NSP-MN and NSP-WI Retail Sales	3,580,073	3,142,828	3,339,031	2,919,141	3,171,532	3,494,812	3,977,066	3,790,147	3,336,551	3,112,578	3,064,172	3,435,142	40,363,073
28	Less Minnesota WindSource	(41,206)	(36,107)	(39,429)	(35,134)	(33,750)	(38,459)	(43,350)	(46,720)	(42,460)	(59,224)	(38,300)	(39,137)	(493,276)
29	Less Minnesota Renewable*Connect	(16,297)	(14,004)	(16,842)	(13,643)	(14,396)	(18,185)	(14,779)	(16,654)	(14,463)	(15,320)	(14,113)	(14,535)	(183,231)
30	**Total System MWh Sales 27+28+29**	3,522,570	3,092,717	3,282,760	2,870,364	3,123,386	3,438,168	3,918,937	3,726,773	3,279,628	3,038,034	3,011,759	3,381,470	39,686,566
31	Minnesota Jurisdictional Retail Sales	2,522,563	2,234,873	2,370,240	2,084,792	2,285,225	2,540,058	2,928,026	2,752,463	2,423,818	2,228,454	2,184,940	2,439,404	28,994,856
32	Less Minnesota WindSource	(41,206)	(36,107)	(39,429)	(35,134)	(33,750)	(38,459)	(43,350)	(46,720)	(42,460)	(59,224)	(38,300)	(39,137)	(493,276)
33	Less Minnesota Renewable*Connect	(16,297)	(14,004)	(16,842)	(13,643)	(14,396)	(18,185)	(14,779)	(16,654)	(14,463)	(15,320)	(14,113)	(14,535)	(183,231)
34	**Total Minnesota Retail Sales 31+32+33**	2,465,060	2,184,762	2,313,969	2,036,015	2,237,079	2,483,414	2,869,897	2,689,089	2,366,895	2,153,910	2,132,527	2,385,732	28,318,349
35	**System Fuel Costs in cents/kWh 26/30x100**	2.481¢	2.877¢	2.849¢	3.493¢	3.257¢	2.923¢	2.802¢	3.046¢	3.357¢	3.047¢	2.747¢	2.170¢	2.909¢
	Minnesota Jurisdictional Energy Costs													
36	System Fuel Costs in cents/kWh 35	2.481¢	2.877¢	2.849¢	3.493¢	3.257¢	2.923¢	2.802¢	3.046¢	3.357¢	3.047¢	2.747¢	2.170¢	
37	Total Minnesota Retail Sales Subject to FCA 34	2,465,060	2,184,762	2,313,969	2,036,015	2,237,079	2,483,414	2,869,897	2,689,089	2,366,895	2,153,910	2,132,527	2,385,732	28,318,349
38	Minnesota Costs Subject to FCA 36x37100	$61,158	$62,856	$65,925	$71,118	$72,862	$72,590	$80,415	$81,910	$79,457	$65,629.638	$58,581	$51,770	$824,270
	MN Direct Assigned Cost (Solar Gardens & Biomass PPA Buyout)													
39	Solar Garden Above Market Direct Recovery	$6,717	$6,320	$11,514	$7,823	$11,102	$9,438	$8,523	$6,929	$10,683	$10,097	$7,012	$3,724	$99,883
40	Laurentian Payment	$0	$0	$0	$0	$0	$13,062	$0	$0	$0	$0	$0	$0	$13,062
41	Benson Buyout costs	$838	$835	$831	$828	$825	$822	$819	$816	$813	$809.396	$806	$803	$9,844
42	MN Direct Assigned Total	$7,555	$7,155	$12,346	$8,651	$11,927	$23,321	$9,342	$7,745	$11,496	$10,906.016	$7,819	$4,528	$122,789
43	Minnesota Direct Assigned Cost in cents/kWh 43/34*100	0.306¢	0.327¢	0.534¢	0.425¢	0.533¢	0.939¢	0.326¢	0.288¢	0.486¢	0.506¢	0.367¢	0.190¢	0.434¢
44	Minnesota Fuel Costs in cents/kWh 35+44	2.787¢	3.204¢	3.383¢	3.918¢	3.790¢	3.862¢	3.128¢	3.334¢	3.843¢	3.553¢	3.114¢	2.360¢	3.343¢
45	**Minnesota Fuel Costs Subtotal 45*34/100**	$68,713	$70,011	$78,271	$79,769	$84,789	$95,912	$89,756	$89,655	$90,952	$76,536	$66,399	$56,298	$947,059
	Other Adjustments													
46	SES Exemption Recovery	$0	$0	$831	$0	$0	$0	$0	$0	$0	$0	$0	$0	$831
47	Saver's Switch Discount Adjustment						$526	$553	$653	$598				$2,331
48	Other													$0
49	Other Adjustments Total	$0	$0	$831	$0	$0	$526	$553	$653	$598	$0	$0	$0	$3,162
50	**Minnesota Fuel Costs 46+50**	$68,713	$70,011	$79,102	$79,769	$84,789	$96,438	$90,309	$90,308	$91,551	$76,536	$66,399	$56,298	$950,221
51	**Minnesota Fuel Costs in cents/kWh 51/34x100**	2.787¢	3.204¢	3.418¢	3.918¢	3.790¢	3.883¢	3.147¢	3.358¢	3.868¢	3.553¢	3.114¢	2.360¢	3.355¢
52	**Minnesota Fuel Costs in $/MWh 52x10**	$27.87	$32.04	$34.18	$39.18	$37.90	$38.83	$31.47	$33.58	$38.68	$35.53	$31.14	$23.60	$33.55
	$/KWh	$0.02787	$0.03204	$0.03418	$0.03918	$0.03790	$0.03883	$0.03147	$0.03358	$0.03868	$0.03553	$0.03114	$0.02360	$0.03355

2023 Monthly Fuel Clause Charges With 2021 & Proposed 2022 True-Up ($/KWh)

	Residential	Commercial & Industrial					Outdoor Lighting
		Non-Demand	Demand				
			Non-TOD	On-Peak	Off-Peak		
January							
Forecast	$0.03012	$0.03050	$0.02955	$0.03693	$0.02419		$0.02363
2021 True-Up	$0.00304	$0.00308	$0.00299	$0.00373	$0.00244		$0.00238
Total	$0.03316	$0.03358	$0.03254	$0.04066	$0.02663		$0.02601
February							
Forecast	$0.03263	$0.03304	$0.03201	$0.04003	$0.02618		$0.02557
2021 True-Up	$0.00352	$0.00357	$0.00345	$0.00432	$0.00283		$0.00276
Total	$0.03615	$0.03661	$0.03546	$0.04435	$0.02901		$0.02833
March							
Forecast	$0.03963	$0.04013	$0.03888	$0.04862	$0.03180		$0.03106
2021 True-Up	$0.00310	$0.00314	$0.00305	$0.00381	$0.00249		$0.00243
Total	$0.04273	$0.04327	$0.04193	$0.05243	$0.03429		$0.03349
April							
Forecast	$0.04404	$0.04460	$0.04321	$0.05401	$0.03536		$0.03454
2021 True-Up	$0.00357	$0.00362	$0.00350	$0.00438	$0.00287		$0.00280
Total	$0.04761	$0.04822	$0.04671	$0.05839	$0.03823		$0.03734
May							
Forecast	$0.04546	$0.04603	$0.04460	$0.05575	$0.03650		$0.03565
2021 True-Up	$0.00335	$0.00339	$0.00328	$0.00411	$0.00269		$0.00262
Total	$0.04881	$0.04942	$0.04788	$0.05986	$0.03919		$0.03827
June							
Forecast	$0.04801	$0.04862	$0.04710	$0.05890	$0.03854		$0.03764
2021 True-Up	$0.00306	$0.00310	$0.00301	$0.00376	$0.00246		$0.00240
Total	$0.05107	$0.05172	$0.05011	$0.06266	$0.04100		$0.04004
July							
Forecast	$0.04295	$0.04349	$0.04213	$0.05269	$0.03446		$0.03366
2021 True-Up	$0.00266	$0.00269	$0.00261	$0.00326	$0.00213		$0.00208
Total	$0.04561	$0.04618	$0.04474	$0.05595	$0.03659		$0.03574
August							
Forecast	$0.04274	$0.04328	$0.04193	$0.05245	$0.03429		$0.03349
2021 True-Up	$0.00273	$0.00276	$0.00268	$0.00335	$0.00219		$0.00214
Total	$0.04547	$0.04604	$0.04461	$0.05580	$0.03648		$0.03563
September							
Forecast	**$0.04175**	**$0.04227**	**$0.04095**	**$0.05121**	**$0.03351**		**$0.03273**
2022 True-Up	**($0.00167)**	**($0.00169)**	**($0.00164)**	**($0.00205)**	**($0.00134)**		**($0.00131)**
Total	**$0.04008**	**$0.04058**	**$0.03931**	**$0.04916**	**$0.03217**		**$0.03142**
October							
Forecast	$0.03881	$0.03930	$0.03808	$0.04761	$0.03115		$0.03043
Total	$0.03881	$0.03930	$0.03808	$0.04761	$0.03115		$0.03043
November							
Forecast	$0.03580	$0.03625	$0.03512	$0.04392	$0.02873		$0.02806
Total	$0.03580	$0.03625	$0.03512	$0.04392	$0.02873		$0.02806
December							
Forecast	$0.03303	$0.03345	$0.03241	$0.04051	$0.02652		$0.02591
Total	$0.03303	$0.03345	$0.03241	$0.04051	$0.02652		$0.02591

Northern States Power Company
Electric Utility - State of Minnesota
2022 & 2021 Under (+)/Over(-) Recovered Expense and Proposed 2022 True-Up Rate Calculation

	($000)	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	2022 Total
	2022 FCA Factors													
	Approved Forecast Fuel Cost Charge													
	(Docket No. E002/AA-21-295, July 30, 2021 Reply Comments Filing . Approval Order Dated December 2, 2021)													
1	Residential	2.597¢	3.066¢	3.268¢	3.256¢	3.453¢	3.979¢	3.392¢	3.386¢	3.328¢	3.116¢	2.891¢	2.662¢	
2	C&I Non-Demand	2.630¢	3.104¢	3.309¢	3.297¢	3.496¢	4.029¢	3.435¢	3.428¢	3.369¢	3.155¢	2.927¢	2.696¢	
3	C&I Demand Non-TOD	2.548¢	3.008¢	3.206¢	3.194¢	3.387¢	3.903¢	3.328¢	3.321¢	3.265¢	3.057¢	2.836¢	2.612¢	
4	C&I Demand On-Peak	3.184¢	3.761¢	4.009¢	3.992¢	4.234¢	4.880¢	4.161¢	4.154¢	4.081¢	3.822¢	3.546¢	3.265¢	
5	C&I Demand Off-Peak	2.086¢	2.460¢	2.623¢	2.614¢	2.772¢	3.194¢	2.722¢	2.716¢	2.671¢	2.501¢	2.320¢	2.138¢	
6	Outdoor Lighting	2.038¢	2.403¢	2.562¢	2.554¢	2.708¢	3.119¢	2.658¢	2.653¢	2.609¢	2.443¢	2.266¢	2.088¢	
	Mid-Year Adjustment													
	(Docket No. E002/AA-21-295, May 19, 2022 Compliance Filing - Rate Adjustment Proposal)													
7	Residential	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.384¢	0.392¢	0.466¢	0.477¢	0.493¢	0.452¢	
8	C&I Non-Demand	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.388¢	0.397¢	0.472¢	0.483¢	0.499¢	0.458¢	
9	C&I Demand Non-TOD	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.376¢	0.384¢	0.457¢	0.468¢	0.483¢	0.443¢	
10	C&I Demand On-Peak	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.471¢	0.481¢	0.572¢	0.586¢	0.604¢	0.554¢	
11	C&I Demand Off-Peak	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.308¢	0.314¢	0.374¢	0.383¢	0.395¢	0.363¢	
12	Outdoor Lighting	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.301¢	0.307¢	0.365¢	0.374¢	0.386¢	0.354¢	
	Forecast Factors with Mid-Year Adjustment													
13	Residential 1+7	2.597¢	3.066¢	3.268¢	3.256¢	3.453¢	3.979¢	3.776¢	3.778¢	3.794¢	3.593¢	3.384¢	3.114¢	
14	C&I Non-Demand 2+8	2.630¢	3.104¢	3.309¢	3.297¢	3.496¢	4.029¢	3.823¢	3.825¢	3.841¢	3.638¢	3.426¢	3.154¢	
15	C&I Demand Non-TOD 3+9	2.548¢	3.008¢	3.206¢	3.194¢	3.387¢	3.903¢	3.704¢	3.705¢	3.722¢	3.525¢	3.319¢	3.055¢	
16	C&I Demand On-Peak 4+10	3.184¢	3.761¢	4.009¢	3.992¢	4.234¢	4.880¢	4.632¢	4.635¢	4.653¢	4.408¢	4.150¢	3.819¢	
17	C&I Demand Off-Peak 5+11	2.086¢	2.460¢	2.623¢	2.614¢	2.772¢	3.194¢	3.030¢	3.030¢	3.045¢	2.884¢	2.715¢	2.501¢	
18	Outdoor Lighting 6+12	2.038¢	2.403¢	2.562¢	2.554¢	2.708¢	3.119¢	2.959¢	2.960¢	2.974¢	2.817¢	2.652¢	2.442¢	
	2021 True Up													
	(Docket No. E002/AA-20-417, March 1, 2022, Annual True-up Compliance Report. Approval Order Dated July 5, 2022)													
19	Residential	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.325¢	0.333¢	0.340¢	0.309¢	
20	C&I Non-Demand	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.329¢	0.337¢	0.344¢	0.313¢	
21	C&I Demand Non-TOD	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.318¢	0.326¢	0.333¢	0.304¢	
22	C&I Demand On-Peak	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.398¢	0.408¢	0.417¢	0.380¢	
23	C&I Demand Off-Peak	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.260¢	0.267¢	0.273¢	0.248¢	
24	Outdoor Lighting	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢	0.254¢	0.261¢	0.266¢	0.242¢	
	2022 Forecast Factors with 2021 True Up													
25	Residential 13+19	2.597¢	3.066¢	3.268¢	3.256¢	3.453¢	3.979¢	3.776¢	3.778¢	4.119¢	3.926¢	3.724¢	3.423¢	
26	C&I Non-Demand 14+20	2.630¢	3.104¢	3.309¢	3.297¢	3.496¢	4.029¢	3.823¢	3.825¢	4.170¢	3.975¢	3.770¢	3.467¢	
27	C&I Demand Non-TOD 15+21	2.548¢	3.008¢	3.206¢	3.194¢	3.387¢	3.903¢	3.704¢	3.705¢	4.040¢	3.851¢	3.652¢	3.359¢	
28	C&I Demand On-Peak 16+22	3.184¢	3.761¢	4.009¢	3.992¢	4.234¢	4.880¢	4.632¢	4.635¢	5.051¢	4.816¢	4.567¢	4.199¢	
29	C&I Demand Off-Peak 17+23	2.086¢	2.460¢	2.623¢	2.614¢	2.772¢	3.194¢	3.030¢	3.030¢	3.305¢	3.151¢	2.988¢	2.749¢	
30	Outdoor Lighting 18+24	2.038¢	2.403¢	2.562¢	2.554¢	2.708¢	3.119¢	2.959¢	2.960¢	3.228¢	3.078¢	2.918¢	2.684¢	
	Minnesota Calendar Month Retail Sales													
	Minnesota Retail Sales:													
31	Residential	860,826	721,935	720,310	596,515	650,592	852,657	1,025,457	912,988	711,275	598,235	634,111	805,346	9,090,247
32	C&I Non-Demand	78,128	72,140	76,560	63,608	65,315	66,566	75,377	71,649	64,024	58,318	59,778	71,558	823,021
33	C&I Demand Non-TOD	750,452	677,452	738,110	644,789	715,889	758,678	848,958	827,569	756,916	695,927	664,292	731,515	8,810,547
34	C&I Demand On-Peak	294,120	283,010	316,644	295,268	317,052	321,465	375,193	356,652	343,561	335,990	311,056	305,081	3,855,092
35	C&I Demand Off-Peak	524,633	469,866	507,880	474,964	530,043	533,012	595,821	575,843	539,028	529,904	504,164	512,833	6,297,991
36	Outdoor Lighting	14,403	10,469	10,734	9,648	6,334	7,680	7,220	7,762	9,014	10,080	11,539	13,071	117,954
37	Total 31+32+33+34+35+36	2,522,562	2,234,872	2,370,238	2,084,792	2,285,225	2,540,058	2,928,026	2,752,463	2,423,818	2,228,454	2,184,940	2,439,404	28,994,852
	Less WindSource & Renewable*Connect													
38	Residential	22,092	18,644	21,864	17,586	16,793	19,314	22,209	23,472	19,854	16,471	15,801	18,166	232,266
39	C&I Non-Demand	405	383	1,267	745	3,587	3,962	4,030	4,068	4,047	4,885	3,526	3,434	34,339
40	C&I Demand Non-TOD	6,230	5,846	18,536	18,348	16,719	18,987	20,717	22,577	21,448	19,796	18,677	18,245	206,126
41	C&I Demand On-Peak	11,714	10,266	5,962	4,914	4,487	5,872	4,562	5,413	4,726	13,634	5,883	5,646	83,079
42	C&I Demand Off-Peak	16,976	14,877	8,640	7,121	6,503	8,509	6,611	7,844	6,848	19,758	8,526	8,181	120,394
43	Outdoor Lighting	85	94	2	63	57	-	-	-	-	-	-	-	301
44	Total 38+39+40+41+42+43	57,502	50,110	56,271	48,777	48,146	56,644	58,129	63,374	56,923	74,544	52,413	53,672	676,505
	Minnesota FCA Calendar Month Sales:													
45	Residential 31-38	838,734	703,291	698,446	578,929	633,799	833,343	1,003,248	889,516	691,421	581,764	618,310	787,180	8,857,981
46	C&I Non-Demand 32-39	77,723	71,757	75,293	62,863	61,728	62,604	71,347	67,581	59,977	53,433	56,252	68,124	788,682
47	C&I Demand Non-TOD 33-40	744,222	671,606	719,574	626,441	699,170	739,691	828,241	804,992	735,468	676,131	645,615	713,270	8,604,421
48	C&I Demand On-Peak 34-41	282,406	272,744	310,682	290,354	312,565	315,593	370,631	351,239	338,835	322,356	305,173	299,435	3,772,013
49	C&I Demand Off-Peak 35-42	507,657	454,989	499,240	467,843	523,540	524,503	589,210	567,999	532,180	510,146	495,638	504,652	6,177,597
50	Outdoor Lighting 36-43	14,318	10,375	10,732	9,585	6,277	7,680	7,220	7,762	9,014	10,080	11,539	13,071	117,653
51	Total 45+46+47+48+49+50	2,465,060	2,184,762	2,313,967	2,036,015	2,237,079	2,483,414	2,869,897	2,689,089	2,366,895	2,153,910	2,132,527	2,385,732	28,318,347

	Recovery Based on 2022 Forecast Factors with Mid-Year Adjustment													
52	Residential 13x45/100	$21,782	$21,563	$22,825	$18,850	$21,885	$33,159	$37,883	$33,606	$26,233	$20,903	$20,924	$24,513	$304,124
53	C&I Non-Demand 14x46/100	$2,044	$2,227	$2,491	$2,073	$2,158	$2,522	$2,728	$2,585	$2,304	$1,944	$1,927	$2,149	$27,152
54	C&I Demand Non-TOD 15x47/100	$18,963	$20,202	$23,070	$20,009	$23,681	$28,870	$30,678	$29,825	$27,374	$23,834	$21,428	$21,790	$289,723
55	C&I Demand On-Peak 16x48/100	$8,992	$10,258	$12,455	$11,591	$13,234	$15,401	$17,168	$16,280	$15,766	$14,209	$12,665	$11,435	$159,454
56	C&I Demand Off-Peak 17x49/100	$10,590	$11,193	$13,095	$12,229	$14,513	$16,753	$17,853	$17,210	$16,205	$14,713	$13,457	$12,621	$170,431
57	Outdoor Lighting 18x49/100	$292	$249	$275	$245	$170	$240	$214	$230	$268	$284	$306	$319	$3,091
58	MN Fuel Recoveries excluding 2021 True Up 52+53+54+55+56+57	$62,662	$65,692	$74,211	$64,996	$75,640	$96,944	$106,523	$99,736	$88,149	$75,886	$70,706	$72,828	$953,975
	2022 Under (+)/Over(-) Recovered Expense													
59	Expected Minnesota Fuel Costs Recovery '2022 Actual' Line 50	$68,713	$70,011	$79,102	$79,769	$84,789	$96,438	$90,309	$90,308	$91,551	$76,536	$66,399	$56,298	$950,221
60														
61	Minnesota Actual Recovery 58	$62,662	$65,692	$74,211	$64,996	$75,640	$96,944	$106,523	$99,736	$88,149	$75,886	$70,706	$72,828	$953,975
62	**2022 Total Under (+)/Over(-) Recovered Exp**	**$6,050**	**$4,318**	**$4,891**	**$14,773**	**$9,148**	**($506)**	**($16,213)**	**($9,428)**	**$3,402**	**$649**	**($4,307)**	**($16,530)**	**($3,753)**
	2021 True Up Recovery (TRUE UP OF 2021 TRUE UP RECOVERY WILL BE DETERMINED AFTER THE 12 MONTHS RECOVERY IS COMPLETED)													
63	Expected 2021 True Up Recovery									$6,814	$6,814	$6,814	$6,814	$27,255
	Actual Recovery													
64	Residential 13x45/100	$0	$0	$0	$0	$0	$0	$0	$0	$2,247	$1,937	$2,102	$2,432	$8,719
65	C&I Non-Demand 14x46/100	$0	$0	$0	$0	$0	$0	$0	$0	$197	$180	$194	$213	$784
66	C&I Demand Non-TOD 15x47/100	$0	$0	$0	$0	$0	$0	$0	$0	$2,339	$2,204	$2,150	$2,168	$8,861
67	C&I Demand On-Peak 16x48/100	$0	$0	$0	$0	$0	$0	$0	$0	$1,349	$1,315	$1,273	$1,138	$5,074
68	C&I Demand Off-Peak 17x49/100	$0	$0	$0	$0	$0	$0	$0	$0	$1,384	$1,362	$1,353	$1,252	$5,350
69	Outdoor Lighting 18x49/100	$0	$0	$0	$0	$0	$0	$0	$0	$23	$26	$31	$32	$112
70	2021 True Up Recovery 52+53+54+55+56+57	$0	$0	$0	$0	$0	$0	$0	$0	$7,538	$7,025	$7,102	$7,235	$28,900
71	**Deferred 2021 Total Under (+)/Over(-) Recovered Exp 63-70**									**($725)**	**($211)**	**($288)**	**($421)**	**($1,645)**

Proposed One-Month Refund

		Sep-23
72	Refund Amount 62	($3,753)
73	Forecast Net Minnesota MWh Sales	2,289,216
74	True Up Refund Factor ($/kWh) 72/73	($0.00164)
	FAF Ratio	
75	Residential	1.0177
76	C&I Non-Demand	1.0305
77	C&I Demand Non-TOD	0.9984
78	C&I Demand On-Peak	1.2486
79	C&I Demand Off-Peak	0.8166
80	Outdoor Lighting	0.7976
	Proposed True Up Factor by Class Category	
81	Residential 74*75	**($0.00167)**
82	C&I Non-Demand 74*76	**($0.00169)**
83	C&I Demand Non-TOD 74*77	**($0.00164)**
84	C&I Demand On-Peak 74*78	**($0.00205)**
85	C&I Demand Off-Peak 74*79	**($0.00134)**
86	Outdoor Lighting 74*80	**($0.00131)**
	Forecast Fuel Cost Factors	
87	Residential	$0.04175
88	C&I Non-Demand	$0.04227
89	C&I Demand Non-TOD	$0.04095
90	C&I Demand On-Peak	$0.05121
91	C&I Demand Off-Peak	$0.03351
92	Outdoor Lighting	$0.03273
	Forecast Fuel Cost Factors With Proposed 2022 True Up	
93	Residential 81+87	**$0.04008**
94	C&I Non-Demand 82+88	**$0.04058**
95	C&I Demand Non-TOD 83+89	**$0.03931**
96	C&I Demand On-Peak 84+90	**$0.04916**
97	C&I Demand Off-Peak 85+91	**$0.03217**
98	Outdoor Lighting 86+92	**$0.03142**

	Proposed One-Month Refund - General TOU Pilot Program	Sep-23
99	True Up Refund Factor ($/kWh) 74	($0.00164)
	FAF Ratio	
100	C&I Demand TOU Pilot Peak	1.2617
101	C&I Demand TOU Pilot Base	1.0708
102	C&I Demand TOU Pilot Off-Peak	0.5579
	Proposed True Up Factor by Class Category	
103	C&I Demand TOU Pilot Peak 99*100	**($0.00207)**
104	C&I Demand TOU Pilot Base 99*101	**($0.00176)**
105	C&I Demand TOU Pilot Off-Peak 99*102	**($0.00092)**
	Forecast Fuel Cost Factors	
106	C&I Demand TOU Pilot Peak	$0.05174
107	C&I Demand TOU Pilot Base	$0.04392
108	C&I Demand TOU Pilot Off-Peak	$0.02291
	Forecast Fuel Cost Factors With Proposed 2022 True Up	
109	C&I Demand TOU Pilot Peak 103+106	**$0.04967**
110	C&I Demand TOU Pilot Base 104+107	**$0.04216**
111	C&I Demand TOU Pilot Off-Peak 105+108	**$0.02199**

Northern States Power Company (Minnesota)
Electric Utility - State of Minnesota
Company Generation, Purchased Power and Other GWh

		Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	2022Total
	Owned Generation													
	Fossil Fuel													
1	Coal	1,304.3	880.6	630.4	187.9	223.3	1,009.8	1,310.8	1,154.5	530.0	618.4	598.8	1,075.0	9,523.9
2	Wood/RDF	42.8	41.5	32.0	36.8	48.2	48.2	48.0	49.4	30.4	48.0	44.1	44.0	513.5
3	Natural Gas CC	398.4	368.3	264.6	248.3	195.9	333.9	493.2	505.1	420.8	263.4	149.1	211.8	3,852.6
4	Natural Gas & Oil CT	21.3	16.9	4.0	11.5	27.2	75.2	123.0	105.7	52.0	26.6	28.1	36.9	528.5
5	Subtotal	1,766.9	1,307.3	930.9	484.6	494.6	1,467.1	1,974.9	1,814.7	1,033.2	956.5	820.1	1,367.7	14,418.5
6	Hydro	53.3	42.6	89.7	156.6	129.6	69.8	49.6	54.0	43.7	39.0	65.8	54.2	848.0
7	Wind	918.0	839.1	910.7	962.4	708.0	644.4	549.2	529.8	671.5	833.8	951.2	843.2	9,361.3
8	Nuclear Fuel	1,220.8	1,191.4	1,300.3	1,260.5	1,247.5	1,221.0	1,258.7	1,264.8	1,227.3	1,046.0	1,138.7	1,319.4	14,696.2
9	Total Fuel 5+6+7+8	3,958.9	3,380.4	3,231.7	2,864.1	2,579.7	3,402.4	3,832.4	3,663.3	2,975.6	2,875.3	2,975.8	3,584.4	39,324.0
	Purchased Energy													
10	LT Purchased Energy (Gas)	256.1	151.4	94.3	143.3	154.8	235.2	345.6	350.3	255.8	158.8	126.7	222.8	2,494.9
11	LT Purchased Energy (Solar)	34.0	47.5	66.1	64.8	86.6	101.5	101.6	88.7	80.3	58.6	34.2	24.0	787.9
12	Community Solar*Gardens	63.8	91.2	123.3	107.8	143.2	170.6	167.0	166.0	152.6	121.4	59.0	37.6	1,403.5
13	LT Purchased Energy (Wind)	567.9	584.3	594.9	668.9	496.9	455.2	391.4	384.8	466.8	589.3	691.6	578.1	6,470.0
14	LT Purchased Energy (Other)	152.8	102.9	164.1	134.7	215.8	226.5	217.5	235.7	225.5	214.2	167.5	162.5	2,219.6
15	Total Purchased Energy 10+11+12+13+14	1,074.5	977.3	1,042.6	1,119.5	1,097.3	1,188.9	1,223.1	1,225.6	1,180.9	1,142.2	1,079.0	1,025.0	13,375.9
16	ST Market Purchase	291.6	219.9	150.0	107.3	318.3	333.5	215.4	199.0	276.8	300.3	157.4	201.0	2,770.6
17	Asset Based Sales Revenues (Market Sales)	(1,609.9)	(1,284.8)	(1,080.5)	(1,000.5)	(765.4)	(1,194.2)	(1,171.6)	(1,149.3)	(1,035.5)	(1,145.0)	(1,041.5)	(1,242.9)	(13,721.3)
18	Net Market Cost 16+17	(1,318.3)	(1,064.9)	(930.5)	(893.2)	(447.1)	(860.7)	(956.2)	(950.2)	(758.7)	(844.7)	(884.2)	(1,042.0)	(10,950.7)
19	MISO Cost													
20	Net MISO D2 and ASM Cost 18+19	(1,318.3)	(1,064.9)	(930.5)	(893.2)	(447.1)	(860.7)	(956.2)	(950.2)	(758.7)	(844.7)	(884.2)	(1,042.0)	(10,950.7)
21	**Total System GWh (At Generator) 9+15+20**	3,715.1	3,292.7	3,343.9	3,090.3	3,229.9	3,730.6	4,099.3	3,938.7	3,397.9	3,172.8	3,170.6	3,567.4	41,749.2
22	Less Solar Gardens - Above Market													
23	Less WindSource	(41.2)	(36.1)	(39.4)	(35.1)	(33.8)	(38.5)	(43.4)	(46.7)	(42.5)	(59.2)	(38.3)	(39.1)	(493.3)
24	Less Renewable*Connect	(16.3)	(14.0)	(16.8)	(13.6)	(14.4)	(18.2)	(14.8)	(16.7)	(14.5)	(15.3)	(14.1)	(14.5)	(183.2)
25	Total Costs Direct Assigned 22+23+24	(57.5)	(50.1)	(56.3)	(48.8)	(48.1)	(56.6)	(58.1)	(63.4)	(56.9)	(74.5)	(52.4)	(53.7)	(676.5)
26	**Net System GWh (At Generator) 21+25**	3,657.6	3,242.6	3,287.6	3,041.6	3,181.7	3,674.0	4,041.2	3,875.3	3,341.0	3,098.3	3,118.2	3,513.7	41,072.7

Northern States Power Company (Minnesota)
Electric Utility - State of Minnesota
Estimated Fuel Related Costs Per MWh (At Generator)

		Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	2022Total
	Own Generation													
	Fossil Fuel													
1	Coal	$24.44	$24.63	$24.33	$27.64	$26.99	$22.78	$24.64	$25.61	$26.88	$27.02	$27.81	$28.12	$25.50
2	Wood/RDF	$8.22	$17.37	$18.39	$14.66	$17.38	$17.89	$20.89	$21.87	$24.34	$27.71	$17.57	$21.63	$19.05
3	Natural Gas CC	$40.57	$49.39	$50.29	$56.35	$67.79	$67.15	$53.40	$65.32	$58.07	$48.22	$57.70	$69.44	$56.36
4	Natural Gas & Oil CT	$69.75	$50.96	$163.58	$44.52	$94.42	$89.02	$70.64	$92.92	$122.02	$118.79	$100.06	$80.02	$88.10
5	Subtotal	$28.23	$31.71	$32.10	$41.77	$45.93	$36.11	$34.60	$40.48	$44.30	$35.45	$35.17	$35.71	$35.81
6	Hydro	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
7	Wind	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
8	Nuclear Fuel	$7.89	$7.82	$7.87	$7.93	$8.13	$8.20	$8.22	$8.17	$8.10	$7.85	$7.75	$7.73	$7.97
9	Total Fuel	$15.03	$15.02	$12.41	$10.56	$12.73	$18.52	$20.53	$22.88	$18.72	$14.65	$12.66	$16.47	$16.11
	Purchased Energy													
10	LT Purchased Energy (Gas)	$45.17	$42.13	$53.36	$53.51	$67.77	$71.23	$65.53	$72.69	$66.85	$59.56	$62.16	$68.06	$62.36
11	LT Purchased Energy (Solar)	$55.11	$62.05	$62.85	$61.09	$62.30	$67.24	$62.79	$62.26	$64.22	$62.62	$52.59	$39.70	$61.73
12	Community Solar*Gardens	$125.66	$127.35	$126.75	$126.54	$135.54	$134.37	$132.68	$130.73	$131.61	$132.72	$133.11	$129.84	$131.12
13	LT Purchased Energy (Wind)	$42.15	$39.53	$38.08	$33.37	$45.96	$38.01	$34.32	$35.86	$37.82	$36.71	$35.85	$36.59	$37.81
14	LT Purchased Energy (Other)	$84.87	$87.67	$89.36	$78.91	$88.56	$91.38	$88.78	$89.45	$87.99	$64.31	$85.62	$93.75	$85.90
15	Total Purchased Energy	$54.31	$54.29	$59.59	$52.00	$70.40	$71.07	$68.62	$71.46	$67.60	$56.60	$52.51	$55.98	$61.57
16	ST Market Purchase	$37.01	$36.95	$69.10	$74.17	$44.20	$52.70	$56.38	$50.66	$98.72	$44.11	$32.30	$49.73	$52.98
17	Asset Based Sales Revenues (Market Sales)	$34.90	$32.05	$24.51	$28.33	$34.70	$55.33	$59.62	$67.31	$52.56	$30.61	$24.36	$46.23	$41.13
18	Net Market Cost	$34.44	$31.04	$17.32	$22.83	$27.94	$56.35	$60.34	$70.80	$35.71	$25.81	$22.95	$45.56	$38.13
19	MISO Cost													
20	Net MISO D2 and ASM Cost	$16.59	$5.34	($4.93)	($24.68)	($10.07)	$42.14	$44.34	$51.33	$16.69	$2.33	$2.43	$35.96	$16.27
21	**Total System $/MWh**	$25.84	$29.81	$31.95	$35.75	$35.48	$29.82	$29.32	$31.13	$36.16	$33.03	$29.07	$22.13	$30.63
22	Less Solar Gardens - Above Market													
23	Less WindSource	$31.91	$64.81	$30.14	$54.62	$37.02	$23.50	$29.62	$33.63	$37.47	$26.73	$49.92	$34.05	$36.87
24	Less Renewable* Connect	$35.38	$35.12	$35.53	$34.89	$35.21	$22.40	$38.84	$35.21	$35.67	$35.52	$35.76	$34.99	$34.33
25	Total Costs Direct Assigned	$149.71	$182.74	$236.58	$209.55	$267.14	$189.74	$178.51	$143.24	$224.67	$163.93	$180.16	$103.74	$183.86
26	**Net System $/MWh**	$23.89	$27.44	$28.45	$32.97	$31.98	$27.35	$27.18	$29.29	$32.95	$29.88	$26.53	$20.88	$28.11

Redline

FUEL COST FACTORS (2023)

Month	Residential	Commercial & Industrial Non-Demand	Commercial & Industrial Non-TOD	Commercial & Industrial Demand On-Peak	Commercial & Industrial Demand Off-Peak	Outdoor Lighting	
January	$0.03316	$0.03358	$0.03254	$0.04066	$0.02663	$0.02601	
February	$0.03615	$0.03661	$0.03546	$0.04435	$0.02901	$0.02833	
March	$0.04273	$0.04327	$0.04193	$0.05243	$0.03429	$0.03349	
April	$0.04761	$0.04822	$0.04671	$0.05839	$0.03823	$0.03734	
May	$0.04881	$0.04942	$0.04788	$0.05986	$0.03919	$0.03827	
June	$0.05107	$0.05172	$0.05011	$0.06266	$0.04100	$0.04004	
July	$0.04561	$0.04618	$0.04474	$0.05595	$0.03659	$0.03574	
August	$0.04547	$0.04604	$0.04461	$0.05580	$0.03648	$0.03563	
September	$0.~~04175~~04008	$0.~~04227~~04058	$0.~~04095~~03931	$0.~~05121~~04916	$0.~~03351~~03217	$0.~~03273~~03142	R
October	$0.03881	$0.03930	$0.03808	$0.04761	$0.03115	$0.03043	
November	$0.03580	$0.03625	$0.03512	$0.04392	$0.02873	$0.02806	
December	$0.03303	$0.03345	$0.03241	$0.04051	$0.02652	$0.02591	

Commercial & Industrial General TOU Service Pilot Program

Month	Peak	Base	Off-Peak	
January	$0.04109	$0.03489	$0.01823	
February	$0.04482	$0.03803	$0.01982	
March	$0.05298	$0.04497	$0.02343	
April	$0.05901	$0.05010	$0.02616	
May	$0.06048	$0.05135	$0.02681	
June	$0.06331	$0.05374	$0.02803	
July	$0.05653	$0.04798	$0.02501	
August	$0.05638	$0.04785	$0.02491	
September	$0.~~05174~~04967	$0.~~04392~~04216	$0.~~02291~~02199	R
October	$0.04811	$0.04084	$0.02129	
November	$0.04438	$0.03767	$0.01963	
December	$0.04093	$0.03475	$0.01815	

CURRENT PERIOD COST OF ENERGY

The Current Period Cost of Energy per kWh is defined as the qualifying costs, forecasted to be incurred during the calendar month, divided by the kWh sales forecasted for the same month. Qualifying kWh sales are all kWh sales excluding intersystem, Renewable*Connect, Renewable*Connect Government and Windsource® Program kWh sales. Qualifying costs are the sum of the following:

(Continued on Sheet No. 5-91.2)

Final

FUEL COST FACTORS (2023)

Month	Residential	Commercial & Industrial Non-Demand	Commercial & Industrial Demand Non-TOD	Commercial & Industrial Demand On-Peak	Commercial & Industrial Demand Off-Peak	Outdoor Lighting	
January	$0.03316	$0.03358	$0.03254	$0.04066	$0.02663	$0.02601	
February	$0.03615	$0.03661	$0.03546	$0.04435	$0.02901	$0.02833	
March	$0.04273	$0.04327	$0.04193	$0.05243	$0.03429	$0.03349	
April	$0.04761	$0.04822	$0.04671	$0.05839	$0.03823	$0.03734	
May	$0.04881	$0.04942	$0.04788	$0.05986	$0.03919	$0.03827	
June	$0.05107	$0.05172	$0.05011	$0.06266	$0.04100	$0.04004	
July	$0.04561	$0.04618	$0.04474	$0.05595	$0.03659	$0.03574	
August	$0.04547	$0.04604	$0.04461	$0.05580	$0.03648	$0.03563	
September	$0.04008	$0.04058	$0.03931	$0.04916	$0.03217	$0.03142	R
October	$0.03881	$0.03930	$0.03808	$0.04761	$0.03115	$0.03043	
November	$0.03580	$0.03625	$0.03512	$0.04392	$0.02873	$0.02806	
December	$0.03303	$0.03345	$0.03241	$0.04051	$0.02652	$0.02591	

Commercial & Industrial General TOU Service Pilot Program

Month	Peak	Base	Off-Peak	
January	$0.04109	$0.03489	$0.01823	
February	$0.04482	$0.03803	$0.01982	
March	$0.05298	$0.04497	$0.02343	
April	$0.05901	$0.05010	$0.02616	
May	$0.06048	$0.05135	$0.02681	
June	$0.06331	$0.05374	$0.02803	
July	$0.05653	$0.04798	$0.02501	
August	$0.05638	$0.04785	$0.02491	
September	$0.04967	$0.04216	$0.02199	R
October	$0.04811	$0.04084	$0.02129	
November	$0.04438	$0.03767	$0.01963	
December	$0.04093	$0.03475	$0.01815	

CURRENT PERIOD COST OF ENERGY
The Current Period Cost of Energy per kWh is defined as the qualifying costs, forecasted to be incurred during the calendar month, divided by the kWh sales forecasted for the same month. Qualifying kWh sales are all kWh sales excluding intersystem, Renewable*Connect, Renewable*Connect Government and Windsource® Program kWh sales. Qualifying costs are the sum of the following:

(Continued on Sheet No. 5-91.2)

Miscellaneous MISO Reporting Requirements

The Commission has required a variety of reporting related to MISO Day 1, Day 2, Day 3, and the Ancillary Services Market (ASM) in a variety of dockets. These reporting items are provided below.

A. Monthly MISO Charge Details

In compliance with the Commission's February 6, 2008 Order in Docket No. E,G999/AA-06-1208 (the 2006 AAA Report docket) and the April 24, 2006 Settlement Agreement in the Company's 2006 Electric Rate Case (Docket No. E002/GR-05-1428, Exhibit 46), Part B, Attachments 2-11 provide monthly MISO charge details for the 2022 reporting period.[1]

B. MISO ASM

The Commission's August 23, 2010 Order in Docket No. E002/M-08-528 requires utilities to report on costs and revenues from their participation in the MISO ancillary services market and to report all negative benefits (costs) of participation in the MISO ancillary services market.

1. Overall Market Performance to Date

During the 2022 AAA Period, MISO continued to operate the electric system reliably and has exceeded compliance thresholds for all North American Electric Reliability Corporation (NERC) reliability standards to which they are subject. The MISO Independent Market Monitor (IMM), which is tasked with monitoring both the behavior of Market Participants and the operation of the market, stated the following:

The MISO markets performed competitively throughout the year, with infrequent market power mitigation and competitive conduct overall. Energy prices rose 65 percent in the first quarter, largely because gas prices were 50 percent higher than the previous winter, even after removing the impact of the Winter Storm Uri event in February 2021. Energy prices more than doubled in the second quarter, largely

[1] The reporting formats are provided in compliance with the Commission's June 12, 2019 Order in Docket No. E002/CI-03-802. See Attachment 3 of the March 1, 2019 Joint Comments in that docket which details the agreed upon disposition of AAA reporting items.

because gas prices increased around 140 percent over the previous spring in the Midwest and South. Coal supply limitations became more pronounced later in the quarter, as resources employed conservation measures in preparation for the peak summer months. MISO's Planning Resource Auction cleared at Cost of New Entry (CONE) in the Midwest as the region was short of capacity by 1.2 GW. Congestion roughly doubled in the spring year over year, with the value of real-time congestion exceeding one billion dollars during the quarter. Wind output continued to be a primary cause of MISO's congestion, contributing to more than $500 million of congestion during the quarter. On average, wind output was curtailed almost 10 percent over the second quarter.

The summer saw energy prices more than double once again from the previous year, and MISO experienced several intervals of shortage pricing during the quarter. Gas prices were volatile, with Henry Hub averaging $7.87 per MMBTU and fluctuating between a high of $9.85 in August and a low of $5.62 in July. A mid-June heat dome across the footprint drove high cooling demand. Coal resources continued to be very economic based on coal prices relative to natural gas prices, but ongoing supply challenges lowered output. Day-ahead and real-time congestion costs doubled over the previous summer – the value of real-time congestion exceeded three quarters of a billion dollars. Much of the congestion occurred in mid to late June when MISO experienced high temperatures and associated load.

Finally, in the Fall energy prices rose much more moderately, at 13 percent year over year, consistent with gas prices that rose 14 and 22 percent at the Chicago Citygate and Henry Hub, respectively. Energy prices were 34 percent lower than the summer quarter because of falling gas prices, lower load, and a reduction in coal conservation measures. The amount of coal capacity conserving coal fell from more than 18 GW at the beginning of the quarter to 8 GW by December 1. Day-ahead and real-time congestion fell 15 and 18 percent, respectively. Transmission upgrades completed over the summer doubled the capacity on a key constraint that had generated substantial congestion in the fall of 2021.[2]

2. Estimated Market Benefits

The comparison of NSP's participation in the MISO ASM market to an alternative

[2] MISO Independent Market Monitor (misoenergy.org)

scenario where NSP must self supply ancillary services will always result in benefits to NSP and its ratepayers. Ancillary services are always supplied by the most economical set of resources within MISO, including periods where NSP sells excess to the market. The alternative for NSP is to self-supply ancillary services from a restricted number of NSP resources and never sell excess to the market. The results of the ASM benefit analysis continue to show an overall benefit for the 2022 AAA reporting period and are provided in the following table.

	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Other Market Charge Types	ASM Admin Fees	Net Savings
Jan '22	77,356,540	77,486,400	129,860	52,571	27,812	49,477
Feb '22	58,110,900	58,268,560	157,660	39,297	14,854	103,509
Mar '22	43,306,440	43,800,260	493,820	22,012	21,416	450,392
Apr '22	40,443,820	41,002,060	558,240	22,294	18,292	517,654
May '22	49,860,970	50,796,840	935,870	6,469	16,400	913,001
Jun '22	90,177,230	90,502,670	325,440	74,539	22,506	228,395
Jul '22	106,329,800	106,471,170	141,370	397,438	29,323	(285,391)
Aug '22	116,382,290	116,539,350	157,060	103,485	27,525	26,051
Sep '22	76,920,620	77,318,260	397,640	65,661	23,497	308,482
Oct '22	51,797,130	52,326,050	528,920	54,811	17,376	456,733
Nov '22	43,457,320	43,976,780	519,460	19,017	19,479	480,964
Dec '22	68,209,730	68,675,090	465,360	283,062	20,771	161,527

The Company estimates the ASM resulted in total NSP System savings of approximately $3.41 million for the 2022 reporting period. Part B, Attachment 12 provides the ASM daily activity and net savings. The Minnesota jurisdictional allocation of the savings is approximately 75 percent, or $2.55 million. This is the savings associated with optimizing the generation units that are carrying ancillary services across the entire MISO footprint, and does not include any additional benefits that have accrued to ratepayers from reducing the regional regulation reserve requirement.

3. *Excessive Deficient Energy Deployment Charges*

The Excessive Deficient Energy Deployment Charge (EDEDC) amount represents the charge to a generator that was not able to maintain actual generator output to within a tolerance band around the set point. During the hours where a generator was unable to meet this requirement, MISO assesses a charge equal to any day ahead or real time payments to the generator for carrying regulation reserve plus the generator's pro rata share of costs to procure regulation from all resources within MISO. Part B, Attachment 13 shows the EDEDCs assessed to each NSP System resource by month during the reporting period.

A certain level of EDEDCs is unavoidable given the current design of the ASM market. Currently for each generator, the Company can only submit a single ramp rate value that represents the average rate at which the generator can increase or decrease output across its entire dispatchable range. For a typical coal unit, the ramp rate varies significantly as the unit moves from minimum load to full load. For example, a coal generator with a minimum capability of 200 MWs and a maximum capability of 400 MWs might be able to operate to 300 MWs with one coal pulverizer in operation, while a generator with a capability between 300 MWs and 400 MWs would require two coal pulverizers to be in operation. The unit might be able to ramp at a rate of 10 MWs/min up to 300 MWs, then slow to 3 MWs/min while the second pulverizer is starting, and then ramp at 5 MWs/min up to 400 MWs. The Company could offer only 3 MWs/min of ramp capability to MISO for dispatch, which would ensure that the unit would be able to follow its dispatch instruction close to 100% of the time, but would drastically under-represent the capability of the unit over most of its dispatchable range.

Offers with low ramp rates mean that the unit will not be able to clear for as much regulation reserve or spinning reserve, and therefore will not be available to fully hedge the Company's cost to procure these services. Low ramp rates also limit the unit's ability to respond to increasing or decreasing LMP prices, which ultimately leads to higher purchase power costs in the market. A more prudent strategy would be to offer 5 or 6 MWs/min of ramp capability for the entire range to strike an appropriate balance between incurring penalties during the limited intervals that the unit would not be able to "keep up," and ensuring the unit can provide sufficient quantities of ancillary and load following services to hedge exposure to market prices.

The ASM benefit calculation is a measure of the extent to which the Company has struck the *appropriate balance* between too much or too little flexibility being offered to MISO. For the 2022 AAA reporting period, the net benefit for the Company was approximately $2.55 million[3] while the amount incurred in EDEDCs was $0.71 million. The $3.41 million in gross benefits would not have been achievable if the Company had been offering ramp rates for its units that would have all but eliminated the chance of incurring an Excessive Deficient Energy charge.

To minimize the incurrence of excessive charges, generation unit performance to MISO setpoints is monitored in real time by the system dispatcher to ensure that plants are keeping up with offered ramp rates. Computer displays show the dispatcher a graphical depiction of actual unit output compared to setpoint along with calculations of the deviation. The system analyst and system dispatcher communicate with the plants daily to discuss operational issues affecting unit performance and adjust offers to MISO accordingly. This iterative process helps ensure that these charges are, to the extent possible, minimized while still creating opportunities for lower overall costs for ratepayers. For these reasons, a certain level of Excessive Deficient Energy Deployment Charges is expected, and prudent, in light of the overwhelming benefits associated with high unit flexibility that more than offset these charges.

4. *Contingency Reserve Deployment Failure Charges*

The Contingency Reserve Deployment Failure Charge (CRDFC) represents the charge incurred by generation or demand response resources that fail to deploy contingency reserves at or above the contingency reserve deployment instruction. This charge is assessed if a unit that is selected to provide spinning or supplemental reserves during a specific hour does not perform and MISO must then deploy another resource.

Part B, Attachment 14 shows NSP incurred a total of $298,238 in CRDFC during the 2022 AAA reporting period. NSP carries reserves on units with Automatic Generation Control (AGC) and units without AGC. For units without AGC, a phone call to the facility is required to deploy the reserves, adding to the time from receiving the signal and deployment. When deploying a large amount of reserves on many facilities, that action requires many more steps and time becomes critical.

[3] The $2.55 million in ASM benefits calculated by the Company for 2022 does not include all the savings made possible by offering high flexibility to MISO. In addition to the ASM related benefits, increased ramp rates and flexibility minimizes overall price volatility in the market, increases the ability to integrate intermittent resources such as wind, and limits uneconomic market purchases or sales.

Additionally, MISO must meet Disturbance Control Standards within 15 minutes but does not always provide market participants the remaining time between the deployment signal and the end of the 15-minute timeframe to deploy reserves. Instead, MISO holds participants to a 10-minute response regardless if MISO has 15 minutes to meet the standard or less than 10 minutes.

The charges were not the result of any improper action by the Company, but simply reflect the fact that generating units are sometimes not able to deliver every requested MW. The Company attempts to minimize these occurrences, as evidenced by the limited charges incurred over the reporting period. Had a similar situation occurred before the start of ASM, the Company would have been required to deploy reserves from another generator in its fleet and would have incurred increased energy costs that were recovered in the FCA. Thus, it is reasonable for the Company to recover these minor charges from MISO.

The Company tests all resources capable of providing supplemental reserve response every two months to validate capability and readiness if called on by MISO during a contingency. If a resource fails to perform during a test, plant management will address the issue with any required maintenance to return the unit to reliable service. The offer to MISO for the unit to provide reserves will be adjusted accordingly to ensure the capabilities of the unit are not overstated during this time.

In short, CRDFCs are prudently incurred for the same reasons described above regarding Excessive Deficient Energy Deployment charges. Generators are complicated mechanical machines whose performance varies based on many conditions. The benefits of making these units available to provide significant amounts of spinning and supplemental reserves to hedge the Company's cost to procure ancillary services more than offsets the cost of the extremely infrequent circumstances where the unit may not be able to provide 100% of the amount required. Also, Xcel Energy is working to modify the rules which evaluate failure to deploy so that this charge is only applied when a unit fails compared to its offered physical capability.

5. *Conclusion*

The analysis performed by the Company and described above captures only the benefit associated with a more optimal assignment of reserves in the MISO footprint;

i.e., freeing up low-cost generation resources to provide energy while carrying reserves on higher cost resources. When combined with the benefits estimated by MISO of a decreasing regulation requirement, the Ancillary Services Market has helped to reduce ratepayer fuel costs significantly during the reporting period.

C. Schedule 10 Administrative Charge Paid to MISO Under MISO Tariff

The Commission's May 9, 2002 Order in Docket Nos. E002/M-00-257, *et al.* and August 16, 2013 Order in Docket No. E999/AA-11-792 require the Company to provide the Schedule 10 Administrative Charges Paid to MISO Under the MISO Tariff, including the allocation factor used and support for why the allocator is reasonable.

Schedule 10 Administrative Charges Paid to MISO Under MISO Tariff
Calendar Year 2022

Period*	Invoiced Amount (NSP System)	Juris Trans Alloc	Interchange Alloc	MN Jurisdiction Net of Interchange
January	1,132,191.14	87.2980%	83.6779%	$ 827,055.81
February	867,661.20	87.2980%	83.6779%	$ 633,818.99
March	1,235,340.25	87.2980%	83.6779%	$ 902,405.34
April	1,182,118.64	87.2980%	83.6779%	$ 863,527.42
May	1,125,451.86	87.2980%	83.6779%	$ 822,132.83
June	1,388,634.32	87.2980%	83.6779%	$ 1,014,385.33
July	1,296,352.09	87.2980%	83.6779%	$ 946,973.96
August	1,336,371.00	87.2980%	83.6779%	$ 976,207.43
September	832,416.86	87.2980%	83.6779%	$ 608,073.30
October	865,523.12	87.2980%	83.6779%	$ 632,257.14
November	942,896.07	87.2980%	83.6779%	$ 688,777.41
December	979,835.00	87.2980%	83.6779%	$ 715,760.97
Total	**$13,184,791.55**			**$ 9,631,375.93**

*The month shown is the MISO billing month. For the Company, these costs are recorded in the Company's books and records the following month. The demand allocators are shown are preliminary at the time of this filing.

For comparison purposes, we also provide the data for calendar year 2021, below.

Schedule 10 Administrative Charges Paid to MISO Under MISO Tariff
2021 AAA Period

Period*	Invoiced Amount (NSP System)	Juris Trans Alloc	Interchange Alloc	MN Jurisdiction Net of Interchange
January	$ 978,970.85	86.9632%	83.6786%	$ 712,393.06
February	$ 877,945.09	86.9632%	83.6786%	$ 638,877.03
March	$ 1,041,223.26	86.9632%	83.6786%	$ 757,693.88
April	$ 963,635.84	86.9632%	83.6786%	$ 701,233.83
May	$ 1,120,017.08	86.9632%	83.6786%	$ 815,031.82
June	$ 1,356,719.97	86.9632%	83.6786%	$ 987,279.54
July	$ 1,066,565.26	86.9632%	83.6786%	$ 776,135.15
August	$ 1,254,029.07	86.9632%	83.6786%	$ 912,551.79
September	$ 1,169,610.12	86.9632%	83.6786%	$ 851,120.47
October	$ 1,195,345.57	86.9632%	83.6786%	$ 869,848.05
November	$ 905,693.14	86.9632%	83.6786%	$ 659,069.17
December	$ 1,247,487.85	86.9632%	83.6786%	$ 907,791.77
Total	**$ 13,177,243.10**			**$ 9,589,025.55**

*The month shown is the MISO billing month. For the Company, these costs are recorded in the Company's books and records the following month. The demand allocators are shown for the month when Schedule 10 costs are recorded on the Company's books and records.

The charges shown are the totals billed to the integrated system of the Company (NSP-Minnesota) and Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin) (collectively, the NSP System).

MISO Schedule 10 charges are recorded to FERC Accounts based on instructions from MISO in their letter dated May 12, 2006. As indicated in their instructions, Schedule 10 costs are allocated to the following accounts:

Percent	FERC Class	FERC Account	FERC Account Description
90.4%	Transmission	561.4	Scheduling, System Control and Dispatch Services
6.5%	Transmission	561.8	Reliability Planning and Standards Development Services
3.1%	Regional Market	575.7	Market Facilities, Monitoring and Compliance Services

The Company allocates costs recorded in these accounts between the NSP-Minnesota and NSP-Wisconsin Companies, as well as to NSP-Minnesota jurisdictions (Minnesota, North Dakota and South Dakota), based on a demand allocator. The Interchange Agreement demand allocator (36 month coincident peak demand) decreased the NSP System allocation to the Company effective January 1, 2022, pursuant to the annual update to the Interchange Agreement allocation factors accepted by FERC in Docket No. ER22-1234-000, letter order dated May 3, 2022.

The State of Minnesota jurisdictional demand allocator (12 month coincident peak demand) increased effective January 1, 2022 based on State of Minnesota demands. The net impact of the decrease in the 2022 Interchange Agreement demand allocator and the increase in the 2022 State of Minnesota jurisdictional demand allocator is an increase in the 2022 NSP System allocation to the Minnesota jurisdiction.

The August 16, 2013 Order in Docket No. E999/AA-11-792 also requires utilities to provide information to support increases in MISO Schedule 10 costs of five percent or higher over the prior year's costs, including an explanation of benefits received by customers for these added costs. The MISO Schedule 10 administative charges increased $7,548 or approximately 0.06 percent from 2021 to 2022.

D. Congestion Costs

The August 16, 2013 Order in Docket No. E999/AA-11-792 also requires that utilities provide data relating to congested paths, including related costs and revenues. We provide the requested analysis and discussion below.

The ten generation-load paths with the highest congestion costs, determined using a load allocation method as NSP bids in at multiple load nodes, are as follows:

Generation Node	Load Node	Total Congestion Cost
[PROTECTED DATA BEGINS		
		PROTECTED DATA ENDS]

NSP's FTR portfolio for these Generation-Load Node pairs (in MW) during the reporting period was:

Generation Node	Load Node	Winter 2021-22	
[PROTECTED DATA BEGINS		Peak	Off Peak
			PROTECTED DATA ENDS]

Generation Node	Load Node	Spring 2022	
[PROTECTED DATA BEGINS		Peak	Off Peak
			PROTECTED DATA ENDS]

Generation Node	Load Node	Summer 2022	
[PROTECTED DATA BEGINS		Peak	Off Peak
			PROTECTED DATA ENDS]

Generation Node	Load Node	Fall 2022	
[PROTECTED DATA BEGINS		Peak	Off Peak
			PROTECTED DATA ENDS]

Generation Node	Load Node	Winter 2022-23	
[PROTECTED DATA BEGINS		Peak	Off Peak
			PROTECTED DATA ENDS]

The Company uses FTRs as a hedging mechanism to manage the risk of congestion charges that may arise from the use of the transmission system in the Day-Ahead market. In order to minimize our customers' exposure to congestion costs, the Company nominates in the Stage 1a step of the FTR Auction **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]. Through this nomination approach, the Company minimizes risk to net congestion costs for its most critical generation units.

During the Stage 1b step of the FTR auction, NSP nominates **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]. This approach has resulted in offsetting some congestion costs with FTR revenues but cannot completely offset congestion due to the limited amount of FTR that MISO makes available to NSP, and thus does not fully cover the installed generator capacity to load node paths.

Below are the FTR Revenues, Congestion Expense, and the Net Revenue/ (Cost) of each of the ten Generation-Load Pairs identified in the tables above.

Award Node	Load Location	FTR Revenue	Congestion Cost	Net Revenue/(Cost)
[PROTECTED DATA BEGINS				
				PROTECTED DATA ENDS]

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
January 2022 Actual					
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (44,617,348.30)	$ 52,205,858.72	$ 7,588,510.42	$ 5,310,365.30
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 7,465,464.77	$ -	$ 7,465,464.77	$ 5,224,259.16
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (128,510.23)	$ -	$ (128,510.23)	$ (89,930.20)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (5,042,710.80)	$ -	$ (5,042,710.80)	$ (3,528,839.65)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 152,700.47	$ -	$ 152,700.47	$ 106,858.29
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (9,476.71)	$ -	$ (9,476.71)	$ (6,631.71)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,604,927.45)	$ 3,597,158.76	$ 1,992,231.31	$ 1,394,143.97
13 c	Real-Time Asset Energy Amount - Loss Component	$ 57,368.78	$ -	$ 57,368.78	$ 40,146.11
14	Real-Time Distribution of Losses Amount	$ (2,111,968.97)	$ -	$ (2,111,968.97)	$ (1,477,935.21)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ (0.75)	$ -	$ (0.75)	$ (0.52)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ 0.75	$ -	$ 0.75	$ 0.52
21	Real-time Net inadvertent Distribution	$ (50,816.62)	$ -	$ (50,816.62)	$ (35,560.97)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 195,930.87	$ -	$ 195,930.87	$ 137,110.50
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (97.25)	$ -	$ (97.25)	$ (68.05)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 25,103,200.42	$ -	$ 25,103,200.42	$ 17,566,973.89
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (70,510.32)	$ -	$ (70,510.32)	$ (49,342.43)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,428,122.54	$ -	$ 1,428,122.54	$ 999,386.17
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (101,126.93)	$ -	$ (101,126.93)	$ (70,767.64)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (276,479.99)	$ -	$ (276,479.99)	$ (193,477.99)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 52.48	$ -	$ 52.48	$ 36.72
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (52.48)	$ -	$ (52.48)	$ (36.72)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 396.17	$ -	$ 396.17	$ 277.24
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (5,374,949.19)	$ -	$ (5,374,949.19)	$ (3,761,336.82)
30	Financial Transmission Rights Monthly Allocation Amount	$ (303,409.00)	$ -	$ (303,409.00)	$ (212,322.65)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ (1,632,060.78)	$ -	$ (1,632,060.78)	$ (1,142,100.16)
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 1,658,342.83	$ -	$ 1,658,342.83	$ 1,160,492.08
37	Financial Transmission Guarantee Uplift Amount	$ (1,508,569.95)	$ -	$ (1,508,569.95)	$ (1,055,682.48)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 501,103.70	$ -	$ 501,103.70	$ 350,667.46
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 126,443.72	$ -	$ 126,443.72	$ 88,484.08
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (150,157.83)	$ 75,353.66	$ (74,804.17)	$ (52,347.23)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 600,163.19	$ -	$ 600,163.19	$ 419,988.32
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (601,631.91)	$ 220,936.22	$ (380,695.69)	$ (266,407.12)
43	Real Time Price Volatility Make Whole Payment	$ (118,371.51)	$ 28,887.25	$ (89,484.26)	$ (62,620.21)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 711,062.64	$ (116,814.02)	$ 594,248.62	$ 415,849.37
19	Real-Time Market Administration Amount	$ 85,287.01	$ (11,380.35)	$ 73,906.66	$ 51,719.16
29	Financial Transmission Rights Market Administration Amount	$ 37,165.31	$ -	$ 37,165.31	$ 26,007.92
33	Day-Ahead Schedule 24 Allocation Amount	$ 110,058.67	$ (17,995.39)	$ 92,063.28	$ 64,424.98
34	Real -Time Schedule 24 Allocation Amount	$ (97,747.55)	$ 101,423.50	$ 3,675.95	$ 2,572.39
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ (20,308.80)	$ 86,547.66	$ 66,238.86	$ 46,353.31
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 6,409,766.32	$ -	$ 6,409,766.32	$ 4,485,491.72
40	Auction Revenue Rights - Monthly ARR Revenue	$ (6,456,472.05)	$ 20,146.47	$ (6,436,325.58)	$ (4,504,077.63)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (235,898.25)	$ -	$ (235,898.25)	$ (165,079.29)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 76,750.07	$ -	$ 76,750.07	$ 53,708.95
	TOTAL MISO CHARGES	**$ (25,794,222.91)**	**$ 56,190,122.48**	**$ 30,395,899.57**	**$ 21,270,752.94**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 705,320.59**	**$ 493,576.44**
	SCHEDULE 24 (FOR RETAIL)			**$ 95,739.23**	**$ 66,997.38**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 29,594,839.75**	**$ 20,710,179.12**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	February 2022 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (27,167,885.66)	$ 37,590,407.27	$ 10,422,521.61	$ 7,362,694.08
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 6,489,794.36	$ -	$ 6,489,794.36	$ 4,584,530.72
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (14,768.65)	$ -	$ (14,768.65)	$ (10,432.89)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (6,694,412.31)	$ -	$ (6,694,412.31)	$ (4,729,077.26)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 232,382.36	$ -	$ 232,382.36	$ 164,159.91
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (4,790.91)	$ -	$ (4,790.91)	$ (3,384.40)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (272,119.11)	$ 3,257,929.69	$ 2,985,810.58	$ 2,109,241.00
13 c	Real-Time Asset Energy Amount - Loss Component	$ (19,238.34)	$ -	$ (19,238.34)	$ (13,590.38)
14	Real-Time Distribution of Losses Amount	$ (1,924,690.96)	$ -	$ (1,924,690.96)	$ (1,359,643.21)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (17,940.82)	$ -	$ (17,940.82)	$ (12,673.78)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 353,051.37	$ -	$ 353,051.37	$ 249,403.10
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (0.93)	$ -	$ (0.93)	$ (0.66)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 21,442,038.38	$ -	$ 21,442,038.38	$ 15,147,118.43
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 39,930.54	$ -	$ 39,930.54	$ 28,207.79
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,669,855.73	$ -	$ 1,669,855.73	$ 1,179,622.11
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (55,065.06)	$ -	$ (55,065.06)	$ (38,899.15)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (51,356.63)	$ -	$ (51,356.63)	$ (36,279.43)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (0.82)	$ -	$ (0.82)	$ (0.58)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (757,344.86)	$ -	$ (757,344.86)	$ (535,004.75)
30	Financial Transmission Rights Monthly Allocation Amount	$ (229,135.70)	$ -	$ (229,135.70)	$ (161,866.40)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (79,517.69)	$ -	$ (79,517.69)	$ (56,173.01)
37	Financial Transmission Guarantee Uplift Amount	$ 76,952.41	$ -	$ 76,952.41	$ 54,360.84
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 863,316.52	$ -	$ 863,316.52	$ 609,865.41
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 107,151.16	$ -	$ 107,151.16	$ 75,693.89
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (68,247.46)	$ 20,975.45	$ (47,272.01)	$ (33,393.97)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 156,889.00	$ -	$ 156,889.00	$ 110,829.77
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (315,933.84)	$ 173,646.78	$ (142,287.06)	$ (100,514.65)
43	Real Time Price Volatility Make Whole Payment	$ (146,032.92)	$ 36,535.19	$ (109,497.73)	$ (77,351.56)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 430,348.28	$ (65,840.11)	$ 364,508.17	$ 257,496.43
19	Real-Time Market Administration Amount	$ 43,748.04	$ (7,363.56)	$ 36,384.48	$ 25,702.78
29	Financial Transmission Rights Market Administration Amount	$ 19,663.25	$ -	$ 19,663.25	$ 13,890.54
33	Day-Ahead Schedule 24 Allocation Amount	$ 89,024.03	$ (13,335.16)	$ 75,688.87	$ 53,468.25
34	Real -Time Schedule 24 Allocation Amount	$ (85,169.94)	$ 121,955.63	$ 36,785.69	$ 25,986.20
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ (67,565.94)	$ 82,359.87	$ 14,793.93	$ 10,450.75
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 6,409,766.32	$ -	$ 6,409,766.32	$ 4,527,997.19
40	Auction Revenue Rights - Monthly ARR Revenue	$ (6,456,472.05)	$ 19,051.48	$ (6,437,420.57)	$ (4,547,532.75)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (235,898.25)	$ -	$ (235,898.25)	$ (166,643.61)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 76,750.07	$ -	$ 76,750.07	$ 54,217.90
	TOTAL MISO CHARGES	**$ (6,162,927.03)**	**$ 41,216,322.53**	**$ 35,053,395.50**	**$ 24,762,474.70**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 420,555.90**	**$ 297,089.76**
	SCHEDULE 24 (FOR RETAIL)			**$ 112,474.56**	**$ 79,454.46**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 34,520,365.04**	**$ 24,385,930.48**

Northern States Power Company

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	March 2022 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (10,712,280.30)	$ 24,517,879.09	$ 13,805,598.79	$ 9,731,362.52
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 5,016,775.37	$ -	$ 5,016,775.37	$ 3,536,250.80
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 13,298.62	$ -	$ 13,298.62	$ 9,374.00
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (7,565,845.03)	$ -	$ (7,565,845.03)	$ (5,333,052.33)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 515,194.63	$ -	$ 515,194.63	$ 363,153.08
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (5,765.73)	$ -	$ (5,765.73)	$ (4,064.18)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,045,827.51)	$ 1,711,425.91	$ 665,598.40	$ 469,170.47
13 c	Real-Time Asset Energy Amount - Loss Component	$ 29,402.17	$ -	$ 29,402.17	$ 20,725.16
14	Real-Time Distribution of Losses Amount	$ (1,485,293.66)	$ -	$ (1,485,293.66)	$ (1,046,961.55)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 10.51	$ -	$ 10.51	$ 7.41
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (10.51)	$ -	$ (10.51)	$ (7.41)
21	Real-time Net inadvertent Distribution	$ (15,018.40)	$ -	$ (15,018.40)	$ (10,586.25)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 202,814.90	$ -	$ 202,814.90	$ 142,961.23
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (1,557.06)	$ -	$ (1,557.06)	$ (1,097.55)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 16,338,203.73	$ -	$ 16,338,203.73	$ 11,516,558.31
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (4,921.28)	$ -	$ (4,921.28)	$ (3,468.94)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 2,034,932.84	$ -	$ 2,034,932.84	$ 1,434,394.08
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 9,402.76	$ -	$ 9,402.76	$ 6,627.87
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 186,010.29	$ -	$ 186,010.29	$ 131,115.90
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 82.67	$ -	$ 82.67	$ 58.27
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (82.67)	$ -	$ (82.67)	$ (58.27)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (7,521.32)	$ -	$ (7,521.32)	$ (5,301.67)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (2,678,842.85)	$ -	$ (2,678,842.85)	$ (1,888,276.73)
30	Financial Transmission Rights Monthly Allocation Amount	$ (135,623.14)	$ -	$ (135,623.14)	$ (95,598.75)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 110,840.68	$ -	$ 110,840.68	$ 78,129.96
37	Financial Transmission Guarantee Uplift Amount	$ (124,687.92)	$ -	$ (124,687.92)	$ (87,890.67)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 1,002,811.60	$ -	$ 1,002,811.60	$ 706,867.07
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 105,689.24	$ -	$ 105,689.24	$ 74,498.78
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (105,604.28)	$ 64,684.36	$ (40,919.92)	$ (28,843.85)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 120,827.58	$ -	$ 120,827.58	$ 85,169.58
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (58,819.54)	$ 37,735.87	$ (21,083.67)	$ (14,861.57)
43	Real Time Price Volatility Make Whole Payment	$ (99,059.44)	$ 35,731.61	$ (63,327.83)	$ (44,638.85)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 691,220.56	$ (87,321.90)	$ 603,898.66	$ 425,679.24
19	Real-Time Market Administration Amount	$ 66,963.90	$ (13,010.63)	$ 53,953.27	$ 38,030.86
29	Financial Transmission Rights Market Administration Amount	$ 25,703.40	$ -	$ 25,703.40	$ 18,117.95
33	Day-Ahead Schedule 24 Allocation Amount	$ 95,844.07	$ (12,337.46)	$ 83,506.61	$ 58,862.58
34	Real -Time Schedule 24 Allocation Amount	$ (92,642.80)	$ 72,153.70	$ (20,489.10)	$ (14,442.46)
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ (30,495.19)	$ 82,359.87	$ 51,864.68	$ 36,558.65
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 4,769,796.97	$ -	$ 4,769,796.97	$ 3,362,159.38
40	Auction Revenue Rights - Monthly ARR Revenue	$ (4,790,198.14)	$ 29,350.72	$ (4,760,847.42)	$ (3,355,850.97)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (176,339.19)	$ -	$ (176,339.19)	$ (124,298.89)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 168,443.44	$ -	$ 168,443.44	$ 118,733.29
	TOTAL MISO CHARGES	**$ 2,367,833.97**	**$ 26,438,651.14**	**$ 28,806,485.11**	**$ 20,305,265.55**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 683,555.33**	**$ 481,828.05**
	SCHEDULE 24 (FOR RETAIL)			**$ 63,017.51**	**$ 44,420.11**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 28,059,912.27**	**$ 19,779,017.39**

Northern States Power Company

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
April 2022 Actual					
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (9,159,595.57)	$ 25,051,707.89	$ 15,892,112.32	$ 11,272,639.66
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 7,816,430.78	$ -	$ 7,816,430.78	$ 5,544,373.58
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 325.29	$ -	$ 325.29	$ 230.74
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (11,665,751.59)	$ -	$ (11,665,751.59)	$ (8,274,785.09)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 992,817.50	$ -	$ 992,817.50	$ 704,228.22
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (325.29)	$ -	$ (325.29)	$ (230.74)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 1,246,288.86	$ 2,575,191.40	$ 3,821,480.26	$ 2,710,663.57
13 c	Real-Time Asset Energy Amount - Loss Component	$ (18,077.93)	$ -	$ (18,077.93)	$ (12,823.09)
14	Real-Time Distribution of Losses Amount	$ (2,116,472.45)	$ -	$ (2,116,472.45)	$ (1,501,262.44)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 123,517.35	$ -	$ 123,517.35	$ 87,613.69
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 289,132.33	$ -	$ 289,132.33	$ 205,088.19
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (89.93)	$ -	$ (89.93)	$ (63.79)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 28,183,518.65	$ -	$ 28,183,518.65	$ 19,991,216.00
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (5,627.69)	$ -	$ (5,627.69)	$ (3,991.85)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 3,963,010.25	$ -	$ 3,963,010.25	$ 2,811,054.04
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 5,627.69	$ -	$ 5,627.69	$ 3,991.85
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 364,281.72	$ -	$ 364,281.72	$ 258,393.38
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (461.41)	$ -	$ (461.41)	$ (327.29)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ 5,796.07	$ -	$ 5,796.07	$ 4,111.29
30	Financial Transmission Rights Monthly Allocation Amount	$ (129,503.20)	$ -	$ (129,503.20)	$ (91,859.59)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 20,634.65	$ -	$ 20,634.65	$ 14,636.63
37	Financial Transmission Guarantee Uplift Amount	$ (30,412.30)	$ -	$ (30,412.30)	$ (21,572.14)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 2,626,802.92	$ -	$ 2,626,802.92	$ 1,863,251.54
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 101,849.92	$ -	$ 101,849.92	$ 72,244.48
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (334,089.26)	$ 182,832.08	$ (151,257.18)	$ (107,290.19)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 198,664.47	$ -	$ 198,664.47	$ 140,917.26
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (195,535.12)	$ 55,677.84	$ (139,857.28)	$ (99,203.98)
43	Real Time Price Volatility Make Whole Payment	$ (54,611.32)	$ 4,713.28	$ (49,898.04)	$ (35,393.82)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 647,141.10	$ (82,697.25)	$ 564,443.85	$ 400,372.96
19	Real-Time Market Administration Amount	$ 70,334.10	$ (8,723.48)	$ 61,610.62	$ 43,701.83
29	Financial Transmission Rights Market Administration Amount	$ 32,244.43	$ -	$ 32,244.43	$ 22,871.71
33	Day-Ahead Schedule 24 Allocation Amount	$ 100,317.77	$ (12,839.16)	$ 87,478.61	$ 62,050.58
34	Real -Time Schedule 24 Allocation Amount	$ (97,768.90)	$ 112,192.82	$ 14,423.92	$ 10,231.22
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ 38,001.77	$ 85,151.73	$ 123,153.50	$ 87,355.60
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 4,769,796.97	$ -	$ 4,769,796.97	$ 3,383,326.36
40	Auction Revenue Rights - Monthly ARR Revenue	$ (4,790,198.14)	$ 30,413.60	$ (4,759,784.54)	$ (3,376,224.31)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (176,339.19)	$ -	$ (176,339.19)	$ (125,081.43)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 168,443.44	$ -	$ 168,443.44	$ 119,480.79
	TOTAL MISO CHARGES	**$ 22,990,118.74**	**$ 27,993,620.75**	**$ 50,983,739.49**	**$ 36,163,935.43**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 658,298.90**	**$ 466,946.50**
	SCHEDULE 24 (FOR RETAIL)			**$ 101,902.53**	**$ 72,281.80**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 50,223,538.06**	**$ 35,624,707.13**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	May 2022 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 6,384,976.73	$ 21,528,399.29	$ 27,913,376.02	$ 19,992,542.49
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 7,387,116.77	$ -	$ 7,387,116.77	$ 5,290,913.07
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (10.00)	$ -	$ (10.00)	$ (7.16)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (23,916,517.28)	$ -	$ (23,916,517.28)	$ (17,129,851.57)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,682,768.52	$ -	$ 1,682,768.52	$ 1,205,258.05
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 438.60	$ -	$ 438.60	$ 314.14
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,967,370.01)	$ 4,350,563.95	$ 2,383,193.94	$ 1,706,927.39
13 c	Real-Time Asset Energy Amount - Loss Component	$ 155,272.85	$ -	$ 155,272.85	$ 111,211.88
14	Real-Time Distribution of Losses Amount	$ (1,334,309.42)	$ -	$ (1,334,309.42)	$ (955,679.38)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 2,349.43	$ -	$ 2,349.43	$ 1,682.74
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 454,652.98	$ -	$ 454,652.98	$ 325,638.47
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 9,435.95	$ -	$ 9,435.95	$ 6,758.36
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 21,360,293.87	$ -	$ 21,360,293.87	$ 15,298,994.38
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (40,521.96)	$ -	$ (40,521.96)	$ (29,023.25)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 7,989,057.21	$ -	$ 7,989,057.21	$ 5,722,044.00
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 41,169.11	$ -	$ 41,169.11	$ 29,486.77
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 884,312.87	$ -	$ 884,312.87	$ 633,376.01
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 3,577.01	$ -	$ 3,577.01	$ 2,561.98
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (18,578,993.25)	$ -	$ (18,578,993.25)	$ (13,306,928.97)
30	Financial Transmission Rights Monthly Allocation Amount	$ (681,472.03)	$ -	$ (681,472.03)	$ (488,094.26)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (696,075.01)	$ -	$ (696,075.01)	$ (498,553.42)
37	Financial Transmission Guarantee Uplift Amount	$ 655,956.21	$ -	$ 655,956.21	$ 469,818.93
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 2,547,550.42	$ -	$ 2,547,550.42	$ 1,824,645.29
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 230,106.64	$ -	$ 230,106.64	$ 164,810.48
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (430,650.87)	$ 146,547.63	$ (284,103.24)	$ (203,484.74)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 932,613.64	$ -	$ 932,613.64	$ 667,970.72
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (1,036,631.34)	$ 601,279.81	$ (435,351.53)	$ (311,814.09)
43	Real Time Price Volatility Make Whole Payment	$ (211,772.06)	$ 34,322.14	$ (177,449.92)	$ (127,095.88)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 567,420.78	$ (56,545.32)	$ 510,875.46	$ 365,906.99
19	Real-Time Market Administration Amount	$ 64,083.55	$ (6,080.78)	$ 58,002.77	$ 41,543.63
29	Financial Transmission Rights Market Administration Amount	$ 27,875.77	$ -	$ 27,875.77	$ 19,965.61
33	Day-Ahead Schedule 24 Allocation Amount	$ 89,822.96	$ (8,952.50)	$ 80,870.46	$ 57,922.27
34	Real -Time Schedule 24 Allocation Amount	$ (94,671.11)	$ 111,937.38	$ 17,266.27	$ 12,366.71
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ 937.16	$ 85,151.73	$ 86,088.89	$ 61,659.89
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 4,769,796.97	$ -	$ 4,769,796.97	$ 3,416,296.49
40	Auction Revenue Rights - Monthly ARR Revenue	$ (4,790,198.14)	$ 28,953.60	$ (4,761,244.54)	$ (3,410,170.94)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (176,339.19)	$ -	$ (176,339.19)	$ (126,300.34)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 168,443.44	$ -	$ 168,443.44	$ 120,645.12
	TOTAL MISO CHARGES	**$ 2,454,497.77**	**$ 26,815,576.93**	**$ 29,270,074.70**	**$ 20,964,257.84**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 596,754.00**	**$ 427,416.22**
	SCHEDULE 24 (FOR RETAIL)			**$ 98,136.73**	**$ 70,288.98**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 28,575,183.97**	**$ 20,466,552.64**

Northern States Power Company

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	June 2022 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (31,665,995.36)	$ 61,301,261.37	$ 29,635,266.01	$ 21,405,770.31
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 7,981,645.76	$ -	$ 7,981,645.76	$ 5,765,201.36
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (10,665.66)	$ -	$ (10,665.66)	$ (7,703.88)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (28,340,952.22)	$ -	$ (28,340,952.22)	$ (20,470,877.95)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 3,411,214.86	$ -	$ 3,411,214.86	$ 2,463,945.55
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 10,950.52	$ -	$ 10,950.52	$ 7,909.64
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 766,576.51	$ 4,027,561.61	$ 4,794,138.12	$ 3,462,841.18
13 c	Real-Time Asset Energy Amount - Loss Component	$ 71,252.21	$ -	$ 71,252.21	$ 51,465.99
14	Real-Time Distribution of Losses Amount	$ (3,458,138.67)	$ -	$ (3,458,138.67)	$ (2,497,838.96)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 82.73	$ -	$ 82.73	$ 59.76
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (82.73)	$ -	$ (82.73)	$ (59.76)
21	Real-time Net inadvertent Distribution	$ 146,142.15	$ -	$ 146,142.15	$ 105,559.55
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 495,402.49	$ -	$ 495,402.49	$ 357,832.86
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (78.00)	$ -	$ (78.00)	$ (56.34)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 30,398,547.13	$ -	$ 30,398,547.13	$ 21,957,093.87
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (46,820.41)	$ -	$ (46,820.41)	$ (33,818.73)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 8,849,540.07	$ -	$ 8,849,540.07	$ 6,392,087.79
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 48,099.32	$ -	$ 48,099.32	$ 34,742.49
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 367,034.37	$ -	$ 367,034.37	$ 265,111.62
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 1,070.28	$ -	$ 1,070.28	$ 773.07
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (1,070.28)	$ -	$ (1,070.28)	$ (773.07)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (41.66)	$ -	$ (41.66)	$ (30.09)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (32,883,959.16)	$ -	$ (32,883,959.16)	$ (23,752,325.24)
30	Financial Transmission Rights Monthly Allocation Amount	$ (322,124.90)	$ -	$ (322,124.90)	$ (232,673.18)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 522,681.87	$ -	$ 522,681.87	$ 377,536.95
37	Financial Transmission Guarantee Uplift Amount	$ (478,145.35)	$ -	$ (478,145.35)	$ (345,367.90)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 1,088,940.74	$ -	$ 1,088,940.74	$ 786,549.89
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 211,870.31	$ -	$ 211,870.31	$ 153,035.48
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (806,552.26)	$ 330,696.94	$ (475,855.32)	$ (343,713.79)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 1,011,288.59	$ -	$ 1,011,288.59	$ 730,461.18
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (1,693,496.20)	$ 630,661.40	$ (1,062,834.80)	$ (767,693.38)
43	Real Time Price Volatility Make Whole Payment	$ (448,116.10)	$ 159,994.47	$ (288,121.63)	$ (208,112.37)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 606,767.34	$ (79,986.80)	$ 526,780.54	$ 380,497.45
19	Real-Time Market Administration Amount	$ 65,841.91	$ (7,004.55)	$ 58,837.36	$ 42,498.66
29	Financial Transmission Rights Market Administration Amount	$ 58,675.52	$ -	$ 58,675.52	$ 42,381.76
33	Day-Ahead Schedule 24 Allocation Amount	$ 84,192.42	$ (12,449.11)	$ 71,743.31	$ 51,820.72
34	Real -Time Schedule 24 Allocation Amount	$ (86,047.70)	$ 101,633.64	$ 15,585.94	$ 11,257.84
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ (12,486,824.24)	$ 12,640,508.73	$ 153,684.49	$ 111,007.44
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 14,246,626.37	$ -	$ 14,246,626.37	$ 10,290,442.87
40	Auction Revenue Rights - Monthly ARR Revenue	$ (14,250,985.44)	$ (1,956.04)	$ (14,252,941.48)	$ (10,295,004.32)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (605,336.30)	$ -	$ (605,336.30)	$ (437,238.86)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 97,656.73	$ -	$ 97,656.73	$ 70,538.17
	TOTAL MISO CHARGES	**$ (57,043,332.44)**	**$ 79,090,921.66**	**$ 22,047,589.22**	**$ 15,925,135.63**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 644,293.42**	**$ 465,377.87**
	SCHEDULE 24 (FOR RETAIL)			**$ 87,329.25**	**$ 63,078.56**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 21,315,966.55**	**$ 15,396,679.21**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	July 2022 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (39,790,408.02)	$ 64,669,509.24	$ 24,879,101.22	$ 18,219,343.14
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 9,677,696.45	$ -	$ 9,677,696.45	$ 7,087,123.88
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (6,928.60)	$ -	$ (6,928.60)	$ (5,073.92)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (27,776,107.33)	$ -	$ (27,776,107.33)	$ (20,340,864.65)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 3,229,958.50	$ -	$ 3,229,958.50	$ 2,365,347.60
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 6,928.60	$ -	$ 6,928.60	$ 5,073.92
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (5,377,666.58)	$ 4,679,403.93	$ (698,262.65)	$ (511,348.33)
13 c	Real-Time Asset Energy Amount - Loss Component	$ 472,267.74	$ -	$ 472,267.74	$ 345,848.83
14	Real-Time Distribution of Losses Amount	$ (3,941,304.02)	$ -	$ (3,941,304.02)	$ (2,886,276.71)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 16,534.13	$ -	$ 16,534.13	$ 12,108.19
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 115,159.91	$ -	$ 115,159.91	$ 84,333.35
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 186,735.34	$ -	$ 186,735.34	$ 136,749.12
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (392.83)	$ -	$ (392.83)	$ (287.68)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 16,968,919.80	$ -	$ 16,968,919.80	$ 12,426,597.32
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (48,026.83)	$ -	$ (48,026.83)	$ (35,170.78)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 6,994,251.93	$ -	$ 6,994,251.93	$ 5,121,996.76
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 48,026.83	$ -	$ 48,026.83	$ 35,170.78
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 1,198,800.61	$ -	$ 1,198,800.61	$ 877,899.87
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 0.00	$ -	$ 0.00	$ 0.00
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 14,906.82	$ -	$ 14,906.82	$ 10,916.49
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (17,479,894.33)	$ -	$ (17,479,894.33)	$ (12,800,791.72)
30	Financial Transmission Rights Monthly Allocation Amount	$ (23,297.09)	$ -	$ (23,297.09)	$ (17,060.81)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 279,916.93	$ -	$ 279,916.93	$ 204,987.41
37	Financial Transmission Guarantee Uplift Amount	$ (275,855.97)	$ -	$ (275,855.97)	$ (202,013.51)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 476,854.77	$ -	$ 476,854.77	$ 349,207.98
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 251,491.25	$ -	$ 251,491.25	$ 184,170.86
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (436,847.79)	$ 268,746.13	$ (168,101.66)	$ (123,103.40)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 524,869.57	$ -	$ 524,869.57	$ 384,369.95
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (708,077.27)	$ 319,907.29	$ (388,169.98)	$ (284,262.76)
43	Real Time Price Volatility Make Whole Payment	$ (281,870.86)	$ 116,139.58	$ (165,731.28)	$ (121,367.53)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 760,965.07	$ (89,245.49)	$ 671,719.58	$ 491,910.44
19	Real-Time Market Administration Amount	$ 66,574.73	$ (7,928.11)	$ 58,646.62	$ 42,947.81
29	Financial Transmission Rights Market Administration Amount	$ 10,560.47	$ -	$ 10,560.47	$ 7,733.59
33	Day-Ahead Schedule 24 Allocation Amount	$ 112,641.34	$ (12,052.24)	$ 100,589.10	$ 73,662.92
34	Real -Time Schedule 24 Allocation Amount	$ (93,303.21)	$ 83,386.98	$ (9,916.23)	$ (7,261.81)
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ (12,979,852.54)	$ 13,017,142.73	$ 37,290.19	$ 27,308.17
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 14,246,626.37	$ -	$ 14,246,626.37	$ 10,433,020.56
40	Auction Revenue Rights - Monthly ARR Revenue	$ (14,250,985.44)	$ 88,050.18	$ (14,162,935.26)	$ (10,371,732.29)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (605,336.38)	$ -	$ (605,336.38)	$ (443,297.01)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 97,656.74	$ -	$ 97,656.74	$ 71,515.51
	TOTAL MISO CHARGES	**$ (68,317,811.19)**	**$ 83,133,060.22**	**$ 14,815,249.03**	**$ 10,849,431.55**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 740,926.67**	**$ 542,591.84**
	SCHEDULE 24 (FOR RETAIL)			**$ 90,672.87**	**$ 66,401.12**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 13,983,649.49**	**$ 10,240,438.60**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	August 2022 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (50,516,419.76)	$ 70,494,662.55	$ 19,978,242.79	$ 14,415,493.76
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 10,998,863.34	$ -	$ 10,998,863.34	$ 7,936,335.92
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (10,996.72)	$ -	$ (10,996.72)	$ (7,934.79)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (29,633,437.87)	$ -	$ (29,633,437.87)	$ (21,382,292.89)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 3,340,160.83	$ -	$ 3,340,160.83	$ 2,410,125.26
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 10,996.72	$ -	$ 10,996.72	$ 7,934.79
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 152,070.68	$ 6,347,710.59	$ 6,499,781.27	$ 4,689,979.86
13 c	Real-Time Asset Energy Amount - Loss Component	$ 267,339.94	$ -	$ 267,339.94	$ 192,901.71
14	Real-Time Distribution of Losses Amount	$ (3,520,667.46)	$ -	$ (3,520,667.46)	$ (2,540,371.56)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 14,607.93	$ -	$ 14,607.93	$ 10,540.49
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 91,273.37	$ -	$ 91,273.37	$ 65,859.18
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 77,270.39	$ -	$ 77,270.39	$ 55,755.20
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (12.07)	$ -	$ (12.07)	$ (8.71)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 36,113,942.48	$ -	$ 36,113,942.48	$ 26,058,363.49
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (40,304.37)	$ -	$ (40,304.37)	$ (29,082.01)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 5,436,862.77	$ -	$ 5,436,862.77	$ 3,923,020.77
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 40,304.37	$ -	$ 40,304.37	$ 29,082.01
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 464,871.01	$ -	$ 464,871.01	$ 335,432.16
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (0.04)	$ -	$ (0.04)	$ (0.03)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (31,643,701.31)	$ -	$ (31,643,701.31)	$ (22,832,817.86)
30	Financial Transmission Rights Monthly Allocation Amount	$ (676,846.58)	$ -	$ (676,846.58)	$ (488,385.18)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (749,904.44)	$ -	$ (749,904.44)	$ (541,100.78)
37	Financial Transmission Guarantee Uplift Amount	$ 744,017.63	$ -	$ 744,017.63	$ 536,853.10
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 159,335.19	$ -	$ 159,335.19	$ 114,969.84
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 209,846.94	$ -	$ 209,846.94	$ 151,417.08
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (144,012.39)	$ 54,493.31	$ (89,519.08)	$ (64,593.36)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 684,416.26	$ -	$ 684,416.26	$ 493,847.15
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (1,256,217.88)	$ 884,671.06	$ (371,546.82)	$ (268,093.19)
43	Real Time Price Volatility Make Whole Payment	$ (158,139.46)	$ 45,819.17	$ (112,320.29)	$ (81,045.79)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 561,495.23	$ (9,600.12)	$ 551,895.11	$ 398,225.24
19	Real-Time Market Administration Amount	$ 48,510.28	$ 1,086.31	$ 49,596.59	$ 35,786.90
29	Financial Transmission Rights Market Administration Amount	$ 97,297.00	$ -	$ 97,297.00	$ 70,205.59
33	Day-Ahead Schedule 24 Allocation Amount	$ 101,770.81	$ (11,757.93)	$ 90,012.88	$ 64,949.66
34	Real -Time Schedule 24 Allocation Amount	$ (87,104.36)	$ 108,083.61	$ 20,979.25	$ 15,137.78
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ (12,860,424.53)	$ 13,017,142.73	$ 156,718.20	$ 113,081.53
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 14,246,626.37	$ -	$ 14,246,626.37	$ 10,279,790.65
40	Auction Revenue Rights - Monthly ARR Revenue	$ (14,250,985.44)	$ 43,812.41	$ (14,207,173.03)	$ (10,251,322.72)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (605,336.65)	$ -	$ (605,336.65)	$ (436,786.50)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 97,656.73	$ -	$ 97,656.73	$ 70,465.16
	TOTAL MISO CHARGES	**$ (72,194,975.06)**	**$ 90,976,123.69**	**$ 18,781,148.63**	**$ 13,551,718.92**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 698,788.70**	**$ 504,217.73**
	SCHEDULE 24 (FOR RETAIL)			**$ 110,992.13**	**$ 80,087.44**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 17,971,367.80**	**$ 12,967,413.76**

Northern States Power Company

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	September 2022 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (17,261,451.71)	$ 52,041,061.47	$ 34,779,609.76	$ 25,100,311.51
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 5,951,512.55	$ -	$ 5,951,512.55	$ 4,295,183.87
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (13,200.03)	$ -	$ (13,200.03)	$ (9,526.41)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (24,338,481.07)	$ -	$ (24,338,481.07)	$ (17,564,988.82)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 2,919,839.90	$ -	$ 2,919,839.90	$ 2,107,237.30
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 13,200.03	$ -	$ 13,200.03	$ 9,526.41
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 1,719,165.94	$ 2,105,207.97	$ 3,824,373.91	$ 2,760,036.04
13 c	Real-Time Asset Energy Amount - Loss Component	$ 109,605.54	$ -	$ 109,605.54	$ 79,101.90
14	Real-Time Distribution of Losses Amount	$ (2,792,430.88)	$ -	$ (2,792,430.88)	$ (2,015,286.70)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 22,808.71	$ -	$ 22,808.71	$ 16,460.96
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (127.12)	$ -	$ (127.12)	$ (91.74)
21	Real-time Net inadvertent Distribution	$ 50,617.39	$ -	$ 50,617.39	$ 36,530.38
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (118,367.22)	$ -	$ (118,367.22)	$ (85,425.17)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (1,807.54)	$ -	$ (1,807.54)	$ (1,304.49)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 8,241,682.60	$ -	$ 8,241,682.60	$ 5,947,990.85
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (23,886.69)	$ -	$ (23,886.69)	$ (17,238.93)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 4,144,504.24	$ -	$ 4,144,504.24	$ 2,991,072.88
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 23,886.69	$ -	$ 23,886.69	$ 17,238.93
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 552,047.55	$ -	$ 552,047.55	$ 398,410.61
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 1,377.68	$ -	$ 1,377.68	$ 994.27
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (1,377.68)	$ -	$ (1,377.68)	$ (994.27)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (199,740.58)	$ -	$ (199,740.58)	$ (144,152.01)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (4,461,099.61)	$ -	$ (4,461,099.61)	$ (3,219,558.55)
30	Financial Transmission Rights Monthly Allocation Amount	$ (72,810.45)	$ -	$ (72,810.45)	$ (52,547.02)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 749,614.98	$ -	$ 749,614.98	$ 540,994.27
37	Financial Transmission Guarantee Uplift Amount	$ (743,057.38)	$ -	$ (743,057.38)	$ (536,261.67)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 550,061.07	$ -	$ 550,061.07	$ 396,976.97
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 81,361.64	$ -	$ 81,361.64	$ 58,718.38
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (779,026.73)	$ 411,923.67	$ (367,103.06)	$ (264,936.88)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 356,531.35	$ -	$ 356,531.35	$ 257,307.31
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (426,555.65)	$ (58,783.31)	$ (485,338.96)	$ (350,267.27)
43	Real Time Price Volatility Make Whole Payment	$ (247,002.93)	$ 56,787.68	$ (190,215.25)	$ (137,277.62)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 794,149.26	$ (157,634.09)	$ 636,515.17	$ 459,370.57
19	Real-Time Market Administration Amount	$ 74,613.12	$ (14,568.59)	$ 60,044.53	$ 43,333.91
29	Financial Transmission Rights Market Administration Amount	$ (40,132.01)	$ -	$ (40,132.01)	$ (28,963.12)
33	Day-Ahead Schedule 24 Allocation Amount	$ 107,874.12	$ (13,504.16)	$ 94,369.96	$ 68,106.44
34	Real -Time Schedule 24 Allocation Amount	$ (95,418.06)	$ 81,582.80	$ (13,835.26)	$ (9,984.85)
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ (11,519,572.44)	$ 12,597,234.90	$ 1,077,662.46	$ 777,744.88
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 9,883,261.64	$ -	$ 9,883,261.64	$ 7,132,712.17
40	Auction Revenue Rights - Monthly ARR Revenue	$ (9,903,009.97)	$ 36,633.65	$ (9,866,376.32)	$ (7,120,526.10)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (497,087.41)	$ -	$ (497,087.41)	$ (358,746.09)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 240,801.85	$ -	$ 240,801.85	$ 173,785.78
	TOTAL MISO CHARGES	**$ (36,947,125.31)**	**$ 67,085,941.99**	**$ 30,138,816.68**	**$ 21,751,068.87**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 656,427.69**	**$ 473,741.36**
	SCHEDULE 24 (FOR RETAIL)			**$ 80,534.70**	**$ 58,121.59**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 29,401,854.29**	**$ 21,219,205.93**

Northern States Power Company

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	October 2022 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (15,524,311.34)	$ 32,012,824.63	$ 16,488,513.29	$ 11,691,535.65
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 5,024,051.38	$ -	$ 5,024,051.38	$ 3,562,411.89
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (4,126.88)	$ -	$ (4,126.88)	$ (2,926.25)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (16,348,163.94)	$ -	$ (16,348,163.94)	$ (11,592,017.92)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,772,202.04	$ -	$ 1,772,202.04	$ 1,256,618.04
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 4,126.88	$ -	$ 4,126.88	$ 2,926.25
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 646,163.53	$ 2,798,481.91	$ 3,444,645.44	$ 2,442,500.08
13 c	Real-Time Asset Energy Amount - Loss Component	$ 21,648.50	$ -	$ 21,648.50	$ 15,350.34
14	Real-Time Distribution of Losses Amount	$ (1,616,198.25)	$ -	$ (1,616,198.25)	$ (1,146,000.20)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 14,289.62	$ -	$ 14,289.62	$ 10,132.36
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (8.31)	$ -	$ (8.31)	$ (5.89)
21	Real-time Net inadvertent Distribution	$ (251,384.23)	$ -	$ (251,384.23)	$ (178,249.41)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 520,732.14	$ -	$ 520,732.14	$ 369,236.34
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (197.54)	$ -	$ (197.54)	$ (140.07)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 14,202,742.96	$ -	$ 14,202,742.96	$ 10,070,760.94
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 923.80	$ -	$ 923.80	$ 655.04
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 2,014,813.70	$ -	$ 2,014,813.70	$ 1,428,647.07
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (923.80)	$ -	$ (923.80)	$ (655.04)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 269,558.00	$ -	$ 269,558.00	$ 191,135.91
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 86.65	$ -	$ 86.65	$ 61.44
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (86.65)	$ -	$ (86.65)	$ (61.44)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (32,248.60)	$ -	$ (32,248.60)	$ (22,866.56)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (2,183,842.20)	$ -	$ (2,183,842.20)	$ (1,548,500.37)
30	Financial Transmission Rights Monthly Allocation Amount	$ (200,765.40)	$ -	$ (200,765.40)	$ (142,357.03)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (182,284.97)	$ -	$ (182,284.97)	$ (129,253.09)
37	Financial Transmission Guarantee Uplift Amount	$ 177,556.08	$ -	$ 177,556.08	$ 125,899.96
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 897,100.36	$ -	$ 897,100.36	$ 636,108.34
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 105,247.84	$ -	$ 105,247.84	$ 74,628.25
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (321,128.68)	$ 140,560.34	$ (180,568.34)	$ (128,035.87)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 122,490.20	$ -	$ 122,490.20	$ 86,854.32
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (67,500.22)	$ 64,252.59	$ (3,247.63)	$ (2,302.80)
43	Real Time Price Volatility Make Whole Payment	$ (135,816.23)	$ 39,845.46	$ (95,970.77)	$ (68,050.14)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 542,953.21	$ (79,553.13)	$ 463,400.08	$ 328,583.81
19	Real-Time Market Administration Amount	$ 56,164.99	$ (6,397.38)	$ 49,767.61	$ 35,288.80
29	Financial Transmission Rights Market Administration Amount	$ 21,039.77	$ -	$ 21,039.77	$ 14,918.70
33	Day-Ahead Schedule 24 Allocation Amount	$ 96,905.88	$ (14,370.18)	$ 82,535.70	$ 58,523.72
34	Real -Time Schedule 24 Allocation Amount	$ (82,788.98)	$ 88,358.61	$ 5,569.63	$ 3,949.27
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ (12,878,321.03)	$ 13,017,142.73	$ 138,821.70	$ 98,434.52
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 9,883,261.64	$ -	$ 9,883,261.64	$ 7,007,939.64
40	Auction Revenue Rights - Monthly ARR Revenue	$ (9,903,009.97)	$ 37,502.99	$ (9,865,506.98)	$ (6,995,350.31)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (497,086.80)	$ -	$ (497,086.80)	$ (352,470.11)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 240,801.85	$ -	$ 240,801.85	$ 170,745.74
	TOTAL MISO CHARGES	**$ (23,595,333.00)**	**$ 48,098,648.57**	**$ 24,503,315.57**	**$ 17,374,603.91**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 534,207.46**	**$ 378,791.31**
	SCHEDULE 24 (FOR RETAIL)			**$ 88,105.33**	**$ 62,472.98**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 23,881,002.78**	**$ 16,933,339.62**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	November 2022 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (11,967,026.42)	$ 22,280,154.94	$ 10,313,128.52	$ 7,303,891.16
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 6,486,459.85	$ -	$ 6,486,459.85	$ 4,593,794.86
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (2,359.55)	$ -	$ (2,359.55)	$ (1,671.06)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (9,626,755.70)	$ -	$ (9,626,755.70)	$ (6,817,793.04)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,032,881.20	$ -	$ 1,032,881.20	$ 731,499.84
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 2,359.55	$ -	$ 2,359.55	$ 1,671.06
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (5,148,323.29)	$ 2,701,231.14	$ (2,447,092.15)	$ (1,733,062.35)
13 c	Real-Time Asset Energy Amount - Loss Component	$ 85,976.92	$ -	$ 85,976.92	$ 60,889.97
14	Real-Time Distribution of Losses Amount	$ (1,382,854.66)	$ -	$ (1,382,854.66)	$ (979,355.58)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 71,002.67	$ -	$ 71,002.67	$ 50,285.01
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 186,071.21	$ -	$ 186,071.21	$ 131,778.04
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 662.77	$ -	$ 662.77	$ 469.38
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 0.14	$ -	$ 0.14	$ 0.10
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 11,067,047.64	$ -	$ 11,067,047.64	$ 7,837,826.45
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (14,831.27)	$ -	$ (14,831.27)	$ (10,503.70)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 2,578,584.25	$ -	$ 2,578,584.25	$ 1,826,186.76
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 14,831.27	$ -	$ 14,831.27	$ 10,503.70
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 753,074.93	$ -	$ 753,074.93	$ 533,337.42
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 0.01	$ -	$ 0.01	$ 0.01
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (251,163.01)	$ -	$ (251,163.01)	$ (177,876.90)
30	Financial Transmission Rights Monthly Allocation Amount	$ (29,038.67)	$ -	$ (29,038.67)	$ (20,565.56)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 157,510.41	$ -	$ 157,510.41	$ 111,550.91
37	Financial Transmission Guarantee Uplift Amount	$ (155,562.07)	$ -	$ (155,562.07)	$ (110,171.07)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ (571,997.75)	$ -	$ (571,997.75)	$ (405,096.21)
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 132,559.47	$ -	$ 132,559.47	$ 93,880.33
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (206,009.56)	$ 172,537.37	$ (33,472.19)	$ (23,705.44)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 424,622.29	$ -	$ 424,622.29	$ 300,723.00
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (600,184.88)	$ 327,252.99	$ (272,931.89)	$ (193,293.90)
43	Real Time Price Volatility Make Whole Payment	$ (227,617.40)	$ 71,954.78	$ (155,662.62)	$ (110,242.28)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 676,989.99	$ (82,411.08)	$ 594,578.91	$ 421,088.48
19	Real-Time Market Administration Amount	$ 91,207.09	$ (12,582.07)	$ 78,625.02	$ 55,683.26
29	Financial Transmission Rights Market Administration Amount	$ 21,607.54	$ -	$ 21,607.54	$ 15,302.74
33	Day-Ahead Schedule 24 Allocation Amount	$ 103,151.64	$ (13,008.11)	$ 90,143.53	$ 63,840.82
34	Real -Time Schedule 24 Allocation Amount	$ (89,557.94)	$ 98,577.03	$ 9,019.09	$ 6,387.44
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ (12,536,894.19)	$ 12,597,234.90	$ 60,340.71	$ 42,734.07
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 9,883,261.64	$ -	$ 9,883,261.64	$ 6,999,453.87
40	Auction Revenue Rights - Monthly ARR Revenue	$ (9,903,009.97)	$ 38,219.94	$ (9,864,790.03)	$ (6,986,372.04)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (497,086.80)	$ -	$ (497,086.80)	$ (352,043.31)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 240,884.14	$ -	$ 240,884.14	$ 170,597.27
	TOTAL MISO CHARGES	**$ (19,199,526.51)**	**$ 38,179,161.83**	**$ 18,979,635.32**	**$ 13,441,623.50**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 694,811.47**	**$ 492,074.48**
	SCHEDULE 24 (FOR RETAIL)			**$ 99,162.62**	**$ 70,228.25**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 18,185,661.23**	**$ 12,879,320.77**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	December 2022 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (26,900,400.57)	$ 41,106,780.08	$ 14,206,379.51	$ 10,023,041.52
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 8,188,431.65	$ -	$ 8,188,431.65	$ 5,777,192.59
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 5,716.43	$ -	$ 5,716.43	$ 4,033.12
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (11,457,488.91)	$ -	$ (11,457,488.91)	$ (8,083,613.91)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 790,145.55	$ -	$ 790,145.55	$ 557,472.20
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (5,716.43)	$ -	$ (5,716.43)	$ (4,033.12)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 1,116,012.08	$ 13,458,429.18	$ 14,574,441.26	$ 10,282,720.50
13 c	Real-Time Asset Energy Amount - Loss Component	$ 161,995.38	$ -	$ 161,995.38	$ 114,292.77
14	Real-Time Distribution of Losses Amount	$ (2,144,781.20)	$ -	$ (2,144,781.20)	$ (1,513,209.68)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 978,286.28	$ -	$ 978,286.28	$ 690,211.32
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 606,843.10	$ -	$ 606,843.10	$ 428,146.64
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (264,209.08)	$ -	$ (264,209.08)	$ (186,407.70)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 36,441.54	$ -	$ 36,441.54	$ 25,710.64
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 11,594,354.87	$ -	$ 11,594,354.87	$ 8,180,177.09
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (19,113.41)	$ -	$ (19,113.41)	$ (13,485.10)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 2,462,574.40	$ -	$ 2,462,574.40	$ 1,737,422.64
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 19,113.41	$ -	$ 19,113.41	$ 13,485.10
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 609,641.96	$ -	$ 609,641.96	$ 430,121.32
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 139,082.11	$ -	$ 139,082.11	$ 98,126.74
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (6,612,732.28)	$ -	$ (6,612,732.28)	$ (4,665,487.79)
30	Financial Transmission Rights Monthly Allocation Amount	$ (95,289.88)	$ -	$ (95,289.88)	$ (67,229.97)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (120,099.63)	$ -	$ (120,099.63)	$ (84,734.02)
37	Financial Transmission Guarantee Uplift Amount	$ 123,032.52	$ -	$ 123,032.52	$ 86,803.26
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ (1,961,545.52)	$ -	$ (1,961,545.52)	$ (1,383,931.22)
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 179,197.28	$ -	$ 179,197.28	$ 126,429.24
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (121,230.65)	$ 53,109.91	$ (68,120.74)	$ (48,061.30)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 2,081,269.37	$ -	$ 2,081,269.37	$ 1,468,400.11
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (1,946,929.08)	$ 666,830.73	$ (1,280,098.35)	$ (903,149.10)
43	Real Time Price Volatility Make Whole Payment	$ (640,622.73)	$ 115,246.07	$ (525,376.66)	$ (370,669.53)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 569,229.19	$ (71,896.92)	$ 497,332.27	$ 350,883.35
19	Real-Time Market Administration Amount	$ 54,195.25	$ (14,999.54)	$ 39,195.71	$ 27,653.79
29	Financial Transmission Rights Market Administration Amount	$ 19,853.54	$ -	$ 19,853.54	$ 14,007.29
33	Day-Ahead Schedule 24 Allocation Amount	$ 108,675.75	$ (13,507.53)	$ 95,168.22	$ 67,144.13
34	Real -Time Schedule 24 Allocation Amount	$ (104,275.44)	$ 115,736.54	$ 11,461.10	$ 8,086.16
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ (13,812,400.78)	$ 13,017,142.73	$ (795,258.05)	$ (561,079.23)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 15,777,513.01	$ -	$ 15,777,513.01	$ 11,131,524.95
40	Auction Revenue Rights - Monthly ARR Revenue	$ (15,782,515.07)	$ 175,272.90	$ (15,607,242.17)	$ (11,011,393.59)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (683,288.39)	$ -	$ (683,288.39)	$ (482,081.16)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 89,943.30	$ -	$ 89,943.30	$ 63,457.79
	TOTAL MISO CHARGES	**$ (36,961,091.08)**	**$ 68,608,144.15**	**$ 31,647,053.07**	**$ 22,327,977.84**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 556,381.52**	**$ 392,544.42**
	SCHEDULE 24 (FOR RETAIL)			**$ 106,629.32**	**$ 75,230.29**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 30,984,042.23**	**$ 21,860,203.12**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	January - December 2022 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (278,898,146.28)	$ 504,800,506.54	$ 225,902,360.26	$ 161,196,617.84
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 88,484,243.03	$ -	$ 88,484,243.03	$ 63,139,493.95
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (172,225.98)	$ -	$ (172,225.98)	$ (122,894.89)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (202,406,624.05)	$ -	$ (202,406,624.05)	$ (144,430,820.41)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 20,072,266.36	$ -	$ 20,072,266.36	$ 14,322,920.07
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 22,925.83	$ -	$ 22,925.83	$ 16,359.13
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (9,769,956.35)	$ 51,610,296.04	$ 41,840,339.69	$ 29,855,913.14
13 c	Real-Time Asset Energy Amount - Loss Component	$ 1,394,813.76	$ -	$ 1,394,813.76	$ 995,293.99
14	Real-Time Distribution of Losses Amount	$ (27,829,110.60)	$ -	$ (27,829,110.60)	$ (19,857,953.24)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 1,117,621.83	$ -	$ 1,117,621.83	$ 797,498.79
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (227.92)	$ -	$ (227.92)	$ (162.64)
21	Real-time Net inadvertent Distribution	$ 986,813.84	$ -	$ 986,813.84	$ 704,158.44
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 2,393,809.28	$ -	$ 2,393,809.28	$ 1,708,144.88
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 41,644.48	$ -	$ 41,644.48	$ 29,716.15
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 241,014,492.53	$ -	$ 241,014,492.53	$ 171,980,146.65
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (273,709.89)	$ -	$ (273,709.89)	$ (195,310.52)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 49,566,109.93	$ -	$ 49,566,109.93	$ 35,368,772.91
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 93,345.66	$ -	$ 93,345.66	$ 66,608.44
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 5,321,796.69	$ -	$ 5,321,796.69	$ 3,797,461.99
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 2,669.76	$ -	$ 2,669.76	$ 1,905.05
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (2,669.76)	$ -	$ (2,669.76)	$ (1,905.05)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (82,052.31)	$ -	$ (82,052.31)	$ (58,549.87)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (122,900,725.98)	$ -	$ (122,900,725.98)	$ (87,697,983.03)
30	Financial Transmission Rights Monthly Allocation Amount	$ (2,899,316.04)	$ -	$ (2,899,316.04)	$ (2,068,858.15)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ (1,632,060.78)	$ -	$ (1,632,060.78)	$ (1,164,585.79)
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 1,671,660.61	$ -	$ 1,671,660.61	$ 1,192,842.94
37	Financial Transmission Guarantee Uplift Amount	$ (1,538,776.09)	$ -	$ (1,538,776.09)	$ (1,098,020.85)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 8,180,334.02	$ -	$ 8,180,334.02	$ 5,837,221.78
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 1,842,815.41	$ -	$ 1,842,815.41	$ 1,314,973.47
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (3,903,557.76)	$ 1,922,460.85	$ (1,981,096.91)	$ (1,413,646.68)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 7,214,645.51	$ -	$ 7,214,645.51	$ 5,148,137.69
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (8,907,512.93)	$ 3,924,069.27	$ (4,983,443.66)	$ (3,556,024.21)
43	Real Time Price Volatility Make Whole Payment	$ (2,769,032.96)	$ 745,976.68	$ (2,023,056.28)	$ (1,443,587.53)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 7,559,742.65	$ (979,546.23)	$ 6,580,196.42	$ 4,695,415.34
19	Real-Time Market Administration Amount	$ 787,523.97	$ (108,952.73)	$ 678,571.24	$ 484,206.49
29	Financial Transmission Rights Market Administration Amount	$ 331,553.99	$ -	$ 331,553.99	$ 236,586.20
33	Day-Ahead Schedule 24 Allocation Amount	$ 1,200,279.46	$ (156,108.93)	$ 1,044,170.53	$ 745,086.32
34	Real -Time Schedule 24 Allocation Amount	$ (1,106,495.99)	$ 1,197,022.24	$ 90,526.25	$ 64,596.60
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ (89,153,720.75)	$ 90,325,120.31	$ 1,171,399.56	$ 835,872.84
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 115,296,100.59	$ -	$ 115,296,100.59	$ 82,271,568.32
40	Auction Revenue Rights - Monthly ARR Revenue	$ (115,528,039.82)	$ 545,451.90	$ (114,982,587.92)	$ (82,047,855.81)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (4,991,372.80)	$ -	$ (4,991,372.80)	$ (3,561,682.19)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 1,764,231.80	$ -	$ 1,764,231.80	$ 1,258,898.75
	TOTAL MISO CHARGES	**$ (318,403,894.05)**	**$ 653,826,295.94**	**$ 335,422,401.89**	**$ 239,346,577.29**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 7,590,321.65**	**$ 5,416,208.03**
	SCHEDULE 24 (FOR RETAIL)			**$ 1,134,696.78**	**$ 809,682.92**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 326,697,383.46**	**$ 233,120,686.34**

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MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	January 2022	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		RSYSTEM - NON-ASSET B	
	Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(1,427,993)	$ (12,048,683.12)	(2,891,765)	$ 40,157,175.60	1,463,772	$ (52,205,858.72)	-	$ -
5a	Day Ahead Non Asset Energy	(108,457)	$ (3,461,887.80)	(108,457)	$ (3,461,887.80)	-	$ -	-	$ (0.11)
13a	Real Time Asset Energy	(42,506)	$ (1,824,038.66)	(187,540)	$ 1,773,120.10	145,034	$ (3,597,158.76)	-	$ -
22a	Real Time Non Asset Energy	(434)	$ (27,549.82)	(434)	$ (27,549.82)	-	$ -	-	$ -
	SUBTOTAL	(1,579,390)	$ (17,362,159.40)	(3,188,196)	$ 38,440,858.08	1,608,806	$ (55,803,017.48)	-	$ (0.11)
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ (128,510.23)	-	$ (128,510.23)	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (2,111,968.97)	-	$ (2,111,968.97)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (2,240,479.20)	-	$ (2,240,479.20)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 711,062.64	-	$ 594,248.62	-	$ 116,814.02	-	$ (0.05)
19	Real Time Market Administration (Schedule 17)	-	$ 85,287.01	-	$ 73,906.66	-	$ 11,380.35	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 37,165.31	-	$ 37,165.31	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 110,058.67	-	$ 92,063.28	-	$ 17,995.39	-	$ -
34	Real -Time Schedule 24 Allocation Amount	-	$ (97,747.55)	-	$ 3,675.95	-	$ (101,423.50)	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 845,826.08	-	$ 801,059.82	-	$ 44,766.26	-	$ (0.05)
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ (70,510.32)	-	$ (70,510.32)	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ (5,374,949.19)	-	$ (5,374,949.19)	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (303,409.00)	-	$ (303,409.00)	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ (1,632,060.78)	-	$ (1,632,060.78)	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ 1,658,342.83	-	$ 1,658,342.83	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ (1,508,569.95)	-	$ (1,508,569.95)	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (7,231,156.41)	-	$ (7,231,156.41)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 126,443.72	-	$ 126,443.72	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (150,157.83)	-	$ (74,804.17)	-	$ (75,353.66)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 600,163.19	-	$ 600,163.19	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (601,631.91)	-	$ (380,695.69)	-	$ (220,936.22)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (118,371.51)	-	$ (89,484.26)	-	$ (28,887.25)	-	$ -
	SUBTOTAL	-	$ (143,554.34)	-	$ 181,622.79	-	$ (325,177.13)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ 203,470.82	-	$ 290,018.48	-	$ (86,547.66)	-	$ 41.75
21	Real Time Net Inadvertent Distribution	-	$ (50,816.62)	-	$ (50,816.62)	-	$ -	-	$ 18.15
23	Real Time Revenue Neutrality Uplift Amount	-	$ 501,103.70	-	$ 501,103.70	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 653,757.90	-	$ 740,305.56	-	$ (86,547.66)	-	$ 59.90
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 6,409,766.32	-	$ 6,409,766.32	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (6,456,472.05)	-	$ (6,436,325.58)	-	$ (20,146.47)	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (235,898.25)	-	$ (235,898.25)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 76,750.07	-	$ 76,750.07	-	$ -	-	$ -
	SUBTOTAL	-	$ (205,853.91)	-	$ (185,707.44)	-	$ (20,146.47)	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (101,126.93)	-	$ (101,126.93)	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ (9,476.71)	-	$ (9,476.71)	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (110,603.64)	-	$ (110,603.64)	-	$ -	-	$ -
	MISO Day 2 Charges	(1,579,390)	$ (25,794,222.92)	(3,188,196)	$ 30,395,899.56	1,608,806	$ (56,190,122.48)	-	$ 59.74
x	Net Congestion Amount	-	$ 26,255,239.14	-	$ 26,255,239.14	-	$ -	-	$ -
y	Net Loss Amount	-	$ 7,675,436.77	-	$ 7,675,436.77	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (33,930,675.91)	-	$ (33,930,675.91)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,579,390)**	**$ (25,794,222.92)**	**(3,188,196)**	**$ 30,395,899.56**	**1,608,806**	**$ (56,190,122.48)**	**-**	**$ 59.74**

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

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MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	February 2022	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		RSYSTEM - NON-ASSET B	
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Revenue**	**MWh**	**Revenue**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(1,009,166)	$ 763,947.10	131,321	$ 38,354,354.37	(1,140,487)	$ (37,590,407.27)	-	$ -
5a	Day Ahead Non Asset Energy	(145,746)	$ (4,792,174.22)	(145,746)	$ (4,792,174.22)	-	$ -	-	$ -
13a	Real Time Asset Energy	(8,714)	$ (342,714.09)	134,280	$ 2,915,215.60	(142,994)	$ (3,257,929.69)	-	$ -
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	(1,163,626)	$ (4,370,941.21)	119,856	$ 36,477,395.75	(1,283,481)	$ (40,848,336.96)	-	$ -
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ (14,768.65)	-	$ (14,768.65)	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (1,924,690.96)	-	$ (1,924,690.96)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (1,939,459.61)	-	$ (1,939,459.61)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 430,348.28	-	$ 364,508.17	-	$ 65,840.11	-	$ -
19	Real Time Market Administration (Schedule 17)	-	$ 43,748.04	-	$ 36,384.48	-	$ 7,363.56	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 19,663.25	-	$ 19,663.25	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 89,024.03	-	$ 75,688.87	-	$ 13,335.16	-	$ -
34	Real -Time Schedule 24 Allocation Amount	-	$ (85,169.94)	-	$ 36,785.69	-	$ (121,955.63)	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 497,613.66	-	$ 533,030.46	-	$ (35,416.80)	-	$ -
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ 39,930.54	-	$ 39,930.54	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ (757,344.86)	-	$ (757,344.86)	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (229,135.70)	-	$ (229,135.70)	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ (79,517.69)	-	$ (79,517.69)	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ 76,952.41	-	$ 76,952.41	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (949,115.30)	-	$ (949,115.30)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 107,151.16	-	$ 107,151.16	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (68,247.46)	-	$ (47,272.01)	-	$ (20,975.45)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 156,889.00	-	$ 156,889.00	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (315,933.84)	-	$ (142,287.06)	-	$ (173,646.78)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (146,032.92)	-	$ (109,497.73)	-	$ (36,535.19)	-	$ -
	SUBTOTAL	-	$ (266,174.06)	-	$ (35,016.64)	-	$ (231,157.42)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ 285,483.67	-	$ 367,843.54	-	$ (82,359.87)	-	$ -
21	Real Time Net Inadvertent Distribution	-	$ (17,940.82)	-	$ (17,940.82)	-	$ -	-	$ (5.16)
23	Real Time Revenue Neutrality Uplift Amount	-	$ 863,316.52	-	$ 863,316.52	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 1,130,859.37	-	$ 1,213,219.24	-	$ (82,359.87)	-	$ (5.16)
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 6,409,766.32	-	$ 6,409,766.32	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (6,456,472.05)	-	$ (6,437,420.57)	-	$ (19,051.48)	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (235,898.25)	-	$ (235,898.25)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 76,750.07	-	$ 76,750.07	-	$ -	-	$ -
	SUBTOTAL	-	$ (205,853.91)	-	$ (186,802.43)	-	$ (19,051.48)	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (55,065.06)	-	$ (55,065.06)	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ (4,790.91)	-	$ (4,790.91)	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (59,855.97)	-	$ (59,855.97)	-	$ -	-	$ -
	MISO Day 2 Charges	(1,163,626)	$ (6,162,927.03)	119,856	$ 35,053,395.50	(1,283,481)	$ (41,216,322.53)	-	$ (5.16)
x	Net Congestion Amount	-	$ 23,060,536.66	-	$ 23,060,536.66	-	$ -	-	$ -
y	Net Loss Amount	-	$ 6,702,937.45	-	$ 6,702,937.45	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (29,763,474.11)	-	$ (29,763,474.11)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,163,626)**	**$ (6,162,927.03)**	**119,856**	**$ 35,053,395.50**	**(1,283,481)**	**$ (41,216,322.53)**	**-**	**$ (5.16)**

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

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MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	March 2022	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		RSYSTEM - NON-ASSET B	
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Revenue**	**MWh**	**Revenue**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(688,078)	$ 10,642,698.82	271,025	$ 35,160,577.91	(959,103)	$ (24,517,879.09)	-	$ -
5a	Day Ahead Non Asset Energy	(188,150)	$ (5,015,717.56)	(188,150)	$ (5,015,717.56)	-	$ -	-	$ -
13a	Real Time Asset Energy	(27,224)	$ (830,415.07)	93,095	$ 881,010.84	(120,318)	$ (1,711,425.91)	-	$ -
22a	Real Time Non Asset Energy	505	$ 8,607.48	505	$ 8,607.48	-	$ -	-	$ -
	SUBTOTAL	(902,947)	$ 4,805,173.67	176,474	$ 31,034,478.67	(1,079,421)	$ (26,229,305.00)	-	$ -
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ 13,298.62	-	$ 13,298.62	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (1,485,293.66)	-	$ (1,485,293.66)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (1,471,995.04)	-	$ (1,471,995.04)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 691,220.56	-	$ 603,898.66	-	$ 87,321.90	-	$ -
19	Real Time Market Administration (Schedule 17)	-	$ 66,963.90	-	$ 53,953.27	-	$ 13,010.63	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 25,703.40	-	$ 25,703.40	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 95,844.07	-	$ 83,506.61	-	$ 12,337.46	-	$ -
34	Real -Time Schedule 24 Allocation Amount	-	$ (92,642.80)	-	$ (20,489.10)	-	$ (72,153.70)	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 787,089.13	-	$ 746,572.84	-	$ 40,516.29	-	$ -
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ (4,921.28)	-	$ (4,921.28)	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ (2,678,842.85)	-	$ (2,678,842.85)	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (135,623.14)	-	$ (135,623.14)	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ 110,840.68	-	$ 110,840.68	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ (124,687.92)	-	$ (124,687.92)	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (2,833,234.51)	-	$ (2,833,234.51)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 105,689.24	-	$ 105,689.24	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (105,604.28)	-	$ (40,919.92)	-	$ (64,684.36)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 120,827.58	-	$ 120,827.58	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (58,819.54)	-	$ (21,083.67)	-	$ (37,735.87)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (99,059.44)	-	$ (63,327.83)	-	$ (35,731.61)	-	$ -
	SUBTOTAL	-	$ (36,966.44)	-	$ 101,185.40	-	$ (138,151.84)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ 154,633.85	-	$ 236,993.72	-	$ (82,359.87)	-	$ -
21	Real Time Net Inadvertent Distribution	-	$ (15,018.40)	-	$ (15,018.40)	-	$ -	-	$ 1.25
23	Real Time Revenue Neutrality Uplift Amount	-	$ 1,002,811.60	-	$ 1,002,811.60	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 1,142,427.05	-	$ 1,224,786.92	-	$ (82,359.87)	-	$ 1.25
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 4,769,796.97	-	$ 4,769,796.97	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (4,790,198.14)	-	$ (4,760,847.42)	-	$ (29,350.72)	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (176,339.19)	-	$ (176,339.19)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 168,443.44	-	$ 168,443.44	-	$ -	-	$ -
	SUBTOTAL	-	$ (28,296.92)	-	$ 1,053.80	-	$ (29,350.72)	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ 9,402.76	-	$ 9,402.76	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ (5,765.73)	-	$ (5,765.73)	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 3,637.03	-	$ 3,637.03	-	$ -	-	$ -
	MISO Day 2 Charges	(902,947)	$ 2,367,833.97	176,474	$ 28,806,485.11	(1,079,421)	$ (26,438,651.14)	-	$ 1.25
x	Net Congestion Amount	-	$ 18,551,625.54	-	$ 18,551,625.54	-	$ -	-	$ -
y	Net Loss Amount	-	$ 5,559,815.11	-	$ 5,559,815.11	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (24,111,440.65)	-	$ (24,111,440.65)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(902,947)**	**$ 2,367,833.97**	**176,474**	**$ 28,806,485.11**	**(1,079,421)**	**$ (26,438,651.14)**	**-**	**$ 1.25**

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

April 2022		NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		RSYSTEM - NON-ASSET B	
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Revenue**	**MWh**	**Revenue**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(781,196)	$ 26,840,353.89	122,853	$ 51,892,061.78	(904,049)	$ (25,051,707.89)	-	$ -
5a	Day Ahead Non Asset Energy	(185,607)	$ (6,709,923.85)	(185,607)	$ (6,709,923.85)	-	$ -	-	$ -
13a	Real Time Asset Energy	22,665	$ 1,592,492.64	118,482	$ 4,167,684.04	(95,817)	$ (2,575,191.40)	-	$ -
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	(944,138)	$ 21,722,922.68	55,728	$ 49,349,821.97	(999,866)	$ (27,626,899.29)	-	$ -
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ 325.29	-	$ 325.29	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (2,116,472.45)	-	$ (2,116,472.45)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (2,116,147.16)	-	$ (2,116,147.16)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 647,141.10	-	$ 564,443.85	-	$ 82,697.25	-	$ -
19	Real Time Market Administration (Schedule 17)	-	$ 70,334.10	-	$ 61,610.62	-	$ 8,723.48	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 32,244.43	-	$ 32,244.43	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 100,317.77	-	$ 87,478.61	-	$ 12,839.16	-	$ -
34	Real -Time Schedule 24 Allocation Amount	-	$ (97,768.90)	-	$ 14,423.92	-	$ (112,192.82)	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 752,268.50	-	$ 760,201.43	-	$ (7,932.93)	-	$ -
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ (5,627.69)	-	$ (5,627.69)	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ 5,796.07	-	$ 5,796.07	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (129,503.20)	-	$ (129,503.20)	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ 20,634.65	-	$ 20,634.65	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ (30,412.30)	-	$ (30,412.30)	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (139,112.47)	-	$ (139,112.47)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 101,849.92	-	$ 101,849.92	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (334,089.26)	-	$ (151,257.18)	-	$ (182,832.08)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 198,664.47	-	$ 198,664.47	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (195,535.12)	-	$ (139,857.28)	-	$ (55,677.84)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (54,611.32)	-	$ (49,898.04)	-	$ (4,713.28)	-	$ -
	SUBTOTAL	-	$ (283,721.31)	-	$ (40,498.11)	-	$ (243,223.20)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ 326,582.75	-	$ 411,734.48	-	$ (85,151.73)	-	$ -
21	Real Time Net Inadvertent Distribution	-	$ 123,517.35	-	$ 123,517.35	-	$ -	-	$ -
23	Real Time Revenue Neutrality Uplift Amount	-	$ 2,626,802.92	-	$ 2,626,802.92	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 3,076,903.02	-	$ 3,162,054.75	-	$ (85,151.73)	-	$ -
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 4,769,796.97	-	$ 4,769,796.97	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (4,790,198.14)	-	$ (4,759,784.54)	-	$ (30,413.60)	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (176,339.19)	-	$ (176,339.19)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 168,443.44	-	$ 168,443.44	-	$ -	-	$ -
	SUBTOTAL	-	$ (28,296.92)	-	$ 2,116.68	-	$ (30,413.60)	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ 5,627.69	-	$ 5,627.69	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ (325.29)	-	$ (325.29)	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 5,302.40	-	$ 5,302.40	-	$ -	-	$ -
	MISO Day 2 Charges	(944,138)	$ 22,990,118.74	55,728	$ 50,983,739.49	(999,866)	$ (27,993,620.75)	-	$ -
x	Net Congestion Amount	-	$ 32,510,349.21	-	$ 32,510,349.21	-	$ -	-	$ -
y	Net Loss Amount	-	$ 8,791,080.42	-	$ 8,791,080.42	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (41,301,429.63)	-	$ (41,301,429.63)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(944,138)**	**$ 22,990,118.74**	**55,728**	**$ 50,983,739.49**	**(999,866)**	**$ (27,993,620.75)**	**-**	**$ -**

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

Northern States Power Company
Electric Operations - State of Minnesota

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	May 2022	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		RSYSTEM - NON-ASSET B	
	Posting Account Description	MWh	Net Cost	MWh	Revenue	MWh	Revenue	MWh	Revenue
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(421,339)	$ 35,132,387.35	266,877	$ 56,660,786.64	(688,216)	$ (21,528,399.29)	-	$ -
5a	Day Ahead Non Asset Energy	(272,362)	$ (14,244,691.53)	(272,362)	$ (14,244,691.53)	-	$ -	-	$ -
13a	Real Time Asset Energy	(13,683)	$ (927,784.30)	62,851	$ 3,422,779.65	(76,534)	$ (4,350,563.95)	-	$ -
22a	Real Time Non Asset Energy	(700)	$ (69,450.50)	(700)	$ (69,450.50)	-	$ -	-	$ -
	SUBTOTAL	(708,084)	$ 19,890,461.02	56,666	$ 45,769,424.26	(764,750)	$ (25,878,963.24)	-	$ -
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ (10.00)	-	$ (10.00)	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (1,334,309.42)	-	$ (1,334,309.42)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (1,334,319.42)	-	$ (1,334,319.42)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 567,420.78	-	$ 510,875.46	-	$ 56,545.32	-	$ -
19	Real Time Market Administration (Schedule 17)	-	$ 64,083.55	-	$ 58,002.77	-	$ 6,080.78	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 27,875.77	-	$ 27,875.77	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 89,822.96	-	$ 80,870.46	-	$ 8,952.50	-	$ -
34	Real -Time Schedule 24 Allocation Amount	-	$ (94,671.11)	-	$ 17,266.27	-	$ (111,937.38)	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 654,531.95	-	$ 694,890.73	-	$ (40,358.78)	-	$ -
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ (40,521.96)	-	$ (40,521.96)	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ (18,578,993.25)	-	$ (18,578,993.25)	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (681,472.03)	-	$ (681,472.03)	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ (696,075.01)	-	$ (696,075.01)	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ 655,956.21	-	$ 655,956.21	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (19,341,106.04)	-	$ (19,341,106.04)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 230,106.64	-	$ 230,106.64	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (430,650.87)	-	$ (284,103.24)	-	$ (146,547.63)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 932,613.64	-	$ 932,613.64	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (1,036,631.34)	-	$ (435,351.53)	-	$ (601,279.81)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (211,772.06)	-	$ (177,449.92)	-	$ (34,322.14)	-	$ -
	SUBTOTAL	-	$ (516,333.99)	-	$ 265,815.59	-	$ (782,149.58)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ 538,053.60	-	$ 623,205.33	-	$ (85,151.73)	-	$ -
21	Real Time Net Inadvertent Distribution	-	$ 2,349.43	-	$ 2,349.43	-	$ -	-	$ -
23	Real Time Revenue Neutrality Uplift Amount	-	$ 2,547,550.42	-	$ 2,547,550.42	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 3,087,953.45	-	$ 3,173,105.18	-	$ (85,151.73)	-	$ -
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 4,769,796.97	-	$ 4,769,796.97	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (4,790,198.14)	-	$ (4,761,244.54)	-	$ (28,953.60)	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (176,339.19)	-	$ (176,339.19)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 168,443.44	-	$ 168,443.44	-	$ -	-	$ -
	SUBTOTAL	-	$ (28,296.92)	-	$ 656.68	-	$ (28,953.60)	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ 41,169.11	-	$ 41,169.11	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ 438.60	-	$ 438.60	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 41,607.71	-	$ 41,607.71	-	$ -	-	$ -
	MISO Day 2 Charges	(708,084)	$ 2,454,497.76	56,666	$ 29,270,074.69	(764,750)	$ (26,815,576.93)	-	$ -
x	Net Congestion Amount	-	$ 30,237,240.96	-	$ 30,237,240.96	-	$ -	-	$ -
y	Net Loss Amount	-	$ 9,234,594.09	-	$ 9,234,594.09	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (39,471,835.05)	-	$ (39,471,835.05)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(708,084)**	**$ 2,454,497.76**	**56,666**	**$ 29,270,074.69**	**(764,750)**	**$ (26,815,576.93)**	**-**	**$ -**

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

Northern States Power Company
Electric Operations - State of Minnesota
MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	June 2022	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		RSYSTEM - NON-ASSET B	
	Posting Account Description	MWh	Net Cost	MWh	Revenue	MWh	Revenue	MWh	Revenue
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(847,791)	$ 6,714,197.55	247,540	$ 68,015,458.92	(1,095,331)	$ (61,301,261.37)	-	$ -
5a	Day Ahead Non Asset Energy	(280,391)	$ (16,080,197.29)	(280,391)	$ (16,080,197.29)	-	$ -	5,200	$ 558,525.00
13a	Real Time Asset Energy	7,885	$ 1,204,863.08	105,911	$ 5,232,424.69	(98,026)	$ (4,027,561.61)	-	$ -
22a	Real Time Non Asset Energy	11	$ 1,191.15	11	$ 1,191.15	-	$ -	-	$ -
	SUBTOTAL	(1,120,286)	$ (8,159,945.51)	73,071	$ 57,168,877.47	(1,193,357)	$ (65,328,822.98)	5,200	$ 558,525.00
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ (10,665.66)	-	$ (10,665.66)	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (3,458,138.67)	-	$ (3,458,138.67)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (3,468,804.33)	-	$ (3,468,804.33)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 606,767.34	-	$ 526,780.54	-	$ 79,986.80	-	$ 611.40
19	Real Time Market Administration (Schedule 17)	-	$ 65,841.91	-	$ 58,837.36	-	$ 7,004.55	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 58,675.52	-	$ 58,675.52	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 84,192.42	-	$ 71,743.31	-	$ 12,449.11	-	$ 80.64
34	Real -Time Schedule 24 Allocation Amount	-	$ (86,047.70)	-	$ 15,585.94	-	$ (101,633.64)	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 729,429.49	-	$ 731,622.67	-	$ (2,193.18)	-	$ 692.04
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ (46,820.41)	-	$ (46,820.41)	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ (32,883,959.16)	-	$ (32,883,959.16)	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (322,124.90)	-	$ (322,124.90)	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ 522,681.87	-	$ 522,681.87	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ (478,145.35)	-	$ (478,145.35)	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (33,208,367.95)	-	$ (33,208,367.95)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 211,870.31	-	$ 211,870.31	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (806,552.26)	-	$ (475,855.32)	-	$ (330,696.94)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 1,011,288.59	-	$ 1,011,288.59	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (1,693,496.20)	-	$ (1,062,834.80)	-	$ (630,661.40)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (448,116.10)	-	$ (288,121.63)	-	$ (159,994.47)	-	$ -
	SUBTOTAL	-	$ (1,725,005.66)	-	$ (603,652.85)	-	$ (1,121,352.81)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ (11,992,732.56)	-	$ 647,776.17	-	$ (12,640,508.73)	-	$ 14.89
21	Real Time Net Inadvertent Distribution	-	$ 146,142.15	-	$ 146,142.15	-	$ -	-	$ 177.26
23	Real Time Revenue Neutrality Uplift Amount	-	$ 1,088,940.74	-	$ 1,088,940.74	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (10,757,649.67)	-	$ 1,882,859.06	-	$ (12,640,508.73)	-	$ 192.15
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 14,246,626.37	-	$ 14,246,626.37	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (14,250,985.44)	-	$ (14,252,941.48)	-	$ 1,956.04	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (605,336.30)	-	$ (605,336.30)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 97,656.73	-	$ 97,656.73	-	$ -	-	$ -
	SUBTOTAL	-	$ (512,038.64)	-	$ (513,994.68)	-	$ 1,956.04	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ 48,099.32	-	$ 48,099.32	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ 10,950.52	-	$ 10,950.52	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 59,049.84	-	$ 59,049.84	-	$ -	-	$ -
	MISO Day 2 Charges	(1,120,286)	$ (57,043,332.43)	73,071	$ 22,047,589.23	(1,193,357)	$ (79,090,921.66)	5,200	$ 559,409.19
x	Net Congestion Amount	-	$ 39,615,079.91	-	$ 39,615,079.91	-	$ -	-	$ -
y	Net Loss Amount	-	$ 11,464,034.83	-	$ 11,464,034.83	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (51,079,114.74)	-	$ (51,079,114.74)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,120,286)**	**$ (57,043,332.43)**	**73,071**	**$ 22,047,589.23**	**(1,193,357)**	**$ (79,090,921.66)**	**5,200**	**$ 559,409.19**

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

Northern States Power Company
Electric Operations - State of Minnesota

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	July 2022	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		:RSYSTEM - NON-ASSET B	
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Revenue**	**MWh**	**Revenue**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(853,892)	$ (13,143,791.78)	221,567	$ 51,525,717.46	(1,075,459)	$ (64,669,509.24)	-	$ -
5a	Day Ahead Non Asset Energy	(276,003)	$ (17,551,896.89)	(276,003)	$ (17,551,896.89)	-	$ -	8,000	$ 585,587.75
13a	Real Time Asset Energy	(50,518)	$ (3,706,598.24)	44,659	$ 972,805.69	(95,177)	$ (4,679,403.93)	-	$ -
22a	Real Time Non Asset Energy	(52)	$ (10,925.15)	(52)	$ (10,925.15)	-	$ -	-	$ -
	SUBTOTAL	(1,180,466)	$ (34,413,212.06)	(9,830)	$ 34,935,701.11	(1,170,636)	$ (69,348,913.17)	8,000	$ 585,587.75
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ (6,928.60)	-	$ (6,928.60)	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (3,941,304.02)	-	$ (3,941,304.02)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (3,948,232.62)	-	$ (3,948,232.62)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 760,965.07	-	$ 671,719.58	-	$ 89,245.49	-	$ 665.40
19	Real Time Market Administration (Schedule 17)	-	$ 66,574.73	-	$ 58,646.62	-	$ 7,928.11	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 10,560.47	-	$ 10,560.47	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 112,641.34	-	$ 100,589.10	-	$ 12,052.24	-	$ 103.04
34	Real -Time Schedule 24 Allocation Amount	-	$ (93,303.21)	-	$ (9,916.23)	-	$ (83,386.98)	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 857,438.40	-	$ 831,599.54	-	$ 25,838.86	-	$ 768.44
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ (48,026.83)	-	$ (48,026.83)	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ (17,479,894.33)	-	$ (17,479,894.33)	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (23,297.09)	-	$ (23,297.09)	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ 279,916.93	-	$ 279,916.93	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ (275,855.97)	-	$ (275,855.97)	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (17,547,157.29)	-	$ (17,547,157.29)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 251,491.25	-	$ 251,491.25	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (436,847.79)	-	$ (168,101.66)	-	$ (268,746.13)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 524,869.57	-	$ 524,869.57	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (708,077.27)	-	$ (388,169.98)	-	$ (319,907.29)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (281,870.86)	-	$ (165,731.28)	-	$ (116,139.58)	-	$ -
	SUBTOTAL	-	$ (650,435.10)	-	$ 54,357.90	-	$ (704,793.00)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ (12,767,678.05)	-	$ 249,464.68	-	$ (13,017,142.73)	-	$ -
21	Real Time Net Inadvertent Distribution	-	$ 115,159.91	-	$ 115,159.91	-	$ -	-	$ 88.85
23	Real Time Revenue Neutrality Uplift Amount	-	$ 476,854.77	-	$ 476,854.77	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (12,175,663.37)	-	$ 841,479.36	-	$ (13,017,142.73)	-	$ 88.85
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 14,246,626.37	-	$ 14,246,626.37	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (14,250,985.44)	-	$ (14,162,935.26)	-	$ (88,050.18)	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (605,336.38)	-	$ (605,336.38)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 97,656.74	-	$ 97,656.74	-	$ -	-	$ -
	SUBTOTAL	-	$ (512,038.71)	-	$ (423,988.53)	-	$ (88,050.18)	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ 48,026.83	-	$ 48,026.83	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ 6,928.60	-	$ 6,928.60	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 54,955.43	-	$ 54,955.43	-	$ -	-	$ -
	MISO Day 2 Charges	(1,180,466)	$ (68,334,345.32)	(9,830)	$ 14,798,714.90	(1,170,636)	$ (83,133,060.22)	8,000	$ 586,445.04
x	Net Congestion Amount	-	$ 25,176,879.16	-	$ 25,176,879.16	-	$ -	-	$ -
y	Net Loss Amount	-	$ 13,379,529.86	-	$ 13,379,529.86	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (38,556,409.02)	-	$ (38,556,409.02)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,180,466)**	**$ (68,334,345.32)**	**(9,830)**	**$ 14,798,714.90**	**(1,170,636)**	**$ (83,133,060.22)**	**8,000**	**$ 586,445.04**

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	August 2022	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		ERSYSTEM - NON-ASSET B	
	Posting Account Description	MWh	Net Cost	MWh	Revenue	MWh	Revenue	MWh	Revenue
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(836,512)	$ (3,403,613.95)	211,476	$ 67,091,048.60	(1,047,988)	$ (70,494,662.55)	-	$ -
5a	Day Ahead Non Asset Energy	(289,152)	$ (20,856,414.28)	(289,152)	$ (20,856,414.28)	-	$ -	9,200	$ 766,983.25
13a	Real Time Asset Energy	(776)	$ 884,281.63	99,882	$ 7,231,992.22	(100,658)	$ (6,347,710.59)	-	$ -
22a	Real Time Non Asset Energy	1	$ (147.43)	1	$ (147.43)	-	$ -	-	$ -
	SUBTOTAL	(1,126,438)	$ (23,375,894.03)	22,208	$ 53,466,479.11	(1,148,646)	$ (76,842,373.14)	9,200	$ 766,983.25
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ (10,996.72)	-	$ (10,996.72)	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (3,520,667.46)	-	$ (3,520,667.46)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (3,531,664.18)	-	$ (3,531,664.18)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 561,495.23	-	$ 551,895.11	-	$ 9,600.12	-	$ 597.28
19	Real Time Market Administration (Schedule 17)	-	$ 48,510.28	-	$ 49,596.59	-	$ (1,086.31)	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 97,297.00	-	$ 97,297.00	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 101,770.81	-	$ 90,012.88	-	$ 11,757.93	-	$ 107.36
34	Real -Time Schedule 24 Allocation Amount	-	$ (87,104.36)	-	$ 20,979.25	-	$ (108,083.61)	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 721,968.96	-	$ 809,780.83	-	$ (87,811.87)	-	$ 704.64
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ (40,304.37)	-	$ (40,304.37)	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ (31,643,701.31)	-	$ (31,643,701.31)	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (676,846.58)	-	$ (676,846.58)	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ (749,904.44)	-	$ (749,904.44)	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ 744,017.63	-	$ 744,017.63	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (32,366,739.07)	-	$ (32,366,739.07)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 209,846.94	-	$ 209,846.94	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (144,012.39)	-	$ (89,519.08)	-	$ (54,493.31)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 684,416.26	-	$ 684,416.26	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (1,256,217.88)	-	$ (371,546.82)	-	$ (884,671.06)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (158,139.46)	-	$ (112,320.29)	-	$ (45,819.17)	-	$ -
	SUBTOTAL	-	$ (664,106.53)	-	$ 320,877.01	-	$ (984,983.54)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ (12,783,018.81)	-	$ 234,123.92	-	$ (13,017,142.73)	-	$ 87.74
21	Real Time Net Inadvertent Distribution	-	$ 91,273.37	-	$ 91,273.37	-	$ -	-	$ (7.91)
23	Real Time Revenue Neutrality Uplift Amount	-	$ 159,335.19	-	$ 159,335.19	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (12,532,410.25)	-	$ 484,732.48	-	$ (13,017,142.73)	-	$ 79.83
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 14,246,626.37	-	$ 14,246,626.37	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (14,250,985.44)	-	$ (14,207,173.03)	-	$ (43,812.41)	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (605,336.65)	-	$ (605,336.65)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 97,656.73	-	$ 97,656.73	-	$ -	-	$ -
	SUBTOTAL	-	$ (512,038.99)	-	$ (468,226.58)	-	$ (43,812.41)	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ 40,304.37	-	$ 40,304.37	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ 10,996.72	-	$ 10,996.72	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 51,301.09	-	$ 51,301.09	-	$ -	-	$ -
	MISO Day 2 Charges	(1,126,438)	$ (72,209,583.00)	22,208	$ 18,766,540.69	(1,148,646)	$ (90,976,123.69)	9,200	$ 767,767.72
x	Net Congestion Amount	-	$ 42,015,676.22	-	$ 42,015,676.22	-	$ -	-	$ -
y	Net Loss Amount	-	$ 14,606,352.04	-	$ 14,606,352.04	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (56,622,028.26)	-	$ (56,622,028.26)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,126,438)**	**$ (72,209,583.00)**	**22,208**	**$ 18,766,540.69**	**(1,148,646)**	**$ (90,976,123.69)**	**9,200**	**$ 767,767.72**

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	September 2022	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		RSYSTEM - NON-ASSET B	
	Posting Account Description	MWh	Net Cost	MWh	Revenue	MWh	Revenue	MWh	Revenue
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(724,391)	$ (3,068,256.55)	247,824	$ 48,972,804.92	(972,215)	$ (52,041,061.47)	-	$ -
5a	Day Ahead Non Asset Energy	(272,230)	$ (17,274,136.93)	(272,230)	$ (17,274,136.93)	-	$ -	-	$ -
13a	Real Time Asset Energy	22,172	$ 2,380,819.02	84,761	$ 4,486,026.99	(62,589)	$ (2,105,207.97)	-	$ -
22a	Real Time Non Asset Energy	629	$ (357,566.35)	629	$ (357,566.35)	-	$ -	-	$ -
	SUBTOTAL	(973,820)	$ (18,319,140.81)	60,984	$ 35,827,128.63	(1,034,804)	$ (54,146,269.44)	-	$ -
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ (13,200.03)	-	$ (13,200.03)	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (2,792,430.88)	-	$ (2,792,430.88)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (2,805,630.91)	-	$ (2,805,630.91)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 794,149.26	-	$ 636,515.17	-	$ 157,634.09	-	$ 113.28
19	Real Time Market Administration (Schedule 17)	-	$ 74,613.12	-	$ 60,044.53	-	$ 14,568.59	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ (40,132.01)	-	$ (40,132.01)	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 107,874.12	-	$ 94,369.96	-	$ 13,504.16	-	$ 4.32
34	Real -Time Schedule 24 Allocation Amount	-	$ (95,418.06)	-	$ (13,835.26)	-	$ (81,582.80)	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 841,086.43	-	$ 736,962.39	-	$ 104,124.04	-	$ 117.60
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ (23,886.69)	-	$ (23,886.69)	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ (4,461,099.61)	-	$ (4,461,099.61)	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (72,810.45)	-	$ (72,810.45)	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ 749,614.98	-	$ 749,614.98	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ (743,057.38)	-	$ (743,057.38)	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (4,551,239.15)	-	$ (4,551,239.15)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 81,361.64	-	$ 81,361.64	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (779,026.73)	-	$ (367,103.06)	-	$ (411,923.67)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 356,531.35	-	$ 356,531.35	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (426,555.65)	-	$ (485,338.96)	-	$ 58,783.31	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (247,002.93)	-	$ (190,215.25)	-	$ (56,787.68)	-	$ -
	SUBTOTAL	-	$ (1,014,692.32)	-	$ (604,764.28)	-	$ (409,928.04)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ (11,481,921.43)	-	$ 1,115,313.47	-	$ (12,597,234.90)	-	$ -
21	Real Time Net Inadvertent Distribution	-	$ 50,617.39	-	$ 50,617.39	-	$ -	-	$ (13.46)
23	Real Time Revenue Neutrality Uplift Amount	-	$ 550,061.07	-	$ 550,061.07	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (10,881,242.97)	-	$ 1,715,991.93	-	$ (12,597,234.90)	-	$ (13.46)
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 9,883,261.64	-	$ 9,883,261.64	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (9,903,009.97)	-	$ (9,866,376.32)	-	$ (36,633.65)	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (497,087.41)	-	$ (497,087.41)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 240,801.85	-	$ 240,801.85	-	$ -	-	$ -
	SUBTOTAL	-	$ (276,033.89)	-	$ (239,400.24)	-	$ (36,633.65)	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ 23,886.69	-	$ 23,886.69	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ 13,200.03	-	$ 13,200.03	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 37,086.72	-	$ 37,086.72	-	$ -	-	$ -
	MISO Day 2 Charges	(973,820)	$ (36,969,806.90)	60,984	$ 30,116,135.09	(1,034,804)	$ (67,085,941.99)	-	$ 104.14
x	Net Congestion Amount	-	$ 12,738,493.81	-	$ 12,738,493.81	-	$ -	-	$ -
y	Net Loss Amount	-	$ 8,979,150.45	-	$ 8,979,150.45	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (21,717,644.26)	-	$ (21,717,644.26)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(973,820)**	**$ (36,969,806.90)**	**60,984**	**$ 30,116,135.09**	**(1,034,804)**	**$ (67,085,941.99)**	**-**	**$ 104.14**

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

Northern States Power Company
Electric Operations - State of Minnesota

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	October 2022	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		RSYSTEM - NON-ASSET B	
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Revenue**	**MWh**	**Revenue**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(846,359)	$ 3,702,483.01	209,292	$ 35,715,307.64	(1,055,650)	$ (32,012,824.63)	-	$ -
5a	Day Ahead Non Asset Energy	(282,122)	$ (12,561,148.20)	(282,122)	$ (12,561,148.20)	-	$ -	-	$ -
13a	Real Time Asset Energy	9,565	$ 937,370.02	98,337	$ 3,735,851.93	(88,772)	$ (2,798,481.91)	-	$ -
22a	Real Time Non Asset Energy	319	$ 458,048.10	319	$ 458,048.10	-	$ -	-	$ -
	SUBTOTAL	(1,118,596)	$ (7,463,247.07)	25,826	$ 27,348,059.47	(1,144,422)	$ (34,811,306.54)	-	$ -
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ (4,126.88)	-	$ (4,126.88)	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (1,616,198.25)	-	$ (1,616,198.25)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ 8.31	-	$ 8.31	-	$ -	-	$ -
	SUBTOTAL	-	$ (1,620,316.82)	-	$ (1,620,316.82)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 542,953.21	-	$ 463,400.08	-	$ 79,553.13	-	$ -
19	Real Time Market Administration (Schedule 17)	-	$ 56,164.99	-	$ 49,767.61	-	$ 6,397.38	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 21,039.77	-	$ 21,039.77	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 96,905.88	-	$ 82,535.70	-	$ 14,370.18	-	$ 0.32
34	Real -Time Schedule 24 Allocation Amount	-	$ (82,788.98)	-	$ 5,569.63	-	$ (88,358.61)	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 634,274.87	-	$ 622,312.79	-	$ 11,962.08	-	$ 0.32
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ 923.80	-	$ 923.80	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ 86.65	-	$ 86.65	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ (2,183,842.20)	-	$ (2,183,842.20)	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (200,765.40)	-	$ (200,765.40)	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ (182,284.97)	-	$ (182,284.97)	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ 177,556.08	-	$ 177,556.08	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (2,388,326.04)	-	$ (2,388,326.04)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 105,247.84	-	$ 105,247.84	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (321,128.68)	-	$ (180,568.34)	-	$ (140,560.34)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 122,490.20	-	$ 122,490.20	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (67,500.22)	-	$ (3,247.63)	-	$ (64,252.59)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (135,816.23)	-	$ (95,970.77)	-	$ (39,845.46)	-	$ -
	SUBTOTAL	-	$ (296,707.09)	-	$ (52,048.70)	-	$ (244,658.39)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ (12,848,083.13)	-	$ 169,059.60	-	$ (13,017,142.73)	-	$ -
21	Real Time Net Inadvertent Distribution	-	$ (251,384.23)	-	$ (251,384.23)	-	$ -	-	$ (5.00)
23	Real Time Revenue Neutrality Uplift Amount	-	$ 897,100.36	-	$ 897,100.36	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (12,202,367.00)	-	$ 814,775.73	-	$ (13,017,142.73)	-	$ (5.00)
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 9,883,261.64	-	$ 9,883,261.64	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (9,903,009.97)	-	$ (9,865,506.98)	-	$ (37,502.99)	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (497,086.80)	-	$ (497,086.80)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 240,801.85	-	$ 240,801.85	-	$ -	-	$ -
	SUBTOTAL	-	$ (276,033.28)	-	$ (238,530.29)	-	$ (37,502.99)	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (923.80)	-	$ (923.80)	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ 4,126.88	-	$ 4,126.88	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ (8.31)	-	$ (8.31)	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ (86.65)	-	$ (86.65)	-	$ -	-	$ -
	SUBTOTAL	-	$ 3,108.12	-	$ 3,108.12	-	$ -	-	$ -
	MISO Day 2 Charges	(1,118,596)	$ (23,609,614.31)	25,826	$ 24,489,034.26	(1,144,422)	$ (48,098,648.57)	-	$ (4.68)
x	Net Congestion Amount	-	$ 16,454,866.06	-	$ 16,454,866.06	-	$ -	-	$ -
y	Net Loss Amount	-	$ 6,817,704.38	-	$ 6,817,704.38	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (23,272,570.44)	-	$ (23,272,570.44)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,118,596)**	**$ (23,609,614.31)**	**25,826**	**$ 24,489,034.26**	**(1,144,422)**	**$ (48,098,648.57)**	**-**	**$ (4.68)**

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

Docket No. E002/AA-21-295
True-Up Report
Part B, Attachment 3

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

November 2022		NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		RSYSTEM - NON-ASSET B	
	Posting Account Description	MWh	Net Cost	MWh	Revenue	MWh	Revenue	MWh	Revenue
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(751,708)	$ 5,586,481.09	156,762	$ 27,866,636.03	(908,469)	$ (22,280,154.94)	-	$ -
5a	Day Ahead Non Asset Energy	(188,467)	$ (6,015,290.26)	(188,467)	$ (6,015,290.26)	-	$ -	-	$ -
13a	Real Time Asset Energy	(136,821)	$ (4,309,271.45)	(4,800)	$ (1,608,040.31)	(132,022)	$ (2,701,231.14)	-	$ -
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	(1,076,996)	$ (4,738,080.62)	(36,505)	$ 20,243,305.46	(1,040,491)	$ (24,981,386.08)	-	$ -
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ (2,359.55)	-	$ (2,359.55)	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (1,382,854.66)	-	$ (1,382,854.66)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (1,385,214.21)	-	$ (1,385,214.21)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 676,989.99	-	$ 594,578.91	-	$ 82,411.08	-	$ -
19	Real Time Market Administration (Schedule 17)	-	$ 91,207.09	-	$ 78,625.02	-	$ 12,582.07	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 21,607.54	-	$ 21,607.54	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 103,151.64	-	$ 90,143.53	-	$ 13,008.11	-	$ -
34	Real -Time Schedule 24 Allocation Amount	-	$ (89,557.94)	-	$ 9,019.09	-	$ (98,577.03)	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 803,398.32	-	$ 793,974.09	-	$ 9,424.23	-	$ -
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ (14,831.27)	-	$ (14,831.27)	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ (251,163.01)	-	$ (251,163.01)	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (29,038.67)	-	$ (29,038.67)	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ 157,510.41	-	$ 157,510.41	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ (155,562.07)	-	$ (155,562.07)	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (293,084.61)	-	$ (293,084.61)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 132,559.47	-	$ 132,559.47	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (206,009.56)	-	$ (33,472.19)	-	$ (172,537.37)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 424,622.29	-	$ 424,622.29	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (600,184.88)	-	$ (272,931.89)	-	$ (327,252.99)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (227,617.40)	-	$ (155,662.62)	-	$ (71,954.78)	-	$ -
	SUBTOTAL	-	$ (476,630.08)	-	$ 95,115.06	-	$ (571,745.14)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ (12,536,231.27)	-	$ 61,003.63	-	$ (12,597,234.90)	-	$ -
21	Real Time Net Inadvertent Distribution	-	$ 186,071.21	-	$ 186,071.21	-	$ -	-	$ (1.77)
23	Real Time Revenue Neutrality Uplift Amount	-	$ (571,997.75)	-	$ (571,997.75)	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (12,922,157.81)	-	$ (324,922.91)	-	$ (12,597,234.90)	-	$ (1.77)
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 9,883,261.64	-	$ 9,883,261.64	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (9,903,009.97)	-	$ (9,864,790.03)	-	$ (38,219.94)	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (497,086.80)	-	$ (497,086.80)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 240,884.14	-	$ 240,884.14	-	$ -	-	$ -
	SUBTOTAL	-	$ (275,950.99)	-	$ (237,731.05)	-	$ (38,219.94)	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ 14,831.27	-	$ 14,831.27	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ 2,359.55	-	$ 2,359.55	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 17,190.82	-	$ 17,190.82	-	$ -	-	$ -
	MISO Day 2 Charges	(1,076,996)	$ (19,270,529.18)	(36,505)	$ 18,908,632.65	(1,040,491)	$ (38,179,161.83)	-	$ (1.77)
x	Net Congestion Amount	-	$ 14,398,706.83	-	$ 14,398,706.83	-	$ -	-	$ -
y	Net Loss Amount	-	$ 7,605,318.11	-	$ 7,605,318.11	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (22,004,024.94)	-	$ (22,004,024.94)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,076,996)**	**$ (19,270,529.18)**	**(36,505)**	**$ 18,908,632.65**	**(1,040,491)**	**$ (38,179,161.83)**	**-**	**$ (1.77)**

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	December 2022	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		RSYSTEM - NON-ASSET B	
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Revenue**	**MWh**	**Revenue**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(729,433)	$ (7,117,614.04)	282,848	$ 33,989,166.04	(1,012,280)	$ (41,106,780.08)	-	$ -
5a	Day Ahead Non Asset Energy	(180,384)	$ (8,204,768.96)	(180,384)	$ (8,204,768.96)	-	$ -	16,800	$ 733,111.00
13a	Real Time Asset Energy	78,808	$ 1,887,649.41	308,671	$ 15,346,078.59	(229,863)	$ (13,458,429.18)	-	$ -
22a	Real Time Non Asset Energy	(450)	$ (89,695.88)	(450)	$ (89,695.88)	-	$ -	-	$ -
	SUBTOTAL	(831,458)	$ (13,524,429.47)	410,685	$ 41,040,779.79	(1,242,143)	$ (54,565,209.26)	16,800	$ 733,111.00
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ 5,716.43	-	$ 5,716.43	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (2,144,781.20)	-	$ (2,144,781.20)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (2,139,064.77)	-	$ (2,139,064.77)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 569,229.19	-	$ 497,332.27	-	$ 71,896.92	-	$ 1,169.28
19	Real Time Market Administration (Schedule 17)	-	$ 54,195.25	-	$ 39,195.71	-	$ 14,999.54	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 19,853.54	-	$ 19,853.54	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 108,675.75	-	$ 95,168.22	-	$ 13,507.53	-	$ 225.12
34	Real -Time Schedule 24 Allocation Amount	-	$ (104,275.44)	-	$ 11,461.10	-	$ (115,736.54)	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 647,678.29	-	$ 663,010.84	-	$ (15,332.55)	-	$ 1,394.40
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ (19,113.41)	-	$ (19,113.41)	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ (6,612,732.28)	-	$ (6,612,732.28)	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (95,289.88)	-	$ (95,289.88)	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ (120,099.63)	-	$ (120,099.63)	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ 123,032.52	-	$ 123,032.52	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (6,724,202.68)	-	$ (6,724,202.68)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 179,197.28	-	$ 179,197.28	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (121,230.65)	-	$ (68,120.74)	-	$ (53,109.91)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 2,081,269.37	-	$ 2,081,269.37	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (1,946,929.08)	-	$ (1,280,098.35)	-	$ (666,830.73)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (640,622.73)	-	$ (525,376.66)	-	$ (115,246.07)	-	$ -
	SUBTOTAL	-	$ (448,315.81)	-	$ 386,870.90	-	$ (835,186.71)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ (13,811,390.33)	-	$ (794,247.60)	-	$ (13,017,142.73)	-	$ (23.44)
21	Real Time Net Inadvertent Distribution	-	$ 606,843.10	-	$ 606,843.10	-	$ -	-	$ 1,285.91
23	Real Time Revenue Neutrality Uplift Amount	-	$ (1,961,545.52)	-	$ (1,961,545.52)	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (15,166,092.75)	-	$ (2,148,950.02)	-	$ (13,017,142.73)	-	$ 1,262.47
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 15,777,513.01	-	$ 15,777,513.01	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (15,782,515.07)	-	$ (15,607,242.17)	-	$ (175,272.90)	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (683,288.39)	-	$ (683,288.39)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 89,943.30	-	$ 89,943.30	-	$ -	-	$ -
	SUBTOTAL	-	$ (598,347.15)	-	$ (423,074.25)	-	$ (175,272.90)	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ 19,113.41	-	$ 19,113.41	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ (5,716.43)	-	$ (5,716.43)	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 13,396.98	-	$ 13,396.98	-	$ -	-	$ -
	MISO Day 2 Charges	(831,458)	$ (37,939,377.36)	410,685	$ 30,668,766.79	(1,242,143)	$ (68,608,144.15)	16,800	$ 735,767.87
x	Net Congestion Amount	-	$ 14,805,653.34	-	$ 14,805,653.34	-	$ -	-	$ -
y	Net Loss Amount	-	$ 9,177,014.12	-	$ 9,177,014.12	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (23,982,667.46)	-	$ (23,982,667.46)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(831,458)**	**$ (37,939,377.36)**	**410,685**	**$ 30,668,766.79**	**(1,242,143)**	**$ (68,608,144.15)**	**16,800**	**$ 735,767.87**

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

Docket No. E002/AA-21-295
True-Up Report
Part B, Attachment 3

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	January - December 2022	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		RSYSTEM - NON-ASSET B	
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Revenue**	**MWh**	**Revenue**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(9,917,857)	$ 50,600,589.37	2,405,164	$ 555,401,095.91	(12,323,020)	$ (504,800,506.54)	-	$ -
5a	Day Ahead Non Asset Energy	(2,669,070)	$ (132,768,247.77)	(2,669,070)	$ (132,768,247.77)	-	$ -	-	$ 2,644,206.89
13a	Real Time Asset Energy	(139,146)	$ (3,053,346.01)	1,248,656	$ 48,556,950.03	(1,387,803)	$ (51,610,296.04)	-	$ -
22a	Real Time Non Asset Energy	(171)	$ (87,488.40)	(171)	$ (87,488.40)	-	$ -	-	$ -
	SUBTOTAL	(12,726,244)	$ (85,308,492.81)	984,579	$ 471,102,309.77	(13,710,823)	$ (556,410,802.58)	-	$ 2,644,206.89
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss								
5c	Day Ahead Non Asset Loss								
3	Day Ahead Financial Bilateral Transaction Loss	-	$ (172,225.98)	-	$ (172,225.98)	-	$ -	-	$ -
13c	Real Time Loss								
22c	Real Time Non Asset Loss								
14	Real Time Distribution Losses	-	$ (27,829,110.60)	-	$ (27,829,110.60)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (28,001,336.58)	-	$ (28,001,336.58)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 7,559,742.65	-	$ 6,580,196.42	-	$ 979,546.23	-	$ 3,156.59
19	Real Time Market Administration (Schedule 17)	-	$ 787,523.97	-	$ 678,571.24	-	$ 108,952.73	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 331,553.99	-	$ 331,553.99	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 1,200,279.46	-	$ 1,044,170.53	-	$ 156,108.93	-	$ 520.80
34	Real -Time Schedule 24 Allocation Amount	-	$ (1,106,495.99)	-	$ 90,526.25	-	$ (1,197,022.24)	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 8,772,604.08	-	$ 8,725,018.43	-	$ 47,585.65	-	$ 3,677.39
	Congestion & FTRs								
1b	Day Ahead Congestion								
5b	Day Ahead Non Asset Congestion								
13b	Real Time Congestion								
22b	Real Time Non Asset Congestion								
2	Day Ahead Financial Bilateral Transaction Congestion	-	$ (273,709.89)	-	$ (273,709.89)	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ (122,900,725.98)	-	$ (122,900,725.98)	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (2,899,316.04)	-	$ (2,899,316.04)	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ (1,632,060.78)	-	$ (1,632,060.78)	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ 1,671,660.61	-	$ 1,671,660.61	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ (1,538,776.09)	-	$ (1,538,776.09)	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (127,572,928.17)	-	$ (127,572,928.17)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 1,842,815.41	-	$ 1,842,815.41	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (3,903,557.76)	-	$ (1,981,096.91)	-	$ (1,922,460.85)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 7,214,645.51	-	$ 7,214,645.51	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (8,907,512.93)	-	$ (4,983,443.66)	-	$ (3,924,069.27)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (2,769,032.96)	-	$ (2,023,056.28)	-	$ (745,976.68)	-	$ -
	SUBTOTAL	-	$ (6,522,642.73)	-	$ 69,864.07	-	$ (6,592,506.80)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ (86,712,830.89)	-	$ 3,612,289.42	-	$ (90,325,120.31)	-	$ 144.38
21	Real Time Net Inadvertent Distribution	-	$ 986,813.84	-	$ 986,813.84	-	$ -	-	$ 1,538.12
23	Real Time Revenue Neutrality Uplift Amount	-	$ 8,180,334.02	-	$ 8,180,334.02	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (77,545,683.03)	-	$ 12,779,437.28	-	$ (90,325,120.31)	-	$ 1,682.50
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 115,296,100.59	-	$ 115,296,100.59	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (115,528,039.82)	-	$ (114,982,587.92)	-	$ (545,451.90)	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (4,991,372.80)	-	$ (4,991,372.80)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 1,764,231.80	-	$ 1,764,231.80	-	$ -	-	$ -
	SUBTOTAL	-	$ (3,459,080.23)	-	$ (2,913,628.33)	-	$ (545,451.90)	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ 93,345.66	-	$ 93,345.66	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ 22,925.83	-	$ 22,925.83	-	$ -	-	$ -
8	Day Ahead Congestion Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
9	Day Ahead Loss Rebate on Option B-Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
17	Real Time Loss Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
18	Real Time Congestion Rebate on Carve Out Grandfathered	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 116,271.49	-	$ 116,271.49	-	$ -	-	$ -
	MISO Day 2 Charges	(12,726,244)	$ (319,521,287.98)	984,579	$ 334,305,007.96	(13,710,823)	$ (653,826,295.94)	-	$ 2,649,566.78
x	Net Congestion Amount	-	$ (8,909,536.88)	-	$ (8,909,536.88)	-	$ -	-	$ -
y	Net Loss Amount	-	$ (849,797.78)	-	$ (849,797.78)	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ 9,759,334.66	-	$ 9,759,334.66	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(12,726,244)**	**$ (319,521,287.98)**	**984,579**	**$ 334,305,007.96**	**(13,710,823)**	**$ (653,826,295.94)**	**-**	**$ 2,649,566.78**

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	January 2022 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (164,671.79)		$ (164,671.79)	$ (115,235.71)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (164,772.45)		$ (164,772.45)	$ (115,306.15)
3	Day-Ahead Supplemental Reserve	$ (54,159.30)		$ (54,159.30)	$ (37,900.15)
4	Real-Time Regulation Amount (See Note 1)	$ (52,009.98)	$ 166,406.21	$ 114,396.23	$ 80,053.36
5	Real-Time Spinning Reserve Amount	$ (59,636.76)	$ 132,154.60	$ 72,517.84	$ 50,747.27
6	Real-Time Supplemental Reserve Amount.	$ (23,918.76)	$ 3,271.65	$ (20,647.11)	$ (14,448.65)
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 51,469.61		$ 51,469.61	$ 36,017.93
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 6,221,466.08		$ 6,221,466.08	$ 4,353,721.05
8b	Real Time Non Excessive Energy Congestion	$ 788,846.39	$ -	$ 788,846.39	$ 552,026.98
8c	Real Time Non Excessive Energy Loss	$ 130,433.58	$ -	$ 130,433.58	$ 91,276.14
9	Real Time Net Regulation Adjustment Amount	$ (1,922,661.82)	$ (4,473.99)	$ (1,927,135.81)	$ (1,348,590.77)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 145,077.50		$ 145,077.50	$ 101,523.81
11	Real Time Spinning Reserve Cost Distribution	$ 102,882.19		$ 102,882.19	$ 71,995.95
12	Real Time Supplemental Reserve Cost Distribution	$ 36,611.14		$ 36,611.14	$ 25,620.12
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 46,932.35	$ (21,318.10)	$ 25,614.25	$ 17,924.60
14	Real Time Contingency Reserve Deployment Failure	$ 212.24	$ -	$ 212.24	$ 148.52
	TOTAL MISO ASM CHARGES	**$ 5,082,100.22**	**$ 276,040.37**	**$ 5,358,140.59**	**$ 3,749,574.33**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (13,389.83)		$ (13,389.83)	$ (9,756.23)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ 457.66		$ 457.66	$ 333.46
	Total	$ (12,932.17)		$ (12,932.17)	$ (9,422.77)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	February 2022 Actual				
	Procurement Charges				
1	Day-Ahead Regulation Amount	$ (138,495.37)		$ (138,495.37)	$ (97,836.12)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (192,760.35)		$ (192,760.35)	$ (136,170.07)
3	Day-Ahead Supplemental Reserve	$ (79,551.59)		$ (79,551.59)	$ (56,196.96)
4	Real-Time Regulation Amount (See Note 1)	$ (16,135.59)	$ 88,068.49	$ 71,932.90	$ 50,814.95
5	Real-Time Spinning Reserve Amount	$ (52,661.24)	$ 174,674.36	$ 122,013.12	$ 86,192.70
6	Real-Time Supplemental Reserve Amount.	$ 5,939.90	$ 6,412.99	$ 12,352.89	$ 8,726.35
	Resource Energy Charges				
7a	Real Time Excessive Energy Amount	$ 11,216.83		$ 11,216.83	$ 7,923.81
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 801,965.84		$ 801,965.84	$ 566,525.97
8b	Real Time Non Excessive Energy Congestion	$ (119,931.61)	$ -	$ (119,931.61)	$ (84,722.28)
8c	Real Time Non Excessive Energy Loss	$ 40,093.71	$ -	$ 40,093.71	$ 28,323.06
9	Real Time Net Regulation Adjustment Amount	$ 7,020.31	$ (7,766.78)	$ (746.47)	$ (527.32)
	Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	$ 145,134.02		$ 145,134.02	$ 102,525.80
11	Real Time Spinning Reserve Cost Distribution	$ 104,423.49		$ 104,423.49	$ 73,767.01
12	Real Time Supplemental Reserve Cost Distribution	$ 91,758.52		$ 91,758.52	$ 64,820.20
	Penalty Charges				
13	Real Time Excessive/Deficient Energy Deployment	$ 42,037.33	$ (22,669.53)	$ 19,367.80	$ 13,681.83
14	Real Time Contingency Reserve Deployment Failure	$ 4,137.11	$ -	$ 4,137.11	$ 2,922.54
	TOTAL MISO ASM CHARGES	**$ 654,191.31**	**$ 238,719.53**	**$ 892,910.84**	**$ 630,771.48**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
	Ramp Capability Amounts (Included in Regulation Amounts)				
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (15,451.47)		$ (15,451.47)	$ (11,291.70)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (1,060.62)		$ (1,060.62)	$ (775.08)
	Total	$ (16,512.09)		$ (16,512.09)	$ (12,066.78)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	March 2022 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (148,111.43)		$ (148,111.43)	$ (104,401.56)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (208,493.43)		$ (208,493.43)	$ (146,963.94)
3	Day-Ahead Supplemental Reserve	$ (106,263.39)		$ (106,263.39)	$ (74,903.49)
4	Real-Time Regulation Amount (See Note 1)	$ 8,637.47	$ 54,408.12	$ 63,045.59	$ 44,439.90
5	Real-Time Spinning Reserve Amount	$ (52,177.28)	$ 119,474.57	$ 67,297.29	$ 47,436.86
6	Real-Time Supplemental Reserve Amount.	$ (466.56)	$ 17,275.91	$ 16,809.35	$ 11,848.66
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 27,113.24		$ 27,113.24	$ 19,111.72
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 3,304,280.84		$ 3,304,280.84	$ 2,329,138.72
8b	Real Time Non Excessive Energy Congestion	$ (244,425.15)	$ -	$ (244,425.15)	$ (172,291.68)
8c	Real Time Non Excessive Energy Loss	$ (38,366.21)	$ -	$ (38,366.21)	$ (27,043.77)
9	Real Time Net Regulation Adjustment Amount	$ 13,224.60	$ (8,433.39)	$ 4,791.21	$ 3,377.25
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 156,330.53		$ 156,330.53	$ 110,195.08
11	Real Time Spinning Reserve Cost Distribution	$ 154,236.36		$ 154,236.36	$ 108,718.93
12	Real Time Supplemental Reserve Cost Distribution	$ 57,644.60		$ 57,644.60	$ 40,632.83
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 45,880.87	$ (11,043.60)	$ 34,837.27	$ 24,556.28
14	Real Time Contingency Reserve Deployment Failure	$ -	$ 440.23	$ 440.23	$ 310.31
	TOTAL MISO ASM CHARGES	**$ 2,969,045.06**	**$ 172,121.84**	**$ 3,141,166.90**	**$ 2,214,162.12**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (22,037.68)		$ (22,037.68)	$ (15,992.64)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (6,588.56)		$ (6,588.56)	$ (4,781.29)
	Total	$ (28,626.24)		$ (28,626.24)	$ (20,773.93)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

			System		Intersystem		Retail		Minnesota Retail
	April 2022 Actual								
Procurement Charges									
1	Day-Ahead Regulation Amount	$	(248,040.09)			$	(248,040.09)	$	(175,940.52)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$	(369,817.64)			$	(369,817.64)	$	(262,320.13)
3	Day-Ahead Supplemental Reserve	$	(163,033.09)			$	(163,033.09)	$	(115,643.11)
4	Real-Time Regulation Amount (See Note 1)	$	135,773.92	$	103,549.06	$	239,322.98	$	169,757.28
5	Real-Time Spinning Reserve Amount	$	(230,742.82)	$	436,357.69	$	205,614.87	$	145,847.34
6	Real-Time Supplemental Reserve Amount.	$	(14,364.66)	$	12,570.33	$	(1,794.33)	$	(1,272.76)
Resource Energy Charges									
7a	Real Time Excessive Energy Amount	$	85,273.13			$	85,273.13	$	60,486.19
7b	Real Time Excessive Energy Congestion					$	-	$	-
7c	Real Time Excessive Energy Loss					$	-	$	-
8a	Real Time Non Excessive Energy Amount	$	713,453.45			$	713,453.45	$	506,068.89
8b	Real Time Non Excessive Energy Congestion	$	562,216.26	$	-	$	562,216.26	$	398,792.88
8c	Real Time Non Excessive Energy Loss	$	214,348.89	$	-	$	214,348.89	$	152,042.58
9	Real Time Net Regulation Adjustment Amount	$	(18,847.42)	$	12,645.72	$	(6,201.70)	$	(4,399.01)
Cost Distribution Charges									
10	Real Time Regulation Reserve Cost Distribution Amount	$	224,754.00			$	224,754.00	$	159,423.17
11	Real Time Spinning Reserve Cost Distribution	$	231,564.74			$	231,564.74	$	164,254.18
12	Real Time Supplemental Reserve Cost Distribution	$	167,602.74			$	167,602.74	$	118,884.47
Penalty Charges									
13	Real Time Excessive/Deficient Energy Deployment	$	37,534.66	$	(23,552.22)	$	13,982.44	$	9,918.07
14	Real Time Contingency Reserve Deployment Failure	$	984.90	$	-	$	984.90	$	698.61
	TOTAL MISO ASM CHARGES	**$**	**1,328,660.97**	**$**	**541,570.58**	**$**	**1,870,231.55**	**$**	**1,326,598.12**

Note 1:

Ramp Capability Amounts (Included in Regulation Amounts)									
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$	(31,024.97)			$	(31,024.97)	$	(22,369.82)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$	(11,753.04)			$	(11,753.04)	$	(8,474.25)
	Total	$	(42,778.01)			$	(42,778.01)	$	(30,844.07)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	May 2022 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (270,816.39)		$ (270,816.39)	$ (193,968.23)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (343,047.30)		$ (343,047.30)	$ (245,702.55)
3	Day-Ahead Supplemental Reserve	$ (110,745.72)		$ (110,745.72)	$ (79,319.98)
4	Real-Time Regulation Amount (See Note 1)	$ (2,700.64)	$ 188,988.85	$ 186,288.21	$ 133,426.17
5	Real-Time Spinning Reserve Amount	$ (141,338.91)	$ 360,033.38	$ 218,694.47	$ 156,636.68
6	Real-Time Supplemental Reserve Amount.	$ (14,643.83)	$ 40,577.83	$ 25,934.00	$ 18,574.84
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 128,285.38		$ 128,285.38	$ 91,882.50
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 4,687,117.33		$ 4,687,117.33	$ 3,357,078.42
8b	Real Time Non Excessive Energy Congestion	$ (3,770,861.91)	$ -	$ (3,770,861.91)	$ (2,700,824.04)
8c	Real Time Non Excessive Energy Loss	$ (427,757.52)	$ -	$ (427,757.52)	$ (306,374.99)
9	Real Time Net Regulation Adjustment Amount	$ (30,228.85)	$ 22,247.79	$ (7,981.06)	$ (5,716.32)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 241,752.01		$ 241,752.01	$ 173,151.30
11	Real Time Spinning Reserve Cost Distribution	$ 232,232.45		$ 232,232.45	$ 166,333.06
12	Real Time Supplemental Reserve Cost Distribution	$ 71,168.60		$ 71,168.60	$ 50,973.46
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 35,864.85	$ (15,187.57)	$ 20,677.28	$ 14,809.80
14	Real Time Contingency Reserve Deployment Failure	$ 23.12	$ -	$ 23.12	$ 16.56
	TOTAL MISO ASM CHARGES	**$ 284,302.67**	**$ 596,660.28**	**$ 880,962.95**	**$ 630,976.68**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (28,880.54)		$ (28,880.54)	$ (20,605.02)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (14,984.50)		$ (14,984.50)	$ (10,690.79)
	Total	$ (43,865.04)		$ (43,865.04)	$ (31,295.81)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	June 2022 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (387,629.86)		$ (387,629.86)	$ (279,987.90)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (363,273.44)		$ (363,273.44)	$ (262,395.07)
3	Day-Ahead Supplemental Reserve	$ (134,198.92)		$ (134,198.92)	$ (96,932.87)
4	Real-Time Regulation Amount (See Note 1)	$ (52,423.28)	$ 316,069.12	$ 263,645.84	$ 190,433.33
5	Real-Time Spinning Reserve Amount	$ (92,491.91)	$ 301,519.06	$ 209,027.15	$ 150,981.85
6	Real-Time Supplemental Reserve Amount.	$ (6,884.58)	$ 45,262.81	$ 38,378.23	$ 27,720.88
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (16,543.91)		$ (16,543.91)	$ (11,949.79)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 7,740,592.91		$ 7,740,592.91	$ 5,591,087.11
8b	Real Time Non Excessive Energy Congestion	$ (1,317,934.47)	$ -	$ (1,317,934.47)	$ (951,953.75)
8c	Real Time Non Excessive Energy Loss	$ 26,644.58	$ -	$ 26,644.58	$ 19,245.58
9	Real Time Net Regulation Adjustment Amount	$ (14,138.33)	$ 26,806.32	$ 12,667.99	$ 9,150.18
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 173,210.40		$ 173,210.40	$ 125,111.14
11	Real Time Spinning Reserve Cost Distribution	$ 179,382.02		$ 179,382.02	$ 129,568.95
12	Real Time Supplemental Reserve Cost Distribution	$ 130,177.82		$ 130,177.82	$ 94,028.40
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 90,976.31	$ (35,196.70)	$ 55,779.61	$ 40,290.02
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 5,955,465.34**	**$ 654,460.61**	**$ 6,609,925.95**	**$ 4,774,398.06**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (22,789.71)		$ (22,789.71)	$ (16,051.11)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (9,045.65)		$ (9,045.65)	$ (6,370.98)
	Total	$ (31,835.36)		$ (31,835.36)	$ (22,422.09)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	July 2022 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (385,722.15)		$ (385,722.15)	$ (282,470.18)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (125,315.68)		$ (125,315.68)	$ (91,770.57)
3	Day-Ahead Supplemental Reserve	$ (130,607.05)		$ (130,607.05)	$ (95,645.52)
4	Real-Time Regulation Amount (See Note 1)	$ (97,816.95)	$ 292,890.88	$ 195,073.93	$ 142,855.60
5	Real-Time Spinning Reserve Amount	$ (74,668.16)	$ 133,056.42	$ 58,388.26	$ 42,758.61
6	Real-Time Supplemental Reserve Amount.	$ 106,986.73	$ 25,264.45	$ 132,251.18	$ 96,849.54
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 15,118.64		$ 15,118.64	$ 11,071.61
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 11,646,611.06		$ 11,646,611.06	$ 8,528,989.91
8b	Real Time Non Excessive Energy Congestion	$ (1,049,875.29)	$ -	$ (1,049,875.29)	$ (768,839.60)
8c	Real Time Non Excessive Energy Loss	$ (475,919.80)	$ -	$ (475,919.80)	$ (348,523.29)
9	Real Time Net Regulation Adjustment Amount	$ 123,182.49	$ (83,099.78)	$ 40,082.71	$ 29,353.18
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 179,333.48		$ 179,333.48	$ 131,328.63
11	Real Time Spinning Reserve Cost Distribution	$ 61,170.38		$ 61,170.38	$ 44,796.00
12	Real Time Supplemental Reserve Cost Distribution	$ 217,118.63		$ 217,118.63	$ 158,999.27
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 83,037.63	$ (58,684.36)	$ 24,353.27	$ 17,834.27
14	Real Time Contingency Reserve Deployment Failure	$ 3,929.16	$ -	$ 3,929.16	$ 2,877.38
	TOTAL MISO ASM CHARGES	**$ 10,096,563.12**	**$ 309,427.61**	**$ 10,405,990.73**	**$ 7,620,464.83**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (10,742.76)		$ (10,742.76)	$ (7,517.68)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (17,223.21)		$ (17,223.21)	$ (12,052.63)
	Total	$ (27,965.97)		$ (27,965.97)	$ (19,570.31)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	August 2022 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (253,746.35)		$ (253,746.35)	$ (183,093.13)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (155,482.31)		$ (155,482.31)	$ (112,189.76)
3	Day-Ahead Supplemental Reserve	$ (64,151.97)		$ (64,151.97)	$ (46,289.47)
4	Real-Time Regulation Amount (See Note 1)	$ (225,143.66)	$ 259,142.57	$ 33,998.91	$ 24,532.24
5	Real-Time Spinning Reserve Amount	$ (102,140.69)	$ 249,599.56	$ 147,458.87	$ 106,400.37
6	Real-Time Supplemental Reserve Amount.	$ 75,892.83	$ (18,350.33)	$ 57,542.50	$ 41,520.35
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (42,689.47)		$ (42,689.47)	$ (30,803.00)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 8,940,025.35		$ 8,940,025.35	$ 6,450,761.51
8b	Real Time Non Excessive Energy Congestion	$ (1,218,423.75)	$ -	$ (1,218,423.75)	$ (879,165.41)
8c	Real Time Non Excessive Energy Loss	$ (313,577.95)	$ -	$ (313,577.95)	$ (226,265.19)
9	Real Time Net Regulation Adjustment Amount	$ (13,172.62)	$ (7,243.19)	$ (20,415.81)	$ (14,731.22)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 162,246.14		$ 162,246.14	$ 117,070.27
11	Real Time Spinning Reserve Cost Distribution	$ 151,469.96		$ 151,469.96	$ 109,294.61
12	Real Time Supplemental Reserve Cost Distribution	$ 22,395.93		$ 22,395.93	$ 16,160.00
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 99,463.36	$ (61,628.62)	$ 37,834.74	$ 27,300.02
14	Real Time Contingency Reserve Deployment Failure	$ 211,246.65	$ (51,511.01)	$ 159,735.64	$ 115,258.79
	TOTAL MISO ASM CHARGES	**$ 7,274,211.45**	**$ 370,008.98**	**$ 7,644,220.43**	**$ 5,515,760.97**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (6,157.02)		$ (6,157.02)	$ (4,349.45)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (22,439.06)		$ (22,439.06)	$ (15,851.44)
	Total	$ (28,596.08)		$ (28,596.08)	$ (20,200.89)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	September 2022 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (165,160.75)		$ (165,160.75)	$ (119,195.88)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (141,448.31)		$ (141,448.31)	$ (102,082.71)
3	Day-Ahead Supplemental Reserve	$ (43,561.26)		$ (43,561.26)	$ (31,437.99)
4	Real-Time Regulation Amount (See Note 1)	$ (167,325.65)	$ 177,294.66	$ 9,969.01	$ 7,194.60
5	Real-Time Spinning Reserve Amount	$ (10,003.08)	$ 56,678.70	$ 46,675.62	$ 33,685.62
6	Real-Time Supplemental Reserve Amount.	$ 7,602.85	$ 5,751.09	$ 13,353.94	$ 9,637.49
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (58,986.13)		$ (58,986.13)	$ (42,570.06)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 9,762,426.82		$ 9,762,426.82	$ 7,045,506.15
8b	Real Time Non Excessive Energy Congestion	$ (129,250.24)	$ -	$ (129,250.24)	$ (93,279.40)
8c	Real Time Non Excessive Energy Loss	$ (68,544.08)	$ -	$ (68,544.08)	$ (49,468.00)
9	Real Time Net Regulation Adjustment Amount	$ 16,716.55	$ (9,348.30)	$ 7,368.25	$ 5,317.64
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 167,417.21		$ 167,417.21	$ 120,824.36
11	Real Time Spinning Reserve Cost Distribution	$ 84,635.27		$ 84,635.27	$ 61,080.95
12	Real Time Supplemental Reserve Cost Distribution	$ 82,884.96		$ 82,884.96	$ 59,817.76
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 73,971.85	$ (43,147.80)	$ 30,824.05	$ 22,245.60
14	Real Time Contingency Reserve Deployment Failure	$ 76.47	$ -	$ 76.47	$ 55.19
	TOTAL MISO ASM CHARGES	**$ 9,411,452.48**	**$ 187,228.35**	**$ 9,598,680.83**	**$ 6,927,331.29**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (1,724.31)		$ (1,724.31)	$ (1,215.44)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (8,710.33)		$ (8,710.33)	$ (6,139.78)
	Total	$ (10,434.64)		$ (10,434.64)	$ (7,355.22)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	October 2022 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (169,858.02)		$ (169,858.02)	$ (120,441.49)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (155,734.38)		$ (155,734.38)	$ (110,426.82)
3	Day-Ahead Supplemental Reserve	$ (37,684.30)		$ (37,684.30)	$ (26,720.86)
4	Real-Time Regulation Amount (See Note 1)	$ (40,046.19)	$ 97,054.85	$ 57,008.66	$ 40,423.22
5	Real-Time Spinning Reserve Amount	$ (12,359.17)	$ 104,903.65	$ 92,544.48	$ 65,620.66
6	Real-Time Supplemental Reserve Amount.	$ 5,870.04	$ 9,000.59	$ 14,870.63	$ 10,544.34
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 119,747.19		$ 119,747.19	$ 84,909.33
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 7,185,574.97		$ 7,185,574.97	$ 5,095,086.77
8b	Real Time Non Excessive Energy Congestion	$ (337,782.81)	$ -	$ (337,782.81)	$ (239,512.18)
8c	Real Time Non Excessive Energy Loss	$ 53,067.95	$ -	$ 53,067.95	$ 37,628.97
9	Real Time Net Regulation Adjustment Amount	$ 13,454.16	$ (7,474.38)	$ 5,979.78	$ 4,240.09
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 168,580.43		$ 168,580.43	$ 119,535.59
11	Real Time Spinning Reserve Cost Distribution	$ 178,758.16		$ 178,758.16	$ 126,752.33
12	Real Time Supplemental Reserve Cost Distribution	$ 48,669.09		$ 48,669.09	$ 34,509.87
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 61,455.34	$ (23,136.17)	$ 38,319.17	$ 27,171.03
14	Real Time Contingency Reserve Deployment Failure	$ 4,189.63	$ -	$ 4,189.63	$ 2,970.75
	TOTAL MISO ASM CHARGES	**$ 7,085,902.09**	**$ 180,348.54**	**$ 7,266,250.63**	**$ 5,152,291.59**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (5,771.84)		$ (5,771.84)	$ (4,094.10)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (5,696.45)		$ (5,696.45)	$ (4,040.62)
	Total	$ (11,468.29)		$ (11,468.29)	$ (8,134.72)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	November 2022 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (152,308.53)		$ (152,308.53)	$ (107,866.87)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (290,932.16)		$ (290,932.16)	$ (206,041.92)
3	Day-Ahead Supplemental Reserve	$ (72,799.53)		$ (72,799.53)	$ (51,557.57)
4	Real-Time Regulation Amount (See Note 1)	$ (71,418.55)	$ 72,614.86	$ 1,196.31	$ 847.24
5	Real-Time Spinning Reserve Amount	$ (84,335.71)	$ 242,036.15	$ 157,700.44	$ 111,685.49
6	Real-Time Supplemental Reserve Amount.	$ 9,820.49	$ 5,420.08	$ 15,240.57	$ 10,793.57
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 17,855.08		$ 17,855.08	$ 12,645.20
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 6,676,756.55		$ 6,676,756.55	$ 4,728,565.45
8b	Real Time Non Excessive Energy Congestion	$ (939,845.33)	$ -	$ (939,845.33)	$ (665,610.63)
8c	Real Time Non Excessive Energy Loss	$ (92,186.09)	$ -	$ (92,186.09)	$ (65,287.38)
9	Real Time Net Regulation Adjustment Amount	$ (6,290.68)	$ 2,621.79	$ (3,668.89)	$ (2,598.36)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 158,879.29		$ 158,879.29	$ 112,520.37
11	Real Time Spinning Reserve Cost Distribution	$ 224,083.74		$ 224,083.74	$ 158,699.01
12	Real Time Supplemental Reserve Cost Distribution	$ 87,559.31		$ 87,559.31	$ 62,010.64
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 37,749.09	$ (13,349.74)	$ 24,399.35	$ 17,279.94
14	Real Time Contingency Reserve Deployment Failure	$ 1,891.62	$ -	$ 1,891.62	$ 1,339.67
	TOTAL MISO ASM CHARGES	**$ 5,504,478.59**	**$ 309,343.14**	**$ 5,813,821.73**	**$ 4,117,423.83**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (22,902.63)		$ (22,902.63)	$ (16,403.67)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (8,970.92)		$ (8,970.92)	$ (6,425.29)
	Total	$ (31,873.55)		$ (31,873.55)	$ (22,828.96)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
December 2022 Actual					
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (249,550.24)		$ (249,550.24)	$ (176,065.44)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (257,324.17)		$ (257,324.17)	$ (181,550.19)
3	Day-Ahead Supplemental Reserve	$ (372,288.87)		$ (372,288.87)	$ (262,661.35)
4	Real-Time Regulation Amount (See Note 1)	$ (576,602.84)	$ 536,696.35	$ (39,906.49)	$ (28,155.27)
5	Real-Time Spinning Reserve Amount	$ (1,379,113.30)	$ 1,273,000.00	$ (106,113.30)	$ (74,866.23)
6	Real-Time Supplemental Reserve Amount.	$ (493,824.98)	$ 96,857.50	$ (396,967.48)	$ (280,072.87)
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (10,754.75)		$ (10,754.75)	$ (7,587.81)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ (9,677,062.66)		$ (9,677,062.66)	$ (6,827,467.95)
8b	Real Time Non Excessive Energy Congestion	$ (1,132,268.97)	$ -	$ (1,132,268.97)	$ (798,850.89)
8c	Real Time Non Excessive Energy Loss	$ 101,965.16	$ -	$ 101,965.16	$ 71,939.58
9	Real Time Net Regulation Adjustment Amount	$ 39,991.15	$ (50,934.05)	$ (10,942.90)	$ (7,720.56)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 171,280.59		$ 171,280.59	$ 120,843.77
11	Real Time Spinning Reserve Cost Distribution	$ 183,323.99		$ 183,323.99	$ 129,340.76
12	Real Time Supplemental Reserve Cost Distribution	$ 648,701.06		$ 648,701.06	$ 457,678.72
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 284,716.90	$ (48,189.28)	$ 236,527.62	$ 166,877.57
14	Real Time Contingency Reserve Deployment Failure	$ 83,197.61	$ (24,111.55)	$ 59,086.06	$ 41,687.05
	TOTAL MISO ASM CHARGES	**$ (12,635,614.32)**	**$ 1,783,318.97**	**$ (10,852,295.35)**	**$ (7,656,631.08)**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (19,379.48)		$ (19,379.48)	$ (13,997.94)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (12,227.41)		$ (12,227.41)	$ (8,831.95)
	Total	$ (31,606.89)		$ (31,606.89)	$ (22,829.89)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	January - December 2022 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (2,734,110.97)		$ (2,734,110.97)	$ (1,950,973.16)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (2,768,401.62)		$ (2,768,401.62)	$ (1,975,441.86)
3	Day-Ahead Supplemental Reserve	$ (1,369,044.99)		$ (1,369,044.99)	$ (976,906.23)
4	Real-Time Regulation Amount (See Note 1)	$ (1,157,211.94)	$ 2,353,184.02	$ 1,195,972.08	$ 853,406.99
5	Real-Time Spinning Reserve Amount	$ (2,291,669.03)	$ 3,583,488.14	$ 1,291,819.11	$ 921,800.34
6	Real-Time Supplemental Reserve Amount.	$ (341,990.53)	$ 249,314.90	$ (92,675.63)	$ (66,130.33)
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 327,104.84		$ 327,104.84	$ 233,411.43
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 58,003,208.54		$ 58,003,208.54	$ 41,389,213.59
8b	Real Time Non Excessive Energy Congestion	$ (8,909,536.88)	$ -	$ (8,909,536.88)	$ (6,357,557.35)
8c	Real Time Non Excessive Energy Loss	$ (849,797.78)	$ -	$ (849,797.78)	$ (606,388.21)
9	Real Time Net Regulation Adjustment Amount	$ (1,791,750.46)	$ (114,452.24)	$ (1,906,202.70)	$ (1,360,204.59)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 2,093,995.60		$ 2,093,995.60	$ 1,494,207.53
11	Real Time Spinning Reserve Cost Distribution	$ 1,888,162.75		$ 1,888,162.75	$ 1,347,331.87
12	Real Time Supplemental Reserve Cost Distribution	$ 1,662,292.40		$ 1,662,292.40	$ 1,186,158.09
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 939,620.54	$ (377,103.69)	$ 562,516.85	$ 401,393.83
14	Real Time Contingency Reserve Deployment Failure	$ 309,888.51	$ (75,182.33)	$ 234,706.18	$ 167,478.74
	TOTAL MISO ASM CHARGES	**$ 43,010,758.98**	**$ 5,619,248.80**	**$ 48,630,007.78**	**$ 34,700,800.69**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (200,252.24)		$ (200,252.24)	$ (146,647.75)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (118,242.09)		$ (118,242.09)	$ (86,590.48)
	Total	$ (318,494.33)		$ (318,494.33)	$ (233,238.23)

Northern States Power Company

SUMMARY OF MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES - SYSTEM

		January 22	February 22	March 22	1st Qt	April 22	May 22	June 22	2nd Qt	July 22	August 22	September 22	3rd Qt	October 22	November 22	December 22	4th Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount	$ (164,671.79)	$ (138,495.37)	$ (148,111.43)	$ (451,278.59)	$ (248,040.09)	$ (270,816.39)	$ (387,629.86)	$ (906,486.34)	$ (385,722.15)	$ (253,746.35)	$ (165,160.75)	$ (804,629.25)	$ (169,858.02)	$ (152,308.53)	$ (249,550.24)	$ (571,716.79)	$ (2,734,110.97)
4	Real-Time Regulation Amount	$ (52,009.98)	$ (16,135.59)	$ 8,637.47	$ (59,508.10)	$ 135,773.92	$ (2,700.64)	$ (52,423.28)	$ 80,650.00	$ (97,816.95)	$ (225,143.66)	$ (167,325.65)	$ (490,286.26)	$ (40,046.19)	$ (71,418.55)	$ (576,602.84)	$ (688,067.58)	$ (1,157,211.94)
10	Real Time Regulation Reserve Cost Distribution Amc	$ 145,077.50	$ 145,134.02	$ 156,330.53	$ 446,542.05	$ 224,754.00	$ 241,752.01	$ 173,210.40	$ 639,716.41	$ 179,333.48	$ 162,246.14	$ 167,417.21	$ 508,996.83	$ 168,580.43	$ 158,879.29	$ 171,280.59	$ 498,740.31	$ 2,093,995.60
	SUBTOTAL	$ (71,604.27)	$ (9,496.94)	$ 16,856.57	$ (64,244.64)	$ 112,487.83	$ (31,765.02)	$ (266,842.74)	$ (186,119.93)	$ (304,205.62)	$ (316,643.87)	$ (165,069.19)	$ (785,918.68)	$ (41,323.78)	$ (64,847.79)	$ (654,872.49)	$ (761,044.06)	$ (1,797,327.31)
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount	$ (164,772.45)	$ (192,760.35)	$ (208,493.43)	$ (566,026.23)	$ (369,817.64)	$ (343,047.30)	$ (363,273.44)	$ (1,076,138.38)	$ (125,315.68)	$ (155,482.31)	$ (141,448.31)	$ (422,246.30)	$ (155,734.38)	$ (290,932.16)	$ (257,324.17)	$ (703,990.71)	$ (2,768,401.62)
5	Real-Time Spinning Reserve Amount	$ (59,636.76)	$ (52,661.24)	$ (52,177.28)	$ (164,475.28)	$ (230,742.82)	$ (141,338.91)	$ (92,491.91)	$ (464,573.64)	$ (74,668.16)	$ (102,140.69)	$ (10,003.08)	$ (186,811.93)	$ (12,359.17)	$ (84,335.71)	$ (1,379,113.30)	$ (1,475,808.18)	$ (2,291,669.03)
11	Real Time Spinning Reserve Cost Distribution	$ 102,882.19	$ 104,423.49	$ 154,236.36	$ 361,542.04	$ 231,564.74	$ 232,232.45	$ 179,382.02	$ 643,179.21	$ 61,170.38	$ 151,469.96	$ 84,635.27	$ 297,275.61	$ 178,758.16	$ 224,083.74	$ 183,323.99	$ 586,165.89	$ 1,888,162.75
	SUBTOTAL	$ (121,527.02)	$ (140,998.10)	$ (106,434.35)	$ (368,959.47)	$ (368,995.72)	$ (252,153.76)	$ (276,383.33)	$ (897,532.81)	$ (138,813.46)	$ (106,153.04)	$ (66,816.12)	$ (311,782.62)	$ 10,664.61	$ (151,184.13)	$ (1,453,113.48)	$ (1,593,633.00)	$ (3,171,907.90)
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve	$ (54,159.30)	$ (79,551.59)	$ (106,263.39)	$ (239,974.28)	$ (163,033.09)	$ (110,745.72)	$ (134,198.92)	$ (407,977.73)	$ (130,607.05)	$ (64,151.97)	$ (43,561.26)	$ (238,320.28)	$ (37,684.30)	$ (72,799.53)	$ (372,288.87)	$ (482,772.70)	$ (1,369,044.99)
6	Real-Time Supplemental Reserve Amount.	$ (23,918.76)	$ 5,939.90	$ (466.56)	$ (18,445.42)	$ (14,364.66)	$ (14,643.83)	$ (6,884.58)	$ (35,893.07)	$ 106,986.73	$ 75,892.83	$ 7,602.85	$ 190,482.41	$ 5,870.04	$ 9,820.49	$ (493,824.98)	$ (478,134.45)	$ (341,990.53)
12	Real Time Supplemental Reserve Cost Distribution	$ 36,611.14	$ 91,758.52	$ 57,644.60	$ 186,014.26	$ 167,602.74	$ 71,168.60	$ 130,177.82	$ 368,949.16	$ 217,118.63	$ 22,395.93	$ 82,884.96	$ 322,399.52	$ 48,669.09	$ 87,559.31	$ 648,701.06	$ 784,929.46	$ 1,662,292.40
	SUBTOTAL	$ (41,466.92)	$ 18,146.83	$ (49,085.35)	$ (72,405.44)	$ (9,795.01)	$ (54,220.95)	$ (10,905.68)	$ (74,921.64)	$ 193,498.31	$ 34,136.79	$ 46,926.55	$ 274,561.65	$ 16,854.83	$ 24,580.27	$ (217,412.79)	$ (175,977.69)	$ (48,743.12)
Other Charges																		
14	Real Time Contingency Reserve Deployment Failure	$ 212.24	$ 4,137.11	$ -	$ 4,349.35	$ 984.90	$ 23.12	$ -	$ 1,008.02	$ 3,929.16	$ 211,246.65	$ 76.47	$ 215,252.28	$ 4,189.63	$ 1,891.62	$ 83,197.61	$ 89,278.86	$ 309,888.51
13	Real Time Excessive/Deficient Energy Deployment	$ 46,932.35	$ 42,037.33	$ 45,880.87	$ 134,850.55	$ 37,534.66	$ 35,864.85	$ 90,976.31	$ 164,375.82	$ 83,037.63	$ 99,463.36	$ 73,971.85	$ 256,472.84	$ 61,455.34	$ 37,749.09	$ 284,716.90	$ 383,921.33	$ 939,620.54
9	Real Time Net Regulation Adjustment Amount	$ (1,922,661.82)	$ 7,020.31	$ 13,224.60	$ (1,902,416.91)	$ (18,847.42)	$ (30,228.85)	$ (14,138.33)	$ (63,214.60)	$ 123,182.49	$ (13,172.62)	$ 16,716.55	$ 126,726.42	$ 13,454.16	$ (6,290.68)	$ 39,991.15	$ 47,154.63	$ (1,791,750.46)
	SUBTOTAL	$ (1,875,517.23)	$ 53,194.75	$ 59,105.47	$ (1,763,217.01)	$ 19,672.14	$ 5,659.12	$ 76,837.98	$ 102,169.24	$ 210,149.28	$ 297,537.39	$ 90,764.87	$ 598,451.54	$ 79,099.13	$ 33,350.03	$ 407,905.66	$ 520,354.82	$ (542,241.41)
	TOTAL MISO ASM CHARGES	**$ (2,110,115.44)**	**$ (79,153.46)**	**$ (79,557.66)**	**$ (2,268,826.56)**	**$ (246,630.76)**	**$ (332,480.61)**	**$ (477,293.77)**	**$ (1,056,405.14)**	**$ (39,371.49)**	**$ (91,122.73)**	**$ (94,193.89)**	**$ (224,688.11)**	**$ 65,294.79**	**$ (158,101.62)**	**$ (1,917,493.10)**	**$ (2,010,299.93)**	**$ (5,560,219.74)**
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT																		
7a	Real Time Excessive Energy Amount	$ 51,469.61	$ 11,216.83	$ 27,113.24	$ 89,799.68	$ 85,273.13	$ 128,285.38	$ (16,543.91)	$ 197,014.60	$ 15,118.64	$ (42,689.47)	$ (58,986.13)	$ (86,556.96)	$ 119,747.19	$ 17,855.08	$ (10,754.75)	$ 126,847.52	$ 327,104.84
7b	Real Time Excessive Energy Congestion				$ -				$ -				$ -				$ -	$ -
7c	Real Time Excessive Energy Loss				$ -				$ -				$ -				$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 6,221,466.08	$ 801,965.84	$ 3,304,280.84	$ 10,327,712.76	$ 713,453.45	$ 4,687,117.33	$ 7,740,592.91	$ 13,141,163.69	$ 11,646,611.06	$ 8,940,025.35	$ 9,762,426.82	$ 30,349,063.23	$ 7,185,574.97	$ 6,676,756.55	$ (9,677,062.66)	$ 4,185,268.86	$ 58,003,208.54
8b	Real Time Non Excessive Energy Congestion	$ 788,846.39	$ (119,931.61)	$ (244,425.15)	$ 424,489.63	$ 562,216.26	$ (3,770,861.91)	$ (1,317,934.47)	$ (4,526,580.12)	$ (1,049,875.29)	$ (1,218,423.75)	$ (129,250.24)	$ (2,397,549.28)	$ (337,782.81)	$ (939,845.33)	$ (1,132,268.97)	$ (2,409,897.11)	$ (8,909,536.88)
8c	Real Time Non Excessive Energy Loss	$ 130,433.58	$ 40,093.71	$ (38,366.21)	$ 132,161.08	$ 214,348.89	$ (427,757.52)	$ 26,644.58	$ (186,764.05)	$ (475,919.80)	$ (313,577.95)	$ (68,544.08)	$ (858,041.83)	$ 53,067.95	$ (92,186.09)	$ 101,965.16	$ 62,847.02	$ (849,797.78)
	SUBTOTAL	**$ 7,192,215.66**	**$ 733,344.77**	**$ 3,048,602.72**	**$ 10,974,163.15**	**$ 1,575,291.73**	**$ 616,783.28**	**$ 6,432,759.11**	**$ 8,624,834.12**	**$ 10,135,934.61**	**$ 7,365,334.18**	**$ 9,505,646.37**	**$ 27,006,915.16**	**$ 7,020,607.30**	**$ 5,662,580.21**	**$ (10,718,121.22)**	**$ 1,965,066.29**	**$ 48,570,978.72**
	GRAND TOTAL MISO ASM CHARGES	**$ 5,082,100.22**	**$ 654,191.31**	**$ 2,969,045.06**	**$ 8,705,336.59**	**$ 1,328,660.97**	**$ 284,302.67**	**$ 5,955,465.34**	**$ 7,568,428.98**	**$ 10,096,563.12**	**$ 7,274,211.45**	**$ 9,411,452.48**	**$ 26,782,227.05**	**$ 7,085,902.09**	**$ 5,504,478.59**	**$ (12,635,614.32)**	**$ (45,233.64)**	**$ 43,010,758.98**

Northern States Power Company

SUMMARY OF MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES - INTERSYSTEM

		January 22	February 22	March 22	1st Qt	April 22	May 22	June 22	2nd Qt	July 22	August 22	September 22	3rd Qt	October 22	November 22	December 22	4th Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount				$ -				$ -				$ -				$ -	$ -
4	Real-Time Regulation Amount	$ 166,406.21	$ 88,068.49	$ 54,408.12	$ 308,882.82	$ 103,549.06	$ 188,988.85	$ 316,069.12	$ 608,607.03	$ 292,890.88	$ 259,142.57	$ 177,294.66	$ 729,328.11	$ 97,054.85	$ 72,614.86	$ 536,696.35	$ 706,366.06	$ 2,353,184.02
10	Real Time Regulation Reserve Cost Distribution Amount				$ -				$ -				$ -				$ -	$ -
	SUBTOTAL	$ 166,406.21	$ 88,068.49	$ 54,408.12	$ 308,882.82	$ 103,549.06	$ 188,988.85	$ 316,069.12	$ 608,607.03	$ 292,890.88	$ 259,142.57	$ 177,294.66	$ 729,328.11	$ 97,054.85	$ 72,614.86	$ 536,696.35	$ 706,366.06	$ 2,353,184.02
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount				$ -				$ -				$ -				$ -	$ -
5	Real-Time Spinning Reserve Amount	$ 132,154.60	$ 174,674.36	$ 119,474.57	$ 426,303.53	$ 436,357.69	$ 360,033.38	$ 301,519.06	$ 1,097,910.13	$ 133,056.42	$ 249,599.56	$ 56,678.70	$ 439,334.68	$ 104,903.65	$ 242,036.15	#########	$ 1,619,939.80	$ 3,583,488.14
11	Real Time Spinning Reserve Cost Distribution				$ -				$ -				$ -				$ -	$ -
	SUBTOTAL	$ 132,154.60	$ 174,674.36	$ 119,474.57	$ 426,303.53	$ 436,357.69	$ 360,033.38	$ 301,519.06	$ 1,097,910.13	$ 133,056.42	$ 249,599.56	$ 56,678.70	$ 439,334.68	$ 104,903.65	$ 242,036.15	$ 1,273,000.00	$ 1,619,939.80	$ 3,583,488.14
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve				$ -				$ -				$ -				$ -	$ -
6	Real-Time Supplemental Reserve Amount.	$ 3,271.65	$ 6,412.99	$ 17,275.91	$ 26,960.55	$ 12,570.33	$ 40,577.83	$ 45,262.81	$ 98,410.97	$ 25,264.45	$ (18,350.33)	$ 5,751.09	$ 12,665.21	$ 9,000.59	$ 5,420.08	$ 96,857.50	$ 111,278.17	$ 249,314.90
12	Real Time Supplemental Reserve Cost Distribution				$ -				$ -				$ -				$ -	$ -
	SUBTOTAL	$ 3,271.65	$ 6,412.99	$ 17,275.91	$ 26,960.55	$ 12,570.33	$ 40,577.83	$ 45,262.81	$ 98,410.97	$ 25,264.45	$ (18,350.33)	$ 5,751.09	$ 12,665.21	$ 9,000.59	$ 5,420.08	$ 96,857.50	$ 111,278.17	$ 249,314.90
Other Charges																		
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ 440.23	$ 440.23	$ -	$ -	$ -	$ -	$ -	$ (51,511.01)	$ -	$ (51,511.01)	$ -	$ -	$ (24,111.55)	$ (24,111.55)	$ (75,182.33)
13	Real Time Excessive/Deficient Energy Deployment	$ (21,318.10)	$ (22,669.53)	$ (11,043.60)	$ (55,031.23)	$ (23,552.22)	$ (15,187.57)	$ (35,196.70)	$ (73,936.49)	$ (58,684.36)	$ (61,628.62)	$ (43,147.80)	$ (163,460.78)	$ (23,136.17)	$ (13,349.74)	$ (48,189.28)	$ (84,675.19)	$ (377,103.69)
9	Real Time Net Regulation Adjustment Amount	$ (4,473.99)	$ (7,766.78)	$ (8,433.39)	$ (20,674.16)	$ 12,645.72	$ 22,247.79	$ 26,806.32	$ 61,699.83	$ (83,099.78)	$ (7,243.19)	$ (9,348.30)	$ (99,691.27)	$ (7,474.38)	$ 2,621.79	$ (50,934.05)	$ (55,786.64)	$ (114,452.24)
	SUBTOTAL	$ (25,792.09)	$ (30,436.31)	$ (19,036.76)	$ (75,265.16)	$ (10,906.50)	$ 7,060.22	$ (8,390.38)	$ (12,236.66)	$ (141,784.14)	$ (120,382.82)	$ (52,496.10)	$ (314,663.06)	$ (30,610.55)	$ (10,727.95)	$ (123,234.88)	$ (164,573.38)	$ (566,738.26)
	TOTAL MISO ASM CHARGES	**$ 276,040.37**	**$ 238,719.53**	**$ 172,121.84**	**$ 686,881.74**	**$ 541,570.58**	**$ 596,660.28**	**$ 654,460.61**	**$ 1,792,691.47**	**$ 309,427.61**	**$ 370,008.98**	**$ 187,228.35**	**$ 866,664.94**	**$ 180,348.54**	**$ 309,343.14**	**$ 1,783,318.97**	**$ 2,273,010.65**	**$ 5,619,248.80**
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT																		
7a	Real Time Excessive Energy Amount				$ -				$ -				$ -				$ -	$ -
7b	Real Time Excessive Energy Congestion				$ -				$ -				$ -				$ -	$ -
7c	Real Time Excessive Energy Loss				$ -				$ -				$ -				$ -	$ -
8a	Real Time Non Excessive Energy Amount				$ -				$ -				$ -				$ -	$ -
8b	Real Time Non Excessive Energy Congestion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8c	Real Time Non Excessive Energy Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	GRAND TOTAL MISO ASM CHARGES	**$ 276,040.37**	**$ 238,719.53**	**$ 172,121.84**	**$ 686,881.74**	**$ 541,570.58**	**$ 596,660.28**	**$ 654,460.61**	**$ 1,792,691.47**	**$ 309,427.61**	**$ 370,008.98**	**$ 187,228.35**	**$ 866,664.94**	**$ 180,348.54**	**$ 309,343.14**	**$ 1,783,318.97**	**$ 2,273,010.65**	**$ 5,619,248.80**

Northern States Power Company

SUMMARY OF MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES - RETAIL

		January 22	February 22	March 22	1st Qt	April 22	May 22	June 22	2nd Qt	July 22	August 22	September 22	3rd Qt	October 22	November 22	December 22	4th Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount	$ (164,671.79)	$ (138,495.37)	$ (148,111.43)	$ (451,278.59)	$ (248,040.09)	$ (270,816.39)	$ (387,629.86)	$ (906,486.34)	$ (385,722.15)	$ (253,746.35)	$ (165,160.75)	$ (804,629.25)	$ (169,858.02)	$ (152,308.53)	$ (249,550.24)	$ (571,716.79)	$ (2,734,110.97)
4	Real-Time Regulation Amount	$ 114,396.23	$ 71,932.90	$ 63,045.59	$ 249,374.72	$ 239,322.98	$ 186,288.21	$ 263,645.84	$ 689,257.03	$ 195,073.93	$ 33,998.91	$ 9,969.01	$ 239,041.85	$ 57,008.66	$ 1,196.31	$ (39,906.49)	$ 18,298.48	$ 1,195,972.08
10	Real Time Regulation Reserve Cost Distribution Amc	$ 145,077.50	$ 145,134.02	$ 156,330.53	$ 446,542.05	$ 224,754.00	$ 241,752.01	$ 173,210.40	$ 639,716.41	$ 179,333.48	$ 162,246.14	$ 167,417.21	$ 508,996.83	$ 168,580.43	$ 158,879.29	$ 171,280.59	$ 498,740.31	$ 2,093,995.60
	SUBTOTAL	$ 94,801.94	$ 78,571.55	$ 71,264.69	$ 244,638.18	$ 216,036.89	$ 157,223.83	$ 49,226.38	$ 422,487.10	$ (11,314.74)	$ (57,501.30)	$ 12,225.47	$ (56,590.57)	$ 55,731.07	$ 7,767.07	$ (118,176.14)	$ (54,678.00)	$ 555,856.71
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount	$ (164,772.45)	$ (192,760.35)	$ (208,493.43)	$ (566,026.23)	$ (369,817.64)	$ (343,047.30)	$ (363,273.44)	$ (1,076,138.38)	$ (125,315.68)	$ (155,482.31)	$ (141,448.31)	$ (422,246.30)	$ (155,734.38)	$ (290,932.16)	$ (257,324.17)	$ (703,990.71)	$ (2,768,401.62)
5	Real-Time Spinning Reserve Amount	$ 72,517.84	$ 122,013.12	$ 67,297.29	$ 261,828.25	$ 205,614.87	$ 218,694.47	$ 209,027.15	$ 633,336.49	$ 58,388.26	$ 147,458.87	$ 46,675.62	$ 252,522.75	$ 92,544.48	$ 157,700.44	$ (106,113.30)	$ 144,131.62	$ 1,291,819.11
11	Real Time Spinning Reserve Cost Distribution	$ 102,882.19	$ 104,423.49	$ 154,236.36	$ 361,542.04	$ 231,564.74	$ 232,232.45	$ 179,382.02	$ 643,179.21	$ 61,170.38	$ 151,469.96	$ 84,635.27	$ 297,275.61	$ 178,758.16	$ 224,083.74	$ 183,323.99	$ 586,165.89	$ 1,888,162.75
	SUBTOTAL	$ 10,627.58	$ 33,676.26	$ 13,040.22	$ 57,344.06	$ 67,361.97	$ 107,879.62	$ 25,135.73	$ 200,377.32	$ (5,757.04)	$ 143,446.52	$ (10,137.42)	$ 127,552.06	$ 115,568.26	$ 90,852.02	$ (180,113.48)	$ 26,306.80	$ 411,580.24
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve	$ (54,159.30)	$ (79,551.59)	$ (106,263.39)	$ (239,974.28)	$ (163,033.09)	$ (110,745.72)	$ (134,198.92)	$ (407,977.73)	$ (130,607.05)	$ (64,151.97)	$ (43,561.26)	$ (238,320.28)	$ (37,684.30)	$ (72,799.53)	$ (372,288.87)	$ (482,772.70)	$ (1,369,044.99)
6	Real-Time Supplemental Reserve Amount.	$ (20,647.11)	$ 12,352.89	$ 16,809.35	$ 8,515.13	$ (1,794.33)	$ 25,934.00	$ 38,378.23	$ 62,517.90	$ 132,251.18	$ 57,542.50	$ 13,353.94	$ 203,147.62	$ 14,870.63	$ 15,240.57	$ (396,967.48)	$ (366,856.28)	$ (92,675.63)
12	Real Time Supplemental Reserve Cost Distribution	$ 36,611.14	$ 91,758.52	$ 57,644.60	$ 186,014.26	$ 167,602.74	$ 71,168.60	$ 130,177.82	$ 368,949.16	$ 217,118.63	$ 22,395.93	$ 82,884.96	$ 322,399.52	$ 48,669.09	$ 87,559.31	$ 648,701.06	$ 784,929.46	$ 1,662,292.40
	SUBTOTAL	$ (38,195.27)	$ 24,559.82	$ (31,809.44)	$ (45,444.89)	$ 2,775.32	$ (13,643.12)	$ 34,357.13	$ 23,489.33	$ 218,762.76	$ 15,786.46	$ 52,677.64	$ 287,226.86	$ 25,855.42	$ 30,000.35	$ (120,555.29)	$ (64,699.52)	$ 200,571.78
Other Charges																		
13	Real Time Excessive/Deficient Energy Deployment	$ 212.24	$ 4,137.11	$ 440.23	$ 4,789.58	$ 984.90	$ 23.12	$ -	$ 1,008.02	$ 3,929.16	$ 159,735.64	$ 76.47	$ 163,741.27	$ 4,189.63	$ 1,891.62	$ 59,086.06	$ 65,167.31	$ 234,706.18
14	Real Time Contingency Reserve Deployment Failure	$ 25,614.25	$ 19,367.80	$ 34,837.27	$ 79,819.32	$ 13,982.44	$ 20,677.28	$ 55,779.61	$ 90,439.33	$ 24,353.27	$ 37,834.74	$ 30,824.05	$ 93,012.06	$ 38,319.17	$ 24,399.35	$ 236,527.62	$ 299,246.14	$ 562,516.85
9	Real Time Net Regulation Adjustment Amount	$ (1,927,135.81)	$ (746.47)	$ 4,791.21	$ (1,923,091.07)	$ (6,201.70)	$ (7,981.06)	$ 12,667.99	$ (1,514.77)	$ 40,082.71	$ (20,415.81)	$ 7,368.25	$ 27,035.15	$ 5,979.78	$ (3,668.89)	$ (10,942.90)	$ (8,632.01)	$ (1,906,202.70)
	SUBTOTAL	$ (1,901,309.32)	$ 22,758.44	$ 40,068.71	$ (1,838,482.17)	$ 8,765.64	$ 12,719.34	$ 68,447.60	$ 89,932.58	$ 68,365.14	$ 177,154.57	$ 38,268.77	$ 283,788.48	$ 48,488.58	$ 22,622.08	$ 284,670.78	$ 355,781.44	$ (1,108,979.67)
	TOTAL MISO ASM CHARGES	**$ (1,834,075.07)**	**$ 159,566.07**	**$ 92,564.18**	**$ (1,581,944.82)**	**$ 294,939.82**	**$ 264,179.67**	**$ 177,166.84**	**$ 736,286.33**	**$ 270,056.12**	**$ 278,886.25**	**$ 93,034.46**	**$ 641,976.83**	**$ 245,643.33**	**$ 151,241.52**	**$ (134,174.13)**	**$ 262,710.72**	**$ 59,029.06**
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT																		
7a	Real Time Excessive Energy Amount	$ 51,469.61	$ 11,216.83	$ 27,113.24	$ 89,799.68	$ 85,273.13	$ 128,285.38	$ (16,543.91)	$ 197,014.60	$ 15,118.64	$ (42,689.47)	$ (58,986.13)	$ (86,556.96)	$ 119,747.19	$ 17,855.08	$ (10,754.75)	$ 126,847.52	$ 327,104.84
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 6,221,466.08	$ 801,965.84	$ 3,304,280.84	$ 10,327,712.76	$ 713,453.45	$ 4,687,117.33	$ 7,740,592.91	$ 13,141,163.69	$ 11,646,611.06	$ 8,940,025.35	$ 9,762,426.82	$ 30,349,063.23	$ 7,185,574.97	$ 6,676,756.55	$ (9,677,062.66)	$ 4,185,268.86	$ 58,003,208.54
8b	Real Time Non Excessive Energy Congestion	$ 788,846.39	$ (119,931.61)	$ (244,425.15)	$ 424,489.63	$ 562,216.26	$ (3,770,861.91)	$ (1,317,934.47)	$ (4,526,580.12)	$ (1,049,875.29)	$ (1,218,423.75)	$ (129,250.24)	$ (2,397,549.28)	$ (337,782.81)	$ (939,845.33)	$ (1,132,268.97)	$ (2,409,897.11)	$ (8,909,536.88)
8c	Real Time Non Excessive Energy Loss	$ 130,433.58	$ 40,093.71	$ (38,366.21)	$ 132,161.08	$ 214,348.89	$ (427,757.52)	$ 26,644.58	$ (186,764.05)	$ (475,919.80)	$ (313,577.95)	$ (68,544.08)	$ (858,041.83)	$ 53,067.95	$ (92,186.09)	$ 101,965.16	$ 62,847.02	$ (849,797.78)
	SUBTOTAL	**$ 7,192,215.66**	**$ 733,344.77**	**$ 3,048,602.72**	**$ 10,974,163.15**	**$ 1,575,291.73**	**$ 616,783.28**	**$ 6,432,759.11**	**$ 8,624,834.12**	**$ 10,135,934.61**	**$ 7,365,334.18**	**$ 9,505,646.37**	**$ 27,006,915.16**	**$ 7,020,607.30**	**$ 5,662,580.21**	**$ (10,718,121.22)**	**$ 1,965,066.29**	**$ 48,570,978.72**
	GRAND TOTAL MISO ASM CHARGES	**$ 5,358,140.59**	**$ 892,910.84**	**$ 3,141,166.90**	**$ 9,392,218.33**	**$ 1,870,231.55**	**$ 880,962.95**	**$ 6,609,925.95**	**$ 9,361,120.45**	**$ 10,405,990.73**	**$ 7,644,220.43**	**$ 9,598,680.83**	**$ 27,648,891.99**	**$ 7,266,250.63**	**$ 5,813,821.73**	**$ (10,852,295.35)**	**$ 2,227,777.01**	**$ 48,630,007.78**

Northern States Power Company

SUMMARY OF MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES - MINNESOTA RETAIL (WEIGHTED BY MWH SALES)

		January 22	February 22	March 22	1st Qt	April 22	May 22	June 22	2nd Qt	July 22	August 22	September 22	3rd Qt	October 22	November 22	December 22	4th Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount	$ (115,235.71)	$ (97,836.12)	$ (104,401.56)	$ (317,473.38)	$ (175,940.52)	$ (193,968.23)	$ (279,987.90)	$ (649,896.65)	$ (282,470.18)	$ (183,093.13)	$ (119,195.88)	$ (584,759.19)	$ (120,441.49)	$ (107,866.87)	$ (176,065.44)	$ (404,373.80)	$ (1,956,503.02)
4	Real-Time Regulation Amount	$ 80,053.36	$ 50,814.95	$ 44,439.90	$ 175,308.22	$ 169,757.28	$ 133,426.17	$ 190,433.33	$ 493,616.78	$ 142,855.60	$ 24,532.24	$ 7,194.60	$ 174,582.44	$ 40,423.22	$ 847.24	$ (28,155.27)	$ 13,115.19	$ 856,622.63
10	Real Time Regulation Reserve Cost Distribution Amc	$ 101,523.81	$ 102,525.80	$ 110,195.08	$ 314,244.70	$ 159,423.17	$ 173,151.30	$ 125,111.14	$ 457,685.61	$ 131,328.63	$ 117,070.27	$ 120,824.36	$ 369,223.26	$ 119,535.59	$ 112,520.37	$ 120,843.77	$ 352,899.73	$ 1,494,053.29
	SUBTOTAL	$ 66,341.47	$ 55,504.64	$ 50,233.43	$ 172,079.53	$ 153,239.92	$ 112,609.24	$ 35,556.58	$ 301,405.74	$ (8,285.96)	$ (41,490.62)	$ 8,823.07	$ (40,953.50)	$ 39,517.32	$ 5,500.74	$ (83,376.93)	$ (38,358.88)	$ 394,172.89
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount	$ (115,306.15)	$ (136,170.07)	$ (146,963.94)	$ (398,440.15)	$ (262,320.13)	$ (245,702.55)	$ (262,395.07)	$ (770,417.76)	$ (91,770.57)	$ (112,189.76)	$ (102,082.71)	$ (306,043.04)	$ (110,426.82)	$ (206,041.92)	$ (181,550.19)	$ (498,018.93)	$ (1,972,919.88)
5	Real-Time Spinning Reserve Amount	$ 50,747.27	$ 86,192.70	$ 47,436.86	$ 184,376.84	$ 145,847.34	$ 156,636.68	$ 150,981.85	$ 453,465.87	$ 42,758.61	$ 106,400.37	$ 33,685.62	$ 182,844.59	$ 65,620.66	$ 111,685.49	$ (74,866.23)	$ 102,439.93	$ 923,127.23
11	Real Time Spinning Reserve Cost Distribution	$ 71,995.95	$ 73,767.01	$ 108,718.93	$ 254,481.89	$ 164,254.18	$ 166,333.06	$ 129,568.95	$ 460,156.19	$ 44,796.00	$ 109,294.61	$ 61,080.95	$ 215,171.56	$ 126,752.33	$ 158,699.01	$ 129,340.76	$ 414,792.09	$ 1,344,601.72
	SUBTOTAL	$ 7,437.08	$ 23,789.64	$ 9,191.86	$ 40,418.57	$ 47,781.39	$ 77,267.18	$ 18,155.72	$ 143,204.29	$ (4,215.97)	$ 103,505.22	$ (7,316.14)	$ 91,973.11	$ 81,946.17	$ 64,342.58	$ (127,075.65)	$ 19,213.09	$ 294,809.07
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve	$ (37,900.15)	$ (56,196.96)	$ (74,903.49)	$ (169,000.60)	$ (115,643.11)	$ (79,319.98)	$ (96,932.87)	$ (291,895.96)	$ (95,645.52)	$ (46,289.47)	$ (31,437.99)	$ (173,372.99)	$ (26,720.86)	$ (51,557.57)	$ (262,661.35)	$ (340,939.78)	$ (975,209.33)
6	Real-Time Supplemental Reserve Amount.	$ (14,448.65)	$ 8,726.35	$ 11,848.66	$ 6,126.36	$ (1,272.76)	$ 18,574.84	$ 27,720.88	$ 45,022.96	$ 96,849.54	$ 41,520.35	$ 9,637.49	$ 148,007.38	$ 10,544.34	$ 10,793.57	$ (280,072.87)	$ (258,734.96)	$ (59,578.26)
12	Real Time Supplemental Reserve Cost Distribution	$ 25,620.12	$ 64,820.20	$ 40,632.83	$ 131,073.14	$ 118,884.47	$ 50,973.46	$ 94,028.40	$ 263,886.32	$ 158,999.27	$ 16,160.00	$ 59,817.76	$ 234,977.02	$ 34,509.87	$ 62,010.64	$ 457,678.72	$ 554,199.23	$ 1,184,135.71
	SUBTOTAL	$ (26,728.68)	$ 17,349.59	$ (22,422.00)	$ (31,801.09)	$ 1,968.60	$ (9,771.68)	$ 24,816.41	$ 17,013.32	$ 160,203.29	$ 11,390.87	$ 38,017.25	$ 209,611.41	$ 18,333.34	$ 21,246.64	$ (85,055.50)	$ (45,475.52)	$ 149,348.12
Other Charges																		
14	Real Time Contingency Reserve Deployment Failure	$ 148.52	$ 2,922.54	$ 310.31	$ 3,381.38	$ 698.61	$ 16.56	$ -	$ 715.17	$ 2,877.38	$ 115,258.79	$ 55.19	$ 118,191.36	$ 2,970.75	$ 1,339.67	$ 41,687.05	$ 45,997.47	$ 168,285.38
13	Real Time Excessive/Deficient Energy Deployment	$ 17,924.60	$ 13,681.83	$ 24,556.28	$ 56,162.71	$ 9,918.07	$ 14,809.80	$ 40,290.02	$ 65,017.88	$ 17,834.27	$ 27,300.02	$ 22,245.60	$ 67,379.89	$ 27,171.03	$ 17,279.94	$ 166,877.57	$ 211,328.54	$ 399,889.03
9	Real Time Net Regulation Adjustment Amount	$ (1,348,590.77)	$ (527.32)	$ 3,377.25	$ (1,345,740.84)	$ (4,399.01)	$ (5,716.32)	$ 9,150.18	$ (965.14)	$ 29,353.18	$ (14,731.22)	$ 5,317.64	$ 19,939.59	$ 4,240.09	$ (2,598.36)	$ (7,720.56)	$ (6,078.82)	$ (1,332,845.21)
	SUBTOTAL	$ (1,330,517.65)	$ 16,077.05	$ 28,243.84	$ (1,286,196.75)	$ 6,217.67	$ 9,110.04	$ 49,440.20	$ 64,767.91	$ 50,064.83	$ 127,827.59	$ 27,618.43	$ 205,510.84	$ 34,381.87	$ 16,021.25	$ 200,844.07	$ 251,247.19	$ (764,670.81)
	TOTAL MISO ASM CHARGES	**$ (1,283,467.78)**	**$ 112,720.91**	**$ 65,247.12**	**$ (1,105,499.74)**	**$ 209,207.58**	**$ 189,214.78**	**$ 127,968.91**	**$ 526,391.27**	**$ 197,766.19**	**$ 201,233.06**	**$ 67,142.61**	**$ 466,141.87**	**$ 174,178.70**	**$ 107,111.20**	**$ (94,664.01)**	**$ 186,625.89**	**$ 73,659.28**
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT																		
7a	Real Time Excessive Energy Amount	$ 36,017.93	$ 7,923.81	$ 19,111.72	$ 63,053.46	$ 60,486.19	$ 91,882.50	$ (11,949.79)	$ 140,418.90	$ 11,071.61	$ (30,803.00)	$ (42,570.06)	$ (62,301.45)	$ 84,909.33	$ 12,645.20	$ (7,587.81)	$ 89,966.71	$ 231,137.63
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 4,353,721.05	$ 566,525.97	$ 2,329,138.72	$ 7,249,385.74	$ 506,068.89	$ 3,357,078.42	$ 5,591,087.11	$ 9,454,234.43	$ 8,528,989.91	$ 6,450,761.51	$ 7,045,506.15	$ 22,025,257.57	$ 5,095,086.77	$ 4,728,565.45	$ (6,827,467.95)	$ 2,996,184.27	$ 41,725,062.01
8b	Real Time Non Excessive Energy Congestion	$ 552,026.98	$ (84,722.28)	$ (172,291.68)	$ 295,013.03	$ 398,792.88	$ (2,700,824.04)	$ (951,953.75)	$ (3,253,984.90)	$ (768,839.60)	$ (879,165.41)	$ (93,279.40)	$ (1,741,284.41)	$ (239,512.18)	$ (665,610.63)	$ (798,850.89)	$ (1,703,973.70)	$ (6,404,229.98)
8c	Real Time Non Excessive Energy Loss	$ 91,276.14	$ 28,323.06	$ (27,043.77)	$ 92,555.43	$ 152,042.58	$ (306,374.99)	$ 19,245.58	$ (135,086.84)	$ (348,523.29)	$ (226,265.19)	$ (49,468.00)	$ (624,256.48)	$ 37,628.97	$ (65,287.38)	$ 71,939.58	$ 44,281.17	$ (622,506.71)
	SUBTOTAL	**$ 5,033,042.11**	**$ 518,050.56**	**$ 2,148,914.99**	**$ 7,700,007.67**	**$ 1,117,390.54**	**$ 441,761.90**	**$ 4,646,429.15**	**$ 6,205,581.59**	**$ 7,422,698.64**	**$ 5,314,527.91**	**$ 6,860,188.68**	**$ 19,597,415.22**	**$ 4,978,112.89**	**$ 4,010,312.63**	**$ (7,561,967.07)**	**$ 1,426,458.45**	**$ 34,929,462.94**
	GRAND TOTAL MISO ASM CHARGES	**$ 3,749,574.33**	**$ 630,771.48**	**$ 2,214,162.12**	**$ 6,594,507.92**	**$ 1,326,598.12**	**$ 630,976.68**	**$ 4,774,398.06**	**$ 6,731,972.86**	**$ 7,620,464.83**	**$ 5,515,760.97**	**$ 6,927,331.29**	**$ 20,063,557.09**	**$ 5,152,291.59**	**$ 4,117,423.83**	**$ (7,656,631.08)**	**$ 1,613,084.34**	**$ 35,003,122.22**

Northern States Power Company

Docket No. E002/AA-21-295

True-up Report

Part B, Attachment 9

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

January 2022	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (164,671.79)	-	$ 1,734.42	$ -	$ (166,406.21)		
2 Day-Ahead Spinning Reserve Amount	-	$ (164,772.45)	-	$ (32,617.85)	$ -	$ (132,154.60)		
3 Day-Ahead Supplemental Reserve	-	$ (9,014.52)	-	$ (5,742.87)	$ -	$ (3,271.65)		
4 Day-Ahead Short Term Reserve Amount	-	$ (45,144.78)	-	$ 92,997.03	$ -	$ (138,141.81)		
5 Real-Time Regulation Amount (See Note 1)	-	$ (190,151.79)	-	$ (190,151.79)	$ -	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (59,636.76)	-	$ (59,636.76)	$ -	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 4,765.14	-	$ 4,765.14	$ -	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ (28,683.90)	-	$ (28,683.90)	$ -	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(6,474)	$ 51,469.61	(6,474)	$ 51,469.61	$ -	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	344,304	$ 7,140,746.06	344,304	$ 7,140,746.06	$ -	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ (1,922,661.82)	-	$ (1,927,135.81)	$ -	$ 4,473.99		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 145,077.50	-	$ 145,077.50	$ -	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 102,882.19	-	$ 102,882.19	$ -	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 19,154.78	-	$ 19,154.78	$ -	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 17,456.36	-	$ 17,456.36	$ -	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 46,932.35	-	$ 25,614.25	$ -	$ 21,318.10		
14 Real Time Contingency Reserve Deployment Failure	-	$ -	-	$ -	$ -	$ -		
15 Real Time Short Term Reserve Deployment Failure	-	$ 271.70	-	$ 212.24	$ -	$ 59.46		
MISO ASM CHARGES	337,830	$ 4,944,017.88	337,830	$ 5,358,140.60	$ -	$ (414,122.72)		
x Net Congestion Amount	-	$ 788,846.39	-	$ 788,846.39	$ -	$ -		
y Net Loss Amount	-	$ 130,433.58	-	$ 130,433.58	$ -	$ -		
z Net Congestion and Loss Energy Offset	-	$ (919,279.97)	-	$ (919,279.97)	$ -	$ -		
SUBTOTAL	-	$ -	-	$ -	$ -	$ -		
Total MISO ASM CHARGES	**337,830**	**$ 4,944,017.88**	**337,830**	**$ 5,358,140.60**	**$ -**	**$ (414,122.72)**		

x No longer reported in 7b, 8b

y No longer reported in 7c, 8c

z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

February 2022	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (138,495.37)	-	$ (50,426.88)	$ -	$ (88,068.49)		
2 Day-Ahead Spinning Reserve Amount	-	$ (192,760.35)	-	$ (18,085.99)	$ -	$ (174,674.36)		
3 Day-Ahead Supplemental Reserve	-	$ (19,120.98)	-	$ (12,707.99)	$ -	$ (6,412.99)		
4 Day-Ahead Short Term Reserve Amount	-	$ (60,430.61)	-	$ (13,061.22)	$ -	$ (47,369.39)		
5 Real-Time Regulation Amount (See Note 1)	-	$ (63,504.98)	-	$ (63,504.98)	$ -	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (52,661.24)	-	$ (52,661.24)	$ -	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 2,951.20	-	$ 2,951.20	$ -	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ 2,988.70	-	$ 2,988.70	$ -	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,597)	$ 11,216.83	(1,597)	$ 11,216.83	$ -	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	46,309	$ 722,127.94	46,309	$ 722,127.94	$ -	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ 7,020.31	-	$ (746.47)	$ -	$ 7,766.78		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 145,134.02	-	$ 145,134.02	$ -	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 104,423.49	-	$ 104,423.49	$ -	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 15,029.57	-	$ 15,029.57	$ -	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 76,728.95	-	$ 76,728.95	$ -	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 42,037.33	-	$ 19,367.80	$ -	$ 22,669.53		
14 Real Time Contingency Reserve Deployment Failure	-	$ 4,137.11	-	$ 4,137.11	$ -	$ -		
15 Real Time Short Term Reserve Deployment Failure	-	$ -	-	$ -	$ -	$ -		
MISO ASM CHARGES	44,712	$ 606,821.92	44,712	$ 892,910.84	$ -	$ (286,088.92)		
x Net Congestion Amount	-	$ (119,931.61)	-	$ (119,931.61)	$ -	$ -		
y Net Loss Amount	-	$ 40,093.71	-	$ 40,093.71	$ -	$ -		
z Net Congestion and Loss Energy Offset	-	$ 79,837.90	-	$ 79,837.90	$ -	$ -		
SUBTOTAL	-	$ -	-	$ -	$ -	$ -		
Total MISO ASM CHARGES	**44,712**	**$ 606,821.92**	**44,712**	**$ 892,910.84**	**$ -**	**$ (286,088.92)**		

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

March 2022	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (148,111.43)	-	$ (93,703.31)	$ -	$ (54,408.12)		
2 Day-Ahead Spinning Reserve Amount	-	$ (208,493.43)	-	$ (89,018.86)	$ -	$ (119,474.57)		
3 Day-Ahead Supplemental Reserve	-	$ (28,793.69)	-	$ (11,517.78)	$ -	$ (17,275.91)		
4 Day-Ahead Short Term Reserve Amount	-	$ (77,469.70)	-	$ (32,173.99)	$ -	$ (45,295.71)		
5 Real-Time Regulation Amount (See Note 1)	-	$ (36,658.24)	-	$ (36,658.24)	$ -	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (52,177.28)	-	$ (52,177.28)	$ -	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 1,599.39	-	$ 1,599.39	$ -	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ (2,065.95)	-	$ (2,065.95)	$ -	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(606)	$ 27,113.24	(606)	$ 27,113.24	$ -	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	30,072	$ 3,021,489.48	30,072	$ 3,021,489.48	$ -	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ 13,224.60	-	$ 4,791.21	$ -	$ 8,433.39		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 156,330.53	-	$ 156,330.53	$ -	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 154,236.36	-	$ 154,236.36	$ -	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 10,618.75	-	$ 10,618.75	$ -	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 47,025.85	-	$ 47,025.85	$ -	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 45,880.87	-	$ 34,837.27	$ -	$ 11,043.60		
14 Real Time Contingency Reserve Deployment Failure	-	$ -	-	$ 440.23	$ -	$ (440.23)		
15 Real Time Short Term Reserve Deployment Failure	-	$ -	-	$ -	$ -	$ -		
MISO ASM CHARGES	29,466	$ 2,923,749.35	29,466	$ 3,141,166.90	$ -	$ (217,417.55)		
x Net Congestion Amount	-	$ (244,425.15)	-	$ (244,425.15)	$ -	$ -		
y Net Loss Amount	-	$ (38,366.21)	-	$ (38,366.21)	$ -	$ -		
z Net Congestion and Loss Energy Offset	-	$ 282,791.36	-	$ 282,791.36	$ -	$ -		
SUBTOTAL	-	$ -	-	$ -	$ -	$ -		
Total MISO ASM CHARGES	**29,466**	**$ 2,923,749.35**	**29,466**	**$ 3,141,166.90**	**$ -**	**$ (217,417.55)**		

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

April 2022	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (248,040.09)	-	$ (144,491.03)	$ -	$ (103,549.06)		
2 Day-Ahead Spinning Reserve Amount	-	$ (369,817.64)	-	$ 66,540.05	$ -	$ (436,357.69)		
3 Day-Ahead Supplemental Reserve	-	$ (30,446.14)	-	$ (17,875.81)	$ -	$ (12,570.33)		
4 Day-Ahead Short Term Reserve Amount	-	$ (132,586.95)	-	$ 30,978.41	$ -	$ (163,565.36)		
5 Real-Time Regulation Amount (See Note 1)	-	$ (27,791.44)	-	$ (27,791.44)	$ -	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (230,742.82)	-	$ (230,742.82)	$ -	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 4,860.88	-	$ 4,860.88	$ -	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ (19,225.54)	-	$ (19,225.54)	$ -	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(5,167)	$ 85,273.13	(5,167)	$ 85,273.13	$ -	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	93,984	$ 1,490,018.60	93,984	$ 1,490,018.60	$ -	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ (18,847.42)	-	$ (6,201.70)	$ -	$ (12,645.72)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 224,754.00	-	$ 224,754.00	$ -	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 231,564.74	-	$ 231,564.74	$ -	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 22,856.56	-	$ 22,856.56	$ -	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 144,746.18	-	$ 144,746.18	$ -	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 37,534.66	-	$ 13,982.44	$ -	$ 23,552.22		
14 Real Time Contingency Reserve Deployment Failure	-	$ -	-	$ -	$ -	$ -		
15 Real Time Short Term Reserve Deployment Failure	-	$ 7,028.70	-	$ 984.90	$ -	$ 6,043.80		
MISO ASM CHARGES	88,816	$ 1,171,139.41	88,816	$ 1,870,231.55	$ -	$ (699,092.14)		
x Net Congestion Amount	-	$ 562,216.26	-	$ 562,216.26	$ -	$ -		
y Net Loss Amount	-	$ 214,348.89	-	$ 214,348.89	$ -	$ -		
z Net Congestion and Loss Energy Offset	-	$ (776,565.15)	-	$ (776,565.15)	$ -	$ -		
SUBTOTAL	-	$ -	-	$ -	$ -	$ -		
Total MISO ASM CHARGES	**88,816**	**$ 1,171,139.41**	**88,816**	**$ 1,870,231.55**	**$ -**	**$ (699,092.14)**		

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

May 2022	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (270,816.39)	-	$ (81,827.54)	$ -	$ (188,988.85)		
2 Day-Ahead Spinning Reserve Amount	-	$ (343,047.30)	-	$ 16,986.08	$ -	$ (360,033.38)		
3 Day-Ahead Supplemental Reserve	-	$ (43,170.88)	-	$ (2,593.05)	$ -	$ (40,577.83)		
4 Day-Ahead Short Term Reserve Amount	-	$ (67,574.84)	-	$ 14,984.14	$ -	$ (82,558.98)		
5 Real-Time Regulation Amount (See Note 1)	-	$ (85,259.62)	-	$ (85,259.62)	$ -	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (141,338.91)	-	$ (141,338.91)	$ -	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ (6,545.99)	-	$ (6,545.99)	$ -	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ (8,097.84)	-	$ (8,097.84)	$ -	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(3,720)	$ 128,285.38	(3,720)	$ 128,285.38	$ -	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	214,696	$ 488,497.91	214,696	$ 488,497.91	$ -	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ (30,228.85)	-	$ (7,981.06)	$ -	$ (22,247.79)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 241,752.01	-	$ 241,752.01	$ -	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 232,232.45	-	$ 232,232.45	$ -	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 17,828.01	-	$ 17,828.01	$ -	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 53,340.59	-	$ 53,340.59	$ -	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 35,864.85	-	$ 20,677.28	$ -	$ 15,187.57		
14 Real Time Contingency Reserve Deployment Failure	-	$ -	-	$ -	$ -	$ -		
15 Real Time Short Term Reserve Deployment Failure	-	$ 23.12	-	$ 23.12	$ -	$ -		
MISO ASM CHARGES	210,976	$ 201,743.70	210,976	$ 880,962.96	$ -	$ (679,219.26)		
x Net Congestion Amount	-	$ (3,770,861.91)	-	$ (3,770,861.91)	$ -	$ -		
y Net Loss Amount	-	$ (427,757.52)	-	$ (427,757.52)	$ -	$ -		
z Net Congestion and Loss Energy Offset	-	$ 4,198,619.43	-	$ 4,198,619.43	$ -	$ -		
SUBTOTAL	-	$ -	-	$ -	$ -	$ -		
Total MISO ASM CHARGES	**210,976**	**$ 201,743.70**	**210,976**	**$ 880,962.96**	**$ -**	**$ (679,219.26)**		

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

Northern States Power Company

Docket No. E002/AA-21-295

True-up Report

Part B, Attachment 9

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

June 2022	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (387,629.86)	-	$ (71,560.74)	$ -	$ (316,069.12)		
2 Day-Ahead Spinning Reserve Amount	-	$ (363,273.44)	-	$ (61,754.38)	$ -	$ (301,519.06)		
3 Day-Ahead Supplemental Reserve	-	$ (54,393.60)	-	$ (9,130.79)	$ -	$ (45,262.81)		
4 Day-Ahead Short Term Reserve Amount	-	$ (79,805.32)	-	$ (3,706.38)	$ -	$ (76,098.94)		
5 Real-Time Regulation Amount (See Note 1)	-	$ (128,522.22)	-	$ (128,522.22)	$ -	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (92,491.91)	-	$ (92,491.91)	$ -	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ (6,035.22)	-	$ (6,035.22)	$ -	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ (849.36)	-	$ (849.36)	$ -	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(2,256)	$ (16,543.91)	(2,256)	$ (16,543.91)	$ -	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	250,041	$ 6,449,303.01	250,041	$ 6,449,303.01	$ -	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ (14,138.33)	-	$ 12,667.99	$ -	$ (26,806.32)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 173,210.40	-	$ 173,210.40	$ -	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 179,382.02	-	$ 179,382.02	$ -	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 45,537.08	-	$ 45,537.08	$ -	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 84,640.74	-	$ 84,640.74	$ -	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 90,976.31	-	$ 55,779.61	$ -	$ 35,196.70		
14 Real Time Contingency Reserve Deployment Failure	-	$ -	-	$ -	$ -	$ -		
15 Real Time Short Term Reserve Deployment Failure	-	$ 18.75	-	$ -	$ -	$ 18.75		
MISO ASM CHARGES	247,785	$ 5,879,385.14	247,785	$ 6,609,925.94	$ -	$ (730,540.80)		
x Net Congestion Amount	-	$ (1,317,934.47)	-	$ (1,317,934.47)	$ -	$ -		
y Net Loss Amount	-	$ 26,644.58	-	$ 26,644.58	$ -	$ -		
z Net Congestion and Loss Energy Offset	-	$ 1,291,289.89	-	$ 1,291,289.89	$ -	$ -		
SUBTOTAL	-	$ -	-	$ -	$ -	$ -		
Total MISO ASM CHARGES	**247,785**	**$ 5,879,385.14**	**247,785**	**$ 6,609,925.94**	**$ -**	**$ (730,540.80)**		

x No longer reported in 7b, 8b

y No longer reported in 7c, 8c

z No longer used to offset the MISO billed energy amount in 7a, 8a

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

July 2022	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (385,722.15)	-	$ (92,831.27)	$ -	$ (292,890.88)		
2 Day-Ahead Spinning Reserve Amount	-	$ (125,315.68)	-	$ 7,740.74	$ -	$ (133,056.42)		
3 Day-Ahead Supplemental Reserve	-	$ (95,667.64)	-	$ (70,403.19)	$ -	$ (25,264.45)		
4 Day-Ahead Short Term Reserve Amount	-	$ (34,939.41)	-	$ (18,405.28)	$ -	$ (16,534.13)		
5 Real-Time Regulation Amount (See Note 1)	-	$ (97,816.95)	-	$ (97,816.95)	$ -	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (74,668.16)	-	$ (74,668.16)	$ -	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 105,789.17	-	$ 105,789.17	$ -	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ 1,197.56	-	$ 1,197.56	$ -	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(3,634)	$ 15,118.64	(3,634)	$ 15,118.64	$ -	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	185,719	$ 10,120,815.97	185,719	$ 10,120,815.97	$ -	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ 123,182.49	-	$ 40,082.71	$ -	$ 83,099.78		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 179,333.48	-	$ 179,333.48	$ -	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 61,170.38	-	$ 61,170.38	$ -	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 158,383.18	-	$ 158,383.18	$ -	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 58,735.45	-	$ 58,735.45	$ -	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 83,037.63	-	$ 24,353.27	$ -	$ 58,684.36		
14 Real Time Contingency Reserve Deployment Failure	-	$ 3,929.16	-	$ 3,929.16	$ -	$ -		
15 Real Time Short Term Reserve Deployment Failure	-	$ -	-	$ -	$ -	$ -		
MISO ASM CHARGES	182,085	$ 10,096,563.12	182,085	$ 10,422,524.86	$ -	$ (325,961.74)		
x Net Congestion Amount	-	$ (1,049,875.29)	-	$ (1,049,875.29)	$ -	$ -		
y Net Loss Amount	-	$ (475,919.80)	-	$ (475,919.80)	$ -	$ -		
z Net Congestion and Loss Energy Offset	-	$ 1,525,795.09	-	$ 1,525,795.09	$ -	$ -		
SUBTOTAL	-	$ -	-	$ -	$ -	$ -		
Total MISO ASM CHARGES	**182,085**	**$ 10,096,563.12**	**182,085**	**$ 10,422,524.86**	**$ -**	**$ (325,961.74)**		

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

Northern States Power Company

Docket No. E002/AA-21-295

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

True-up Report

Part B, Attachment 9

August 2022	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (253,746.35)	-	$ 5,396.22	$ -	$ (259,142.57)		
2 Day-Ahead Spinning Reserve Amount	-	$ (155,482.31)	-	$ 94,117.25	$ -	$ (249,599.56)		
3 Day-Ahead Supplemental Reserve	-	$ (39,161.50)	-	$ (57,511.83)	$ -	$ 18,350.33		
4 Day-Ahead Short Term Reserve Amount	-	$ (24,990.47)	-	$ (10,382.54)	$ -	$ (14,607.93)		
5 Real-Time Regulation Amount (See Note 1)	-	$ (225,143.66)	-	$ (225,143.66)	$ -	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (102,140.69)	-	$ (102,140.69)	$ -	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 76,077.64	-	$ 76,077.64	$ -	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ (184.81)	-	$ (184.81)	$ -	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,362)	$ (42,689.47)	(1,362)	$ (42,689.47)	$ -	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	144,415	$ 7,408,023.66	144,415	$ 7,408,023.66	$ -	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ (13,172.62)	-	$ (20,415.81)	$ -	$ 7,243.19		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 162,246.14	-	$ 162,246.14	$ -	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 151,469.96	-	$ 151,469.96	$ -	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 5,635.85	-	$ 5,635.85	$ -	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 16,760.08	-	$ 16,760.08	$ -	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 99,463.36	-	$ 37,834.74	$ -	$ 61,628.62		
14 Real Time Contingency Reserve Deployment Failure	-	$ 211,246.65	-	$ 159,735.64	$ -	$ 51,511.01		
15 Real Time Short Term Reserve Deployment Failure	-	$ -	-	$ -	$ -	$ -		
MISO ASM CHARGES	143,053	$ 7,274,211.46	143,053	$ 7,658,828.37	$ -	$ (384,616.91)		
x Net Congestion Amount	-	$ (1,218,423.75)	-	$ (1,218,423.75)	$ -	$ -		
y Net Loss Amount	-	$ (313,577.95)	-	$ (313,577.95)	$ -	$ -		
z Net Congestion and Loss Energy Offset	-	$ 1,532,001.70	-	$ 1,532,001.70	$ -	$ -		
SUBTOTAL	-	$ -	-	$ -	$ -	$ -		
Total MISO ASM CHARGES	**143,053**	**$ 7,274,211.46**	**143,053**	**$ 7,658,828.37**	**$ -**	**$ (384,616.91)**		

x No longer reported in 7b, 8b

y No longer reported in 7c, 8c

z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

September 2022	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (165,160.75)	-	$ 12,133.91	$ -	$ (177,294.66)		
2 Day-Ahead Spinning Reserve Amount	-	$ (141,448.31)	-	$ (84,769.61)	$ -	$ (56,678.70)		
3 Day-Ahead Supplemental Reserve	-	$ (23,017.01)	-	$ (17,265.92)	$ -	$ (5,751.09)		
4 Day-Ahead Short Term Reserve Amount	-	$ (20,544.25)	-	$ 2,137.34	$ -	$ (22,681.59)		
5 Real-Time Regulation Amount (See Note 1)	-	$ (167,325.65)	-	$ (167,325.65)	$ -	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (10,003.08)	-	$ (10,003.08)	$ -	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 5,741.16	-	$ 5,741.16	$ -	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ 1,861.69	-	$ 1,861.69	$ -	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(2,074)	$ (58,986.13)	(2,074)	$ (58,986.13)	$ -	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	207,155	$ 9,564,632.50	207,155	$ 9,564,632.50	$ -	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ 16,716.55	-	$ 7,368.25	$ -	$ 9,348.30		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 167,417.21	-	$ 167,417.21	$ -	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 84,635.27	-	$ 84,635.27	$ -	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 29,732.70	-	$ 29,732.70	$ -	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 53,152.26	-	$ 53,152.26	$ -	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 73,971.85	-	$ 30,824.05	$ -	$ 43,147.80		
14 Real Time Contingency Reserve Deployment Failure	-	$ -	-	$ -	$ -	$ -		
15 Real Time Short Term Reserve Deployment Failure	-	$ 82.94	-	$ 76.47	$ -	$ 6.47		
MISO ASM CHARGES	205,081	$ 9,411,458.95	205,081	$ 9,621,362.42	$ -	$ (209,903.47)		
x Net Congestion Amount	-	$ (129,250.24)	-	$ (129,250.24)	$ -	$ -		
y Net Loss Amount	-	$ (68,544.08)	-	$ (68,544.08)	$ -	$ -		
z Net Congestion and Loss Energy Offset	-	$ 197,794.32	-	$ 197,794.32	$ -	$ -		
SUBTOTAL	-	$ -	-	$ -	$ -	$ -		
Total MISO ASM CHARGES	**205,081**	**$ 9,411,458.95**	**205,081**	**$ 9,621,362.42**	**$ -**	**$ (209,903.47)**		

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

October 2022	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (169,858.02)	-	$ (72,803.17)	$ -	$ (97,054.85)		
2 Day-Ahead Spinning Reserve Amount	-	$ (155,734.38)	-	$ (50,830.73)	$ -	$ (104,903.65)		
3 Day-Ahead Supplemental Reserve	-	$ (15,467.08)	-	$ (6,466.49)	$ -	$ (9,000.59)		
4 Day-Ahead Short Term Reserve Amount	-	$ (22,217.22)	-	$ (7,935.91)	$ -	$ (14,281.31)		
5 Real-Time Regulation Amount (See Note 1)	-	$ (40,046.19)	-	$ (40,046.19)	$ -	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (12,359.17)	-	$ (12,359.17)	$ -	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 2,601.55	-	$ 2,601.55	$ -	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ 3,268.49	-	$ 3,268.49	$ -	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(5,925)	$ 119,747.19	(5,925)	$ 119,747.19	$ -	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	232,601	$ 6,900,860.11	232,601	$ 6,900,860.11	$ -	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ 13,454.16	-	$ 5,979.78	$ -	$ 7,474.38		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 168,580.43	-	$ 168,580.43	$ -	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 178,758.16	-	$ 178,758.16	$ -	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 22,145.93	-	$ 22,145.93	$ -	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 26,523.16	-	$ 26,523.16	$ -	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 61,455.34	-	$ 38,319.17	$ -	$ 23,136.17		
14 Real Time Contingency Reserve Deployment Failure	-	$ -	-	$ -	$ -	$ -		
15 Real Time Short Term Reserve Deployment Failure	-	$ 5,852.90	-	$ 4,189.63	$ -	$ 1,663.27		
MISO ASM CHARGES	226,676	$ 7,087,565.36	226,676	$ 7,280,531.94	$ -	$ (192,966.58)		
x Net Congestion Amount	-	$ (337,782.81)	-	$ (337,782.81)	$ -	$ -		
y Net Loss Amount	-	$ 53,067.95	-	$ 53,067.95	$ -	$ -		
z Net Congestion and Loss Energy Offset	-	$ 284,714.86	-	$ 284,714.86	$ -	$ -		
SUBTOTAL	-	$ -	-	$ -	$ -	$ -		
Total MISO ASM CHARGES	**226,676**	**$ 7,087,565.36**	**226,676**	**$ 7,280,531.94**	**$ -**	**$ (192,966.58)**		

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

November 2022	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (152,308.53)	-	$ (79,693.67)	$ -	$ (72,614.86)		
2 Day-Ahead Spinning Reserve Amount	-	$ (290,932.16)	-	$ (48,896.01)	$ -	$ (242,036.15)		
3 Day-Ahead Supplemental Reserve	-	$ (15,535.56)	-	$ (10,115.48)	$ -	$ (5,420.08)		
4 Day-Ahead Short Term Reserve Amount	-	$ (57,263.97)	-	$ 13,738.70	$ -	$ (71,002.67)		
5 Real-Time Regulation Amount (See Note 1)	-	$ (71,418.55)	-	$ (71,418.55)	$ -	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (84,335.71)	-	$ (84,335.71)	$ -	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 13,463.47	-	$ 13,463.47	$ -	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ (3,642.98)	-	$ (3,642.98)	$ -	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,639)	$ 17,855.08	(1,639)	$ 17,855.08	$ -	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	257,360	$ 5,644,725.13	257,360	$ 5,644,725.13	$ -	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ (6,290.68)	-	$ (3,668.89)	$ -	$ (2,621.79)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 158,879.29	-	$ 158,879.29	$ -	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 224,083.74	-	$ 224,083.74	$ -	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 7,150.09	-	$ 7,150.09	$ -	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 80,409.22	-	$ 80,409.22	$ -	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 37,749.09	-	$ 24,399.35	$ -	$ 13,349.74		
14 Real Time Contingency Reserve Deployment Failure	-	$ 125.90	-	$ 125.90	$ -	$ -		
15 Real Time Short Term Reserve Deployment Failure	-	$ 1,910.03	-	$ 1,765.72	$ -	$ 144.31		
MISO ASM CHARGES	255,721	$ 5,504,622.90	255,721	$ 5,884,824.40	$ -	$ (380,201.50)		
x Net Congestion Amount	-	$ (939,845.33)	-	$ (939,845.33)	$ -	$ -		
y Net Loss Amount	-	$ (92,186.09)	-	$ (92,186.09)	$ -	$ -		
z Net Congestion and Loss Energy Offset	-	$ 1,032,031.42	-	$ 1,032,031.42	$ -	$ -		
SUBTOTAL	-	$ -	-	$ -	$ -	$ -		
Total MISO ASM CHARGES	**255,721**	**$ 5,504,622.90**	**255,721**	**$ 5,884,824.40**	**$ -**	**$ (380,201.50)**		

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

December 2022	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (249,550.24)	-	$ 287,146.11	$ -	$ (536,696.35)		
2 Day-Ahead Spinning Reserve Amount	-	$ (257,324.17)	-	$ 1,015,675.83	$ -	$ (1,273,000.00)		
3 Day-Ahead Supplemental Reserve	-	$ (99,883.02)	-	$ (3,025.52)	$ -	$ (96,857.50)		
4 Day-Ahead Short Term Reserve Amount	-	$ (272,405.85)	-	$ 705,880.43	$ -	$ (978,286.28)		
5 Real-Time Regulation Amount (See Note 1)	-	$ (576,602.84)	-	$ (576,602.84)	$ -	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (1,379,113.30)	-	$ (1,379,113.30)	$ -	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 135,299.24	-	$ 135,299.24	$ -	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ (629,124.22)	-	$ (629,124.22)	$ -	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,447)	$ (10,754.75)	(1,447)	$ (10,754.75)	$ -	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	(217,245)	$ (10,707,366.47)	(217,245)	$ (10,707,366.47)	$ -	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ 39,991.15	-	$ (10,942.90)	$ -	$ 50,934.05		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 171,280.59	-	$ 171,280.59	$ -	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 183,323.99	-	$ 183,323.99	$ -	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ (9,191.33)	-	$ (9,191.33)	$ -	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 657,892.39	-	$ 657,892.39	$ -	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 284,716.90	-	$ 236,527.62	$ -	$ 48,189.28		
14 Real Time Contingency Reserve Deployment Failure	-	$ 83,197.61	-	$ 59,086.06	$ -	$ 24,111.55		
15 Real Time Short Term Reserve Deployment Failure	-	$ 2,440.50	-	$ -	$ -	$ 2,440.50		
MISO ASM CHARGES	(218,692)	$ (12,633,173.82)	(218,692)	$ (9,874,009.07)	$ -	$ (2,759,164.75)		
x Net Congestion Amount	-	$ (1,132,268.97)	-	$ (1,132,268.97)	$ -	$ -		
y Net Loss Amount	-	$ 101,965.16	-	$ 101,965.16	$ -	$ -		
z Net Congestion and Loss Energy Offset	-	$ 1,030,303.81	-	$ 1,030,303.81	$ -	$ -		
SUBTOTAL	-	$ -	-	$ -	$ -	$ -		
Total MISO ASM CHARGES	**(218,692)**	**$ (12,633,173.82)**	**(218,692)**	**$ (9,874,009.07)**	**$ -**	**$ (2,759,164.75)**		

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

January - December 2022	NET INVOICE		RETAIL		INTERSYSTEM - ASSET BASED		INTERSYSTEM - NON-ASSET BASED	
Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**
Procurement Charges								
1 Day-Ahead Regulation Amount	-	$ (2,734,110.97)	-	$ (380,926.95)	$ -	$ (2,353,184.02)		
2 Day-Ahead Spinning Reserve Amount	-	$ (2,768,401.62)	-	$ 815,086.52	$ -	$ (3,583,488.14)		
3 Day-Ahead Supplemental Reserve	-	$ (473,671.62)	-	$ (224,356.72)	$ -	$ (249,314.90)		
4 Day-Ahead Short Term Reserve Amount	-	$ (895,373.37)	-	$ 775,050.73	$ -	$ (1,670,424.10)		
5 Real-Time Regulation Amount (See Note 1)	-	$ (1,710,242.13)	-	$ (1,710,242.13)	$ -	$ -		
6 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (2,291,669.03)	-	$ (2,291,669.03)	$ -	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 340,567.63	-	$ 340,567.63	$ -	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ (682,558.16)	-	$ (682,558.16)	$ -	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(35,901)	$ 327,104.84	(35,901)	$ 327,104.84	$ -	$ -		
7b Real Time Excessive Energy Congestion								
7c Real Time Excessive Energy Loss								
8a Real Time Non Excessive Energy Amount	1,789,410	$ 48,243,873.90	1,789,410	$ 48,243,873.90	$ -	$ -		
8b Real Time Non Excessive Energy Congestion								
8c Real Time Non Excessive Energy Loss								
9 Real Time Net Regulation Adjustment Amount	-	$ (1,791,750.46)	-	$ (1,906,202.70)	$ -	$ 114,452.24		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 2,093,995.60	-	$ 2,093,995.60	$ -	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 1,888,162.75	-	$ 1,888,162.75	$ -	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 344,881.17	-	$ 344,881.17	$ -	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 1,317,411.23	-	$ 1,317,411.23	$ -	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 939,620.54	-	$ 562,516.85	$ -	$ 377,103.69		
14 Real Time Contingency Reserve Deployment Failure	-	$ 302,636.43	-	$ 227,454.10	$ -	$ 75,182.33		
15 Real Time Short Term Reserve Deployment Failure	-	$ 17,628.64	-	$ 7,252.08	$ -	$ 10,376.56		
MISO ASM CHARGES	1,753,510	$ 42,468,105.37	1,753,510	$ 49,747,401.71	$ -	$ (7,279,296.34)		
x Net Congestion Amount	-	$ (8,909,536.88)	-	$ (8,909,536.88)	$ -	$ -		
y Net Loss Amount	-	$ (849,797.78)	-	$ (849,797.78)	$ -	$ -		
z Net Congestion and Loss Energy Offset	-	$ 9,759,334.66	-	$ 9,759,334.66	$ -	$ -		
SUBTOTAL	-	$ -	-	$ -	$ -	$ -		
Total MISO ASM CHARGES	**1,753,510**	**$ 42,468,105.37**	**1,753,510**	**$ 49,747,401.71**	**$ -**	**$ (7,279,296.34)**		

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	January 2022	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(1,427,993)	$ (12,048,683.12)	3,681,461	$ 152,643,358.52	(6,573,225)	$ (112,486,182.92)			1,463,772	$ (52,205,858.72)				
5a	Day Ahead Non Asset Energy	(108,457)	$ (3,461,887.80)	51	$ 1,474.08	(108,508)	$ (3,463,361.88)					-	$ 0.11	-	$ (0.22)
13a	Real Time Asset Energy	(42,506)	$ (1,824,038.66)	40,526	$ 1,641,851.81	(228,066)	$ 131,268.29			145,034	$ (3,597,158.76)				
22a	Real Time Non Asset Energy	(434)	$ (27,549.82)	1	$ 33.89	(435)	$ (27,583.71)					-	$ -	-	$ -
	SUBTOTAL	(1,579,390)	$ (17,362,159.40)	3,722,039	$ 154,286,718.30	(6,910,235)	$ (115,845,860.22)	-	$ -	1,608,806	$ (55,803,017.48)	-	$ 0.11	-	$ (0.22)
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (128,510.23)		$ 7,951.04		$ (136,461.27)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (2,111,968.97)		$ -		$ (2,111,968.97)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (2,240,479.20)		$ 7,951.04		$ (2,248,430.24)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 711,062.64		$ 594,248.62		$ -		$ 116,814.02				$ (0.05)		
19	Real Time Market Administration (Schedule 17)		$ 85,287.01		$ 73,906.66		$ -		$ 11,380.35				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 37,165.31		$ 37,165.31		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 110,058.67		$ 92,063.28		$ -		$ 17,995.39				$ -		
34	Real -Time Schedule 24 Allocation Amount		$ (97,747.55)		$ 3,675.95		$ -				$ (101,423.50)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 845,826.08		$ 801,059.82		$ -		$ 146,189.76		$ (101,423.50)		$ (0.05)		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ (70,510.32)		$ 132,567.93		$ (203,078.25)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (5,374,949.19)		$ 4,413,104.81		$ (9,788,054.00)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (303,409.00)		$ -		$ (303,409.00)								$ -
32	Financial Transmission Rights Yearly Allocation		$ (1,632,060.78)		$ -		$ (1,632,060.78)						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 1,658,342.83		$ 1,658,342.83		$ -								$ -
37	Financial Transmission Guarantee Uplift Amount		$ (1,508,569.95)		$ -		$ (1,508,569.95)						$ -		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (7,231,156.41)		$ 6,204,015.57		$ (13,435,171.98)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 126,443.72		$ 126,443.72				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (150,157.83)				$ (74,804.17)				$ (75,353.66)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 600,163.19		$ 600,163.19				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (601,631.91)				$ (380,695.69)				$ (220,936.22)				
43	Real Time Price Volatility Make Whole Payment		$ (118,371.51)		$ -		($89,484.26)				$ (28,887.25)				
	SUBTOTAL		$ (143,554.34)		$ 726,606.91		$ (544,984.12)		$ -		$ (325,177.13)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 203,470.82		$ 404,763.88		$ (114,745.40)				$ (86,547.66)		$ 41.75		
21	Real Time Net Inadvertent Distribution		$ (50,816.62)		$ 93,418.93		$ (144,235.55)						$ 150.67		$ (132.52)
23	Real Time Revenue Neutrality Uplift Amount		$ 501,103.70		$ 1,182,675.29		$ (681,571.59)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 653,757.90		$ 1,680,858.10		$ (940,552.54)		$ -		$ (86,547.66)		$ 192.42		$ (132.52)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 6,409,766.32		$ 6,546,688.64		$ (136,922.32)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (6,456,472.05)		$ 127,673.70		$ (6,563,999.28)				$ (20,146.47)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (235,898.25)		$ -		$ (235,898.25)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 76,750.07		$ 76,750.07		$ -								
	SUBTOTAL		$ (205,853.91)		$ 6,751,112.41		$ (6,936,819.85)		$ -		$ (20,146.47)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (101,126.93)		$ 280.37		$ (101,407.30)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (9,476.71)		$ 225.38		$ (9,702.09)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered														
18	Real Time Congestion Rebate on Carve Out Grandfathered														
	SUBTOTAL	-	$ (110,603.64)	-	$ 505.75	-	$ (111,109.39)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(1,579,390)	$ (25,794,222.92)	3,722,039	$ 170,458,827.90	(6,910,235)	$ (140,062,928.34)	-	$ 146,189.76	1,608,806	$ (56,336,312.24)	-	$ 192.48	-	$ (132.74)
x	Net Congestion Amount		$ 26,255,239.14		$ 26,255,239.14				$ -						
y	Net Loss Amount		$ 7,675,436.77		$ 7,675,436.77				$ -						
z	Net Congestion and Loss Energy Offset		$ (33,930,675.91)		$ (33,930,675.91)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,579,390)**	$ (25,794,222.92)	3,722,039	$ 170,458,827.90	(6,910,235)	$ (140,062,928.34)	-	$ 146,189.76	1,608,806	$ (56,336,312.24)	-	$ 192.48	-	$ (132.74)

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

February 2022		NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(1,009,166)	$ 763,947.10	3,253,321	$ 130,658,361.05	(3,122,000)	$ (92,304,006.68)			(1,140,487)	$ (37,590,407.27)				
5a	Day Ahead Non Asset Energy	(145,746)	$ (4,792,174.22)	5	$ 180.75	(145,751)	$ (4,792,354.97)					-	$ -	-	$ -
13a	Real Time Asset Energy	(8,714)	$ (342,714.09)	48,145	$ 1,877,712.58	86,135	$ 1,037,503.02			(142,994)	$ (3,257,929.69)				
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(1,163,626)	$ (4,370,941.21)	3,301,472	$ 132,536,254.38	(3,181,616)	$ (96,058,858.63)	-	$ -	(1,283,481)	$ (40,848,336.96)	-	$ -	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (14,768.65)		$ 5,458.05		$ (20,226.70)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (1,924,690.96)		$ -		$ (1,924,690.96)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,939,459.61)		$ 5,458.05		$ (1,944,917.66)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 430,348.28		$ 364,508.17		$ -		$ 65,840.11				$ -		
19	Real Time Market Administration (Schedule 17)		$ 43,748.04		$ 36,384.48		$ -		$ 7,363.56				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 19,663.25		$ 19,663.25		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 89,024.03		$ 75,688.87		$ -		$ 13,335.16				$ -		
34	Real -Time Schedule 24 Allocation Amount		$ (85,169.94)		$ 36,785.69		$ -				$ (121,955.63)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 497,613.66		$ 533,030.46		$ -		$ 86,538.83		$ (121,955.63)		$ -		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ 39,930.54		$ 67,592.77		$ (27,662.23)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (757,344.86)		$ 5,408,082.33		$ (6,165,427.19)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (229,135.70)		$ -		$ (229,135.70)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (79,517.69)		$ -		$ (79,517.69)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 76,952.41		$ 76,952.41		$ -						$ -		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (949,115.30)		$ 5,552,627.51		$ (6,501,742.81)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 107,151.16		$ 107,151.16				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (68,247.46)				$ (47,272.01)				$ (20,975.45)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 156,889.00		$ 156,889.00				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (315,933.84)				$ (142,287.06)				$ (173,646.78)				
43	Real Time Price Volatility Make Whole Payment		$ (146,032.92)		$ -		($109,497.73)				$ (36,535.19)				
	SUBTOTAL		$ (266,174.06)		$ 264,040.16		$ (299,056.80)		$ -		$ (231,157.42)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 285,483.67		$ 489,349.03		$ (121,505.49)				$ (82,359.87)		$ -		
21	Real Time Net Inadvertent Distribution		$ (17,940.82)		$ 180,207.60		$ (198,148.42)						$ 4.42		$ (9.58)
23	Real Time Revenue Neutrality Uplift Amount		$ 863,316.52		$ 1,371,390.46		$ (508,073.94)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 1,130,859.37		$ 2,040,947.09		$ (827,727.85)		$ -		$ (82,359.87)		$ 4.42		$ (9.58)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 6,409,766.32		$ 6,546,688.64		$ (136,922.32)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (6,456,472.05)		$ 127,673.70		$ (6,565,094.27)				$ (19,051.48)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (235,898.25)		$ -		$ (235,898.25)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 76,750.07		$ 76,750.07		$ -								
	SUBTOTAL		$ (205,853.91)		$ 6,751,112.41		$ (6,937,914.84)		$ -		$ (19,051.48)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (55,065.06)		$ 1,689.91		$ (56,754.97)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (4,790.91)		$ 659.13		$ (5,450.04)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered														
18	Real Time Congestion Rebate on Carve Out Grandfathered														
	SUBTOTAL	-	$ (59,855.97)	-	$ 2,349.04	-	$ (62,205.01)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(1,163,626)	$ (6,162,927.03)	3,301,472	$ 147,685,819.10	(3,181,616)	$ (112,632,423.60)	-	$ 86,538.83	(1,283,481)	$ (41,302,861.36)	-	$ 4.42	-	$ (9.58)
x	Net Congestion Amount		$ 23,060,536.66		$ 23,060,536.66				$ -						
y	Net Loss Amount		$ 6,702,937.45		$ 6,702,937.45				$ -						
z	Net Congestion and Loss Energy Offset		$ (29,763,474.11)		$ (29,763,474.11)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,163,626)**	$ (6,162,927.03)	3,301,472	$ 147,685,819.10	(3,181,616)	$ (112,632,423.60)	-	$ 86,538.83	(1,283,481)	$ (41,302,861.36)	-	$ 4.42	-	$ (9.58)

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

March 2022		NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(688,078)	$ 10,642,698.82	3,248,180	$ 109,560,127.02	(2,977,155)	$ (74,399,549.11)			(959,103)	$ (24,517,879.09)				
5a	Day Ahead Non Asset Energy	(188,150)	$ (5,015,717.56)	-	$ 0.30	(188,150)	$ (5,015,717.86)					-	$ -	-	$ -
13a	Real Time Asset Energy	(27,224)	$ (830,415.07)	49,568	$ 1,711,615.10	43,526	$ (830,604.26)			(120,318)	$ (1,711,425.91)				
22a	Real Time Non Asset Energy	505	$ 8,607.48	505	$ 8,607.53	-	$ (0.05)					-	$ -	-	$ -
	SUBTOTAL	(902,947)	$ 4,805,173.67	3,298,253	$ 111,280,349.95	(3,121,779)	$ (80,245,871.28)	-	$ -	(1,079,421)	$ (26,229,305.00)	-	$ -	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 13,298.62		$ 6,184.62		$ 7,114.00								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (1,485,293.66)		$ -		$ (1,485,293.66)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,471,995.04)		$ 6,184.62		$ (1,478,179.66)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 691,220.56		$ 603,898.66		$ -		$ 87,321.90				$ -		
19	Real Time Market Administration (Schedule 17)		$ 66,963.90		$ 53,953.27		$ -		$ 13,010.63				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 25,703.40		$ 25,703.40		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 95,844.07		$ 83,506.61		$ -		$ 12,337.46				$ -		
34	Real -Time Schedule 24 Allocation Amount		$ (92,642.80)		$ (20,489.10)		$ -				$ (72,153.70)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 787,089.13		$ 746,572.84		$ -		$ 112,669.99		$ (72,153.70)		$ -		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ (4,921.28)		$ (1,463.86)		$ (3,457.42)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (2,678,842.85)		$ 3,182,604.33		$ (5,861,447.18)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (135,623.14)		$ -		$ (135,623.14)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 110,840.68		$ 110,840.68		$ -								$ -
37	Financial Transmission Guarantee Uplift Amount		$ (124,687.92)		$ -		$ (124,687.92)						$ -		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (2,833,234.51)		$ 3,291,981.15		$ (6,125,215.66)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 105,689.24		$ 105,689.24				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (105,604.28)				$ (40,919.92)				$ (64,684.36)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 120,827.58		$ 120,827.58				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (58,819.54)				$ (21,083.67)				$ (37,735.87)				
43	Real Time Price Volatility Make Whole Payment		$ (99,059.44)		$ -		($63,327.83)				$ (35,731.61)				
	SUBTOTAL		$ (36,966.44)		$ 226,516.82		$ (125,331.42)		$ -		$ (138,151.84)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 154,633.85		$ 356,911.06		$ (119,917.34)				$ (82,359.87)		$ -		
21	Real Time Net Inadvertent Distribution		$ (15,018.40)		$ 46,239.23		$ (61,257.63)						$ 2.98		$ (1.73)
23	Real Time Revenue Neutrality Uplift Amount		$ 1,002,811.60		$ 1,411,840.21		$ (409,028.61)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 1,142,427.05		$ 1,814,990.50		$ (590,203.58)		$ -		$ (82,359.87)		$ 2.98		$ (1.73)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 4,769,796.97		$ 4,906,441.23		$ (136,644.26)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (4,790,198.14)		$ 135,433.04		$ (4,896,280.46)				$ (29,350.72)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (176,339.19)		$ -		$ (176,339.19)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 168,443.44		$ 168,443.44		$ -								
	SUBTOTAL		$ (28,296.92)		$ 5,210,317.71		$ (5,209,263.91)		$ -		$ (29,350.72)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 9,402.76		$ 12,008.04		$ (2,605.28)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (5,765.73)		$ 419.73		$ (6,185.46)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered														
18	Real Time Congestion Rebate on Carve Out Grandfathered														
	SUBTOTAL	-	$ 3,637.03	-	$ 12,427.77	-	$ (8,790.74)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(902,947)	$ 2,367,833.97	3,298,253	$ 122,589,341.36	(3,121,779)	$ (93,782,856.25)	-	$ 112,669.99	(1,079,421)	$ (26,551,321.13)	-	$ 2.98	-	$ (1.73)
x	Net Congestion Amount		$ 18,551,625.54		$ 18,551,625.54				$ -						
y	Net Loss Amount		$ 5,559,815.11		$ 5,559,815.11				$ -						
z	Net Congestion and Loss Energy Offset		$ (24,111,440.65)		$ (24,111,440.65)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(902,947)**	$ 2,367,833.97	3,298,253	$ 122,589,341.36	(3,121,779)	$ (93,782,856.25)	-	$ 112,669.99	(1,079,421)	$ (26,551,321.13)	-	$ 2.98	-	$ (1.73)

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

April 2022		NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(781,196)	$ 26,840,353.89	3,052,319	$ 136,052,197.73	(2,929,466)	$ (84,160,135.95)			(904,049)	$ (25,051,707.89)				
5a	Day Ahead Non Asset Energy	(185,607)	$ (6,709,923.85)	14	$ 892.20	(185,621)	$ (6,710,816.05)					-	$ -	-	$ -
13a	Real Time Asset Energy	22,665	$ 1,592,492.64	76,689	$ 3,539,682.54	41,794	$ 628,001.50			(95,817)	$ (2,575,191.40)				
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(944,138)	$ 21,722,922.68	3,129,022	$ 139,592,772.47	(3,073,294)	$ (90,242,950.50)	-	$ -	(999,866)	$ (27,626,899.29)	-	$ -	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 325.29		$ 1,951.73		$ (1,626.44)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (2,116,472.45)		$ -		$ (2,116,472.45)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (2,116,147.16)		$ 1,951.73		$ (2,118,098.89)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 647,141.10		$ 564,443.85		$ -		$ 82,697.25				$ -		
19	Real Time Market Administration (Schedule 17)		$ 70,334.10		$ 61,610.62		$ -		$ 8,723.48				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 32,244.43		$ 32,244.43		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 100,317.77		$ 87,478.61		$ -		$ 12,839.16				$ -		
34	Real -Time Schedule 24 Allocation Amount		$ (97,768.90)		$ 14,423.92		$ -				$ (112,192.82)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 752,268.50		$ 760,201.43		$ -		$ 104,259.89		$ (112,192.82)		$ -		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ (5,627.69)		$ 21,739.07		$ (27,366.76)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ 5,796.07		$ 9,924,677.60		$ (9,918,881.53)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (129,503.20)		$ -		$ (129,503.20)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 20,634.65		$ 20,634.65		$ -								$ -
37	Financial Transmission Guarantee Uplift Amount		$ (30,412.30)		$ -		$ (30,412.30)						$ -		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (139,112.47)		$ 9,967,051.32		$ (10,106,163.79)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 101,849.92		$ 101,849.92				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (334,089.26)				$ (151,257.18)				$ (182,832.08)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 198,664.47		$ 198,664.47				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (195,535.12)				$ (139,857.28)				$ (55,677.84)				
43	Real Time Price Volatility Make Whole Payment		$ (54,611.32)		$ -		($49,898.04)				$ (4,713.28)				
	SUBTOTAL		$ (283,721.31)		$ 300,514.39		$ (341,012.50)		$ -		$ (243,223.20)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 326,582.75		$ 529,260.63		$ (117,526.15)				$ (85,151.73)		$ -		
21	Real Time Net Inadvertent Distribution		$ 123,517.35		$ 623,216.54		$ (499,699.19)						$ -		$ -
23	Real Time Revenue Neutrality Uplift Amount		$ 2,626,802.92		$ 3,318,356.02		$ (691,553.10)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 3,076,903.02		$ 4,470,833.19		$ (1,308,778.44)		$ -		$ (85,151.73)		$ -		$ -
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 4,769,796.97		$ 4,906,441.23		$ (136,644.26)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (4,790,198.14)		$ 135,433.04		$ (4,895,217.58)				$ (30,413.60)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (176,339.19)		$ -		$ (176,339.19)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 168,443.44		$ 168,443.44		$ -								
	SUBTOTAL		$ (28,296.92)		$ 5,210,317.71		$ (5,208,201.03)		$ -		$ (30,413.60)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 5,627.69		$ 27,366.76		$ (21,739.07)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (325.29)		$ 1,626.44		$ (1,951.73)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered														
18	Real Time Congestion Rebate on Carve Out Grandfathered														
	SUBTOTAL	-	$ 5,302.40	-	$ 28,993.20	-	$ (23,690.80)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(944,138)	$ 22,990,118.74	3,129,022	$ 160,332,635.44	(3,073,294)	$ (109,348,895.95)	-	$ 104,259.89	(999,866)	$ (28,097,880.64)	-	$ -	-	$ -
x	Net Congestion Amount		$ 32,510,349.21		$ 32,510,349.21				$ -						
y	Net Loss Amount		$ 8,791,080.42		$ 8,791,080.42				$ -						
z	Net Congestion and Loss Energy Offset		$ (41,301,429.63)		$ (41,301,429.63)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(944,138)**	$ 22,990,118.74	3,129,022	$ 160,332,635.44	(3,073,294)	$ (109,348,895.95)	-	$ 104,259.89	(999,866)	$ (28,097,880.64)	-	$ -	-	$ -

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

Northern States Power Company
Electric Operations - State of Minnesota

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	May 2022	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(421,339)	$ 35,132,387.35	3,134,513	$ 165,981,034.56	(2,867,636)	$ (109,320,247.92)			(688,216)	$ (21,528,399.29)				
5a	Day Ahead Non Asset Energy	(272,362)	$ (14,244,691.53)	20	$ 1,061.31	(272,382)	$ (14,245,752.84)					-	$ -	-	$ -
13a	Real Time Asset Energy	(13,683)	$ (927,784.30)	60,705	$ 3,099,593.36	2,146	$ 323,186.29			(76,534)	$ (4,350,563.95)				
22a	Real Time Non Asset Energy	(700)	$ (69,450.50)	-	$ -	(700)	$ (69,450.50)					-	$ -	-	$ -
	SUBTOTAL	(708,084)	$ 19,890,461.02	3,195,238	$ 169,081,689.23	(3,138,572)	$ (123,312,264.97)	-	$ -	(764,750)	$ (25,878,963.24)	-	$ -	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (10.00)		$ 4,418.07		$ (4,428.07)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (1,334,309.42)		$ -		$ (1,334,309.42)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,334,319.42)		$ 4,418.07		$ (1,338,737.49)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 567,420.78		$ 510,875.46		$ -		$ 56,545.32				$ -		
19	Real Time Market Administration (Schedule 17)		$ 64,083.55		$ 58,002.77		$ -		$ 6,080.78				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 27,875.77		$ 27,875.77		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 89,822.96		$ 80,870.46		$ -		$ 8,952.50				$ -		
34	Real -Time Schedule 24 Allocation Amount		$ (94,671.11)		$ 17,266.27		$ -				$ (111,937.38)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 654,531.95		$ 694,890.73		$ -		$ 71,578.60		$ (111,937.38)		$ -		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ (40,521.96)		$ 14,950.14		$ (55,472.10)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (18,578,993.25)		$ 3,339,458.49		$ (21,918,451.74)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (681,472.03)		$ -		$ (681,472.03)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (696,075.01)		$ -		$ (696,075.01)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 655,956.21		$ 655,956.21		$ -						$ -		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (19,341,106.04)		$ 4,010,364.84		$ (23,351,470.88)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 230,106.64		$ 230,106.64				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (430,650.87)				$ (284,103.24)				$ (146,547.63)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 932,613.64		$ 932,613.64				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (1,036,631.34)				$ (435,351.53)				$ (601,279.81)				
43	Real Time Price Volatility Make Whole Payment		$ (211,772.06)		$ -		($177,449.92)				$ (34,322.14)				
	SUBTOTAL		$ (516,333.99)		$ 1,162,720.28		$ (896,904.69)		$ -		$ (782,149.58)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 538,053.60		$ 745,680.19		$ (122,474.86)				$ (85,151.73)		$ -		
21	Real Time Net Inadvertent Distribution		$ 2,349.43		$ 123,445.23		$ (121,095.80)						$ -		$ -
23	Real Time Revenue Neutrality Uplift Amount		$ 2,547,550.42		$ 3,123,064.09		$ (575,513.67)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 3,087,953.45		$ 3,992,189.51		$ (819,084.33)		$ -		$ (85,151.73)		$ -		$ -
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 4,769,796.97		$ 4,906,441.23		$ (136,644.26)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (4,790,198.14)		$ 135,433.04		$ (4,896,677.58)				$ (28,953.60)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (176,339.19)		$ -		$ (176,339.19)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 168,443.44		$ 168,443.44		$ -								
	SUBTOTAL		$ (28,296.92)		$ 5,210,317.71		$ (5,209,661.03)		$ -		$ (28,953.60)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 41,169.11		$ 55,472.10		$ (14,302.99)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 438.60		$ 4,428.07		$ (3,989.47)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered														
18	Real Time Congestion Rebate on Carve Out Grandfathered														
	SUBTOTAL	-	$ 41,607.71	-	$ 59,900.17	-	$ (18,292.46)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(708,084)	$ 2,454,497.76	3,195,238	$ 184,216,490.54	(3,138,572)	$ (154,946,415.85)	-	$ 71,578.60	(764,750)	$ (26,887,155.53)	-	$ -	-	$ -
x	Net Congestion Amount		$ 30,237,240.96		$ 30,237,240.96				$ -						
y	Net Loss Amount		$ 9,234,594.09		$ 9,234,594.09				$ -						
z	Net Congestion and Loss Energy Offset		$ (39,471,835.05)		$ (39,471,835.05)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(708,084)**	$ 2,454,497.76	3,195,238	$ 184,216,490.54	(3,138,572)	$ (154,946,415.85)	-	$ 71,578.60	(764,750)	$ (26,887,155.53)	-	$ -	-	$ -

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

Docket No. E002/AA-21-295
True-Up Report
Part B, Attachment 10

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

June 2022		NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(847,791)	$ 6,714,197.55	3,603,464	$ 227,859,854.87	(3,355,924)	$ (159,844,395.95)			(1,095,331)	$ (61,301,261.37)				
5a	Day Ahead Non Asset Energy	(280,391)	$ (16,080,197.29)	3,200	$ 229,231.56	(283,591)	$ (16,309,428.85)					5,200	$ 558,525.00	-	$ -
13a	Real Time Asset Energy	7,885	$ 1,204,863.08	69,538	$ 4,503,185.90	36,373	$ 729,238.79			(98,026)	$ (4,027,561.61)				
22a	Real Time Non Asset Energy	11	$ 1,191.15	11	$ 1,191.15	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(1,120,286)	$ (8,159,945.51)	3,676,213	$ 232,593,463.48	(3,603,142)	$ (175,424,586.01)	-	$ -	(1,193,357)	$ (65,328,822.98)	5,200	$ 558,525.00	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (10,665.66)		$ 624.26		$ (11,289.92)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (3,458,138.67)		$ -		$ (3,458,138.67)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (3,468,804.33)		$ 624.26		$ (3,469,428.59)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 606,767.34		$ 527,013.50		$ (232.96)		$ 79,986.80				$ 611.40		
19	Real Time Market Administration (Schedule 17)		$ 65,841.91		$ 58,837.36		$ -		$ 7,004.55				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 58,675.52		$ 58,675.52		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 84,192.42		$ 71,779.15		$ (35.84)		$ 12,449.11				$ 80.64		
34	Real -Time Schedule 24 Allocation Amount		$ (86,047.70)		$ 15,585.94		$ -				$ (101,633.64)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 729,429.49		$ 731,891.47		$ (268.80)		$ 99,440.46		$ (101,633.64)		$ 692.04		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ (46,820.41)		$ 23,743.21		$ (70,563.62)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (32,883,959.16)		$ 3,145,511.66		$ (36,029,470.82)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (322,124.90)		$ -		$ (322,124.90)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 522,681.87		$ 522,681.87		$ -								$ -
37	Financial Transmission Guarantee Uplift Amount		$ (478,145.35)		$ -		$ (478,145.35)						$ -		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (33,208,367.95)		$ 3,691,936.74		$ (36,900,304.69)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 211,870.31		$ 211,870.31				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (806,552.26)				$ (475,855.32)				$ (330,696.94)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 1,011,288.59		$ 1,011,288.59				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (1,693,496.20)				$ (1,062,834.80)				$ (630,661.40)				
43	Real Time Price Volatility Make Whole Payment		$ (448,116.10)		$ -		($288,121.63)				$ (159,994.47)				
	SUBTOTAL		$ (1,725,005.66)		$ 1,223,158.90		$ (1,826,811.75)		$ -		$ (1,121,352.81)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ (11,992,732.56)		$ 13,255,295.64		$ (12,607,519.47)				$ (12,640,508.73)		$ 14.89		
21	Real Time Net Inadvertent Distribution		$ 146,142.15		$ 311,102.88		$ (164,960.73)						$ 251.73		$ (74.47)
23	Real Time Revenue Neutrality Uplift Amount		$ 1,088,940.74		$ 2,086,123.73		$ (997,182.99)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ (10,757,649.67)		$ 15,652,522.25		$ (13,769,663.19)		$ -		$ (12,640,508.73)		$ 266.62		$ (74.47)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 14,246,626.37		$ 14,397,722.96		$ (151,096.59)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (14,250,985.44)		$ 109,462.99		$ (14,362,404.47)				$ 1,956.04				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (605,336.30)		$ -		$ (605,336.30)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 97,656.73		$ 97,656.73		$ -								
	SUBTOTAL		$ (512,038.64)		$ 14,604,842.68		$ (15,118,837.36)		$ -		$ 1,956.04		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 48,099.32		$ 70,563.62		$ (22,464.30)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 10,950.52		$ 11,289.92		$ (339.40)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered														
18	Real Time Congestion Rebate on Carve Out Grandfathered														
	SUBTOTAL	-	$ 59,049.84	-	$ 81,853.54	-	$ (22,803.70)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(1,120,286)	$ (57,043,332.43)	3,676,213	$ 268,580,293.32	(3,603,142)	$ (246,532,704.09)	-	$ 99,440.46	(1,193,357)	$ (79,190,362.12)	5,200	$ 559,483.66	-	$ (74.47)
x	Net Congestion Amount		$ 39,615,079.91		$ 39,615,079.91				$ -						
y	Net Loss Amount		$ 11,464,034.83		$ 11,464,034.83				$ -						
z	Net Congestion and Loss Energy Offset		$ (51,079,114.74)		$ (51,079,114.74)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,120,286)**	$ (57,043,332.43)	3,676,213	$ 268,580,293.32	(3,603,142)	$ (246,532,704.09)	-	$ 99,440.46	(1,193,357)	$ (79,190,362.12)	5,200	$ 559,483.66	-	$ (74.47)

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

Northern States Power Company
Electric Operations - State of Minnesota

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	July 2022	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(853,892)	$ (13,143,791.78)	4,015,479	$ 260,477,674.71	(3,793,913)	$ (208,951,957.25)			(1,075,459)	$ (64,669,509.24)				
5a	Day Ahead Non Asset Energy	(276,003)	$ (17,551,896.89)	-	$ 0.36	(276,003)	$ (17,551,897.25)					8,000	$ 585,587.75	-	$ -
13a	Real Time Asset Energy	(50,518)	$ (3,706,598.24)	52,439	$ 3,607,752.61	(7,780)	$ (2,634,946.92)			(95,177)	$ (4,679,403.93)				
22a	Real Time Non Asset Energy	(52)	$ (10,925.15)	548	$ 45,987.49	(600)	$ (56,912.64)					-	$ -	-	$ -
	SUBTOTAL	(1,180,466)	$ (34,413,212.06)	4,068,466	$ 264,131,415.17	(4,078,296)	$ (229,195,714.06)	-	$ -	(1,170,636)	$ (69,348,913.17)	8,000	$ 585,587.75	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (6,928.60)		$ 960.35		$ (7,888.95)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (3,941,304.02)		$ -		$ (3,941,304.02)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (3,948,232.62)		$ 960.35		$ (3,949,192.97)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 760,965.07		$ 671,719.58		$ -		$ 89,245.49				$ 665.40		
19	Real Time Market Administration (Schedule 17)		$ 66,574.73		$ 58,646.62		$ -		$ 7,928.11				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 10,560.47		$ 10,560.47		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 112,641.34		$ 100,589.10		$ -		$ 12,052.24				$ 103.04		
34	Real -Time Schedule 24 Allocation Amount		$ (93,303.21)		$ 9,987.01		$ (19,903.24)				$ (83,386.98)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 857,438.40		$ 851,502.78		$ (19,903.24)		$ 109,225.84		$ (83,386.98)		$ 768.44		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ (48,026.83)		$ 1,906.27		$ (49,933.10)								
15	Real Time Financial Bilateral Congestion		$ -		$ -										
28	Financial Transmission Rights Hourly Allocation		$ (17,479,894.33)		$ 2,733,024.29		$ (20,212,918.62)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (23,297.09)		$ -		$ (23,297.09)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 279,916.93		$ 279,916.93		$ -								$ -
37	Financial Transmission Guarantee Uplift Amount		$ (275,855.97)		$ -		$ (275,855.97)						$ -		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (17,547,157.29)		$ 3,014,847.49		$ (20,562,004.78)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 251,491.25		$ 251,491.25				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (436,847.79)				$ (168,101.66)				$ (268,746.13)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 524,869.57		$ 524,869.57				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (708,077.27)		$ -		$ (388,169.98)				$ (319,907.29)				
43	Real Time Price Volatility Make Whole Payment		$ (281,870.86)		$ -		($165,731.28)				$ (116,139.58)				
	SUBTOTAL		$ (650,435.10)		$ 776,360.82		$ (722,002.92)		$ -		$ (704,793.00)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ (12,767,678.05)		$ 13,361,236.17		$ (13,111,771.49)				$ (13,017,142.73)		$ -		
21	Real Time Net Inadvertent Distribution		$ 115,159.91		$ 257,143.70		$ (141,983.79)						$ 227.09		$ (138.24)
23	Real Time Revenue Neutrality Uplift Amount		$ 476,854.77		$ 1,335,543.29		$ (858,688.52)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ (12,175,663.37)		$ 14,953,923.16		$ (14,112,443.80)		$ -		$ (13,017,142.73)		$ 227.09		$ (138.24)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 14,246,626.37		$ 14,397,722.96		$ (151,096.59)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (14,250,985.44)		$ 109,462.99		$ (14,272,398.25)				$ (88,050.18)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (605,336.38)		$ -		$ (605,336.38)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 97,656.74		$ 97,656.74		$ -								
	SUBTOTAL		$ (512,038.71)		$ 14,604,842.69		$ (15,028,831.22)		$ -		$ (88,050.18)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 48,026.83		$ 49,933.10		$ (1,906.27)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 6,928.60		$ 7,888.95		$ (960.35)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered		$ -				$ -								
18	Real Time Congestion Rebate on Carve Out Grandfathered		$ -				$ -								
	SUBTOTAL	-	$ 54,955.43	-	$ 57,822.05	-	$ (2,866.62)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(1,180,466)	$ (68,334,345.32)	4,068,466	$ 298,391,674.51	(4,078,296)	$ (283,592,959.61)	-	$ 109,225.84	(1,170,636)	$ (83,242,286.06)	8,000	$ 586,583.28	-	$ (138.24)
x	Net Congestion Amount		$ 25,176,879.16		$ 25,176,879.16				$ -						
y	Net Loss Amount		$ 13,379,529.86		$ 13,379,529.86				$ -						
z	Net Congestion and Loss Energy Offset		$ (38,556,409.02)		$ (38,556,409.02)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,180,466)**	$ (68,334,345.32)	4,068,466	$ 298,391,674.51	(4,078,296)	$ (283,592,959.61)	-	$ 109,225.84	(1,170,636)	$ (83,242,286.06)	8,000	$ 586,583.28	-	$ (138.24)

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

Docket No. E002/AA-21-295
True-Up Report
Part B, Attachment 10

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	August 2022	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(836,512)	$ (3,403,613.95)	3,834,955	$ 284,914,999.66	(3,623,479)	$ (217,823,951.06)			(1,047,988)	$ (70,494,662.55)				
5a	Day Ahead Non Asset Energy	(289,152)	$ (20,856,414.28)	-	$ 0.62	(289,152)	$ (20,856,414.90)					9,200	$ 766,983.25	-	$ -
13a	Real Time Asset Energy	(776)	$ 884,281.63	71,544	$ 6,055,315.53	28,338	$ 1,176,676.69			(100,658)	$ (6,347,710.59)				
22a	Real Time Non Asset Energy	1	$ (147.43)	1	$ (147.41)	-	$ (0.02)					-	$ -	-	$ -
	SUBTOTAL	(1,126,438)	$ (23,375,894.03)	3,906,500	$ 290,970,168.40	(3,884,293)	$ (237,503,689.29)	-	$ -	(1,148,646)	$ (76,842,373.14)	9,200	$ 766,983.25	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (10,996.72)		$ 943.62		$ (11,940.34)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (3,520,667.46)		$ -		$ (3,520,667.46)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (3,531,664.18)		$ 943.62		$ (3,532,607.80)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 561,495.23		$ 551,895.11		$ -		$ 9,600.12				$ 597.28		
19	Real Time Market Administration (Schedule 17)		$ 48,510.28		$ 49,596.59		$ -		$ (1,086.31)				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 97,297.00		$ 97,297.00		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 101,770.81		$ 90,012.88		$ -		$ 11,757.93				$ 107.36		
34	Real -Time Schedule 24 Allocation Amount		$ (87,104.36)		$ 20,979.25		$ -				$ (108,083.61)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 721,968.96		$ 809,780.83		$ -		$ 20,271.74		$ (108,083.61)		$ 704.64		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ (40,304.37)		$ 10,267.74		$ (50,572.11)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (31,643,701.31)		$ 3,081,068.95		$ (34,724,770.26)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (676,846.58)		$ -		$ (676,846.58)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (749,904.44)		$ -		$ (749,904.44)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 744,017.63		$ 744,017.63		$ -						$ -		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (32,366,739.07)		$ 3,835,354.32		$ (36,202,093.39)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 209,846.94		$ 209,846.94				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (144,012.39)				$ (89,519.08)				$ (54,493.31)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 684,416.26		$ 684,416.26				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (1,256,217.88)				$ (371,546.82)				$ (884,671.06)				
43	Real Time Price Volatility Make Whole Payment		$ (158,139.46)		$ -		($112,320.29)				$ (45,819.17)				
	SUBTOTAL		$ (664,106.53)		$ 894,263.20		$ (573,386.19)		$ -		$ (984,983.54)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ (12,783,018.81)		$ 13,303,940.21		$ (13,069,816.29)				$ (13,017,142.73)		$ 87.74		
21	Real Time Net Inadvertent Distribution		$ 91,273.37		$ 296,196.74		$ (204,923.37)						$ 198.49		$ (206.40)
23	Real Time Revenue Neutrality Uplift Amount		$ 159,335.19		$ 887,182.76		$ (727,847.57)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ (12,532,410.25)		$ 14,487,319.71		$ (14,002,587.23)		$ -		$ (13,017,142.73)		$ 286.23		$ (206.40)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 14,246,626.37		$ 14,397,722.96		$ (151,096.59)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (14,250,985.44)		$ 109,462.99		$ (14,316,636.02)				$ (43,812.41)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (605,336.65)		$ -		$ (605,336.65)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 97,656.73		$ 97,656.73		$ -								
	SUBTOTAL		$ (512,038.99)		$ 14,604,842.68		$ (15,073,069.26)		$ -		$ (43,812.41)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 40,304.37		$ 50,572.11		$ (10,267.74)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 10,996.72		$ 11,940.34		$ (943.62)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered														
18	Real Time Congestion Rebate on Carve Out Grandfathered														
	SUBTOTAL	-	$ 51,301.09	-	$ 62,512.45	-	$ (11,211.36)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(1,126,438)	$ (72,209,583.00)	3,906,500	$ 325,665,185.21	(3,884,293)	$ (306,898,644.52)	-	$ 20,271.74	(1,148,646)	$ (90,996,395.43)	9,200	$ 767,974.12	-	$ (206.40)
x	Net Congestion Amount		$ 42,015,676.22		$ 42,015,676.22				$ -						
y	Net Loss Amount		$ 14,606,352.04		$ 14,606,352.04				$ -						
z	Net Congestion and Loss Energy Offset		$ (56,622,028.26)		$ (56,622,028.26)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,126,438)**	$ (72,209,583.00)	3,906,500	$ 325,665,185.21	(3,884,293)	$ (306,898,644.52)	-	$ 20,271.74	(1,148,646)	$ (90,996,395.43)	9,200	$ 767,974.12	-	$ (206.40)

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	September 2022	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(724,391)	$ (3,068,256.55)	3,287,213	$ 196,817,714.91	(3,039,389)	$ (147,844,909.99)			(972,215)	$ (52,041,061.47)				
5a	Day Ahead Non Asset Energy	(272,230)	$ (17,274,136.93)	41	$ 2,003.90	(272,271)	$ (17,276,140.83)					-	$ -	-	$ -
13a	Real Time Asset Energy	22,172	$ 2,380,819.02	66,624	$ 4,724,142.46	18,137	$ (238,115.47)			(62,589)	$ (2,105,207.97)				
22a	Real Time Non Asset Energy	629	$ (357,566.35)	629	$ (357,566.32)	-	$ (0.03)					-	$ -	-	$ -
	SUBTOTAL	(973,820)	$ (18,319,140.81)	3,354,508	$ 201,186,294.95	(3,293,523)	$ (165,359,166.32)	-	$ -	(1,034,804)	$ (54,146,269.44)	-	$ -	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (13,200.03)		$ 743.09		$ (13,943.12)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (2,792,430.88)		$ -		$ (2,792,430.88)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (2,805,630.91)		$ 743.09		$ (2,806,374.00)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 794,149.26		$ 636,515.17		$ -		$ 157,634.09				$ 113.28		
19	Real Time Market Administration (Schedule 17)		$ 74,613.12		$ 60,044.53		$ -		$ 14,568.59				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ (40,132.01)		$ (40,132.01)		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 107,874.12		$ 94,369.96		$ -		$ 13,504.16				$ 4.32		
34	Real -Time Schedule 24 Allocation Amount		$ (95,418.06)		$ 10,179.73		$ (24,014.99)				$ (81,582.80)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 841,086.43		$ 760,977.38		$ (24,014.99)		$ 185,706.84		$ (81,582.80)		$ 117.60		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ (23,886.69)		$ 20,515.32		$ (44,402.01)								
15	Real Time Financial Bilateral Congestion		$ -		$ -										
28	Financial Transmission Rights Hourly Allocation		$ (4,461,099.61)		$ 3,139,463.39		$ (7,600,563.00)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (72,810.45)		$ -		$ (72,810.45)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 749,614.98		$ 749,614.98		$ -								$ -
37	Financial Transmission Guarantee Uplift Amount		$ (743,057.38)		$ -		$ (743,057.38)						$ -		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (4,551,239.15)		$ 3,909,593.69		$ (8,460,832.84)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 81,361.64		$ 81,361.64				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (779,026.73)				$ (367,103.06)				$ (411,923.67)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 356,531.35		$ 356,531.35				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (426,555.65)		$ -		$ (485,338.96)				$ 58,783.31				
43	Real Time Price Volatility Make Whole Payment		$ (247,002.93)		$ -		($190,215.25)				$ (56,787.68)				
	SUBTOTAL		$ (1,014,692.32)		$ 437,892.99		$ (1,042,657.27)		$ -		$ (409,928.04)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ (11,481,921.43)		$ 13,861,119.33		$ (12,745,805.86)				$ (12,597,234.90)		$ -		
21	Real Time Net Inadvertent Distribution		$ 50,617.39		$ 262,890.96		$ (212,273.57)						$ 22.17		$ (35.63)
23	Real Time Revenue Neutrality Uplift Amount		$ 550,061.07		$ 1,279,269.88		$ (729,208.81)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ (10,881,242.97)		$ 15,403,280.17		$ (13,687,288.24)		$ -		$ (12,597,234.90)		$ 22.17		$ (35.63)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 9,883,261.64		$ 10,136,435.26		$ (253,173.62)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (9,903,009.97)		$ 224,363.60		$ (10,090,739.92)				$ (36,633.65)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (497,087.41)		$ -		$ (497,087.41)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 240,801.85		$ 241,043.15		$ (241.30)								
	SUBTOTAL		$ (276,033.89)		$ 10,601,842.01		$ (10,841,242.25)		$ -		$ (36,633.65)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 23,886.69		$ 44,402.01		$ (20,515.32)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 13,200.03		$ 13,943.12		$ (743.09)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered		$ -				$ -								
18	Real Time Congestion Rebate on Carve Out Grandfathered		$ -				$ -								
	SUBTOTAL	-	$ 37,086.72	-	$ 58,345.13	-	$ (21,258.41)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(973,820)	$ (36,969,806.90)	3,354,508	$ 232,358,969.41	(3,293,523)	$ (202,242,834.32)	-	$ 185,706.84	(1,034,804)	$ (67,271,648.83)	-	$ 139.77	-	$ (35.63)
x	Net Congestion Amount		$ 12,738,493.81		$ 12,738,493.81				$ -						
y	Net Loss Amount		$ 8,979,150.45		$ 8,979,150.45				$ -						
z	Net Congestion and Loss Energy Offset		$ (21,717,644.26)		$ (21,717,644.26)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(973,820)**	$ (36,969,806.90)	3,354,508	$ 232,358,969.41	(3,293,523)	$ (202,242,834.32)	-	$ 185,706.84	(1,034,804)	$ (67,271,648.83)	-	$ 139.77	-	$ (35.63)

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

Northern States Power Company
Electric Operations - State of Minnesota

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

October 2022		NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(846,359)	$ 3,702,483.01	3,060,914	$ 129,557,928.69	(2,851,622)	$ (93,842,621.05)			(1,055,650)	$ (32,012,824.63)				
5a	Day Ahead Non Asset Energy	(282,122)	$ (12,561,148.20)	-	$ 0.41	(282,122)	$ (12,561,148.61)					-	$ -	-	$ -
13a	Real Time Asset Energy	9,565	$ 937,370.02	54,535	$ 2,759,179.51	43,802	$ 976,672.42			(88,772)	$ (2,798,481.91)				
22a	Real Time Non Asset Energy	319	$ 458,048.10	319	$ 458,048.10	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(1,118,596)	$ (7,463,247.07)	3,115,768	$ 132,775,156.71	(3,089,942)	$ (105,427,097.24)	-	$ -	(1,144,422)	$ (34,811,306.54)	-	$ -	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (4,126.88)		$ 1,172.17		$ (5,299.05)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (1,616,198.25)		$ 15,650.46		$ (1,631,848.71)								
16	Real Time Financial Bilateral Loss		$ 8.31		$ 8.31										
	SUBTOTAL		$ (1,620,316.82)		$ 16,830.94		$ (1,637,147.76)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 542,953.21		$ 463,400.08		$ -		$ 79,553.13				$ -		
19	Real Time Market Administration (Schedule 17)		$ 56,164.99		$ 50,029.53		$ (261.92)		$ 6,397.38				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 21,039.77		$ 21,039.77		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 96,906.20		$ 82,535.70		$ -		$ 14,370.18				$ 0.32		
34	Real -Time Schedule 24 Allocation Amount		$ (82,788.98)		$ 10,268.12		$ (4,698.49)				$ (88,358.61)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 634,275.19		$ 627,273.20		$ (4,960.41)		$ 100,320.69		$ (88,358.61)		$ 0.32		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ 923.80		$ 14,762.71		$ (13,838.91)								
15	Real Time Financial Bilateral Congestion		$ 86.65		$ 86.65										
28	Financial Transmission Rights Hourly Allocation		$ (2,183,842.20)		$ 2,517,273.63		$ (4,701,115.83)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (200,765.40)		$ -		$ (200,765.40)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (182,284.97)		$ -		$ (182,284.97)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 177,556.08		$ 177,556.08		$ -						$ -		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (2,388,326.04)		$ 2,709,679.07		$ (5,098,005.11)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 105,247.84		$ 105,247.84				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (321,128.68)				$ (180,568.34)				$ (140,560.34)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 122,490.20		$ 122,490.20				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (67,500.22)		$ 100.20		$ (3,347.83)				$ (64,252.59)				
43	Real Time Price Volatility Make Whole Payment		$ (135,816.23)		$ 83.74		($96,054.51)				$ (39,845.46)				
	SUBTOTAL		$ (296,707.09)		$ 227,921.98		$ (279,970.68)		$ -		$ (244,658.39)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ (12,848,083.13)		$ 14,214,827.73		$ (14,045,768.13)				$ (13,017,142.73)		$ -		
21	Real Time Net Inadvertent Distribution		$ (251,389.23)		$ 170,902.76		$ (422,286.99)						$ 3.42		$ (8.42)
23	Real Time Revenue Neutrality Uplift Amount		$ 897,100.36		$ 1,479,793.32		$ (582,692.96)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ (12,202,372.00)		$ 15,865,523.81		$ (15,050,748.08)		$ -		$ (13,017,142.73)		$ 3.42		$ (8.42)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 9,883,261.64		$ 10,136,435.26		$ (253,173.62)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (9,903,009.97)		$ 224,363.60		$ (10,089,870.58)				$ (37,502.99)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (497,086.80)		$ -		$ (497,086.80)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 240,801.85		$ 240,801.85		$ -								
	SUBTOTAL		$ (276,033.28)		$ 10,601,600.71		$ (10,840,131.00)		$ -		$ (37,502.99)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (923.80)		$ 13,838.91		$ (14,762.71)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 4,126.88		$ 5,299.05		$ (1,172.17)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered		$ (8.31)				$ (8.31)								
18	Real Time Congestion Rebate on Carve Out Grandfathered		$ (86.65)				$ (86.65)								
	SUBTOTAL	-	$ 3,108.12	-	$ 19,137.96	-	$ (16,029.84)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(1,118,596)	$ (23,609,618.99)	3,115,768	$ 162,843,124.38	(3,089,942)	$ (138,354,090.12)	-	$ 100,320.69	(1,144,422)	$ (48,198,969.26)	-	$ 3.74	-	$ (8.42)
x	Net Congestion Amount		$ 16,454,866.06		$ 16,454,866.06				$ -						
y	Net Loss Amount		$ 6,817,704.38		$ 6,817,704.38				$ -						
z	Net Congestion and Loss Energy Offset		$ (23,272,570.44)		$ (23,272,570.44)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,118,596)**	$ (23,609,618.99)	3,115,768	$ 162,843,124.38	(3,089,942)	$ (138,354,090.12)	-	$ 100,320.69	(1,144,422)	$ (48,198,969.26)	-	$ 3.74	-	$ (8.42)

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

November 2022		NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(751,708)	$ 5,586,481.09	3,213,952	$ 103,058,382.85	(3,057,191)	$ (75,191,746.82)			(908,469)	$ (22,280,154.94)				
5a	Day Ahead Non Asset Energy	(188,467)	$ (6,015,290.26)	21	$ 798.58	(188,488)	$ (6,016,088.84)					-	$ -	-	$ -
13a	Real Time Asset Energy	(136,821)	$ (4,309,271.45)	47,441	$ 1,504,716.66	(52,241)	$ (3,112,756.97)			(132,022)	$ (2,701,231.14)				
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(1,076,996)	$ (4,738,080.62)	3,261,414	$ 104,563,898.09	(3,297,920)	$ (84,320,592.63)	-	$ -	(1,040,491)	$ (24,981,386.08)	-	$ -	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (2,359.55)		$ 1,269.97		$ (3,629.52)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (1,382,854.66)		$ 33,192.54		$ (1,416,047.20)								
16	Real Time Financial Bilateral Loss		$ -		$ -										
	SUBTOTAL		$ (1,385,214.21)		$ 34,462.51		$ (1,419,676.72)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 676,989.99		$ 594,578.91		$ -		$ 82,411.08				$ -		
19	Real Time Market Administration (Schedule 17)		$ 91,207.09		$ 78,915.27		$ (290.25)		$ 12,582.07				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 21,607.54		$ 21,607.54		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 103,151.64		$ 90,143.53		$ -		$ 13,008.11				$ -		
34	Real -Time Schedule 24 Allocation Amount		$ (89,557.94)		$ 14,063.51		$ (5,044.42)				$ (98,577.03)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 803,398.32		$ 799,308.76		$ (5,334.67)		$ 108,001.26		$ (98,577.03)		$ -		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ (14,831.27)		$ 9,401.52		$ (24,232.79)								
15	Real Time Financial Bilateral Congestion		$ -		$ -										
28	Financial Transmission Rights Hourly Allocation		$ (251,163.01)		$ 3,473,249.49		$ (3,724,412.50)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (29,038.67)		$ -		$ (29,038.67)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 157,510.41		$ 157,510.41		$ -								$ -
37	Financial Transmission Guarantee Uplift Amount		$ (155,562.07)		$ -		$ (155,562.07)						$ -		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (293,084.61)		$ 3,640,161.42		$ (3,933,246.03)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 132,559.47		$ 132,559.47				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (206,009.56)				$ (33,472.19)				$ (172,537.37)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 424,622.29		$ 424,622.29				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (600,184.88)		$ 34.73		$ (272,966.62)				$ (327,252.99)				
43	Real Time Price Volatility Make Whole Payment		$ (227,617.40)		$ 1,852.39		($157,515.01)				$ (71,954.78)				
	SUBTOTAL		$ (476,630.08)		$ 559,068.88		$ (463,953.82)		$ -		$ (571,745.14)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ (12,536,231.27)		$ 12,763,832.54		$ (12,702,828.91)				$ (12,597,234.90)		$ -		
21	Real Time Net Inadvertent Distribution		$ 186,069.44		$ 342,057.70		$ (155,986.49)						$ 0.42		$ (2.19)
23	Real Time Revenue Neutrality Uplift Amount		$ (571,997.75)		$ 721,566.16		$ (1,293,563.91)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ (12,922,159.58)		$ 13,827,456.40		$ (14,152,379.31)		$ -		$ (12,597,234.90)		$ 0.42		$ (2.19)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 9,883,261.64		$ 10,136,435.26		$ (253,173.62)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (9,903,009.97)		$ 224,363.60		$ (10,089,153.63)				$ (38,219.94)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (497,086.80)		$ -		$ (497,086.80)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 240,884.14		$ 240,884.14		$ -								
	SUBTOTAL		$ (275,950.99)		$ 10,601,683.00		$ (10,839,414.05)		$ -		$ (38,219.94)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 14,831.27		$ 24,232.79		$ (9,401.52)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 2,359.55		$ 3,629.52		$ (1,269.97)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered		$ -				$ -								
18	Real Time Congestion Rebate on Carve Out Grandfathered		$ -				$ -								
	SUBTOTAL	-	$ 17,190.82	-	$ 27,862.31	-	$ (10,671.49)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(1,076,996)	$ (19,270,530.95)	3,261,414	$ 134,053,901.37	(3,297,920)	$ (115,145,268.72)	-	$ 108,001.26	(1,040,491)	$ (38,287,163.09)	-	$ 0.42	-	$ (2.19)
x	Net Congestion Amount		$ 14,398,706.83		$ 14,398,706.83				$ -						
y	Net Loss Amount		$ 7,605,318.11		$ 7,605,318.11				$ -						
z	Net Congestion and Loss Energy Offset		$ (22,004,024.94)		$ (22,004,024.94)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,076,996)**	$ (19,270,530.95)	3,261,414	$ 134,053,901.37	(3,297,920)	$ (115,145,268.72)	-	$ 108,001.26	(1,040,491)	$ (38,287,163.09)	-	$ 0.42	-	$ (2.19)

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

Docket No. E002/AA-21-295
True-Up Report
Part B, Attachment 10

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	December 2022	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(729,433)	$ (7,117,614.04)	3,630,502	$ 162,660,442.69	(3,347,654)	$ (128,671,276.65)			(1,012,280)	$ (41,106,780.08)				
5a	Day Ahead Non Asset Energy	(180,384)	$ (8,204,768.96)	-	$ 5,090.16	(180,384)	$ (8,209,859.12)					16,800	$ 733,111.00	-	$ -
13a	Real Time Asset Energy	78,808	$ 1,887,649.41	32,352	$ 1,546,279.29	276,318	$ 13,799,799.30			(229,863)	$ (13,458,429.18)				
22a	Real Time Non Asset Energy	(450)	$ (89,695.88)	-	$ -	(450)	$ (89,695.88)					-	$ -	-	$ -
	SUBTOTAL	(831,458)	$ (13,524,429.47)	3,662,854	$ 164,211,812.14	(3,252,169)	$ (123,171,032.35)	-	$ -	(1,242,143)	$ (54,565,209.26)	16,800	$ 733,111.00	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 5,716.43		$ 7,651.04		$ (1,934.61)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (2,144,781.20)		$ 242,296.32		$ (2,387,077.52)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (2,139,064.77)		$ 249,947.36		$ (2,389,012.13)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 569,229.19		$ 497,332.27		$ -		$ 71,896.92				$ 1,169.28		
19	Real Time Market Administration (Schedule 17)		$ 54,195.25		$ 39,359.10		$ (163.39)		$ 14,999.54				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 19,853.54		$ 19,853.54		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 108,675.75		$ 95,168.22		$ -		$ 13,507.53				$ 225.12		
34	Real -Time Schedule 24 Allocation Amount		$ (104,275.44)		$ 11,269.04		$ 192.06				$ (115,736.54)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 647,678.29		$ 662,982.17		$ 28.67		$ 100,403.99		$ (115,736.54)		$ 1,394.40		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ (19,113.41)		$ 21,560.83		$ (40,674.24)								
15	Real Time Financial Bilateral Congestion		$ -		$ -										
28	Financial Transmission Rights Hourly Allocation		$ (6,612,732.28)		$ 4,128,632.07		$ (10,741,364.35)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (95,289.88)		$ -		$ (95,289.88)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (120,099.63)		$ -		$ (120,099.63)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 123,032.52		$ 123,032.52		$ -						$ -		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (6,724,202.68)		$ 4,273,225.42		$ (10,997,428.10)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 179,197.28		$ 179,197.28				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (121,230.65)				$ (68,120.74)				$ (53,109.91)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 2,081,269.37		$ 2,081,269.37				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (1,946,929.08)		$ 1.37		$ (1,280,099.72)				$ (666,830.73)				
43	Real Time Price Volatility Make Whole Payment		$ (640,622.73)		$ 34.66		($525,411.32)				$ (115,246.07)				
	SUBTOTAL		$ (448,315.81)		$ 2,260,502.68		$ (1,873,631.78)		$ -		$ (835,186.71)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ (13,811,390.33)		$ 13,316,340.41		$ (14,110,588.01)				$ (13,017,142.73)		$ (23.44)		
21	Real Time Net Inadvertent Distribution		$ 606,843.10		$ 913,869.12		$ (307,026.02)						$ 1,842.08		$ (556.17)
23	Real Time Revenue Neutrality Uplift Amount		$ (1,961,545.52)		$ 2,689,227.81		$ (4,650,773.33)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ (15,166,092.75)		$ 16,919,437.34		$ (19,068,387.36)		$ -		$ (13,017,142.73)		$ 1,818.64		$ (556.17)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 15,777,513.01		$ 16,166,095.28		$ (388,582.27)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (15,782,515.07)		$ 388,578.28		$ (15,995,820.45)				$ (175,272.90)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (683,288.39)		$ -		$ (683,288.39)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 89,943.30		$ 89,943.30		$ -								
	SUBTOTAL		$ (598,347.15)		$ 16,644,616.86		$ (17,067,691.11)		$ -		$ (175,272.90)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 19,113.41		$ 40,674.24		$ (21,560.83)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (5,716.43)		$ 1,934.61		$ (7,651.04)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered		$ -				$ -								
18	Real Time Congestion Rebate on Carve Out Grandfathered		$ -				$ -								
	SUBTOTAL	-	$ 13,396.98	-	$ 42,608.85	-	$ (29,211.87)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(831,458)	$ (37,939,377.36)	3,662,854	$ 205,265,132.82	(3,252,169)	$ (174,596,366.03)	-	$ 100,403.99	(1,242,143)	$ (68,708,548.14)	16,800	$ 736,324.04	-	$ (556.17)
x	Net Congestion Amount		$ 14,805,653.34		$ 14,805,653.34				$ -						
y	Net Loss Amount		$ 9,177,014.12		$ 9,177,014.12				$ -						
z	Net Congestion and Loss Energy Offset		$ (23,982,667.46)		$ (23,982,667.46)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(831,458)**	$ (37,939,377.36)	3,662,854	$ 205,265,132.82	(3,252,169)	$ (174,596,366.03)	-	$ 100,403.99	(1,242,143)	$ (68,708,548.14)	16,800	$ 736,324.04	-	$ (556.17)

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

Northern States Power Company
Electric Operations - State of Minnesota

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

January - December 2022		NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(9,917,857)	$ 50,600,589.37	41,016,274	$ 2,060,242,077.26	(38,611,110)	$ (1,504,840,981.35)			(12,323,020)	$ (504,800,506.54)				
5a	Day Ahead Non Asset Energy	(2,669,070)	$ (132,768,247.77)	3,352	$ 240,734.23	(2,672,422)	$ (133,008,982.00)					-	$ 2,644,207.11	-	$ (0.22)
13a	Real Time Asset Energy	(139,146)	$ (3,053,346.01)	670,107	$ 36,571,027.35	578,550	$ 11,985,922.68			(1,387,803)	$ (51,610,296.04)				
22a	Real Time Non Asset Energy	(171)	$ (87,488.40)	2,014	$ 156,154.43	(2,185)	$ (243,642.83)					-	$ -	-	$ -
	SUBTOTAL	(12,726,244)	$ (85,308,492.81)	41,691,746	$ 2,097,209,993.27	(40,707,167)	$ (1,626,107,683.50)	-	$ -	(13,710,823)	$ (556,410,802.58)	-	$ 2,644,207.11	-	$ (0.22)
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (172,225.98)		$ 39,328.01		$ (211,553.99)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (27,829,110.60)		$ 291,139.32		$ (28,120,249.92)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (28,001,336.58)		$ 330,467.33		$ (28,331,803.91)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 7,559,742.65		$ 6,580,196.42		$ -		$ 979,546.23				$ 3,156.59		
19	Real Time Market Administration (Schedule 17)		$ 787,523.97		$ 679,286.80		$ (715.56)		$ 108,952.73				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 331,553.99		$ 331,553.99		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 1,200,279.46		$ 1,044,206.37		$ (35.84)		$ 156,108.93				$ 520.80		
34	Real -Time Schedule 24 Allocation Amount		$ (1,106,495.99)		$ 126,341.47		$ (35,815.22)				$ (1,197,022.24)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 8,772,604.08		$ 8,761,585.05		$ (36,566.62)		$ 1,244,607.89		$ (1,197,022.24)		$ 3,677.39		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ (273,709.89)		$ 337,543.65		$ (611,253.54)								
15	Real Time Financial Bilateral Congestion		$ -		$ -										
28	Financial Transmission Rights Hourly Allocation		$ (122,900,725.98)		$ 48,486,151.04		$ (171,386,877.02)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (2,899,316.04)		$ -		$ (2,899,316.04)								$ -
32	Financial Transmission Rights Yearly Allocation		$ (1,632,060.78)		$ -		$ (1,632,060.78)						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 1,671,660.61		$ 1,671,660.61		$ -								$ -
37	Financial Transmission Guarantee Uplift Amount		$ (1,538,776.09)		$ -		$ (1,538,776.09)						$ -		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (127,572,928.17)		$ 50,495,355.30		$ (178,068,283.47)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 1,842,815.41		$ 1,842,815.41				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (3,903,557.76)				$ (1,981,096.91)				$ (1,922,460.85)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 7,214,645.51		$ 7,214,645.51				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (8,907,512.93)		$ 136.30		$ (4,983,579.96)				$ (3,924,069.27)				
43	Real Time Price Volatility Make Whole Payment		$ (2,769,032.96)		$ 1,970.79		($2,025,027.07)				$ (745,976.68)				
	SUBTOTAL		$ (6,522,642.73)		$ 9,059,568.01		$ (8,989,703.94)		$ -		$ (6,592,506.80)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ (86,712,830.89)		$ 96,602,556.82		$ (92,990,267.40)				$ (90,325,120.31)		$ 144.38		
21	Real Time Net Inadvertent Distribution		$ 986,813.84		$ 3,620,691.39		$ (2,633,877.55)						$ 2,703.47		$ (1,165.35)
23	Real Time Revenue Neutrality Uplift Amount		$ 8,180,334.02		$ 20,886,033.02		$ (12,705,699.00)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ (77,545,683.03)		$ 121,109,281.23		$ (108,329,843.95)		$ -		$ (90,325,120.31)		$ 2,847.85		$ (1,165.35)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 115,296,100.59		$ 117,581,270.91		$ (2,285,170.32)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (115,528,039.82)		$ 2,051,704.57		$ (117,034,292.49)				$ (545,451.90)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (4,991,372.80)		$ -		$ (4,991,372.80)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 1,764,231.80		$ 1,764,473.10		$ (241.30)								
	SUBTOTAL		$ (3,459,080.23)		$ 121,397,448.58		$ (124,311,076.91)		$ -		$ (545,451.90)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 93,345.66		$ 391,033.96		$ (297,688.30)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 22,925.83		$ 63,284.26		$ (40,358.43)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered		$ -				$ -								
18	Real Time Congestion Rebate on Carve Out Grandfathered		$ -				$ -								
	SUBTOTAL	-	$ 116,271.49	-	$ 454,318.22	-	$ (338,046.73)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(12,726,244)	$ (319,521,287.98)	41,691,746	$ 2,408,818,016.99	(40,707,167)	$ (2,074,513,009.03)	-	$ 1,244,607.89	(13,710,823)	$ (655,070,903.83)	-	$ 2,650,732.35	-	$ (1,165.57)
x	Net Congestion Amount		$ (8,909,536.88)		$ (8,909,536.88)				$ -						
y	Net Loss Amount		$ (849,797.78)		$ (849,797.78)				$ -						
z	Net Congestion and Loss Energy Offset		$ 9,759,334.66		$ 9,759,334.66										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(12,726,244)**	$ (319,521,287.98)	41,691,746	$ 2,408,818,016.99	(40,707,167)	$ (2,074,513,009.03)	-	$ 1,244,607.89	(13,710,823)	$ (655,070,903.83)	-	$ 2,650,732.35	-	$ (1,165.57)

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

January 2022	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**
Procurement Charges														
1 Day-Ahead Regulation Amount		$ (164,671.79)		$ -		$ 1,734.42				$ (166,406.21)				
2 Day-Ahead Spinning Reserve Amount		$ (164,772.45)		$ -		$ (32,617.85)				$ (132,154.60)				
3 Day-Ahead Supplemental Reserve		$ (9,014.52)		$ -		$ (5,742.87)				$ (3,271.65)				
4 Day-Ahead Short Term Reserve Amount		$ (45,144.78)		$ 20,110.67		$ 72,886.36				$ (138,141.81)				
5 Real-Time Regulation Amount (See Note 1)		$ (190,151.79)		$ 52,509.45		$ (242,661.24)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (59,636.76)		$ 47,851.66		$ (107,488.42)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 4,765.14		$ 8,054.57		$ (3,289.43)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ (28,683.90)		$ 4,663.22		$ (33,347.12)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(6,474)	$ 51,469.61	39	$ (545.44)	(6,513)	$ 52,015.05								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	344,304	$ 7,140,746.06	771,151	$ 14,519,174.61	(426,847)	$ (7,378,428.55)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (1,922,661.82)		$ 16,364.45		$ (1,943,500.26)		$ 4,473.99						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 145,077.50		$ 145,077.50		$ -								
11 Real Time Spinning Reserve Cost Distribution		$ 102,882.19		$ 102,882.19		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 19,154.78		$ 19,154.78		$ -								
13 Real Time Short Term Reserve Cost Distribution		$ 17,456.36		$ 36,001.96		$ (18,545.60)								
Penalty Charges														
13 Real Time Excessive/Deficient Energy Deployment		$ 46,932.35		$ 25,614.25		$ -		$ 21,318.10						
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -				$ -				
15 Real Time Short Term Reserve Deployment Failure		$ 271.70		$ 212.24		$ -				$ 59.46				
MISO ASM CHARGES	337,830	$ 4,944,017.88	771,190	$ 14,997,126.11	(433,360)	$ (9,638,985.51)	-	$ 25,792.09	-	$ (439,914.81)	-	$ -	-	$ -
x Net Congestion Amount		$ 788,846.39		$ 788,846.39				$ -						
y Net Loss Amount		$ 130,433.58		$ 130,433.58				$ -						
z Net Congestion and Loss Energy Offset		$ (919,279.97)		$ (919,279.97)										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	337,830	$ 4,944,017.88	771,190	$ 14,997,126.11	(433,360)	$ (9,638,985.51)	-	$ 25,792.09	-	$ (439,914.81)	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

February 2022	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
Procurement Charges														
1 Day-Ahead Regulation Amount		$ (138,495.37)		$ -		$ (50,426.88)				$ (88,068.49)				
2 Day-Ahead Spinning Reserve Amount		$ (192,760.35)		$ -		$ (18,085.99)				$ (174,674.36)				
3 Day-Ahead Supplemental Reserve		$ (19,120.98)		$ -		$ (12,707.99)				$ (6,412.99)				
4 Day-Ahead Short Term Reserve Amount		$ (60,430.61)		$ 50,064.69		$ (63,125.91)				$ (47,369.39)				
5 Real-Time Regulation Amount (See Note 1)		$ (63,504.98)		$ 45,242.05		$ (108,747.03)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (52,661.24)		$ 38,117.71		$ (90,778.95)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 2,951.20		$ 3,849.43		$ (898.23)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ 2,988.70		$ 6,085.33		$ (3,096.63)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(1,597)	$ 11,216.83	23	$ (116.63)	(1,621)	$ 11,333.46								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	46,309	$ 722,127.94	447,635	$ 8,271,724.72	(401,326)	$ (7,549,596.78)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 7,020.31		$ 11,101.76		$ (11,848.23)		$ 7,766.78						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 145,134.02		$ 145,134.02		$ -								
11 Real Time Spinning Reserve Cost Distribution		$ 104,423.49		$ 104,423.49		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 15,029.57		$ 15,029.57		$ -								
13 Real Time Short Term Reserve Cost Distribution		$ 76,728.95		$ 139,437.56		$ (62,708.61)								
Penalty Charges														
13 Real Time Excessive/Deficient Energy Deployment		$ 42,037.33		$ 19,367.80		$ -		$ 22,669.53						
14 Real Time Contingency Reserve Deployment Failure		$ 4,137.11		$ 4,137.11		$ -				$ -				
15 Real Time Short Term Reserve Deployment Failure		$ -		$ -		$ -				$ -				
MISO ASM CHARGES	44,712	$ 606,821.92	447,658	$ 8,853,598.61	(402,947)	$ (7,960,687.77)	-	$ 30,436.31	-	$ (316,525.23)	-	$ -	-	$ -
x Net Congestion Amount		$ (119,931.61)		$ (119,931.61)				$ -						
y Net Loss Amount		$ 40,093.71		$ 40,093.71				$ -						
z Net Congestion and Loss Energy Offset		$ 79,837.90		$ 79,837.90										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	44,712	$ 606,821.92	447,658	$ 8,853,598.61	(402,947)	$ (7,960,687.77)	-	$ 30,436.31	-	$ (316,525.23)	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

March 2022	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**
Procurement Charges														
1 Day-Ahead Regulation Amount		$ (148,111.43)		$ -		$ (93,703.31)				$ (54,408.12)				
2 Day-Ahead Spinning Reserve Amount		$ (208,493.43)		$ -		$ (89,018.86)				$ (119,474.57)				
3 Day-Ahead Supplemental Reserve		$ (28,793.69)		$ -		$ (11,517.78)				$ (17,275.91)				
4 Day-Ahead Short Term Reserve Amount		$ (77,469.70)		$ 21,684.41		$ (53,858.40)				$ (45,295.71)				
5 Real-Time Regulation Amount (See Note 1)		$ (36,658.24)		$ 48,264.63		$ (84,922.87)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (52,177.28)		$ 39,525.56		$ (91,702.84)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 1,599.39		$ 2,114.26		$ (514.87)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ (2,065.95)		$ 4,532.04		$ (6,597.99)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(606)	$ 27,113.24	93	$ (585.47)	(699)	$ 27,698.71								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	30,072	$ 3,021,489.48	391,968	$ 7,108,395.84	(361,896)	$ (4,086,906.36)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 13,224.60		$ 12,034.14		$ (7,242.93)		$ 8,433.39						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 156,330.53		$ 156,330.53		$ -								
11 Real Time Spinning Reserve Cost Distribution		$ 154,236.36		$ 154,236.36		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 10,618.75		$ 10,618.75		$ -								
13 Real Time Short Term Reserve Cost Distribution		$ 47,025.85		$ 90,264.91		$ (43,239.06)								
Penalty Charges														
13 Real Time Excessive/Deficient Energy Deployment		$ 45,880.87		$ 34,837.27		$ -		$ 11,043.60						
14 Real Time Contingency Reserve Deployment Failure		$ -		$ 440.23		$ -				$ (440.23)				
15 Real Time Short Term Reserve Deployment Failure		$ -		$ -		$ -				$ -				
MISO ASM CHARGES	29,466	$ 2,923,749.35	392,061	$ 7,682,693.46	(362,595)	$ (4,541,526.56)	-	$ 19,476.99	-	$ (236,894.54)	-	$ -	-	$ -
x Net Congestion Amount		$ (244,425.15)		$ (244,425.15)				$ -						
y Net Loss Amount		$ (38,366.21)		$ (38,366.21)				$ -						
z Net Congestion and Loss Energy Offset		$ 282,791.36		$ 282,791.36										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	29,466	$ 2,923,749.35	392,061	$ 7,682,693.46	(362,595)	$ (4,541,526.56)	-	$ 19,476.99	-	$ (236,894.54)	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

April 2022	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
Procurement Charges														
1 Day-Ahead Regulation Amount		$ (248,040.09)		$ -		$ (144,491.03)				$ (103,549.06)				
2 Day-Ahead Spinning Reserve Amount		$ (369,817.64)		$ -		$ 66,540.05				$ (436,357.69)				
3 Day-Ahead Supplemental Reserve		$ (30,446.14)		$ -		$ (17,875.81)				$ (12,570.33)				
4 Day-Ahead Short Term Reserve Amount		$ (132,586.95)		$ 0.41		$ 30,978.00				$ (163,565.36)				
5 Real-Time Regulation Amount (See Note 1)		$ (27,791.44)		$ 99,461.74		$ (127,253.18)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (230,742.82)		$ 91,361.28		$ (322,104.10)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 4,860.88		$ 5,254.98		$ (394.10)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ (19,225.54)		$ 10,161.75		$ (29,387.29)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(5,167)	$ 85,273.13	58	$ (1,161.41)	(5,225)	$ 86,434.54								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	93,984	$ 1,490,018.60	424,942	$ 4,309,093.09	(330,959)	$ (2,819,074.49)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (18,847.42)		$ 22,669.02		$ (28,870.72)		$ (12,645.72)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 224,754.00		$ 224,754.00		$ -								
11 Real Time Spinning Reserve Cost Distribution		$ 231,564.74		$ 231,564.74		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 22,856.56		$ 22,856.56		$ -								
13 Real Time Short Term Reserve Cost Distribution		$ 144,746.18		$ 145,334.29		$ (588.11)								
Penalty Charges														
13 Real Time Excessive/Deficient Energy Deployment		$ 37,534.66		$ 13,982.44		$ -		$ 23,552.22						
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -				$ -				
15 Real Time Short Term Reserve Deployment Failure		$ 7,028.70		$ 984.90		$ -				$ 6,043.80				
MISO ASM CHARGES	88,816	$ 1,171,139.41	425,000	$ 5,176,317.79	(336,184)	$ (3,306,086.24)	-	$ 10,906.50	-	$ (709,998.64)	-	$ -	-	$ -
x Net Congestion Amount		$ 562,216.26		$ 562,216.26				$ -						
y Net Loss Amount		$ 214,348.89		$ 214,348.89				$ -						
z Net Congestion and Loss Energy Offset		$ (776,565.15)		$ (776,565.15)										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	88,816	$ 1,171,139.41	425,000	$ 5,176,317.79	(336,184)	$ (3,306,086.24)	-	$ 10,906.50	-	$ (709,998.64)	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

May 2022	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
Procurement Charges														
1 Day-Ahead Regulation Amount		$ (270,816.39)		$ -		$ (81,827.54)				$ (188,988.85)				
2 Day-Ahead Spinning Reserve Amount		$ (343,047.30)		$ -		$ 16,986.08				$ (360,033.38)				
3 Day-Ahead Supplemental Reserve		$ (43,170.88)		$ -		$ (2,593.05)				$ (40,577.83)				
4 Day-Ahead Short Term Reserve Amount		$ (67,574.84)		$ 0.49		$ 14,983.65				$ (82,558.98)				
5 Real-Time Regulation Amount (See Note 1)		$ (85,259.62)		$ 133,583.10		$ (218,842.72)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (141,338.91)		$ 82,001.30		$ (223,340.21)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (6,545.99)		$ 21,053.95		$ (27,599.94)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ (8,097.84)		$ 4,290.30		$ (12,388.14)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(3,720)	$ 128,285.38	117	$ (2,777.19)	(3,837)	$ 131,062.57								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	214,696	$ 488,497.91	516,277	$ 11,713,658.52	(301,581)	$ (11,225,160.61)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (30,228.85)		$ 45,111.63		$ (53,092.69)		$ (22,247.79)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 241,752.01		$ 241,752.01		$ -								
11 Real Time Spinning Reserve Cost Distribution		$ 232,232.45		$ 232,232.45		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 17,828.01		$ 17,828.01		$ -								
13 Real Time Short Term Reserve Cost Distribution		$ 53,340.59		$ 53,549.66		$ (209.07)								
Penalty Charges														
13 Real Time Excessive/Deficient Energy Deployment		$ 35,864.85		$ 20,677.28		$ -		$ 15,187.57						
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -				$ -				
15 Real Time Short Term Reserve Deployment Failure		$ 23.12		$ 23.12		$ -				$ -				
MISO ASM CHARGES	210,976	$ 201,743.70	516,394	$ 12,562,984.63	(305,418)	$ (11,682,021.67)	-	$ (7,060.22)	-	$ (672,159.04)	-	$ -	-	$ -
x Net Congestion Amount		$ (3,770,861.91)		$ (3,770,861.91)				$ -						
y Net Loss Amount		$ (427,757.52)		$ (427,757.52)				$ -						
z Net Congestion and Loss Energy Offset		$ 4,198,619.43		$ 4,198,619.43										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	210,976	$ 201,743.70	516,394	$ 12,562,984.63	(305,418)	$ (11,682,021.67)	-	$ (7,060.22)	-	$ (672,159.04)	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

June 2022	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
Procurement Charges														
1 Day-Ahead Regulation Amount		$ (387,629.86)		$ -		$ (71,560.74)				$ (316,069.12)				
2 Day-Ahead Spinning Reserve Amount		$ (363,273.44)		$ -		$ (61,754.38)				$ (301,519.06)				
3 Day-Ahead Supplemental Reserve		$ (54,393.60)		$ -		$ (9,130.79)				$ (45,262.81)				
4 Day-Ahead Short Term Reserve Amount		$ (79,805.32)		$ 0.66		$ (3,707.04)				$ (76,098.94)				
5 Real-Time Regulation Amount (See Note 1)		$ (128,522.22)		$ 176,629.84		$ (305,152.06)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (92,491.91)		$ 65,316.03		$ (157,807.94)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (6,035.22)		$ 7,955.49		$ (13,990.71)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ (849.36)		$ 2,319.22		$ (3,168.58)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(2,256)	$ (16,543.91)	68	$ (1,351.16)	(2,323)	$ (15,192.75)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	250,041	$ 6,449,303.01	600,096	$ 19,292,316.89	(350,055)	$ (12,843,013.88)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (14,138.33)		$ 62,135.26		$ (49,467.27)		$ (26,806.32)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 173,210.40		$ 173,210.40		$ -								
11 Real Time Spinning Reserve Cost Distribution		$ 179,382.02		$ 179,382.02		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 45,537.08		$ 45,537.08		$ -								
13 Real Time Short Term Reserve Cost Distribution		$ 84,640.74		$ 85,130.34		$ (489.60)								
Penalty Charges														
13 Real Time Excessive/Deficient Energy Deployment		$ 90,976.31		$ 55,779.61		$ -		$ 35,196.70						
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -				$ -				
15 Real Time Short Term Reserve Deployment Failure		$ 18.75		$ -		$ -				$ 18.75				
MISO ASM CHARGES	247,785	$ 5,879,385.14	600,164	$ 20,144,361.68	(352,378)	$ (13,534,435.74)	-	$ 8,390.38	-	$ (738,931.18)	-	$ -	-	$ -
x Net Congestion Amount		$ (1,317,934.47)		$ (1,317,934.47)				$ -						
y Net Loss Amount		$ 26,644.58		$ 26,644.58				$ -						
z Net Congestion and Loss Energy Offset		$ 1,291,289.89		$ 1,291,289.89										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	247,785	$ 5,879,385.14	600,164	$ 20,144,361.68	(352,378)	$ (13,534,435.74)	-	$ 8,390.38	-	$ (738,931.18)	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

July 2022	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
Procurement Charges														
1 Day-Ahead Regulation Amount		$ (385,722.15)		$ -		$ (92,831.27)				$ (292,890.88)				
2 Day-Ahead Spinning Reserve Amount		$ (125,315.68)		$ -		$ 7,740.74				$ (133,056.42)				
3 Day-Ahead Supplemental Reserve		$ (95,667.64)		$ -		$ (70,403.19)				$ (25,264.45)				
4 Day-Ahead Short Term Reserve Amount		$ (34,939.41)		$ 0.25		$ (18,405.53)				$ (16,534.13)				
5 Real-Time Regulation Amount (See Note 1)		$ (97,816.95)		$ 283,051.02		$ (380,867.97)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (74,668.16)		$ 152,684.62		$ (227,352.78)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 105,789.17		$ 128,299.88		$ (22,510.71)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ 1,197.56		$ 5,647.98		$ (4,450.42)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(3,634)	$ 15,118.64	50	$ (651.78)	(3,684)	$ 15,770.42								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	185,719	$ 10,120,815.97	514,779	$ 25,490,707.85	(329,059)	$ (15,369,891.88)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 123,182.49		$ 91,769.09		$ (51,686.38)		$ 83,099.78						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 179,333.48		$ 179,333.48		$ -								
11 Real Time Spinning Reserve Cost Distribution		$ 61,170.38		$ 61,170.38		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 158,383.18		$ 158,383.18		$ -								
13 Real Time Short Term Reserve Cost Distribution		$ 58,735.45		$ 59,094.41		$ (358.96)								
Penalty Charges														
13 Real Time Excessive/Deficient Energy Deployment		$ 83,037.63		$ 24,353.27		$ -		$ 58,684.36						
14 Real Time Contingency Reserve Deployment Failure		$ 3,929.16		$ 3,929.16		$ -				$ -				
15 Real Time Short Term Reserve Deployment Failure		$ -		$ -		$ -				$ -				
MISO ASM CHARGES	182,085	$ 10,096,563.12	514,828	$ 26,637,772.79	(332,743)	$ (16,215,247.93)	-	$ 141,784.14	-	$ (467,745.88)	-	$ -	-	$ -
x Net Congestion Amount		$ (1,049,875.29)		$ (1,049,875.29)				$ -						
y Net Loss Amount		$ (475,919.80)		$ (475,919.80)				$ -						
z Net Congestion and Loss Energy Offset		$ 1,525,795.09		$ 1,525,795.09										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	182,085	$ 10,096,563.12	514,828	$ 26,637,772.79	(332,743)	$ (16,215,247.93)	-	$ 141,784.14	-	$ (467,745.88)	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

August 2022	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
Procurement Charges														
1 Day-Ahead Regulation Amount		$ (253,746.35)		$ -		$ 5,396.22				$ (259,142.57)				
2 Day-Ahead Spinning Reserve Amount		$ (155,482.31)		$ -		$ 94,117.25				$ (249,599.56)				
3 Day-Ahead Supplemental Reserve		$ (39,161.50)		$ -		$ (57,511.83)				$ 18,350.33				
4 Day-Ahead Short Term Reserve Amount		$ (24,990.47)		$ 0.71		$ (10,383.25)				$ (14,607.93)				
5 Real-Time Regulation Amount (See Note 1)		$ (225,143.66)		$ 138,033.17		$ (363,176.83)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (102,140.69)		$ 139,781.24		$ (241,921.93)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 76,077.64		$ 96,942.33		$ (20,864.69)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ (184.81)		$ 5,443.34		$ (5,628.15)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(1,362)	$ (42,689.47)	222	$ (1,871.11)	(1,584)	$ (40,818.36)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	144,415	$ 7,408,023.66	481,741	$ 25,831,273.91	(337,326)	$ (18,423,250.25)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (13,172.62)		$ 29,157.66		$ (49,573.47)		$ 7,243.19						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 162,246.14		$ 162,246.14		$ -								
11 Real Time Spinning Reserve Cost Distribution		$ 151,469.96		$ 151,469.96		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 5,635.85		$ 5,635.85		$ -								
13 Real Time Short Term Reserve Cost Distribution		$ 16,760.08		$ 17,038.86		$ (278.78)								
Penalty Charges														
13 Real Time Excessive/Deficient Energy Deployment		$ 99,463.36		$ 37,834.74		$ -		$ 61,628.62						
14 Real Time Contingency Reserve Deployment Failure		$ 211,246.65		$ 159,735.64		$ -				$ 51,511.01				
15 Real Time Short Term Reserve Deployment Failure		$ -		$ -		$ -				$ -				
MISO ASM CHARGES	143,053	$ 7,274,211.46	481,963	$ 26,772,722.44	(338,911)	$ (19,113,894.07)	-	$ 68,871.81	-	$ (453,488.72)	-	$ -	-	$ -
x Net Congestion Amount		$ (1,218,423.75)		$ (1,218,423.75)				$ -						
y Net Loss Amount		$ (313,577.95)		$ (313,577.95)				$ -						
z Net Congestion and Loss Energy Offset		$ 1,532,001.70		$ 1,532,001.70										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	143,053	$ 7,274,211.46	481,963	$ 26,772,722.44	(338,911)	$ (19,113,894.07)	-	$ 68,871.81	-	$ (453,488.72)	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

September 2022	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
Procurement Charges														
1 Day-Ahead Regulation Amount		$ (165,160.75)		$ -		$ 12,133.91				$ (177,294.66)				
2 Day-Ahead Spinning Reserve Amount		$ (141,448.31)		$ -		$ (84,769.61)				$ (56,678.70)				
3 Day-Ahead Supplemental Reserve		$ (23,017.01)		$ -		$ (17,265.92)				$ (5,751.09)				
4 Day-Ahead Short Term Reserve Amount		$ (20,544.25)		$ 0.62		$ 2,136.72				$ (22,681.59)				
5 Real-Time Regulation Amount (See Note 1)		$ (167,325.65)		$ 71,279.19		$ (238,604.84)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (10,003.08)		$ 53,858.31		$ (63,861.39)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 5,741.16		$ 8,622.99		$ (2,881.83)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ 1,861.69		$ 3,636.99		$ (1,775.30)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(2,074)	$ (58,986.13)	37	$ 68.29	(2,110)	$ (59,054.42)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	207,155	$ 9,564,632.50	482,341	$ 19,821,631.67	(275,187)	$ (10,256,999.17)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 16,716.55		$ 45,367.96		$ (37,999.71)		$ 9,348.30						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 167,417.21		$ 167,417.21		$ -								
11 Real Time Spinning Reserve Cost Distribution		$ 84,635.27		$ 84,635.27		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 29,732.70		$ 29,732.70		$ -								
13 Real Time Short Term Reserve Cost Distribution		$ 53,152.26		$ 53,718.35		$ (566.09)								
Penalty Charges														
13 Real Time Excessive/Deficient Energy Deployment		$ 73,971.85		$ 30,824.05		$ -		$ 43,147.80						
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -				$ -				
15 Real Time Short Term Reserve Deployment Failure		$ 82.94		$ 76.47		$ -				$ 6.47				
MISO ASM CHARGES	205,081	$ 9,411,458.95	482,378	$ 20,370,870.07	(277,297)	$ (10,749,507.65)	-	$ 52,496.10	-	$ (262,399.57)	-	$ -	-	$ -
x Net Congestion Amount		$ (129,250.24)		$ (129,250.24)				$ -						
y Net Loss Amount		$ (68,544.08)		$ (68,544.08)				$ -						
z Net Congestion and Loss Energy Offset		$ 197,794.32		$ 197,794.32										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	205,081	$ 9,411,458.95	482,378	$ 20,370,870.07	(277,297)	$ (10,749,507.65)	-	$ 52,496.10	-	$ (262,399.57)	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

October 2022	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
Procurement Charges														
1 Day-Ahead Regulation Amount		$ (169,858.02)		$ -		$ (72,803.17)				$ (97,054.85)				
2 Day-Ahead Spinning Reserve Amount		$ (155,734.38)		$ -		$ (50,830.73)				$ (104,903.65)				
3 Day-Ahead Supplemental Reserve		$ (15,467.08)		$ -		$ (6,466.49)				$ (9,000.59)				
4 Day-Ahead Short Term Reserve Amount		$ (22,217.22)		$ 0.44		$ (7,936.35)				$ (14,281.31)				
5 Real-Time Regulation Amount (See Note 1)		$ (40,046.19)		$ 96,775.26		$ (136,821.45)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (12,359.17)		$ 93,144.62		$ (105,503.79)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 2,601.55		$ 2,955.43		$ (353.88)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ 3,268.49		$ 4,943.20		$ (1,674.71)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(5,925)	$ 119,747.19	39	$ 91,671.89	(5,963)	$ 28,075.30								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	232,601	$ 6,900,860.11	502,040	$ 14,672,973.87	(269,439)	$ (7,772,113.76)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 13,454.16		$ 21,002.55		$ (15,022.77)		$ 7,474.38						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 168,580.43		$ 168,647.61		$ (67.18)								
11 Real Time Spinning Reserve Cost Distribution		$ 178,758.16		$ 179,561.87		$ (803.71)								
12 Real Time Supplemental Reserve Cost Distribution		$ 22,145.93		$ 22,635.21		$ (489.28)								
13 Real Time Short Term Reserve Cost Distribution		$ 26,523.16		$ 27,133.67		$ (610.51)								
Penalty Charges														
13 Real Time Excessive/Deficient Energy Deployment		$ 61,455.34		$ 38,360.58		$ (41.41)		$ 23,136.17						
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -				$ -				
15 Real Time Short Term Reserve Deployment Failure		$ 5,852.90		$ 4,189.63		$ -				$ 1,663.27				
MISO ASM CHARGES	226,676	$ 7,087,565.36	502,078	$ 15,423,995.83	(275,402)	$ (8,143,463.89)	-	$ 30,610.55	-	$ (223,577.13)	-	$ -	-	$ -
x Net Congestion Amount		$ (337,782.81)		$ (337,782.81)				$ -						
y Net Loss Amount		$ 53,067.95		$ 53,067.95				$ -						
z Net Congestion and Loss Energy Offset		$ 284,714.86		$ 284,714.86										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	226,676	$ 7,087,565.36	502,078	$ 15,423,995.83	(275,402)	$ (8,143,463.89)	-	$ 30,610.55	-	$ (223,577.13)	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

November 2022	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
Procurement Charges														
1 Day-Ahead Regulation Amount		$ (152,308.53)		$ -		$ (79,693.67)				$ (72,614.86)				
2 Day-Ahead Spinning Reserve Amount		$ (290,932.16)		$ -		$ (48,896.01)				$ (242,036.15)				
3 Day-Ahead Supplemental Reserve		$ (15,535.56)		$ -		$ (10,115.48)				$ (5,420.08)				
4 Day-Ahead Short Term Reserve Amount		$ (57,263.97)		$ 0.54		$ 13,738.16				$ (71,002.67)				
5 Real-Time Regulation Amount (See Note 1)		$ (71,418.55)		$ 34,193.67		$ (105,612.22)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (84,335.71)		$ 68,054.82		$ (152,390.53)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 13,463.47		$ 16,461.74		$ (2,998.27)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ (3,642.98)		$ 22,766.87		$ (26,409.85)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(1,639)	$ 17,855.08	1,394	$ 20,317.55	(3,033)	$ (2,462.47)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	257,360	$ 5,644,725.13	576,299	$ 12,606,671.52	(318,939)	$ (6,961,946.39)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (6,290.68)		$ 8,567.09		$ (12,235.98)		$ (2,621.79)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 158,879.29		$ 158,860.49		$ 18.80								
11 Real Time Spinning Reserve Cost Distribution		$ 224,083.74		$ 226,910.95		$ (2,827.21)								
12 Real Time Supplemental Reserve Cost Distribution		$ 7,150.09		$ 7,676.74		$ (526.65)								
13 Real Time Short Term Reserve Cost Distribution		$ 80,409.22		$ 82,291.30		$ (1,882.08)								
Penalty Charges														
13 Real Time Excessive/Deficient Energy Deployment		$ 37,749.09		$ 24,968.85		$ (569.50)		$ 13,349.74						
14 Real Time Contingency Reserve Deployment Failure		$ 125.90		$ 125.90		$ -				$ -				
15 Real Time Short Term Reserve Deployment Failure		$ 1,910.03		$ 1,765.72		$ -				$ 144.31				
MISO ASM CHARGES	255,721	$ 5,504,622.90	577,692	$ 13,279,633.75	(321,971)	$ (7,394,809.35)	-	$ 10,727.95	-	$ (390,929.45)	-	$ -	-	$ -
x Net Congestion Amount		$ (939,845.33)		$ (939,845.33)				$ -						
y Net Loss Amount		$ (92,186.09)		$ (92,186.09)				$ -						
z Net Congestion and Loss Energy Offset		$ 1,032,031.42		$ 1,032,031.42										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	255,721	$ 5,504,622.90	577,692	$ 13,279,633.75	(321,971)	$ (7,394,809.35)	-	$ 10,727.95	-	$ (390,929.45)	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

December 2022	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
Procurement Charges														
1 Day-Ahead Regulation Amount		$ (249,550.24)		$ -		$ 287,146.11				$ (536,696.35)				
2 Day-Ahead Spinning Reserve Amount		$ (257,324.17)		$ -		$ 1,015,675.83				$ (1,273,000.00)				
3 Day-Ahead Supplemental Reserve		$ (99,883.02)		$ -		$ (3,025.52)				$ (96,857.50)				
4 Day-Ahead Short Term Reserve Amount		$ (272,405.85)		$ 9.25		$ 705,871.18				$ (978,286.28)				
5 Real-Time Regulation Amount (See Note 1)		$ (576,602.84)		$ 102,280.84		$ (678,883.68)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (1,379,113.30)		$ 284,299.76		$ (1,663,413.06)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 135,299.24		$ 866,552.45		$ (731,253.21)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ (629,124.22)		$ 147,781.42		$ (776,905.64)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(1,447)	$ (10,754.75)	370	$ (307.65)	(1,816)	$ (10,447.10)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	(217,245)	$ (10,707,366.47)	395,850	$ 17,518,308.71	(613,096)	$ (28,225,675.18)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 39,991.15		$ 107,069.73		$ (118,012.63)		$ 50,934.05						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 171,280.59		$ 171,293.56		$ (12.97)								
11 Real Time Spinning Reserve Cost Distribution		$ 183,323.99		$ 183,979.30		$ (655.31)								
12 Real Time Supplemental Reserve Cost Distribution		$ (9,191.33)		$ 5,029.48		$ (14,220.81)								
13 Real Time Short Term Reserve Cost Distribution		$ 657,892.39		$ 751,426.23		$ (93,533.84)								
Penalty Charges														
13 Real Time Excessive/Deficient Energy Deployment		$ 284,716.90		$ 236,574.79		$ (47.17)		$ 48,189.28						
14 Real Time Contingency Reserve Deployment Failure		$ 83,197.61		$ 59,086.06		$ -				$ 24,111.55				
15 Real Time Short Term Reserve Deployment Failure		$ 2,440.50		$ -		$ -				$ 2,440.50				
MISO ASM CHARGES	(218,692)	$ (12,633,173.82)	396,220	$ 20,433,383.93	(614,912)	$ (30,307,393.00)	-	$ 99,123.33	-	$ (2,858,288.08)	-	$ -	-	$ -
x Net Congestion Amount		$ (1,132,268.97)		$ (1,132,268.97)				$ -						
y Net Loss Amount		$ 101,965.16		$ 101,965.16				$ -						
z Net Congestion and Loss Energy Offset		$ 1,030,303.81		$ 1,030,303.81										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	(218,692)	$ (12,633,173.82)	396,220	$ 20,433,383.93	(614,912)	$ (30,307,393.00)	-	$ 99,123.33	-	$ (2,858,288.08)	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

January - December 2022	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
Posting Account Description	MWh	Net Cost	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
Procurement Charges														
1 Day-Ahead Regulation Amount		$ (2,734,110.97)		$ -		$ (380,926.95)				$ (2,353,184.02)				
2 Day-Ahead Spinning Reserve Amount		$ (2,768,401.62)		$ -		$ 815,086.52				$ (3,583,488.14)				
3 Day-Ahead Supplemental Reserve		$ (473,671.62)		$ -		$ (224,356.72)				$ (249,314.90)				
4 Day-Ahead Short Term Reserve Amount		$ (895,373.37)		$ 91,873.14		$ 683,177.59				$ (1,670,424.10)				
5 Real-Time Regulation Amount (See Note 1)		$ (1,710,242.13)		$ 1,281,303.96		$ (2,991,546.09)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (2,291,669.03)		$ 1,155,996.91		$ (3,447,665.94)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 340,567.63		$ 1,168,117.50		$ (827,549.87)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ (682,558.16)		$ 222,271.66		$ (904,829.82)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(35,901)	$ 327,104.84	2,508	$ 102,689.89	(38,408)	$ 224,414.95								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	1,789,410	$ 48,243,873.90	6,105,119	$ 181,155,931.20	(4,315,709)	$ (132,912,057.30)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (1,791,750.46)		$ 472,350.34		$ (2,378,553.04)		$ 114,452.24						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 2,093,995.60		$ 2,094,056.95		$ (61.35)								
11 Real Time Spinning Reserve Cost Distribution		$ 1,888,162.75		$ 1,892,448.98		$ (4,286.23)								
12 Real Time Supplemental Reserve Cost Distribution		$ 344,881.17		$ 360,117.91		$ (15,236.74)								
13 Real Time Short Term Reserve Cost Distribution		$ 1,317,411.23		$ 1,540,421.54		$ (223,010.31)								
Penalty Charges														
13 Real Time Excessive/Deficient Energy Deployment		$ 939,620.54		$ 563,174.93		$ (658.08)		$ 377,103.69						
14 Real Time Contingency Reserve Deployment Failure		$ 302,636.43		$ 227,454.10		$ -				$ 75,182.33				
15 Real Time Short Term Reserve Deployment Failure		$ 17,628.64		$ 7,252.08		$ -				$ 10,376.56				
MISO ASM CHARGES	1,753,510	$ 42,468,105.37	6,107,627	$ 192,335,461.09	(4,354,117)	$ (142,588,059.38)	-	$ 491,555.93	-	$ (7,770,852.27)	-	$ -	-	$ -
x Net Congestion Amount		$ (8,909,536.88)		$ (8,909,536.88)				$ -						
y Net Loss Amount		$ (849,797.78)		$ (849,797.78)				$ -						
z Net Congestion and Loss Energy Offset		$ 9,759,334.66		$ 9,759,334.66										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	1,753,510	$ 42,468,105.37	6,107,627	$ 192,335,461.09	(4,354,117)	$ (142,588,059.38)	-	$ 491,555.93	-	$ (7,770,852.27)	-	$ -	-	$ -

x No longer reported in 7b, 8b
y No longer reported in 7c, 8c
z No longer used to offset the MISO billed energy amount in 7a, 8a

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Cont Reserve Depl Failure Charge	Excessive/Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
1/1/2022	2,146,670	2,164,360	17,690	0.82%	0	369	-14	7,634	1,110	874	16,461
1/2/2022	2,999,790	3,007,470	7,680	0.26%	0	914	1,046	9,281	1,756	1,104	4,616
1/3/2022	2,195,160	2,204,580	9,420	0.43%	0	2,853	316	7,349	1,529	888	5,363
1/4/2022	1,388,770	1,387,380	-1,390	-0.10%	0	475	280	5,781	1,599	738	(2,883)
1/5/2022	1,602,190	1,620,760	18,570	1.15%	0	594	137	5,793	631	642	17,196
1/6/2022	3,684,260	3,688,690	4,430	0.12%	0	2,817	344	8,887	1,818	1,071	198
1/7/2022	3,615,990	3,619,690	3,700	0.10%	0	1,316	-1,268	9,799	2,199	1,200	2,452
1/8/2022	1,644,330	1,645,740	1,410	0.09%	0	71	196	6,678	693	737	406
1/9/2022	2,226,770	2,230,380	3,610	0.16%	0	3,361	142	7,750	259	801	(693)
1/10/2022	3,467,810	3,464,490	-3,320	-0.10%	0	1,013	1,664	10,527	364	1,089	(7,086)
1/11/2022	2,140,840	2,140,530	-310	-0.01%	0	370	-328	7,349	622	797	(1,149)
1/12/2022	2,582,450	2,585,490	3,040	0.12%	0	512	-211	8,802	810	961	1,778
1/13/2022	2,532,370	2,534,000	1,630	0.06%	0	1,175	444	8,769	329	910	(898)
1/14/2022	2,468,430	2,471,630	3,200	0.13%	0	442	973	8,301	147	845	941
1/15/2022	2,470,440	2,474,670	4,230	0.17%	0	1,250	121	8,452	465	892	1,968
1/16/2022	1,279,030	1,296,460	17,430	1.34%	0	218	127	6,046	607	665	16,419
1/17/2022	3,015,520	3,015,040	-480	-0.02%	0	1,507	1,972	9,282	581	986	(4,946)
1/18/2022	2,024,800	2,025,270	470	0.02%	0	518	-1,271	7,287	1,627	891	331
1/19/2022	2,035,850	2,036,210	360	0.02%	0	413	23	6,832	640	747	(823)
1/20/2022	4,192,790	4,195,350	2,560	0.06%	0	1,204	195	10,751	954	1,170	(10)
1/21/2022	1,901,800	1,902,770	970	0.05%	0	1,745	8	7,520	840	836	(1,619)
1/22/2022	2,700,750	2,703,450	2,700	0.10%	0	1,560	-975	9,001	1,241	1,024	1,091
1/23/2022	2,695,860	2,696,550	690	0.03%	0	2,244	376	9,276	785	1,006	(2,937)
1/24/2022	2,374,730	2,375,640	910	0.04%	0	715	-93	7,534	525	806	(518)
1/25/2022	3,368,020	3,370,930	2,910	0.09%	0	181	675	9,335	769	1,010	1,043
1/26/2022	2,429,900	2,429,650	-250	-0.01%	0	1,305	-21	7,229	818	805	(2,338)
1/27/2022	1,974,680	1,975,130	450	0.02%	0	679	242	6,223	293	652	(1,122)
1/28/2022	3,763,770	3,764,910	1,140	0.03%	0	1,794	485	10,830	795	1,163	(2,302)
1/29/2022	1,661,500	1,661,160	-340	-0.02%	0	610	231	6,823	262	709	(1,890)
1/30/2022	2,899,120	2,904,310	5,190	0.18%	0	2,944	342	8,878	683	956	948
1/31/2022	1,872,150	1,893,710	21,560	1.14%	0	4,033	7,210	7,262	1,114	838	9,480
2/1/2022	1,758,030	1,769,630	11,600	0.66%	0	980	7	4,906	667	557	10,056
2/2/2022	1,668,430	1,692,400	23,970	1.42%	0	850	-15	4,873	16	489	22,646
2/3/2022	1,694,490	1,722,340	27,850	1.62%	0	6	-18	4,891	53	494	27,368
2/4/2022	3,001,710	3,005,850	4,140	0.14%	0	1,462	-503	6,440	722	716	2,465
2/5/2022	1,956,490	1,974,380	17,890	0.91%	0	158	13	4,863	169	503	17,216
2/6/2022	1,618,680	1,621,380	2,700	0.17%	0	1,272	574	4,278	41	432	422
2/7/2022	3,386,560	3,410,940	24,380	0.71%	0	4,743	-429	6,669	251	692	19,374

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Cont Reserve Depl Failure Charge	Excessive/Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
2/8/2022	1,037,120	1,049,190	12,070	1.15%	0	0	0	3,327	46	337	11,733
2/9/2022	1,043,310	1,056,220	12,910	1.22%	0	48	24	3,518	118	364	12,475
2/10/2022	1,569,970	1,577,910	7,940	0.50%	0	2,064	41	3,847	218	406	5,429
2/11/2022	742,370	759,850	17,480	2.30%	0	14	-50	3,040	72	311	17,205
2/12/2022	3,156,700	3,170,110	13,410	0.42%	0	912	491	6,320	1,168	749	11,258
2/13/2022	2,870,040	2,881,440	11,400	0.40%	0	3,085	-392	6,545	737	728	7,979
2/14/2022	3,012,520	3,012,820	300	0.01%	0	725	709	6,561	739	730	(1,863)
2/15/2022	2,171,480	2,176,110	4,630	0.21%	0	1,210	-516	5,335	150	549	3,387
2/16/2022	1,697,240	1,678,140	-19,100	-1.14%	0	83	-9	4,513	299	481	(19,655)
2/17/2022	2,727,550	2,702,890	-24,660	-0.91%	0	1,474	1,165	6,021	173	619	(27,919)
2/18/2022	1,395,150	1,371,900	-23,250	-1.69%	0	175	585	4,191	78	427	(24,437)
2/19/2022	1,429,330	1,436,570	7,240	0.50%	0	1,197	-505	4,199	304	450	6,098
2/20/2022	784,760	796,240	11,480	1.44%	0	132	295	3,172	113	329	10,725
2/21/2022	1,452,660	1,450,500	-2,160	-0.15%	0	155	641	3,936	358	429	(3,386)
2/22/2022	2,106,930	2,106,600	-330	-0.02%	0	39	1,732	5,085	195	528	(2,629)
2/23/2022	3,489,850	3,489,580	-270	-0.01%	0	1,502	3,172	6,735	220	696	(5,640)
2/24/2022	3,893,710	3,897,630	3,920	0.10%	0	616	1,371	7,415	331	775	1,158
2/25/2022	3,591,250	3,593,230	1,980	0.06%	0	871	1,344	6,786	169	695	(931)
2/26/2022	1,096,940	1,101,380	4,440	0.40%	0	169	168	3,768	98	387	3,717
2/27/2022	2,225,410	2,228,170	2,760	0.12%	0	523	2,817	5,218	326	554	(1,135)
2/28/2022	1,532,220	1,535,160	2,940	0.19%	0	1,938	184	4,214	39	425	393
3/1/2022	2,838,660	2,845,650	6,990	0.25%	0	54	154	10,186	235	1,042	5,740
3/2/2022	2,229,980	2,230,500	520	0.02%	0	3,172	2,964	9,067	136	920	(6,536)
3/3/2022	2,448,580	2,454,130	5,550	0.23%	0	162	-177	9,137	485	962	4,603
3/4/2022	1,179,940	1,199,350	19,410	1.62%	0	970	-109	6,441	205	665	17,884
3/5/2022	956,380	972,270	15,890	1.63%	0	914	-258	5,924	102	603	14,631
3/6/2022	777,270	799,590	22,320	2.79%	0	0	71	5,326	56	538	21,710
3/7/2022	1,520,960	1,534,410	13,450	0.88%	0	1,126	13	6,860	436	730	11,582
3/8/2022	980,560	1,002,720	22,160	2.21%	0	418	552	5,613	655	627	20,563
3/9/2022	1,289,150	1,311,460	22,310	1.70%	0	517	8	6,565	976	754	21,031
3/10/2022	2,297,340	2,299,040	1,700	0.07%	0	1,266	438	8,388	620	901	(905)
3/11/2022	726,430	744,340	17,910	2.41%	0	229	125	5,077	175	525	17,031
3/12/2022	1,857,010	1,874,870	17,860	0.95%	0	839	265	7,433	298	773	15,983
3/13/2022	1,700,030	1,710,010	9,980	0.58%	0	614	-539	7,396	187	758	9,147
3/14/2022	1,914,190	1,919,220	5,030	0.26%	0	483	-93	7,927	500	843	3,797
3/15/2022	1,631,060	1,643,950	12,890	0.78%	0	99	74	7,163	125	729	11,989
3/16/2022	746,150	764,680	18,530	2.42%	0	0	156	5,165	-11	515	17,859
3/17/2022	1,240,760	1,264,410	23,650	1.87%	0	54	-795	6,221	77	630	23,761

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Cont Reserve Depl Failure Charge	Excessive/Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
3/18/2022	1,058,740	1,075,110	16,370	1.52%	0	340	12	5,867	131	600	15,418
3/19/2022	1,705,100	1,710,440	5,340	0.31%	0	326	-278	7,368	223	759	4,533
3/20/2022	934,760	950,150	15,390	1.62%	0	2	40	5,682	32	571	14,777
3/21/2022	820,390	843,150	22,760	2.70%	0	243	820	5,463	113	558	21,140
3/22/2022	748,270	768,250	19,980	2.60%	0	4	85	4,310	309	462	19,429
3/23/2022	808,700	828,850	20,150	2.43%	0	6	5	5,669	208	588	19,551
3/24/2022	1,336,180	1,361,220	25,040	1.84%	0	271	20	6,707	519	723	24,026
3/25/2022	580,940	611,000	30,060	4.92%	0	0	0	4,920	-141	478	29,582
3/26/2022	759,410	782,660	23,250	2.97%	0	103	0	5,123	229	535	22,612
3/27/2022	2,218,120	2,234,320	16,200	0.73%	0	1,808	-305	7,888	215	810	13,886
3/28/2022	1,698,950	1,714,970	16,020	0.93%	0	3,083	233	7,497	190	769	11,935
3/29/2022	1,345,740	1,359,560	13,820	1.02%	0	121	41	6,748	190	694	12,964
3/30/2022	1,272,210	1,284,050	11,840	0.92%	0	161	-240	6,285	131	642	11,277
3/31/2022	1,684,480	1,705,930	21,450	1.26%	0	1,837	-494	6,908	239	715	19,392
4/1/2022	2,196,240	2,203,380	7,140	0.32%	0	4,534	-3,640	8,129	243	837	5,409
4/2/2022	2,072,830	2,082,290	9,460	0.45%	0	508	-971	7,811	264	807	9,115
4/3/2022	1,596,580	1,601,140	4,560	0.28%	0	410	-189	6,830	199	703	3,636
4/4/2022	2,070,000	2,077,400	7,400	0.36%	0	3,420	366	7,552	286	784	2,831
4/5/2022	791,470	799,920	8,450	1.06%	0	399	-34	5,156	-4	515	7,570
4/6/2022	715,720	723,810	8,090	1.12%	0	1,388	-1,687	5,222	-43	518	7,872
4/7/2022	896,230	883,590	-12,640	-1.43%	0	22	-92	5,484	87	557	(13,127)
4/8/2022	1,018,070	1,007,010	-11,060	-1.10%	0	77	157	5,497	81	558	(11,852)
4/9/2022	1,326,440	1,350,170	23,730	1.76%	0	611	-74	5,917	34	595	22,597
4/10/2022	584,210	623,050	38,840	6.23%	0	0	0	4,767	-113	465	38,375
4/11/2022	2,731,710	2,750,710	19,000	0.69%	0	4,621	-5,970	7,949	351	830	19,519
4/12/2022	819,280	862,980	43,700	5.06%	0	0	0	5,083	-58	503	43,197
4/13/2022	904,040	920,040	16,000	1.74%	0	2,098	617	5,432	4	544	12,741
4/14/2022	1,225,380	1,240,870	15,490	1.25%	0	15	-18	5,933	5	594	14,899
4/15/2022	1,210,650	1,218,190	7,540	0.62%	0	38	0	5,662	-51	561	6,941
4/16/2022	1,418,480	1,429,240	10,760	0.75%	0	826	91	5,865	31	590	9,254
4/17/2022	1,271,270	1,284,450	13,180	1.03%	0	743	-177	5,775	2	578	12,036
4/18/2022	988,020	1,005,730	17,710	1.76%	0	4,201	1,200	5,500	142	564	11,745
4/19/2022	2,248,400	2,279,160	30,760	1.35%	0	1,373	-937	6,876	366	724	29,600
4/20/2022	1,396,380	1,408,090	11,710	0.83%	0	463	-1,871	5,905	30	594	12,525
4/21/2022	2,777,050	2,785,780	8,730	0.31%	0	3,725	-587	8,020	323	834	4,758
4/22/2022	673,710	685,360	11,650	1.70%	0	34	154	5,074	-52	502	10,959
4/23/2022	583,480	631,460	47,980	7.60%	0	0	0	4,780	-189	459	47,521
4/24/2022	575,400	629,550	54,150	8.60%	0	0	0	4,773	-176	460	53,690

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4/25/2022	1,811,920	1,826,570	14,650	0.80%	0	3,691	-1,327	6,320	201	652	11,634
4/26/2022	3,029,620	3,052,120	22,500	0.74%	0	3,486	-496	8,713	548	926	18,584
4/27/2022	919,710	933,060	13,350	1.43%	0	0	-11	5,102	-14	509	12,852
4/28/2022	1,286,690	1,307,340	20,650	1.58%	0	630	156	5,878	208	609	19,256
4/29/2022	643,570	686,590	43,020	6.27%	0	0	0	4,779	-201	458	42,562
4/30/2022	661,270	713,010	51,740	7.26%	0	7	315	4,785	-149	464	50,955
5/1/2022	663,360	716,950	53,590	7.47%	0	0	0	4,217	-141	408	53,182
5/2/2022	2,434,160	2,452,460	18,300	0.75%	0	709	-3,334	6,286	591	688	20,237
5/3/2022	2,076,690	2,092,170	15,480	0.74%	0	2,052	-2,018	5,959	-25	593	14,853
5/4/2022	2,574,060	2,582,300	8,240	0.32%	0	981	412	6,570	396	697	6,151
5/5/2022	2,507,290	2,526,080	18,790	0.74%	0	2,720	-1,920	6,336	300	664	17,326
5/6/2022	2,684,860	2,705,560	20,700	0.77%	0	3,658	-36	6,256	216	647	16,430
5/7/2022	968,480	997,090	28,610	2.87%	0	0	0	4,648	-171	448	28,162
5/8/2022	714,860	747,960	33,100	4.43%	0	0	0	4,235	-153	408	32,692
5/9/2022	834,780	880,080	45,300	5.15%	0	4	-129	4,217	-67	415	45,011
5/10/2022	2,815,860	2,828,090	12,230	0.43%	0	239	-2,892	6,028	573	660	14,223
5/11/2022	1,284,500	1,315,910	31,410	2.39%	0	2,458	-244	4,805	537	534	28,661
5/12/2022	1,044,820	1,089,660	44,840	4.12%	0	1,680	-450	4,482	98	458	43,151
5/13/2022	2,109,680	2,151,490	41,810	1.94%	0	1,556	-8,211	5,361	337	570	47,895
5/14/2022	1,061,040	1,097,670	36,630	3.34%	0	532	-1,841	4,435	574	501	37,439
5/15/2022	1,153,100	1,198,530	45,430	3.79%	0	22	0	4,548	6	455	44,953
5/16/2022	2,776,150	2,799,290	23,140	0.83%	0	4,512	424	6,438	525	696	17,508
5/17/2022	1,712,880	1,754,200	41,320	2.36%	0	1,531	475	5,158	58	522	38,793
5/18/2022	1,821,480	1,881,330	59,850	3.18%	0	1,866	-6,125	4,359	551	491	63,618
5/19/2022	1,869,770	1,879,740	9,970	0.53%	0	2,063	148	4,511	295	481	7,278
5/20/2022	765,340	818,210	52,870	6.46%	0	0	0	4,119	70	419	52,451
5/21/2022	2,398,720	2,427,100	28,380	1.17%	0	1,782	205	5,867	348	622	25,771
5/22/2022	1,782,740	1,781,250	-1,490	-0.08%	0	271	105	5,275	151	543	(2,408)
5/23/2022	1,938,740	1,963,440	24,700	1.26%	0	2,003	-263	5,372	277	565	22,396
5/24/2022	711,960	756,610	44,650	5.90%	0	0	0	4,082	-191	389	44,261
5/25/2022	1,167,170	1,196,800	29,630	2.48%	0	0	30	4,503	119	462	29,137
5/26/2022	1,474,120	1,495,120	21,000	1.40%	0	169	197	4,786	44	483	20,152
5/27/2022	2,097,830	2,111,030	13,200	0.63%	0	370	72	5,426	17	544	12,213
5/28/2022	1,200,910	1,214,220	13,310	1.10%	0	60	119	4,570	619	519	12,612
5/29/2022	1,259,400	1,280,680	21,280	1.66%	0	1,632	-8	5,006	44	505	19,152
5/30/2022	1,182,810	1,208,520	25,710	2.13%	0	45	2,488	5,078	254	533	22,643
5/31/2022	773,410	847,300	73,890	8.72%	0	694	-4,343	4,616	193	481	77,058
6/1/2022	3,694,740	3,696,460	1,720	0.05%	0	2,347	583	6,549	819	737	(1,946)

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Cont Reserve Depl Failure Charge	Excessive/Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
6/2/2022	2,107,100	2,120,470	13,370	0.63%	0	71	426	5,240	424	566	12,306
6/3/2022	3,032,700	3,040,900	8,200	0.27%	0	2,345	-63	6,157	113	627	5,291
6/4/2022	1,330,130	1,356,740	26,610	1.96%	0	159	-59	4,623	334	496	26,014
6/5/2022	2,025,930	2,038,270	12,340	0.61%	0	870	-72	5,554	154	571	10,972
6/6/2022	2,052,640	2,053,900	1,260	0.06%	0	1,462	-1,127	5,851	462	631	293
6/7/2022	3,701,090	3,698,530	-2,560	-0.07%	0	3,149	-3,024	7,694	520	821	(3,506)
6/8/2022	3,958,250	3,972,470	14,220	0.36%	0	401	-149	7,797	1,257	905	13,063
6/9/2022	3,428,770	3,433,590	4,820	0.14%	0	1,434	-2,369	7,239	217	746	5,009
6/10/2022	3,923,630	3,929,300	5,670	0.14%	0	5,729	-2,017	7,956	536	849	1,109
6/11/2022	1,591,750	1,602,250	10,500	0.66%	0	529	-317	5,461	47	551	9,737
6/12/2022	3,299,440	3,319,600	20,160	0.61%	0	6,197	2,930	7,109	688	780	10,253
6/13/2022	2,125,260	2,143,010	17,750	0.83%	0	3,033	-412	5,787	981	677	14,452
6/14/2022	4,722,050	4,739,050	17,000	0.36%	0	4,064	-971	7,921	1,347	927	12,981
6/15/2022	3,527,930	3,556,530	28,600	0.80%	0	612	529	7,700	1,919	962	26,497
6/16/2022	3,248,930	3,266,700	17,770	0.54%	0	2,504	-4,416	7,111	894	800	18,882
6/17/2022	4,478,080	4,486,040	7,960	0.18%	0	9,923	-4,137	8,699	659	936	1,237
6/18/2022	849,430	861,280	11,850	1.38%	0	270	-12	3,931	273	420	11,172
6/19/2022	1,490,570	1,511,410	20,840	1.38%	0	578	1,002	4,954	212	517	18,743
6/20/2022	4,112,510	4,123,520	11,010	0.27%	0	4,203	-361	8,046	664	871	6,296
6/21/2022	4,607,910	4,633,800	25,890	0.56%	0	14,294	-2,032	8,772	1,763	1,054	12,574
6/22/2022	5,586,450	5,574,180	-12,270	-0.22%	0	6,853	-3,903	10,314	657	1,097	(16,318)
6/23/2022	3,800,090	3,798,580	-1,510	-0.04%	0	4,076	473	8,442	798	924	(6,983)
6/24/2022	3,711,260	3,709,870	-1,390	-0.04%	0	1,488	3,379	8,264	1,032	930	(7,187)
6/25/2022	1,306,490	1,326,040	19,550	1.47%	0	245	-251	5,154	762	592	18,964
6/26/2022	1,819,670	1,823,660	3,990	0.22%	0	1,310	-55	5,473	467	594	2,141
6/27/2022	3,247,510	3,255,930	8,420	0.26%	0	1,833	-822	7,860	546	841	6,568
6/28/2022	2,411,140	2,427,310	16,170	0.67%	0	1,616	-161	6,484	257	674	14,040
6/29/2022	1,689,730	1,705,700	15,970	0.94%	0	1,247	196	5,678	551	623	13,905
6/30/2022	3,296,050	3,297,580	1,530	0.05%	3,929	4,107	871	7,287	599	789	(8,165)
7/1/2022	4,184,580	4,192,390	7,810	0.19%	0	3,067	-4,283	10,307	554	1,086	7,940
7/2/2022	2,906,480	2,916,300	9,820	0.34%	0	1,297	-719	8,821	1,311	1,013	8,229
7/3/2022	1,526,210	1,530,120	3,910	0.26%	0	168	4,530	6,612	928	754	(1,541)
7/4/2022	1,939,550	1,964,370	24,820	1.26%	0	1,081	-43	6,733	231	696	23,086
7/5/2022	4,270,990	4,267,900	-3,090	-0.07%	0	9,285	1,216	10,102	721	1,082	(14,673)
7/6/2022	4,133,860	4,135,580	1,720	0.04%	0	3,345	1,506	10,051	1,125	1,118	(4,249)
7/7/2022	4,171,750	4,173,530	1,780	0.04%	0	2,037	4,868	9,973	519	1,049	(6,175)
7/8/2022	4,089,960	4,088,740	-1,220	-0.03%	0	5,124	-362	10,530	236	1,077	(7,058)
7/9/2022	2,943,700	2,946,740	3,040	0.10%	0	3,329	49,626	8,607	239	885	(50,800)

Northern States Power Company, a Minnesota Corporation
Electric Operations – State of Minnesota
MISO – Ancillary Services Market

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Cont Reserve Depl Failure Charge	Excessive/Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
7/10/2022	1,403,800	1,421,320	17,520	1.23%	0	522	24,611	6,010	148	616	(8,228)
7/11/2022	1,972,510	1,973,600	1,090	0.06%	0	1,840	-638	6,948	308	726	(838)
7/12/2022	3,958,120	3,955,680	-2,440	-0.06%	0	1,729	-3,235	9,435	587	1,002	(1,936)
7/13/2022	3,982,760	3,981,150	-1,610	-0.04%	0	1,848	290	9,690	160	985	(4,734)
7/14/2022	3,310,770	3,312,810	2,040	0.06%	0	2,431	-702	8,716	764	948	(637)
7/15/2022	4,112,660	4,111,230	-1,430	-0.03%	0	1,797	-586	9,690	336	1,003	(3,643)
7/16/2022	3,884,040	3,875,260	-8,780	-0.23%	0	1,920	-377	9,820	-6	981	(11,304)
7/17/2022	4,044,990	4,042,100	-2,890	-0.07%	0	3,936	-1,194	10,267	100	1,037	(6,669)
7/18/2022	5,040,080	5,029,060	-11,020	-0.22%	0	7,090	19,023	10,947	584	1,153	(38,286)
7/19/2022	2,908,580	2,914,200	5,620	0.19%	0	5,167	7,570	8,532	968	950	(8,067)
7/20/2022	3,498,680	3,499,560	880	0.03%	0	4,343	-1,789	8,972	802	977	(2,651)
7/21/2022	5,070,530	5,073,960	3,430	0.07%	0	3,662	-2,886	11,095	517	1,161	1,493
7/22/2022	4,736,270	4,744,620	8,350	0.18%	0	1,882	2,915	10,370	439	1,081	2,471
7/23/2022	2,614,630	2,645,360	30,730	1.16%	0	371	-180	8,207	500	871	29,668
7/24/2022	2,868,100	2,867,880	-220	-0.01%	0	540	-1,128	8,117	356	847	(480)
7/25/2022	4,078,630	4,083,360	4,730	0.12%	0	2,100	-892	9,819	892	1,071	2,452
7/26/2022	3,540,730	3,545,060	4,330	0.12%	0	4,036	-1,460	8,227	393	862	892
7/27/2022	2,847,380	2,860,870	13,490	0.47%	211,247	711	14,241	7,246	209	746	(213,455)
7/28/2022	3,050,130	3,063,640	13,510	0.44%	0	576	-735	7,625	565	819	12,849
7/29/2022	4,702,060	4,708,400	6,340	0.13%	0	1,317	-2,381	10,541	365	1,091	6,313
7/30/2022	3,023,040	3,032,440	9,400	0.31%	0	2,278	-482	8,290	1,165	946	6,659
7/31/2022	1,514,230	1,513,940	-290	-0.02%	0	1,042	-5	6,701	213	691	(2,018)
8/1/2022	4,558,850	4,570,570	11,720	0.26%	0	5,028	8,330	9,141	623	976	(2,615)
8/2/2022	3,951,810	3,952,010	200	0.01%	0	1,752	-640	8,501	1,027	953	(1,865)
8/3/2022	4,349,210	4,354,370	5,160	0.12%	0	2,932	-5,732	9,326	576	990	6,970
8/4/2022	4,094,220	4,094,260	40	0.00%	0	18,682	2,242	9,062	801	986	(21,870)
8/5/2022	2,822,030	2,825,570	3,540	0.13%	0	7,517	1,910	7,574	1,099	867	(6,754)
8/6/2022	3,050,300	3,056,780	6,480	0.21%	0	3,503	606	7,747	1,573	932	1,439
8/7/2022	2,710,090	2,721,730	11,640	0.43%	0	3,312	-445	7,479	1,301	878	7,895
8/8/2022	4,067,000	4,082,060	15,060	0.37%	0	3,772	11,707	8,905	779	968	(1,388)
8/9/2022	4,511,260	4,518,660	7,400	0.16%	0	1,017	-1,082	9,196	369	957	6,509
8/10/2022	4,972,270	4,979,130	6,860	0.14%	0	3,716	-991	9,908	401	1,031	3,104
8/11/2022	3,671,350	3,680,200	8,850	0.24%	0	3,314	-441	8,531	1,103	963	5,014
8/12/2022	1,131,200	1,135,460	4,260	0.38%	0	791	-58	5,003	54	506	3,022
8/13/2022	3,022,830	3,023,710	880	0.03%	0	1,812	-569	7,228	683	791	(1,154)
8/14/2022	3,045,100	3,045,950	850	0.03%	0	1,023	-270	7,720	317	804	(707)
8/15/2022	3,519,360	3,519,050	-310	-0.01%	0	1,272	-266	8,573	371	894	(2,210)
8/16/2022	4,174,210	4,177,710	3,500	0.08%	0	1,784	63	9,180	222	940	712

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Cont Reserve Depl Failure Charge	Excessive/Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
8/17/2022	4,952,410	4,953,800	1,390	0.03%	0	1,717	-1,911	9,934	97	1,003	581
8/18/2022	4,396,900	4,397,880	980	0.02%	0	906	-2,768	9,350	486	984	1,859
8/19/2022	4,225,230	4,232,580	7,350	0.17%	0	1,142	-853	9,134	734	987	6,074
8/20/2022	3,682,260	3,686,760	4,500	0.12%	0	1,941	-3,096	8,692	105	880	4,775
8/21/2022	3,776,970	3,781,730	4,760	0.13%	0	399	-741	8,818	493	931	4,171
8/22/2022	4,925,100	4,925,910	810	0.02%	0	933	-2,574	9,580	287	987	1,464
8/23/2022	4,927,700	4,929,310	1,610	0.03%	0	3,051	-273	9,332	248	958	(2,126)
8/24/2022	4,214,530	4,211,680	-2,850	-0.07%	0	760	-811	8,553	189	874	(3,674)
8/25/2022	4,461,670	4,461,050	-620	-0.01%	0	1,330	-256	8,904	84	899	(2,593)
8/26/2022	4,219,850	4,224,270	4,420	0.10%	0	2,065	-2,032	8,793	449	924	3,463
8/27/2022	1,170,640	1,186,610	15,970	1.35%	0	1,229	-2,413	5,246	322	557	16,597
8/28/2022	1,412,660	1,433,150	20,490	1.43%	0	12,946	13,155	5,498	182	568	(6,179)
8/29/2022	3,598,590	3,605,650	7,060	0.20%	0	1,015	-304	7,775	538	831	5,518
8/30/2022	4,178,210	4,177,520	-690	-0.02%	0	3,049	-6	7,952	324	828	(4,561)
8/31/2022	4,588,480	4,594,230	5,750	0.13%	0	3,143	-2,847	8,342	433	878	4,577
9/1/2022	4,219,200	4,217,730	-1,470	-0.03%	0	2,443	-640	9,257	269	953	(4,225)
9/2/2022	3,933,260	3,932,240	-1,020	-0.03%	0	4,042	-1,000	8,367	222	859	(4,921)
9/3/2022	2,691,010	2,705,680	14,670	0.54%	0	317	-631	7,332	168	750	14,234
9/4/2022	2,089,200	2,096,190	6,990	0.33%	0	317	39	6,685	20	670	5,964
9/5/2022	2,637,540	2,645,690	8,150	0.31%	0	405	16	7,232	526	776	6,953
9/6/2022	3,924,220	3,927,650	3,430	0.09%	0	629	323	8,643	649	929	1,549
9/7/2022	4,032,370	4,030,350	-2,020	-0.05%	0	471	-682	8,876	338	921	(2,731)
9/8/2022	2,079,220	2,102,300	23,080	1.10%	0	1,965	3,353	6,427	327	675	17,086
9/9/2022	2,958,860	2,977,460	18,600	0.62%	0	584	4,652	7,921	352	827	12,537
9/10/2022	2,851,960	2,870,610	18,650	0.65%	0	1,794	145	7,968	319	829	15,883
9/11/2022	3,300,990	3,314,450	13,460	0.41%	0	3,821	-139	8,843	460	930	8,848
9/12/2022	3,744,570	3,754,030	9,460	0.25%	0	3,058	1,122	9,427	203	963	4,317
9/13/2022	3,692,860	3,697,880	5,020	0.14%	0	2,703	464	9,239	448	969	884
9/14/2022	2,297,380	2,304,770	7,390	0.32%	0	1,761	41	7,205	914	812	4,776
9/15/2022	2,113,290	2,132,350	19,060	0.89%	0	2,536	1,292	6,357	164	652	14,581
9/16/2022	3,174,400	3,185,910	11,510	0.36%	0	318	-887	8,188	238	843	11,237
9/17/2022	2,271,070	2,277,760	6,690	0.29%	0	2,187	-6,245	7,245	217	746	10,002
9/18/2022	3,231,590	3,240,700	9,110	0.28%	0	2,401	5,596	8,370	116	849	264
9/19/2022	3,945,690	3,950,390	4,700	0.12%	0	3,023	5,455	9,633	1,244	1,088	(4,865)
9/20/2022	4,066,200	4,056,230	-9,970	-0.25%	0	2,787	-3,143	9,134	1,531	1,066	(10,680)
9/21/2022	789,110	818,450	29,340	3.58%	0	461	850	4,899	18	492	27,537
9/22/2022	2,844,880	2,861,590	16,710	0.58%	0	2,336	-578	8,445	1,600	1,004	13,948
9/23/2022	1,063,490	1,087,110	23,620	2.17%	0	3	-5	5,280	533	581	23,041

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9/24/2022	828,770	849,640	20,870	2.46%	0	67	0	5,012	1,640	665	20,138
9/25/2022	711,290	738,960	27,670	3.74%	0	308	-25	4,509	-25	448	26,939
9/26/2022	1,002,620	1,037,370	34,750	3.35%	0	844	-347	5,420	18	544	33,709
9/27/2022	2,640,360	2,655,050	14,690	0.55%	0	8,179	351	8,308	654	896	5,264
9/28/2022	2,224,960	2,248,060	23,100	1.03%	0	5,235	-330	7,673	337	801	17,393
9/29/2022	774,440	795,490	21,050	2.65%	0	1,427	-5	4,766	3	477	19,152
9/30/2022	785,820	806,170	20,350	2.52%	0	185	16	4,826	-19	481	19,668
10/1/2022	1,048,350	1,072,000	23,650	2.21%	0	1,408	-671	4,540	360	490	22,422
10/2/2022	1,012,390	1,032,900	20,510	1.99%	0	1,775	-465	4,436	-32	440	18,759
10/3/2022	1,556,510	1,588,190	31,680	1.99%	0	1,398	234	5,073	105	518	29,531
10/4/2022	2,091,380	2,114,820	23,440	1.11%	0	2,200	1,849	6,108	186	629	18,761
10/5/2022	2,186,870	2,211,120	24,250	1.10%	0	1,284	1,452	6,568	166	673	20,840
10/6/2022	866,300	890,340	24,040	2.70%	0	342	112	4,079	92	417	23,169
10/7/2022	2,159,850	2,189,460	29,610	1.35%	0	1,375	-651	5,946	23	597	28,289
10/8/2022	1,115,040	1,145,430	30,390	2.65%	0	388	22	4,532	-34	450	29,530
10/9/2022	1,914,800	1,946,890	32,090	1.65%	0	1,771	-238	5,682	357	604	29,952
10/10/2022	1,945,110	1,977,510	32,400	1.64%	0	5,066	7,576	5,800	35	583	19,174
10/11/2022	826,480	856,690	30,210	3.53%	0	33	450	4,082	108	419	29,308
10/12/2022	796,550	826,460	29,910	3.62%	0	351	62	3,950	-84	387	29,111
10/13/2022	800,370	829,710	29,340	3.54%	0	1,168	1,061	3,962	-17	395	26,717
10/14/2022	1,711,800	1,746,320	34,520	1.98%	0	266	-223	4,659	726	539	33,938
10/15/2022	1,239,790	1,264,400	24,610	1.95%	0	243	-25	4,639	1,135	577	23,814
10/16/2022	1,026,950	1,052,400	25,450	2.42%	0	297	0	4,060	426	449	24,704
10/17/2022	2,285,190	2,293,930	8,740	0.38%	0	1,823	-922	5,748	1,015	676	7,163
10/18/2022	2,543,110	2,556,890	13,780	0.54%	0	1,547	78	6,319	965	728	11,427
10/19/2022	2,433,440	2,427,100	-6,340	-0.26%	0	2,734	-113	6,397	346	674	(9,635)
10/20/2022	2,318,270	2,335,490	17,220	0.74%	0	2,121	578	6,115	1,089	720	13,800
10/21/2022	2,055,360	2,065,250	9,890	0.48%	0	1,366	954	5,606	556	616	6,953
10/22/2022	1,016,700	1,025,680	8,980	0.88%	0	295	54	3,844	378	422	8,208
10/23/2022	896,930	909,330	12,400	1.36%	0	599	123	3,459	255	371	11,306
10/24/2022	1,813,730	1,814,930	1,200	0.07%	0	819	1,401	5,115	885	600	(1,620)
10/25/2022	1,841,540	1,845,440	3,900	0.21%	0	2,533	-1	5,128	585	571	796
10/26/2022	2,221,570	2,220,210	-1,360	-0.06%	0	2,162	-516	6,031	339	637	(3,643)
10/27/2022	1,796,780	1,798,430	1,650	0.09%	0	2,081	1,659	5,379	489	587	(2,677)
10/28/2022	1,853,890	1,855,510	1,620	0.09%	0	1,119	-42	5,471	372	584	(41)
10/29/2022	1,743,250	1,742,560	-690	-0.04%	0	692	-89	5,287	641	593	(1,886)
10/30/2022	2,072,310	2,074,880	2,570	0.12%	0	932	-298	6,326	108	643	1,293
10/31/2022	2,606,520	2,615,780	9,260	0.35%	0	1,322	-115	7,249	600	785	7,268

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Cont Reserve Depl Failure Charge	Excessive/Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
11/1/2022	2,194,300	2,204,420	10,120	0.46%	0	1,926	-202	7,237	669	791	7,606
11/2/2022	913,180	939,750	26,570	2.83%	0	8	0	4,069	459	453	26,109
11/3/2022	829,710	855,400	25,690	3.00%	0	10	232	3,797	414	421	25,027
11/4/2022	1,127,710	1,154,720	27,010	2.34%	0	103	285	4,675	191	487	26,136
11/5/2022	612,060	634,610	22,550	3.55%	0	18	275	3,605	162	377	21,881
11/6/2022	583,780	607,770	23,990	3.95%	0	11	27	3,483	61	354	23,598
11/7/2022	2,105,580	2,109,380	3,800	0.18%	0	2,367	254	6,358	646	700	479
11/8/2022	948,280	954,970	6,690	0.70%	0	2,005	227	4,451	236	469	3,990
11/9/2022	1,171,680	1,183,220	11,540	0.98%	0	673	-627	5,077	367	544	10,950
11/10/2022	1,184,700	1,189,850	5,150	0.43%	0	192	-24	5,281	457	574	4,409
11/11/2022	1,230,040	1,235,060	5,020	0.41%	0	141	0	5,898	767	666	4,213
11/12/2022	2,181,120	2,190,280	9,160	0.42%	0	4,241	-294	7,925	465	839	4,374
11/13/2022	3,011,250	3,028,930	17,680	0.58%	0	355	-200	10,516	290	1,081	16,444
11/14/2022	3,607,870	3,619,960	12,090	0.33%	0	3,114	-2,014	11,303	370	1,167	9,822
11/15/2022	3,760,920	3,777,170	16,250	0.43%	0	3,788	72	10,804	536	1,134	11,256
11/16/2022	1,450,360	1,458,610	8,250	0.57%	0	175	1,612	6,736	439	717	5,746
11/17/2022	1,149,960	1,154,850	4,890	0.42%	0	359	-129	6,018	348	637	4,024
11/18/2022	1,041,870	1,060,420	18,550	1.75%	0	149	0	5,676	202	588	17,814
11/19/2022	733,630	767,060	33,430	4.36%	0	0	0	4,866	-129	474	32,956
11/20/2022	724,710	772,660	47,950	6.21%	0	36	0	4,812	-77	474	47,440
11/21/2022	2,978,540	2,986,850	8,310	0.28%	0	642	-859	8,798	733	953	7,574
11/22/2022	1,310,120	1,320,510	10,390	0.79%	0	1,183	31	6,631	2,869	950	8,226
11/23/2022	1,220,450	1,224,680	4,230	0.35%	0	43	-453	6,436	857	729	3,911
11/24/2022	1,079,440	1,085,070	5,630	0.52%	0	194	0	5,961	351	631	4,805
11/25/2022	1,010,070	1,017,660	7,590	0.75%	0	135	0	5,741	275	602	6,853
11/26/2022	817,030	845,930	28,900	3.42%	0	68	9	4,769	-19	475	28,348
11/27/2022	951,400	975,150	23,750	2.44%	0	1,116	-3,218	5,311	43	535	25,316
11/28/2022	770,620	805,810	35,190	4.37%	0	175	-1,394	4,974	-14	496	35,913
11/29/2022	933,470	967,960	34,490	3.56%	0	230	17	5,049	-6	504	33,738
11/30/2022	1,823,470	1,848,070	24,600	1.33%	0	1,964	-27	6,495	75	657	22,006
12/1/2022	1,132,480	1,165,260	32,780	2.81%	0	1,199	-1,212	4,371	78	445	32,348
12/2/2022	955,450	986,400	30,950	3.14%	0	1,174	34	4,159	-124	404	29,338
12/3/2022	1,072,490	1,100,240	27,750	2.52%	0	1,663	144	4,186	199	439	25,504
12/4/2022	1,153,560	1,159,180	5,620	0.48%	0	1,781	74	4,636	40	468	3,298
12/5/2022	2,415,890	2,416,300	410	0.02%	0	850	2,517	6,385	1,175	756	(3,713)
12/6/2022	3,032,950	3,032,890	-60	0.00%	0	1,004	230	8,203	222	843	(2,137)
12/7/2022	3,076,060	3,075,610	-450	-0.01%	0	180	-2,869	8,577	644	922	1,316
12/8/2022	2,759,560	2,760,320	760	0.03%	0	1,889	-637	7,903	536	844	(1,335)

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Cont Reserve Depl Failure Charge	Excessive/Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
12/9/2022	2,933,580	2,933,630	50	0.00%	0	1,074	-1,215	8,237	425	866	(675)
12/10/2022	2,734,020	2,735,690	1,670	0.06%	0	1,092	-1,958	7,734	284	802	1,734
12/11/2022	2,397,040	2,401,430	4,390	0.18%	0	2,470	34	7,057	723	778	1,108
12/12/2022	939,090	967,250	28,160	2.91%	0	307	-347	3,736	243	398	27,802
12/13/2022	815,870	878,350	62,480	7.11%	0	53	-10	3,822	6	383	62,054
12/14/2022	2,879,890	2,884,890	5,000	0.17%	0	2,295	-692	6,511	800	731	2,666
12/15/2022	1,687,680	1,707,640	19,960	1.17%	0	923	204	5,714	673	639	18,194
12/16/2022	1,160,220	1,169,170	8,950	0.77%	0	458	30	4,700	186	489	7,973
12/17/2022	1,287,520	1,301,940	14,420	1.11%	0	1,275	-20	4,881	163	504	12,661
12/18/2022	3,817,340	3,819,970	2,630	0.07%	0	9,211	-559	8,094	219	831	(6,853)
12/19/2022	4,116,340	4,123,390	7,050	0.17%	3,644	2,283	-846	9,193	777	997	973
12/20/2022	3,548,940	3,551,710	2,770	0.08%	0	2,298	-345	8,102	354	846	(28)
12/21/2022	4,078,190	4,093,680	15,490	0.38%	0	1,338	-2,107	8,769	383	915	15,344
12/22/2022	1,421,430	1,425,220	3,790	0.27%	0	634	6	5,447	159	561	2,589
12/23/2022	1,564,410	1,588,710	24,300	1.53%	79,418	24,161	57,898	5,762	1,013	678	(137,854)
12/24/2022	1,949,160	2,001,060	51,900	2.59%	0	12,448	-3,692	5,868	1,720	759	42,386
12/25/2022	4,136,460	4,141,900	5,440	0.13%	0	36,750	-407	7,705	798	850	(31,753)
12/26/2022	4,374,900	4,401,810	26,910	0.61%	0	49,454	-8,698	8,023	306	833	(14,678)
12/27/2022	1,538,200	1,565,900	27,700	1.77%	0	1,052	-217	5,660	1,017	668	26,198
12/28/2022	1,292,740	1,299,860	7,120	0.55%	0	205	4	5,008	203	521	6,390
12/29/2022	1,441,530	1,444,190	2,660	0.18%	0	1,165	15	5,438	251	569	911
12/30/2022	1,460,800	1,466,260	5,460	0.37%	0	2,130	-194	5,639	23	566	2,958
12/31/2022	1,035,940	1,075,240	39,300	3.65%	0	2,054	-31	4,529	162	469	36,808
Total	**822,352,790**	**827,163,490**	**4,810,700**	**0.01**	**298,238**	**707,832**	**134,586**	**2,437,330**	**155,181**	**259,251**	**3,410,793**

Excessive Deficient Energy Deployment Charge by NSP Resource

LOCATION	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
Anson_G2	$ 66	$ -	$ -	$ -	$ 8	$ 12	$ 172	$ 551	$ -	$ -	$ -	$ -
Anson_G3	$ 66	$ -	$ -	$ -	$ 1,178	$ 30	$ 649	$ 18	$ 750	$ -	$ -	$ 2
Anson_G4	$ -	$ -	$ -	$ -	$ -	$ 13	$ 1,598	$ 390	$ 15	$ 299	$ 319	$ 70
Blk_Dog_G52	$ -	$ 1,524	$ 1,753	$ 4,430	$ -	$ 1,032	$ 1,612	$ 1,331	$ 1,377	$ -	$ -	$ -
Blk_Dog_G6	$ -	$ 2,345	$ 281	$ 8,266	$ 487	$ 16,958	$ 25,837	$ 51,098	$ 4,813	$ 4,747	$ 5,603	$ 2,345
Blue_Lk_G7	$ -	$ 15	$ -	$ 15	$ 14	$ 2,997	$ 2,933	$ 1,199	$ 203	$ -	$ -	$ -
Blue_Lk_G8	$ 760	$ -	$ -	$ -	$ 15	$ 2,053	$ 947	$ 747	$ 421	$ -	$ -	$ -
Blue_Lk_G8	$ 760	$ -	$ -	$ -	$ 15	$ 2,053	$ 947	$ 747	$ 421	$ -	$ -	$ -
Canon_Falls1	$ 304	$ -	$ -	$ 19	$ 23	$ 1,132	$ 639	$ 1,244	$ 716	$ 6	$ 30	$ 12
Canon_Falls2	$ 3	$ -	$ -	$ 54	$ 14	$ 1,443	$ 1,245	$ 2,246	$ 2,238	$ 13	$ 16	$ 13,940
CC Highbridge1	$ 117	$ 245	$ 1,440	$ 1,935	$ 2,216	$ 80	$ 4,390	$ 693	$ 5,595	$ 624	$ 461	$ 11,505
CC Highbridge2	$ 6	$ 1,104	$ 1,472	$ 1,395	$ 484	$ 356	$ 223	$ 353	$ 12,287	$ 1,906	$ 1,095	$ 8,146
CC Mankato1	$ 1,191	$ 779	$ 401	$ 2,955	$ 9,035	$ 8,232	$ 4,510	$ 2,341	$ 5,447	$ 3,127	$ 3,314	$ 8,214
CC Mankato2	$ 1,947	$ 703	$ 155	$ 2,527	$ 3,620	$ 7,163	$ 3,134	$ 2,768	$ 4,231	$ 3,707	$ 2,303	$ 8,586
CCRiverside1	$ 6,141	$ 2,704	$ 1,041	$ 846	$ 3,116	$ 16,206	$ 3,647	$ 5,816	$ 2,097	$ 5,275	$ 110	$ 35,019
CCRiverside2	$ 3,635	$ 3,056	$ 1,452	$ 1,907	$ 3,868	$ 10,757	$ 1,215	$ 3,160	$ 2,323	$ 2,807	$ 371	$ 33,460
CORNEL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HOLCOM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_1	$ -	$ -	$ -	$ 12	$ 20	$ -	$ 217	$ 1,031	$ 32	$ -	$ 7	$ -
InvrHils_2	$ -	$ -	$ -	$ -	$ 371	$ -	$ 49	$ 37	$ 10	$ 318	$ 40	$ 12
InvrHils_3	$ 0	$ -	$ -	$ -	$ 22	$ 756	$ 1,504	$ 49	$ 3	$ -	$ -	$ 3
InvrHils_4	$ -	$ -	$ -	$ -	$ 5	$ 4	$ 3,031	$ 67	$ 1	$ -	$ -	$ -
InvrHils_5	$ 2	$ -	$ -	$ -	$ -	$ 104	$ 185	$ 7	$ 28	$ 1	$ -	$ 42
InvrHils_6	$ -	$ -	$ -	$ -	$ 0	$ 12	$ 45	$ 29	$ -	$ -	$ 8	$ 58
JIMFL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
King_G1	$ 8,700	$ 3,216	$ 1,745	$ -	$ -	$ 1,722	$ 6,299	$ 10,096	$ -	$ -	$ 2,181	$ 30,705
LSPower_1	$ 12,059	$ 8,847	$ 5,321	$ 11,730	$ 5,955	$ 7,900	$ 12,680	$ 6,911	$ 9,061	$ 12,853	$ 5,770	$ 5,359
NSP.BIGBLUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BR_DIR_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BSTAR1.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BSTAR2.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.FENTON.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MNDAK.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MORAINE2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLE.CWS1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLE.CWS1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLE.CWS2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLES.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.ODELL.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PROSE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PVALEY.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SHERCO_G1	$ 1,036	$ 838	$ 3,155	$ -	$ 64	$ 920	$ 714	$ 1,696	$ 2,323	$ 1,549	$ 1,914	$ 3,727
SHERCO_G2	$ 2,746	$ 987	$ 1,008	$ 1,224	$ 78	$ 3,833	$ 2,367	$ 2,824	$ 2,282	$ 4,278	$ 1,788	$ 3,087
Wheaton_1	$ 61	$ 5	$ -	$ -	$ 92	$ 362	$ 7	$ 28	$ 30	$ -	$ 5	$ 33
Wheaton_2	$ 52	$ 14	$ -	$ -	$ 1,164	$ 558	$ 8	$ 49	$ 157	$ -	$ 8	$ 334
Wheaton_3	$ 77	$ 3	$ -	$ -	$ 1,072	$ 217	$ 8	$ 38	$ 80	$ -	$ 6	$ 62
Wheaton_4	$ 236	$ 19	$ -	$ -	$ 685	$ 2,095	$ 7	$ 27	$ 81	$ -	$ 11	$ 103
Wheaton_6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5	$ -	$ -	$ -	$ -
WI Ewngton 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Grand Meadow	$ -	$ -	$ -	$ 5	$ -	$ -	$ -	$ -	$ 4	$ -	$ 59	$ 44
WI Jeffers 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Valley View	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WISSOTATR3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WISSOTATR4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Totals	**$ 39,964**	**$ 26,403**	**$ 19,223**	**$ 37,321**	**$ 33,624**	**$ 89,001**	**$ 80,819**	**$ 97,597**	**$ 57,028**	**$ 41,512**	**$ 25,418**	**$ 164,868**

Northern States Power Company, a Minnesota Corporation
Electric Operations – State of Minnesota
MISO – Ancillary Services Market

Contingency Reserve Deployment Failure Charges by NSP Resource

LOCATION	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
Anson_G2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anson_G3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anson_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G52	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Canon_Falls1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Canon_Falls2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC Highbridge1	$ -	$ -	$ -	$ -	$ -	$ -	$ 51,511	$ -	$ -	$ -	$ -	$ -
CC Highbridge2	$ -	$ -	$ -	$ -	$ -	$ -	$ 53,800	$ -	$ -	$ -	$ -	$ -
CC Mankato1	$ -	$ -	$ -	$ -	$ -	$ 2,342	$ 26,201	$ -	$ -	$ -	$ -	$ -
CC Mankato2	$ -	$ -	$ -	$ -	$ -	$ 1,587	$ 26,668	$ -	$ -	$ -	$ -	$ -
CCRiverside1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCRiverside2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CORNEL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HOLCOM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_1	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,267	$ -	$ -	$ -	$ -	$ -
InvrHils_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,164
InvrHils_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,164
InvrHils_4	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,267	$ -	$ -	$ -	$ -	$ -
InvrHils_5	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,267	$ -	$ -	$ -	$ -	$ 14,164
InvrHils_6	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,267	$ -	$ -	$ -	$ -	$ 14,164
JIMFL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
King_G1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LSPower_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BIGBLUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BR_DIR_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BSTAR1.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BSTAR2.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.FENTON.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MNDAK.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MORAINE2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLE.CWS1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLE.CWS1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLE.CWS2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLES.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.ODELL.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PROSE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PVALEY.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SHERCO_G1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SHERCO_G2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,493
Wheaton_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,913
Wheaton_6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Ewngton 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Grand Meadow	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Jeffers 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Valley View	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WISSOTATR3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WISSOTATR4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Totals	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 3,929**	**$ 211,247**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 83,062**

2022 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 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 2022 reporting year as compared to the 2022 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 2023 curtailment forecast in our May 2, 2022 Petition and July 29, 2022 Reply Comments in Docket No. E002/AA-22-179. We will provide an estimate of 2023 curtailment payments, including forecast assumptions, in our 2024 fuel forecast Petition to be filed by May 1, 2023.

II. Curtailment Overview

The Company 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 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) are now in-service and will positively impact curtailment by reducing local congestion. However, the Company believes future 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.

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.

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	1340

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[1]

Company	MW	Location	In-Service Dates
Alliant Energy	1,150	IA	2019-2021
Great River Energy	1448	ND	2020-2025
MidAmerican[2]	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

[1] The wind repowering projects being developed by NSP are not included in this list.
[2] MidAmerican has announced they are pursuing an additional 2,042 MW of wind generation and 50 MW of solar generation that if approved would go into service in 2024.

transmission capacity in that area. Table 3 shows historic southwest Minnesota projects that increased the available transmission outlet in that area.

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	Actual/Planned 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, though the expected in-service date is late 2023.[3] The Huntley – Wilmarth line, which went into service on December 1, 2021, was classified as an Economic Project 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

[3] The Cardinal – Hickory Creek line is involved in litigation that could negatively impact the in-service date.

ones listed in Table 5, have had, or will have, a positive impact on Company-owned and PPA wind facilities.

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	December 2023

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.

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

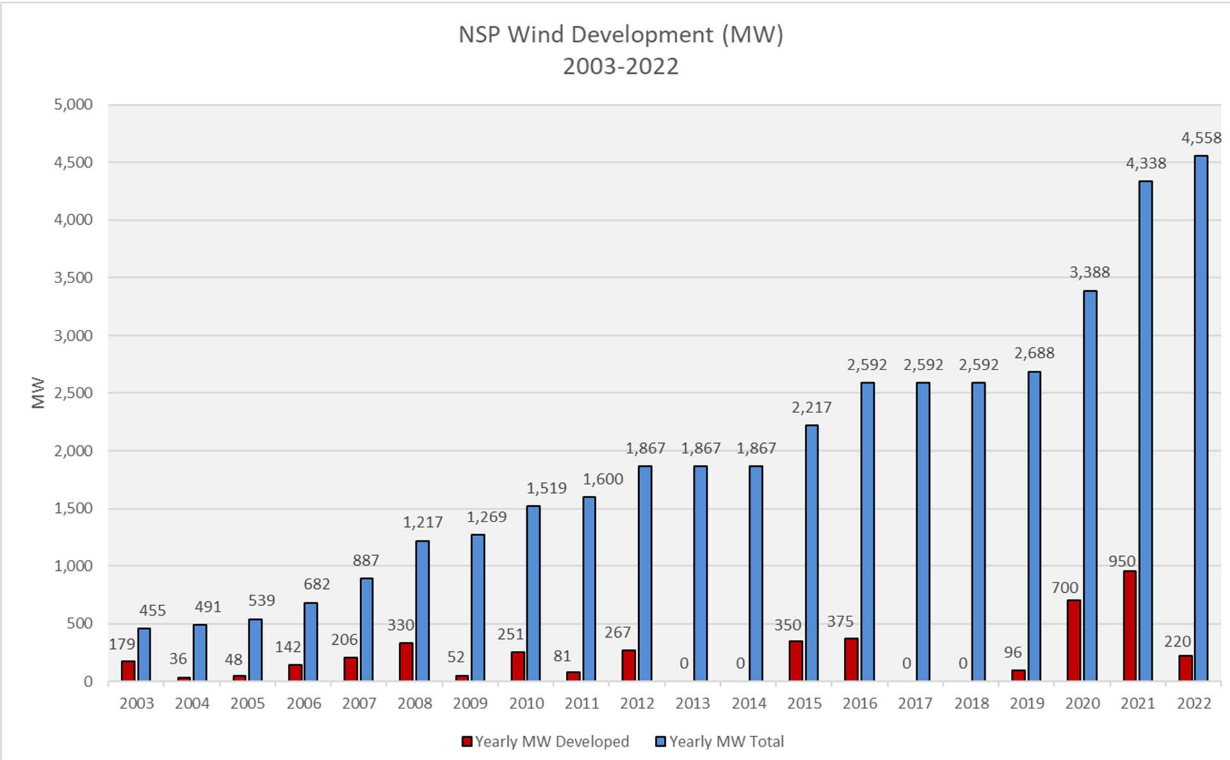
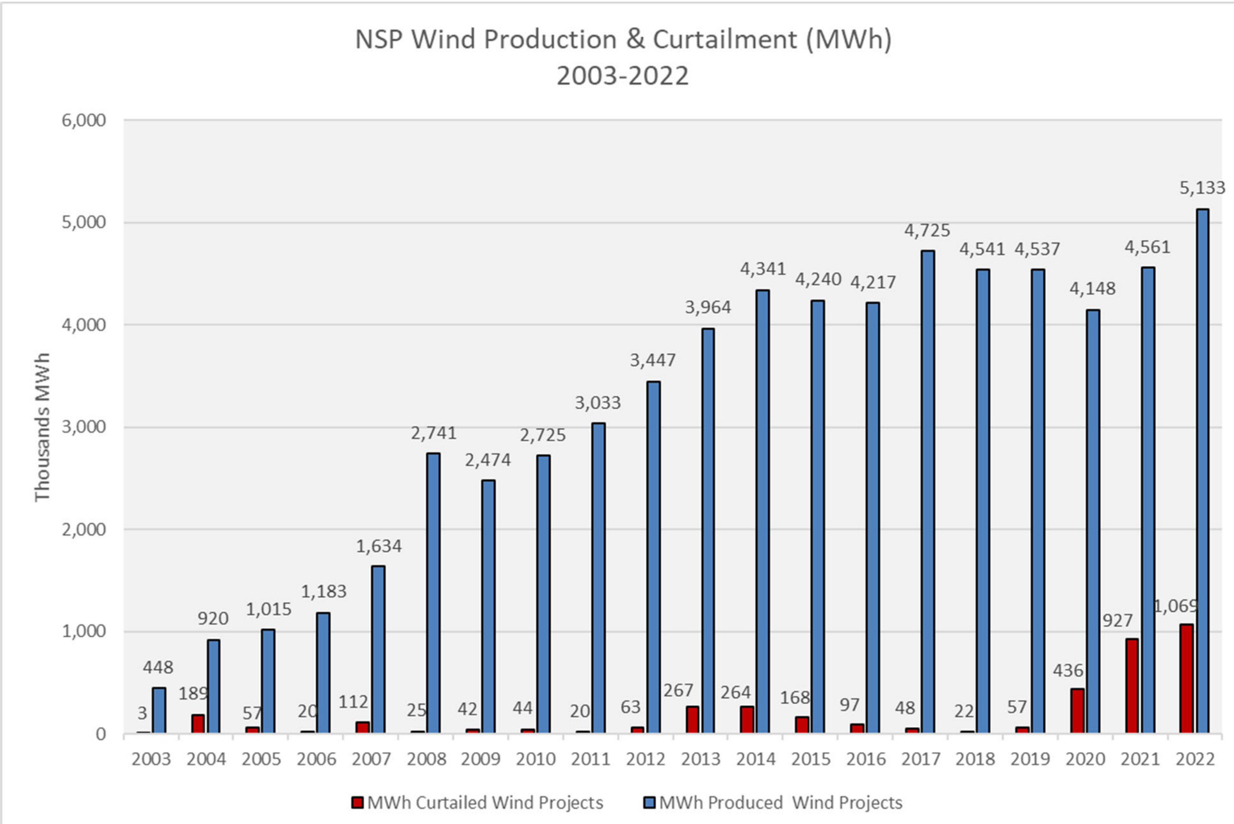


Chart 2 shows the comparison between total wind energy produced and the wind energy curtailed from the projects through December 2022.[4] Despite the lead/lag time associated with generation and transmission development, Chart 2 shows that wind curtailment is small compared to the total wind generation 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.

[4] Part C, Attachment 2.

Chart 2



The 2022 Curtailment in summarized in Table 6.

Table 6
2022 Wind Curtailment MWh and Costs

	MWh	Costs
Curtailment	1,069,391	$49,540,011

It is important to note that of the $49,540,011in 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.[5]

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

[5] 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 actually is 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: 2022 Wind Curtailment Breakdown

Type	Curtailment (MWh)
Economic	1,052,414
Transmission Related	16,977
Total	1,069,391

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.[6]

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

Table 8
2022 Real Time Binding Constraints

Constraint Name	Contingency Description	State	RTBC Hours	Avg Shadow Price
Forman_230_115_TR1_flo_Hankinson_Wahpeton_230kV	HANKINSON-WAHPETON 230+WAHPETN TR2	ND	2,446.8	($374.4)
Ellendal_AberdeenJct_115kV_flo_TwinBrooks_BigSto	TWIN BROOKS - BIG STONE SOUTH 345	ND	846.7	($55.6)
NSP34011_MURPHYCR_MURPHHAYWA16_1_1	HELENA-SHEAS LAKE 345	MN	450.5	($152.6)
Watertn_345_230_XF_FTLO_Hawkn_Lk_Lyon_Co_345kV	LYON CO - HAWKS NEST LAKE 345	SD	416.1	($116.7)
OTP23100_JOHNJCT_JOHNJGRACE11_1_1	HANKINSON-WAHPETON 230+WAHPETN TR2	MN	396.8	($1,272.5)
ScottCounty_BlueLake_345kV_flo_Helena_ChubLake_3	CHUB LAKE-HELENA 345 (0960)	MN	335.9	($74.2)
PrairieIsland_NorthRochester_345_FLO_Hampton_Nor	HAMPTON - NORTH ROCHESTER 345	MN	317.7	($88.6)
Blair_Granite_Falls_230_KV_FLO_Hawksnest_Ln_Lyon	LYON CO - HAWKS NEST LAKE 345	SD	231.1	($245.7)
FoxLake_Rutland_161kV_flo_LakefieldJct_Huntley_3	HUNTLEY - LAKEFIELD 345	MN	215.5	($261.7)
ALENSP01_EAU_CLA_TR9_TR9	EAU CLAIRE - ARPIN 345	WI	209.8	($482.3)
OTP23100_MORRISOT_MORRIGRANT11_1_1	HANKINSON-WAHPETON 230+WAHPETN TR2	MN	203.3	($879.6)
NSP34008_MURPHYCR_MURPHHAYWA16_1_1	SHEAS LAKE - WILMARTH 345	MN	164.7	($130.7)
Bigstone_BrownsVally_230kV_flo_Oaks_Ellenda_230k	ELLENDALE-OAKES 230	SD	161.8	($237.1)
NSPALW02_SOUTHBND_TR6_TR6	WILMARTH - HUNTLEY 345	MN	158.0	($513.5)
White_Split_Rock_345_kV_FTLO_Hawks_Nest_Lyon_Cou	LYON CO - HAWKS NEST LAKE 345	MN	154.5	($139.7)
NSP34X12_WILMART_TR9_TR9	WILMARTH 345/115 T10	MN	134.8	($252.4)

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 binding constraints listed above 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
2022 Significant Transmission Outages

Request	Company	KV	From_Station	To_Station	Start	End	Duration
1-26308777	GRE, NSP	345/115	LYON_CO TR9		5/28/2021	5/3/2022	341
1-25868944	GRE, OTP	115	JOHNJCT	MORRISOT	9/27/2021	2/1/2022	128
1-26406529	MDU	230	MANDAN	NAPOLNSW	8/15/2022	11/18/2022	96
1-26458059	MDU	230	MANDAN	NAPOLNSW	11/30/2021	2/18/2022	81
1-26224013	ITC_MW	161	ADAMS	HAYWARD	3/28/2022	6/7/2022	72
1-26224013	ITC_MW	161	BARTONS	ADAMS_I	3/28/2022	6/7/2022	72
1-26224013	DPC,	161	BVR_CRK	ADAMS_I	3/28/2022	6/7/2022	72
1-26224013	ITC_MW	345/161	ADAMS TR1		3/28/2022	6/7/2022	72
1-26597650	NSP	345	CRANDAL	FIELDON	5/11/2022	7/8/2022	59
1-26597650	GRE, NSP	345	FIELDON	WILMART	5/11/2022	7/8/2022	59
1-26215034	NSP	345/161	EAU_CLA TR10		5/10/2022	7/6/2022	58
1-26488066	NSP	345	LAKEFLD	NOBLES	6/24/2022	7/25/2022	32
1-26516536	GRE, NSP	230	PYNSVIL	WILLMRU	10/3/2022	11/2/2022	31
1-26516536	GRE	230	WILLMRU	GRANITF	10/3/2022	11/2/2022	31
1-26500578	ATC, NSP	345	EAU_CLA	ARPIN	11/28/2022	12/21/2022	24
1-26634491	NSP	345	CRANDAL	FIELDON	10/10/2022	11/1/2022	23
1-26634491	GRE, NSP	345	FIELDON	WILMART	10/10/2022	11/1/2022	23
1-26614542	ITC_MW	161	MOWERCTY	ADAMS_I	6/17/2022	7/7/2022	21
1-26642057	NSP	115	BUFFRID	YANKEE	10/17/2022	11/3/2022	18
1-26454153	ITC_MW	345	HUNTLEY2	LAKEFLD	1/31/2022	2/14/2022	15

The Company believes that many of the binding constraints listed in Table 8 were caused or made worse by the transmission outages identified in Table 9. The Forman Transformer binding constraint, which was the most common binding constraint in 2022, was negatively impacted by the Napoleon – Mandan 230 kV line outage[7]. The Napoleon – Mandan outage also likely contributed to the Ellendale – Aberdeen Jct. binding constraint. The Fox Lake – Rutland 161 kV and Wilmarth TR 9 transformer binding constraints occurred almost exclusively during the Crandall – Fielden –

[7] The Napoleon – Mandan 230 kV line was required to be rebuilt to provide transmission capacity for a new generator interconnection.

Wilmarth outages. The Johnson Jct. – Graceville binding constraint only occurred during the Johnson Jct. – Morris 115 kV line outage. The Murphy Creek – Hayward 161 kV constraint was negatively impacted by the Adams area outages[8].

The remaining binding constraints were likely negatively impacted by the various transmission outages that occurred throughout 2022.

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.

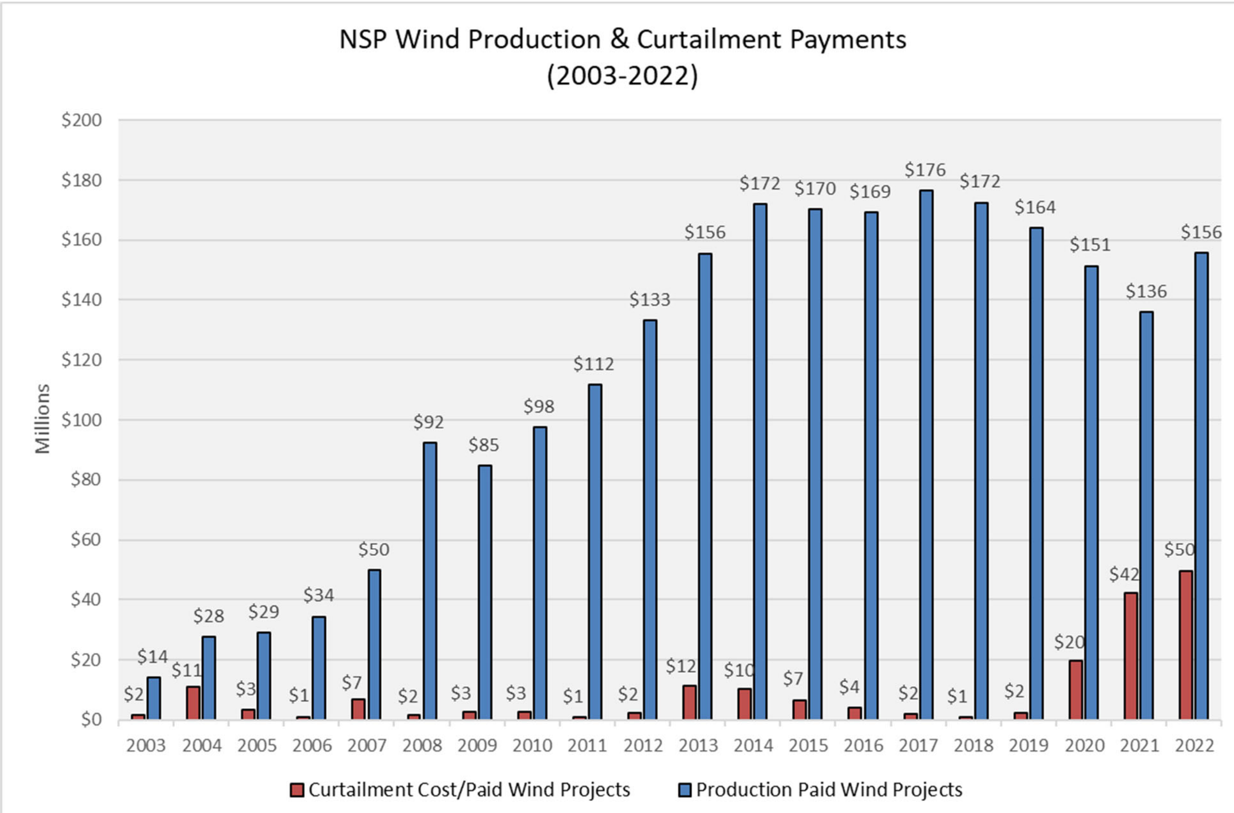
The Company is also working to identify binding constraints that are likely to occur going forward and are developing plans to mitigate these constraints. The mitigation plans will be designed to cost effectively reduce both curtailment and congestion. The plans include breaker reconfiguration and transmission facility upgrades.

V. WIND PRODUCTION AND CURTAILMENT PAYMENTS

Chart 3 shows the corresponding production and curtailment costs for 2003 through 2022.[9] As with wind generation produced and curtailed, paid curtailment is a very small portion of total cost of wind generation on the system.

[8] Adams area outages included the Adams 345/161 kV transformer, Adams - Hayward, Barton- Adams and Beaver Creek – Adams 161 kV lines.
[9] The data for 2021-2022 is shown in Part C, Attachment 2.

Chart 3



The Company has typically provided estimates of future potential curtailment payment estimates in the AAA Report. However, going forward these estimates will be provided in our fuel forecast Petition, including the one that will be filed by May 1, 2023. 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 and all but one of the MISO Multi-Value Projects (MVPs)[10] 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

[10] The Cardinal - Hickory Creek 345 kV MVP line is scheduled to go into service in late 2023.

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 true-up and AAA 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 developing plans to mitigate these constraints.

PUBLIC DOCUMENT-
NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Total
2022 AAA Period

	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			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			519,125.58	$ 15,715,595.96	99,216.95	$ 4,491,208.90	$ 20,206,804.86
Dec-22			427,886.52	$ 13,749,195.05	47,091.44	$ 2,157,549.42	$ 15,906,744.47
Total-22			5,132,713.69	$ 155,819,501.37	1,069,391.11	$ 49,540,011.47	$ 205,260,153.67

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 3 (MISO)
2022 AAA Period

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			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			385,427.73	$ 11,753,056.65	47,091.44	$ 2,157,549.42	$ 13,910,606.07
Total-22			4,541,529.61	$ 128,794,587.97	1,069,391.11	$ 49,540,011.47	$ 178,334,599.44

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Lake Benton I
2022 AAA Period

[PROTECTED DATA BEGINS

	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	Reason Codes	Total Xcel Energy Paid
Jan-21								
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Northern Alternative Energy (NAE)
2022 AAA Period

[PROTECTED DATA BEGINS

	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	Reason Codes	Total Xcel Energy Paid
Jan-21								
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Velva
2022 AAA Period

[PROTECTED DATA BEGINS

	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	Reason Codes	Total Xcel Energy Paid
Jan-21								
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Fenton (EnXco)
2022 AAA Period

[PROTECTED DATA BEGINS

	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	Reason Codes	Total Xcel Energy Paid
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - MinnDakota (Formerly Ivanhoe)
2022 AAA Period

[PROTECTED DATA BEGINS

	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	Reason Codes	Total Xcel Energy Paid
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Lincoln Heights Wind Holding North*
2022 AAA Period

[PROTECTED DATA BEGINS

	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	Reason Codes	Total Xcel Energy Paid
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**Effective 7/1/16 Norgaard North changed name to Lincoln Heights Wind Holdings North LLC.*

PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Lincoln Heights Wind Holding South*
2022 AAA Period

[PROTECTED DATA BEGINS

	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	Reason Codes	Total Xcel Energy Paid
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**Effective 7/1/16 Norgaard North changed name to Lincoln Heights Wind Holdings South LLC.*

PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - JJN Windfarm, LLC.
2022 AAA Period

[PROTECTED DATA BEGINS

	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	Reason Codes	Total Xcel Energy Paid
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Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Ulik
2022 AAA Period

[PROTECTED DATA BEGINS

	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	Reason Codes	Total Xcel Energy Paid
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Ewington
2022 AAA Period

[PROTECTED DATA BEGINS

	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	Reason Codes	Total Xcel Energy Paid
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Moraine II Wind LLC
2022 AAA Period

[PROTECTED DATA BEGINS

	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	Reason Codes	Total Xcel Energy Paid
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Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Prairie Rose
2022 AAA Period

[PROTECTED DATA BEGINS

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	Reason Codes	
Jan-21								
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PROTECTED DATA ENDS]

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Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Zephyr Wind, LLC
2022 AAA Period

[PROTECTED DATA BEGINS

	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	Reason Codes	Total Xcel Energy Paid
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Big Blue Wind Farm
2022 AAA Period

[PROTECTED DATA BEGINS

	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	Reason Codes	Total Xcel Energy Paid
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Valley View Wind
2022 AAA Period

[PROTECTED DATA BEGINS

	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	Reason Codes	Total Xcel Energy Paid
Jan-21								
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Ridgewind Power Partners LLC
2022 AAA Period

[PROTECTED DATA BEGINS

	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	Reason Codes	Total Xcel Energy Paid
Jan-21								
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Grant County Wind LLC
2022 AAA Period

[PROTECTED DATA BEGINS

	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	Reason Codes	Total Xcel Energy Paid
Jan-21								
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Adams Wind Generations
2022 AAA Period

[PROTECTED DATA BEGINS

	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	Reason Codes	Total Xcel Energy Paid
Jan-21								
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Odell
2022 AAA Period

[PROTECTED DATA BEGINS

	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	Reason Codes	Total Xcel Energy Paid
Jan-21								
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Woodstock Hills
2022 AAA Period

[PROTECTED DATA BEGINS

	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	Reason Codes	Total Xcel Energy Paid
Jan-21								
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Cisco
2022 AAA Period

[PROTECTED DATA BEGINS

	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	Reason Codes	Total Xcel Energy Paid
Jan-21								
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PROTECTED DATA ENDS]

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Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Crowned Ridge
2022 AAA Period

[PROTECTED DATA BEGINS

	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	Reason Codes	Total Xcel Energy Paid
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PROTECTED DATA ENDS]

PUBLIC DOCUMENT-
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Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Glen Ullin
2022 AAA Period

[PROTECTED DATA BEGINS

	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	Reason Codes	Total Xcel Energy Paid
Jan-21								
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**PUBLIC DOCUMENT-
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Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Dakota Range III
2022 AAA Period

[PROTECTED DATA BEGINS

	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	Reason Codes	Total Xcel Energy Paid
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								
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Oct-22								
Nov-22								
Dec-22								
Total-22								

PROTECTED DATA ENDS]

Wind Curtailment Summary Report - Company Owned Facilities
2022 AAA Reporting Period

	MWh Curtailed												
Project	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**2022 Total**
Blazing Star 1	664	393	315	3,488	1,709	48	68	101	0	9	2	12	6,809
Blazing Star 2	620	360	380	1,679	461	22	49	67	0	6	0	17	3,661
Border	0	0	2,315	135	98	1,027	234	26	5,834	67	62	38	9,836
Lake Benton II (Buffalo Ridge / Chanarambie)	115	17	256	1,442	103	371	62	248	38	122	663	373	3,810
Community Wind North	0	11	2	44	9	0	1	3	0	0	0	0	69
Courtenay	299	13	31	0	1,809	2,175	14	24	453	6	11	34	4,868
Crowned Ridge II	39,258	1,604	3	16,812	12,479	2,739	747	299	3,140	107	168	115	77,472
Dakota Range 1&2	30,178	8,125	3,020	2,077	12,645	2,159	606	1,758	2,415	720	334	374	64,410
Foxtail	4,898	25,651	15,114	5,903	10,740	4,917	3,302	506	6,217	11,610	18,386	9,813	117,057
Freeborn	5,394	23,493	12,733	35,399	586	2,307	120	441	8	0	46	3,134	83,661
Grand Meadow	101	1,551	396	3,081	5,301	979	9	0	1,096	649	206	481	13,849
Jeffers	191	339	59	237	845	278	1	24	2	205	0	0	2,183
Mower County	0	1,177	292	4	773	15	654	326	0	0	0	0	3,240
Noble	9,996	34,223	28,533	44,036	21,489	7,944	4,146	795	4,190	25,595	36,032	6,706	223,684
Pleasant Valley	1	89	4	72	1,153.0	19.9	0.0	5.1	0.0	0.0	40.1	1,033.1	2,417

Plant Operations and Maintenance

The Commission's March 15, 2010 ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS AND SETTING FURTHER REQUIREMENTS in Docket No. E999/AA-08-995 and April 6, 2012 ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS AND REQUIRING ADDITIONAL FILINGS in Docket Nos. E999/AA-09-961 and E999/AA-10-884 require utilities to provide additional details about plant forced outages, contractor performance, and actions taken to prevent future outages. We provide this information below.

A. Forced Outages

Part C, Attachment 4 provides for each forced outage during the 2022 AAA reporting year the following details: [1]

- a description of the equipment that resulted in the forced outage;
- a description of the equipment failure;
- the change in energy costs resulting from the outage;
- the failure history during the reporting period; and
- the steps taken to alleviate reoccurrence of the outage.

In addition, Part C, Attachment 5 provides a comparison of forecasted outage costs by unit to actual outages experienced.

B. Contractor Performance

Xcel Energy continues to prioritize its careful oversight of contractor and supplier performance. The Company focuses on three areas, as discussed further below.

First, Xcel Energy uses a quality assurance and control protocol for the majority of our contracts. This proactive approach is designed to draw attention to the required quality steps Xcel Energy expects each contractor to follow.

Second, Xcel Energy has awarded several master agreements with companies that consistently exceed others in technology, quality and contract management (including following the Scope of Work).

[1] The information is presented in Minnesota Power's Attachment A outage report format, as specified by the Department in its June 5, 2013 review of utilities' 2011-2012 AAA Reports.

Third, Xcel Energy has invested time and resources to develop more detailed Scopes of Work. Scopes of Work are included in the purchase order and set the expectation for the work. Detailed scopes of work yield an acceptable work product, favorable project scheduling, and reduced unit outage extensions.

In the event problems arise with services, equipment, and/or materials provided by a vendor/supplier, the Company utilizes a Non Conformance Reporting Process to correct deficiencies. In addition, special conditions that hold suppliers and contractors accountable for quality management are placed in all contracts. Remedies for problems that adversely affect generating plant performance can include the direct costs of re-work, including labor and/or materials.

The Company strives to contract for generation plant repair and maintenance services with parties who have a history of performing work safely, reliably, and in a timely manner.

C. Operational Initiatives

As we have stated in prior AAA reports, we have several operational improvement initiatives at work under the Generation Operating Model Initiative. The Generation Operating Model I launched in 2011 was successful in its purpose to standardize processes, create efficiencies, and identify and share best practices across the fleet. This success led to the development and implementation of the Generation Operating Model II in 2019.

A significant organizational change in the Generation Operating Model II was the creation of the Performance Optimization department that centralizes technical support services to correspond to the evolving generation portfolio. The Performance Optimization department is comprised of Reliability Engineering, Fleet Engineering, and Analytics & Practices. A brief explanation of each Performance Optimization area follows.

- The Reliability Engineering department is responsible for the daily engineering activities at our plants and provides on-site support. The Reliability Engineers ensure our plant design basis is maintained and a consistent asset strategy is implemented across the fleet and for similar generations types.

- The Fleet Engineering department is responsible for developing and implementing asset and equipment strategies consistently across the fleet. This department is broken into fleet engineering teams for common systems including Electrical and Controls, Boilers and Balance of Plant, Steam Turbines, Gas Turbines, Materials Engineering, and Non-Destructive Examination and Testing. This department also includes an Asset Strategy and Budget Integration team to ensure that fleet asset strategies are effectively integrated and prioritized.

- The Analytics and Practices department includes both a Monitoring and Diagnostics team and a System and Equipment Analytics team. The Monitoring and Diagnostics team utilizes the Company's remote monitoring capability and predictive analytics to identify abnormal operational issues and alert plant personnel for corrective actions prior to failure. The System and Equipment Analytics team integrates equipment monitoring, asset performance management analytical tools, and financial analysis.

The key focus of the 2019 Operations Model II is continuous improvement. Continuous Improvement is accomplished by utilizing Lean Management (people-based tools to improve processes, inventory management, and customer relationships); standardized Event Assessments and Root Cause Analysis (process that identifies forced outages and equipment failure to prevent recurrence); and Operating Model Governance (monitoring, documenting, and resolving issues that arise while improving performance).

Lastly, as we mature in our use of the Operating Model II, we have implemented the GE Asset Performance Management (GE-APM) software that leverages technology to effectively enable Asset Performance Management. It consolidates and analyzes data from a variety of sources to optimize the cost, risk, and reliability of selected generation equipment. Outputs of GE-APM include optimized equipment maintenance strategies and the development of Intelligent Asset Health and Operational Risk analytical models and dashboards.

D. Generation Maintenance Costs

The Commission's February 6, 2008 ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS, REQUIRING FURTHER FILINGS, AND AMENDING ORDER OF DECEMBER 20, 2006 ON PASSING MISO DAY 2 COSTS THROUGH FUEL CLAUSE in

Docket Nos. E,G999/AA-06-1208 and E002/M-04-1970 *et al.* requires utilities to provide a comparison of the actual expenses pertaining to maintenance of generation plants to the generation maintenance budget from the utility's most recent rate case. We provide this information as Part C, Attachment 6.

PUBLIC DOCUMENT
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Northern States Power Company
State of Minnesota-Electric Operations
Unit Forced Outage Information
2022 AAA Reporting Period: January 1 - December 31, 2022

Protected Data is Shaded

[PROTECTED DATA BEGINS

Unit	Outage Category	Primary Reason for Unplanned Outage	Outage Dates Start	Outage Dates End	Duration (Days)	Equipment that resulted in the forced outage	Description of Equipment Failure	Change in Energy Costs ($s)	Failure History During Reporting Period	Steps Taken to Alleviate Reoccurrence
King_G1	Forced	High vibs on 12 BFP	1/1/2022	1/31/2022	31	12 steam driven boiler feed pump	Degradation of rotating element		Similar derates were reported during this time period on 2/1/22, 3/1/22, 6/17/22, 7/1/22, 7/17/22, 8/1/22, 9/2/22, 9/20/22, and 10/1/22 . All events were to support the repairs of this one (#12) BFP.	Both 12 and 13 BFP elements were replaced with rebuilt elements in the Fall of 2022, allowing equipment to run until retirement in 2028.
SHERCO_G2	Forced	Derate due to 5 Coal Mill operation (21 Hot Air Blast Gate issue & 24 Mills OOS).	1/1/2022	1/6/2022	5	21 and 24 Coal Mills	24 Coal Mill removed from service due to metal shavings found in oil system. 21 Coal Mill failed due to loss of signal from Hot Air Blast Gate. Found a failed control signal cable that required replacement.		Similar occurrences on 8/29/22 and 10/23/22 for Unit 1, 6/1/22, 7/25/22, 8/26/22, 10/25/22, 11/7/22, 11/8/22, and 12/14/22 for Unit 2, and 12/30/22 for Unit 3. Derates due to having more than one coal mill out of service preventing the unit from making full load capability.	With 24 Coal Mill being in an emergency use only status, all future work, both planned and unexpected maintenance, on U2 coal mills will result in a derate.
SHERCO_G1	Forced	Derate due to loss of 11 coal feeder, no ability to add to current silo levels until repair is completed	1/1/2022	1/2/2022	2	11 Transfer Hopper Feeder	Loss of 11 coal feeder due to failure of feeder belt tail pulley. This prevented coal from being delivered to 4 of 7 coal mills until repaired.		Similar derates were reported during this time period on 1/3/22, 3/7/22 and 11/20/22.	Tail pulley was replaced and belt was aligned.
SHERCO_G2	Forced	Immediate derate due to loss of 22 coal feeder. Only 2 coal mills available for use.	1/1/2022	1/2/2022	1	22 Coal Feeder	24 Coal Mill removed from service due to metal shavings found in oil system. Loss of coal flow to 22 feeder due to frozen coal plugging outlet from 22 Coal Silo.		Used air blasters to clear plugged coal to return flow to 22 feeder.	With 24 Coal Mill being in an emergency use only status, all future work, both planned and unexpected maintenance, on U2 coal mills will result in a derate.
Blk_Dog_G52	Forced	U2 trip due to generator protection relay (59N)-Ground on Isophase Bus insulation	1/2/2022	1/18/2022	16	Section of bus bar from U2 generator to U2 GSU transformer.	Insulation failure of the bus bar section resulted in a path to ground which prevented the unit from operating.		Two events in January from this same failure. First repair attempt was unsuccessful, second repair was successful. Equipment was then replaced in May 2022.	Damaged section of bus bar was fixed temporarily in January 2022 and then replaced in May 2022.
SHERC3	Forced	Derate due to loss of additional additive feed pump. Only have 4 operational SDA's at this time.	1/2/2022	1/3/2022	1	Spray Dryer Absorbers (SDAs)	31 SDA out of service due to failed additive feed pump, 32 SDA out of service due to plugged head tank screen, 33 SDA out of service due to failed additive feed pump and 36 SDA out of service due to high bearing temperatures.		Similar events on 3/13/2022 and 12/20/22. All events were related to number of available SDA's and how many are necessary for full load operation to maintain available environmental limits.	Repairs were prioritized to restore additive feed flow to 2 SDA's to allow unit to return to full power operations.
SHERCO_G1	Forced	U1 Derate to 260 MWn due to the loss of 11 coal feeder.	1/3/2022	1/6/2022	3	11 Transfer Hopper Feeder	Loss of 11 coal feeder due to failure of welds on belt head pulley. This prevented coal from being delivered to 4 of 7 coal mills until repaired.		Similar derates were reported during this time period on 1/1/22, 3/7/22 and 11/20/22.	Welds were repaired, failed head pulley was replaced and belt was re-aligned.
SHERCO_G1	Forced	Derate due to loss of 12 Boiler Circ Pump. 3 of 4 BCPs available for service.	1/6/2022	1/31/2022	25	12 Boiler Circ Pump	During normal operation of 12 BCP, the pump exhibited high vibrations and was removed from service. Investigation revealed the pump casing wear ring became liberated causing damage to the impeller and other pump/motor components. This required the pump/motor assembly to be sent offiste for repairs.With only 3 of 4 BCPs available, unit derated to 610 MWh.		Similar derates were reported during this time period on 2/1/22, 3/1/22, 3/9/22, 3/11/22, 6/1/22, 7/1/22, 7/27/22, 8/1/22, 8/4/22, 8/12, 8/17, 9/1/22 and 9/10/22. All events were to support the repairs of 12 Boiler Circ Pumps.	Pump/Motor assemble required an outage to remove, install the blank and send to Hayward Tyler for evaluation, quote, rewind and repair. Decision was made to leave unit online during the the winter months. Outage was taken 4/18/22 and motor removed then sent offsite. Hayward Tyler received the assembly on 5/2/22 and issued an inspection report on 5/18/22 which showed damage to both the pump assembly as well as the motor rotor and stator assembly. Assembly shiped back to the site on 7/12/22. A decision was made to leave unit online through summer months. A maintenance outage was taken on 9/25/22 to remove the blank and reinstall the assembly.
King_G1	Forced	Secondary superheat leak 2 secondary 7 reheat	1/6/2022	1/12/2022	6	Secondary super heat boiler tube that failed	Tube had been fatigued over years and cut other tubes by orginal leak		None	Tube was repaired, increased inspection of the tube that failed, with plan for replacement if any other wear detected.
SHERCO_G2	Forced	212 Mod OOS Major Clean, 203 Mod OOS reaction tank relining, and 204 module OOS spray pump failure.	1/17/2022	1/18/2022	1	Scrubber Modules	212 Module was removed from service for major clean, 203 module out of service for reaction tank relining and 204 module experienced a spray pump failure. Unit unable to make full load with more than 2 modules out of service.		Similar occurrences on 9/7/22 and 9/12/22 for Unit 1 and 1/7/22, 10/1/22, 10/4/22, 10/26/22, 10/30/22 and 11/1/22 for Unit 2. Derates necessary to support daily module cleaning and flushing with two or more modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module (12 total per unit) has increased from once a year to once every 8 months. This strategy will still require some smaller derates to complete all required cleaning evolutions but these smaller derates should be limited mainly to the spring and fall when energy prices are historically less. There will also be derates due to loss of other module components during times which we need to have two major cleans in progress at once due to the loss of redundancy.
Blk_Dog_G52	Forced	Unit 2 trip due to generator protection relay-Ground on isophase Busbar due to failed isulator	1/20/2022	1/29/2022	10	Section of bus bar from U2 generator to U2 GSU transformer.	Insulation failure of the bus bar section resulted in a path to ground which prevented the unit from operating.		Two events in January from this same failure. First repair attempt was unsuccessful, second repair was successful. Equipment was then replaced in May 2022.	Damaged section of bus bar was fixed temporarily in January 2022 and then replaced in May 2022.
Monticello_1	Forced	Drywell leakage forced outage to repair XR-7-2	1/24/2022	1/27/2022	3	Recirculating Loop Drain Valve	Body to Bonnet leak on the Recirculating Loop Drain Valve		None	Valve was disassembled and repaired.
King_G1	Forced	High vibs on 12 BFP extended	2/1/2022	2/28/2022	28	12 steam driven boiler feed pump	Degradation of rotating element		Similar derates were reported during this time period on 1/1/22, 2/1/22, 3/1/22, 6/17/22, 7/1/22, 7/17/22, 8/1/22, 9/2/22, 9/20/22, and 10/1/22 . All events were to support the repairs of this one (#12) BFP.	Both 12 and 13 BFP elements were replaced with rebuilt elements in the Fall of 2022, allowing equipment to run until retirement in 2028
SHERCO_G1	Forced	Derate due to loss of 12 Boiler Circ Pump. 3 of 4 BCPs available for service.	2/1/2022	2/28/2022	28	12 Boiler Circ Pump	During normal operation of 12 BCP, the pump exhibited high vibrations and was removed from service. Investigation revealed the pump casing wear ring became liberated causing damage to the impeller and other pump/motor components. This required the pump/motor assembly to be sent offiste for repairs. With only 3 of 4 BCPs available, unit derated to 610 MWh.		Similar derates were reported during this time period on 1/6/22, 3/1/22, 3/9/22, 3/11/22, 6/1/22, 7/1/22, 7/27/22, 8/1/22, 8/4/22, 8/12, 8/17, 9/1/22 and 9/10/22. All events were to support the repairs of this one (#12) circ pump.	Pump/Motor assemble required an outage to remove, install the blank and send to Hayward Tyler for evaluation, quote, rewind and repair. Decision was made to leave unit online during the the winter months. Outage was taken 4/18/22 and motor removed then sent offsite. Hayward Tyler received the assembly on 5/2/22 and issued an inspection report on 5/18/22 which showed damage to both the pump assembly as well as the motor rotor and stator assembly. Assembly shiped back to the site on 7/12/22. A decision was made to leave unit online through summer months. A maintenance outage was taken on 9/25/22 to remove the blank and reinstall the assembly.
SHERC3	Forced	Derate due to an apparent tube leak on 36-1 HP Feedwater heater requiring feedwater string to be taken out of service.	2/11/2022	2/28/2022	17	36-1 Feedwater Heater (FWH)	During operation of Unit 3, operations personnel noted emergency dump valve opening to maintain level in 36-1 feedwater heater due an apparent tube leak. Heater string was isolated and a tube leak was verified in 36-1 feedwater heater. Unit derated due to feedwater heater string out of service.		Similar events on 3/1/2022, 3/16/22, 11/27/2022, and 12/1/22. All events were related to leaking tubes 36 Feedwater Heaters at their end of life.	Heater string removed from service and unit derated until a favorable market condition would allow for unit to be taken offline to repair the tube leak. Working with marketing determined that the best time for this would be during the planned outage for state mandated boiler inspection in September. Heater will be repaired and remaining tubes will have eddy current testing performed to determine if there are any other suspectable tubes.
King_G1	Forced	Feedwater pump	2/18/2022	2/22/2022	4	13 steam driven boiler feed pump	First stage of pump element crack		Similar event on 2/22/2022	Both 12 and 13 BFP elements were replaced with rebuilt elements in the Fall of 2022, allowing equipment to run until retirement in 2028
King_G1	Forced	Feedwater pump	2/22/2022	2/28/2022	6	13 steam driven boiler feed pump	First stage of pump element crack		Similar event on 2/18/2023	Both 12 and 13 BFP elements were replaced with rebuilt elements in the Fall of 2022, allowing equipment to run until retirement in 2028
King_G1	Forced	High vibs on 12 BFP	3/1/2022	3/31/2022	31	12 steam driven boiler feed pump	Degradation of rotating element		Similar derates were reported during this time period on 1/1/22, 2/1/22, 3/1/22, 6/17/22, 7/1/22, 7/17/22, 8/1/22, 9/2/22, 9/20/22, and 10/1/22. All events were to support the repairs of this one (#12) BFP.	Both 12 and 13 BFP elements were replaced with rebuilt elements in the Fall of 2022, allowing equipment to run until retirement in 2028
SHERCO_G1	Forced	Derate due to loss of 12 Boiler Circ Pump. 3 of 4 BCPs available for service.	3/1/2022	3/7/2022	7	12 Boiler Circ Pump	During normal operation of 12 BCP, the pump exhibited high vibrations and was removed from service. Investigation revealed the pump casing wear ring became liberated causing damage to the impeller and other pump/motor components. This required the pump/motor assembly to be sent offiste for repairs. With only 3 of 4 BCPs available, unit derated to 610 MWh.		Similar derates were reported during this time period on 1/6/22, 2/1/22, 3/9/22, 3/11/22, 6/1/22, 7/1/22, 7/27/22, 8/1/22, 8/4/22, 8/12, 8/17, 9/1/22 and 9/10/22. All events were to support the repairs of this one (#12) circ pump.	Pump/Motor assemble required an outage to remove, install the blank and send to Hayward Tyler for evaluation, quote, rewind and repair. Decision was made to leave unit online during the the winter months. Outage was taken 4/18/22 and motor removed then sent offsite. Hayward Tyler received the assembly on 5/2/22 and issued an inspection report on 5/18/22 which showed damage to both the pump assembly as well as the motor rotor and stator assembly. Assembly shiped back to the site on 7/12/22. A decision was made to leave unit online through summer months. A maintenance outage was taken on 9/25/22 to remove the blank and reinstall the assembly.
SHERC3	Forced	Apparent tube leak on 36-1 HP Feedwater heater requiring feedwater string to be taken out of service.	3/1/2022	3/13/2022	13	36-1 Feedwater Heater (FWH)	During operation of Unit 3, operations personnel noted emergency dump valve opening to maintain level in 36-1 feedwater heater due an apparent tube leak. Heater string was isolated and a tube leak was verified in 36-1 feedwater heater. Unit derated due to feedwater heater string out of service.		Similar events on 2/11/22, 3/16/22, 11/27/2022, and 12/1/22. All events were related to leaking tubes. 36 Feedwater Heaters at their end of life.	Heater string removed from service and unit derated until a favorable market condition would allow for unit to be taken offline to repair the tube leak. Working with marketing determined that the best time for this would be during the planned outage for state mandated boiler inspection in September. Heater will be repaired and remaining tubes will have eddy current testing performed to determine if there are any other suspectable tubes.
SHERCO_G1	Forced	Derate needed for three mills available. 11 transfer hopper feeder tail pulley issues, not able to fill bottom four silos.	3/7/2022	3/8/2022	1	11 Transfer Hopper Feeder	Loss of 11 coal feeder due to failure of feeder belt tail pulley. This prevented coal from being delivered to 4 of 7 coal mills until repaired.		Similar derates were reported during this time period on 1/1/22 and 1/3/22.	Modifications were made to the drag chain system for cleaning out area around the belts which led to belt misalignment and tail pulley failure. Tail pulley was replaced and belt re-algined.
SHERCO_G1	Forced	Derate due to loss of 12 Boiler Circ Pump. 3 of 4 BCPs available for service.	3/9/2022	3/10/2022	1	12 Boiler Circ Pump	During normal operation of 12 BCP, the pump exhibited high vibrations and was removed from service. Investigation revealed the pump casing wear ring became liberated causing damage to the impeller and other pump/motor components. This required the pump/motor assembly to be sent offiste for repairs. With only 3 of 4 BCPs available, unit derated to 610 MWh.		Similar derates were reported during this time period on 1/6/22, 2/1/22, 3/1/22, 3/11/22, 6/1/22, 7/1/22, 7/27/22, 8/1/22, 8/4/22, 8/12, 8/17, 9/1/22 and 9/10/22. All events were to support the repairs of this one (#12) circ pump.	Pump/Motor assemble required an outage to remove, install the blank and send to Hayward Tyler for evaluation, quote, rewind and repair. Decision was made to leave unit online during the the winter months. Outage was taken 4/18/22 and motor removed then sent offsite. Hayward Tyler received the assembly on 5/2/22 and issued an inspection report on 5/18/22 which showed damage to both the pump assembly as well as the motor rotor and stator assembly. Assembly shiped back to the site on 7/12/22. A decision was made to leave unit online through summer months. A maintenance outage was taken on 9/25/22 to remove the blank and reinstall the assembly.

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NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
State of Minnesota-Electric Operations
Unit Forced Outage Information
2022 AAA Reporting Period: January 1 - December 31, 2022

Protected Data is Shaded

[PROTECTED DATA BEGINS

Unit	Outage Category	Primary Reason for Unplanned Outage	Outage Dates Start	End	Duration (Days)	Equipment that resulted in the forced outage	Description of Equipment Failure	Change in Energy Costs ($s)	Failure History During Reporting Period	Steps Taken to Alleviate Reoccurrence
SHERCO_G1	Forced	Derate due to loss of 12 Boiler Circ Pump. 3 of 4 BCPs available for service.	3/11/2022	3/31/2022	21	12 Boiler Circ Pump	During normal operation of 12 BCP, the pump exhibited high vibrations and was removed from service. Investigation revealed the pump casing wear ring became liberated causing damage to the impeller and other pump/motor components. This required the pump/motor assembly to be sent offiste for repairs. With only 3 of 4 BCPs available, unit derated to 610 MWh.		Similar derates were reported during this time period on 1/6/22, 2/1/22, 3/1/22, 3/9/22, 6/1/22, 7/1/22, 7/27/22, 8/1/22, 8/4/22, 8/12, 8/17, 9/1/22 and 9/10/22. All events were to support the repairs of this one (#12) circ pump.	Pump/Motor assemble required an outage to remove, install the blank and send to Hayward Tyler for evaluation, quote, rewind and repair. Decision was made to leave unit online during the the winter months. Outage was taken 4/18/22 and motor removed then sent offsite. Hayward Tyler received the assembly on 5/2/22 and issued an inspection report on 5/18/22 which showed damage to both the pump assembly as well as the motor rotor and stator assembly. Assembly shiped back to the site on 7/12/22. A decision was made to leave unit online through summer months. A maintenance outage was taken on 9/25/22 to remove the blank and reinstall the assembly.
SHERC3	Forced	Derated needed with four SDA'a available. 32 & 36 held out, 31 restricted flow, 34 HI/low spindle sump alarm in.	3/13/2022	3/16/2022	3	Spray Dryer Absorbers (SDAs)	32 and 36 SDA's motors were removed for maintenance. 31 SDA out of service due to low additive feed flow, 34 SDA removed from service due to leak in water wheel protection to the SDA spindle.		Similar events on 3/1/2022 and 12/20/22. All events were related to number of available SDA's and how many are necessary for full load operation to maintain available environmental limits.	Repairs were prioritized to restore additive feed flow to 31 SDA and repair the leak in 34 SDA to return 2 SDA's to service, allowing unit to return to full power operations.
SHERC3	Forced	Apparent tube leak on 36-1 HP Feedwater heater requiring feedwater string to be taken out of service	3/16/2022	3/31/2022	15	36-1 Feedwater Heater (FWH)	During operation of Unit 3, operations personnel noted emergency dump valve opening to maintain level in 36-1 feedwater heater due an apparent tube leak. Heater string was isolated and a tube leak was verified in 36-1 feedwater heater. Unit derated due to feedwater heater string out of service.		Similar events on 2/11/22, 3/1/2022, 11/27/22, and 12/1/22. All events were related to leaking tubes in 36 Feedwater Heaters at their end of life.	Heater string removed from service and unit derated until a favorable market condition would allow for unit to be taken offline to repair the tube leak. Working with marketing determined that the best time for this would be during the planned outage for state mandated boiler inspection in September. Heater will be repaired and remaining tubes will have eddy current testing performed to determine if there are any other suspectable tubes.
SHERCO_G1	Forced	Derated and available for 610 MWn due to loss of 12 Boiler Circ Pump. 3 of 4 BCPs available for service	6/1/2022	6/30/2022	30	12 Boiler Circ Pump	During normal operation of 12 BCP, the pump exhibited high vibrations and was removed from service. Investigation revealed the pump casing wear ring became liberated causing damage to the impeller and other pump/motor components. This required the pump/motor assembly to be sent offiste for repairs. With only 3 of 4 BCPs available, unit derated to 610 MWh.		Similar derates were reported during this time period on 1/6/22, 2/1/22, 3/1/22, 3/9/22, 3/11/22, 7/1/22, 7/27/22, 8/1/22, 8/4/22, 8/12, 8/17, 9/1/22 and 9/10/22. All events were to support the repairs of this one (#12) circ pump.	Pump/Motor assemble required an outage to remove, install the blank and send to Hayward Tyler for evaluation, quote, rewind and repair. Decision was made to leave unit online during the the winter months. Outage was taken 4/18/22 and motor removed then sent offsite. Hayward Tyler received the assembly on 5/2/22 and issued an inspection report on 5/18/22 which showed damage to both the pump assembly as well as the motor rotor and stator assembly. Assembly shiped back to the site on 7/12/22. A decision was made to leave unit online through summer months. A maintenance outage was taken on 9/25/22 to remove the blank and reinstall the assembly.
SHERCO_G2	Forced	Derate due to 5 Coal Mill operation. 24 & 27 Coal Mills out of service (27 Mill coal leaks on transport lines).	6/1/2022	6/6/2022	6	24 and 27 Coal Mills	24 Coal Mill removed from Service due to metal shavings found in oil system. 27 Coal Mill hot air blast gate cylinder failed requiring coal mill to be shut down for replacement.		Similar occurrences on 8/29/22 and 10/23/22 for Unit 1, 1/1/22,7/25/22, 8/26/22, 10/25/22, 11/7/22, 11/8/22, and 12/14/22 for Unit 2, and 12/30/22 for Unit 3. Derates due to having more than one coal mill out of service preventing the unit from making full load capability.	With 24 Coal Mill being in an emergency use only status, all future work, both planned and unexpected maintenance, on U2 coal mills will result in a derate.
King_G1	Forced	Derate of King due to feedwater constraints. Current load range of 380-435 MW Net available on AGC.	6/17/2022	6/30/2022	13	12 steam driven boiler feed pump	Degradation of rotating element		Similar derates were reported during this time period on 1/1/22, 2/1/22, 3/1/22, 6/17/22, 7/1/22, 7/17/22, 8/1/22, 9/2/22, 9/20/22, and 10/1/22. All events were to support the repairs of this one (#12) BFP.	Both 12 and 13 BFP elements were replaced with rebuilt elements in the Fall of 2022, allowing equipment to run until retirement in 2028
King_G1	Forced	Derate of King due to feedwater constraints.	7/1/2022	7/2/2022	2	12 steam driven boiler feed pump	Degradation of rotating element		Similar derates were reported during this time period on 1/1/22, 2/1/22, 3/1/22, 6/17/22, 7/1/22, 7/17/22, 8/1/22, 9/2/22, 9/20/22, and 10/1/22. All events were to support the repairs of this one (#12) BFP.	Both 12 and 13 BFP elements were replaced with rebuilt elements in the Fall of 2022, allowing equipment to run until retirement in 2028
SHERCO_G1	Forced	Derated due to loss of 12 Boiler Circ Pump. 3 of 4 BCPs available for service.	7/1/2022	7/26/2022	25	12 Boiler Circ Pump	During normal operation of 12 BCP, the pump exhibited high vibrations and was removed from service. Investigation revealed the pump casing wear ring became liberated causing damage to the impeller and other pump/motor components. This required the pump/motor assembly to be sent offiste for repairs. With only 3 of 4 BCPs available, unit derated to 610 MWh.		Similar derates were reported during this time period on 1/6/22, 2/1/22, 3/1/22, 3/9/22, 3/11/22, 6/1/22, 7/27/22, 8/1/22, 8/4/22, 8/12, 8/17, 9/1/22 and 9/10/22. All events were to support the repairs of this one (#12) circ pump.	Pump/Motor assemble required an outage to remove, install the blank and send to Hayward Tyler for evaluation, quote, rewind and repair. Decision was made to leave unit online during the the winter months. Outage was taken 4/18/22 and motor removed then sent offsite. Hayward Tyler received the assembly on 5/2/22 and issued an inspection report on 5/18/22 which showed damage to both the pump assembly as well as the motor rotor and stator assembly. Assembly shiped back to the site on 7/12/22. A decision was made to leave unit online through summer months. A maintenance outage was taken on 9/25/22 to remove the blank and reinstall the assembly.
King_G1	Forced	Derate of King due to feedwater constraints.	7/17/2022	7/29/2022	12	12 steam driven boiler feed pump	Degradation of rotating element		Similar derates were reported during this time period on 1/1/22, 2/1/22, 3/1/22, 6/17/22, 7/1/22, 7/17/22, 8/1/22, 9/2/22, 9/20/22, and 10/1/22. All events were to support the repairs of this one (#12) BFP.	Both 12 and 13 BFP elements were replaced with rebuilt elements in the Fall of 2022, allowing equipment to run until retirement in 2028
SHERCO_G2	Forced	Leak between 22 CMill Feeder and 22 Coal Mill, also OOS with Bearing issue.	7/25/2022	7/28/2022	3	22 and 24 Coal Mills	24 Coal Mill removed from Service due to metal shavings found in oil system. Coal leak was discovered on coal transport line for 22 coal mill requiring mill to be removed from service to prevent creating a combustible dust concerns.		Similar occurrences on 8/29/22 and 10/23/22 for Unit 1, 1/1/22, 6/1/22, 8/26/22, 10/25/22, 11/7/22, 11/8/22, and 12/14/22 for Unit 2, and 12/30/22 for Unit 3. Derates due to having more than one coal mill out of service preventing the unit from making full load capability.	With 24 Coal Mill being in an emergency use only status, all future work, both planned and unexpected maintenance, on U2 coal mills will result in a derate.
SHERCO_G1	Forced	Derated and available for 610 MWn due to loss of 12 Boiler Circ Pump. 3 of 4 BCPs available for service.	7/27/2022	7/31/2022	4	12 Boiler Circ Pump	During normal operation of 12 BCP, the pump exhibited high vibrations and was removed from service. Investigation revealed the pump casing wear ring became liberated causing damage to the impeller and other pump/motor components. This required the pump/motor assembly to be sent offiste for repairs. With only 3 of 4 BCPs available, unit derated to 610 MWh.		Similar derates were reported during this time period on 1/6/22, 2/1/22, 3/1/22, 3/9/22, 3/11/22, 6/1/22, 7/1/22, 8/1/22, 8/4/22, 8/12, 8/17, 9/1/22 and 9/10/22. All events were to support the repairs of this one (#12) circ pump.	Pump/Motor assemble required an outage to remove, install the blank and send to Hayward Tyler for evaluation, quote, rewind and repair. Decision was made to leave unit online during the the winter months. Outage was taken 4/18/22 and motor removed then sent offsite. Hayward Tyler received the assembly on 5/2/22 and issued an inspection report on 5/18/22 which showed damage to both the pump assembly as well as the motor rotor and stator assembly. Assembly shiped back to the site on 7/12/22. A decision was made to leave unit online through summer months. A maintenance outage was taken on 9/25/22 to remove the blank and reinstall the assembly.
King_G1	Forced	High Circulating Water Temperature	7/29/2022	7/31/2022	3	12 Circulating water booster pump	Discharge valve on booster failed		None	New valve ordered and planned to be installed the Spring of 2023
King_G1	Forced	Derate of King due to feedwater constraints.	8/1/2022	8/21/2022	20	12 steam driven boiler feed pump	Degradation of rotating element		Similar derates were reported during this time period on 1/1/22, 2/1/22, 3/1/22, 6/17/22, 7/1/22, 7/17/22, 8/1/22, 9/2/22, 9/20/22, and 10/1/22. All events were to support the repairs of this one (#12) BFP.	Both 12 and 13 BFP elements were replaced with rebuilt elements in the Fall of 2022, allowing from equipment to run until retirement in 2028
SHERCO_G1	Forced	Derated and available for 610 MWn due to loss of 12 Boiler Circ Pump. 3 of 4 BCPs available for service.	8/1/2022	8/2/2022	2	12 Boiler Circ Pump	During normal operation of 12 BCP, the pump exhibited high vibrations and was removed from service. Investigation revealed the pump casing wear ring became liberated causing damage to the impeller and other pump/motor components. This required the pump/motor assembly to be sent offiste for repairs. With only 3 of 4 BCPs available, unit derated to 610 MWh.		Similar derates were reported during this time period on 1/6/22, 2/1/22, 3/1/22, 3/9/22, 3/11/22, 6/1/22, 7/1/22, 7/27/22, 8/4/22, 8/12, 8/17, 9/1/22 and 9/10/22. All events were to support the repairs of this one (#12) circ pump.	Pump/Motor assemble required an outage to remove, install the blank and send to Hayward Tyler for evaluation, quote, rewind and repair. Decision was made to leave unit online during the the winter months. Outage was taken 4/18/22 and motor removed then sent offsite. Hayward Tyler received the assembly on 5/2/22 and issued an inspection report on 5/18/22 which showed damage to both the pump assembly as well as the motor rotor and stator assembly. Assembly shiped back to the site on 7/12/22. A decision was made to leave unit online through summer months. A maintenance outage was taken on 9/25/22 to remove the blank and reinstall the assembly.
CC Highbridge2	Forced	Reheat tube leak on HRSG 7 requires weld repair and post weld heat treat. Results in a derate of 9ST.	8/2/2022	8/5/2022	3	HRSG 7 reheat section lower header drain connection.	Drain to header fatigue crack.		None	Fleet Engineering considering redesign of drain to header connection.
SHERCO_G1	Forced	Derated and available for 610 MWn due to loss of 12 Boiler Circ Pump. 3 of 4 BCPs available for service.	8/4/2022	8/11/2022	7	12 Boiler Circ Pump	During normal operation of 12 BCP, the pump exhibited high vibrations and was removed from service. Investigation revealed the pump casing wear ring became liberated causing damage to the impeller and other pump/motor components. This required the pump/motor assembly to be sent offiste for repairs. With only 3 of 4 BCPs available, unit derated to 610 MWh.		Similar derates were reported during this time period on 1/6/22, 2/1/22, 3/1/22, 3/9/22, 3/11/22, 6/1/22, 7/1/22, 7/27/22, 8/1/22, 8/12, 8/17, 9/1/22 and 9/10/22. All events were to support the repairs of this one (#12) circ pump.	Pump/Motor assemble required an outage to remove, install the blank and send to Hayward Tyler for evaluation, quote, rewind and repair. Decision was made to leave unit online during the the winter months. Outage was taken 4/18/22 and motor removed then sent offsite. Hayward Tyler received the assembly on 5/2/22 and issued an inspection report on 5/18/22 which showed damage to both the pump assembly as well as the motor rotor and stator assembly. Assembly shiped back to the site on 7/12/22. A decision was made to leave unit online through summer months. A maintenance outage was taken on 9/25/22 to remove the blank and reinstall the assembly.
SHERCO_G1	Forced	Derate needed for 11 ID Fan inlet damper linkage failed.	8/11/2022	8/12/2022	1	11 Induced Draft Fan	11 Induced Draft Fan inlet damper linkage broke requiring fan to be taken out of service.		Similar occurences were reported during this time period on 11/1/22, 11/23/22 and 12/2/22 to support the repairs of 13 ID Fan. Similar occurence on 12/1/23 for 24 Induced Draft Fan.	Damper linkage was repaired and the ID fan was returned to normal operation.

Northern States Power Company
State of Minnesota-Electric Operations
Unit Forced Outage Information
2022 AAA Reporting Period: January 1 - December 31, 2022

Protected Data is Shaded

[PROTECTED DATA BEGINS

Unit	Outage Category	Primary Reason for Unplanned Outage	Outage Dates Start	Outage Dates End	Duration (Days)	Equipment that resulted in the forced outage	Description of Equipment Failure	Change in Energy Costs ($s)	Failure History During Reporting Period	Steps Taken to Alleviate Reoccurrence
SHERCO_G1	Forced	Derated and available for 610MWn due to loss of 12 boiler circ pump. 3 out of 4 available for service.	8/12/2022	8/16/2022	4	12 Boiler Circ Pump	During normal operation of 12 BCP, the pump exhibited high vibrations and was removed from service. Investigation revealed the pump casing wear ring became liberated causing damage to the impeller and other pump/motor components. This required the pump/motor assembly to be sent offiste for repairs. With only 3 of 4 BCPs available, unit derated to 610 MWh.		Similar derates were reported during this time period on 1/6/22, 2/1/22, 3/1/22, 3/9/22, 3/11/22, 6/1/22, 7/1/22, 7/27/22, 8/1/22, 8/4/22, 8/17, 9/1/22 and 9/10/22. All events were to support the repairs of this one (#12) circ pump.	Pump/Motor assemble required an outage to remove, install the blank and send to Hayward Tyler for evaluation, quote, rewind and repair. Decision was made to leave unit online during the the winter months. Outage was taken 4/18/22 and motor removed then sent offsite. Hayward Tyler received the assembly on 5/2/22 and issued an inspection report on 5/18/22 which showed damage to both the pump assembly as well as the motor rotor and stator assembly. Assembly shiped back to the site on 7/12/22. A decision was made to leave unit online through summer months. A maintenance outage was taken on 9/25/22 to remove the blank and reinstall the assembly.
SHERC3	Forced	Unit offline @ 0200 on 8/16 to allow for steam leak repairs.	8/16/2022	8/22/2022	6	Boiler Blowdown Line	Coupling TEAM installed to try to inject vavles that were leaking by to stop leakage failed resulting in an unisolable steam leak.		Similar events on 8/16/22, 8/22/22, 10/7/22 and 11/4/22.	Affected piping and valves were replaced.
SHERCO_G1	Forced	Derated and available for 610MWn due to loss of 12 boiler circ pump. 3 out of 4 available for service.	8/17/2022	8/29/2022	12	12 Boiler Circ Pump	During normal operation of 12 BCP, the pump exhibited high vibrations and was removed from service. Investigation revealed the pump casing wear ring became liberated causing damage to the impeller and other pump/motor components. This required the pump/motor assembly to be sent offiste for repairs. With only 3 of 4 BCPs available, unit derated to 610 MWh.		Similar derates were reported during this time period on 1/6/22, 2/1/22, 3/1/22, 3/9/22, 3/11/22, 6/1/22, 7/1/22, 7/27/22, 8/1/22, 8/4/22, 8/12, 9/1/22 and 9/10/22. All events were to support the repairs of this one (#12) circ pump.	Pump/Motor assemble required an outage to remove, install the blank and send to Hayward Tyler for evaluation, quote, rewind and repair. Decision was made to leave unit online during the the winter months. Outage was taken 4/18/22 and motor removed then sent offsite. Hayward Tyler received the assembly on 5/2/22 and issued an inspection report on 5/18/22 which showed damage to both the pump assembly as well as the motor rotor and stator assembly. Assembly shiped back to the site on 7/12/22. A decision was made to leave unit online through summer months. A maintenance outage was taken on 9/25/22 to remove the blank and reinstall the assembly.
SHERC3	Forced	During U3's start-up process a steam leak was discovered in the West Main-steam line.	8/22/2022	8/26/2022	4	Main Steam Line	Gamma inspection plug on one of the main steam lines developed an unisolable steam leak.		Similar events on 8/16/22, 8/22/22, 10/7/22 and 11/4/22.	Failed weld was excavated and repaired. Additionally, excavated and re-welded similar gamma inspection plugs to prevent future failure of those gamma plugs.
SHERCO_G2	Forced	Derate unit to HOL of 565 MWn due to 24 Coal Mill out of service and 26 Coal Mill taken out of service.	8/26/2022	8/30/2022	4	24 and 26 Coal Mills	24 Coal Mill removed from Service due to metal shavings found in oil system. Failure of 26 Coal Mill's classifier belt resulted in a derate until the belt could be replaced.		Similar occurrences on 8/29/22 and 10/23/22 for Unit 1, 1/1/22, 6/1/22, 7/25/22, 10/25/22, 11/7/22, 11/8/22, and 12/14/22 for Unit 2, and 12/30/22 for Unit 3. Derates due to having more than one coal mill out of service preventing the unit from making full load capability.	With 24 Coal Mill being in an emergency use only status, all future work, both planned and unexpected maintenance, on U2 coal mills will result in a derate.
SHERCO_G1	Forced	5 coal mills available due to leak repairs needed on 11 and 14 Coal Mills.	8/29/2022	8/31/2022	2	11 and 14 Coal Mills.	Coal leaks were discovered on transport lines 11 and 14 coal mills requiring mills to be removed from service to prevent creating a combustible dust concerns.		Similar occurrences on 10/23/22 for Unit 1, 1/1/22, 6/1/22, 7/25/22, 8/26/22, 10/25/22, 11/7/22, 11/8/22, and 12/14/22 for Unit 2, and 12/30/22 for Unit 3. Derates due to having more than one coal mill out of service preventing the unit from making full load capability.	Coal mills removed proactively to prevent creation of a combustible dust condition due to coal leaks. Leaks were repaired and mills returned to service.
SHERCO_G2	Forced	Unit offline to address plugging of the bottom ash system internal to the units bottom ash hoppers.	9/1/2022	9/24/2022	24	Bottom Ash Hoppers	Plugging on all 6 bottom ash hoppers and failure of multiple crushers required unit to be removed from service to restore bottom ash system.		None	Bottom ash was cleaned, crusher maintenance was performed and refractory was repaired to get bottom ash system in a condition to run to end of life.
SHERCO_G1	Forced	Derated and available for 610 MWn due to loss of 12 boiler circ pump. 3 of 4 available for service.	9/1/2022	9/7/2022	6	12 Boiler Circ Pump	During normal operation of 12 BCP, the pump exhibited high vibrations and was removed from service. Investigation revealed the pump casing wear ring became liberated causing damage to the impeller and other pump/motor components. This required the pump/motor assembly to be sent offiste for repairs. With only 3 of 4 BCPs available, unit derated to 610 MWh.		Similar derates were reported during this time period on 1/6/22, 2/1/22, 3/1/22, 3/9/22, 3/11/22, 6/1/22, 7/1/22, 7/27/22, 8/1/22, 8/4/22, 8/12, 8/17 and 9/10/22. All events were to support the repairs of this one (#12) circ pump.	Pump/Motor assemble required an outage to remove, install the blank and send to Hayward Tyler for evaluation, quote, rewind and repair. Decision was made to leave unit online during the the winter months. Outage was taken 4/18/22 and motor removed then sent offsite. Hayward Tyler received the assembly on 5/2/22 and issued an inspection report on 5/18/22 which showed damage to both the pump assembly as well as the motor rotor and stator assembly. Assembly shiped back to the site on 7/12/22. A decision was made to leave unit online through summer months. A maintenance outage was taken on 9/25/22 to remove the blank and reinstall the assembly.
King_G1	Forced	Derate of King due to feedwater constraints. Current load range of 380-435 MW Net available on AGC.	9/2/2022	9/18/2022	16	12 steam driven boiler feed pump	Degradation of rotating element		Similar derates were reported during this time period on 1/1/22, 2/1/22, 3/1/22, 6/17/22, 7/1/22, 7/17/22, 8/1/22, 9/2/22, 9/20/22, and 10/1/22. All events were to support the repairs of this one (#12) BFP.	Both 12 and 13 BFP elements were replaced with rebuilt elements in the Fall of 2022, allowing equipment to run until retirement in 2028
SHERCO_G1	Forced	Derate due to Opacity spikes, (102 mixer, 112 major clean, 105 purge air fan, and flushing)	9/7/2022	9/10/2022	3	Scrubber Modules	112 Module was removed from service for major clean, 102 module mixer failed and 105 module purge air fan failed. Unit unable to make full load with more than 2 modules out of service.		Similar occurrences on 9/7/22 for Unit 1 and 1/7/22, 10/1/22, 10/4/22, 10/26/22, 10/30/22 and 11/1/22 for Unit 2. Derates necessary to support daily module cleaning and flushing with two or more modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module (12 total per unit) has increased from once a year to once every 8 months. This strategy will still require some smaller derates to complete all required cleaning evolutions but these smaller derates should be limited mainly to the spring and fall when energy prices are historically less. There will also be derates due to loss of other module components during times which we need to have two major cleans in progress at once due to the loss of redundancy.
SHERC3	Forced	Unit tripped while operating at the low operating limit due to loss of all 4 ID fans. Troubleshooting in progress.	9/9/2022	9/16/2022	7	Induced Draft Fans and Main Turbine Generator	Lightening strike caused fuses to blow in 33 and 34 inverters causing all 4 ID fans to trip. During subsequent startup a significant rub developed in the turbine generator causing high vibrations. Off site technical was brought in to help troubleshoot and resolve the issue.		None	Replaced fuses in inverters and recommenced startup. High vibrations on the turbine generator during subsequent startup required the turbine to be placed on the turning gear while troubleshooting activities took place to determine the cause.
SHERCO_G1	Forced	Derated and available for 610 MWn due to loss of 12 boiler circ pump. Three of 4 available for service.	9/10/2022	9/12/2022	2	12 Boiler Circ Pump	During normal operation of 12 BCP, the pump exhibited high vibrations and was removed from service. Investigation revealed the pump casing wear ring became liberated causing damage to the impeller and other pump/motor components. This required the pump/motor assembly to be sent offiste for repairs. With only 3 of 4 BCPs available, unit derated to 610 MWh.		Similar derates were reported during this time period on 1/6/22, 2/1/22, 3/1/22, 3/9/22, 3/11/22, 6/1/22, 7/1/22, 7/27/22, 8/1/22, 8/4/22, 8/12, 8/17 and 9/1/22. All events were to support the repairs of this one (#12) circ pump.	Pump/Motor assemble required an outage to remove, install the blank and send to Hayward Tyler for evaluation, quote, rewind and repair. Decision was made to leave unit online during the the winter months. Outage was taken 4/18/22 and motor removed then sent offsite. Hayward Tyler received the assembly on 5/2/22 and issued an inspection report on 5/18/22 which showed damage to both the pump assembly as well as the motor rotor and stator assembly. Assembly shiped back to the site on 7/12/22. A decision was made to leave unit online through summer months. A maintenance outage was taken on 9/25/22 to remove the blank and reinstall the assembly.
SHERCO_G1	Forced	Derate due to Opacity spikes. 10 scrubber modules available.	9/12/2022	9/25/2022	13	Scrubber Modules	112 Module was removed from service for major clean, 102 module mixer failed. Additional modules removed alternatively to perform daily flushing and cleaning. Unit unable to make full load with more than 2 modules out of service.		Similar occurrences on 9/12/22 for Unit 1 and 10/1/22, 10/4/22, 10/26/22, 10/30/22 and 11/1/22. Derates necessary to support daily module cleaning and flushing with two or more modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module (12 total per unit) has increased from once a year to once every 8 months. This strategy will still require some smaller derates to complete all required cleaning evolutions but these smaller derates should be limited mainly to the spring and fall when energy prices are historically less. There will also be derates due to loss of other module components during times which we need to have two major cleans in progress at once due to the loss of reduncancy.
King_G1	Forced	Startup Bypass System	9/18/2022	9/20/2022	1	230D Flash tank drain to dearator valve	Valve stuck open due to faield mechanical operator		None	Operator replaced and imporved operation with new operator to prevent failure
King_G1	Forced	Derate of King due to feedwater constraints. Current load range of 380-435 MW Net available on AGC.	9/20/2022	9/30/2022	11	12 steam driven boiler feed pump	Degradation of rotating element		Similar derates were reported during this time period on 1/1/22, 2/1/22, 3/1/22, 6/17/22, 7/1/22, 7/17/22, 8/1/22, 9/2/22, 9/20/22, and 10/1/22. All events were to support the repairs of this one (#12) BFP.	Both 12 and 13 BFP elements were replaced with rebuilt elements in the Fall of 2022, allowing from equipment to run until retirement in 2028
SHERCO_G2	Forced	Unit 2 derated to HOL of 260 MW net. 22 FD fan out of service. AGC not available.	9/24/2022	9/25/2022	1	22 Forced Draft Fan	22 Forced Draft Fan had an 86 Lockout and 87-C target on the breaker. Investigation found faulty breaker.		None	Replaced breaker with a spare to allow unit to return to normal fan configuration.
King_G1	Forced	Derate of King due to feedwater constraints.	10/1/2022	10/8/2022	8	12 steam driven boiler feed pump	Degradation of rotating element		Similar derates were reported during this time period on 1/1/22, 2/1/22, 3/1/22, 6/17/22, 7/1/22, 7/17/22, 8/1/22, 9/2/22, and 9/20/22 . All events were to support the repairs of this one (#12) BFP.	Both 12 and 13 BFP elements were replaced with rebuilt elements in the Fall of 2022, allowing equipment to run until retirement in 2028
SHERCO_G2	Forced	U2 derate due to 8 of 12 module availability. 206 and 210 modules OOS for major cleans. 208 module out for spray pp belts & tank cleaning.	10/1/2022	10/4/2022	3	Scrubber Modules	206 and 210 Modules were removed from service for major clean and 208 removed from service for reaction tank cleaning. Unit unable to make full load with more than 2 modules out of service.		Similar occurrences on 9/7/22 and 9/12/22 for Unit 1 and 1/7/22, 10/4/22, 10/26/22, 10/30/22 and 11/1/22 for Unit 2. Derates necessary to support daily module cleaning and flushing with two or more modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module (12 total per unit) has increased from once a year to once every 8 months. This strategy will still require some smaller derates to complete all required cleaning evolutions but these smaller derates should be limited mainly to the spring and fall when energy prices are historically less. There will also be derates due to loss of other module components during times which we need to have two major cleans in progress at once due to the loss of reduncancy.
SHERCO_G2	Forced	U2 derate due to 8 of 12 module availability. 206 and 210 modules OOS for major cleans. 208 module out for spray pp belts & tank cleaning.	10/4/2022	10/7/2022	3	Scrubber Modules	206 and 210 Modules were removed from service for major clean and 208 removed from service for reaction tank cleaning. Unit unable to make full load with more than 2 modules out of service.		Similar occurrences on 9/7/22 and 9/12/22 for Unit 1 and 1/7/22, 10/1/22, 10/26/22, 10/30/22 and 11/1/22 for Unit 2. Derates necessary to support daily module cleaning and flushing with two or more modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module (12 total per unit) has increased from once a year to once every 8 months. This strategy will still require some smaller derates to complete all required cleaning evolutions but these smaller derates should be limited mainly to the spring and fall when energy prices are historically less. There will also be derates due to loss of other module components during times which we need to have two major cleans in progress at once due to the loss of reduncancy.

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NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
State of Minnesota-Electric Operations
Unit Forced Outage Information
2022 AAA Reporting Period: January 1 - December 31, 2022

Protected Data is Shaded

[PROTECTED DATA BEGINS

Unit	Outage Category	Primary Reason for Unplanned Outage	Outage Dates Start	Outage Dates End	Duration (Days)	Equipment that resulted in the forced outage	Description of Equipment Failure	Change in Energy Costs ($s)	Failure History During Reporting Period	Steps Taken to Alleviate Reoccurrence
SHERCO_G2	Forced	U2 derate due to 8 of 12 module availability. 206 and 210 modules OOS for major cleans. 208 module out for spray pp belts & tank cleaning.	10/4/2022	10/22/2022	19	Scrubber Modules	206 and 210 Modules were removed from service for major clean and 208 removed from service for reaction tank cleaning. Unit unable to make full load with more than 2 modules out of service.		Similar occurrences on 9/7/22 and 9/12/22 for Unit 1 and 1/7/22, 10/1/22, 10/26/22, 10/30/22 and 11/1/22 for Unit 2. Derates necessary to support daily module cleaning and flushing with two or more modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module (12 total per unit) has increased from once a year to once every 8 months. This strategy will still require some smaller derates to complete all required cleaning evolutions but these smaller derates should be limited mainly to the spring and fall when energy prices are historically less. There will also be derates due to loss of other module components during times which we need to have two major cleans in progress at once due to the loss of reduncancy.
SHERC3	Forced	Un-isolable steam leak on steam drum blowdown line requiring unit offline to repair.	10/7/2022	10/14/2022	7	Boiler Blowdown Line	One of the unit blowdown valves developed a through wall leak creating an unisolable steam leak.		Similar events on 8/16/22, 8/22/22, 10/7/22 and 11/4/22.	Affected piping and valve was replaced.
CC Highbridge1	Forced	U8 IP level control valve developed a leak in the valve body.	10/8/2022	10/10/2022	2	Unit 8 IP level control valve	Valve body leak due to internal corrosion.		None	Valve body replaced with upgraded material.
CC Highbridge2	Forced	U8 IP level control valve developed a leak in the valve body.	10/8/2022	10/10/2022	2	Unit 8 IP level control valve	Valve body leak due to internal corrosion.		None	Valve body replaced with upgraded material.
SHERCO_G1	Forced	Derate due to the loss of 12 Circ water pump during start up restoration.	10/14/2022	10/18/2022	4	12 Circulating Water Pump	12 Circ Water pump had an 86 Lockout and 87-C target on the breaker. Investigation found faulty breaker.		None	Repaired and replaced breaker to return to normal operation.
SHERC3	Forced	Derate necessary due to above seat drain failed to open on startup, do not have permissive to reset 32 BFP.	10/15/2022	10/16/2022	1	32 Boiler Feed Pump Above Seat Drain Valve	During unit startup activities, operators were unable to get the above seat drain to open. Unit derated until valve could be troubleshot and repaired.		None	Mechanical maintenance and Instrumentation & Control troubleshot and repaired valve to allow 32 BFP to be returned to service.
SHERCO_G1	Forced	Derate due to 5 of 7 mills available. Unit in startup.	10/23/2022	10/25/2022	2	12 and 17 Coal Mills	12 Coal mill was out of service for performance of a major overhaul. Loss of 17 Coal feeder resulted in only 5 of 7 mills being available for operation.		Similar occurrences on 8/29/22 for Unit 1, 1/1/22, 6/1/22, 7/25/22, 8/26/22, 10/25/22, 11/7/22, 11/8/22, and 12/14/22 for Unit 2, and 12/30/22 for Unit 3. Derates due to having more than one coal mill out of service preventing the unit from making full load capability.	Troubleshot and repaired 17 Coal Feeder to allow operation of 17 Coal Mill and a return to full power operation.
SHERCO_G1	Forced	Condenser (AES) inner loop repair. Inner loop required OOS for waterbox entry.	10/25/2022	10/28/2022	3	Main Condenser Tubing	Condenser developed a tube leak as noticed by plant chemists.		None	Isolated inner loop to confirm leak, brought in vendor to determine leaking location(s) and had mechanical maintenance plug the failed tubes.
SHERCO_G2	Forced	Derate needed for two Coal Mills OOS. 24 Cmill GB, 27 Cmill silo fill gate issues.	10/25/2022	10/26/2022	1	24 and 27 Coal Mills	24 Coal Mill removed from Service due to metal shavings found in oil system. Failure of 27 Coal Mill silo fill gate preventing adding coal to 27 coal mill silo. Mill removed from service once silo emptied until gate could be repaired.		Similar occurrences on 8/29/22 and 10/23/22 for Unit 1, 1/1/22, 6/1/22, 7/25/22, 8/26/22, 10/25/22, 11/7/22, 11/8/22, and 12/14/22 for Unit 2, and 12/30/22 for Unit 3. Derates due to having more than one coal mill out of service preventing the unit from making full load capability.	With 24 Coal Mill being in an emergency use only status, all future work, both planned and unexpected maintenance, on U2 coal mills will result in a derate
SHERCO_G2	Forced	Derate due to 9 of 12 module availability. 206 major clean, 204 module out for mixer blade fail, one module out for flushing & general cleans	10/26/2022	10/30/2022	5	Scrubber Modules	206 Module was removed from service for major clean and 204 module mixer failed. Additional modules removed alternatively to perform daily flushing and cleaning. Unit unable to make full load with more than 2 modules out of service.		Similar occurrences on 9/7/22 and 9/12/22 for Unit 1 and 1/7/22, 10/1/22, 10/4/22, 10/30/22 and 11/1/22 for Unit 2. Derates necessary to support daily module cleaning and flushing with two or more modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module (12 total per unit) has increased from once a year to once every 8 months. This strategy will still require some smaller derates to complete all required cleaning evolutions but these smaller derates should be limited mainly to the spring and fall when energy prices are historically less. There will also be derates due to loss of other module components during times which we need to have two major cleans in progress at once due to the loss of reduncancy.
SHERCO_G2	Forced	Derate due to 8 of 12 modules available. 201 & 203 Modules Mini Major cleans, 206 module OOS Major clean, one additional to flush and nightly GC.	10/30/2022	10/31/2022	1	Scrubber Modules	201, 203 and 206 Modules were removed from service for major clean. Additional modules removed alternatively to perform daily flushing and cleaning. Unit unable to make full load with more than 2 modules out of service.		Similar occurrences on 9/7/22 and 9/12/22 for Unit 1 and 1/7/22, 10/1/22, 10/4/22, 10/26/22, and 11/1/22 for Unit 2. Derates necessary to support daily module cleaning and flushing with two or more modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module (12 total per unit) has increased from once a year to once every 8 months. This strategy will still require some smaller derates to complete all required cleaning evolutions but these smaller derates should be limited mainly to the spring and fall when energy prices are historically less. There will also be derates due to loss of other module components during times which we need to have two major cleans in progress at once due to the loss of reduncancy.
SHERCO_G2	Forced	8 of 12 modules available. 201 & 203 Modules Mini Major cleans, 206 module OOS Major clean, one additional to flush and nightly GC	11/1/2022	11/7/2022	6	Scrubber Modules	201, 203 and 206 Modules were removed from service for major clean. Additional modules removed alternatively to perform daily flushing and cleaning. Unit unable to make full load with more than 2 modules out of service.		Similar occurrences on 9/7/22 and 9/12/22 for Unit 1 and 1/7/22, 10/1/22, 10/4/22, 10/26/22, and 10/30/22 for Unit 2. Derates necessary to support daily module cleaning and flushing with two or more modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module (12 total per unit) has increased from once a year to once every 8 months. This strategy will still require some smaller derates to complete all required cleaning evolutions but these smaller derates should be limited mainly to the spring and fall when energy prices are historically less. There will also be derates due to loss of other module components during times which we need to have two major cleans in progress at once due to the loss of reduncancy.
SHERCO_G1	Forced	U1 derate of 535MWn needed for 13 ID Fan breaker fail (86 lockout & 50-2 ground).	11/1/2022	11/20/2022	19	13 Induced Draft Fan	During normal operation of 13 ID Fan, the breaker tripped causing the fan to be removed from service. Investigation found an 86 lockout and 50-2 lockout. The motor was meggered and found to be shorted to ground. Motor was removed and shipped off to L&S Electric on 11/23/22 for a motor rewind.		Similar occurence on 8/11/23 for 11 Induced Draft Fan. Similar occurences were reported during this time period on 11/23/22 and 12/2/22 to support the repairs of 13 ID Fan. Similar occurence on 12/1/23 for 24 Induced Draft Fan.	13 ID Fan was removed and shipped to L&S Electric on 11/23/22. Motor was disassembled and found to require a complete rewind. Materials shortages and sourcing delays have challenged the return date for the ID fan motor to the site. L&S Electric continues to work with their vendors to expedite completing the motor rewind and testing prior to shipping back for re-install.
SHERC3	Forced	Offline due to steam leak off the high-pressure extraction line to deaerator requiring the unit to come offline to repair.	11/4/2022	11/13/2022	2	High Pressure Extraction Line	Steam quenching event caused previously repaired weld to re-crack open causing an unisolable steam leak.		Similar events on 8/16/22, 8/22/22, 10/7/22 and 11/4/22.	Failed weld was excavated and repaired.
SHERCO_G2	Forced	4 of 7 Coal Mills available: - 22 Mill start issue - 23 Lube Oil issue - 24 Out of Commission (gearbox).	11/7/2022	11/8/2022	1	22, 23 and 24 Coal Mills	22 Coal Mill failed to start during startup and Metal Shavings were found in 23 and 24 Coal Mill oil samples. Mills removed from service.		Similar occurrences on 8/29/22 and 10/23/22 for Unit 1, 1/1/22, 6/1/22, 7/25/22, 8/26/22, 10/25/22, 11/8/22, and 12/14/22 for Unit 2, and 12/30/22 for Unit 3. Derates due to having more than one coal mill out of service preventing the unit from making full load capability.	23 and 24 Coal Mills moved to emergency use only due to metal shavings in oil. Unit derated until repair decision is made due to pending scheduled unit retirement date of 12/31/23.
SHERCO_G2	Forced	loss of 23 & 24 Coal Mills.	11/8/2022	11/30/2022	22	23 and 24 Coal Mills	Metal Shavings found in 23 and 24 Coal Mill oil samples. Mills removed from service.		Similar occurrences on 8/29/22 and 10/23/22 for Unit 1, 1/1/22, 6/1/22, 7/25/22, 8/26/22, 10/25/22, 11/7/22, and 12/14/22 for Unit 2, and 12/30/22 for Unit 3. Derates due to having more than one coal mill out of service preventing the unit from making full load capability.	23 and 24 Coal Mills moved to emergency use only due to metal shavings in oil. Unit derated until repair decision is made due to pending scheduled unit retirement date of 12/31/23.
SHERC3	Forced	inadequate feedwater pump capacity. 33 boiler feed pump being taken out of service recirc valve failure.	11/13/2022	11/15/2022	1	33 Boiler Feed Pump	33 Boiler Feed Pump removed from service due to failed recirc valve. Unit running with 32 Boiler Feed Pump and 31 Startup Feed Pump		Similar to event on 11/15/22 (supporting same repair)	Repaired recirc valve to allow return to full power operation.
SHERC3	Forced	inadequate feedwater pump capacity. 33 boiler feed pump being taken out of service recirc valve failure. 31 boiler feed pump prewarming valve is leaking.	11/15/2022	11/18/2022	3	31 and 33 Boiler Feed Pumps	33 Boiler Feed Pump removed from service due to failed recirc valve. While running with 32 Boiler Feed Pump and 31 Startup Feed Pump, 31 Startup Feed Pump pre-warming valve developed a steam leak requiring pump to be removed from service.		Similar to event on 11/13/22 (original event).	Repaired recirc valve to allow return to full power operation. Re-packed pre-warming valve to return 31 Startup Feed Pump to being available for use.
SHERCO_G1	Forced	Derate due to only 3 coal mills available with loss of 12 transfer hopper feeder limiting coal supply to those 3 mills.	11/20/2022	11/23/2022	3	12 Transfer Hopper Feeder	Loss of 12 Transfer Hopper Feeder due to failure of feeder belt pulley. This prevented coal from being delivered to 3 of 7 coal mills until repaired.		Similar derates were reported during this time period on 1/1/22, 1/3/22 and 3/7/22.	Tail pulley was replaced and belt was aligned.
SHERCO_G1	Forced	U1 derate of 535MWn needed for 13 ID Fan breaker fail (86 lockout & 50-2 ground).	11/23/2022	11/28/2022	5	13 Induced Draft Fan	During normal operation of 13 ID Fan, the breaker tripped causing the fan to be removed from service. Investigation found an 86 lockout and 50-2 lockout. The motor was meggered and found to be shorted to ground. Motor was removed and shipped off to L&S Electric on 11/23/22 for a motor rewind.		Similar occurence on 8/11/23 for 11 Induced Draft Fan. Similar occurences were reported during this time period on 11/1/22 and 12/2/22 to support the repairs of 13 ID Fan. Similar occurence on 12/1/23 for 24 Induced Draft Fan.	13 ID Fan was removed and shipped to L&S Electric on 11/23/22. Motor was disassembled and found to require a complete rewind. Materials shortages and sourcing delays have challenged the return date for the ID fan motor to the site. L&S Electric continues to work with their vendors to expedite completing the motor rewind and testing prior to shipping back for re-install.
SHERC3	Forced	Feedwater Heater 36-2 developed a tube leak requiring that string to be taken out of service	11/27/2022	11/30/2022	3	36-2 Feedwater Heater (FWH)	During operation of Unit 3, operations personnel noted emergency dump valve opening to maintain level in 36-2 feedwater heater due to an apparent tube leak. Heater string was isolated and a tube leak was verified in 36-2 feedwater heater. Unit derated due to feedwater heater string out of service.		Similar events on 2/11/22, 3/1/2022, 3/16/22, and 12/1/22. All events were related to leaking tubes 36 Feedwater Heaters at their end of life.	Heater string removed from service and unit derated until a favorable market condition would allow for unit to be taken offline to repair the tube leak. Working with marketing determined that the best time for this would be during the planned outage for state mandated boiler inspection in September. Heater will be repaired and remaining tubes will have eddy current testing performed to determine if there are any other suspectable tubes.
SHERCO_G2	Forced	Derate due to loss of 22 ID fan outlet damper. 22 ID fan not available until damper is repaired.	12/1/2022	12/14/2022	13	22 Induced Draft Fan	22 Induced Draft Fan outlet damper linkage broke requiring fan to be taken out of service.		Similar occurence on 8/11/23 for 11 Induced Draft Fan. Similar occurences were reported during this time period on 11/1/22, 11/23/22, and 12/2/22 to support the repairs of 13 ID Fan.	Damper linkage was repaired and the ID fan was returned to normal operation.
SHERC3	Forced	Feedwater Heater 36-2 developed a tube leak requiring that string to be taken out of service.	12/1/2022	12/2/2022	2	36-2 Feedwater Heater (FWH)	During operation of Unit 3, operations personnel noted emergency dump valve opening to maintain level in 36-2 feedwater heater due an apparent tube leak. Heater string was isolated and a tube leak was verified in 36-2 feedwater heater. Unit derated due to feedwater heater string out of service.		Similar events on 2/11/22, 3/1/2022, 3/16/22, and 11/27/22.All events were related to leaking tubes 36 Feedwater Heaters at their end of life.	Heater string removed from service and unit derated until a favorable market condition would allow for unit to be taken offline to repair the tube leak. Working with marketing determined that the best time for this would be during the planned outage for state mandated boiler inspection in September. Heater will be repaired and remaining tubes will have eddy current testing performed to determine if there are any other suspectable tubes.
SHERCO_G1	Forced	U1 derate of 535MWn needed for 13 ID Fan breaker fail (86 lockout & 50-2 ground).	12/2/2022	12/31/2022	29	13 Induced Draft Fan	During normal operation of 13 ID Fan, the breaker tripped causing the fan to be removed from service. Investigation found an 86 lockout and 50-2 lockout. The motor was meggered and found to be shorted to ground. Motor was removed and shipped off to L&S Electric on 11/23/22 for a motor rewind.		Similar occurence on 8/11/23 for 11 Induced Draft Fan. Similar occurences were reported during this time period on 11/1/22 and 11/23/22 to support the repairs of 13 ID Fan. Similar occurence on 12/1/23 for 24 Induced Draft Fan.	13 ID Fan was removed and shipped to L&S Electric on 11/23/22. Motor was disassembled and found to require a complete rewind. Materials shortages and sourcing delays have challenged the return date for the ID fan motor to the site. L&S Electric continues to work with their vendors to expedite completing the motor rewind and testing prior to shipping back for re-install.
SHERC3	Forced	Require unit offline due to imminent bearing failure on 32 Condenser Exhauster	12/2/2022	12/10/2022	8	32 Condenser Exhauster	With 31 Condenser Exhauster removed for pump replacement, failure of 32 Cond Exhauster seal water pump resulted in damage to 32 Cond Exhauster bearing requiring the unit to be taken offline prior to tripping on condenser overpressure.		None	Expedited completion of repairs to 31 Condenser Exhauster to allow unit to return to service. Purchased replacement pump for 32 Condenser Exhauster.

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Northern States Power Company
State of Minnesota-Electric Operations
Unit Forced Outage Information
2022 AAA Reporting Period: January 1 - December 31, 2022

Protected Data is Shaded

[PROTECTED DATA BEGINS

Unit	Outage Category	Primary Reason for Unplanned Outage	Outage Dates Start	Outage Dates End	Duration (Days)	Equipment that resulted in the forced outage	Description of Equipment Failure	Change in Energy Costs ($s)	Failure History During Reporting Period	Steps Taken to Alleviate Reoccurrence
SHERCO_G2	Forced	Unit 2 derated to a HOL of 565MWn due to loss of 23 & 24 Coal Mills.	12/14/2022	12/31/2022	18	23 and 24 Coal Mills	Metal Shavings found in 23 and 24 Coal Mill oil samples. Mills removed from service.		Similar occurrences on 8/29/22 and 10/23/22 for Unit 1, 1/1/22, 6/1/22, 7/25/22, 8/26/22, 10/25/22, 11/7/22, and 11/8/22 for Unit 2, and 12/30/22 for Unit 3. Derates due to having more than one coal mill out of service preventing the unit from making full load capability.	23 and 24 Coal Mills moved to emergency use only due to metal shavings in oil. Unit derated until repair decision is made due to pending scheduled unit retirement date of 12/31/23.
SHERC3	Forced	Derate due to multiple issues in the AQCS. 31 Recycle silo running high D/P being taken OOS.	12/20/2022	12/22/2022	2	Spray Dryer Absorbers (SDAs)	32 SDA was removed from service due to high vibrations on the motor, 31 SDA was removed from service due to plugging in the addtive feed lines, 35 SDA removed from service due to temperature instrument.		Similar events on 3/1/2022 and 3/13/22. All events were related to number of available SDA's and how many are necessary for full load operation to maintain available environmental limits.	Repairs were prioritized to restore additive feed flow to 2 SDA's to allow unit to return to full power operations.
SHERC3	Forced	Derate due coal leak on 304 coal mill.	12/30/2022	12/31/2022	1	304, 305 and 306 Coal Mills	304 Coal mill developed a coal leak while operating requiring the mill to be removed from service. 305 Coal mill was out of service due to a broken coal feeder belt and 306 coal mill was out of service due to a broken rotating throat assembly. Unit unable to make full load with 3 coal mills out of service.		Similar occurrences on 8/29/22 and 10/23/22 for Unit 1 and 1/1/22, 6/1/22, 7/25/22, 8/26/22, 10/25/22, 11/7/22, 11/8/22, and 12/14/22 for Unit 2. Derates due to having more than two coal mills out of service preventing the unit from making full load capability.	Repaired coal leak and replaced feeder belt to restore coal mill redundancy.

PROTECTED DATA ENDS]

Northern States Power Company
Unit Outage Information
UNPLANNED OUTAGES

Protected Data is Shaded

[PROTECTED DATA BEGINS

					Actual ($)				As Forecasted ($)				Actual ($/MWh)			As Forecasted ($/MWh)		
Unit	Type of Plant	Outage Category	Date	Duration (Days)	Outage MWh	Replacement Cost ($)	Unit Cost ($)	Energy Cost Due to Outages ($)	Outage MWh	Replacement Cost ($)	Unit Cost ($)	Energy Cost Due to Outages ($)	Replacement Cost $/MWh	Unit Cost $/MWh	Outage Cost $/MWh	Replacement Cost $/MWh	Unit Cost $/MWh	Outage Cost $/MWh
Blk_Dog_G52	Steam	Forced	1/2/2022 - 1/18/2022	16		213,709												
Blk_Dog_G52	Steam	Forced	1/20/2022 - 1/29/2022	10		326,398												
Black Dog Total				**26**		**540,106**				770,625			60.63			32.37		
CC Highbridge1	CC	Forced	10/8/2022 - 10/10/2022	2		102,916												
High Bridge 1x1 Total				**2**		**102,916**				65,722			63.92			28.96		
CC Highbridge2	CC	Forced	8/2/2022 - 8/5/2022	3		547,959												
CC Highbridge2	CC	Forced	10/8/2022 - 10/10/2022	2		102,919												
High Bridge 2x1 Total				**5**		**650,878**				176,358			83.65			32.16		
Riverside 1x1 Total				**0**		**0**				813,849			-			29.79		
Riverside 2x1 Total				**0**		**0**				646,840			-			27.36		
King_G1	Steam	Forced	1/1/2022 - 1/31/2022	31		806,057												
King_G1	Steam	Forced	1/6/2022 - 1/12/2022	6		3,160,464												
King_G1	Steam	Forced	2/1/2022 - 2/28/2022	28		177,957												
King_G1	Steam	Forced	2/18/2022 - 2/22/2022	4		120,145												
King_G1	Steam	Forced	2/22/2022 - 2/28/2022	6		162,888												
King_G1	Steam	Forced	3/1/2022 - 3/31/2022	31		99,498												
King_G1	Steam	Forced	6/17/2022 - 6/30/2022	13		355,208												
King_G1	Steam	Forced	7/1/2022 - 7/2/2022	2		93,899												
King_G1	Steam	Forced	7/17/2022 - 7/29/2022	12		1,208,048												
King_G1	Steam	Forced	7/29/2022 - 7/31/2022	3		703,802												
King_G1	Steam	Forced	8/1/2022 - 8/21/2022	20		2,065,648												
King_G1	Steam	Forced	9/2/2022 - 9/18/2022	16		1,833,151												
King_G1	Steam	Forced	9/20/2022 - 9/30/2022	11		687,564												
King_G1	Steam	Forced	9/18/2022 - 9/20/2022	1		994,697												
King_G1	Steam	Forced	10/1/2022 - 10/8/2022	8		475,645												
Allen S King Total				**192**		**12,944,671**				2,386,625			51.42			41.39		
SHERCO_G1	Steam	Forced	1/1/2022 - 1/2/2022	2		561,400												
SHERCO_G1	Steam	Forced	1/3/2022 - 1/6/2022	3		761,665												
SHERCO_G1	Steam	Forced	1/6/2022 - 1/31/2022	25		1,489,890												
SHERCO_G1	Steam	Forced	2/1/2022 - 2/28/2022	28		1,035,846												
SHERCO_G1	Steam	Forced	3/1/2022 - 3/7/2022	7		322,811												
SHERCO_G1	Steam	Forced	3/7/2022 - 3/8/2022	1		207,191												
SHERCO_G1	Steam	Forced	3/9/2022 - 3/10/2022	1		28,379												
SHERCO_G1	Steam	Forced	3/11/2022 - 3/31/2022	21		638,816												
SHERCO_G1	Steam	Forced	6/1/2022 - 6/30/2022	30		2256551												
SHERCO_G1	Steam	Forced	7/1/2022 - 7/26/2022	25		2,089,167												
SHERCO_G1	Steam	Forced	7/27/2022 - 7/31/2022	4		368,327												
SHERCO_G1	Steam	Forced	8/1/2022 - 8/2/2022	2		189,446												
SHERCO_G1	Steam	Forced	8/4/2022 - 8/11/2022	7		477,853												
SHERCO_G1	Steam	Forced	8/11/2022 - 8/12/2022	1		78,170												
SHERCO_G1	Steam	Forced	8/12/2022 - 8/16/2022	4		190,178												
SHERCO_G1	Steam	Forced	8/17/2022 - 8/29/2022	12		1,283,701												
SHERCO_G1	Steam	Forced	8/29/2022 - 8/31/2022	2		354,310												
SHERCO_G1	Steam	Forced	9/1/2022 - 9/7/2022	6		558,871												
SHERCO_G1	Steam	Forced	9/7/2022 - 9/10/2022	3		608,160												
SHERCO_G1	Steam	Forced	9/10/2022 - 9/12/2022	2		187,907												
SHERCO_G1	Steam	Forced	9/12/2022 - 9/25/2022	13		2,292,473												
SHERCO_G1	Steam	Forced	10/14/2022 - 10/18/2022	4		1,284,550												
SHERCO_G1	Steam	Forced	10/23/2022 - 10/25/2022	2		169,912												
SHERCO_G1	Steam	Forced	10/25/2022 - 10/28/2022	3		1,211,148												
SHERCO_G1	Steam	Forced	11/1/2022 - 11/20/2022	19		765,771												
SHERCO_G1	Steam	Forced	11/20/2022 - 11/23/2022	3		717,894												
SHERCO_G1	Steam	Forced	11/23/2022 - 11/28/2022	5		75,198												
SHERCO_G1	Steam	Forced	12/2/2022 - 12/31/2022	29		2,137,918												
Sherburne 1 Total				**263**		**22,343,504**				9,954,204			48.15			29.29		

Northern States Power Company
Unit Outage Information
UNPLANNED OUTAGES

Protected Data is Shaded

[PROTECTED DATA BEGINS

							Actual ($)				As Forecasted ($)				Actual ($/MWh)			As Forecasted ($/MWh)		
Unit	Type of Plant	Outage Category	Date			Duration (Days)	Outage MWh	Replacement Cost ($)	Unit Cost ($)	Energy Cost Due to Outages ($)	Outage MWh	Replacement Cost ($)	Unit Cost ($)	Energy Cost Due to Outages ($)	Replacement Cost $/MWh	Unit Cost $/MWh	Outage Cost $/MWh	Replacement Cost $/MWh	Unit Cost $/MWh	Outage Cost $/MWh
SHERCO_G2	Steam	Forced	1/1/2022	-	1/6/2022	5		343,347												
SHERCO_G2	Steam	Forced	1/1/2022	-	1/2/2022	1		459,099												
SHERCO_G2	Steam	Forced	1/17/2022	-	1/18/2022	1		86,327												
SHERCO_G2	Steam	Forced	6/1/2022	-	6/6/2022	6		164,249												
SHERCO_G2	Steam	Forced	7/25/2022	-	7/28/2022	3		448,124												
SHERCO_G2	Steam	Forced	8/26/2022	-	8/30/2022	4		497,537												
SHERCO_G2	Steam	Forced	9/24/2022	-	9/25/2022	1		624,229												
SHERCO_G2	Steam	Forced	9/1/2022	-	9/24/2022	24		22,280,886												
SHERCO_G2	Steam	Forced	10/1/2022	-	10/4/2022	3		376,902												
SHERCO_G2	Steam	Forced	10/4/2022	-	10/7/2022	3		673,617												
SHERCO_G2	Steam	Forced	10/4/2022	-	10/22/2022	19		2,129,453												
SHERCO_G2	Steam	Forced	10/25/2022	-	10/26/2022	1		43,097												
SHERCO_G2	Steam	Forced	10/26/2022	-	10/30/2022	5		316,473												
SHERCO_G2	Steam	Forced	10/30/2022	-	10/31/2022	1		165,428												
SHERCO_G2	Steam	Forced	11/1/2022	-	11/7/2022	6		116,914												
SHERCO_G2	Steam	Forced	11/7/2022	-	11/8/2022	1		193,448												
SHERCO_G2	Steam	Forced	11/8/2022	-	11/30/2022	22		1,564,913												
SHERCO_G2	Steam	Forced	12/1/2022	-	12/14/2022	13		1,141,762												
SHERCO_G2	Steam	Forced	12/14/2022	-	12/31/2022	18		2,215,937												
Sherburne 2 Total						**106**		**30,484,043**				8,795,929			54.74			34.67		
SHERC3	Steam	Forced	1/2/2022	-	1/3/2022	1		121,208												
SHERC3	Steam	Forced	2/11/2022	-	2/28/2022	17		675,528												
SHERC3	Steam	Forced	3/1/2022	-	3/13/2022	13		882,584												
SHERC3	Steam	Forced	3/13/2022	-	3/16/2022	3		67,623												
SHERC3	Steam	Forced	3/16/2022	-	3/31/2022	15		179,112												
SHERC3	Steam	Forced	8/16/2022	-	8/22/2022	6		4,854,842												
SHERC3	Steam	Forced	8/22/2022	-	8/26/2022	4		3,484,746												
SHERC3	Steam	Forced	9/9/2022	-	9/16/2022	7		4,608,655												
SHERC3	Steam	Forced	10/15/2022	-	10/16/2022	1		70,962												
SHERC3	Steam	Forced	10/7/2022	-	10/14/2022	7		3,395,551												
SHERC3	Steam	Forced	11/13/2022	-	11/15/2022	1		347,660												
SHERC3	Steam	Forced	11/15/2022	-	11/18/2022	3		732,158												
SHERC3	Steam	Forced	11/27/2022	-	11/30/2022	3		147,906												
SHERC3	Steam	Forced	11/4/2022	-	11/13/2022	2		2,483,250												
SHERC3	Steam	Forced	12/1/2022	-	12/2/2022	2		20,083												
SHERC3	Steam	Forced	12/20/2022	-	12/22/2022	2		260,008												
SHERC3	Steam	Forced	12/30/2022	-	12/31/2022	1		41,428												
SHERC3	Steam	Forced	12/2/2022	-	12/10/2022	8		3,640,691												
Sherburne 3 Total						**98**		**26,013,995**				2,646,622			48.44			30.49		
Monticello_1	Nuclear	Forced	1/24/2022	-	1/27/2022	3		1,938,888												
Monticello Total						**3**		**1,938,888**				434,076			37.53			20.29		
Prairie Island 1 Total						**0**		**0**				873,301			0			20.69		
Prairie Island 2 Total						**0**		**0**				2,707,285			0			23.83		
Total						**696**	**1,879,641**	**95,019,002**	**46,142,137**	**48,538,577**	**997,783**	**30,271,437**	**19,573,263**	**10,698,174**	**50.55**	**24.55**	**25.82**	30.34	19.62	10.72

PROTECTED DATA ENDS]

Notes:

Protected Data is Shaded

[PROTECTED DATA BEGINS

Unit	Type of Plant	Outage Category	Date	Duration (Days)	Actual ($) Outage MWh	Actual ($) Replacement Cost ($)	Actual ($) Unit Cost ($)	Actual ($) Energy Cost Due to Outages ($)	As Forecasted ($) Outage MWh	As Forecasted ($) Replacement Cost ($)	As Forecasted ($) Unit Cost ($)	As Forecasted ($) Energy Cost Due to Outages ($)	Actual ($/MWh) Replacement Cost $/MWh	Actual ($/MWh) Unit Cost $/MWh	Actual ($/MWh) Outage Cost $/MWh	As Forecasted ($/MWh) Replacement Cost $/MWh	As Forecasted ($/MWh) Unit Cost $/MWh	As Forecasted ($/MWh) Outage Cost $/MWh
Blk_Dog_G52	Steam	Scheduled	5/1/2022 - 5/31/2022	31		1,530,092												
Blk_Dog_G52	Steam	Scheduled	6/1/2022 - 6/3/2022	2		442,050												
Blk_Dog_G52	Steam	Scheduled	09/22/2022 - 09/30/2022	9		424,068												
Blk_Dog_G52	Steam	Scheduled	10/01/2022 - 10/31/2022	31		3,788,857												
Blk_Dog_G52	Steam	Scheduled	11/01/2022 - 11/30/2022	30		1,056,236												
Black Dog 25 Total				**102**		**7,241,303**				5,232,523			61.74			27.61		
CC Highbridge1	CC	Scheduled	10/22/2022 - 10/30/2022	9		1,135,209												
Highbridge 1x1 Total				**9**		**1,135,209**				4,197,367			50.50			27.20		
CC Highbridge2	CC	Scheduled	10/22/2022 - 10/30/2022	9		1,135,362												
Highbridge 2x1 Total				**9**		**1,135,362**				1,147,506			50.51			27.12		
CCRiverside1	CC	Scheduled	5/1/2022 - 5/4/2022	3		528,631												
CCRiverside1	CC	Scheduled	12/01/2022 - 12/16/2022	16		551,686												
Riverside 1x1 Total				**19**		**1,080,317**				1,559,665			62.45			27.65		
CCRiverside2	CC	Scheduled	5/1/2022 - 5/4/2022	4		528,677												
CCRiverside2	CC	Scheduled	12/01/2022 - 12/12/2022	12		551,688												
Riverside 2x1 Total				**15**		**1,080,365**				1,466,041			62.46			26.35		
King_G1	Steam	Scheduled	7/2/2022 - 7/17/2022	15		9,431,155												
King_G1	Steam	Scheduled	8/21/2022 - 8/31/2022	11		9,254,617												
King_G1	Steam	Scheduled	09/01/2022 - 09/02/2022	2		1,888,103												
King_G1	Steam	Scheduled	10/08/2022 - 10/31/2022	23		10,366,348												
King_G1	Steam	Scheduled	11/01/2022 - 11/09/2022	9		2,361,184												
Allen S King Total				**59**		**33,301,406**				-			48.60			-		
SHERCO_G1	Steam	Scheduled	7/26/2022 - 7/27/2022	2		1,831,231												
SHERCO_G1	Steam	Scheduled	09/25/2022 - 09/30/2022	6		2,779,576												
SHERCO_G1	Steam	Scheduled	10/01/2022 - 10/07/2022	7		4,044,818												
SHERCO_G1	Steam	Scheduled	11/28/2022 - 11/30/2022	2		197,808												
Sherburne 1 Total				**16**		**8,853,433**				3,202,521			42.00			28.70		
Sherburne 2 Total										-			-			-		
SHERC3	Steam	Scheduled	5/30/2022 - 5/31/2022	2		348,638												
SHERC3	Steam	Scheduled	6/1/2022 - 6/2/2022	2		558,263												
SHERC3	Steam	Scheduled	10/22/2022 - 10/30/2022	8		2,794,186												
Sherburne 3 Total				**12**		**3,701,087**				608,934			39.29			30.49		
Monticello_1	Nuclear	Scheduled	1/4/2022 - 1/8/2022	4		1,546,228												
Monticello Total				**4**		**1,546,228**				624,972			44.67			20.29		
PR_ISLD_1	Nuclear	Scheduled	9/20/2022 - 9/30/2022	11		131,082												
PR_ISLD_1	Nuclear	Scheduled	10/1/2022 - 10/14/2022	13		885,623												
PR_ISLD_1	Nuclear	Scheduled	10/14/2022 - 10/31/2022	17		8,912,266												
PR_ISLD_1	Nuclear	Scheduled	11/1/2022 - 11/9/2022	8		2,740,400												
Prairie Island 1 Total				**50**		**12,669,371**				5,877,907			33.23			19.42		
PR_ISLD_2	Nuclear	Scheduled	10/02/2022 - 10/04/2022	2		38,252												
Prairie Island 2 Total				**2**		**38,252**				418,594			39.85			23.83		
Total				**298**	**1,603,956**	**71,782,333**	**38,056,388**	**34,383,664**	**980,872**	**24,336,030**	**16,853,602**	**7,482,428**	**44.75**	**23.73**	**21.44**	**24.81**	**17.18**	**7.63**

PROTECTED DATA ENDS]

Notes:

(1) Outages/Derates of one day durations or longer and greater than or equal to 500 MWh are included

Northern States Power Company
Expenses Pertaining to Maintenance of Generation Plants

Energy Allocation Ratios	**87.3278%**	**86.8458%**	**86.8907% ****
Demand Allocation Ratios	**87.3461%**	**86.9632%**	**87.2459% ****

			NSP Minnesota Company Totals			Minnesota Jurisdictional Totals *		
	FERC Account Description	**Allocation Method**	**2016 Test Year**	**2021 Actuals**	**2022 Actuals**	**2016 Test Year**	**2021 Actuals**	**2022 Actuals**
510	Stm Maint Super&Eng	Energy	$ 2,008,848	$ 1,542,150	$ 1,285,539	$ 1,754,283	$ 1,339,293	$ 1,117,014
511	Stm Maint of Structures	Demand	$ 2,784,311	$ 4,343,962	$ 3,902,411	$ 2,431,987	$ 3,777,648	$ 3,404,693
512	Stm Maint of Boiler Plt	Energy	$ 39,704,208	$ 19,972,701	$ 17,112,746	$ 34,672,811	$ 17,345,452	$ 14,869,385
513	Stm Maint of Elec Plant	Energy	$ 4,931,682	$ 7,600,877	$ 3,473,602	$ 4,306,730	$ 6,601,043	$ 3,018,237
514	Stm Maint of Misc Stm Plt	Demand	$ 18,325,365	$ 7,380,213	$ 7,060,544	$ 16,006,492	$ 6,418,070	$ 6,160,035
528	Nuc Maint Super & Eng	Energy	$ 6,183,520	$ 7,690,102	$ 7,614,287	$ 5,399,932	$ 6,678,531	$ 6,616,108
529	Nuc Maint of Structures	Demand	$ 9,368		$ -	$ 8,183	$ -	$ -
530	Nuc Mtc of React Plt Equip	Energy	$ 48,934,011	$ 32,883,569	$ 29,836,448	$ 42,732,995	$ 28,557,999	$ 25,925,098
531	Nuc Maint of Elect Plant	Energy	$ 13,522,861	$ 12,513,587	$ 11,972,440	$ 11,809,217	$ 10,867,525	$ 10,402,937
532	Nuc Mtc of Misc Nuc Plant	Demand	$ 25,463,010	$ 24,961,813	$ 25,024,623	$ 22,240,946	$ 21,707,591	$ 21,832,958
541	Hydro Mtc Super& Eng	Energy	$ 5,509	$ 882	$ 240	$ 4,811	$ 766	$ 208
542	Hyd Maint of Structures	Demand	$ 22,000	$ 45,690	$ 48,860	$ 19,216	$ 39,734	$ 42,628
543	Hydro Mtc Resv, Dams	Demand	$ 22,000	$ 66,760	$ 189,740	$ 19,216	$ 58,057	$ 165,541
544	Hyd Maint of Elec Plant	Energy	$ 88,144	$ 180,673	$ 39,868	$ 76,974	$ 156,907	$ 34,641
545	Hyd Mt Misc Hyd Plnt Mjr	Demand	$ 59,713	$ 4,031	$ 1,328	$ 52,157	$ 3,506	$ 1,158
551	Oth Maint Super & Eng	Demand	$ 310,346	$ 1,828,452	$ 1,719,645	$ 271,075	$ 1,590,080	$ 1,500,320
552	Oth Maint of Structures	Demand	$ 3,242,151	$ 6,916,872	$ 6,860,460	$ 2,831,892	$ 6,015,133	$ 5,985,470
553	Oth Mtc of Gen & Ele Plant	Demand	$ 17,225,836	$ 10,741,953	$ 10,748,762	$ 15,046,096	$ 9,341,546	$ 9,377,854
554	Oth Mtc Misc Gen Plt Mjr	Demand	$ 1,866,543	$ 11,789,215	$ 13,371,788	$ 1,630,353	$ 10,252,278	$ 11,666,337
Production Maintenance Expense Totals			**$ 184,709,427**	**$ 150,463,504**	**$ 140,263,331**	**$ 161,315,366**	**$ 130,751,158**	**$ 122,120,623**

*Minnesota jurisdictional totals do not reflect Interchange Agreement billings to NSP-Wisconsin.

**Preliminary Minnesota Demand and Energy Allocation Ratios

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Power Purchase Agreement Cost

PROTECTED DATA HAS BEEN SHADED

[PROTECTED DATA BEGINS

Reference	Termination	Term (yrs)	Counterparty	MW	Fuel Type	MWh January 2022	February 2022	March 2022	April 2022	May 2022	June 2022	July 2022	August 2022	September 2022	October 2022	November 2022	December 2022	Total
Barron County	12/31/2022	10	Barron County Waste-to-Energy Facility	1.865	RDF													
CC Calpine	12/31/2026	20	Mankato Energy Center LLC	375	Gas													
CC Calpine II	5/31/2039	20	Mankato Energy Center II LLC	345	Gas													
CC LSPower	9/30/2027	30	LSP- Cottage Grove, L.P.	245.1	Gas													
CT Invenergy 1	4/10/2025	17	Invenergy Cannon Falls LLC	178.5	Oil/Gas													
CT Invenergy 2	4/10/2025	17	Invenergy Cannon Falls LLC	178.5	Oil/Gas													
DPC Flambeau	1/31/2037	Life of Project	Dairyland Flambeau	2	Hydro													
Deuel Harvest Wind Energy LLC	9/30/2036	15	Deuel Harvest Wind Energy LLC	300	Wind													
Eau Galle	7/31/2026	35	Eau Galle Renewable Energy Co. Inc.	0.300	Hydro													
Elk Creek	12/11/2022	20	Elk Creek Solar, LLC	80.0	Solar													
Green Whey Dairy	2/16/2022	10	Green Whey Dairy	3.2	Digester													
Gundersen Lutheran Landfill	2/16/2022	10	Gundersen Lutheran	1.137	Landfill													
Hastings	6/30/2033	45	City of Hastings Hydro	0.450	Hydro													
Heartland Divide	4/30/2047	25	Heartland Divide Wind II, LLC	200.040	Wind													
Heller DairyFarm	5/1/2023	10	Cow Poo LLC	2.7	RDF													
HERC	12/30/2024	28	Hennepin Energy Resource Recovery (HERC)	33.7	Digester													
Keller	12/31/2022	MTM	Keller Paving & Landscaping, Inc.	0.19	Solar													
Koda	5/31/2022	10	KODA Energy, LLC	12	Biomass													
Lac Courte Oreilles	12/31/2021	35	Lac Courte Orielles Band of Lake Superior Chippewa Indians	3.1	Hydro													
Manitoba Hydro	4/30/2025	10	Manitoba Hydro Electric Board	Summer: 375, Winter: 325 (Summer = May thru October)	Hydro													
SAF	12/18/2031	20	SAF Hydroelectric, LLC	9.2	Hydro													
Solar Aurora	12/30/2036	20	Aurora Distributed Solar	100	Solar													
Solar Best Power International PV	5/26/2030	20	St. John's Solar	0.5	Solar													
Solar Best Power International PV II	10/11/2030	15	School Sisters of Notre Dame Solar Park	0.718	Solar													
Solar Dragonfly	9/10/2033	15	Dragonfly Solar, LLC	0.8	Solar													
Solar Marshall	6/8/2042	25.5	Marshall Solar, LLC	62.25	Solar													
Solar North Star	12/20/2041	25.67	North Star Solar PV	100	Solar													
Solar Slayton	1/3/2033	10	Slayton Solar, LLC	1.66	Solar													
St Cloud	10/31/2021	33	The City of St. Cloud	Summer: 8.1, Winter: 6.6 (Summer = May thru October)	Hydro													
StPaul CoGen	3/24/2023	20	St. Paul Cogeneration	25	Biomass													
Western Technical College Angelo Dam	3/31/2024	10	Western Technical College	0.205	Hydro													
Wind CBED Adams	3/8/2031	20	Adams Wind Generations, LLC	19.8	Wind													
Wind CBED Big Blue	12/14/2032	20	Big Blue Wind Farm, LLC	36	Wind													
Wind CBED Community Wind North	5/27/2031	20	North Wind Turbines LLC North Community Turbines LLC	30	Wind													
Wind CBED Community Wind South	12/25/2032	20	Zephyr Wind, LLC	30	Wind													
Wind CBED Danielson	3/10/2031	20	Danielson Wind Farms, LLC	19.8	Wind													
Wind CBED Ewington	5/27/2028	20	Ewington Energy Systems, LLC	19.95	Wind													
Wind CBED Hilltop	2/19/2029	20	Hilltop Power	2	Wind													
Wind CBED Jeffers	10/9/2028	20	Jeffers Wind 20 LLC	50	Wind													
Wind CBED Ridgewind	1/12/2031	20	Ridgewind Power Partners LLC	25.3	Wind													
Wind CBED Roseville	8/8/2030	20	Grant County Wind	20	Wind													
Wind CBED Uilk	1/14/2030	20	Uilk Wind Farm, LLC	4.5	Wind													
Wind CBED Valley View	11/29/2031	20	Valley View Transmission, LLC	10	Wind													
Wind CBED Winona	10/26/2031	20	Winona County Wind, LLC	1.5	Wind													
Wind CBED Woodstock	6/23/2030	20	Woodstock Municipal Wind, LLC	0.75	Wind													
Wind Crown Ridge	1/9/2045	25	Crowned Ridge Wind, LLC	200	Wind													
Wind Clean Energy	12/31/2039	20	ALLETE Clean Energy, Inc.	106.08	Wind													
Wind Dakota Range III	4/30/2033	20	DAKOTA RANGE III, LLC	153.6	Wind													
Wind Eastridge	4/30/2026	20	Bendwind, LLC DeGreeff DP, LLC DeGreeffpa LLC Groen Wind LLC Hillcrest Wind LLC LarswindLLC Sierra Wind LLC TAIR Windfarm LLC	10	Wind													
Wind Fenton	11/12/2032	25	Fenton Power Partners I, LLC	205.5	Wind													
Wind FPL	12/2/2026	20	FPL Energy Mower County, LLC	98.9	Wind													
Wind Garwin McNeilus	Various	20-25	Bangladesh Children's Support LLC, Brandon Wind LLC, BT Windfarm LLC, Burmese Children's Support, LLC, GarMar Foundation I, LLC/ REAP I, Gar Mar Wind I, LLC, GM Windfarm LLC, Henslin Creek LLC, Indian Children's Support, LLC, McNeilus Windfarm LLC, Salvadoran Children's Support , SG (JCKD) Windfarm LLC, Southeast Asian Children's Support, LLC, Triton Wind LLC, Wasioja Wind LLC, Wilhelm Wind LLC	27.5	Wind													

Northern States Power Company
Electric Utility - State of Minnesota
Power Purchase Agreement Cost

PROTECTED DATA HAS BEEN SHADED						MWh												
Reference	**Termination**	**Term (yrs)**	**Counterparty**	**MW**	**Fuel Type**	**January 2022**	**February 2022**	**March 2022**	**April 2022**	**May 2022**	**June 2022**	**July 2022**	**August 2022**	**September 2022**	**October 2022**	**November 2022**	**December 2022**	**Total**
						[PROTECTED DATA BEGINS												
Wind Geronimo Odell	7/28/2036	20	Odell Wind, LLC	200	Wind													
Wind Lakota	4/30/2034	30	Northern Alternative Energy Lakota Ridge LLC	11.25	Wind													
Wind Minn Dakota	12/30/2022	15	MinnDakota Wind LLC	150	Wind													
Wind Moraine II	2/17/2029	10	Moraine Wind II LLC	49.5	Wind													
Wind Norgaard	5/10/2026	20	Roadrunner ,I LLC, Salty Dog-I LLC, Wallys Windfarm LLC, Windy Dog I LLC, Breezy Bucks-I & II LLC, Salty Dog II, LLC	8.75	Wind													
Wind North Shaokatan	10/31/2033	30	Autumn Hills LLC, Jack River LLC,Jessica Mills LLC, Julia Hills LLC, Sun River LLC, Tsar Nicholas, LLC	13.53	Wind													
Wind Phase 2	12/13/2028	30	Lake Benton Power Partners LLC (LBI)	105.75	Wind													
Wind Phase 4	12/14/2023	20	Chanarambie Power Partners, LLC	85.5	Wind													
Wind Prairie Rose	12/10/2032	20	Prairie Rose Wind, LLC	200	Wind													
Wind Ruthton	1/22/2031	30	Ruthton Ridge LLC, Florence Hills LLC,Hadley Ridge LLC,Hope Creek LLC, Soliloquy Ridge LLC, Spartan Hills LLC,Twin Lake Hills LL, Winter's Spawn LLC	15.84	Wind													
Wind Shaokatan	4/30/2034	30	Northern Alternative Enrgy Shakotan Hills LLC	11.88	Wind													
Wind Source Cisco	5/27/2028	20	Cisco Wind Energy LLC	8	Wind													
Wind Source Garwin McNeilus	4/30/2025	20	Ashland Windfarm LLC, Elsinore Wind LLC, Gar Mar Foundation II / REAP II, Grant Windfarm LLC, Zumbro Windfarm	9.25	Wind													
Wind Source JJN	12/16/2029	25	JJN Windfarm, LLC	1.5	Wind													
Wind Source MinWind	2/1/2025	20	Minwind III -IX, LLC	11.55	Wind													
Wind Source West Ridge	12/27/2028	25	Westridge Windfarm LLC, Tofteland Windfarm LLC, TG Windfarm LLC, CG Windfarm LLC, , Fey Windfarm LLC,	9.5	Wind													
Wind Stahl	12/31/2024	20	Stahl Wind Energy LLC, Northern Lights Wind LLC, Lucky Wind LLC, Greenback Energy LLC Cartensen Wind LLC	8.25	Wind													
Wind Tholen	8/27/2025	20	Tholen Transmission Projects	13.2	Wind													
Wind University of Minnesota	10/26/2031		UMORE Park, LLC	2.5	Wind													
Wind Various	Various	30	Agassiz Beach LLC, Metro Wind LLC, Shanes Wind Farm LLC, Carlton College LLC,Kas Brothers Wind LLC, Ed Olsen Wind LLC, Rock Ridge Windfarm LLC, Southridge Windfarm LLC, St.Olaf College, Windvest Windfarm LLC	16.34	Wind													
Wind Velva	1/18/2026	20	Velva Windfarm, LLC	11.88	Wind													
Wind Viking	12/17/2018	15	Buffalo Ridge Wind Farm LLC, Moulton Heights Wind Power Project LLC, Muncie Power Partners LLC, North Ridge Wind Farm LLC, Vandy South Project, Viking Wind Farm LLC, Vindy Power Partners LLC, Wilson-West Windfarm LLC	12	Wind													
Wind Westridge	Various 2028	25	K-Brink Wind Farm, LLC Bisson Windfarm LLC, Boeve Windfarm LLC, Windcurrents Windfarm, LLC	7.6	Wind													
Wind Woodstock	4/30/2034	30	Woodstock Wind Farm, LLC	10.2	Wind													
																		PROTECTED DATA ENDS]

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Power Purchase Agreement Cost

PROTECTED DATA HAS BEEN SHADED

Reference	Termination	Term (yrs)	Counterparty	MW	Fuel Type	$ Energy and Curtailment January 2022	February 2022	March 2022	April 2022	May 2022	June 2022	July 2022	August 2022	September 2022	October 2022	November 2022	December 2022	Total	Summary $/MWH	Total Capacity $
						[PROTECTED DATA BEGINS														
Barron County	12/31/2022	10	Barron County Waste-to-Energy Facility	1.865	RDF															
CC Calpine	12/31/2026	20	Mankato Energy Center LLC	375	Gas															
CC Calpine II	5/31/2039	20	Mankato Energy Center II LLC	345	Gas															
CC LSPower	9/30/2027	30	LSP- Cottage Grove, L.P.	245.1	Gas															
CT Invenergy 1	4/10/2025	17	Invenergy Cannon Falls LLC	178.5	Oil/Gas															
CT Invenergy 2	4/10/2025	17	Invenergy Cannon Falls LLC	178.5	Oil/Gas															
DPC Flambeau	1/31/2037	Life of Project	Dairyland Flambeau	2	Hydro															
Deuel Harvest Wind Energy LLC	9/30/2036	15	Deuel Harvest Wind Energy LLC	300	Wind															
Eau Galle	7/31/2026	35	Eau Galle Renewable Energy Co. Inc.	0.300	Hydro															
Elk Creek	12/11/2022	20	Elk Creek Solar, LLC	80.0	Solar															
Green Whey Dairy	2/16/2022	10	Green Whey Dairy	3.2	Digester															
Gundersen Lutheran Landfill	2/16/2022	10	Gundersen Lutheran	1.137	Landfill															
Hastings	6/30/2033	45	City of Hastings Hydro	0.450	Hydro															
Heartland Divide	4/30/2047	25	Heartland Divide Wind II, LLC	200.040	Wind															
Heller DairyFarm	5/1/2023	10	Cow Poo LLC	2.7	RDF															
HERC	12/30/2024	28	Hennepin Energy Resource Recovery (HERC)	33.7	Digester															
Keller	12/31/2022	MTM	Keller Paving & Landscaping, Inc.	0.19	Solar															
Koda	5/31/2022	10	KODA Energy, LLC	12	Biomass															
Lac Courte Oreilles	12/31/2021	35	Lac Courte Oreilles Band of Lake Superior Chippewa Indians	3.1	Hydro															
Manitoba Hydro	4/30/2025	10	Manitoba Hydro Electric Board	Summer: 375, Winter: 325 (Summer = May thru October)	Hydro															
SAF	12/18/2031	20	SAF Hydroelectric, LLC	9.2	Hydro															
Solar Aurora	12/30/2036	20	Aurora Distributed Solar	100	Solar															
Solar Best Power International PV	5/26/2030	20	St. John's Solar	0.5	Solar															
Solar Best Power International PV II	10/11/2030	15	School Sisters of Notre Dame Solar Park	0.718	Solar															
Solar Dragonfly	9/10/2033	15	Dragonfly Solar, LLC	0.8	Solar															
Solar Marshall	6/8/2042	25.5	Marshall Solar, LLC	62.25	Solar															
Solar North Star	12/20/2041	25.67	North Star Solar PV	100	Solar															
Solar Slayton	1/3/2033	10	Slayton Solar, LLC	1.66	Solar															
St Cloud	10/31/2021	33	The City of St. Cloud	Summer: 8.1, Winter: 6.6 (Summer = May thru October)	Hydro															
StPaul CoGen	3/24/2023	20	St. Paul Cogeneration	25	Biomass															
Western Technical College Angelo Dam	3/31/2024	10	Western Technical College	0.205	Hydro															
Wind CBED Adams	3/8/2031	20	Adams Wind Generations, LLC	19.8	Wind															
Wind CBED Big Blue	12/14/2032	20	Big Blue Wind Farm, LLC	36	Wind															
Wind CBED Community Wind North	5/27/2031	20	North Wind Turbines LLC North Community Turbines LLC	30	Wind															
Wind CBED Community Wind South	12/25/2032	20	Zephyr Wind, LLC	30	Wind															
Wind CBED Danielson	3/10/2031	20	Danielson Wind Farms, LLC	19.8	Wind															
Wind CBED Ewington	5/27/2028	20	Ewington Energy Systems, LLC	19.95	Wind															
Wind CBED Hilltop	2/19/2029	20	Hilltop Power	2	Wind															
Wind CBED Jeffers	10/9/2028	20	Jeffers Wind 20 LLC	50	Wind															
Wind CBED Ridgewind	1/12/2031	20	Ridgewind Power Partners LLC	25.3	Wind															
Wind CBED Roseville	8/8/2030	20	Grant County Wind	20	Wind															
Wind CBED Uilk	1/14/2030	20	Uilk Wind Farm, LLC	4.5	Wind															
Wind CBED Valley View	11/29/2031	20	Valley View Transmission, LLC	10	Wind															
Wind CBED Winona	10/26/2031	20	Winona County Wind, LLC	1.5	Wind															
Wind CBED Woodstock	6/23/2030	20	Woodstock Municipal Wind, LLC	0.75	Wind															
Wind Crown Ridge	1/9/2045	25	Crowned Ridge Wind, LLC	200	Wind															
Wind Clean Energy	12/31/2039	20	ALLETE Clean Energy, Inc.	106.08	Wind															
Wind Dakota Range III	4/30/2033	20	DAKOTA RANGE III, LLC	153.6	Wind															
Wind Eastridge	4/30/2026	20	Bendwind, LLC DeGreeff DP, LLC DeGreeffpa LLC Groen Wind LLC Hillcrest Wind LLC LarswindLLC Sierra Wind LLC TAIR Windfarm LLC	10	Wind															
Wind Fenton	11/12/2032	25	Fenton Power Partners I, LLC	205.5	Wind															
Wind FPL	12/2/2026	20	FPL Energy Mower County, LLC	98.9	Wind															
Wind Garwin McNeilus	Various	20-25	Bangladesh Children's Support LLC, Brandon Wind LLC, BT Windfarm LLC, Burmese Children's Support, LLC, GarMar Foundation I, LLC/ REAP I, Gar Mar Wind I, LLC, GM Windfarm LLC, Henslin Creek LLC, Indian Children's Support, LLC, McNeilus Windfarm LLC, Salvadoran Children's Support , SG (JCKD) Windfarm LLC, Southeast Asian Children's Support, LLC, Triton Wind LLC, Wasioja Wind LLC, Wilhelm Wind LLC	27.5	Wind															

Northern States Power Company
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Reference	Termination	Term (yrs)	Counterparty	MW	Fuel Type	$ Energy and Curtailment January 2022	February 2022	March 2022	April 2022	May 2022	June 2022	July 2022	August 2022	September 2022	October 2022	November 2022	December 2022	Total	Summary $/MWH	Total Capacity $
						[PROTECTED DATA BEGINS														
Wind Geronimo Odell	7/28/2036	20	Odell Wind, LLC	200	Wind															
Wind Lakota	4/30/2034	30	Northern Alternative Energy Lakota Ridge LLC	11.25	Wind															
Wind Minn Dakota	12/30/2022	15	MinnDakota Wind LLC	150	Wind															
Wind Moraine II	2/17/2029	10	Moraine Wind II LLC	49.5	Wind															
Wind Norgaard	5/10/2026	20	Roadrunner ,I LLC, Salty Dog-I LLC, Wallys Windfarm LLC, Windy Dog I LLC, Breezy Bucks-I & II LLC, Salty Dog II, LLC	8.75	Wind															
Wind North Shaokatan	10/31/2033	30	Autumn Hills LLC, Jack River LLC,Jessica Mills LLC, Julia Hills LLC, Sun River LLC, Tsar Nicholas, LLC	13.53	Wind															
Wind Phase 2	12/13/2028	30	Lake Benton Power Partners LLC (LBI)	105.75	Wind															
Wind Phase 4	12/14/2023	20	Chanarambie Power Partners, LLC	85.5	Wind															
Wind Prairie Rose	12/10/2032	20	Prairie Rose Wind, LLC	200	Wind															
Wind Ruthton	1/22/2031	30	Ruthton Ridge LLC, Florence Hills LLC,Hadley Ridge LLC,Hope Creek LLC, Soliloquy Ridge LLC, Spartan Hills LLC,Twin Lake Hills LL, Winter's Spawn LLC	15.84	Wind															
Wind Shaokatan	4/30/2034	30	Northern Alternative Enrgy Shakotan Hills LLC	11.88	Wind															
Wind Source Cisco	5/27/2028	20	Cisco Wind Energy LLC	8	Wind															
Wind Source Garwin McNeilus	4/30/2025	20	Ashland Windfarm LLC, Elsinore Wind LLC, Gar Mar Foundation II / REAP II, Grant Windfarm LLC, Zumbro Windfarm	9.25	Wind															
Wind Source JJN	12/16/2029	25	JJN Windfarm, LLC	1.5	Wind															
Wind Source MinWind	2/1/2025	20	Minwind III -IX, LLC	11.55	Wind															
Wind Source West Ridge	12/27/2028	25	Westridge Windfarm LLC, Tofteland Windfarm LLC, TG Windfarm LLC, CG Windfarm LLC, , Fey Windfarm LLC,	9.5	Wind															
Wind Stahl	12/31/2024	20	Stahl Wind Energy LLC, Northern Lights Wind LLC, Lucky Wind LLC, Greenback Energy LLC Cartensen Wind LLC	8.25	Wind															
Wind Tholen	8/27/2025	20	Tholen Transmission Projects	13.2	Wind															
Wind University of Minnesota	10/26/2031		UMORE Park, LLC	2.5	Wind															
Wind Various	Various	30	Agassiz Beach LLC, Metro Wind LLC, Shanes Wind Farm LLC, Carlton College LLC,Kas Brothers Wind LLC, Ed Olsen Wind LLC, Rock Ridge Windfarm LLC, Southridge Windfarm LLC, St.Olaf College, Windvest Windfarm LLC	16.34	Wind															
Wind Velva	1/18/2026	20	Velva Windfarm, LLC	11.88	Wind															
Wind Viking	12/17/2018	15	Buffalo Ridge Wind Farm LLC, Moulton Heights Wind Power Project LLC, Muncie Power Partners LLC, North Ridge Wind Farm LLC, Vandy South Project, Viking Wind Farm LLC, Vindy Power Partners LLC, Wilson-West Windfarm LLC	12	Wind															
Wind Westridge	Various 2028	25	K-Brink Wind Farm, LLC Bisson Windfarm LLC, Boeve Windfarm LLC, Windcurrents Windfarm, LLC	7.6	Wind															
Wind Woodstock	4/30/2034	30	Woodstock Wind Farm, LLC	10.2	Wind															

PROTECTED DATA ENDS]

Community Solar Gardens

In its September 17, 2014 ORDER APPROVING SOLAR-GARDEN PLAN WITH MODIFICATIONS in Docket No. E002/M-13-867 (the Community Solar Gardens docket), the Commission directed the Company to "include information about its bill credits, as reported in its Annual Compliance Report in this docket, in the Company's annual FCA Annual Automatic Adjustment (AAA) Report, reflecting the same time period covered by the AAA report."

At the end of 2022, there were 461 active Community Solar Gardens in-service and 19 of these came on-line during the 2022 AAA reporting period. The location, start date, and number of subscriptions for these gardens are detailed in Part C, Attachment 9. Since bill credits do not begin until the first day of the month after the community solar garden receives permission to operate, there were a total of 461 gardens receiving bill credits during this reporting period. A total of $184,141,566 in Community Solar Gardens bill credits were included in this year's FCA. The corresponding subscribed and unsubscribed energy bill credits were $183,584,635 and $556,923, respectively. The Community Solar Gardens expenses included in the FCA are shown in Part C, Attachment 10. We note that total Community Solar Gardens expenses included in FCA recovery during the AAA reporting period may vary from other CSG reporting due to timing between production and recording ledger expenses.

To comply with the fuel clause treatment approved in Docket No. E002/M-13-867, the bill credits and unsubscribed energy are recorded as fuel purchases in FERC Account 555. To allocate the costs to jurisdiction, the Company first divides the costs into market and above market categories. To determine market costs, the Company reviews the solar garden production by hour and the corresponding LMP price at that hour. These costs are allocated to jurisdiction based on sales. Costs above market are directly assigned to the Minnesota fuel clause.

The following table based on FCA data from Part C, Attachment 10 shows the breakdown of the total Minnesota Community Solar Garden market and above market expenses in the 2022 AAA period:

	System	MN Amount[1]	Estimated MN Retail Allocator
Market	$84,147,422	$60,477,514	0.713550
Above Market	$99,994,144	$99,994,144	1.000000
Total	$184,141,566	$160,471,658	

Our Community Solar Garden program continues to grow, and we anticipate further growth over the coming years. The Company's most recent solar garden annual compliance report was submitted on April 1, 2022 in Docket No. E002/M-13-867, and the next report is due on April 1, 2023.

[1] $118,200 in solar gardens developer late fees were credited to the FCA. This credit has resulted in a net solar garden cost recovery of $110,645,956 during the AAA reporting period.

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Nov. 2022)
1	Le Sueur	9/9/2015	0.036	4
2	Lincoln	4/25/2016	0.204	16
3	Ramsey	5/12/2016	0.125	5
4	Hennepin	8/22/2016	0.036	17
5	Chisago	12/14/2016	5	41
6	Dakota	12/14/2016	5	85
7	Chisago	12/15/2016	4	40
8	Carver	12/15/2016	5	624
9	Scott	12/19/2016	3	223
10	Dakota	12/20/2016	5	29
11	Stearns	12/21/2016	5	55
12	Carver	12/21/2016	5	624
13	Dakota	12/22/2016	5	28
14	Scott	12/22/2016	3	223
15	Stearns	1/4/2017	3	21
16	Stearns	1/5/2017	3	274
17	Goodhue	1/12/2017	4.86	45
18	Dakota	1/13/2017	5	28
19	Chisago	1/13/2017	3.888	29
20	Stearns	1/20/2017	5	55
21	Dakota	2/13/2017	5	204
22	Goodhue	2/13/2017	4	307
23	Carver	2/28/2017	4.86	31
24	Goodhue	3/2/2017	4	307
25	Washington	3/10/2017	0.036	6
26	Wabasha	3/13/2017	3	183
27	Dakota	3/15/2017	5	204
28	Blue Earth	5/31/2017	3	17
29	Redwood	5/31/2017	3	51
30	Winona	5/31/2017	0.25	28
31	Rice	6/30/2017	5	269
32	Dodge	7/18/2017	5	481
33	Washington	7/18/2017	5	200
34	Olmsted	7/19/2017	5	445
35	Kandiyohi	8/14/2017	2	10
36	Pipestone	8/18/2017	2	48
37	Chisago	8/22/2017	3	20
38	Stearns	8/24/2017	2	26
39	Chippewa	8/29/2017	2	15
40	Dakota	8/31/2017	5	44

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Nov. 2022)
41	Pope	9/13/2017	5	46
42	Stearns	9/13/2017	2.188	25
43	Stearns	9/13/2017	4.86	45
44	Lincoln	9/14/2017	0.2	20
45	Sherburne	9/22/2017	5	177
46	Dodge	9/27/2017	4	34
47	Benton	9/29/2017	2	27
48	McLeod	10/25/2017	3	44
49	Chippewa	10/25/2017	3	56
50	Hennepin	10/25/2017	5	26
51	McLeod	10/26/2017	5	145
52	Pipestone	10/30/2017	5	60
53	Stearns	10/30/2017	3	37
54	Benton	10/30/2017	5	37
55	Wright	11/3/2017	5	1118
56	Stearns	11/9/2017	5	45
57	Wright	11/13/2017	5	1081
58	Chippewa	11/14/2017	3	56
59	Stearns	11/16/2017	4	165
60	Nicollet	11/20/2017	5	32
61	Blue Earth	11/20/2017	5	53
62	Scott	11/30/2017	4.69	40
63	Scott	11/30/2017	0.7	6
64	Dakota	11/30/2017	2.7	126
65	Rice	11/30/2017	5	203
66	Stearns	12/13/2017	5	45
67	Chisago	12/13/2017	5	30
68	Carver	12/15/2017	5	60
69	Chisago	12/18/2017	5	25
70	Dodge	12/18/2017	5	79
71	Scott	12/20/2017	2.991	24
72	Carver	12/21/2017	4.361	45
73	Renville	12/28/2017	3	66
74	Washington	1/10/2018	5	80
75	Carver	1/16/2018	3	19
76	Le Sueur	1/18/2018	3	17
77	Dakota	1/23/2018	4.95	45
78	Wabasha	1/29/2018	4	23
79	Pipestone	1/31/2018	4.7	89
80	Sherburne	2/12/2018	3.25	349

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Nov. 2022)
81	Rice	2/14/2018	0.998	157
82	Le Sueur	2/23/2018	3	46
83	Carver	2/26/2018	1.996	310
84	Waseca	2/26/2018	5	68
85	Rice	2/28/2018	5	30
86	Le Sueur	2/28/2018	5	52
87	Washington	2/28/2018	4	682
88	Faribault	3/2/2018	1.84	21
89	Rice	3/2/2018	3	21
90	Steele	3/5/2018	3.4	227
91	Carver	3/6/2018	3	18
92	Chisago	3/13/2018	5	25
93	Carver	3/14/2018	0.998	143
94	Sherburne	3/14/2018	5	41
95	Pope	3/15/2018	5	464
96	Chippewa	3/25/2018	4	42
97	Benton	3/25/2018	2	16
98	Scott	3/28/2018	4.95	70
99	Goodhue	4/12/2018	0.8	137
100	Washington	4/13/2018	3	25
101	Pope	4/19/2018	3	292
102	Washington	4/20/2018	5	30
103	Goodhue	4/26/2018	0.998	130
104	Chisago	4/30/2018	3	18
105	Stearns	4/30/2018	5	55
106	Sherburne	4/30/2018	4	42
107	Goodhue	5/11/2018	1	26
108	Renville	5/16/2018	1	23
109	Renville	5/17/2018	1	20
110	Goodhue	5/22/2018	1	9
111	Blue Earth	5/30/2018	1	9
112	Washington	5/31/2018	3	25
113	Steele	6/5/2018	1	6
114	Hennepin	6/6/2018	0.18	31
115	Chippewa	6/15/2018	4	42
116	Lyon	6/15/2018	3	47
117	Rice	6/20/2018	1	18
118	Le Sueur	6/29/2018	3	21
119	Sherburne	6/29/2018	5	35
120	Watonwan	7/2/2018	0.25	21

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Nov. 2022)
121	Sherburne	7/13/2018	5	50
122	Washington	7/16/2018	2.5	15
123	Steele	7/18/2018	1	6
124	Goodhue	7/19/2018	5	37
125	Washington	7/24/2018	3	25
126	Dakota	7/27/2018	5	40
127	Goodhue	7/30/2018	2	18
128	Chisago	8/1/2018	1	25
129	DOUGLAS	8/2/2018	5	277
130	Le Sueur	8/6/2018	5	443
131	Blue Earth	8/7/2018	3.54	513
132	Chisago	8/9/2018	5	34
133	Wright	8/14/2018	0.972	5
134	Benton	8/14/2018	4.95	35
135	Carver	8/16/2018	4	1240
136	Wright	8/27/2018	5	440
137	Chisago	8/30/2018	1	10
138	Washington	9/4/2018	5	1346
139	Washington	9/7/2018	0.75	93
140	Goodhue	9/14/2018	1	11
141	Dakota	9/17/2018	0.75	9
142	Goodhue	9/19/2018	1	23
143	Waseca	9/27/2018	1	5
144	Chisago	9/28/2018	1	49
145	Chisago	9/28/2018	1	7
146	Hennepin	9/28/2018	0.32	25
147	Blue Earth	10/16/2018	5	38
148	Wright	10/17/2018	4	29
149	McLeod	10/25/2018	1	5
150	Waseca	10/25/2018	1	5
151	Washington	10/29/2018	4.875	45
152	Benton	10/30/2018	1	10
153	Waseca	11/1/2018	1	10
154	Chippewa	11/14/2018	1	139
155	Kandiyohi	11/14/2018	1	25
156	Pope	11/16/2018	1	17
157	Sherburne	11/16/2018	1	5
158	Chisago	11/26/2018	1	11
159	Chisago	11/27/2018	1	15
160	Wright	11/28/2018	5	35

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Nov. 2022)
161	Scott	11/28/2018	0.823	8
162	Hennepin	11/28/2018	0.527	77
163	Scott	11/28/2018	1	8
164	Chisago	11/28/2018	1	9
165	Chisago	11/28/2018	1	12
166	Chisago	11/29/2018	1	13
167	Sherburne	12/3/2018	5	55
168	Chisago	12/7/2018	1	7
169	Sherburne	12/10/2018	4.8	45
170	Chisago	12/11/2018	0.5	20
171	Stearns	12/17/2018	1	62
172	Benton	12/17/2018	1	9
173	Benton	12/17/2018	1	7
174	Chippewa	12/18/2018	1	13
175	Le Sueur	12/19/2018	1	11
176	Murray	12/20/2018	1	8
177	Murray	12/20/2018	1	11
178	Yellow Medicine	12/21/2018	5	136
179	Ramsey	1/8/2019	0.54	5
180	Dodge	1/9/2019	1	11
181	Hennepin	1/11/2019	5	649
182	Meeker	1/23/2019	0.76	9
183	Stearns	1/28/2019	0.324	9
184	Nicollet	1/31/2019	1	7
185	Waseca	2/13/2019	1	11
186	Chisago	2/27/2019	2	18
187	Stearns	3/4/2019	0.72	9
188	Stearns	3/4/2019	1	12
189	Blue Earth	3/5/2019	0.24	11
190	McLeod	3/12/2019	3	87
191	Washington	3/22/2019	1	198
192	Stearns	3/25/2019	1	10
193	Wabasha	3/26/2019	0.85	128
194	Pope	3/26/2019	1	17
195	Sherburne	3/28/2019	5	89
196	Pope	3/28/2019	1	16
197	Renville	3/29/2019	1	15
198	Goodhue	4/11/2019	5	526
199	Wright	4/15/2019	5	1031
200	Stearns	4/16/2019	1	12

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Nov. 2022)
201	Chisago	4/22/2019	3	238
202	Washington	4/22/2019	1	185
203	Wright	4/29/2019	5	1031
204	Rice	4/30/2019	1	7
205	Carver	5/1/2019	1	6
206	Lyon	5/3/2019	1	12
207	Benton	5/13/2019	5	276
208	Dodge	5/15/2019	1	101
209	Dodge	5/15/2019	0.4	67
210	Kandiyohi	5/21/2019	1	9
211	Chisago	5/21/2019	1	8
212	Wright	5/31/2019	5	170
213	Stearns	6/3/2019	5	40
214	Dakota	6/7/2019	5	35
215	Dakota	6/7/2019	5	30
216	Sibley	6/14/2019	3.25	66
217	Stearns	6/18/2019	3	42
218	Freeborn	6/18/2019	0.25	37
219	Chisago	7/3/2019	1	13
220	Carver	7/22/2019	1	8
221	Scott	7/24/2019	0.598	65
222	Carver	7/25/2019	1	8
223	Sherburne	7/26/2019	3	31
224	Hennepin	7/30/2019	0.18	20
225	Sherburne	7/31/2019	0.996	148
226	Dakota	8/6/2019	1	385
227	Rice	8/8/2019	1	47
228	Scott	8/13/2019	1	12
229	Chisago	8/16/2019	0.998	200
230	Stearns	8/16/2019	1	158
231	Stearns	8/16/2019	1	156
232	Wabasha	8/20/2019	1	160
233	Wabasha	8/20/2019	1	143
234	Winona	8/21/2019	5	209
235	Winona	8/22/2019	1	124
236	Wabasha	8/22/2019	1	125
237	Winona	8/22/2019	1	99
238	Chippewa	8/26/2019	1	22
239	Carver	8/29/2019	1	6
240	McLeod	8/30/2019	1	12

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Nov. 2022)
241	Chisago	9/3/2019	1	5
242	Waseca	9/6/2019	1	11
243	Olmsted	9/9/2019	1	6
244	Pope	9/11/2019	1	11
245	Pope	9/11/2019	1	9
246	Hennepin	9/18/2019	0.96	188
247	Rice	9/18/2019	1	13
248	Blue Earth	9/24/2019	0.62	35
249	Goodhue	9/27/2019	4.4	51
250	Blue Earth	9/27/2019	0.62	28
251	Rice	10/9/2019	1	16
252	Stearns	10/23/2019	1	25
253	Stearns	10/25/2019	4.75	77
254	Sherburne	10/29/2019	1	13
255	Scott	10/30/2019	0.4	5
256	Waseca	11/18/2019	0.996	152
257	Sherburne	11/26/2019	1	14
258	Stearns	12/3/2019	1	13
259	Meeker	12/11/2019	1	41
260	Dakota	12/11/2019	1	15
261	DOUGLAS	12/11/2019	1	25
262	Meeker	12/13/2019	1	199
263	Rice	12/13/2019	1	8
264	Pope	12/16/2019	1	8
265	Stearns	12/16/2019	1	9
266	Nicollet	12/18/2019	1	181
267	Blue Earth	12/18/2019	1	167
268	McLeod	12/18/2019	1	162
269	Chisago	12/19/2019	1	12
270	Stearns	12/23/2019	1	15
271	Sherburne	12/23/2019	1	14
272	Sherburne	12/26/2019	1	9
273	Stearns	12/27/2019	1	202
274	DOUGLAS	12/27/2019	1	181
275	McLeod	12/27/2019	1	9
276	Renville	12/30/2019	1	13
277	Sherburne	12/30/2019	0.94	7
278	Goodhue	12/31/2019	0.59	12
279	Winona	1/3/2020	1	165
280	Winona	1/3/2020	1	177

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Nov. 2022)
281	Stearns	1/13/2020	1	12
282	Rice	1/14/2020	1	9
283	Dakota	1/15/2020	1	7
284	Meeker	1/17/2020	1	6
285	Winona	2/12/2020	1	21
286	Goodhue	2/13/2020	1	26
287	Pope	2/17/2020	1	12
288	Hennepin	2/17/2020	0.29	6
289	Rice	2/20/2020	1	9
290	Goodhue	2/26/2020	1	19
291	Pope	2/26/2020	1	13
292	Waseca	2/27/2020	1	8
293	Goodhue	2/28/2020	1	210
294	Goodhue	2/28/2020	1	187
295	Sherburne	2/28/2020	1	20
296	Waseca	3/4/2020	1	9
297	Washington	3/9/2020	3	15
298	Goodhue	3/9/2020	1	202
299	Rice	3/20/2020	1	9
300	Sibley	3/26/2020	1	13
301	Dakota	3/26/2020	1	9
302	Sibley	4/3/2020	1	18
303	Olmsted	4/3/2020	1	8
304	Dodge	4/7/2020	1	12
305	DOUGLAS	4/9/2020	1	16
306	Olmsted	4/13/2020	1	11
307	Olmsted	4/16/2020	1	9
308	Rice	4/24/2020	0.96	108
309	Scott	4/27/2020	3	773
310	Rice	4/27/2020	1	15
311	Goodhue	4/30/2020	1	27
312	Chisago	5/19/2020	1	9
313	Benton	5/20/2020	1	10
314	Stearns	5/21/2020	1	5
315	Dodge	5/21/2020	1	10
316	Carver	5/28/2020	1	51
317	Pope	5/30/2020	1	25
318	Dakota	6/2/2020	1	235
319	Dakota	6/4/2020	1	236
320	Waseca	6/16/2020	1	8

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Nov. 2022)
321	Rice	6/17/2020	2	37
322	Winona	6/24/2020	1	16
323	Winona	6/24/2020	1	37
324	Benton	7/10/2020	1	20
325	Rice	7/13/2020	5	84
326	Rice	7/20/2020	4	105
327	McLeod	7/20/2020	4	32
328	Nicollet	7/30/2020	1	9
329	Goodhue	7/30/2020	1	16
330	Stearns	7/31/2020	1	14
331	Wright	7/31/2020	1	24
332	Le Sueur	7/31/2020	1	7
333	Sherburne	7/31/2020	1	26
334	Goodhue	8/18/2020	1	10
335	Sherburne	9/1/2020	1	10
336	Redwood	9/14/2020	0.86	30
337	Chisago	9/14/2020	1	9
338	Waseca	9/15/2020	1	13
339	Chippewa	9/16/2020	1	20
340	Redwood	9/16/2020	1	29
341	Waseca	9/21/2020	1	11
342	Steele	9/22/2020	1	14
343	Nicollet	9/22/2020	1	10
344	Washington	9/28/2020	1	18
345	Redwood	9/28/2020	1	24
346	Freeborn	9/29/2020	1	23
347	Wright	10/1/2020	1	8
348	Dodge	10/6/2020	1	13
349	Dakota	10/6/2020	1	6
350	Clay	10/8/2020	1	38
351	Clay	10/8/2020	1	35
352	Clay	10/8/2020	1	36
353	Clay	10/8/2020	1	29
354	Nicollet	10/8/2020	1	24
355	Benton	10/14/2020	1	8
356	Rice	10/15/2020	0.7	7
357	Kandiyohi	10/19/2020	1	14
358	Kandiyohi	10/19/2020	1	12
359	Washington	10/20/2020	1	81
360	Clay	10/21/2020	1	31

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Nov. 2022)
361	Goodhue	10/26/2020	1	8
362	Waseca	10/27/2020	1	9
363	Renville	10/29/2020	1	14
364	Freeborn	10/30/2020	1	57
365	Chippewa	10/30/2020	1	23
366	Benton	11/3/2020	1	87
367	Dakota	11/4/2020	1	10
368	Goodhue	11/5/2020	1	19
369	Dodge	11/9/2020	1	17
370	Olmsted	11/9/2020	1	12
371	Sherburne	11/10/2020	1	10
372	Dodge	11/16/2020	1	7
373	Rice	11/19/2020	1	10
374	Goodhue	11/19/2020	1	8
375	Dodge	11/23/2020	1	12
376	Winona	11/30/2020	1	19
377	Stearns	12/1/2020	1	11
378	Renville	12/4/2020	1	11
379	McLeod	12/4/2020	1	8
380	Lyon	12/7/2020	1	29
381	Stearns	12/9/2020	1	14
382	Chisago	12/9/2020	1	6
383	Carver	12/10/2020	1	87
384	Chisago	12/11/2020	1	8
385	Pope	12/14/2020	1	9
386	Pope	12/14/2020	1	7
387	Stearns	12/16/2020	1	7
388	Nicollet	12/17/2020	1	8
389	Pope	12/21/2020	1	17
390	Rice	12/21/2020	1	78
391	Pope	12/28/2020	1	25
392	McLeod	12/30/2020	1	34
393	Dodge	1/4/2021	1	18
394	Dodge	1/4/2021	1	34
395	Waseca	1/6/2021	1	16
396	Le Sueur	1/28/2021	1	13
397	Kandiyohi	2/2/2021	1	9
398	Blue Earth	3/2/2021	1	10
399	Stearns	3/22/2021	0.86	26
400	Rice	3/23/2021	0.83	10

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Nov. 2022)
401	Rice	3/25/2021	1	9
402	Redwood	3/31/2021	1	6
403	Redwood	3/31/2021	0.86	12
404	Waseca	4/7/2021	1	13
405	Benton	4/21/2021	1	8
406	Benton	4/22/2021	1	6
407	Sherburne	6/2/2021	1	242
408	Washington	6/8/2021	1	216
409	Steele	6/16/2021	1	9
410	Rice	7/9/2021	1	202
411	Wright	7/13/2021	4	230
412	Dodge	7/13/2021	0.78	24
413	Pope	7/20/2021	1	92
414	Renville	7/20/2021	1	90
415	Renville	7/21/2021	1	156
416	McLeod	7/21/2021	1	99
417	Chisago	7/21/2021	1	8
418	Chisago	8/3/2021	1	8
419	Chisago	8/3/2021	1	9
420	Pipestone	8/5/2021	1	42
421	Goodhue	8/13/2021	1	6
422	Benton	8/19/2021	0.7	110
423	Pope	9/1/2021	1	100
424	Le Sueur	9/2/2021	1	13
425	Pope	9/23/2021	1	8
426	Goodhue	9/28/2021	1	193

Northern States Power Company
Electric Utility - State of Minnesota

2022 Minnesota Jurisdictional Solar Gardens Program Cost Recovery Through Fuel Clause Rider

	January 2022	February 2022	March 2022	April 2022	May 2022	June 2022	July 2022	August 2022	September 2022	October 2022	November 2022	December 2022	Total 2022
System Portion of Bill Credits & Unsubscribed Energy Payments													
Without Solar Gardens Developer Late Fees													
Market Amount Allocated to All Jurisdictions													
[1] Solar Gardens Subscribed Energy	$1,272,674	$5,291,219	$4,108,297	$5,799,329	$8,241,011	$13,442,173	$13,590,389	$14,654,332	$9,325,640	$5,949,814	$808,042	$1,107,569	$83,590,490
[2] Solar Gardens Unsubscribed Energy <40 KW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8	$8
[3] Solar Gardens Unsubscribed Energy > 40 KW	$24,739	$8,270	$4,429	$21,570	$65,721	$48,852	$50,349	$121,472	$71,190	$63,938	$28,121	$48,271	$556,923
[4] Total Costs (System) [1]+[2]+[3]	$1,297,414	$5,299,489	$4,112,726	$5,820,899	$8,306,733	$13,491,024	$13,640,738	$14,775,804	$9,396,831	$6,013,752	$836,164	$1,155,848	$84,147,422
													$183,584,635
Above Market Amount Recoverable in Minnesota Jurisdiction													
[5] Minnesota Direct Assigned Above Market Amount	$6,716,868	$6,320,378	$11,514,469	$7,822,785	$11,142,832	$9,441,706	$8,522,854	$6,929,226	$10,702,668	$10,096,620	$7,059,312	$3,724,427	$99,994,144
[6] **Total Bill Credits & Unsubscribed Energy Payments [4]+[5]**	**$8,014,281**	**$11,619,867**	**$15,627,195**	**$13,643,684**	**$19,449,565**	**$22,932,730**	**$22,163,592**	**$21,705,030**	**$20,099,498**	**$16,110,372**	**$7,895,476**	**$4,880,275**	**$184,141,566**
Detailed Derivation of Solar Gardens Cost Recovery from Minnesota Retail Customers													
Above Market Bill Credits Allocated to Minnesota Fuel Clause Recovery													
[7] Solar Gardens Cost Recovery for MN FCA [5]	**$6,716,868**	**$6,320,378**	**$11,514,469**	**$7,822,785**	**$11,142,832**	**$9,441,706**	**$8,522,854**	**$6,929,226**	**$10,702,668**	**$10,096,620**	**$7,059,312**	**$3,724,427**	**$99,994,144**
MWh Sales Weighting													
[8] Minnesota Jurisdiction Retail MWh Subject to FCA	2,465,060	2,184,762	2,313,969	2,036,015	2,237,079	2,483,414	2,869,897	2,689,089	2,366,895	2,153,910	2,132,527	2,385,732	28,318,349
[9] NSP System MWh Sales Exclude Windsource & Renewable*Connect	3,522,570	3,092,717	3,282,760	2,870,364	3,123,386	3,438,168	3,918,937	3,726,773	3,279,628	3,038,034	3,011,759	3,381,470	39,686,566
[10] Allocation Weighting [8]/[9]	69.9790%	70.6422%	70.4885%	70.9323%	71.6235%	72.2307%	73.2315%	72.1560%	72.1696%	70.8982%	70.8067%	70.5531%	71.3550%
Market Bill Credits and Payments Allocated to MN Fuel Clause Recovery													
[11] Market Amount Allocated to All Jurisdictions [4]	$1,297,414	$5,299,489	$4,112,726	$5,820,899	$8,306,733	$13,491,024	$13,640,738	$14,775,804	$9,396,831	$6,013,752	$836,164	$1,155,848	$84,147,422
[12] Allocation Weighting [10]	69.9790%	70.6422%	70.4885%	70.9323%	71.6235%	72.2307%	73.2315%	72.1560%	72.1696%	70.8982%	70.8067%	70.5531%	71.3550%
[13] Market Amount Allocated to Minnesota Jurisdiction [11]*[12]	**$907,917**	**$3,743,674**	**$2,898,999**	**$4,128,897**	**$5,949,574**	**$9,744,666**	**$9,989,319**	**$10,661,624**	**$6,781,657**	**$4,263,639**	**$592,060**	**$815,487**	**$60,477,514**
Total Solar Gardens Costs Recovery Included in MN Fuel Cost Charge													
[14] Market and Above Market Allocated Amount [17]+[13]	**$7,624,785**	**$10,064,052**	**$14,413,469**	**$11,951,682**	**$17,092,407**	**$19,186,371**	**$18,512,173**	**$17,590,850**	**$17,484,324**	**$14,360,259**	**$7,651,372**	**$4,539,914**	**$160,471,658**
[15] **Solar Gardens Developer Late Fees (Credit Back to MN Customer**	**$0**	**$0**	**$0**	**$0**	**($41,000)**	**($4,000)**	**$0**	**$0**	**($19,392)**	**$0**	**($46,940)**	**$0**	**($111,332)**
[16] **Net Solar Gardens Costs Recovery Included in MN Fuel Cost Cha**	**$7,624,785**	**$10,064,052**	**$14,413,469**	**$11,951,682**	**$17,133,407**	**$19,190,371**	**$18,512,173**	**$17,590,850**	**$17,503,716**	**$14,360,259**	**$7,698,312**	**$4,539,914**	**$160,582,990**
Market Bill Credits and Payments Allocated to Other Jurisdictions													
[17] Cost Allocated to Other Jurisdictions (Market Portion Based on LMP) [	$389,496	$1,555,816	$1,213,726	$1,692,002	$2,357,158	$3,746,358	$3,651,419	$4,114,180	$2,615,174	$1,750,113	$244,104	$340,361	$23,669,908
Direct Assigned Minnesota Cost Removed from System Cost													
[18] Minnesota Direct Assigned Above Market Amount [5]	$6,716,868	$6,320,378	$11,514,469	$7,822,785	$11,142,832	$9,441,706	$8,522,854	$6,929,226	$10,702,668	$10,096,620	$7,059,312	$3,724,427	$99,994,144
[19] Solar Gardens Developer Late Fees (Credit Back to MN Customers) [15]	$0	$0	$0	$0	($41,000)	($4,000)	$0	$0	($19,392)	$0	($46,940)		($111,332)
[20] Direct Assigned Minnesota Cost Removed from System Cost [18]+[19]	**$6,716,868**	**$6,320,378**	**$11,514,469**	**$7,822,785**	**$11,101,832**	**$9,437,706**	**$8,522,854**	**$6,929,226**	**$10,683,276**	**$10,096,620**	**$7,012,372**	**$3,724,427**	**$99,882,812**

FUEL PROCUREMENT POLICIES

A. Coal

Xcel Energy's coal procurement policy provides that coal and transportation services will be purchased at the lowest reasonable cost within the constraints of environmental regulations, supply reliability, operational compatibility, and consistency with Xcel Energy's inventory needs. The Company obtains its coal through a combination of long- and short-term contracts, including spot coal markets. A listing of current coal supply and transportation contracts and cost changes is shown on Part D, Attachments 3, 4 and 6.

Formal analysis of coal supply requirements for future years is performed on a regular basis. This multi-year analysis generally leads to solicitations for offers to supply unfulfilled requirements and/or bids to purchase coal. The solicitation process typically leads to purchases to fill the targeted percentages of near-term requirements based on a layered approach that varies from station to station. For example, purchases for the King Station are targeted at **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS] When the transaction terms are attractive, Xcel Energy may fill different proportions of its future requirements. Xcel Energy continually reviews the current year's coal consumption to determine changes in coal requirements caused by such variables as weather, transportation availability, outage schedule revisions, capacity factors, and alternative electric sources. If there is an imbalance during an operational year between purchased coal supplies and station requirements, the additional fuel supply need is then corrected through such means as purchases based on spot coal market and transportation conditions at that time. Xcel Energy also monitors future years' needs on a continual basis.

The coal procurement strategy addresses the risk of supply interruption and exposure to market price fluctuations. Supply interruption can result from mine and/or transportation failures. Supply diversification is used to minimize the risk of mine failures and to enhance market competition. Multiple suppliers are pre-qualified for each plant. Also, new contracts for coal supply generally do not include a specific destination, which allows coal to be moved to the generating facility where it is most needed. Supply interruptions resulting from transportation failures have been minimized through plant-specific inventory targets. When transportation performance degrades, the Company initiates close contact with our rail providers at all management levels to improve and restore service levels. Where necessary, other communication channels may be explored to exert all possible pressure to improve transportation service. **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]

Fuel transportation service contracts are executed for various multiyear terms depending on market conditions, anticipated future market conditions, and plant delivery requirements. Proposed rates are vetted internally and externally through consultants and are compared to peers in the market to ensure price competitiveness. The final agreements for transportation of fuels may include minimum tonnage requirements.

B. Nuclear

The spot market price for uranium started 2023 at $47.75 per pound, which is an increase of $5.65 as compared to the beginning of 2022. During the early part of first quarter of 2023, the spot market price has ranged from $47.75 per pound to a high of $50.50 per pound in late January. This market volatility is mainly due to geopolitical pressures, transportation challenges, and the potential for disruption of supply from Russia.

Spot market volume declined in 2022. However, there has been an increase in activity of term contracting. The 2022 term contracting volume is the highest since 2012. Continued strength in reported long-term market prices, which have risen to $51 per pound in December of 2022 from $40.50 per pound in December of 2021 and $32 per pound in July of 2021, has resulted in several uranium mine operators announcing restarts of existing mines. While forecasted levels of uranium production have increased, continued growth in forecasted global demand has also increased. The world's forecasted uncovered requirements of 1.6 million pounds in 2030 rises to 3.8 billion pounds by 2040 as new nuclear plants are completed and existing nuclear plants in Japan are expected to be restarted. Throughout 2022 and continuing into

2023, uranium security of supply issues remain of concern as the impact of supply chain and transportation challenges due to geopolitical pressures and Russia's on-going war in the Ukraine. Differences between supply and demand is projected to be covered by end user inventories in 2023. Spot market volume at 57.4 million pounds of U_3O_8 for 2022 is significantly below the 102.4 million pounds of U_3O_8 reported for 2021. Spot market volumes in 2023 are predicted to range from 53 to 98 million pounds of U_3O_8. Spot market prices for 2023 through 2025 are projected to average about 6 percent higher than 2022. The current market analysis forecasts global supply and inventories meeting demand until about 2024, with small supply deficits projected in 2024 and 2025 (2 million and 4 million pounds, respectively). The current market analysis forecasts a global supply deficit relative to projected demand of between 4 to 8 million pounds in the years 2026 through 2028, but will continue to be dependent on the willingness of suppliers to bring new supply into the market.

The potential western sanctions against Russia continue to provide uncertainty with regard to price impacts or supply interruptions. Numerous U.S. utilities have contracted for supply of enriched uranium from Russia beyond 2022. If sanctions impact the supply of enriched uranium from Russia to customers in the U.S. or EU, either directly (or indirectly through sanctions on the banking infrastructure), the price of uranium could continue be significantly impacted. A list of current nuclear fuel components of service contracts is shown on Part D, Attachment 2.

C. Natural Gas

In contracting for natural gas, a combination of baseload purchases, daily spot purchases, and storage are utilized to meet the portfolio requirements. The basic premise is that base load purchases are used to meet the minimum daily portfolio requirements, and the incremental burns above the minimum requirements are met using a combination of daily spot purchases and storage.

D. Woody Biomass

Xcel Energy establishes woody biomass supply contracts with a diverse group of suppliers. Sources of woody biomass include waste products from lumber mills and wood products industries, chipped bark and limbs from municipal tree trimming operations, chipped slash from logging operations, chipped pallets and demolition debris diverted from landfills, as well as shredded creosote-treated railroad ties. All wood fuel is chipped to sizing specifications and delivered by truck to the plants. There are currently between 25 and 30 suppliers that provide wood fuel to two plants. Our practice has been to establish long-term relationships with a select group of local suppliers. The criteria for selection of suppliers are: 1) dependable supply, 2) consistent quality, and 3) reasonable pricing. By ensuring that these suppliers sustain viable small businesses, we, in turn, can be reasonably confident that we will receive consistent supplies of wood fuel to our plants. Contracts are typically executed with terms from 1 to 5 years. See Part D, Attachment 5 for a listing of the contracts, and Part D, Attachment 6 for a listing of cost changes. We have been able to maintain biomass pricing for our power plants below pulpwood industry prices to avoid potential competition for woody biomass with the pulp and paper industry.

E. Refuse-Derived Fuel (RDF)

Xcel Energy has established five contracts for the supply of refuse-derived fuel (RDF) for three power plants (Red Wing and Wilmarth, Minnesota, and French Island, Wisconsin). See Part D, Attachment 5 for a listing of the contracts, and Part D, Attachment 6 for a listing of cost changes. Four of the contracts provide for the delivery of processed RDF to two of the plants. Xcel Energy also has a service agreement with La Crosse County, Wisconsin, which provides for the processing of municipal solid waste (MSW) into RDF and combustion of the RDF at the French Island facility in La Crosse. Almost all of the county's MSW is processed and disposed at the Xcel Energy facility, with the exception of materials recovered for recycling, and non-combustible or non-recoverable materials and ash byproducts which are disposed in the County's landfill.

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

Nuclear Fuel Components of Services for the Period of January through December 2022

	Supplier & Corporate Headquarters Location	Description of Fuel or Services	Quantity of Volume	Contract Expiration Date
	[PROTECTED DATA BEGINS			
1				
2				
3				
4				
5				
6				
				PROTECTED DATA ENDS]

	Supplier & Corporate Headquarters Location	Description of Fuel or Services	Quantity of Volume	Contract Expiration Date
[PROTECTED DATA BEGINS				
7				
8				
9				
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14				
				PROTECTED DATA ENDS]

	Supplier & Corporate Headquarters Location	Description of Fuel or Services	Quantity of Volume	Contract Expiration Date
[PROTECTED DATA BEGINS				
15				
16				
17				
18				
19				
				PROTECTED DATA ENDS]

Coal Contracts

	Supplier & Corporate Headquarters Location	Description of Fuel or Services	Quantity or Volume (million tons/year)	Contract Expiration Date
[PROTECTED DATA BEGINS				
1				
2				
3				
4				
5				
6				
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8				
				PROTECTED DATA ENDS]

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Transportation & Related Services Contracts

	Supplier & Corporate Headquarters Location	Description of Fuel or Service	Quantity or Volume	Contract Expiration Date
[PROTECTED DATA BEGINS				
1				
2				
3				
4				
				PROTECTED DATA ENDS]

Wood and RDF Contracts

	Supplier & Corporate Headquarters Location	Description of Fuel or Service	Quantity or Volume	Contract Expiration Date
[PROTECTED DATA BEGINS				
1				
2				
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4				
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				PROTECTED DATA ENDS]

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

	Supplier & Corporate Headquarters Location	Description of Fuel or Service	Quantity or Volume	Contract Expiration Date
[PROTECTED DATA BEGINS				
12				
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23				
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	Supplier & Corporate Headquarters Location	Description of Fuel or Service	Quantity or Volume	Contract Expiration Date
[PROTECTED DATA BEGINS				
24				
25				
26				
27				
28				
29				
				PROTECTED DATA ENDS]

Cost Changes – January 1, 2022 to January 1, 2023

	Contract	Percent Change
[PROTECTED DATA BEGINS		

PROTECTED DATA ENDS]

Cost Changes – January 1, 2022 to January 1, 2023

	Contract*	Percent Change
[PROTECTED DATA BEGINS		
		PROTECTED DATA ENDS]

Northern States Power Company
Electric Operations - State of Minnesota
Summary of Actions Taken to Minimize Cost

	Contract*	**Percent Change**
[PROTECTED DATA BEGINS		
		PROTECTED DATA ENDS]

*The majority of wood contracts are renewed with similar terms on an annual basis. The cost change represented is the related contract price on January 1, 2022 compared to the contract price on January 1, 2023.

DISPATCHING POLICIES AND PROCEDURES

The goal for Xcel Energy's dispatching policies and procedures is to provide our native load customers with low-priced reliable electric energy services. This goal is achieved primarily by closely monitoring our load and managing our generation system and purchased energy resources to provide the most economic loading of our own generation units in conjunction with leveraging the competitive wholesale energy and fuel markets. We discuss the Company's policies about self-commitment and self-scheduling of plants in our March 1 annual report filed in Docket No. E999/CI-19-704.

Xcel Energy devotes significant resources to managing our participation in MISO's wholesale energy market, which began operation on April 1, 2005 and increased functions on January 6, 2009. The MISO market altered the method by which we optimize our resources on behalf of our ratepayers, since all resources and load must be scheduled and cleared through MISO's Day Ahead and Real Time markets. However, this change has not altered our overarching goal of reliably providing our customers with the lowest possible energy cost. The Company continues to purchase energy in the the MISO Day Ahead and Real Time markets whenever the market price of purchased energy is below our avoided cost of production. Additionally, we continue to work with MISO to coordinate our efforts to obtain maximum value of our generation and purchased resources for customers.

The Company uses MISO Ancillary Services Market to co-optimize energy and ancillary services markets, resulting in a net benefit to ratepayers.

Another component of the Company's dispatching policy is forecasting how much wind will be on the system at a given time. The Company developed a wind generation forecasting tool in partnership with the National Center for Atmospheric Research. Xcel Energy uses this tool to forecast output from all NSP system wind farms, resulting in a reduction of wind forecast error. Similarly, Xcel Energy uses a solar forecast developed in conjunction with Global Weather Corporation (GWC) to estimate production from NSP system solar facilities. Reductions in forecast error translate directly into a long term decrease in fuel and purchased power costs because improved forecast for renewable energy reduces the need for excessive commitment of thermal resources.

In summary, Xcel Energy's dispatching policies and procedures, while focused on reliable service, are influenced by a goal of lowest cost in an uncertain environment.

Based on the best available information and analytical tools, Xcel Energy attempts to optimally offer our generation units to both minimize energy costs and mitigate the risks of higher than expected costs. These efforts include dispatching practices aimed at controlling wind curtailment costs. Given the potential uncertainties regarding load, generation plant availability, transmission limitations, and wholesale market prices, this requires continual analysis and rapid response to changing conditions, both on an expected (day ahead) and real-time basis.

FUEL SUPPLY

a. Nuclear Fuel

1. Nuclear fuel costs are economically competitive. The average total fuel cost at Prairie Island and Monticello was approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** mills/kWh in 2022.

2. **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** have been managed to ensure security of supply and take advantage of market opportunities.

3. Two contracts were executed in **[PROTECTED DATA BEGINS**

   PROTECTED DATA ENDS]

b. Fossil Fuel

1. Public documents released by the U.S. Energy Information Agency report average coal costs for utility consumption delivered in the U.S. was $1.98/MBtu during 2021. (https://www.eia.gov/electricity/annual/html/epa_07_01.html) During this same period, Northern States Power Company – Minnesota's average delivered coal cost was **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. NSP's average delivered coal cost for 2020 was **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**.

2. NSP has re-emphasized its program to review or modify, as appropriate, coal procurement strategy **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]

3. NSP maintained contract supplies, satisfied generation coal requirements, and produced fuel expense reductions.

4. Xcel Energy Services, Inc. negotiates terms with existing major coal suppliers on behalf of NSP **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]

c. MISO Energy Charges

The Company actively checks, investigates, and disputes (when appropriate) calculations and the charges billed by MISO in the Day 2 energy market. From January through December 2022, the Company submitted two disputes for operating days in 2022, although the second one was rejected as a duplicate.

NSP MISO Dispute Status

Disputed $ Amount			Dispute Status			
YEAR	Op Month	Operating Date	GRANTED	DENIED	OPEN	TOTAL
2022	2022-12	12/15/22	$0.00	$1,916,558.13	$0.00	$1,916,558.13
TOTAL			$0.00	$1,916,558,13	$0.00	$1,916,558.13

The total dollar amount disputed in the 2022 AAA period was $1,916,558.13, which is higher than the 2021 AAA period of $0. The dispute was denied and was closed. All other discrepancies not requiring a formal dispute are identified during our daily checkout process and generally resolved through the normal settlement process.

ENERGY CONSERVATION AND OPTMIZATION PROGRAM

Xcel Energy's Energy Conservation and Optimization Program (ECO) is designed to help our customers use energy wisely. The Company has developed nearly 40 commercial and residential convservation improvement programs with the intent of providing customers the opportunity to lower their energy consumption and overall energy bills. As part of this portfolio, the Company has several electric load management programs available to customers including rate discounts for reducing electric loads on days with peak demand for electricity or rebates for participation in control events utilizing a smart thermostat.

Minn. Stat. § 216B.2401 and 216B.241 require certain Minnesota utilities, including Xcel Energy's electric utility, to invest in cost-effective conservation improvements through ECO. ECO programs are subject to regulation by the Minnesota Department of Commerce (Department). Currently, the Company offers a wide variety of programs that assist customers in implementing energy efficiency measures, ranging from rebates for high efficiency equipment to home energy squad visits. By conserving energy (i.e. using less of it) and varying loads (i.e. interrupting a constant demand to lessen the peak kilowatt impact), customers will experience an overall reduction in their utility bills. Both methods mitigate the Company's power producing and purchasing needs. Moreover, both are considered in the Company's integrated resource planning process.

The Company is required to file with the Department every three years, an Energy Conservation and Optimization Triennial Plan detailing our goals, budgets and cost-effectiveness analyses for the next planning cycle. A detailed description and analysis of the Company's electric conservation policy and programs may be found in the Company's current 2021-2023 Conservation Improvement Plan (CIP) Triennial Plan,[1] which was filed on July 1, 2020 and approved on November 25, 2020.[2]

On April 1 of each year, the Company is required to file with the Department an annual Status Report, which details the cost-effectiveness and spending for the prior year's program. The Deputy Commissioner issued approval of the Company's 2021 CIP Status Report on July 7, 2022.[3]

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[1] Minn.Stat. §216B.241 was adjusted in 2021 to enact changes to the Conservation Improvement Plan to modernize its scope to include additional load management technologies and beneficial electrification. This change is under the Energy Conservation and Optimization Act or ECO.

[2] Docket No. E,G002/CIP-20-473

[3] Docket No. E,G002/CIP-20-473

OTHER ACTIONS TO MINIMIZE COSTS

The Company continues to actively represent the interests of its Minnesota electric customers before national regulatory agencies to minimize the cost of wholesale electric supplies and third party transmission services to be recovered from Minnesota retail electric customers. The Company does this as an individual intervenor, through intervenor groups such as the MISO Transmission Owners (TOs), and through its membership in the Edison Electric Institute (EEI), which actively represents its members in major policy proceedings such as Federal Energy Regulatory Commission (FERC) rulemakings.

1. PARTICIPATION IN THE MISO TRANSMISSION OWNERS COMMITTEE

Northern States Power Company Minnesota (NSPM) and Northern States Power Company Wisconsin (NSPW) are transmission-owning members of MISO. NSPM and NSPW (jointly, the NSP Companies)[1] participate in the MISO Transmission Owning Committee (TOC). Not all MISO transmission-owning companies participate in the TOC.

The MISO TOC members jointly intervene in numerous FERC and other proceedings. The MISO TOC members own a substantial portion of the transmission facilities subject to MISO functional control, representing approximately two-thirds of all load in the MISO footprint. Other Minnesota entities that are MISO TOC members include Great River Energy, Minnesota Power, Otter Tail Power Company, Southern Minnesota Municipal Power Agency, ITC Midwest, LLC, Minnesota Municipal Power Agency, and Central Minnesota Municipal Power Agency. NSPM is also a participant on the Transmission Owners Tariff Working Group, which makes recommendations to the TOC on certain rate and revenue distribution changes pursuant to the MISO Transmission Owners Agreement (TOA). Xcel Energy representatives also participate in all other MISO committees, such as the Market Sub-Committee, Planning Advisory Committee, Reliability Sub-Committee and Regional Criteria and Benefits Working Group. These committees are critical to ensuring the development of transmission system additions that achieve maximum efficiency benefits.

[1] The Company and NSPW are jointly referred to as the "NSP Companies," and their integrated electric generation and transmission system is referred to as the "NSP System."

2. SIGNIFICANT MISO DEVELOPMENTS/ACTIONS

The Company has been active in a number of proceedings before the FERC. To the extent the Department or the Commission or another stakeholder desires information related to specific proceedings, the Company will provide the additional information upon request.

414 Nicollet Mall
Minneapolis, MN 55401

January 18, 2023

Lindsey Simpson
Deloitte & Touche LLP
50 South Sixth Street, Suite 2800
Minneapolis, MN 55402

**RE: 2022 ANNUAL AUTOMATIC ADJUSTMENT (AAA) CHARGES REPORT – ELECTRIC OPERATION
DOCKET NO. E002/AA-21-295**

Dear Ms. Simpson:

The purpose of this letter is to notify Deloitte & Touche LLP, external auditor for Northern States Power Company, doing business as Xcel Energy, of certain requirements established by the Minnesota Public Utilities Commission for the upcoming Annual Automatic Adjustment (AAA) of Charges Report – Electric Operations and True-Up Report. The Company's 2022 Electric AAA and True-Up Report will be filed with the Commission and Minnesota Department of Commerce – Division of Energy Resources by March 1, 2023. This report covers the 2022 calendar year period per the Commission's December 19, 2017 and June 12, 2019 Orders in Docket No. E999/CI-03-802, which changed the process for how fuel clause factors are set and reported in Minnesota.

Scope of the Electric AAA Report

The Company's Electric AAA and True-Up Report, among other things, will provide detailed results of the Company's fuel clause for the reporting period January – December 2022. The Company implemented monthly fuel rates approved per the Commission's December 2, 2021 Order in Docket No. E002/AA-21-295. Monthly rates were later adjusted pursuant to the Company's May 19, 2022 filing in Docket No. E002/AA-21-295 and the Commission's July 5, 2022 Order in Docket No. E002/M-20-417. Appendix A to this letter shows the implemented 2022 monthly factors. The Department will prepare comprehensive analyses of the AAA and True-Up Reports filed by all regulated electric utilities, and the Commission will conduct a hearing to review and act on the Reports and the Department's recommendations.

AAA Report Independent Audit Requirements

The rules governing the automatic adjustment clauses for Minnesota electric utilities and AAA Reports are set forth in Minn. Rule 7825.2600 *et seq*. Minn. Rule 7825.2820 requires an annual independent auditor's report evaluating the utility's accounting for automatic adjustments for the reporting year. Pursuant to the Commission's December 19, 2017 and June 12, 2019 Orders in Docket No. E999/CI-03-802, Xcel Energy's Fuel Clause Adjustment (FCA) as of 2022 is based on an annual forecast of system energy costs and sales as approved by the Commission that reflects the following:

1. The fuel costs are unbundled from the energy charges (or base rates). The Base Cost of Energy embedded in the energy charges is listed separately with the monthly adjustments as "Fuel Cost Charge" line item on bill; and
2. Instead of a single factor, the monthly fuel cost factors are differentiated by six customer class categories.

Per the Commission's November 5, 2019 Order in Docket No. E999/CI-03-802, the Company no longer recovers energy-related costs via its base cost of energy.

The Fuel Clause Rider as defined in the Company's Minnesota Electric Rate Book - MPUC No. 2, Sheet Nos. 5-91, 5-91.1, 5-91.2 and 5-91.3 also include variances authorized by the MPUC. We note the dockets in which these variances were approved in Appendix B.

For the twelve months ending December 31, 2022, computations of the monthly fuel clause adjustment factors also reflected the MISO Day 2 and ASM charges recovery, wind contracts curtailment payments, renewable energy purchase agreements, Windsource exemption and end-of-life nuclear fuel accrual. Please see Appendix B for a list of dockets in which these additional items were approved.

The 2022 Electric AAA and True-Up Report also covers the refunds in the FCA true-up pursuant to the ongoing Asset Based Margin Sharing Program as defined in the Company's Minnesota Electric Rate Book—MPUC No. 2, Sheet No. 5-91.2.[1]

AAA Report Additional Independent Audit Requirements

In compliance with the Commission's March 20, 2002 Order in Docket No. E002/M-01-1953, the Company is required to submit a written request that its external auditors specifically examine the wholesale electric transactions that use gas financial instruments to hedge the price risk associated with those transactions. In preparing

[1] Pursuant to Commission Order in the Company's 2010 rate case (Docket No. E002/GR-10-971) dated May 14, 2012, the Non-Asset Based Margins can no longer be credited through the FCA.

the auditor report to be submitted with the Company's 2022 Electric AAA and True-Up Report to be filed by March 1, 2023, the Company's external auditors should include a statement certifying the following:

- The accounting separation of retail and wholesale financial instruments is implemented appropriately; and
- An audit has been performed to ensure no wholesale electric financial instrument gains or losses are recorded in Account 555 or in Account 804.

The Commission's July 21, 2017 Order in Docket No. E999/AA-15-611 requires that the independent auditor report includes the following:

- comparison of the documentation in support of payments and invoices received from energy suppliers;
- comparison of the base costs of power approved by the Commission to the bases used by the utility;
- recalculation of the billing adjustment charge (credit) per kWh charged to customers for purchased power for the entire applicable period by customer class;
- comparison of the accounting records for the revenues billed to customers for energy delivered for the relevant period to the total sales of electric energy;
- on a test basis, an examination of individual billings in each customer class by recalculating the automatic adjustment of charges and credits and tracing to individual customers' subsidiary records to ensure that the calculated credit or charge was correctly recorded;
- an examination of any corrections to FCA charges or other billing errors;
- a reconciliation of total revenue and cost of power in the utility's general ledger; and
- a recalculation of any true-up, and tracing of the related revenue and expense amounts to the utility's accounting records.

Audit Completion Date

We are requesting the completion of this audit by no later than February 24, 2023. We will gladly work with you to establish a revised schedule if necessary. The Deloitte & Touche independent audit report should be provided to Lisa Peterson, Director, Regulatory Pricing & Analysis, 414 Nicollet Mall – 401 7th Floor, Minneapolis, Minnesota 55401.

Thank you for your attention to this matter. Please do not hesitate to call me at

612-330-5570 with any questions. We will schedule a follow-up meeting to ensure that all the audit requirements are understood.

Sincerely,

/s/

REBECCA D. EILERS
REGULATORY MANAGER

cc: Lisa Peterson
John Chow

Xcel Energy **Northern States Power Company**

Minnesota Retail Electric Fuel Cost Charges ($/KWh)

FUEL COST CHARGE ($/kWh)					
		C&I Demand			
			TOD		
Residential	C&I Non-Demand	Non-TOD	On-Peak	Off-Peak	Outdoor Lighting

2022 Forecast

	Residential	C&I Non-Demand	Non-TOD	On-Peak	Off-Peak	Outdoor Lighting
FAF Ratio *	1.0177	1.0305	0.9984	1.2486	0.8166	0.7976
January	$0.02597	$0.02630	$0.02548	$0.03184	$0.02086	$0.02038
February	$0.03066	$0.03104	$0.03008	$0.03761	$0.02460	$0.02403
March	$0.03268	$0.03309	$0.03206	$0.04009	$0.02623	$0.02562
April	$0.03256	$0.03297	$0.03194	$0.03992	$0.02614	$0.02554
May	$0.03453	$0.03496	$0.03387	$0.04234	$0.02772	$0.02708
June	$0.03979	$0.04029	$0.03903	$0.04880	$0.03194	$0.03119
July	$0.03392	$0.03435	$0.03328	$0.04161	$0.02722	$0.02658
Mid Year Adj	$0.00384	$0.00388	$0.00376	$0.00471	$0.00308	$0.00301
July Total	$0.03776	$0.03823	$0.03704	$0.04632	$0.03030	$0.02959
August	$0.03386	$0.03428	$0.03321	$0.04154	$0.02716	$0.02653
Mid Year Adj	$0.00392	$0.00397	$0.00384	$0.00481	$0.00314	$0.00307
August Total	$0.03778	$0.03825	$0.03705	$0.04635	$0.03030	$0.02960
September	$0.03328	$0.03369	$0.03265	$0.04081	$0.02671	$0.02609
Mid Year Adj	$0.00466	$0.00472	$0.00457	$0.00572	$0.00374	$0.00365
2021 True Up	$0.00325	$0.00329	$0.00318	$0.00398	$0.00260	$0.00254
September Total	$0.04119	$0.04170	$0.04040	$0.05051	$0.03305	$0.03228
October	$0.03116	$0.03155	$0.03057	$0.03822	$0.02501	$0.02443
Mid Year Adj	$0.00477	$0.00483	$0.00468	$0.00586	$0.00383	$0.00374
2021 True Up	$0.00333	$0.00337	$0.00326	$0.00408	$0.00267	$0.00261
October Total	$0.03926	$0.03975	$0.03851	$0.04816	$0.03151	$0.03078
November	$0.02891	$0.02927	$0.02836	$0.03546	$0.02320	$0.02266
Mid Year Adj	$0.00493	$0.00499	$0.00483	$0.00604	$0.00395	$0.00386
2021 True Up	$0.00340	$0.00344	$0.00333	$0.00417	$0.00273	$0.00266
November Total	$0.03724	$0.03770	$0.03652	$0.04567	$0.02988	$0.02918
December	$0.02662	$0.02696	$0.02612	$0.03265	$0.02138	$0.02088
Mid Year Adj	$0.00452	$0.00458	$0.00443	$0.00554	$0.00363	$0.00354
2021 True Up	$0.00309	$0.00313	$0.00304	$0.00380	$0.00248	$0.00242
December Total	$0.03423	$0.03467	$0.03359	$0.04199	$0.02749	$0.02684
Average	**$0.03530**	**$0.03575**	**$0.03463**	**$0.04330**	**$0.02834**	**$0.02768**

* FAF Ratio effective since October 1, 2017.

2021

	Residential	C&I Non-Demand	Non-TOD	On-Peak	Off-Peak	Outdoor Lighting
January	$0.02315	$0.02344	$0.02271	$0.02839	$0.01859	$0.01816
February	$0.02613	$0.02646	$0.02564	$0.03206	$0.02097	$0.02048
March	$0.02716	$0.02750	$0.02665	$0.03332	$0.02180	$0.02129
April	$0.02854	$0.02890	$0.02800	$0.03500	$0.02292	$0.02239
May	$0.03236	$0.03277	$0.03175	$0.03970	$0.02597	$0.02537
June	$0.03617	$0.03663	$0.03548	$0.04438	$0.02902	$0.02834
July	$0.03086	$0.03125	$0.03027	$0.03786	$0.02476	$0.02418
August	$0.03012	$0.03049	$0.02954	$0.03696	$0.02416	$0.02359
September **	$0.03067	$0.03106	$0.03010	$0.03763	$0.02462	$0.02405
October #	$0.03130	$0.03169	$0.03070	$0.03838	$0.02511	$0.02453
November #	$0.02869	$0.02905	$0.02814	$0.03519	$0.02302	$0.02247
December #	$0.02672	$0.02706	$0.02621	$0.03279	$0.02145	$0.02095
Average	$0.02932	$0.02969	$0.02877	$0.03597	$0.02353	$0.02298

** Included 2020 True Up # Included 2021 Mid-Year True Up.

Appendix B

New Orders issued or new activities are underlined

The Fuel Clause Rider as defined in the Company's Minnesota Electric Rate Book - MPUC No. 2, Sheet Nos. 5-91, 5-91.1, 5-91.2 and 5-91.3 also include variances authorized by the MPUC. These variances were approved in the following dockets.

- Wind, Biomass and Others – E002/M-95-244, E002/M-96-934, E,G002/M-97-985, E002/M-17-530, E002/M-17-531, E002/M-17-532, E002/M-17-551, and E002/M-17-694
- Fuel Clause Reform – E999/CI-03-802, Orders dated December 19, 2017, June 12, 2019, and November 5, 2019
- <u>2021 Fuel Forecast and Factors – E002/AA-20-417, Order dated July 5, 2022</u>
- 2022 Fuel Forecast and Factors– E002/AA-21-295, Order dated December 2, 2021 and <u>Rate Adjustment filing dated May 19, 2022</u>

For the 12 months ending December 31, 2022, computations of the monthly fuel clause adjustment factors also reflected the MISO Day 2 and ASM charges recovery, wind contracts curtailment payments, renewable energy purchase agreements, Windsource exemption and end-of-life nuclear fuel accrual. These additional components of the FCA were approved by the MPUC in the following dockets:

- MISO ASM – E002/M-08-528
- MISO Day 2 – E002/M-04-1970
- Wind Contracts Curtailment Payments – E002/M-00-622, E002/M-02-51, E002/M-04-404, E002/M-04-864, E002/CN-01-1958, E,G999/AA-04-1279, E002/M-05-1850, E002/M-05-1934, and E002/M-06-85
- Renewable Energy Purchase Agreements:
    - KODA Energy, LLC, E002/M-08-1098, Order dated January 29, 2009
    - Woodstock, LLC, Amendment approved in E002/M-17-26, Order dated October 8, 2018.
    - Winona, LLC, E002/M-09-1247, Notice of Approval dated December 1, 2009
    - Adams, LLC, E002/M-09-1366, Notice of Approval dated December 29, 2009
    - Danielson, LLC, E002/M-09-1367, Notice of Approval dated December 29, 2009
    - Best Power, LLC, Amendment approved in E002/M-14-490, Order dated September 8, 2014

- WM Renewable Energy, LLC, E002/M-10-161, Order dated April 30, 2010
- Big Blue, LLC, Amendment approved in E002/M-13-1002, Order dated February 27, 2014.
- Hilltop, E002/M-08-47, Notice of Approval dated February 15, 2008
- Valley View, E002/M-08-1235, Order dated March 9, 2009
- Ridgewind, E002/M-08-1428, Notice of Approval dated January 2, 2009
- Moraine II, Amendment approved in E002/M-19-58, Order dated March 25, 2019
- Ewington Energy Systems LLC, E002/M-06-1472, Notice of Approval dated November 30, 2006
- Uilk Wind Farm, LLC, E002/M-08-1502, Notice of Approval dated February 6, 2009
- Prairie Rose Wind, LLC, E002/M-11-713, Order dated December 28, 2011
- Diamond K Dairy, E002/M-10-486, Order dated August 26, 2010
- School Sisters, E002/M-15-619, Order dated September 14, 2015
- Aurora Solar, E002/M-15-330, Order dated August 2, 2015
- Marshall and NorthStar Solar, E002/M-14-162, Order dated March 24, 2015
- Slayton Solar, E002/M-11-490, Order dated September 14, 2011
- Dragonfly Solar, E002/M-17-561, Order dated October 12, 2017
- University of Minnesota South East Plant, E002/M-20-39, Order dated April 10, 2020
- Crowned Ridge and Clean Energy #1 – E002/M-16-777, Order dated September 1, 2017
- Dakota Range III – E002/M-18-765, Order dated July 19, 2019
- St. Paul Cogeneration – E002/M-21-590, Order dated January 24, 2022

- WindSource Exemption – E002/M-01-1479, E002/M-09-1177, Order dated June 21, 2010
- End-Of-Life Nuclear Fuel Accrual – E002/M-05-1648
- Community Solar Gardens Program – E002/M-13-867
- Renewable*Connect Government Program – E002/M-15-985
- Renewable*Connect – Docket No. E002/M-19-33
- Solar Energy Standard Exemption – E002/M-17-425, Order dated October 12, 2017
- Acquisition of Community Wind North and Jeffers Wind Facilities – E002/PA-18-777, Order dated December 3, 2019

Northern States Power Company, a Minnesota corporation

Schedule of Fuel Adjustment Clause Factors of Northern States Power Company, a Minnesota corporation, for the period from January 1, 2022 to December 31, 2022, and Independent Accountant's Report on Applying Agreed-Upon Procedures

Deloitte.

Deloitte & Touche LLP

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INDEPENDENT ACCOUNTANT'S REPORT

To the Board of Directors of
Northern States Power Company, a Minnesota corporation

We have performed the procedures enumerated below, on Northern States Power Company, a Minnesota corporation's (the "Company") Schedule of Fuel Adjustment Clause Factors filed with the Minnesota Public Utilities Commission (the "Commission"), covering the period from January 1, 2022 to December 31, 2022, in accordance with Commission Rules 7825.2700 to 7825.2820 governing automatic adjustment of energy charges, and with the Fuel Clause Riders and Dockets as defined on Sheet Nos. 5-91, 5-91.1, 5-91.2, and 5-91.3 of the Company's tariff (the "subject matter"). The Company is responsible for the subject matter.

The Company has agreed to and acknowledged that the procedures performed are appropriate to meet the intended purpose of assisting the Company and the Commission (each and collectively, the "specified parties") in evaluating the subject matter from January 1, 2022 to December 31, 2022.

We make no representation regarding the appropriateness of the procedures either for the purpose for which our report has been requested or for any other purpose. Accordingly, this report may not be suitable for either the purpose of which this report has been requested or for any other purpose. The procedures performed may not address all the items of interest to a user of this report and may not meet the needs of all users of this report and, as such, users are responsible for determining whether the procedures performed are appropriate for their purposes. The procedures performed are specified in Commission Rules 7825.2700 to 7825.2820 governing automatic adjustment of energy charges.

Our procedures and findings are as follows:

a. We compared the documentation in support of payments and invoices received from energy suppliers for the period from January 1, 2022 to December 31, 2022 for 24 selections related to energy costs made during our procedures and found them to be in agreement.

b. We compared the base costs of power, approved by the Commission, to the base costs of power used by the Company for the period from January 1, 2022 to December 31, 2022 and found them to be in agreement.

c. We recalculated the billing adjustment charge (credit) per kWh charged to customers for purchased power for the period from January 1, 2022 to December 31, 2022, by customer class, and noted no exceptions between our recalculation and the Company's reported adjustment.

d. We compared the accounting records for the revenues billed to customers for energy delivered to the total sales of electric energy for the period from January 1, 2022 to December 31, 2022 and found them to be in agreement.

e. We randomly selected 24 individual billings across each of the customer class categories for the period from January 1, 2022 to December 31, 2022 and recalculated the automatic adjustment of charges and credits and traced to individual customer's subsidiary records to ensure that the calculated credit or charge was correctly recorded, noting no exceptions.

f. We did not identify any corrections to Fuel Adjustment Clause charges or other billing errors for the period from January 1, 2022 to December 31, 2022.

g. We reconciled total revenue and the cost of power for the period from January 1, 2022 to December 31, 2022 to the Company's general ledger and found them to be in agreement, when considering applicable reconciling items, with the Fuel Adjustment Clause Factors calculation underlying detail.

h. We have recalculated the true-up calculation and have traced the related revenue and expense amounts for the period from January 1, 2022 to December 31, 2022 to the company's accounting records and found them to be in agreement with the amounts used in the true-up calculation.

i. We selected a sample of 12 accounting records and through inspection we identified no exceptions with the accounting separation of retail and wholesale financial instruments.

j. We inspected vendor invoices and traced gains and losses to the accounting records for one selection to determine if any wholesale electric financial instrument gains or losses were recorded in accordance with the Federal Energy Regulatory Commission Uniform System of Accounts ("account" or "accounts") account 555 or account 804 and we didn't identify any such gains or losses as mentioned above in these accounts.

We were engaged by the Company to perform this agreed-upon procedures engagement and conducted our engagement in accordance with attestation standards established by the American Institute of Certified Public Accountants. We were not engaged to and did not conduct an examination or review engagement, the objective of which would be the expression of an opinion or conclusion, respectively, on the subject matter. Accordingly, we do not express such an opinion or conclusion. Had we performed additional procedures, other matters might have come to our attention that would have been reported to you.

We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements related to our agreed-upon procedures engagement.

This report is intended solely for the information and use of the Company and the Commission and is not intended to be, and should not be used by anyone other than the specified parties.

Deloitte & Touche LLP

February 28, 2023

NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION

STATE OF MINNESOTA RETAIL ELECTRIC CUSTOMERS
SCHEDULE OF FUEL ADJUSTMENT CLAUSE FACTORS
FOR THE PERIOD FROM JANUARY 1, 2022 TO DECEMBER 31, 2022
(DOLLAR PER KWH)

	Residential	C&I Non-Demand	C&I Demand Non-TOD	C&I Demand On-Peak	C&I Demand Off-Peak	Outdoor Lighting
January 1, 2022	$ 0.02597	$ 0.02630	$ 0.02548	$ 0.03184	$ 0.02086	$ 0.02038
February 1, 2022	$ 0.03066	$ 0.03104	$ 0.03008	$ 0.03761	$ 0.02460	$ 0.02403
March 1, 2022	$ 0.03268	$ 0.03309	$ 0.03206	$ 0.04009	$ 0.02623	$ 0.02562
April 1, 2022	$ 0.03256	$ 0.03297	$ 0.03194	$ 0.03992	$ 0.02614	$ 0.02554
May 1, 2022	$ 0.03453	$ 0.03496	$ 0.03387	$ 0.04234	$ 0.02772	$ 0.02708
June 1, 2022	$ 0.03979	$ 0.04029	$ 0.03903	$ 0.04880	$ 0.03194	$ 0.03119
July 1, 2022	$ 0.03776	$ 0.03823	$ 0.03704	$ 0.04632	$ 0.03030	$ 0.02959
August 1, 2022	$ 0.03778	$ 0.03825	$ 0.03705	$ 0.04635	$ 0.03030	$ 0.02960
September 1, 2022	$ 0.04119	$ 0.04170	$ 0.04040	$ 0.05051	$ 0.03305	$ 0.03228
October 1, 2022	$ 0.03926	$ 0.03975	$ 0.03851	$ 0.04816	$ 0.03151	$ 0.03078
November 1, 2022	$ 0.03724	$ 0.03770	$ 0.03652	$ 0.04567	$ 0.02988	$ 0.02918
December 1, 2022	$ 0.03423	$ 0.03467	$ 0.03359	$ 0.04199	$ 0.02749	$ 0.02684

TRUE-UP FACTORS FOR THE PERIOD JANUARY 1, 2022 TO DECEMBER 31, 2022
(DOLLAR PER KWH)

Annual true-up filing March 1, 2023 (true-up factors proposed for September 2023)	Residential	C&I Non-Demand	C&I Demand Non-TOD	C&I Demand On-Peak	C&I Demand Off-Peak	Outdoor Lighting
September 2023	$ (0.00167)	$ (0.00169)	$ (0.00164)	$ (0.00205)	$ (0.00134)	$ (0.00131)

This Schedule of Fuel Adjustment Clause Factors is based on the requirements of the Minnesota Public Utilities Commission (the "Commission") Rules 7825.2700 to 7825.2820 governing automatic adjustment of energy charges, and with the Fuel Clause Riders and Dockets as defined on Sheet Nos. 5-91, 5-91.1, 5-91.2 and 5.-91.3 of the electric rates filed by the Company with the Commission, including Commission Revisions.

Miscellaneous Purchased Power Reporting

1. Renewable Energy Purchase Agreement (REPA) with KODA Energy, LLC (Docket No. E002/M-08-1098)

The Company is required to report in this annual report whether Xcel Energy has obtained any revenue from any source as a result of this REPA and to itemize any such revenues by source and amount. As of this AAA reporting period, the Company has not received any new revenue as described in this Order. The Company will continue to monitor and report any such revenue in future AAA reports.

2. Power Purchase Agreement with WM Renewable Energy, LLC (Docket No. E002/M-10-161)

On April 30, 2010, the Commission approved the Company's Replacement Power Purchase Agreement with WM Renewable Energy, LLC. The Order also requires the Company to report any curtailments and curtailment payments of power from this Burnsville landfill gas facility in the monthly FCA filings. This PPA was terminated effective March 26, 2021, and the Company is not aware of any curtailments or curtailment payments during the current reporting period. We will cease reporting on this PPA in future annual reports since the PPA has been terminated.

3. Power Purchase Agreement with Diamond K Dairy, Inc. (Docket No. E002/M-10-486)

On August 26, 2010, the Commission approved the Company's Power Purchase Agreement with Diamond K Dairy, Inc. The Company is required to report in the AAA report any revenues the Company has received from any or all sources as a result of this PPA, and to report and itemize any such revenues by source and amount. This PPA was terminated effective April 6, 2019, and the Company has not received any new revenue as described in this Order during the current reporting period. We will cease reporting on this PPA in future annual reports since the PPA has been terminated.

4. HERC PPA (Docket No. E002/M-17-532)

In a February 1, 2018 letter filed in Docket No. E002/M-17-532, the Company committed to provide the Commission with additional supporting information about the interim costs associated with the HERC PPA.

By way of background, the NSP-HERC PPA dated August 1, 1986, as amended, provides that HERC may offer the output of the plant to NSP for an additional seven years (January 1, 2018 through December 31, 2024) at its fair market value to NSP at the time it is offered. The Commission's December 28, 2017 Order in Docket No. E002/M-17-532 did not approve certain prices negotiated by the parties. Pursuant to the PPA, in May 2018 HERC notified NSP that it desired to arbitrate the pricing for the seven-year extension term (Extension Term).

Pending resolution of permanent pricing for the Extension Term, the parties entered into an interim agreement (Interim Agreement) in which NSP purchased HERC's energy during 2018 at the day-ahead MISO Locational Marginal Price (LMP) at the NSP.ALDRIHERC node as adjusted for any applicable MISO market charges and real time settlement differences (LMP Pricing). NSP and HERC entered into an amendment to the Interim Agreement on October 20, 2020, which extended the Interim Agreement through December 31, 2021. LMP pricing was used throughout the 2021 calendar year AAA reporting period.

On April 1, 2021 a decision was rendered in the arbitration case in favor of NSP that the fair market value of HERC's energy during the Extension Term is LMP Pricing. NSP and HERC subsequently entered into an Extension Amendment to the HERC PPA dated November 22, 2021 agreeing that LMP Pricing applies to energy sold by HERC to NSP during the Extension Term and that no retroactive adjustment to the LMP Pricing of energy previously sold to NSP during the Extension Term is required.

Part C, Attachment 7 shows the production and invoiced amounts under the HERC Extension Amendment for the 2022 calendar year. The total cost paid during reporting period was $9.0 million, which is an average cost of $45.13/MWh.

5. Offsetting Revenues or Compensation Resulting from Contracts, Investments Paid for by Ratepayers

The Commission's April 6, 2012 ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS AND REQUIRING ADDITIONAL FILINGS in Docket Nos. E999/AA-09-961 and E999/AA-10-884, the 2009 and 2010 AAA report dockets, requires the Company to report in future AAA filings any offsetting revenues or compensation recovered as a result of contracts, investments, or expenditures paid for by their ratepayers.

As of this current AAA reporting period, all applicable offsetting revenues and/or compensation resulting from fuel and purchased energy related contracts, investments, and expenditures paid for by ratepayers are credited back to ratepayers through the fuel clause. Credits during the 2022 reporting period are commercial operation date (COD) delay damage payments of $5.0 million for the Heartland Divide Wind II, LLC PPA and a $0.3 million refund of excess purchased power costs from the Lac Courte Oreilles Band of Lake Superior Chippewa Indians PPA, which was terminated effective December 31, 2021.

Renewable*Connect Neutrality Charge
(Docket No. E002/M-15-985)

The Commission's February 27, 2017 Order in Docket No. E002/M-15-985, approving the Company's Renewable*Connect program, requires the Company to "provide in its Annual Automatic Adjustment reports a separate section discussing the pilot programs' impact on non-participants and the effectiveness of the neutrality charge to address any cost shift between participants and nonparticipants."

To test the effectiveness of the Company's neutrality charge, the Company reviewed the actual system impact of the resources across the identified categories. Line losses, which accounted for nearly two-thirds of neutrality expenses in 2022, were the most significant impact across the cost categories as illustrated in Table 1 below. Curtailments on program solar resources totaled approximately $219,000, and $42,796 were allocated to the program. Wind curtailments associated with the program's wind resource decreased in 2022. Wind curtailments totaled approximately $949,000 and $148,367 were allocated to the program.

Wind integration cost rates provided in the Company's Dakota Range filing in Docket No. E002/M-17-694 were also used to estimate the cost of the integration of the program's wind resources. The analysis results in an estimate of approximately $240,000 in wind integration costs for the 2022 reporting period.

To understand the potential impact of the Renewable*Connect Program on non-participant energy cost, the Company performed an analysis that compared the marginal cost of energy: in this case, on- and off-peak LMP pricing, to the PPA cost of solar and wind resources allocated to Renewable*Connect consistent with the analysis the Company performed for the prior annual compliance filing. Since Odell Wind and NorthStar Solar Energy were originally procured for the Fuel Clause paying customers, moving this higher cost energy from the Fuel Clause to Renewable*Connect has a positive impact on non-participants.

Overall, neutrality payments fell short of participant cost by approximately $243,000 in 2022. However, over the life of the program, when factoring the economic benefit of moving the higher priced Odell wind and North Star solar from the Fuel Clause to Renewable*Connect, the net result is that non-participants have received roughly a $2.5 million benefit due to the Renewable*Connect program.

Table 1: Non-Participants Impact

(in $000s)	Total	2022	2021	2020	2019	2018	2017
Line Losses	$3,014	$712	$677	$641	$532	$359	$92
Solar Curtailments	$163	$43	$29	$66	$17	$4	$3
Wind Curtailments	$500	$148	$302	$35	$11	$4	$0
Economic/Balancing	$1,160	$240	$228	$230	$227	$185	$50
Total	$4,836	$1,143	$1,236	$973	$787	$552	$145
Neutrality Payments	$4,455	$900	$876	$891	$884	$717	$187
Non-Participant Cost/(Benefit)	$381	$243	$360	$82	($97)	($165)	($42)
Net Economic Cost/(Benefit)[1]	($2,878)	$2,168	$566[2]	($2,889)	($1,792)	($688)	($244)
Total Cost/(Benefit)	($2,498)	$2,411	$926	($2,807)	($1,889)	($853)	($286)

[1] Since Odell Wind and NorthStar Solar Energy were originally procured for the system, moving this higher cost energy from the Fuel Clause to Renewable*Connect provides a benefit to non-participant relative to energy procured at LMP.

[2] Corrected Net Economic Cost/(Benefit) & Total Cost/(Benefit) for 2021. The 2021 report inadvertently used 2020 Renewable*Connect Production Costs instead of 2021 costs.

Unusual Items Over $500,000
(Docket Nos. E999/AA-09-961, E999/AA-10-884 and E999/AA-18-373)

The Commission's April 6, 2012 ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS AND REQUIRING ADDITIONAL FILINGS in Docket Nos. E999/AA-09-961 and E999/AA-10-884 (the 2008-2009 and 2009-2010 AAA report dockets) requires the Company to provide footnotes in future monthly FCA filings and future AAA filings to explain unusual adjustments of $500,000 and higher on a going forward basis. In addition, the Commission's November 13, 2019 Order in Docket No. E999/AA-18-373 (the 2017-2018 AAA report docket) requires the Company to identify and include error reports in future AAA filings and annual FCA true-up filings under the new FCA reform process. Table 1 below describes any such unusual items or errors during the 2022 reporting period.

Table 1: Unusual Items Over $500,000

Item Pertaining To	Period Affected	Descriptions	Amount (negative indicates cost decrease)	FCA Impact
Windsource Program Expenses	Feb-22	We recorded the true up of expenses allocated to the Windsource program related to 2020 and 2021.	($1,507,135)	Yes
Heartland Divide Delay Damages	Apr-22	Heartland Divide Wind II delayed COD until April 12, 2022, which resulted in delay damage payments of $5,000,000 (System Total).	($5,000,000)	Yes
Lake Benton Wind	Oct-22	We recorded a $5,000,000 reduction of purchased power expense for funds received for congestion impacts due to settlement with NEE.	($5,000,000)	Yes

The Commission's July 21, 2017 Order in Docket No. E999/AA-15-611 requires electric utilities to identify all dockets in which the Commission has granted rule variances to a utility's FCA (such as those authorizing true-up provisions, those allowing costs of purchased power adjustments to flow through the FCA, and those allowing MISO costs and revenues to be included in the FCA). The variances and dockets pertaining to the 2022 FCA true-up and AAA reporting period are listed below.

- Wind, Biomass and Others – E002/M-95-244, E002/M-96-934, E,G002/M-97-985, E002/M-17-530, E002/M-17-531, E002/M-17-532, E002/M-17-551, and E002/M-17-694
- Fuel Clause Reform – E999/CI-03-802, Orders dated December 19, 2017, June 12, 2019, and November 5, 2019
- 2021 Fuel Forecast and Factors – E002/AA-20-417, Order dated July 5, 2022
- 2022 Fuel Forecast and Factors– E002/AA-21-295, Order dated December 2, 2021 and Rate Adjustment filing dated May 19, 2022

For the 12 months ending December 31, 2022, computations of the monthly fuel clause adjustment factors also reflected the MISO Day 2 and ASM charges recovery, wind contracts curtailment payments, renewable energy purchase agreements, Windsource exemption and end-of-life nuclear fuel accrual. These additional components of the FCA were approved by the MPUC in the following dockets:

- MISO ASM – E002/M-08-528
- MISO Day 2 – E002/M-04-1970
- Wind Contracts Curtailment Payments – E002/M-00-622, E002/M-02-51, E002/M-04-404, E002/M-04-864, E002/CN-01-1958, E,G999/AA-04-1279, E002/M-05-1850, E002/M-05-1934, and E002/M-06-85
- Renewable Energy Purchase Agreements:
    - KODA Energy, LLC, E002/M-08-1098, Order dated January 29, 2009
    - Woodstock, LLC, Amendment approved in E002/M-17-26, Order dated October 8, 2018.
    - Winona, LLC, E002/M-09-1247, Notice of Approval dated December 1, 2009
    - Adams, LLC, E002/M-09-1366, Notice of Approval dated December 29, 2009
    - Danielson, LLC, E002/M-09-1367, Notice of Approval dated December 29, 2009

  - Best Power, LLC, Amendment approved in E002/M-14-490, Order dated September 8, 2014
  - WM Renewable Energy, LLC, E002/M-10-161, Order dated April 30, 2010
  - Big Blue, LLC, Amendment approved in E002/M-13-1002, Order dated February 27, 2014.
  - Hilltop, E002/M-08-47, Notice of Approval dated February 15, 2008
  - Valley View, E002/M-08-1235, Order dated March 9, 2009
  - Ridgewind, E002/M-08-1428, Notice of Approval dated January 2, 2009
  - Moraine II, Amendment approved in E002/M-19-58, Order dated March 25, 2019
  - Ewington Energy Systems LLC, E002/M-06-1472, Notice of Approval dated November 30, 2006
  - Uilk Wind Farm, LLC, E002/M-08-1502, Notice of Approval dated February 6, 2009
  - Prairie Rose Wind, LLC, E002/M-11-713, Order dated December 28, 2011
  - Diamond K Dairy, E002/M-10-486, Order dated August 26, 2010
  - School Sisters, E002/M-15-619, Order dated September 14, 2015
  - Aurora Solar, E002/M-15-330, Order dated August 2, 2015
  - Marshall and NorthStar Solar, E002/M-14-162, Order dated March 24, 2015
  - Slayton Solar, E002/M-11-490, Order dated September 14, 2011
  - Dragonfly Solar, E002/M-17-561, Order dated October 12, 2017
  - University of Minnesota South East Plant, E002/M-20-39, Order dated April 10, 2020
  - Crowned Ridge and Clean Energy #1 – E002/M-16-777, Order dated September 1, 2017
  - Dakota Range III – E002/M-18-765, Order dated July 19, 2019
  - St. Paul Cogeneration – E002/M-21-590, Order dated January 24, 2022
- WindSource Exemption – E002/M-01-1479, E002/M-09-1177, Order dated June 21, 2010
- End-Of-Life Nuclear Fuel Accrual – E002/M-05-1648
- Community Solar Gardens Program – E002/M-13-867
- Renewable*Connect Government Program – E002/M-15-985
- Renewable*Connect – Docket No. E002/M-19-33
- Solar Energy Standard Exemption – E002/M-17-425, Order dated October 12, 2017
- Acquisition of Community Wind North and Jeffers Wind Facilities – E002/PA-18-777, Order dated December 3, 2019

Former AAA	Description	Docket or Rule	April 30, 2021 Annual Forecast of Rates	March 1, 2023 Annual True-Up Filing
Part D, Section 1 and all Schedules	Policies and Actions: Fuel Procurement	Rule 7825.2800	Part D, Attachment 1	Part D, Attachment 1
D-1, Schedule 1	Nuclear Fuel Component of Service	Rule 7825.2800	Part D, Attachment 2	Part D, Attachment 2
D-1, Schedule 2	Coal Contracts	Rule 7825.2800	Part D, Attachment 3	Part D, Attachment 3
D-1, Schedule 3	Transportation & Related Services Contracts	Rule 7825.2800	Part D, Attachment 4	Part D, Attachment 4
D-1, Schedule 4	Wood and RDF Contracts	Rule 7825.2800	Part D, Attachment 5	Part D, Attachment 5
D-1, Schedule 5	Cost Changes	Rule 7825.2800	Part D, Attachment 6	Part D, Attachment 6
Part D, Section 2	Policies and Actions: Dispatching Policies and Procedures	Rule 7825.2800	Part D, Attachment 7	Part D, Attachment 7
Part D, Section 3	Policies and Actions: Fuel Supply	Rule 7825.2800	Part D, Attachment 8	Part D, Attachment 8
Part D, Section 4	Policies and Actions: Conservation and Load Management Policy	Rule 7825.2800	Part D, Attachment 9	Part D, Attachment 9
Part D, Section 5	Policies and Actions: Other Actions to Minimize Costs	Rule 7825.2800	Part D, Attachment 10	Part D, Attachment 10
Part E, Section 1	Annual Report of Automatic Adjustment Charges: Base Cost of Fuel	Rule 7825.2810; Docket 04-1279	Part A, Attachment 1 and discussed in Petition	Report Narrative
Part E, Section 2	Annual Report of Automatic Adjustment Charges: Billing Adjustment Amounts Charged to Customers for Each Type of Energy Cost	Rule 7825.2810; Docket 04-1279	Discussed in Petition	Part A
Part E, Section 3	Annual Report of Automatic Adjustment Charges: Total Cost of Fuel Delivered to Customers	Rule 7825.2810; Docket 04-1279	Discussed in Petition	Part A
Part E, Section 4	Annual Report of Automatic Adjustment Charges: Revenue Collected from Customers for Energy Delivered	Rule 7825.2810; Docket 04-1279	Discussed in Petition	Part A
Part E, Section 5	Annual Report of Automatic Adjustment Charges: Monthly Fuel Clause Adjustment	Rule 7825.2810; Docket 04-1279	Part A, Attachment 1 and discussed in Petition	Part A, Attachment 4
Part F, Schedule 1	Memo Engaging Auditor	Rule 7825.2820	NA	Part E, Attachment 1
Part F, Schedule 2	Independent Auditor’s Report	Rule 7825.2820	NA	Part E, Attachment 2
Part G, Schedule 1	5-Year Fuel Cost Forecast – Per Unit Summary	Rule 7825.2830	Part A, Attachment 1 Part E, Attachment 1	NA
Part G, Schedule 2	5-Year Fuel Cost Forecast – Cost Summary	Rule 7825.2830	Part A, Attachment 2 Part E, Attachment 2	NA
Part G, Schedule 3	5-Year Fuel Cost Forecast – Energy Summary	Rule 7825.2830	Part A, Attachment 3 Part E, Attachment 3	NA
Part G, Schedule 4	Fossil Fuel Costs	Rule 7825.2830	Part B, Attachment 2	NA
Part G, Schedule 5	Coal Burn Expenses	Rule 7825.2830	Part B, Attachment 3	NA
Part G, Schedule 6	Nuclear Fuel Expenses	Rule 7825.2830	Part B, Attachment 4	NA
Part G, Schedule 7	Peak Demand and Energy Requirements	Rule 7825.2830	Part A, Attachment 4 Part E, Attachment 4	NA
Part G, Schedule 8	Estimated Load Management Impact	Rule 7825.2830	Part E, Attachment 5	NA

Former AAA	Description	Docket or Rule	April 30, 2021 Annual Forecast of Rates	March 1, 2023 Annual True-Up Filing
Part H, Section 3	Natural Gas Financial Instruments	Dockets M-01-1953 and AA-02-950	NA	Report Narrative Part E, Attachments 1 and 2
Part H, Section 5, Schedule 1	Wind Curtailment Summary	Dockets M-00-622, M-02-51, M-04-404, CN-01-1958, M-04-864, M-05-1850, M-05-1934 and M-06-85	NA	Part C, Attachment 2
Part H, Section 5, Schedule 2	Wind Curtailment Report Narrative	Docket AA-04-1279	Discussed in Petition Part G, Workpaper 10	Part C, Attachment 1
Part H, Section 6	KODA PPA	Docket M-08-1098	NA	Part F, Attachment 1
Part H, Section 7	WMRE PPA	Docket M-10-61	NA	Part F, Attachment 1
Part H, Section 8	Diamond K Dairy PPA	Docket M-486	NA	Part F, Attachment 1
Part H, Section 9 and Schedules H-9-1 and H-9-2	Community Solar Gardens	Docket M-13-867	Discussed in Petition Part B, Attachment 12 Part G, Workpapers 8 & 9	Part C, Attachments 8, 9, 10 Report Narrative
Part H, Section 10	FCA Rule Variance Dockets	Docket AA-15-611	Discussed in Petition Part C, Attachment 2	Part F, Attachment 4
Part H, Section 11	HERC	Docket M-17-532	NA	Part F, Attachment 1
Part J, Sections 1-3	Summary of key factors affecting costs in the forecast, and plan for acquiring fuel and purchased energy	Docket 04-1970, Docket 06-1208, Docket GR-05-1428	Discussed in Petition	NA
Part J, Section 5	Monthly MISO Day 2 charges and allocation	Docket AA-07-1130	Discussed in Petition Part B, Attachment 8 Part F, Workpaper 5	Part B
Part J, Section 6	Annual and Daily Ancillary Services Market charges and summary	Docket M-08-528	NA	Part B
Part K, Section 1	Generation facilities maintenance expenses	Docket AA-06-1208	NA	Part C, Attachment 6
Part K, Section 3	Contractor and supplier performance	Docket AA-08-995	NA	Part C, Attachment 3
Part K, Section 4 Schedule 1	Offsetting Revenues and/or compensation Received by IOUs	Docket AA-10-884	NA	Part F, Attachment 1
Part K, Section 4 Schedule 2	Handling of forced outages	Docket 08-995 and Docket AA-10-884	NA	Part C, Attachments 3, 4, 5
Part K, Section 4 Schedule 3	Unusual Adjustments over $500,000	Dockets AA-09-961 and AA-10-884	NA	Part F, Attachment 3
New Compliance	Self-Scheduling	Docket AA-17-492	NA	Provided in 3/1/23 Report in Docket No. E999/CI-19-704
Part M	Notice of Reports Availability	Rule 7825.2840	Addendum to Petition	Part F, Attachment 7
New Compliance	Renewable*Connect Neutrality	Docket M-15-985	Discussed in Petition Part G, Workpaper 14	Part F, Attachment 2

TRADE SECRET JUSTIFICATION:
Under Minnesota Stat. § 13.37, trade secret information is defined as including a compilation of government data that 1) was supplied by the affected individual or organization, 2) is subject of efforts by the individual or organization that are reasonable under the circumstances to maintain its secrecy, and 3) derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use.

The fuel supply, fuel cost, fuel cost forecast and wind curtailment information designated as Trade Secret in this True-Up and AAA Report meets this definition for the following reasons:

1. This information meets the first criterion as it is submitted by Xcel Energy, which is an affected organization.

2. The information meets the second criterion in the statute because Xcel Energy makes extensive efforts to maintain the secrecy of this information. The information is not available outside of the Company except to (i) the other parties involved in the contracts subject to the non-disclosure provisions contained in the contracts, and (ii) regulatory agencies under the confidentiality provisions of state or federal law. This is evidenced by the non-disclosure provisions in the contracts.

3. The information meets the third criterion in the statute because the information has economic value to Xcel Energy, its customers, suppliers, and competitors. First, if suppliers knew the terms of Xcel Energy's electric and fuel supply and transportation contracts, they may be able to use this knowledge to fashion bids to Xcel Energy. While their bids may be competitive with existing contracts, they could be at a price higher than the best price the supplier can offer or the current market price. Second, suppliers will be reluctant to offer special favorable terms to Xcel Energy if they know other competitors or customers will gain knowledge of the terms and demand similar terms in the future. Third, competitors of Xcel Energy also purchase these services. These competitors may be able to leverage knowledge of Xcel Energy's costs to gain similar terms or may negotiate slightly better prices from the supplier. Any of these results would harm Xcel Energy and its customers. Because Xcel Energy competes for purchased energy, fuel and transportation services in a competitive marketplace, disclosure would directly harm Xcel

Energy by making its delivered supply costs less competitive. The forecast of future fuel costs includes assumptions of future market prices for fuel not yet procured under contract. This information would give future potential suppliers knowledge of Xcel Energy's forecast of fuel prices that may not be the actual market price when procurement bids are requested. This knowledge may directly affect the prices submitted under bid or renegotiated during contract renewal.

Contract confidentiality clauses in existing fuel supply contracts require suppliers' authorization prior to the release of any information pertaining to contract terms and conditions. Suppliers limit the public disclosure of this information to maintain their competitive position in the marketplace. Fuel and transportation services are not purchased in an open, commoditized marketplace. Prices are the result of closed bidding or direct negotiations and are not publicly available.

Xcel Energy requests Trade Secret protection of this information to maintain the Company's competitive position in the marketplace. If our competitors knew our pricing information, they could use it to possibly extract advantageous terms from Xcel Energy or other suppliers, which would result in financial harm to Xcel Energy and its customers.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE 2022 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES

DOCKET NO. E002/AA-21-295

NOTICE OF REPORT AVAILABILITY
ANNUAL TRUE-UP REPORT

On March 1, 2023, Northern States Power Company, doing business as Xcel Energy, filed a report with the Minnesota Public Utilities Commission for the 12 months ending December 31, 2022 involving the following MPUC Rules:

7825.2800	Annual Reports; Policies & Actions
7825.2810	Annual Report; Automatic Adjustment Charges
7825.2820	Annual Auditor's Report
7825.2830	Annual Five-Year Projection

Also included in the report are the MISO Day 2 and ASM compliance reporting requirements and additional fuel clause related reporting requirements under various Commission Orders.

The aforementioned report is available for public inspection at the MPUC offices, 121 East 7th Place, Suite 350 St. Paul, MN 55101-2147, on the Minnesota Department of Commerce edockets website (https://www.edockets.state.mn.us/EFiling) and upon written request to the following:

Xcel Energy
Regulatory Administration
414 Nicollet Mall – 401 7th Floor
Minneapolis, MN 55401

CERTIFICATE OF SERVICE

I, Joshua DePauw, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

<u>xx</u> by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

<u>xx</u> electronic filing

Docket No. **E002/AA-21-295**
E002/GR-21-630
E002/GR-15-826

Dated this 1st day of March 2023

/s/
____
Joshua DePauw
Regulatory Administrator

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Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-295_AA-21-295
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