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Minneapolis, Minnesota 55401

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March 1, 2021

—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
2020 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES
DOCKET NO. E002/AA-19-293

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 2020 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
MANAGER, REGULATORY ANALYSIS

Enclosures
c: Service List

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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 2020 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES

DOCKET NO. E002/AA-19-293

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 2020 fuel forecast to 2020 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 2020 actual fuel expense was $746.3 million, or $49.8 million lower than our approved forecast of $796.1 million. The actual average fuel cost of $27.07 per MWh was 2.6% lower than the authorized rate of $27.81 per MWh. Notwithstanding these lower expenses, however, a comparison of actual fuel expenses of $746.3 million to actual recoveries of $741.3 million shows that, after the $25 million in pandemic relief provided to customers last summer, the Company under-collected expenses for the year by $5.0 million. When accounting for the authorized true-up refund for November and December 2019 actuals being under-refunded by $1.2 million in March and April 2020, our total under-recovery for the year is $3.8 million, or 0.5 percent of our 2020 fuel expense.

The significant drivers for differences between our 2020 forecast and actuals were:

1) a reduction in coal production due to a shift from must-commit status to economic dispatch and seasonal operations of coal units;
2) a corresponding increase in gas production;

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

3) lower gas and LMP prices than forecast;
4) less wind production than forecast due to the reduction in size of the Crowned Ridge project, lower production during wind repowering construction, delayed in-service dates of several new wind facilities, and lower wind output than forecast;
5) less community solar garden production than forecast; and
6) lower cost recovery due to lower sales, largely driven by the pandemic;
7) higher costs from the MISO market than forecast.

In this report, we provide details of the variance between forecast and actuals, discuss the prudency of our management of fuel costs in 2020, propose to implement true-up factors by class on September 1, 2021 to collect the $3.8 million of under-collected costs, and provide various additional compliance reports.

2020 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 2020 calendar year is the first forecasted year under the fuel reform mechanism, and so this is the first true-up report.

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 November 11, 2019 Order in Docket No. E002/AA-19-293 approved the Company's fuel forecast and resulting monthly rate factors by customer class for calendar year 2020. The Commission's May 22, 2020 Order in Docket No. E002/AA-20-182 approved November-December 2019 true-up factors by customer class which adjusted the approved rates for the months of March and April 2020. The Commission's June 9, 2020 Order in Docket Nos. E002/M-20-437 and E002/AA-19-293 approved a $25 million fuel clause adjustment reduction as a pandemic relief measure which reduced the rate factors by customer class for the months of June, July and August 2020.

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 1, 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.

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

II. 2020 FORECAST VERSUS ACTUALS COMPARISON

A. Summary

The Company's approved 2020 FCA forecast included $796.1 million in fuel costs, and an average rate of $27.81 per MWh. Actual costs for 2020 were $746.3 million, or 6.3 percent lower than forecast. The actual cost per MWh was $27.07 per MWh, or 2.6 percent lower than authorized. One of the primary drivers to the difference between our forecasted fuel costs and actual fuel costs was a major shift in how we dispatched coal units on our system; we changed from must-commit status on a majority of our coal units to a combination of economic and seasonal commitment. This change in coal dispatch, along with lower natural gas commodity prices, resulted in an increase in the use of natural gas on the system due to reduced operation of coal units. Another significant driver was less wind production than forecasted, largely driven by COVID-19 pandemic-related construction delays on several new wind projects, the reduction in size of the Crowned Ridge project that occurred after the forecast, lower production during construction of several repowering projects, and overall lower wind performance. Finally, solar production was lower than forecast.

Fuel revenue collections for 2020 were significantly less than forecasted as a result of significantly lower sales due to the pandemic. Additionally, the 2019 true-up of $13.6 million authorized to be refunded through FCA rates in March and April of 2020 was under-refunded by $1.2 million due to lower sales than forecasted. The result is that the Company's total fuel costs were under-collected by approximately $3.8 million during 2020. Table 1 below summarizes the 2020 forecast to actuals comparison.

Table 1: 2020 Fuel Cost and Revenue Comparison Summary
MN Jurisdiction

	Actual (000s)	Forecast (000s)	Variance (000s)	Variance (%)
Total FCA Costs	$746,292	$796,051	($49,759)	-6.3%
MWh Sales	27,564,206	28,627,389	(1,063,184)	-3.7%
FCA Cost in $/MWh	$27.07	$27.81	($0.74)	-2.6%
Fuel Collections – net of $25M relief	$741,262	$796,051	($54,789)	-6.9%
2019 True-up	($1,188)			
(Over) Under Recovery	$3,842			

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 2020 Fuel Costs and Prudency of True-Up Proposal

The Company successfully managed our system in line with our forecast in 2020, despite a worldwide pandemic and other unpredictable occurrences, as evidenced by a minimal under-collection of 0.5 percent of total fuel costs, after reducing rates mid-year to provide immediate pandemic relief for our customers. We were able to manage our generation fleet successfully, with outstanding nuclear plant performance evidenced by less nuclear forced outage costs. In addition, we made major changes to our coal dispatch to reduce environmental impacts and also reduce costs. Obviously the pandemic was a significant, unforeseen event, which was out of the Company's control and impacted not only sales but also the timely completion of both wind and solar projects expected to be operational in 2020. This resulted in less wind than forecast due to wind project construction changes and delays that also were out of the Company's control.

Although the Company's year-end results reveal under-collection of $3.8 million, in April 2020, the Company estimated a year-end fuel cost over-collection of $25 million, and implemented an authorized rate reduction in June, July, and August to provide immediate relief from economic impacts of the pandemic. At the time, we believed the Company still would end the year on target even with the early refund, but several factors impacted the results throughout the year. First, system congestion had been trending in-line with the forecast in April, and we had no indicators that it would increase dramatically, as it did in June through December. Second, Revenue Neutrality Uplift (RNU) charges related to Hurricane Laura in August could not have been anticipated in April. Third, we had not anticipated in April the full extent the pandemic would have on supply chain and construction timelines for wind projects. Most of the projects, including Blazing Star I, Blazing Star II, and Freeborn came on-line later than anticipated in April. Finally, in early April, we were assuming a return to more normal sales levels by the fourth quarter of 2020 under the assumption that the advance of the pandemic would slow. In reality, COVID-19 infection rates actually worsened after summer, and sales levels did not rebound as expected.

Despite the unexpected impacts of a global pandemic, the Company managed its 2020 fuel costs closely in line with the approved forecast. Because our under-recovery is driven by the factors listed above that are outside of the Company's control, and because the Company actually reduced fuel costs for 2020, we believe our proposal to recover the relatively small under-collected 2020 fuel costs is reasonable, and we request the Commission approve a true up for that amount.

C. Proposed True-Up Rate Factors

Given the relatively small size of the under-recovery, we propose to collect the $3.8 million in one month, September 2021, as outlined in the Commission's June 12 Order. The previously-approved monthly fuel cost charges would resume for the remaining months of the year beginning in October 2021. Table 2 below shows the specific rates we propose be implemented in the month of September 2021 by customer class.

Table 2: Proposed September True-Up Factors by Customer Class ($/kWh)

	Residential	Commercial & Industrial				Outdoor Lighting
		Non-Demand	Demand			
			Non-TOD	On-Peak	Off-Peak	
Proposed True-Up	$0.00177	$0.00179	$0.00174	$0.00217	$0.00142	$0.00139
Approved Rate	$0.02890	$0.02927	$0.02836	$0.03546	$0.02320	$0.02266
Total September Rates	$0.03067	$0.03106	$0.03010	$0.03763	$0.02462	$0.02405

To determine the proposed true-up factors by customer class, we compare the 2020 forecasted Minnesota cost to the actual cost, which includes the mid-year rate adjustment as well as the under-refund of the 2019 final true up. The resulting amount, divided by the forecasted Minnesota jurisdiction MWh sales subject to the Fuel Clause Adjustment, yields the true-up per unit cost. This per unit cost multiplied by the Fuel Adjustment Factor (FAF) ratio determines the proposed class true up factors. The proposed class true up factors will be added to the September 2021 fuel cost charge. The true-up factor details are shown in Part A, Attachment 3 and Part A, Attachment 5. We provide the proposed tariff sheet reflecting the total proposed September 2021 rates as Part A, Attachment 9.

We propose to update the Company web site with the true-up factors by August 1, 2021, 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.

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 fuel price input for hydro generation in the model because hydro generation does not require any fuel purchases.

Figure 1: Hydro Forecast to Actuals

	2020 ($000)			2020 GWh			2020 $/MWh		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
Hydro	0	0	0	1,245	905	340	$0.00	$0.00	$0.00

Company-owned hydro facilities experienced higher than normal water flows in 2020, which resulted in more hydro generation than forecast. More hydro generation than forecast reduced 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

	2020 ($000)			2020 GWh			2020 $/MWh		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
Owned Wind	0	0	0	5,001	5,683	(681)	$0.00	$0.00	$0.00

Actual 2020 Company-owned wind production was less than forecast primarily due to the reduction in size of the Crowned Ridge project in addition to pandemic-related supply chain and construction delays for wind projects forecasted to have been placed in-service in 2020: Blazing Star I, Blazing Star II, and Freeborn.[3] Construction delay caused 75% of the variance between the forecasted and actual wind production in 2020. The remainder of the variance was caused by below average wind output over the course of the year. There is no fuel price input for wind generation in the forecast model because wind generation does not require any fuel purchases. Less actual wind generation than forecast increased generation from other fuel types.

[3] These delays are more fully discussed in the Company's October 9, 2020 update letter in Docket No. E002/M-16-777 and October 19, 2020 Reply Comments in Docket No. E002/M-19-732.

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

	2020 ($000)			2020 GWh			2020 $/MWh		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Coal	$182,474	$262,686	($80,212)	8,527	12,160	(3,633)	$21.40	$21.60	-$0.20

The 2020 forecast modeled all coal units as must-commit year-round. However, the Company offered both the King plant and Sherco 1 into the market on an economic basis relatively early in the year. In addition, we implemented our seasonal dispatch plan at the King and Sherco 2 units in fall 2020.[4] As a result, the coal units ran significantly less than forecasted, and actual Company-owned coal generation cost was less than forecast. See Part C, Attachment 3 for a more detailed discussion of plant operations and maintenance. See Part C, Attachments 4 and 5 which provide details on actual outages in 2020, including a comparison of forecast to actual outage costs by unit.

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.

[4] The Commission reviewed this Unit Commitment Plan in Docket No. E002/M-19-809. We provide additional details about the results of operating our plants under this Plan in our March 1, 2021 annual report filed in that docket.

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

	2020 ($000)			2020 GWh			2020 $/MWh		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
Wood/ RDF	9,013	11,912	(2,899)	554	453	100	$16.28	$26.27	-$9.99

Actual 2020 Company-owned wood/RDF cost was less than forecast due to lower realized wood prices at Bayfront.

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 forecasted natural gas rates. For peaking plants, the model uses the MISO calculation of each unit's Equivalent Forced Outage Rate – Demand (eFORd) based on three-years of history. We discuss detailed 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. 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 forecast filing.

Figure 5: Company-Owned Natural Gas Forecast to Actuals

	2020 ($000)			2020 GWh			2020 $/MWh		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
Owned Gas (CC)	120,536	86,497	34,040	6,121	2,687	3,434	$19.69	$32.19	-$12.50
Owned Gas (CT)	18,924	16,546	2,378	715	321	394	$26.45	$51.53	-$25.07

Actual 2020 Company-owned natural gas generation was higher than forecast due to a combination of the seasonal and economic dispatch of the Company's owned coal units and lower actual gas prices than forecasted. Mild weather and high storage inventory levels contributed to gas prices remaining low in 2020. The injection season ending October ended 5% higher than 2019 and the five-year average. Also, consumption was down in 2020 as a result of the COVID-19 pandemic. Given the low natural gas prices, gas generation was used as a replacement for the reduced coal generation. The higher use of gas than forecasted, was off-set by lower gas commodity prices. The fixed gas demand costs were spread over greater volumes, which lowered the average $/MWh, as seen in Figure 5.

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

	2020 ($000)			2020 GWh			2020 $/MWh		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Nuclear	119,986	116,954	3,032	14,677	14,071	606	$8.17	$8.31	-$0.14

Actual Company-owned nuclear generation experienced better-than-forecast performance in 2020 due to a lower than forecast outage rate. Recent investments made in our nuclear plants have paid off over the past several years, and that success continued into 2020. As of March 1, 2021 Monticello continues to operate at 657 continuous days online, Prairie Island Unit 1 at 139 days following a fall 2020 refueling outage, and unit 2 at 490 days. Over the past several years, plants have experienced improved performance during plant refueling outages, which were completed on time and on budget. In short, our nuclear fleet has never performed better.

Part C, Attachments 4 and 5 provide details on actual outages in 2020, 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 forecasted purchased natural gas rates.

Figure 7: Purchased Natural Gas Forecast to Actuals

	2020 ($000)			2020 GWh			2020 $/MWh		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
Gas PPAs	79,565	54,866	24,699	3,716	1,995	1,721	$21.41	$27.50	-$6.09

Actual 2020 purchased natural gas generation was higher than forecast due to a combination of the seasonal and economic dispatch of the Company's owned coal units and lower actual gas prices than forecasted. Mild weather and high storage inventory levels contributed to gas prices remaining low in 2020. The injection season ending October ended 5% higher than 2019 and the five-year average. Also, consumption was down in 2020 as a result of the COVID-19 pandemic. Given the low natural gas prices, gas generation was used as a replacement for the reduced coal generation. The higher use of gas than forecasted, however, was off-set by the lower gas commodity prices. The fixed gas costs were spread over greater volumes, which lowered the average $/MWh, as seen in Figure 7.

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

	2020 ($000)			2020 GWh			2020 $/MWh		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
Solar PPAs	41,490	46,819	(5,329)	589	671	(82)	$70.41	$69.77	$0.64

Actual 2020 purchased solar production volumes were lower than forecast for the Aurora, North Star and Marshall facilities. See Part C, Attachment 7 for actual solar PPA production and cost by month and by contract.

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 for 2018 escalated to 2020, incorporating the Value of Solar (VOS) Rate for projects with 2017 and 2018 VOS vintages forecasted to be in-service in 2020.

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

	2020 ($000)			2020 GWh			2020 $/MWh		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
CSG Market	151,466	175,824	(24,358)	1,200	1,351	(152)	$126.27	$130.13	-$3.86
CSG Above Market	130,420	143,527	(13,107)						
Total CSG	281,886	319,351	(37,465)						

The 2020 actual CSG production and cost were lower than forecasted. The CSG forecast is based on assumptions of when community solar projects are completed (or receive permission to operate) and assumptions of how many under which rate vintages will operational during the forecast year. Completion dates can be impacted by weather, construction, and scheduling. In the case of 2020, operation dates were impacted by the pandemic as well. All of these factors have an impact on the actual production and bill credits.

See Part C, Attachments 8-10 for more details about actual CGS 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

	2020 ($000)			2020 GWh			2020 $/MWh		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
Wind PPAs	201,803	222,159	(20,356)	5,539	6,816	(1,277)	$36.43	$32.59	$3.84

Actual purchased wind generation was less than forecast due to several factors. First, the reduction of the size of the Crowned Ridge PPA project from 300 to 200 MW accounts for 41 percent of the variance.[5] Second, the Community Wind North, Jeffers, and Mower facilities had reduced production during construction for repowering of the facilities as compared to the forecast. Reduced generation at these facilities accounts for 40 percent of the variance. The remainder of the variance was primarily caused by below average wind output over the course of the year, as discussed above in relation to Company-owned wind. We note that actual curtailment costs in 2020 were significantly higher than forecast. We provide greater detail on wind curtailment results in Part C, Attachments 1 and 2, and later in this report.

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

	2020 ($000)			2020 GWh			2020 $/MWh		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
Other PPAs	136,985	142,057	(5,073)	1,780	1,879	(98)	$76.95	$75.62	$1.33

Actual 2020 other purchased generation costs were lower than forecast due to lower volumes and prices for the HERC facility,[6] lower volumes for the Manitoba Hydro facility, and lower prices at the St. Paul Cogeneration facility.

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[5] See the Company's August 30, 2019 letter in Docket No E002/M-16-777 for more information about the reduction in size of the Crowned Ridge PPA project.

[6] The HERC facility was offline for more than a month. See Part C, Attachment 7 and Part F, Attachment 1 for the detailed monthly production and costs of the facility in accordance with our commitment to provide such details in Docket No. E002/M-17-532.

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. The simulation can make this decision hourly within the constraints of the modeled system. In addition, the model forecasts monthly intersystem sales opportunities of excess generation after system native requirements are fulfilled. This is done through an hourly dispatch simulation based on projected hourly market prices designed to represent LMP for the NSP system. The sum of these quantities represent the equivalent MISO Day 2 and Day 3 costs for the Forecast.

Figure 12: Market Purchases and Sales Forecast to Actuals

	2020 ($000)			**2020 GWh**		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Net MISO	($91,379)	($101,316)	$9,937	(8,979)	(5,283)	(3,696)

Actual 2020 net market purchases and sales were higher than forecast due to high revenue neutrality uplift (RNU) charges resulting from Hurricane Laura and high congestion costs from June through December. The likely contributors to the increase in congestion were: 1) new wind additions on our system and elsewhere in MISO west; 2) transmission work on our system to improve deliverability of wind to our load; 3) transmission work on other utility systems that impact our wind generators. Wind additions and transmission work for other utility systems is particularly hard to account for as we have no knowledge of this work in advance and very little knowledge of it after the fact.

In addition, Locational Marginal Prices (LMPs) were lower in 2020 than in 2019. MINN.HUB is a weighted average of price nodes in the northwest region of the MISO market, inclusive of the entire NSP service territory. On average, LMPs at MINN.HUB for the day-ahead market were 22.6% lower in 2020 than in 2019. LMPs have a direct impact on the cost to purchase power to serve NSP load in the MISO market and lower LMPs result in lower market expenses to serve NSP load. However, lower LMPs also reduce the revenue NSP receives from short-term market sales, which also impacts final costs to our customers.

Table 3 below compares the 2020 forecast to actuals by primary MISO charge type.

Table 3: MISO Charge Type Forecast to Actuals ($000s)

Category	Actual	Forecast	Variance
Congestion	63,309	34,171	29,138
FTR	(36,690)	(31,988)	(4,702)
Incremental Transmission losses	(10,111)	(6,087)	(4,024)
RSG/RNU	11,829	4,071	7,758
ASM	(1,359)	(1,568)	209
MISO Charges TOTAL	26,978	(1,400)	28,378

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.

xiii. Retail Sales

Actual Minnesota retail sales in 2020, net of Windsource and Renewable*Connect sales, were 28,141,222 MWh, compared with the 2020 sales forecast of 29,109,898 MWh developed in February 2019 and used in the creation of the 2020 fuel forecast. This results in an actual-to-forecast variance of -968,676 MWh. As summarized in Table 4 below, contributing factors to the forecast variance include achievement of more DSM savings than forecasted, unforeseen loss of electricity sales due to large commercial and industrial customer relocations/ shutdowns of operations, and COVID-19 pandemic impacts from reduced economic and business activity. These factors were in part offset by the positive effects of weather on actual 2020 sales, less Combined Heat and Power (CHP) plant generation than forecasted, and other additional factors. In summary, the COVID pandemic impact on sales, which is estimated to be a reduction of 981,588 MWh, was the largest contributor to the forecast variance in 2020.

Table 4: Sales-to-Forecast Variance in 2020 (MWh)

	2020 Minnesota Juris.
Feb 2019 Cal Mth Sales Forecast	29,109,898
Actual 2020 Cal Mth Sales	28,141,222
Actual Sales Variance from Forecast	(968,676)
Contribution to Forecast Variance:	
DSM Forecast Variance	(223,395)
	[PROTECTED DATA BEGINS
C&I Relocations/Shutdowns	
	PROTECTED DATA ENDS]
2020 Weather Impact	153,077
COVID Pandemic Impact	(981,588)
	[PROTECTED DATA BEGINS
CHP Forecast Variance	
	PROTECTED DATA ENDS]
Solar Forecast Variance	(2,469)
Other Factors	150,362
Total	(968,676)

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 2020, 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.[7] The 2019 annual FCA recovery of $525,932 is shown in Part A, Attachment 2, line 112, the month the excluded customers were issued their bill credit.[8] The amount is also

[7] The Fuel Clause Adjustment (FCA), Renewable Development Fund (RDF) and the Conservation Improvement Program (CIP) Riders.

[8] The Company provided this amount in the June 1, 2020 SES Annual Report filed in Docket No. E999/M-20-464.

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.

iii. Saver's Switch Discount Recovery

The Saver's Switch discount is applied during the months of June through September, and therefore our 2020 true-up shows these amounts for those months in our detailed monthly actuals report shown in Part A, Attachment 2, line 113. 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. Asset Based Margins

Table 5 below provides a comparison of the forecasted asset-based margins to the actual asset-based margins for 2020.

Table 5: Actual 2020 Asset-Based Margins
($ millions)

	Revenue	Cost	Margin
Forecast	119.3	72.2	47.1
Actuals	200.2	148.6	51.6
Variance	(80.9)	(76.4)	(4.5)

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 2020 and 2021 test year rate case applications a demonstration that the proposed base rates exclude Fuel Clause-Adjustment-related costs, though both of the rate case petitions have been, or are in the process of being, withdrawn.[9]

[9] Docket Nos. E002/GR-19-564 and E002/GR-20-723

2. *Monthly Fuel Cost Charges*

See Part A, Attachment 8 for the monthly fuel cost charges implemented in 2020.

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, 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 2021-2025 was provided as part of the Company's May 1, 2020 fuel forecast for calendar year 2021. The monthly five-year projection of fuel cost by energy source for the period of 2022-2026 will be provided as part of the Company's May 1, 2021 fuel forecast for calendar year 2022.

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 2013 and 2015 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 2020 Annual True-Up Report, our proposal to recover $3.8 million in under-recovered fuel costs for the 2020 calendar year, and the Electric AAA reporting requirements included in this report.

Dated: March 1, 2021

Northern States Power Company

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Part D: Policies and Actions – MN Rule 7825.2800

Part E: Annual Auditor's Report – MN Rule 7825.2820

Part F: Miscellaneous Compliance Reports

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

	2020 ($000)
MN Jurisdiction Fuel Collections (includes $25M refund for Jun-Aug 2020)	$741,262
MN Jurisdiction Fuel Costs	$746,292
(Over)/Under Recovey	**$5,030**

		2020 ($000)				2020 GWh			2020 $/MWh		
		Actual	Forecast (1)	Variance		Actual	Forecast (1)	Variance	Actual	Forecast (1)	Variance
1	Coal	$182,474	$262,686	($80,212)		8,527	12,160	(3,633)	$21.40	$21.60	-$0.20
2	Wood/RDF	9,013	11,912	(2,899)		554	453	100	$16.28	$26.27	-$9.99
3	Natural Gas CC	120,536	86,497	34,040		6,121	2,687	3,434	$19.69	$32.19	-$12.50
4	Natural Gas & Oil CT	18,924	16,546	2,378		715	321	394	$26.45	$51.53	-$25.07
5	Nuclear Fuel	119,986	116,954	3,032		14,677	14,071	606	$8.17	$8.31	-$0.14
6	Total Fuel	$450,934	$494,594	($43,660)		30,595	29,693	902	$14.74	$16.66	-$1.92
7	Hydro	0	0	0		1,245	905	340	$0.00	$0.00	$0.00
8	Wind	0	0	0		5,001	5,683	(681)	$0.00	$0.00	$0.00
9	LT Purchased Energy (Gas)	79,565	54,866	24,699		3,716	1,995	1,721	$21.41	$27.50	-$6.09
10	LT Purchased Energy (Solar)	41,490	46,819	(5,329)		589	671	(82)	$70.41	$69.77	$0.64
11	Community Solar*Gardens	151,466	175,824	(24,358)		1,200	1,351	(152)	$126.27	$130.13	-$3.86
12	LT Purchased Energy (Wind)	201,803	222,159	(20,356)		5,539	6,816	(1,277)	$36.43	$32.59	$3.84
13	LT Purchased Energy (Other)	136,985	142,057	(5,073)		1,780	1,879	(98)	$76.95	$75.62	$1.33
14	Total Purchased Power	$611,309	$641,725	($30,416)		12,824	12,712	112	$47.67	$50.48	-$2.81
15	Net MISO Day 2 and Day 3	($91,379)	($101,316)	$9,937		(8,979)	(5,283)	(3,696)			
16	Less Costs Direct Assigned (2)	(146,207)	(157,527)	11,320		(577)	(483)	(95)			
17	**Net System Costs**	**$824,657**	**$877,476**	**($52,819)**		**40,109**	**43,226**	**(3,118)**	**$20.56**	**$20.30**	**$0.26**
18	**Net System Mwh Sales**	**38,456,373**	**39,986,817**	**(1,530,444)**							
19	**System Cost in $/Mwh**	**$21.44**	**$21.94**	**($0.50)**							
20	MN Jurisdictional Fuel Cost	$591,397	$628,440	($37,043)							
	Direct Assigned Costs:										
21	Solar Gardens - Above Market Cost	130,420	143,527	(13,107)							
22	Biomass Termination Costs	23,699	24,084	(385)							
23	Other Adjustments (3)	777		777							
24	**Total MN Jurisdiction FCA Costs**	**$746,292**	**$796,051**	**($49,759)**	**-6.3%**						
25	**MN Jursdiction Mwh Sales**	**27,564,206**	**28,627,389**	**(1,063,184)**	**-3.7%**						
26	**MN Jurisdiction FCA Cost in $/MWh**	**$27.07**	**$27.81**	**($0.74)**	**-2.6%**						

(1) As filed with the MPUC in July 2019
(2) Community Solar Garden, Windsource, Renewable Connect
(3) Solar Energy Standard Exemption, Saver's Switch, Other

26.89 average rate charged customers
27.07 average rate fuel costs

Northern States Power Company (Minnesota)
Electric Utility - State of Minnesota
2020 Fuel, Purchased Power and Other Costs

	($000)	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	2020 Total
	Own Generation													
	Fossil Fuel													
1	Coal	$14,991	$10,732	$10,173	$5,920	$5,471	$13,208	$26,842	$27,199	$16,488	$15,215	$16,258	$19,978	$182,474
2	Wood/RDF	$774	$647	$521	$666	$933	$668	$1,174	$847	$403	$837	$801	$742	$9,013
3	Natural Gas CC	$15,151	$10,395	$8,014	$7,387	$8,819	$11,049	$12,383	$10,526	$6,936	$9,951	$7,020	$12,905	$120,536
4	Natural Gas & Oil CT	$576	$440	$1,300	$1,137	$1,344	$3,153	$5,406	$2,292	$679	$1,973	$349	$277	$18,924
5	Subtotal	$31,491	$22,213	$20,008	$15,110	$16,567	$28,078	$45,804	$40,864	$24,506	$27,974	$24,429	$33,902	$330,948
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	$10,814	$10,116	$10,738	$10,491	$10,611	$10,201	$10,267	$9,809	$8,210	$8,718	$9,835	$10,176	$119,986
9	Total Fuel 5+6+7+8	$42,305	$32,329	$30,746	$25,601	$27,179	$38,279	$56,072	$50,673	$32,717	$36,693	$34,263	$44,078	$450,934
	Purchased Energy													
10	LT Purchased Energy (Gas)	$7,396	$6,640	$6,562	$6,051	$2,131	$6,802	$9,760	$6,659	$4,080	$7,157	$7,654	$8,673	$79,565
11	LT Purchased Energy (Solar)	$1,012	$2,650	$3,360	$4,625	$4,884	$5,577	$5,687	$4,751	$3,553	$2,413	$1,751	$1,226	$41,490
12	Community Solar*Gardens	$4,149	$9,447	$10,452	$13,164	$14,545	$18,463	$19,400	$17,363	$12,607	$11,923	$12,946	$7,007	$151,466
13	LT Purchased Energy (Wind)	$13,793	$19,878	$22,265	$16,269	$16,103	$17,079	$10,483	$13,053	$16,603	$17,097	$20,386	$18,793	$201,803
14	LT Purchased Energy (Other)	$9,958	$9,242	$9,977	$6,182	$12,679	$14,527	$14,549	$14,449	$14,182	$11,330	$9,543	$10,366	$136,985
15	ST Market Purchases	$7,712	$4,988	$5,165	$2,424	$6,468	$11,331	$10,630	$9,580	$13,287	$9,703	$13,153	$14,351	$108,791
16	Total Purchased Energy 10+11+12+13+14+15	$44,020	$52,845	$57,781	$48,716	$56,812	$73,780	$70,509	$65,854	$64,311	$59,623	$65,433	$60,416	$720,100
17	**Total System Cost 9+16**	$86,325	$85,174	$88,527	$74,317	$83,990	$112,059	$126,580	$116,527	$97,028	$96,316	$99,696	$104,494	$1,171,034
18	Less Sales Revenue	($18,288)	($12,421)	($14,567)	($13,044)	($11,501)	($11,853)	($23,235)	($21,777)	($10,809)	($17,837)	($17,769)	($27,069)	($200,170)
19	Less Solar Gardens - Above Market Cost	($3,566)	($8,034)	($8,990)	($11,418)	($12,650)	($16,104)	($15,897)	($14,379)	($11,080)	($10,521)	($11,867)	($6,088)	($130,594)
20	Less WindSource	($445)	($995)	($684)	($638)	($781)	($718)	($873)	($853)	($782)	($953)	($846)	($907)	($9,474)
21	Less Renewable Connect	($508)	($505)	($508)	($475)	($446)	($493)	($567)	($552)	($539)	($493)	($526)	($526)	($6,139)
22	**Net System Costs 17+18+19+20+21**	$63,517	$63,219	$63,779	$48,742	$58,613	$82,890	$86,009	$78,966	$73,819	$66,512	$68,687	$69,905	$824,656.727
	Calendar Month MWh Sales													
23	Total NSP-MN and NSP-WI Retail Sales	3,456,860	3,109,819	3,175,079	2,657,435	2,815,976	3,436,467	4,057,948	3,825,698	3,023,878	3,097,099	3,036,833	3,340,298	39,033,390
24	Less Minnesota WindSource	(34,282)	(30,748)	(32,300)	(29,598)	(27,111)	(31,273)	(36,882)	(38,343)	(35,556)	(32,614)	(28,745)	(37,022)	(394,474)
25	Less Minnesota Renewable*Connect	(15,325)	(14,157)	(16,050)	(14,249)	(13,396)	(14,729)	(17,351)	(16,217)	(15,859)	(14,443)	(15,394)	(15,371)	(182,541)
26	**Total System MWh Sales 23+24+25**	3,407,253	3,064,914	3,126,729	2,613,588	2,775,469	3,390,465	4,003,715	3,771,138	2,972,463	3,050,042	2,992,694	3,287,905	38,456,375
27	Minnesota Jurisdictional Retail Sales	2,457,803	2,216,988	2,265,445	1,901,244	2,036,360	2,508,440	2,979,971	2,789,581	2,197,143	2,231,177	2,179,251	2,377,818	28,141,221
28	Less Minnesota WindSource	(34,282)	(30,748)	(32,300)	(29,598)	(27,111)	(31,273)	(36,882)	(38,343)	(35,556)	(32,614)	(28,745)	(37,022)	(394,474)
29	Less Minnesota Renewable*Connect	(15,325)	(14,157)	(16,050)	(14,249)	(13,396)	(14,729)	(17,351)	(16,217)	(15,859)	(14,443)	(15,394)	(15,371)	(182,541)
30	**Total Minnesota Retail Sales 27+28+29**	2,408,196	2,172,083	2,217,095	1,857,397	1,995,853	2,462,438	2,925,738	2,735,021	2,145,728	2,184,120	2,135,112	2,325,425	27,564,206
31	**System Fuel Costs in cents/kWh 22/26x100**	1.864¢	2.063¢	2.040¢	1.865¢	2.112¢	2.445¢	2.148¢	2.094¢	2.483¢	2.181¢	2.295¢	2.126¢	2.144¢
	Minnesota Jurisdictional Energy Costs													
32	Minnesota Costs Subject to FCA 30x31x10	$44,889	$44,810	$45,229	$34,640	$42,152	$60,207	$62,845	$57,271	$53,278	$47,636	$49,001	$49,439	$591,397
33	Solar Garden Above Market Direct Recovery	$3,564	$8,021	$8,970	$11,399	$12,628	$16,077	$15,878	$14,360	$11,069	$10,515	$11,855	$6,085	$130,420
34	Laurentian Payment	$0	$0	$0	$0	$0	$13,134	$0	$0	$0	$0	$0	$0	$13,134
35	Pine Bend Payment	$46	$50	$16	$0	$0	$0	$0	$0	$0	$0	$0	$0	$113
36	Benson Buyout costs	$893	$893	$886	$883	$815	$878	$875	$872	$869	$866	$863	$861	$10,452
37	SES Exemption Recovery	$0	$0	$526	$0	$0	$0	$0	$0	$0	$0	$0	$0	$526
38	Saver's Switch Discount Adjustment	$0	$0	$0	$0	$0	$198	($6)	($43)	$74	$0	$0	$0	$223
39	Other	$1	$7	($6)	($5)	$9	$2	$12	$3	($7)	($1)	$8	$7	$28
40	**Minnesota Fuel Costs 32+33+34+35+36+37+38+39**	$49,392	$53,781	$55,621	$46,918	$55,604	$90,495	$79,603	$72,463	$65,283	$59,015	$61,726	$56,392	$746,292
41	**Minnesota Fuel Costs in cents/kWh 30/40x100**	$2.051	$2.476	$2.509	$2.526	$2.786	$3.675	$2.721	$2.649	$3.042	$2.702	$2.891	$2.425	$0.271
42	**Minnesota Fuel Costs in $/MWh 41x10**	$20.51	$24.76	$25.09	$25.26	$27.86	$36.75	$27.21	$26.49	$30.42	$27.02	$28.91	$24.25	$27.07

Northern States Power Company (Minnesota)
Electric Utility - State of Minnesota

2021 Monthly Fuel Clause Charges with Proposed 2020 True-up ($/KWh)

	Residential	Commercial & Industrial				Outdoor Lighting
		Non-Demand	Demand			
			Non-TOD	On-Peak	Off-Peak	
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	$0.02890	$0.02927	$0.02836	$0.03546	$0.02320	$0.02266
Proposed 2020 True-up	$0.00177	$0.00179	$0.00174	$0.00217	$0.00142	$0.00139
September w/ True-up	$0.03067	$0.03106	$0.03010	$0.03763	$0.02462	$0.02405
October	$0.02743	$0.02777	$0.02691	$0.03364	$0.02201	$0.02150
November	$0.02474	$0.02505	$0.02427	$0.03035	$0.01985	$0.01938
December	$0.02310	$0.02339	$0.02266	$0.02834	$0.01854	$0.01811

Northern States Power Company (Minnesota)
Electric Utility - State of Minnesota
2020 Under (+)/Over(-) Recovered Expense

	($000)	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	2020 Total
	FCA Factors Excluding 2019 True Up													
	From Docket No. E002/AA-19-293, April 23, 2020 Rate Adjustment Filing (Att A page 2). Approved in June 9, 2020 Order													
1	Residential	2.472¢	2.685¢	2.801¢	2.919¢	3.080¢	3.134¢	2.717¢	2.657¢	2.879¢	2.782¢	2.519¢	2.335¢	
2	C&I Non-Demand	2.503¢	2.719¢	2.836¢	2.956¢	3.119¢	3.173¢	2.752¢	2.691¢	2.915¢	2.817¢	2.550¢	2.364¢	
3	C&I Demand Non-TOD	2.426¢	2.634¢	2.748¢	2.864¢	3.022¢	3.074¢	2.666¢	2.607¢	2.824¢	2.729¢	2.471¢	2.291¢	
4	C&I Demand On-Peak	3.031¢	3.293¢	3.436¢	3.579¢	3.778¢	3.845¢	3.334¢	3.260¢	3.531¢	3.412¢	3.090¢	2.864¢	
5	C&I Demand Off-Peak	1.986¢	2.155¢	2.248¢	2.344¢	2.473¢	2.515¢	2.180¢	2.132¢	2.310¢	2.233¢	2.021¢	1.874¢	
6	Outdoor Lighting	1.940¢	2.105¢	2.196¢	2.290¢	2.416¢	2.456¢	2.130¢	2.083¢	2.257¢	2.181¢	1.974¢	1.831¢	
	Minnesota Calendar Month Retail Sales													
	Minnesota Retail Sales:													
7	Residential	780,072	660,714	648,795	595,560	626,606	877,170	1,114,150	969,175	642,143	654,234	659,721	799,130	9,027,470
8	C&I Non-Demand	79,787	73,190	71,683	54,662	56,515	65,522	76,098	72,257	57,917	60,209	62,199	69,168	799,207
9	C&I Demand Non-TOD	757,792	697,897	714,898	552,681	600,499	723,920	830,925	810,565	648,811	692,763	660,412	691,460	8,382,623
10	C&I Demand On-Peak	299,764	300,805	317,507	261,552	281,769	309,998	363,871	359,400	317,941	313,070	302,421	297,307	3,725,405
11	C&I Demand Off-Peak	525,051	473,274	501,636	427,583	463,814	523,696	587,014	570,953	519,093	501,630	481,006	507,393	6,082,143
12	Outdoor Lighting	15,338	11,108	10,926	9,205	7,157	8,134	7,913	7,231	11,238	9,271	13,492	13,360	124,373
13	Total 7+8+9+10+11+12	2,457,804	2,216,988	2,265,445	1,901,243	2,036,360	2,508,440	2,979,971	2,789,581	2,197,143	2,231,177	2,179,251	2,377,818	28,141,221
	Less WindSource & Renewable*Connect													
14	Residential	18,353	14,878	16,588	15,778	14,093	17,991	22,571	20,148	18,664	16,337	15,220	18,842	209,463
15	C&I Non-Demand	297	253	261	199	162	615	262	242	233	209	221	244	3,198
16	C&I Demand Non-TOD	19,156	5,654	5,749	4,772	4,342	5,277	18,373	6,328	20,431	6,988	6,183	6,004	109,257
17	C&I Demand On-Peak	4,774	9,809	10,480	9,400	8,916	9,010	5,299	11,348	4,913	9,578	9,164	11,116	103,807
18	C&I Demand Off-Peak	6,919	14,216	15,188	13,622	12,922	13,057	7,679	16,444	7,118	13,880	13,279	16,109	150,433
19	Outdoor Lighting	109	95	84	75	72	52	49	50	56	65	72	78	857
20	Total 14+15+16+17+18+19	49,608	44,905	48,350	43,846	40,507	46,002	54,233	54,560	51,415	47,057	44,139	52,393	577,015
	Minnesota FCA Calendar Month Sales:													
21	Residential 7-14	761,719	645,836	632,207	579,782	612,513	859,179	1,091,579	949,027	623,479	637,897	644,501	780,288	8,818,007
22	C&I Non-Demand 8-15	79,490	72,937	71,422	54,463	56,353	64,907	75,836	72,015	57,684	60,000	61,978	68,924	796,009
23	C&I Demand Non-TOD 9-16	738,636	692,243	709,149	547,909	596,157	718,643	812,552	804,237	628,380	685,775	654,229	685,456	8,273,366
24	C&I Demand On-Peak 10-17	294,990	290,996	307,027	252,152	272,853	300,988	358,572	348,052	313,028	303,492	293,257	286,191	3,621,598
25	C&I Demand Off-Peak 11-18	518,132	459,058	486,448	413,961	450,892	510,639	579,335	554,509	511,975	487,750	467,727	491,284	5,931,710
26	Outdoor Lighting 12-19	15,229	11,013	10,842	9,130	7,085	8,082	7,864	7,181	11,182	9,206	13,420	13,282	123,516
27	Total 20+21+22+23+24+25	2,408,196	2,172,083	2,217,095	1,857,397	1,995,853	2,462,438	2,925,738	2,735,021	2,145,728	2,184,120	2,135,112	2,325,425	27,564,206
	Recovery Based on Forecast Factors													
28	Residential 1x21/100	$18,830	$17,341	$17,708	$16,924	$18,865	$26,927	$29,658	$25,216	$17,950	$17,746	$16,235	$18,220	$241,619
29	C&I Non-Demand 2x22/100	$1,990	$1,983	$2,026	$1,610	$1,758	$2,059	$2,087	$1,938	$1,681	$1,690	$1,580	$1,629	$22,032
30	C&I Demand Non-TOD 3x23/100	$17,919	$18,234	$19,487	$15,692	$18,016	$22,091	$21,663	$20,966	$17,745	$18,715	$16,166	$15,704	$222,399
31	C&I Demand On-Peak 4x24/100	$8,941	$9,582	$10,549	$9,025	$10,308	$11,573	$11,955	$11,346	$11,053	$10,355	$9,062	$8,197	$121,947
32	C&I Demand Off-Peak 5x25/100	$10,290	$9,893	$10,935	$9,703	$11,151	$12,843	$12,630	$11,822	$11,827	$10,891	$9,453	$9,207	$130,644
33	Outdoor Lighting 6x26/100	$295	$232	$238	$209	$171	$198	$168	$150	$252	$201	$265	$243	$2,622
34	MN Fuel Recoveries excluding TU 28+29+30+31+32+33	$58,265	$57,265	$60,944	$53,163	$60,269	$75,691	$78,160	$71,438	$60,509	$59,599	$52,761	$53,199	$741,262
	2020 Under (+)/Over(-) Recovered Expense													
35	Minnesota Actual Fuel Costs (Pt A Att 2) Line 40	$49,392	$53,781	$55,621	$46,918	$55,604	$90,495	$79,603	$72,463	$65,283	$59,015	$61,726	$56,392	$746,292
36	Minnesota Actual Recovery 34	$58,265	$57,265	$60,944	$53,163	$60,269	$75,691	$78,160	$71,438	$60,509	$59,599	$52,761	$53,199	$741,262
37	**2020 Total Under (+)/Over(-) Recovered Exp**	($8,873)	($3,484)	($5,323)	($6,245)	($4,665)	$14,804	$1,443	$1,025	$4,774	($584)	$8,965	$3,192	$5,030

Northern States Power Company (Minnesota)
Electric Utility - State of Minnesota
2019 True-up and 2020 Proposed True-up Factors

	($000)	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	2020 Total
1	2019 Under (+)/Over(-) Recovery			($6,414)	($7,197)									**($13,611)**
	From Docket No. E002/AA-20-182, January 31, 2020 True-up Filing, page 3													
	Refund Factors ($/kWh)													
	From Docket No. E002/AA-20-182, January 31, 2020 True-up Filing, page 4. Approved in May 22, 2020 Order													
2	Residential			-2.930¢	-3.320¢									
3	C&I Non-Demand			-2.970¢	-3.360¢									
4	C&I Demand Non-TOD			-2.870¢	-3.260¢									
5	C&I Demand On-Peak			-3.600¢	-4.070¢									
6	C&I Demand Off-Peak			-2.350¢	-2.670¢									
7	Outdoor Lighting			-2.300¢	-2.600¢									
	Minnesota FCA Calendar Month Sales													
8	Residential			632,207	579,782									1,211,989
9	C&I Non-Demand			71,422	54,463									125,885
10	C&I Demand Non-TOD			709,149	547,909									1,257,058
11	C&I Demand On-Peak			307,027	252,152									559,179
12	C&I Demand Off-Peak			486,448	413,961									900,409
13	Outdoor Lighting			10,842	9,130									19,972
14	Total 45+46+47+48+49+50			2,217,095	1,857,397									**4,074,492**
	Actual Refunded Amount													
15	Residential 2x8/1000			($1,852)	($1,925)									($3,777)
16	C&I Non-Demand 3x9/1000			($212)	($183)									($395)
17	C&I Demand Non-TOD 4x10/1000			($2,035)	($1,786)									($3,821)
18	C&I Demand On-Peak 5x11/1000			($1,105)	($1,026)									($2,132)
19	C&I Demand Off-Peak 6x12/1000			($1,143)	($1,105)									($2,248)
20	Outdoor Lighting 7x13/1000			($25)	($24)									($49)
21	Total 15+16+17+18+19+20			($6,373)	($6,049)									**($12,422)**
22	**2019 Under (+)/Over(-) Recovered Expense**			($41)	($1,147)									**($1,188)**

	2020 Net Under (+)/Over (-) Recovery	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	2020 Total
1	2020 Total Under (+)/Over(-) Recovery (Pt A Att 4) Line 37	($8,873)	($3,484)	($5,323)	($6,245)	($4,665)	$14,804	$1,443	$1,025	$4,774	($584)	$8,965	$3,192	$5,030
2	2019 Total Under (+)/Over(-) Recovery 22	$0	$0	($41)	($1,147)	$0	$0	$0	$0	$0	$0	$0	$0	($1,188)
3	**2020 Net Under (+)/Over (-) Recovery 1+2**	($8,873)	($3,484)	($5,364)	($7,392)	($4,665)	$14,804	$1,443	$1,025	$4,774	($584)	$8,965	**$3,192**	**$3,842**

Proposed True Up Recovery to be Included in September 2021 FCA Factors

2020 Net Under (+)/Over (-) Recovery ($000)		$3,842		
Forecasted 2021 September Minnesota Retail MWh Sales Subject to FCA		2,205,893		
Proposed True Up Factor ($/kWh)		$0.00174		
	FAF Ratio	**Proposed True Up Factors ($/kWh)**	Approved Factors for September 2021 ($/kWh)	Proposed September 2021 Factors ($/kWh)
Residential 62	1.0177	**$0.00177**	$0.02890	$0.03067
C&I Non-Demand 63	1.0305	**$0.00179**	$0.02927	$0.03106
C&I Demand Non-TOD 64	0.9984	**$0.00174**	$0.02836	$0.03010
C&I Demand On-Peak 65	1.2486	**$0.00217**	$0.03546	$0.03763
C&I Demand Off-Peak 66	0.8166	**$0.00142**	$0.02320	$0.02462
Outdoor Lighting 67	0.7976	**$0.00139**	$0.02266	$0.02405

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

		Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	2020 Total
	Own Generation													
	Fossil Fuel													
1	Coal	685.6	472.0	446.4	258.4	320.5	419.3	1,238.7	1,322.7	813.0	749.6	805.1	996.3	8,527.6
2	Wood/RDF	42.1	33.4	43.5	44.6	52.7	47.3	51.7	52.1	35.4	51.1	50.2	49.5	553.5
3	Natural Gas CC	841.6	553.0	423.8	437.4	449.8	568.5	697.0	551.6	338.6	462.0	254.1	543.9	6,121.3
4	Natural Gas & Oil CT	15.3	13.7	50.9	45.0	49.3	114.2	206.0	78.2	21.4	67.4	12.3	41.8	715.4
5	Subtotal	1,584.5	1,072.1	964.6	785.4	872.2	1,149.2	2,193.5	2,004.7	1,208.4	1,330.0	1,121.7	1,631.5	15,917.8
6	Hydro	109.9	74.2	133.1	142.7	118.2	102.0	128.7	104.2	76.5	88.5	101.1	65.5	1,244.5
7	Wind	295.9	403.5	428.6	404.8	407.7	419.1	278.8	326.5	435.1	479.9	579.8	541.6	5,001.4
8	Nuclear Fuel	1,320.1	1,233.4	1,304.5	1,248.3	1,261.4	1,195.8	1,232.5	1,191.4	1,023.2	1,076.3	1,275.1	1,315.2	14,677.3
9	Total Fuel 5+6+7+8	3,310.5	2,783.1	2,830.8	2,581.2	2,659.5	2,866.1	3,833.5	3,626.8	2,743.1	2,974.7	3,077.8	3,553.9	36,841.0
	Purchased Energy													
10	LT Purchased Energy (Gas)	371.2	289.9	363.4	328.3	121.5	307.2	473.3	310.2	182.6	302.4	307.5	358.9	3,716.4
11	LT Purchased Energy (Solar)	18.5	39.1	48.4	63.9	67.8	74.1	72.6	68.4	48.3	38.2	28.5	21.4	589.1
12	Community Solar*Gardens	31.1	74.3	82.6	113.2	131.7	146.6	145.2	131.7	107.4	100.3	87.8	47.7	1,199.6
13	LT Purchased Energy (Wind)	437.6	574.3	565.4	496.6	432.0	434.5	302.1	389.2	436.3	451.6	522.9	496.0	5,538.8
14	LT Purchased Energy (Other)	143.9	131.9	129.1	98.7	167.3	178.9	187.2	177.9	169.7	147.1	114.1	134.4	1,780.3
15	ST Market Purchases	210.5	121.2	122.9	111.0	225.0	315.7	266.5	282.3	217.0	231.2	216.8	186.9	2,507.1
16	Total Purchased Energy 10+11+12+13+14+15	1,212.8	1,230.7	1,311.8	1,211.6	1,145.4	1,456.9	1,446.9	1,359.7	1,161.3	1,270.9	1,277.8	1,245.3	15,331.2
17	**Total System GWh (At Generator) 9+16**	4,523.2	4,013.8	4,142.7	3,792.8	3,804.9	4,323.1	5,280.4	4,986.5	3,904.4	4,245.6	4,355.6	4,799.2	52,172.2
18	Less Sales Revenue	(909.8)	(725.2)	(921.5)	(923.3)	(823.4)	(697.1)	(1,062.2)	(1,077.2)	(759.0)	(1,048.6)	(1,150.7)	(1,388.4)	(11,486.4)
19	Less Solar Gardens - Above Market													
20	Less WindSource	(34.3)	(30.7)	(32.3)	(29.6)	(27.1)	(31.3)	(36.9)	(38.3)	(35.6)	(32.6)	(28.7)	(37.0)	(394.5)
21	Less Renewable Connect	(15.3)	(14.2)	(16.1)	(14.2)	(13.4)	(14.7)	(17.4)	(16.2)	(15.9)	(14.4)	(15.4)	(15.4)	(182.5)
22	**Net System GWh (At Generator)** 17+18+19+20+21	3,563.8	3,243.7	3,172.8	2,825.7	2,941.0	3,580.0	4,164.0	3,854.7	3,094.0	3,150.0	3,160.7	3,358.4	40,108.8

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

		Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	2020 Total
	Own Generation													
	Fossil Fuel													
1	Coal	$21.86	$22.73	$22.79	$22.91	$17.07	$31.50	$21.67	$20.56	$20.28	$20.30	$20.19	$20.05	$21.40
2	Wood/RDF	$18.39	$19.39	$11.97	$14.94	$17.72	$14.12	$22.69	$16.24	$11.38	$16.39	$15.96	$15.00	$16.28
3	Natural Gas CC	$18.00	$18.80	$18.91	$16.89	$19.61	$19.44	$17.77	$19.08	$20.49	$21.54	$27.62	$23.72	$19.69
4	Natural Gas & Oil CT	$37.68	$32.21	$25.55	$25.29	$27.26	$27.61	$26.24	$29.32	$31.70	$29.27	$28.41	$6.62	$26.45
5	Subtotal	$19.87	$20.72	$20.74	$19.24	$18.99	$24.43	$20.88	$20.38	$20.28	$21.03	$21.78	$20.78	$20.79
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	$8.19	$8.20	$8.23	$8.40	$8.41	$8.53	$8.33	$8.23	$8.02	$8.10	$7.71	$7.74	$8.17
9	Total Fuel	$12.78	$11.62	$10.86	$9.92	$10.22	$13.36	$14.63	$13.97	$11.93	$12.33	$11.13	$12.40	$12.24
	Purchased Energy													
10	LT Purchased Energy (Gas)	$19.93	$22.90	$18.06	$18.43	$17.54	$22.14	$20.62	$21.46	$22.34	$23.66	$24.89	$24.17	$21.41
11	LT Purchased Energy (Solar)	$54.73	$67.82	$69.42	$72.41	$72.09	$75.29	$78.34	$69.44	$73.54	$63.22	$61.35	$57.34	$70.43
12	Community Solar*Gardens	$133.61	$127.08	$126.49	$116.33	$110.43	$125.92	$133.63	$131.87	$117.42	$118.88	$147.45	$146.85	$126.27
13	LT Purchased Energy (Wind)	$31.52	$34.61	$39.38	$32.76	$37.27	$39.31	$34.70	$33.54	$38.05	$37.86	$38.98	$37.89	$36.43
14	LT Purchased Energy (Other)	$69.19	$70.06	$77.28	$62.63	$75.77	$81.21	$77.72	$81.22	$83.59	$77.01	$83.61	$77.14	$76.95
15	ST Market Purchases	$36.64	$41.16	$42.04	$21.84	$28.74	$35.90	$39.88	$33.94	$61.22	$41.96	$60.66	$76.78	$43.39
16	Total Purchased Energy	$36.30	$42.94	$44.05	$40.21	$49.60	$50.64	$48.73	$48.43	$55.38	$46.91	$51.21	$48.51	$46.97
17	**Total System $/MWh**	$19.08	$21.22	$21.37	$19.59	$22.07	$25.92	$23.97	$23.37	$24.85	$22.69	$22.89	$21.77	$22.45
18	Less Sales Revenue	$20.10	$17.13	$15.81	$14.13	$13.97	$17.00	$21.87	$20.22	$14.24	$17.01	$15.44	$19.50	$17.43
19	Less Solar Gardens - Above Market													
20	Less WindSource	$12.99	$32.35	$21.17	$21.55	$28.80	$22.96	$23.68	$22.24	$21.99	$29.22	$29.45	$24.49	$24.02
21	Less Renewable Connect	$33.18	$35.69	$31.62	$33.37	$33.33	$33.48	$32.66	$34.06	$33.97	$34.14	$34.17	$34.21	$33.63
22	**Net System $/MWh**	$17.82	$19.49	$20.10	$17.25	$19.93	$23.15	$20.66	$20.49	$23.86	$21.12	$21.73	$20.81	$20.56

Northern States Power Company
Electric Utility - State of Minnesota
Minnesota Retail Electric 2020 Fuel Cost Charges

	FUEL COST CHARGE ($/kWh)					
	Residential	C&I Non-Demand	C&I Demand Non-TOD	C&I Demand TOD On-Peak	C&I Demand TOD Off-Peak	Outdoor Lighting
2020 Factors						
FAF Ratio *	1.0177	1.0305	0.9984	1.2486	0.8166	0.7976
January	$0.02472	$0.02503	$0.02426	$0.03031	$0.01986	$0.01940
February	$0.02685	$0.02719	$0.02634	$0.03293	$0.02155	$0.02105
March						
Forecast	$0.02801	$0.02836	$0.02748	$0.03436	$0.02248	$0.02196
True Up **	($0.00293)	($0.00297)	($0.00287)	($0.00360)	($0.00235)	($0.00230)
Total	$0.02508	$0.02539	$0.02461	$0.03076	$0.02013	$0.01966
April						
Forecast	$0.02919	$0.02956	$0.02864	$0.03579	$0.02344	$0.02290
True Up **	($0.00332)	($0.00336)	($0.00326)	($0.00407)	($0.00267)	($0.00260)
Total	$0.02587	$0.02620	$0.02538	$0.03172	$0.02077	$0.02030
May	$0.03080	$0.03119	$0.03022	$0.03778	$0.02473	$0.02416
June						
Forecast	$0.03471	$0.03515	$0.03405	$0.04258	$0.02785	$0.02721
Refund ***	($0.00337)	($0.00342)	($0.00331)	($0.00413)	($0.00270)	($0.00265)
Total	$0.03134	$0.03173	$0.03074	$0.03845	$0.02515	$0.02456
July						
Forecast	$0.03011	$0.03048	$0.02953	$0.03694	$0.02416	$0.02359
Refund ***	($0.00294)	($0.00296)	($0.00287)	($0.00360)	($0.00236)	($0.00229)
Total	$0.02717	$0.02752	$0.02666	$0.03334	$0.02180	$0.02130
August						
Forecast	$0.02964	$0.03002	$0.02908	$0.03637	$0.02379	$0.02323
Refund ***	($0.00307)	($0.00311)	($0.00301)	($0.00377)	($0.00247)	($0.00240)
Total	$0.02657	$0.02691	$0.02607	$0.03260	$0.02132	$0.02083
September	$0.02879	$0.02915	$0.02824	$0.03531	$0.02310	$0.02257
October	$0.02782	$0.02817	$0.02729	$0.03412	$0.02233	$0.02181
November	$0.02519	$0.02550	$0.02471	$0.03090	$0.02021	$0.01974
December	**$0.02335**	**$0.02364**	**$0.02291**	**$0.02864**	**$0.01874**	**$0.01831**
YTD Average	**$0.02270**	**$0.02299**	**$0.02227**	**$0.02785**	**$0.01822**	**$0.01780**

* FAF Ratio effective since October 1, 2017. ** True up from November and December 2019. *** Summer FCA Rate Adjustment.

Redline

FUEL COST FACTORS (2021) ~~N~~

Month	Residential	Commercial & Industrial Non-Demand	Demand Non-TOD	Demand On-Peak	Demand 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	~~$0.02890~~ $0.03067	~~$0.02927~~ $0.03106	~~$0.02836~~ $0.03010	~~$0.03546~~ $0.03763	~~$0.02320~~ $0.02462	~~$0.02266~~ $0.02405 R
October	$0.02743	$0.02777	$0.02691	$0.03364	$0.02201	$0.02150
November	$0.02474	$0.02505	$0.02427	$0.03035	$0.01985	$0.01938
December	$0.02310	$0.02339	$0.02266	$0.02834	$0.01854	$0.01811

~~N~~

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:

1. The cost of fuels consumed in the Company's generating stations as recorded in Federal Energy Regulatory Commission (FERC) Accounts 151 and 518.

2. The cost of energy purchases as recorded in FERC Account 555, exclusive of capacity or demand charges, irrespective of the designation assigned to such transaction, when such energy is purchased on an economic dispatch basis.

3. All Midwest ISO (MISO) costs and revenues authorized by the Commission to flow through this Fuel Clause Rider and excluding MISO costs and revenues that are recoverable in base rates, as prescribed in applicable Commission Orders.

4. All fuel and purchased energy expenses incurred by the Company over the duration of any Commission-approved contract, as provided for by Minnesota Statutes, Section 216B.1645, except any such expenses recovered in base rates or other riders.

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(Continued on Sheet No. 5-91.2)

Clean

FUEL COST FACTORS (2021)

Month	Residential	Commercial & Industrial				Outdoor Lighting
		Non-Demand	Demand			
			Non-TOD	On-Peak	Off-Peak	
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 R
October	$0.02743	$0.02777	$0.02691	$0.03364	$0.02201	$0.02150
November	$0.02474	$0.02505	$0.02427	$0.03035	$0.01985	$0.01938
December	$0.02310	$0.02339	$0.02266	$0.02834	$0.01854	$0.01811

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:

1. The cost of fuels consumed in the Company's generating stations as recorded in Federal Energy Regulatory Commission (FERC) Accounts 151 and 518.

2. The cost of energy purchases as recorded in FERC Account 555, exclusive of capacity or demand charges, irrespective of the designation assigned to such transaction, when such energy is purchased on an economic dispatch basis.

3. All Midwest ISO (MISO) costs and revenues authorized by the Commission to flow through this Fuel Clause Rider and excluding MISO costs and revenues that are recoverable in base rates, as prescribed in applicable Commission Orders.

4. All fuel and purchased energy expenses incurred by the Company over the duration of any Commission-approved contract, as provided for by Minnesota Statutes, Section 216B.1645, except any such expenses recovered in base rates or other riders.

(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 2020 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 2020 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. Concerning 2020 system conditions, the MISO Independent Market Monitor, which is tasked with monitoring both the behavior of Market Participants and the operation of the market, stated the following: 2020 began with milder weather and finished with no major emergency events resulting in average loads being off by as much as 30%. Power prices were also lower by 29% mainly due to natural gas prices being significantly lower than those in the previous winter months. Spring saw energy prices were still lower by 30% and MISO calculated that loads were down 8% due to COVID-19. The summer months saw average loads rebound to levels seen in 2019 as the negative

[1] We have reduced the number of detailed MISO reporting formats 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.

effects of COVID-19 were offset by hotter temperatures. The summer peak load was slightly above 117 GW, occurring on August 24. In the fall, loads were down 7% with most of that attributed to COVID-19 and energy prices were off by 14% when compared to 2019. Also, MISO experienced several days of record high wind outputs, and an all-time high wind output peak was set on November 15 at nearly 19 GW, serving one third of all the load. Finally, despite some challenging operational hazards presented with COVID-19 along with Hurricanes Laura and Delta, throughout the report period, MISO performed market functions fairly well.[2]

2. *Estimated Market Benefits*

The comparison of NSP's participation in the MISO ASM market to an alternative 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 2020 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 '20	(25,490,286)	(25,656,951)	166,665	40,374	37,124	89,167
Feb '20	(26,131,159)	(26,223,051)	91,892	31,829	26,074	33,989
Mar '20	(24,374,496)	(24,507,973)	133,477	25,826	21,041	86,611
Apr '20	(21,864,780)	(22,004,025)	139,245	21,141	29,134	88,970
May '20	(19,983,594)	(20,183,606)	200,012	23,177	24,332	152,503
Jun '20	(23,864,705)	(24,161,234)	296,529	35,509	30,785	230,235
Jul '20	(15,294,677)	(15,426,957)	132,280	37,888	31,599	62,794
Aug '20	(8,318,796)	(8,858,790)	539,994	9,699	30,728	499,568
Sep '20	(8,701,780)	(8,990,851)	289,071	12,851	21,974	254,247
Oct '20	(15,480,996)	(15,852,921)	371,925	21,672	28,590	321,663
Nov '20	(11,321,012)	(11,476,707)	155,695	26,672	25,360	103,663
Dec '20	(14,385,190)	(14,582,336)	197,146	25,346	33,419	138,381

[2] https://cdn.misoenergy.org/2020%20IMM%20Quarterly%20Report%20Fall504033.pdf

The Company estimates the ASM resulted in total NSP System savings of approximately $2.0 million for the 2020 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 $1.546 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 Excessive Deficient Energy Deployment charges 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 2020 AAA reporting period, the net benefit for the Company was approximately $2.0 million[3] while the amount incurred in EDEDCs was $0.4 million. The $2.4 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.

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[3] The $2.0 million in ASM benefits calculated by the Company for 2020 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.

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 15 shows NSP incurred a total of $2,991 in CRDFC during the 2020 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. 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
2020 AAA Period

Period*	Invoiced Amount (NSP System)	Juris Trans Alloc	Interchange Alloc	MN Jurisdiction Net of Interchange
January	$ 772,810.86	87.2614%	83.7498%	$ 564,779.82
February	$ 979,664.29	87.2614%	83.7498%	$ 715,950.89
March	$ 726,909.90	87.2614%	83.7498%	$ 531,234.83
April	$ 990,418.00	87.2614%	83.7498%	$ 723,809.83
May	$ 986,164.65	87.2614%	83.7498%	$ 720,701.43
June	$ 935,744.42	87.2614%	83.7498%	$ 683,853.70
July	$ 984,804.62	87.2614%	83.7498%	$ 719,707.51
August	$ 1,138,434.58	87.2614%	83.7498%	$ 831,982.20
September	$ 856,111.99	87.2614%	83.7498%	$ 625,657.33
October	$ 892,354.51	87.2614%	83.7498%	$ 652,143.81
November	$ 965,488.28	87.2614%	83.7498%	$ 705,590.88
December	$ 1,124,282.02	87.2614%	83.7498%	$ 821,639.33
Total	**$ 11,353,188.12**			**$ 8,297,051.56**

*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.

For comparison purposes, we also provide the data for calendar year 2019, below.

Schedule 10 Administrative Charges Paid to MISO Under MISO Tariff
Calendar Year 2019

Period*	Invoiced Amount (NSP System)	Juris Trans Alloc	Interchange Alloc	MN Jurisdiction Net of Interchange
January	$ 1,079,382.45	87.0633%	83.8864%	$ 788,319.07
February	$ 803,802.44	87.0633%	83.8864%	$ 587,051.23
March	$ 1,014,495.24	87.0633%	83.8864%	$ 740,929.17
April	$ 946,324.88	87.0633%	83.8864%	$ 691,141.45
May	$ 916,927.37	87.0633%	83.8864%	$ 669,671.19
June	$ 966,529.75	87.0633%	83.8864%	$ 705,897.93
July	$ 836,241.49	87.0633%	83.8864%	$ 610,742.85
August	$ 928,299.84	87.0633%	83.8864%	$ 677,976.99
September	$ 1,112,281.31	87.0633%	83.8864%	$ 812,346.51
October	$ 937,600.10	87.0633%	83.8864%	$ 684,769.37
November	$ 833,525.66	87.0633%	83.8864%	$ 608,759.37
December	$ 960,801.27	87.0633%	83.8864%	$ 701,714.18
Total	**$ 11,336,211.80**			**$8,279,319.31**

*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, 2020, pursuant to the annual update to the Interchange Agreement allocation factors accepted by FERC in Docket No. ER20-1249-000, letter order dated May 5, 2020.

The State of Minnesota jurisdictional demand allocator (12 month coincident peak demand) increased effective January 1, 2020 based on State of Minnesota demands. The net impact of the decrease in the 2020 Interchange Agreement demand allocator and the increase in the 2020 State of Minnesota jurisdictional demand allocator is an increase in the 2020 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 2020 amount of $11.4 million invoiced for MISO Schedule 10 administrative charges does not exceed the 2019 amount of $11.3 million by 5% or more, so no additional analysis is required.

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 2019-20	
[PROTECTED DATA BEGINS		**Peak**	**Peak Off**
			PROTECTED DATA ENDS]

Generation Node	Load Node	Spring 2020	
[PROTECTED DATA BEGINS		Peak	Peak Off
			PROTECTED DATA ENDS]

Generation Node	Load Node	Summer 2020	
[PROTECTED DATA BEGINS		Peak	Peak Off
			PROTECTED DATA ENDS]

Generation Node	Load Node	Fall 2020	
[PROTECTED DATA BEGINS		Peak	Peak Off
			PROTECTED DATA ENDS]

Generation Node	Load Node	Winter 2020-21	
[PROTECTED DATA BEGINS		Peak	Peak Off
			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]

Northern States Power Company

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	January 2020 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (13,664,095.31)	$ 15,281,435.21	$ 1,617,339.90	$ 1,143,111.91
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,463,499.62	$ -	$ 2,463,499.62	$ 1,741,165.08
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 911.27	$ -	$ 911.27	$ 644.07
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (2,662,705.60)	$ -	$ (2,662,705.60)	$ (1,881,960.92)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 168,470.70	$ -	$ 168,470.70	$ 119,072.60
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (911.27)	$ -	$ (911.27)	$ (644.07)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (679,931.39)	$ 2,670,205.67	$ 1,990,274.28	$ 1,406,696.41
13 c	Real-Time Asset Energy Amount - Loss Component	$ 28,603.35	$ -	$ 28,603.35	$ 20,216.42
14	Real-Time Distribution of Losses Amount	$ (709,133.44)	$ -	$ (709,133.44)	$ (501,205.02)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 36,499.45	$ -	$ 36,499.45	$ 25,797.27
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 7.59	$ -	$ 7.59	$ 5.36
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ -	$ -	$ -	$ -
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,373,432.80	$ -	$ 2,373,432.80	$ 1,677,507.18
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 5,965.44	$ -	$ 5,965.44	$ 4,216.28
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 21,326.25	$ -	$ 21,326.25	$ 15,073.08
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (5,965.44)	$ -	$ (5,965.44)	$ (4,216.28)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 7,126.96	$ -	$ 7,126.96	$ 5,037.23
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	$ -	$ -	$ -	$ -
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,184,430.87)	$ -	$ (1,184,430.87)	$ (837,138.21)
30	Financial Transmission Rights Monthly Allocation Amount	$ (89,274.04)	$ -	$ (89,274.04)	$ (63,097.57)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ (6,000.37)	$ -	$ (6,000.37)	$ (4,240.97)
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (51,912.89)	$ -	$ (51,912.89)	$ (36,691.26)
37	Financial Transmission Guarantee Uplift Amount	$ 158,412.36	$ -	$ 158,412.36	$ 111,963.51
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 344,512.71	$ -	$ 344,512.71	$ 243,496.49
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 76,283.62	$ -	$ 76,283.62	$ 53,916.13
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (91,615.49)	$ 67,092.79	$ (24,522.70)	$ (17,332.28)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 50,802.10	$ -	$ 50,802.10	$ 35,906.17
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (11,981.69)	$ 12,782.80	$ 801.11	$ 566.21
43	Real Time Price Volatility Make Whole Payment	$ (148,084.41)	$ 24,074.42	$ (124,009.99)	$ (87,648.43)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 805,185.59	$ (77,031.21)	$ 728,154.38	$ 514,648.74
19	Real-Time Market Administration Amount	$ 71,250.25	$ (11,003.05)	$ 60,247.20	$ 42,581.83
29	Financial Transmission Rights Market Administration Amount	$ 26,540.06	$ -	$ 26,540.06	$ 18,758.12
33	Day-Ahead Schedule 24 Allocation Amount	$ 95,698.49	$ (9,149.97)	$ 86,548.52	$ 61,171.21
34	Real -Time Schedule 24 Allocation Amount	$ (92,613.79)	$ 83,811.45	$ (8,802.34)	$ (6,221.36)
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	$ 44,676.61	$ 12,290.57	$ 56,967.18	$ 40,263.56
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,123,444.70	$ -	$ 1,123,444.70	$ 794,034.09
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,123,867.22)	$ 53,019.56	$ (1,070,847.66)	$ (756,859.28)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (207,296.29)	$ -	$ (207,296.29)	$ (146,513.95)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 42,660.70	$ -	$ 42,660.70	$ 30,151.95
	TOTAL MISO CHARGES	**$ (12,784,508.89)**	**$ 18,107,528.24**	**$ 5,323,019.35**	**$ 3,762,231.31**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 814,941.64**	**$ 575,988.69**
	SCHEDULE 24 (FOR RETAIL)			**$ 77,746.18**	**$ 54,949.85**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 4,430,331.53**	**$ 3,131,292.77**

Northern States Power Company

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	February 2020 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (6,018,450.22)	$ 9,297,231.98	$ 3,278,781.76	$ 2,323,649.58
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,119,119.41	$ -	$ 2,119,119.41	$ 1,501,805.02
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 1,340.79	$ -	$ 1,340.79	$ 950.21
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (2,187,166.16)	$ -	$ (2,187,166.16)	$ (1,550,029.28)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 149,186.61	$ -	$ 149,186.61	$ 105,727.50
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (1,340.79)	$ -	$ (1,340.79)	$ (950.21)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (927,304.90)	$ 2,570,666.15	$ 1,643,361.25	$ 1,164,638.56
13 c	Real-Time Asset Energy Amount - Loss Component	$ 14,877.48	$ -	$ 14,877.48	$ 10,543.57
14	Real-Time Distribution of Losses Amount	$ (591,412.23)	$ -	$ (591,412.23)	$ (419,129.69)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 38,123.41	$ -	$ 38,123.41	$ 27,017.79
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (14.39)	$ -	$ (14.39)	$ (10.20)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (307.63)	$ -	$ (307.63)	$ (218.02)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,563,775.02	$ -	$ 2,563,775.02	$ 1,816,929.33
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 2,766.05	$ -	$ 2,766.05	$ 1,960.28
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 129,680.20	$ -	$ 129,680.20	$ 91,903.45
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (2,766.05)	$ -	$ (2,766.05)	$ (1,960.28)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (51,303.24)	$ -	$ (51,303.24)	$ (36,358.25)
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	$ 322.32	$ -	$ 322.32	$ 228.43
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,875,545.10)	$ -	$ (1,875,545.10)	$ (1,329,185.62)
30	Financial Transmission Rights Monthly Allocation Amount	$ (89,523.55)	$ -	$ (89,523.55)	$ (63,444.71)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ (0.17)	$ -	$ (0.17)	$ (0.12)
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 10,383.88	$ -	$ 10,383.88	$ 7,358.98
37	Financial Transmission Guarantee Uplift Amount	$ (10,039.34)	$ -	$ (10,039.34)	$ (7,114.81)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 177,128.63	$ -	$ 177,128.63	$ 125,529.81
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 40,481.08	$ -	$ 40,481.08	$ 28,688.66
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (59,631.25)	$ 15,961.13	$ (43,670.12)	$ (30,948.71)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 19,482.50	$ -	$ 19,482.50	$ 13,807.11
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (1,644.65)	$ 11,327.24	$ 9,682.59	$ 6,861.98
43	Real Time Price Volatility Make Whole Payment	$ (59,208.19)	$ 53,396.83	$ (5,811.36)	$ (4,118.47)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 614,153.73	$ (47,010.03)	$ 567,143.70	$ 401,930.75
19	Real-Time Market Administration Amount	$ 56,224.91	$ (17,013.00)	$ 39,211.91	$ 27,789.20
29	Financial Transmission Rights Market Administration Amount	$ 23,493.72	$ -	$ 23,493.72	$ 16,649.83
33	Day-Ahead Schedule 24 Allocation Amount	$ 90,256.88	$ (6,860.80)	$ 83,396.08	$ 59,102.22
34	Real -Time Schedule 24 Allocation Amount	$ (84,023.82)	$ 88,212.74	$ 4,188.92	$ 2,968.66
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	$ 133,223.48	$ 11,497.63	$ 144,721.11	$ 102,562.83
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,123,444.70	$ -	$ 1,123,444.70	$ 796,177.36
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,123,867.22)	$ 55,838.52	$ (1,068,028.70)	$ (756,904.43)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (207,296.29)	$ -	$ (207,296.29)	$ (146,909.42)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 42,660.70	$ -	$ 42,660.70	$ 30,233.34
	TOTAL MISO CHARGES	**$ (5,940,719.69)**	**$ 12,033,248.39**	**$ 6,092,528.70**	**$ 4,317,732.25**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 629,849.33**	**$ 446,369.79**
	SCHEDULE 24 (FOR RETAIL)			**$ 87,585.00**	**$ 62,070.87**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 5,375,094.37**	**$ 3,809,291.58**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	March 2020 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (9,619,892.34)	$ 12,130,881.50	$ 2,510,989.16	$ 1,780,487.38
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 1,848,618.40	$ -	$ 1,848,618.40	$ 1,310,814.79
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (1,190.39)	$ -	$ (1,190.39)	$ (844.08)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (2,373,873.21)	$ -	$ (2,373,873.21)	$ (1,683,261.46)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 218,815.70	$ -	$ 218,815.70	$ 155,157.42
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 1,190.39	$ -	$ 1,190.39	$ 844.08
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (768,350.50)	$ 2,045,009.34	$ 1,276,658.84	$ 905,250.80
13 c	Real-Time Asset Energy Amount - Loss Component	$ 57,718.34	$ -	$ 57,718.34	$ 40,926.81
14	Real-Time Distribution of Losses Amount	$ (276,694.25)	$ -	$ (276,694.25)	$ (196,197.83)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 205,432.69	$ -	$ 205,432.69	$ 145,667.82
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 3,669.11	$ -	$ 3,669.11	$ 2,601.69
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (482.54)	$ -	$ (482.54)	$ (342.16)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 3,596,708.32	$ -	$ 3,596,708.32	$ 2,550,347.03
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (660.08)	$ -	$ (660.08)	$ (468.05)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 222,181.20	$ -	$ 222,181.20	$ 157,543.82
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 660.08	$ -	$ 660.08	$ 468.05
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 101,555.02	$ -	$ 101,555.02	$ 72,010.44
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	$ (1,319.45)	$ -	$ (1,319.45)	$ (935.59)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (3,929,675.14)	$ -	$ (3,929,675.14)	$ (2,786,446.51)
30	Financial Transmission Rights Monthly Allocation Amount	$ (54,490.34)	$ -	$ (54,490.34)	$ (38,637.91)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (60,407.68)	$ -	$ (60,407.68)	$ (42,833.76)
37	Financial Transmission Guarantee Uplift Amount	$ 62,381.04	$ -	$ 62,381.04	$ 44,233.03
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 124,952.38	$ -	$ 124,952.38	$ 88,600.99
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 46,930.49	$ -	$ 46,930.49	$ 33,277.38
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (33,041.29)	$ (11,572.87)	$ (44,614.16)	$ (31,634.92)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 20,258.92	$ -	$ 20,258.92	$ 14,365.16
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (2,268.11)	$ 746.15	$ (1,521.96)	$ (1,079.19)
43	Real Time Price Volatility Make Whole Payment	$ (144,850.29)	$ 45,985.32	$ (98,864.97)	$ (70,102.98)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 500,478.89	$ (53,759.50)	$ 446,719.39	$ 316,758.93
19	Real-Time Market Administration Amount	$ 45,399.19	$ (10,745.25)	$ 34,653.94	$ 24,572.35
29	Financial Transmission Rights Market Administration Amount	$ 44,638.31	$ -	$ 44,638.31	$ 31,652.05
33	Day-Ahead Schedule 24 Allocation Amount	$ 99,264.65	$ (10,015.67)	$ 89,248.98	$ 63,284.50
34	Real -Time Schedule 24 Allocation Amount	$ (78,460.00)	$ 89,416.44	$ 10,956.44	$ 7,768.97
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	$ 788,134.30	$ 12,290.57	$ 800,424.87	$ 567,563.73
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,307,930.05	$ -	$ 1,307,930.05	$ 927,424.53
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,308,091.42)	$ 6,509.43	$ (1,301,581.99)	$ (922,923.26)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (165,478.97)	$ -	$ (165,478.97)	$ (117,337.51)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 25,524.46	$ -	$ 25,524.46	$ 18,098.84
	TOTAL MISO CHARGES	**$ (9,496,784.07)**	**$ 14,244,745.46**	**$ 4,747,961.39**	**$ 3,366,675.35**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 526,011.64**	**$ 372,983.32**
	SCHEDULE 24 (FOR RETAIL)			**$ 100,205.42**	**$ 71,053.47**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 4,121,744.33**	**$ 2,922,638.56**

Northern States Power Company

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	April 2020 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (9,162,168.42)	$ 10,772,353.76	$ 1,610,185.34	$ 1,144,309.44
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 1,420,562.66	$ -	$ 1,420,562.66	$ 1,009,550.40
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (825.34)	$ -	$ (825.34)	$ (586.54)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (1,685,255.90)	$ -	$ (1,685,255.90)	$ (1,197,659.79)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 169,188.78	$ -	$ 169,188.78	$ 120,237.29
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 825.34	$ -	$ 825.34	$ 586.54
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,465,914.94)	$ 1,824,851.83	$ 358,936.89	$ 255,085.46
13 c	Real-Time Asset Energy Amount - Loss Component	$ 78,924.44	$ -	$ 78,924.44	$ 56,089.18
14	Real-Time Distribution of Losses Amount	$ (395,148.88)	$ -	$ (395,148.88)	$ (280,820.22)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ (1.76)	$ -	$ (1.76)	$ (1.25)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ 1.76	$ -	$ 1.76	$ 1.25
21	Real-time Net inadvertent Distribution	$ (138,359.00)	$ -	$ (138,359.00)	$ (98,327.51)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 12,698.00	$ -	$ 12,698.00	$ 9,024.08
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (724.45)	$ -	$ (724.45)	$ (514.84)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,587,122.63	$ -	$ 2,587,122.63	$ 1,838,588.87
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (1,908.93)	$ -	$ (1,908.93)	$ (1,356.62)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 421,514.18	$ -	$ 421,514.18	$ 299,557.23
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 1,908.93	$ -	$ 1,908.93	$ 1,356.62
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 204,188.33	$ -	$ 204,188.33	$ 145,110.40
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 28.30	$ -	$ 28.30	$ 20.11
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (28.30)	$ -	$ (28.30)	$ (20.11)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (324.63)	$ -	$ (324.63)	$ (230.70)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (2,668,152.09)	$ -	$ (2,668,152.09)	$ (1,896,174.03)
30	Financial Transmission Rights Monthly Allocation Amount	$ (263,476.32)	$ -	$ (263,476.32)	$ (187,244.56)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (93,025.52)	$ -	$ (93,025.52)	$ (66,110.39)
37	Financial Transmission Guarantee Uplift Amount	$ 88,306.19	$ -	$ 88,306.19	$ 62,756.51
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 499,577.98	$ -	$ 499,577.98	$ 355,034.78
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 66,893.10	$ -	$ 66,893.10	$ 47,538.88
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (131,874.13)	$ 73,762.07	$ (58,112.06)	$ (41,298.46)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 61,467.53	$ -	$ 61,467.53	$ 43,683.09
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (113,764.26)	$ 106,615.91	$ (7,148.35)	$ (5,080.11)
43	Real Time Price Volatility Make Whole Payment	$ (360,624.72)	$ 105,172.05	$ (255,452.67)	$ (181,542.39)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 721,919.99	$ (86,996.40)	$ 634,923.59	$ 451,220.76
19	Real-Time Market Administration Amount	$ 75,819.33	$ (16,063.64)	$ 59,755.69	$ 42,466.54
29	Financial Transmission Rights Market Administration Amount	$ 37,070.73	$ -	$ 37,070.73	$ 26,345.03
33	Day-Ahead Schedule 24 Allocation Amount	$ 94,485.30	$ (11,005.17)	$ 83,480.13	$ 59,326.77
34	Real -Time Schedule 24 Allocation Amount	$ (74,746.63)	$ 82,344.87	$ 7,598.24	$ 5,399.84
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	$ 130,988.21	$ 11,894.10	$ 142,882.31	$ 101,542.08
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,307,930.05	$ -	$ 1,307,930.05	$ 929,505.86
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,308,091.42)	$ 8,103.77	$ (1,299,987.65)	$ (923,861.44)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (165,479.06)	$ -	$ (165,479.06)	$ (117,600.90)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 25,524.46	$ -	$ 25,524.46	$ 18,139.45
	TOTAL MISO CHARGES	**$ (10,022,948.48)**	**$ 12,871,033.15**	**$ 2,848,084.67**	**$ 2,024,046.61**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 731,750.01**	**$ 520,032.34**
	SCHEDULE 24 (FOR RETAIL)			**$ 91,078.37**	**$ 64,726.61**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 2,025,256.29**	**$ 1,439,287.66**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	May 2020 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (5,625,702.29)	$ 9,745,861.13	$ 4,120,158.84	$ 2,962,825.88
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 1,133,090.81	$ -	$ 1,133,090.81	$ 814,811.01
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (2,711.07)	$ -	$ (2,711.07)	$ (1,949.54)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (4,124,776.16)	$ -	$ (4,124,776.16)	$ (2,966,146.22)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 502,544.58	$ -	$ 502,544.58	$ 361,382.21
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 2,711.07	$ -	$ 2,711.07	$ 1,949.54
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 647,175.42	$ 1,418,506.77	$ 2,065,682.19	$ 1,485,441.92
13 c	Real-Time Asset Energy Amount - Loss Component	$ 22,813.33	$ -	$ 22,813.33	$ 16,405.17
14	Real-Time Distribution of Losses Amount	$ (430,385.94)	$ -	$ (430,385.94)	$ (309,492.58)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ 0.00	$ -	$ 0.00	$ 0.00
21	Real-time Net inadvertent Distribution	$ (65,577.62)	$ -	$ (65,577.62)	$ (47,157.18)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 10,289.18	$ -	$ 10,289.18	$ 7,399.00
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (899.95)	$ -	$ (899.95)	$ (647.16)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,462,909.00	$ -	$ 2,462,909.00	$ 1,771,089.61
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (273.60)	$ -	$ (273.60)	$ (196.75)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,014,585.58	$ -	$ 1,014,585.58	$ 729,593.33
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 273.60	$ -	$ 273.60	$ 196.75
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 11,378.75	$ -	$ 11,378.75	$ 8,182.51
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	$ (596.78)	$ -	$ (596.78)	$ (429.15)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,766,600.32)	$ -	$ (1,766,600.32)	$ (1,270,370.72)
30	Financial Transmission Rights Monthly Allocation Amount	$ (101,537.77)	$ -	$ (101,537.77)	$ (73,016.29)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 8,648.58	$ -	$ 8,648.58	$ 6,219.24
37	Financial Transmission Guarantee Uplift Amount	$ (3,204.96)	$ -	$ (3,204.96)	$ (2,304.70)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 736,528.70	$ -	$ 736,528.70	$ 529,641.30
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 40,705.97	$ -	$ 40,705.97	$ 29,271.86
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (116,968.22)	$ 60,404.01	$ (56,564.21)	$ (40,675.59)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 27,817.73	$ -	$ 27,817.73	$ 20,003.86
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (9,019.09)	$ (1,114.15)	$ (10,133.24)	$ (7,286.86)
43	Real Time Price Volatility Make Whole Payment	$ (31,652.40)	$ 28,331.01	$ (3,321.39)	$ (2,388.43)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 632,134.58	$ (71,186.22)	$ 560,948.36	$ 403,380.64
19	Real-Time Market Administration Amount	$ 56,433.44	$ (9,168.51)	$ 47,264.93	$ 33,988.44
29	Financial Transmission Rights Market Administration Amount	$ 32,565.06	$ -	$ 32,565.06	$ 23,417.69
33	Day-Ahead Schedule 24 Allocation Amount	$ 90,934.77	$ (10,139.48)	$ 80,795.29	$ 58,100.28
34	Real -Time Schedule 24 Allocation Amount	$ (78,551.27)	$ 81,228.93	$ 2,677.66	$ 1,925.52
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	$ (60,172.84)	$ 12,290.57	$ (47,882.27)	$ (34,432.37)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,307,930.05	$ -	$ 1,307,930.05	$ 940,538.74
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,308,091.42)	$ 8,343.52	$ (1,299,747.90)	$ (934,654.92)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (165,479.06)	$ -	$ (165,479.06)	$ (118,996.78)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 25,524.46	$ -	$ 25,524.46	$ 18,354.76
	TOTAL MISO CHARGES	**$ (5,125,206.10)**	**$ 11,263,357.58**	**$ 6,138,151.48**	**$ 4,413,974.02**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 640,778.35**	**$ 460,786.77**
	SCHEDULE 24 (FOR RETAIL)			**$ 83,472.95**	**$ 60,025.80**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 5,413,900.18**	**$ 3,893,161.45**

Northern States Power Company

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	June 2020 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (4,799,200.25)	$ 10,587,170.19	$ 5,787,969.94	$ 4,203,705.72
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 1,952,570.30	$ -	$ 1,952,570.30	$ 1,418,119.14
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (2,199.06)	$ -	$ (2,199.06)	$ (1,597.14)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (4,782,517.35)	$ -	$ (4,782,517.35)	$ (3,473,462.33)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 603,174.18	$ -	$ 603,174.18	$ 438,075.31
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 2,580.58	$ -	$ 2,580.58	$ 1,874.23
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (694,551.94)	$ 997,211.29	$ 302,659.35	$ 219,816.42
13 c	Real-Time Asset Energy Amount - Loss Component	$ 106,440.75	$ -	$ 106,440.75	$ 77,306.14
14	Real-Time Distribution of Losses Amount	$ (622,972.41)	$ -	$ (622,972.41)	$ (452,454.44)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 53,086.50	$ -	$ 53,086.50	$ 38,555.84
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 9,172.67	$ -	$ 9,172.67	$ 6,661.96
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (555.30)	$ -	$ (555.30)	$ (403.31)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 7,817,754.78	$ -	$ 7,817,754.78	$ 5,677,904.49
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 12,243.40	$ -	$ 12,243.40	$ 8,892.18
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,000,845.66	$ -	$ 1,000,845.66	$ 726,897.46
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (11,392.32)	$ -	$ (11,392.32)	$ (8,274.05)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 188,665.78	$ -	$ 188,665.78	$ 137,024.80
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	$ (906.60)	$ -	$ (906.60)	$ (658.45)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (3,775,851.16)	$ -	$ (3,775,851.16)	$ (2,742,337.52)
30	Financial Transmission Rights Monthly Allocation Amount	$ (131,623.41)	$ -	$ (131,623.41)	$ (95,595.88)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (166,943.32)	$ -	$ (166,943.32)	$ (121,248.14)
37	Financial Transmission Guarantee Uplift Amount	$ 158,299.42	$ -	$ 158,299.42	$ 114,970.22
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 69,276.66	$ -	$ 69,276.66	$ 50,314.48
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 43,901.42	$ -	$ 43,901.42	$ 31,884.87
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (179,532.48)	$ 29,594.79	$ (149,937.69)	$ (108,897.24)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 66,345.82	$ -	$ 66,345.82	$ 48,185.86
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (54,368.22)	$ 10,013.88	$ (44,354.34)	$ (32,213.82)
43	Real Time Price Volatility Make Whole Payment	$ (204,153.53)	$ 31,937.25	$ (172,216.28)	$ (125,077.80)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 783,195.49	$ (64,044.19)	$ 719,151.30	$ 522,307.56
19	Real-Time Market Administration Amount	$ 76,993.12	$ (5,074.24)	$ 71,918.88	$ 52,233.48
29	Financial Transmission Rights Market Administration Amount	$ 33,175.41	$ -	$ 33,175.41	$ 24,094.75
33	Day-Ahead Schedule 24 Allocation Amount	$ 93,115.55	$ (7,800.36)	$ 85,315.19	$ 61,962.99
34	Real -Time Schedule 24 Allocation Amount	$ (86,564.11)	$ 91,762.81	$ 5,198.70	$ 3,775.73
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	$ 3,194.57	$ 1,438.80	$ 4,633.37	$ 3,365.14
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,693,305.82	$ -	$ 2,693,305.82	$ 1,956,102.95
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,698,826.26)	$ 3,733.44	$ (2,695,092.82)	$ (1,957,400.82)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (236,849.95)	$ -	$ (236,849.95)	$ (172,020.16)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 10,503.72	$ -	$ 10,503.72	$ 7,628.68
	TOTAL MISO CHARGES	**$ (2,671,166.07)**	**$ 11,675,943.66**	**$ 9,004,777.59**	**$ 6,540,019.30**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 824,245.59**	**$ 598,635.78**
	SCHEDULE 24 (FOR RETAIL)			**$ 90,513.89**	**$ 65,738.72**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 8,090,018.11**	**$ 5,875,644.79**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	July 2020 Actual				
	Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (14,867,092.18)	$ 21,271,939.63	$ 6,404,847.45	$ 4,680,379.49
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,431,575.28	$ -	$ 2,431,575.28	$ 1,776,887.76
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (2,986.53)	$ -	$ (2,986.53)	$ (2,182.42)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (6,630,748.31)	$ -	$ (6,630,748.31)	$ (4,845,457.86)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 783,749.69	$ -	$ 783,749.69	$ 572,729.64
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 2,897.51	$ -	$ 2,897.51	$ 2,117.37
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,059,390.43)	$ 1,559,847.26	$ 500,456.83	$ 365,711.74
13 c	Real-Time Asset Energy Amount - Loss Component	$ 101,114.58	$ -	$ 101,114.58	$ 73,890.07
14	Real-Time Distribution of Losses Amount	$ (844,769.75)	$ -	$ (844,769.75)	$ (617,320.40)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 373,187.58	$ -	$ 373,187.58	$ 272,708.99
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 3,809.57	$ -	$ 3,809.57	$ 2,783.87
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 1,165.35	$ -	$ 1,165.35	$ 851.59
	Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 5,139,205.90	$ -	$ 5,139,205.90	$ 3,755,504.57
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 4,966.47	$ -	$ 4,966.47	$ 3,629.28
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,229,394.84	$ -	$ 1,229,394.84	$ 898,387.42
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (5,165.05)	$ -	$ (5,165.05)	$ (3,774.39)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 315,620.62	$ -	$ 315,620.62	$ 230,641.60
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	$ 641.04	$ -	$ 641.04	$ 468.44
	FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	$ (4,171,284.07)	$ -	$ (4,171,284.07)	$ (3,048,190.07)
30	Financial Transmission Rights Monthly Allocation Amount	$ (190,323.43)	$ -	$ (190,323.43)	$ (139,079.95)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 2,905.26	$ -	$ 2,905.26	$ 2,123.04
37	Financial Transmission Guarantee Uplift Amount	$ 18,786.20	$ -	$ 18,786.20	$ 13,728.12
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
	Uplift (RNU) Charges				
23	Real-Time Revenue Neutrality Uplift Amount	$ 202,020.75	$ -	$ 202,020.75	$ 147,627.84
	Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 85,730.36	$ -	$ 85,730.36	$ 62,647.96
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (27,697.25)	$ 16,577.65	$ (11,119.60)	$ (8,125.71)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 394,093.42	$ -	$ 394,093.42	$ 287,986.06
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (186,741.55)	$ 63,609.24	$ (123,132.31)	$ (89,979.65)
43	Real Time Price Volatility Make Whole Payment	$ (335,854.47)	$ 25,290.15	$ (310,564.32)	$ (226,946.68)
	Market Administration Charges				
4	Day-Ahead Market Administration Amount	$ 666,441.34	$ (69,129.18)	$ 597,312.16	$ 436,489.33
19	Real-Time Market Administration Amount	$ 59,366.94	$ (6,557.09)	$ 52,809.85	$ 38,591.10
29	Financial Transmission Rights Market Administration Amount	$ 35,084.39	$ -	$ 35,084.39	$ 25,638.12
33	Day-Ahead Schedule 24 Allocation Amount	$ 99,141.21	$ (10,508.37)	$ 88,632.84	$ 64,768.96
34	Real -Time Schedule 24 Allocation Amount	$ (88,321.61)	$ 100,431.73	$ 12,110.12	$ 8,849.54
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	$ 52,589.48	$ 1,486.76	$ 54,076.24	$ 39,516.53
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
	Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,693,305.82	$ -	$ 2,693,305.82	$ 1,968,148.88
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,698,826.26)	$ 3,695.78	$ (2,695,130.48)	$ (1,969,482.26)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (234,999.62)	$ -	$ (234,999.62)	$ (171,727.34)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 10,489.95	$ -	$ 10,489.95	$ 7,665.59
	TOTAL MISO CHARGES	**$ (16,636,916.96)**	**$ 22,956,683.56**	**$ 6,319,766.60**	**$ 4,618,206.16**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 685,206.40**	**$ 500,718.56**
	SCHEDULE 24 (FOR RETAIL)			**$ 100,742.96**	**$ 73,618.50**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 5,533,817.24**	**$ 4,043,869.10**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	August 2020 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (14,125,818.10)	$ 20,427,007.50	$ 6,301,189.40	$ 4,569,942.90
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,245,565.67	$ -	$ 2,245,565.67	$ 1,628,598.39
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (4,391.06)	$ -	$ (4,391.06)	$ (3,184.62)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (6,007,314.60)	$ -	$ (6,007,314.60)	$ (4,356,809.96)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 722,090.44	$ -	$ 722,090.44	$ 523,696.70
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 4,391.06	$ -	$ 4,391.06	$ 3,184.62
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (521,366.63)	$ 1,034,611.13	$ 513,244.50	$ 372,231.00
13 c	Real-Time Asset Energy Amount - Loss Component	$ 28,252.91	$ -	$ 28,252.91	$ 20,490.45
14	Real-Time Distribution of Losses Amount	$ (709,775.66)	$ -	$ (709,775.66)	$ (514,765.39)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (21,807.88)	$ -	$ (21,807.88)	$ (15,816.18)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 305.10	$ -	$ 305.10	$ 221.27
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 5.59	$ -	$ 5.59	$ 4.05
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 3,984,892.43	$ -	$ 3,984,892.43	$ 2,890,046.58
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (4,937.58)	$ -	$ (4,937.58)	$ (3,580.98)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 794,226.84	$ -	$ 794,226.84	$ 576,013.68
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 4,937.58	$ -	$ 4,937.58	$ 3,580.98
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 58,297.84	$ -	$ 58,297.84	$ 42,280.56
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	$ 13.66	$ -	$ 13.66	$ 9.91
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (2,926,937.62)	$ -	$ (2,926,937.62)	$ (2,122,763.97)
30	Financial Transmission Rights Monthly Allocation Amount	$ (141,201.53)	$ -	$ (141,201.53)	$ (102,406.53)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (36,382.83)	$ -	$ (36,382.83)	$ (26,386.68)
37	Financial Transmission Guarantee Uplift Amount	$ 31,333.26	$ -	$ 31,333.26	$ 22,724.47
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 326,052.32	$ -	$ 326,052.32	$ 236,469.72
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 71,294.60	$ -	$ 71,294.60	$ 51,706.47
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (110,415.29)	$ 33,637.72	$ (76,777.57)	$ (55,683.00)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 143,250.16	$ -	$ 143,250.16	$ 103,892.30
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (35,576.95)	$ 30,188.85	$ (5,388.10)	$ (3,907.72)
43	Real Time Price Volatility Make Whole Payment	$ (227,358.52)	$ (241.68)	$ (227,600.20)	$ (165,067.24)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 668,649.28	$ (77,828.08)	$ 590,821.20	$ 428,493.57
19	Real-Time Market Administration Amount	$ 60,022.83	$ (4,900.47)	$ 55,122.36	$ 39,977.54
29	Financial Transmission Rights Market Administration Amount	$ 33,086.16	$ -	$ 33,086.16	$ 23,995.77
33	Day-Ahead Schedule 24 Allocation Amount	$ 102,030.51	$ (11,192.83)	$ 90,837.68	$ 65,880.10
34	Real -Time Schedule 24 Allocation Amount	$ (85,266.26)	$ 96,699.92	$ 11,433.66	$ 8,292.27
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	$ 72,027.39	$ 1,486.76	$ 73,514.15	$ 53,316.20
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,693,305.82	$ -	$ 2,693,305.82	$ 1,953,322.31
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,698,826.26)	$ 3,702.46	$ (2,695,123.80)	$ (1,954,640.80)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (235,924.74)	$ -	$ (235,924.74)	$ (171,104.62)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 10,476.18	$ -	$ 10,476.18	$ 7,597.86
	TOTAL MISO CHARGES	**$ (15,838,793.88)**	**$ 21,533,171.28**	**$ 5,694,377.40**	**$ 4,129,851.99**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 679,029.72**	**$ 492,466.87**
	SCHEDULE 24 (FOR RETAIL)			**$ 102,271.34**	**$ 74,172.38**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 4,913,076.34**	**$ 3,563,212.74**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	September 2020 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (5,065,974.72)	$ 9,836,563.53	$ 4,770,588.81	$ 3,443,738.74
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 1,514,311.29	$ -	$ 1,514,311.29	$ 1,093,133.92
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (4,591.09)	$ -	$ (4,591.09)	$ (3,314.16)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (4,536,887.29)	$ -	$ (4,536,887.29)	$ (3,275,036.93)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 620,753.23	$ -	$ 620,753.23	$ 448,102.33
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 4,591.09	$ -	$ 4,591.09	$ 3,314.16
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 8,722.50	$ 852,372.25	$ 861,094.75	$ 621,597.35
13 c	Real-Time Asset Energy Amount - Loss Component	$ 52,849.65	$ -	$ 52,849.65	$ 38,150.51
14	Real-Time Distribution of Losses Amount	$ (978,688.25)	$ -	$ (978,688.25)	$ (706,484.41)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (373,981.79)	$ -	$ (373,981.79)	$ (269,965.75)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 4,401.94	$ -	$ 4,401.94	$ 3,177.62
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (226.82)	$ -	$ (226.82)	$ (163.73)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 7,931,269.55	$ -	$ 7,931,269.55	$ 5,725,335.24
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (8,117.10)	$ -	$ (8,117.10)	$ (5,859.48)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 958,140.99	$ -	$ 958,140.99	$ 691,651.99
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 8,117.10	$ -	$ 8,117.10	$ 5,859.48
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 25,592.82	$ -	$ 25,592.82	$ 18,474.66
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	$ (150.36)	$ -	$ (150.36)	$ (108.54)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (5,854,979.92)	$ -	$ (5,854,979.92)	$ (4,226,526.74)
30	Financial Transmission Rights Monthly Allocation Amount	$ (249,468.92)	$ -	$ (249,468.92)	$ (180,083.80)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (652,256.82)	$ -	$ (652,256.82)	$ (470,843.78)
37	Financial Transmission Guarantee Uplift Amount	$ 636,580.03	$ -	$ 636,580.03	$ 459,527.20
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 7,570,051.42	$ -	$ 7,570,051.42	$ 5,464,583.17
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 117,826.40	$ -	$ 117,826.40	$ 85,055.19
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (184,650.00)	$ 82,759.53	$ (101,890.47)	$ (73,551.54)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 88,418.58	$ -	$ 88,418.58	$ 63,826.61
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (23,371.30)	$ 3,373.57	$ (19,997.73)	$ (14,435.74)
43	Real Time Price Volatility Make Whole Payment	$ 12,906.68	$ 11,527.26	$ 24,433.94	$ 17,638.10
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 554,421.86	$ (55,651.27)	$ 498,770.59	$ 360,046.88
19	Real-Time Market Administration Amount	$ 47,515.50	$ (5,629.38)	$ 41,886.12	$ 30,236.28
29	Financial Transmission Rights Market Administration Amount	$ 37,371.93	$ -	$ 37,371.93	$ 26,977.63
33	Day-Ahead Schedule 24 Allocation Amount	$ 83,076.54	$ (8,266.27)	$ 74,810.27	$ 54,003.19
34	Real -Time Schedule 24 Allocation Amount	$ (80,498.48)	$ 93,326.27	$ 12,827.79	$ 9,259.98
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	$ 71,359.64	$ 1,438.80	$ 72,798.44	$ 52,550.92
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,625,455.56	$ -	$ 2,625,455.56	$ 1,895,234.19
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,625,916.66)	$ 4,260.91	$ (2,621,655.75)	$ (1,892,491.23)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (214,163.14)	$ -	$ (214,163.14)	$ (154,597.67)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 15,573.91	$ -	$ 15,573.91	$ 11,242.32
	TOTAL MISO CHARGES	**$ 2,135,385.55**	**$ 10,816,075.20**	**$ 12,951,460.75**	**$ 9,349,254.13**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 578,028.64**	**$ 417,260.78**
	SCHEDULE 24 (FOR RETAIL)			**$ 87,638.06**	**$ 63,263.17**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 12,285,794.05**	**$ 8,868,730.17**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

October 2020 Actual

		System	Intersystem	System Retail	Minnesota Retail
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (11,496,525.26)	$ 16,057,661.93	$ 4,561,136.67	$ 3,266,207.42
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,340,640.14	$ -	$ 2,340,640.14	$ 1,676,120.83
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (2,132.40)	$ -	$ (2,132.40)	$ (1,527.00)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (4,835,933.01)	$ -	$ (4,835,933.01)	$ (3,462,987.72)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 485,695.12	$ -	$ 485,695.12	$ 347,803.87
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 2,132.40	$ -	$ 2,132.40	$ 1,527.00
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 35,403.37	$ 1,562,332.47	$ 1,597,735.84	$ 1,144,130.74
13 c	Real-Time Asset Energy Amount - Loss Component	$ 19,689.22	$ -	$ 19,689.22	$ 14,099.35
14	Real-Time Distribution of Losses Amount	$ (643,189.75)	$ -	$ (643,189.75)	$ (460,585.00)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 1.29	$ -	$ 1.29	$ 0.92
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (1.29)	$ -	$ (1.29)	$ (0.92)
21	Real-time Net inadvertent Distribution	$ (9,621.84)	$ -	$ (9,621.84)	$ (6,890.15)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 2,482.74	$ -	$ 2,482.74	$ 1,777.88
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (142.05)	$ -	$ (142.05)	$ (101.72)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 5,782,287.86	$ -	$ 5,782,287.86	$ 4,140,667.75
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 459.45	$ -	$ 459.45	$ 329.01
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 915,129.27	$ -	$ 915,129.27	$ 655,319.55
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (459.45)	$ -	$ (459.45)	$ (329.01)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 42,934.66	$ -	$ 42,934.66	$ 30,745.30
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ (12.92)	$ -	$ (12.92)	$ (9.25)
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ 12.92	$ -	$ 12.92	$ 9.25
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (355.24)	$ -	$ (355.24)	$ (254.39)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (2,370,282.95)	$ -	$ (2,370,282.95)	$ (1,697,347.90)
30	Financial Transmission Rights Monthly Allocation Amount	$ (80,242.36)	$ -	$ (80,242.36)	$ (57,461.16)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (66,548.02)	$ -	$ (66,548.02)	$ (47,654.71)
37	Financial Transmission Guarantee Uplift Amount	$ 44,598.27	$ -	$ 44,598.27	$ 31,936.60
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 638,807.22	$ -	$ 638,807.22	$ 457,446.69
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 123,192.46	$ -	$ 123,192.46	$ 88,217.51
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (233,129.24)	$ 88,549.30	$ (144,579.94)	$ (103,532.98)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 113,725.41	$ -	$ 113,725.41	$ 81,438.20
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (91,829.26)	$ 56,761.43	$ (35,067.83)	$ (25,111.90)
43	Real Time Price Volatility Make Whole Payment	$ (270,533.14)	$ 64,501.73	$ (206,031.41)	$ (147,538.07)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 678,669.94	$ (89,036.78)	$ 589,633.16	$ 422,233.39
19	Real-Time Market Administration Amount	$ 61,383.45	$ (8,494.21)	$ 52,889.24	$ 37,873.72
29	Financial Transmission Rights Market Administration Amount	$ 26,618.57	$ -	$ 26,618.57	$ 19,061.43
33	Day-Ahead Schedule 24 Allocation Amount	$ 94,875.65	$ (12,462.69)	$ 82,412.96	$ 59,015.51
34	Real -Time Schedule 24 Allocation Amount	$ (83,939.09)	$ 75,463.90	$ (8,475.19)	$ (6,069.04)
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	$ 60,626.06	$ 1,486.76	$ 62,112.82	$ 44,478.68
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,625,455.56	$ -	$ 2,625,455.56	$ 1,880,075.75
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,625,916.66)	$ 3,936.04	$ (2,621,980.62)	$ (1,877,587.36)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (214,163.14)	$ -	$ (214,163.14)	$ (153,361.17)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 15,573.91	$ -	$ 15,573.91	$ 11,152.40
	TOTAL MISO CHARGES	**$ (8,914,562.13)**	**$ 17,800,699.88**	**$ 8,886,137.75**	**$ 6,363,319.32**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 669,140.97**	**$ 479,168.54**
	SCHEDULE 24 (FOR RETAIL)			**$ 73,937.77**	**$ 52,946.47**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 8,143,059.01**	**$ 5,831,204.31**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	November 2020 Actual				
	Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (11,537,023.10)	$ 15,897,550.18	$ 4,360,527.08	$ 3,110,980.84
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,394,170.57	$ -	$ 2,394,170.57	$ 1,708,100.57
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (708.72)	$ -	$ (708.72)	$ (505.63)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (2,223,459.65)	$ -	$ (2,223,459.65)	$ (1,586,308.32)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 190,751.76	$ -	$ 190,751.76	$ 136,090.22
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 708.72	$ -	$ 708.72	$ 505.63
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 599,972.31	$ 1,726,928.29	$ 2,326,900.60	$ 1,660,107.38
13 c	Real-Time Asset Energy Amount - Loss Component	$ (12,378.65)	$ -	$ (12,378.65)	$ (8,831.44)
14	Real-Time Distribution of Losses Amount	$ (730,299.79)	$ -	$ (730,299.79)	$ (521,026.15)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (14,296.99)	$ -	$ (14,296.99)	$ (10,200.07)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (1,108.34)	$ -	$ (1,108.34)	$ (790.74)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (4.57)	$ -	$ (4.57)	$ (3.26)
	Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 6,090,441.83	$ -	$ 6,090,441.83	$ 4,345,173.76
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (13,010.72)	$ -	$ (13,010.72)	$ (9,282.39)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 250,273.42	$ -	$ 250,273.42	$ 178,555.44
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 13,010.72	$ -	$ 13,010.72	$ 9,282.39
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 101,498.80	$ -	$ 101,498.80	$ 72,413.45
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (0.00)	$ -	$ (0.00)	$ (0.00)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (3.18)	$ -	$ (3.18)	$ (2.27)
	FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	$ (584,048.19)	$ -	$ (584,048.19)	$ (416,684.20)
30	Financial Transmission Rights Monthly Allocation Amount	$ (57,459.03)	$ -	$ (57,459.03)	$ (40,993.65)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 9,480.32	$ -	$ 9,480.32	$ 6,763.65
37	Financial Transmission Guarantee Uplift Amount	$ (19,783.92)	$ -	$ (19,783.92)	$ (14,114.67)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
	Uplift (RNU) Charges				
23	Real-Time Revenue Neutrality Uplift Amount	$ 555,216.02	$ -	$ 555,216.02	$ 396,114.13
	Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 104,585.51	$ -	$ 104,585.51	$ 74,615.64
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (139,130.87)	$ 85,661.59	$ (53,469.28)	$ (38,147.20)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 204,780.30	$ -	$ 204,780.30	$ 146,098.76
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (138,612.24)	$ 65,909.20	$ (72,703.04)	$ (51,869.36)
43	Real Time Price Volatility Make Whole Payment	$ 1,448.79	$ 13,434.01	$ 14,882.80	$ 10,618.01
	Market Administration Charges				
4	Day-Ahead Market Administration Amount	$ 627,410.14	$ (89,464.83)	$ 537,945.31	$ 383,792.49
19	Real-Time Market Administration Amount	$ 63,680.00	$ (10,871.03)	$ 52,808.97	$ 37,676.11
29	Financial Transmission Rights Market Administration Amount	$ 26,238.72	$ -	$ 26,238.72	$ 18,719.79
33	Day-Ahead Schedule 24 Allocation Amount	$ 93,946.67	$ (13,609.37)	$ 80,337.30	$ 57,315.96
34	Real -Time Schedule 24 Allocation Amount	$ (83,499.62)	$ 100,374.30	$ 16,874.68	$ 12,039.10
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	$ 43,183.48	$ 1,438.80	$ 44,622.28	$ 31,835.38
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
	Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,625,455.56	$ -	$ 2,625,455.56	$ 1,873,108.87
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,625,916.66)	$ 4,276.35	$ (2,621,640.31)	$ (1,870,386.91)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (214,163.14)	$ -	$ (214,163.14)	$ (152,792.86)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 15,573.91	$ -	$ 15,573.91	$ 11,111.07
	TOTAL MISO CHARGES	**$ (4,383,079.83)**	**$ 17,781,627.49**	**$ 13,398,547.66**	**$ 9,559,079.51**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 616,993.00**	**$ 440,188.39**
	SCHEDULE 24 (FOR RETAIL)			**$ 97,211.98**	**$ 69,355.06**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 12,684,342.68**	**$ 9,049,536.06**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	December 2020 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (22,520,628.75)	$ 25,790,049.33	$ 3,269,420.58	$ 2,312,351.59
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,646,477.41	$ -	$ 2,646,477.41	$ 1,871,764.77
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (2,031.29)	$ -	$ (2,031.29)	$ (1,436.66)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (2,837,734.93)	$ -	$ (2,837,734.93)	$ (2,007,034.80)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 236,172.81	$ -	$ 236,172.81	$ 167,037.11
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 2,031.29	$ -	$ 2,031.29	$ 1,436.66
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 855,589.26	$ 1,104,970.87	$ 1,960,560.13	$ 1,386,638.46
13 c	Real-Time Asset Energy Amount - Loss Component	$ (22,014.36)	$ -	$ (22,014.36)	$ (15,570.02)
14	Real-Time Distribution of Losses Amount	$ (673,124.03)	$ -	$ (673,124.03)	$ (476,078.06)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (9,356.62)	$ -	$ (9,356.62)	$ (6,617.62)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 9,581.06	$ -	$ 9,581.06	$ 6,776.36
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 2.17	$ -	$ 2.17	$ 1.53
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 8,093,979.09	$ -	$ 8,093,979.09	$ 5,724,600.11
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (5,997.02)	$ -	$ (5,997.02)	$ (4,241.49)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 126,173.94	$ -	$ 126,173.94	$ 89,238.60
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 5,997.02	$ -	$ 5,997.02	$ 4,241.49
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 35,768.56	$ -	$ 35,768.56	$ 25,297.90
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	$ (1.21)	$ -	$ (1.21)	$ (0.86)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,925,936.62)	$ -	$ (1,925,936.62)	$ (1,362,150.42)
30	Financial Transmission Rights Monthly Allocation Amount	$ (48,720.19)	$ -	$ (48,720.19)	$ (34,458.16)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (307,690.84)	$ -	$ (307,690.84)	$ (217,619.42)
37	Financial Transmission Guarantee Uplift Amount	$ 309,546.77	$ -	$ 309,546.77	$ 218,932.05
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 802,449.46	$ -	$ 802,449.46	$ 567,545.61
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 129,438.24	$ -	$ 129,438.24	$ 91,547.33
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (281,603.78)	$ 77,626.88	$ (203,976.90)	$ (144,266.02)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 84,757.66	$ -	$ 84,757.66	$ 59,946.25
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (41,486.80)	$ 22,063.63	$ (19,423.17)	$ (13,737.36)
43	Real Time Price Volatility Make Whole Payment	$ (75,368.67)	$ 10,494.28	$ (64,874.39)	$ (45,883.48)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 759,840.32	$ (123,610.72)	$ 636,229.60	$ 449,983.87
19	Real-Time Market Administration Amount	$ 55,670.32	$ (5,164.48)	$ 50,505.84	$ 35,721.09
29	Financial Transmission Rights Market Administration Amount	$ 29,024.12	$ -	$ 29,024.12	$ 20,527.79
33	Day-Ahead Schedule 24 Allocation Amount	$ 103,445.62	$ (16,888.82)	$ 86,556.80	$ 61,218.72
34	Real -Time Schedule 24 Allocation Amount	$ (90,734.75)	$ 89,415.63	$ (1,319.12)	$ (932.97)
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	$ 16,668.65	$ 1,486.76	$ 18,155.41	$ 12,840.71
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,635,397.07	$ -	$ 1,635,397.07	$ 1,156,661.53
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,639,395.05)	$ 35,439.71	$ (1,603,955.34)	$ (1,134,423.85)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (202,829.08)	$ -	$ (202,829.08)	$ (143,454.21)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 22,549.31	$ -	$ 22,549.31	$ 15,948.37
	TOTAL MISO CHARGES	**$ (14,724,093.84)**	**$ 26,985,883.07**	**$ 12,261,789.23**	**$ 8,672,352.52**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 715,759.56**	**$ 506,232.75**
	SCHEDULE 24 (FOR RETAIL)			**$ 85,237.68**	**$ 60,285.75**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 11,460,791.99**	**$ 8,105,834.02**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	January - December 2020 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (128,502,570.94)	$ 177,095,705.87	$ 48,593,134.93	$ 34,829,886.63
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 24,510,201.56	$ -	$ 24,510,201.56	$ 17,568,068.88
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (21,514.89)	$ -	$ (21,514.89)	$ (15,421.13)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (44,888,372.17)	$ -	$ (44,888,372.17)	$ (32,174,440.19)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 4,850,593.60	$ -	$ 4,850,593.60	$ 3,476,738.54
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 21,807.39	$ -	$ 21,807.39	$ 15,630.79
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (3,969,947.87)	$ 19,367,513.32	$ 15,397,565.45	$ 11,036,444.96
13 c	Real-Time Asset Energy Amount - Loss Component	$ 476,891.04	$ -	$ 476,891.04	$ 341,819.08
14	Real-Time Distribution of Losses Amount	$ (7,605,594.38)	$ -	$ (7,605,594.38)	$ (5,451,428.28)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ (0.47)	$ -	$ (0.47)	$ (0.34)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ 0.47	$ -	$ 0.47	$ 0.34
21	Real-time Net inadvertent Distribution	$ 73,327.89	$ -	$ 73,327.89	$ 52,558.91
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 55,294.23	$ -	$ 55,294.23	$ 39,633.00
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (2,170.20)	$ -	$ (2,170.20)	$ (1,555.52)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 58,423,779.21	$ -	$ 58,423,779.21	$ 41,876,154.10
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (8,504.22)	$ -	$ (8,504.22)	$ (6,095.53)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 7,083,472.37	$ -	$ 7,083,472.37	$ 5,077,189.19
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 9,156.72	$ -	$ 9,156.72	$ 6,563.22
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 1,041,324.90	$ -	$ 1,041,324.90	$ 746,385.85
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 15.38	$ -	$ 15.38	$ 11.02
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (15.38)	$ -	$ (15.38)	$ (11.02)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (2,680.43)	$ -	$ (2,680.43)	$ (1,921.24)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (33,033,724.05)	$ -	$ (33,033,724.05)	$ (23,677,436.44)
30	Financial Transmission Rights Monthly Allocation Amount	$ (1,497,340.89)	$ -	$ (1,497,340.89)	$ (1,073,242.41)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ (6,000.54)	$ -	$ (6,000.54)	$ (4,300.98)
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (1,403,749.88)	$ -	$ (1,403,749.88)	$ (1,006,159.60)
37	Financial Transmission Guarantee Uplift Amount	$ 1,475,215.32	$ -	$ 1,475,215.32	$ 1,057,383.57
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 12,046,574.25	$ -	$ 12,046,574.25	$ 8,634,569.80
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 947,263.25	$ -	$ 947,263.25	$ 678,965.69
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (1,589,289.29)	$ 620,054.59	$ (969,234.70)	$ (694,714.07)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 1,275,200.13	$ -	$ 1,275,200.13	$ 914,019.56
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (710,664.12)	$ 382,277.75	$ (328,386.37)	$ (235,376.05)
43	Real Time Price Volatility Make Whole Payment	$ (1,843,332.87)	$ 413,902.63	$ (1,429,430.24)	$ (1,024,566.40)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 8,012,501.15	$ (904,748.41)	$ 7,107,752.74	$ 5,094,592.53
19	Real-Time Market Administration Amount	$ 729,759.28	$ (110,684.35)	$ 619,074.93	$ 443,731.60
29	Financial Transmission Rights Market Administration Amount	$ 384,907.18	$ -	$ 384,907.18	$ 275,888.22
33	Day-Ahead Schedule 24 Allocation Amount	$ 1,140,271.84	$ (127,899.80)	$ 1,012,372.04	$ 725,633.43
34	Real -Time Schedule 24 Allocation Amount	$ (1,007,219.43)	$ 1,072,488.99	$ 65,269.56	$ 46,782.97
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	$ 1,356,499.03	$ 70,526.88	$ 1,427,025.91	$ 1,022,843.06
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 23,762,360.76	$ -	$ 23,762,360.76	$ 17,032,042.33
40	Auction Revenue Rights - Monthly ARR Revenue	$ (23,785,632.51)	$ 190,859.49	$ (23,594,773.02)	$ (16,911,921.21)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (2,464,122.48)	$ -	$ (2,464,122.48)	$ (1,766,198.18)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 262,635.67	$ -	$ 262,635.67	$ 188,248.21
	TOTAL MISO CHARGES	**$ (104,403,394.39)**	**$ 198,069,996.96**	**$ 93,666,602.57**	**$ 67,136,996.88**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 8,111,734.85**	**$ 5,814,212.35**
	SCHEDULE 24 (FOR RETAIL)			**$ 1,077,641.60**	**$ 772,416.41**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 84,477,226.12**	**$ 60,550,368.13**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

January 2020	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**
Day Ahead & Real Time Energy								
1a Day Ahead Asset Energy	(727,169)	$ (13,664,095.31)	48,308	$ 1,617,339.90	(775,477)	$ (15,281,435.21)		
5a Day Ahead Non Asset Energy	(112,961)	$ (2,662,705.60)	(112,961)	$ (2,662,705.60)			11,784	$ 239,580.24
13a Real Time Asset Energy	(37,194)	$ (679,931.39)	75,392	$ 1,990,274.28	(112,586)	$ (2,670,205.67)		
22a Real Time Non Asset Energy	-	$ 7.59	-	$ 7.59			-	$ -
SUBTOTAL	(877,324)	$ (17,006,724.71)	10,739	$ 944,916.17	(888,063)	$ (17,951,640.88)	11,784	$ 239,580.24
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,463,499.62		$ 2,463,499.62		$ -		
5c Day Ahead Non Asset Loss		$ 168,470.70		$ 168,470.70		$ -		
3 Day Ahead Financial Bilateral Transaction Loss		$ 911.27		$ 911.27		$ -		
13c Real Time Loss		$ 28,603.35		$ 28,603.35		$ -		
22c Real Time Non Asset Loss		$ -		$ -		$ -		
14 Real Time Distribution Losses		$ (709,133.44)		$ (709,133.44)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 1,952,351.50	-	$ 1,952,351.50	-	$ -	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 805,185.59		$ 728,154.38		$ 77,031.21		$ 1,168.23
19 Real Time Market Administration (Schedule 17)		$ 71,250.25		$ 60,247.20		$ 11,003.05		$ -
29 Financial Transmission Rights Administration (Schedule 16)		$ 26,540.06		$ 26,540.06		$ -		$ 98.88
33 Day-Ahead Schedule 24 Allocation Amount		$ 95,698.49		$ 86,548.52		$ 9,149.97		$ 136.25
34 Real -Time Schedule 24 Allocation Amount		$ (92,613.79)		$ (8,802.34)		$ (83,811.45)		$ -
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 906,060.60	-	$ 892,687.82	-	$ 13,372.78	-	$ 1,403.36
Congestion & FTRs								
1b Day Ahead Congestion		$ 2,373,432.80		$ 2,373,432.80		$ -		
5b Day Ahead Non Asset Congestion		$ 21,326.25		$ 21,326.25		$ -		
13b Real Time Congestion		$ 7,126.96		$ 7,126.96		$ -		
22b Real Time Non Asset Congestion		$ -		$ -		$ -		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 5,965.44		$ 5,965.44				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (1,184,430.87)		$ (1,184,430.87)		$ -		$ 15,263.53
30 Financial Transmission Rights Monthly Allocation		$ (89,274.04)		$ (89,274.04)				$ (497.16)
32 Financial Transmission Rights Yearly Allocation		$ (6,000.37)		$ (6,000.37)				$ (17.23)
31 Financial Transmission Rights Transaction		$ -		$ -				$ -
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (51,912.89)		$ (51,912.89)				$ 282.86
37 Financial Transmission Guarantee Uplift Amount		$ 158,412.36		$ 158,412.36				$ 285.36
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				$ 7,129.50
SUBTOTAL	-	$ 1,234,645.64	-	$ 1,234,645.64	-	$ -	-	$ 22,446.86
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 76,283.62		$ 76,283.62		$ -		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (91,615.49)		$ (24,522.70)		$ (67,092.79)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 50,802.10		$ 50,802.10		$ -		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (11,981.69)		$ 801.11		$ (12,782.80)		
43 Real Time Price Volatility Make Whole Payment		$ (148,084.41)		$ (124,009.99)		$ (24,074.42)		
SUBTOTAL	-	$ (124,595.87)	-	$ (20,645.86)	-	$ (103,950.01)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 44,676.61		$ 56,967.18		$ (12,290.57)		$ -
21 Real Time Net Inadvertent Distribution		$ 36,499.45		$ 36,499.45				$ 62.87
23 Real Time Revenue Neutrality Uplift Amount		$ 344,512.71		$ 344,512.71		$ -		$ -
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		$ -
SUBTOTAL	-	$ 425,688.77	-	$ 437,979.34	-	$ (12,290.57)	-	$ 62.87
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 1,123,444.70		$ 1,123,444.70				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (1,123,867.22)		$ (1,070,847.66)		$ (53,019.56)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (207,296.29)		$ (207,296.29)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 42,660.70		$ 42,660.70				
SUBTOTAL	-	$ (165,058.11)	-	($112,039)	-	($53,020)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (5,965.44)		$ (5,965.44)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (911.27)		$ (911.27)				
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	-	$ (6,876.71)	-	$ (6,876.71)	-	$ -	-	$ -
Total MISO Day 2 Charges	(877,324)	$ (12,784,508.89)	10,739	$ 5,323,019.35	(888,063)	$ (18,107,528.24)	11,784	$ 263,493.33

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

February 2020		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**
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(390,423)	$ (6,018,450.22)	148,196	$ 3,278,781.76	(538,619)	$ (9,297,231.98)		
5a	Day Ahead Non Asset Energy	(97,355)	$ (2,187,166.16)	(97,355)	$ (2,187,166.16)			10,968	$ 200,157.90
13a	Real Time Asset Energy	(55,390)	$ (927,304.90)	137,725	$ 1,643,361.25	(193,115)	$ (2,570,666.15)		
22a	Real Time Non Asset Energy	-	$ (14.39)	-	$ (14.39)			-	
	SUBTOTAL	(543,168)	$ (9,132,935.67)	188,566	$ 2,734,962.46	(731,734)	$ (11,867,898.13)	10,968	$ 200,157.90
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss		$ 2,119,119.41		$ 2,119,119.41		$ -		
5c	Day Ahead Non Asset Loss		$ 149,186.61		$ 149,186.61		$ -		
3	Day Ahead Financial Bilateral Transaction Loss		$ 1,340.79		$ 1,340.79		$ -		
13c	Real Time Loss		$ 14,877.48		$ 14,877.48		$ -		
22c	Real Time Non Asset Loss		$ (307.63)		$ (307.63)		$ -		
14	Real Time Distribution Losses		$ (591,412.23)		$ (591,412.23)				
16	Real Time Financial Bilateral Loss		$ -		$ -				
	SUBTOTAL	-	$ 1,692,804.43	-	$ 1,692,804.43	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy		$ -		$ -				
27	Real Time Virtual Energy		$ -		$ -				
	SUBTOTAL	-	$0	-	$0	-	$0	-	$0
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)		$ 614,153.73		$ 567,143.70		$ 47,010.03		$ 952.80
19	Real Time Market Administration (Schedule 17)		$ 56,224.91		$ 39,211.91		$ 17,013.00		$ -
29	Financial Transmission Rights Administration (Schedule 16)		$ 23,493.72		$ 23,493.72		$ -		$ 86.00
33	Day-Ahead Schedule 24 Allocation Amount		$ 90,256.88		$ 83,396.08		$ 6,860.80		$ 140.72
34	Real -Time Schedule 24 Allocation Amount		$ (84,023.82)		$ 4,188.92		$ (88,212.74)		$ -
35	Schedule 24 Admin Allocation		$ -				$ -		$ -
	SUBTOTAL	-	$ 700,105.42	-	$ 717,434.33	-	$ (17,328.91)	-	$ 1,179.52
	Congestion & FTRs								
1b	Day Ahead Congestion		$ 2,563,775.02		$ 2,563,775.02		$ -		
5b	Day Ahead Non Asset Congestion		$ 129,680.20		$ 129,680.20		$ -		
13b	Real Time Congestion		$ (51,303.24)		$ (51,303.24)		$ -		
22b	Real Time Non Asset Congestion		$ 322.32		$ 322.32		$ -		
2	Day Ahead Financial Bilateral Transaction Congestion		$ 2,766.05		$ 2,766.05				
15	Real Time Financial Bilateral Congestion		$ -		$ -				
28	Financial Transmission Rights Hourly Allocation		$ (1,875,545.10)		$ (1,875,545.10)		$ -		$ (2,009.53)
30	Financial Transmission Rights Monthly Allocation		$ (89,523.55)		$ (89,523.55)				$ (116.18)
32	Financial Transmission Rights Yearly Allocation		$ (0.17)		$ (0.17)				$ -
31	Financial Transmission Rights Transaction		$ -		$ -				$ -
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 10,383.88		$ 10,383.88				$ (40.79)
37	Financial Transmission Guarantee Uplift Amount		$ (10,039.34)		$ (10,039.34)				$ 94.16
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				$ 7,552.00
	SUBTOTAL	-	$ 680,516.07	-	$ 680,516.07	-	$ -	-	$ 5,479.66
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 40,481.08		$ 40,481.08		$ -		
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (59,631.25)		$ (43,670.12)		$ (15,961.13)		
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 19,482.50		$ 19,482.50		$ -		
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (1,644.65)		$ 9,682.59		$ (11,327.24)		
43	Real Time Price Volatility Make Whole Payment		$ (59,208.19)		$ (5,811.36)		$ (53,396.83)		
	SUBTOTAL	-	$ (60,520.51)	-	$ 20,164.69	-	$ (80,685.20)	-	$ -
	Other Charges								
20	Real Time Miscellaneous		$ 133,223.48		$ 144,721.11		$ (11,497.63)		
21	Real Time Net Inadvertent Distribution		$ 38,123.41		$ 38,123.41				$ 72.49
23	Real Time Revenue Neutrality Uplift Amount		$ 177,128.63		$ 177,128.63		$ -		$ -
26	Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		$ -
	SUBTOTAL	-	$ 348,475.52	-	$ 359,973.15	-	$ (11,497.63)	-	$ 72.49
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions		$ 1,123,444.70		$ 1,123,444.70				
40	Auction Revenue Rights - Monthly ARR Revenue		$ (1,123,867.22)		$ (1,068,028.70)		$ (55,838.52)		
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (207,296.29)		$ (207,296.29)				
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 42,660.70		$ 42,660.70				
	SUBTOTAL	-	$ (165,058.11)	-	($109,220)	-	($55,839)	-	$0
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (2,766.05)		$ (2,766.05)				
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (1,340.79)		$ (1,340.79)				
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	-	$ (4,106.84)	-	$ (4,106.84)	-	$ -	-	$ -
	Total MISO Day 2 Charges	(543,168)	$ (5,940,719.69)	188,566	$ 6,092,528.70	(731,734)	$ (12,033,248.39)	10,968	$ 206,889.57

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

March 2020	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**
Day Ahead & Real Time Energy								
1a Day Ahead Asset Energy	(645,852)	$ (9,619,892.34)	113,368	$ 2,510,989.16	(759,220)	$ (12,130,881.50)		
5a Day Ahead Non Asset Energy	(110,508)	$ (2,373,873.21)	(110,508)	$ (2,373,873.21)			11,784	$ 187,407.02
13a Real Time Asset Energy	(56,399)	$ (768,350.50)	101,372	$ 1,276,658.84	(157,771)	$ (2,045,009.34)		
22a Real Time Non Asset Energy	218	$ 3,669.11	218	$ 3,669.11			-	$ -
SUBTOTAL	(812,541)	$ (12,758,446.94)	104,450	$ 1,417,443.90	(916,991)	$ (14,175,890.84)	11,784	$ 187,407.02
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 1,848,618.40		$ 1,848,618.40		$ -		
5c Day Ahead Non Asset Loss		$ 218,815.70		$ 218,815.70		$ -		
3 Day Ahead Financial Bilateral Transaction Loss		$ (1,190.39)		$ (1,190.39)		$ -		
13c Real Time Loss		$ 57,718.34		$ 57,718.34		$ -		
22c Real Time Non Asset Loss		$ (482.54)		$ (482.54)		$ -		
14 Real Time Distribution Losses		$ (276,694.25)		$ (276,694.25)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 1,846,785.26	-	$ 1,846,785.26	-	$ -	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 500,478.89		$ 446,719.39		$ 53,759.50		$ 824.56
19 Real Time Market Administration (Schedule 17)		$ 45,399.19		$ 34,653.94		$ 10,745.25		$ -
29 Financial Transmission Rights Administration (Schedule 16)		$ 44,638.31		$ 44,638.31		$ -		$ 0.40
33 Day-Ahead Schedule 24 Allocation Amount		$ 99,264.65		$ 89,248.98		$ 10,015.67		$ 171.44
34 Real -Time Schedule 24 Allocation Amount		$ (78,460.00)		$ 10,956.44		$ (89,416.44)		$ -
35 Schedule 24 Admin Allocation		$ -				$ -		$ -
SUBTOTAL	-	$ 611,321.04	-	$ 626,217.06	-	$ (14,896.02)	-	$ 996.40
Congestion & FTRs								
1b Day Ahead Congestion		$ 3,596,708.32		$ 3,596,708.32		$ -		
5b Day Ahead Non Asset Congestion		$ 222,181.20		$ 222,181.20		$ -		
13b Real Time Congestion		$ 101,555.02		$ 101,555.02		$ -		
22b Real Time Non Asset Congestion		$ (1,319.45)		$ (1,319.45)		$ -		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (660.08)		$ (660.08)				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (3,929,675.14)		$ (3,929,675.14)		$ -		$ 77.08
30 Financial Transmission Rights Monthly Allocation		$ (54,490.34)		$ (54,490.34)				$ (306.85)
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				$ -
31 Financial Transmission Rights Transaction		$ -		$ -				$ -
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (60,407.68)		$ (60,407.68)				$ 229.77
37 Financial Transmission Guarantee Uplift Amount		$ 62,381.04		$ 62,381.04				$ (229.77)
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				$ -
SUBTOTAL	-	$ (63,727.11)	-	$ (63,727.11)	-	$ -	-	$ (229.77)
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 46,930.49		$ 46,930.49		$ -		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (33,041.29)		$ (44,614.16)		$ 11,572.87		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 20,258.92		$ 20,258.92		$ -		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (2,268.11)		$ (1,521.96)		$ (746.15)		
43 Real Time Price Volatility Make Whole Payment		$ (144,850.29)		$ (98,864.97)		$ (45,985.32)		
SUBTOTAL	-	$ (112,970.28)	-	$ (77,811.68)	-	$ (35,158.60)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 788,134.30		$ 800,424.87		$ (12,290.57)		
21 Real Time Net Inadvertent Distribution		$ 205,432.69		$ 205,432.69				$ 294.75
23 Real Time Revenue Neutrality Uplift Amount		$ 124,952.38		$ 124,952.38		$ -		$ -
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		$ -
SUBTOTAL	-	$ 1,118,519.37	-	$ 1,130,809.94	-	$ (12,290.57)	-	$ 294.75
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 1,307,930.05		$ 1,307,930.05				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (1,308,091.42)		$ (1,301,581.99)		$ (6,509.43)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (165,478.97)		$ (165,478.97)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 25,524.46		$ 25,524.46				
SUBTOTAL	-	$ (140,115.88)	-	($133,606)	-	($6,509)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 660.08		$ 660.08				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 1,190.39		$ 1,190.39				
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	-	$ 1,850.47	-	$ 1,850.47	-	$ -	-	$ -
Total MISO Day 2 Charges	(812,541)	$ (9,496,784.07)	104,450	$ 4,747,961.39	(916,991)	$ (14,244,745.46)	11,784	$ 188,468.40

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MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

April 2020	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**
Day Ahead & Real Time Energy								
1a Day Ahead Asset Energy	(718,332)	$ (9,162,168.42)	65,298	$ 1,610,185.34	(783,630)	$ (10,772,353.76)		
5a Day Ahead Non Asset Energy	(84,861)	$ (1,685,255.90)	(84,861)	$ (1,685,255.90)			11,472	$ 169,825.70
13a Real Time Asset Energy	(88,607)	$ (1,465,914.94)	49,610	$ 358,936.89	(138,217)	$ (1,824,851.83)		
22a Real Time Non Asset Energy	720	$ 12,698.00	720	$ 12,698.00			-	$ -
SUBTOTAL	(891,080)	$ (12,300,641.26)	30,767	$ 296,564.33	(921,847)	$ (12,597,205.59)	11,472	$ 169,825.70
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 1,420,562.66		$ 1,420,562.66		$ -		
5c Day Ahead Non Asset Loss		$ 169,188.78		$ 169,188.78		$ -		
3 Day Ahead Financial Bilateral Transaction Loss		$ (825.34)		$ (825.34)		$ -		
13c Real Time Loss		$ 78,924.44		$ 78,924.44		$ -		
22c Real Time Non Asset Loss		$ (724.45)		$ (724.45)		$ -		
14 Real Time Distribution Losses		$ (395,148.88)		$ (395,148.88)				
16 Real Time Financial Bilateral Loss		$ (1.76)		$ (1.76)				
SUBTOTAL	-	$ 1,271,975.45	-	$ 1,271,975.45	-	$ -	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 721,919.99		$ 634,923.59		$ 86,996.40		$ 1,290.58
19 Real Time Market Administration (Schedule 17)		$ 75,819.33		$ 59,755.69		$ 16,063.64		
29 Financial Transmission Rights Administration (Schedule 16)		$ 37,070.73		$ 37,070.73		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 94,485.30		$ 83,480.13		$ 11,005.17		$ 171.35
34 Real -Time Schedule 24 Allocation Amount		$ (74,746.63)		$ 7,598.24		$ (82,344.87)		$ -
35 Schedule 24 Admin Allocation		$ -				$ -		$ -
SUBTOTAL	-	$ 854,548.72	-	$ 822,828.38	-	$ 31,720.34	-	$ 1,461.93
Congestion & FTRs								
1b Day Ahead Congestion		$ 2,587,122.63		$ 2,587,122.63		$ -		
5b Day Ahead Non Asset Congestion		$ 421,514.18		$ 421,514.18		$ -		
13b Real Time Congestion		$ 204,188.33		$ 204,188.33		$ -		
22b Real Time Non Asset Congestion		$ (324.63)		$ (324.63)		$ -		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (1,908.93)		$ (1,908.93)				
15 Real Time Financial Bilateral Congestion		$ 28.30		$ 28.30				
28 Financial Transmission Rights Hourly Allocation		$ (2,668,152.09)		$ (2,668,152.09)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (263,476.32)		$ (263,476.32)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (93,025.52)		$ (93,025.52)				
37 Financial Transmission Guarantee Uplift Amount		$ 88,306.19		$ 88,306.19				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ 274,272.14	-	$ 274,272.14	-	$ -	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 66,893.10		$ 66,893.10		$ -		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (131,874.13)		$ (58,112.06)		$ (73,762.07)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 61,467.53		$ 61,467.53		$ -		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (113,764.26)		$ (7,148.35)		$ (106,615.91)		
43 Real Time Price Volatility Make Whole Payment		$ (360,624.72)		$ (255,452.67)		$ (105,172.05)		
SUBTOTAL	-	$ (477,902.48)	-	$ (192,352.45)	-	$ (285,550.03)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 130,988.21		$ 142,882.31		$ (11,894.10)		
21 Real Time Net Inadvertent Distribution		$ (138,359.00)		$ (138,359.00)				$ (307.72)
23 Real Time Revenue Neutrality Uplift Amount		$ 499,577.98		$ 499,577.98		$ -		$ -
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		$ -
SUBTOTAL	-	$ 492,207.19	-	$ 504,101.29	-	$ (11,894.10)	-	$ (307.72)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 1,307,930.05		$ 1,307,930.05				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (1,308,091.42)		$ (1,299,987.65)		$ (8,103.77)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (165,479.06)		$ (165,479.06)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 25,524.46		$ 25,524.46				
SUBTOTAL	-	$ (140,115.97)	-	($132,012)	-	($8,104)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 1,908.93		$ 1,908.93				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 825.34		$ 825.34				
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		$ (28.30)		$ (28.30)				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ 1.76		$ 1.76				
SUBTOTAL	-	$ 2,707.73	-	$ 2,707.73	-	$ -	-	$ -
Total MISO Day 2 Charges	(891,080)	$ (10,022,948.48)	30,767	$ 2,848,084.67	(921,847)	$ (12,871,033.15)	11,472	$ 170,979.91

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MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

May 2020	NET INVOICE		RETAIL		Intersystem			
					ASSET BASED		NON-ASSET BASED	
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	(555,397)	$ (5,625,702.29)	170,184	$ 4,120,158.84	(725,581)	$ (9,745,861.13)		
5a Day Ahead Non Asset Energy	(187,339)	$ (4,124,776.16)	(187,339)	$ (4,124,776.16)			11,592	$ 179,305.32
13a Real Time Asset Energy	53,649	$ 647,175.42	150,070	$ 2,065,682.19	(96,421)	$ (1,418,506.77)		
22a Real Time Non Asset Energy	537	$ 10,289.18	537	$ 10,289.18			-	$ -
SUBTOTAL	(688,550)	$ (9,093,013.85)	133,452	$ 2,071,354.05	(822,002)	$ (11,164,367.90)	11,592	$ 179,305.32
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 1,133,090.81		$ 1,133,090.81		$ -		
5c Day Ahead Non Asset Loss		$ 502,544.58		$ 502,544.58		$ -		
3 Day Ahead Financial Bilateral Transaction Loss		$ (2,711.07)		$ (2,711.07)		$ -		
13c Real Time Loss		$ 22,813.33		$ 22,813.33		$ -		
22c Real Time Non Asset Loss		$ (899.95)		$ (899.95)		$ -		
14 Real Time Distribution Losses		$ (430,385.94)		$ (430,385.94)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 1,224,451.76	-	$ 1,224,451.76	-	$ -	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 632,134.58		$ 560,948.36		$ 71,186.22		$ 1,126.41
19 Real Time Market Administration (Schedule 17)		$ 56,433.44		$ 47,264.93		$ 9,168.51		$ -
29 Financial Transmission Rights Administration (Schedule 16)		$ 32,565.06		$ 32,565.06		$ -		$ -
33 Day-Ahead Schedule 24 Allocation Amount		$ 90,934.77		$ 80,795.29		$ 10,139.48		$ 162.72
34 Real -Time Schedule 24 Allocation Amount		$ (78,551.27)		$ 2,677.66		$ (81,228.93)		$ -
35 Schedule 24 Admin Allocation		$ -				$ -		$ -
SUBTOTAL	-	$ 733,516.58	-	$ 724,251.30	-	$ 9,265.28	-	$ 1,289.13
Congestion & FTRs								
1b Day Ahead Congestion		$ 2,462,909.00		$ 2,462,909.00		$ -		
5b Day Ahead Non Asset Congestion		$ 1,014,585.58		$ 1,014,585.58		$ -		
13b Real Time Congestion		$ 11,378.75		$ 11,378.75		$ -		
22b Real Time Non Asset Congestion		$ (596.78)		$ (596.78)		$ -		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (273.60)		$ (273.60)				
15 Real Time Financial Bilateral Congestion		$ 0.00		$ 0.00				
28 Financial Transmission Rights Hourly Allocation		$ (1,766,600.32)		$ (1,766,600.32)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (101,537.77)		$ (101,537.77)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ 8,648.58		$ 8,648.58				
37 Financial Transmission Guarantee Uplift Amount		$ (3,204.96)		$ (3,204.96)				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ 1,625,308.48	-	$ 1,625,308.48	-	$ -	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 40,705.97		$ 40,705.97		$ -		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (116,968.22)		$ (56,564.21)		$ (60,404.01)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 27,817.73		$ 27,817.73		$ -		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (9,019.09)		$ (10,133.24)		$ 1,114.15		
43 Real Time Price Volatility Make Whole Payment		$ (31,652.40)		$ (3,321.39)		$ (28,331.01)		
SUBTOTAL	-	$ (89,116.01)	-	$ (1,495.14)	-	$ (87,620.87)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ (60,172.84)		$ (47,882.27)		$ (12,290.57)		
21 Real Time Net Inadvertent Distribution		$ (65,577.62)		$ (65,577.62)				$ (93.77)
23 Real Time Revenue Neutrality Uplift Amount		$ 736,528.70		$ 736,528.70		$ -		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 610,778.24	-	$ 623,068.81	-	$ (12,290.57)	-	$ (93.77)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 1,307,930.05		$ 1,307,930.05				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (1,308,091.42)		$ (1,299,747.90)		$ (8,343.52)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (165,479.06)		$ (165,479.06)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 25,524.46		$ 25,524.46				
SUBTOTAL	-	$ (140,115.97)	-	($131,772)	-	($8,344)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 273.60		$ 273.60				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 2,711.07		$ 2,711.07				
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		$ 0.00		$ 0.00				
SUBTOTAL	-	$ 2,984.67	-	$ 2,984.67	-	$ -	-	$ -
Total MISO Day 2 Charges	(688,550)	$ (5,125,206.10)	133,452	$ 6,138,151.48	(822,002)	$ (11,263,357.58)	11,592	$ 180,500.68

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MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

June 2020	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**
Day Ahead & Real Time Energy								
1a Day Ahead Asset Energy	(401,713)	$ (4,799,200.25)	240,917	$ 5,787,969.94	(642,630)	$ (10,587,170.19)		
5a Day Ahead Non Asset Energy	(184,083)	$ (4,782,517.35)	(184,083)	$ (4,782,517.35)			11,472	$ 182,201.13
13a Real Time Asset Energy	1,191	$ (694,551.94)	51,295	$ 302,659.35	(50,104)	$ (997,211.29)		
22a Real Time Non Asset Energy	530	$ 9,172.67	530	$ 9,172.67			-	$ -
SUBTOTAL	(584,075)	$ (10,267,096.87)	108,659	$ 1,317,284.61	(692,734)	$ (11,584,381.48)	11,472	$ 182,201.13
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 1,952,570.30		$ 1,952,570.30		$ -		
5c Day Ahead Non Asset Loss		$ 603,174.18		$ 603,174.18		$ -		
3 Day Ahead Financial Bilateral Transaction Loss		$ (2,199.06)		$ (2,199.06)		$ -		
13c Real Time Loss		$ 106,440.75		$ 106,440.75		$ -		
22c Real Time Non Asset Loss		$ (555.30)		$ (555.30)		$ -		
14 Real Time Distribution Losses		$ (622,972.41)		$ (622,972.41)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 2,036,458.46	-	$ 2,036,458.46	-	$ -	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 783,195.49		$ 719,151.30		$ 64,044.19		$ 1,147.01
19 Real Time Market Administration (Schedule 17)		$ 76,993.12		$ 71,918.88		$ 5,074.24		$ -
29 Financial Transmission Rights Administration (Schedule 16)		$ 33,175.41		$ 33,175.41		$ -		$ -
33 Day-Ahead Schedule 24 Allocation Amount		$ 93,115.55		$ 85,315.19		$ 7,800.36		$ 136.16
34 Real -Time Schedule 24 Allocation Amount		$ (86,564.11)		$ 5,198.70		$ (91,762.81)		$ -
35 Schedule 24 Admin Allocation		$ -				$ -		$ -
SUBTOTAL	-	$ 899,915.46	-	$ 914,759.48	-	$ (14,844.02)	-	$ 1,283.17
Congestion & FTRs								
1b Day Ahead Congestion		$ 7,817,754.78		$ 7,817,754.78		$ -		
5b Day Ahead Non Asset Congestion		$ 1,000,845.66		$ 1,000,845.66		$ -		
13b Real Time Congestion		$ 188,665.78		$ 188,665.78		$ -		
22b Real Time Non Asset Congestion		$ (906.60)		$ (906.60)		$ -		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 12,243.40		$ 12,243.40				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (3,775,851.16)		$ (3,775,851.16)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (131,623.41)		$ (131,623.41)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (166,943.32)		$ (166,943.32)				
37 Financial Transmission Guarantee Uplift Amount		$ 158,299.42		$ 158,299.42				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ 5,102,484.55	-	$ 5,102,484.55	-	$ -	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 43,901.42		$ 43,901.42		$ -		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (179,532.48)		$ (149,937.69)		$ (29,594.79)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 66,345.82		$ 66,345.82		$ -		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (54,368.22)		$ (44,354.34)		$ (10,013.88)		
43 Real Time Price Volatility Make Whole Payment		$ (204,153.53)		$ (172,216.28)		$ (31,937.25)		
SUBTOTAL	-	$ (327,806.99)	-	$ (256,261.07)	-	$ (71,545.92)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 3,194.57		$ 4,633.37		$ (1,438.80)		
21 Real Time Net Inadvertent Distribution		$ 53,086.50		$ 53,086.50				$ 64.89
23 Real Time Revenue Neutrality Uplift Amount		$ 69,276.66		$ 69,276.66		$ -		$ -
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		$ -
SUBTOTAL	-	$ 125,557.73	-	$ 126,996.53	-	$ (1,438.80)	-	$ 64.89
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 2,693,305.82		$ 2,693,305.82				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (2,698,826.26)		$ (2,695,092.82)		$ (3,733.44)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (236,849.95)		$ (236,849.95)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 10,503.72		$ 10,503.72				
SUBTOTAL	-	$ (231,866.67)	-	($228,133)	-	($3,733)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (11,392.32)		$ (11,392.32)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 2,580.58		$ 2,580.58				
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	-	$ (8,811.74)	-	$ (8,811.74)	-	$ -	-	$ -
Total MISO Day 2 Charges	(584,075)	$ (2,671,166.07)	108,659	$ 9,004,777.59	(692,734)	$ (11,675,943.66)	11,472	$ 183,549.19

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MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

July 2020	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**
Day Ahead & Real Time Energy								
1a Day Ahead Asset Energy	(799,702)	$ (14,867,092.18)	163,913	$ 6,404,847.45	(963,615)	$ (21,271,939.63)		
5a Day Ahead Non Asset Energy	(195,627)	$ (6,630,748.31)	(195,627)	$ (6,630,748.31)			11,880	$ 253,804.23
13a Real Time Asset Energy	(24,043)	$ (1,059,390.43)	67,107	$ 500,456.83	(91,150)	$ (1,559,847.26)		
22a Real Time Non Asset Energy	62	$ 3,809.57	62	$ 3,809.57			-	$ -
SUBTOTAL	(1,019,310)	$ (22,553,421.35)	35,455	$ 278,365.54	(1,054,765)	$ (22,831,786.89)	11,880	$ 253,804.23
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,431,575.28		$ 2,431,575.28		$ -		
5c Day Ahead Non Asset Loss		$ 783,749.69		$ 783,749.69		$ -		
3 Day Ahead Financial Bilateral Transaction Loss		$ (2,986.53)		$ (2,986.53)		$ -		
13c Real Time Loss		$ 101,114.58		$ 101,114.58		$ -		
22c Real Time Non Asset Loss		$ 1,165.35		$ 1,165.35		$ -		
14 Real Time Distribution Losses		$ (844,769.75)		$ (844,769.75)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 2,469,848.62	-	$ 2,469,848.62	-	$ -	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 666,441.34		$ 597,312.16		$ 69,129.18		$ 850.41
19 Real Time Market Administration (Schedule 17)		$ 59,366.94		$ 52,809.85		$ 6,557.09		
29 Financial Transmission Rights Administration (Schedule 16)		$ 35,084.39		$ 35,084.39		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 99,141.21		$ 88,632.84		$ 10,508.37		$ 127.20
34 Real -Time Schedule 24 Allocation Amount		$ (88,321.61)		$ 12,110.12		$ (100,431.73)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 771,712.27	-	$ 785,949.36	-	$ (14,237.09)	-	$ 977.61
Congestion & FTRs								
1b Day Ahead Congestion		$ 5,139,205.90		$ 5,139,205.90		$ -		
5b Day Ahead Non Asset Congestion		$ 1,229,394.84		$ 1,229,394.84		$ -		
13b Real Time Congestion		$ 315,620.62		$ 315,620.62		$ -		
22b Real Time Non Asset Congestion		$ 641.04		$ 641.04		$ -		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 4,966.47		$ 4,966.47				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (4,171,284.07)		$ (4,171,284.07)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (190,323.43)		$ (190,323.43)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ 2,905.26		$ 2,905.26				
37 Financial Transmission Guarantee Uplift Amount		$ 18,786.20		$ 18,786.20				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ 2,349,912.83	-	$ 2,349,912.83	-	$ -	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 85,730.36		$ 85,730.36		$ -		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (27,697.25)		$ (11,119.60)		$ (16,577.65)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 394,093.42		$ 394,093.42		$ -		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (186,741.55)		$ (123,132.31)		$ (63,609.24)		
43 Real Time Price Volatility Make Whole Payment		$ (335,854.47)		$ (310,564.32)		$ (25,290.15)		
SUBTOTAL	-	$ (70,469.49)	-	$ 35,007.55	-	$ (105,477.04)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 52,589.48		$ 54,076.24		$ (1,486.76)		
21 Real Time Net Inadvertent Distribution		$ 373,187.58		$ 373,187.58				$ 411.39
23 Real Time Revenue Neutrality Uplift Amount		$ 202,020.75		$ 202,020.75		$ -		$ -
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		$ -
SUBTOTAL	-	$ 627,797.81	-	$ 629,284.57	-	$ (1,486.76)	-	$ 411.39
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 2,693,305.82		$ 2,693,305.82				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (2,698,826.26)		$ (2,695,130.48)		$ (3,695.78)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (234,999.62)		$ (234,999.62)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 10,489.95		$ 10,489.95				
SUBTOTAL	-	$ (230,030.11)	-	($226,334)	-	($3,696)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (5,165.05)		$ (5,165.05)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 2,897.51		$ 2,897.51				
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	-	$ (2,267.54)	-	$ (2,267.54)	-	$ -	-	$ -
Total MISO Day 2 Charges	(1,019,310)	$ (16,636,916.96)	35,455	$ 6,319,766.60	(1,054,765)	$ (22,956,683.56)	11,880	$ 255,193.23

August 2020	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**
Day Ahead & Real Time Energy								
1a Day Ahead Asset Energy	(829,193)	$ (14,125,818.10)	178,390	$ 6,301,189.40	(1,007,583)	$ (20,427,007.50)		
5a Day Ahead Non Asset Energy	(187,759)	$ (6,007,314.60)	(187,759)	$ (6,007,314.60)			11,688	$ 235,824.16
13a Real Time Asset Energy	(29,065)	$ (521,366.63)	35,166	$ 513,244.50	(64,231)	$ (1,034,611.13)		
22a Real Time Non Asset Energy	10	$ 305.10	10	$ 305.10			-	
SUBTOTAL	(1,046,007)	$ (20,654,194.23)	25,807	$ 807,424.40	(1,071,814)	$ (21,461,618.63)	11,688	$ 235,824.16
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,245,565.67		$ 2,245,565.67		$ -		
5c Day Ahead Non Asset Loss		$ 722,090.44		$ 722,090.44		$ -		
3 Day Ahead Financial Bilateral Transaction Loss		$ (4,391.06)		$ (4,391.06)		$ -		
13c Real Time Loss		$ 28,252.91		$ 28,252.91		$ -		
22c Real Time Non Asset Loss		$ 5.59		$ 5.59		$ -		
14 Real Time Distribution Losses		$ (709,775.66)		$ (709,775.66)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 2,281,747.89	-	$ 2,281,747.89	-	$ -	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 668,649.28		$ 590,821.20		$ 77,828.08		$ 901.75
19 Real Time Market Administration (Schedule 17)		$ 60,022.83		$ 55,122.36		$ 4,900.47		
29 Financial Transmission Rights Administration (Schedule 16)		$ 33,086.16		$ 33,086.16		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 102,030.51		$ 90,837.68		$ 11,192.83		$ 140.24
34 Real -Time Schedule 24 Allocation Amount		$ (85,266.26)		$ 11,433.66		$ (96,699.92)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 778,522.52	-	$ 781,301.06	-	$ (2,778.54)	-	$ 1,041.99
Congestion & FTRs								
1b Day Ahead Congestion		$ 3,984,892.43		$ 3,984,892.43		$ -		
5b Day Ahead Non Asset Congestion		$ 794,226.84		$ 794,226.84		$ -		
13b Real Time Congestion		$ 58,297.84		$ 58,297.84		$ -		
22b Real Time Non Asset Congestion		$ 13.66		$ 13.66		$ -		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (4,937.58)		$ (4,937.58)				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (2,926,937.62)		$ (2,926,937.62)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (141,201.53)		$ (141,201.53)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (36,382.83)		$ (36,382.83)				
37 Financial Transmission Guarantee Uplift Amount		$ 31,333.26		$ 31,333.26				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ 1,759,304.47	-	$ 1,759,304.47	-	$ -	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 71,294.60		$ 71,294.60		$ -		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (110,415.29)		$ (76,777.57)		$ (33,637.72)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 143,250.16		$ 143,250.16		$ -		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (35,576.95)		$ (5,388.10)		$ (30,188.85)		
43 Real Time Price Volatility Make Whole Payment		$ (227,358.52)		$ (227,600.20)		$ 241.68		
SUBTOTAL	-	$ (158,806.00)	-	$ (95,221.11)	-	$ (63,584.89)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 72,027.39		$ 73,514.15		$ (1,486.76)		
21 Real Time Net Inadvertent Distribution		$ (21,807.88)		$ (21,807.88)				$ 8.90
23 Real Time Revenue Neutrality Uplift Amount		$ 326,052.32		$ 326,052.32		$ -		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 376,271.83	-	$ 377,758.59	-	$ (1,486.76)	-	$ 8.90
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 2,693,305.82		$ 2,693,305.82				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (2,698,826.26)		$ (2,695,123.80)		$ (3,702.46)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (235,924.74)		$ (235,924.74)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 10,476.18		$ 10,476.18				
SUBTOTAL	-	$ (230,969.00)	-	($227,267)	-	($3,702)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 4,937.58		$ 4,937.58				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 4,391.06		$ 4,391.06				
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	-	$ 9,328.64	-	$ 9,328.64	-	$ -	-	$ -
Total MISO Day 2 Charges	(1,046,007)	$ (15,838,793.88)	25,807	$ 5,694,377.40	(1,071,814)	$ (21,533,171.28)	11,688	$ 236,875.05

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

September 2020		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
	Day Ahead & Real Time Energy								
1a	Day Ahead Asset Energy	(532,222)	$ (5,065,974.72)	154,821	$ 4,770,588.81	(687,043)	$ (9,836,563.53)		
5a	Day Ahead Non Asset Energy	(189,049)	$ (4,536,887.29)	(189,049)	$ (4,536,887.29)			11,376	$ 166,562.15
13a	Real Time Asset Energy	(11,457)	$ 8,722.50	58,422	$ 861,094.75	(69,879)	$ (852,372.25)		
22a	Real Time Non Asset Energy	259	$ 4,401.94	259	$ 4,401.94			-	
	SUBTOTAL	(732,469)	$ (9,589,737.57)	24,453	$ 1,099,198.21	(756,922)	$ (10,688,935.78)	11,376	$ 166,562.15
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss		$ 1,514,311.29		$ 1,514,311.29		$ -		
5c	Day Ahead Non Asset Loss		$ 620,753.23		$ 620,753.23		$ -		
3	Day Ahead Financial Bilateral Transaction Loss		$ (4,591.09)		$ (4,591.09)		$ -		
13c	Real Time Loss		$ 52,849.65		$ 52,849.65		$ -		
22c	Real Time Non Asset Loss		$ (226.82)		$ (226.82)		$ -		
14	Real Time Distribution Losses		$ (978,688.25)		$ (978,688.25)				
16	Real Time Financial Bilateral Loss		$ -		$ -				
	SUBTOTAL	-	$ 1,204,408.01	-	$ 1,204,408.01	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy		$ -		$ -				
27	Real Time Virtual Energy		$ -		$ -				
	SUBTOTAL	-	$0	-	$0	-	$0	-	$0
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)		$ 554,421.86		$ 498,770.59		$ 55,651.27		$ 920.75
19	Real Time Market Administration (Schedule 17)		$ 47,515.50		$ 41,886.12		$ 5,629.38		
29	Financial Transmission Rights Administration (Schedule 16)		$ 37,371.93		$ 37,371.93		$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 83,076.54		$ 74,810.27		$ 8,266.27		$ 140.00
34	Real -Time Schedule 24 Allocation Amount		$ (80,498.48)		$ 12,827.79		$ (93,326.27)		
35	Schedule 24 Admin Allocation		$ -				$ -		
	SUBTOTAL	-	$ 641,887.35	-	$ 665,666.70	-	$ (23,779.35)	-	$ 1,060.75
	Congestion & FTRs								
1b	Day Ahead Congestion		$ 7,931,269.55		$ 7,931,269.55		$ -		
5b	Day Ahead Non Asset Congestion		$ 958,140.99		$ 958,140.99		$ -		
13b	Real Time Congestion		$ 25,592.82		$ 25,592.82		$ -		
22b	Real Time Non Asset Congestion		$ (150.36)		$ (150.36)		$ -		
2	Day Ahead Financial Bilateral Transaction Congestion		$ (8,117.10)		$ (8,117.10)				
15	Real Time Financial Bilateral Congestion		$ -		$ -				
28	Financial Transmission Rights Hourly Allocation		$ (5,854,979.92)		$ (5,854,979.92)		$ -		
30	Financial Transmission Rights Monthly Allocation		$ (249,468.92)		$ (249,468.92)				
32	Financial Transmission Rights Yearly Allocation		$ -		$ -				
31	Financial Transmission Rights Transaction		$ -		$ -				
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (652,256.82)		$ (652,256.82)				
37	Financial Transmission Guarantee Uplift Amount		$ 636,580.03		$ 636,580.03				
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
	SUBTOTAL	-	$ 2,786,610.27	-	$ 2,786,610.27	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 117,826.40		$ 117,826.40		$ -		
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (184,650.00)		$ (101,890.47)		$ (82,759.53)		
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 88,418.58		$ 88,418.58		$ -		
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (23,371.30)		$ (19,997.73)		$ (3,373.57)		
43	Real Time Price Volatility Make Whole Payment		$ 12,906.68		$ 24,433.94		$ (11,527.26)		
	SUBTOTAL	-	$ 11,130.36	-	$ 108,790.72	-	$ (97,660.36)	-	$ -
	Other Charges								
20	Real Time Miscellaneous		$ 71,359.64		$ 72,798.44		$ (1,438.80)		
21	Real Time Net Inadvertent Distribution		$ (373,981.79)		$ (373,981.79)				$ (454.22)
23	Real Time Revenue Neutrality Uplift Amount		$ 7,570,051.42		$ 7,570,051.42		$ -		
26	Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
	SUBTOTAL	-	$ 7,267,429.27	-	$ 7,268,868.07	-	$ (1,438.80)	-	$ (454.22)
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions		$ 2,625,455.56		$ 2,625,455.56				
40	Auction Revenue Rights - Monthly ARR Revenue		$ (2,625,916.66)		$ (2,621,655.75)		$ (4,260.91)		
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (214,163.14)		$ (214,163.14)				
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 15,573.91		$ 15,573.91				
	SUBTOTAL	-	$ (199,050.33)	-	($194,789)	-	($4,261)	-	$0
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 8,117.10		$ 8,117.10				
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 4,591.09		$ 4,591.09				
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	-	$ 12,708.19	-	$ 12,708.19	-	$ -	-	$ -
	Total MISO Day 2 Charges	(732,469)	$ 2,135,385.55	24,453	$ 12,951,460.75	(756,922)	$ (10,816,075.20)	11,376	$ 167,168.68

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MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

October 2020	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
Day Ahead & Real Time Energy								
1a Day Ahead Asset Energy	(775,287)	$ (11,496,525.26)	180,292	$ 4,561,136.67	(955,579)	$ (16,057,661.93)		
5a Day Ahead Non Asset Energy	(173,278)	$ (4,835,933.01)	(173,278)	$ (4,835,933.01)			11,784	$ 236,730.96
13a Real Time Asset Energy	(1,695)	$ 35,403.37	88,535	$ 1,597,735.84	(90,230)	$ (1,562,332.47)		
22a Real Time Non Asset Energy	111	$ 2,482.74	111	$ 2,482.74			-	
SUBTOTAL	(950,149)	$ (16,294,572.16)	95,660	$ 1,325,422.24	(1,045,809)	$ (17,619,994.40)	11,784	$ 236,730.96
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,340,640.14		$ 2,340,640.14		$ -		
5c Day Ahead Non Asset Loss		$ 485,695.12		$ 485,695.12		$ -		
3 Day Ahead Financial Bilateral Transaction Loss		$ (2,132.40)		$ (2,132.40)		$ -		
13c Real Time Loss		$ 19,689.22		$ 19,689.22		$ -		
22c Real Time Non Asset Loss		$ (142.05)		$ (142.05)		$ -		
14 Real Time Distribution Losses		$ (643,189.75)		$ (643,189.75)				
16 Real Time Financial Bilateral Loss		$ 1.29		$ 1.29				
SUBTOTAL	-	$ 2,200,561.57	-	$ 2,200,561.57	-	$ -	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 678,669.94		$ 589,633.16		$ 89,036.78		$ 1,104.36
19 Real Time Market Administration (Schedule 17)		$ 61,383.45		$ 52,889.24		$ 8,494.21		
29 Financial Transmission Rights Administration (Schedule 16)		$ 26,618.57		$ 26,618.57		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 94,875.65		$ 82,412.96		$ 12,462.69		$ 154.64
34 Real -Time Schedule 24 Allocation Amount		$ (83,939.09)		$ (8,475.19)		$ (75,463.90)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 777,608.52	-	$ 743,078.74	-	$ 34,529.78	-	$ 1,259.00
Congestion & FTRs								
1b Day Ahead Congestion		$ 5,782,287.86		$ 5,782,287.86		$ -		
5b Day Ahead Non Asset Congestion		$ 915,129.27		$ 915,129.27		$ -		
13b Real Time Congestion		$ 42,934.66		$ 42,934.66		$ -		
22b Real Time Non Asset Congestion		$ (355.24)		$ (355.24)		$ -		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 459.45		$ 459.45				
15 Real Time Financial Bilateral Congestion		$ (12.92)		$ (12.92)				
28 Financial Transmission Rights Hourly Allocation		$ (2,370,282.95)		$ (2,370,282.95)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (80,242.36)		$ (80,242.36)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (66,548.02)		$ (66,548.02)				
37 Financial Transmission Guarantee Uplift Amount		$ 44,598.27		$ 44,598.27				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ 4,267,968.02	-	$ 4,267,968.02	-	$ -	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 123,192.46		$ 123,192.46		$ -		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (233,129.24)		$ (144,579.94)		$ (88,549.30)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 113,725.41		$ 113,725.41		$ -		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (91,829.26)		$ (35,067.83)		$ (56,761.43)		
43 Real Time Price Volatility Make Whole Payment		$ (270,533.14)		$ (206,031.41)		$ (64,501.73)		
SUBTOTAL	-	$ (358,573.77)	-	$ (148,761.31)	-	$ (209,812.46)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 60,626.06		$ 62,112.82		$ (1,486.76)		
21 Real Time Net Inadvertent Distribution		$ (9,621.84)		$ (9,621.84)				$ (10.57)
23 Real Time Revenue Neutrality Uplift Amount		$ 638,807.22		$ 638,807.22		$ -		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 689,811.44	-	$ 691,298.20	-	$ (1,486.76)	-	$ (10.57)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 2,625,455.56		$ 2,625,455.56				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (2,625,916.66)		$ (2,621,980.62)		$ (3,936.04)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (214,163.14)		$ (214,163.14)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 15,573.91		$ 15,573.91				
SUBTOTAL	-	$ (199,050.33)	-	($195,114)	-	($3,936)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (459.45)		$ (459.45)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 2,132.40		$ 2,132.40				
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		$ 12.92		$ 12.92				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ (1.29)		$ (1.29)				
SUBTOTAL	-	$ 1,684.58	-	$ 1,684.58	-	$ -	-	$ -
Total MISO Day 2 Charges	(950,149)	$ (8,914,562.13)	95,660	$ 8,886,137.75	(1,045,809)	$ (17,800,699.88)	11,784	$ 237,979.39

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MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

November 2020	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
Day Ahead & Real Time Energy								
1a Day Ahead Asset Energy	(980,827)	$ (11,537,023.10)	39,859	$ 4,360,527.08	(1,020,686)	$ (15,897,550.18)		
5a Day Ahead Non Asset Energy	(88,777)	$ (2,223,459.65)	(88,777)	$ (2,223,459.65)			11,280	$ 205,095.71
13a Real Time Asset Energy	17,734	$ 599,972.31	143,848	$ 2,326,900.60	(126,114)	$ (1,726,928.29)		
22a Real Time Non Asset Energy	-	$ (1,108.34)	-	$ (1,108.34)			-	
SUBTOTAL	(1,051,870)	$ (13,161,618.78)	94,930	$ 4,462,859.69	(1,146,800)	$ (17,624,478.47)	11,280	$ 205,095.71
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,394,170.57		$ 2,394,170.57		$ -		
5c Day Ahead Non Asset Loss		$ 190,751.76		$ 190,751.76		$ -		
3 Day Ahead Financial Bilateral Transaction Loss		$ (708.72)		$ (708.72)		$ -		
13c Real Time Loss		$ (12,378.65)		$ (12,378.65)		$ -		
22c Real Time Non Asset Loss		$ (4.57)		$ (4.57)		$ -		
14 Real Time Distribution Losses		$ (730,299.79)		$ (730,299.79)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 1,841,530.60	-	$ 1,841,530.60	-	$ -	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 627,410.14		$ 537,945.31		$ 89,464.83		$ 987.12
19 Real Time Market Administration (Schedule 17)		$ 63,680.00		$ 52,808.97		$ 10,871.03		
29 Financial Transmission Rights Administration (Schedule 16)		$ 26,238.72		$ 26,238.72		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 93,946.67		$ 80,337.30		$ 13,609.37		$ 148.00
34 Real -Time Schedule 24 Allocation Amount		$ (83,499.62)		$ 16,874.68		$ (100,374.30)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 727,775.91	-	$ 714,204.98	-	$ 13,570.93	-	$ 1,135.12
Congestion & FTRs								
1b Day Ahead Congestion		$ 6,090,441.83		$ 6,090,441.83		$ -		
5b Day Ahead Non Asset Congestion		$ 250,273.42		$ 250,273.42		$ -		
13b Real Time Congestion		$ 101,498.80		$ 101,498.80		$ -		
22b Real Time Non Asset Congestion		$ (3.18)		$ (3.18)		$ -		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (13,010.72)		$ (13,010.72)				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (584,048.19)		$ (584,048.19)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (57,459.03)		$ (57,459.03)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ 9,480.32		$ 9,480.32				
37 Financial Transmission Guarantee Uplift Amount		$ (19,783.92)		$ (19,783.92)				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ 5,777,389.33	-	$ 5,777,389.33	-	$ -	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 104,585.51		$ 104,585.51		$ -		
11 Day Ahead Revenue Sufficiency Guarantee Make Whole Payment		$ (139,130.87)		$ (53,469.28)		$ (85,661.59)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 204,780.30		$ 204,780.30		$ -		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (138,612.24)		$ (72,703.04)		$ (65,909.20)		
43 Real Time Price Volatility Make Whole Payment		$ 1,448.79		$ 14,882.80		$ (13,434.01)		
SUBTOTAL	-	$ 33,071.49	-	$ 198,076.29	-	$ (165,004.80)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 43,183.48		$ 44,622.28		$ (1,438.80)		
21 Real Time Net Inadvertent Distribution		$ (14,296.99)		$ (14,296.99)				$ (21.20)
23 Real Time Revenue Neutrality Uplift Amount		$ 555,216.02		$ 555,216.02		$ -		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 584,102.51	-	$ 585,541.31	-	$ (1,438.80)	-	$ (21.20)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 2,625,455.56		$ 2,625,455.56				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (2,625,916.66)		$ (2,621,640.31)		$ (4,276.35)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (214,163.14)		$ (214,163.14)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 15,573.91		$ 15,573.91				
SUBTOTAL	-	$ (199,050.33)	-	($194,774)	-	($4,276)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 13,010.72		$ 13,010.72				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 708.72		$ 708.72				
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		$ (0.00)		$ (0.00)				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ -		$ -				
SUBTOTAL	-	$ 13,719.44	-	$ 13,719.44	-	$ -	-	$ -
Total MISO Day 2 Charges	(1,051,870)	$ (4,383,079.83)	94,930	$ 13,398,547.66	(1,146,800)	$ (17,781,627.49)	11,280	$ 206,209.63

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MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

December 2020	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**
Day Ahead & Real Time Energy								
1a Day Ahead Asset Energy	(1,235,826)	$ (22,520,628.75)	92,786	$ 3,269,420.58	(1,328,612)	$ (25,790,049.33)		
5a Day Ahead Non Asset Energy	(108,563)	$ (2,837,734.93)	(108,563)	$ (2,837,734.93)			11,784	$ 255,406.81
13a Real Time Asset Energy	35,256	$ 855,589.26	89,780	$ 1,960,560.13	(54,524)	$ (1,104,970.87)		
22a Real Time Non Asset Energy	(2)	$ 9,581.06	(2)	$ 9,581.06			-	
SUBTOTAL	(1,309,135)	$ (24,493,193.36)	74,001	$ 2,401,826.84	(1,383,136)	$ (26,895,020.20)	11,784	$ 255,406.81
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,646,477.41		$ 2,646,477.41		$ -		
5c Day Ahead Non Asset Loss		$ 236,172.81		$ 236,172.81		$ -		
3 Day Ahead Financial Bilateral Transaction Loss		$ (2,031.29)		$ (2,031.29)		$ -		
13c Real Time Loss		$ (22,014.36)		$ (22,014.36)		$ -		
22c Real Time Non Asset Loss		$ 2.17		$ 2.17		$ -		
14 Real Time Distribution Losses		$ (673,124.03)		$ (673,124.03)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 2,185,482.71	-	$ 2,185,482.71	-	$ -	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 759,840.32		$ 636,229.60		$ 123,610.72		$ 1,097.81
19 Real Time Market Administration (Schedule 17)		$ 55,670.32		$ 50,505.84		$ 5,164.48		
29 Financial Transmission Rights Administration (Schedule 16)		$ 29,024.12		$ 29,024.12		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 103,445.62		$ 86,556.80		$ 16,888.82		$ 151.12
34 Real -Time Schedule 24 Allocation Amount		$ (90,734.75)		$ (1,319.12)		$ (89,415.63)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 857,245.63	-	$ 800,997.24	-	$ 56,248.39	-	$ 1,248.93
Congestion & FTRs								
1b Day Ahead Congestion		$ 8,093,979.09		$ 8,093,979.09		$ -		
5b Day Ahead Non Asset Congestion		$ 126,173.94		$ 126,173.94		$ -		
13b Real Time Congestion		$ 35,768.56		$ 35,768.56		$ -		
22b Real Time Non Asset Congestion		$ (1.21)		$ (1.21)		$ -		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (5,997.02)		$ (5,997.02)				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (1,925,936.62)		$ (1,925,936.62)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (48,720.19)		$ (48,720.19)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (307,690.84)		$ (307,690.84)				
37 Financial Transmission Guarantee Uplift Amount		$ 309,546.77		$ 309,546.77				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ 6,277,122.48	-	$ 6,277,122.48	-	$ -	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 129,438.24		$ 129,438.24		$ -		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (281,603.78)		$ (203,976.90)		$ (77,626.88)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 84,757.66		$ 84,757.66		$ -		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (41,486.80)		$ (19,423.17)		$ (22,063.63)		
43 Real Time Price Volatility Make Whole Payment		$ (75,368.67)		$ (64,874.39)		$ (10,494.28)		
SUBTOTAL	-	$ (184,263.35)	-	$ (74,078.56)	-	$ (110,184.79)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 16,668.65		$ 18,155.41		$ (1,486.76)		
21 Real Time Net Inadvertent Distribution		$ (9,356.62)		$ (9,356.62)				$ (11.29)
23 Real Time Revenue Neutrality Uplift Amount		$ 802,449.46		$ 802,449.46		$ -		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 809,761.49	-	$ 811,248.25	-	$ (1,486.76)	-	$ (11.29)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 1,635,397.07		$ 1,635,397.07				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (1,639,395.05)		$ (1,603,955.34)		$ (35,439.71)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (202,829.08)		$ (202,829.08)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 22,549.31		$ 22,549.31				
SUBTOTAL	-	$ (184,277.75)	-	($148,838)	-	($35,440)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 5,997.02		$ 5,997.02				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 2,031.29		$ 2,031.29				
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	-	$ 8,028.31	-	$ 8,028.31	-	$ -	-	$ -
Total MISO Day 2 Charges	(1,309,135)	$ (14,724,093.84)	74,001	$ 12,261,789.23	(1,383,136)	$ (26,985,883.07)	11,784	$ 256,644.45

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

January - December 2020	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**
Day Ahead & Real Time Energy								
1a Day Ahead Asset Energy	(8,591,943)	$ (128,502,570.94)	1,596,332	$ 48,593,134.93	(10,188,275)	$ (177,095,705.87)		
5a Day Ahead Non Asset Energy	(1,720,160)	$ (44,888,372.17)	(1,720,160)	$ (44,888,372.17)			138,864	$ 2,511,901.33
13a Real Time Asset Energy	(196,020)	$ (3,969,947.87)	1,048,322	$ 15,397,565.45	(1,244,342)	$ (19,367,513.32)		
22a Real Time Non Asset Energy	2,445	$ 55,294.23	2,445	$ 55,294.23			-	
SUBTOTAL	(10,505,678)	$ (177,305,596.75)	926,939	$ 19,157,622.44	(11,432,617)	$ (196,463,219.19)	138,864	$ 2,511,901.33
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 24,510,201.56		$ 24,510,201.56		$ -		
5c Day Ahead Non Asset Loss		$ 4,850,593.60		$ 4,850,593.60		$ -		
3 Day Ahead Financial Bilateral Transaction Loss		$ (21,514.89)		$ (21,514.89)		$ -		
13c Real Time Loss		$ 476,891.04		$ 476,891.04		$ -		
22c Real Time Non Asset Loss		$ (2,170.20)		$ (2,170.20)		$ -		
14 Real Time Distribution Losses		$ (7,605,594.38)		$ (7,605,594.38)				
16 Real Time Financial Bilateral Loss		$ (0.47)		$ (0.47)				
SUBTOTAL	-	$ 22,208,406.26	-	$ 22,208,406.26	-	$ -	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 8,012,501.15		$ 7,107,752.74		$ 904,748.41		$ 12,371.79
19 Real Time Market Administration (Schedule 17)		$ 729,759.28		$ 619,074.93		$ 110,684.35		$ -
29 Financial Transmission Rights Administration (Schedule 16)		$ 384,907.18		$ 384,907.18		$ -		$ 185.28
33 Day-Ahead Schedule 24 Allocation Amount		$ 1,140,271.84		$ 1,012,372.04		$ 127,899.80		$ 1,779.84
34 Real -Time Schedule 24 Allocation Amount		$ (1,007,219.43)		$ 65,269.56		$ (1,072,488.99)		$ -
35 Schedule 24 Admin Allocation		$ -				$ -		$ -
SUBTOTAL	-	$ 9,260,220.02	-	$ 9,189,376.45	-	$ 70,843.57	-	$ 14,336.91
Congestion & FTRs								
1b Day Ahead Congestion		$ 58,423,779.21		$ 58,423,779.21		$ -		
5b Day Ahead Non Asset Congestion		$ 7,083,472.37		$ 7,083,472.37		$ -		
13b Real Time Congestion		$ 1,041,324.90		$ 1,041,324.90		$ -		
22b Real Time Non Asset Congestion		$ (2,680.43)		$ (2,680.43)		$ -		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (8,504.22)		$ (8,504.22)				
15 Real Time Financial Bilateral Congestion		$ 15.38		$ 15.38				
28 Financial Transmission Rights Hourly Allocation		$ (33,033,724.05)		$ (33,033,724.05)		$ -		$ 13,331.08
30 Financial Transmission Rights Monthly Allocation		$ (1,497,340.89)		$ (1,497,340.89)				$ (920.19)
32 Financial Transmission Rights Yearly Allocation		$ (6,000.54)		$ (6,000.54)				$ (17.23)
31 Financial Transmission Rights Transaction		$ -		$ -				$ -
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (1,403,749.88)		$ (1,403,749.88)				$ 471.84
37 Financial Transmission Guarantee Uplift Amount		$ 1,475,215.32		$ 1,475,215.32				$ 149.75
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				$ 14,681.50
SUBTOTAL	-	$ 32,071,807.17	-	$ 32,071,807.17	-	$ -	-	$ 27,696.75
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 947,263.25		$ 947,263.25		$ -		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (1,589,289.29)		$ (969,234.70)		$ (620,054.59)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 1,275,200.13		$ 1,275,200.13		$ -		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (710,664.12)		$ (328,386.37)		$ (382,277.75)		
43 Real Time Price Volatility Make Whole Payment		$ (1,843,332.87)		$ (1,429,430.24)		$ (413,902.63)		
SUBTOTAL	-	$ (1,920,822.90)	-	$ (504,587.93)	-	$ (1,416,234.97)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 1,356,499.03		$ 1,427,025.91		$ (70,526.88)		
21 Real Time Net Inadvertent Distribution		$ 73,327.89		$ 73,327.89				$ 16.52
23 Real Time Revenue Neutrality Uplift Amount		$ 12,046,574.25		$ 12,046,574.25		$ -		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 13,476,401.17	-	$ 13,546,928.05	-	$ (70,526.88)	-	$ 16.52
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 23,762,360.76		$ 23,762,360.76				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (23,785,632.51)		$ (23,594,773.02)		$ (190,859.49)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (2,464,122.48)		$ (2,464,122.48)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 262,635.67		$ 262,635.67				
SUBTOTAL	-	$ (2,224,758.56)	-	($2,033,899)	-	($190,859)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 9,156.72		$ 9,156.72				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 21,807.39		$ 21,807.39				
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		$ (15.38)		$ (15.38)				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ 0.47		$ 0.47				
SUBTOTAL	-	$ 30,949.20	-	$ 30,949.20	-	$ -	-	$ -
Total MISO Day 2 Charges	(10,505,678)	$ (104,403,394.39)	926,939	$ 93,666,602.57	(11,432,617)	$ (198,069,996.96)	138,864	$ 2,553,951.51

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	January 2020 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (222,870.11)		$ (222,870.11)	$ (157,521.30)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (184,405.08)		$ (184,405.08)	$ (130,334.78)
3	Day-Ahead Supplemental Reserve	$ (36,839.82)		$ (36,839.82)	$ (26,037.84)
4	Real-Time Regulation Amount (See Note 1)	$ 50,363.99	$ 108,151.73	$ 158,515.72	$ 112,036.57
5	Real-Time Spinning Reserve Amount	$ 46,863.35	$ 105,337.28	$ 152,200.63	$ 107,573.15
6	Real-Time Supplemental Reserve Amount.	$ 2,974.45	$ 31,929.35	$ 34,903.80	$ 24,669.49
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (13,268.54)		$ (13,268.54)	$ (9,378.01)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 3,060,253.43		$ 3,060,253.43	$ 2,162,941.84
8b	Real Time Non Excessive Energy Congestion	$ (131,073.51)	$ -	$ (131,073.51)	$ (92,640.82)
8c	Real Time Non Excessive Energy Loss	$ (68,882.86)	$ -	$ (68,882.86)	$ (48,685.39)
9	Real Time Net Regulation Adjustment Amount	$ 5,697.01	$ (192.85)	$ 5,504.16	$ 3,890.26
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 111,321.30		$ 111,321.30	$ 78,680.25
11	Real Time Spinning Reserve Cost Distribution	$ 76,300.71		$ 76,300.71	$ 53,928.21
12	Real Time Supplemental Reserve Cost Distribution	$ 21,400.92		$ 21,400.92	$ 15,125.85
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 29,363.95	$ (8,927.10)	$ 20,436.85	$ 14,444.46
14	Real Time Contingency Reserve Deployment Failure	$ -	$ (70.54)	$ (70.54)	$ (49.86)
	TOTAL MISO ASM CHARGES	**$ 2,747,199.19**	**$ 236,227.87**	**$ 2,983,427.06**	**$ 2,108,642.10**

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	$ (4,576.10)		$ (4,576.10)	$ (3,234.32)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (156.10)		$ (156.10)	$ (110.33)
	Total	$ (4,732.20)		$ (4,732.20)	$ (3,344.65)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	February 2020 Actual				
	Procurement Charges				
1	Day-Ahead Regulation Amount	$ (231,511.33)		$ (231,511.33)	$ (164,070.45)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (123,481.97)		$ (123,481.97)	$ (87,510.80)
3	Day-Ahead Supplemental Reserve	$ (28,971.64)		$ (28,971.64)	$ (20,532.00)
4	Real-Time Regulation Amount (See Note 1)	$ 34,791.79	$ 225,547.43	$ 260,339.22	$ 184,500.57
5	Real-Time Spinning Reserve Amount	$ (31,632.62)	$ 209,090.18	$ 177,457.56	$ 125,762.92
6	Real-Time Supplemental Reserve Amount.	$ (173.46)	$ 38,092.05	$ 37,918.59	$ 26,872.64
	Resource Energy Charges				
7a	Real Time Excessive Energy Amount	$ (7,907.35)		$ (7,907.35)	$ (5,603.88)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ (653,150.90)		$ (653,150.90)	$ (462,883.45)
8b	Real Time Non Excessive Energy Congestion	$ 84,356.90	$ -	$ 84,356.90	$ 59,783.14
8c	Real Time Non Excessive Energy Loss	$ 105,131.56	$ -	$ 105,131.56	$ 74,506.00
9	Real Time Net Regulation Adjustment Amount	$ (6,457.85)	$ 4,480.34	$ (1,977.51)	$ (1,401.45)
	Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	$ 108,152.70		$ 108,152.70	$ 76,647.06
11	Real Time Spinning Reserve Cost Distribution	$ 61,960.75		$ 61,960.75	$ 43,911.15
12	Real Time Supplemental Reserve Cost Distribution	$ 9,808.49		$ 9,808.49	$ 6,951.21
	Penalty Charges				
13	Real Time Excessive/Deficient Energy Deployment	$ 35,284.70	$ (11,010.04)	$ 24,274.66	$ 17,203.28
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ (643,800.23)**	**$ 466,199.96**	**$ (177,600.27)**	**$ (125,864.06)**

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	$ (3,314.81)		$ (3,314.81)	$ (2,349.18)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (300.97)		$ (300.97)	$ (213.30)
	Total	$ (3,615.78)		$ (3,615.78)	$ (2,562.48)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	March 2020 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (255,634.08)		$ (255,634.08)	$ (181,264.52)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (144,262.47)		$ (144,262.47)	$ (102,293.36)
3	Day-Ahead Supplemental Reserve	$ (25,943.42)		$ (25,943.42)	$ (18,395.91)
4	Real-Time Regulation Amount (See Note 1)	$ 40,133.03	$ 197,601.80	$ 237,734.83	$ 168,572.56
5	Real-Time Spinning Reserve Amount	$ (2,179.89)	$ 137,358.29	$ 135,178.40	$ 95,852.04
6	Real-Time Supplemental Reserve Amount.	$ 1,541.92	$ 15,487.35	$ 17,029.27	$ 12,075.08
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (13,806.90)		$ (13,806.90)	$ (9,790.17)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 1,102,922.19		$ 1,102,922.19	$ 782,057.95
8b	Real Time Non Excessive Energy Congestion	$ (380,280.51)	$ -	$ (380,280.51)	$ (269,648.57)
8c	Real Time Non Excessive Energy Loss	$ (70,454.08)	$ -	$ (70,454.08)	$ (49,957.44)
9	Real Time Net Regulation Adjustment Amount	$ 5,814.23	$ 853.06	$ 6,667.29	$ 4,727.63
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 114,733.74		$ 114,733.74	$ 81,355.18
11	Real Time Spinning Reserve Cost Distribution	$ 64,205.18		$ 64,205.18	$ 45,526.49
12	Real Time Supplemental Reserve Cost Distribution	$ 10,844.98		$ 10,844.98	$ 7,689.94
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 28,080.16	$ (12,401.72)	$ 15,678.44	$ 11,117.24
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 475,714.08**	**$ 338,898.78**	**$ 814,612.86**	**$ 577,624.12**

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	$ (4,216.73)		$ (4,216.73)	$ (2,989.99)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (657.06)		$ (657.06)	$ (465.91)
	Total	$ (4,873.79)		$ (4,873.79)	$ (3,455.90)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	April 2020 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (228,122.10)		$ (228,122.10)	$ (162,119.39)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (174,548.54)		$ (174,548.54)	$ (124,046.31)
3	Day-Ahead Supplemental Reserve	$ (26,195.52)		$ (26,195.52)	$ (18,616.35)
4	Real-Time Regulation Amount (See Note 1)	$ (447.45)	$ 239,748.71	$ 239,301.26	$ 170,064.08
5	Real-Time Spinning Reserve Amount	$ (12,702.87)	$ 175,962.92	$ 163,260.05	$ 116,023.92
6	Real-Time Supplemental Reserve Amount.	$ 2,183.33	$ 22,216.39	$ 24,399.72	$ 17,340.13
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (4,390.42)		$ (4,390.42)	$ (3,120.14)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 1,006,642.11		$ 1,006,642.11	$ 715,389.74
8b	Real Time Non Excessive Energy Congestion	$ (400,723.14)	$ -	$ (400,723.14)	$ (284,781.67)
8c	Real Time Non Excessive Energy Loss	$ (95,665.65)	$ -	$ (95,665.65)	$ (67,986.65)
9	Real Time Net Regulation Adjustment Amount	$ (18,100.30)	$ 11,149.23	$ (6,951.07)	$ (4,939.91)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 118,425.63		$ 118,425.63	$ 84,161.47
11	Real Time Spinning Reserve Cost Distribution	$ 73,008.37		$ 73,008.37	$ 51,884.81
12	Real Time Supplemental Reserve Cost Distribution	$ 10,046.35		$ 10,046.35	$ 7,139.63
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 31,387.24	$ (20,695.02)	$ 10,692.22	$ 7,598.63
14	Real Time Contingency Reserve Deployment Failure	$ 2,991.10	$ (1,229.13)	$ 1,761.97	$ 1,252.18
	TOTAL MISO ASM CHARGES	**$ 283,788.14**	**$ 427,153.10**	**$ 710,941.24**	**$ 505,244.18**

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	$ (4,256.44)		$ (4,256.44)	$ (3,024.92)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (727.17)		$ (727.17)	$ (516.78)
	Total	$ (4,983.61)		$ (4,983.61)	$ (3,541.70)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
May 2020 Actual					
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (173,139.55)		$ (173,139.55)	$ (124,505.48)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (175,388.58)		$ (175,388.58)	$ (126,122.76)
3	Day-Ahead Supplemental Reserve	$ (26,014.04)		$ (26,014.04)	$ (18,706.82)
4	Real-Time Regulation Amount (See Note 1)	$ 20,340.19	$ 122,573.05	$ 142,913.24	$ 102,769.59
5	Real-Time Spinning Reserve Amount	$ 4,100.79	$ 168,116.92	$ 172,217.71	$ 123,842.58
6	Real-Time Supplemental Reserve Amount.	$ 807.82	$ 26,124.14	$ 26,931.96	$ 19,366.90
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (2,062.16)		$ (2,062.16)	$ (1,482.91)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 539,584.76		$ 539,584.76	$ 388,017.98
8b	Real Time Non Excessive Energy Congestion	$ (16,754.64)	$ -	$ (16,754.64)	$ (12,048.34)
8c	Real Time Non Excessive Energy Loss	$ 21,319.36	$ -	$ 21,319.36	$ 15,330.85
9	Real Time Net Regulation Adjustment Amount	$ 10,568.36	$ (1,566.02)	$ 9,002.34	$ 6,473.63
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 119,108.36		$ 119,108.36	$ 85,651.39
11	Real Time Spinning Reserve Cost Distribution	$ 91,828.37		$ 91,828.37	$ 66,034.22
12	Real Time Supplemental Reserve Cost Distribution	$ 10,161.05		$ 10,161.05	$ 7,306.86
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 15,153.90	$ (8,779.41)	$ 6,374.49	$ 4,583.93
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 439,613.99**	**$ 306,468.68**	**$ 746,082.67**	**$ 536,511.61**

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	$ (4,018.37)		$ (4,018.37)	$ (2,889.63)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (562.69)		$ (562.69)	$ (404.63)
	Total	$ (4,581.06)		$ (4,581.06)	$ (3,294.26)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	June 2020 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (190,604.54)		$ (190,604.54)	$ (138,432.89)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (131,163.20)		$ (131,163.20)	$ (95,261.64)
3	Day-Ahead Supplemental Reserve	$ (19,929.95)		$ (19,929.95)	$ (14,474.79)
4	Real-Time Regulation Amount (See Note 1)	$ (1,893.88)	$ 103,314.79	$ 101,420.91	$ 73,660.31
5	Real-Time Spinning Reserve Amount	$ (23,070.70)	$ 108,631.66	$ 85,560.96	$ 62,141.49
6	Real-Time Supplemental Reserve Amount.	$ 2,973.76	$ 9,854.50	$ 12,828.26	$ 9,316.95
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (1,102.93)		$ (1,102.93)	$ (801.04)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 3,605,397.26		$ 3,605,397.26	$ 2,618,539.70
8b	Real Time Non Excessive Energy Congestion	$ (829,572.58)	$ -	$ (829,572.58)	$ (602,504.68)
8c	Real Time Non Excessive Energy Loss	$ (210,120.57)	$ -	$ (210,120.57)	$ (152,607.05)
9	Real Time Net Regulation Adjustment Amount	$ (1,692.54)	$ 1,103.93	$ (588.61)	$ (427.50)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 116,678.80		$ 116,678.80	$ 84,741.86
11	Real Time Spinning Reserve Cost Distribution	$ 88,495.02		$ 88,495.02	$ 64,272.45
12	Real Time Supplemental Reserve Cost Distribution	$ 11,651.19		$ 11,651.19	$ 8,462.06
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 37,428.39	$ (24,593.07)	$ 12,835.32	$ 9,322.08
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 2,453,473.53**	**$ 198,311.81**	**$ 2,651,785.34**	**$ 1,925,947.32**

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	$ (5,379.01)		$ (5,379.01)	$ (3,906.68)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ 253.35		$ 253.35	$ 184.00
	Total	$ (5,125.66)		$ (5,125.66)	$ (3,722.68)

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	July 2020 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (189,774.56)		$ (189,774.56)	$ (138,678.86)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (132,236.62)		$ (132,236.62)	$ (96,632.68)
3	Day-Ahead Supplemental Reserve	$ (26,502.26)		$ (26,502.26)	$ (19,366.68)
4	Real-Time Regulation Amount (See Note 1)	$ (147,283.73)	$ 215,664.23	$ 68,380.50	$ 49,969.45
5	Real-Time Spinning Reserve Amount	$ (20,599.84)	$ 76,574.64	$ 55,974.80	$ 40,903.91
6	Real-Time Supplemental Reserve Amount.	$ 2,818.84	$ 8,309.52	$ 11,128.36	$ 8,132.11
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (11,540.52)		$ (11,540.52)	$ (8,433.30)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 4,763,154.91		$ 4,763,154.91	$ 3,480,703.13
8b	Real Time Non Excessive Energy Congestion	$ (436,551.51)	$ -	$ (436,551.51)	$ (319,012.55)
8c	Real Time Non Excessive Energy Loss	$ (83,886.68)	$ -	$ (83,886.68)	$ (61,300.68)
9	Real Time Net Regulation Adjustment Amount	$ 5,062.61	$ 913.89	$ 5,976.50	$ 4,367.36
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 126,976.29		$ 126,976.29	$ 92,788.66
11	Real Time Spinning Reserve Cost Distribution	$ 106,609.09		$ 106,609.09	$ 77,905.21
12	Real Time Supplemental Reserve Cost Distribution	$ 10,384.42		$ 10,384.42	$ 7,588.48
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 39,381.87	$ (27,068.58)	$ 12,313.29	$ 8,998.01
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 4,006,012.31**	**$ 274,393.70**	**$ 4,280,406.01**	**$ 3,127,931.56**

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	$ (7,095.33)		$ (7,095.33)	$ (5,184.95)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (231.01)		$ (231.01)	$ (168.81)
	Total	$ (7,326.34)		$ (7,326.34)	$ (5,353.77)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	August 2020 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (174,236.43)		$ (174,236.43)	$ (126,365.12)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (187,878.92)		$ (187,878.92)	$ (136,259.34)
3	Day-Ahead Supplemental Reserve	$ (27,590.60)		$ (27,590.60)	$ (20,010.11)
4	Real-Time Regulation Amount (See Note 1)	$ (39,634.79)	$ 106,625.88	$ 66,991.09	$ 48,585.34
5	Real-Time Spinning Reserve Amount	$ 8,906.63	$ 116,890.86	$ 125,797.49	$ 91,234.74
6	Real-Time Supplemental Reserve Amount.	$ 2,501.23	$ 14,615.52	$ 17,116.75	$ 12,413.94
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (16,514.00)		$ (16,514.00)	$ (11,976.79)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 3,764,276.99		$ 3,764,276.99	$ 2,730,045.05
8b	Real Time Non Excessive Energy Congestion	$ (154,142.30)	$ -	$ (154,142.30)	$ (111,791.83)
8c	Real Time Non Excessive Energy Loss	$ (21,641.96)	$ -	$ (21,641.96)	$ (15,695.85)
9	Real Time Net Regulation Adjustment Amount	$ (18,708.65)	$ 7,189.62	$ (11,519.03)	$ (8,354.19)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 121,423.76		$ 121,423.76	$ 88,062.68
11	Real Time Spinning Reserve Cost Distribution	$ 101,451.06		$ 101,451.06	$ 73,577.47
12	Real Time Supplemental Reserve Cost Distribution	$ 16,044.18		$ 16,044.18	$ 11,636.06
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 22,427.61	$ (13,084.28)	$ 9,343.33	$ 6,776.26
14	Real Time Contingency Reserve Deployment Failure	$ 50.05	$ (7.17)	$ 42.88	$ 31.10
	TOTAL MISO ASM CHARGES	**$ 3,396,733.86**	**$ 232,230.43**	**$ 3,628,964.29**	**$ 2,631,909.40**

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	$ (4,396.65)		$ (4,396.65)	$ (3,188.67)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ 335.53		$ 335.53	$ 243.34
	Total	$ (4,061.12)		$ (4,061.12)	$ (2,945.33)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	September 2020 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (78,115.27)		$ (78,115.27)	$ (56,388.97)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (69,129.43)		$ (69,129.43)	$ (49,902.37)
3	Day-Ahead Supplemental Reserve	$ (30,007.76)		$ (30,007.76)	$ (21,661.66)
4	Real-Time Regulation Amount (See Note 1)	$ (29,479.98)	$ 39,327.29	$ 9,847.31	$ 7,108.46
5	Real-Time Spinning Reserve Amount	$ (35,757.93)	$ 43,835.34	$ 8,077.41	$ 5,830.83
6	Real-Time Supplemental Reserve Amount.	$ 2,065.01	$ 17,301.87	$ 19,366.88	$ 13,980.34
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (1,092.26)		$ (1,092.26)	$ (788.47)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 912,356.30		$ 912,356.30	$ 658,601.46
8b	Real Time Non Excessive Energy Congestion	$ (287,920.60)	$ -	$ (287,920.60)	$ (207,840.87)
8c	Real Time Non Excessive Energy Loss	$ (49,677.68)	$ -	$ (49,677.68)	$ (35,860.76)
9	Real Time Net Regulation Adjustment Amount	$ (481.01)	$ 2,169.70	$ 1,688.69	$ 1,219.01
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 114,611.55		$ 114,611.55	$ 82,734.49
11	Real Time Spinning Reserve Cost Distribution	$ 60,382.83		$ 60,382.83	$ 43,588.47
12	Real Time Supplemental Reserve Cost Distribution	$ 12,017.27		$ 12,017.27	$ 8,674.89
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 14,182.03	$ (9,519.21)	$ 4,662.82	$ 3,365.94
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 533,953.07**	**$ 93,114.99**	**$ 627,068.06**	**$ 452,660.80**

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	$ (1,387.13)		$ (1,387.13)	$ (1,001.33)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (877.62)		$ (877.62)	$ (633.53)
	Total	$ (2,264.75)		$ (2,264.75)	$ (1,634.85)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	October 2020 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (218,072.97)		$ (218,072.97)	$ (156,160.98)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (122,021.50)		$ (122,021.50)	$ (87,378.99)
3	Day-Ahead Supplemental Reserve	$ (26,511.85)		$ (26,511.85)	$ (18,985.00)
4	Real-Time Regulation Amount (See Note 1)	$ 5,647.71	$ 111,503.33	$ 117,151.04	$ 83,891.28
5	Real-Time Spinning Reserve Amount	$ 1,635.37	$ 71,663.46	$ 73,298.83	$ 52,488.93
6	Real-Time Supplemental Reserve Amount.	$ 3,123.52	$ 10,841.37	$ 13,964.89	$ 10,000.19
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (1,205.29)		$ (1,205.29)	$ (863.10)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 1,565,283.81		$ 1,565,283.81	$ 1,120,892.00
8b	Real Time Non Excessive Energy Congestion	$ (212,325.68)	$ -	$ (212,325.68)	$ (152,045.37)
8c	Real Time Non Excessive Energy Loss	$ (16,813.64)	$ -	$ (16,813.64)	$ (12,040.16)
9	Real Time Net Regulation Adjustment Amount	$ (11,133.29)	$ 9,075.02	$ (2,058.27)	$ (1,473.92)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 130,622.30		$ 130,622.30	$ 93,537.98
11	Real Time Spinning Reserve Cost Distribution	$ 90,394.99		$ 90,394.99	$ 64,731.41
12	Real Time Supplemental Reserve Cost Distribution	$ 24,260.42		$ 24,260.42	$ 17,372.77
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 38,842.45	$ (28,290.65)	$ 10,551.80	$ 7,556.09
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 1,251,726.35**	**$ 174,792.53**	**$ 1,426,518.88**	**$ 1,021,523.12**

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	$ (3,214.52)		$ (3,214.52)	$ (2,301.90)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ 332.47		$ 332.47	$ 238.08
	Total	$ (2,882.05)		$ (2,882.05)	$ (2,063.82)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	November 2020 Actual				
	Procurement Charges				
1	Day-Ahead Regulation Amount	$ (125,759.98)		$ (125,759.98)	$ (89,722.38)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (71,977.62)		$ (71,977.62)	$ (51,351.82)
3	Day-Ahead Supplemental Reserve	$ (14,264.35)		$ (14,264.35)	$ (10,176.78)
4	Real-Time Regulation Amount (See Note 1)	$ (18,025.71)	$ 58,905.64	$ 40,879.93	$ 29,165.44
5	Real-Time Spinning Reserve Amount	$ 2,180.37	$ 53,475.87	$ 55,656.24	$ 39,707.47
6	Real-Time Supplemental Reserve Amount.	$ 445.87	$ 5,452.83	$ 5,898.70	$ 4,208.38
	Resource Energy Charges				
7a	Real Time Excessive Energy Amount	$ (4,004.37)		$ (4,004.37)	$ (2,856.88)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 902,542.73		$ 902,542.73	$ 643,911.41
8b	Real Time Non Excessive Energy Congestion	$ (296,288.71)	$ -	$ (296,288.71)	$ (211,384.65)
8c	Real Time Non Excessive Energy Loss	$ 71,805.07	$ -	$ 71,805.07	$ 51,228.71
9	Real Time Net Regulation Adjustment Amount	$ (7,801.66)	$ 4,952.75	$ (2,848.91)	$ (2,032.53)
	Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	$ 128,336.29		$ 128,336.29	$ 91,560.43
11	Real Time Spinning Reserve Cost Distribution	$ 78,756.35		$ 78,756.35	$ 56,188.05
12	Real Time Supplemental Reserve Cost Distribution	$ 9,896.54		$ 9,896.54	$ 7,060.60
	Penalty Charges				
13	Real Time Excessive/Deficient Energy Deployment	$ 23,487.52	$ (7,359.05)	$ 16,128.47	$ 11,506.72
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 679,328.34**	**$ 115,428.04**	**$ 794,756.38**	**$ 567,012.16**

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	$ (234.93)		$ (234.93)	$ (167.61)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (1,384.41)		$ (1,384.41)	$ (987.70)
	Total	$ (1,619.34)		$ (1,619.34)	$ (1,155.30)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	December 2020 Actual				
	Procurement Charges				
1	Day-Ahead Regulation Amount	$ (121,729.03)		$ (121,729.03)	$ (86,094.86)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (124,767.91)		$ (124,767.91)	$ (88,244.16)
3	Day-Ahead Supplemental Reserve	$ (14,308.14)		$ (14,308.14)	$ (10,119.67)
4	Real-Time Regulation Amount (See Note 1)	$ (38,295.32)	$ 71,949.11	$ 33,653.79	$ 23,802.20
5	Real-Time Spinning Reserve Amount	$ 1,490.37	$ 52,570.97	$ 54,061.34	$ 38,235.77
6	Real-Time Supplemental Reserve Amount.	$ 88.42	$ 2,271.86	$ 2,360.28	$ 1,669.35
	Resource Energy Charges				
7a	Real Time Excessive Energy Amount	$ 6,020.77		$ 6,020.77	$ 4,258.29
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 2,891,182.72		$ 2,891,182.72	$ 2,044,836.63
8b	Real Time Non Excessive Energy Congestion	$ (150,979.98)	$ -	$ (150,979.98)	$ (106,783.08)
8c	Real Time Non Excessive Energy Loss	$ 123,250.84	$ -	$ 123,250.84	$ 87,171.19
9	Real Time Net Regulation Adjustment Amount	$ 6,382.21	$ (1,911.10)	$ 4,471.11	$ 3,162.27
	Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	$ 129,829.89		$ 129,829.89	$ 91,824.33
11	Real Time Spinning Reserve Cost Distribution	$ 86,520.15		$ 86,520.15	$ 61,192.80
12	Real Time Supplemental Reserve Cost Distribution	$ 12,437.90		$ 12,437.90	$ 8,796.91
	Penalty Charges				
13	Real Time Excessive/Deficient Energy Deployment	$ 27,863.65	$ (18,629.08)	$ 9,234.57	$ 6,531.30
14	Real Time Contingency Reserve Deployment Failure	$ 15,421.81	$ -	$ 15,421.81	$ 10,907.33
	TOTAL MISO ASM CHARGES	**$ 2,850,408.35**	**$ 106,251.76**	**$ 2,956,660.11**	**$ 2,091,146.59**

Note 1:

		System		Retail	Minnesota Retail
	Ramp Capability Amounts (Included in Regulation Amounts)				
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (860.19)		$ (860.19)	$ (608.38)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (1,664.70)		$ (1,664.70)	$ (1,177.39)
	Total	$ (2,524.89)		$ (2,524.89)	$ (1,785.77)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	January - December 2020 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (2,209,569.95)		$ (2,209,569.95)	$ (1,583,743.69)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (1,641,261.84)		$ (1,641,261.84)	$ (1,176,400.00)
3	Day-Ahead Supplemental Reserve	$ (303,079.35)		$ (303,079.35)	$ (217,236.85)
4	Real-Time Regulation Amount (See Note 1)	$ (123,784.15)	$ 1,600,912.99	$ 1,477,128.84	$ 1,058,755.11
5	Real-Time Spinning Reserve Amount	$ (60,766.97)	$ 1,319,508.39	$ 1,258,741.42	$ 902,222.53
6	Real-Time Supplemental Reserve Amount.	$ 21,350.71	$ 202,496.75	$ 223,847.46	$ 160,446.15
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (70,873.97)		$ (70,873.97)	$ (50,800.02)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 23,460,446.31		$ 23,460,446.31	$ 16,815,640.45
8b	Real Time Non Excessive Energy Congestion	$ (3,212,256.26)	$ -	$ (3,212,256.26)	$ (2,302,434.73)
8c	Real Time Non Excessive Energy Loss	$ (295,636.29)	$ -	$ (295,636.29)	$ (211,901.92)
9	Real Time Net Regulation Adjustment Amount	$ (30,850.88)	$ 38,217.57	$ 7,366.69	$ 5,280.19
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 1,440,220.61		$ 1,440,220.61	$ 1,032,300.56
11	Real Time Spinning Reserve Cost Distribution	$ 979,912.87		$ 979,912.87	$ 702,367.82
12	Real Time Supplemental Reserve Cost Distribution	$ 158,953.71		$ 158,953.71	$ 113,932.55
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 342,883.47	$ (190,357.21)	$ 152,526.26	$ 109,325.57
14	Real Time Contingency Reserve Deployment Failure	$ 18,462.96	$ (1,306.84)	$ 17,156.12	$ 12,296.92
	TOTAL MISO ASM CHARGES	**$ 18,474,150.98**	**$ 2,969,471.65**	**$ 21,443,622.63**	**$ 15,370,050.65**

Note 1:

		System		Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (42,950.21)		$ (42,950.21)	$ (30,847.58)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (5,640.38)		$ (5,640.38)	$ (4,012.93)
	Total	$ (48,590.59)		$ (48,590.59)	$ (34,860.51)

Northern States Power Company

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

		January 20	February 20	March 20	1st Qt	April 20	May 20	June 20	2nd Qt	July 20	August 20	September 20	3rd Qt	October 20	November 20	December 20	4th Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount	$ (222,870.11)	$ (231,511.33)	$ (255,634.08)	$ (710,015.52)	$ (228,122.10)	$ (173,139.55)	$ (190,604.54)	$ (591,866.19)	$ (189,774.56)	$ (174,236.43)	$ (78,115.27)	$ (442,126.26)	$ (218,072.97)	$ (125,759.98)	$ (121,729.03)	$ (465,561.98)	$ (2,209,569.95)
4	Real-Time Regulation Amount	$ 50,363.99	$ 34,791.79	$ 40,133.03	$ 125,288.81	$ (447.45)	$ 20,340.19	$ (1,893.88)	$ 17,998.86	$ (147,283.73)	$ (39,634.79)	$ (29,479.98)	$ (216,398.50)	$ 5,647.71	$ (18,025.71)	$ (38,295.32)	$ (50,673.32)	$ (123,784.15)
10	Real Time Regulation Reserve Cost Distribution Amo	$ 111,321.30	$ 108,152.70	$ 114,733.74	$ 334,207.74	$ 118,425.63	$ 119,108.36	$ 116,678.80	$ 354,212.79	$ 126,976.29	$ 121,423.76	$ 114,611.55	$ 363,011.60	$ 130,622.30	$ 128,336.29	$ 129,829.89	$ 388,788.48	$ 1,440,220.61
	SUBTOTAL	$ (61,184.82)	$ (88,566.84)	$ (100,767.31)	$ (250,518.97)	$ (110,143.92)	$ (33,691.00)	$ (75,819.62)	$ (219,654.54)	$ (210,082.00)	$ (92,447.46)	$ 7,016.30	$ (295,513.16)	$ (81,802.96)	$ (15,449.40)	$ (30,194.46)	$ (127,446.82)	$ (893,133.49)
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount	$ (184,405.08)	$ (123,481.97)	$ (144,262.47)	$ (452,149.52)	$ (174,548.54)	$ (175,388.58)	$ (131,163.20)	$ (481,100.32)	$ (132,236.62)	$ (187,878.92)	$ (69,129.43)	$ (389,244.97)	$ (122,021.50)	$ (71,977.62)	$ (124,767.91)	$ (318,767.03)	$ (1,641,261.84)
5	Real-Time Spinning Reserve Amount	$ 46,863.35	$ (31,632.62)	$ (2,179.89)	$ 13,050.84	$ (12,702.87)	$ 4,100.79	$ (23,070.70)	$ (31,672.78)	$ (20,599.84)	$ 8,906.63	$ (35,757.93)	$ (47,451.14)	$ 1,635.37	$ 2,180.37	$ 1,490.37	$ 5,306.11	$ (60,766.97)
11	Real Time Spinning Reserve Cost Distribution	$ 76,300.71	$ 61,960.75	$ 64,205.18	$ 202,466.64	$ 73,008.37	$ 91,828.37	$ 88,495.02	$ 253,331.76	$ 106,609.09	$ 101,451.06	$ 60,382.83	$ 268,442.98	$ 90,394.99	$ 78,756.35	$ 86,520.15	$ 255,671.49	$ 979,912.87
	SUBTOTAL	$ (61,241.02)	$ (93,153.84)	$ (82,237.18)	$ (236,632.04)	$ (114,243.04)	$ (79,459.42)	$ (65,738.88)	$ (259,441.34)	$ (46,227.37)	$ (77,521.23)	$ (44,504.53)	$ (168,253.13)	$ (29,991.14)	$ 8,959.10	$ (36,757.39)	$ (57,789.43)	$ (722,115.94)
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve	$ (36,839.82)	$ (28,971.64)	$ (25,943.42)	$ (91,754.88)	$ (26,195.52)	$ (26,014.04)	$ (19,929.95)	$ (72,139.51)	$ (26,502.26)	$ (27,590.60)	$ (30,007.76)	$ (84,100.62)	$ (26,511.85)	$ (14,264.35)	$ (14,308.14)	$ (55,084.34)	$ (303,079.35)
6	Real-Time Supplemental Reserve Amount.	$ 2,974.45	$ (173.46)	$ 1,541.92	$ 4,342.91	$ 2,183.33	$ 807.82	$ 2,973.76	$ 5,964.91	$ 2,818.84	$ 2,501.23	$ 2,065.01	$ 7,385.08	$ 3,123.52	$ 445.87	$ 88.42	$ 3,657.81	$ 21,350.71
12	Real Time Supplemental Reserve Cost Distribution	$ 21,400.92	$ 9,808.49	$ 10,844.98	$ 42,054.39	$ 10,046.35	$ 10,161.05	$ 11,651.19	$ 31,858.59	$ 10,384.42	$ 16,044.18	$ 12,017.27	$ 38,445.87	$ 24,260.42	$ 9,896.54	$ 12,437.90	$ 46,594.86	$ 158,953.71
	SUBTOTAL	$ (12,464.45)	$ (19,336.61)	$ (13,556.52)	$ (45,357.58)	$ (13,965.84)	$ (15,045.17)	$ (5,305.00)	$ (34,316.01)	$ (13,299.00)	$ (9,045.19)	$ (15,925.48)	$ (38,269.67)	$ 872.09	$ (3,921.94)	$ (1,781.82)	$ (4,831.67)	$ (122,774.93)
Other Charges																		
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -	$ 2,991.10	$ -	$ -	$ 2,991.10	$ -	$ 50.05	$ -	$ 50.05	$ -	$ -	$ 15,421.81	$ 15,421.81	$ 18,462.96
13	Real Time Excessive/Deficient Energy Deployment	$ 29,363.95	$ 35,284.70	$ 28,080.16	$ 92,728.81	$ 31,387.24	$ 15,153.90	$ 37,428.39	$ 83,969.53	$ 39,381.87	$ 22,427.61	$ 14,182.03	$ 75,991.51	$ 38,842.45	$ 23,487.52	$ 27,863.65	$ 90,193.62	$ 342,883.47
9	Real Time Net Regulation Adjustment Amount	$ 5,697.01	$ (6,457.85)	$ 5,814.23	$ 5,053.39	$ (18,100.30)	$ 10,568.36	$ (1,692.54)	$ (9,224.48)	$ 5,062.61	$ (18,708.65)	$ (481.01)	$ (14,127.05)	$ (11,133.29)	$ (7,801.66)	$ 6,382.21	$ (12,552.74)	$ (30,850.88)
	SUBTOTAL	$ 35,060.96	$ 28,826.85	$ 33,894.39	$ 97,782.20	$ 16,278.04	$ 25,722.26	$ 35,735.85	$ 77,736.15	$ 44,444.48	$ 3,769.01	$ 13,701.02	$ 61,914.51	$ 27,709.16	$ 15,685.86	$ 49,667.67	$ 93,062.69	$ 330,495.55
	TOTAL MISO ASM CHARGES	$ (99,829.33)	$ (172,230.44)	$ (162,666.62)	$ (434,726.39)	$ (222,074.76)	$ (102,473.33)	$ (111,127.65)	$ (435,675.74)	$ (225,163.89)	$ (175,244.87)	$ (39,712.69)	$ (440,121.45)	$ (83,212.85)	$ 5,273.62	$ (19,066.00)	$ (97,005.23)	$ (1,407,528.81)
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT																		
7a	Real Time Excessive Energy Amount	$ (13,268.54)	$ (7,907.35)	$ (13,806.90)	$ (34,982.79)	$ (4,390.42)	$ (2,062.16)	$ (1,102.93)	$ (7,555.51)	$ (11,540.52)	$ (16,514.00)	$ (1,092.26)	$ (29,146.78)	$ (1,205.29)	$ (4,004.37)	$ 6,020.77	$ 811.11	$ (70,873.97)
7b	Real Time Excessive Energy Congestion				$ -				$ -				$ -				$ -	$ -
7c	Real Time Excessive Energy Loss				$ -				$ -				$ -				$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 3,060,253.43	$ (653,150.90)	$ 1,102,922.19	$ 3,510,024.72	$ 1,006,642.11	$ 539,584.76	$ 3,605,397.26	$ 5,151,624.13	$ 4,763,154.91	$ 3,764,276.99	$ 912,356.30	$ 9,439,788.20	$ 1,565,283.81	$ 902,542.73	$ 2,891,182.72	$ 5,359,009.26	$ 23,460,446.31
8b	Real Time Non Excessive Energy Congestion	$ (131,073.51)	$ 84,356.90	$ (380,280.51)	$ (426,997.12)	$ (400,723.14)	$ (16,754.64)	$ (829,572.58)	$ (1,247,050.36)	$ (436,551.51)	$ (154,142.30)	$ (287,920.60)	$ (878,614.41)	$ (212,325.68)	$ (296,288.71)	$ (150,979.98)	$ (659,594.37)	$ (3,212,256.26)
8c	Real Time Non Excessive Energy Loss	$ (68,882.86)	$ 105,131.56	$ (70,454.08)	$ (34,205.38)	$ (95,665.65)	$ 21,319.36	$ (210,120.57)	$ (284,466.86)	$ (83,886.68)	$ (21,641.96)	$ (49,677.68)	$ (155,206.32)	$ (16,813.64)	$ 71,805.07	$ 123,250.84	$ 178,242.27	$ (295,636.29)
	SUBTOTAL	$ 2,847,028.52	$ (471,569.79)	$ 638,380.70	$ 3,013,839.43	$ 505,862.90	$ 542,087.32	$ 2,564,601.18	$ 3,612,551.40	$ 4,231,176.20	$ 3,571,978.73	$ 573,665.76	$ 8,376,820.69	$ 1,334,939.20	$ 674,054.72	$ 2,869,474.35	$ 4,878,468.27	$ 19,881,679.79
	GRAND TOTAL MISO ASM CHARGES	$ 2,747,199.19	$ (643,800.23)	$ 475,714.08	$ 2,579,113.04	$ 283,788.14	$ 439,613.99	$ 2,453,473.53	$ 3,176,875.66	$ 4,006,012.31	$ 3,396,733.86	$ 533,953.07	$ 7,936,699.24	$ 1,251,726.35	$ 679,328.34	$ 2,850,408.35	$ 4,781,463.04	$ 18,474,150.98

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

		January 20	February 20	March 20	1st Qt	April 20	May 20	June 20	2nd Qt	July 20	August 20	September 20	3rd Qt	October 20	November 20	December 20	4th Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount				$ -				$ -				$ -				$ -	$ -
4	Real-Time Regulation Amount	$ 108,151.73	$ 225,547.43	$ 197,601.80	$ 531,300.96	$ 239,748.71	$ 122,573.05	$ 103,314.79	$ 465,636.55	$ 215,664.23	$ 106,625.88	$ 39,327.29	$ 361,617.40	$ 111,503.33	$ 58,905.64	$ 71,949.11	$ 242,358.08	$ 1,600,912.99
10	Real Time Regulation Reserve Cost Distribution Amount				$ -				$ -				$ -				$ -	$ -
	SUBTOTAL	$ 108,151.73	$ 225,547.43	$ 197,601.80	$ 531,300.96	$ 239,748.71	$ 122,573.05	$ 103,314.79	$ 465,636.55	$ 215,664.23	$ 106,625.88	$ 39,327.29	$ 361,617.40	$ 111,503.33	$ 58,905.64	$ 71,949.11	$ 242,358.08	$ 1,600,912.99
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount				$ -				$ -				$ -				$ -	$ -
5	Real-Time Spinning Reserve Amount	$ 105,337.28	$ 209,090.18	$ 137,358.29	$ 451,785.75	$ 175,962.92	$ 168,116.92	$ 108,631.66	$ 452,711.50	$ 76,574.64	$ 116,890.86	$ 43,835.34	$ 237,300.84	$ 71,663.46	$ 53,475.87	$ 52,570.97	$ 177,710.30	$ 1,319,508.39
11	Real Time Spinning Reserve Cost Distribution				$ -				$ -				$ -				$ -	$ -
	SUBTOTAL	$ 105,337.28	$ 209,090.18	$ 137,358.29	$ 451,785.75	$ 175,962.92	$ 168,116.92	$ 108,631.66	$ 452,711.50	$ 76,574.64	$ 116,890.86	$ 43,835.34	$ 237,300.84	$ 71,663.46	$ 53,475.87	$ 52,570.97	$ 177,710.30	$ 1,319,508.39
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve				$ -				$ -				$ -				$ -	$ -
6	Real-Time Supplemental Reserve Amount.	$ 31,929.35	$ 38,092.05	$ 15,487.35	$ 85,508.75	$ 22,216.39	$ 26,124.14	$ 9,854.50	$ 58,195.03	$ 8,309.52	$ 14,615.52	$ 17,301.87	$ 40,226.91	$ 10,841.37	$ 5,452.83	$ 2,271.86	$ 18,566.06	$ 202,496.75
12	Real Time Supplemental Reserve Cost Distribution				$ -				$ -				$ -				$ -	$ -
	SUBTOTAL	$ 31,929.35	$ 38,092.05	$ 15,487.35	$ 85,508.75	$ 22,216.39	$ 26,124.14	$ 9,854.50	$ 58,195.03	$ 8,309.52	$ 14,615.52	$ 17,301.87	$ 40,226.91	$ 10,841.37	$ 5,452.83	$ 2,271.86	$ 18,566.06	$ 202,496.75
Other Charges																		
14	Real Time Contingency Reserve Deployment Failure	$ (70.54)	$ -	$ -	$ (70.54)	$ (1,229.13)	$ -	$ -	$ (1,229.13)	$ -	$ (7.17)	$ -	$ (7.17)	$ -	$ -	$ -	$ -	$ (1,306.84)
13	Real Time Excessive/Deficient Energy Deployment	$ (8,927.10)	$ (11,010.04)	$ (12,401.72)	$ (32,338.86)	$ (20,695.02)	$ (8,779.41)	$ (24,593.07)	$ (54,067.50)	$ (27,068.58)	$ (13,084.28)	$ (9,519.21)	$ (49,672.07)	$ (28,290.65)	$ (7,359.05)	$ (18,629.08)	$ (54,278.78)	$ (190,357.21)
9	Real Time Net Regulation Adjustment Amount	$ (192.85)	$ 4,480.34	$ 853.06	$ 5,140.55	$ 11,149.23	$ (1,566.02)	$ 1,103.93	$ 10,687.14	$ 913.89	$ 7,189.62	$ 2,169.70	$ 10,273.21	$ 9,075.02	$ 4,952.75	$ (1,911.10)	$ 12,116.67	$ 38,217.57
	SUBTOTAL	$ (9,190.49)	$ (6,529.70)	$ (11,548.66)	$ (27,268.85)	$ (10,774.92)	$ (10,345.43)	$ (23,489.14)	$ (44,609.49)	$ (26,154.69)	$ (5,901.83)	$ (7,349.51)	$ (39,406.03)	$ (19,215.63)	$ (2,406.30)	$ (20,540.18)	$ (42,162.11)	$ (153,446.48)
	TOTAL MISO ASM CHARGES	$ 236,227.87	$ 466,199.96	$ 338,898.78	$ 1,041,326.61	$ 427,153.10	$ 306,468.68	$ 198,311.81	$ 931,933.59	$ 274,393.70	$ 232,230.43	$ 93,114.99	$ 599,739.12	$ 174,792.53	$ 115,428.04	$ 106,251.76	$ 396,472.33	$ 2,969,471.65
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	$ 236,227.87	$ 466,199.96	$ 338,898.78	$ 1,041,326.61	$ 427,153.10	$ 306,468.68	$ 198,311.81	$ 931,933.59	$ 274,393.70	$ 232,230.43	$ 93,114.99	$ 599,739.12	$ 174,792.53	$ 115,428.04	$ 106,251.76	$ 396,472.33	$ 2,969,471.65

Northern States Power Company

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

		January 20	February 20	March 20	1st Qt	April 20	May 20	June 20	2nd Qt	July 20	August 20	September 20	3rd Qt	October 20	November 20	December 20	4th Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount	$ (222,870.11)	$ (231,511.33)	$ (255,634.08)	$ (710,015.52)	$ (228,122.10)	$ (173,139.55)	$ (190,604.54)	$ (591,866.19)	$ (189,774.56)	$ (174,236.43)	$ (78,115.27)	$ (442,126.26)	$ (218,072.97)	$ (125,759.98)	$ (121,729.03)	$ (465,561.98)	$ (2,209,569.95)
4	Real-Time Regulation Amount	$ 158,515.72	$ 260,339.22	$ 237,734.83	$ 656,589.77	$ 239,301.26	$ 142,913.24	$ 101,420.91	$ 483,635.41	$ 68,380.50	$ 66,991.09	$ 9,847.31	$ 145,218.90	$ 117,151.04	$ 40,879.93	$ 33,653.79	$ 191,684.76	$ 1,477,128.84
10	Real Time Regulation Reserve Cost Distribution Amc	$ 111,321.30	$ 108,152.70	$ 114,733.74	$ 334,207.74	$ 118,425.63	$ 119,108.36	$ 116,678.80	$ 354,212.79	$ 126,976.29	$ 121,423.76	$ 114,611.55	$ 363,011.60	$ 130,622.30	$ 128,336.29	$ 129,829.89	$ 388,788.48	$ 1,440,220.61
	SUBTOTAL	$ 46,966.91	$ 136,980.59	$ 96,834.49	$ 280,781.99	$ 129,604.79	$ 88,882.05	$ 27,495.17	$ 245,982.01	$ 5,582.23	$ 14,178.42	$ 46,343.59	$ 66,104.24	$ 29,700.37	$ 43,456.24	$ 41,754.65	$ 114,911.26	$ 707,779.50
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount	$ (184,405.08)	$ (123,481.97)	$ (144,262.47)	$ (452,149.52)	$ (174,548.54)	$ (175,388.58)	$ (131,163.20)	$ (481,100.32)	$ (132,236.62)	$ (187,878.92)	$ (69,129.43)	$ (389,244.97)	$ (122,021.50)	$ (71,977.62)	$ (124,767.91)	$ (318,767.03)	$ (1,641,261.84)
5	Real-Time Spinning Reserve Amount	$ 152,200.63	$ 177,457.56	$ 135,178.40	$ 464,836.59	$ 163,260.05	$ 172,217.71	$ 85,560.96	$ 421,038.72	$ 55,974.80	$ 125,797.49	$ 8,077.41	$ 189,849.70	$ 73,298.83	$ 55,656.24	$ 54,061.34	$ 183,016.41	$ 1,258,741.42
11	Real Time Spinning Reserve Cost Distribution	$ 76,300.71	$ 61,960.75	$ 64,205.18	$ 202,466.64	$ 73,008.37	$ 91,828.37	$ 88,495.02	$ 253,331.76	$ 106,609.09	$ 101,451.06	$ 60,382.83	$ 268,442.98	$ 90,394.99	$ 78,756.35	$ 86,520.15	$ 255,671.49	$ 979,912.87
	SUBTOTAL	$ 44,096.26	$ 115,936.34	$ 55,121.11	$ 215,153.71	$ 61,719.88	$ 88,657.50	$ 42,892.78	$ 193,270.16	$ 30,347.27	$ 39,369.63	$ (669.19)	$ 69,047.71	$ 41,672.32	$ 62,434.97	$ 15,813.58	$ 119,920.87	$ 597,392.45
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve	$ (36,839.82)	$ (28,971.64)	$ (25,943.42)	$ (91,754.88)	$ (26,195.52)	$ (26,014.04)	$ (19,929.95)	$ (72,139.51)	$ (26,502.26)	$ (27,590.60)	$ (30,007.76)	$ (84,100.62)	$ (26,511.85)	$ (14,264.35)	$ (14,308.14)	$ (55,084.34)	$ (303,079.35)
6	Real-Time Supplemental Reserve Amount.	$ 34,903.80	$ 37,918.59	$ 17,029.27	$ 89,851.66	$ 24,399.72	$ 26,931.96	$ 12,828.26	$ 64,159.94	$ 11,128.36	$ 17,116.75	$ 19,366.88	$ 47,611.99	$ 13,964.89	$ 5,898.70	$ 2,360.28	$ 22,223.87	$ 223,847.46
12	Real Time Supplemental Reserve Cost Distribution	$ 21,400.92	$ 9,808.49	$ 10,844.98	$ 42,054.39	$ 10,046.35	$ 10,161.05	$ 11,651.19	$ 31,858.59	$ 10,384.42	$ 16,044.18	$ 12,017.27	$ 38,445.87	$ 24,260.42	$ 9,896.54	$ 12,437.90	$ 46,594.86	$ 158,953.71
	SUBTOTAL	$ 19,464.90	$ 18,755.44	$ 1,930.83	$ 40,151.17	$ 8,250.55	$ 11,078.97	$ 4,549.50	$ 23,879.02	$ (4,989.48)	$ 5,570.33	$ 1,376.39	$ 1,957.24	$ 11,713.46	$ 1,530.89	$ 490.04	$ 13,734.39	$ 79,721.82
Other Charges																		
13	Real Time Excessive/Deficient Energy Deployment	$ (70.54)	$ -	$ -	$ (70.54)	$ 1,761.97	$ -	$ -	$ 1,761.97	$ -	$ 42.88	$ -	$ 42.88	$ -	$ -	$ 15,421.81	$ 15,421.81	$ 17,156.12
14	Real Time Contingency Reserve Deployment Failure	$ 20,436.85	$ 24,274.66	$ 15,678.44	$ 60,389.95	$ 10,692.22	$ 6,374.49	$ 12,835.32	$ 29,902.03	$ 12,313.29	$ 9,343.33	$ 4,662.82	$ 26,319.44	$ 10,551.80	$ 16,128.47	$ 9,234.57	$ 35,914.84	$ 152,526.26
9	Real Time Net Regulation Adjustment Amount	$ 5,504.16	$ (1,977.51)	$ 6,667.29	$ 10,193.94	$ (6,951.07)	$ 9,002.34	$ (588.61)	$ 1,462.66	$ 5,976.50	$ (11,519.03)	$ 1,688.69	$ (3,853.84)	$ (2,058.27)	$ (2,848.91)	$ 4,471.11	$ (436.07)	$ 7,366.69
	SUBTOTAL	$ 25,870.47	$ 22,297.15	$ 22,345.73	$ 70,513.35	$ 5,503.12	$ 15,376.83	$ 12,246.71	$ 33,126.66	$ 18,289.79	$ (2,132.82)	$ 6,351.51	$ 22,508.48	$ 8,493.53	$ 13,279.56	$ 29,127.49	$ 50,900.58	$ 177,049.07
	TOTAL MISO ASM CHARGES	$ 136,398.54	$ 293,969.52	$ 176,232.16	$ 606,600.22	$ 205,078.34	$ 203,995.35	$ 87,184.16	$ 496,257.85	$ 49,229.81	$ 56,985.56	$ 53,402.30	$ 159,617.67	$ 91,579.68	$ 120,701.66	$ 87,185.76	$ 299,467.10	$ 1,561,942.84
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT																		
7a	Real Time Excessive Energy Amount	$ (13,268.54)	$ (7,907.35)	$ (13,806.90)	$ (34,982.79)	$ (4,390.42)	$ (2,062.16)	$ (1,102.93)	$ (7,555.51)	$ (11,540.52)	$ (16,514.00)	$ (1,092.26)	$ (29,146.78)	$ (1,205.29)	$ (4,004.37)	$ 6,020.77	$ 811.11	$ (70,873.97)
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 3,060,253.43	$ (653,150.90)	$ 1,102,922.19	$ 3,510,024.72	$ 1,006,642.11	$ 539,584.76	$ 3,605,397.26	$ 5,151,624.13	$ 4,763,154.91	$ 3,764,276.99	$ 912,356.30	$ 9,439,788.20	$ 1,565,283.81	$ 902,542.73	$ 2,891,182.72	$ 5,359,009.26	$ 23,460,446.31
8b	Real Time Non Excessive Energy Congestion	$ (131,073.51)	$ 84,356.90	$ (380,280.51)	$ (426,997.12)	$ (400,723.14)	$ (16,754.64)	$ (829,572.58)	$ (1,247,050.36)	$ (436,551.51)	$ (154,142.30)	$ (287,920.60)	$ (878,614.41)	$ (212,325.68)	$ (296,288.71)	$ (150,979.98)	$ (659,594.37)	$ (3,212,256.26)
8c	Real Time Non Excessive Energy Loss	$ (68,882.86)	$ 105,131.56	$ (70,454.08)	$ (34,205.38)	$ (95,665.65)	$ 21,319.36	$ (210,120.57)	$ (284,466.86)	$ (83,886.68)	$ (21,641.96)	$ (49,677.68)	$ (155,206.32)	$ (16,813.64)	$ 71,805.07	$ 123,250.84	$ 178,242.27	$ (295,636.29)
	SUBTOTAL	$ 2,847,028.52	$ (471,569.79)	$ 638,380.70	$ 3,013,839.43	$ 505,862.90	$ 542,087.32	$ 2,564,601.18	$ 3,612,551.40	$ 4,231,176.20	$ 3,571,978.73	$ 573,665.76	$ 8,376,820.69	$ 1,334,939.20	$ 674,054.72	$ 2,869,474.35	$ 4,878,468.27	$ 19,881,679.79
	GRAND TOTAL MISO ASM CHARGES	$ 2,983,427.06	$ (177,600.27)	$ 814,612.86	$ 3,620,439.65	$ 710,941.24	$ 746,082.67	$ 2,651,785.34	$ 4,108,809.25	$ 4,280,406.01	$ 3,628,964.29	$ 627,068.06	$ 8,536,438.36	$ 1,426,518.88	$ 794,756.38	$ 2,956,660.11	$ 5,177,935.37	$ 21,443,622.63

Northern States Power Company

Docket No. E002/AA-19-293
True-Up Report
Part B, Attachment 8

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

		January 20	February 20	March 20	1st Qt	April 20	May 20	June 20	2nd Qt	July 20	August 20	September 20	3rd Qt	October 20	November 20	December 20	4th Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount	(157,521.30)	(164,070.45)	(181,264.52)	(502,856.27)	(162,119.39)	(124,505.48)	(138,432.89)	(425,057.76)	(138,678.86)	(126,365.12)	(56,388.97)	(321,432.95)	(156,160.98)	(89,722.38)	(86,094.86)	(331,978.22)	(1,581,325.20)
4	Real-Time Regulation Amount	112,036.57	184,500.57	168,572.56	465,109.70	170,064.08	102,769.59	73,660.31	346,493.98	49,969.45	48,585.34	7,108.46	105,663.26	83,891.28	29,165.44	23,802.20	136,858.92	1,054,125.85
10	Real Time Regulation Reserve Cost Distribution Amc	78,680.25	76,647.06	81,355.18	236,682.49	84,161.47	85,651.39	84,741.86	254,554.72	92,788.66	88,062.68	82,734.49	263,585.84	93,537.98	91,560.43	91,824.33	276,922.74	1,031,745.79
	SUBTOTAL	33,195.52	97,077.18	68,663.21	198,935.91	92,106.16	63,915.51	19,969.28	175,990.95	4,079.25	10,282.91	33,453.99	47,816.15	21,268.29	31,003.48	29,531.66	81,803.44	504,546.44
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount	(130,334.78)	(87,510.80)	(102,293.36)	(320,138.94)	(124,046.31)	(126,122.76)	(95,261.64)	(345,430.71)	(96,632.68)	(136,259.34)	(49,902.37)	(282,794.39)	(87,378.99)	(51,351.82)	(88,244.16)	(226,974.97)	(1,175,339.02)
5	Real-Time Spinning Reserve Amount	107,573.15	125,762.92	95,852.04	329,188.12	116,023.92	123,842.58	62,141.49	302,007.99	40,903.91	91,234.74	5,830.83	137,969.48	52,488.93	39,707.47	38,235.77	130,432.17	899,597.76
11	Real Time Spinning Reserve Cost Distribution	53,928.21	43,911.15	45,526.49	143,365.85	51,884.81	66,034.22	64,272.45	182,191.49	77,905.21	73,577.47	43,588.47	195,071.15	64,731.41	56,188.05	61,192.80	182,112.25	702,740.74
	SUBTOTAL	31,166.58	82,163.27	39,085.17	152,415.02	43,862.43	63,754.03	31,152.31	138,768.77	22,176.44	28,552.86	(483.07)	50,246.23	29,841.34	44,543.70	11,184.42	85,569.45	426,999.48
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve	(26,037.84)	(20,532.00)	(18,395.91)	(64,965.75)	(18,616.35)	(18,706.82)	(14,474.79)	(51,797.96)	(19,366.68)	(20,010.11)	(21,661.66)	(61,038.45)	(18,985.00)	(10,176.78)	(10,119.67)	(39,281.45)	(217,083.61)
6	Real-Time Supplemental Reserve Amount.	24,669.49	26,872.64	12,075.08	63,617.21	17,340.13	19,366.90	9,316.95	46,023.99	8,132.11	12,413.94	13,980.34	34,526.40	10,000.19	4,208.38	1,669.35	15,877.91	160,045.50
12	Real Time Supplemental Reserve Cost Distribution	15,125.85	6,951.21	7,689.94	29,767.00	7,139.63	7,306.86	8,462.06	22,908.56	7,588.48	11,636.06	8,674.89	27,899.42	17,372.77	7,060.60	8,796.91	33,230.28	113,805.26
	SUBTOTAL	13,757.50	13,291.85	1,369.11	28,418.46	5,863.41	7,966.94	3,304.23	17,134.58	(3,646.09)	4,039.89	993.57	1,387.37	8,387.95	1,092.20	346.59	9,826.74	56,767.15
Other Charges																		
14	Real Time Contingency Reserve Deployment Failure	(49.86)	-	-	(49.86)	1,252.18	-	-	1,252.18	-	31.10	-	31.10	-	-	10,907.33	10,907.33	12,140.75
13	Real Time Excessive/Deficient Energy Deployment	14,444.46	17,203.28	11,117.24	42,764.98	7,598.63	4,583.93	9,322.08	21,504.64	8,998.01	6,776.26	3,365.94	19,140.21	7,556.09	11,506.72	6,531.30	25,594.11	109,003.94
9	Real Time Net Regulation Adjustment Amount	3,890.26	(1,401.45)	4,727.63	7,216.44	(4,939.91)	6,473.63	(427.50)	1,106.22	4,367.36	(8,354.19)	1,219.01	(2,767.81)	(1,473.92)	(2,032.53)	3,162.27	(344.18)	5,210.66
	SUBTOTAL	18,284.87	15,801.83	15,844.87	49,931.57	3,910.90	11,057.55	8,894.58	23,863.03	13,365.37	(1,546.83)	4,584.96	16,403.50	6,082.17	9,474.19	20,600.90	36,157.26	126,355.36
	TOTAL MISO ASM CHARGES	96,404.47	208,334.13	124,962.36	429,700.96	145,742.90	146,694.03	63,320.40	355,757.33	35,974.97	41,328.83	38,549.45	115,853.24	65,579.76	86,113.57	61,663.57	213,356.89	1,114,668.42
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT																		
7a	Real Time Excessive Energy Amount	(9,378.01)	(5,603.88)	(9,790.17)	(24,772.06)	(3,120.14)	(1,482.91)	(801.04)	(5,404.09)	(8,433.30)	(11,976.79)	(788.47)	(21,198.56)	(863.10)	(2,856.88)	4,258.29	538.30	(50,836.41)
7b	Real Time Excessive Energy Congestion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7c	Real Time Excessive Energy Loss	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8a	Real Time Non Excessive Energy Amount	2,162,941.84	(462,883.45)	782,057.95	2,482,116.34	715,389.74	388,017.98	2,618,539.70	3,721,947.42	3,480,703.13	2,730,045.05	658,601.46	6,869,349.63	1,120,892.00	643,911.41	2,044,836.63	3,809,640.04	16,883,053.42
8b	Real Time Non Excessive Energy Congestion	(92,640.82)	59,783.14	(269,648.57)	(302,506.25)	(284,781.67)	(12,048.34)	(602,504.68)	(899,334.70)	(319,012.55)	(111,791.83)	(207,840.87)	(638,645.25)	(152,045.37)	(211,384.65)	(106,783.08)	(470,213.10)	(2,310,699.30)
8c	Real Time Non Excessive Energy Loss	(48,685.39)	74,506.00	(49,957.44)	(24,136.83)	(67,986.65)	15,330.85	(152,607.05)	(205,262.85)	(61,300.68)	(15,695.85)	(35,860.76)	(112,857.29)	(12,040.16)	51,228.71	87,171.19	126,359.74	(215,897.24)
	SUBTOTAL	2,012,237.63	(334,198.19)	452,661.76	2,130,701.20	359,501.28	389,817.58	1,862,626.93	2,611,945.78	3,091,956.59	2,590,580.57	414,111.36	6,096,648.52	955,943.36	480,898.59	2,029,483.03	3,466,324.98	14,305,620.48
	GRAND TOTAL MISO ASM CHARGES	2,108,642.10	(125,864.06)	577,624.12	2,560,402.16	505,244.18	536,511.61	1,925,947.32	2,967,703.11	3,127,931.56	2,631,909.40	452,660.80	6,212,501.77	1,021,523.12	567,012.16	2,091,146.59	3,679,681.87	15,420,288.90

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

January 2020	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		$ (222,870.11)		$ (222,870.11)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (184,405.08)		$ (184,405.08)		$ -		
3 Day-Ahead Supplemental Reserve		$ (36,839.82)		$ (36,839.82)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ 50,363.99		$ 158,515.72		$ (108,151.73)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 46,863.35		$ 152,200.63		$ (105,337.28)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 2,974.45		$ 34,903.80		$ (31,929.35)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(822)	$ (13,268.54)	(822)	$ (13,268.54)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	165,884	$ 3,060,253.43	165,884	$ 3,060,253.43		$ -		
8b Real Time Non Excessive Energy Congestion		$ (131,073.51)		$ (131,073.51)		$ -		
8c Real Time Non Excessive Energy Loss		$ (68,882.86)		$ (68,882.86)		$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ 5,697.01	-	$ 5,504.16		$ 192.85		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 111,321.30		$ 111,321.30		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 76,300.71		$ 76,300.71		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 21,400.92		$ 21,400.92		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 29,363.95		$ 20,436.85		$ 8,927.10		
14 Real Time Contingency Reserve Deployment Failure		$ -		$ (70.54)		$ 70.54		
TOTAL MISO ASM CHARGES	**165,062**	**$ 2,747,199.19**	**165,062**	**$ 2,983,427.06**		**$ (236,227.87)**		**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

February 2020	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		$ (231,511.33)		$ (231,511.33)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (123,481.97)		$ (123,481.97)		$ -		
3 Day-Ahead Supplemental Reserve		$ (28,971.64)		$ (28,971.64)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ 34,791.79		$ 260,339.22		$ (225,547.43)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (31,632.62)		$ 177,457.56		$ (209,090.18)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (173.46)		$ 37,918.59		$ (38,092.05)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(617)	$ (7,907.35)	(617)	$ (7,907.35)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	(71,486)	$ (653,150.90)	(71,486)	$ (653,150.90)		$ -		
8b Real Time Non Excessive Energy Congestion		$ 84,356.90		$ 84,356.90		$ -		
8c Real Time Non Excessive Energy Loss		$ 105,131.56		$ 105,131.56		$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ (6,457.85)	-	$ (1,977.51)		$ (4,480.34)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 108,152.70		$ 108,152.70		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 61,960.75		$ 61,960.75		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 9,808.49		$ 9,808.49		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 35,284.70		$ 24,274.66		$ 11,010.04		
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**(72,103)**	**$ (643,800.23)**	**(72,103)**	**$ (177,600.27)**		**$ (466,199.96)**		**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

March 2020	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		$ (255,634.08)		$ (255,634.08)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (144,262.47)		$ (144,262.47)		$ -		
3 Day-Ahead Supplemental Reserve		$ (25,943.42)		$ (25,943.42)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ 40,133.03		$ 237,734.83		$ (197,601.80)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (2,179.89)		$ 135,178.40		$ (137,358.29)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 1,541.92		$ 17,029.27		$ (15,487.35)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(2,354)	$ (13,806.90)	(2,354)	$ (13,806.90)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	88,300	$ 1,102,922.19	88,300	$ 1,102,922.19		$ -		
8b Real Time Non Excessive Energy Congestion		$ (380,280.51)		$ (380,280.51)		$ -		
8c Real Time Non Excessive Energy Loss		$ (70,454.08)		$ (70,454.08)		$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ 5,814.23	-	$ 6,667.29		$ (853.06)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 114,733.74		$ 114,733.74		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 64,205.18		$ 64,205.18		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 10,844.98		$ 10,844.98		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 28,080.16		$ 15,678.44		$ 12,401.72		
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**85,946**	**$ 475,714.08**	**85,946**	**$ 814,612.86**		**$ (338,898.78)**		**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

April 2020	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		$ (228,122.10)		$ (228,122.10)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (174,548.54)		$ (174,548.54)		$ -		
3 Day-Ahead Supplemental Reserve		$ (26,195.52)		$ (26,195.52)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (447.45)		$ 239,301.26		$ (239,748.71)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (12,702.87)		$ 163,260.05		$ (175,962.92)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 2,183.33		$ 24,399.72		$ (22,216.39)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(581)	$ (4,390.42)	(581)	$ (4,390.42)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	15,421	$ 1,006,642.11	15,421	$ 1,006,642.11		$ -		
8b Real Time Non Excessive Energy Congestion		$ (400,723.14)		$ (400,723.14)		$ -		
8c Real Time Non Excessive Energy Loss		$ (95,665.65)		$ (95,665.65)		$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ (18,100.30)	-	$ (6,951.07)		$ (11,149.23)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 118,425.63		$ 118,425.63		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 73,008.37		$ 73,008.37		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 10,046.35		$ 10,046.35		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 31,387.24		$ 10,692.22		$ 20,695.02		
14 Real Time Contingency Reserve Deployment Failure		$ 2,991.10		$ 1,761.97		$ 1,229.13		
TOTAL MISO ASM CHARGES	**14,840**	**$ 283,788.14**	**14,840**	**$ 710,941.24**		**$ (427,153.10)**		**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

May 2020	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		$ (173,139.55)		$ (173,139.55)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (175,388.58)		$ (175,388.58)		$ -		
3 Day-Ahead Supplemental Reserve		$ (26,014.04)		$ (26,014.04)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ 20,340.19		$ 142,913.24		$ (122,573.05)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 4,100.79		$ 172,217.71		$ (168,116.92)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 807.82		$ 26,931.96		$ (26,124.14)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(264)	$ (2,062.16)	(264)	$ (2,062.16)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	43,319	$ 539,584.76	43,319	$ 539,584.76		$ -		
8b Real Time Non Excessive Energy Congestion		$ (16,754.64)		$ (16,754.64)		$ -		
8c Real Time Non Excessive Energy Loss		$ 21,319.36		$ 21,319.36		$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ 10,568.36	-	$ 9,002.34		$ 1,566.02		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 119,108.36		$ 119,108.36		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 91,828.37		$ 91,828.37		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 10,161.05		$ 10,161.05		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 15,153.90		$ 6,374.49		$ 8,779.41		
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**43,055**	**$ 439,613.99**	**43,055**	**$ 746,082.67**		**$ (306,468.68)**		**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

June 2020					Intersystem			
	NET INVOICE		RETAIL		ASSET BASED		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		$ (190,604.54)		$ (190,604.54)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (131,163.20)		$ (131,163.20)		$ -		
3 Day-Ahead Supplemental Reserve		$ (19,929.95)		$ (19,929.95)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (1,893.88)		$ 101,420.91		$ (103,314.79)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (23,070.70)		$ 85,560.96		$ (108,631.66)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 2,973.76		$ 12,828.26		$ (9,854.50)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,624)	$ (1,102.93)	(1,624)	$ (1,102.93)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	135,125	$ 3,605,397.26	135,125	$ 3,605,397.26		$ -		
8b Real Time Non Excessive Energy Congestion		$ (829,572.58)		$ (829,572.58)		$ -		
8c Real Time Non Excessive Energy Loss		$ (210,120.57)		$ (210,120.57)		$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ (1,692.54)	-	$ (588.61)		$ (1,103.93)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 116,678.80		$ 116,678.80		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 88,495.02		$ 88,495.02		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 11,651.19		$ 11,651.19		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 37,428.39		$ 12,835.32		$ 24,593.07		
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**133,501**	**$ 2,453,473.53**	**133,501**	**$ 2,651,785.34**		**$ (198,311.81)**		**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

July 2020	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		$ (189,774.56)		$ (189,774.56)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (132,236.62)		$ (132,236.62)		$ -		
3 Day-Ahead Supplemental Reserve		$ (26,502.26)		$ (26,502.26)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (147,283.73)		$ 68,380.50		$ (215,664.23)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (20,599.84)		$ 55,974.80		$ (76,574.64)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 2,818.84		$ 11,128.36		$ (8,309.52)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,275)	$ (11,540.52)	(1,275)	$ (11,540.52)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	265,388	$ 4,763,154.91	265,388	$ 4,763,154.91		$ -		
8b Real Time Non Excessive Energy Congestion		$ (436,551.51)		$ (436,551.51)		$ -		
8c Real Time Non Excessive Energy Loss		$ (83,886.68)		$ (83,886.68)		$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ 5,062.61	-	$ 5,976.50		$ (913.89)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 126,976.29		$ 126,976.29		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 106,609.09		$ 106,609.09		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 10,384.42		$ 10,384.42		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 39,381.87		$ 12,313.29		$ 27,068.58		
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**264,113**	**$ 4,006,012.31**	**264,113**	**$ 4,280,406.01**		**$ (274,393.70)**		**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

August 2020	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		$ (174,236.43)		$ (174,236.43)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (187,878.92)		$ (187,878.92)		$ -		
3 Day-Ahead Supplemental Reserve		$ (27,590.60)		$ (27,590.60)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (39,634.79)		$ 66,991.09		$ (106,625.88)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 8,906.63		$ 125,797.49		$ (116,890.86)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 2,501.23		$ 17,116.75		$ (14,615.52)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(496)	$ (16,514.00)	(496)	$ (16,514.00)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	177,801	$ 3,764,276.99	177,801	$ 3,764,276.99		$ -		
8b Real Time Non Excessive Energy Congestion		$ (154,142.30)		$ (154,142.30)		$ -		
8c Real Time Non Excessive Energy Loss		$ (21,641.96)		$ (21,641.96)		$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ (18,708.65)	-	$ (11,519.03)		$ (7,189.62)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 121,423.76		$ 121,423.76		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 101,451.06		$ 101,451.06		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 16,044.18		$ 16,044.18		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 22,427.61		$ 9,343.33		$ 13,084.28		
14 Real Time Contingency Reserve Deployment Failure		$ 50.05		$ 42.88		$ 7.17		
TOTAL MISO ASM CHARGES	**177,305**	**$ 3,396,733.86**	**177,305**	**$ 3,628,964.29**		**$ (232,230.43)**		**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

September 2020	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		$ (78,115.27)		$ (78,115.27)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (69,129.43)		$ (69,129.43)		$ -		
3 Day-Ahead Supplemental Reserve		$ (30,007.76)		$ (30,007.76)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (29,479.98)		$ 9,847.31		$ (39,327.29)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (35,757.93)		$ 8,077.41		$ (43,835.34)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 2,065.01		$ 19,366.88		$ (17,301.87)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,119)	$ (1,092.26)	(1,119)	$ (1,092.26)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	152,371	$ 912,356.30	152,371	$ 912,356.30		$ -		
8b Real Time Non Excessive Energy Congestion		$ (287,920.60)		$ (287,920.60)		$ -		
8c Real Time Non Excessive Energy Loss		$ (49,677.68)		$ (49,677.68)		$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ (481.01)	-	$ 1,688.69		$ (2,169.70)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 114,611.55		$ 114,611.55		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 60,382.83		$ 60,382.83		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 12,017.27		$ 12,017.27		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 14,182.03		$ 4,662.82		$ 9,519.21		
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**151,252**	**$ 533,953.07**	**151,252**	**$ 627,068.06**		**$ (93,114.99)**		**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

October 2020	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		$ (218,072.97)		$ (218,072.97)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (122,021.50)		$ (122,021.50)		$ -		
3 Day-Ahead Supplemental Reserve		$ (26,511.85)		$ (26,511.85)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ 5,647.71		$ 117,151.04		$ (111,503.33)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 1,635.37		$ 73,298.83		$ (71,663.46)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 3,123.52		$ 13,964.89		$ (10,841.37)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,036)	$ (1,205.29)	(1,036)	$ (1,205.29)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	169,051	$ 1,565,283.81	169,051	$ 1,565,283.81		$ -		
8b Real Time Non Excessive Energy Congestion		$ (212,325.68)		$ (212,325.68)		$ -		
8c Real Time Non Excessive Energy Loss		$ (16,813.64)		$ (16,813.64)		$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ (11,133.29)	-	$ (2,058.27)		$ (9,075.02)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 130,622.30		$ 130,622.30		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 90,394.99		$ 90,394.99		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 24,260.42		$ 24,260.42		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 38,842.45		$ 10,551.80		$ 28,290.65		
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**168,015**	**$ 1,251,726.35**	**168,015**	**$ 1,426,518.88**		**$ (174,792.53)**		**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

November 2020	NET INVOICE		RETAIL		Intersystem ASSET BASED		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		$ (125,759.98)		$ (125,759.98)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (71,977.62)		$ (71,977.62)		$ -		
3 Day-Ahead Supplemental Reserve		$ (14,264.35)		$ (14,264.35)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (18,025.71)		$ 40,879.93		$ (58,905.64)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 2,180.37		$ 55,656.24		$ (53,475.87)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 445.87		$ 5,898.70		$ (5,452.83)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(991)	$ (4,004.37)	(991)	$ (4,004.37)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	39,495	$ 902,542.73	39,495	$ 902,542.73		$ -		
8b Real Time Non Excessive Energy Congestion		$ (296,288.71)		$ (296,288.71)		$ -		
8c Real Time Non Excessive Energy Loss		$ 71,805.07		$ 71,805.07		$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ (7,801.66)	-	$ (2,848.91)		$ (4,952.75)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 128,336.29		$ 128,336.29		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 78,756.35		$ 78,756.35		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 9,896.54		$ 9,896.54		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 23,487.52		$ 16,128.47		$ 7,359.05		
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**38,504**	**$ 679,328.34**	**38,504**	**$ 794,756.38**		**$ (115,428.04)**		**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

December 2020	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		$ (121,729.03)		$ (121,729.03)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (124,767.91)		$ (124,767.91)		$ -		
3 Day-Ahead Supplemental Reserve		$ (14,308.14)		$ (14,308.14)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (38,295.32)		$ 33,653.79		$ (71,949.11)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 1,490.37		$ 54,061.34		$ (52,570.97)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 88.42		$ 2,360.28		$ (2,271.86)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,482)	$ 6,020.77	(1,482)	$ 6,020.77		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	232,306	$ 2,891,182.72	232,306	$ 2,891,182.72		$ -		
8b Real Time Non Excessive Energy Congestion		$ (150,979.98)		$ (150,979.98)		$ -		
8c Real Time Non Excessive Energy Loss		$ 123,250.84		$ 123,250.84		$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ 6,382.21	-	$ 4,471.11		$ 1,911.10		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 129,829.89		$ 129,829.89		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 86,520.15		$ 86,520.15		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 12,437.90		$ 12,437.90		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 27,863.65		$ 9,234.57		$ 18,629.08		
14 Real Time Contingency Reserve Deployment Failure		$ 15,421.81		$ 15,421.81		$ -		
TOTAL MISO ASM CHARGES	**230,824**	**$ 2,850,408.35**	**230,824**	**$ 2,956,660.11**		**$ (106,251.76)**		**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

January - December 2020	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		$ (2,209,569.95)		$ (2,209,569.95)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (1,641,261.84)		$ (1,641,261.84)		$ -		
3 Day-Ahead Supplemental Reserve		$ (303,079.35)		$ (303,079.35)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (123,784.15)		$ 1,477,128.84		$ (1,600,912.99)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (60,766.97)		$ 1,258,741.42		$ (1,319,508.39)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 21,350.71		$ 223,847.46		$ (202,496.75)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(12,661)	$ (70,873.97)	(12,661)	$ (70,873.97)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	1,412,975	$ 23,460,446.31	1,412,975	$ 23,460,446.31		$ -		
8b Real Time Non Excessive Energy Congestion		$ (3,212,256.26)		$ (3,212,256.26)		$ -		
8c Real Time Non Excessive Energy Loss		$ (295,636.29)		$ (295,636.29)		$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ (30,850.88)	-	$ 7,366.69		$ (38,217.57)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 1,440,220.61		$ 1,440,220.61		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 979,912.87		$ 979,912.87		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 158,953.71		$ 158,953.71		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 342,883.47		$ 152,526.26		$ 190,357.21		
14 Real Time Contingency Reserve Deployment Failure		$ 18,462.96		$ 17,156.12		$ 1,306.84		
TOTAL MISO ASM CHARGES	**1,400,314**	**$ 18,474,150.98**	**1,400,314**	**$ 21,443,622.63**		**$ (2,969,471.65)**		**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

Docket No. E002/AA-19-293
True-Up Report
Part B, Attachment 10

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	January 2020	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	(727,169)	$ (8,827,162.87)	3,634,892	$ 74,967,000.82	(3,586,584)	$ (68,512,728.48)			(775,477)	$ (15,281,435.21)				
5a	Day Ahead Non Asset Energy	(112,961)	$ (2,472,908.66)	72	$ 1,501.80	(113,033)	$ (2,474,410.46)					11,784	$ 239,580.24	-	$ -
13a	Real Time Asset Energy	(37,194)	$ (644,201.09)	41,813	$ 961,537.66	33,579	$ 1,064,466.92			(112,586)	$ (2,670,205.67)				
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(877,324)	$ (11,944,272.62)	3,676,777	$ 75,930,040.28	(3,666,038)	$ (69,922,672.02)	-	$ -	(888,063)	$ (17,951,640.88)	11,784	$ 239,580.24	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 911.27		$ 1,740.14		$ (828.87)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (709,133.44)		$ -		$ (709,133.44)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (708,222.17)		$ 1,740.14		$ (709,962.31)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 805,185.59		$ 728,154.38		$ -		$ 77,031.21				$ 1,168.23		
19	Real Time Market Administration (Schedule 17)		$ 71,250.25		$ 60,247.20		$ -		$ 11,003.05				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 26,540.06		$ 26,540.06		$ -						$ 98.88		
33	Day-Ahead Schedule 24 Allocation Amount		$ 95,698.49		$ 86,548.52		$ -		$ 9,149.97				$ 136.25		
34	Real -Time Schedule 24 Allocation Amount		$ (92,613.79)		$ (8,802.34)		$ -				$ (83,811.45)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 906,060.60		$ 892,687.82		$ -		$ 97,184.23		$ (83,811.45)		$ 1,403.36		$ -
	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		$ 5,965.44		$ 7,014.99		$ (1,049.55)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (1,184,430.87)		$ 821,788.12		$ (2,006,218.99)						$ 19,984.06		$ (4,720.53)
30	Financial Transmission Rights Monthly Allocation		$ (89,274.04)		$ -		$ (89,274.04)								$ (497.16)
32	Financial Transmission Rights Yearly Allocation		$ (6,000.37)		$ 0.05		$ (6,000.42)						$ -		$ (17.23)
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (51,912.89)		$ -		$ (51,912.89)								$ 282.86
37	Financial Transmission Guarantee Uplift Amount		$ 158,412.36		$ 158,412.36		$ -						$ 285.36		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ 7,129.50		$ -
	SUBTOTAL		$ (1,167,240.37)		$ 987,215.52		$ (2,154,455.89)		$ -		$ -		$ 27,398.92		$ (4,952.06)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 76,283.62		$ 76,283.62										
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (91,615.49)				$ (24,522.70)				$ (67,092.79)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 50,802.10		$ 50,802.10										
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (11,981.69)				$ 801.11				$ (12,782.80)				
43	Real Time Price Volatility Make Whole Payment		$ (148,084.41)		$ -		($124,009.99)				$ (24,074.42)				
	SUBTOTAL		$ (124,595.87)		$ 127,085.72		$ (147,731.58)		$ -		$ (103,950.01)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 44,684.20		$ 123,738.90		$ (66,764.13)				$ (12,290.57)		$ -		
21	Real Time Net Inadvertent Distribution		$ 36,499.45		$ 68,282.75		$ (31,783.30)						$ 161.60		$ (98.73)
23	Real Time Revenue Neutrality Uplift Amount		$ 344,512.71		$ 609,295.86		$ (264,783.15)								
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 425,696.36		$ 801,317.51		$ (363,330.58)		$ -		$ (12,290.57)		$ 161.60		$ (98.73)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 1,123,444.70		$ 1,302,629.36		$ (179,184.66)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (1,123,867.22)		$ 177,460.39		$ (1,248,308.05)				$ (53,019.56)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (207,296.29)		$ -		$ (207,296.29)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 42,660.70		$ 42,660.70		$ -								
	SUBTOTAL		$ (165,058.11)		$ 1,522,750.45		$ (1,634,789.00)		$ -		$ (53,019.56)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (5,965.44)		$ 1,049.55		$ (7,014.99)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (911.27)		$ 828.87		$ (1,740.14)								
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	-	$ (6,876.71)	-	$ 1,878.42	-	$ (8,755.13)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(877,324)	$ (12,784,508.89)	3,676,777	$ 80,264,715.86	(3,666,038)	$ (74,941,696.51)	-	$ 97,184.23	(888,063)	$ (18,204,712.47)	11,784	$ 268,544.12	-	$ (5,050.79)
x	Net Congestion Amount		$ 2,401,886.01		$ 2,401,886.01										
y	Net Loss Amount		$ 2,660,573.67		$ 2,660,573.67										
z	Net Congestion and Loss Energy Offset		$ (5,062,459.68)		$ (5,062,459.68)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(877,324)**	$ (12,784,508.89)	3,676,777	$ 80,264,715.86	(3,666,038)	$ (74,941,696.51)	-	$ 97,184.23	(888,063)	$ (18,204,712.47)	11,784	$ 268,544.12	-	$ (5,050.79)

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 2020	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	(390,423)	$ (1,335,555.80)	3,281,637	$ 61,307,861.70	(3,133,441)	$ (53,346,185.52)			(538,619)	$ (9,297,231.98)				
5a	Day Ahead Non Asset Energy	(97,355)	$ (1,908,299.34)	76	$ 1,339.84	(97,431)	$ (1,909,639.18)					10,968	$ 200,157.90	-	$ -
13a	Real Time Asset Energy	(55,390)	$ (963,730.66)	28,117	$ 503,766.94	109,608	$ 1,103,168.55			(193,115)	$ (2,570,666.15)				
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(543,168)	$ (4,207,585.80)	3,309,830	$ 61,812,968.48	(3,121,264)	$ (54,152,656.15)	-	$ -	(731,734)	$ (11,867,898.13)	10,968	$ 200,157.90	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 1,340.79		$ 2,208.83		$ (868.04)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (591,412.23)		$ -		$ (591,412.23)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (590,071.44)		$ 2,208.83		$ (592,280.27)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 614,153.73		$ 567,143.70		$ -		$ 47,010.03				$ 952.80		
19	Real Time Market Administration (Schedule 17)		$ 56,224.91		$ 39,211.91		$ -		$ 17,013.00				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 23,493.72		$ 23,493.72		$ -						$ 86.00		
33	Day-Ahead Schedule 24 Allocation Amount		$ 90,256.88		$ 83,396.08		$ -		$ 6,860.80				$ 140.72		
34	Real -Time Schedule 24 Allocation Amount		$ (84,023.82)		$ 4,188.92		$ -				$ (88,212.74)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 700,105.42		$ 717,434.33		$ -		$ 70,883.83		$ (88,212.74)		$ 1,179.52		$ -
	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		$ 2,766.05		$ 5,570.90		$ (2,804.85)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (1,875,545.10)		$ 728,344.34		$ (2,603,889.44)						$ 4,685.50		$ (6,695.03)
30	Financial Transmission Rights Monthly Allocation		$ (89,523.55)		$ -		$ (89,523.55)								$ (116.18)
32	Financial Transmission Rights Yearly Allocation		$ (0.17)		$ -		$ (0.17)						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 10,383.88		$ 10,383.88		$ -								$ (40.79)
37	Financial Transmission Guarantee Uplift Amount		$ (10,039.34)		$ -		$ (10,039.34)						$ 94.16		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ 7,552.00		$ -
	SUBTOTAL		$ (1,961,958.23)		$ 744,299.12		$ (2,706,257.35)		$ -		$ -		$ 12,331.66		$ (6,852.00)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 40,481.08		$ 40,481.08										
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (59,631.25)				$ (43,670.12)				$ (15,961.13)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 19,482.50		$ 19,482.50										
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (1,644.65)				$ 9,682.59				$ (11,327.24)				
43	Real Time Price Volatility Make Whole Payment		$ (59,208.19)		$ -		($5,811.36)				$ (53,396.83)				
	SUBTOTAL		$ (60,520.51)		$ 59,963.58		$ (39,798.89)		$ -		$ (80,685.20)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 133,223.77		$ 212,505.40		$ (67,784.00)				$ (11,497.63)		$ -		
21	Real Time Net Inadvertent Distribution		$ 38,123.41		$ 77,030.00		$ (38,906.59)						$ 147.43		$ (74.94)
23	Real Time Revenue Neutrality Uplift Amount		$ 177,128.63		$ 330,526.11		$ (153,397.48)								
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 348,475.81		$ 620,061.51		$ (260,088.07)		$ -		$ (11,497.63)		$ 147.43		$ (74.94)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 1,123,444.70		$ 1,302,629.36		$ (179,184.66)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (1,123,867.22)		$ 177,460.39		$ (1,245,489.09)				$ (55,838.52)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (207,296.29)		$ -		$ (207,296.29)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 42,660.70		$ 42,660.70		$ -								
	SUBTOTAL		$ (165,058.11)		$ 1,522,750.45		$ (1,631,970.04)		$ -		$ (55,838.52)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (2,766.05)		$ 2,804.85		$ (5,570.90)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (1,340.79)		$ 868.04		$ (2,208.83)								
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	-	$ (4,106.84)	-	$ 3,672.89	-	$ (7,779.73)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(543,168)	$ (5,940,719.70)	3,309,830	$ 65,483,359.19	(3,121,264)	$ (59,390,830.50)	-	$ 70,883.83	(731,734)	$ (12,104,132.22)	10,968	$ 213,816.51	-	$ (6,926.94)
x	Net Congestion Amount		$ 2,642,474.30		$ 2,642,474.30										
y	Net Loss Amount		$ 2,282,875.87		$ 2,282,875.87										
z	Net Congestion and Loss Energy Offset		$ (4,925,350.17)		$ (4,925,350.17)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(543,168)**	$ (5,940,719.70)	3,309,830	$ 65,483,359.19	(3,121,264)	$ (59,390,830.50)	-	$ 70,883.83	(731,734)	$ (12,104,132.22)	10,968	$ 213,816.51	-	$ (6,926.94)

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 2020	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	(645,852)	$ (4,174,565.60)	3,193,393	$ 52,645,415.09	(3,080,025)	$ (44,689,099.19)			(759,220)	$ (12,130,881.50)				
5a	Day Ahead Non Asset Energy	(110,508)	$ (1,932,876.32)	57	$ 778.98	(110,565)	$ (1,933,655.30)					11,784	$ 187,407.02	-	$ -
13a	Real Time Asset Energy	(56,399)	$ (609,077.15)	63,682	$ 1,242,754.54	37,690	$ 193,177.65			(157,771)	$ (2,045,009.34)				
22a	Real Time Non Asset Energy	218	$ 1,865.21	218	$ 1,865.21	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(812,541)	$ (6,714,653.86)	3,257,350	$ 53,890,813.82	(3,152,900)	$ (46,429,576.84)	-	$ -	(916,991)	$ (14,175,890.84)	11,784	$ 187,407.02	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (1,190.39)		$ 596.72		$ (1,787.11)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (276,694.25)		$ -		$ (276,694.25)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (277,884.64)		$ 596.72		$ (278,481.36)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 500,478.89		$ 446,719.39		$ -		$ 53,759.50				$ 824.56		
19	Real Time Market Administration (Schedule 17)		$ 45,399.19		$ 34,653.94		$ -		$ 10,745.25				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 44,638.31		$ 44,638.31		$ -						$ 0.40		
33	Day-Ahead Schedule 24 Allocation Amount		$ 99,264.65		$ 89,248.98		$ -		$ 10,015.67				$ 171.44		
34	Real -Time Schedule 24 Allocation Amount		$ (78,460.00)		$ 10,956.44		$ -				$ (89,416.44)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 611,321.04		$ 626,217.06		$ -		$ 74,520.42		$ (89,416.44)		$ 996.40		$ -
	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		$ (660.08)		$ 2,787.18		$ (3,447.26)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (3,929,675.14)		$ 360,994.94		$ (4,290,670.08)						$ -		$ 77.08
30	Financial Transmission Rights Monthly Allocation		$ (54,490.34)		$ -		$ (54,490.34)								$ (306.85)
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (60,407.68)		$ -		$ (60,407.68)								$ 229.77
37	Financial Transmission Guarantee Uplift Amount		$ 62,381.04		$ 62,381.04		$ -						$ (229.77)		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (3,982,852.20)		$ 426,163.16		$ (4,409,015.36)		$ -		$ -		$ (229.77)		$ (0.00)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 46,930.49		$ 46,930.49										
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (33,041.29)				$ (44,614.16)				$ 11,572.87				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 20,258.92		$ 20,258.92										
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (2,268.11)				$ (1,521.96)				$ (746.15)				
43	Real Time Price Volatility Make Whole Payment		$ (144,850.29)		$ -		$ (98,864.97)				$ (45,985.32)				
	SUBTOTAL		$ (112,970.28)		$ 67,189.41		$ (145,001.09)		$ -		$ (35,158.60)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 788,136.20		$ 819,222.10		$ (18,795.33)				$ (12,290.57)		$ -		
21	Real Time Net Inadvertent Distribution		$ 205,432.69		$ 242,137.66		$ (36,704.97)						$ 367.28		$ (72.53)
23	Real Time Revenue Neutrality Uplift Amount		$ 124,952.38		$ 585,077.52		$ (460,125.14)								
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 1,118,521.27		$ 1,646,437.28		$ (515,625.44)		$ -		$ (12,290.57)		$ 367.28		$ (72.53)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 1,307,930.05		$ 1,394,880.32		$ (86,950.27)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (1,308,091.42)		$ 86,415.28		$ (1,387,997.27)				$ (6,509.43)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (165,478.97)		$ -		$ (165,478.97)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 25,524.46		$ 25,524.46		$ -								
	SUBTOTAL		$ (140,115.88)		$ 1,506,820.06		$ (1,640,426.51)		$ -		$ (6,509.43)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 660.08		$ 3,447.26		$ (2,787.18)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 1,190.39		$ 1,787.11		$ (596.72)								
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	-	$ 1,850.47	-	$ 5,234.37	-	$ (3,383.90)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(812,541)	$ (9,496,784.08)	3,257,350	$ 58,169,471.88	(3,152,900)	$ (53,421,510.50)	-	$ 74,520.42	(916,991)	$ (14,319,265.88)	11,784	$ 188,540.93	-	$ (72.53)
x	Net Congestion Amount		$ 3,919,125.09		$ 3,919,125.09										
y	Net Loss Amount		$ 2,124,669.90		$ 2,124,669.90										
z	Net Congestion and Loss Energy Offset		$ (6,043,794.99)		$ (6,043,794.99)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(812,541)**	$ (9,496,784.08)	3,257,350	$ 58,169,471.88	(3,152,900)	$ (53,421,510.50)	-	$ 74,520.42	(916,991)	$ (14,319,265.88)	11,784	$ 188,540.93	-	$ (72.53)

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

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	April 2020	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	(718,332)	$ (5,154,483.14)	2,803,408	$ 42,391,059.33	(2,738,110)	$ (36,773,188.71)			(783,630)	$ (10,772,353.76)				
5a	Day Ahead Non Asset Energy	(84,861)	$ (1,094,552.92)	38	$ 498.07	(84,899)	$ (1,095,050.99)					11,472	$ 169,825.70	-	$ -
13a	Real Time Asset Energy	(88,607)	$ (1,182,802.17)	27,728	$ 480,313.56	21,882	$ 161,736.10			(138,217)	$ (1,824,851.83)				
22a	Real Time Non Asset Energy	720	$ 11,646.82	720	$ 11,646.82	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(891,080)	$ (7,420,191.41)	2,831,894	$ 42,883,517.78	(2,801,127)	$ (37,706,503.60)	-	$ -	(921,847)	$ (12,597,205.59)	11,472	$ 169,825.70	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (825.34)		$ 712.23		$ (1,537.57)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (395,148.88)		$ -		$ (395,148.88)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (395,974.22)		$ 712.23		$ (396,686.45)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 721,919.99		$ 634,923.59		$ -		$ 86,996.40				$ 1,290.58		
19	Real Time Market Administration (Schedule 17)		$ 75,819.33		$ 59,755.69		$ -		$ 16,063.64				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 37,070.73		$ 37,070.73		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 94,485.30		$ 83,480.13		$ -		$ 11,005.17				$ 171.35		
34	Real -Time Schedule 24 Allocation Amount		$ (74,746.63)		$ 7,598.24		$ -				$ (82,344.87)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 854,548.72		$ 822,828.38		$ -		$ 114,065.21		$ (82,344.87)		$ 1,461.93		$ -
	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		$ (1,908.93)		$ 3,277.23		$ (5,186.16)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (2,668,152.09)		$ 486,669.58		$ (3,154,821.67)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (263,476.32)		$ -		$ (263,476.32)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (93,025.52)		$ -		$ (93,025.52)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 88,306.19		$ 88,306.19		$ -						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (2,938,256.67)		$ 578,253.00		$ (3,516,509.67)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 66,893.10		$ 66,893.10										
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (131,874.13)				$ (58,112.06)				$ (73,762.07)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 61,467.53		$ 61,467.53										
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (113,764.26)				$ (7,148.35)				$ (106,615.91)				
43	Real Time Price Volatility Make Whole Payment		$ (360,624.72)		$ -		($255,452.67)				$ (105,172.05)				
	SUBTOTAL		$ (477,902.48)		$ 128,360.63		$ (320,713.08)		$ -		$ (285,550.03)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 130,990.31		$ 251,103.92		$ (108,219.51)				$ (11,894.10)		$ -		
21	Real Time Net Inadvertent Distribution		$ (138,359.00)		$ (1,145.05)		$ (137,213.95)						$ 1.43		$ (309.15)
23	Real Time Revenue Neutrality Uplift Amount		$ 499,577.98		$ 696,050.62		$ (196,472.64)								
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 492,209.29		$ 946,009.49		$ (441,906.10)		$ -		$ (11,894.10)		$ 1.43		$ (309.15)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 1,307,930.05		$ 1,394,880.32		$ (86,950.27)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (1,308,091.42)		$ 86,415.28		$ (1,386,402.93)				$ (8,103.77)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (165,479.06)		$ -		$ (165,479.06)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 25,524.46		$ 25,524.46		$ -								
	SUBTOTAL		$ (140,115.97)		$ 1,506,820.06		$ (1,638,832.26)		$ -		$ (8,103.77)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 1,908.93		$ 5,186.16		$ (3,277.23)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 825.34		$ 1,537.57		$ (712.23)								
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	-	$ 2,734.27	-	$ 6,723.73	-	$ (3,989.46)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(891,080)	$ (10,022,948.47)	2,831,894	$ 46,873,225.30	(2,801,127)	$ (44,025,140.62)	-	$ 114,065.21	(921,847)	$ (12,985,098.36)	11,472	$ 171,289.06	-	$ (309.15)
x	Net Congestion Amount		$ 3,212,500.51		$ 3,212,500.51										
y	Net Loss Amount		$ 1,667,951.43		$ 1,667,951.43										
z	Net Congestion and Loss Energy Offset		$ (4,880,451.94)		$ (4,880,451.94)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(891,080)**	$ (10,022,948.47)	2,831,894	$ 46,873,225.30	(2,801,127)	$ (44,025,140.62)	-	$ 114,065.21	(921,847)	$ (12,985,098.36)	11,472	$ 171,289.06	-	$ (309.15)

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

	May 2020	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	(555,397)	$ (2,029,702.44)	2,876,499	$ 44,779,433.03	(2,706,315)	$ (37,063,274.34)			(725,581)	$ (9,745,861.13)				
5a	Day Ahead Non Asset Energy	(187,339)	$ (2,607,646.00)	-	$ -	(187,339)	$ (2,607,646.00)					11,592	$ 179,305.32	-	$ -
13a	Real Time Asset Energy	53,649	$ 681,367.47	126,793	$ 1,800,587.66	23,277	$ 299,286.58			(96,421)	$ (1,418,506.77)				
22a	Real Time Non Asset Energy	537	$ 8,792.45	537	$ 8,792.46	-	$ (0.01)					-	$ -	-	$ -
	SUBTOTAL	(688,550)	$ (3,947,188.52)	3,003,829	$ 46,588,813.15	(2,870,377)	$ (39,371,633.77)	-	$ -	(822,002)	$ (11,164,367.90)	11,592	$ 179,305.32	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (2,711.07)		$ 59.88		$ (2,770.95)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (430,385.94)		$ -		$ (430,385.94)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (433,097.01)		$ 59.88		$ (433,156.89)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 632,134.58		$ 560,948.36		$ -		$ 71,186.22				$ 1,126.41		
19	Real Time Market Administration (Schedule 17)		$ 56,433.44		$ 47,264.93		$ -		$ 9,168.51				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 32,565.06		$ 32,565.06		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 90,934.77		$ 80,795.29		$ -		$ 10,139.48				$ 162.72		
34	Real -Time Schedule 24 Allocation Amount		$ (78,551.27)		$ 2,677.66		$ -				$ (81,228.93)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 733,516.58		$ 724,251.30		$ -		$ 90,494.21		$ (81,228.93)		$ 1,289.13		$ -
	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		$ (273.60)		$ 7,575.31		$ (7,848.91)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (1,766,600.32)		$ 881,917.30		$ (2,648,517.62)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (101,537.77)		$ -		$ (101,537.77)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 8,648.58		$ 8,648.58		$ -								$ -
37	Financial Transmission Guarantee Uplift Amount		$ (3,204.96)		$ -		$ (3,204.96)						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (1,862,968.07)		$ 898,141.19		$ (2,761,109.26)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 40,705.97		$ 40,705.97										
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (116,968.22)				$ (56,564.21)				$ (60,404.01)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 27,817.73		$ 27,817.73										
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (9,019.09)				$ (10,133.24)				$ 1,114.15				
43	Real Time Price Volatility Make Whole Payment		$ (31,652.40)		$ -		($3,321.39)				$ (28,331.01)				
	SUBTOTAL		$ (89,116.01)		$ 68,523.70		$ (70,018.84)		$ -		$ (87,620.87)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ (60,172.83)		$ (26,517.90)		$ (21,364.36)				$ (12,290.57)		$ -		
21	Real Time Net Inadvertent Distribution		$ (65,577.62)		$ 41,015.14		$ (106,592.76)						$ 70.84		$ (164.61)
23	Real Time Revenue Neutrality Uplift Amount		$ 736,528.70		$ 1,313,971.02		$ (577,442.32)								
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 610,778.25		$ 1,328,468.26		$ (705,399.44)		$ -		$ (12,290.57)		$ 70.84		$ (164.61)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 1,307,930.05		$ 1,394,880.32		$ (86,950.27)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (1,308,091.42)		$ 86,415.28		$ (1,386,163.18)				$ (8,343.52)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (165,479.06)		$ -		$ (165,479.06)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 25,524.46		$ 25,524.46		$ -								
	SUBTOTAL		$ (140,115.97)		$ 1,506,820.06		$ (1,638,592.51)		$ -		$ (8,343.52)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 273.60		$ 7,848.91		$ (7,575.31)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 2,711.07		$ 2,770.95		$ (59.88)								
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														
18	Real Time Congestion Rebate on Carve Out Grandfathered														
	SUBTOTAL	-	$ 2,984.67	-	$ 10,619.86	-	$ (7,635.19)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(688,550)	$ (5,125,206.08)	3,003,829	$ 51,125,697.40	(2,870,377)	$ (44,987,545.90)	-	$ 90,494.21	(822,002)	$ (11,353,851.79)	11,592	$ 180,665.29	-	$ (164.61)
x	Net Congestion Amount		$ 3,488,276.55		$ 3,488,276.55										
y	Net Loss Amount		$ 1,657,548.77		$ 1,657,548.77										
z	Net Congestion and Loss Energy Offset		$ (5,145,825.32)		$ (5,145,825.32)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(688,550)**	$ (5,125,206.08)	3,003,829	$ 51,125,697.40	(2,870,377)	$ (44,987,545.90)	-	$ 90,494.21	(822,002)	$ (11,353,851.79)	11,592	$ 180,665.29	-	$ (164.61)

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

	June 2020	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	(401,713)	$ 4,971,124.86	3,619,114	$ 60,853,376.54	(3,378,197)	$ (45,295,081.49)			(642,630)	$ (10,587,170.19)				
5a	Day Ahead Non Asset Energy	(184,083)	$ (3,178,497.52)	10	$ 131.35	(184,093)	$ (3,178,628.87)					11,472	$ 182,201.13	-	$ -
13a	Real Time Asset Energy	1,191	$ (399,445.42)	122,645	$ 1,884,871.08	(71,350)	$ (1,287,105.21)			(50,104)	$ (997,211.29)				
22a	Real Time Non Asset Energy	530	$ 7,710.76	530	$ 7,710.76	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(584,075)	$ 1,400,892.68	3,742,299	$ 62,746,089.73	(3,633,640)	$ (49,760,815.57)	-	$ -	(692,734)	$ (11,584,381.48)	11,472	$ 182,201.13	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (2,199.06)		$ 670.76		$ (2,869.82)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (622,972.41)		$ -		$ (622,972.41)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (625,171.47)		$ 670.76		$ (625,842.23)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 783,195.49		$ 719,151.30		$ -		$ 64,044.19				$ 1,147.01		
19	Real Time Market Administration (Schedule 17)		$ 76,993.12		$ 71,918.88		$ -		$ 5,074.24				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 33,175.41		$ 33,175.41		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 93,115.55		$ 85,315.19		$ -		$ 7,800.36				$ 136.16		
34	Real -Time Schedule 24 Allocation Amount		$ (86,564.11)		$ 5,198.70		$ -				$ (91,762.81)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 899,915.46		$ 914,759.48		$ -		$ 76,918.79		$ (91,762.81)		$ 1,283.17		$ -
	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		$ 12,243.40		$ 16,208.56		$ (3,965.16)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (3,775,851.16)		$ 876,704.18		$ (4,652,555.34)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (131,623.41)		$ -		$ (131,623.41)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (166,943.32)		$ -		$ (166,943.32)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 158,299.42		$ 158,299.42		$ -						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (3,903,875.07)		$ 1,051,212.16		$ (4,955,087.23)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 43,901.42		$ 43,901.42										
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (179,532.48)				$ (149,937.69)				$ (29,594.79)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 66,345.82		$ 66,345.82										
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (54,368.22)				$ (44,354.34)				$ (10,013.88)				
43	Real Time Price Volatility Make Whole Payment		$ (204,153.53)		$ -		($172,216.28)				$ (31,937.25)				
	SUBTOTAL		$ (327,806.99)		$ 110,247.24		$ (366,508.31)		$ -		$ (71,545.92)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 3,194.58		$ 99,433.47		$ (94,800.09)				$ (1,438.80)		$ -		
21	Real Time Net Inadvertent Distribution		$ 53,086.50		$ 84,153.86		$ (31,067.36)						$ 113.26		$ (48.37)
23	Real Time Revenue Neutrality Uplift Amount		$ 69,276.66		$ 500,320.54		$ (431,043.88)								
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 125,557.74		$ 683,907.87		$ (556,911.33)		$ -		$ (1,438.80)		$ 113.26		$ (48.37)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 2,693,305.82		$ 2,724,473.63		$ (31,167.81)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (2,698,826.26)		$ 31,090.37		$ (2,726,183.19)				$ (3,733.44)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (236,849.95)		$ -		$ (236,849.95)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 10,503.72		$ 10,503.72		$ -								
	SUBTOTAL		$ (231,866.67)		$ 2,766,067.72		$ (2,994,200.95)		$ -		$ (3,733.44)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (11,392.32)		$ 3,965.16		$ (15,357.48)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 2,580.58		$ 2,869.82		$ (289.24)								
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	-	$ (8,811.74)	-	$ 6,834.98	-	$ (15,646.72)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(584,075)	$ (2,671,166.06)	3,742,299	$ 68,279,789.94	(3,633,640)	$ (59,275,012.34)	-	$ 76,918.79	(692,734)	$ (11,752,862.45)	11,472	$ 183,597.56	-	$ (48.37)
x	Net Congestion Amount		$ 9,006,359.62		$ 9,006,359.62										
y	Net Loss Amount		$ 2,661,629.93		$ 2,661,629.93										
z	Net Congestion and Loss Energy Offset		$ (11,667,989.55)		$ (11,667,989.55)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(584,075)**	$ (2,671,166.06)	3,742,299	$ 68,279,789.94	(3,633,640)	$ (59,275,012.34)	-	$ 76,918.79	(692,734)	$ (11,752,862.45)	11,472	$ 183,597.56	-	$ (48.37)

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-19-293
True-Up Report
Part B, Attachment 10

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	July 2020	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	(799,702)	$ (7,296,310.99)	4,145,916	$ 94,231,852.56	(3,982,003)	$ (80,256,223.92)			(963,615)	$ (21,271,939.63)				
5a	Day Ahead Non Asset Energy	(195,627)	$ (4,617,603.80)	-	$ -	(195,627)	$ (4,617,603.80)					11,880	$ 253,804.23	-	$ -
13a	Real Time Asset Energy	(24,043)	$ (642,655.22)	73,699	$ 1,601,345.70	(6,592)	$ (684,153.66)			(91,150)	$ (1,559,847.26)				
22a	Real Time Non Asset Energy	62	$ 5,615.55	412	$ 19,149.52	(350)	$ (13,533.97)					-	$ -	-	$ -
	SUBTOTAL	(1,019,310)	$ (12,550,954.46)	4,220,027	$ 95,852,347.78	(4,184,572)	$ (85,571,515.35)	-	$ -	(1,054,765)	$ (22,831,786.89)	11,880	$ 253,804.23	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (2,986.53)		$ 256.56		$ (3,243.09)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (844,769.75)		$ -		$ (844,769.75)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (847,756.28)		$ 256.56		$ (848,012.84)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 666,441.34		$ 597,312.16		$ -		$ 69,129.18				$ 850.41		
19	Real Time Market Administration (Schedule 17)		$ 59,366.94		$ 52,809.85		$ -		$ 6,557.09				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 35,084.39		$ 35,084.39		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 99,141.21		$ 88,632.84		$ -		$ 10,508.37				$ 127.20		
34	Real -Time Schedule 24 Allocation Amount		$ (88,321.61)		$ 12,110.12		$ -				$ (100,431.73)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 771,712.27		$ 785,949.36		$ -		$ 86,194.64		$ (100,431.73)		$ 977.61		$ -
	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		$ 4,966.47		$ 15,442.67		$ (10,476.20)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (4,171,284.07)		$ 679,530.09		$ (4,850,814.16)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (190,323.43)		$ -		$ (190,323.43)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 2,905.26		$ 2,905.26		$ -								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 18,786.20		$ 18,786.20		$ -						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (4,334,949.57)		$ 716,664.22		$ (5,051,613.79)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 85,730.36		$ 85,730.36				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (27,697.25)				$ (11,119.60)				$ (16,577.65)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 394,093.42		$ 394,093.42				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (186,741.55)				$ (123,132.31)				$ (63,609.24)				
43	Real Time Price Volatility Make Whole Payment		$ (335,854.47)		$ -		($310,564.32)				$ (25,290.15)				
	SUBTOTAL		$ (70,469.49)		$ 479,823.78		$ (444,816.23)		$ -		$ (105,477.04)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 52,589.89		$ 59,479.83		$ (5,403.18)				$ (1,486.76)		$ -		
21	Real Time Net Inadvertent Distribution		$ 373,187.58		$ 452,371.30		$ (79,183.72)						$ 510.15		$ (98.76)
23	Real Time Revenue Neutrality Uplift Amount		$ 202,020.75		$ 693,422.30		$ (491,401.55)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 627,798.22		$ 1,205,273.43		$ (575,988.45)		$ -		$ (1,486.76)		$ 510.15		$ (98.76)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 2,693,305.82		$ 2,724,473.63		$ (31,167.81)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (2,698,826.26)		$ 31,090.37		$ (2,726,220.85)				$ (3,695.78)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (234,999.62)		$ -		$ (234,999.62)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 10,489.95		$ 10,503.72		$ (13.77)								
	SUBTOTAL		$ (230,030.11)		$ 2,766,067.72		$ (2,992,402.05)		$ -		$ (3,695.78)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (5,165.05)		$ 10,476.20		$ (15,641.25)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 2,897.51		$ 3,243.09		$ (345.58)								
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	-	$ (2,267.54)	-	$ 13,719.29	-	$ (15,986.83)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(1,019,310)	$ (16,636,916.96)	4,220,027	$ 101,820,102.14	(4,184,572)	$ (95,500,335.54)	-	$ 86,194.64	(1,054,765)	$ (23,042,878.20)	11,880	$ 255,291.99	-	$ (98.76)
x	Net Congestion Amount		$ 6,684,862.40		$ 6,684,862.40				$ -						
y	Net Loss Amount		$ 3,317,604.90		$ 3,317,604.90				$ -						
z	Net Congestion and Loss Energy Offset		$ (10,002,467.30)		$ (10,002,467.30)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,019,310)**	$ (16,636,916.96)	4,220,027	$ 101,820,102.14	(4,184,572)	$ (95,500,335.54)	-	$ 86,194.64	(1,054,765)	$ (23,042,878.20)	11,880	$ 255,291.99	-	$ (98.76)

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 2020	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	(829,193)	$ (7,895,359.99)	3,818,104	$ 81,900,071.17	(3,639,714)	$ (69,368,423.66)			(1,007,583)	$ (20,427,007.50)				
5a	Day Ahead Non Asset Energy	(187,759)	$ (4,490,997.32)	-	$ -	(187,759)	$ (4,490,997.32)					11,688	$ 235,824.16	-	$ -
13a	Real Time Asset Energy	(29,065)	$ (434,815.89)	73,986	$ 1,753,623.27	(38,820)	$ (1,153,828.03)			(64,231)	$ (1,034,611.13)				
22a	Real Time Non Asset Energy	10	$ 324.33	10	$ 324.33	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(1,046,007)	$ (12,820,848.87)	3,892,100	$ 83,654,018.77	(3,866,293)	$ (75,013,249.01)	-	$ -	(1,071,814)	$ (21,461,618.63)	11,688	$ 235,824.16	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (4,391.06)		$ 227.98		$ (4,619.04)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (709,775.66)		$ -		$ (709,775.66)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (714,166.72)		$ 227.98		$ (714,394.70)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 668,649.28		$ 590,821.20		$ -		$ 77,828.08				$ 901.75		
19	Real Time Market Administration (Schedule 17)		$ 60,022.83		$ 55,122.36		$ -		$ 4,900.47				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 33,086.16		$ 33,086.16		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 102,030.51		$ 90,837.68		$ -		$ 11,192.83				$ 140.24		
34	Real -Time Schedule 24 Allocation Amount		$ (85,266.26)		$ 11,433.66		$ -				$ (96,699.92)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 778,522.52		$ 781,301.06		$ -		$ 93,921.38		$ (96,699.92)		$ 1,041.99		$ -
	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		$ (4,937.58)		$ 3,914.47		$ (8,852.05)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (2,926,937.62)		$ 651,752.90		$ (3,578,690.52)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (141,201.53)		$ -		$ (141,201.53)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (36,382.83)		$ -		$ (36,382.83)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 31,333.26		$ 31,333.26		$ -						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (3,078,126.30)		$ 687,000.63		$ (3,765,126.93)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 71,294.60		$ 71,294.60				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (110,415.29)				$ (76,777.57)				$ (33,637.72)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 143,250.16		$ 143,250.16				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (35,576.95)				$ (5,388.10)				$ (30,188.85)				
43	Real Time Price Volatility Make Whole Payment		$ (227,358.52)		$ -		($227,600.20)				$ 241.68				
	SUBTOTAL		$ (158,806.00)		$ 214,544.76		$ (309,765.87)		$ -		$ (63,584.89)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 72,027.39		$ 80,752.84		$ (7,238.69)				$ (1,486.76)		$ -		
21	Real Time Net Inadvertent Distribution		$ (21,807.88)		$ 179,357.00		$ (201,164.88)						$ 236.86		$ (227.96)
23	Real Time Revenue Neutrality Uplift Amount		$ 326,052.32		$ 637,920.19		$ (311,867.87)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 376,271.83		$ 898,030.03		$ (520,271.44)		$ -		$ (1,486.76)		$ 236.86		$ (227.96)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 2,693,305.82		$ 2,724,473.63		$ (31,167.81)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (2,698,826.26)		$ 31,090.37		$ (2,726,214.17)				$ (3,702.46)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (235,924.74)		$ -		$ (235,924.74)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 10,476.18		$ 10,489.95		$ (13.77)								
	SUBTOTAL		$ (230,969.00)		$ 2,766,053.95		$ (2,993,320.49)		$ -		$ (3,702.46)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 4,937.58		$ 8,852.05		$ (3,914.47)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 4,391.06		$ 4,619.04		$ (227.98)								
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	-	$ 9,328.64	-	$ 13,471.09	-	$ (4,142.45)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(1,046,007)	$ (15,838,793.90)	3,892,100	$ 89,014,648.27	(3,866,293)	$ (83,320,270.89)	-	$ 93,921.38	(1,071,814)	$ (21,627,092.66)	11,688	$ 237,103.01	-	$ (227.96)
x	Net Congestion Amount		$ 4,837,430.77		$ 4,837,430.77				$ -						
y	Net Loss Amount		$ 2,995,914.61		$ 2,995,914.61				$ -						
z	Net Congestion and Loss Energy Offset		$ (7,833,345.38)		$ (7,833,345.38)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,046,007)**	$ (15,838,793.90)	3,892,100	$ 89,014,648.27	(3,866,293)	$ (83,320,270.89)	-	$ 93,921.38	(1,071,814)	$ (21,627,092.66)	11,688	$ 237,103.01	-	$ (227.96)

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 2020	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	(532,222)	$ 4,379,606.14	3,057,232	$ 48,448,801.27	(2,902,411)	$ (34,232,631.60)			(687,043)	$ (9,836,563.53)				
5a	Day Ahead Non Asset Energy	(189,049)	$ (2,957,993.06)	-	$ 396,622.50	(189,049)	$ (3,354,615.56)					11,376	$ 166,562.15	-	$ -
13a	Real Time Asset Energy	(11,457)	$ 87,164.95	64,304	$ 1,414,619.86	(5,882)	$ (475,082.66)			(69,879)	$ (852,372.25)				
22a	Real Time Non Asset Energy	259	$ 3,205.69	259	$ 3,205.69	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(732,469)	$ 1,511,983.72	3,121,795	$ 50,263,249.32	(3,097,342)	$ (38,062,329.82)	-	$ -	(756,922)	$ (10,688,935.78)	11,376	$ 166,562.15	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (4,591.09)		$ 109.12		$ (4,700.21)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (978,688.25)		$ -		$ (978,688.25)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (983,279.34)		$ 109.12		$ (983,388.46)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 554,421.86		$ 498,770.59		$ -		$ 55,651.27				$ 920.75		
19	Real Time Market Administration (Schedule 17)		$ 47,515.50		$ 41,886.12		$ -		$ 5,629.38				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 37,371.93		$ 37,371.93		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 83,076.54		$ 74,810.27		$ -		$ 8,266.27				$ 140.00		
34	Real -Time Schedule 24 Allocation Amount		$ (80,498.48)		$ 12,827.79		$ -				$ (93,326.27)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 641,887.35		$ 665,666.70		$ -		$ 69,546.92		$ (93,326.27)		$ 1,060.75		$ -
	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		$ (8,117.10)		$ 8,619.72		$ (16,736.82)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (5,854,979.92)		$ 656,839.95		$ (6,511,819.87)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (249,468.92)		$ -		$ (249,468.92)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (652,256.82)		$ -		$ (652,256.82)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 636,580.03		$ 636,580.03		$ -						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (6,128,242.73)		$ 1,302,039.70		$ (7,430,282.43)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 117,826.40		$ 117,826.40				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (184,650.00)				$ (101,890.47)				$ (82,759.53)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 88,418.58		$ 88,418.58				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (23,371.30)				$ (19,997.73)				$ (3,373.57)				
43	Real Time Price Volatility Make Whole Payment		$ 12,906.68		$ -		$24,433.94				$ (11,527.26)				
	SUBTOTAL		$ 11,130.36		$ 206,244.98		$ (97,454.26)		$ -		$ (97,660.36)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 72,178.71		$ 98,510.10		$ (24,892.59)				$ (1,438.80)		$ -		
21	Real Time Net Inadvertent Distribution		$ (373,981.79)		$ 869.49		$ (374,851.28)						$ 9.45		$ (463.67)
23	Real Time Revenue Neutrality Uplift Amount		$ 7,570,051.42		$ 7,748,097.38		$ (178,045.96)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 7,268,248.34		$ 7,847,476.97		$ (577,789.83)		$ -		$ (1,438.80)		$ 9.45		$ (463.67)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 2,625,455.56		$ 2,764,876.93		$ (139,421.37)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (2,625,916.66)		$ 138,213.49		$ (2,759,869.24)				$ (4,260.91)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (214,163.14)		$ -		$ (214,163.14)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 15,573.91		$ 15,573.91		$ -								
	SUBTOTAL		$ (199,050.33)		$ 2,918,664.33		$ (3,113,453.75)		$ -		$ (4,260.91)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 8,117.10		$ 16,736.82		$ (8,619.72)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 4,591.09		$ 4,700.21		$ (109.12)								
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	-	$ 12,708.19	-	$ 21,437.03	-	$ (8,728.84)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(732,469)	$ 2,135,385.56	3,121,795	$ 63,224,888.15	(3,097,342)	$ (50,273,427.39)	-	$ 69,546.92	(756,922)	$ (10,885,622.12)	11,376	$ 167,632.35	-	$ (463.67)
x	Net Congestion Amount		$ 8,914,853.00		$ 8,914,853.00				$ -						
y	Net Loss Amount		$ 2,187,687.35		$ 2,187,687.35				$ -						
z	Net Congestion and Loss Energy Offset		$ (11,102,540.35)		$ (11,102,540.35)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(732,469)**	$ 2,135,385.56	3,121,795	$ 63,224,888.15	(3,097,342)	$ (50,273,427.39)	-	$ 69,546.92	(756,922)	$ (10,885,622.12)	11,376	$ 167,632.35	-	$ (463.67)

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 2020	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	(775,287)	$ (3,373,597.30)	3,146,793	$ 64,850,918.43	(2,966,501)	$ (52,166,853.80)			(955,579)	$ (16,057,661.93)				
5a	Day Ahead Non Asset Energy	(173,278)	$ (3,435,108.61)	107	$ 134,956.34	(173,385)	$ (3,570,064.95)					11,784	$ 236,730.96	-	$ -
13a	Real Time Asset Energy	(1,695)	$ 98,027.25	63,164	$ 1,477,145.87	25,371	$ 183,213.85			(90,230)	$ (1,562,332.47)				
22a	Real Time Non Asset Energy	111	$ 1,542.44	111	$ 1,542.45	-	$ (0.01)					-	$ -	-	$ -
	SUBTOTAL	(950,149)	$ (6,709,136.22)	3,210,175	$ 66,464,563.09	(3,114,515)	$ (55,553,704.91)	-	$ -	(1,045,809)	$ (17,619,994.40)	11,784	$ 236,730.96	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (2,132.40)		$ 614.40		$ (2,746.80)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (643,189.75)		$ -		$ (643,189.75)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (645,322.15)		$ 614.40		$ (645,936.55)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 678,669.94		$ 589,633.16		$ -		$ 89,036.78				$ 1,104.36		
19	Real Time Market Administration (Schedule 17)		$ 61,383.45		$ 52,889.24		$ -		$ 8,494.21				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 26,618.57		$ 26,618.57		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 94,875.65		$ 82,412.96		$ -		$ 12,462.69				$ 154.64		
34	Real -Time Schedule 24 Allocation Amount		$ (83,939.09)		$ (8,475.19)		$ -				$ (75,463.90)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 777,608.52		$ 743,078.74		$ -		$ 109,993.68		$ (75,463.90)		$ 1,259.00		$ -
	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		$ 459.45		$ 9,362.21		$ (8,902.76)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (2,370,282.95)		$ 838,645.83		$ (3,208,928.78)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (80,242.36)		$ -		$ (80,242.36)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (66,548.02)		$ -		$ (66,548.02)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 44,598.27		$ 44,598.27		$ -						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (2,472,015.61)		$ 892,606.31		$ (3,364,621.92)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 123,192.46		$ 123,192.46				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (233,129.24)				$ (144,579.94)				$ (88,549.30)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 113,725.41		$ 113,725.41				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (91,829.26)				$ (35,067.83)				$ (56,761.43)				
43	Real Time Price Volatility Make Whole Payment		$ (270,533.14)		$ -		($206,031.41)				$ (64,501.73)				
	SUBTOTAL		$ (358,573.77)		$ 236,917.87		$ (385,679.18)		$ -		$ (209,812.46)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 61,069.08		$ 83,741.85		$ (21,186.01)				$ (1,486.76)		$ -		
21	Real Time Net Inadvertent Distribution		$ (9,621.84)		$ 44,604.43		$ (54,226.27)						$ 69.37		$ (79.94)
23	Real Time Revenue Neutrality Uplift Amount		$ 638,807.22		$ 1,084,601.64		$ (445,794.42)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 690,254.46		$ 1,212,947.92		$ (521,206.70)		$ -		$ (1,486.76)		$ 69.37		$ (79.94)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 2,625,455.56		$ 2,764,876.93		$ (139,421.37)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (2,625,916.66)		$ 138,213.49		$ (2,760,194.11)				$ (3,936.04)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (214,163.14)		$ -		$ (214,163.14)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 15,573.91		$ 15,573.91		$ -								
	SUBTOTAL		$ (199,050.33)		$ 2,918,664.33		$ (3,113,778.62)		$ -		$ (3,936.04)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (459.45)		$ 8,902.76		$ (9,362.21)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 2,132.40		$ 2,746.80		$ (614.40)								
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	-	$ 1,672.95	-	$ 11,649.56	-	$ (9,976.61)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(950,149)	$ (8,914,562.15)	3,210,175	$ 72,481,042.22	(3,114,515)	$ (63,594,904.49)	-	$ 109,993.68	(1,045,809)	$ (17,910,693.56)	11,784	$ 238,059.33	-	$ (79.94)
x	Net Congestion Amount		$ 6,739,996.55		$ 6,739,996.55				$ -						
y	Net Loss Amount		$ 2,845,882.43		$ 2,845,882.43				$ -						
z	Net Congestion and Loss Energy Offset		$ (9,585,878.98)		$ (9,585,878.98)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(950,149)**	$ (8,914,562.15)	3,210,175	$ 72,481,042.22	(3,114,515)	$ (63,594,904.49)	-	$ 109,993.68	(1,045,809)	$ (17,910,693.56)	11,784	$ 238,059.33	-	$ (79.94)

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-19-293
True-Up Report
Part B, Attachment 10

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	November 2020	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	(980,827)	$ (3,052,410.68)	3,050,850	$ 55,714,721.48	(3,010,991)	$ (42,869,581.98)			(1,020,686)	$ (15,897,550.18)				
5a	Day Ahead Non Asset Energy	(88,777)	$ (1,782,434.47)	6	$ 320,524.79	(88,783)	$ (2,102,959.26)					11,280	$ 205,095.71	-	$ -
13a	Real Time Asset Energy	17,734	$ 689,092.45	68,587	$ 1,418,561.31	75,261	$ 997,459.43			(126,114)	$ (1,726,928.29)				
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(1,051,870)	$ (4,145,752.70)	3,119,443	$ 57,453,807.58	(3,024,513)	$ (43,975,081.81)	-	$ -	(1,146,800)	$ (17,624,478.47)	11,280	$ 205,095.71	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (708.72)		$ 822.92		$ (1,531.64)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (730,299.79)		$ -		$ (730,299.79)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (731,008.51)		$ 822.92		$ (731,831.43)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 627,410.14		$ 537,945.31		$ -		$ 89,464.83				$ 987.12		
19	Real Time Market Administration (Schedule 17)		$ 63,680.00		$ 52,808.97		$ -		$ 10,871.03				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 26,238.72		$ 26,238.72		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 93,946.67		$ 80,337.30		$ -		$ 13,609.37				$ 148.00		
34	Real -Time Schedule 24 Allocation Amount		$ (83,499.62)		$ 16,874.68		$ -				$ (100,374.30)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 727,775.91		$ 714,204.98		$ -		$ 113,945.23		$ (100,374.30)		$ 1,135.12		$ -
	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		$ (13,010.72)		$ 5,390.32		$ (18,401.04)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (584,048.19)		$ 1,461,322.49		$ (2,045,370.68)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (57,459.03)		$ -		$ (57,459.03)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 9,480.32		$ 9,480.32		$ -								$ -
37	Financial Transmission Guarantee Uplift Amount		$ (19,783.92)		$ -		$ (19,783.92)						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (664,821.54)		$ 1,476,193.13		$ (2,141,014.67)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 104,585.51		$ 104,585.51				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (139,130.87)				$ (53,469.28)				$ (85,661.59)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 204,780.30		$ 204,780.30				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (138,612.24)				$ (72,703.04)				$ (65,909.20)				
43	Real Time Price Volatility Make Whole Payment		$ 1,448.79		$ -		$14,882.80				$ (13,434.01)				
	SUBTOTAL		$ 33,071.49		$ 309,365.81		$ (111,289.52)		$ -		$ (165,004.80)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 42,067.39		$ 50,583.24		$ (7,077.05)				$ (1,438.80)		$ -		
21	Real Time Net Inadvertent Distribution		$ (14,296.99)		$ 13,497.61		$ (27,794.60)						$ 18.85		$ (40.05)
23	Real Time Revenue Neutrality Uplift Amount		$ 555,216.02		$ 945,031.56		$ (389,815.54)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 582,986.42		$ 1,009,112.41		$ (424,687.19)		$ -		$ (1,438.80)		$ 18.85		$ (40.05)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 2,625,455.56		$ 2,764,876.93		$ (139,421.37)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (2,625,916.66)		$ 138,213.49		$ (2,759,853.80)				$ (4,276.35)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (214,163.14)		$ -		$ (214,163.14)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 15,573.91		$ 15,573.91		$ -								
	SUBTOTAL		$ (199,050.33)		$ 2,918,664.33		$ (3,113,438.31)		$ -		$ (4,276.35)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 13,010.72		$ 18,401.04		$ (5,390.32)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 708.72		$ 1,531.64		$ (822.92)								
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	-	$ 13,719.44	-	$ 19,932.68	-	$ (6,213.24)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(1,051,870)	$ (4,383,079.82)	3,119,443	$ 63,902,103.84	(3,024,513)	$ (50,503,556.17)	-	$ 113,945.23	(1,146,800)	$ (17,895,572.72)	11,280	$ 206,249.68	-	$ (40.05)
x	Net Congestion Amount		$ 6,442,210.87		$ 6,442,210.87				$ -						
y	Net Loss Amount		$ 2,572,539.11		$ 2,572,539.11				$ -						
z	Net Congestion and Loss Energy Offset		$ (9,014,749.98)		$ (9,014,749.98)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,051,870)**	$ (4,383,079.82)	3,119,443	$ 63,902,103.84	(3,024,513)	$ (50,503,556.17)	-	$ 113,945.23	(1,146,800)	$ (17,895,572.72)	11,280	$ 206,249.68	-	$ (40.05)

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-19-293
True-Up Report
Part B, Attachment 10

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	December 2020	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	(1,235,826)	$ (11,780,172.22)	3,400,442	$ 75,345,012.75	(3,307,656)	$ (61,335,135.64)			(1,328,612)	$ (25,790,049.33)				
5a	Day Ahead Non Asset Energy	(108,563)	$ (2,475,388.18)	23	$ 429.93	(108,586)	$ (2,475,818.11)					11,784	$ 255,406.81	-	$ -
13a	Real Time Asset Energy	35,256	$ 869,343.45	67,015	$ 1,567,959.61	22,765	$ 406,354.71			(54,524)	$ (1,104,970.87)				
22a	Real Time Non Asset Energy	(2)	$ (34.91)	-	$ -	(2)	$ (34.91)					-	$ -	-	$ -
	SUBTOTAL	(1,309,135)	$ (13,386,251.86)	3,467,480	$ 76,913,402.29	(3,393,479)	$ (63,404,633.95)	-	$ -	(1,383,136)	$ (26,895,020.20)	11,784	$ 255,406.81	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (2,031.29)		$ 708.23		$ (2,739.52)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (673,124.03)		$ -		$ (673,124.03)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (675,155.32)		$ 708.23		$ (675,863.55)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 759,840.32		$ 636,229.60		$ -		$ 123,610.72				$ 1,097.81		
19	Real Time Market Administration (Schedule 17)		$ 55,670.32		$ 50,505.84		$ -		$ 5,164.48				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 29,024.12		$ 29,024.12		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 103,445.62		$ 86,556.80		$ -		$ 16,888.82				$ 151.12		
34	Real -Time Schedule 24 Allocation Amount		$ (90,734.75)		$ (1,319.12)		$ -				$ (89,415.63)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 857,245.63		$ 800,997.24		$ -		$ 145,664.02		$ (89,415.63)		$ 1,248.93		$ -
	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		$ (5,997.02)		$ 3,428.60		$ (9,425.62)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (1,925,936.62)		$ 641,734.85		$ (2,567,671.47)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (48,720.19)		$ -		$ (48,720.19)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (307,690.84)		$ -		$ (307,690.84)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 309,546.77		$ 309,546.77		$ -						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (1,978,797.90)		$ 954,710.22		$ (2,933,508.12)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 129,438.24		$ 129,438.24				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (281,603.78)				$ (203,976.90)				$ (77,626.88)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 84,757.66		$ 84,757.66				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (41,486.80)				$ (19,423.17)				$ (22,063.63)				
43	Real Time Price Volatility Make Whole Payment		$ (75,368.67)		$ -		($64,874.39)				$ (10,494.28)				
	SUBTOTAL		$ (184,263.35)		$ 214,195.90		$ (288,274.46)		$ -		$ (110,184.79)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 26,285.57		$ 64,853.63		$ (37,081.30)				$ (1,486.76)		$ -		
21	Real Time Net Inadvertent Distribution		$ (9,356.62)		$ 44,372.80		$ (53,729.42)						$ 61.05		$ (72.34)
23	Real Time Revenue Neutrality Uplift Amount		$ 802,449.46		$ 1,066,704.41		$ (264,254.95)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 819,378.41		$ 1,175,930.84		$ (355,065.67)		$ -		$ (1,486.76)		$ 61.05		$ (72.34)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 1,635,397.07		$ 1,702,032.22		$ (66,635.15)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (1,639,395.05)		$ 66,003.13		$ (1,669,958.47)				$ (35,439.71)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (202,829.08)		$ -		$ (202,829.08)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 22,549.31		$ 22,549.31		$ -								
	SUBTOTAL		$ (184,277.75)		$ 1,790,584.66		$ (1,939,422.70)		$ -		$ (35,439.71)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 5,997.02		$ 9,425.62		$ (3,428.60)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 2,031.29		$ 2,739.52		$ (708.23)								
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	-	$ 8,028.31	-	$ 12,165.14	-	$ (4,136.83)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(1,309,135)	$ (14,724,093.83)	3,467,480	$ 81,862,694.52	(3,393,479)	$ (69,600,905.28)	-	$ 145,664.02	(1,383,136)	$ (27,131,547.09)	11,784	$ 256,716.79	-	$ (72.34)
x	Net Congestion Amount		$ 8,255,920.38		$ 8,255,920.38				$ -						
y	Net Loss Amount		$ 2,860,638.03		$ 2,860,638.03				$ -						
z	Net Congestion and Loss Energy Offset		$ (11,116,558.41)		$ (11,116,558.41)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,309,135)**	$ (14,724,093.83)	3,467,480	$ 81,862,694.52	(3,393,479)	$ (69,600,905.28)	-	$ 145,664.02	(1,383,136)	$ (27,131,547.09)	11,784	$ 256,716.79	-	$ (72.34)

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-19-293
True-Up Report
Part B, Attachment 10

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	January - December 2020	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	(8,591,943)	$ (45,568,590.03)	40,028,280	$ 757,435,524.17	(38,431,948)	$ (625,908,408.33)			(10,188,275)	$ (177,095,705.87)				
5a	Day Ahead Non Asset Energy	(1,720,160)	$ (32,954,306.20)	389	$ 856,783.60	(1,720,549)	$ (33,811,089.80)					138,864	$ 2,511,901.33	-	$ -
13a	Real Time Asset Energy	(196,020)	$ (2,451,732.03)	821,533	$ 16,107,087.06	226,789	$ 808,694.23			(1,244,342)	$ (19,367,513.32)				
22a	Real Time Non Asset Energy	2,445	$ 40,668.34	2,797	$ 54,237.24	(352)	$ (13,568.90)					-	$ -	-	$ -
	SUBTOTAL	(10,505,678)	$ (80,933,959.92)	40,852,999	$ 774,453,632.07	(39,926,060)	$ (658,924,372.80)	-	$ -	(11,432,617)	$ (196,463,219.19)	138,864	$ 2,511,901.33	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (21,514.89)		$ 8,727.77		$ (30,242.66)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (7,605,594.38)		$ -		$ (7,605,594.38)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (7,627,109.27)		$ 8,727.77		$ (7,635,837.04)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 8,012,501.15		$ 7,107,752.74		$ -		$ 904,748.41				$ 12,371.79		
19	Real Time Market Administration (Schedule 17)		$ 729,759.28		$ 619,074.93		$ -		$ 110,684.35				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 384,907.18		$ 384,907.18		$ -						$ 185.28		
33	Day-Ahead Schedule 24 Allocation Amount		$ 1,140,271.84		$ 1,012,372.04		$ -		$ 127,899.80				$ 1,779.84		
34	Real -Time Schedule 24 Allocation Amount		$ (1,007,219.43)		$ 65,269.56		$ -				$ (1,072,488.99)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 9,260,220.02		$ 9,189,376.45		$ -		$ 1,143,332.56		$ (1,072,488.99)		$ 14,336.91		$ -
	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		$ (8,504.22)		$ 88,592.16		$ (97,096.38)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (33,033,724.05)		$ 9,086,244.57		$ (42,119,968.62)						$ 24,669.56		$ (11,338.48)
30	Financial Transmission Rights Monthly Allocation		$ (1,497,340.89)		$ -		$ (1,497,340.89)								$ (920.19)
32	Financial Transmission Rights Yearly Allocation		$ (6,000.54)		$ 0.05		$ (6,000.59)						$ -		$ (17.23)
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (1,403,749.88)		$ -		$ (1,403,749.88)								$ 471.84
37	Financial Transmission Guarantee Uplift Amount		$ 1,475,215.32		$ 1,475,215.32		$ -						$ 149.75		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ 14,681.50		$ -
	SUBTOTAL		$ (34,474,104.26)		$ 10,650,052.10		$ (45,124,156.36)		$ -		$ -		$ 39,500.81		$ (11,804.06)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 947,263.25		$ 947,263.25				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (1,589,289.29)				$ (969,234.70)				$ (620,054.59)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 1,275,200.13		$ 1,275,200.13				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (710,664.12)				$ (328,386.37)				$ (382,277.75)				
43	Real Time Price Volatility Make Whole Payment		$ (1,843,332.87)		$ -		($1,429,430.24)				$ (413,902.63)				
	SUBTOTAL		$ (1,920,822.90)		$ 2,222,463.38		$ (2,727,051.31)		$ -		$ (1,416,234.97)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 1,366,274.26		$ 1,917,407.38		$ (480,606.24)				$ (70,526.88)		$ -		
21	Real Time Net Inadvertent Distribution		$ 73,327.89		$ 1,246,546.99		$ (1,173,219.10)						$ 1,767.57		$ (1,751.05)
23	Real Time Revenue Neutrality Uplift Amount		$ 12,046,574.25		$ 16,211,019.15		$ (4,164,444.90)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 13,486,176.40		$ 19,374,973.52		$ (5,818,270.24)		$ -		$ (70,526.88)		$ 1,767.57		$ (1,751.05)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 23,762,360.76		$ 24,959,983.58		$ (1,197,622.82)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (23,785,632.51)		$ 1,188,081.33		$ (24,782,854.35)				$ (190,859.49)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (2,464,122.48)		$ -		$ (2,464,122.48)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 262,635.67		$ 262,663.21		$ (27.54)								
	SUBTOTAL		$ (2,224,758.56)		$ 26,410,728.12		$ (28,444,627.19)		$ -		$ (190,859.49)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 9,156.72		$ 97,096.38		$ (87,939.66)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 21,807.39		$ 30,242.66		$ (8,435.27)								
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	-	$ 30,964.11	-	$ 127,339.04	-	$ (96,374.93)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(10,505,678)	$ (104,403,394.38)	40,852,999	$ 842,437,292.45	(39,926,060)	$ (748,770,689.87)	-	$ 1,143,332.56	(11,432,617)	$ (199,213,329.52)	138,864	$ 2,567,506.62	-	$ (13,555.11)
x	Net Congestion Amount		$ 66,545,896.05		$ 66,545,896.05				$ -						
y	Net Loss Amount		$ 29,835,516.00		$ 29,835,516.00				$ -						
z	Net Congestion and Loss Energy Offset		$ (96,381,412.05)		$ (96,381,412.05)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(10,505,678)**	$ (104,403,394.38)	40,852,999	$ 842,437,292.45	(39,926,060)	$ (748,770,689.87)	-	$ 1,143,332.56	(11,432,617)	$ (199,213,329.52)	138,864	$ 2,567,506.62	-	$ (13,555.11)

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

January 2020	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		$ (222,870.11)		$ -		$ (114,718.38)				$ (108,151.73)				
2 Day-Ahead Spinning Reserve Amount		$ (184,405.08)		$ -		$ (79,067.80)				$ (105,337.28)				
3 Day-Ahead Supplemental Reserve		$ (36,839.82)		$ -		$ (4,910.47)				$ (31,929.35)				
4 Real-Time Regulation Amount		$ 50,363.99		$ 85,687.84		$ (35,323.85)								
5 Real-Time Spinning Reserve Amount		$ 46,863.35		$ 125,056.44		$ (78,193.09)								
6 Real-Time Supplemental Reserve Amount.		$ 2,974.45		$ 3,522.56		$ (548.11)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(822)	$ (13,268.54)	17	$ 12.48	(839)	$ (13,281.02)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	165,884	$ 2,860,297.06	472,220	$ 8,853,725.00	(306,336)	$ (5,993,427.94)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 5,697.01		$ 14,129.30		$ (8,625.14)		$ 192.85						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 111,321.30		$ 111,321.30		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 76,300.71		$ 76,300.71		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 21,400.92		$ 21,400.92		$ -								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 29,363.95		$ 20,436.85		$ -		$ 8,927.10						
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ (70.54)		$ 70.54						
MISO ASM CHARGES	165,062	$ 2,747,199.19	472,237	$ 9,311,593.40	(307,175)	$ (6,328,166.34)	-	$ 9,190.49	-	$ (245,418.36)	-	$ -	-	$ -
x Net Congestion Amount		$ (131,073.51)		$ (131,073.51)										
y Net Loss Amount		$ (68,882.86)		$ (68,882.86)										
z Net Congestion and Loss Energy Offset		$ 199,956.37		$ 199,956.37										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	165,062	$ 2,747,199.19	472,237	$ 9,311,593.40	(307,175)	$ (6,328,166.34)	-	$ 9,190.49	-	$ (245,418.36)	-	$ -	-	$ -

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

February 2020	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		$ (231,511.33)		$ -		$ (5,963.90)				$ (225,547.43)				
2 Day-Ahead Spinning Reserve Amount		$ (123,481.97)		$ -		$ 85,608.21				$ (209,090.18)				
3 Day-Ahead Supplemental Reserve		$ (28,971.64)		$ -		$ 9,120.41				$ (38,092.05)				
4 Real-Time Regulation Amount		$ 34,791.79		$ 75,566.07		$ (40,774.28)								
5 Real-Time Spinning Reserve Amount		$ (31,632.62)		$ 29,552.57		$ (61,185.19)								
6 Real-Time Supplemental Reserve Amount.		$ (173.46)		$ 497.43		$ (670.89)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(617)	$ (7,907.35)	48	$ 612.05	(665)	$ (8,519.40)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	(71,486)	$ (463,662.43)	325,007	$ 4,967,367.29	(396,493)	$ (5,431,029.72)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (6,457.85)		$ 8,917.89		$ (10,895.40)		$ (4,480.34)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 108,152.70		$ 108,152.70		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 61,960.75		$ 61,960.75		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 9,808.49		$ 9,808.49		$ -								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 35,284.70		$ 24,274.66		$ -		$ 11,010.04						
14 Real Time Contigniecy Reserve Deployment Failure		$ -		$ -		$ -		$ -						
MISO ASM CHARGES	(72,103)	$ (643,800.22)	325,055	$ 5,286,709.90	(397,158)	$ (5,464,310.16)	-	$ 6,529.70	-	$ (472,729.66)	-	$ -	-	$ -
x Net Congestion Amount		$ 84,356.90		$ 84,356.90										
y Net Loss Amount		$ 105,131.56		$ 105,131.56										
z Net Congestion and Loss Energy Offset		$ (189,488.46)		$ (189,488.46)										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	(72,103)	$ (643,800.22)	325,055	$ 5,286,709.90	(397,158)	$ (5,464,310.16)	-	$ 6,529.70	-	$ (472,729.66)	-	$ -	-	$ -

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 2020	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		$ (255,634.08)		$ -		$ (58,032.28)				$ (197,601.80)				
2 Day-Ahead Spinning Reserve Amount		$ (144,262.47)		$ -		$ (6,904.18)				$ (137,358.29)				
3 Day-Ahead Supplemental Reserve		$ (25,943.42)		$ -		$ (10,456.07)				$ (15,487.35)				
4 Real-Time Regulation Amount		$ 40,133.03		$ 94,139.27		$ (54,006.24)								
5 Real-Time Spinning Reserve Amount		$ (2,179.89)		$ 65,305.81		$ (67,485.70)								
6 Real-Time Supplemental Reserve Amount.		$ 1,541.92		$ 1,600.58		$ (58.66)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(2,354)	$ (13,806.90)	104	$ 1,581.10	(2,458)	$ (15,388.00)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	88,300	$ 652,187.61	360,354	$ 5,185,008.50	(272,054)	$ (4,532,820.89)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 5,814.23		$ 20,012.68		$ (13,345.39)		$ (853.06)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 114,733.74		$ 114,733.74		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 64,205.18		$ 64,205.18		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 10,844.98		$ 10,844.98		$ -								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 28,080.16		$ 15,678.44		$ -		$ 12,401.72						
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -		$ -						
MISO ASM CHARGES	85,946	$ 475,714.09	360,458	$ 5,573,110.28	(274,512)	$ (4,758,497.41)	-	$ 11,548.66	-	$ (350,447.44)	-	$ -	-	$ -
x Net Congestion Amount		$ (380,280.51)		$ (380,280.51)										
y Net Loss Amount		$ (70,454.08)		$ (70,454.08)										
z Net Congestion and Loss Energy Offset		$ 450,734.59		$ 450,734.59										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	85,946	$ 475,714.09	360,458	$ 5,573,110.28	(274,512)	$ (4,758,497.41)	-	$ 11,548.66	-	$ (350,447.44)	-	$ -	-	$ -

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

April 2020	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		$ (228,122.10)		$ -		$ 11,626.61				$ (239,748.71)				
2 Day-Ahead Spinning Reserve Amount		$ (174,548.54)		$ -		$ 1,414.38				$ (175,962.92)				
3 Day-Ahead Supplemental Reserve		$ (26,195.52)		$ -		$ (3,979.13)				$ (22,216.39)				
4 Real-Time Regulation Amount		$ (447.45)		$ 64,353.43		$ (64,800.88)								
5 Real-Time Spinning Reserve Amount		$ (12,702.87)		$ 44,998.87		$ (57,701.74)								
6 Real-Time Supplemental Reserve Amount.		$ 2,183.33		$ 2,427.70		$ (244.37)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(581)	$ (4,390.42)	3	$ 14.28	(584)	$ (4,404.70)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	15,421	$ 510,253.31	354,536	$ 4,389,919.91	(339,115)	$ (3,879,666.60)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (18,100.30)		$ 17,998.15		$ (24,949.22)		$ (11,149.23)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 118,425.63		$ 118,425.63		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 73,008.37		$ 73,008.37		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 10,046.35		$ 10,046.35		$ -								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 31,387.24		$ 10,692.22		$ -		$ 20,695.02						
14 Real Time Contignecy Reserve Deployment Failure		$ 2,991.10		$ 1,761.97		$ -		$ 1,229.13						
MISO ASM CHARGES	14,840	$ 283,788.13	354,539	$ 4,733,646.88	(339,699)	$ (4,022,705.65)	-	$ 10,774.92	-	$ (437,928.02)	-	$ -	-	$ -
x Net Congestion Amount		$ (400,723.14)		$ (400,723.14)										
y Net Loss Amount		$ (95,665.65)		$ (95,665.65)										
z Net Congestion and Loss Energy Offset		$ 496,388.79		$ 496,388.79										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	14,840	$ 283,788.13	354,539	$ 4,733,646.88	(339,699)	$ (4,022,705.65)	-	$ 10,774.92	-	$ (437,928.02)	-	$ -	-	$ -

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

May 2020	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		$ (173,139.55)		$ -		$ (50,566.50)				$ (122,573.05)				
2 Day-Ahead Spinning Reserve Amount		$ (175,388.58)		$ -		$ (7,271.66)				$ (168,116.92)				
3 Day-Ahead Supplemental Reserve		$ (26,014.04)		$ -		$ 110.10				$ (26,124.14)				
4 Real-Time Regulation Amount		$ 20,340.19		$ 60,630.20		$ (40,290.01)								
5 Real-Time Spinning Reserve Amount		$ 4,100.79		$ 51,096.90		$ (46,996.11)								
6 Real-Time Supplemental Reserve Amount.		$ 807.82		$ 868.02		$ (60.20)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(264)	$ (2,062.16)	25	$ 43.35	(289)	$ (2,105.51)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	43,319	$ 544,149.46	364,142	$ 4,396,811.66	(320,823)	$ (3,852,662.20)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 10,568.36		$ 12,680.30		$ (3,677.96)		$ 1,566.02						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 119,108.36		$ 119,108.36		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 91,828.37		$ 91,828.37		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 10,161.05		$ 10,161.05		$ -								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 15,153.90		$ 6,374.49		$ -		$ 8,779.41						
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -		$ -						
MISO ASM CHARGES	43,055	$ 439,613.97	364,167	$ 4,749,602.70	(321,112)	$ (4,003,520.05)	-	$ 10,345.43	-	$ (316,814.11)	-	$ -	-	$ -
x Net Congestion Amount		$ (16,754.64)		$ (16,754.64)										
y Net Loss Amount		$ 21,319.36		$ 21,319.36										
z Net Congestion and Loss Energy Offset		$ (4,564.72)		$ (4,564.72)										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	43,055	$ 439,613.97	364,167	$ 4,749,602.70	(321,112)	$ (4,003,520.05)	-	$ 10,345.43	-	$ (316,814.11)	-	$ -	-	$ -

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 2020	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		$ (190,604.54)		$ -		$ (87,289.75)				$ (103,314.79)				
2 Day-Ahead Spinning Reserve Amount		$ (131,163.20)		$ -		$ (22,531.54)				$ (108,631.66)				
3 Day-Ahead Supplemental Reserve		$ (19,929.95)		$ -		$ (10,075.45)				$ (9,854.50)				
4 Real-Time Regulation Amount		$ (1,893.88)		$ 60,175.51		$ (62,069.39)								
5 Real-Time Spinning Reserve Amount		$ (23,070.70)		$ 45,813.40		$ (68,884.10)								
6 Real-Time Supplemental Reserve Amount.		$ 2,973.76		$ 3,378.60		$ (404.84)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(1,624)	$ (1,102.93)	32	$ (30.43)	(1,656)	$ (1,072.50)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	135,125	$ 2,565,704.10	448,935	$ 6,828,158.70	(313,810)	$ (4,262,454.60)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (1,692.54)		$ 9,789.89		$ (10,378.50)		$ (1,103.93)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 116,678.80		$ 116,678.80		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 88,495.02		$ 88,495.02		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 11,651.19		$ 11,651.19		$ -								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 37,428.39		$ 12,835.32		$ -		$ 24,593.07						
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -		$ -						
MISO ASM CHARGES	133,501	$ 2,453,473.52	448,967	$ 7,176,946.00	(315,466)	$ (4,525,160.67)	-	$ 23,489.14	-	$ (221,800.95)	-	$ -	-	$ -
x Net Congestion Amount		$ (829,572.58)		$ (829,572.58)										
y Net Loss Amount		$ (210,120.57)		$ (210,120.57)										
z Net Congestion and Loss Energy Offset		$ 1,039,693.15		$ 1,039,693.15										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	133,501	$ 2,453,473.52	448,967	$ 7,176,946.00	(315,466)	$ (4,525,160.67)	-	$ 23,489.14	-	$ (221,800.95)	-	$ -	-	$ -

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 2020	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		$ (189,774.56)		$ -		$ 25,889.67				$ (215,664.23)				
2 Day-Ahead Spinning Reserve Amount		$ (132,236.62)		$ -		$ (55,661.98)				$ (76,574.64)				
3 Day-Ahead Supplemental Reserve		$ (26,502.26)		$ -		$ (18,192.74)				$ (8,309.52)				
4 Real-Time Regulation Amount		$ (147,283.73)		$ 48,943.56		$ (196,227.29)								
5 Real-Time Spinning Reserve Amount		$ (20,599.84)		$ 40,069.39		$ (60,669.23)								
6 Real-Time Supplemental Reserve Amount.		$ 2,818.84		$ 5,385.61		$ (2,566.77)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(1,275)	$ (11,540.52)	14	$ 140.26	(1,289)	$ (11,680.78)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	265,388	$ 4,242,716.72	560,480	$ 9,655,366.15	(295,092)	$ (5,412,649.43)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 5,062.61		$ 31,169.92		$ (25,193.42)		$ (913.89)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 126,976.29		$ 126,976.29		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 106,609.09		$ 106,609.09		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 10,384.42		$ 10,384.42		$ -								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 39,381.87		$ 12,313.29		$ -		$ 27,068.58						
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -		$ -						
MISO ASM CHARGES	264,113	$ 4,006,012.31	560,494	$ 10,037,357.98	(296,381)	$ (5,756,951.97)	-	$ 26,154.69	-	$ (300,548.39)	-	$ -	-	$ -
x Net Congestion Amount		$ (436,551.51)		$ (436,551.51)				$ -						
y Net Loss Amount		$ (83,886.68)		$ (83,886.68)				$ -						
z Net Congestion and Loss Energy Offset		$ 520,438.19		$ 520,438.19										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	264,113	$ 4,006,012.31	560,494	$ 10,037,357.98	(296,381)	$ (5,756,951.97)	-	$ 26,154.69	-	$ (300,548.39)	-	$ -	-	$ -

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 2020	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		$ (174,236.43)		$ -		$ (67,610.55)				$ (106,625.88)				
2 Day-Ahead Spinning Reserve Amount		$ (187,878.92)		$ -		$ (70,988.06)				$ (116,890.86)				
3 Day-Ahead Supplemental Reserve		$ (27,590.60)		$ -		$ (12,975.08)				$ (14,615.52)				
4 Real-Time Regulation Amount		$ (39,634.79)		$ 61,834.86		$ (101,469.65)								
5 Real-Time Spinning Reserve Amount		$ 8,906.63		$ 77,364.21		$ (68,457.58)								
6 Real-Time Supplemental Reserve Amount.		$ 2,501.23		$ 3,293.70		$ (792.47)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(496)	$ (16,514.00)	522	$ (2,920.44)	(1,018)	$ (13,593.56)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	177,801	$ 3,588,492.75	479,074	$ 8,299,752.82	(301,273)	$ (4,711,260.07)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (18,708.65)		$ 18,810.45		$ (30,329.48)		$ (7,189.62)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 121,423.76		$ 121,423.76		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 101,451.06		$ 101,451.06		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 16,044.18		$ 16,044.18		$ -								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 22,427.61		$ 9,343.33		$ -		$ 13,084.28						
14 Real Time Contignecy Reserve Deployment Failure		$ 50.05		$ 42.88		$ -		$ 7.17						
MISO ASM CHARGES	177,305	$ 3,396,733.88	479,596	$ 9,386.21	(302,291)	$ (5,077,476.50)	-	$ 13,091.45	-	$ (238,132.26)	-	$ -	-	$ -
x Net Congestion Amount		$ (154,142.30)		$ (154,142.30)				$ -						
y Net Loss Amount		$ (21,641.96)		$ (21,641.96)				$ -						
z Net Congestion and Loss Energy Offset		$ 175,784.26		$ 175,784.26										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	177,305	$ 3,396,733.88	479,596	$ 8,706,440.81	(302,291)	$ (5,077,476.50)	-	$ 5,901.83	-	$ (238,132.26)	-	$ -	-	$ -

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

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

September 2020	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		$ (78,115.27)		$ -		$ (38,787.98)				$ (39,327.29)				
2 Day-Ahead Spinning Reserve Amount		$ (69,129.43)		$ -		$ (25,294.09)				$ (43,835.34)				
3 Day-Ahead Supplemental Reserve		$ (30,007.76)		$ -		$ (12,705.89)				$ (17,301.87)				
4 Real-Time Regulation Amount		$ (29,479.98)		$ 27,713.94		$ (57,193.92)								
5 Real-Time Spinning Reserve Amount		$ (35,757.93)		$ 22,979.25		$ (58,737.18)								
6 Real-Time Supplemental Reserve Amount.		$ 2,065.01		$ 2,659.33		$ (594.32)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(1,119)	$ (1,092.26)	46	$ 325.68	(1,165)	$ (1,417.94)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	152,371	$ 574,758.01	410,415	$ 3,961,429.21	(258,044)	$ (3,386,671.20)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (481.01)		$ 5,868.41		$ (4,179.72)		$ (2,169.70)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 114,611.55		$ 114,611.55		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 60,382.83		$ 60,382.83		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 12,017.27		$ 12,017.27		$ -								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 14,182.03		$ 4,662.82		$ -		$ 9,519.21						
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -								
MISO ASM CHARGES	151,252	$ 533,953.06	410,461	$ 4,212,650.29	(259,209)	$ (3,585,582.24)	-	$ 7,349.51	-	$ (100,464.50)	-	$ -	-	$ -
x Net Congestion Amount		$ (287,920.60)		$ (287,920.60)				$ -						
y Net Loss Amount		$ (49,677.68)		$ (49,677.68)				$ -						
z Net Congestion and Loss Energy Offset		$ 337,598.28		$ 337,598.28										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	151,252	$ 533,953.06	410,461	$ 4,212,650.29	(259,209)	$ (3,585,582.24)	-	$ 7,349.51	-	$ (100,464.50)	-	$ -	-	$ -

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

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

October 2020	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		$ (218,072.97)		$ -		$ (106,569.64)				$ (111,503.33)				
2 Day-Ahead Spinning Reserve Amount		$ (122,021.50)		$ -		$ (50,358.04)				$ (71,663.46)				
3 Day-Ahead Supplemental Reserve		$ (26,511.85)		$ -		$ (15,670.48)				$ (10,841.37)				
4 Real-Time Regulation Amount		$ 5,647.71		$ 85,605.73		$ (79,958.02)								
5 Real-Time Spinning Reserve Amount		$ 1,635.37		$ 61,375.11		$ (59,739.74)								
6 Real-Time Supplemental Reserve Amount.		$ 3,123.52		$ 3,937.66		$ (814.14)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(1,036)	$ (1,205.29)	31	$ 62.74	(1,067)	$ (1,268.03)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	169,051	$ 1,336,144.51	417,887	$ 5,561,136.23	(248,836)	$ (4,224,991.72)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (11,133.29)		$ 21,108.90		$ (23,167.17)		$ (9,075.02)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 130,622.30		$ 130,622.30		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 90,394.99		$ 90,394.99		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 24,260.42		$ 24,260.42		$ -								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 38,842.45		$ 10,551.80		$ -		$ 28,290.65						
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -								
MISO ASM CHARGES	168,015	$ 1,251,726.37	417,918	$ 5,989,055.88	(249,903)	$ (4,562,536.98)	-	$ 19,215.63	-	$ (194,008.16)	-	$ -	-	$ -
x Net Congestion Amount		$ (212,325.68)		$ (212,325.68)				$ -						
y Net Loss Amount		$ (16,813.64)		$ (16,813.64)				$ -						
z Net Congestion and Loss Energy Offset		$ 229,139.32		$ 229,139.32										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	168,015	$ 1,251,726.37	417,918	$ 5,989,055.88	(249,903)	$ (4,562,536.98)	-	$ 19,215.63	-	$ (194,008.16)	-	$ -	-	$ -

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 2020	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		$ (125,759.98)		$ -		$ (66,854.34)				$ (58,905.64)				
2 Day-Ahead Spinning Reserve Amount		$ (71,977.62)		$ -		$ (18,501.75)				$ (53,475.87)				
3 Day-Ahead Supplemental Reserve		$ (14,264.35)		$ -		$ (8,811.52)				$ (5,452.83)				
4 Real-Time Regulation Amount		$ (18,025.71)		$ 38,036.59		$ (56,062.30)								
5 Real-Time Spinning Reserve Amount		$ 2,180.37		$ 26,437.47		$ (24,257.10)								
6 Real-Time Supplemental Reserve Amount.		$ 445.87		$ 1,537.84		$ (1,091.97)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(991)	$ (4,004.37)	20	$ (99.70)	(1,011)	$ (3,904.67)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	39,495	$ 678,059.08	396,919	$ 5,159,772.28	(357,424)	$ (4,481,713.20)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (7,801.66)		$ 7,941.24		$ (10,790.15)		$ (4,952.75)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 128,336.29		$ 128,336.29		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 78,756.35		$ 78,756.35		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 9,896.54		$ 9,896.54		$ -								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 23,487.52		$ 16,128.47		$ -		$ 7,359.05						
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -								
MISO ASM CHARGES	38,504	$ 679,328.33	396,939	$ 5,466,743.37	(358,435)	$ (4,671,987.00)	-	$ 2,406.30	-	$ (117,834.34)	-	$ -	-	$ -
x Net Congestion Amount		$ (296,288.71)		$ (296,288.71)				$ -						
y Net Loss Amount		$ 71,805.07		$ 71,805.07				$ -						
z Net Congestion and Loss Energy Offset		$ 224,483.64		$ 224,483.64										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	38,504	$ 679,328.33	396,939	$ 5,466,743.37	(358,435)	$ (4,671,987.00)	-	$ 2,406.30	-	$ (117,834.34)	-	$ -	-	$ -

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 ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

December 2020	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		$ (121,729.03)		$ -		$ (49,779.92)				$ (71,949.11)				
2 Day-Ahead Spinning Reserve Amount		$ (124,767.91)		$ -		$ (72,196.94)				$ (52,570.97)				
3 Day-Ahead Supplemental Reserve		$ (14,308.14)		$ -		$ (12,036.28)				$ (2,271.86)				
4 Real-Time Regulation Amount		$ (38,295.32)		$ 42,740.50		$ (81,035.82)								
5 Real-Time Spinning Reserve Amount		$ 1,490.37		$ 38,844.64		$ (37,354.27)								
6 Real-Time Supplemental Reserve Amount.		$ 88.42		$ 547.88		$ (459.46)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(1,482)	$ 6,020.77	115	$ (301.06)	(1,597)	$ 6,321.83								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	232,306	$ 2,863,453.57	432,282	$ 6,584,176.32	(199,976)	$ (3,720,722.75)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 6,382.21		$ 17,599.45		$ (13,128.34)		$ 1,911.10						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 129,829.89		$ 129,829.89		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 86,520.15		$ 86,520.15		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 12,437.90		$ 12,437.90		$ -								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 27,863.65		$ 9,234.57		$ -		$ 18,629.08						
14 Real Time Contignecy Reserve Deployment Failure		$ 15,421.81		$ 15,421.81		$ -								
MISO ASM CHARGES	230,824	$ 2,850,408.34	432,397	$ 6,937,052.05	(201,573)	$ (3,980,391.95)	-	$ 20,540.18	-	$ (126,791.94)	-	$ -	-	$ -
x Net Congestion Amount		$ (150,979.98)		$ (150,979.98)				$ -						
y Net Loss Amount		$ 123,250.84		$ 123,250.84				$ -						
z Net Congestion and Loss Energy Offset		$ 27,729.14		$ 27,729.14										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	230,824	$ 2,850,408.34	432,397	$ 6,937,052.05	(201,573)	$ (3,980,391.95)	-	$ 20,540.18	-	$ (126,791.94)	-	$ -	-	$ -

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 2020	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		$ (2,209,569.95)		$ -		$ (608,656.96)				$ (1,600,912.99)				
2 Day-Ahead Spinning Reserve Amount		$ (1,641,261.84)		$ -		$ (321,753.45)				$ (1,319,508.39)				
3 Day-Ahead Supplemental Reserve		$ (303,079.35)		$ -		$ (100,582.60)				$ (202,496.75)				
4 Real-Time Regulation Amount		$ (123,784.15)		$ 745,427.50		$ (869,211.65)								
5 Real-Time Spinning Reserve Amount		$ (60,766.97)		$ 628,894.06		$ (689,661.03)								
6 Real-Time Supplemental Reserve Amount.		$ 21,350.71		$ 29,656.91		$ (8,306.20)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(12,661)	$ (70,873.97)	977	$ (559.69)	(13,638)	$ (70,314.28)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	1,412,975	$ 19,952,553.75	5,022,251	$ 73,842,624.07	(3,609,276)	$ (53,890,070.32)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (30,850.88)		$ 186,026.58		$ (178,659.89)		$ (38,217.57)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 1,440,220.61		$ 1,440,220.61		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 979,912.87		$ 979,912.87		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 158,953.71		$ 158,953.71		$ -								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 342,883.47		$ 152,526.26		$ -		$ 190,357.21						
14 Real Time Contignecy Reserve Deployment Failure		$ 18,462.96		$ 17,156.12		$ -		$ 1,306.84						
MISO ASM CHARGES	1,400,314	$ 18,474,150.97	5,023,228	$ 169,682.38	(3,622,914)	$ (56,737,216.38)	-	$ 191,664.05	-	$ (3,122,918.13)	-	$ -	-	$ -
x Net Congestion Amount		$ (3,212,256.26)		$ (3,212,256.26)				$ -						
y Net Loss Amount		$ (295,636.29)		$ (295,636.29)				$ -						
z Net Congestion and Loss Energy Offset		$ 3,507,892.55		$ 3,507,892.55										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	1,400,314	$ 18,474,150.97	5,023,228	$ 78,180,839.00	(3,622,914)	$ (56,737,216.38)	-	$ 153,446.48	-	$ (3,122,918.13)	-	$ -	-	$ -

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

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
1/1/2020	(766,327)	(774,529)	8,202	1.06%	0	50	1	9,172	368	954	7,197
1/2/2020	(785,880)	(791,195)	5,315	0.67%	0	753	-63	11,215	1,138	1,235	3,390
1/3/2020	(744,119)	(749,515)	5,396	0.72%	0	644	302	11,057	690	1,175	3,276
1/4/2020	(719,524)	(724,214)	4,690	0.65%	0	625	-15	10,586	444	1,103	2,976
1/5/2020	(619,665)	(620,317)	652	0.11%	0	3	5	6,221	74	630	14
1/6/2020	(692,195)	(697,261)	5,066	0.73%	0	1,166	991	10,020	509	1,053	1,856
1/7/2020	(708,605)	(719,190)	10,585	1.47%	0	587	457	9,042	693	973	8,567
1/8/2020	(817,790)	(823,665)	5,875	0.71%	0	1,173	103	10,333	462	1,080	3,520
1/9/2020	(737,995)	(735,257)	-2,738	-0.37%	0	991	-35	8,391	1,003	939	(4,634)
1/10/2020	(794,427)	(797,595)	3,168	0.40%	0	363	-525	10,799	724	1,152	2,178
1/11/2020	(641,953)	(649,646)	7,693	1.18%	0	2,454	1,978	9,161	1,555	1,072	2,190
1/12/2020	(716,806)	(724,211)	7,405	1.02%	0	1,743	107	9,252	1,645	1,090	4,466
1/13/2020	(855,812)	(863,036)	7,224	0.84%	0	1,473	401	11,351	1,186	1,254	4,096
1/14/2020	(868,682)	(868,820)	138	0.02%	0	1,549	-64	11,107	654	1,176	(2,523)
1/15/2020	(822,804)	(830,070)	7,266	0.88%	0	1,183	156	11,090	696	1,179	4,749
1/16/2020	(896,312)	(913,997)	17,685	1.93%	0	1,841	22	11,729	709	1,244	14,579
1/17/2020	(797,027)	(795,710)	-1,317	-0.17%	0	179	53	9,673	727	1,040	(2,589)
1/18/2020	(672,985)	(671,959)	-1,026	-0.15%	0	1,529	19	8,107	589	870	(3,443)
1/19/2020	(882,427)	(868,115)	-14,312	-1.65%	0	2,499	-141	10,646	1,281	1,193	(17,864)
1/20/2020	(1,412,085)	(1,407,106)	-4,979	-0.35%	0	1,338	-277	14,023	1,641	1,566	(7,606)
1/21/2020	(1,129,332)	(1,131,037)	1,705	0.15%	0	791	18	11,984	1,198	1,318	(422)
1/22/2020	(801,365)	(810,405)	9,040	1.12%	0	806	-38	11,624	1,176	1,280	6,992
1/23/2020	(871,518)	(879,515)	7,997	0.91%	0	1,264	318	13,822	1,052	1,487	4,927
1/24/2020	(803,201)	(814,425)	11,224	1.38%	0	3,542	1,131	13,093	1,119	1,421	5,130
1/25/2020	(722,583)	(734,229)	11,646	1.59%	0	463	56	11,996	1,118	1,311	9,816
1/26/2020	(693,084)	(705,785)	12,701	1.80%	0	815	-52	11,945	1,069	1,301	10,636
1/27/2020	(840,243)	(847,307)	7,064	0.83%	0	1,860	414	12,985	880	1,386	3,403
1/28/2020	(964,287)	(973,235)	8,948	0.92%	0	2,568	87	13,384	618	1,400	4,893
1/29/2020	(1,026,719)	(1,038,234)	11,515	1.11%	0	2,102	-1,080	13,449	607	1,406	9,087
1/30/2020	(940,050)	(945,667)	5,617	0.59%	0	327	-1,678	13,308	1,653	1,496	5,472
1/31/2020	(744,484)	(751,704)	7,220	0.96%	0	1,426	-386	12,230	1,166	1,340	4,840
2/1/2020	(980,844)	(983,696)	2,852	0.29%	0	16	-9	9,038	621	966	1,879
2/2/2020	(594,540)	(595,127)	587	0.10%	0	0	0	6,003	80	608	(21)
2/3/2020	(621,097)	(623,829)	2,732	0.44%	0	194	114	7,884	301	818	1,606
2/4/2020	(1,005,112)	(1,007,926)	2,814	0.28%	0	999	6	9,570	924	1,049	759
2/5/2020	(1,084,095)	(1,085,996)	1,901	0.18%	0	4,336	-110	10,030	734	1,076	(3,402)
2/6/2020	(1,093,741)	(1,096,543)	2,802	0.26%	0	1,568	-99	10,098	974	1,107	226
2/7/2020	(1,072,032)	(1,072,474)	442	0.04%	0	258	-410	10,094	1,162	1,126	(531)
2/8/2020	(1,057,443)	(1,060,325)	2,882	0.27%	0	811	-37	8,521	642	916	1,192
2/9/2020	(915,900)	(918,337)	2,437	0.27%	0	7	97	6,995	340	733	1,599
2/10/2020	(1,226,161)	(1,229,360)	3,199	0.26%	0	1,144	-357	9,624	1,058	1,068	1,343

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
2/11/2020	(946,435)	(950,465)	4,030	0.42%	0	860	70	9,429	326	975	2,125
2/12/2020	(912,479)	(916,829)	4,350	0.47%	0	69	112	8,234	822	906	3,263
2/13/2020	(1,193,530)	(1,194,517)	987	0.08%	0	806	-20	10,513	1,718	1,223	(1,022)
2/14/2020	(1,053,597)	(1,047,900)	-5,697	-0.54%	0	361	69	8,373	921	929	(7,056)
2/15/2020	(624,204)	(625,115)	911	0.15%	0	628	-88	6,407	243	665	(294)
2/16/2020	(881,713)	(882,118)	405	0.05%	0	670	69	8,597	332	893	(1,227)
2/17/2020	(998,874)	(998,337)	-537	-0.05%	0	1,224	-8	8,791	917	971	(2,723)
2/18/2020	(884,924)	(886,136)	1,212	0.14%	0	1,005	27	7,704	1,056	876	(697)
2/19/2020	(1,055,787)	(1,066,773)	10,986	1.03%	0	2,790	-339	9,227	289	952	7,583
2/20/2020	(1,103,006)	(1,113,298)	10,292	0.92%	0	2,203	-1,344	9,563	716	1,028	8,405
2/21/2020	(871,108)	(874,862)	3,754	0.43%	0	727	8	5,751	330	608	2,411
2/22/2020	(608,644)	(612,215)	3,571	0.58%	0	19	98	5,169	60	523	2,931
2/23/2020	(575,812)	(577,434)	1,622	0.28%	0	265	8	5,936	127	606	742
2/24/2020	(859,902)	(865,513)	5,611	0.65%	0	1,521	19	9,146	822	997	3,074
2/25/2020	(660,113)	(666,767)	6,654	1.00%	0	1,298	117	7,483	326	781	4,458
2/26/2020	(751,770)	(756,067)	4,297	0.57%	0	2,492	-68	8,811	359	917	956
2/27/2020	(961,893)	(971,225)	9,332	0.96%	0	1,724	1,292	9,733	430	1,016	5,299
2/28/2020	(885,811)	(892,087)	6,276	0.70%	0	1,444	2,354	9,567	607	1,017	1,460
2/29/2020	(650,592)	(651,780)	1,188	0.18%	0	1,027	-209	6,870	346	722	(351)
3/1/2020	(528,016)	(527,257)	-759	-0.14%	0	0	0	4,402	147	455	(1,214)
3/2/2020	(906,662)	(918,474)	11,812	1.29%	0	1,786	124	6,792	462	725	9,177
3/3/2020	(651,861)	(656,961)	5,100	0.78%	0	741	968	4,729	151	488	2,903
3/4/2020	(851,922)	(855,622)	3,700	0.43%	0	904	-523	6,231	309	654	2,665
3/5/2020	(603,711)	(606,573)	2,862	0.47%	0	259	-11	4,420	-11	441	2,173
3/6/2020	(845,407)	(848,831)	3,424	0.40%	0	1,973	922	6,100	333	643	(114)
3/7/2020	(556,583)	(558,679)	2,096	0.38%	0	2	30	4,191	-98	409	1,655
3/8/2020	(538,319)	(540,359)	2,040	0.38%	0	8	3	4,198	-28	417	1,612
3/9/2020	(837,839)	(844,385)	6,546	0.78%	0	809	-174	6,711	614	732	5,179
3/10/2020	(1,229,358)	(1,243,067)	13,709	1.10%	0	791	-590	8,337	745	908	12,600
3/11/2020	(1,013,959)	(1,023,914)	9,955	0.97%	0	2,579	-397	7,111	449	756	7,017
3/12/2020	(624,183)	(626,617)	2,434	0.39%	0	4	62	4,208	120	433	1,935
3/13/2020	(915,202)	(929,411)	14,209	1.53%	0	3,092	-677	6,878	975	785	11,009
3/14/2020	(911,695)	(920,393)	8,698	0.95%	0	452	107	7,240	898	814	7,326
3/15/2020	(884,762)	(890,322)	5,560	0.62%	0	402	342	6,950	671	762	4,054
3/16/2020	(908,342)	(915,254)	6,912	0.76%	0	436	-458	7,395	667	806	6,127
3/17/2020	(1,005,423)	(1,009,791)	4,368	0.43%	0	898	-403	7,793	947	874	2,999
3/18/2020	(927,064)	(927,676)	612	0.07%	0	1,308	2,124	7,592	912	850	(3,670)
3/19/2020	(744,932)	(746,675)	1,743	0.23%	0	1,206	135	6,073	292	636	(235)
3/20/2020	(738,784)	(739,129)	345	0.05%	0	750	-44	6,385	644	703	(1,064)
3/21/2020	(869,554)	(869,211)	-343	-0.04%	0	58	-39	7,401	815	822	(1,183)
3/22/2020	(818,928)	(822,624)	3,696	0.45%	0	369	-78	6,497	640	714	2,692

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3/23/2020	(864,599)	(866,705)	2,106	0.24%	0	527	-132	7,906	914	882	829
3/24/2020	(724,693)	(726,792)	2,099	0.29%	0	28	65	5,862	373	624	1,382
3/25/2020	(806,232)	(800,686)	-5,546	-0.69%	0	806	323	7,161	1,059	822	(7,497)
3/26/2020	(829,374)	(829,766)	392	0.05%	0	1,911	46	7,657	680	834	(2,398)
3/27/2020	(744,738)	(743,871)	-867	-0.12%	0	102	56	7,117	355	747	(1,772)
3/28/2020	(516,051)	(517,480)	1,429	0.28%	0	24	11	4,210	85	430	964
3/29/2020	(514,549)	(515,849)	1,300	0.25%	0	4	396	3,993	126	412	489
3/30/2020	(741,846)	(755,086)	13,240	1.75%	0	1,192	50	6,671	284	695	11,302
3/31/2020	(719,908)	(730,513)	10,605	1.45%	0	795	-626	7,005	661	767	9,669
4/1/2020	(812,989)	(810,290)	-2,699	-0.33%	0	6	4	6,790	-23	677	(3,386)
4/2/2020	(572,031)	(571,505)	-526	-0.09%	0	41	62	6,648	-10	664	(1,294)
4/3/2020	(576,998)	(576,226)	-772	-0.13%	0	2,484	969	7,641	360	800	(5,025)
4/4/2020	(769,205)	(776,827)	7,622	0.98%	2,991	233	-1,722	10,925	766	1,169	4,951
4/5/2020	(671,613)	(675,493)	3,880	0.57%	0	11	48	10,916	425	1,134	2,687
4/6/2020	(818,808)	(828,285)	9,477	1.14%	0	641	-310	11,631	1,420	1,305	7,841
4/7/2020	(678,303)	(682,448)	4,145	0.61%	0	1,742	250	11,300	556	1,186	967
4/8/2020	(685,741)	(686,232)	491	0.07%	0	74	219	8,583	148	873	(675)
4/9/2020	(657,545)	(659,771)	2,226	0.34%	0	332	-37	7,357	372	773	1,158
4/10/2020	(728,404)	(730,074)	1,670	0.23%	0	1,216	-4,299	11,228	839	1,207	3,546
4/11/2020	(693,718)	(685,180)	-8,538	-1.25%	0	871	-17	10,211	475	1,069	(10,461)
4/12/2020	(664,780)	(664,229)	-551	-0.08%	0	646	58	7,171	494	766	(2,022)
4/13/2020	(829,602)	(831,661)	2,059	0.25%	0	341	258	9,146	535	968	492
4/14/2020	(926,384)	(939,501)	13,117	1.40%	0	1,329	-1,579	12,106	826	1,293	12,073
4/15/2020	(991,300)	(997,118)	5,818	0.58%	0	1,224	-4,128	13,771	1,305	1,508	7,214
4/16/2020	(872,197)	(883,816)	11,619	1.31%	0	1,752	-763	12,904	984	1,389	9,241
4/17/2020	(607,005)	(621,768)	14,763	2.37%	0	8,080	227	10,276	2,375	1,265	5,190
4/18/2020	(500,460)	(514,054)	13,594	2.64%	0	14	0	5,953	-86	587	12,994
4/19/2020	(726,972)	(720,055)	-6,917	-0.96%	0	558	153	8,783	126	891	(8,519)
4/20/2020	(552,155)	(566,380)	14,225	2.51%	0	713	-488	6,514	113	663	13,338
4/21/2020	(782,752)	(787,601)	4,849	0.62%	0	822	-1,872	9,269	572	984	4,915
4/22/2020	(818,269)	(825,990)	7,721	0.93%	0	652	-55	8,997	766	976	6,148
4/23/2020	(894,169)	(906,931)	12,762	1.41%	0	2,269	-716	10,023	884	1,091	10,118
4/24/2020	(820,698)	(815,657)	-5,041	-0.62%	0	283	-20	9,405	452	986	(6,289)
4/25/2020	(804,636)	(790,931)	-13,705	-1.73%	0	52	216	9,269	331	960	(14,933)
4/26/2020	(688,093)	(686,873)	-1,220	-0.18%	0	30	318	8,327	-78	825	(2,393)
4/27/2020	(755,081)	(753,308)	-1,773	-0.24%	0	451	264	8,498	318	882	(3,369)
4/28/2020	(521,507)	(554,591)	33,084	5.97%	0	528	26	5,970	202	617	31,913
4/29/2020	(631,959)	(645,071)	13,112	2.03%	0	0	0	6,496	7	650	12,462
4/30/2020	(811,406)	(816,159)	4,753	0.58%	0	1,586	2,102	9,115	667	978	87
5/1/2020	(657,022)	(693,353)	36,331	5.24%	0	2	17	5,194	-25	517	35,796
5/2/2020	(519,717)	(535,368)	15,651	2.92%	0	242	32	6,281	283	656	14,720

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5/3/2020	(589,009)	(603,491)	14,482	2.40%	0	17	49	6,623	44	667	13,750
5/4/2020	(592,596)	(595,810)	3,214	0.54%	0	1,232	60	7,149	262	741	1,182
5/5/2020	(528,663)	(539,997)	11,334	2.10%	0	209	35	8,312	328	864	10,226
5/6/2020	(505,885)	(486,014)	-19,871	-4.09%	0	17	1,421	8,009	244	825	(22,135)
5/7/2020	(580,739)	(581,198)	459	0.08%	0	212	76	7,969	294	826	(655)
5/8/2020	(595,262)	(624,743)	29,481	4.72%	0	8	1,210	5,237	-54	518	27,745
5/9/2020	(543,195)	(570,781)	27,586	4.83%	0	244	-477	5,190	-124	507	27,312
5/10/2020	(549,814)	(565,795)	15,981	2.82%	0	7	13	5,269	-26	524	15,437
5/11/2020	(643,470)	(629,796)	-13,674	-2.17%	0	973	-594	8,194	595	879	(14,932)
5/12/2020	(604,990)	(594,068)	-10,922	-1.84%	0	2,284	-199	8,631	155	879	(13,886)
5/13/2020	(511,781)	(511,801)	20	0.00%	0	529	-135	6,090	149	624	(998)
5/14/2020	(661,805)	(656,505)	-5,300	-0.81%	0	372	-234	9,200	1,072	1,027	(6,464)
5/15/2020	(791,938)	(799,025)	7,087	0.89%	0	2,969	2,227	9,470	950	1,042	849
5/16/2020	(599,902)	(598,945)	-957	-0.16%	0	37	177	6,582	100	668	(1,840)
5/17/2020	(441,629)	(503,719)	62,090	12.33%	0	0	0	5,260	-3	526	61,564
5/18/2020	(593,764)	(599,189)	5,425	0.91%	0	4	109	5,950	247	620	4,693
5/19/2020	(596,971)	(599,690)	2,719	0.45%	0	76	-26	6,974	831	780	1,889
5/20/2020	(554,554)	(555,840)	1,286	0.23%	0	118	30	6,494	350	684	453
5/21/2020	(564,533)	(563,353)	-1,180	-0.21%	0	10	38	7,041	527	757	(1,985)
5/22/2020	(725,322)	(724,380)	-942	-0.13%	0	374	45	8,768	741	951	(2,312)
5/23/2020	(807,227)	(810,867)	3,640	0.45%	0	2,093	-1,434	9,817	534	1,035	1,946
5/24/2020	(740,509)	(744,179)	3,670	0.49%	0	211	278	8,069	233	830	2,351
5/25/2020	(763,335)	(766,599)	3,264	0.43%	0	698	349	8,891	904	980	1,237
5/26/2020	(1,124,545)	(1,125,105)	560	0.05%	0	1,956	1,284	11,747	1,008	1,276	(3,956)
5/27/2020	(1,214,205)	(1,226,140)	11,935	0.97%	0	1,563	-599	11,897	1,184	1,308	9,663
5/28/2020	(552,256)	(553,102)	846	0.15%	0	72	19	6,758	173	693	62
5/29/2020	(537,527)	(536,881)	-646	-0.12%	0	821	1,186	6,727	277	700	(3,353)
5/30/2020	(723,878)	(724,418)	540	0.07%	0	805	64	8,555	220	878	(1,207)
5/31/2020	(567,551)	(563,454)	-4,097	-0.73%	0	0	1	5,573	-74	550	(4,648)
6/1/2020	(974,984)	(973,887)	-1,097	-0.11%	0	917	-45	7,366	284	765	(2,734)
6/2/2020	(1,070,077)	(1,101,904)	31,827	2.89%	0	1,100	-88	11,057	1,158	1,221	29,593
6/3/2020	(1,371,926)	(1,376,417)	4,491	0.33%	0	2,625	1,305	13,196	1,447	1,464	(903)
6/4/2020	(1,426,332)	(1,436,884)	10,552	0.73%	0	3,417	-179	14,829	1,874	1,670	5,644
6/5/2020	(1,138,471)	(1,146,059)	7,588	0.66%	0	1,579	-236	13,595	1,701	1,530	4,716
6/6/2020	(584,887)	(583,413)	-1,474	-0.25%	0	452	13	6,758	111	687	(2,626)
6/7/2020	(559,874)	(556,836)	-3,038	-0.55%	0	231	42	6,727	-30	670	(3,981)
6/8/2020	(807,005)	(820,223)	13,218	1.61%	0	564	-93	9,005	663	967	11,780
6/9/2020	(716,249)	(715,732)	-517	-0.07%	0	2,204	-350	9,391	509	990	(3,362)
6/10/2020	(546,359)	(542,375)	-3,984	-0.73%	0	0	8	6,166	-21	614	(4,606)
6/11/2020	(494,654)	(501,923)	7,269	1.45%	0	16	82	6,827	230	706	6,466
6/12/2020	(714,042)	(709,096)	-4,946	-0.70%	0	3,219	498	9,275	535	981	(9,644)

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6/13/2020	(410,933)	(455,611)	44,678	9.81%	0	0	0	5,022	-77	495	44,183
6/14/2020	(410,562)	(453,720)	43,158	9.51%	0	0	0	5,129	51	518	42,640
6/15/2020	(556,376)	(600,428)	44,052	7.34%	0	137	2	6,632	600	723	43,190
6/16/2020	(493,095)	(527,556)	34,461	6.53%	0	1,747	222	7,630	560	819	31,673
6/17/2020	(793,045)	(822,827)	29,782	3.62%	0	215	-96	9,465	1,063	1,053	28,611
6/18/2020	(703,075)	(718,377)	15,302	2.13%	0	1,367	-13	9,201	926	1,013	12,935
6/19/2020	(931,083)	(938,637)	7,554	0.80%	0	2,862	-1,824	11,375	569	1,194	5,322
6/20/2020	(651,637)	(654,523)	2,886	0.44%	0	4,473	-980	9,676	487	1,016	(1,623)
6/21/2020	(745,240)	(746,666)	1,426	0.19%	0	2,500	-125	9,461	722	1,018	(1,967)
6/22/2020	(630,796)	(627,265)	-3,531	-0.56%	0	944	-53	9,924	589	1,051	(5,473)
6/23/2020	(615,510)	(613,953)	-1,557	-0.25%	0	766	-520	9,389	449	984	(2,787)
6/24/2020	(953,610)	(951,308)	-2,302	-0.24%	0	1,290	314	10,971	666	1,164	(5,070)
6/25/2020	(1,187,152)	(1,186,632)	-520	-0.04%	0	447	59	10,486	1,173	1,166	(2,192)
6/26/2020	(1,279,881)	(1,287,284)	7,403	0.58%	0	517	16	11,781	1,593	1,337	5,533
6/27/2020	(908,606)	(909,855)	1,249	0.14%	0	1,616	-791	11,812	1,409	1,322	(898)
6/28/2020	(523,508)	(525,267)	1,759	0.33%	0	1,842	399	9,323	515	984	(1,466)
6/29/2020	(828,088)	(832,685)	4,597	0.55%	0	1,240	-1,191	11,326	1,243	1,257	3,291
6/30/2020	(837,648)	(843,891)	6,243	0.74%	0	1,330	-481	12,224	1,836	1,406	3,989
7/1/2020	(1,505,792)	(1,497,037)	-8,755	-0.58%	0	1,126	-318	9,610	898	1,051	(10,614)
7/2/2020	(1,036,655)	(1,029,566)	-7,089	-0.69%	0	1,214	397	10,190	653	1,084	(9,785)
7/3/2020	(738,393)	(731,555)	-6,838	-0.93%	0	1,072	-199	9,475	859	1,033	(8,744)
7/4/2020	(848,236)	(855,198)	6,962	0.81%	0	1,133	40	10,222	953	1,117	4,671
7/5/2020	(863,865)	(864,075)	210	0.02%	0	1,511	1,290	10,108	688	1,080	(3,671)
7/6/2020	(1,278,634)	(1,385,398)	106,764	7.71%	0	759	-751	11,247	1,023	1,227	105,530
7/7/2020	(1,213,993)	(1,250,193)	36,200	2.90%	0	1,611	-3,313	11,041	723	1,176	36,726
7/8/2020	(1,018,803)	(1,027,748)	8,945	0.87%	0	1,781	516	9,844	888	1,073	5,575
7/9/2020	(796,803)	(837,299)	40,496	4.84%	0	1,148	-879	11,113	1,300	1,241	38,986
7/10/2020	(578,065)	(592,142)	14,077	2.38%	0	2,884	-610	10,412	422	1,083	10,720
7/11/2020	(94,366)	(91,262)	-3,104	-3.40%	0	2,729	418	8,874	350	922	(7,173)
7/12/2020	(206,695)	(208,412)	1,717	0.82%	0	1,014	1,083	9,470	399	987	(1,367)
7/13/2020	111,344	116,141	-4,797	-4.13%	0	186	84	7,922	400	832	(5,899)
7/14/2020	(81,108)	(75,792)	-5,316	-7.01%	0	186	-273	8,842	437	928	(6,157)
7/15/2020	(255,886)	(255,127)	-759	-0.30%	0	766	170	8,824	680	950	(2,645)
7/16/2020	(344,636)	(343,061)	-1,575	-0.46%	0	526	-855	9,919	712	1,063	(2,310)
7/17/2020	(256,248)	(251,920)	-4,328	-1.72%	0	1,580	-338	9,549	944	1,049	(6,620)
7/18/2020	(177,230)	(180,719)	3,489	1.93%	0	388	3,999	8,542	928	947	(1,846)
7/19/2020	(175,370)	(177,611)	2,241	1.26%	0	1,148	-325	9,300	1,254	1,055	362
7/20/2020	(510,557)	(510,277)	-280	-0.05%	0	1,149	-412	10,946	392	1,134	(2,151)
7/21/2020	(320,781)	(326,149)	5,368	1.65%	0	1,588	146	10,333	335	1,067	2,567
7/22/2020	(238,046)	(235,021)	-3,025	-1.29%	0	3,010	3,504	9,895	532	1,043	(10,582)
7/23/2020	(160,784)	(156,027)	-4,757	-3.05%	0	791	78	8,671	658	933	(6,559)

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7/24/2020	(284,060)	(285,267)	1,207	0.42%	0	681	762	8,847	1,345	1,019	(1,255)
7/25/2020	(69,082)	(62,566)	-6,516	-10.41%	0	320	274	7,395	635	803	(7,912)
7/26/2020	(156,304)	(149,993)	-6,311	-4.21%	0	776	615	8,498	1,128	963	(8,665)
7/27/2020	(225,777)	(220,079)	-5,698	-2.59%	0	419	-339	9,009	1,230	1,024	(6,802)
7/28/2020	(473,369)	(466,309)	-7,060	-1.51%	0	432	1,837	8,567	485	905	(10,234)
7/29/2020	(661,109)	(653,860)	-7,249	-1.11%	0	691	-1,725	9,335	473	981	(7,197)
7/30/2020	(386,849)	(381,444)	-5,405	-1.42%	0	700	-702	8,027	699	873	(6,275)
7/31/2020	(448,525)	(441,991)	-6,534	-1.48%	0	1,229	-838	8,715	826	954	(7,879)
8/1/2020	(749,292)	(777,795)	28,503	3.66%	0	854	96	10,484	1,133	1,162	26,391
8/2/2020	133,865	104,891	28,974	27.62%	0	1,080	23	7,399	682	808	27,064
8/3/2020	(217,615)	(249,795)	32,180	12.88%	0	491	-65	10,478	372	1,085	30,669
8/4/2020	(137,756)	(180,832)	43,076	23.82%	0	116	-14	10,462	547	1,101	41,874
8/5/2020	(38,984)	(78,131)	39,147	50.10%	0	572	-987	9,457	368	982	38,579
8/6/2020	(142,313)	(175,786)	33,473	19.04%	0	411	-301	9,845	728	1,057	32,306
8/7/2020	121,789	81,677	40,112	49.11%	0	2,417	411	8,278	463	874	36,409
8/8/2020	(225,955)	(240,751)	14,796	6.15%	0	1,671	-155	9,794	838	1,063	12,217
8/9/2020	(258,853)	(276,689)	17,836	6.45%	0	482	-318	10,413	1,421	1,183	16,489
8/10/2020	(247,666)	(253,026)	5,360	2.12%	0	1,928	-1,558	10,119	868	1,099	3,892
8/11/2020	(476,112)	(482,803)	6,691	1.39%	0	530	-902	10,614	701	1,131	5,931
8/12/2020	45,722	31,945	13,777	43.13%	0	440	-51	7,534	461	799	12,588
8/13/2020	(26,440)	(24,873)	-1,567	-6.30%	0	287	-1,385	7,943	359	830	(1,299)
8/14/2020	108,274	83,449	24,825	29.75%	0	381	124	8,022	187	821	23,500
8/15/2020	(128,150)	(137,374)	9,224	6.71%	0	192	-5,842	8,998	170	917	13,957
8/16/2020	(167,113)	(162,687)	-4,426	-2.72%	0	242	-665	9,016	109	912	(4,915)
8/17/2020	(205,565)	(216,840)	11,275	5.20%	0	83	-62	9,781	290	1,007	10,247
8/18/2020	(311,944)	(315,742)	3,798	1.20%	0	773	72	9,841	284	1,013	1,941
8/19/2020	(163,744)	(179,669)	15,925	8.86%	0	164	-239	8,933	280	921	15,079
8/20/2020	(188,058)	(188,945)	887	0.47%	0	765	1,242	8,747	359	911	(2,031)
8/21/2020	(441,036)	(439,510)	-1,526	-0.35%	0	497	-1,340	9,843	334	1,018	(1,701)
8/22/2020	(560,831)	(558,106)	-2,725	-0.49%	0	947	-751	10,387	683	1,107	(4,028)
8/23/2020	(424,364)	(424,341)	-23	-0.01%	0	573	-547	10,565	1,389	1,195	(1,245)
8/24/2020	(992,467)	(1,051,465)	58,998	5.61%	0	2,534	942	11,454	898	1,235	54,286
8/25/2020	(701,450)	(749,077)	47,627	6.36%	0	1,718	-215	10,536	1,093	1,163	44,962
8/26/2020	(524,109)	(537,683)	13,574	2.52%	0	1,851	318	9,544	883	1,043	10,363
8/27/2020	(740,905)	(813,211)	72,306	8.89%	0	1,024	-1,539	10,860	1,960	1,282	71,539
8/28/2020	(196,849)	(185,680)	-11,169	-6.02%	0	593	11	8,384	922	931	(12,703)
8/29/2020	(135,198)	(135,953)	755	0.56%	0	242	-1,031	6,463	483	695	849
8/30/2020	(301,345)	(301,901)	556	0.18%	0	16	-17	5,347	257	560	(3)
8/31/2020	(24,332)	(22,087)	-2,245	-10.16%	0	589	-18	7,434	785	822	(3,638)
9/1/2020	(865,370)	(867,757)	2,387	0.28%	0	170	78	7,712	264	798	1,341
9/2/2020	(293,788)	(285,687)	-8,101	-2.84%	0	361	-98	9,847	1,030	1,088	(9,452)

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
9/3/2020	(95,979)	(96,556)	577	0.60%	0	83	79	6,241	608	685	(269)
9/4/2020	(153,435)	(167,910)	14,475	8.62%	0	323	4	8,027	275	830	13,318
9/5/2020	(341,946)	(390,705)	48,759	12.48%	0	356	19	7,148	137	728	47,656
9/6/2020	(232,935)	(252,620)	19,685	7.79%	0	619	160	4,738	10	475	18,430
9/7/2020	(226,080)	(261,446)	35,366	13.53%	0	348	177	5,046	184	523	34,318
9/8/2020	(247,182)	(309,786)	62,604	20.21%	0	859	-289	5,287	-18	527	61,507
9/9/2020	(421,418)	(470,246)	48,828	10.38%	0	182	-13	7,933	418	835	47,824
9/10/2020	(591,072)	(589,050)	-2,022	-0.34%	0	15	-101	8,930	305	924	(2,860)
9/11/2020	(444,305)	(438,341)	-5,964	-1.36%	0	42	26	8,589	342	893	(6,924)
9/12/2020	(386,258)	(381,448)	-4,810	-1.26%	0	89	-289	8,076	227	830	(5,440)
9/13/2020	(351,909)	(350,294)	-1,615	-0.46%	0	116	398	7,866	507	837	(2,966)
9/14/2020	(238,087)	(252,905)	14,818	5.86%	0	856	-121	7,838	300	814	13,268
9/15/2020	(29,310)	(26,824)	-2,486	-9.27%	0	236	-339	6,434	303	674	(3,056)
9/16/2020	(164,103)	(166,511)	2,408	1.45%	0	308	79	7,143	873	802	1,220
9/17/2020	(134,646)	(126,580)	-8,066	-6.37%	0	388	148	8,916	215	913	(9,515)
9/18/2020	(101,206)	(97,060)	-4,146	-4.27%	0	706	30	8,729	960	969	(5,851)
9/19/2020	(101,008)	(119,342)	18,334	15.36%	0	14	-6	4,019	354	437	17,889
9/20/2020	(126,537)	(152,965)	26,428	17.28%	0	12	-1	3,850	391	424	25,993
9/21/2020	(281,909)	(270,030)	-11,879	-4.40%	0	805	-44	6,513	494	701	(13,341)
9/22/2020	(504,885)	(507,204)	2,319	0.46%	0	579	-643	7,988	872	886	1,497
9/23/2020	(428,110)	(428,658)	548	0.13%	0	1,111	-537	7,614	849	846	(873)
9/24/2020	(516,453)	(515,268)	-1,185	-0.23%	0	1,574	-394	7,721	846	857	(3,221)
9/25/2020	(324,968)	(313,579)	-11,389	-3.63%	0	1,238	-66	6,372	566	694	(13,254)
9/26/2020	(151,046)	(156,681)	5,635	3.60%	0	565	-1	6,163	724	689	4,383
9/27/2020	(91,380)	(118,488)	27,108	22.88%	0	168	-140	4,228	645	487	26,592
9/28/2020	(150,465)	(173,940)	23,475	13.50%	0	1,532	-234	5,108	442	555	21,621
9/29/2020	(357,418)	(352,642)	-4,776	-1.35%	0	629	-31	6,323	228	655	(6,029)
9/30/2020	(348,572)	(350,328)	1,756	0.50%	0	751	-34	5,200	786	599	441
10/1/2020	(834,993)	(850,347)	15,354	1.81%	0	275	-16	6,815	355	717	14,378
10/2/2020	(683,077)	(685,680)	2,603	0.38%	0	375	-120	9,831	356	1,019	1,330
10/3/2020	(283,090)	(296,198)	13,108	4.43%	0	97	-155	8,949	67	902	12,264
10/4/2020	(240,674)	(252,896)	12,222	4.83%	0	711	-405	8,738	286	902	11,014
10/5/2020	(211,673)	(215,459)	3,786	1.76%	0	976	-517	7,303	750	805	2,521
10/6/2020	(255,626)	(262,709)	7,083	2.70%	0	2,347	-290	7,607	474	808	4,218
10/7/2020	(406,448)	(421,883)	15,435	3.66%	0	1,537	-82	8,726	256	898	13,082
10/8/2020	(287,567)	(294,328)	6,761	2.30%	0	417	-247	7,779	461	824	5,767
10/9/2020	(255,502)	(267,867)	12,365	4.62%	0	399	-415	7,117	444	756	11,624
10/10/2020	(183,857)	(183,225)	-632	-0.34%	0	2,769	115	7,541	435	798	(4,313)
10/11/2020	(318,169)	(322,358)	4,189	1.30%	0	871	11	5,559	1,187	675	2,633
10/12/2020	(353,938)	(367,934)	13,996	3.80%	0	972	344	7,972	1,146	912	11,768
10/13/2020	(490,744)	(493,495)	2,751	0.56%	0	9,631	2,228	8,446	637	908	(10,017)

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
10/14/2020	(430,852)	(493,667)	62,815	12.72%	0	555	3	6,501	703	720	61,537
10/15/2020	(510,330)	(541,932)	31,602	5.83%	0	169	2	8,035	769	880	30,551
10/16/2020	(531,768)	(527,844)	-3,924	-0.74%	0	949	-1,426	9,030	667	970	(4,418)
10/17/2020	(308,444)	(363,759)	55,315	15.21%	0	26	-75	7,185	147	733	54,631
10/18/2020	(482,624)	(480,369)	-2,255	-0.47%	0	2,423	-1,497	9,634	100	973	(4,153)
10/19/2020	(709,433)	(712,418)	2,985	0.42%	0	2,648	-899	10,995	454	1,145	90
10/20/2020	(675,392)	(671,629)	-3,763	-0.56%	0	196	-1,656	10,122	596	1,072	(3,375)
10/21/2020	(889,880)	(896,722)	6,842	0.76%	0	415	-659	9,668	1,038	1,071	6,016
10/22/2020	(424,882)	(451,696)	26,814	5.94%	0	1,732	51	8,403	1,733	1,014	24,018
10/23/2020	(458,566)	(493,505)	34,939	7.08%	0	494	78	7,840	1,319	916	33,451
10/24/2020	(912,172)	(910,933)	-1,239	-0.14%	0	889	-3,002	10,256	859	1,111	(237)
10/25/2020	(373,628)	(374,684)	1,056	0.28%	0	49	0	9,533	138	967	40
10/26/2020	(739,931)	(730,458)	-9,473	-1.30%	0	797	-2,779	10,300	897	1,120	(8,611)
10/27/2020	(685,947)	(683,994)	-1,953	-0.29%	0	739	-162	9,115	459	957	(3,488)
10/28/2020	(659,699)	(730,796)	71,097	9.73%	0	34	-16	8,723	780	950	70,129
10/29/2020	(615,624)	(621,170)	5,546	0.89%	0	1,431	-446	9,571	885	1,046	3,515
10/30/2020	(718,459)	(711,129)	-7,330	-1.03%	0	303	-2,044	10,103	868	1,097	(6,686)
10/31/2020	(548,007)	(541,837)	-6,170	-1.14%	0	456	65	8,183	1,064	925	(7,616)
11/1/2020	(664,810)	(666,819)	2,009	0.30%	0	1,789	346	8,006	1,213	922	(1,048)
11/2/2020	(217,545)	(219,084)	1,539	0.70%	0	238	-421	8,054	506	856	866
11/3/2020	(116,228)	(122,030)	5,802	4.75%	0	1,708	11	8,276	1,604	988	3,095
11/4/2020	(251,047)	(274,970)	23,923	8.70%	0	0	0	6,419	-128	629	23,294
11/5/2020	(379,451)	(378,060)	-1,391	-0.37%	0	416	31	7,496	316	781	(2,619)
11/6/2020	(489,273)	(490,581)	1,308	0.27%	0	443	0	7,301	446	775	90
11/7/2020	(477,868)	(477,680)	-188	-0.04%	0	1,336	-132	7,348	246	759	(2,151)
11/8/2020	(496,331)	(497,925)	1,594	0.32%	0	1,111	-130	6,641	263	690	(78)
11/9/2020	(493,502)	(490,711)	-2,791	-0.57%	0	453	210	7,211	452	766	(4,220)
11/10/2020	(587,716)	(585,437)	-2,279	-0.39%	0	1,152	-58	9,541	399	994	(4,367)
11/11/2020	(415,847)	(411,529)	-4,318	-1.05%	0	237	625	9,859	310	1,017	(6,197)
11/12/2020	(413,923)	(408,758)	-5,165	-1.26%	0	1,229	-328	9,523	437	996	(7,061)
11/13/2020	(416,425)	(415,305)	-1,120	-0.27%	0	1,073	-149	8,435	261	870	(2,914)
11/14/2020	(381,262)	(386,357)	5,095	1.32%	0	302	-325	7,301	417	772	4,346
11/15/2020	(402,609)	(400,626)	-1,983	-0.49%	0	587	-45	7,125	420	755	(3,279)
11/16/2020	(425,187)	(422,919)	-2,268	-0.54%	0	1,565	-88	8,584	480	906	(4,651)
11/17/2020	(506,282)	(511,038)	4,756	0.93%	0	2,048	-202	9,372	315	969	1,941
11/18/2020	(357,922)	(357,712)	-210	-0.06%	0	284	-4	7,386	108	749	(1,240)
11/19/2020	(375,729)	(373,567)	-2,162	-0.58%	0	954	-85	8,302	499	880	(3,911)
11/20/2020	(430,612)	(436,220)	5,608	1.29%	0	1,330	-783	9,162	297	946	4,115
11/21/2020	(332,254)	(332,377)	123	0.04%	0	1,022	-574	9,510	20	953	(1,279)
11/22/2020	(343,697)	(341,000)	-2,697	-0.79%	0	74	-15	9,238	245	948	(3,704)
11/23/2020	(334,706)	(333,128)	-1,578	-0.47%	0	103	-114	9,607	112	972	(2,538)

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
11/24/2020	(449,998)	(450,940)	942	0.21%	0	387	-1,336	10,005	666	1,067	824
11/25/2020	(399,137)	(406,147)	7,010	1.73%	0	770	-666	8,542	130	867	6,039
11/26/2020	(107,081)	(146,621)	39,540	26.97%	0	202	-19	6,282	-77	621	38,736
11/27/2020	(131,063)	(169,585)	38,522	22.72%	0	0	0	6,302	-87	621	37,901
11/28/2020	(119,338)	(161,295)	41,957	26.01%	0	31	0	6,316	-21	630	41,297
11/29/2020	(265,663)	(268,941)	3,278	1.22%	0	168	3	6,695	216	691	2,417
11/30/2020	(538,506)	(539,345)	839	0.16%	0	2,654	7,257	9,367	325	969	(10,041)
12/1/2020	(1,073,438)	(1,072,374)	-1,064	-0.10%	0	3,354	-1,588	10,104	262	1,037	(3,866)
12/2/2020	(392,533)	(404,937)	12,404	3.06%	0	860	-1,167	9,723	133	986	11,725
12/3/2020	(314,793)	(327,036)	12,243	3.74%	0	139	-149	8,425	191	862	11,390
12/4/2020	(456,026)	(463,128)	7,102	1.53%	0	451	69	9,832	291	1,012	5,570
12/5/2020	(547,159)	(543,680)	-3,479	-0.64%	0	109	5	11,288	313	1,160	(4,753)
12/6/2020	(369,648)	(367,395)	-2,253	-0.61%	0	157	-39	11,662	590	1,225	(3,597)
12/7/2020	(678,031)	(674,684)	-3,347	-0.50%	0	679	1,833	11,002	313	1,131	(6,990)
12/8/2020	(606,302)	(600,383)	-5,919	-0.99%	0	1,082	-99	9,880	12	989	(7,891)
12/9/2020	(574,375)	(573,746)	-629	-0.11%	0	829	64	9,947	891	1,084	(2,606)
12/10/2020	(490,373)	(520,111)	29,738	5.72%	0	210	6	7,651	745	840	28,682
12/11/2020	(533,341)	(535,625)	2,284	0.43%	0	1,032	-180	9,629	1,441	1,107	324
12/12/2020	(509,202)	(502,139)	-7,063	-1.41%	0	1,358	-140	10,436	317	1,075	(9,356)
12/13/2020	(214,585)	(215,604)	1,019	0.47%	0	343	-277	9,025	304	933	20
12/14/2020	(627,367)	(622,150)	-5,217	-0.84%	0	100	-267	10,449	821	1,127	(6,177)
12/15/2020	(761,803)	(758,800)	-3,003	-0.40%	0	536	-1,766	11,855	397	1,225	(2,998)
12/16/2020	(383,215)	(386,109)	2,894	0.75%	0	833	-270	11,169	178	1,135	1,196
12/17/2020	(503,862)	(506,084)	2,222	0.44%	0	4,091	1,022	11,660	1,147	1,281	(4,172)
12/18/2020	(275,491)	(278,584)	3,093	1.11%	0	3,241	2,026	10,991	1,151	1,214	(3,388)
12/19/2020	(270,570)	(263,662)	-6,908	-2.62%	0	99	211	10,638	160	1,080	(8,298)
12/20/2020	(399,973)	(461,165)	61,192	13.27%	0	44	0	7,871	120	799	60,348
12/21/2020	(312,071)	(341,962)	29,891	8.74%	0	569	-29	9,535	598	1,013	28,337
12/22/2020	(416,488)	(417,201)	713	0.17%	0	178	24	9,653	260	991	(480)
12/23/2020	(427,438)	(444,751)	17,313	3.89%	0	1,929	164	9,397	665	1,006	14,214
12/24/2020	(429,703)	(424,883)	-4,820	-1.13%	0	840	-318	9,893	734	1,063	(6,406)
12/25/2020	(163,388)	(175,889)	12,501	7.11%	0	240	200	9,104	162	927	11,134
12/26/2020	(611,423)	(595,615)	-15,808	-2.65%	0	691	-371	12,546	304	1,285	(17,413)
12/27/2020	(446,947)	(443,259)	-3,688	-0.83%	0	124	0	11,424	123	1,155	(4,967)
12/28/2020	(596,112)	(609,902)	13,790	2.26%	0	466	-63	12,539	182	1,272	12,115
12/29/2020	(456,843)	(449,376)	-7,467	-1.66%	0	833	-30	12,687	929	1,362	(9,632)
12/30/2020	(258,512)	(307,662)	49,150	15.98%	0	882	-7	9,958	389	1,035	47,241
12/31/2020	(284,178)	(294,440)	10,262	3.49%	0	179	1	9,912	185	1,010	9,072
Total	**(215,211,471)**	**(217,925,402)**	**2,713,931**	**0.02**	**2,991**	**339,413**	**(30,423)**	**3,187,309**	**214,288**	**340,160**	**2,061,790**

Excessive Deficient Energy Deployment Charge by NSP Resource

LOCATION	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
Agassiz Beach1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ALTW.MOWERCO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ALTW.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anson_G2	$ -	$ -	$ 1	$ -	$ -	$ 57	$ 60	$ 347	$ -	$ -	$ 2	$ -
Anson_G3	$ -	$ -	$ -	$ 3	$ -	$ 822	$ 1,117	$ 225	$ -	$ 290	$ 282	$ -
Anson_G4	$ -	$ -	$ 289	$ 240	$ 23	$ 877	$ 1,464	$ 81	$ 236	$ 348	$ 1,046	$ -
BayFrnt_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BayFrnt_G5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BayFrnt_G6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BigFalls_ A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_dog_G2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_dog_G5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_dog_G6	$ 2,835	$ 546	$ 1,240	$ 12,145	$ 9,535	$ 20,475	$ 16,836	$ 6,983	$ 1,417	$ 17,433	$ 3,253	$ 3,815
Blk_Dog_G52	$ 848	$ 455	$ 646	$ 385	$ 560	$ 691	$ 789	$ 810	$ 347	$ 1,031	$ -	$ 117
Blue_Lk_G1	$ -	$ -	$ -	$ -	$ -	$ -	$ 2	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G2	$ -	$ -	$ -	$ -	$ -	$ -	$ 8	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G3	$ -	$ -	$ -	$ -	$ -	$ -	$ 10	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ 9	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G7	$ -	$ 15	$ -	$ 51	$ 41	$ 384	$ 204	$ 48	$ 11	$ -	$ -	$ 13
Blue_Lk_G8	$ 5	$ -	$ 18	$ 12	$ 120	$ 1,498	$ 395	$ 137	$ 10	$ -	$ -	$ 20
BuffR_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BuffR_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Canon_Falls1	$ -	$ 332	$ 36	$ 36	$ 9	$ 777	$ 405	$ 235	$ 24	$ 113	$ -	$ 18
Canon_Falls2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 37	$ -	$ 154	$ -	$ -
CC Highbridge1	$ 40	$ 14	$ 7	$ 21	$ -	$ 6	$ 7	$ 11	$ -	$ 40	$ -	$ 673
CC Highbridge2	$ 18	$ 5	$ 41	$ 76	$ 54	$ 8	$ 65	$ 45	$ 34	$ 1,253	$ 31	$ 1,011
CC Mankato	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC Mankato1	$ 2,805	$ 560	$ 809	$ 851	$ 651	$ 570	$ 434	$ 561	$ 437	$ 2,239	$ 1,970	$ 2,605
CC Mankato2	$ 1,601	$ 293	$ 646	$ 504	$ 240	$ 330	$ 434	$ 395	$ 248	$ 979	$ 2,447	$ 1,017
CCRiverside1	$ 420	$ 429	$ 94	$ 20	$ 24	$ 64	$ 687	$ 1,475	$ 191	$ 582	$ 2,361	$ 1,672
CCRiverside2	$ 236	$ 112	$ 147	$ 21	$ 356	$ 126	$ 2,529	$ 2,866	$ 3,779	$ 1,663	$ 4,657	$ 4,020
CedarFalls_A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHPFALTR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHPFALTR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CORNEL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DPC.FLAMBEAU	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Elliot_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Flambe_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

LOCATION	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
French_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Garwin_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GRE.ELKRI1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GRE.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GRE.STANTO1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HBC7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HBC8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hennipin1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Herc_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HiBridge9_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HiBridge9_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HOLCOM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_1	$ -	$ -	$ -	$ -	$ -	$ 1	$ 137	$ -	$ -	$ -	$ -	$ -
InvrHils_2	$ -	$ -	$ -	$ -	$ -	$ -	$ 17	$ -	$ -	$ -	$ -	$ -
InvrHils_3	$ -	$ -	$ -	$ -	$ -	$ 44	$ 17	$ -	$ -	$ 231	$ -	$ -
InvrHils_4	$ -	$ -	$ -	$ -	$ -	$ 12	$ 11	$ 4	$ -	$ 8	$ -	$ -
InvrHils_5	$ -	$ -	$ -	$ -	$ -	$ 6	$ 5	$ 33	$ -	$ 228	$ -	$ -
InvrHils_6	$ -	$ -	$ -	$ -	$ -	$ 23	$ 209	$ 11	$ -	$ 3	$ -	$ -
JIMFL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
King_G1	$ 30	$ -	$ -	$ -	$ -	$ 362	$ 135	$ 141	$ 6	$ -	$ -	$ -
LSPower_1	$ 9,038	$ 8,287	$ 8,439	$ 5,134	$ 971	$ 7,147	$ 5,712	$ 5,854	$ 4,424	$ 6,329	$ 4,025	$ 6,727
Menomone_A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MHEB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Monticello_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MP.LASKIN1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MP.NSP1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP ROCK_CO BAT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.ADAMSWD1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BAT.GEN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BAT.SER	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BIGBLUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.CWN1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.CWN2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.DANIELSN1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.GRANTCO1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.KEYCITYTWO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MANKATECG2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MANKATECG3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MARSHSOLAR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MNDAK1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MNDAK2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

LOCATION	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
NSP.MORAINE2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLE.CWS1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLE.CWS2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLES_TR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLES_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NSTARSOLAR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.ODELL1.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.ODELL2.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PRISL1_LD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PRISL2_LD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PROSE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PROSE_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PROSE_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PVALEY.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.RIVRSD10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.SHAKOBIO1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSPHATFIHAT1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.BRDRS1.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.COURTNY.WF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.FIBROMIN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.FIBROMIN1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.GRANTCO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.MPC.COYT1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTPGRANTCO1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PR_ISLD_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PR_ISLD_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rapidan_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Redwing_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Redwing_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIV9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIVRSD71	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIVRSD72	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIVRSD9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock Ridge_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock_County	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SHERC3	$ 11,192	$ 5,313	$ -	$ -	$ 1,280	$ 4,057	$ 1,104	$ 1,850	$ 2,125	$ 1,909	$ 1,555	$ 582
SHERCO_G1	$ 7,061	$ 7,733	$ 3,794	$ 2,608	$ 957	$ 433	$ 777	$ 481	$ 291	$ 318	$ 781	$ 752
SHERCO_G2	$ 1,982	$ 6,371	$ 8,009	$ 6,873	$ 3,330	$ 791	$ 650	$ 1,754	$ 1,381	$ 300	$ 1,253	$ 1,386
South Ridge_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St Paul Cogen	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St_Croix_7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
StCloud_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
STCRO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SWPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UofMGen1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
W_Triw_TR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Docket No. E002/AA-19-293
True-Up Report
Part B, Attachment 13

LOCATION	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
WAUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
West_Pipestone	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_1	$ -	$ -	$ -	$ -	$ -	$ 2	$ 102	$ 22	$ -	$ 1	$ -	$ 536
Wheaton_2	$ -	$ -	$ -	$ -	$ -	$ 17	$ 28	$ 20	$ -	$ 226	$ -	$ 233
Wheaton_3	$ -	$ -	$ -	$ -	$ -	$ 10	$ 101	$ 19	$ 20	$ -	$ -	$ 719
Wheaton_4	$ -	$ -	$ -	$ -	$ -	$ 25	$ 87	$ 20	$ 53	$ 2	$ -	$ 565
Wheaton_5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Eastridge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Ewington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Ewngton 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Fenton 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Fenton 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Grand Meadow	$ -	$ -	$ -	$ -	$ 3	$ -	$ 2	$ -	$ -	$ 0	$ 2	$ -
WI Jeffers 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi UILK_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Valley View	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Velva	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Yankee 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Yankee 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wilmart_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wilmart_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Windvest_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WISSOTATR3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WISSOTATR4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Woodstk_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Totals	**$ 38,109**	**$ 30,464**	**$ 24,217**	**$ 28,981**	**$ 18,154**	**$ 39,616**	**$ 34,547**	**$ 24,464**	**$ 15,034**	**$ 35,682**	**$ 23,665**	**$ 26,479**

Contigency Reserve Deployment Failure Charges by NSP Resource

LOCATION	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
Agassiz Beach1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ALTW.MOWERCO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ALTW.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anson_G2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anson_G3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anson_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BayFrnt_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BayFrnt_G5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BayFrnt_G6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BigFalls_ A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_dog_G2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_dog_G5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_dog_G6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G52	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BuffR_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BuffR_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Canon_Falls1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Canon_Falls2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC Highbridge1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC Highbridge2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC Mankato	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC Mankato1	$ -	$ -	$ -	$ 2,991	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC Mankato2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCRiverside1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCRiverside2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CedarFalls_A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHPFALTR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHPFALTR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CORNEL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DPC.FLAMBEAU	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Elliot_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Flambe_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Garwin_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

LOCATION	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
GranCty_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GRE.ELKRI1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GRE.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GRE.STANTO1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HBC7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HBC8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hennipin1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Herc_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HiBridge9_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HiBridge9_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HOLCOM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
JIMFL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
King_G1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LSPower_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Menomone_A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MHEB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Monticello_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MP.LASKIN1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MP.NSP1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP ROCK_CO BAT_SER_UNIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.ADAMSWD1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BAT.GEN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BAT.SER	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BIGBLUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.CWN1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.CWN2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.DANIELSN1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.GRANTCO1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.KEYCITYTWO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MANKATECG2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MANKATECG3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MARSHSOLAR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MNDAK1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MNDAK2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MORAINE2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLE.CWS1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLE.CWS2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLES_TR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLES_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

LOCATION	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
NSP.NSTARSOLAR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.ODELL1.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.ODELL2.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PRISL1_LD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PRISL2_LD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PROSE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PROSE_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PROSE_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PVALEY.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.RIVRSD10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.SHAKOBIO1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSPHATFIHAT1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.BRDRS1.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.COURTNY.WF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.FIBROMIN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.FIBROMIN1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.GRANTCO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.MPC.COYT1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTPGRANTCO1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PR_ISLD_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PR_ISLD_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rapidan_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Redwing_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Redwing_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIV9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIVRSD71	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIVRSD72	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIVRSD9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock Ridge_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock_County	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SHERC3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SHERCO_G1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SHERCO_G2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
South Ridge_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St Paul Cogen	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St_Croix_7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
StCloud_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
STCRO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SWPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UofMGen1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
W_Triw_TR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WAUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
West_Pipestone	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Eastridge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

LOCATION	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
WI Ewington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Ewngton 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Fenton 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Fenton 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Grand Meadow	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Jeffers 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi UILK_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Valley View	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Velva	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Yankee 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Yankee 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wilmart_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wilmart_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Windvest_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WISSOTATR3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WISSOTATR4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Woodstk_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Totals	**$ -**	**$ -**	**$ -**	**$ 2,991**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

2020 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 2020 reporting year as compared to the 2020 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 2021 curtailment forecast in our May 1, 2020 Petition and July 31, 2020 Reply Comments in Docket No. E002/AA-20-417. We will provide an estimate of 2022 curtailment payments, including forecast assumptions, in our 2022 fuel forecast Petition to be filed on May 1, 2021.

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) and all but one of of 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 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.

To better manage regional congestion, MISO and the industry utilize Dispatchable Intermittent Resources (DIRs), which provides 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 existing 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
Fenton	200
Glen Ullin Wind	100
MinnDakota	150
Moraine II	50
Mower County	100
Odell	200
Prairie Rose	200
Valley View	10
Zephyr	30
Total	1,284

The federal Production Tax Credit (PTC), which provides tax benefits to wind generating plants, is scheduled to expire over the next few years. As in the past, the uncertainty of PTC expiration is closely 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 6,287 MW of new wind generation in Minnesota, North Dakota, South Dakota, and Iowa that has recently gone into service, or is expected to go into service in 2021. This includes 2,100 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	2019-2020
Great River Energy[2]	309	ND	2020-2023
MidAmerican	2,216	IA	2019-2020
Minnesota Municipal Power Agency	111	MN	2021
Minnesota Power	250	MN	2020
Northern States Power	2,100	ND, SD, MN	2019-2021
Ottertail Power	150	ND	2020
Total	6,287		

The required transmission upgrades for these wind projects were not all be in-service at the time the projects begin producing energy – including the Cardinal - Spring Green - Dubuque area 345 kV Line. A number of transmission facilities that were identified in the interconnection studies as overloaded were, or will be taken out of service and rebuilt.[3] This will have a negative effect on LMP pricing in the MISO energy market that has 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] This does not include the wind repowering projects that NSP is pursueing.
[2] Great River Energy has announced plans to install an additional 800 MW of wind generation in 2022 and 2023.
[3] This is especially true in the area around Big Stone in South Dakota. A significant number of 115 kV and 230 kV lines, mostly owned by Otter Tail Power Company are being taken out of service and rebuilt. Xcel Energy will also be rebuilding an existing 345 kV that connects to the Twin Cities.

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 - LaCrosse, 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, including all but one of the Multi-Value Projects (MVP), have been placed in service. The remaining MVP is expected to be completed in 2023. The MVPs were designed to expand and enhance the region's transmission system, reduce congestion, provide access to affordable energy sources, and meet public policy requirements including renewable energy mandates. The completion of the MVP projects, particularly the ones listed in the following table, 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	Ottertail 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 LaCrosse - 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	Ottertail Power Company, Montana Dakota Utilities	February 5, 2019
Cardinal - Spring Green - Dubuque area 345 kV Line	American Transmission Company, ITC Midwest	End 2023

One of the design goals for the North LaCrosse - North Madison and Cardinal - Spring Green - Dubuque area 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, CURTAILMENT AND CURTAILMENT PROJECTIONS

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
NSP Wind Development
(2003 – 2021)

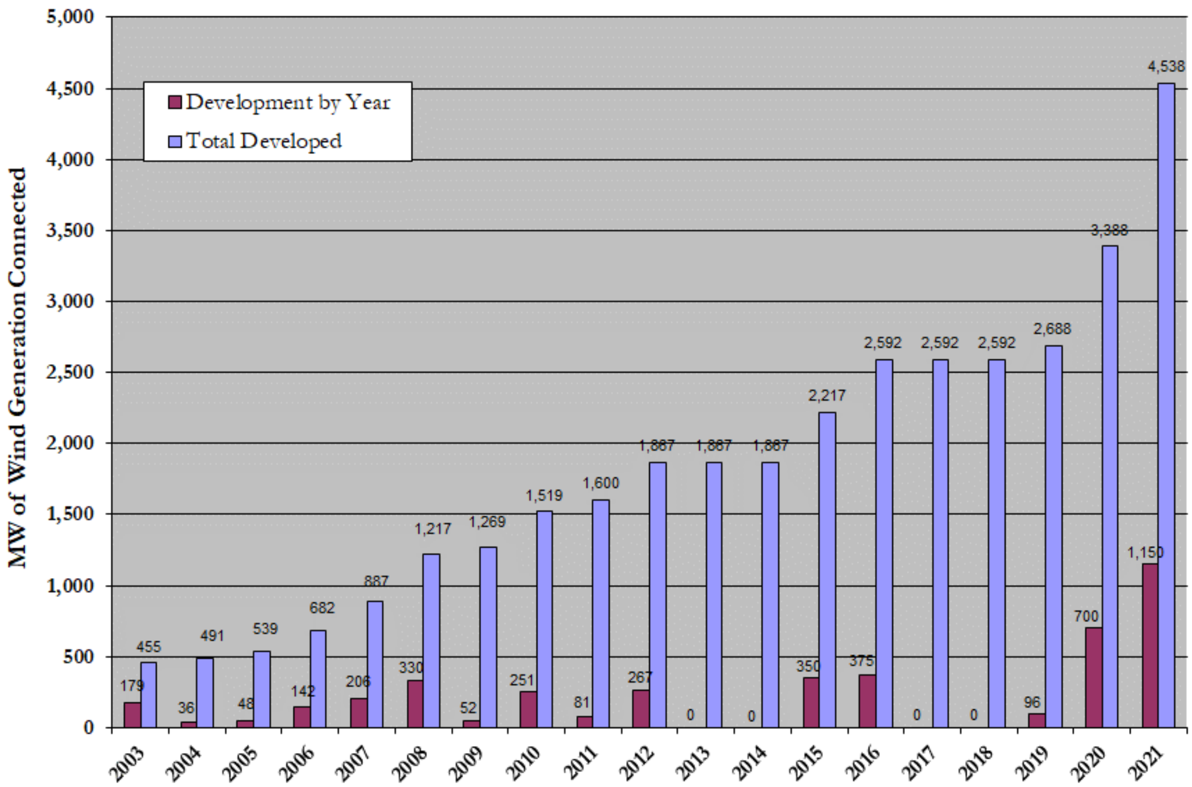
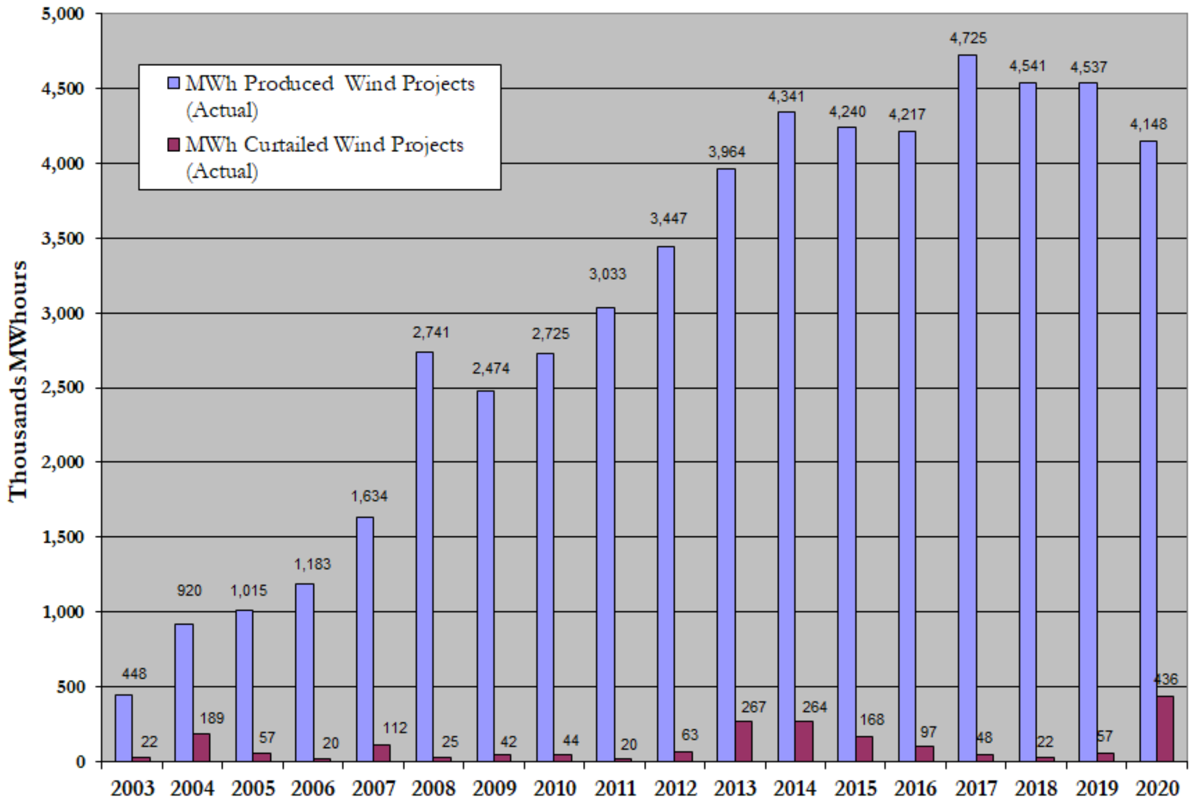


Chart 2 shows the comparison between total wind energy produced and the wind energy curtailed from the projects through December 2020.[4] Despite the lead/lag time associated with generation and transmission development, Chart 2 shows that wind curtailment is small compared to the total wind generation 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
NSP Wind Production & Curtailment (MWh)
(2003 – 2020)



Curtailment during 2020 was broken up into two categories to better explain the reasons for the curtailment and its cause. To support the analysis the Company identified hours during 2020 where local transmission-related outages impacted wind projects. These hours were assigned as Transmission Curtailment. During hours where transmission outages did not occur, or where transmission outages did not impact a specific wind farm, the hours were assigned as DIR Curtailment[5] based on if a project was registered as a DIR. This hourly information was then compared to hourly curtailment data for each of the reporting wind farms and total MWh and curtailment costs were calculated. It should be noted that the hourly data was only assigned one category and did not overlap and Transmission Curtailment was not assigned for regional transmission outages.

[5] The Company stopped performing manual curtailment of non-DIR PPA wind facilities during the 2018/2019 AAA period since analysis of the economic impact of manual curtailment showed minimal customer economic value.

The Transmission Curtailment was very small compared to the DIR Curtailment during 2020. The results of the Transmission and DIR analysis are summarized in Table 6.

Table 6
2020 Wind Curtailment MWh and Costs

Events	MWh	Costs
Transmission Events	6,384	$291,759
DIR Curtailment Events	429,889	$19,321,213
Totals	436,273	$19,612,973

It is important to note that of the $19,612,973 in total curtailment costs, the vast majority of these costs are associated with the contractual energy price of the PPAs. These are contractually obligated sunk costs which are not economically relevant to the decision to curtail the generation from a wind farm.[6]

Transmission Curtailment Events
Wind curtailment costs totaling $291,759 were due to the transmission events described below.

The primary goal when planning construction and maintenance work that will impact wind generation output is to perform multiple outages at the same time, and schedule 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.

It should be noted that only specific wind generation facilities are used to manage the transmission events. For example, a Split Rock – Nobles County 345 kV line outage could be managed by limiting output of Nobles, Chanarambie Power Partners, Fenton, Ridgewind, or Moraine II.

The Company experienced planned and unplanned outages of the Split Rock – Nobles County 345 kV line, Fenton – Nobles County #1 & #2 115 kV lines and Nobles County TR10 Transformer that contributed to curtailment during this period. The facilities were taken out of service as the result of adverse weather conditions, for

[6] The PPA contract language can generally be described as "take or pay" in which NSP must pay for the wind energy that could be produced, regardless of whether it actually is produced or if it is curtailed.

NSP and other utility maintenance activities, and to accommodate upgrades related to interconnecting new generating facilities.

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. It should be noted that not all DIR farms are equipped with setpoint controls. In such situations, a phone call or e-mail is required to initiate a DIR curtailment. Non-DIR units are not equipped with setpoint control.

DIR Curtailment Events

Wind curtailment costs totaling $19,321,213 were due to the MISO-directed DIR control as described below.

DIR related curtailment was due to negative LMP prices associated with congestion throughout the Minnesota and Iowa region due to regional transmission outages, or local congestion due to local transmission outages, as well as the higher levels of wind generation present where all required transmission improvements have not been completed or where sufficient transmission outlets did not exist.

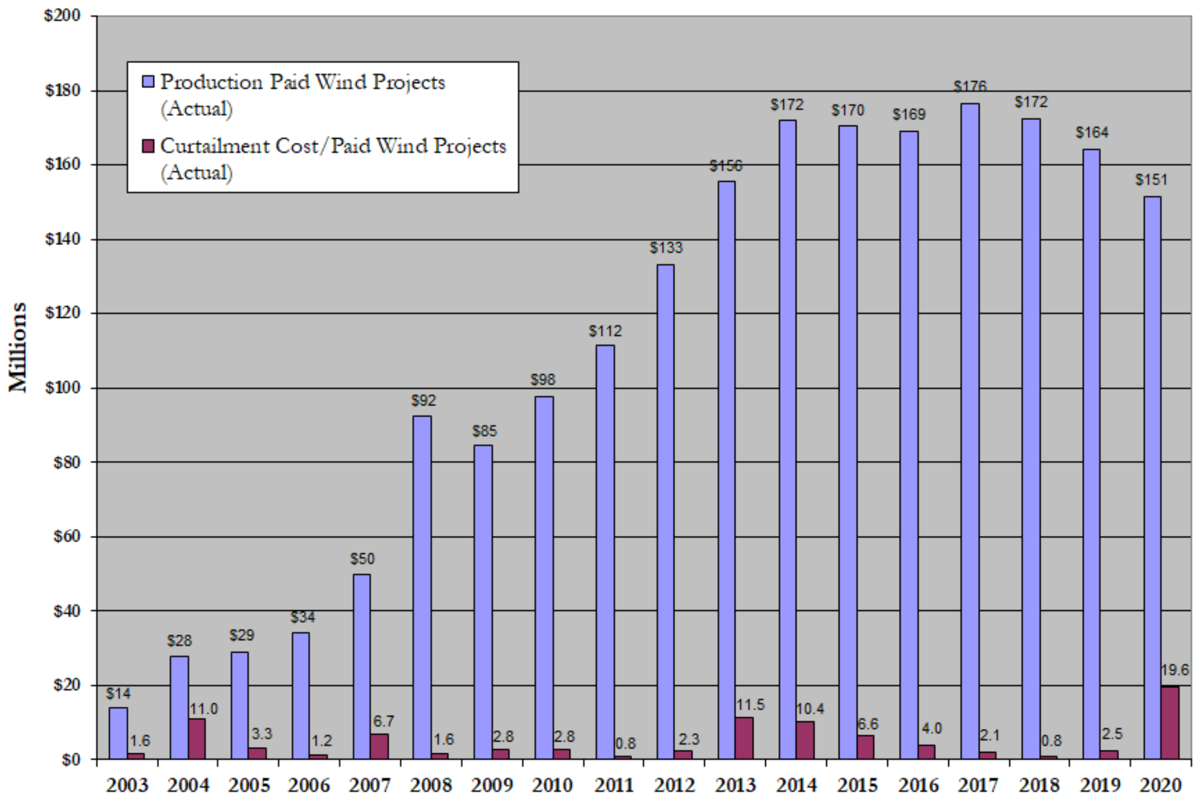
Both PTC and non-PTC DIR wind farms are managed by MISO through automatic control, and these facilities are required to comply with the MISO cost signals. Failure to comply would expose the Company to Revenue Sufficiency Guarantee charges.

V. WIND PRODUCTION AND CURTAILMENT PAYMENTS

Chart 3 shows the corresponding production and curtailment costs for 2003 through 2020.[7] As with wind generation produced and curtailed, paid curtailment is a very small portion of total cost of wind generation on the system.

[7] The data for 2018-2020 is shown in Part C, Attachment 2.

Chart 3
NSP Wind Production & Curtailment Payments
(2003 – 2020)



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 on May 1, 2020. 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) and all but one of the MISO Multi-Value Projects (MVPs)[8] are now in-service and have positively impacted curtailment by reducing local congestion. However, the Company anticipates that wind generation curtailment and associated payment to vendors will continue to occur

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

over the coming years because of regional congestion and the resulting negative LMP in the MISO energy market, along with transmission outages required for construction, maintenance, or repair activities and wind generation projects going into service before all required transmission facilities are completed. 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 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.

PUBLIC DOCUMENT

NOT PUBLIC DATA HAS BEEN EXCISED

Part C, Attachment 2

Wind Curtailment Report

Docket Nos. E002/M-02-51, E002/M-00-622, E002/M-04-404, E002/M-04-864, E,G999/AA-04-1279, E002/M-05-1850, E002/M-05-1934 & E002/M-06-85, E002/M-08-1487 E002/M-09-1366

2020 AAA Period

List of Wind Projects

LAKE BENTON I

LAKE BENTON II

CHANARAMBIE

MORAINE (Formerly Navitas)

NAE (Multiple Sites)

VELVA

FENTON (enXco)

FPL ENERGY MOWER COUNTY

MINNDAKOTA (Formerly Ivanhoe)

LINCOLN HEIGHTS WIND NORTH & SOUTH (Formerly Norgaard N & S)

BUFFALO RIDGE WIND ENERGY (Formerly Wind Power Partners 1993)

JEFFERS WIND 20, LLC

ULIK

EWINGTON

MORAINE II WIND LLC

PRAIRIE ROSE

ZEPHRY WIND

BIG BLUE WIND FARM

VALLEY VIEW WIND

RIDGEWIND POWER PARTNERS LLC

GRANT COUNT WIND LLC

ADAMS WIND GENETATIONS LLC

ODELL

WOODSTOCK HILLS

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Total
2020 AAA Period

Production Month	Date Paid: Delivered MWh	Date Paid: Lost MWh	Wind Production Delivered: MWh Delivered	Wind Production Delivered: Amount Xcel Energy Paid	Lost Production: Lost MWh	Lost Production: Amount Xcel Energy Paid	Total Xcel Energy Paid
Jan-18			517,112.61	19,554,286.92	1,511.09	61,457.59	$ 19,615,744.51
Feb-18			418,166.06	15,810,253.22	233.23	10,491.35	$ 15,820,744.57
Mar-18			456,664.46	17,253,894.46	840.25	35,475.95	$ 17,289,370.41
Apr-18			389,872.84	14,871,852.82	2,458.29	108,258.95	$ 14,980,111.77
May-18			321,602.85	12,231,504.86	805.13	39,345.01	$ 12,270,849.87
Jun-18			376,960.04	14,294,249.66	956.44	37,717.50	$ 14,331,967.16
Jul-18			252,109.41	9,524,606.84	558.38	25,341.15	$ 9,549,947.99
Aug-18			260,557.95	9,854,956.67	564.99	26,170.63	$ 9,881,127.30
Sep-18			372,900.25	14,204,082.85	1,483.22	64,512.97	$ 14,268,595.82
Oct-18			406,941.22	15,440,333.05	392.86	18,908.20	$ 15,459,241.25
Nov-18			391,946.75	14,949,146.73	1,497.05	66,292.63	$ 15,015,439.36
Dec-18			376,229.82	14,485,535.21	10,741.09	338,305.25	$ 14,823,840.46
Total-18			4,541,064.26	$ 172,474,703.29	$ 22,042.03	$ 832,277.18	$ 173,306,980.47
Jan-19			409,935.57	15,794,417.19	2,691.44	138,614.09	$ 15,933,031.28
Feb-19			316,550.82	12,067,583.35	1,755.04	84,703.94	$ 12,152,287.29
Mar-19			411,474.86	15,202,176.47	1,869.04	93,395.08	$ 15,295,571.55
Apr-19			320,446.94	11,945,738.10	15,514.36	714,235.19	$ 12,659,973.29
May-19			419,819.81	14,792,059.29	8,719.31	367,154.52	$ 15,159,213.81
Jun-19			307,889.93	10,765,318.39	2,914.02	116,848.22	$ 10,882,166.61
Jul-19			261,647.61	9,175,408.30	5,882.20	225,357.99	$ 9,400,766.29
Aug-19			238,064.67	8,453,872.37	1,705.60	68,807.54	$ 8,522,679.91
Sep-19			422,465.39	15,040,484.98	1,016.19	47,264.76	$ 15,087,749.74
Oct-19			527,632.25	18,941,335.79	11,579.78	477,171.98	$ 19,418,507.77
Nov-19			484,992.26	17,217,454.47	1,823.17	77,334.60	$ 17,294,789.07
Dec-19			416,115.75	14,719,570.78	1,533.90	70,503.00	$ 14,790,073.78
Total-19			4,537,035.83	$ 164,115,419.48	57,004.05	$ 2,481,390.91	$ 166,596,810.39
Jan-20			399,651.01	14,281,994.44	1,583.27	65,900.77	$ 14,347,895.21
Feb-20			503,731.90	17,936,163.91	5,269.02	229,785.49	$ 18,165,949.40
Mar-20			491,554.55	17,679,218.49	19,126.61	849,968.99	$ 18,529,187.48
Apr-20			426,745.32	15,159,859.92	19,377.19	842,513.17	$ 16,002,373.09
May-20			295,839.59	11,005,702.99	38,161.09	1,789,868.33	$ 12,795,571.32
Jun-20			303,865.09	11,215,457.53	68,698.92	3,054,847.02	$ 14,270,304.55
Jul-20			203,130.29	7,708,535.67	11,701.62	508,971.38	$ 8,217,507.05
Aug-20			267,227.71	10,037,747.80	13,175.80	604,055.79	$ 10,641,803.59
Sep-20			284,608.69	10,541,870.58	55,057.72	2,436,060.69	$ 12,977,931.27
Oct-20			293,763.86	10,900,396.21	73,618.56	3,273,477.66	$ 14,173,873.87
Nov-20			350,138.46	12,659,381.03	87,314.17	3,902,384.06	$ 16,561,765.09
Dec-20			327,718.91	12,277,242.13	43,189.37	2,055,139.30	$ 14,332,381.43
Total-20			4,147,975.37	$ 151,403,570.70	436,273.34	$ 19,612,972.65	$ 171,016,543.35

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 1 (ATC)
2020 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-18							
Feb-18							
Mar-18							
Apr-18							
May-18							
Jun-18							
Jul-18							
Aug-18							
Sep-18							
Oct-18							
Nov-18							
Dec-18							
Total-18							
Jan-19							
Feb-19							
Mar-19							
Apr-19							
May-19							
Jun-19							
Jul-19							
Aug-19							
Sep-19							
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Total-19							
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Feb-20							
Mar-20							
Apr-20							
May-20							
Jun-20							
Jul-20							
Aug-20							
Sep-20							
Oct-20							
Nov-20							
Dec-20							
Total-20							

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 2 (Low Load)
2020 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-18							
Feb-18							
Mar-18							
Apr-18							
May-18							
Jun-18							
Jul-18							
Aug-18							
Sep-18							
Oct-18							
Nov-18							
Dec-18							
Total-18							
Jan-19							
Feb-19							
Mar-19							
Apr-19							
May-19							
Jun-19							
Jul-19							
Aug-19							
Sep-19							
Oct-19							
Nov-19							
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Total-19							
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Feb-20							
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May-20							
Jun-20							
Jul-20							
Aug-20							
Sep-20							
Oct-20							
Nov-20							
Dec-20							
Total-20							

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 3 (MISO)
2020 AAA Period

Production Month	Date Paid: Delivered MWh	Date Paid: Lost MWh	Wind Production Delivered: MWh Delivered	Wind Production Delivered: Amount Xcel Energy Paid	Lost Production: Lost MWh	Lost Production: Amount Xcel Energy Paid	Total Xcel Energy Paid
Jan-18			161,780.11	7,280,301.87	1,511.09	61,457.59	$ 7,341,759.46
Feb-18			113,091.36	5,536,884.67	233.23	10,491.35	$ 5,547,376.02
Mar-18			208,117.65	8,568,537.26	840.25	35,475.95	$ 8,604,013.21
Apr-18			152,131.99	7,033,848.29	2,458.29	108,258.95	$ 7,142,107.24
May-18			128,803.87	5,936,773.66	805.12	39,345.01	$ 5,976,118.67
Jun-18			164,397.54	7,366,182.11	956.44	37,717.50	$ 7,403,899.61
Jul-18			103,125.62	4,460,620.74	558.38	25,341.15	$ 4,485,961.89
Aug-18			112,300.16	5,084,272.85	564.99	26,170.63	$ 5,110,443.48
Sep-18			136,694.24	6,133,579.28	1,483.22	64,512.97	$ 6,198,092.25
Oct-18			55,002.98	2,166,371.84	392.86	18,908.20	$ 2,185,280.04
Nov-18			110,378.69	4,609,900.25	1,497.05	66,292.63	$ 4,676,192.88
Dec-18			157,458.72	6,744,439.49	10,741.09	338,305.25	$ 7,082,744.74
Total-18			1,603,282.93	$ 70,921,712.31	22,042.02	$ 832,277.18	$ 71,753,989.49
Jan-19			34,790.48	1,584,575.48	2,691.44	138,614.09	$ 1,723,189.57
Feb-19			46,095.81	1,975,647.30	1,755.04	84,703.94	$ 2,060,351.24
Mar-19			133,223.00	5,104,484.91	1,869.04	93,395.08	$ 5,197,879.99
Apr-19			132,374.40	5,618,629.76	15,514.36	714,235.19	$ 6,332,864.95
May-19			143,861.13	6,224,849.74	8,719.31	367,154.52	$ 6,592,004.26
Jun-19			103,936.66	4,463,954.31	2,914.02	116,848.22	$ 4,580,802.53
Jul-19			64,936.43	2,490,433.42	5,882.20	225,357.99	$ 2,715,791.41
Aug-19			65,097.85	2,490,144.14	1,705.60	68,807.54	$ 2,543,812.57
Sep-19			152,102.41	6,518,938.81	1,016.19	47,264.76	$ 6,566,203.57
Oct-19			192,968.52	8,558,704.45	11,579.78	477,171.98	$ 9,035,876.43
Nov-19			85,834.03	3,248,563.99	1,823.17	77,334.60	$ 3,325,898.59
Dec-19			143,811.28	6,362,151.94	1,533.90	70,503.00	$ 6,432,654.94
Total-19			1,299,031.99	$ 54,641,078.25	57,004.06	$ 2,481,390.91	$ 57,107,330.05
Jan-20			152,447.62	6,394,615.97	1,583.27	65,900.77	$ 6,460,516.74
Feb-20			199,042.07	8,284,249.02	5,269.02	229,785.49	$ 8,514,034.51
Mar-20			190,537.12	7,939,476.63	19,126.61	849,968.99	$ 8,789,445.62
Apr-20			158,348.00	6,624,111.36	19,377.19	842,513.17	$ 7,466,624.53
May-20			145,484.94	6,215,334.19	38,161.09	1,789,868.33	$ 8,005,202.52
Jun-20			226,908.24	8,515,332.08	68,698.92	3,054,847.02	$ 11,570,179.10
Jul-20			116,826.05	4,996,335.18	11,701.62	508,971.38	$ 5,505,306.56
Aug-20			168,459.46	6,230,107.58	13,175.80	604,055.79	$ 6,834,163.37
Sep-20			210,090.70	7,707,155.08	55,057.72	2,436,060.69	$ 10,143,215.77
Oct-20			211,822.27	7,810,296.30	73,618.56	3,273,477.66	$ 11,083,773.96
Nov-20			290,736.26	10,515,693.78	87,314.17	3,902,384.06	$ 14,418,077.84
Dec-20			268,369.30	9,992,099.21	43,189.37	2,055,139.30	$ 12,047,238.51
Total-20			2,339,072.03	$ 91,224,806.38	436,273.34	$ 19,612,972.65	$ 110,837,779.03

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Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 4 (Other-Paid)
2020 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-18							
Feb-18							
Mar-18							
Apr-18							
May-18							
Jun-18							
Jul-18							
Aug-18							
Sep-18							
Oct-18							
Nov-18							
Dec-18							
Total-17							
Jan-19							
Feb-19							
Mar-19							
Apr-19							
May-19							
Jun-19							
Jul-19							
Aug-19							
Sep-19							
Oct-19							
Nov-19							
Dec-19							
Total-19							
Jan-20							
Feb-20							
Mar-20							
Apr-20							
May-20							
Jun-20							
Jul-20							
Aug-20							
Sep-20							
Oct-20							
Nov-20							
Dec-20							
Total-20							

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Lake Benton I
2020 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 Paid
Jan-18								
Feb-18								
Mar-18								
Apr-18								
May-18								
Jun-18								
Jul-18								
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PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Lake Benton II
2020 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 Paid
Jan-18								
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PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Chanarambie
2020 AAA Period

[PROTECTED DATA BEGINS

	Date Paid		Wind Production Delivered		Lost Production			Total
Production Month	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	Reason Codes	Total Paid
Jan-18								
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PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Moraine (Formerly Navitas)
2020 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 Paid
Jan-18								
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PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Northern Alternative Energy (NAE)
2020 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 Paid
Jan-18								
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PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Northern Alternative Energy (NAE)
2020 AAA Period

[PROTECTED DATA BEGINS

	Lost MWh	Curtailment Payment	Reason Codes
Autumn Hills, LLC			
Florence Hills, LLC			
Hadley Ridge, LLC			
Hope Creek, LLC			
Jack River, LLC			
Jessica Mills, LLC			
Julia Hills, LLC			
Ruthon Ridge, LLC			
Soliloquoy, LLC			
Spartan Hills, LLC			
Sun River, LLC			
Tsar Nicolas, LLC			
Twin Lake Hills, LLC			
Winter's Spawn, LLC			
Total			

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Velva
2020 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-18								
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PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Fenton (EnXco)
2020 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-18								
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PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - FPL Energy Mower County
2020 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-18								
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PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - MinnDakota (Formerly Ivanhoe)
2020 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-18								
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PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Lincoln Heights Wind Holding North*
2020 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-18								
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Total-20								

**Effective 7/1/16 Norgaard North changed name to Lincoln Heights Wind Holdings North LLC.*

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Lincoln Heights Wind Holding South*
2020 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-18								
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Jul-18								
Aug-18								
Sep-18								
Oct-18								
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Total-20								

**Effective 7/1/16 Norgaard North changed name to Lincoln Heights Wind Holdings South LLC.*

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Buffalo Ridge Wind Energy*
2020 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-18								
Feb-18								
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Apr-18								
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**Effective 9/1/15 Wind Power Partners 1993 changed name to Buffalo Ridge Wind Energy. Reporting of Wind Power Partners 1993 contract initiated on 12/2009.*

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - WITH TRADE SECRET DATA EXCISED

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - JJN Windfarm, LLC.
2020 AAA Period

[TRADE SECRET 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-08								
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PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Jeffers Wind 20, LLC
2020 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-18								
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PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Ulik
2020 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-18								
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PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Ewington
2020 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-18								
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PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Moraine II Wind LLC
2020 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-18								
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PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Prairie Rose
2020 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-18								
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PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Zephyr Wind, LLC
2020 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-18								
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PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Big Blue Wind Farm
2020 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-18								
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PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Valley View Wind
2020 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-18								
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PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Ridgewind Power Partners LLC
2020 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-18								
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PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Grant County Wind LLC
2020 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-18								
Feb-18								
Mar-18								
Apr-18								
May-18								
Jun-18								
Jul-18								
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Sep-18								
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PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Adams Wind Generations
2020 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-18								
Feb-18								
Mar-18								
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Sep-18								
Oct-18								
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PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Odell
2020 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-18								
Feb-18								
Mar-18								
Apr-18								
May-18								
Jun-18								
Jul-18								
Aug-18								
Sep-18								
Oct-18								
Nov-18								
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PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Woodstock Hills
2020 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-18								
Feb-18								
Mar-18								
Apr-18								
May-18								
Jun-18								
Jul-18								
Aug-18								
Sep-18								
Oct-18								
Nov-18								
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Nov-20								
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Total-20								

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Cisco
2020 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-18								
Feb-18								
Mar-18								
Apr-18								
May-18								
Jun-18								
Jul-18								
Aug-18								
Sep-18								
Oct-18								
Nov-18								
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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 2020 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 alliance-like agreements with companies that consistently exceed others in technology, quality and contract management (including following the Scope of Work). As Xcel Energy increases the percentage of

[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.

spend with these select companies, the possibility of contractor service or supplier product failure decreases.

Third, Xcel Energy has invested time and resources in developing a better Scope of Work. Successful adherence to the Scope of Work by a contractor or vendor is measured by completion of the total work scope defined in the bid Technical Specification that is part of the Purchase Order and/or contract. By writing Scopes of Work with greater level of detail and expectations, Xcel Energy gets better project scheduling, reducing 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, including the formation of the Performance Optimization department and the application of Continuous Improvement practices that include Lean Management, Event Assessments and Root Cause Analysis, Work Management Processes, and Operating Model governance. We provide greater detail on each of these initiatives below.

Generation Operating Model

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 broken down into Reliability Engineering, Fleet Engineering, and Analytics & Practices. A brief explanation of each Performance Opimization 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.

Lean Management is a continuous improvement tools to eliminate waste and inefficiency. The people-based system produces improved processes, inventory management, teamwork, and customer relationships.

The standardized Event Assessments (EAs) and Root Cause Analysis (RCAs) practices have the objective of identifying the causes of events, not only to correct, but to share and prevent recurrence in the fleet. EAs and RCAs are performed for forced outages, major process breakdowns, equipment failures, and environmental permit exceedances.

Work Management processes continue to be improved. The System Analysis Program (SAP) software implemented in 2016 has allowed efficiencies and standardization in the Energy Supply work management processes. Along with SAP software, wireless tablets have been provided to field workers and permit electronic access, transfer, management, and completion of work order assignments.

Lastly, the Operating Model Governance role is to monitor, document, and provide resolutions for issues that arise while using the Operating Model Governance to continuously improve perfromance. Leadership is committed to ensure all aspects of continuous improvement are successful.

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.

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Unit Outage Information
2020 AAA Reporting Period: January 1 - December 31, 2020

[PROTECTED DATA BEGINS

Unit	Outage Category	Primary Reason for outage	Outage Dates Start	End	Duration (Days)	Q1. Equipment that resulted in the forced outage	Q2. Description of Equipment Failure	Q3. Change in Energy Costs	Q4. Failure History During Reporting Period	Q5. Steps Taken to Alleviate Reoccurrence
JANUARY 2020										
NONE										
FEBRUARY 2020										
SHERCO_G1	Forced	PA Fan operation after start-up	02/21/2020	02/22/2020	**1**	11 PA Fan would not start - electricians investigating	Fan motor received a lockout due to a degraded connection on a single phase on the motor side of an Elastimold connector.		No similar failures were reported during this reporting period.	Elastimold connector was replaced.
SHERC3	Forced	7 COAL MILL OPERATION	02/12/2020	02/13/2020	**1**	coal feeder motor being replaced.	Electrical clutch on the feeder motor was not engaging.		No similar failures were reported during this reporting period.	Feeder motor was replaced.
MARCH 2020										
PR_ISLD_1	Forced	Miscellaneous (Balance of Plant)	03/05/2020	03/07/2020	**2**	LEFM (Leading Edge Flow Meter) 0 and Flex Power ops	Transducer failure		none	Transducer replaced
PR_ISLD_1	Forced	Miscellaneous (Balance of Plant)	03/10/2020	03/13/2020	**2**	LEFM (Leading Edge Flow Meter) 0 and Flex Power ops	APU Failure		none	APU replaced
APRIL 2020										
CC Highbridge1	Forced	Having stability issues at high loads and warm weather.	04/17/2020	04/23/2020	**7**	Refurbished fuel nozzles installed during Major overhaul by Mitsubishi	Fuel nozzles resulted in high dynamics and NOx emissions at high loads. Mitsubishi retuned combustor and activated a 20 degree exhaust temperature bias resulting in derate.		First occurrence of this event following Major overhaul.	Fuel Gas Temperature was raised to 400 F for Summer which alleviated the derate. Working with Mitsubishi on replacement fuel nozzles as the issue will resurface with the return of cold weather in Fall 2020
MAY 2020										
SHERC3	Forced	Dry Scrubbers\Performance	05/26/2020	05/28/2020	**3**	CEMS (Continuous Emissions Monitoring System)	Increasing SO2 emissions required the unit to derate until the cause could be discovered and corrected. There is a lag time on knowing actual SO2 emissions as our official reporting method is from coal samples which are sent off stie to be analyzed. Our in line SO2 detector which is used for control cannot be certified due to duct configuration.		No similar failures were reported during this reporting period.	Issue with the SO2 inlet analyzer was discovered which wasn't allowing the correct amount of flow through the analyzer. This was corrected by our technician. We are exploring the possiblilty of relocation of the inlet analyzer so it could be certified.
JUNE 2020										
SHERCO_G1	Forced	Scrubber Module operation	06/01/2020	06/02/2020	**2**	Derated due to 9 Scrubber Module operation	102 scrubber module out for major clean, we experienced a low flow condition on 103 module spray pump and a soft start module failure on 108 module spray pump which causesed the derate.		Similar failures occurred on 7/16/20 and 7/21/20 of this reporting period.	103 module was opened up and the reaction tank cleaned up to the suction strainer due to plugging. 108 module spray pump soft start module was replaced.
SHERC3	Forced	Feedwater heater tube leak	06/01/2020	06/02/2020	**1**	Feedwater heater tube leak on HP Heater 37-1. Heater string removed from service.	This feedwater heater had just been replaced during the spring overhaul as part of a capital project replacement. Following placinng in service, a pin hole leak developed on the nitrogen blanket port which is a plug that is threaded in place and seal welded at the factory.		No similar failures were reported during this reporting period.	Plug was re-seal welded.
SHERC3	Forced	high amp and fan stall alarms	06/08/2020	06/10/2020	**2**	Derated due to high amp and fan stall alarms for 31 & 32 FD Fans.	Plugged secondary air preheat air coils caused high amps and fan stall alarms on the forced draft fans resulting in a unit derate.		Similar failure occurred on 7/6/20 of this reporting period.	Ash buildup in the coiils was able to be pressure washed clean.
SHERC3	Forced	Tube leak	06/10/2020	06/12/2020	**3**	Tube leak on HP Feedwater Heater 36-1 requires feedwater string to be isolated.	Tube (54-4) was found to be leaking, tube (2-1) had a failed plug from a previous repair, and some minor tube plug weld leaks in the outlet on the right hand corner of the heater.		Similar failure occurred on 12/15/20 of this reporting period.	Leaking tubes and their surrounding tubes were plugged with welded plugs. Heater was air tested. This heater is original equipment. Both 36-1 and 36-2 heaters are scheduled to be replaced in 2023. The 37 heaters were just replaced during the 2020 overhaul.
SHERCO_G1	Forced	DA steam leak repair	06/25/2020	06/30/2020	**6**	Deareator	There was a single leak point in the weld between one of the downcomers and the DA shell. This was a partial penetration weld that had a defect in it that went almost to the inside surface of the DA. Some erosion took place and resulted in removal of weld material such that it connected to the defect resulting in a through wall leak		No similar failures were reported during this reporting period. Event continuation on 7/1/20.	Area was excavated and rewelded. The excavated area was approximately 3" long and ½" deep. Grinding was started with another check for cracking. Air pressure was applied to the weep hole where the steam was initially coming out of, the inside surface was inspected with snoop and only the one spot had any air leakage. Further excavation was performed and the flaw in the weld remained localized to the area. Once fully excavated, it was seen that the weld contained a defect and no cracking was observed.
JULY 2020										
SHERCO_G1	Forced	3 scubber modules unavailable requiring immediate derate.	07/14/2020	07/16/2020	**2**	Scrubber Modules	112 scrubber module out for major clean, failed inlet damper linkage on 111 module requiring off line repair, 105 module bleed pump flush valve..		No similar failures were reported during this reporting period.	111 module inlet damper linkage repaired during the Septermber 5th maintenance outage. 105 module bleed pump flush valve was replaced.
SHERCO_G1	Forced	Air emmision control/ opacity reduction, 8 scrubber modules in service.	07/16/2020	07/21/2020	**6**		112 scrubber module out for major clean, failed inlet damper linkage on 111 module requiring off line repair, 102 module spray pump soft start. Needed to take modules out for flushing and cleaning to maintiain in service srrubbers operational.		Similar failures occurred on 6/1/20 and 7/21/20 of this reporting period.	111 module inlet damper linkage repaired during the Septermber 5th maintenance outage. 102 module spray pump soft start module was replaced.
SHERCO_G1	Forced	Air emission control - 3 Scrubber modules out of service - 102 (soft start), 111 (inlet damper), and 112 (major)	07/21/2020	07/24/2020	**2**		112 scrubber module out for major clean, failed inlet damper linkage on 111 module requiring off line repair, 102 spray pump module soft start.		Similar failures occurred on 6/1/20 and 7/16/20 of this reporting period.	111 module inlet damper linkage repaired during the Septermber 5th maintenance outage. 102 module spray pump soft start module was replaced.
SHERCO_G1	Forced	Derate needed because of failure of thickener drive rake mech.	07/24/2020	07/31/2020	**8**	Unit 1 Thickener Gear Box	Gearbox on Unit 1 Thickener failed. One of two thickeners is available for service to serve the needs of both Units 1 and 2 scrubber modules. Derate of both units required to permit time to prep and fill the redundant, Unit 2 thickener.		Failure is common to both SHERCO G1 and SHERCO G2, no other similar failures were reported during this reporting period.	Unit 2 Thickener placed in service. Gearboxes are nearing end of life. Capital replacement is being persued for the Unit 1 thickener gear box.
SHERCO_G2	Forced	CMILL internal fire. Suspect failed Classifier. Only 5 CMILLs in service.	07/01/2020	07/14/2020	**14**	27 Coal Mill	Internal mill fire caused damage to the rotating classifier vanes.		No similar failures were reported during this reporting period.	All rotating classifier vanes were replaced.

Unit Outage Information
2020 AAA Reporting Period: January 1 - December 31, 2020

[PROTECTED DATA BEGINS

Unit	Outage Category	Primary Reason for outage	Outage Dates Start	End	Duration (Days)	Q1. Equipment that resulted in the forced outage	Q2. Description of Equipment Failure	Q3. Change in Energy Costs	Q4. Failure History During Reporting Period	Q5. Steps Taken to Alleviate Reoccurrence
SHERCO_G2	Forced	26 Coal Mill roll issue, removed from service. Down to 4 coal mills in service.	07/06/2020	07/09/2020	**3**	26 Coal Mill	Bearing failure on one mill roll assembly.		No similar failures were reported during this reporting period.	Replaced roll with assembly from 27 Mill which was OOS due to fire. Damaged Roll assembly was sent to Riley Power for rebuild. 26 Mill is next for Level II Capital Overhaul.
SHERCO_G2	Forced	Derate needed because of failure of thickener drive rake mech.	07/24/2020	07/31/2020	**8**	Unit 1 Thickener Gear Box	Gearbox on Unit 1 Thickener failed. One of two thickeners is available for service to serve the needs of both Units 1 and 2 scrubber modules. Derate of both units required to permit time to prep and fill the redundant, Unit 2 thickener.		Failure is common to both SHERCO G1 and SHERCO G2, no other similar failures were reported during this reporting period.	Unit 2 Thickener placed in service. Gearboxes are nearing end of life. Capital replacement is being persued for the Unit 1 thickener gear box.
SHERC3	Forced	Available 860 MWN due to Fan Stall Alarms coming in.	07/06/2020	07/31/2020	**25**	Derated due to high amp and fan stall alarms for 31 & 32 FD Fans.	Plugged secondary air preheat air coils caused high amps and fan stall alarms on the forced draft fans resulting in a unit derate.		Similar failure occurred on 6/8/20 of this reporting period.	Ash buildup in the coiils was able to be pressure washed clean.
SHERC3	Forced	Abnormal noise in 310 coal mill. Following burning out coal silo, remove from service resulting in 7 coal mill operation.	07/09/2020	07/15/2020	**6**	310 coal mill	Rotating throat assembly failure.		No similar failures were reported during this reporting period.	As mills experience failures and during mill overhauls, we will be going back to a bolted lower support bracket design as opposed to a pinned attachement. This will restrict movement of the rotating throats.
Monticello_1	Forced	Derate to maintain discharge canal temperature within limit.	07/05/2020	07/07/2020	**2**	None	None - this was an Environmental derate to maintain plant discharge temperatures to the river		Not an equipment failure - derates are completed in the summer to maintain the plant within environmental limits	A project is in implementation phase to rebuild the Cooling towers in order to mitigate these summer derates. The first will be complete prior to summer 2021 and the second prior to summer 2022. Derates are timed typically at night when demand is low to minimize the impact to the grid
King_G1	Forced	Wet Coal. Heavy rains resulted in wet coal pile.	07/26/2020	07/31/2020	**5**	Stockfeeders/coal silos	Unable to keep coal feeding from coal silos to stockfeeders and unable to keep stockfeeders from plugging up		No similar failures were reported during this reprting period. Heavy rains.	Work with yard on maintaining coal live pile levels higher when the chance of major precipitation is expected. Work with fuel supply to turn over storage piles so that reclaim coal doesn't become as saturated from sitting on the group for extended periods of time.
SHERCO1_ G1	Forced	Unit required offline for DA steam leak repair	07/01/2020	07/03/2020	**2**	Deareator	Continuation of 6/25/2020 event. There was a single leak point in the weld between one of the downcomers and the DA shell. This was a partial penetration weld that had a defect in it that went almost to the inside surface of the DA. Some erosion took place and resulted in removal of weld material such that it connected to the defect resulting in a through wall leak		No similar failures were reported during this reporting period. This is a continuation of the event on 6/25/20.	Continuation of 6/25/2020 event. Area was excavated and rewelded. The excavated area was approximately 3" long and ½" deep. Grinding was started with another check for cracking. Air pressure was applied to the weep hole where the steam was initially coming out of, the inside surface was inspected with snoop and only the one spot had any air leakage. Further excavation was performed and the flaw in the weld remained localized to the area. Once fully excavated, it was seen that the weld contained a defect and no cracking was observed.
AUGUST 2020										
SHERCO_G1	Forced	Wet Scrubbers	08/03/2020	08/31/2020	**28**	Scrubber Modules	With two other modules out of service for major cleaning to maintain our 8 month cleaning schedule, 111 module inlet damper failed resulting in the derate. The inlet dampers are hung from the upper bearing and the upper shaft is welded on top of the damper just below the duct ceiling. That weld failed causing the damper to drop down onto the floor. Unit needed to be off line to repair, this was done during a 9/15/20 maintenance outage.		No similar failures were reported during this reporting period.	The inlet damper was jacked back up into place and rewelded back to the shaft. To strengthen the weld, a small window was cut out in the damper itself and a seal weld was completed on the inside as well.
SHERCO_G2	Forced	Coal Mill Feeder tripped	08/03/2020	08/05/2020	**2**	26 Coal Mill Feeder	Failed motor on the feeder while redundant mill was out for overhaul.		Similar Failure on 12/5/20 of this reporting period.	Replaced Feeder Motor.
SHERCO_G2	Forced	Load reduction to maintain environmental margins for SO2 removal on Common Stack	08/29/2020	08/31/2020	**3**	Scrubber Modules	Units required to take periodic derates due to high daily common stack SO2 averages which reduced margin to the compliant 30 day rolling average of 0.05 lbs/MMBtu		Multiple similar failures during this reporting period.	A team was formed including plant management, engineering, environmental services, and the services of a retired former plant engineer with extensive experience on the scrubber modules. Causes for higher SO2: 1)Unusually high U1&2 loads compared to past operation. (Largest contributor) 2)Low calcium to sulfur ratios in some of U1&2's recent coal trains. (Large contributor) 3)Lower than normal reaction tank levels, and scrubber imbalances in U1&2's wet scrubber modules. (Contributing factor) 4)Lower than normal slurry spray flows in U1&2's wet scrubber modules. (Contributing factor) Corrective Actions: 1)Increase tank levels to higher than we have typically run 2)Balanced modules on multiple occasions 3)During Unit 1 outage in early September a.Cleaned 101 module strainer, suspected plugging as the cause for lower spray flows b.Replaced 103 module plugged PC spray nozzles, that is the suspected cause for lower spray flows c.Replaced plugged makeup nozzles on 106 module, module was having trouble keeping up tank level d.12 drain pump discharge line was cleaned, weren't getting valid slurry samples for the modules e.Rodded out all U1 Module Level probes to verify accurate level readings 4)Starting cleaning 2 modules on Unit 1 to get caught up on the cleaning schedule 5)Notifications written for Unit 2 Scrubber Makeup headers that appear to be restricted

Unit Outage Information
2020 AAA Reporting Period: January 1 - December 31, 2020

Unit	Outage Category	Primary Reason for outage	Outage Dates Start	End	Duration (Days)	Q1. Equipment that resulted in the forced outage	Q2. Description of Equipment Failure	[PROTECTED DATA BEGINS Q3. Change in Energy Costs	Q4. Failure History During Reporting Period	Q5. Steps Taken to Alleviate Reoccurrence
SHERC3	Forced	Available 860 MWN due to Fan Stall Alarms coming in.	08/01/2020	08/10/2020	9	Derated due to high amp and fan stall alarms for 31 & 32 FD Fans.	Continuation of 7/6/20 event. Plugged secondary air preheat air coils caused high amps and fan stall alarms on the forced draft fans resulting in a unit derate.		Similar failure occurred on 6/8/20 of this reporting period. This is a continuation of 7/6/20 event.	Continuation of 7/6/20 event. Ash buildup in the coiils was able to be pressure washed clean.
SHERC3	Forced	Derate to 680 MWN due to only 4 available SDA"s.	08/10/2020	08/11/2020	1	36 Additive Feed Pump	While operating with 32 and 37 SDAs out of service due to issues with their associated additive feed pumps and 38 SDA out of service due to CSC CV 3016 being stuck at 75% open, 36 Additive feed pump was discovered to have a belt failure and the lines from the pump to SDA were plugging up		No similar failures were reported during this reporting period.	The supply lines for the various additive feed pump supplies to their respective SDA's were cleaned and the belt replaced on 36 pump. Overhauls will include cleaning of these lines while the unit is off line.
PR_ISLD_1	Forced	Unit tripped, power range flux rate instrumentation	08/26/2020	08/30/2020	4	Power range Neutron Monitor	While testing the redundant channel, a spurious trip occurred on this equipment. A plant trip occurs when both channel trip together.		No other failures	repaired equipment, initiated study to determine opportunities to bypass the trip function during testing thereby maintaining a single failure proof set up
CCRiverside1	Forced	Unit 9 in outage due to water intake restrictions	08/11/2020	08/14/2020	3		Riverside Unit 9 was unavailable due to work downstream of the plant intake. The river level required to perform the downstream work was lower than what is needed to run both circulating water pumps. Without both circulating water pumps in service, condenser vacuum can not be maintained with higher summer river temperatures when operating in 2X1 mode. Therefore, Riverside was only available for 1x1 operation during this work.		No similar failures during this reporting period.	This event is considered to be "Outside of Management Control". There are currently no actions to be taken by the Riverside Plant to alleviate this event from reoccurrence.
SHERC3	Forced	Boiler Tube Leaks	08/11/2020	08/21/2020	9	Boiler Economizer	Sootblower erosion caused a tube failure on a horiztonal reheat tube. The steam from the failure caused collateral damage to an adjacent economizer support tube that also ruptured.		No similar failures were reported during this reporting period.	Limitoque was sent off site for repairs.
SHERC3	Forced	Boiler Tube Leaks	08/22/2020	08/29/2020	7	Boiler Final Superheat	Initiating tube failure was short term overheating due to oxide exfoliation pluggage. It is hypothesized that the source of this oxide is from the outlet headers downstream of the finishing superheat assemblies. This indicates the oxide traveled backwards from the headers into the pendants. It is theorized this could happen during boiler air tests, during shutdowns when the steam inside the pendants and header are condensing, or during boiler drains when vents and drains are manipulated.		No similar failures were reported during this reporting period.	Two window welds were done on this tube section to complete the repair.
SEPTEMBER 2020										
SHERCO_G2	Forced	Derate for Exciter Cooler East Hot Sensor Issue	09/09/2020	09/10/2020	1	Exciter Cooler temperature RTD	Exciter East Hot air temperture RTD failed. After testing to verify this, the unit was released for normal dispatch.		No similar failures were reported during this reporting period.	RTD was replaced during the next off line opportunity.
SHERCO_G1	Forced	Derated due to 12 LP Heater Extraction Block Valve not opening	09/15/2020	09/30/2020	15	12 Feedwater Heater Extraction Block Valve	Following startup of the unit, it was discovered that 12 FW heater extraction block valve, LE WV 1001, would not open electrically or manually. Unit had to be derated to 610 MWn based on GE recommendations. Limitorque actuator failure which could not be removed safely until the unit was taken off line during the reheater tube leak repair.		No similar failures were reported during this reporting period.	Limitoque was sent off site for repairs.
SHERCO_G2	Forced	U2 offline for boiler leak discovered after unit shutdown. Couton bottom tube leak.	09/20/2020	09/25/2020	5	Boiler Couton Bottom	Following shutdown for economy, a tube leak was discovered which was located on the bottom of the first tube on the southeast couton bottom. It appears the leak developed right at the end of where a wear bar was welded onto the tube		No similar failures were reported during this reporting period.	Two window welds were done on this tube section to complete the repair.
PR_ISLD_2	Forced	Circ Pump Trip	09/22/2020	09/28/2020	5	Circ water pump trip	failure of control circuitry		None	replaced failed component, completed causal evaluation on the trip
OCTOBER 2020										
SHERCO_G1	Forced	Derated due to 12 LP Heater Extraction Block Valve not opening	10/01/2020	10/30/2020	30	12 Feedwater Heater Extraction Block Valve	Continuation of 9/15/20 event. Following startup of the unit, it was discovered that 12 FW heater extraction block valve, LE WV 1001, would not open electrically or manually. Unit had to be derated to 610 MWn based on GE recommendations. Limitorque actuator failure which could not be removed safely until the unit was taken off line during the reheater tube leak repair.		No similar failures were reported during this reporting period. This is a continuation of the 9/15/20 event.	Limitoque was sent off site for repairs.
SHERCO_G1	Forced	Reduced to MIN load to investigate detected tube leak - Reheat tube leak.	10/22/2020	10/25/2020	4	Boiler Reheater	Tube leak could be heard outside the boiler near the reheater section. Unit was derated to reduce boiler pressure to prevent collateral damage until unit could be taken off line for repairs.		Associated failure on 10/26/20.	Through wall tube repairs were completed on the leaking tubes when the unit came off line.
SHERCO_G2	Forced	Derated due to Deaerator water makeup limitations.	10/26/2020	10/28/2020	2	Condensate Drag Valve	Condensate drag valve, CV CD 2010, lost its auto function and would not control in manual.		No similar failures were reported during this reporting period.	Drag valve was repaired by I&C technicians.
SHERCO_G1	Forced	Reheater tube leak repairs	10/26/2020	10/30/2020	5	Boiler Reheater	Two tube leaks were discovered in the rear Reheater section on pendants 105 and 106.		Associated failure on 10/22/20.	Through wall tube repairs were completed on the leaking tubes.

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Unit Outage Information
2020 AAA Reporting Period: January 1 - December 31, 2020

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Unit	Outage Category	Primary Reason for outage	Outage Dates Start	End	Duration (Days)	Q1. Equipment that resulted in the forced outage	Q2. Description of Equipment Failure	Q3. Change in Energy Costs	Q4. Failure History During Reporting Period	Q5. Steps Taken to Alleviate Reoccurrence
NOVEMBER 2020										
SHERCO_G1	Forced	ACG not available because of a stuck superheat spray block valve. Load reduced to maintain superheat temps.	11/01/2020	11/03/2020	2	Desuperheat Spray DC Block Valve	Block valve failed closed during unit startup. Unit needed to be derated to control steam temperatures until it was taken off line for repair.		Associated failure on 11/3/20.	Limitoque was sent off site for repairs and reinstalled.
SHERCO_G1	Forced	Reduced load to allow Module Upper Field drying 108 MOD UPR Field OOS. This is to maintain margin to Environnmental limits (Opacity).	11/14/2020	11/15/2020	1	Scrubber Modules	With two other modules out of service for major cleaning to maintain our 8 month cleaning schedule, the upper field on 108 module failed so the unit needed to be derated to stay below our opacity compliance limits.		No similar failures were reported during this reporting period.	Capacitors on the module field power supplies are being changed out with an improved design as well as cooling fans being added to the power supplies. 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	Derate due to 3 scrubber modules out of service. 103 and 106 Modules in major cleans and emergent failure of 110 module spray pump.	11/20/2020	11/21/2020	1	Scrubber Modules	With two other modules out of service for major cleaning to maintain our 8 month cleaning schedule, the spray pump on 110 module failed, causing the derate.		No similar failures were reported during this reporting period.	Spray pump was repaired. 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	Need to come off to repair desuperheat spray DC block valve.	11/03/2020	11/09/2020	6	Desuperheat Spray DC Block Valve	Limitorque failure which prevented the valve from opening and preventing the unit from going over 215MWn. Unit needed to be taken off line to safely remove actuator.		Associated failure on 11/1/20.	Limitoque was sent off site for repairs and reinstalled.
DECEMBER 2020										
CC Highbridge1	Forced	U7 is derated due to combustion issues	12/01/2020	12/31/2020	31	Refurbished fuel nozzles installed during Major overhaul by Mitsubishi	Fuel nozzles resulted in high dynamics and NOx emissions at high loads. Mitsubishi retuned combustor and activated a 20 degree exhaust temperature bias resulting in derate.		Continuation of event from April 2020.	Working with Mitsubishi on replacement fuel nozzles. Same issue resurfaced with the return of cold weather as in April 2020.
SHERCO_G1	Forced	Derated due to feed water side relief vlv failure.	12/14/2020	12/15/2020	1	17 Feedwater Heater relief valve	17 Feedwater Heater feedwater side relief valve failed open. Heater needed to be bypassed and isolated to perform repairs, causing the derate.		No similar failures were reported during this reporting period.	Relief valve was replaced.
SHERCO_G2	Forced	Derated due to loss of 23 cmill feeder control. Unable to operate 5 mill operation available.	12/05/2020	12/07/2020	2	23 Coal Mill Feeder	Clutch failure on motor would cause feeder to ramp up to maximum speed.		Similar Failure on 8/3/20 of this reporting period.	Coal Feeder Motor was replaced.
SHERCO_G2	Forced	Unit derate for 5 mill operation. 21 mill internal temp.	12/13/2020	12/16/2020	3	21 Coal Mill	Mill needed to be taken out of service to investigate a hot door temperature alarm.		Similar failure occurred on 12/16/20 of this reporting period.	Mill was opened up and nothing was noted which may have caused this. Placed back in service.
SHERCO_G2	Forced	21 CMILL Internal temp issues. 5 Mill operation.	12/16/2020	12/18/2020	2	21 Coal Mill	Mill needed to be taken out of service to investigate a hot door temperature alarm.		Similar failure occurred on 12/13/20 of this reporting period.	Mill was opened up and nothing was noted which may have caused this but a small adjustment was made on the air inlet vanes which seems to have corrected the problem.
SHERC3	Forced	Derate due to severe packing leak on 32 second stage superheat attemperation spray control valve.	12/09/2020	12/15/2020	5	32 Second Stage Superheat Attemperation Control Valve	Severe packing leak required a unit derate to lower pressure to reduce collateral damage risk in the area until unit could be taken off line for repair.		No similar failures were reported during this reporting period.	Packings replaced on this valve and the other three attemperation control valves.
CC Highbridge1	Forced	Mitsubishi returning to site to correct burner issues causing derate.	12/01/2020	12/02/2020	1	Refurbished fuel nozzles installed during Major overhaul by Mitsubishi	Fuel nozzles resulted in high dynamics and NOx emissions at high loads. Mitsubishi retuned combustor and activated a 20 degree exhaust temperature bias resulting in derate.		Continuation of event from April 2020.	Mitsubishi replaced refurbished fuel nozzles with new fuel nozzles under warranty and issue is still not resolved. Mitsubishi is resizing orifices in another set of fuel nozzles to be installed when available in 2021.
SHERCO_G1	Forced	Unit needs to be offline for investigation and repairs to suspected leak on CRH header.	12/07/2020	12/14/2020	7	Cold Reheat Pipe	Small leak was found on a gasket on a flanged spool piece section of the pipe. The unit was taken off line so scaffold could be installed and insulation removed to determine if their was a risk of catastrophic failure of the pipe.		No similar failures were reported during this reporting period.	Repairs will be made during the Unit 1 overhaul scheduled for spring of 2021.
SHERC3	Forced	Coal silo burn down to repair possible superheat leak.	12/15/2020	12/20/2020	5	36-1 High Pressure Feedwater Heater	Leaks were found on already plugged tubes in the corner section of the heater as well as one new leaking tube. The new leaking tube is in close proximity to tubes that had their tube plugs fail. Due to proximity to the tubes with the failed plugs, there is a high degree of confidence that damage from previous failed tubes in the area caused this tube to fail. It is also likely that the failed tube plugs at least contributed to, if not caused, this failure by opening up a previously failed tube		Similar failure occurred on 6/10/20 of this reporting period.	The failed plug welds were removed and the tubes were replugged via buildup of new weld material. An additional three tubes were plugged due to their proximity to the new leaking tube and tubes with leaking plugs. Both 36-1 and 36-2 heaters are scheduled to be replaced in 2023.

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					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
Black Dog 25				0		0												
Black Dog Total				**0**		**0**				5,967,708			0			28.94		
High Bridge 1x1	CC	Forced	04/17/2020 - 04/23/2020	7		89,180												
High Bridge 1x1	CC	Forced	12/01/2020 - 12/31/2020	31		39,427												
High Bridge 1x1	CC	Forced	12/01/2020 - 12/02/2020	1		263,019												
High Bridge 1x1 Total				**39**		**391,626**				457,392			23.58			26.03		
High Bridge 2x1				0		0												
High Bridge 2x1 Total				**0**		**0**				755,914			0			28.64		
Riverside 1x1	CC	Forced	08/11/2020 - 08/14/2020	3		119,484												
Riverside 1x1 Total				**3**		**119,484**				984,307			25.70			29.33		
Riverside 2x1				0		0												
Riverside 2x1 Total				**0**		**0**				854,535			0			28.28		
Allen S King	Steam	Forced	07/26/2020 - 07/31/2020	5		366,657												
Allen S King Total				**5**		**366,657**				4,354,389			25.53			29.35		
Sherburne 1	Steam	Forced	02/21/2020 - 02/22/2020	1		18,691												
Sherburne 1	Steam	Forced	06/01/2020 - 06/02/2020	2		12,981												
Sherburne 1	Steam	Forced	07/14/2020 - 07/16/2020	2		21,741												
Sherburne 1	Steam	Forced	07/16/2020 - 07/21/2020	6		29,037												
Sherburne 1	Steam	Forced	07/21/2020 - 07/24/2020	2		21,484												
Sherburne 1	Steam	Forced	07/24/2020 - 07/31/2020	8		1,168,676												
Sherburne 1	Steam	Forced	08/03/2020 - 08/31/2020	28		948,643												
Sherburne 1	Steam	Forced	09/15/2020 - 09/30/2020	15		303,128												
Sherburne 1	Steam	Forced	10/01/2020 - 10/30/2020	30		554,964												
Sherburne 1	Steam	Forced	10/22/2020 - 10/25/2020	4		681,324												
Sherburne 1	Steam	Forced	11/01/2020 - 11/03/2020	2		234,603												
Sherburne 1	Steam	Forced	11/14/2020 - 11/15/2020	1		13,042												
Sherburne 1	Steam	Forced	11/20/2020 - 11/21/2020	1		35,645												
Sherburne 1	Steam	Forced	12/14/2020 - 12/15/2020	1		56,467												
Sherburne 1	Steam	Forced	06/25/2020 - 06/30/2020	6		1,397,716												
Sherburne 1	Steam	Forced	07/01/2020 - 07/03/2020	2		764,531												
Sherburne 1	Steam	Forced	10/26/2020 - 10/30/2020	5		2,004,302												
Sherburne 1	Steam	Forced	11/03/2020 - 11/09/2020	6		1,338,931												
Sherburne 1	Steam	Forced	12/07/2020 - 12/14/2020	7		2,251,561												
Sherburne 1 Total				**129**		**11,857,465**				8,769,290			20.28			27.58		
Sherburne 2	Steam	Forced	07/01/2020 - 07/14/2020	14		370,844												
Sherburne 2	Steam	Forced	07/06/2020 - 07/09/2020	3		420,966												
Sherburne 2	Steam	Forced	07/24/2020 - 07/31/2020	8		589,059												
Sherburne 2	Steam	Forced	08/03/2020 - 08/05/2020	2		86,422												
Sherburne 2	Steam	Forced	08/29/2020 - 08/31/2020	3		482,964												
Sherburne 2	Steam	Forced	09/09/2020 - 09/10/2020	1		54,902												
Sherburne 2	Steam	Forced	10/26/2020 - 10/28/2020	2		14,103												
Sherburne 2	Steam	Forced	12/05/2020 - 12/07/2020	2		138,811												
Sherburne 2	Steam	Forced	12/13/2020 - 12/16/2020	3		246,057												
Sherburne 2	Steam	Forced	12/16/2020 - 12/18/2020	2		135,535												
Sherburne 2	Steam	Forced	09/20/2020 - 09/25/2020	5		864,620												
Sherburne 2 Total				**46**		**3,404,284**				11,091,724			22.28			27.65		
Sherburne 3	Steam	Forced	02/12/2020 - 02/13/2020	1		-												
Sherburne 3	Steam	Forced	05/26/2020 - 05/28/2020	3		51,483												
Sherburne 3	Steam	Forced	06/01/2020 - 06/02/2020	1		15,476												
Sherburne 3	Steam	Forced	06/08/2020 - 06/10/2020	2		9,818												
Sherburne 3	Steam	Forced	06/10/2020 - 06/12/2020	3		12,902												
Sherburne 3	Steam	Forced	07/06/2020 - 07/31/2020	25		149,807												
Sherburne 3	Steam	Forced	07/09/2020 - 07/15/2020	6		66,067												
Sherburne 3	Steam	Forced	08/01/2020 - 08/10/2020	9		87,501												
Sherburne 3	Steam	Forced	08/10/2020 - 08/11/2020	1		71,359												
Sherburne 3	Steam	Forced	12/09/2020 - 12/15/2020	5		739,715												
Sherburne 3	Steam	Forced	08/11/2020 - 08/21/2020	9		1,969,334												
Sherburne 3	Steam	Forced	08/22/2020 - 08/29/2020	7		2,132,713												
Sherburne 3	Steam	Forced	12/15/2020 - 12/20/2020	5		1,523,284												
Sherburne 3 Total				**78**		**6,829,458**				2,528,306			21.87			27.82		
Monticello	Nuclear	Forced	07/05/2020 - 07/07/2020	2		164,241												
Monticello Total				**2**		**164,241**				5,842,303			24.79			20.68		
Prairie Island 1	Nuclear	Forced	03/05/2020 - 03/07/2020	2		7,165												
Prairie Island 1	Nuclear	Forced	03/10/2020 - 03/13/2020	2		15,280												
Prairie Island 1	Nuclear	Forced	08/26/2020 - 08/30/2020	4		2,130,723												
Prairie Island 1 Total				**9**		**2,153,168**				4,895,725			21.29			22.96		
Prairie Island 2	Nuclear	Forced	09/22/2020 - 09/28/2020	5		241,031												
Prairie Island 2 Total				**5**		**241,031**				6,388,352			12.61			19.88		
Total				**316**	**1,212,160**	**25,527,416**	**14,179,347**	**11,348,069**	**2,249,727**	**57,183,898**	**36,274,729**	**20,909,170**	**21.06**	**11.70**	**9.36**	25.42	16.12	9.29

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Notes:
(1) Outages/Derates of one day durations or longer and greater than or equal to 500 MWh are included
(2) Unplanned outage forecast included Calpine I & II and LS Power.

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					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
Black Dog 25	Steam	Scheduled	04/21/2020 - 04/23/2020	2		67,672												
Black Dog 25	Steam	Scheduled	10/25/2020 - 10/31/2020	7		257,601												
Black Dog 25	Steam	Scheduled	11/01/2020 - 11/30/2020	30		670,955												
Black Dog 25	Steam	Scheduled	12/01/2020 - 12/17/2020	16		662,929												
Black Dog 25 Total				**55**		**1,659,157**				544,936			26.09			23.46		
Highbridge 1x1	CC	Scheduled	03/01/2020 - 03/18/2020	17		551,065												
Highbridge 1x1	CC	Scheduled	03/18/2020 - 03/22/2020	4		177,411												
Highbridge 1x1 Total				**22**		**728,476**				1,214,938			21.63			25.40		
Highbridge 2x1	CC	Scheduled	03/01/2020 - 03/12/2020	12		315,905												
Highbridge 2x1 Total				**12**		**315,905**				510,505			21.31			25.18		
Riverside 1x1	CC	Scheduled	09/12/2020 - 09/30/2020	19		217,852												
Riverside 1x1	CC	Scheduled	10/01/2020 - 10/23/2020	23		904,987												
Riverside 1x1 Total				**42**		**1,122,839**				1,032,784			22.22			23.49		
Riverside 2x1	CC	Scheduled	10/03/2020 - 10/09/2020	7		173,410												
Riverside 2x1 Total				**7**		**173,410**				0			0			0		
Allen S King				0		0												
Allen S King Total				**0**		**0**				0			0			0		
Sherburne 1	Steam	Scheduled	09/05/2020 - 09/12/2020	8		1,419,645												
Sherburne 1 Total				**8**		**1,419,645**				0			0			0		
Sherburne 2	Steam	Scheduled	10/18/2020 - 10/22/2020	5		1,862,073												
Sherburne 2 Total				**5**		**1,862,073**				0			0			0		
Sherburne 3	Steam	Scheduled	02/19/2020 - 02/21/2020	3		14,829												
Sherburne 3	Steam	Scheduled	03/01/2020 - 03/31/2020	31		3,654,559												
Sherburne 3	Steam	Scheduled	04/01/2020 - 04/30/2020	30		2,952,412												
Sherburne 3	Steam	Scheduled	05/04/2020 - 05/19/2020	14		1,633,940												
Sherburne 3	Steam	Scheduled	06/12/2020 - 06/18/2020	6		607,514												
Sherburne 3 Total				**84**		**8,863,254**				8,278,967			15.62			25.38		
Monticello	Nuclear	Scheduled	10/20/2020 - 10/23/2020	2		689,739												
Monticello	Nuclear	Scheduled	10/23/2020 - 10/24/2020	2		169,623												
Monticello Total				**4**		**859,362**				0			0			0		
Prairie Island 1	Nuclear	Scheduled	08/20/2020 - 08/31/2020	12		209,200												
Prairie Island 1	Nuclear	Scheduled	09/01/2020 - 09/18/2020	18		205,054												
Prairie Island 1	Nuclear	Scheduled	10/18/2020 - 10/21/2020	3		75,620												
Prairie Island 1	Nuclear	Scheduled	09/18/2020 - 09/30/2020	12		1,626,379												
Prairie Island 1	Nuclear	Scheduled	10/01/2020 - 10/13/2020	13		2,280,943												
Prairie Island 1 Total				**57**		**4,397,195**				6,007,328			12.69			17.42		
Prairie Island 2	Nuclear	Scheduled	10/18/2020 - 10/21/2020	3		88,215												
Prairie Island 2 Total				**3**		**88,215**				0			0			0		
Total				**276**	**1,275,809**	**20,761,055**	**20,070,608**	**690,446**	**854,253**	**18,666,160**	**13,319,768**	**5,346,392**	**16.27**	**15.73**	**0.54**	**21.85**	**15.59**	**6.26**

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Notes:
(1) Outages/Derates of one day durations or longer and greater than or equal to 500 MWh are included
(2) Planned outage forecast included Calpine I & II and LS Power.

Northern States Power Company Docket No. E002/AA-19-293

Expenses Pertaining to Maintenance of Generation Plants True-Up Report

Part C, Attachment 6

Energy Allocation Ratios	**87.3278%**	**86.8573%**	**86.6378%** **
Demand Allocation Ratios	**87.3461%**	**87.0633%**	**87.3441%** **

			NSP Minnesota Company Totals			Minnesota Jurisdictional Totals *		
	FERC Account Description	**Allocation Method**	**2016 Test Year**	**2019 Actuals**	**2020 Actuals**	**2016 Test Year**	**2019 Actuals**	**2020 Actuals**
510	Stm Maint Super&Eng	Energy	$ 2,008,848	$ 3,765,365	$ 1,727,407	$ 1,754,283	$ 3,270,494	$ 1,496,587
511	Stm Maint of Structures	Demand	$ 2,784,311	$ 6,419,921	$ 4,791,181	$ 2,431,987	$ 5,589,395	$ 4,184,814
512	Stm Maint of Boiler Plt	Energy	$ 39,704,208	$ 22,850,699	$ 21,082,459	$ 34,672,811	$ 19,847,500	$ 18,265,379
513	Stm Maint of Elec Plant	Energy	$ 4,931,682	$ 6,807,557	$ 5,815,433	$ 4,306,730	$ 5,912,861	$ 5,038,363
514	Stm Maint of Misc Stm Plt	Demand	$ 18,325,365	$ 11,713,257	$ 9,075,166	$ 16,006,492	$ 10,197,948	$ 7,926,622
528	Nuc Maint Super & Eng	Energy	$ 6,183,520	$ 7,262,125	$ 8,157,846	$ 5,399,932	$ 6,307,686	$ 7,067,779
529	Nuc Maint of Structures	Demand	$ 9,368	$ 24,683	$ -	$ 8,183	$ 21,489	$ -
530	Nuc Mtc of React Plt Equip	Energy	$ 48,934,011	$ 38,926,797	$ 36,272,972	$ 42,732,995	$ 33,810,765	$ 31,426,105
531	Nuc Maint of Elect Plant	Energy	$ 13,522,861	$ 12,389,211	$ 13,209,510	$ 11,809,217	$ 10,760,934	$ 11,444,429
532	Nuc Mtc of Misc Nuc Plant	Demand	$ 25,463,010	$ 31,045,208	$ 26,866,098	$ 22,240,946	$ 27,028,983	$ 23,465,952
541	Hydro Mtc Super& Eng	Energy	$ 5,509	$ 2,653	$ -	$ 4,811	$ 2,305	$ -
542	Hyd Maint of Structures	Demand	$ 22,000	$ 39,246	$ 29,054	$ 19,216	$ 34,169	$ 25,377
543	Hydro Mtc Resv, Dams	Demand	$ 22,000	$ 62,498	$ 123,772	$ 19,216	$ 54,413	$ 108,107
544	Hyd Maint of Elec Plant	Energy	$ 88,144	$ 120,543	$ 150,823	$ 76,974	$ 104,700	$ 130,670
545	Hyd Mt Misc Hyd Plnt Mjr	Demand	$ 59,713	$ 4,755	$ 2,894	$ 52,157	$ 4,139	$ 2,528
551	Oth Maint Super & Eng	Demand	$ 310,346	$ 1,698,454	$ 1,990,705	$ 271,075	$ 1,478,730	$ 1,738,764
552	Oth Maint of Structures	Demand	$ 3,242,151	$ 6,650,945	$ 5,748,189	$ 2,831,892	$ 5,790,532	$ 5,020,704
553	Oth Mtc of Gen & Ele Plant	Demand	$ 17,225,836	$ 6,306,898	$ 9,490,585	$ 15,046,096	$ 5,490,994	$ 8,289,466
554	Oth Mtc Misc Gen Plt Mjr	Demand	$ 1,866,543	$ 5,025,921	$ 6,267,182	$ 1,630,353	$ 4,375,733	$ 5,474,014
Production Maintenance Expense Totals			**$ 184,709,427**	**$ 161,116,736**	**$ 150,801,276**	**$ 161,315,366**	**$ 140,083,770**	**$ 131,105,658**

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

**Preliminary Minnesota Demand and Energy Allocation Ratios

	Generation Maintenance O&M Costs
2016 Test Year	$ 184,709,427
2019 Actual	$ 161,116,736
2020 Actual	$ 150,801,276

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Eau Galle	7/31/2026	35	Eau Galle Renewable Energy Co. Inc.	0.300	Hydro													
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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													
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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													
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Wind CBED Uilk	1/14/2030	20	Uilk Wind Farm, LLC	4.5	Wind													
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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 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													
Wind Geronimo Odell	7/28/2036	20	Odell Wind, LLC	200	Wind													

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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													
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Wind Source Cisco	5/27/2028	20	Cisco Wind Energy LLC	8	Wind													
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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													
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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													
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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 2020, there were 382 active Community Solar Gardens in-service and 114 of these came on-line during the 2020 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 365 gardens receiving bill credits during this reporting period. These gardens received a total of $145,321,146 bill credits, as shown in Part C, Attachment 10. The corresponding subscribed and unsubscribed energy bill credits were $143,993,415 and $1,327,732, respectively. 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 2020 AAA period:

	System	MN Amount[1]	Estimated MN Retail Allocator
Market	$29,355,206	$21,269,584	0.726456
Above Market	$115,965,941	$115,965,941	1.0000000
Total	$145,321,146	$137,235,525	

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, 2020 in Docket No. E002/M-13-867, and the next report is due on April 1, 2021.

[1] $1,088,376 in solar gardens developer late fees were credited to the FCA. This credit has resulted in a net solar garden cost recovery of $130,419,802 during the AAA reporting period.

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2020)
1	Le Sueur	9/9/2015	0.036	5
2	Lincoln	4/25/2016	0.204	18
3	Ramsey	5/12/2016	0.125	7
4	Hennepin	8/22/2016	0.036	18
5	Chisago	12/14/2016	1	26
6	Dakota	12/14/2016	1	33
7	Chisago	12/15/2016	1	26
8	Carver	12/15/2016	1	675
9	Scott	12/19/2016	1	80
10	Dakota	12/20/2016	1	14
11	Stearns	12/21/2016	1	35
12	Dakota	12/22/2016	1	13
13	Stearns	1/4/2017	1	12
14	Stearns	1/5/2017	1	293
15	Goodhue	1/12/2017	0.972	28
16	Dakota	1/13/2017	1	13
17	Chisago	1/13/2017	0.972	16
18	Goodhue	2/13/2017	1	300
19	Carver	2/28/2017	0.972	13
20	Washington	3/10/2017	0.036	7
21	Wabasha	3/13/2017	1	189
22	Dakota	3/15/2017	1	204
23	Blue Earth	5/31/2017	1	12
24	Redwood	5/31/2017	1	41
25	Winona	5/31/2017	0.25	31
26	Rice	6/30/2017	1	282
27	Dodge	7/18/2017	1	494
28	Washington	7/18/2017	1	202
29	Olmsted	7/19/2017	1	437
30	Kandiyohi	8/14/2017	1	7
31	Pipestone	8/18/2017	1	46
32	Chisago	8/22/2017	1	11
33	Stearns	8/24/2017	1	20
34	Chippewa	8/29/2017	1	10
35	Dakota	8/31/2017	1	26
36	Pope	9/13/2017	1	19
37	Stearns	9/13/2017	0.972	17
38	Stearns	9/13/2017	0.972	24
39	Lincoln	9/14/2017	0.2	21
40	Sherburne	9/22/2017	1	153
41	Dodge	9/27/2017	1	21
42	Benton	9/29/2017	1	22
43	McLeod	10/25/2017	1	38
44	Chippewa	10/25/2017	1	50

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2020)
45	Hennepin	10/25/2017	1	12
46	McLeod	10/26/2017	1	100
47	Pipestone	10/30/2017	1	40
48	Stearns	10/30/2017	1	24
49	Benton	10/30/2017	1	23
50	Wright	11/3/2017	1	1192
51	Stearns	11/9/2017	1	14
52	Wright	11/13/2017	1	1169
53	Stearns	11/16/2017	1	122
54	Nicollet	11/20/2017	1	13
55	Blue Earth	11/20/2017	1	35
56	Scott	11/30/2017	0.998	13
57	Scott	11/30/2017	0.7	7
58	Dakota	11/30/2017	1	135
59	Rice	11/30/2017	1	210
60	Stearns	12/13/2017	1	14
61	Chisago	12/13/2017	1	11
62	Carver	12/15/2017	1	34
63	Chisago	12/18/2017	1	10
64	Dodge	12/18/2017	1	34
65	Scott	12/20/2017	0.997	12
66	Carver	12/21/2017	0.396	14
67	Renville	12/28/2017	1	47
68	Washington	1/10/2018	1	21
69	Carver	1/16/2018	1	11
70	Le Sueur	1/18/2018	1	12
71	Dakota	1/23/2018	0.99	14
72	Wabasha	1/29/2018	1	12
73	Pipestone	1/31/2018	1	44
74	Sherburne	2/12/2018	0.25	177
75	Rice	2/14/2018	0.998	163
76	Le Sueur	2/23/2018	1	33
77	Carver	2/26/2018	0.998	311
78	Waseca	2/26/2018	1	29
79	Rice	2/28/2018	1	11
80	Le Sueur	2/28/2018	1	39
81	Washington	2/28/2018	1	702
82	Faribault	3/2/2018	1	14
83	Rice	3/2/2018	1	10
84	Steele	3/5/2018	0.4	83
85	Carver	3/6/2018	1	12
86	Chisago	3/13/2018	1	12
87	Carver	3/14/2018	0.998	143
88	Sherburne	3/14/2018	1	22

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2020)
89	Pope	3/15/2018	1	497
90	Benton	3/25/2018	1	12
91	Scott	3/28/2018	0.99	19
92	Goodhue	4/12/2018	0.8	139
93	Washington	4/13/2018	1	16
94	Pope	4/19/2018	1	280
95	Washington	4/20/2018	1	12
96	Goodhue	4/26/2018	0.998	132
97	Chisago	4/30/2018	1	9
98	Stearns	4/30/2018	1	30
99	Sherburne	4/30/2018	1	29
100	Goodhue	5/11/2018	1	27
101	Renville	5/16/2018	1	24
102	Renville	5/17/2018	1	21
103	Goodhue	5/22/2018	1	10
104	Blue Earth	5/30/2018	1	10
105	Steele	6/5/2018	1	7
106	Hennepin	6/6/2018	0.18	32
107	Chippewa	6/15/2018	1	28
108	Lyon	6/15/2018	1	37
109	Rice	6/20/2018	1	19
110	Le Sueur	6/29/2018	1	12
111	Sherburne	6/29/2018	1	14
112	Watonwan	7/2/2018	0.25	23
113	Sherburne	7/13/2018	1	15
114	Washington	7/16/2018	1	10
115	Steele	7/18/2018	1	7
116	Goodhue	7/19/2018	1	18
117	Dakota	7/27/2018	1	23
118	Goodhue	7/30/2018	1	16
119	Chisago	8/1/2018	1	26
120	DOUGLAS	8/2/2018	1	304
121	Le Sueur	8/6/2018	1	467
122	Blue Earth	8/7/2018	1	535
123	Chisago	8/9/2018	1	16
124	Wright	8/14/2018	0.972	6
125	Benton	8/14/2018	0.99	13
126	Carver	8/16/2018	0.25	338
127	Wright	8/27/2018	1	442
128	Chisago	8/30/2018	1	11
129	Washington	9/4/2018	0.25	444
130	Washington	9/7/2018	0.25	96
131	Goodhue	9/14/2018	1	12
132	Dakota	9/17/2018	0.75	9

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2020)
133	Goodhue	9/19/2018	1	24
134	Waseca	9/27/2018	1	6
135	Chisago	9/28/2018	1	50
136	Chisago	9/28/2018	1	8
137	Hennepin	9/28/2018	0.32	32
138	Blue Earth	10/16/2018	1	22
139	Wright	10/17/2018	1	24
140	McLeod	10/25/2018	1	6
141	Waseca	10/25/2018	1	6
142	Washington	10/29/2018	1	14
143	Benton	10/30/2018	1	11
144	Waseca	11/1/2018	1	11
145	Chippewa	11/14/2018	1	143
146	Kandiyohi	11/14/2018	1	27
147	Pope	11/16/2018	1	18
148	Sherburne	11/16/2018	1	6
149	Chisago	11/26/2018	1	12
150	Chisago	11/27/2018	1	16
151	Wright	11/28/2018	1	12
152	Scott	11/28/2018	0.823	9
153	Hennepin	11/28/2018	0.527	72
154	Scott	11/28/2018	1	9
155	Chisago	11/28/2018	1	10
156	Chisago	11/28/2018	1	12
157	Chisago	11/29/2018	1	14
158	Sherburne	12/3/2018	1	16
159	Chisago	12/7/2018	1	8
160	Sherburne	12/10/2018	1	15
161	Chisago	12/11/2018	0.5	19
162	Stearns	12/17/2018	1	64
163	Benton	12/17/2018	1	10
164	Benton	12/17/2018	1	8
165	Chippewa	12/18/2018	1	14
166	Le Sueur	12/19/2018	1	12
167	Murray	12/20/2018	1	9
168	Murray	12/20/2018	1	12
169	Yellow Medicine	12/21/2018	1	83
170	Ramsey	1/8/2019	0.54	8
171	Dodge	1/9/2019	1	12
172	Hennepin	1/11/2019	1	697
173	Meeker	1/23/2019	0.76	10
174	Stearns	1/28/2019	0.324	9
175	Nicollet	1/31/2019	1	8
176	Waseca	2/13/2019	1	12

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2020)
177	Chisago	2/27/2019	1	11
178	Stearns	3/4/2019	0.72	10
179	Stearns	3/4/2019	1	13
180	Blue Earth	3/5/2019	0.24	8
181	McLeod	3/12/2019	1	32
182	Washington	3/22/2019	1	127
183	Stearns	3/25/2019	1	11
184	Wabasha	3/26/2019	0.85	133
185	Pope	3/26/2019	1	18
186	Sherburne	3/28/2019	1	24
187	Pope	3/28/2019	1	17
188	Renville	3/29/2019	1	16
189	Goodhue	4/11/2019	1	543
190	Stearns	4/16/2019	1	12
191	Chisago	4/22/2019	1	219
192	Washington	4/22/2019	1	110
193	Wright	4/29/2019	1	1070
194	Rice	4/30/2019	1	8
195	Carver	5/1/2019	1	7
196	Lyon	5/3/2019	1	13
197	Benton	5/13/2019	1	287
198	Dodge	5/15/2019	1	78
199	Dodge	5/15/2019	0.4	81
200	Kandiyohi	5/21/2019	1	10
201	Chisago	5/21/2019	1	9
202	Wright	5/31/2019	1	150
203	Stearns	6/3/2019	1	14
204	Dakota	6/7/2019	1	16
205	Dakota	6/7/2019	1	12
206	Sibley	6/14/2019	1	58
207	Stearns	6/18/2019	1	16
208	Freeborn	6/18/2019	0.25	39
209	Chisago	7/3/2019	1	15
210	Carver	7/22/2019	1	10
211	Scott	7/24/2019	0.598	64
212	Carver	7/25/2019	1	9
213	Sherburne	7/26/2019	1	17
214	Hennepin	7/30/2019	0.18	21
215	Sherburne	7/31/2019	0.996	148
216	Dakota	8/6/2019	1	143
217	Rice	8/8/2019	1	50
218	Scott	8/13/2019	1	13
219	Chisago	8/16/2019	0.998	210
220	Stearns	8/16/2019	1	166

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2020)
221	Stearns	8/16/2019	1	155
222	Wabasha	8/20/2019	1	154
223	Wabasha	8/20/2019	1	140
224	Winona	8/21/2019	1	197
225	Winona	8/22/2019	1	129
226	Wabasha	8/22/2019	1	117
227	Winona	8/22/2019	1	90
228	Chippewa	8/26/2019	1	23
229	Carver	8/29/2019	1	7
230	McLeod	8/30/2019	1	13
231	Chisago	9/3/2019	1	7
232	Waseca	9/6/2019	1	11
233	Olmsted	9/9/2019	1	7
234	Pope	9/11/2019	1	12
235	Pope	9/11/2019	1	10
236	Hennepin	9/18/2019	0.96	191
237	Rice	9/18/2019	1	14
238	Blue Earth	9/24/2019	0.62	34
239	Goodhue	9/27/2019	1	32
240	Blue Earth	9/27/2019	0.62	28
241	Rice	10/9/2019	1	17
242	Stearns	10/23/2019	1	26
243	Stearns	10/25/2019	0.95	41
244	Sherburne	10/29/2019	1	15
245	Scott	10/30/2019	0.4	6
246	Waseca	11/18/2019	0.996	150
247	Sherburne	11/26/2019	1	15
248	Stearns	12/3/2019	1	13
249	Meeker	12/11/2019	1	42
250	Dakota	12/11/2019	1	16
251	DOUGLAS	12/11/2019	1	26
252	Meeker	12/13/2019	1	202
253	Rice	12/13/2019	1	10
254	Pope	12/16/2019	1	7
255	Stearns	12/16/2019	1	10
256	Nicollet	12/18/2019	1	189
257	Blue Earth	12/18/2019	1	168
258	McLeod	12/18/2019	1	158
259	Chisago	12/19/2019	1	11
260	Stearns	12/23/2019	1	16
261	Sherburne	12/23/2019	1	15
262	Sherburne	12/26/2019	1	10
263	Stearns	12/27/2019	1	196
264	DOUGLAS	12/27/2019	1	156

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2020)
265	McLeod	12/27/2019	1	10
266	Renville	12/30/2019	1	14
267	Sherburne	12/30/2019	0.94	8
268	Goodhue	12/31/2019	0.59	6
269	Winona	1/3/2020	1	195
270	Winona	1/3/2020	1	200
271	Stearns	1/13/2020	1	17
272	Rice	1/14/2020	1	10
273	Dakota	1/15/2020	1	8
274	Meeker	1/17/2020	1	7
275	Winona	2/12/2020	1	22
276	Goodhue	2/13/2020	1	27
277	Pope	2/17/2020	1	12
278	Hennepin	2/17/2020	0.29	7
279	Rice	2/20/2020	1	12
280	Goodhue	2/26/2020	1	20
281	Pope	2/26/2020	1	14
282	Waseca	2/27/2020	1	9
283	Goodhue	2/28/2020	1	217
284	Goodhue	2/28/2020	1	197
285	Sherburne	2/28/2020	1	21
286	Waseca	3/4/2020	1	10
287	Washington	3/9/2020	1	8
288	Goodhue	3/9/2020	1	215
289	Rice	3/20/2020	1	11
290	Sibley	3/26/2020	1	16
291	Dakota	3/26/2020	1	11
292	Sibley	4/3/2020	1	19
293	Olmsted	4/3/2020	1	9
294	Dodge	4/7/2020	1	13
295	DOUGLAS	4/9/2020	1	18
296	Olmsted	4/13/2020	1	12
297	Olmsted	4/16/2020	1	0
298	Rice	4/24/2020	0.96	104
299	Scott	4/27/2020	1	793
300	Rice	4/27/2020	1	16
301	Goodhue	4/30/2020	1	28
302	Chisago	5/19/2020	1	10
303	Benton	5/20/2020	1	10
304	Stearns	5/21/2020	1	6
305	Dodge	5/21/2020	1	12
306	Carver	5/28/2020	1	52
307	Pope	5/30/2020	1	28
308	Dakota	6/2/2020	1	233

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2020)
309	Dakota	6/4/2020	1	239
310	Waseca	6/16/2020	1	9
311	Rice	6/17/2020	1	22
312	Winona	6/24/2020	1	17
313	Winona	6/24/2020	1	40
314	Benton	7/10/2020	1	21
315	Rice	7/13/2020	1	30
316	Rice	7/20/2020	1	31
317	McLeod	7/20/2020	1	12
318	Nicollet	7/30/2020	1	13
319	Goodhue	7/30/2020	1	17
320	Stearns	7/31/2020	1	16
321	Wright	7/31/2020	1	25
322	Le Sueur	7/31/2020	1	9
323	Sherburne	7/31/2020	1	27
324	Goodhue	8/18/2020	1	11
325	Sherburne	9/1/2020	1	11
326	Redwood	9/14/2020	0.86	31
327	Chisago	9/14/2020	1	10
328	Waseca	9/15/2020	1	14
329	Chippewa	9/16/2020	1	23
330	Redwood	9/16/2020	1	32
331	Waseca	9/21/2020	1	12
332	Steele	9/22/2020	1	9
333	Nicollet	9/22/2020	1	7
334	Redwood	9/28/2020	1	25
335	Washington	9/28/2020	1	21
336	Freeborn	9/29/2020	1	25
337	Wright	10/1/2020	1	9
338	Dodge	10/6/2020	1	14
339	Dakota	10/6/2020	1	7
340	Clay	10/8/2020	1	42
341	Clay	10/8/2020	1	38
342	Clay	10/8/2020	1	37
343	Clay	10/8/2020	1	32
344	Nicollet	10/8/2020	1	27
345	Benton	10/14/2020	1	9
346	Rice	10/15/2020	0.7	8
347	Kandiyohi	10/19/2020	1	15
348	Kandiyohi	10/19/2020	1	13
349	Washington	10/20/2020	1	86
350	Clay	10/21/2020	1	31
351	Goodhue	10/26/2020	1	9
352	Waseca	10/27/2020	1	10

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2020)
353	Renville	10/29/2020	1	15
354	Freeborn	10/30/2020	1	55
355	Chippewa	10/30/2020	1	26
356	Benton	11/3/2020	1	100
357	Dakota	11/4/2020	1	11
358	Goodhue	11/5/2020	1	20
359	Olmsted	11/9/2020	1	10
360	Dodge	11/9/2020	1	18
361	Sherburne	11/10/2020	1	11
362	Dodge	11/16/2020	1	9
363	Goodhue	11/19/2020	1	9
364	Rice	11/19/2020	1	11
365	Dodge	11/23/2020	1	11
366	Winona	11/30/2020	1	22
367	Stearns	12/1/2020	1	0
368	Renville	12/4/2020	1	0
369	McLeod	12/4/2020	1	0
370	Lyon	12/7/2020	1	0
371	Chisago	12/9/2020	1	0
372	Stearns	12/9/2020	1	0
373	Carver	12/10/2020	1	0
374	Chisago	12/11/2020	1	0
375	Pope	12/14/2020	1	0
376	Pope	12/14/2020	1	0
377	Stearns	12/16/2020	1	0
378	Nicollet	12/17/2020	1	0
379	Rice	12/21/2020	1	0
380	Pope	12/21/2020	1	0
381	Pope	12/28/2020	1	0
382	McLeod	12/30/2020	1	0

Northern States Power Company
Electric Utility - State of Minnesota

2020 Minnesota Jurisdictional Solar Gardens Program Cost Recovery Through Fuel Clause Rider

		January	February	March	Apri	May	June	July	August	September	October	November	December	Total 2020
	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	$569,343	$1,395,993	$1,468,122	$1,729,251	$1,873,000	$2,309,341	$3,476,586	$2,958,866	$1,418,118	$1,347,418	$1,063,643	$859,707	$20,469,388
[2]	Solar Gardens Unsubscribed Energy <40 KW	$3	$0	$1	$0	$0	$0	$0	$0	$0	$26	$0	$0	$29
[3]	Solar Gardens Unsubscribed Energy > 40 KW	$15,840	$29,997	$14,142	$35,948	$44,373	$76,555	$45,163	$44,529	$119,779	$60,825	$27,562	$62,184	$576,898
[4]	Total Costs (System) [1]+[2]+[3]	$585,186	$1,425,990	$1,482,265	$1,765,198	$1,917,372	$2,385,896	$3,521,750	$3,003,396	$1,537,897	$1,408,268	$1,091,205	$921,891	$21,046,314
	Above Market Amount Recoverable in Minnesota Jurisdiction													
[5]	Minnesota Direct Assigned Above Market Amount	$3,580,230	$8,051,009	$9,153,390	$11,679,647	$13,084,410	$16,162,629	$15,877,804	$14,362,480	$11,068,799	$10,535,941	$11,867,097	$6,084,742	$131,508,178
[6]	**Total Bill Credits & Unsubscribed Energy Payments** [4]+[5]	**$4,165,415**	**$9,476,999**	**$10,635,655**	**$13,444,845**	**$15,001,783**	**$18,548,525**	**$19,399,554**	**$17,365,876**	**$12,606,696**	**$11,944,209**	**$12,958,303**	**$7,006,633**	**$152,554,492**
	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]	**$3,580,230**	**$8,051,009**	**$9,153,390**	**$11,679,647**	**$13,084,410**	**$16,162,629**	**$15,877,804**	**$14,362,480**	**$11,068,799**	**$10,535,941**	**$11,867,097**	**$6,084,742**	**$131,508,178**
	MWh Sales Weighting													
[8]	Minnesota Jurisdiction Retail MWh Subject to FCA	2,408,196	2,172,083	2,217,095	1,857,397	1,995,853	2,462,438	2,925,738	2,735,021	2,145,728	2,184,120	2,135,112	2,325,425	27,564,206
[9]	NSP System MWh Sales Exclude Windsource & Renewable*Connect	3,407,253	3,064,914	3,126,729	2,613,588	2,775,469	3,390,465	4,003,715	3,771,138	2,972,463	3,050,042	2,992,694	3,287,905	38,456,375
[10]	Allocation Weighting [8]/[9]	70.6785%	70.8693%	70.9078%	71.0669%	71.9105%	72.6283%	73.0756%	72.5251%	72.1869%	71.6095%	71.3441%	70.7266%	71.6766%
	Market Bill Credits and Payments Allocated to MN Fuel Clause Recovery													
[11]	Market Amount Allocated to All Jurisdictions [4]	$585,186	$1,425,990	$1,482,265	$1,765,198	$1,917,372	$2,385,896	$3,521,750	$3,003,396	$1,537,897	$1,408,268	$1,091,205	$921,891	$21,046,314
[12]	Allocation Weighting [10]	70.6785%	70.8693%	70.9078%	71.0669%	71.9105%	72.6283%	73.0756%	72.5251%	72.1869%	71.6095%	71.3441%	70.7266%	71.6766%
[13]	Market Amount Allocated to Minnesota Jurisdiction [11]*[12]	**$413,601**	**$1,010,589**	**$1,051,041**	**$1,254,472**	**$1,378,792**	**$1,732,836**	**$2,573,539**	**$2,178,215**	**$1,110,160**	**$1,008,454**	**$778,511**	**$652,023**	**$15,142,233**
	Total Solar Gardens Costs Recovery Included in MN Fuel Cost Charge													
[14]	Market and Above Market Allocated Amount [17]+[13]	**$3,993,830**	**$9,061,598**	**$10,204,432**	**$12,934,119**	**$14,463,202**	**$17,895,465**	**$18,451,343**	**$16,540,695**	**$12,178,958**	**$11,544,395**	**$12,645,608**	**$6,736,765**	**$146,650,411**
[15]	**Solar Gardens Developer Late Fees (Credit Back to MN Customers)**	**$16,240**	**$30,400**	**$183,600**	**$280,400**	**$456,304**	**$85,200**	**$0**	**$2,832**	**$0**	**$21,000**	**$12,400**	**$0**	**$1,088,376**
[16]	**Net Solar Gardens Costs Recovery Included in MN Fuel Cost Charge**	**$3,977,590**	**$9,031,198**	**$10,020,832**	**$12,653,719**	**$14,006,898**	**$17,810,265**	**$18,451,343**	**$16,537,863**	**$12,178,958**	**$11,523,395**	**$12,633,208**	**$6,736,765**	**$145,562,035**
	Market Bill Credits and Payments Allocated to Other Jurisdictions													
[17]	Cost Allocated to Other Jurisdictions (Market Portion Based on LMP) [4]-[1	$171,585	$415,401	$431,223	$510,726	$538,581	$653,060	$948,211	$825,180	$427,737	$399,814	$312,694	$269,869	$5,904,081
	Direct Assigned Minnesota Cost Removed from System Cost													
[18]	Minnesota Direct Assigned Above Market Amount [5]	$3,580,230	$8,051,009	$9,153,390	$11,679,647	$13,084,410	$16,162,629	$15,877,804	$14,362,480	$11,068,799	$10,535,941	$11,867,097	$6,084,742	$131,508,178
[19]	Solar Gardens Developer Late Fees (Credit Back to MN Customers) [15]	$16,240	$30,400	$183,600	$280,400	$456,304	$85,200	$0	$2,832	$0	$21,000	$12,400	$0	$1,088,376
[20]	Direct Assigned Minnesota Cost Removed from System Cost [18]-[19]	**$3,563,990**	**$8,020,609**	**$8,969,790**	**$11,399,247**	**$12,628,106**	**$16,077,429**	**$15,877,804**	**$14,359,648**	**$11,068,799**	**$10,514,941**	**$11,854,697**	**$6,084,742**	**$130,419,802**

FUEL PROCUREMENT POLICIES

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 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**

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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.

In 2020, we began to offer the King Station and Unit 2 of the Sherburne County Generating Station into the MISO market on a seasonal basis. Although we expect this change in approach to dispatching these units will have an impact on our total coal requirements for these units, we do not expect it to change our general coal purchasing strategy to meet the lower requirements.

Nuclear

The market price for uranium during the early part of first quarter of 2021 has been trending lower with a high spot market price of $30.40 per pound in early January to a low of $29.10 per pound in early February.

Even at today's market prices, the cost of nuclear fuel continues to be higher than the historical costs of the 1990s and early 2000s, when the market price for uranium was less than $10.00 per pound. With the continued weakness in market prices, the current prices are at a level that is impacting the forecast levels of uranium production. Existing supply in the marketplace has decreased through the closure of mines, reduction of production targets, suspension of production at mines throughout the world, and buying by producers to fulfill contractual obligations. Global uranium production is forecasted to increase by 9% in 2021. Early closures of nuclear power plants in the United States have reduced demand, but uranium demand and supply are forecasted to be at similar levels in 2021 and 2022. Unpredicted differences between supply and demand is projected to be covered by end user inventories. Spot market volume at 91.7 million pounds of U_3O_8 for 2020 is significantly above the 56.3 million pounds of U_3O_8 for 2019 and is approximately 3.4 percent greater than the volume for this period in 2018 (88.7 million pounds). Volume in the later part of 2020 declined from record levels in the first part of 2020 and spot market prices also declined in the later part of 2020. For the rest of 2021 and into 2022, prices will likely decrease moderately as uranium end users draw down inventories, producers cover obligations, and anticipated U.S policy-related decisions occur. Spot market volumes are forecasted to remain low through early 2021. Longer-term prices will likely increase as production beyond 2023 is forecasted to be below demand and potential impacts that may occur based on any actions that are taken as a result of policy-related decisions. Additionally, demand is likely to increase with the restart of more reactors in Japan and as construction and start-up of new nuclear power plants world-wide continues. Prices could be further impacted if supply projections are not met. Closings of nuclear reactors world-wide have decreased demand and increased uranium end-user inventories. The current market analysis forecasts supply and inventories meeting demand until about 2024, but will continue to be dependent on the willingness of suppliers to bring new supply into the market, as well as the interest of companies and governments to continue construction of new nuclear power plants. Continued developments in government programs and agreements will favorably influence supply/demand projections and should help to moderate future increases to nuclear fuel prices.

Several trade activities, such as uncertainty with regard to trade policy with China and implementation of the new Russian Suspension Agreement beyond 2020 and continued threats of 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 2020. If quotas under the new Russian Suspension Agreement and/or 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 be significantly impacted. A list of current nuclear fuel components of service contracts is shown on Part D, Attachment 2.

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. In light of the February 2021 natural gas market price spike, the Company will be assessing the performance of this strategy.

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 20 and 25 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. Delivered wood fuel costs have seen a modest decline in price recently, primarily due to fuel switching to low-cost natural gas by many biomass fuel consumers such as wood product and paper mills. 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.

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 LaCrosse. 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.

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Nuclear Fuel Components of Services for the Period of January through December 2020

	Supplier & Corporate Headquarters Location	Description of Fuel or Services	Quantity of Volume	Contract Expiration Date
	[PROTECTED DATA BEGINS			
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
				PROTECTED DATA ENDS]

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	[PROTECTED DATA BEGINS			
13				
14				
15				
16				
17				
				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				
				PROTECTED DATA ENDS]

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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				
5				
6				
				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				
3				
4				
5				
6				
7				
8				
9				
10				
11				
				PROTECTED DATA ENDS]

	Supplier & Corporate Headquarters Location	Description of Fuel or Service	Quantity or Volume	Contract Expiration Date
[PROTECTED DATA BEGINS				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
				PROTECTED DATA ENDS]

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

Cost Changes – January 1, 2020 to January 1, 2021

	Contract	Percent Change
[PROTECTED DATA BEGINS		

PROTECTED DATA ENDS]

Cost Changes – January 1, 2020 to January 1, 2021

	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, 2020 compared to the contract price on January 1, 2021.

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 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 2020.

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

3. A contract was executed in **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**

   A contract was executed in **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**

   A contract was executed in **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**

   A contract amendment was executed in **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]

A contract amendment was executed in **[PROTECTED DATA BEGINS** **PROTECTED DATA ENDS]**

A contract amendment was 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 $2.02/MBtu during 2019. (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 2018 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**

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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 2020, the Company disputed approximately 2 days of 104 MISO invoices. As a result, $6.5M in in charges were disputed for the NSP System.

NSP MISO Dispute Status

Disputed $ Amount			Dispute Status			
YEAR	Op Month	Operating Date	GRANTED	DENIED	OPEN	TOTAL
2020	2020-04	04/06/20	$0.00	$114,632.00	$0.00	$114,632.00
	2020-08	08/27/20	$0.00	$6,357,910.00	$0.00	$6,357,910.00
2020 Total			$0.00	$6,472,542.00	$0.00	$6,472,542.00
TOTAL			$0.00	$6,472,542.00	$0.00	$6,472,542.00

The total dollar amount disputed in the 2020 AAA period is higher than in the 2018 - 2019 AAA period. During the current period, the Company found a similar number of discrepancies requiring a formal dispute to be filed with MISO where one dispute related to Hurricane Laura uplift charges represented a majority of the total dollar amount disputed. The Hurricane Laura uplift dispute was denied by MISO and the Company is currently pursuing a remedy through MISO's Alternative Dispute Resolution process. Discrepancies not requiring a formal dispute are routinely resolved through the normal settlement process.

CONSERVATION IMPROVEMENT PROGRAM

Xcel Energy's Conservation Improvement Program (CIP) is designed to help our customers use energy wisely. The Company has developed nearly 40 commercial and residential CIP programs with the intent of providing customers the opportunity to lower their energy consumption and overall energy bills.

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 CIP. CIP 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 CIP 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.

Additionally, the Company has several electric load management programs available to customers. These programs provide customers rate discounts for reducing electric load on days with peak demand for electricity or rebates for participation in control events utilizing a smart thermostat or energy management systems.

The Company is required to file with the Department every three years, a CIP 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 CIP Triennial Plan, which was filed on July 1, 2020 and approved on November 25, 2020.[1]

On April 1 of each year, the Company is required to file with the Department an annual CIP Status Report, which details the cost-effectiveness and spending for the prior year's CIP program. The Deputy Commissioner issued approval of the Company's 2019 CIP Status Report on August 6, 2020.[2]

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[1] Docket No. E,G002/CIP-20-473
[2] Docket No. E,G002/CIP-16-115.08

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)[1] are transmission-owning members of MISO. NSPM and NSPW (the NSP Companies) 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.

Xcel Energy℠

414 Nicollet Mall
Minneapolis, MN 55401

February 1, 2021

Judith Dockendorf
Deloitte & Touche LLP
50 South Sixth Street, Suite 2800
Minneapolis, MN 55402

**RE: 2020 ANNUAL AUTOMATIC ADJUSTMENT (AAA) CHARGES REPORT – ELECTRIC OPERATION
DOCKET NO. E002/AA-19-293**

Dear Ms. Dockendorf:

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 filing. The Company's 2020 AAA Electric Report will be filed with the Commission and Minnesota Department of Commerce – Division of Energy Resources by March 1, 2021. We note that this report differs from past reports in that it will cover a 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 Report, among other things, will provide detailed results of the Company's fuel clause for the reporting period January – December 2020. The Company implemented monthly fuel rates approved per the Commission's November 14, 2019 Order in Docket No. E002/AA-19-293 and later adjusted by the Commission's May 22, 2020 Order in Docket No. E002/AA-20-182 and June 6, 2020 Order in Docket No. E002/M-20-437. Appendix A to this letter shows the 2020 monthly factors. The Department will prepare comprehensive analyses of the AAA reports filed by all regulated electric utilities, and the Commission will conduct a hearing to review and act on the AAA 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 2020 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, 2020, 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 2020 Electric AAA 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 2020 Electric AAA Report to be filed by March 1, 2021, 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 26, 2021. We will gladly work with you to establish a revised schedule if necessary. The Deloitte & Touche independent audit report should be provided to Amy Liberkowski, 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 be scheduling a follow-up meeting to ensure that all the audit requirements are understood.

Sincerely,

/s/

REBECCA D. EILERS
REGULATORY POLICY SPECIALIST

cc: Amy Liberkowski
Lisa Peterson
John Chow

Xcel Energy

Northern States Power Company

Minnesota Retail Electric Fuel Cost Charges & Riders Tables

LAST REVISED 9/30/2020

FUEL COST CHARGE ($/kWh)						
	Residential	C&I Non-Demand	C&I Demand			Outdoor Lighting
			Non-TOD	TOD		
				On-Peak	Off-Peak	
2020 Factors						
FAF Ratio *	1.0177	1.0305	0.9984	1.2486	0.8166	0.7976
January	$0.02472	$0.02503	$0.02426	$0.03031	$0.01986	$0.01940
February	$0.02685	$0.02719	$0.02634	$0.03293	$0.02155	$0.02105
March						
Forecast	$0.02801	$0.02836	$0.02748	$0.03436	$0.02248	$0.02196
True Up **	($0.00293)	($0.00297)	($0.00287)	($0.00360)	($0.00235)	($0.00230)
Total	$0.02508	$0.02539	$0.02461	$0.03076	$0.02013	$0.01966
April						
Forecast	$0.02919	$0.02956	$0.02864	$0.03579	$0.02344	$0.02290
True Up **	($0.00332)	($0.00336)	($0.00326)	($0.00407)	($0.00267)	($0.00260)
Total	$0.02587	$0.02620	$0.02538	$0.03172	$0.02077	$0.02030
May	$0.03080	$0.03119	$0.03022	$0.03778	$0.02473	$0.02416
June						
Forecast	$0.03471	$0.03515	$0.03405	$0.04258	$0.02785	$0.02721
Refund ***	($0.00337)	($0.00342)	($0.00331)	($0.00413)	($0.00270)	($0.00265)
Total	$0.03134	$0.03173	$0.03074	$0.03845	$0.02515	$0.02456
July						
Forecast	$0.03011	$0.03048	$0.02953	$0.03694	$0.02416	$0.02359
Refund ***	($0.00294)	($0.00296)	($0.00287)	($0.00360)	($0.00236)	($0.00229)
Total	$0.02717	$0.02752	$0.02666	$0.03334	$0.02180	$0.02130
August						
Forecast	$0.02964	$0.03002	$0.02908	$0.03637	$0.02379	$0.02323
Refund ***	($0.00307)	($0.00311)	($0.00301)	($0.00377)	($0.00247)	($0.00240)
Total	$0.02657	$0.02691	$0.02607	$0.03260	$0.02132	$0.02083
September	$0.02879	$0.02915	$0.02824	$0.03531	$0.02310	$0.02257
October	$0.02782	$0.02817	$0.02729	$0.03412	$0.02233	$0.02181
November	$0.02519	$0.02550	$0.02471	$0.03090	$0.02021	$0.01974
December	**$0.02335**	**$0.02364**	**$0.02291**	**$0.02864**	**$0.01874**	**$0.01831**
YTD Average	**$0.02270**	**$0.02299**	**$0.02227**	**$0.02785**	**$0.01822**	**$0.01780**

* FAF Ratio effective since October 1, 2017. ** True up from November and December 2019 amounts subject to Commission approval *** Summer FCA Rate Adjustment.

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
- Forecast FCA – E002/M-00-420, E002/M-01-477, E,G002/M-01-838, E002/M-02-645, E002/M-03-585, E002/M-04-595, E002/M-05-613, E002/M-06-589, E002/M-07-484, E002/M-08-451, E002/M-14-364, and E002/M-17-445
- Fuel Clause Reform – E999/CI-03-802, Orders dated December 19, 2017, June 12, 2019, and November 5, 2019
- <u>2019 Fuel Factor True-Up – E002/AA-20-182</u>
- <u>2020 Fuel Forecast and Factors – E002/AA-19-293</u>
- <u>Adjustment to 2020 Fuel Factors – E002/AA-20-437</u>

For the 12 months ending December 31, 2020, 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, E002/M-09-1055, Notice of Approval dated October 12, 2009. Amendment approved in E002/M-17-26, Order dated October 8, 2018.
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[1] On July 24, 2013, the Company notified the MPUC that the PPAs with Goodhue North and Goodhue South had been terminated. The MPUC issued an Order closing the associated dockets on October 23, 2013.
[2] Id.
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- Solar Energy Standard Exemption – E002/M-17-425, Order dated October 12, 2017
- Sherco 3 Outage Settlement – E002/GR-12-961, E002/GR-13-868, E999/AA-13-599, E999/AA-14-579, E999/AA-16-523, E999/AA-17-482 and E999/AA-18-373, Order dated April 11, 2019

[5] ORDER ALLOWING ADDITION OF LIMITED SOLAR ENERGY TO WINDSOURCE PROGRAM, REQUIRING CUSTOMER NOTIFICATION AND REQUIRING COMPLIANCE FILING, June 21, 2010.

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, 2020 to December 31, 2020, and Independent Accountants' Report on Applying Agreed-Upon Procedures

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INDEPENDENT ACCOUNTANTS' REPORT ON APPLYING AGREED-UPON PROCEDURES

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

We have performed the procedures enumerated below, which were agreed to by Northern States Power Company, a Minnesota Corporation (the "Company") and the Minnesota Public Utilities Commission (the "Commission"), solely to assist you with the compliance of 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, as well as with Docket No. E-999/AA-15-611 on the Schedule of Fuel Adjustment Clause Factors ("the Schedule"). The Company's management is responsible for maintaining compliance with those requirements. The sufficiency of these procedures is solely the responsibility of those parties specified in this report. Consequently, we make no representation regarding the sufficiency of the procedures enumerated below either for the purpose for which this report has been requested or for any other purpose.

Our procedures and findings are as follows:

a. On a sample basis, we compared the documentation in support of payments and invoices received from energy suppliers for the 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 Minnesota Public Utilities Commission, to the bases used by the Company 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, 2020 to December 31, 2020, 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, 2020 to December 31, 2020 and found them to be in agreement.

e. We randomly selected twelve individual billings for each class of service for the period from January 1, 2020 to December 31, 2020, and recalculated the automatic adjustment charges and credits used by the Company and traced these amounts to the individual customer's subsidiary records to ensure that the calculated credit or charge was 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, 2020 to December 31, 2020.

g. We reconciled and gained an understanding of total revenue and the cost of power 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 to the Company's accounting records and found them to be in agreement with the amounts used in the true-up calculation.

i. Through inspection of a sample of twelve accounting records, we identified no exceptions with the accounting separation of retail and wholesale financial instruments.

j. On a sample basis, we inspected vendor invoices and traced gains and losses to the accounting records for one selection. We did not identify any wholesale electric financial instrument gains or losses recorded in Account 555 or Account 804.

This agreed-upon procedures engagement was conducted 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, the objective of which would be the expression of an opinion or conclusion, respectively, on the Schedule. 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.

This report is intended solely for the information and use of the Board of Directors 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 26, 2021

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, 2020 TO DECEMBER 31, 2020
(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, 2020	$ 0.02472	$ 0.02503	$ 0.02426	$ 0.03031	$ 0.01986	$ 0.01940
February 1, 2020	$ 0.02685	$ 0.02719	$ 0.02634	$ 0.03293	$ 0.02155	$ 0.02105
March 1, 2020	$ 0.02508	$ 0.02539	$ 0.02461	$ 0.03076	$ 0.02013	$ 0.01966
April 1, 2020	$ 0.02587	$ 0.02620	$ 0.02538	$ 0.03172	$ 0.02077	$ 0.02030
May 1, 2020	$ 0.03080	$ 0.03119	$ 0.03022	$ 0.03778	$ 0.02473	$ 0.02416
June 1, 2020	$ 0.03134	$ 0.03173	$ 0.03074	$ 0.03845	$ 0.02515	$ 0.02456
July 1, 2020	$ 0.02717	$ 0.02752	$ 0.02666	$ 0.03334	$ 0.02180	$ 0.02130
August 1, 2020	$ 0.02657	$ 0.02691	$ 0.02607	$ 0.03260	$ 0.02132	$ 0.02083
September 1, 2020	$ 0.02879	$ 0.02915	$ 0.02824	$ 0.03531	$ 0.02310	$ 0.02257
October 1, 2020	$ 0.02782	$ 0.02817	$ 0.02729	$ 0.03412	$ 0.02233	$ 0.02181
November 1, 2020	$ 0.02519	$ 0.02550	$ 0.02471	$ 0.03090	$ 0.02021	$ 0.01974
December 1, 2020	$ 0.02335	$ 0.02364	$ 0.02291	$ 0.02864	$ 0.01874	$ 0.01831

ANNUAL TRUE-UP FOR THE PERIOD FROM JANUARY 1, 2020 TO DECEMBER 31, 2020
(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
Annual true-up filing March 1, 2021 (factors proposed for September 2021)	$ 0.00177	$ 0.00179	$ 0.00174	$ 0.00217	$ 0.00142	$ 0.00139

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.-91.3 of the electric rates filed by the Company with the Commission, including Commission Revisions.

Miscellaneous Purchased Power Reporting

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

The Company is required to report in the AAA 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. The Company is not aware of any curtailments or curtailment payments during the current reporting period.

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. As of this AAA reporting period, the Company has not received any new revenue as described in this Order.

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

In a February 1, 2018 letter 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-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 desires 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 will purchase 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. The pricing under the Interim Agreement is subject to retroactive adjustment upon approval by the Commission of permanent pricing for the Extension Term. 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 2020 calendar year AAA reporting period.

Part C, Attachment 7 shows the production and invoiced amounts under the interim HERC agreement for the 2020 calendar year. The total cost paid during reporting period was $2.8 million, which is an average cost of $16.90/MWh. We note that due to an outage that extended from September into November, production and therefore cost from the HERC PPA were less than in prior years.

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. There were no offsetting revenues and/or compensation credited during the 2020 reporting period.

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 2020, were the most significant impact across the cost categories as illustrated in Table 1 below. Curtailments, on the other hand, were expected to have a larger impact based on experience with other resources. More specifically, the Company expected wind resources would be curtailed more often and solar resources would see minimal curtailments. In 2020, as was the case from 2017 through 2019, the opposite occurred. The program's wind resources were curtailed less than the program's solar resources. Curtailments on program solar resources totaled nearly $485,000, and $66,150 were allocated to the program. Wind curtailments totaled nearly $190,000 and $35,234 were allocated to the program. Overall curtailment costs on the Renewable*Connect facilities increased over four-fold in 2020 compared to 2019.

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 nearly $230,000 in wind integration costs for the 2020 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 an positive impact on non-participants. The results continue to indicate that non-participants see a strong benefit. For 2020, the Company calculated that benefit to be nearly $2.9 million.

Overall, neutrality payments fell short of participant cost by $81,866. However, when factoring the economic benefit of moving the higher priced Odell wind and Northstar solar from the Fuel Clause to Renewable*Connect, the net result is that non-participants received roughly a $2.8 million benefit due to the Renewable*Connect program.

Table 1 – Non-Participants Impact

	2020
Line Losses	$641,278
Solar Curtailments	$66,150
Wind Curtailments	$35,234
Integration/Balancing	$230,001
Total	$972,663
Neutrality Payments	$890,797
Non-Participant Cost/(Benefit)	$81,866

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 2020 reporting period.

Table 1: Unusual Items Over $500,000

Item Pertaining To	Period Affected	Descriptions	Amount (negative indicates cost decrease)	FCA Impact
MISO/PJM Congestion settlement (one time)	Mar-20	We've become aware of a settlement between MISO/PJM and a number of market participants who believe they were overcharged congestion costs related to loads pseudo-tied out of MISO into PJM. MISO will be paying $10.4M to these parties and recovering it via market charges to other market participants. NSP's share is estimated at ~$580k.	$580,000	Yes
Spring Coal Inventory Adjustment	May-20	Biannually, aerial imaging is used to measure the physical quantity of coal inventory at generation plants. Actual quantities are compared to Aligne inventory and a true-up adjustment is made to Aligne and SAP. This true-up is subject to contractual provisions with Sherco. Internal approval is also required to comply with SOX controls. Spring 2020 adjustments were booked as of 2020 Q2 close. This adjustment resulted in a net $1.7M decrease in inventory and a corresponding increase in fuel expense.	$1,702,888	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 are listed below.

We note that prior to Fuel Clause Reform, the Commission had approved regular variances to the Fuel Clause Rules allowing the Company to implement forecasted rates on a monthly basis. In compliance with the Commission's December 1, 2017 Order in Docket No. E002/M-17-445, the Fuel Clause Reform process has superseded this rule variance approval.

- 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
- Forecast FCA – E002/M-00-420, E002/M-01-477, E,G002/M-01-838, E002/M-02-645, E002/M-03-585, E002/M-04-595, E002/M-05-613, E002/M-06-589, E002/M-07-484, E002/M-08-451, E002/M-14-364, and E002/M-17-445
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- Sherco Land Sale Sharing Refund – E002/M-17-528, Order dated February 6, 2018
- Solar Energy Standard Exemption – E002/M-17-425, Order dated October 12, 2017
- Sherco 3 Outage Settlement – E002/GR-12-961, E002/GR-13-868, E999/AA-13-599, E999/AA-14-579, E999/AA-16-523, E999/AA-17-482 and E999/AA-18-373, Order dated April 11, 2019

[5] ORDER ALLOWING ADDITION OF LIMITED SOLAR ENERGY TO WINDSOURCE PROGRAM, REQUIRING CUSTOMER NOTIFICATION AND REQUIRING COMPLIANCE FILING, June 21, 2010.

Former AAA	Description	Docket or Rule	May 1, 2019 Annual Forecast of Rates	March 1, 2021 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 on Petition page 19	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 on Petition pages 18- 19	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 on Petition pages 18-19	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 on Petition pages 18-19	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 on Petition pages 18-19	Part A, Attachment 8
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	May 1, 2019 Annual Forecast of Rates	March 1, 2021 Annual True-Up Filing
Part H, Section 3	Natural Gas Financial Instruments	Dockets M-01-1953 and AA-02-950	NA	Report Narrative, p 18 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 on Petition pages 10 and 12 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 on Petition pages 9-10 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 on Petition page 17 Part C, Attachment 2	Part F, Attachment 4
Part H, Section 11	HERC	Docket 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 on Petition page 11 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 3/1/21 Report in Docket No. E999/CI-19-704
Part M	Notice of Reports Availability	Rule 7825.2840	Addendum to Petition	Part F, Attachment 6
New Compliance	Renewable*Connect Neutrality	Docket M-15-985	Discussed on Petition page 12 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 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 2020 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES

DOCKET NO. E002/AA-19-293

NOTICE OF REPORT AVAILABILITY
ANNUAL TRUE-UP REPORT

On March 1, 2021, 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, 2020 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, Mustafa Adam, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

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

xx electronic filing

DOCKET NO. **E002/AA-19-293**
E002/GR-15-826
E002/GR-13-868

Dated this 1st day of March 2021

/s/

____

Mustafa Adam
Regulatory Administrator

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