414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

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August 31, 2018

- VIA ELECTRONIC FILING -

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: ANNUAL REPORT
2018 ANNUAL AUTOMATIC ADJUSTMENT OF CHARGES REPORT - ELECTRIC
DOCKET NO. E999/AA-18-373

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed annual report pursuant to Minnesota Rules 7825.2800 to 7825.2840 governing Automatic Adjustment of Charges. This report covers the Company's electric utility operations. The natural gas utility report is being filed separately.

Various attachments to this filing contain information that Xcel Energy considers Not Public. We provide justification for the identification of the data designated as Not Public in Attachment L of this filing.

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document with the Minnesota Public Utilities Commission, and a filing summary has been served on the parties on the attached service lists. Please contact Rebecca Eilers at 612- 330-5570 or rebecca.d.eilers@xcelenergy.com or me at 612-330-6613 or amy.a.liberkowski@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

AMY LIBERKOWSKI
DIRECTOR, REGULATORY PRICING & ANALYSIS

Enclosures
c Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie J. Sieben	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF NORTHERN STATES POWER COMPANY'S ANNUAL AUTOMATIC ADJUSTMENT OF CHARGES REPORT FOR ITS ELECTRIC OPERATION

ANNUAL REPORT

DOCKET NO. E999/AA-18-373

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits this Annual Report as required in Minnesota Rules 7825.2800 to 7825.2840 governing Automatic Adjustment Charges (AAA) for electric utilities for the period July 1, 2017 to June 30, 2018. This Report includes a summary of our fuel costs over the past 12 months, a forecast of fuel costs over the next five years, and information on our efforts to manage fuel costs.

Our overall fuel costs have increased modestly by 2.7 percent compared to the 2016-2017 time period. In 2017 – 2018, the total net system fuel cost was about $1.055 billion, and in 2016 – 2017 the total net system fuel cost was about $1.027 billion. On a total system energy basis, the per unit cost has increased by 2.1 percent from $25.08 per MWh in 2016 – 2017 to $25.60 per MWh in 2017 – 2018. Stable natural gas prices and energy market price attributed to favorable fuel costs during this period whereas the increased presence of higher cost solar resources has resulted in an overall modest increase in total fuel costs.

I. SUMMARY OF FILING

Pursuant to Minn. R. 7829.1300, subp. 1, a one-paragraph summary of the filing accompanies this Report.

II. SERVICE ON OTHER PARTIES

The Company has electronically filed this document with the Minnesota Public Utilities Commission, and copies of the Notice of Report Availability have been served on the parties on the attached service lists.

III. GENERAL FILING INFORMATION

Pursuant to Minn. R. 7829.1300, subp. 3, the Company provides the following required information.

A. Name, Address, and Telephone Number of Utility

Northern States Power Company
414 Nicollet Mall
Minneapolis, Minnesota 55401
(612) 330-5500

B. Name, Address, and Telephone Number of Utility Attorney

Ryan Long
Lead Assistant General Counsel
Xcel Energy
414 Nicollet Mall – 401 8th Floor
Minneapolis, Minnesota 55401
(612) 215-4659

C. Date of Filing and Date Modified Rates Take Effect

Consistent with the filing requirement in Minn. Rules 7825.2840, the date of this filing is August 31, 2018. The information contained in this filing is submitted in compliance with the aforementioned Rules concerning AAA reports.

D. Statute Controlling Schedule for Processing the Filing

No statute establishes a schedule for processing this filing. The applicable rules are Minn. R. 7825.2800 through 7825.2840.

E. Utility Employee Responsible for Filing

Amy A. Liberkowski
Director, Regulatory Pricing & Analysis
Xcel Energy
414 Nicollet Mall – 401 7th Floor
Minneapolis, Minnesota 55401

(612) 330-6613

IV. MISCELLANEOUS INFORMATION

Pursuant to Minnesota Rule 7829.0700, the Company requests that the following persons be placed on the Commission's official service list for this matter:

Ryan Long	Carl Cronin
Lead Assistant General Counsel	Regulatory Administrator
Xcel Energy	Xcel Energy
414 Nicollet Mall – 401 - 8th Floor	414 Nicollet Mall – 401 - 7th Floor
Minneapolis, Minnesota 55401	Minneapolis, Minnesota 55401
ryan.j.long@xcelenergy.com	Regulatory.Records@xcelenergy.com

V. DESCRIPTION AND PURPOSE OF FILING

A. Background

As noted above, this filing contains information provided in response to the annual reporting requirements specified in the following rule sections:

7825.2800 Annual Reports: Policies and Actions ....Part D
7825.2810 Annual Report: Automatic Adjustment Charges ....Part E
7825.2820 Annual Auditor's Report...Part F
7825.2830 Annual Five-Year Projection. ....Part G

We provide the Annual Notice of Reports Availability under Minn. Rule7825.2840 at the end of our filing. Attachment L contains the justification for treating certain information contained in this filing as Not Public.

7825.2800 Annual Reports: Policies and Actions

Part D includes the following schedules and a brief summary of the topics listed in the rule:

Section 1 Procurement Policies
Section 2 Dispatching Policies and Procedures
Section 3 Fuel Supply
Section 4 Conservation and Load Management Policy
Section 5 Other Actions

7825.2810 Annual Report: Automatic Adjustment of Charges

Part E contains a summary of the annual reporting (by month) of all electric automatic adjustment charges for each customer class for the prior year commencing July 1, 2017 and ending June 30, 2018. It includes the following schedules as set forth in Subp. 1:

Section 1 Base Cost of Fuel
Section 2 Billing Adjustment Amounts Charged Customers for Each
Section 3 Total Cost of Fuel Delivered to Customers
Section 4 Revenue Collected from Customers for Energy Delivered
Section 5 Monthly Fuel Cost Charge

7825.2820 Annual Auditor's Report

Part F, Section 2 contains the independent auditor's report evaluating the Company's accounting of electric automatic adjustments for the 12 months ending June 30, 2018. Deloitte & Touche LLP prepared this report. In addition, Part F, Section 1 contains the Company's letter of instruction to the independent auditor.

We note that the audit report found that billing month sales were used instead of calendar month sales for the margin sharing component of one monthly FCA report during this AAA period. We are putting processes in place to give this section of the monthly report a higher level of scrutiny to prevent this occurrence in the future.

7825.2830 Annual Five-Year Projection and FCA Settlement Compliance

This report contains a monthly five-year projection of fuel cost by energy source. This five-year projection, which contains Not Public information, is submitted as Part G. In addition, in compliance with the "FCA Settlement" in the Company's 2005 electric rate case (Docket No. E002/GR-05-1428), the Company is providing its quarterly 12-month FCA forecast provided to customers who have signed the protective agreement (Part J, Section 4, Schedule 1). The FCA forecast also discusses monthly deviations in FCA filings. This requirement is also cited in paragraph D in the December 20, 2006 Order in Docket No. E002/M-04-1970, the MISO Day 2 cost recovery docket.

7825.2840 Annual Notice of Reports Availability

Minn. Rules part 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. The Company's notice is submitted as Part M and includes the following schedules:

Schedule 1 Notice of Reports Availability
Schedule 2 Certificate of Service
Schedule 3 Service Lists

VI. OTHER SUBMITTALS

We have included additional Parts H, I, J and K, as described in more detail below, which provide information that falls outside the requirements of the Commission's rules concerning the AAA. We note that with the forthcoming FCA Reform approved by the Commission, some of these reporting requirements may not be necessary during future annual reviews of the fuel clause. Annual reporting issues are being discussed as part of the reform process in Docket No. E999/CI-03-802.

A. Justification of Trade Secret Data Protection

Pursuant to Rule 7829.0500, the Company is requesting that certain parts of this report be designated as trade secret information. Justification for trade secret protection is provided in Attachment L.

B. Miscellaneous Compliance Reports

Parts H, I, J and K contain responses related to various compliance reports required by Commission Orders issued in prior Company filings and AAA reports. The following is a list of these additional reports in compliance with Commission Orders for the referenced dockets:

Investigation of NSP's Practices Regarding Energy Marketing and Fuel Clause	E002/CI-00-415	Part H, Section 2
Natural Gas Financial Instruments	E002/M-01-1953 and E999/AA-02-951	Part H, Section 3
Transmission Transformer Report	E,G999/AA-07-1130, E999/M-07-1028, E999/M-09-602	Part H, Section 4
Wind Curtailment Report	E002/M-00-622, E002/M-02-51, E002/M-04-404, E002/CN-01-1958, E002/M-04-864, E,G999/AA-04-1279, E002/M-05-1850, E002/M-05-1934 and	Part H, Section 5

	E002/M-06-85	
Renewable Energy Purchase Agreement with KODA Energy, LLC	E002/M-08-1098	Part H, Section 6
Power Purchase Agreement with WM Renewable Energy, LLC	E002/M-10-61	Part H, Section 7
Power Purchase Agreement with Diamond K Dairy, Inc.	E002/M-10-486	Part H, Section 8
Community Solar Gardens	E002/M-13-867	Part H, Section 9
Rule Variance Dockets	E002/AA-15-611	Part H, Section 10
MISO "Day 1" Operations	E002/M-00-257	Part I, Sections 1-9
MISO "Day 2" Operations	E002/M-04-1970 *et al* E002/GR-05-1428 E,G999/AA-06-1208 E999/AA-14-469	Part J, Sections 1, 2, 3 and 5
FCA Quarterly Forecasts	E002/GR-05-1428	Part J, Section 4
2006 AAA & MISO Filing Requirements	E,G999/AA-06-1208, E002/M-04-1970 *et al*	Part K, Section 1
2007 AAA Filing Requirements	E,G999/AA-07-1130	Part K, Section 2
2008 AAA Filing Requirements	E,G999/AA-08-995	Part K, Section 3
2009 & 2010 AAA Filing Requirements	E999/AA-09-961 and E999/AA-10-884	Part K, Section 4
2011 AAA Filing Requirements	E999/AA-11-792	Part K, Section 5

In addition to the above-noted compliance requirements, we made a commitment in a February 1, 2018 letter in Docket No. E002/M-17-532 to provide additional supporting information about the interim costs associated with the Hennepin Energy Recovery Center (HERC) PPA. These costs impact the second half of the 2017-2018 AAA reporting period. We require additional time to assemble the information and will provide it in a supplemental filing in this AAA docket within 45 days.

CONCLUSION

The Company submits this annual report for its electric utility operation pursuant to the Commission's rules regarding Automatic Adjustment of Charges.

Dated: August 31, 2018

Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie J. Sieben	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF NORTHERN STATES POWER COMPANY ANNUAL AUTOMATIC ADJUSTMENT OF CHARGES REPORT FOR ITS ELECTRIC OPERATION

ANNUAL REPORT

DOCKET NO. E999/AA-18-373

SUMMARY

Please take notice that on August 31, 2018, Northern States Power Company, doing business as Xcel Energy, filed with the Minnesota Public Utilities Commission the annual report for its electric operations pursuant to the Commission's rules (Minn. R. Parts 7825.2800 to 7825.2840) regarding the Automatic Adjustment of Charges.

NORTHERN STATES POWER COMPANY
2017-2018
ANNUAL AUTOMATIC ADJUSTMENTS REPORTS
(Electric Utility)

SUBMITTED TO THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Docket No. E999/AA-18-373

August 31, 2018

TABLE OF CONTENTS

LIST OF SCHEDULES

2017 – 2018 ELECTRIC AAA REPORT

A. Overview

This report provides an overview of fuel costs (actual and forecast) as well as other expenses the Company is authorized to recover through the fuel clause rider during the twelve-month period of July 1, 2017 – June 30, 2018. The Company has been providing detailed information in its monthly Fuel Clause Adjustment (FCA) filings during this reporting period. The Company will continue to provide this type of information in its monthly FCA filings to keep the agencies informed of any significant events. We note that the Commission's December 19, 2017 Order in Docket No. E999/CI-03-802 approved reforms to the fuel clause mechanism that will impact implementation and reporting on the fuel clause in the near future.

B. Reporting Requirements

This report also includes the compliance reporting related to the effects of the Midcontinent Independent System Operator, Inc. (MISO) Day 2 wholesale energy market adopted by the Commission in its Orders in Docket No. E002/M-04-1970 *et al.*[1] Certain reporting requirements are similar to the additional forecast information required by the Settlement Agreement – Advanced Forecast for Fuel and Purchased Energy Costs (FCA Settlement) in our 2005 electric general rate case (Docket No. E002/GR-05-1428).[2] In addition to submitting additional compliance information in this AAA report and monthly FCA filings, the Company has been providing on a quarterly basis the 12-month fuel cost forecast information to customers who have signed protective agreements with the Company. Currently there are 17 representatives from intervening parties who have signed the protective agreements and are receiving the FCA forecast information.

Pursuant to Minnesota Rule, this report contains the annual reporting requirements specified in the following rule sections:

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

[1] *In the Matter of Xcel Energy's Petition for Affirmation that MISO Day 2 Costs are Recoverable Under the Fuel Clause Rules and Associated Variances et al.*, ORDER ESTABLISHING ACCOUNTING TREATMENT FOR MISO DAY 2 COSTS, Docket No. E002/M-04-1970 *et al.* (December 20, 2006), *aff'd by* Minnesota Court of Appeals in A07-0730.

[2] The FCA Settlement was approved in Docket No. E002/GR-05-1428, Order dated September 1, 2006.

7825.2840 Annual Notice of Reports Availability

C. Additional Compliance Reports

We have included additional compliance reports pursuant to other Commission Orders related to the Automatic Adjustment of Charges. The following is a list of these additional reports and the dockets in which the Commission ordered the reports to be provided:

Investigation of NSP's Practices Regarding Energy Marketing and Fuel Clause	E002/CI-00-415	Part H, Section 2
Natural Gas Financial Instruments	E002/M-01-1953 and E999/AA-02-951	Part H, Section 3
Transmission Transformer Report	E,G999/AA-07-1130, E999/M-07-1028, E999/M-09-602	Part H, Section 4
Wind Curtailment Report	E002/M-00-622, E002/M-02-51, E002/M-04-404, E002/CN-01-1958, E002/M-04-864, E,G999/AA-04-1279, E002/M-05-1850, E002/M-05-1934 and E002/M-06-85	Part H, Section 5
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Power Purchase Agreement with WM Renewable Energy, LLC	E002/M-10-61	Part H, Section 7
Power Purchase Agreement with Diamond K Dairy, Inc.	E002/M-10-486	Part H, Section 8
Community Solar Gardens	E002/M-13-867	Part H, Section 9
Rule Variance Dockets	E999/AA-15-611	Part H, Section 10
MISO "Day 1" Operations	E002/M-00-257	Part I, Sections 1-9
MISO "Day 2" Operations	E002/M-04-1970 *et al* E002/GR-05-1428 E,G999/AA-06-1208 E999/AA-14-479	Part J, Sections 1, 2, 3 and 5
FCA Quarterly Forecasts	E002/GR-05-1428	Part J, Section 4
MISO Ancillary Services Market (ASM)	E002/M-08-528	Part J, Sections 6 and 7
2006 AAA & MISO Filing Requirements	E,G999/AA-06-1208 and E002/M-04-1970 *et al*	Part K, Section 1
2007 AAA Filing Requirements	E,G999/AA-07-1130	Part K, Section 2
2008 AAA Filing Requirements	E,G999/AA-08-995	Part K, Section 3
2009 & 2010 AAA Filing Requirements	E999/AA-09-961 and E999/AA-10-884	Part K, Section 4
2011 AAA Filing Requirements	E999/AA-11-792	Part K, Section 5

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-18-373

PART D

POLICIES AND ACTIONS

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, Section 1, Schedules 2, 3 and 5.

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**

PROTECTED DATA ENDS]

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

Nuclear

Following the March 2011 events at the Fukushima-Daiichi Nuclear Plant in Japan, the market price for uranium dropped 30 percent from the high earlier in 2011. The market price for uranium during the first two quarters of 2018 has been relatively stable overall with a high spot market price of $23.75 per pound in January to a low of $20.50 per pound in mid-April. The spot market opened the first quarter at $23.75 per pound and ended the second quarter at $22.55 per pound. The market price for uranium is at 30.8 percent of the pre-Fukushima price peak of January 2011. The market continues to show no signs of immediate recovery to pre-Fukushima-Daiichi levels.

Even at today's market prices, the cost of nuclear fuel continues to be substantially 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 decrease through the closure of mines, reduction of production targets and suspension of production at mines throughout the world. New supply entering the marketplace continues to slow due to the continuing low market price of uranium. Several planned uranium mine expansions globally have been cancelled or delayed until market conditions improve. Uncertainty continues in predicting the impact of the Japan event on worldwide construction of new nuclear power plants and the associated demand for uranium. Early closures of nuclear power plants in the United States have reduced demand. Uranium demand exceeds supply. However, the difference between supply and demand is projected to be covered by end user inventories. Spot market volume at 25.9 million pounds of U3O8 for the first two quarters of 2018 is significantly above the 15 million pounds of U3O8 for this period in 2017 and is approximately 12 percent higher than the volume for this period in 2016. For the rest of 2018 and into 2019, prices will likely remain steady to slightly increasing as uranium end users draw down inventories and producers cover obligations. Spot market volumes are forecasted to remain steady. Longer-term prices will likely increase as production cuts result in supplies continuing below demand. Additionally demand is likely to increase with the restart of more reactors in Japan and 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 2021, 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 the U.S. Department of Commerce initiating a Section 232 investigation into uranium imports, uncertainty with regard to trade policy with China 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. If the sanctions impact the supply of uranium in the form 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 listing of current nuclear fuel components of service contracts is shown on Part D, Section 1, Schedule 1.

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.

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. 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). 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.

[PROTECTED DATA BEGINS

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Conclusion

Commodity fuel cost variability and the impact on purchased wholesale energy prices affects retail rates charged to our electric customers in Minnesota through the FCA. The Company has worked to respond to the various factors beyond our control to minimize the costs for our customers.

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Nuclear Fuel Components of Services for the Period of July 2017 through June 2018

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

* New contracts

Transportation & Related Services Contracts

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

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

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

Cost Changes - July 1, 2017 to June 30, 2018

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

Cost Changes - July 1, 2017 to June 30, 2018

	Contract	Percent Change
[PROTECTED DATA BEGINS		
		PROTECTED DATA ENDS]

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.

In addition to monitoring our load and managing our generation and purchased resources, Xcel Energy continually monitors weather patterns and energy market trends in the Midwest and other regions to obtain the lowest cost energy possible for our customers. In general, Xcel Energy will purchase energy for its customers on the wholesale market whenever the market price of energy is below our avoided cost of generation. Since market prices cannot be predicted with certainty, Xcel Energy must carefully assess potential needs in the face of varying market conditions. These assessments are an integral part of our cost and risk minimization efforts.

Xcel Energy also 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 both in the bilateral market and 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 energy procurement and dispatch processes of Minnesota utilities within the context of the MISO Day 2 market were described in detail in the joint report dated June 22, 2006 in Docket Nos. E002/M-04-1970 *et al*. The Company incorporates that report by reference.

Detailed descriptions of MISO's administration of its market were included in the joint filing dated May 9, 2008 in Docket No. E999/M-08-528. The Company uses MISO ASM to co-optimize energy and ancillary services markets, resulting in a net benefit to ratepayers (See Part J, Section 6 of this AAA report).

Another component of the Company's dispatching policy is the ability to forecast 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. In the fall of 2009, Xcel Energy began using this tool to forecast output from all NSP system wind farms and steadily reduced its wind forecast error. Reductions in forecast error translate directly into a decrease in fuel and purchased power costs because an improved wind forecast from the Company helps MISO improve unit commitment.

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 dispatch 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. For more information on wind curtailment, please see Part H, Section 5. 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 2017.

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

3. Two contracts were executed **[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 $2.16/MBtu during 2016. (http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.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 2015 was **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**.

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

PROTECTED DATA ENDS]

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

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

PROTECTED DATA ENDS]

c. MISO Energy Charges

The Company actively checks, investigates, and disputes (when appropriate) calculations and the charges billed by MISO in the Day 2 energy market. From July 2017 through June 2018, the Company disputed approximately three days of 104 MISO invoices. As a result, $12,338 in disputed amounts were granted by MISO for the NSP System (through adjustments to MISO settlements).

NSP MISO Dispute Status

Disputed $ Amount			**Dispute Status**			
Year	Op Month	Operating Date	**GRANTED**	**DENIED**	**OPEN**	**TOTAL**
2017	2017-12	12/27/17	$0.00	$5,885.00	$0.00	$5,885.00
2017 Total			$0.00	$5,885.00	$0.00	$5,885.00
2018	2018-02	02/05/18	$0.00	$886.85	$0.00	$886.85
	2018-03	03/29/18	$12,337.78	$0.00	$0.00	$12,337.78
2018 Total			$12,337.78	$886.85	$0.00	$13,224.63
TOTAL			$12,337.78	$6,771.85	$0.00	$19,109.63

The total dollar amount disputed in the 2017 – 2018 AAA period is lower than in the 2016 – 2017 AAA period. During the current period the Company found fewer settlement discrepancies requiring a formal dispute to be filed with MISO. Discrepancies not requiring a formal dispute are routinely resolved through the normal settlement process.

CONSERVATION IMPROVEMENT PROGRAM

Xcel Energy's Conservation Improvement Program (CIP), including energy efficiency, conservation and load management, is designed to help our customers use energy wisely. The Company has developed 36 commercial and residential CIP programs with the intent of providing our 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 customer education pilots aimed to help control demand through smart thermostats. 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 and daily operations in the MISO Day Ahead and Real Time energy markets.

The Company has three electric load management programs available to customers: Electric Rate Savings, Saver's Switch® and AC Rewards. These programs provide customers rate discounts for reducing electric load on days with peak demand for electricity (termed "control periods" or "control days").

In the Electric Rate Savings program, business participants receive a monthly discount on their demand charges in return for reducing electric loads when notified by Xcel Energy. Customers must be able to reduce their electric loads by a minimum of 50 kW on control days. Participants save anywhere from 40 to 60 percent on demand charges over the entire year for the demand they agree to reduce during control periods.

Electric Rate Savings is designed to be utilized on hot, humid summer weekdays. Although control days typically occur during the summer months, they can occur anytime through the year when the reliability of the system may be at risk.

The Saver's Switch program is a direct load control load management offering available to both business and residential customers.

Similar to Electric Rate Savings, Saver's Switch is designed to be utilized on hot, humid summer weekdays. Saver's Switch participants receive electric bill discounts from June through September for agreeing to have the Company control electric central air conditioners during times of peak electric demand.[1]

Our newest program is AC Rewards, which utilizes a smart thermostat to control customer load during summer weekdays. The opt-in control program allows customers to take control of their energy use during these peak times, earning an overall summer incentive.

The Company is also required to file with the Department no more than every three years, a CIP 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 CIP Triennial Plan for 2017-2019, which was filed on June 1, 2016 and approved on November 3, 2016.[2]

On April 1 of each year, the Company is required to file with the Department an Annual Status Report, which details the cost-effectiveness and spending for the prior year's CIP program. The Deputy Commissioner issued his approval of the Company's 2017 Electric and Gas CIP Status Report on August 6, 2018.[3]

[1] Saver's Switch also has an additional water heating component providing year round incentives.
[2] Docket No. E,G002/CIP-16-115
[3] Docket No. E,G002/CIP-16-115.06.

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. In this schedule, references to "the Commission" are references to the FERC, not the Minnesota Public Utilities Commission.

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

[1] As described elsewhere in this AAA Report, 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."

are critical to ensuring the development of transmission system additions that achieve maximum efficiency benefits.

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.

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-18-373

PART E

AUTOMATIC ADJUSTMENT CHARGES

BASE COST OF ENERGY

On November 2, 2015 the Company filed a Petition to increase electric rates (Docket No. E002/GR-15-826). A new Base Cost of Energy of $0.02680 per kWh was approved in the associated docket, Docket No. E002/MR-15-827, and went into effect January 1, 2016. The Commission issued its Order approving the rate case on June 12, 2017. Final rates were implemented on October 1, 2017.

The table below shows the Fuel Adjustment Factor (FAF) Ratio and Base Cost of Energy by the Service Category effective during the July 1, 2017 through September 30, 2017 portion of the 2017-2018 AAA period.

Effective January 1, 2016 to September 30, 2017[1]

Service Category	FAF Ratio	Base Cost of Energy
Residential	1.0185	$0.02730
C & I Non-Demand	1.0493	$0.02812
C & I Demand	1.0028	$0.02688
C & I Demand TOD On-Pk	1.2732	$0.03412
C & I Demand TOD Off-Pk	0.7987	$0.02141
Outdoor Lighting	0.7446	$0.01996

The table below shows the Fuel Adjustment Factor (FAF) Ratio and Base Cost of Energy by the Service Category effective during the October 1, 2017 through June 30, 2018 portion of the 2017-2018 AAA period.

Effective October 1, 2017 to Present[2]

Service Category	FAF Ratio	Base Cost of Energy
Residential	1.0177	$0.02727
C & I Non-Demand	1.0305	$0.02762
C & I Demand	0.9984	$0.02676
C & I Demand TOD On-Pk	1.2486	$0.03346
C & I Demand TOD Off-Pk	0.8166	$0.02188
Outdoor Lighting	0.7976	$0.02138

[1] The Commission's December 22, 2015 Order in Docket Nos. E002/GR-15-826 and E002/MR-15-827 authorized the new Base Cost of Energy with the implementation of interim rates on January 1, 2016.
[2] The Commission's June 12, 2017 Order in Docket No. E002/GR-15-826 authorized final rates which were implemented on October 1, 2017.

BILLING ADJUSTMENT AMOUNTS CHARGED TO CUSTOMERS FOR EACH TYPE OF ENERGY COST

Please refer to lines [2b] of Part E, Section 5, Schedule 1, Page 2 of 5 for this information. The billing adjustments for the reporting period reflect several specific and distinct adjustments.

1. Class-Specific Fuel Cost Charge (FCC) Adjustments

The average system fuel cost is differentiated by six (6) separate class-specific charges. Schedule 1 includes detailed fuel, purchased energy costs and MISO Day 2 and ASM expenses data pursuant to reporting requirements under Minn. Rule 7825.2810 and the Commission's December 1, 2017 Order granting the Company's Renewal of Forecast FCA Method Rule Variance (Docket No. E002/M-17-445).

2. Exemption of WindSource

Pursuant to Commission Orders approving the Company's Voluntary Renewable Energy Rider (Windsource Program), beginning with the calendar month of March 2003, the Company is required to exempt Windsource energy from the Fuel Clause Adjustment.[1] Line [1b 13] of Part E, Section 5, Schedule 1, Page 1 of 5 illustrates this amount of exempted energy.

As addressed in the Company's Windsource proceeding, a purchase of Renewable Energy Credits (RECs) is used to resolve the program deficit when wind farms do not generate enough wind energy to meet Windsource sales requirement over a 12 month period.[2]

As part of the 2011 test year general electric rate case (Docket No. E002/GR-10-971), the Company also agreed with the Department of Commerce's recommendation to more promptly credit retail customers through the FCC the Windsource "Brown Energy" as a result of use of RECs in place of a physical energy purchase. The May 2013 FCC was the beginning of such credits to retail customers on a quarterly basis that was previously applied annually. Beginning with July 2013 actuals, the "Brown

[1] ORDER APPROVING XCEL'S RENEWABLE ENERGY RIDER WITH MODIFICATIONS, Docket No. E002/M-01-1479 (May 7, 2002); ORDER REQUIRING REVISED TARIFF, Docket No. E002/M-01-1479 (January 10, 2003).

[2] *See* Company response to Information Request No. DOC-14, November 20, 2009 in PETITION FOR APPROVAL OF REVISIONS TO ITS VOLUNTARY RENEWABLE AND HIGH EFFICIENCY PURCHASE (WINDSOURCE PROGRAM) RIDER (Docket No. E002/M-09-1177).

Energy" credit had been computed and returned to Minnesota retail customers on a monthly basis.

3. MISO Day 2 Energy Market Charges

Pursuant to Commission Orders in Docket No. E002/M-04-1970 *et al.*,[3] the Company was authorized to recover certain MISO Day 2 wholesale energy market costs incurred starting April 1, 2005 through the FCA.

In November 2005, the Company filed its electric general rate case (Docket No. E002/GR-05-1428) using a 2006 test year. The rate case sought recovery of all MISO Day 1 and Day 2 charges in either base rates or the FCA. The Commission's interim rate order transferred collection of the MISO Schedule 16 and 17 energy market administrative charges from the base cost of the FCR to base rates.[4] Because the Company's FCA is on a forecast basis, the Company's March 2006 forecast excluded the Schedule 16 and 17 costs from the fuel and energy costs, pursuant to the Commission's decisions in Docket Nos. E002/GR-05-1428 and E002/M-05-1759. Schedule 16 and 17 costs were collected in interim rates outside of the FCA effective January 1, 2006. Line items [1b 5] and [1b 10] of Part E Section 5 Schedule 1, Page 1 of 5 contain the monthly MISO Day 2 charges and Schedules 16, 17 and 24 amounts excluded from the monthly fuel clause.[5]

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[3] ORDER AUTHORIZING INTERIM ACCOUNTING FOR MISO DAY 2 COSTS, SUBJECT TO REFUND WITH INTEREST, Docket No. E002/M-04-1970 et al. (April 7, 2005); and ORDER ESTABLISHING SECOND INTERIM ACCOUNTING FOR MISO DAY 2 COSTS, PROVIDING FOR REFUNDS, AND INITIATING INVESTIGATION, Docket No. E002/M-04-1970 et al. (December 21, 2005); ORDER ON RECONSIDERATION SUSPENDING REFUND, GRANTING DEFERRED ACCOUNTING AND REQUIRING FILINGS (February 24, 2006); and ORDER ESTABLISHING ACCOUNTING TREATMENT FOR MISO DAY 2 COSTS (December 20, 2006) (together the "MISO Day 2 Orders"). *Aff'd by* Minnesota Court of Appeals in A07-0730 (April 15, 2008).

[4] "Xcel [Energy] has submitted a revised schedule, which the Commission finds consistent with the Commission's decision to reclassify Schedule 16 and 17 costs from fuel costs (hence collectible through the Fuel Adjustment Clause) to those recoverable through the base tariff rates." *In the Matter of Xcel Energy's Petition for Approval of a New Base Cost of Energy*, Docket No. E002/M-05-1759, ORDER APPROVING NEW BASE ELECTRIC COST AND REQUIRING ADJUSTED TARIFF (December 30, 2005), p. 2.

[5] The Company included its 2005 Schedule 16 and 17 costs in the FCA pending the outcome of Docket No. E002/M-04-1970, based on the April 7, 2005 interim order. The settlement in the Company's 2005 rate case (Docket No. E002/GR-05-1428) allowed base rate recovery of fifty percent; and deferred accounting of fifty percent of the 2006 test year Schedule 16 and 17 costs (approximately $8.9 million total) until the Company's next electric general rate case, rather than recover the full costs in the final rates in the 2005 rate case. The Commission approved the settlement agreement on September 1, 2006.

As a result of the obligations in the 2005 rate case and MISO Day 2 dockets, the following monthly refunds have been incorporated since the March 2007 FCC:

a. Asset Based Margin Sharing

The ongoing Asset Based Margin Sharing is included in the monthly Fuel Cost Charge on a two months lag basis.

b. Deferred Auction Revenue Rights(ARR) Credit

On March 17, 2009, the Commission issued an Order in Docket No. E001, E015, E002, E017/M-08-528, which authorized the Company to flow through three new Financial Transmission Rights (FTRs) amounts and four ARR charge types.

The three new FTR items are:
- FTR Full Funding Guarantee Amount
- FTR Guarantee Uplift Amount
- FTR Monthly Transaction Amount;

The four new ARR charge types are:
- ARR- FTR Auction Transactions
- Monthly ARR Revenue
- Infeasible ARR Uplift
- ARR Stage 2 Distribution

4. MISO Ancillary Services Market (ASM) Charges

On December 20, 2006 the Commission issued an Order in Docket No. E002/M-04-1970, et al., adopting the recommendation of the Joint Report and Recommendation (Joint Report) prepared by stakeholders, which, except for Schedules 16 and 17 costs, allowed the Company to recover the charges for MISO Day 2 operations.[6] On February 6, 2008 the Commission issued an Order in Docket No. E001/M-05-406, et. al., which made certain amendments to the December 20, 2006 Order, namely requiring Revenue Sufficiency Guarantee (RSG) charges and Revenue Neutrality Uplift (RNU) charges to be allocated on a straight megawatt-hour basis. Finally, and as noted above, on August 23, 2010 the Commission issued an order in Docket No.

[6] Those stakeholders included Minnesota investor-owned electric utilities, Minnesota Department of Commerce, MISO, Minnesota Chamber of Commerce and Large Power Interveners.

E001, E015, E002, E017/M-08-528,[7] which authorized the Company to recover costs and flow through revenues related to the new MISO ASM charge types. Line [1b 11] of Part E Section 5 Schedule 1, Page 1 of 5 contains the monthly MISO ASM charges. In compliance with the Commission's March 16, 2018 Order, Day-Ahead and Real-Time Ramp Capability charges are reported as separate line items and are not combined with other MISO ancillary services market charges.

5. Community Solar Garden Program Cost Recovery

Pursuant to the Commission's September 17, 2014 Order in our Community Solar Gardens Program (Docket No. E002/M-13-867), the Company is authorized to recover certain costs associated with this program through the Minnesota FCR. The costs include customer bill credits, additional Renewable Energy Credits (RECs) and unsubscribed energy. As of August 2018, the Company is recovering the monthly fuel costs from 414 community solar gardens. See Part H, Section 9 of this report for more detailed information.

6. Renewable*Connect Program

Pursuant to the Commission's February 27, 2017 Order in Docket No. E002/M-15-985, beginning with calendar month March 2017, the Company is required to exempt Renewable*Connect and Renewable*Connect Government pilot program energy from the Fuel Clause Adjustment. Line [1b 16] of Part E, Section 5, Schedule 1, Page 1 of 5 illustrates this amount of exempted energy.

[7] Pursuant to the final Order, the Contingency Reserve Deployment Failure and the Excess/Deficient Energy charges are subject to refund.

TOTAL COST OF FUEL DELIVERED TO CUSTOMERS

Line item 37 of Part E, Section 5, Schedule 1, Page 3 of 5, contains the Minnesota retail portion of NSP System fuel and purchased energy costs. (The "NSP System" refers to the integrated generation and transmission systems of Northern States Power Company-Minnesota and Northern States Power Company-Wisconsin.)

The class differentiated FCC method was used July 1, 2017 through June 30, 2018, the 2018 AAA reporting period. The individual class totals were reported on line items [3 23] through [3 29].

REVENUE COLLECTED FROM CUSTOMERS FOR ENERGY DELIVERED

Line [4 8] and Line [4 16] of Part E, Section 5, Schedule 1, Page 4 of 5 contain the Minnesota retail electric fuel revenues collected under both the Base Cost of Energy and fuel clause adjustment (fuel cost excess of Base).

While comparing line item cost and revenues may appear to reveal a mismatch between the current month cost and the collections in that month, such a comparison does not necessarily reveal an accurate picture of the financial impact such collections have on the Company. Following accepted accounting principles, each month Xcel Energy books an estimate of the expected future recovery of the energy costs associated with the current month. This accounting properly matches the energy expense of a particular month with the future cost recovery (the fuel clause revenue) associated with those expenses.

Line items [4 48] to [4 55] of Part E, Section 5, Schedule 1, Page 4 of 5 are the actual fuel costs and the individual class totals that included the forecast true-up and any applicable refunds during the AAA reporting period.

In compliance with the Commission's December 7, 2005 Order in the 2004 electric AAA proceeding (Docket No. E,G999/AA-04-1279), the Company has included Part E, Section 5, Schedules 2, 3, 4 and 5 showing the reasonable proxies for billing adjustment amounts for each type of energy cost, pursuant to the Commission's interpretation of Rule 7825.2810, subp 1B.

Northern States Power Company, A Minnesota Corporation
Electric Operations - State of Minnesota
Monthly Fuel Clause Charge July 2017 - June 2018

	Month Fuel Cost Charges Applied to Customer Billing	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	12 Months
	MONTH AHEAD FORECASTED COST OF FUEL													
	Account 151 Fossil Fuel													
[1a 1]	Coal	$32,402,770	$32,500,184	$25,948,458	$27,690,895	$24,634,851	$29,294,225	$30,860,473	$25,734,099	$17,270,361	$10,315,173	$18,154,278	$27,386,384	$302,192,151
[1a 2]	Wood/RDF	$1,142,767	$1,124,618	$1,070,668	$1,185,377	$1,086,913	$1,123,231	$1,143,911	$991,790	$828,518	$617,376	$1,034,012	$1,030,926	$12,380,107
[1a 3]	Natural Gas CC	$10,962,672	$10,746,686	$5,359,691	$4,291,095	$5,249,738	$7,444,458	$8,548,849	$7,825,244	$9,501,269	$7,767,976	$4,277,339	$7,860,273	$89,835,290
[1a 4]	Natural Gas / Oil CT	$2,635,057	$1,465,898	$864,887	$612,261	$131,754	$179,114	$130,933	$135,667	$206,623	$1,205,384	$867,676	$981,966	$9,417,220
[1a 5]	Total Fossil Fuel	$47,143,266	$45,837,385	$33,243,704	$33,779,628	$31,103,256	$38,041,028	$40,684,166	$34,686,800	$27,806,771	$19,905,909	$24,333,305	$37,259,549	$413,824,767
[1a 6]	Account 518 Nuclear Fuel	$9,841,977	$9,966,346	$9,392,823	$7,695,490	$8,253,560	$9,599,197	$9,162,921	$8,652,638	$9,807,830	$9,407,687	$9,775,478	$9,209,157	$110,765,104
[1a 7]	Account 555 Energy Purchases	$57,085,822	$49,784,346	$48,025,637	$49,630,998	$49,324,436	$44,383,973	$49,642,895	$46,314,932	$53,062,843	$53,609,247	$59,813,739	$54,800,713	$615,479,581
[1a 8]	Net System Cost Sum [1a 1]..[1a 7]	$114,071,065	$105,588,077	$90,662,164	$91,106,116	$88,681,252	$92,024,198	$99,489,982	$89,654,370	$90,677,444	$82,922,843	$93,922,522	$101,269,419	$1,140,069,452
[1a 9]	Forecasted System MWH Sales *	3,973,369	3,944,551	3,400,109	3,285,424	3,183,102	3,509,587	3,602,659	3,119,221	3,359,635	2,892,349	3,163,879	3,528,208	40,962,093
[1a 10]	Forecasted Minn. Retail Sales Subject to FCC *	2,960,756	2,930,900	2,526,499	2,405,054	2,305,703	2,529,862	2,579,879	2,247,452	2,410,908	2,089,506	2,301,051	2,599,882	29,887,451
[1a 11]	Forecasted Cost of Fuel Per kWh [1a 8]/[1a 9]/10 **	2.871¢	2.677¢	2.666¢	2.773¢	2.786¢	2.622¢	2.762¢	2.874¢	2.699¢	2.867¢	2.969¢	2.870¢	2.783¢
	ACTUAL COST OF FUEL													
[1b 1]	Account 151 Fossil Fuel	$48,664,413	$41,926,845	$35,370,005	$33,417,119	$36,457,251	$40,888,441	$43,351,795	$34,883,316	$31,744,097	$28,170,912	$33,197,286	$40,375,901	$448,447,381
[1b 2]	Account 518 Nuclear Fuel	$10,193,117	$10,199,102	$9,534,887	$8,123,036	$7,621,744	$10,239,608	$10,299,950	$9,411,203	$10,302,765	$10,129,474	$10,487,805	$10,121,540	$116,664,231
[1b 3]	Account 555 Economic Dispatch (Ex Wind Curtailment Payment)	$48,479,504	$42,732,740	$47,303,818	$50,412,752	$51,619,278	$49,040,748	$49,693,601	$41,532,026	$50,020,304	$47,962,232	$52,425,322	$55,212,054	$586,434,379
[1b 4]	Acct 555 Wind Curtailment Payment	$290,657	$122,578	$2,734	$65,238	$133,307	$20,176	$16,365	$58,950	$5,843	$21,570	$100,762	$185,320	$1,023,501
[1b 5]	Account 555 MISO Day 2	$5,481,308	$3,853,904	$4,883,384	$8,179,114	$7,016,897	$7,654,277	$8,681,027	$4,814,592	$5,189,121	$7,551,752	$4,113,537	$5,411,108	$72,830,021
[1b 6]	- Less: Account 555 MISO Day 2 - Sched. 16 & 17	$647,212	$583,173	$591,437	$817,066	$567,047	$704,053	$591,619	$499,337	$740,733	$810,205	$615,523	$740,530	$7,907,934
[1b 7]	- Less: Account 555 MISO Day 2 - Sched. 24	$63,879	$90,918	$90,769	$78,134	$102,498	$100,192	$97,293	$102,867	$57,411	$122,644	$100,978	$126,227	$1,133,809
[1b 8]	- Less: RSG/RNU Allocation Adjustment	$72,241	$37,288	$134,060	$268,515	$66,402	$178,826	$139,464	$38,013	$107,640	$69,568	$43,348	$301,450	$1,456,815
[1b 9]	- Less: Congestion and Loss Allocation Adjustment	$675,226	$589,201	$934,605	$1,247,920	$780,326	$863,955	$1,138,637	$416,738	$550,591	$688,554	$470,672	$679,715	$9,036,140
[1b 10]	Account 555 MISO Day 2 - Net	$4,022,750	$2,553,324	$3,132,513	$5,767,479	$5,500,625	$5,807,251	$6,714,014	$3,757,637	$3,732,746	$5,860,781	$2,883,017	$3,563,186	$53,295,323
[1b 11]	Account 555 MISO ASM	$2,389,388	$820,245	($742,344)	($373,773)	$788,590	$2,847,233	$5,376,891	$2,051,479	$1,592,920	$2,473,665	$3,516,586	$3,679,185	$24,420,065
[1b 12]	Less: Fuel Cost - Intersystem Sales	$10,116,936	$8,363,988	$6,956,938	$9,950,534	$10,476,616	$15,202,377	$18,184,853	$9,428,246	$8,483,791	$8,390,948	$8,088,351	$16,774,874	$130,418,453
[1b 13]	Less: Net Windsource Program Expenses***	$828,232	$835,903	$790,964	$627,177	$706,043	$842,189	$648,339	$792,738	$439,234	$681,943	$712,040	$645,135	$8,549,937
[1b 14]	Less: Solar Gardens Program Costs (Above Market Portion)	$1,545,018	$1,083,508	$1,403,783	$1,491,177	$1,626,438	$1,067,338	$2,023,834	$1,910,837	$5,048,402	$5,548,760	$5,580,368	$5,026,916	$33,356,380
[1b 15]	Less: Solar Garden Developer Late Fees	$0	$0	$0	$0	$0	$0	$0	($57,793)	($141,778)	($91,880)	($173,600)	($163,180)	($628,232)
[1b 16]	Less: Renewable*Connect Program Energy Costs	$27,790	$113,139	$264,241	$265,261	$331,281	$308,708	$338,065	$319,653	$333,926	$320,759	$321,228	$320,053	$3,264,103
[1b 17]	Final Adjusted Net System Cost [1]+[2]+[3]+[4]+[10]+[11]-[12]-[13]-[14]-	$101,521,852	$87,958,298	$85,185,687	$85,077,701	$88,980,417	$91,422,846	$94,257,525	$79,300,931	$83,235,101	$79,768,103	$88,082,390	$90,533,388	$1,055,324,239
[1b 18]	Total MWH Sales (Cal. Month)	3,956,718	3,632,912	3,524,144	3,209,823	3,225,798	3,560,225	3,636,405	3,123,056	3,391,209	3,046,918	3,389,085	3,816,044	41,512,337
[1b 19]	Total Retail State of Minnesota	2,928,623	2,673,791	2,618,866	2,336,054	2,328,726	2,553,136	2,593,495	2,239,833	2,435,319	2,213,115	2,485,230	2,813,617	30,219,805
[1b 20]	MN Windsource & Renewable*Connect MWh not subject to FCA	16,693	20,979	22,720	23,904	27,392	23,944	27,776	24,602	25,800	24,330	24,320	26,177	288,637
[1b 21]	Total Retail State of Minnesota subject to FCA	2,911,930	2,652,812	2,596,146	2,312,150	2,301,334	2,529,192	2,565,719	2,215,231	2,409,519	2,188,785	2,460,910	2,787,440	29,931,168
[1b 22]	Actual Cost of Fuel per kWh [1b 17])/([1b 18]-[1b 20])/10**	2.577¢	2.435¢	2.433¢	2.670¢	2.782¢	2.585¢	2.612¢	2.559¢	2.473¢	2.639¢	2.618¢	2.389¢	2.560¢
[1b 23	Deviation (Actual Vs. Forecast) [1a 11] - [1b 22] **	-0.294¢	-0.242¢	-0.233¢	-0.103¢	-0.004¢	-0.037¢	-0.150¢	-0.315¢	-0.226¢	-0.228¢	-0.351¢	-0.481¢	-0.223¢
	MONTHLY FUEL CLAUSE ADJUSTMENT FACTOR													
[1c 1]	Forecasted Cost of Fuel Per kWh [1a 11] **	2.871¢	2.677¢	2.666¢	2.773¢	2.786¢	2.622¢	2.762¢	2.874¢	2.699¢	2.867¢	2.969¢	2.870¢	2.783¢
	True Up and Other Recoveries													
[1c 2]	Prior (2 Months Lag) Unrecovered Expenses	$1,175,770	($2,508,024)	($4,564,964)	($12,784,979)	($7,294,019)	($6,862,233)	($4,647,306)	($992,212)	$1,601,180	$276,919	($1,470,033)	($6,944,860)	($45,014,761)
[1c 3]	Less: Prior (2 Months Lag) Recovered Expenses	$1,155,534	($2,561,850)	($4,499,180)	($11,566,384)	($7,500,492)	($6,578,893)	($4,632,917)	($989,801)	$1,584,885	$272,502	($1,466,963)	($7,240,524)	($44,024,083)
[1c 4]	Less: Actual Recovery	$65,301,444	$74,430,858	$83,788,981	$70,991,293	$69,272,336	$63,934,455	$64,033,982	$66,167,620	$70,526,741	$63,561,029	$64,931,172	$62,452,788	$819,392,699
[1c 5]	Actual Cost Should have been recovered	$59,413,626	$64,735,690	$75,040,436	$64,595,972	$63,164,233	$61,734,406	$64,023,112	$65,379,613	$67,016,580	$56,687,761	$59,587,404	$57,762,037	$759,140,870
	Other Recoveries/Adjustment													
[1c 6]	Saver's Switch Discount	$0	$6,672	($24,721)	($294,528)	($149,459)	$0	$0	$0	$0	$0	$0	$0	($462,036)
[1c 7]	SES Exemption	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$90,331	$0	$90,331
[1c 8]	Solar Garden Recovery	$1,302,631	$1,314,177	$1,545,018	$1,083,508	$1,403,783	$1,491,177	$1,626,438	$1,067,338	$2,023,834	$1,910,837	$5,048,402	$5,548,760	$25,365,904
[1c 9]	Developer Late Fee	$0	$0	$0	$0	$0	$0	$0	$0	$0	($57,793)	($141,778)	($91,880)	($291,451)
	Other Refunds													
[1c 10]	PI Refund	$0	($4,464,486)	$0	($37,296)	$0	$0	$0	$0	$0	$0	$0	$0	($4,501,782)
[1c 11]	Inver Hills	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1,929,053)	$0	$0	($1,929,053)
[1c 12]	Others	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
[1c 13]	Balance of Unrecovered Expenses [2]-[3]-[4]+Sum[1c 5]..[1c 12]	($4,564,951)	($12,784,979)	($7,294,032)	($6,862,232)	($4,647,306)	($992,212)	$1,601,179	$276,920	($1,470,032)	($6,944,860)	($349,883)	$1,061,793	($42,970,595)
[1c 14]	Forecasted Minn. Retail Sales Subject to FCC *	$2,960,756	$2,930,900	$2,526,499	$2,405,054	$2,305,703	$2,529,862	$2,579,879	$2,247,452	$2,410,908	$2,089,506	$2,301,051	$2,599,882	$29,887,451
[1c 15]	True-Up Factor [1c 13]/[1c 14]/10 **	-0.154¢	-0.436¢	-0.289¢	-0.285¢	-0.202¢	-0.039¢	0.062¢	0.012¢	-0.061¢	-0.332¢	-0.015¢	0.041¢	
[1c 16]	System Asset Based Margins Sharing Refund [5a 3]	-0.084¢	-0.022¢	-0.066¢	-0.067¢	-0.059¢	-0.084¢	-0.074¢	-0.101¢	-0.155¢	-0.086¢	-0.085¢	-0.043¢	
[1c 17]	Fuel Clause Charge [11]+[27]+[28] **	2.633¢	2.219¢	2.311¢	2.421¢	2.525¢	2.499¢	2.750¢	2.786¢	2.483¢	2.449¢	2.869¢	2.868¢	

* Calendar Month
** In Cents Per KWh

Northern States Power Company, A Minnesota Corporation
Electric Operations - State of Minnesota
Monthly Fuel Clause Charge July 2017 - June 2018

		Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	12 Months
RULE 7825.2810 SUBPART 1 A: COMMISSION-APPROVED BASE COST OF FUEL														
[2a 1]	System Base cost of Fuel **	2.680	2.680	2.680	2.680	2.680	2.680	2.680	2.680	2.680	2.680	2.680	2.680	
[2a 2]	Residential FAF Ratio	1.0185	1.0185	1.0185	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	
[2a 3]	Non-Demand FAF Ratio	1.0493	1.0493	1.0493	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	
[2a 4]	C & I Demand Non-TOD FAF Ratio	1.0028	1.0028	1.0028	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	
[2a 5]	C & I Demand TOD On-Peak FAF Ratio	1.2732	1.2732	1.2732	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	
[2a 6]	C & I Demand TOD Off-Peak FAF Ratio	0.7987	0.7987	0.7987	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	
[2a 7]	Outdoor Lighting FAF Ratio	0.7446	0.7446	0.7446	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	
[2a 8]	Residential [2a 1]*[2a 2]	2.730 ¢	2.730 ¢	2.730 ¢	2.727 ¢	2.727 ¢	2.727 ¢	2.727 ¢	2.727 ¢	2.727 ¢	2.727 ¢	2.727 ¢	2.727 ¢	
[2a 9]	C & I Non-Demand [2a 1]*[2a 3]	2.812 ¢	2.812 ¢	2.812 ¢	2.762 ¢	2.762 ¢	2.762 ¢	2.762 ¢	2.762 ¢	2.762 ¢	2.762 ¢	2.762 ¢	2.762 ¢	
[2a 10]	C & I Demand Non-TOD [2a 1]*[2a 4]	2.688 ¢	2.688 ¢	2.688 ¢	2.676 ¢	2.676 ¢	2.676 ¢	2.676 ¢	2.676 ¢	2.676 ¢	2.676 ¢	2.676 ¢	2.676 ¢	
[2a 11]	C & I Demand TOD On-Peak [2a 1]*[2a 5]	3.412 ¢	3.412 ¢	3.412 ¢	3.346 ¢	3.346 ¢	3.346 ¢	3.346 ¢	3.346 ¢	3.346 ¢	3.346 ¢	3.346 ¢	3.346 ¢	
[2a 12]	C & I Demand TOD Off-Peak [2a 1]*[2a 6]	2.141 ¢	2.141 ¢	2.141 ¢	2.188 ¢	2.188 ¢	2.188 ¢	2.188 ¢	2.188 ¢	2.188 ¢	2.188 ¢	2.188 ¢	2.188 ¢	
[2a 13]	Outdoor Lighting [2a 1]*[2a 7]	1.996 ¢	1.996 ¢	1.996 ¢	2.138 ¢	2.138 ¢	2.138 ¢	2.138 ¢	2.138 ¢	2.138 ¢	2.138 ¢	2.138 ¢	2.138 ¢	
RULE 7825.2810 SUBPART 1 B: BILLING ADJUSTMENT AMOUNTS CHARGED CUSTOMERS FOR EACH TYPE OF ENERGY COST														
[2b 1]	System Fuel Cost Excess of Base Cost [1a 11]-[2a 1] **	0.191¢	-0.003¢	-0.014¢	0.093¢	0.106¢	-0.058¢	0.082¢	0.194¢	0.019¢	0.187¢	0.289¢	0.190¢	
[2b 2]	Residential [2b 1]*[2a 2]	0.195¢	-0.003¢	-0.014¢	0.095¢	0.108¢	-0.059¢	0.083¢	0.197¢	0.019¢	0.190¢	0.294¢	0.193¢	
[2b 3]	C & I Non-Demand [2b 1]*[2a 3]	0.200¢	-0.003¢	-0.015¢	0.096¢	0.109¢	-0.060¢	0.085¢	0.200¢	0.020¢	0.193¢	0.298¢	0.196¢	
[2b 4]	C & I Demand Non-TOD [2b 1]*[2a 4]	0.192¢	-0.003¢	-0.014¢	0.093¢	0.106¢	-0.058¢	0.082¢	0.194¢	0.019¢	0.187¢	0.289¢	0.190¢	
[2b 5]	C & I Demand TOD On-Peak [2b 1]*[2a 5]	0.243¢	-0.004¢	-0.018¢	0.116¢	0.132¢	-0.072¢	0.102¢	0.242¢	0.024¢	0.233¢	0.361¢	0.237¢	
[2b 6]	C & I Demand TOD Off-Peak [2b 1]*[2a 6]	0.153¢	-0.002¢	-0.011¢	0.076¢	0.087¢	-0.047¢	0.067¢	0.158¢	0.016¢	0.153¢	0.236¢	0.155¢	
[2b 7]	Outdoor Lighting [2b 1]*[2a 7]	0.142¢	-0.002¢	-0.010¢	0.074¢	0.085¢	-0.046¢	0.065¢	0.155¢	0.015¢	0.149¢	0.231¢	0.152¢	
[2b 8]	System True-Up Factor [1c 15] **	-0.154¢	-0.436¢	-0.289¢	-0.285¢	-0.202¢	-0.039¢	0.062¢	0.012¢	-0.061¢	-0.332¢	-0.015¢	0.041¢	
[2b 9]	Residential [1c 15]*[2a 2]	-0.157¢	-0.444¢	-0.294¢	-0.290¢	-0.205¢	-0.040¢	0.063¢	0.013¢	-0.062¢	-0.338¢	-0.015¢	0.042¢	
[2b 10]	C & I Non-Demand [1c 15]*[2a 3]	-0.162¢	-0.458¢	-0.303¢	-0.294¢	-0.208¢	-0.040¢	0.064¢	0.013¢	-0.063¢	-0.343¢	-0.016¢	0.042¢	
[2b 11]	C & I Demand Non-TOD [1c 15]*[2a 4]	-0.155¢	-0.437¢	-0.290¢	-0.285¢	-0.201¢	-0.039¢	0.062¢	0.012¢	-0.061¢	-0.332¢	-0.015¢	0.041¢	
[2b 12]	C & I Demand TOD On-Peak [1c 15]*[2a 5]	-0.196¢	-0.555¢	-0.368¢	-0.356¢	-0.252¢	-0.049¢	0.077¢	0.015¢	-0.076¢	-0.415¢	-0.019¢	0.051¢	
[2b 13]	C & I Demand TOD Off-Peak [1c 5]*[2a 6]	-0.123¢	-0.348¢	-0.231¢	-0.233¢	-0.165¢	-0.032¢	0.051¢	0.010¢	-0.050¢	-0.271¢	-0.012¢	0.033¢	
[2b 14]	Outdoor Lighting [1c 15]*[2a 7]	-0.115¢	-0.325¢	-0.215¢	-0.228¢	-0.161¢	-0.031¢	0.050¢	0.010¢	-0.049¢	-0.265¢	-0.012¢	0.033¢	
[2b 15]	System Asset Based Margins Sharing Refund [1c 16]	-0.084¢	-0.022¢	-0.066¢	-0.067¢	-0.059¢	-0.084¢	-0.074¢	-0.101¢	-0.155¢	-0.086¢	-0.085¢	-0.043¢	
[2b 16]	Residential [1c 16]*[2a 2]	-0.085¢	-0.022¢	-0.067¢	-0.068¢	-0.060¢	-0.085¢	-0.075¢	-0.102¢	-0.158¢	-0.087¢	-0.086¢	-0.043¢	
[2b 17]	C & I Non-Demand [1c 16]*[2a 3]	-0.088¢	-0.023¢	-0.069¢	-0.069¢	-0.061¢	-0.086¢	-0.076¢	-0.104¢	-0.160¢	-0.088¢	-0.087¢	-0.044¢	
[2b 18]	C & I Demand Non-TOD [1c 16]*[2a 4]	-0.084¢	-0.022¢	-0.066¢	-0.066¢	-0.059¢	-0.084¢	-0.074¢	-0.100¢	-0.155¢	-0.086¢	-0.085¢	-0.042¢	
[2b 19]	C & I Demand TOD On-Peak [1c 16]*[2a 5]	-0.106¢	-0.028¢	-0.084¢	-0.083¢	-0.074¢	-0.105¢	-0.092¢	-0.126¢	-0.193¢	-0.107¢	-0.106¢	-0.053¢	
[2b 20]	C & I Demand TOD Off-Peak [1c 16]*[2a 6]	-0.067¢	-0.018¢	-0.053¢	-0.054¢	-0.048¢	-0.069¢	-0.060¢	-0.082¢	-0.127¢	-0.070¢	-0.069¢	-0.035¢	
[2b 21]	Outdoor Lighting [1c 16]*[2a 7]	-0.062¢	-0.016¢	-0.049¢	-0.053¢	-0.047¢	-0.067¢	-0.059¢	-0.080¢	-0.124¢	-0.068¢	-0.068¢	-0.034¢	
[2b 22]	System Fuel Clause Charge Factor ** [2a 1]+[2b 1]+[2b 8]+[2b 15]	2.633¢	2.219¢	2.311¢	2.421¢	2.525¢	2.499¢	2.750¢	2.786¢	2.483¢	2.449¢	2.869¢	2.868¢	
[2b 23]	Residential [2b 22]*[2a 2]	2.682¢	2.260¢	2.354¢	2.464¢	2.570¢	2.543¢	2.799¢	2.835¢	2.527¢	2.492¢	2.919¢	2.919¢	
[2b 24]	C & I Non-Demand [2b 22]*[2a 3]	2.763¢	2.328¢	2.425¢	2.495¢	2.603¢	2.575¢	2.835¢	2.871¢	2.559¢	2.524¢	2.957¢	2.956¢	
[2b 25]	C & I Demand Non-TOD [2b 22]*[2a 4]	2.641¢	2.226¢	2.318¢	2.418¢	2.522¢	2.495¢	2.746¢	2.782¢	2.479¢	2.445¢	2.865¢	2.864¢	
[2b 26]	C & I Demand TOD On-Peak [2b 22]*[2a 5]	3.353¢	2.825¢	2.942¢	3.023¢	3.153¢	3.120¢	3.434¢	3.478¢	3.100¢	3.057¢	3.582¢	3.581¢	
[2b 27]	C & I Demand TOD Off-Peak [2b 22]*[2a 6]	2.104¢	1.773¢	1.846¢	1.977¢	2.062¢	2.040¢	2.245¢	2.274¢	2.027¢	1.999¢	2.342¢	2.342¢	
[2b 28]	Outdoor Lighting [2b 22]*[2a 7]	1.961¢	1.653¢	1.721¢	1.931¢	2.015¢	1.994¢	2.194¢	2.222¢	1.981¢	1.954¢	2.289¢	2.288¢	

		Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	12 Months
RULE 7825.2810 SUBPART 1 D: TOTAL COST OF FUEL DELIVERED TO CUSTOMERS														
[3 1]	Actual Cost of Fuel Per kWh [20] **	2.577	2.435	2.433	2.670	2.782	2.585	2.612	2.559	2.473	2.639	2.618	2.389	
[3 2]	Minnesota MWh Retail Sales (Cal. Mo) [1b 19]	2,928,623	2,673,791	2,618,866	2,336,054	2,328,726	2,553,136	2,593,495	2,239,833	2,435,319	2,213,115	2,485,230	2,813,617	30,219,805
[3 3]	Residential	928,888	741,688	723,868	591,135	653,518	784,713	815,951	665,720	655,960	577,781	672,554	889,366	8,701,142
[3 4]	C & I Non-Demand	95,366	73,448	71,888	61,242	65,947	77,280	85,403	71,934	79,538	69,486	71,564	74,878	897,974
[3 5]	C & I Demand Non-TOD	884,860	818,448	827,929	721,453	709,333	782,234	791,478	680,900	774,942	696,631	786,843	863,097	9,338,148
[3 6]	C & I Demand TOD On-Peak	395,673	399,010	387,075	368,801	347,824	339,343	319,194	311,581	355,749	319,921	370,492	380,329	4,294,992
[3 7]	C & I Demand TOD Off-Peak	614,409	630,216	597,988	578,963	535,920	557,774	561,580	497,571	555,844	538,599	574,143	597,003	6,840,010
[3 8]	Outdoor Lighting	9,427	10,981	10,118	14,460	16,184	11,792	19,889	12,127	13,286	10,697	9,634	8,944	147,539
[3 9]	Minnesota WindSource KWh Not Subject to FCA (Cal. Mo.) [1b 20] a)	16,693	20,979	22,720	23,904	27,392	23,944	27,776	24,602	25,800	24,330	24,320	26,177	288,637
[3 10]	Residential	11,799	13,929	11,781	12,032	11,185	11,595	15,182	12,044	13,384	11,854	11,784	13,763	150,332
[3 11]	C & I Non-Demand	136	170	152	158	139	152	188	170	1,670	166	160	177	3,438
[3 12]	C & I Demand Non-TOD	1,904	2,829	3,004	3,567	5,991	3,470	3,677	3,281	3,525	3,379	3,343	3,994	41,964
[3 13]	C & I Demand TOD On-Peak	1,162	1,652	3,176	3,324	4,112	3,560	3,561	3,716	2,946	3,644	3,687	3,364	37,904
[3 14]	C & I Demand TOD Off-Peak	1,688	2,395	4,603	4,818	5,960	5,160	5,160	5,385	4,269	5,282	5,342	4,875	54,937
[3 15]	Outdoor Lighting	4	4	4	5	5	7	8	6	6	5	4	4	62
[3 16]	To Retail State of Minnesota subject to FCA [1b 21]	2,911,930	2,652,812	2,596,146	2,312,150	2,301,334	2,529,192	2,565,719	2,215,231	2,409,519	2,188,785	2,460,910	2,787,440	29,931,168
[3 17]	Residential	917,089	727,759	712,087	579,103	642,333	773,118	800,769	653,676	642,576	565,927	660,770	875,603	8,550,810
[3 18]	C & I Non-Demand	95,230	73,278	71,736	61,084	65,808	77,128	85,215	71,764	77,868	69,320	71,404	74,701	894,536
[3 19]	C & I Demand Non-TOD	882,956	815,619	824,925	717,886	703,342	778,764	787,801	677,619	771,417	693,252	783,500	859,103	9,296,184
[3 20]	C & I Demand TOD On-Peak	394,511	397,358	383,899	365,477	343,712	335,783	315,633	307,865	352,803	316,277	366,805	376,965	4,257,088
[3 21]	C & I Demand TOD Off-Peak	612,721	627,821	593,385	574,145	529,960	552,614	556,420	492,186	551,575	533,317	568,801	592,128	6,785,073
[3 22]	Outdoor Lighting	9,423	10,977	10,114	14,455	16,179	11,785	19,881	12,121	13,280	10,692	9,630	8,940	147,477
[3 23]	Total Cost of Fuel Delivered [3 1]x[3 16]x10	$75,040,436	$64,595,972	$63,164,232	$61,734,405	$64,023,112	$65,379,613	$67,016,580	$56,687,761	$59,587,405	$57,762,036	$64,426,624	$66,591,942	$766,010,118
[3 24]	Residential [3 1]x[3 17]x10	$23,633,384	$17,720,932	$17,325,077	$15,462,050	$17,869,704	$19,985,100	$20,916,086	$16,727,569	$15,890,904	$14,934,814	$17,298,959	$20,918,156	$218,682,735
[3 25]	C & I Non-Demand [3 1]x[3 18]x10	$2,454,077	$1,784,319	$1,745,337	$1,630,943	$1,830,779	$1,993,759	$2,225,816	$1,836,441	$1,925,676	$1,829,355	$1,869,357	$1,784,607	$22,910,466
[3 26]	C & I Demand Non-TOD [3 1]x[3 19]x10	$22,753,776	$19,860,323	$20,070,425	$19,167,556	$19,566,974	$20,131,049	$20,577,362	$17,340,270	$19,077,142	$18,294,920	$20,512,030	$20,523,971	$237,875,798
[3 27]	C & I Demand TOD On-Peak [3 1]x[3 20]x10	$10,166,548	$9,675,667	$9,340,263	$9,758,236	$9,562,068	$8,679,991	$8,244,334	$7,878,265	$8,724,818	$8,346,550	$9,602,955	$9,005,694	$108,985,389
[3 28]	C & I Demand TOD Off-Peak [3 1]x[3 21]x10	$15,789,820	$15,287,441	$14,437,057	$15,329,672	$14,743,487	$14,285,072	$14,533,690	$12,595,040	$13,640,450	$14,074,236	$14,891,210	$14,145,938	$173,753,113
[3 29]	Outdoor Lighting [3 1]x[3 22]x10	$242,831	$267,290	$246,074	$385,949	$450,100	$304,642	$519,292	$310,176	$328,414	$282,162	$252,113	$213,577	$3,802,620

Northern States Power Company, A Minnesota Corporation
Electric Operations - State of Minnesota
Monthly Fuel Clause Charge July 2017 - June 2018

		Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	12 Months
RULE 7825.2810 SUBPART 1 E: REVENUE COLLECTED FROM CUSTOMERS FOR ENERGY DELIVERED														
[4 1]	Minnesota MWh Retail Sales Subject to FCA (Cal. Mo) [1b 21]	2,911,930	2,652,812	2,596,146	2,312,150	2,301,334	2,529,192	2,565,719	2,215,231	2,409,519	2,188,785	2,460,910	2,787,440	29,931,168
[4 2]	Residential [3 17]	917,089	727,759	712,087	579,103	642,333	773,118	800,769	653,676	642,576	565,927	660,770	875,603	8,550,810
[4 3]	C & I Non-Demand [3 18]	95,230	73,278	71,736	61,084	65,808	77,128	85,215	71,764	77,868	69,320	71,404	74,701	894,536
[4 4]	C & I Demand Non-TOD [3 19]	882,956	815,619	824,925	717,886	703,342	778,764	787,801	677,619	771,417	693,252	783,500	859,103	9,296,184
[4 5]	C & I Demand TOD On-Peak [3 20]	394,511	397,358	383,899	365,477	343,712	335,783	315,633	307,865	352,803	316,277	366,805	376,965	4,257,088
[4 6]	C & I Demand TOD Off-Peak [3 21]	612,721	627,821	593,385	574,145	529,960	552,614	556,420	492,186	551,575	533,317	568,801	592,128	6,785,073
[4 7]	Outdoor Lighting [3 22]	9,423	10,977	10,114	14,455	16,179	11,785	19,881	12,121	13,280	10,692	9,630	8,940	147,477
[4 8]	Base Cost Revenues													
[4 9]	Residential [2a 8]x[4 2]x10	$25,032,678	$19,864,764	$19,436,984	$15,794,664	$17,519,221	$21,086,299	$21,840,462	$17,828,595	$17,525,849	$15,435,297	$18,022,079	$23,881,511	$233,268,403
[4 10]	C & I Non-Demand [2a 9]x[4 3]x10	$2,677,986	$2,060,668	$2,017,305	$1,686,981	$1,817,446	$2,130,075	$2,353,417	$1,981,935	$2,150,512	$1,914,438	$1,971,993	$2,063,047	$24,825,803
[4 11]	C & I Demand Non-TOD [2a 10]x[4 4]x10	$23,729,478	$21,919,793	$22,169,892	$19,208,562	$18,819,406	$20,837,482	$21,079,286	$18,131,133	$20,640,897	$18,549,427	$20,964,204	$22,987,122	$249,036,682
[4 12]	C & I Demand TOD On-Peak [2a 11]x[4 5]x10	$13,461,410	$13,558,554	$13,099,310	$12,229,767	$11,501,456	$11,236,132	$10,561,863	$10,301,926	$11,805,663	$10,583,413	$12,274,205	$12,614,184	$143,227,883
[4 13]	C & I Demand TOD Off-Peak [2a 12]x[4 6]x10	$13,115,391	$13,438,609	$12,701,501	$12,565,094	$11,598,111	$12,093,891	$12,177,185	$10,771,432	$12,071,153	$11,671,579	$12,448,142	$12,958,650	$147,610,738
[4 14]	Outdoor Lighting [2a 13]x[4 7]x10	$188,039	$219,049	$201,828	$308,985	$345,837	$251,912	$424,970	$259,095	$283,869	$228,549	$205,848	$191,099	$3,109,080
[4 15]	Total Sum[4 9]..[4 14]	$78,204,982	$71,061,437	$69,626,820	$61,794,053	$61,601,477	$67,635,791	$68,437,183	$59,274,116	$64,477,943	$58,382,703	$65,886,471	$74,695,613	$801,078,589
	Fuel Clause Revenues													
[4 16]	Fuel Cost Excess of Base													
[4 17]	Residential [2b 2]x[4 2]x10	$1,784,013	($22,269)	($101,544)	$548,121	$692,949	($456,372)	$668,242	$1,290,553	$124,274	$1,077,016	$1,943,457	$1,693,066	$9,241,506
[4 18]	C & I Non-Demand [2b 2]x[4 3]x10	$190,860	($2,308)	($10,538)	$58,543	$71,882	($46,099)	$72,007	$143,471	$15,247	$133,580	$212,648	$146,265	$985,558
[4 19]	C & I Demand Non-TOD [2b 2]x[4 4]x10	$1,691,126	($24,550)	($115,819)	$666,557	$744,347	($450,982)	$644,973	$1,312,480	$146,338	$1,294,301	$2,260,711	$1,629,718	$9,799,200
[4 20]	C & I Demand TOD On-Peak [2b 2]x[4 5]x10	$959,372	($15,179)	($68,411)	$424,392	$454,903	($243,174)	$323,177	$745,741	$83,685	$738,475	$1,323,616	$894,274	$5,620,871
[4 21]	C & I Demand TOD Off-Peak [2b 2]x[4 6]x10	$934,706	($15,068)	($66,340)	$436,006	$458,733	($261,718)	$372,579	$779,721	$85,604	$814,375	$1,342,370	$918,687	$5,799,655
[4 22]	Outdoor Lighting [2b 2]x[4 7]x10	$13,401	($245)	($1,054)	$10,723	$13,679	($5,452)	$13,002	$18,755	$2,012	$15,947	$22,198	$13,548	$116,514
[4 23]	Total Sum[4 17]..[4 22]	$5,573,478	($79,619)	($363,706)	$2,144,342	$2,436,493	($1,463,797)	$2,093,980	$4,290,721	$457,160	$4,073,694	$7,105,000	$5,295,558	$31,563,304
[4 24]	True-Up													
[4 25]	Residential [2b 9]x[4 2]x10	($1,440,142)	($3,233,310)	($2,093,835)	($1,681,570)	($1,317,586)	($308,582)	$505,790	$81,964	($398,738)	($1,914,259)	($102,248)	$363,927	($11,538,589)
[4 26]	C & I Non-Demand [2b 10]x[4 3]x10	($154,066)	($335,407)	($217,313)	($179,603)	($136,686)	($31,172)	$54,501	$9,112	($48,928)	($237,425)	($11,188)	$31,439	($1,256,736)
[4 27]	C & I Demand Non-TOD [2b 11]x[4 4]x10	($1,365,174)	($3,567,795)	($2,388,232)	($2,045,027)	($1,415,370)	($304,941)	$488,161	$83,354	($469,608)	($2,300,467)	($118,943)	$350,299	($13,053,743)
[4 28]	C & I Demand TOD On-Peak [2b 12]x[4 5]x10	($774,445)	($2,206,871)	($1,411,113)	($1,302,037)	($864,999)	($164,433)	$244,593	$47,362	($268,596)	($1,312,537)	($69,638)	$192,226	($7,890,488)
[4 29]	C & I Demand TOD Off-Peak [2b 13]x[4 6]x10	($754,535)	($2,187,347)	($1,368,257)	($1,337,735)	($872,266)	($176,986)	$281,999	$49,519	($274,635)	($1,447,492)	($70,622)	$197,475	($7,960,882)
[4 30]	Outdoor Lighting [2b 14]x[4 7]x10	($10,818)	($35,654)	($21,742)	($32,896)	($26,010)	($3,687)	$9,841	$1,191	($6,458)	($28,344)	($1,168)	$2,912	($152,833)
[4 31]	Total Sum[4 25]..[4 30]	($4,499,180)	($11,566,384)	($7,500,492)	($6,578,868)	($4,632,917)	($989,801)	$1,584,885	$272,502	($1,466,963)	($7,240,524)	($373,807)	$1,138,278	($41,853,271)
[4 32]	Margin Sharing Refund													
[4 33]	Residential [2b 16]x[4 2]x10	($780,067)	($162,778)	($479,982)	($392,198)	($386,305)	($660,436)	($600,657)	($669,528)	($1,013,214)	($493,890)	($569,716)	($379,215)	($6,587,986)
[4 34]	C & I Non-Demand [2b 17]x[4 3]x10	($83,451)	($16,886)	($49,816)	($41,890)	($40,075)	($66,715)	($64,723)	($74,429)	($124,327)	($61,257)	($62,339)	($32,759)	($718,667)
[4 35]	C & I Demand Non-TOD [2b 18]x[4 4]x10	($739,458)	($179,616)	($547,470)	($476,971)	($414,972)	($652,643)	($579,719)	($680,892)	($1,193,305)	($593,535)	($662,716)	($365,016)	($7,086,313)
[4 36]	C & I Demand TOD On-Peak [2b 19]x[4 5]x10	($419,484)	($111,105)	($323,481)	($303,678)	($253,611)	($351,921)	($290,471)	($386,875)	($682,519)	($338,641)	($388,010)	($200,300)	($4,050,096)
[4 37]	C & I Demand TOD Off-Peak [2b 20]x[4 6]x10	($408,703)	($110,120)	($313,657)	($312,002)	($255,743)	($378,789)	($334,898)	($404,508)	($697,864)	($373,461)	($393,508)	($205,770)	($4,189,023)
[4 38]	Outdoor Lighting [2b 21]x[4 7]x10	($5,860)	($1,795)	($4,984)	($7,672)	($7,626)	($7,890)	($11,687)	($9,730)	($16,411)	($7,313)	($6,507)	($3,035)	($90,510)
[4 39]	Total Sum[4 33]..[4 38]	($2,437,023)	($582,300)	($1,719,390)	($1,534,411)	($1,358,332)	($2,118,394)	($1,882,155)	($2,225,962)	($3,727,640)	($1,868,097)	($2,082,796)	($1,186,095)	($22,722,595)
[4 40]	Total Fuel Clause Revenues													
[4 41]	Residential [4 9]+[4 17]	$26,816,691	$19,842,495	$19,335,440	$16,342,785	$18,212,170	$20,629,927	$22,508,704	$19,119,148	$17,650,123	$16,512,313	$19,965,536	$25,574,577	$242,509,909
[4 42]	C & I Non-Demand [4 10]+[4 18]	$2,868,846	$2,058,360	$2,006,767	$1,745,524	$1,889,328	$2,083,976	$2,425,424	$2,125,406	$2,165,759	$2,048,018	$2,184,641	$2,209,312	$25,811,361
[4 43]	C & I Demand Non-TOD [4 11]+[4 19]	$25,420,604	$21,895,243	$22,054,073	$19,875,119	$19,563,753	$20,386,500	$21,724,259	$19,443,613	$20,787,235	$19,843,728	$23,224,915	$24,616,840	$258,835,882
[4 44]	C & I Demand TOD On-Peak [4 12]+[4 20]	$14,420,782	$13,543,375	$13,030,899	$12,654,159	$11,956,359	$10,992,958	$10,885,040	$11,047,667	$11,889,348	$11,321,888	$13,597,821	$13,508,458	$148,848,754
[4 45]	C & I Demand TOD Off-Peak [4 13]+[4 21]	$14,050,097	$13,423,541	$12,635,161	$13,001,100	$12,056,844	$11,832,173	$12,549,764	$11,551,153	$12,156,757	$12,485,954	$13,790,512	$13,877,337	$153,410,393
[4 46]	Outdoor Lighting [4 14]+[4 22]	$201,440	$218,804	$200,774	$319,708	$359,516	$246,460	$437,972	$277,850	$285,881	$244,496	$228,046	$204,647	$3,225,594
[4 47]	Total Sum[4 41]..[4 46]	$83,778,460	$70,981,818	$69,263,114	$63,938,395	$64,037,970	$66,171,994	$70,531,163	$63,564,837	$64,935,103	$62,456,397	$72,991,471	$79,991,171	$832,641,893
[4 48]	Total Fuel Clause Revenues including True-Up & Refund													
[4 49]	Residential [4 33]+[4 41]	$26,036,624	$19,679,717	$18,855,458	$15,950,587	$17,825,865	$19,969,491	$21,908,047	$18,449,620	$16,636,909	$16,018,423	$19,395,820	$25,195,362	$235,921,923
[4 50]	C & I Non-Demand [4 34]+[4 42]	$2,785,395	$2,041,474	$1,956,951	$1,703,634	$1,849,253	$2,017,261	$2,360,701	$2,050,977	$2,041,432	$1,986,761	$2,122,302	$2,176,553	$25,092,694
[4 51]	C & I Demand Non-TOD [4 35]+[4 43]	$24,681,146	$21,715,627	$21,506,603	$19,398,148	$19,148,781	$19,733,857	$21,144,540	$18,762,721	$19,593,930	$19,250,193	$22,562,199	$24,251,824	$251,749,569
[4 52]	C & I Demand TOD On-Peak [4 36]+[4 44]	$14,001,298	$13,432,270	$12,707,418	$12,350,481	$11,702,748	$10,641,037	$10,594,569	$10,660,792	$11,206,829	$10,983,247	$13,209,811	$13,308,158	$144,798,658
[4 53]	C & I Demand TOD Off-Peak [4 37]+[4 45]	$13,641,394	$13,313,421	$12,321,504	$12,689,098	$11,801,101	$11,453,384	$12,214,866	$11,146,645	$11,458,893	$12,112,493	$13,397,004	$13,671,567	$149,221,370
[4 54]	Outdoor Lighting [4 38]+[4 46]	$195,580	$217,009	$195,790	$312,036	$351,890	$238,570	$426,285	$268,120	$269,470	$237,183	$221,539	$201,612	$3,135,084
[4 55]	Total Sum[4 49]..[4 54]	$81,341,437	$70,399,518	$67,543,724	$62,403,984	$62,679,638	$64,053,600	$68,649,008	$61,338,875	$61,207,463	$60,588,300	$70,908,675	$78,805,076	$809,919,298

	Accounting Month	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	12 Months
	Refund Included in Fuel Cost Charge Month	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	
RULE 7825.2810 SUBPART 1 G: AMOUNT OF REFUNDS CREDITED TO CUSTOMERS														
[5a 1]	**System Asset Based Margins Sharing Refund**	($2,472,649)	($643,655)	($1,672,053)	($1,600,494)	($1,362,564)	($2,123,553)	($1,901,493)	($2,261,924)	($3,735,414)	($1,791,822)	($1,949,441)	($1,106,394)	($22,621,456)
[5a 2]	Forecasted Minnesota Jurisdiction MWh Sales	2,960,755	2,930,900	2,526,499	2,405,054	2,305,703	2,529,862	2,579,879	2,247,452	2,410,908	2,089,506	2,301,051	2,599,882	29,887,451
[5a 3]	Refund Factor [5a 1]/[5a 3]/10	-0.084¢	-0.022¢	-0.066¢	-0.067¢	-0.059¢	-0.084¢	-0.074¢	-0.101¢	-0.155¢	-0.086¢	-0.085¢	-0.043¢	-0.076¢
	Class Refund Factors													
[5a 4]	Residential	1.0185	1.0185	1.0185	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	
[5a 5]	C & I Non-Demand	1.0493	1.0493	1.0493	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	
[5a 6]	C & I Demand Non-TOD	1.0028	1.0028	1.0028	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	
[5a 7]	C & I Demand TOD On-Peak	1.2732	1.2732	1.2732	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	
[5a 8]	C & I Demand TOD Off-Peak	0.7987	0.7987	0.7987	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	
[5a 9]	Outdoor Lighting	0.7446	0.7446	0.7446	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	
	Class Refund Factors													
[5a 10]	Residential [5a 3]x[5a 4]	-0.085¢	-0.022¢	-0.067¢	-0.068¢	-0.060¢	-0.085¢	-0.075¢	-0.102¢	-0.158¢	-0.087¢	-0.086¢	-0.043¢	
[5a 11]	C & I Non-Demand [5a 3]x[5a 5]	-0.088¢	-0.023¢	-0.069¢	-0.069¢	-0.061¢	-0.087¢	-0.076¢	-0.104¢	-0.160¢	-0.088¢	-0.087¢	-0.044¢	.
[5a 12]	C & I Demand Non-TOD [5a 3]x[5a 6]	-0.084¢	-0.022¢	-0.066¢	-0.066¢	-0.059¢	-0.084¢	-0.074¢	-0.100¢	-0.155¢	-0.086¢	-0.085¢	-0.042¢	
[5a 13]	C & I Demand TOD On-Peak [5a 3]x[5a 7]	-0.106¢	-0.028¢	-0.084¢	-0.083¢	-0.074¢	-0.105¢	-0.092¢	-0.126¢	-0.193¢	-0.107¢	-0.106¢	-0.053¢	
[5a 14]	C & I Demand TOD Off-Peak [5a 3]x[5a 8]	-0.067¢	-0.018¢	-0.053¢	-0.054¢	-0.048¢	-0.069¢	-0.060¢	-0.082¢	-0.127¢	-0.070¢	-0.069¢	-0.035¢	
[5a 15]	Outdoor Lighting [5a 3]x[5a 9]	-0.062¢	-0.016¢	-0.049¢	-0.053¢	-0.047¢	-0.067¢	-0.059¢	-0.080¢	-0.124¢	-0.068¢	-0.068¢	-0.034¢	
	Minnesota MWh Retail Sales Subject to FCA (Cal. Mo)													
[5a 16]	Residential	917,089	727,759	712,087	579,103	642,333	773,118	800,769	653,676	642,576	565,927	660,770	875,603	
[5a 17]	C & I Non-Demand	95,230	73,278	71,736	61,084	65,808	77,128	85,215	71,764	77,868	69,320	71,404	74,701	
[5a 18]	C & I Demand Non-TOD	882,956	815,619	824,925	717,886	703,342	778,764	787,801	677,619	771,417	693,252	783,500	859,103	
[5a 19]	C & I Demand TOD On-Peak	394,511	397,358	383,899	365,477	343,712	335,783	315,633	307,865	352,803	316,277	366,805	376,965	
[5a 20]	C & I Demand TOD Off-Peak	612,721	627,821	593,385	574,145	529,960	552,614	556,420	492,186	551,575	533,317	568,801	592,128	
[5a 21]	Outdoor Lighting	9,423	10,977	10,114	14,455	16,179	11,785	19,881	12,121	13,280	10,692	9,630	8,940	
	Amount of Margin Sharing Refund Credited to Customers													
[5a 22]	Residential [5a 10]x[5a 16]x10	($780,067)	($162,778)	($479,982)	($392,198)	($386,305)	($660,436)	($600,657)	($669,528)	($1,013,214)	($493,890)	($569,716)	($379,215)	($6,587,985)
[5a 23]	C & I Non-Demand [5a 11]x[5a 17]x10	($83,451)	($16,886)	($49,816)	($41,890)	($40,075)	($66,723)	($64,723)	($74,429)	($124,327)	($61,257)	($62,339)	($32,759)	($718,675)
[5a 24]	C & I Demand Non-TOD [5a 12]x[5a 17]x10	($739,458)	($179,616)	($547,470)	($476,971)	($414,972)	($652,643)	($579,719)	($680,892)	($1,193,305)	($593,535)	($662,716)	($365,016)	($7,086,311)
[5a 25]	C & I Demand TOD On-Peak [5a 13]x[5a 18]x10	($419,484)	($111,105)	($323,481)	($303,678)	($253,611)	($351,921)	($290,471)	($386,875)	($682,519)	($338,641)	($388,010)	($200,300)	($4,050,096)
[5a 26]	C & I Demand TOD Off-Peak [5a 14]x[5a 19]x10	($408,703)	($110,120)	($313,657)	($312,002)	($255,743)	($378,789)	($334,898)	($404,508)	($697,864)	($373,461)	($393,508)	($205,770)	($4,189,023)
[5a 27]	Outdoor Lighting [5a 15]x[5a 20]x10	($5,860)	($1,795)	($4,984)	($7,672)	($7,626)	($7,890)	($11,687)	($9,730)	($16,411)	($7,313)	($6,507)	($3,035)	($90,510)
[5a 28]	Total Sum[5a 22]..[5a 28]	**($2,437,022)**	**($582,300)**	**($1,719,391)**	**($1,534,411)**	**($1,358,332)**	**($2,118,402)**	**($1,882,156)**	**($2,225,962)**	**($3,727,640)**	**($1,868,096)**	**($2,082,795)**	**($1,186,095)**	**($22,722,601)**
	Other Refunds to Customers													
[5b 1]	**2015 AAA PI Outage Cost Disallowance (Interest Refund)**	$0	($37,296)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($37,296)
[5b 2]	Refund Factor [5b 1]/[5a 2]/10	$0	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
[5b 3]	**Gain on Sale of Inver Hills Generating Plant Facilities Sharing**	$0	$0	$0	$0	$0	$0	$0	($1,929,053)	$0	$0	$0	($253,000)	($2,182,053)
[5b 4]	Refund Factor [5b 3]/[5a 2]/10	$0	$0	$0	$0	$0	$0	$0	($0)	$0	$0	$0	($0)	
[5b 5]	**Sherco Land Sale Gain Refund**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1,275,903)	($1,275,903)
[5b 6]	Refund Factor [5b 5]/[5a 2]/10	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	
[5b 7]	Total of Other Refund Factors [5b 2]+[5b 4]+[5b 6]	$0	($0)	$0	$0	$0	$0	$0	($0)	$0	$0	$0	($0)	
	Class Refund Factors													
[5b 8]	Residential [5b 7]x[5a 4]	$0	($0)	$0	$0	$0	$0	$0	($0)	$0	$0	$0	($0)	
[5b 9]	C & I Non-Demand [5b 7]x[5a 5]	$0	($0)	$0	$0	$0	$0	$0	($0)	$0	$0	$0	($0)	
[5b 10]	C & I Demand Non-TOD [5b 7]x[5a 6]	$0	($0)	$0	$0	$0	$0	$0	($0)	$0	$0	$0	($0)	
[5b 11]	C & I Demand TOD On-Peak [5b 7]x[5a 7]	$0	($0)	$0	$0	$0	$0	$0	($0)	$0	$0	$0	($0)	
[5b 12]	C & I Demand TOD Off-Peak [5b 7]x[5a 8]	$0	($0)	$0	$0	$0	$0	$0	($0)	$0	$0	$0	($0)	
[5b 13]	Outdoor Lighting [5b 7]x[5a 9]	$0	($0)	$0	$0	$0	$0	$0	($0)	$0	$0	$0	($0)	
	Amount of Other Refund Credited to Customers													
[5b 14]	Residential [5a 16]x[5b 8]	$0	($9,439)	$0	$0	$0	$0	$0	($570,999)	$0	$0	$0	($524,022)	($1,104,460)
[5b 15]	C & I Non-Demand [5a 17]x[5b 9]	$0	($979)	$0	$0	$0	$0	$0	($63,476)	$0	$0	$0	($45,269)	($109,724)
[5b 16]	C & I Demand Non-TOD [5a 18]x[5b 10]	$0	($10,415)	$0	$0	$0	$0	$0	($580,692)	$0	$0	$0	($504,397)	($1,095,504)
[5b 17]	C & I Demand TOD On-Peak [5a 19]x[5b 11]	$0	($6,441)	$0	$0	$0	$0	$0	($329,942)	$0	$0	$0	($276,787)	($613,170)
[5b 18]	C & I Demand TOD Off-Peak [5a 20]x[5b 12]	$0	($6,385)	$0	$0	$0	$0	$0	($344,978)	$0	$0	$0	($284,346)	($635,709)
[5b 19]	Outdoor Lighting [5a 21]x[5b 13]	$0	($104)	$0	$0	$0	$0	$0	($8,298)	$0	$0	$0	($4,193)	($12,595)
[5b 20]	Total Sum[5b 14]..[5b 20]	**$0**	**($33,764)**	**$0**	**$0**	**$0**	**$0**	**$0**	**($1,898,386)**	**$0**	**$0**	**$0**	**($1,639,013)**	**($3,571,162)**
	Total Asset Based Margin Sharing and Other Refunds													
[5c 1]	Residential [5a 16]+[5b 9]	($780,067)	($172,217)	($479,982)	($392,198)	($386,305)	($660,436)	($600,657)	($1,240,527)	($1,013,214)	($493,890)	($569,716)	($903,237)	($7,692,445)
[5c 2]	C & I Non-Demand [5a 17]+[5b 10]	($83,451)	($17,865)	($49,816)	($41,890)	($40,075)	($66,723)	($64,723)	($137,905)	($124,327)	($61,257)	($62,339)	($78,028)	($828,399)
[5c 3]	C & I Demand Non-TOD [5a 18]+[5b 11]	($739,458)	($190,031)	($547,470)	($476,971)	($414,972)	($652,643)	($579,719)	($1,261,584)	($1,193,305)	($593,535)	($662,716)	($869,412)	($8,181,815)
[5c 4]	C & I Demand TOD On-Peak [5a 19]+[5b 12]	($419,484)	($117,546)	($323,481)	($303,678)	($253,611)	($351,921)	($290,471)	($716,817)	($682,519)	($338,641)	($388,010)	($477,087)	($4,663,266)
[5c 5]	C & I Demand TOD Off-Peak [5a 20]+[5b 13]	($408,703)	($116,505)	($313,657)	($312,002)	($255,743)	($378,789)	($334,898)	($749,486)	($697,864)	($373,461)	($393,508)	($490,116)	($4,824,732)
[5c 6]	Outdoor Lighting [5a 21]+[5b 14]	($5,860)	($1,899)	($4,984)	($7,672)	($7,626)	($7,890)	($11,687)	($18,028)	($16,411)	($7,313)	($6,507)	($7,228)	($103,106)
[5c 7]	Total Sum[5d 1]..[5d 6]	**($2,437,022)**	**($616,063)**	**($1,719,391)**	**($1,534,411)**	**($1,358,332)**	**($2,118,402)**	**($1,882,156)**	**($4,124,348)**	**($3,727,640)**	**($1,868,096)**	**($2,082,795)**	**($2,825,108)**	**($26,293,763)**

Northern States Power Company
Electric Operations - State of Minnesota
Monthly Fuel Clause Adjustment July 2017 - June 2018
Fuel, Purchased Power and Other Costs

	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Total
A. Actual Costs of Fuel Used by Company to Generate Electricity													
Account 151 Fossil Fuel													
[1] Coal (5004001)	29,479,191	29,076,188	24,869,636	24,453,064	29,963,002	26,322,064	29,389,794	23,229,006	17,823,987	13,687,692	17,013,170	23,644,800	288,951,594
[2] Wood/Refuse-Derived Fuel (5005001/5006001/4280161)	975,712	906,770	596,826	1,049,569	1,000,864	938,372	1,111,255	676,935	635,020	729,243	937,951	881,605	10,440,122
[3] Natural Gas / Oil CC (5002041)	14,199,391	9,896,227	7,259,031	6,530,688	5,077,518	13,428,322	12,107,507	10,490,070	12,848,151	12,694,805	11,856,078	14,565,038	130,952,826
[4] Natural Gas / Oil CT (5002001/5002021/5003001/500311)	4,010,120	2,047,661	2,644,510	1,383,799	415,867	199,681	743,239	487,306	436,940	1,059,173	3,390,088	1,284,459	18,102,843
[5] Total Fossil Fuel	48,664,414	41,926,846	35,370,003	33,417,120	36,457,251	40,888,439	43,351,795	34,883,317	31,744,098	28,170,913	33,197,287	40,375,902	448,447,385
[6] Account 518 Nuclear Fuel	10,193,117	10,199,102	9,534,888	8,123,036	7,621,744	10,239,607	10,299,950	9,411,203	10,302,765	10,129,474	10,487,805	10,121,540	116,664,231
[7] Total Own Generation	58,857,531	52,125,948	44,904,891	41,540,156	44,078,995	51,128,046	53,651,745	44,294,520	42,046,863	38,300,387	43,685,092	50,497,442	565,111,616
B. Cost of Energy/Power Purchased by Company													
Account 555 Energy Purchases													
[8] Long Term Energy Purchase Contract Total (5066001/5066011)	24,829,033	24,749,889	23,522,862	20,978,236	19,470,463	18,585,801	18,349,815	15,770,991	18,543,298	16,872,018	22,659,120	20,777,360	245,108,887
[8A] MISO	7,901,964	4,690,050	4,141,040	7,805,341	7,805,487	10,501,510	14,066,674	6,871,475	6,806,231	10,845,372	7,660,392	9,100,516	98,196,053
[8B] Less: MISO Schedule 16 and 17	(647,212)	(583,173)	(591,437)	(817,066)	(567,047)	(704,053)	(591,619)	(499,337)	(740,733)	(810,205)	(615,523)	(740,530)	(7,907,934)
[8C] Less: MISO Schedule 24	(63,879)	(90,918)	(90,769)	(78,134)	(102,498)	(100,192)	(97,293)	(102,867)	(57,411)	(122,644)	(100,978)	(126,227)	(1,133,809)
[8D] Less: RSG/RNU	(72,241)	(37,288)	(134,060)	(268,515)	(66,402)	(178,826)	(139,464)	(38,013)	(107,640)	(69,568)	(43,348)	(301,450)	(1,456,815)
[8E] Less: MISO ARR													-
[8F] Less: MISO Congestion & Loss	(706,495)	(605,102)	(934,605)	(1,247,920)	(780,326)	(863,955)	(1,147,393)	(422,143)	(574,781)	(714,611)	(500,942)	(689,938)	(9,188,211)
[9] SPP (5066021)	10,699	9,288	4,847	7,790	21,873	5,648	19,086	10,451	9,748	11,323	5,677	3,380	119,810
[10] Others - Wind (5069001/5069006/5069011)	9,648,055	8,026,844	14,948,807	21,300,829	22,437,990	21,638,658	22,009,148	17,704,811	20,129,353	17,550,660	13,939,595	15,262,006	204,596,755
[11] Others - Tolling (Plant Gas & Oil) (5066071/5066081)	3,040,755	1,552,575	2,333,676	1,838,098	3,200,037	2,305,424	639,577	588,262	1,212,185	163,897	2,522,913	834,011	20,231,411
[12] Others - Qualifying Facilities (5067001)	161,823	97,771	104,630	182,652	72,975	125,648	135,445	156,786	189,287	155,197	147,283	180,715	1,710,212
[13] Solar (5070001)	7,396,529	5,511,028	5,547,195	4,226,719	3,433,185	2,357,920	4,480,750	4,789,317	9,627,680	11,518,329	12,303,057	10,815,181	82,006,889
[14] Others - Asset Based Trading	1,555,042	1,520,067	756,697	1,592,232	2,310,102	2,942,949	2,211,325	1,036,533	950,816	1,159,919	1,354,938	2,076,427	19,467,047
[15] Others - Non-Asset Based Trading	2,132,574	1,404,109	126,827	392,093	856,051	1,144,860	1,917,324	1,582,646	(571,206)	616,770	(357,651)	5,496,401	14,740,798
[16] Other - Renewable*Connect Neutrality Charge	(4,349)	(16,252)	(38,989)	(40,661)	(50,090)	(45,985)	(49,780)	(48,820)	(48,866)	(48,492)	(48,850)	(48,108)	(489,243)
[17] Other - REC Related Fuel Costs	(321,221)	(330,942)	(260,512)	(127,706)	(101,993)	(185,357)	(72,654)	(217,046)	(48,722)	(153,933)	(230,027)	(212,660)	(2,262,773)
[18] Total Purchases	54,861,077	45,897,945	49,436,209	55,743,990	57,939,807	57,530,051	61,730,942	47,183,046	55,319,237	56,974,032	58,695,657	62,427,084	663,739,077
C. Fuel-Related Costs Recovered through Intersystem Sales													
[19] Estimated Energy Generated by Company Total	6,429,320	5,439,812	6,073,414	7,966,209	7,310,462	11,114,569	14,056,204	6,809,068	8,104,182	6,614,259	7,091,063	9,202,046	96,210,608
[20] Estimated Energy Purchased by Company Total	3,687,616	2,924,176	883,524	1,984,325	3,166,153	4,087,809	4,128,649	2,619,179	379,610	1,776,689	997,287	7,572,828	34,207,845
[21] Total	10,116,936	8,363,988	6,956,938	9,950,534	10,476,616	15,202,377	18,184,853	9,428,247	8,483,792	8,390,949	8,088,350	16,774,874	130,418,453
D. Other Deductions or Additions to Fuel Clause Adjustment Calculation													
Deduction from Account 555													
[22] Purchased Power for WindSource Program	507,011	504,961	530,452	499,472	604,050	656,832	575,685	575,692	390,512	528,010	482,013	432,475	6,287,164
[23] Purchased Power for Renewable*Connect	27,790	113,139	264,241	265,261	331,281	308,708	338,065	319,653	333,926	320,759	321,228	320,053	3,264,102
[24] Purchased Power Solar*Gardens/Above Market Solar	1,545,018	1,083,508	1,403,783	1,491,177	1,626,438	1,067,338	2,026,559	1,853,044	4,922,769	5,472,699	5,406,768	4,863,736	32,762,837
[25] Other - MISO Excess Congestion	-	-	-	-	-	-	-	-	-	793,898	-	-	793,898
E. TOTAL													
[26] Total [7]+[18]-[21]-[22]-[23]-[24]-[25]	101,521,853	87,958,298	85,185,686	85,077,702	88,980,417	91,422,842	94,257,525	79,300,931	83,235,102	79,768,105	88,082,390	90,533,388	1,055,324,239

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		Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Total
F. MWh of Generation														
	Account 151 Fossil Fuel													
[1]	Coal	1,321,765	1,298,110	1,110,541	1,091,787	1,336,112	1,291,381	1,339,126	1,023,804	789,919	567,427	712,860	1,039,458	12,922,290
[2]	Wood/Refuse-Derived Fuel	42,711	42,552	31,796	37,715	34,634	34,208	31,368	32,997	29,096	32,038	43,377	40,096	432,588
[3]	Natural Gas CC	489,503	338,453	205,367	189,565	155,928	321,474	409,515	371,268	540,003	482,431	493,471	612,643	4,609,621
[4]	Natural Gas / Oil CT	79,735	34,584	54,397	26,850	1,165	(1,186)	200	4,459	(2)	14,021	80,165	29,276	323,664
[5]	Total Fossil Fuel	1,933,714	1,713,699	1,402,101	1,345,917	1,527,839	1,645,877	1,780,209	1,432,528	1,359,016	1,095,917	1,329,873	1,721,473	18,288,163
[6]	Account 518 Nuclear Fuel	1,262,031	1,249,318	1,220,651	1,061,304	980,224	1,312,521	1,316,058	1,189,670	1,297,004	1,258,964	1,268,764	1,217,192	14,633,701
[7]	Total Own Generation	3,195,745	2,963,017	2,622,752	2,407,221	2,508,063	2,958,398	3,096,267	2,622,198	2,656,020	2,354,881	2,598,637	2,938,665	32,921,864
G. Purchased Energy/Power MWh														
	Account 555 Energy Purchases	[PROTECTED DATA BEGINS												
[8]	Long Term Energy Purchase Contract Total													
[8A]	MISO													
[8B]	Less: MISO Schedule 16 and 17													
[8C]	Less: MISO Schedule 24													
[8D]	Less: RSG/RNU													
[8E]	Less: MISO ARR													
[8F]	Less: MISO Congestion & Loss													
[9]	SPP (5066021)													
[10]	Others - Wind													
[11]	Others - Tolling													
[12]	Others - Qualifying Facilities													
[13]	Others - Solar													
[14]	Others - Asset Based													
[15]	Others - Non-Asset Based													
[16]	Other - Renewable*Connect Neutrality Charge													
[17]	Other - REC Related Fuel Costs													
[18]	Total Purchases													
H. Intersystem Sales MWh														
[19]	Estimated Energy Generated by Company Total													
[20]	Estimated Energy Purchased by Company Total													
[21]	Total													
I. MWh Related to Other Deductions or Additions to Fuel Clause Adjustment Calculation														
	Deduction from Account 555													
[22]	Purchased Power for WindSource Program													
[23]	Purchased Power for Renewable*Connect													
[24]	Purchased Power Solar*Gardens/Above Market Solar													
[25]	Other - MISO Excess Congestion													
J. TOTAL MWH														PROTECTED DATA ENDS]
[26]	Total [7]+[18]-[21]-[22]-[23]-[24]-[25]	3,921,869	3,433,427	3,167,386	2,751,464	2,891,152	3,219,626	3,255,406	2,911,574	2,906,228	2,804,869	3,036,545	3,291,562	37,591,108

Northern States Power Company
Electric Operations - State of Minnesota
Monthly Fuel Clause Adjustment July 2017 - June 2018
Estimated Fuel-Related Costs per MWh

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

	(in $/MWh)	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Total
K.	**Estimated Company's Generated Electricity Sold to Retail Customers**													
	Account 151 Fossil Fuel	**[PROTECTED DATA BEGINS**												
[1]	Coal													
[2]	Wood/Refuse-Derived Fuel													
[3]	Natural Gas CC													
[4]	Natural Gas / Oil CT													
[5]	Total Fossil Fuel													
[6]	Account 518 Nuclear Fuel													
[7]	Total Own Generation													
L.	**Estimated Purchased Energy/Power Sold to Retail Customers**													
	Account 555 Energy Purchases													
[8]	Long Term Energy Purchase Contract Total													
[8A]	MISO													
[8B]	Less: MISO Schedule 16 and 17													
[8C]	Less: MISO Schedule 24													
[8D]	Less: RSG/RNU													
[8E]	Less: MISO ARR													
[8F]	Less: MISO Congestion & Loss													
[9]	SPP (5066021)													
[10]	Others - Wind													
[11]	Others - Tolling													
[12]	Others - Qualifying Facilities													
[13]	Others - Solar													
[14]	Others - Asset Based													
[15]	Others - Non-Asset Based													
[16]	Other - Renewable*Connect Neutrality Charge													
[17]	Other - REC Related Fuel Costs													
[18]	Total Purchases													
M.	**Estimated Intersystem Sales-Related**													
[19]	Estimated Energy Generated by Company Total													
[20]	Estimated Energy Purchased by Company Total													
[21]	Total													
N.	**Other Deductions or Additions**													
	Deduction from Account 555													
[22]	Purchased Power for WindSource Program													
[23]	Purchased Power for Renewable*Connect													
[24]	Purchased Power Solar*Gardens/Above Market Solar													
[25]	Other - MISO Excess Congestion													
O.	**SYSTEM TOTAL**													**PROTECTED DATA ENDS]**
[26]	Total [7]+[18]-[21]-[22]-[23]-[24]-[25]	$ 25.89	$ 25.62	$ 26.89	$ 30.92	$ 30.78	$ 28.40	$ 28.95	$ 27.24	$ 28.64	$ 28.44	$ 29.01	$ 27.50	$ 28.07

Northern States Power Company
Electric Operations - State of Minnesota
Monthly Fuel Clause Adjustment July 2017 - June 2018
Costs Recovered from Sales of Energy to Other Utilities

Docket No. E999/AA-18-373
Part E, Section 5
Schedule 5
Page 1 of 1

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

		Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Total
Costs Recovered from Sales of Energy to Other Utilities														
		[PROTECTED DATA BEGINS												
[1]	Generation													
[2]	Purchases													
[3]	Total													
[4]	Generation %													
[5]	Purchases %													
[6]	Total													
MWh Sales of Energy to Other Utilities														
[1]	Generation													
[2]	Purchases													
[3]	Total													
[4]	Generation %													
[5]	Purchases %													
[6]	Total													
														PROTECTED DATA ENDS]

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-18-373

Xcel Energy®

PART F

AUDITOR'S REPORT

Xcel Energy[SM]

414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

July 24, 2018

Dang Le
Audit Senior Assistant
Deloitte & Touche LLP
50 South Sixth Street, Suite 2800
Minneapolis, MN 55402

RE: 2017 - 2018 ANNUAL AUTOMATIC ADJUSTMENT (AAA) CHARGES REPORT – ELECTRIC OPERATION DOCKET NO. E999/AA-18-373

Dear Mr. Le:

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 ongoing and new requirements established by the Minnesota Public Utilities Commission for the upcoming Annual Automatic Adjustment (AAA) of Charges Report – Electric Operations filing. The Company's 2017-2018 AAA Electric Report will be filed with the Commission and Minnesota Department of Commerce – Division of Energy Resources by August 31, 2018.

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 July 2017 to June 2018. The Department will then prepare a comprehensive analysis of the AAA reports filed by all regulated electric utilities, and the Commission will conduct a hearing to review and act on the AAA Report 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 approval of our 2005 electric rate case (Docket No. E002/GR-05-1428), the Fuel Clause Adjustment (FCA) as of 2007 is based on Xcel Energy's monthly forecast of system energy costs and sales including a "true-up" 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.

On November 2, 2015 the Company filed a Petition to increase electric rates (Docket No. E002/GR-15-826). In the associated docket, E002/MR-15-827, a new Base Cost of Energy of $0.02680 per kWh was approved (a decrease of $0.0100 over the previous Base Cost of Energy) along with the interim rates that went into effect January 1, 2016. The current Base Cost of Energy became effective with the implementation of final rates in Docket No. E002/GR-15-826 on October 1, 2017.

The table below shows the current and prior effective Base Cost of Energy by the 6 customer class categories:

Customer Class Category	**Current Base Cost of Energy ($/kWh)**[1]	**Prior Base Cost of Energy ($/kWh)**[2]
Residential	$0.02727	$0.02730
C & I Non-Demand	$0.02762	$0.02812
C & I Demand	$0.02676	$0.02688
C & I Demand Time of Day On-Peak	$0.03346	$0.03412
C & I Demand Time of Day Off-Peak	$0.02188	$0.02141
Outdoor Lighting	$0.02138	$0.01996

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 A.

For the twelve months ending June 30, 2018, 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 A for a list of dockets in which these additional items were approved.

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[1] As part of the most recent rate case (Docket No. E002/ GR-15-826) the new FAF ratios were approved by the MPUC in the Order dated June 12, 2017. The new FAF ratios became effective October 1, 2017.
[2] Effective January 1, 2016, pursuant to the MPUC's acceptance of the proposed Base Cost of Energy with the implementation of the interim rate (Docket Nos. E002/GR-15-826 and E002/MR-15-827).

The 2017-2018 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.[3]

At the Department of Commerce's recommendation, in order to more promptly report REC purchases with Windsource energy needs, the Windsource "brown energy" credit is computed and returned to retail customers on a monthly basis.

Pursuant to the Commission's September 17, 2014 Order in Docket No. E002/M-13-867), we are authorized to recover the costs of the Solar*Rewards Community program through the FCA. These costs include customer bill credits, additional REC credits and unsubscribed energy. Currently there are 374 solar garden facilities generating energy. Each garden was added to the monthly FCA calculation in the month it went online.

Pursuant to the Commission's February 27, 2017 Order in Docket No. E002/M-15-985, the Renewable*Connect and Renewable*Connect Government programs have been in operations during the 2017-2018 AAA period Program energy utilized over the assigned level is credited back to the FCA through the monthly Neutrality Adjustment.

In compliance with the Commission's February 16, 2018 Order in Docket No. E002/PA-17-529, the Company credited the applicable transaction gains through the Minnesota FCA upon completion of our sale of the Inver Hills Generating Plant Facilities (land and oil tanks) to Flint Hills.

We note that the Commission has approved reforms to the fuel clause mechanism in Docket No. E999/CI-03-802 which could impact future AAA filings and audits. The December 19, 2017 Order in the noted docket requires that implementation of the reforms begins no later than July 1, 2019.

AAA Report Additional Independent Audit Requirements

In compliance with the Commission's 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 the auditor report to be submitted with the Company's 2017-2018 Electric AAA Report to be filed by August

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[3] 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.

31, 2018, 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 August 27, 2018. If this is not possible, please let us know, and we will gladly work with you to establish a revised schedule. 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 CASE SPECIALIST

cc: Amy Liberkowski
Lisa Peterson
John Chow

Appendix A

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, and E002/M-14-364

For the twelve months ending June 30, 2018, 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
  - Winona, LLC, E002/M-09-1247, Notice of Approval dated December 1, 2009
  - Goodhue North, LLC, E002/M-09-1349, Order dated April 28, 2010[1]
  - Goodhue South, LLC, E002/M-09-1350, Order dated April 28, 2010[2]
  - Adams, LLC, E002/M-09-1366, Notice of Approval dated December 29, 2009
  - Danielson, LLC, E002/M-09-1367, Notice of Approval dated December 29, 2009
  - Best Power, LLC, E002/M-09-1481, Order dated June 25, 2010[3]

[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.

  - WM Renewable Energy, LLC, E002/M-10-161, Order dated April 30, 2010
  - Big Blue, LLC, E002/M-10-733, Notice of Approval dated August 26, 2010[4]
  - Community Wind North, LLC, E002/M-10-734, Order dated August 26, 2010
  - Hilltop, E002/M-08-47, Notice of Approval dated February 15, 2008
  - Valley View, E002/M-08-1235, Order dated March 9, 2009
  - Ridgewind, E002/M-08-1428, Notice of Approval dated January 2, 2009
  - Moraine II, E002/M-08-1487, Order dated April 24, 2009
  - Ewington Energy Systems LLC, E002/M-06-1472, Notice of Approval dated November 30, 2006
  - Jeffers Wind 20, LLC, E002/M-06-1234, Notice of Approval dated November 30, 2006
  - Uilk Wind Farm, LLC, E002/M-08-1502, Notice of Approval dated February 6, 2009
  - Prairie Rose Wind, LLC, E002/M-11-713, Order dated December 28, 2011
  - Diamond K Dairy, E002/M-10-486, Order dated August 26, 2010
  - School Sisters, E002/M-15-619, Order dated September 14, 2015
  - Aurora Solar, E002/M-15-330, Order dated August 2, 2015
  - Marshall and NorthStar Solar, E002/M-14-162, Order dated March 24, 2015
  - Slayton Solar, E002/M-11-490, Order dated September 14, 2011
- WindSource Exemption – E002/M-01-1479, E002/M-09-1177 [5]
- End-Of-Life Nuclear Fuel Accrual – E002/M-05-1648
- Community Solar Gardens Program – E002/M-13-867
- Renewable*Connect Government Program – E002/M-15-985
- Inver Hills Sales Gain Sharing Refund – E002/PA-17-529, Order dated February 16, 2018
- Sherco Land Sale Sharing Refund – E002/M-17-528, Order dated February 6, 2018)

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[3] The amended PPA was approved by the Commission's September 8, 2014 Order in Docket No. E002/M-14-490.

[4] The amended PPA was approved by the Commission's February 27, 2014 Order in Docket No. E002/M-13-1002.

[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 July 1, 2017 to June 30, 2018, and Independent Accountants' Report on Applying Agreed-Upon Procedures

Deloitte.

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USA

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www.deloitte.com

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") (the specified parties), 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-002/MR-15-827. 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 documentation supporting payments and invoices received from the energy provider and found them to be in agreement.

b. We obtained the Commission Approved Bases Costs of Power, Docket No. E-002/MR-15-827 and compared the base costs of power to the bases in use 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 July 1, 2017 to June 30, 2018, by customer class, and noted no exceptions between our recalculation and the Company's reported adjustment.

d. We obtained the accounting records for the revenues billed to customers for energy delivered for the period from July 1, 2017 to June 30, 2018. We compared the total sales of electric energy to the Company's general ledger and found them to be in agreement.

e. On a sample basis, we examined individual billings for each class of service, 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 FCA charges or other billing errors for the period from July 1, 2017 to June 30, 2018, with the exception of the following:

    i. The Minnesota asset-based margin sharing refund calculation for the month of February 2018 utilized billing month sales as compared to calendar month sales. As a result, the asset based margins for February 2018 were over-refunded by $127,000.

g. We have reconciled the total revenue and the cost of power to the Company's general ledger and found them to be in agreement with FCA calculation underlying detail.

h. We have recalculated the true-up calculation and have traced the related revenue and expense amounts to the Company's general ledger and found them to be in agreement with the amounts used in the true-up calculation.

i. 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 to express an opinion or conclusion, respectively, on management's assertions. 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

August 30, 2018

NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION

STATE OF MINNESOTA RETAIL ELECTRIC CUSTOMERS
SCHEDULE OF FUEL ADJUSTMENT CLAUSE FACTORS
FOR THE PERIOD FROM JULY 1, 2017 TO JUNE 30, 2018
(CENTS PER KWH)

	Residential	C&I Non-Demand	C&I Demand Non-TOD	C&I Demand On-Peak	C&I Demand Off-Peak	Outdoor Lighting
July 1, 2017	2.682	2.763	2.641	3.353	2.104	1.961
August 1, 2017	2.260	2.328	2.226	2.825	1.773	1.653
September 1, 2017	2.354	2.425	2.318	2.942	1.846	1.721
October 1, 2017	2.464	2.495	2.418	3.023	1.977	1.932
November 1, 2017	2.570	2.603	2.522	3.153	2.062	2.015
December 1, 2017	2.543	2.575	2.495	3.120	2.040	1.994
January 1, 2018	2.799	2.835	2.746	3.434	2.245	2.194
February 1, 2018	2.835	2.871	2.782	3.478	2.274	2.222
March 1, 2018	2.527	2.559	2.479	3.100	2.027	1.981
April 1, 2018	2.492	2.524	2.445	3.057	1.999	1.954
May 1, 2018	2.919	2.957	2.865	3.582	2.342	2.289
June 1, 2018	2.919	2.956	2.864	3.581	2.342	2.288

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

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-18-373

PART G

FIVE-YEAR PROJECTION

ANNUAL FIVE-YEAR PROJECTION

In compliance with the reporting requirement, the following schedules contain the trade secret five-year (2019 - 2023) projection of fuel cost by energy source:

Part G, Section 1, Schedule 1 – 5-Year Fuel Cost Forecast – Per Unit Summary
Part G, Section 1, Schedule 2 – 5-Year Fuel Cost Forecast – Cost Summary
Part G, Section 1, Schedule 3 – 5-Year Fuel Cost Forecast – Energy Summary

These estimates are developed by applying inflation projections either to current market prices or to inflation escalation clauses contained in fuel contracts with existing and potential suppliers. Fossil fuel price projections are developed by projecting several fuel price components. These components include mine prices, freight rates, oil, natural gas, wood commodity prices, and related items. The price projections are accomplished by escalating each individual component based on published price index forecasts developed by IHS Global Insight, CERA, Wood Mackenzie, PIRA and NYMEX. Long-term coal pricing is based on forecasts provided by JD Energy and the John T. Boyd Company. We utilize price forecasts from Ux Consulting, LLC and Energy Resources International for the future prices of uranium concentrates, conversion services and enrichment services. Forecasted escalations rates for current contracts with escalation indices are provided by Xcel Energy.

The detailed trade secret information is provided as follows:

Part G, Section 1, Schedule 4 – Fossil Fuel Costs
Part G, Section 1, Schedule 5 – Coal Burn Expenses
Part G, Section 1, Schedule 6 – Nuclear Fuel Expenses

The energy and peak demand forecasts in Part G Section 1 Schedule 7 were used as assumptions in developing the projection of fossil and nuclear fuel costs. Fuel cost projections for 2019 through 2023 are based on Xcel Energy's July 2018 forecast. Part G, Section 1, Schedule 8 includes the estimated load management impact for the same period.

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Xcel Energy (Northern States Power Company)

2019 - NSP July Production Forecast (COB 18.07.09 pricing)

Production Cost Summary ($/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
COST	**[PROTECTED DATA BEGINS**												
Hydro (MN)													
Hydro (WI)													
Solar													
Wind (MN)													
Total Renewable													
Coal (MN)													
Coal (WI)													
Wood (WI)													
RDF (MN)													
RDF (WI)													
Natural Gas 1 (MN)													
Natural Gas 2 (MN)													
Natural Gas (WI)													
Fuel Oil (MN)													
Fuel Oil (WI)													
Total Fossil													
Nuclear													
Purchase - Energy (other)													
Purchase - Energy (WI)													
Purchase - Wind Energy													
Purchase - Solar Energy													
Purchase - Gas Energy													
Mkt Purchase - Energy													
Total Purchases													
Total Cost													
SALES													
Sale - Energy													
Market Sale - Energy													
Total Gross Revenue													
NET													

PROTECTED DATA ENDS]

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Xcel Energy (Northern States Power Company)

2020 - NSP July Production Forecast (COB 18.07.09 pricing)

Production Cost Summary ($/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
COST	**[PROTECTED DATA BEGINS**												
Hydro (MN)													
Hydro (WI)													
Solar													
Wind (MN)													
Total Renewable													
Coal (MN)													
Coal (WI)													
Wood (WI)													
RDF (MN)													
RDF (WI)													
Natural Gas 1 (MN)													
Natural Gas 2 (MN)													
Natural Gas (WI)													
Fuel Oil (MN)													
Fuel Oil (WI)													
Total Fossil													
Nuclear													
Purchase - Energy (other)													
Purchase - Energy (WI)													
Purchase - Wind Energy													
Purchase - Solar Energy													
Purchase - Gas Energy													
Mkt Purchase - Energy													
Total Purchases													
Total Cost													
SALES													
Sale - Energy													
Market Sale - Energy													
Total Gross Revenue													
NET													

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Xcel Energy (Northern States Power Company)
2021 - NSP July Production Forecast (COB 18.07.20 pricing)
Production Cost Summary ($/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
COST	**[PROTECTED DATA BEGINS**												
Hydro (MN)													
Hydro (WI)													
Solar													
Wind (MN)													
Total Renewable													
Coal (MN)													
Coal (WI)													
Wood (WI)													
RDF (MN)													
RDF (WI)													
Natural Gas 1 (MN)													
Natural Gas 2 (MN)													
Natural Gas (WI)													
Fuel Oil (MN)													
Fuel Oil (WI)													
Total Fossil													
Nuclear													
Purchase - Energy (other)													
Purchase - Energy (WI)													
Purchase - Wind Energy													
Purchase - Solar Energy													
Purchase - Gas Energy													
Mkt Purchase - Energy													
Total Purchases													
Total Cost													
SALES													
Sale - Energy													
Market Sale - Energy													
Total Gross Revenue													
NET													

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Xcel Energy (Northern States Power Company)
2022 - NSP July Production Forecast (COB 18.07.09 pricing)
Production Cost Summary ($/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
COST	**[PROTECTED DATA BEGINS**												
Hydro (MN)													
Hydro (WI)													
Solar													
Wind (MN)													
Total Renewable													
Coal (MN)													
Coal (WI)													
Wood (WI)													
RDF (MN)													
RDF (WI)													
Natural Gas 1 (MN)													
Natural Gas 2 (MN)													
Natural Gas (WI)													
Fuel Oil (MN)													
Fuel Oil (WI)													
Total Fossil													
Nuclear													
Purchase - Energy (other)													
Purchase - Energy (WI)													
Purchase - Wind Energy													
Purchase - Solar Energy													
Purchase - Gas Energy													
Mkt Purchase - Energy													
Total Purchases													
Total Cost													
SALES													
Sale - Energy													
Market Sale - Energy													
Total Gross Revenue													
NET													

PROTECTED DATA ENDS]

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Xcel Energy (Northern States Power Company)
2023 - NSP July Production Forecast (COB 18.07.09 pricing)
Production Cost Summary ($/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
COST	**[PROTECTED DATA BEGINS**												
Hydro (MN)													
Hydro (WI)													
Solar													
Wind (MN)													
Total Renewable													
Coal (MN)													
Coal (WI)													
Wood (WI)													
RDF (MN)													
RDF (WI)													
Natural Gas 1 (MN)													
Natural Gas 2 (MN)													
Natural Gas (WI)													
Fuel Oil (MN)													
Fuel Oil (WI)													
Total Fossil													
Nuclear													
Purchase - Energy (other)													
Purchase - Energy (WI)													
Purchase - Wind Energy													
Purchase - Solar Energy													
Purchase - Gas Energy													
Mkt Purchase - Energy													
Total Purchases													
Total Cost													
SALES													
Sale - Energy													
Market Sale - Energy													
Total Gross Revenue													
NET													

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Xcel Energy (Northern States Power Company)
2019 - NSP July Production Forecast (COB 18.07.09 pricing)
Cost Summary ($1000s)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
COST	**[PROTECTED DATA BEGINS**												
Hydro (MN)													
Hydro (WI)													
Solar													
Wind (MN)													
Total Renewable													
Coal (MN)													
Coal (WI)													
Wood (WI)													
RDF (MN)													
RDF (WI)													
Natural Gas 1 (MN)													
Natural Gas 2 (MN)													
Natural Gas (WI)													
Fuel Oil (MN)													
Fuel Oil (WI)													
Total Fossil Cost													
Nuclear													
Purchase - Energy (other)													
Purchase - Energy (WI)													
Purchase - Wind Energy													
Purchase - Solar Energy													
Purchase - Gas Energy													
Mkt Purchase - Energy													
Total Purchase Cost													
Net MISO Costs													
Total Cost													
REVENUE													
Sale - Energy													
Market Sale - Energy													
Total Gross Revenue													
NET COST													

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Xcel Energy (Northern States Power Company)
2020 - NSP July Production Forecast (COB 18.07.09 pricing)
Cost Summary ($1000s)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
COST	**[PROTECTED DATA BEGINS**												
Hydro (MN)													
Hydro (WI)													
Solar													
Wind (MN)													
Total Renewable													
Coal (MN)													
Coal (WI)													
Wood (WI)													
RDF (MN)													
RDF (WI)													
Natural Gas 1 (MN)													
Natural Gas 2 (MN)													
Natural Gas (WI)													
Fuel Oil (MN)													
Fuel Oil (WI)													
Total Fossil Cost													
Nuclear													
Purchase - Energy (other)													
Purchase - Energy (WI)													
Purchase - Wind Energy													
Purchase - Solar Energy													
Purchase - Gas Energy													
Mkt Purchase - Energy													
Total Purchase Cost													
Net MISO Costs													
Total Cost													
REVENUE													
Sale - Energy													
Market Sale - Energy													
Total Gross Revenue													
NET COST													

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Xcel Energy (Northern States Power Company)
2021 - NSP July Production Forecast (COB 18.07.20 pricing)
Cost Summary ($1000s)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
COST	**[PROTECTED DATA BEGINS**												
Hydro (MN)													
Hydro (WI)													
Solar													
Wind (MN)													
Total Renewable													
Coal (MN)													
Coal (WI)													
Wood (WI)													
RDF (MN)													
RDF (WI)													
Natural Gas 1 (MN)													
Natural Gas 2 (MN)													
Natural Gas (WI)													
Fuel Oil (MN)													
Fuel Oil (WI)													
Total Fossil Cost													
Nuclear													
Purchase - Energy (other)													
Purchase - Energy (WI)													
Purchase - Wind Energy													
Purchase - Solar Energy													
Purchase - Gas Energy													
Mkt Purchase - Energy													
Total Purchase Cost													
Net MISO Costs													
Total Cost													
REVENUE													
Sale - Energy													
Market Sale - Energy													
Total Gross Revenue													
NET COST													

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Xcel Energy (Northern States Power Company)
2022 - NSP July Production Forecast (COB 18.07.09 pricing)
Cost Summary ($1000s)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
COST	**[PROTECTED DATA BEGINS**												
Hydro (MN)													
Hydro (WI)													
Solar													
Wind (MN)													
Total Renewable													
Coal (MN)													
Coal (WI)													
Wood (WI)													
RDF (MN)													
RDF (WI)													
Natural Gas 1 (MN)													
Natural Gas 2 (MN)													
Natural Gas (WI)													
Fuel Oil (MN)													
Fuel Oil (WI)													
Total Fossil Cost													
Nuclear													
Purchase - Energy (other)													
Purchase - Energy (WI)													
Purchase - Wind Energy													
Purchase - Solar Energy													
Purchase - Gas Energy													
Mkt Purchase - Energy													
Total Purchase Cost													
Net MISO Costs													
Total Cost													
REVENUE													
Sale - Energy													
Market Sale - Energy													
Total Gross Revenue													
NET COST													

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Xcel Energy (Northern States Power Company)
2023 - NSP July Production Forecast (COB 18.07.09 pricing)
Cost Summary ($1000s)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
COST	**[PROTECTED DATA BEGINS**												
Hydro (MN)													
Hydro (WI)													
Solar													
Wind (MN)													
Total Renewable													
Coal (MN)													
Coal (WI)													
Wood (WI)													
RDF (MN)													
RDF (WI)													
Natural Gas 1 (MN)													
Natural Gas 2 (MN)													
Natural Gas (WI)													
Fuel Oil (MN)													
Fuel Oil (WI)													
Total Fossil Cost													
Nuclear													
Purchase - Energy (other)													
Purchase - Energy (WI)													
Purchase - Wind Energy													
Purchase - Solar Energy													
Purchase - Gas Energy													
Mkt Purchase - Energy													
Total Purchase Cost													
Net MISO Costs													
Total Cost													
REVENUE													
Sale - Energy													
Market Sale - Energy													
Total Gross Revenue													
NET COST													

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Xcel Energy (Northern States Power Company)
2019 - NSP July Production Forecast (COB 18.07.09 pricing)
Energy Summary (GWh)

[PROTECTED DATA BEGINS

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
RESOURCES													
Hydro (MN)													
Hydro (WI)													
Solar													
Wind (MN)													
Total Renewable													
Coal (MN)													
Coal (WI)													
Wood (WI)													
RDF (MN)													
RDF (WI)													
Natural Gas 1 (MN)													
Natural Gas 2 (MN)													
Natural Gas (WI)													
Fuel Oil (MN)													
Fuel Oil (WI)													
Total Fossil													
Nuclear													
Purchase - Energy (other)													
Purchase - Energy (WI)													
Purchase - Wind Energy													
Purchase - Solar Energy													
Purchase - Gas Energy													
Mkt Purchase - Energy													
Total Purchases													
Total GWh													
SALES													
Sale - Energy													
Market Sale - Energy													
Total Gross Sales													
NET													

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Xcel Energy (Northern States Power Company)
2020 - NSP July Production Forecast (COB 18.07.09 pricing)
Energy Summary (GWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
RESOURCES	**[PROTECTED DATA BEGINS**												
Hydro (MN)													
Hydro (WI)													
Solar													
Wind (MN)													
Total Renewable													
Coal (MN)													
Coal (WI)													
Wood (WI)													
RDF (MN)													
RDF (WI)													
Natural Gas 1 (MN)													
Natural Gas 2 (MN)													
Natural Gas (WI)													
Fuel Oil (MN)													
Fuel Oil (WI)													
Total Fossil													
Nuclear													
Purchase - Energy (other)													
Purchase - Energy (WI)													
Purchase - Wind Energy													
Purchase - Solar Energy													
Purchase - Gas Energy													
Mkt Purchase - Energy													
Total Purchases													
Total GWh													
SALES													
Sale - Energy													
Market Sale - Energy													
Total Gross Sales													
NET													

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Xcel Energy (Northern States Power Company)
2021 - NSP July Production Forecast (COB 18.07.20 pricing)
Energy Summary (GWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
RESOURCES	**[PROTECTED DATA BEGINS**												
Hydro (MN)													
Hydro (WI)													
Solar													
Wind (MN)													
Total Renewable													
Coal (MN)													
Coal (WI)													
Wood (WI)													
RDF (MN)													
RDF (WI)													
Natural Gas 1 (MN)													
Natural Gas 2 (MN)													
Natural Gas (WI)													
Fuel Oil (MN)													
Fuel Oil (WI)													
Total Fossil													
Nuclear													
Purchase - Energy (other)													
Purchase - Energy (WI)													
Purchase - Wind Energy													
Purchase - Solar Energy													
Purchase - Gas Energy													
Mkt Purchase - Energy													
Total Purchases													
Total GWh													
SALES													
Sale - Energy													
Market Sale - Energy													
Total Gross Sales													
NET													

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Xcel Energy (Northern States Power Company)
2022 - NSP July Production Forecast (COB 18.07.09 pricing)
Energy Summary (GWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
RESOURCES	**[PROTECTED DATA BEGINS**												
Hydro (MN)													
Hydro (WI)													
Solar													
Wind (MN)													
Total Renewable													
Coal (MN)													
Coal (WI)													
Wood (WI)													
RDF (MN)													
RDF (WI)													
Natural Gas 1 (MN)													
Natural Gas 2 (MN)													
Natural Gas (WI)													
Fuel Oil (MN)													
Fuel Oil (WI)													
Total Fossil													
Nuclear													
Purchase - Energy (other)													
Purchase - Energy (WI)													
Purchase - Wind Energy													
Purchase - Solar Energy													
Purchase - Gas Energy													
Mkt Purchase - Energy													
Total Purchases													
Total GWh													
SALES													
Sale - Energy													
Market Sale - Energy													
Total Gross Sales													
NET													

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Xcel Energy (Northern States Power Company)
2023 - NSP July Production Forecast (COB 18.07.09 pricing)
Energy Summary (GWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
RESOURCES	**[PROTECTED DATA BEGINS**												
Hydro (MN)													
Hydro (WI)													
Solar													
Wind (MN)													
Total Renewable													
Coal (MN)													
Coal (WI)													
Wood (WI)													
RDF (MN)													
RDF (WI)													
Natural Gas 1 (MN)													
Natural Gas 2 (MN)													
Natural Gas (WI)													
Fuel Oil (MN)													
Fuel Oil (WI)													
Total Fossil													
Nuclear													
Purchase - Energy (other)													
Purchase - Energy (WI)													
Purchase - Wind Energy													
Purchase - Solar Energy													
Purchase - Gas Energy													
Mkt Purchase - Energy													
Total Purchases													
Total GWh													
Sale - Demand													
Sale - Energy													
Market Sale - Energy													
Total Gross Sales													
NET													

PROTECTED DATA ENDS]

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2019

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2019 Total AVG
		[PROTECTED DATA BEGINS												
Allen S King 1	Coal													
Angus Anson 2	Gas													
Angus Anson 2	Oil													
Angus Anson 3	Gas													
Angus Anson 3	Oil													
Angus Anson 4	Gas													
Angus Anson	AVG COST													
Black Dog 25 CC	Gas													
Black Dog 6	Gas													
Black Dog	AVG COST													
Blue Lake 1	Oil													
Blue Lake 2	Oil													
Blue Lake 3	Oil													
Blue Lake 4	Oil													
Blue Lake 7	Gas													
Blue Lake 8	Gas													
Blue Lake	AVG COST													
Calpine I	Gas													
Calpine II	Gas													
Calpine	AVG COST													
French Island 1	Gas													
French Island 1	Wood/RDF													
French Island 2	Gas													
French Island 2	Wood/RDF													
French Island 3	Oil													
French Island 4	Oil													
French Island	AVG COST													
Granite City 1	Gas													
Granite City 2	Gas													
Granite City 3	Gas													
Granite City 4	Gas													
Granite City	AVG COST													
High Bridge CC 1x1	Gas													
High Bridge CC 2x1	Gas													
High Bridge	AVG COST													
Invenergy 1	Gas													
Invenergy 1	Oil													
Invenergy 2	Gas													
Invenergy 2	Oil													
Invenergy	AVG COST													
Inver Hills 1F	Oil													
Inver Hills 1G	Gas													
Inver Hills 2F	Oil													
Inver Hills 2G	Gas													
Inver Hills 3F	Oil													
Inver Hills 3G	Gas													
Inver Hills 4F	Oil													
Inver Hills 4G	Gas													
Inver Hills 5F	Oil													
Inver Hills 5G	Gas													
Inver Hills 6F	Oil													
Inver Hills 6G	Gas													
Inver Hills	AVG COST													
LS Power	AVG COST													
Red Wing 1	RDF													
Red Wing 1	Gas													
Red Wing 2	RDF													
Red Wing 2	Gas													
Red Wing	AVG COST													
Riverside CC 1x1	Gas													
Riverside CC 2x1	Gas													
Riverside	AVG COST													
Sherburne 1	Coal													
Sherburne 2	Coal													
Sherburne 3	Coal													
Sherburne	AVG COST													
Wheaton 1	Gas													
Wheaton 1	Oil													
Wheaton 2	Gas													
Wheaton 2	Oil													
Wheaton 3	Gas													
Wheaton 3	Oil													
Wheaton 4	Gas													
Wheaton 4	Oil													
Wheaton 5	Oil													
Wheaton 6	Oil													
Wheaton	AVG COST													
Wilmarth 1	RDF													
Wilmarth 1	Gas													
Wilmarth 2	RDF													
Wilmarth 2	Gas													
Wilmarth	AVG COST													
SYSTEM MN	AVG COST													

PROTECTED DATA ENDS]

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2020

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2020 Total AVG
		[PROTECTED DATA BEGINS												
Allen S King 1	Coal													
Angus Anson 2	Gas													
Angus Anson 2	Oil													
Angus Anson 3	Gas													
Angus Anson 3	Oil													
Angus Anson 4	Gas													
Angus Anson	AVG COST													
Black Dog 25 CC	Gas													
Black Dog 6	Gas													
Black Dog	AVG COST													
Blue Lake 1	Oil													
Blue Lake 2	Oil													
Blue Lake 3	Oil													
Blue Lake 4	Oil													
Blue Lake 7	Gas													
Blue Lake 8	Gas													
Blue Lake	AVG COST													
Calpine I	Gas													
Calpine II	Gas													
Calpine	AVG COST													
French Island 1	Gas													
French Island 1	Wood/RDF													
French Island 2	Gas													
French Island 2	Wood/RDF													
French Island 3	Oil													
French Island 4	Oil													
French Island	AVG COST													
Granite City 1	Gas													
Granite City 2	Gas													
Granite City 3	Gas													
Granite City 4	Gas													
Granite City	AVG COST													
High Bridge CC 1x1	Gas													
High Bridge CC 2x1	Gas													
HighBridge	AVG COST													
Invenergy 1	Gas													
Invenergy 1	Oil													
Invenergy 2	Gas													
Invenergy 2	Oil													
Invenergy	AVG COST													
Inver Hills 1F	Oil													
Inver Hills 1G	Gas													
Inver Hills 2F	Oil													
Inver Hills 2G	Gas													
Inver Hills 3F	Oil													
Inver Hills 3G	Gas													
Inver Hills 4F	Oil													
Inver Hills 4G	Gas													
Inver Hills 5F	Oil													
Inver Hills 5G	Gas													
Inver Hills 6F	Oil													
Inver Hills 6G	Gas													
Inver Hills	AVG COST													
LS Power	AVG COST													
Red Wing 1	RDF													
Red Wing 1	Gas													
Red Wing 2	RDF													
Red Wing 2	Gas													
Red Wing	AVG COST													
Riverside CC 1x1	Gas													
Riverside CC 2x1	Gas													
Riverside	AVG COST													
Sherburne 1	Coal													
Sherburne 2	Coal													
Sherburne 3	Coal													
Sherburne	AVG COST													
Wheaton 1	Gas													
Wheaton 1	Oil													
Wheaton 2	Gas													
Wheaton 2	Oil													
Wheaton 3	Gas													
Wheaton 3	Oil													
Wheaton 4	Gas													
Wheaton 4	Oil													
Wheaton 5	Oil													
Wheaton 6	Oil													
Wheaton	AVG COST													
Wilmarth 1	RDF													
Wilmarth 1	Gas													
Wilmarth 2	RDF													
Wilmarth 2	Gas													
Wilmarth	AVG COST													
SYSTEM MN	AVG COST													

PROTECTED DATA ENDS]

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2021

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

[PROTECTED DATA BEGINS

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2021 Total AVG
Allen S King 1	Coal													
Angus Anson 2	Gas													
Angus Anson 2	Oil													
Angus Anson 3	Gas													
Angus Anson 3	Oil													
Angus Anson 4	Gas													
Angus Anson	AVG COST													
Black Dog 25 CC	Gas													
Black Dog 6	Gas													
Black Dog	AVG COST													
Blue Lake 1	Oil													
Blue Lake 2	Oil													
Blue Lake 3	Oil													
Blue Lake 4	Oil													
Blue Lake 7	Gas													
Blue Lake 8	Gas													
Blue Lake	AVG COST													
Calpine I	Gas													
Calpine II	Gas													
Calpine	AVG COST													
French Island 1	Gas													
French Island 1	Wood/RDF													
French Island 2	Gas													
French Island 2	Wood/RDF													
French Island 3	Oil													
French Island 4	Oil													
French Island	AVG COST													
Granite City 1	Gas													
Granite City 2	Gas													
Granite City 3	Gas													
Granite City 4	Gas													
Granite City	AVG COST													
High Bridge CC 1x1	Gas													
High Bridge CC 2x1	Gas													
HighBridge	AVG COST													
Invenergy 1	Gas													
Invenergy 1	Oil													
Invenergy 2	Gas													
Invenergy 2	Oil													
Invenergy	AVG COST													
Inver Hills 1F	Oil													
Inver Hills 1G	Gas													
Inver Hills 2F	Oil													
Inver Hills 2G	Gas													
Inver Hills 3F	Oil													
Inver Hills 3G	Gas													
Inver Hills 4F	Oil													
Inver Hills 4G	Gas													
Inver Hills 5F	Oil													
Inver Hills 5G	Gas													
Inver Hills 6F	Oil													
Inver Hills 6G	Gas													
Inver Hills	AVG COST													
LS Power	AVG COST													
Red Wing 1	RDF													
Red Wing 1	Gas													
Red Wing 2	RDF													
Red Wing 2	Gas													
Red Wing	AVG COST													
Riverside CC 1x1	Gas													
Riverside CC 2x1	Gas													
Riverside	AVG COST													
Sherburne 1	Coal													
Sherburne 2	Coal													
Sherburne 3	Coal													
Sherburne	AVG COST													
Wheaton 1	Gas													
Wheaton 1	Oil													
Wheaton 2	Gas													
Wheaton 2	Oil													
Wheaton 3	Gas													
Wheaton 3	Oil													
Wheaton 4	Gas													
Wheaton 4	Oil													
Wheaton 5	Oil													
Wheaton 6	Oil													
Wheaton	AVG COST													
Wilmarth 1	RDF													
Wilmarth 1	Gas													
Wilmarth 2	RDF													
Wilmarth 2	Gas													
Wilmarth	AVG COST													
SYSTEM MN	AVG COST													

PROTECTED DATA ENDS]

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2022

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

[PROTECTED DATA BEGINS

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2022 Total AVG
Allen S King 1	Coal													
Angus Anson 2	Gas													
Angus Anson 2	Oil													
Angus Anson 3	Gas													
Angus Anson 3	Oil													
Angus Anson 4	Gas													
Angus Anson	AVG COST													
Black Dog 25 CC	Gas													
Black Dog 6	Gas													
Black Dog	AVG													
Blue Lake 1	Oil													
Blue Lake 2	Oil													
Blue Lake 3	Oil													
Blue Lake 4	Oil													
Blue Lake 7	Gas													
Blue Lake 8	Gas													
Blue Lake	AVG													
Calpine I	Gas													
Calpine II	Gas													
Calpine	AVG COST													
French Island 1	Gas													
French Island 1	Wood/RDF													
French Island 2	Gas													
French Island 2	Wood/RDF													
French Island 3	Oil													
French Island 4	Oil													
French Island	AVG COST													
Granite City 1	Gas													
Granite City 2	Gas													
Granite City 3	Gas													
Granite City 4	Gas													
Granite City	AVG													
High Bridge CC 1x1	Gas													
High Bridge CC 2x1	Gas													
HighBridge	AVG													
Invenergy 1	Gas													
Invenergy 1	Oil													
Invenergy 2	Gas													
Invenergy 2	Oil													
Invenergy	AVG COST													
Inver Hills 1F	Oil													
Inver Hills 1G	Gas													
Inver Hills 2F	Oil													
Inver Hills 2G	Gas													
Inver Hills 3F	Oil													
Inver Hills 3G	Gas													
Inver Hills 4F	Oil													
Inver Hills 4G	Gas													
Inver Hills 5F	Oil													
Inver Hills 5G	Gas													
Inver Hills 6F	Oil													
Inver Hills 6G	Gas													
Inver Hills	AVG COST													
LS Power	AVG COST													
Red Wing 1	RDF													
Red Wing 1	Gas													
Red Wing 2	RDF													
Red Wing 2	Gas													
Red Wing	AVG COST													
Riverside CC 1x1	Gas													
Riverside CC 2x1	Gas													
Riverside	AVG COST													
Sherburne 1	Coal													
Sherburne 2	Coal													
Sherburne 3	Coal													
Sherburne	AVG COST													
Wheaton 1	Gas													
Wheaton 1	Oil													
Wheaton 2	Gas													
Wheaton 2	Oil													
Wheaton 3	Gas													
Wheaton 3	Oil													
Wheaton 4	Gas													
Wheaton 4	Oil													
Wheaton 5	Oil													
Wheaton 6	Oil													
Wheaton	AVG COST													
Wilmarth 1	RDF													
Wilmarth 1	Gas													
Wilmarth 2	RDF													
Wilmarth 2	Gas													
Wilmarth	AVG COST													
SYSTEM MN	AVG COST													

PROTECTED DATA ENDS]

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2023

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

[PROTECTED DATA BEGINS

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2023 Total AVG
Allen S King 1	Coal													
Angus Anson 2	Gas													
Angus Anson 2	Oil													
Angus Anson 3	Gas													
Angus Anson 3	Oil													
Angus Anson 4	Gas													
Angus Anson	AVG COST													
Black Dog 25 CC	Gas													
Black Dog 6	Gas													
Black Dog	AVG COST													
Blue Lake 1	Oil													
Blue Lake 2	Oil													
Blue Lake 3	Oil													
Blue Lake 4	Oil													
Blue Lake 7	Gas													
Blue Lake 8	Gas													
Blue Lake	AVG COST													
Calpine I	Gas													
Calpine II	Gas													
Calpine	AVG COST													
French Island 1	Gas													
French Island 1	Wood/RDF													
French Island 2	Gas													
French Island 2	Wood/RDF													
French Island 3	Oil													
French Island 4	Oil													
French Island	AVG COST													
Granite City 1	Gas													
Granite City 2	Gas													
Granite City 3	Gas													
Granite City 4	Gas													
Granite City	AVG COST													
High Bridge CC 1x1	Gas													
High Bridge CC 2x1	Gas													
HighBridge	AVG COST													
Invenergy 1	Gas													
Invenergy 1	Oil													
Invenergy 2	Gas													
Invenergy 2	Oil													
Invenergy	AVG COST													
Inver Hills 1F	Oil													
Inver Hills 1G	Gas													
Inver Hills 2F	Oil													
Inver Hills 2G	Gas													
Inver Hills 3F	Oil													
Inver Hills 3G	Gas													
Inver Hills 4F	Oil													
Inver Hills 4G	Gas													
Inver Hills 5F	Oil													
Inver Hills 5G	Gas													
Inver Hills 6F	Oil													
Inver Hills 6G	Gas													
Inver Hills	AVG COST													
LS Power	AVG COST													
Red Wing 1	Gas													
Red Wing 1	RDF													
Red Wing 2	Gas													
Red Wing 2	RDF													
Red Wing	AVG													
Riverside CC 1x1	Gas													
Riverside CC 2x1	Gas													
Riverside	AVG COST													
Sherburne 1	Coal													
Sherburne 2	Coal													
Sherburne 3	Coal													
Sherburne	AVG COST													
Wheaton 1	Gas													
Wheaton 1	Oil													
Wheaton 2	Gas													
Wheaton 2	Oil													
Wheaton 3	Gas													
Wheaton 3	Oil													
Wheaton 4	Gas													
Wheaton 4	Oil													
Wheaton 5	Oil													
Wheaton 6	Oil													
Wheaton	AVG COST													
Wilmarth 1	Gas													
Wilmarth 1	RDF													
Wilmarth 2	Gas													
Wilmarth 2	RDF													
Wilmarth	AVG COST													
SYSTEM MN	AVG COST													

PROTECTED DATA ENDS]

Coal Expense
$/Mbtu
2019

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2019
	[PROTECTED DATA BEGINS												
Allen S King 1													
Bay Front 4													
Bay Front 5													
Bay Front 6													
Bay Front AVG													
Sherburne 1													
Sherburne 2													
Sherburne 3													
Sherco AVG													
System													

PROTECTED DATA ENDS]

Coal Expense
$/Mbtu
2020

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2020
	[PROTECTED DATA BEGINS												
Allen S King 1													
Bay Front 4													
Bay Front 5													
Bay Front 6													
Bay Front AVG													
Sherburne 1													
Sherburne 2													
Sherburne 3													
Sherco AVG													
System													

PROTECTED DATA ENDS]

Coal Expense
$/Mbtu
2021

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2021
	[PROTECTED DATA BEGINS												
Allen S King 1													
Bay Front 4													
Bay Front 5													
Bay Front 6													
Bay Front AVG													
Sherburne 1													
Sherburne 2													
Sherburne 3													
Sherco AVG													
System													

PROTECTED DATA ENDS]

Coal Expense
$/Mbtu
2022

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

[PROTECTED DATA BEGINS

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2022
Allen S King 1													
Bay Front 4													
Bay Front 5													
Bay Front 6													
Bay Front AVG													
Sherburne 1													
Sherburne 2													
Sherburne 3													
Sherco AVG													
System													

PROTECTED DATA ENDS]

Coal Expense
$/Mbtu
2023

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

[PROTECTED DATA BEGINS

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2023
Allen S King 1													
Bay Front 4													
Bay Front 5													
Bay Front 6													
Bay Front AVG													
Sherburne 1													
Sherburne 2													
Sherburne 3													
Sherco AVG													
System													

PROTECTED DATA ENDS]

Northern States Power Company
Electric Operations - State of Minnesota
Work Papers For Five Year Projection of Fuel Costs
Nuclear Fuel Expense (Units noted in row)

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

[PROTECTED DATA BEGINS

Item ID	Item Description (AAA2018 07-26-18 14:44:09)	Jan 2019	Feb 2019	Mar 2019	Apr 2019	May 2019	Jun 2019	Jul 2019	Aug 2019	Sep 2019	Oct 2019	Nov 2019	Dec 2019
1	Prairie Island 1 - Heat Generation (1000 MBTU)												
2	Prairie Island 1 - Net Electric Generation (MWHe-Net)												
3	Prairie Island 1 - Maximum Capacity (MWe-Net)												
4	Prairie Island 1 - Current Capability (MWe-Net)												
5	Prairie Island 1 - Thermal Capability (MWth)												
6	Prairie Island 1 - Monthly Capacity Factor (%)												
7	Prairie Island 1 - Monthly Minor Outage Rate (%)												
8	Prairie Island 1 - Days Offline in Month for Refueling												
9	Prairie Island 1 - Refueling Outage Start Date												
10	Prairie Island 1 - Refueling Outage Start Time (HH.MM)												
11	Prairie Island 1 - Refueling Outage End Date												
12	Prairie Island 1 - Refueling Outage End Time (HH.MM)												
13	Prairie Island 1 - Fuel Expense - Dollars												
14	Prairie Island 1 - Fuel Expense - Cents/MBTU												
15	Prairie Island 1 - Fuel Expense - Cents/Kwhe												
16	Prairie Island 2 - Heat Generation (1000 MBTU)												
17	Prairie Island 2 - Net Electric Generation (MWHe-Net)												
18	Prairie Island 2 - Maximum Capacity (MWe-Net)												
19	Prairie Island 2 - Current Capability (MWe-Net)												
20	Prairie Island 2 - Thermal Capability (MWth)												
21	Prairie Island 2 - Monthly Capacity Factor (%)												
22	Prairie Island 2 - Monthly Minor Outage Rate (%)												
23	Prairie Island 2 - Days Offline in Month for Refuelin												
24	Prairie Island 2 - Refueling Outage Start Date												
25	Prairie Island 2 - Refueling Outage Start Time (HH.MM												
26	Prairie Island 2 - Refueling Outage End Date												
27	Prairie Island 2 - Refueling Outage End Time (HH.MM)												
28	Prairie Island 2 - Fuel Expense - Dollars												
29	Prairie Island 2 - Fuel Expense - Cents/MBTU												
30	Prairie Island 2 - Fuel Expense - Cents/Kwhe												
31	Monticello - Heat Generation (1000 MBTU)												
32	Monticello - Net Electric Generation (MWHe-Net)												
33	Monticello - Maximum Capacity (MWe-Net)												
34	Monticello - Current Capability (MWe-Net)												
35	Monticello - Thermal Capability (MWth)												
36	Monticello - Monthly Capacity Factor (%)												
37	Monticello - Monthly Minor Outage Rate (%)												
38	Monticello - Days Offline in Month for Refuelin												
39	Monticello - Refueling Outage Start Date												
40	Monticello - Refueling Outage Start Time (HH.MM												
41	Monticello - Refueling Outage End Date												
42	Monticello - Refueling Outage End Time (HH.MM)												
43	Monticello - Fuel Expense - Dollars												
44	Monticello - Fuel Expense - Cents/MBTU												
45	Monticello - Fuel Expense - Cents/Kwhe												
46	Prairie Island 1 - Cents/Kwhe - Fuel Commodities												
47	Prairie Island 1 - Cents/Kwhe - Fuel Services												
48	Prairie Island 1 - Cents/Kwhe - DOE Disposal Fee												
49	Prairie Island 1 - Cents/Kwhe - D&D Fee												
50	Prairie Island 1 - Cents/Kwhe - End of Life Recovery												
51	Prairie Island 1 - Cents/Kwhe - Other Global Costs												
52	Prairie Island 1 - Cents/Kwhe - AFUDC and A&G												
53	Prairie Island 2 - Cents/Kwhe - Fuel Commodities												
54	Prairie Island 2 - Cents/Kwhe - Fuel Services												
55	Prairie Island 2 - Cents/Kwhe - DOE Disposal Fee												
56	Prairie Island 2 - Cents/Kwhe - D&D Fee												
57	Prairie Island 2 - Cents/Kwhe - End of Life Recovery												
58	Prairie Island 2 - Cents/Kwhe - Other Global Costs												
59	Prairie Island 2 - Cents/Kwhe - AFUDC and A&G												
60	Monticello - Cents/Kwhe - Fuel Commodities												
61	Monticello - Cents/Kwhe - Fuel Services												
62	Monticello - Cents/Kwhe - DOE Disposal Fee												
63	Monticello - Cents/Kwhe - D&D Fee												
64	Monticello - Cents/Kwhe - End of Life Recovery												
65	Monticello - Cents/Kwhe - Other Global Costs												
66	Monticello - Cents/Kwhe - AFUDC and A&G												
67	Prairie Island 1 - EOL Recovery Expense - Dollars												
68	Prairie Island 2 - EOL Recovery Expense - Dollars												
69	Monticello - EOL Recovery Expense - Dollars												

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

[PROTECTED DATA BEGINS

Item ID	Item Description (AAA2018 07-26-18 14:44:09)	Jan 2020	Feb 2020	Mar 2020	Apr 2020	May 2020	Jun 2020	Jul 2020	Aug 2020	Sep 2020	Oct 2020	Nov 2020	Dec 2020
1	Prairie Island 1 - Heat Generation (1000 MBTU)												
2	Prairie Island 1 - Net Electric Generation (MWHe-Net)												
3	Prairie Island 1 - Maximum Capacity (MWe-Net)												
4	Prairie Island 1 - Current Capability (MWe-Net)												
5	Prairie Island 1 - Thermal Capability (MWth)												
6	Prairie Island 1 - Monthly Capacity Factor (%)												
7	Prairie Island 1 - Monthly Minor Outage Rate (%)												
8	Prairie Island 1 - Days Offline in Month for Refueling												
9	Prairie Island 1 - Refueling Outage Start Date												
10	Prairie Island 1 - Refueling Outage Start Time (HH.MM)												
11	Prairie Island 1 - Refueling Outage End Date												
12	Prairie Island 1 - Refueling Outage End Time (HH.MM)												
13	Prairie Island 1 - Fuel Expense - Dollars												
14	Prairie Island 1 - Fuel Expense - Cents/MBTU												
15	Prairie Island 1 - Fuel Expense - Cents/Kwhe												
16	Prairie Island 2 - Heat Generation (1000 MBTU)												
17	Prairie Island 2 - Net Electric Generation (MWHe-Net)												
18	Prairie Island 2 - Maximum Capacity (MWe-Net)												
19	Prairie Island 2 - Current Capability (MWe-Net)												
20	Prairie Island 2 - Thermal Capability (MWth)												
21	Prairie Island 2 - Monthly Capacity Factor (%)												
22	Prairie Island 2 - Monthly Minor Outage Rate (%)												
23	Prairie Island 2 - Days Offline in Month for Refuelin												
24	Prairie Island 2 - Refueling Outage Start Date												
25	Prairie Island 2 - Refueling Outage Start Time (HH.MM												
26	Prairie Island 2 - Refueling Outage End Date												
27	Prairie Island 2 - Refueling Outage End Time (HH.MM)												
28	Prairie Island 2 - Fuel Expense - Dollars												
29	Prairie Island 2 - Fuel Expense - Cents/MBTU												
30	Prairie Island 2 - Fuel Expense - Cents/Kwhe												
31	Monticello - Heat Generation (1000 MBTU)												
32	Monticello - Net Electric Generation (MWHe-Net)												
33	Monticello - Maximum Capacity (MWe-Net)												
34	Monticello - Current Capability (MWe-Net)												
35	Monticello - Thermal Capability (MWth)												
36	Monticello - Monthly Capacity Factor (%)												
37	Monticello - Monthly Minor Outage Rate (%)												
38	Monticello - Days Offline in Month for Refuelin												
39	Monticello - Refueling Outage Start Date												
40	Monticello - Refueling Outage Start Time (HH.MM												
41	Monticello - Refueling Outage End Date												
42	Monticello - Refueling Outage End Time (HH.MM)												
43	Monticello - Fuel Expense - Dollars												
44	Monticello - Fuel Expense - Cents/MBTU												
45	Monticello - Fuel Expense - Cents/Kwhe												
46	Prairie Island 1 - Cents/Kwhe - Fuel Commodities												
47	Prairie Island 1 - Cents/Kwhe - Fuel Services												
48	Prairie Island 1 - Cents/Kwhe - DOE Disposal Fee												
49	Prairie Island 1 - Cents/Kwhe - D&D Fee												
50	Prairie Island 1 - Cents/Kwhe - End of Life Recovery												
51	Prairie Island 1 - Cents/Kwhe - Other Global Costs												
52	Prairie Island 1 - Cents/Kwhe - AFUDC and A&G												
53	Prairie Island 2 - Cents/Kwhe - Fuel Commodities												
54	Prairie Island 2 - Cents/Kwhe - Fuel Services												
55	Prairie Island 2 - Cents/Kwhe - DOE Disposal Fee												
56	Prairie Island 2 - Cents/Kwhe - D&D Fee												
57	Prairie Island 2 - Cents/Kwhe - End of Life Recovery												
58	Prairie Island 2 - Cents/Kwhe - Other Global Costs												
59	Prairie Island 2 - Cents/Kwhe - AFUDC and A&G												
60	Monticello - Cents/Kwhe - Fuel Commodities												
61	Monticello - Cents/Kwhe - Fuel Services												
62	Monticello - Cents/Kwhe - DOE Disposal Fee												
63	Monticello - Cents/Kwhe - D&D Fee												
64	Monticello - Cents/Kwhe - End of Life Recovery												
65	Monticello - Cents/Kwhe - Other Global Costs												
66	Monticello - Cents/Kwhe - AFUDC and A&G												
67	Prairie Island 1 - EOL Recovery Expense - Dollars												
68	Prairie Island 2 - EOL Recovery Expense - Dollars												
69	Monticello - EOL Recovery Expense - Dollars												

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

[PROTECTED DATA BEGINS

Item ID	Item Description (AAA2018 07-26-18 14:44:09)	Jan 2021	Feb 2021	Mar 2021	Apr 2021	May 2021	Jun 2021	Jul 2021	Aug 2021	Sep 2021	Oct 2021	Nov 2021	Dec 2021
1	Prairie Island 1 - Heat Generation (1000 MBTU)												
2	Prairie Island 1 - Net Electric Generation (MWHe-Net)												
3	Prairie Island 1 - Maximum Capacity (MWe-Net)												
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6	Prairie Island 1 - Monthly Capacity Factor (%)												
7	Prairie Island 1 - Monthly Minor Outage Rate (%)												
8	Prairie Island 1 - Days Offline in Month for Refueling												
9	Prairie Island 1 - Refueling Outage Start Date												
10	Prairie Island 1 - Refueling Outage Start Time (HH.MM)												
11	Prairie Island 1 - Refueling Outage End Date												
12	Prairie Island 1 - Refueling Outage End Time (HH.MM)												
13	Prairie Island 1 - Fuel Expense - Dollars												
14	Prairie Island 1 - Fuel Expense - Cents/MBTU												
15	Prairie Island 1 - Fuel Expense - Cents/Kwhe												
16	Prairie Island 2 - Heat Generation (1000 MBTU)												
17	Prairie Island 2 - Net Electric Generation (MWHe-Net)												
18	Prairie Island 2 - Maximum Capacity (MWe-Net)												
19	Prairie Island 2 - Current Capability (MWe-Net)												
20	Prairie Island 2 - Thermal Capability (MWth)												
21	Prairie Island 2 - Monthly Capacity Factor (%)												
22	Prairie Island 2 - Monthly Minor Outage Rate (%)												
23	Prairie Island 2 - Days Offline in Month for Refuelin												
24	Prairie Island 2 - Refueling Outage Start Date												
25	Prairie Island 2 - Refueling Outage Start Time (HH.MM												
26	Prairie Island 2 - Refueling Outage End Date												
27	Prairie Island 2 - Refueling Outage End Time (HH.MM)												
28	Prairie Island 2 - Fuel Expense - Dollars												
29	Prairie Island 2 - Fuel Expense - Cents/MBTU												
30	Prairie Island 2 - Fuel Expense - Cents/Kwhe												
31	Monticello - Heat Generation (1000 MBTU)												
32	Monticello - Net Electric Generation (MWHe-Net)												
33	Monticello - Maximum Capacity (MWe-Net)												
34	Monticello - Current Capability (MWe-Net)												
35	Monticello - Thermal Capability (MWth)												
36	Monticello - Monthly Capacity Factor (%)												
37	Monticello - Monthly Minor Outage Rate (%)												
38	Monticello - Days Offline in Month for Refuelin												
39	Monticello - Refueling Outage Start Date												
40	Monticello - Refueling Outage Start Time (HH.MM												
41	Monticello - Refueling Outage End Date												
42	Monticello - Refueling Outage End Time (HH.MM)												
43	Monticello - Fuel Expense - Dollars												
44	Monticello - Fuel Expense - Cents/MBTU												
45	Monticello - Fuel Expense - Cents/Kwhe												
46	Prairie Island 1 - Cents/Kwhe - Fuel Commodities												
47	Prairie Island 1 - Cents/Kwhe - Fuel Services												
48	Prairie Island 1 - Cents/Kwhe - DOE Disposal Fee												
49	Prairie Island 1 - Cents/Kwhe - D&D Fee												
50	Prairie Island 1 - Cents/Kwhe - End of Life Recovery												
51	Prairie Island 1 - Cents/Kwhe - Other Global Costs												
52	Prairie Island 1 - Cents/Kwhe - AFUDC and A&G												
53	Prairie Island 2 - Cents/Kwhe - Fuel Commodities												
54	Prairie Island 2 - Cents/Kwhe - Fuel Services												
55	Prairie Island 2 - Cents/Kwhe - DOE Disposal Fee												
56	Prairie Island 2 - Cents/Kwhe - D&D Fee												
57	Prairie Island 2 - Cents/Kwhe - End of Life Recovery												
58	Prairie Island 2 - Cents/Kwhe - Other Global Costs												
59	Prairie Island 2 - Cents/Kwhe - AFUDC and A&G												
60	Monticello - Cents/Kwhe - Fuel Commodities												
61	Monticello - Cents/Kwhe - Fuel Services												
62	Monticello - Cents/Kwhe - DOE Disposal Fee												
63	Monticello - Cents/Kwhe - D&D Fee												
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65	Monticello - Cents/Kwhe - Other Global Costs												
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67	Prairie Island 1 - EOL Recovery Expense - Dollars												
68	Prairie Island 2 - EOL Recovery Expense - Dollars												
69	Monticello - EOL Recovery Expense - Dollars												

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

[PROTECTED DATA BEGINS

Item ID	Item Description (AAA2018 07-26-18 14:44:09)	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022
1	Prairie Island 1 - Heat Generation (1000 MBTU)												
2	Prairie Island 1 - Net Electric Generation (MWHe-Net)												
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8	Prairie Island 1 - Days Offline in Month for Refueling												
9	Prairie Island 1 - Refueling Outage Start Date												
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11	Prairie Island 1 - Refueling Outage End Date												
12	Prairie Island 1 - Refueling Outage End Time (HH.MM)												
13	Prairie Island 1 - Fuel Expense - Dollars												
14	Prairie Island 1 - Fuel Expense - Cents/MBTU												
15	Prairie Island 1 - Fuel Expense - Cents/Kwhe												
16	Prairie Island 2 - Heat Generation (1000 MBTU)												
17	Prairie Island 2 - Net Electric Generation (MWHe-Net)												
18	Prairie Island 2 - Maximum Capacity (MWe-Net)												
19	Prairie Island 2 - Current Capability (MWe-Net)												
20	Prairie Island 2 - Thermal Capability (MWth)												
21	Prairie Island 2 - Monthly Capacity Factor (%)												
22	Prairie Island 2 - Monthly Minor Outage Rate (%)												
23	Prairie Island 2 - Days Offline in Month for Refuelin												
24	Prairie Island 2 - Refueling Outage Start Date												
25	Prairie Island 2 - Refueling Outage Start Time (HH.MM												
26	Prairie Island 2 - Refueling Outage End Date												
27	Prairie Island 2 - Refueling Outage End Time (HH.MM)												
28	Prairie Island 2 - Fuel Expense - Dollars												
29	Prairie Island 2 - Fuel Expense - Cents/MBTU												
30	Prairie Island 2 - Fuel Expense - Cents/Kwhe												
31	Monticello - Heat Generation (1000 MBTU)												
32	Monticello - Net Electric Generation (MWHe-Net)												
33	Monticello - Maximum Capacity (MWe-Net)												
34	Monticello - Current Capability (MWe-Net)												
35	Monticello - Thermal Capability (MWth)												
36	Monticello - Monthly Capacity Factor (%)												
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38	Monticello - Days Offline in Month for Refuelin												
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44	Monticello - Fuel Expense - Cents/MBTU												
45	Monticello - Fuel Expense - Cents/Kwhe												
46	Prairie Island 1 - Cents/Kwhe - Fuel Commodities												
47	Prairie Island 1 - Cents/Kwhe - Fuel Services												
48	Prairie Island 1 - Cents/Kwhe - DOE Disposal Fee												
49	Prairie Island 1 - Cents/Kwhe - D&D Fee												
50	Prairie Island 1 - Cents/Kwhe - End of Life Recovery												
51	Prairie Island 1 - Cents/Kwhe - Other Global Costs												
52	Prairie Island 1 - Cents/Kwhe - AFUDC and A&G												
53	Prairie Island 2 - Cents/Kwhe - Fuel Commodities												
54	Prairie Island 2 - Cents/Kwhe - Fuel Services												
55	Prairie Island 2 - Cents/Kwhe - DOE Disposal Fee												
56	Prairie Island 2 - Cents/Kwhe - D&D Fee												
57	Prairie Island 2 - Cents/Kwhe - End of Life Recovery												
58	Prairie Island 2 - Cents/Kwhe - Other Global Costs												
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60	Monticello - Cents/Kwhe - Fuel Commodities												
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9	Prairie Island 1 - Refueling Outage Start Date												
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12	Prairie Island 1 - Refueling Outage End Time (HH.MM)												
13	Prairie Island 1 - Fuel Expense - Dollars												
14	Prairie Island 1 - Fuel Expense - Cents/MBTU												
15	Prairie Island 1 - Fuel Expense - Cents/Kwhe												
16	Prairie Island 2 - Heat Generation (1000 MBTU)												
17	Prairie Island 2 - Net Electric Generation (MWHe-Net)												
18	Prairie Island 2 - Maximum Capacity (MWe-Net)												
19	Prairie Island 2 - Current Capability (MWe-Net)												
20	Prairie Island 2 - Thermal Capability (MWth)												
21	Prairie Island 2 - Monthly Capacity Factor (%)												
22	Prairie Island 2 - Monthly Minor Outage Rate (%)												
23	Prairie Island 2 - Days Offline in Month for Refuelin												
24	Prairie Island 2 - Refueling Outage Start Date												
25	Prairie Island 2 - Refueling Outage Start Time (HH.MM												
26	Prairie Island 2 - Refueling Outage End Date												
27	Prairie Island 2 - Refueling Outage End Time (HH.MM)												
28	Prairie Island 2 - Fuel Expense - Dollars												
29	Prairie Island 2 - Fuel Expense - Cents/MBTU												
30	Prairie Island 2 - Fuel Expense - Cents/Kwhe												
31	Monticello - Heat Generation (1000 MBTU)												
32	Monticello - Net Electric Generation (MWHe-Net)												
33	Monticello - Maximum Capacity (MWe-Net)												
34	Monticello - Current Capability (MWe-Net)												
35	Monticello - Thermal Capability (MWth)												
36	Monticello - Monthly Capacity Factor (%)												
37	Monticello - Monthly Minor Outage Rate (%)												
38	Monticello - Days Offline in Month for Refuelin												
39	Monticello - Refueling Outage Start Date												
40	Monticello - Refueling Outage Start Time (HH.MM												
41	Monticello - Refueling Outage End Date												
42	Monticello - Refueling Outage End Time (HH.MM)												
43	Monticello - Fuel Expense - Dollars												
44	Monticello - Fuel Expense - Cents/MBTU												
45	Monticello - Fuel Expense - Cents/Kwhe												
46	Prairie Island 1 - Cents/Kwhe - Fuel Commodities												
47	Prairie Island 1 - Cents/Kwhe - Fuel Services												
48	Prairie Island 1 - Cents/Kwhe - DOE Disposal Fee												
49	Prairie Island 1 - Cents/Kwhe - D&D Fee												
50	Prairie Island 1 - Cents/Kwhe - End of Life Recovery												
51	Prairie Island 1 - Cents/Kwhe - Other Global Costs												
52	Prairie Island 1 - Cents/Kwhe - AFUDC and A&G												
53	Prairie Island 2 - Cents/Kwhe - Fuel Commodities												
54	Prairie Island 2 - Cents/Kwhe - Fuel Services												
55	Prairie Island 2 - Cents/Kwhe - DOE Disposal Fee												
56	Prairie Island 2 - Cents/Kwhe - D&D Fee												
57	Prairie Island 2 - Cents/Kwhe - End of Life Recovery												
58	Prairie Island 2 - Cents/Kwhe - Other Global Costs												
59	Prairie Island 2 - Cents/Kwhe - AFUDC and A&G												
60	Monticello - Cents/Kwhe - Fuel Commodities												
61	Monticello - Cents/Kwhe - Fuel Services												
62	Monticello - Cents/Kwhe - DOE Disposal Fee												
63	Monticello - Cents/Kwhe - D&D Fee												
64	Monticello - Cents/Kwhe - End of Life Recovery												
65	Monticello - Cents/Kwhe - Other Global Costs												
66	Monticello - Cents/Kwhe - AFUDC and A&G												
67	Prairie Island 1 - EOL Recovery Expense - Dollars												
68	Prairie Island 2 - EOL Recovery Expense - Dollars												
69	Monticello - EOL Recovery Expense - Dollars												

PROTECTED DATA ENDS]

2019 Electric Production Forecast
Peak Demand and Energy Requirements

	Base Peak Demand (MW)	Energy Requirements (MWH)	Load Factor (%)
January	6,354	3,910,921	82.73%
February	6,083	3,353,315	82.04%
March	5,867	3,518,941	80.62%
April	5,414	3,149,323	80.79%
May	6,994	3,427,012	65.86%
June	8,377	3,818,994	63.32%
July	9,109	4,261,842	62.88%
August	8,756	4,179,020	64.15%
September	7,838	3,495,849	61.95%
October	5,719	3,402,357	79.97%
November	5,776	3,401,333	81.79%
December	6,394	3,804,175	79.96%
Annual	**9,109**	**43,723,081**	**54.79%**

2020 Electric Production Forecast
Peak Demand and Energy Requirements

	Base Peak Demand (MW)	Energy Requirements (MWH)	Load Factor (%)
January	6,324	3,911,407	83.13%
February	6,054	3,479,438	82.58%
March	5,833	3,516,460	81.03%
April	5,378	3,143,292	81.17%
May	7,031	3,422,453	65.43%
June	8,402	3,819,577	63.14%
July	9,133	4,264,386	62.76%
August	8,807	4,179,292	63.78%
September	7,862	3,493,430	61.71%
October	5,695	3,399,016	80.22%
November	5,756	3,398,576	82.00%
December	6,379	3,807,681	80.23%
Annual	**9,133**	**43,835,010**	**54.79%**

2021 Electric Production Forecast
Peak Demand and Energy Requirements

	Base Peak Demand (MW)	**Energy Requirements (MWH)**	**Load Factor (%)**
January	6,339	3,902,360	82.74%
February	6,063	3,338,464	81.94%
March	5,838	3,507,078	80.74%
April	5,377	3,133,362	80.94%
May	7,088	3,412,341	64.71%
June	8,445	3,809,781	62.66%
July	9,170	4,251,931	62.32%
August	8,868	4,165,369	63.13%
September	7,900	3,482,017	61.22%
October	5,689	3,387,571	80.04%
November	5,755	3,388,230	81.77%
December	6,381	3,797,764	79.99%
Annual	**9,170**	**43,576,268**	**54.24%**

2022 Electric Production Forecast
Peak Demand and Energy Requirements

	Base Peak Demand (MW)	**Energy Requirements (MWH)**	**Load Factor (%)**
January	6,354	3,905,400	82.61%
February	6,077	3,339,489	81.77%
March	5,851	3,507,861	80.59%
April	5,384	3,133,006	80.82%
May	7,157	3,413,903	64.11%
June	8,504	3,811,768	62.25%
July	9,235	4,254,093	61.91%
August	8,969	4,166,386	62.44%
September	7,965	3,482,600	60.72%
October	5,703	3,389,053	79.88%
November	5,771	3,389,551	81.58%
December	6,401	3,800,009	79.79%
Annual	**9,235**	**43,593,120**	**53.89%**

2023 Electric Production Forecast
Peak Demand and Energy Requirements

	Base Peak Demand (MW)	Energy Requirements (MWH)	Load Factor (%)
January	6,345	3,899,698	82.60%
February	6,067	3,331,083	81.70%
March	5,839	3,500,240	80.57%
April	5,366	3,124,278	80.87%
May	7,199	3,405,703	63.59%
June	8,538	3,805,395	61.91%
July	9,272	4,248,130	61.58%
August	9,039	4,157,742	61.83%
September	8,005	3,474,836	60.29%
October	5,692	3,380,825	79.84%
November	5,764	3,381,160	81.48%
December	6,402	3,795,487	79.68%
Annual	**9,272**	**43,504,577**	**53.56%**

Estimated Load Management Impact

Summer Peak (MW)

	System Base Peak	Total Load Mgmt/ Load Relief	Net Peak
2018	9,129	610	8,519
2019	9,109	619	8,490
2020	9,133	628	8,504
2021	9,170	637	8,533
2022	9,235	645	8,590
2023	9,272	651	8,621
2024	9,314	653	8,660
2025	9,335	656	8,679
2026	9,381	658	8,723
2027	9,463	656	8,807
2028	9,565	656	8,909
2029	9,604	656	8,948
2030	9,663	656	9,007
2031	9,703	656	9,048
2032	9,816	656	9,161
2033	9,983	656	9,328
2034	10,113	656	9,457

Average Annual Growth Rates

2018-2028	0.47%		0.45%
2028-2034	0.93%		1.00%
2018-2034	0.64%		0.65%

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-18-373

PART H

ADDITIONAL REPORTING REQUIREMENTS

ADDITIONAL REPORTING REQUIREMENTS (NON-MISO)

Part H contains the Company's various compliance reports required by Commission Orders in prior Company miscellaneous filings, investigations, and AAA Reports, other than the compliance reports by the Commission's Orders regarding the Company's participation in the MISO Day 1, Day 2 and ASM operations.

1. History of Nuclear Fuel Sinking Fund (Docket No. E002/M-81-306)

This reporting item was discontinued pursuant to the Commission's March 16, 2018 Order in Docket No. E999/AA-16-523.

2. Investigation of NSP's Practices Regarding Energy Marketing and Fuel Clause (Docket No. E002/CI-00-415)

On April 3, 2000, the Residential and Small Business Utilities Division of the Office of the Attorney General (OAG) filed a request that the Commission initiate a summary investigation into the Company's automatic adjustment of its electric rates (Docket No. E002/CI-00-415). The purpose of the investigation was to determine whether the Company's practices related to the costs included in its retail electric fuel adjustment clause and costs assigned to wholesale electric sales result in a rate that is just and reasonable. Through an Order issued on July 20, 2000, the Commission required the parties to meet and submit a report. In the period between the Commission's July 20, 2000 Order and April 20, 2001, the Commission issued three Orders accepting updates and setting due dates for further reports or updates. On April 20, 2001, the OAG filed its final report, in which it concluded that a formal Commission investigation was no longer warranted provided that the Company complied with reporting requirements set forth in the report.

On June 15, 2001, the Commission issued an Order accepting the final report submitted by the OAG and closed the docket. The Order also required the Company to provide with its AAA reports a monthly comparison of generation costs allocated to retail and wholesale for the months of June, July, and August. The Company has attached the June and July data as Part H, Section 2, Schedule 1. Since the August 2018 data will not be available until mid-September, the Company will report the September data in a subsequent supplemental filing after the data has been booked.

3. Natural Gas Financial Instruments (Docket Nos. E002/M-01-1953 and E,G999/AA-02-950)

On March 20, 2002, the Commission issued an Order in the above-referenced dockets which 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.[1] The Company also proposed 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 and PGA submitted September 1, 2002. The Department agreed with this recommendation and the Commission included the requirement in its Order. We continue to comply with this requirement, and Part F, Schedule 1 contains a copy of the letter that was sent to facilitate the independent audit by Deloitte & Touche LLP in compliance with the Commission's Order. We note that new 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 we send to the auditor. See Part F, Schedule 1.

4. Annual Transmission Transformers Report (Docket Nos. E,G999/AA-07-1130, E999/M-07-1028 and E999/M-09-602)

On August 31, 2009, the Commission issued an Order in the above-referenced dockets in regards to the 2006-2007 AAA Reports, as well as the 2007 and 2009 Minnesota Biennial Transmission Projects Report and Renewable Energy Standards Report. As a part of its decision, the Commission required all Minnesota electric utilities to report in their AAA reports, and their biennial transmission projects reports, the number of transformers over 100 kV (low side or distribution side) by size, and to assess whether they are maintaining in inventory or otherwise have access to a reasonable level of spare transformers in different sizes due to the increased cost of replacement power during outages.

The following table illustrates the NSP System spare transmission transformer inventory and planned deliveries:

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[1] One purpose of the filing was to correctly account for and segregate the costs of financial instruments purchased to limit volatility in electric generation fuel costs from those purchased to limit volatility in the cost of natural gas purchased for the Company's retail local distribution company function.

Primary Voltage Class	Secondary Voltage Class	Maximum MVA	NSP Operating Company	Location	Status
345	115	672	Minnesota	Inver Hills	Storage
345	161	336	Minnesota	Maple Grove	Storage
345	115	672	Minnesota	Maple Grove	Storage
345	115	448	Minnesota	Maple Grove	Storage
230	115	336	Minnesota	Maple Grove	Storage
230	115	112	Minnesota	Minn Valley	Storage
230	115	50	Minnesota	Minn Valley	Storage
230	115	50	Minnesota	Minn Valley	Storage
161	115	187	Minnesota	Maple Grove	Storage

The Company believes that it maintains a reasonable level of transformers in inventory in order to: (1) maintain the reliability of the system; (2) remain consistent with North American Electric Reliability Corporation (NERC) reliability criteria; and (3) balance the economic benefit to ratepayers.

However, while the Company believes it maintains a reasonable inventory, and while transmission transformers are typically designed to provide high reliability performance and durability, they do fail from time to time regardless of the efforts of the Company. Such failures may result, for example, from extreme weather conditions, exposure to excessive dust, or natural corrosion. Despite the Company's long-standing practice of improving and maintaining the transmission capability throughout the NSP System, when outages of individual transformers occur it can affect purchased energy costs.

Part H, Section 4, Schedule 1 contains a list of all NSP System transmission transformers exceeding 100 kV.

5. Wind Curtailment Report (Docket Nos. E002/M-00-622, E002/M-02-51, E002/M-04-404, E002/CN-01-1958, E002/M-04-864, E,G999/AA-04-1279, E002/M-05-1850, E002/M-05-1934 and E002/M-06-85)

The Company has been providing wind curtailment reporting in its monthly FCA reports since the May FCA report dated April 28, 2004. Additionally, the Commission's April 4, 2006 Order regarding curtailment payments to wind developers introduced a new element to the regulatory review of wind power purchases—projection of curtailment costs given existing and planned wind-generated energy purchases and the transmission system. Part H, Section 5, Schedule 1 contains a summary of wind production and curtailment payments during the July 1, 2017 – June 30, 2018 AAA reporting period.

Part H, Section 5, Schedule 2 contains an explanation of the factors affecting wind curtailment costs for the 2017-2018 AAA reporting period, and our projection of expenses associated with wind curtailment for the next five years. The actual curtailment expenses will depend on the wind resource experienced at each turbine, the timing of outages of existing transmission facilities and construction of additional transmission facilities, and the operation of wind generators as Dispatchable Intermittent Resources (DIR) in the MISO energy market.

6. 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.

7. 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. The Company will continue to monitor and report such curtailment transactions in the monthly fuel clause adjustment filings.

8. 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.

9. Community Solar Gardens (Docket No. E002/M-13-867)

In its September 17, 2014 ORDER APPROVING SOLAR-GARDEN PLAN WITH MODIFICATIONS, 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."

In the reporting period between July 2017 – June 2018, there were 111 active Community Solar Gardens in-service and 86 of these came on-line during the July 2017 – June 2018 AAA reporting period. The location, start date and number of subscriptions for these gardens are detailed in Part H, Section 9, Schedule 1. The total system amount of expense related to the 111 solar gardens during this reporting period was $48,314,608.63. The corresponding subscribed and unsubscribed energy bill credits were $47,045,242.93 and $1,269,365.70 respectively. Total Community Solar Gardens expenses booked for FCA recovery during the AAA reporting period are a lesser amount (as shown in Part H, Section 9, Schedule 2).

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. The market costs are allocated to jurisdiction through normal allocations, and above market costs are direct assigned to Minnesota. 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 H, Section 9, Schedule 2 shows the breakdown of the total Minnesota Community Solar Garden market and above market expenses in the 2017-2018 AAA period:

	System	MN Amount[i]	Estimated MN Retail Allocator
Market	$10,639,815	$7,736,220	0.726067
Above Market	$33,356,379	$33,356,379	1.0000000
Total	$43,996,195	$41,092,600	

We anticipate more community solar gardens to be in place by our next AAA reporting period. The Company's most recent solar garden annual compliance report was submitted on March 31, 2018 in Docket No. E002/M-13-867.

10. FCA Rule Variance Dockets (Docket No. E999/AA-15-611)

The Commission's July 21, 2017 Order in above-referenced docket 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). Please see Part H, Section 10, Schedule 1 for a list of relevant dockets.

[i] $628,232 in solar gardens developer late fees were credited to the FCA. This credit has resulted in a net solar garden cost recovery of $40,464,368 during the AAA reporting period.

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Table 1: GENERATION COSTS ALLOCATION BETWEEN RETAIL & WHOLESALE CLASS

[PROTECTED DATA BEGINS

	Retail		Wholesale		Retail & Wholesale	
	MWh	Cost ($/MWh)	MWh	Cost ($/MWh)	MWh	Cost ($/MWh)
	[1]	[2]	[3]	[4]	[5] [1] + [3]	[6] {[1]x[2]+[3]x[4]}/[5]
June 2018						
July 2018						
August 2018						

PROTECTED DATA ENDS]

Source: Xcel Energy Commercial Accounting

	Primary Voltage Class	Secondary Voltage Class	Maximum MVA	Operating Company	Location	Status
1	345	161	300	Minnesota	Adams Substation	In-service standalone
2	230	115	336	Minnesota	Blue Lake Substation	In-service duplicate
3	345	115	336	Minnesota	Blue Lake Substation	In-service duplicate
4	345	161	448	Wisconsin	Briggs Road Substation	In-service standalone
5	345	115	448	Minnesota	Brookings County Substation	In-service duplicate
6	345	115	448	Minnesota	Brookings County Substation	In-service duplicate
7	345	115	448	Minnesota	Chisago County Substation	In-service duplicate
8	345	115	448	Minnesota	Chisago County Substation	In-service duplicate
9	500	345	1200	Minnesota	Chisago County Substation	In-service duplicate
10	500	345	1200	Minnesota	Chisago County Substation	In-service duplicate
11	161	115	187	Minnesota	Collville Substation	In-service standalone
12	345	115	672	Minnesota	Coon Creek Substation	In-service duplicate
13	345	115	672	Minnesota	Coon Creek Substation	In-service duplicate
14	161	115	186	Wisconsin	Crystal Cave Substation	In-service standalone
15	345	161	300	Wisconsin	Eau Claire Substation	In-service duplicate
16	345	161	300	Wisconsin	Eau Claire Substation	In-service duplicate
17	345	115	448	Minnesota	Eden Prairie Substation	In-service duplicate
18	345	115	448	Minnesota	Eden Prairie Substation	In-service duplicate
19	345	115	448	Minnesota	Elm Creek Substation	In-service standalone
20	161	115	187	Wisconsin	Gingles Substation	In-service standalone
21	345	230	336	Minnesota	Hazel Creek Substation	In-service standalone
22	161	115	187	Wisconsin	Hydro Lane Substation	In-service standalone
23	345	115	598	Minnesota	Inver Hills Substation	In-service standalone
24	345	115	448	Minnesota	King Substation	In-service standalone
25	345	115	448	Minnesota	Kohlman Lake Substation	In-service duplicate
26	345	115	450	Minnesota	Kohlman Lake Substation	In-service duplicate
27	161	115	336	Minnesota	Lawrence Creek	In-service standalone
28	345	115	448	Minnesota	Lyon County	In-service standalone
29	230	115	187	Minnesota	Maple River Substation	In-service duplicate
30	230	115	187	Minnesota	Maple River Substation	In-service duplicate
31	230	115	187	Minnesota	Minnesota Valley Substation	In-service duplicate
32	230	115	186	Minnesota	Minnesota Valley Substation	In-service duplicate
33	345	230	336	Minnesota	Monticello Substation	In-service duplicate
34	345	115	336	Minnesota	Monticello Substation	In-service duplicate
35	345	115	672	Minnesota	Nobles County Substation	In-service duplicate
36	345	115	672	Minnesota	Nobles County Substation	In-service duplicate
37	345	161	672	Minnesota	North Rochester	In-service standalone
38	161	115	178	Wisconsin	Osprey Substation	In-service standalone
39	345	115	450	Minnesota	Parkers Lake Substation	In-service duplicate
40	345	115	450	Minnesota	Parkers Lake Substation	In-service duplicate
41	230	115	336	Minnesota	Paynesville Transmission Substation	In-service standalone
42	161	115	112	Wisconsin	Pine Lake Substation	In-service standalone
43	345	161	224	Minnesota	Prairie Island Substation	In-service standalone
44	230	115	336	Minnesota	Prairie Substation	In-service duplicate
45	230	115	336	Minnesota	Prairie Substation	In-service duplicate
46	230	115	336	Minnesota	Prairie Substation	In-service duplicate
47	345	115	448	Minnesota	Quarry Substation	In-service standalone
48	345	230	336	Minnesota	Red Rock Substation	In-service duplicate
49	345	115	448	Minnesota	Red Rock Substation	In-service duplicate
50	345	115	448	Minnesota	Red Rock Substation	In-service duplicate
51	345	115	649	Minnesota	Scott County Substation	In-service duplicate
52	345	115	672	Minnesota	Scott County Substation	In-service duplicate
53	345	115	336	Minnesota	Sheas Lake Substation	In-service standalone
54	345	115	448	Minnesota	Sherco Substation	In-service standalone
55	230	115	187	Minnesota	Sheyenne Substation	In-service duplicate
56	230	115	187	Minnesota	Sheyenne Substation	In-service duplicate
57	161	115	187	Minnesota	Split Rock Substation	In-service duplicate
58	230	115	336	Minnesota	Split Rock Substation	In-service duplicate
59	345	115	358	Minnesota	Split Rock Substation	In-service duplicate
60	345	115	358	Minnesota	Split Rock Substation	In-service duplicate
61	161	115	187	Minnesota	South Bend Substation	In-service standalone
62	345	161	336	Wisconsin	Stone Lake Substation	In-service standalone
63	345	115	672	Minnesota	Terminal Substation	In-service duplicate
64	345	115	672	Minnesota	Terminal Substation	In-service duplicate
65	345	115	448	Minnesota	Wilmarth Substation	In-service duplicate
66	345	115	448	Minnesota	Wilmarth Substation	In-service duplicate

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Total
For January 2016 to June 2018

Production Month	Date Paid		Wind Production Delivered		Lost Production		Total Xcel Energy Paid
	Delivered MWh	Lost MWh	MWh Delivered	Amount Xcel Energy Paid	Lost MWh	Amount Xcel Energy Paid	
Jan-16			374,389.00	15,077,234.58	5,120.00	222,057.33	$ 15,299,291.91
Feb-16			388,803.00	15,722,028.86	7,923.00	302,623.95	$ 16,024,652.81
Mar-16			386,342.00	15,537,502.86	17,246.00	688,637.00	$ 16,226,139.86
Apr-16			488,078.00	19,628,605.94	16,513.00	701,619.02	$ 20,330,224.96
May-16			300,210.00	12,086,544.34	13,389.00	522,839.56	$ 12,609,383.90
Jun-16			283,453.00	11,516,998.71	9,418.00	392,281.62	$ 11,830,709.52
Jul-16			222,615.00	8,835,936.12	6,738.00	258,663.79	$ 9,045,420.14
Aug-16			185,274.00	7,513,341.19	5,140.00	188,369.29	$ 7,701,710.48
Sep-16			323,595.00	13,054,247.43	3,101.00	152,864.95	$ 13,207,112.38
Oct-16			383,683.00	15,048,348.05	5,221.00	269,424.99	$ 15,094,832.64
Nov-16			394,308.00	15,747,276.81	5,418.00	204,925.09	$ 15,952,201.90
Dec-16			486,347.00	19,376,718.44	1,955.00	79,007.00	$ 19,455,725.44
Total-16			4,217,097.00	$ 169,144,783.33	97,182.00	$ 3,983,313.59	$ 172,777,405.94
Jan-17			430,915.00	16,121,114.26	3,697.00	157,640.79	$ 16,278,755.05
Feb-17			413,435.00	16,507,567.11	6,934.00	276,825.34	$ 16,784,392.45
Mar-17			416,890.00	16,715,428.81	11,980.00	523,111.92	$ 17,238,540.73
Apr-17			457,766.00	14,278,919.80	7,291.00	309,809.33	$ 14,588,729.13
May-17			419,789.00	15,783,918.29	5,970.00	243,464.35	$ 16,027,382.64
Jun-17			325,258.00	12,144,565.98	6,822.00	309,043.74	$ 12,453,609.72
Jul-17			225,540.00	8,477,405.53	277.00	14,625.98	$ 8,492,031.51
Aug-17			179,181.00	6,687,158.36	54.00	2,734.06	$ 6,689,892.42
Sep-17			348,409.00	13,076,351.03	1,268.00	65,237.53	$ 13,141,588.56
Oct-17			516,819.00	19,352,565.13	2,931.00	133,307.49	$ 19,485,872.62
Nov-17			496,866.00	18,739,626.55	435.00	18,782.21	$ 18,758,408.76
Dec-17			494,304.00	18,583,732.70	479.00	16,365.01	$ 18,600,097.71
Total-17			4,725,172.00	$ 176,468,353.55	48,138.00	$ 2,070,947.75	$ 178,539,301.30
Jan-18			517,112.61	19,554,286.92	1,458.00	58,950.29	$ 19,613,237.21
Feb-18			418,166.06	15,810,253.22	134.82	5,843.30	$ 15,816,096.52
Mar-18			456,664.46	17,253,894.46	548.61	21,570.10	$ 17,275,464.56
Apr-18			389,872.84	14,871,852.82	2,303.34	100,761.56	$ 14,972,614.38
May-18			321,602.85	12,231,504.86	428.37	18,532.00	$ 12,250,036.86
Jun-18							
Jul-18							
Aug-18							
Sep-18							
Oct-18							
Nov-18							
Dec-18							
Total-17			2,103,418.81	79,721,792.28	4,873.14	205,657.25	79,927,449.53

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 1 (ATC)
For January 2016 to June 2018

	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-16			-	0.00	-	0.00	
Feb-16			-	0.00	-	0.00	
Mar-16			-	0.00	-	0.00	
Apr-16			-	0.00	-	0.00	
May-16			-	0.00	-	0.00	
Jun-16			-	0.00	-	0.00	
Jul-16			-	0.00	-	0.00	
Aug-16			-	0.00	-	0.00	
Sep-16			-	0.00	-	0.00	
Oct-16			-	0.00	-	0.00	
Nov-16			-	0.00	-	0.00	
Dec-16			-	0.00	-	0.00	
Total-16							
Jan-17			-	0.00	-	0.00	
Feb-17			-	0.00	-	0.00	
Mar-17			-	0.00	-	0.00	
Apr-17			-	0.00	-	0.00	
May-17			-	0.00	-	0.00	
Jun-17			-	0.00	-	0.00	
Jul-17			-	0.00	-	0.00	
Aug-17			-	0.00	-	0.00	
Sep-17			-	0.00	-	0.00	
Oct-17			-	0.00	-	0.00	
Nov-17			-	0.00	-	0.00	
Dec-17			-	0.00	-	0.00	
Total-17							
Jan-18			-	0.00	-	0.00	
Feb-18			-	0.00	-	0.00	
Mar-18			-	0.00	-	0.00	
Apr-18			-	0.00	-	0.00	
May-18			-	0.00	-	0.00	
Jun-18							
Jul-18							
Aug-18							
Sep-18							
Oct-18							
Nov-18							
Dec-18							
Total-18							

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 2 (Low Load)
For January 2016 to June 2018

	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-16			-	0.00	-	0.00	
Feb-16			-	0.00	-	0.00	
Mar-16			-	0.00	-	0.00	
Apr-16			-	0.00	-	0.00	
May-16			-	0.00	-	0.00	
Jun-16			-	0.00	-	0.00	
Jul-16			-	0.00	-	0.00	
Aug-16			-	0.00	-	0.00	
Sep-16			-	0.00	-	0.00	
Oct-16			-	0.00	-	0.00	
Nov-16			-	0.00	-	0.00	
Dec-16			-	0.00	-	0.00	
Total-16							
Jan-17			-	0.00	-	0.00	
Feb-17			-	0.00	-	0.00	
Mar-17			-	0.00	-	0.00	
Apr-17			-	0.00	-	0.00	
May-17			-	0.00	-	0.00	
Jun-17			-	0.00	-	0.00	
Jul-17			-	0.00	-	0.00	
Aug-17			-	0.00	-	0.00	
Sep-17			-	0.00	-	0.00	
Oct-17			-	0.00	-	0.00	
Nov-17			-	0.00	-	0.00	
Dec-17			-	0.00	-	0.00	
Total-17							
Jan-18			-	0.00	-	0.00	
Feb-18			-	0.00	-	0.00	
Mar-18			-	0.00	-	0.00	
Apr-18			-	0.00	-	0.00	
May-18			-	0.00	-	0.00	
Jun-18							
Jul-18							
Aug-18							
Sep-18							
Oct-18							
Nov-18							
Dec-18							
Total-18							

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 3 (MISO)
For January 2016 to June 2018

	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-16			*225,468.00*	*9,135,666.90*	*5,120.00*	*222,057.33*	*$ 9,357,724.23*
Feb-16			*230,076.00*	*9,421,305.86*	*7,923.00*	*302,623.95*	*$ 9,723,929.81*
Mar-16			*251,333.00*	*10,190,224.97*	*17,246.00*	*688,637.00*	*$ 10,878,861.97*
Apr-16			*332,804.00*	*13,160,914.46*	*16,513.00*	*703,186.58*	*$ 13,864,101.04*
May-16			*96,831.00*	*3,733,261.17*	*13,389.00*	*522,839.56*	*$ 4,256,100.73*
Jun-16			*207,896.00*	*8,356,565.77*	*9,418.00*	*392,281.62*	*$ 8,748,847.39*
Jul-16			*184,949.00*	*7,356,397.69*	*6,738.00*	*258,663.79*	*$ 7,615,061.48*
Aug-16			*93,543.00*	*3,878,745.12*	*5,140.00*	*188,369.29*	*$ 4,067,114.41*
Sep-16			*282,377.00*	*11,190,785.34*	*3,101.00*	*152,864.95*	*$ 11,343,650.29*
Oct-16			*265,571.00*	*10,430,700.92*	*5,221.00*	*269,424.99*	*$ 10,700,125.91*
Nov-16			*133,867.00*	*5,020,146.81*	*5,418.00*	*204,925.09*	*$ 5,225,071.90*
Dec-16			*117,644.00*	*5,206,149.55*	*1,955.00*	*79,007.00*	*$ 5,285,156.55*
Total-16			*2,422,359.00*	*$ 97,080,864.56*	*97,182.00*	*$ 3,984,881.15*	*$ 101,065,745.71*
Jan-17			*185,333.00*	*6,652,404.63*	*3,697.00*	*157,640.77*	*$ 6,810,045.40*
Feb-17			*186,522.00*	*7,471,418.20*	*6,934.00*	*276,825.34*	*$ 7,748,243.54*
Mar-17			*173,389.00*	*6,688,109.31*	*11,980.00*	*523,111.92*	*$ 7,211,221.23*
Apr-17			*208,551.00*	*8,133,830.65*	*7,291.00*	*309,809.33*	*$ 8,443,639.98*
May-17			*140,001.00*	*5,528,045.13*	*5,970.00*	*243,464.35*	*$ 5,771,509.48*
Jun-17			*142,504.00*	*5,704,337.23*	*6,822.00*	*309,043.74*	*$ 6,013,380.97*
Jul-17			*22,344.00*	*1,266,241.66*	*277.00*	*14,625.98*	*$ 1,280,867.64*
Aug-17			*22,910.00*	*1,180,091.68*	*54.00*	*2,734.06*	*$ 1,182,825.74*
Sep-17			*75,520.00*	*3,539,468.64*	*1,268.00*	*65,237.53*	*$ 3,604,706.17*
Oct-17			*109,037.00*	*5,029,142.90*	*2,931.00*	*133,307.49*	*$ 5,162,450.39*
Nov-17			*129,002.00*	*5,142,020.66*	*435.00*	*18,782.21*	*$ 5,160,802.87*
Dec-17			*97,506.00*	*4,362,695.93*	*479.00*	*16,365.01*	*$ 4,379,060.94*
Total-17			*1,492,619.00*	*$ 60,697,806.62*	*48,138.00*	*$ 2,070,947.73*	*$ 62,768,754.35*
Jan-18			*90,734.12*	*3,924,799.96*	*1,458.00*	*58,950.29*	*$ 3,983,750.25*
Feb-18			*54,843.51*	*2,785,838.57*	*134.82*	*5,843.30*	*$ 2,791,681.87*
Mar-18			*144,991.48*	*5,587,088.09*	*548.61*	*21,570.10*	*$ 5,608,658.19*
Apr-18			*93,370.50*	*4,258,543.18*	*2,303.34*	*100,761.56*	*$ 4,359,304.74*
May-18			*82,315.24*	*3,741,116.04*	*428.37*	*18,532.00*	*$ 3,759,648.04*
Jun-18							
Jul-18							
Aug-18							
Sep-18							
Oct-18							
Nov-18							
Dec-18							
Total-18			*466,254.85*	*$ 20,297,385.84*	*4,873.14*	*$ 205,657.25*	*20,503,043.09*

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 4 (Other-Paid)
For January 2016 to June 2018

	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-16			-	*0.00*	-	*0.00*	
Feb-16			-	*0.00*	-	*0.00*	
Mar-16			-	*0.00*	-	*0.00*	
Apr-16			-	*0.00*	-	*0.00*	
May-16			-	*0.00*	-	*0.00*	
Jun-16			-	*0.00*	-	*0.00*	
Jul-16			-	*0.00*	-	*0.00*	
Aug-16			-	*0.00*	-	*0.00*	
Sep-16			-	*0.00*	-	*0.00*	
Oct-16			-	*0.00*	-	*0.00*	
Nov-16			-	*0.00*	-	*0.00*	
Dec-16			-	*0.00*	-	*0.00*	
Total-16							
Jan-17			-	*0.00*	-	*0.00*	
Feb-17			-	*0.00*	-	*0.00*	
Mar-17			-	*0.00*	-	*0.00*	
Apr-17			-	*0.00*	-	*0.00*	
May-17			-	*0.00*	-	*0.00*	
Jun-17			-	*0.00*	-	*0.00*	
Jul-17			-	*0.00*	-	*0.00*	
Aug-17			-	*0.00*	-	*0.00*	
Sep-17			-	*0.00*	-	*0.00*	
Oct-17			-	*0.00*	-	*0.00*	
Nov-17			-	*0.00*	-	*0.00*	
Dec-17			-	*0.00*	-	*0.00*	
Total-17							
Jan-18			-	*0.00*	-	*0.00*	
Feb-18			-	*0.00*	-	*0.00*	
Mar-18			-	*0.00*	-	*0.00*	
Apr-18			-	*0.00*	-	*0.00*	
May-18			-	*0.00*	-	*0.00*	
Jun-18							
Jul-18							
Aug-18							
Sep-18							
Oct-18							
Nov-18							
Dec-18							
Total-17							

2017 – 2018 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. In compliance with the Commission's Order, this report provides a summary of the Company's experience regarding wind curtailment payments, an estimate of potential curtailment payments over the next five years, and the assumptions used to develop our forecast.

II. CURTAILMENT UPDATE

In past AAA Curtailment Reports, the Company has worked with the Department and made efforts to improve communications about the events and activity that cause wind generation curtailment. The Department's review and evaluation over the years has helped identify areas where our reports could be more descriptive of the reasons for wind curtailment and efforts made to minimize resulting costs. In addition, the Company continues to utilize initiatives to reduce curtailment which we believe are having a positive impact on curtailment or costs associated with curtailment. Examples include, where possible, scheduling transmission activities which can impact curtailment during low wind months and manual economic curtailment.

The Company expects that some level of wind curtailment from Power Purchase Agreement (PPA) facilities will occur during 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 a number 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. Manual curtailment of non-DIR PPA wind facilities, which were developed prior to DIR reform measures, also continues to be used to manage the wind resources when appropriate.

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
Fenton	200
Odell	200
Prairie Rose	200
MinnDakota	150
Mower County	100
Moraine II	50
Big Blue	36
Zephyr	30
Valley View	10
Total	976

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 5,550 MW of planned wind generation in Minnesota, North Dakota, South Dakota and Iowa that is expected to go into service in in the next three years – which includes 1,850 MW of Company-owned and PPA wind. Table 2 shows planned wind developments by other regional companies. All of these wind developments will be registered and operated as DIRs.

Table 2
Wind Generation Additions

Company	MW	Location	In-Service Date
NSP	1850	ND, SD, MN	2019-2021
Alliant Energy	1000	Iowa	2019-2020
Great River Energy	300	ND	2019
MidAmerican	2000	Iowa	2018-2020
Minnesota Power	250	MN	2019
Ottertail Power	150	ND	2020
Total	5550		

The required transmission upgrades for these wind projects will likely not all be in-service by the time the projects begin producing energy. This will have a negative effect on LMP pricing in the MISO regional energy market that could potentially impact real-time wind generation on the NSP System. This potential impact will lessen due to mitigation measures such as: (1) the use of DIR and set-point control technology, (2) placing in service the required transmission facilities and transmission system improvements, and (3) improved transmission outage scheduling.

III. Transmission System Improvements

Since 1994, wind energy resources have been the dominant factor in determining the need for transmission infrastructure improvements in southwestern Minnesota. To meet this need, the Company, often in cooperation with other utilities, has planned, engineered and constructed a number of projects designed to increase the transmission capacity in that area. Table 3 shows historic southwest Minnesota projects that increased the available transmission outlet in that area.

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 2015
Fargo North Dakota - Northwest Twin Cities 345 kV Line	Xcel Energy, Great River Energy	April 2015
Southeast Twin Cities - LaCrosse, Wisconsin 345 kV Line	Xcel Energy, SMMPA and non-MISO	September 2016

In addition to transmission projects developed by the Company, MISO has identified and approved a number of new transmission infrastructure projects including 17 MVPs designed to accommodate the planned and expected generation expansion in the MISO footprint.[1] The MVPs will help 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, or will have, a positive impact on Company-owned and PPA wind facilities.

[1] The MISO Board of Directors approved the new transmission projects, which included the CapX2020 Brookings County – Southeast Twin Citites 345 kV line as an MVP, on December 13, 2012.

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 2017
Lakefield Jct. - Winnebago - Winco - Kossuth County & Obrien County - Kossuth County - Webster 345 kV Line	MidAmerica Energy, ITC Midwest	End 2018
North LaCrosse - North Madison	American Transmission Company, Xcel Energy	End 2018
Winco to Hazleton 345 kV Line	MidAmerica Energy, ITC Midwest	End 2019
Ellendale to Big Stone South 345 kV Line	Ottertail Power Company, Montana Dakota Utilities	End 2019
North Madison - Cardinal - Spring Green - Dubuque area 345 kV Line	American Transmission Company, ITC Midwest	End 2023

IV. Wind Generation, Curtailment and Curtailment Projections

Chart 1 shows Company-owned and PPA wind generation facilities throughout the NSP service territory on an incremental and cumulative basis. No wind projects have come on-line, or are scheduled to come on-line in 2018.

Chart 1
NSP Wind Development
(1993 – 2018)

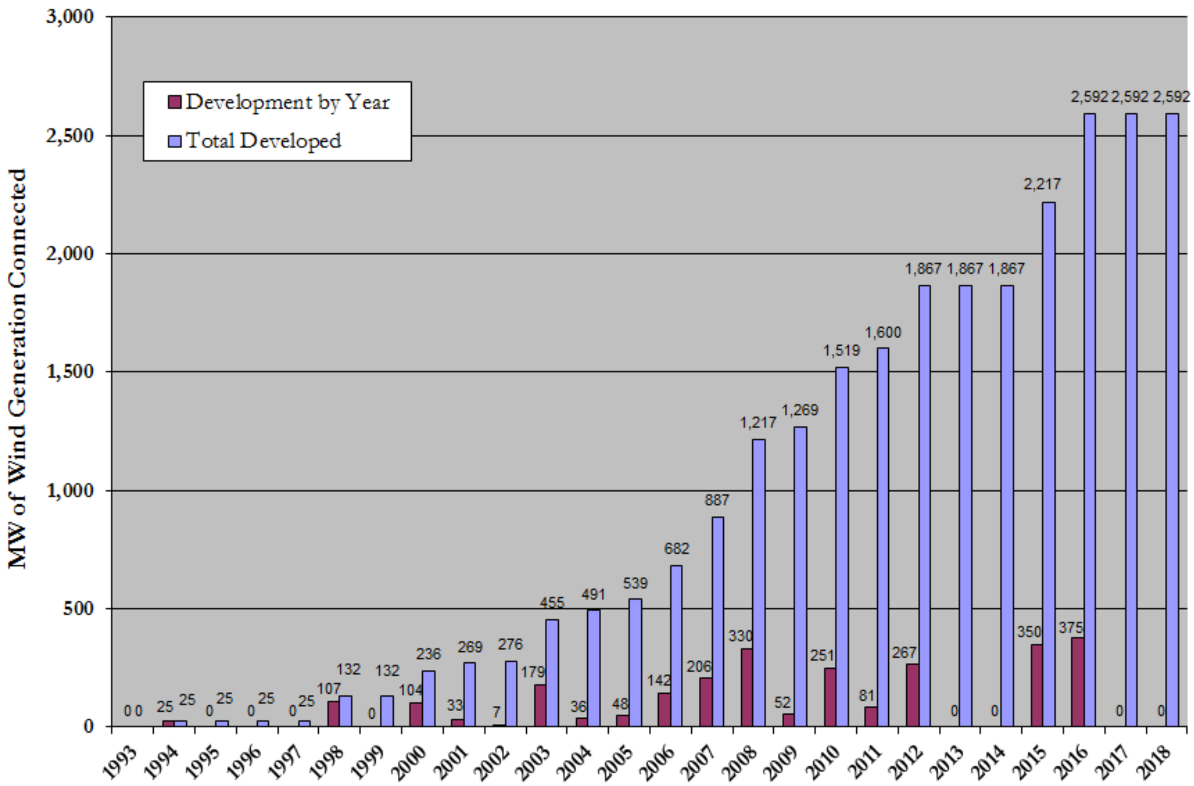
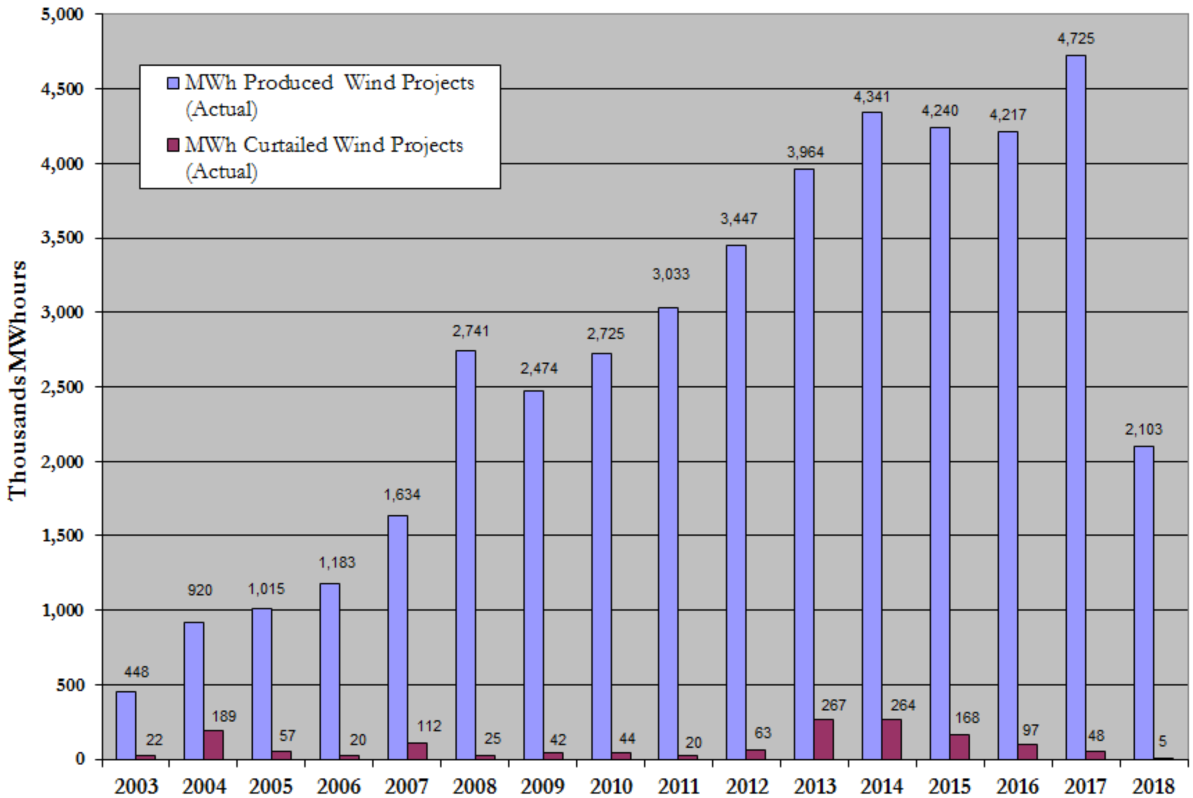


Chart 2 shows the comparison between total wind energy produced and the wind energy curtailed from the projects through May 2018[2]. Despite the lead/lag time associated with generation and transmission development, Chart 2 shows that wind curtailment is small compared to the total wind generation delivered.

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.

[2] AAA Part H, Section 5, Schedule 1.

Chart 2
NSP Wind Production & Curtailment (MWh)
(2003 – 2017 Full Calendar Years, 2018 Partial Year through May)



Curtailment during July 2017 to June 2018 was broken up into three categories to better explain the reasons for the curtailment and its cause. To support the analysis the Company identified hours during the 2017/2018 AAA period where transmission-related outages impacted wind projects. During hours where transmission outages did not occur, or where transmission outages did not impact a specific wind farm, the hours were assigned as either manual curtailment or DIR curtailment 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.

A total of $452,457 in curtailment payments[3] were made during this reporting period for these three categories:

1) Transmission Events ($255). This includes Chanarambie and Yankee transformer outages;
2) DIR Curtailments Events ($413,132). This was driven by negative LMP related reasons; and
3) Manual Curtailments Events ($39,071). This was also driven by negative LMP related reasons.

The MWh and curtailment costs determined during the curtailment analysis are compiled in Table 6 and Table 7 below. These results are further separated to show MWh and curtailment costs for projects that are still eligible for the PTC and those that are not. Note: the curtailment values in this section do not exactly match the curtailment values shown in AAA Part H, Section 5, Schedule 1. This data is based on the Company's analysis and estimated volumes from curtailment events and not based on the customer submitted invoices.

Table 6
2017/2018 Wind Curtailment MWh

Events	MWh		
	Total	Projects / No PTC	Projects / PTC
Transmission Events	5	5	0
DIR Curtailment Events	8,950	8,950	0
Manual Curtailment Events	1,069	1,069	0
Totals	10,024	10,024	0

[3] The curtailment analysis in this section used Company data – not AAA Part H, Section 5, Schedule 1 data and included June of 2018.

Table 7
2017/2018 Wind Curtailment Costs

Events	Payments		
	Total	Projects / No PTC	Projects / PTC
Transmission Events	$255	$255	$0
DIR Curtailment Events	$413,004	$413,004	$0
Manual Curtailment Events	$39,198	$39,198	$0
Totals	$452,457	$452,457	$0

As can be seen in Tables 6 and 7, the majority of the curtailment was related to DIR and Manual Curtailment Events and occurred at projects that are no longer eligible for the PTC.

It is important to note that of the $452,457 in total curtailment costs, the vast majority of these total 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.[4]

<u>Transmission Curtailment Events</u>
Wind curtailment costs totaling $255 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. For example, from September through the end of 2013, there were unavoidable transmission outages taken which resulted in significantly increased levels of curtailment than had been experienced in a number of years. Summer months are also high load months and transmission outages may not be possible due to load serving needs.

[4] 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.

If should be noted that only specific wind generation are used to manage the different transmission events. For example, Chanarambie transformer outages can impact Lake Benton II, Chanarambie Power Partners, Ridgewind, Moraine I, and Moraine II while Yankee transformer outages can impact MinnDakota.

Chanarambie and Yankee Transformer outages.

The Company experienced planned and unplanned outages of transformers at the Chanarambie and Yankee substations that contributed to curtailment during this period. The facilities were taken out of service for maintenance activies and as the result of adverse weather conditions.

Curtailment Procedures

The Company has detailed wind curtailment guidelines in place to ensure that wind resources are managed economically and for the reliability of the system, consistent with the terms of the related purchased power contracts. NSP Generation Control and Dispatch strives to minimize total generation costs including the consideration of wind farm curtailment costs and production tax credits. Specific curtailment procedures are in place that take into account how the asset is registered in the MISO Market, whether the wind farm is equipped with setpoint control equipment, which wind farms are registered as DIR, and which are Intermittent. A curtailment matrix has been established and is maintained that lists CP Node location, contract price, compensable curtailment threshold, and curtailment for economics. The list is organized from highest to lowest curtailment threshold, that is, the market price below which it is economic to curtail if curtailment is compensable.

For DIR units, MISO performs a 10-minute forecast every five minutes. This forecast 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 manual curtailment. Non-DIR units are not equipped with setpoint control.

DIR Curtailment Events

Wind curtailment costs totaling $413,004 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, as well as the higher levels of wind generation present where all required transmission improvements have not been completed or where sufficient transmission outlet 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.

Manual Curtailment Events

Wind curtailment costs totaling $39,198 were due to the Manual Curtailment Events as described below.

Concerning the prudency of non-transmission limited, manual economic, congestion and negative LMP related curtailments, NSP performed an analysis of the economic impact of this curtailment type and determined that the curtailments produced customer economic value by reducing costs by $265.41 as shown in Table 7.

Table 8
Manual Actions Related to Economics
(July 2017 – June 2018)

Connection Node	MWh	Curtailment Benefit $	Average Benefit $/MWh	PTC or No PTC
Lake Benton I	828.00	$157.25	$ 0.19	No PTC
Lake Benton II	20.00	$67.82	$ 3.39	No PTC
ValleyView Wind	2.00	($5.78)	$(2.89)	No PTC
Ridgewind Power Partners	219.00	$46.12	$ 0.21	No PTC
Totals	1,069.00	$265.41	$ 0.25	

To perform this analysis the Company started with estimated hourly averaged curtailment volumes[5] and hourly averaged LMP values for all non-DIR wind farms. The Company then manually subtracted the curtailment volumes for hours that were specifically identified as Transmission Curtailment Events. The resulting hourly curtailment data represents all manual curtailments that were made for economic reasons and not due to a transmission limitation. The hourly curtailment volume for

[5] NSP used hourly averaged curtailment data based on the Company's analysis and estimated volumes from curtailment events and not based on the customer submitted invoices. As a result, the data does not perfectly match the curtailment volumes on the customer invoices, which is the basis for the volumes used in the Company's response to Information Request No. DOC-008, Attachment B in Docket No. E002/AA-14-579.

each wind farm was then multiplied by the corresponding hourly LMP for that wind farm to determine the hourly settlement impact of the curtailed wind generation. It is important to note that the bulk of these total costs are associated with the contractual energy price of the PPA. These are contractually obligated sunk costs which are not economically relevant to the decision to curtail the generation from a wind farm. The only economically relevant factor in the decision whether or not to curtail a wind farm is whether the real-time LMP is above or below the dispatch price for the wind farm.

III. Wind Production and Curtailment Payments

Chart 3 shows the corresponding production and curtailment costs through May, 2018.[6] As with wind generation produced and curtailed, paid curtailment is a very small portion of total cost of wind generation on the system.

[6] AAA Part H, Section 5, Schedule 1

Chart 3
NSP Wind Production & Curtailment Payments
(2003 – 2017 Full Calendar Years, 2018 Partial Year through May)

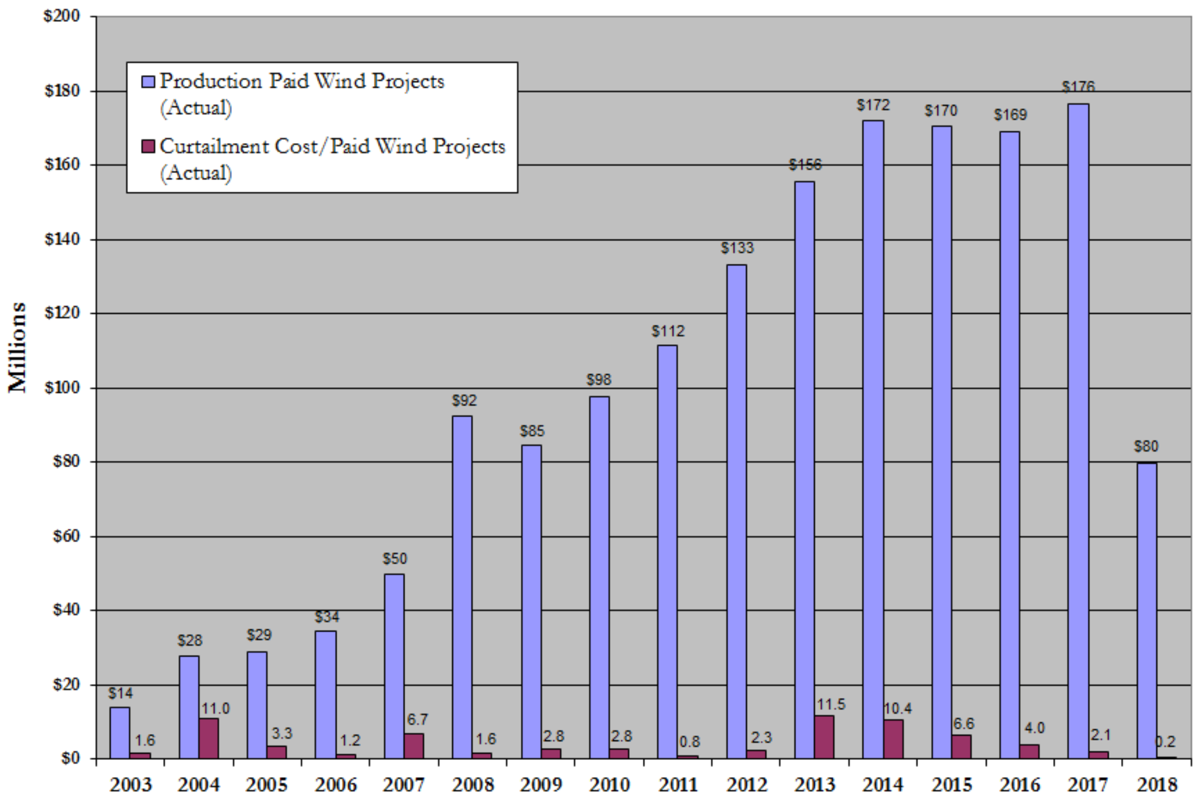
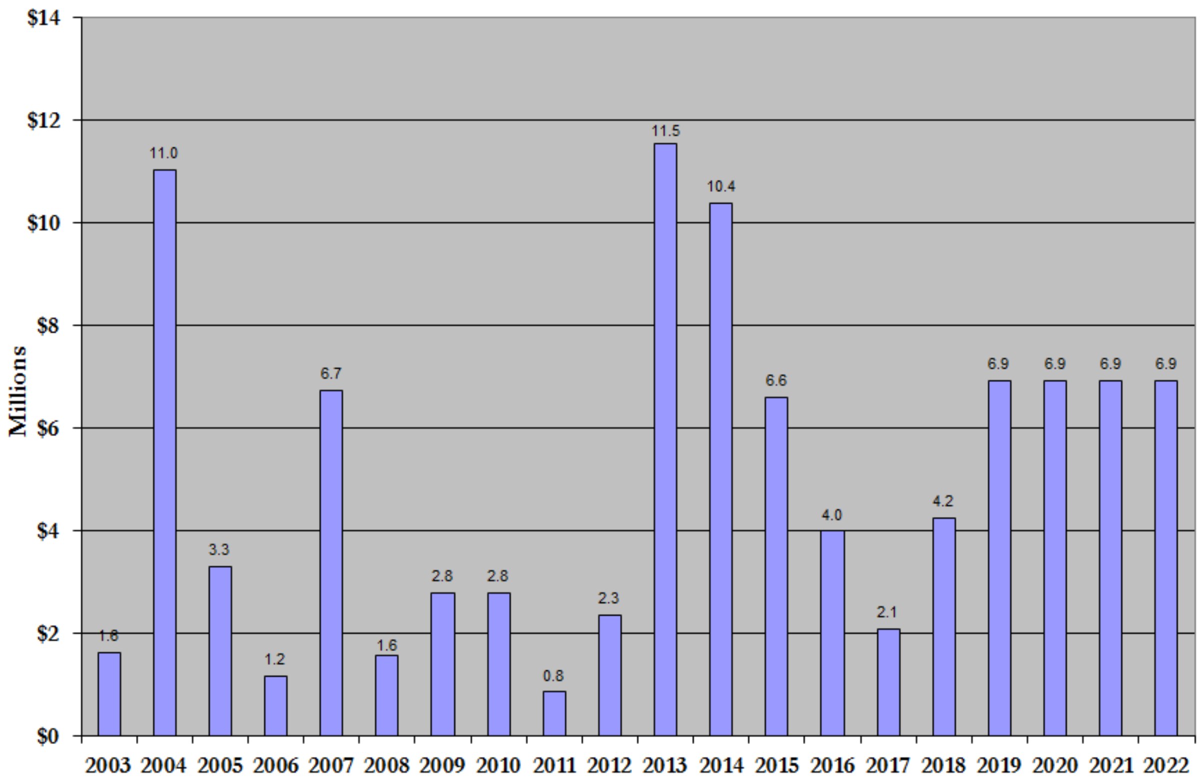


Chart 4 shows the Company's historical wind curtailment costs along with the five-year estimate of future costs.[7]

Chart 4
NSP Wind Curtailment Payments
(2003 –2017 Actual, 2018 – 2022 Projected)



As was the case in the 2016 - 2017 AAA Report, we are 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. Our projections used the average of the last five years of historical curtailment data to project the level of future curtailment. This approach will help capture and reflect ongoing trends with wind and transmission development, as well as the outages necessary for maintenance, repair and construction activity.

[7] AAA Part H, Section 5, Schedule 1

Future wind generation additions and completion of the MVP transmission projects will likely impact the amount of future curtailment experienced. While it is reasonable to expect curtailment levels will be reduced once the new transmission lines are in service, the reduction will likely be off-set by the new wind projects going into service. In the Company's recent filing for Acquisition of Wind Generation under Docket No. E002/M-16-777, a detailed discussion on wind curtailment was also provided. The filing stated that the Company expects wind curtailment to be higher when the new projects first go into service, and then decline as new transmission and other changes on the MISO system occur to better accommodate increased wind penetration. While we continue to believe that this will be the case there is no certainty as to when, and if, the numerous wind generation projects currently in the development queue will actually come to fruition. As such, the Company did not try to predict the specific impact that future wind generation or completion of the MVP transmission projects would have on curtailment.

VI. CONCLUSION

The Company anticipates that wind generation curtailment and associated payment to vendors will occur over the next five 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.

	Location (County)	Meter Install Date(s)	Rated AC Power Output (MW)	Number of Subscriptions*
1	Benton	9/29/2017	2.000	22
2	Benton	10/30/2017	5.000	21
3	Benton	3/25/2018	2.000	13
4	Blue Earth	11/20/2017	5.000	35
5	Blue Earth	5/30/2018	1.000	8
6	Blue Earth**	5/31/2017	3.000	12
7	Carver	3/14/2018	0.998	148
8	Carver	2/26/2018	1.996	302
9	Carver	12/15/2017	5.000	21
10	Carver	3/6/2018	3.000	11
11	Carver	12/21/2017	4.361	14
12	Carver**	12/15/2016	5.000	689
13	Carver**	2/28/2017	4.860	14
14	Chipewa	3/25/2018 & 6/15/18	4.000	14
15	Chippewa	10/25/2017 & 11/14/2017	3.000	50
16	Chippewa	8/29/2017	2.000	10
17	Chisago	4/30/2018	3.000	9
18	Chisago	12/18/2017	5.000	10
19	Chisago	3/13/2018	5.000	11
20	Chisago	8/22/2017	3.000	13
21	Chisago	12/13/2017	5.000	11
22	Chisago**	12/14/2016	5.000	26
23	Chisago**	12/15/2016	4.000	26
24	Chisago**	1/13/2017	3.888	19
25	Dakota	11/30/2017	5.000	14
26	Dakota	1/23/2018	4.950	14
27	Dakota	2/13/17 & 3/15/2017	5.000	196
28	Dakota	7/27/2018	5.000	
29	Dakota	8/31/2017	5.000	26
30	Dakota	11/30/2017	2.700	97
31	Dakota**	1/13/2017	5.000	13
32	Dakota**	12/22/2016	5.000	13
33	Dakota**	12/14/2016	5.000	37
34	Dodge	9/27/2017	4.000	21
35	Dodge	7/18/2017	5.000	484
36	Dodge	12/18/2017	5.000	34

	Location (County)	Meter Install Date(s)	Rated AC Power Output (MW)	Number of Subscriptions*
37	Fairbault	3/2/2018	1.840	9
38	Goodhue	7/19/2018	5.000	
39	Goodhue	7/30/2018	2.000	
40	Goodhue	2/13/2017 & 3/2/2017	4.000	326
41	Goodhue	4/12/2018	0.800	134
42	Goodhue	4/26/2018	0.998	127
43	Goodhue	5/11/2018	1.000	24
44	Goodhue	5/22/2018	1.000	13
45	Goodhue**	1/12/2017	4.860	27
46	Hennepin	10/25/2017	5.000	11
47	Hennepin	6/6/2018	0.180	
48	Hennepin**	8/22/2016	0.036	19
49	Kaniyohi	8/14/2017	2.000	7
50	Le Sueur	2/28/2018	5.000	39
51	Le Sueur	6/29/2018	3.000	
52	Le Sueur	1/18/2018	3.000	12
53	Le Sueur**	9/9/2015	0.036	6
54	Lincoln	9/14/2017	0.200	21
55	Lincoln**	4/25/2016	0.204	14
56	Lyon	6/15/2018	3.000	
57	McLeod	10/25/2017	3.000	38
58	McLeod	10/26/2017	5.000	99
59	Nicollet	11/20/2017	5.000	13
60	Olmsted	7/19/2017	5.000	442
61	Pipestone	10/30/2017	5.000	41
62	Pipestone	8/18/2017	2.000	47
63	Pipestone	1/31/2018	4.700	44
64	Pope	9/13/2017	5.000	19
65	Pope	3/15/2018	5.000	216
66	Pope	4/19/2018	3.000	276
67	Ramsey**	5/12/2016	0.125	7
68	Redwood**	5/31/2017	3.000	42
69	Renville	12/28/2017	3.000	48
70	Renville	5/16/2018	1.000	9
71	Renville	5/17/2018	1.000	20
72	Rice	2/14/2018	0.998	153
73	Rice	2/28/2018	5.000	11
74	Rice	3/2/2018	3.000	9

	Location (County)	Meter Install Date(s)	Rated AC Power Output (MW)	Number of Subscriptions*
75	Rice	11/30/2017	5.000	114
76	Rice	6/20/2018	1.000	
77	Rice**	6/30/2017	5.000	263
78	Scott	3/28/2018	4.950	20
79	Scott	12/20/2017	2.991	11
80	Scott	11/30/2017	4.690	13
81	Scott	11/30/2017	0.700	7
82	Scott**	12/19/2016	3.000	80
83	Sherburne	3/14/2018	5.000	18
84	Sherburne	7/13/2018	5.000	
85	Sherburne	9/22/2017	5.000	145
86	Sherburne	6/29/2018	5.000	
87	Sherburne	2/12/2018	3.250	154
88	Sherburne	4/30/2018	4.000	31
89	Stearns	11/9/2017	5.000	14
90	Stearns	8/24/2017	2.000	20
91	Stearns	11/16/2017	4.000	127
92	Stearns	12/13/2017	5.000	14
93	Stearns	9/13/2017	2.188	17
94	Stearns	9/13/2017	4.860	26
95	Stearns	10/30/2017	3.000	22
96	Stearns	4/30/2018	5.000	30
97	Stearns**	12/21/2016	5.000	35
98	Stearns**	1/4/2017	3.000	12
99	Stearns**	1/5/2017	3.000	298
100	Steele	3/5/2018	3.400	82
101	Steele	7/18/2018	1.000	
102	Steele	6/5/2018	1.000	
103	Wabasha	1/29/2018	4.000	12
104	Wabasha**	3/13/2017	3.000	169
105	Waconia	1/16/2018	3.000	10
106	Waseca	2/26/2018	5.000	29
107	Washington	4/20/2018	5.000	12
108	Washington	7/16/2018	2.500	
109	Washington	2/23/2018	3.000	13
110	Washington	7/18/2017	5.000	170
111	Washington	1/10/2018	5.000	21
112	Washington	2/28/2018	4.000	436

	Location (County)	Meter Install Date(s)	Rated AC Power Output (MW)	Number of Subscriptions*
113	Washington	4/13/2018	3.000	9
114	Washington**	3/10/2017	0.036	6
115	Watonwan	7/2/2018	0.250	
116	Winona**	5/31/2017	0.250	30
117	Wright	11/13/2017	5.000	1167
118	Wright	11/3/2017	5.000	1214

Total	**400.795**	**9,632**

Northern States Power Company
Electric Operations - State of Minnesota
Derivation of Adjustment for Fuel Clause Rider
Minnesota Jurisdictional Solar Gardens Program Cost Recovery

		July 2017	August 2017	September 2017	October 2017	November 2017	December 2017	January 2018	February 2018	March 2018	April 2018	May 2018	June 2018	Total
	System Portion of Bill Credits & Unsubscribed Energy Payments (Market Amount Allocated to All Jurisdictions)													
[1]	Solar Gardens Subscribed Energy	$576,430	$438,805	$457,277	$224,910	$267,246	$210,524	$670,858	$628,259	$910,957	$1,442,173	$2,104,358	$1,613,844	$9,545,641
[2]	Solar Gardens Unsubscribed Energy <40 KW	$0	$0	$0	$5	$32	$18	$6	$0	$0	$0	$1	$1	$63
[3]	Solar Gardens Unsubscribed Energy > 40 KW	$32,941	$49,098	$81,302	$175,277	$93,024	$69,616	$103,786	$80,291	$64,711	$53,670	$149,315	$141,081	$1,094,112
[4]	Total Costs (System) [1]+[2]+[3]	$609,371	$487,903	$538,579	$400,192	$360,301	$280,158	$774,649	$708,550	$975,668	$1,495,844	$2,253,674	$1,754,926	$10,639,815
	Above Market Amount Recoverable in Minnesota Jurisdiction													
[5]	Minnesota Direct Assigned Above Market Amount	$1,545,018	$1,083,508	$1,403,783	$1,491,177	$1,626,438	$1,067,338	$2,023,834	$1,910,837	$5,048,402	$5,548,760	$5,580,368	$5,026,916	$33,356,379
[6]	Total Bill Credits & Unsubscribed Energy Payments [4]+[5]	**$2,154,389**	**$1,571,410**	**$1,942,362**	**$1,891,369**	**$1,986,740**	**$1,347,496**	**$2,798,483**	**$2,619,387**	**$6,024,071**	**$7,044,604**	**$7,834,042**	**$6,781,842**	**$43,996,195**

Detailed Derivation of Solar Gardens Cost Recovery from Minnesota Retail Customers

		July 2017	August 2017	September 2017	October 2017	November 2017	December 2017	January 2018	February 2018	March 2018	April 2018	May 2018	June 2018	Total
	Above Market Bill Credits Allocated to Minnesota Fuel Clause Recovery													
[7]	Minnesota Direct Assigned Above Market Amount [5]	$1,545,018	$1,083,508	$1,403,783	$1,491,177	$1,626,438	$1,067,338	$2,023,834	$1,910,837	$5,048,402	$5,548,760	$5,580,368	$5,026,916	$33,356,379
	MWh Sales Weighting													
[8]	Minnesota Jurisdiction Retail MWh Subject to FCA	2,911,930	2,652,812	2,596,146	2,312,150	2,301,334	2,529,192	2,565,719	2,215,231	2,409,519	2,188,785	2,460,910	2,787,440	29,931,168
[9]	NSP System MWh Sales Exclude Windsource & Renewable*Connect	3,940,025	3,611,933	3,501,424	3,185,919	3,198,406	3,536,281	3,608,629	3,098,454	3,365,409	3,022,588	3,364,765	3,789,867	41,223,700
[10]	Allocation Weighting [8]/[9]	73.9064%	73.4458%	74.1454%	72.5740%	71.9525%	71.5212%	71.0996%	71.4947%	71.5966%	72.4143%	73.1376%	73.5498%	72.6067%
	Market Bill Credits and Payments Allocated to MN Fuel Clause Recovery													
[11]	Total Solar Gardens Costs Allocation [6]*[10]	$1,592,231	$1,154,134	$1,440,173	$1,372,643	$1,429,509	$963,746	$1,989,709	$1,872,723	$4,313,031	$5,101,299	$5,729,634	$4,988,032	$31,946,864
[12]	Allocated Solar Gardens Costs in Excess of Avoided LMP [5]*[10]	($1,141,867)	($795,790)	($1,040,841)	($1,082,207)	($1,170,263)	($763,373)	($1,438,937)	($1,366,148)	($3,614,485)	($4,018,094)	($4,081,350)	($3,697,287)	($24,210,644)
[13]	Allocated Avoided LMP (Allocated System Portion) [11]+[12]	**$450,364**	**$358,344**	**$399,331**	**$290,435**	**$259,246**	**$200,373**	**$550,772**	**$506,576**	**$698,545**	**$1,083,204**	**$1,648,284**	**$1,290,745**	**$7,736,220**
	Total Solar Gardens Costs Recovery Included in MN Fuel Cost Charge													
[14]	Market and Above Market Allocated Amount [7]+[13]	**$1,995,382**	**$1,441,851**	**$1,803,115**	**$1,781,612**	**$1,885,684**	**$1,267,710**	**$2,574,606**	**$2,417,413**	**$5,746,948**	**$6,631,965**	**$7,228,652**	**$6,317,661**	**$41,092,600**
[15]	**Solar Gardens Developer Late Fees (Credit Back to MN Customers)**								$57,793	$141,778	$91,880	$173,600	$163,180	$628,232
[16]	**Net Solar Gardens Costs Recovery Included in MN Fuel Cost Charg**	**$1,995,382**	**$1,441,851**	**$1,803,115**	**$1,781,612**	**$1,885,684**	**$1,267,710**	**$2,574,606**	**$2,359,620**	**$5,605,169**	**$6,540,085**	**$7,055,052**	**$6,154,481**	**$40,464,368**

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

- Fuel Clause Terms – E002/M-95-244 (Order dated September 5, 1995)
- Variance to Include Certain Fuels and Purchased Power Costs – E002/M-96-934 (Order dated November 12, 1996)
- Tariff Updates – E,G002/M-97-985 (Order dated February 3, 1998)
- HERC – E002/M-17-532 (Order dated December 28, 2017)
- Benson – E002/M-17-530 (Order dated January 23, 2018)
- Laurentian – E002/M-17-551 (Order dated January 23, 2018)
- Pine Bend – E002/M-17-531 (Order dated February 16, 2018)
- Dakota Range – E002/M-17-694 (Order dated May 17, 2018)
- Forecast FCA
    - E002/M-00-420 (Order dated June 27, 2000)
    - E002/M-01-477 (Order dated July 27, 2001)
    - E,G002/M-01-838 (Order dated December 23, 2002)
    - E002/M-02-645 (Order dated July 17, 2002)
    - E002/M-03-585 (Order dated July 10, 2003)
    - E002/M-04-595 (Order dated August 13, 2004)
    - E002/M-05-613 (Order dated July 27, 2005)
    - E002/M-06-589 (Order dated July 17, 2006)
    - E002/M-07-484 (Order dated July 6, 2007)
    - E002/M-08-451 (Order dated July 16, 2008)
    - E002/M-14-364 (Order dated October 24, 2014)
    - E002/M-17-445 (Order dated December 1, 2017)

For the twelve months ending June 30, 2018, 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, end-of-life nuclear fuel accrual, and gain sharing. These additional components of the FCA were approved by the MPUC in the following dockets:

- MISO ASM – E002/M-08-528 (Orders dated February 26, 2009; March 17, 2009; and August 23, 2010)
- MISO Day 2 – E002/M-04-1970 (Orders dated April 7, 2005, December 21, 2005, February 24, 2006, December 20, 2006 and February 7, 2008)

- Wind Contracts Curtailment Payments –
    - Chanarambie – E002/M-00-622, (Order dated July 17, 2002)
    - Navitas Energy – E002/M-02-51 (Order dated July 17, 2002)
    - Ivanhoe Wind – E002/M-04-404 (Order dated October 4, 2004)
    - Velva Wind – E002/M-04-864 (Order dated July 19, 2006)
    - Buffalo Ridge – E002/CN-01-1958 (Order dated March 11, 2003)
    - 2003-2204 Electric AAA Docket – E,G999/AA-04-1279 (Order dated April 4, 2006)
    - Fenton Power Partners – E002/M-05-1850 (Order dated March 31, 2006)
    - FPL/Mower County – E002/M-05-1934 (Order dated March 31, 2006)
    - MinnDakota Wind – E002/M-06-85 (Order dated May 3, 2006)
- 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)
    - Winona, LLC – E002/M-09-1247 (Notice of Approval dated December 1, 2009)
    - Goodhue North, LLC – E002/M-09-1349 (Order dated April 28, 2010)[1]
    - Goodhue South, LLC – E002/M-09-1350 (Order dated April 28, 2010)[2]
    - Adams, LLC – E002/M-09-1366 (Notice of Approval dated December 29, 2009)
    - Danielson, LLC – E002/M-09-1367 (Notice of Approval dated December 29, 2009)
    - Best Power, LLC – E002/M-09-1481 (Order dated June 25, 2010)[3]
    - WM Renewable Energy, LLC, E002/M-10-161 (Order dated April 30, 2010)
    - Big Blue, LLC – E002/M-10-733 (Notice of Approval dated August 26, 2010)[4]
    - Community Wind North, LLC – E002/M-10-734 (Order dated August 26, 2010)
    - Hilltop – E002/M-08-47 (Notice of Approval dated February 15, 2008)

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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.
[3] The amended PPA was approved by the Commission's September 8, 2014 Order in Docket No. E002/M-14-490.
[4] The amended PPA was approved by the Commission's February 27, 2014 Order in Docket No. E002/M-13-1002.

  - Valley View – E002/M-08-1235 (Order dated March 9, 2009)
  - Ridgewind – E002/M-08-1428 (Notice of Approval dated January 2, 2009)
  - Moraine II – E002/M-08-1487 (Order dated April 24, 2009)
  - Ewington Energy Systems LLC – E002/M-06-1472 (Notice of Approval dated November 30, 2006)
  - Jeffers Wind 20, LLC – E002/M-06-1234 (Notice of Approval dated November 30, 2006)
  - Uilk Wind Farm, LLC – E002/M-08-1502, Notice of Approval dated February 6, 2009
  - Prairie Rose Wind, LLC – E002/M-11-713 (Order dated December 28, 2011)
  - Diamond K Dairy – E002/M-10-486 (Order dated August 26, 2010)
  - School Sisters – E002/M-15-619 (Order dated September 14, 2015)
  - Aurora Solar – E002/M-15-330 (Order dated August 2, 2015)
  - Marshall and NorthStar Solar – E002/M-14-162 (Order dated March 24, 2015)
  - Slayton Solar – E002/M-11-490 (Order dated September 14, 2011)
- WindSource Exemption – E002/M-01-1479 (Orders dated February 26, 2002 and May 7, 2002) and E002/M-09-1177 (Order dated June 21, 2010)[5]
- Community Solar Gardens Program – E002/M-13-867 (Order dated September 17, 2014)
- Renewable*Connect Government Program – E002/M-15-985 (Order dated February 27, 2017)
- Sherco Land Sale – E002/M-17-528 (Order dated February 6, 2018)
- Inver Hills – E002/PA-17-529 (Order dated February 16, 2018)

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

Annual Automatic Adjustment Report

Docket No. E999/AA-18-373

Xcel Energy®

PART I

MISO Day 1 Operations Impact

MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC. DAY 1 OPERATIONS IMPACT
(Docket No. E002/M-00-257 et al.)

Part I contains the Company's various compliance reports required by Commission Orders issued in prior Company miscellaneous filings, rate cases, and Annual Automatic Adjustment of Charges Reports associated with the Company's participation in the Midcontinent Independent System Operator, Inc. (MISO).

Background

On May 9, 2002, the Commission issued an Order approving the Company's petition to transfer functional control of certain transmission facilities (those at 100 kV and above) to MISO. In compliance with the Order, the Company provides the following information:

1. Section 2, Item C, Part 3(a): Schedule 10 Administrative Charges Paid to MISO Under MISO Tariff

2017-2018 AAA Period

Period*	Invoiced Amount (NSP System)	Juris Trans Alloc	Interchange Alloc	MN Jurisdiction Net of Interchange
July 2017	$1,091,627.19	87.4350%	84.2464%	$804,101.76
August 2017	$1,007,193.95	87.4350%	84.2464%	$741,907.52
September 2017	$1,133,189.01	87.4350%	84.2464%	$834,716.54
October 2017	$947,789.47	87.4350%	84.2464%	$698,149.68
November 2017	$940,127.90	87.4350%	84.2464%	$692,506.11
December 2017	$956,640.09	87.4350%	84.2464%	$704,669.12
January 2018	$1,016,481.13	87.3171%	84.2615%	$747,872.92
February 2018	$896,812.46	87.3171%	84.2615%	$659,827.06
March 2018	$1,017,318.98	87.3171%	84.2615%	$748,489.37
April 2018	$923,179.62	87.3171%	84.2615%	$679,226.62
May 2018	$1,118,523.81	87.3171%	84.2615%	$822,950.52
June 2018	$1,076,530.52	87.3171%	84.2615%	$792,054.08
Total	**$12,125,414.13**			**$8,926,471.31**

*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.

2016-2017 AAA Period

Period*	Invoiced Amount (NSP System)	Juris Trans Alloc	Interchange Alloc	MN Jurisdiction Net of Interchange
July 2016	$896,649.27	87.7424%	84.1349%	$661,924.25
August 2016	$1,095,761.50	87.7424%	84.1349%	$808,912.84
September 2016	$779,304.06	87.7424%	84.1349%	$575,297.69
October 2016	$864,930.98	87.7424%	84.1349%	$638,509.18
November 2016	$833,487.52	87.7424%	84.1349%	$615,296.99
December 2016	$1,046,982.15	87.7424%	84.1349%	$772,902.96
January 2017	$851,213.75	87.4350%	84.2464%	$627,011.20
February 2017	$832,756.16	87.4350%	84.2464%	$613,415.18
March 2017	$976,947.83	87.4350%	84.2464%	$719,627.98
April 2017	$797,187.18	87.4350%	84.2464%	$587,214.77
May 2017	$849,912.12	87.4350%	84.2464%	$626,052.41
June 2017	$1,119,885.42	87.4350%	84.2464%	$824,917.01
Total	**$10,945,017.94**			**$8,071,082.45**

*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 and Northern States Power Company, a Wisconsin corporation (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) increased the NSP System allocation to the Company effective January 1, 2017, pursuant to the annual update to the Interchange Agreement allocation factors accepted by FERC in Docket No. ER17-1377-000, letter order dated May 26, 2017. The 2018 Interchange Agreement demand allocator was approved in FERC Docket No. ER18-1117-000, and the letter order approving that filing was issued on April 24, 2018.

The State of Minnesota jurisdictional demand allocator (12 month coincident peak demand) decreased effective January 1, 2017 based on State of Minnesota demands. The net impact of the increase in the 2017 Interchange Agreement demand allocator and the decrease in the 2017 State of Minnesota jurisdictional demand allocator is a slight decrease in the 2017 NSP System allocation to the Minnesota jurisdiction.

Order Point 18 of the Commission's August 16, 2013 Order in Docket No. E999/AA-11-792 (the 2011 AAA docket) requires utilities to

> *…provide in the initial filing of all future electric AAA reports the Minnesota jurisdictional Schedule 10 costs together with the allocation factor used and support for why the allocator is reasonable. Additionally, the electric utilities shall 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.*

For comparison purposes, the 2016-2017 amount invoiced for MISO Schedule 10 administrative charges was $10.95 million. The amount invoiced for the 2017-2018 AAA reporting period was $12.13 million. This is an increase of 10.8%. The increase in Schedule 10 expense is primarily based on increased Schedule 10 Demand and Energy rates in addition to increased Network Load. Please see Part I, Section 1, Schedule 1 for a breakout of the year-over-year increase. According to MISO, the increase in MISO Schedule 10 rates are driven in part by:

1. the execution of MISO's Market System Enhancement design and implementation,
2. additional staffing needs for portfolio future scenario planning, cyber and physical security improvements to respond to increasing threats and sophistication, and NERC Critical Infrastructure Protection compliance; and
3. Scope increases related to Generator Interconnection, in response to increases in complexity, requests and/or sophistication for Generator Interconnection studies and security, as well as NERC Audit Support

2. Section 2, Item C, Part 3(b):
MISO Administrative Charges Deferred by MISO for Later Recovery

MISO has deferred costs associated with the integration of the Entergy Operating Companies, Cleco Power LLC, South Mississippi Electric Power Association, Lafayette Utilities Systems and East Texas Electric Cooperative that will be recovered over a five-year period, beginning on January 1, 2014, the date of the integration of the first Entergy Operating Company.

3. Section 2, Item C, Part 5(c):
Each Instance Where MISO Directed NSP to Curtail NSP's Own Generation for Reliability Reasons that Resulted in an Interruption of Firm Retail Electric Service to NSP's Retail Customers in Minnesota

There was no instance of said conditions occurring during this reporting period.

4. Section 2, Item C, Part 5(d):
Each Instance Where MISO Directed the Curtailment of a Delivery of a Firm Purchased Power Supply that Subsequently Resulted in an Interruption of Firm Retail Electric Service to NSP's Retail Customers in Minnesota

There was no instance of said conditions occurring during this reporting period.

5. Section 2, Item c, Part 8(b):
Changes to MISO Tariffs That May Ultimately Affect the Rates of Retail Customers in Minnesota, and on NSP's Efforts to Minimize MISO Transmission Service Costs

In the period July 1, 2017 to June 30, 2018, MISO submitted a significant number of filings to FERC, including proposed tariff changes to the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff, compliance filings, generation interconnection agreements, answers to complaints, and various other filings. Many of the proposed tariff changes and other filings may ultimately affect the rates of our retail electric customers in Minnesota in some manner. All MISO filings to FERC during the reporting period are available (cataloged by month) at the MISO web site (www.misoenergy.org), at the "FERC Filings and Orders" tab available under the "Library" tab at the MISO home page.

6. Section 2, Item C, Part 8(c) Annual Analysis of How the Transfer of Operational Control to the MISO Has Affected NSP's Transmission and Energy Costs and Revenues

a. Overall Transmission Costs and Revenues

As a result of the transfer of operational control of NSP's transmission assets (and the transmission assets of numerous neighboring utilities) to MISO and participation in MISO's regional Tariff, the Company has realized savings on the cost of transmission services purchased to deliver energy supplies purchased to serve our native load customers. This benefit stems primarily from the broad region covered by the MISO Tariff and the conversion of point-to-point transmission service under MAPP Schedule F or individual provider OATTs to network integration transmission service under the MISO Tariff beginning in 2002. This change also had the effect of eliminating most rate "pancaking" (the accumulation of transmission rates assessed by adjacent or distant transmission systems or control areas) for purchased power transactions with delivery points within the MISO region.

These benefits are particularly important to the Company, since it purchases a substantial portion of energy supplies to serve our native load customers. The benefits of this change were discussed in the Direct and Rebuttal testimony of Mr. Stephen Beuning in the 2005 NSP electric rate case (Docket No. E002/GR-05-1428).[1] Mr. Beuning's testimony is incorporated by reference.

On the transmission revenue side of the equation, participating in the MISO regional tariff initially reduced the Company's third party transmission service tariff revenues due to the adoption of the MISO regional tariff. Just as the Company in MISO Day 1 operations could contract for network transmission service under license plate rates to deliver power to our system, other MISO members could transmit power across our transmission system without paying the Company directly for this use. Revenues from MISO point-to-point service also decreased due to lower volumes of point-to-point service associated with bilateral transactions since the start of the Day 2 energy market in 2005, and the FERC-mandated elimination of "regional through and out" charges (RTOR) for transactions crossing the border between MISO and PJM

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[1] On November 3, 2008, Mr. Beuning provided additional testimony regarding the benefits received by the Company as a result of MISO operations. The testimony was provided as a part of the Company's 2008 rate case in Docket No. E002/GR-08-1065.

Interconnection L.L.C. in late 2004. Transmission service revenue has increased as the Company has invested in new transmission facilities and reflected the cost of the new facilities in its annual updates to the Attachment O – NSP formula transmission rate contained in the MISO Tariff.

Overall transmission costs and revenues were discussed at length in the Direct Testimony of Mr. Ian Benson in the most recent NSP electric rate case (Docket No. E002/GR-15-826. Mr. Benson's testimony is also incorporated by reference.

b. Overall Energy Costs for Retail Customers, Including Analysis of How MISO Membership Has Affected NSP's Ability to Use Its Own Generating Sources When They Are the Least-Cost Power Source

On April 1, 2005, MISO began operation of the Day 2 wholesale Day Ahead and Real Time energy markets, pursuant to its Tariff. MISO initiated regional security constrained economic dispatch with the day-ahead and real-time energy markets. Under the Day 2 tariffs, all MISO participants that own or operate generation are now required to submit offers for their generation resources (either owned generation or purchases) that are "Network Resources" belonging to the market. At the same time, each MISO load serving entity (LSE) must bid their load requirements into the market. Since the Company is a market participant with generation and also an LSE, the Company participates with both bids and offers. After receipt of the generation offers and load bids, MISO performs a supply cost optimization analysis that evaluates and reflects delivery constraints on the transmission grid. MISO "clears" the day-ahead and real-time markets over its entire footprint based on participants' bids and offers and the limitations of the transmission system, with optimized cost of supply.

The impact of MISO Day 2 market operations was discussed in the testimony of Mr. Beuning in the Company's 2005 electric rate case, and that testimony is incorporated by reference. The impact was also discussed in the June 22, 2006 Joint Report to the Commission in Docket No. E002/M-04-1970 *et al.*, and in the Company's Reply Comments to the 2007 AAA report (Docket No. E,G999/AA-07-1130). The discussion in those documents is also incorporated by reference.

On January 6, 2009, MISO further enhanced their market by incorporating ancillary services in their market design (Day 3). The Ancillary Services Market (ASM) allowed for further optimization of supply for energy, as well as for regulating reserves, spinning reserves, and supplemental reserves. MISO uses a co-optimitized algorithm that finds the least cost solution for supplying both energy and the reserves. This allows the Company to more fully use its own generation to serve native load when it is least cost. It also allows the Company to procure energy and reserves at a lower cost when the Company's own generation is not least cost.

Along with the launch of the ASM, MISO allows demand response to be used into its market. These consist of demand response for emergencies as well as economic demand response. MISO allows the Company to include its demand response programs in MISO's resource adequacy construct and these programs will be available for system emergencies that include the NSP System. The emergency procedures that describe the circumstances where MISO can call on the Company's demand response programs can be found on MISO's website (www.misoenergy.org).

In summary, NSP makes available to MISO both its Company-owned and purchased resources for regional dispatch optimization. NSP uses proprietary resource trading methods to ensure that least cost resources remain available for native supply, while ensuring that competitive regional supply alternatives have the opportunity to clear when they can provide energy at lower costs.

In general, operation of the Day 2 and ASM market has not negatively affected the Company's ability to use its own resources (Company-owned generation or bilateral purchased power) when those native resources are the least cost power resource. In particular, the Day 2 market has facilitated the integration of wind energy resources in the regional dispatch much more efficiently than would be the case if NSP system operations had continued on a stand-alone basis.

c. Overall Energy Costs for Retail Customers, Including ….NSP's Ability to Access Low-Cost Power on the Wholesale Market for Its Retail Customers

The Company continues to experience the benefits and efficiencies of the MISO Day 2 and Day 3 Markets, which enhanced NSP's ability to access low-cost power and ancillary services. On a qualitative basis, our experience with the regional generation dispatch market operated by MISO shows benefits related to integration of wind generation resources in the regional economic dispatch. Absent MISO's provision of access to generation on a large regional basis, NSP would experience more disruptive local dispatch requirements, increasing costs for our customers.

7. Section 2, Item C, Part 8(d)
Each Instance Where MISO Directed NSP to Redispatch NSP's Owned Generation for Reliability Reasons, Including an Explanation of Financial Impact on Rates, if Any, and the Reason for the Redispatch, if Known.

Pursuant to the Commission's February 6, 2008 Order on the Company's 2006 AAA report (Docket No. E,G999/AA-06-1208), this reporting item is no longer required.

	July'17 - June'18	July'16 - June'17	YOY Increase
Avg Network Load	6,760.78	6,646.28	114.50
Avg Sch 10 Demand Rate	0.0705	0.0666	0.0039
Avg Sch 10 Energy Rate	0.0973	0.0911	0.0062

	2017 - 2018	Schedule 10 Rates	
	Network Load	Demand	Energy
Jul-17	8,687.74	0.0573	0.082
Aug-17	7,876.59	0.0591	0.0851
Sep-17	8,281.63	0.0637	0.0956
Oct-17	5,784.85	0.0799	0.1088
Nov-17	5,918.74	0.081	0.1041
Dec-17	6,372.84	0.0709	0.0945
Jan-18	6,539.90	0.073	0.0993
Feb-18	6,265.18	0.0755	0.1008
Mar-18	5,658.69	0.087	0.1168
Apr-18	5,568.69	0.0824	0.1101
May-18	8,244.94	0.0607	0.0887
Jun-18	5,929.59	0.056	0.0818
Average	6,760.78	0.0705	0.0973

	2016 - 2017	Schedule 10 Rates	
	Network Load	Demand	Energy
Jul-16	8,812.87	0.0473	0.0672
Aug-16	8,723.41	0.0584	0.0834
Sep-16	6,725.63	0.055	0.077
Oct-16	5,817.78	0.0695	0.0911
Nov-16	5,781.30	0.0673	0.0943
Dec-16	6,540.45	0.075	0.1012
Jan-17	6,425.60	0.0616	0.082
Feb-17	6,007.52	0.0722	0.0939
Mar-17	5,624.37	0.0858	0.1106
Apr-17	5,298.53	0.0725	0.1
May-17	6,035.57	0.0663	0.0949
Jun-17	7,962.37	0.0686	0.0981
Average	6,646.28	0.0666	0.0911

Northern States Power Company

MISO Schedule 10 Cost Variance

Schedule 10 Analysis

2017-2018	Jul-17	Total Network Load	Total MISO Sch 10 Charges	Aug-17	Total Network Load	Total MISO Sch 10 Charges	Sep-17	Total Network Load	Total MISO Sch 10 Charges	Oct-17	Total Network Load	Total MISO Sch 10 Charges	Nov-17	Total Network Load	Total MISO Sch 10 Charges
Schedule 10 Demand Rate	0.0573	8687.743951	370,454.22	0.0591	7876.591478	346,424.81	0.0637	8281.630312	379,920.43	0.0799	5784.849068	344,002.71	0.0810	5918.739759	345,297.54
Schedule 10 Energy Rate	0.0820	8687.743951	346,452.60	0.0851	7876.591478	330,894.62	0.0956	8281.630312	417,274.96	0.1088	5784.849068	362,465.08	0.1041	5918.739759	351,546.77
Schedule 10 FERC Rate	0.0586	8687.743951	378,858.94	0.0570	7876.591478	334,115.32	0.0570	8281.630312	339,960.18	0.0570	5784.849068	245,408.71	0.0570	5918.739759	242,987.14

2016-2017	Jul-16	Total Network Load	Total MISO Sch 10 Charges	Aug-16	Total Network Load	Total MISO Sch 10 Charges	Sep-16	Total Network Load	Total MISO Sch 10 Charges	Oct-16	Total Network Load	Total MISO Sch 10 Charges	Nov-16	Total Network Load	Total MISO Sch 10 Charges
Schedule 10 Demand Rate	0.0473	8812.869931	310,205.85	0.0584	8723.40506	379,115.37	0.0550	6725.629073	266,414.12	0.0695	5817.775711	300,928.97	0.0673	5781.302059	280,235.68
Schedule 10 Energy Rate	0.0672	8812.869931	304,164.44	0.0834	8723.40506	348,078.71	0.0770	6725.629073	240,517.85	0.0911	5817.775711	322,120.62	0.0943	5781.302059	312,139.38
Schedule 10 FERC Rate	0.0444	8812.869931	291,186.90	0.0586	8723.40506	380,413.69	0.0586	6725.629073	283,852.11	0.0586	5817.775711	253,732.91	0.0586	5781.302059	244,009.07

Source: NSPP & NSPX MC Final Settlement File (Cost Adder Tab)

Northern States Power Company

MISO Schedule 10 Cost Variance

Schedule 10 Analysis

2017-2018	Dec-17	Total Network Load	Total MISO Sch 10 Charges	Jan-18	Total Network Load	Total MISO Sch 10 Charges	Feb-18	Total Network Load	Total MISO Sch 10 Charges	Mar-18	Total Network Load	Total MISO Sch 10 Charges	Apr-18	Total Network Load	Total MISO Sch 10 Charges
Schedule 10 Demand Rate	0.0709	6372.843824	336,270.46	0.0730	6539.896659	355,303.49	0.0755	6265.1773	317,971.50	0.0870	5658.690307	366,405.18	0.0824	5568.687345	330,497.73
Schedule 10 Energy Rate	0.0945	6372.843824	349,743.56	0.0993	6539.896659	383,451.57	0.1008	6265.1773	338,511.26	0.1168	5658.690307	410,688.38	0.1101	5568.687345	363,890.03
Schedule 10 FERC Rate	0.0570	6372.843824	270,344.39	0.0570	6539.896659	277,428.75	0.0570	6265.1773	240,057.96	0.0570	5658.690307	240,058.55	0.0570	5568.687345	228,620.99

2016-2017	Dec-16	Total Network Load	Total MISO Sch 10 Charges	Jan-17	Total Network Load	Total MISO Sch 10 Charges	Feb-17	Total Network Load	Total MISO Sch 10 Charges	Mar-17	Total Network Load	Total MISO Sch 10 Charges	Apr-17	Total Network Load	Total MISO Sch 10 Charges
Schedule 10 Demand Rate	0.0750	6540.453269	365,068.89	0.0616	6425.595367	294,579.27	0.0722	6007.518853	291,572.25	0.0858	5624.369024	359,160.39	0.0725	5298.531473	276,687.73
Schedule 10 Energy Rate	0.1012	6540.453269	399,648.28	0.0820	6425.595367	279,406.62	0.0939	6007.518853	307,226.90	0.1106	5624.369024	375,592.32	0.1000	5298.531473	299,865.32
Schedule 10 FERC Rate	0.0586	6540.453269	285,240.51	0.0586	6425.595367	280,232.89	0.0586	6007.518853	236,650.04	0.0586	5624.369024	245,300.69	0.0586	5298.531473	223,640.03

Source: NSPP & NSPX MC Final Settlement File (Cost Adder Tab)

Schedule 10 Analysis

2017-2018	May-18	Total Network Load	Total MISO Sch 10 Charges	Jun-18	Total Network Load	Total MISO Sch 10 Charges	Yearly Average Rate	Yearly Average Rate Change	YOY Rate % Change	Yearly Average Network Load	Yearly Average Load Change	YOY Load % Change
Schedule 10 Demand Rate	0.0607	8244.939525	372,438.37	0.0560	5929.590784	360,121.75	0.0705	0.0039	5.88%	6,760.7817	114.4997	1.72%
Schedule 10 Energy Rate	0.0887	8244.939525	399,399.20	0.0818	5929.590784	357,943.44	0.0973	0.0062	6.76%	6,760.7817	114.4997	1.72%
Schedule 10 FERC Rate	0.0570	8244.939525	349,736.22	0.0570	5929.590784	366,552.48	0.0571	(0.0003)	-0.49%	6,760.7817	114.4997	1.72%

2016-2017	May-17	Total Network Load	Total MISO Sch 10 Charges	Jun-17	Total Network Load	Total MISO Sch 10 Charges						
Schedule 10 Demand Rate	0.0663	6035.565149	297,816.17	0.0686	7962.368632	393,376.09	0.0666			6,646.2820		
Schedule 10 Energy Rate	0.0949	6035.565149	296,358.50	0.0981	7962.368632	394,555.70	0.0911			6,646.2820		
Schedule 10 FERC Rate	0.0586	6035.565149	263,228.18	0.0586	7962.368632	336,032.64	0.0574			6,646.2820		

Source: NSPP & NSPX MC Final Settlement File (Cost Adder Tab)

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-18-373

Xcel Energy®

PART J

MISO DAY 2 AND ASM

Midcontinent Independent System Operator, Inc. (MISO) Day 2 Accounting and Recovery (Docket No. E002/M-04-1970 *et al.*), Electric Rate Case Settlement Agreement (Docket No. E002/M-05-1428), and 2006 AAA Order (Docket No. E,G999/AA-06-1208) Compliance Report

1. Background

On December 21, 2005, the Commission issued its ORDER ESTABLISHING SECOND INTERIM ACCOUNTING FOR MISO DAY 2 COSTS, PROVIDING FOR REFUNDS, AND INITIATING INVESTIGATION in Docket No. E002/M-04-1970 *et al.* In compliance with the Order the Company is required to report the following information as part of its AAA report:

- Order Item 5:
  Each petitioner shall limit its level of activity in the real-time market to five percent of total purchases for retail customers, or make real-time market activities subject to prudence review on an annual basis in the annual automatic adjustment of charges docket arising pursuant to Minnesota Rules part 7825.2810.
- Order Item 7, Part C:
  In annual reports regarding the automatic adjustment of charges, each petitioner shall provide the following:
  - Information on the net cost of congestion costs and financial transmission rights (FTR) revenues from serving ratepayers. The report should also include information on the amount of excess FTR revenues recovered from MISO as calculated in the FTR Monthly Allocation Amount and the FTR Yearly Allocation Amount.
  - A summary of the effects of each of the thirty-two MISO Day 2 charges on ratepayers and/or the petitioner over the course of the year.

On December 20, 2006, the Commission issued a second order in Docket No. E002/M-04-1970, its ORDER ESTABLISHING ACCOUNTING TREATMENT FOR MISO DAY 2 COSTS (MISO Day 2 Order). In this Order, all Minnesota electric utilities are required to report additional information in their monthly FCA filings and AAA reports. Specifically for Xcel Energy, certain reporting requirements are similar to the ones included in the Company's 2005 Electric Rate Case Settlement in Docket No. E002/M-05-1428. And on February 6, 2008, the Commission issued its Order in Docket No. E,G999/AA-06-1208, *In the Matter of the Review of the 2006 Annual*

Automatic Adjustment of Charges for All Electric and Gas Utilities (2006 AAA Order), which also established additional reporting requirements for the Company's AAA Report. The following table is a side by side comparison of the reporting requirements from the MISO Day 2 Order, 2005 Rate Case Settlement, and 2006 AAA Order applicable to this AAA Report:

MISO Day 2 Order	2005 Rate Case Settlement	2006 AAA Order	Descriptions	Report In	Xcel Energy's Compliance
7A	Item 1		Overview of anticipated events, planned action and cost minimization plans for fuel costs	AAA	First reported in Attachment D of 2005-2006 AAA. See Part J, Section 4 for this year's report.
7B	Item 2		Annual FCA forecast and explanation of previous year's forecast deviation (Note: Quarterly for Xcel Energy per FCA Settlement Agreement)	AAA (FCA)	Quarterly FCA forecast of 12-monthly FCA provided to customers who signed the protective agreement since 4th quarter in 2006. Monthly deviation explained in FCA filings and during meeting with customers.[1]
7C	Item 3		Provide to customers who signed protective agreement summary of AAA filing stating key factors affecting costs and update FCA forecast	Same Time as AAA	Separate mailing to customers who signed protective agreement after September AAA filing.
7G		 Paragraphs 21, 22 & 24	Monthly MISO reporting using format per June 22, 2006 Joint Report and Recommendation, Exhibit D Provide MISO information according to spreadsheet in DOC IR201 in 2007 AAA	FCA and AAA	Joint Report format listed in Part J Section 3 Schedule 3 of this AAA report. Part J Section 5 Schedule 7 of this AAA report
		Paragraph 18	Actual and budget comparison of generation plant maintenance		Part J Section 6 Schedule 1 of this AAA report

[1] Pursuant to Settlement Agreement item 4, the Company shall meet at least twice yearly with interested parties to discuss the FCA forecast. A similar requirement is also cited in paragraph 7D in the December 20, 2006 Order in Docket No. E002/M-04-1970 *et al.* The Company has conducted the required meetings.

2. Level of Activity in the Real-Time Market

The Company's strategy currently is **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]. The Company believes that this strategy meets the intent of the Commission's Order in Docket No. E002/M-04-1970 **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS].

3. Compliance with MISO Order Paragraphs 7A and 7C and FCA Settlement Agreement Items 1 & 3

As results of the MISO Day 2 Order and 2005 Rate Case Settlement referenced above, the Company is required to provide additional information in its AAA reports on, *inter alia*, its plans to hedge volatility in fuel and purchased energy costs. This discussion and the following Quarterly Forecast (see next section) will also be provided to interested parties who have signed a protective agreement with the Company.

A. Managing Price Risk Volatility

The Company addresses fuel and purchased power price risk through an integrated analysis of its future costs over the next twelve months. The first step is to develop a forecast of the incremental cost of serving NSP System[2] full requirements customers (e.g., retail and wholesale "native load" customers). This forecast is developed using PLEXOS®, a system dispatch model that optimizes the Company's generation and purchased power portfolio to achieve the lowest expected cost portfolio to serve native load customers. Key inputs for the PLEXOS® model include expected fuel and purchased power costs, planned outages at generation facilities, and expected unplanned outage probabilities at generation facilities. This forecast provides the Company with "buy signals" whereby trading personnel can lower expected costs by

[2] As discussed in detail in Docket No. E002/GR-05-1428, the "NSP System" refers to the combined systems of the Company and Northern States Power Company, a Wisconsin corporation (NSPW). The Company and NSPW operate a single integrated generation and transmission system. The NSP System costs are allocated between the Company and NSPW pursuant to the Interchange Agreement.

purchasing energy at prices below the predicted incremental cost of serving native load customers. These buy signals also address potential price volatility that can occur due to planned and unplanned unit outages, since these potential occurrences are incorporated into the PLEXOS® model.

In a separate analysis, the Company analyzes its Financial Transmission Rights (FTR) position in the MISO market to ensure that the Company is appropriately hedged against congestion cost risk. Finally, the Company reviews its exposure to fuel price risk. As discussed below, this has typically been a long-term issue for the NSP System due to the predominance of coal and nuclear energy in our generation fleet. However, the increase in natural gas-fired generation and purchased power in the resource portfolio help mitigate this risk.

A description of all of these activities is provided in greater detail below.

i. Incremental Cost Forecast and Buy Signals

The Company develops an incremental cost forecast for the NSP System using the PLEXOS® model as opportunities for bi-lateral transactions dictate, i.e. on an as needed basis. The PLEXOS® model incorporates all key load and resource data, including hourly loads, production costs, and generation resource availability. Thus, key generation unit or scheduled transmission outages are taken into account and are incorporated into the purchase instructions provided to trading personnel.

ii. FTR and Congestion Analysis

The Company operates in the MISO wholesale energy and ancillary services market, which uses security constrained regional dispatch with locational marginal pricing (LMP) and FTRs to provide a hedge against congestion risk. The Company periodically reviews its FTR portfolio to ensure that it is properly hedged against congestion cost risk in the MISO day-ahead market (there is no FTR protection in the real-time market). The Company analyzes key congestion risks between our generation and purchase power nodes and our load nodes to determine the optimal FTR portfolio. The Company has the ability to adjust this portfolio annually through the MISO FTR allocation process and monthly through the FTR auction process.
[PROTECTED DATA BEGINS
PROTECTED DATA ENDS]

iv. Fuel Hedging

Xcel Energy's current coal acquisition strategy **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]. Implementation of this strategy **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS] Xcel Energy's strategy is **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS] Xcel Energy's coal acquisition strategy also **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]

The Company contracts for natural gas storage on Northern Natural Gas (NNG) and ANR Pipeline to provide operational flexibility and to ensure availability of fuel for power plant operations. Storage gas also provides price stability and certainty throughout the year as previously stored gas can be withdrawn to displace daily spot purchases if and when market prices spike. Gas stored on ANR Pipeline is purchased during the summer and used as a source of supply during the winter months. ANR storage is projected to cover approximately 19 percent of the 2017-2018 winter gas generation requirements. The Company's storage service on Northern Natural Gas (NNG) was converted to a new service requested by NSP specifically for electric generation customers effective June 1, 2018. Through this conversion NSP now has more flexibility to inject and withdraw throughout the year to manage daily swings in demand for gas fired generation. Unlike traditional storage services which must be filled during the summer months for use during the winter, the new Electric Generation (EG) service on NNG allows for withdrawals, and hence protection against price volatility year-round, including the summer months when electric demand peaks. With such a significant portion of system requirements covered through the use of storage, the Company does not use financial instruments to hedge natural gas.

vi. Outage Management

The Company attempts to schedule maintenance for its generating facilities during periods when energy demand, and prices, is expected to be relatively low. These periods typically occur in the fall and spring when weather conditions are more moderate. The Company submits outage information to MISO for approval.

B. Summary of 2018 - 2019 Fuel and Purchased Energy Costs

In this section the Company explains the main factors contributing to changes in forecast fuel and purchase power expense for 2019 as compared to actual and forecast costs for 2018, prior to cost adjustment for wholesale sales revenues. Forecast costs for 2019 are projected to be $15.7 million lower than projected costs for 2018, which represents a decrease of 1.3 percent.

The cost change between 2018 and 2019 is driven by a number of different factors that are discussed below. For 2019, there are significant cost increases for long-term purchases from natural gas-fired and solar resources. The increase for solar generation is primarily driven by a substantial increase in forecast costs for the Solar*Rewards Community program. These cost increases are partially offset by a significant decline in purchases from the Biomass PPAs, three of which were terminated in 2018. In addition, there are cost decreases for owned coal, natural gas and nuclear fueled resources which are driven primarily by reduced volumes from these sources of generation. Finally there is a significant decrease in forecast costs for purchases from the MISO market driven by lower expected purchases from the market.

i. Cost Drivers for Company-Owned Coal Generation

In 2019, fuel costs for the Company's base load coal generating units are expected to increase by approximately $2.4 million due to **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. Production is forecast to decrease by **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** in 2019 due to greater renewable generation on the system and reduced dispatch of coal generation compared to 2018.

ii. Cost Drivers for Company-Owned Nuclear Generation

Compared to 2018, fuel costs for the Company's base load nuclear generating units are expected to decrease by approximately $2.8 million. The decrease in cost is driven by lower generation volume due to **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. Escalation in contract prices for the components required to manufacture nuclear fuel partially offsets the cost decrease due to lower generation volume.

iii. Company-Owned Natural Gas Generation

Total costs for Company-owned natural gas generation are projected to decrease by $16.5 million due to lower forecast generation of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. This decrease is driven by lower generation that results from greater renewable generation on the system in addition to the start-up of the Mankato II combined cycle plant in 2019 that is under a purchase power agreement. This new PPA offsets some generation from Company-owned gas plants. Lower forward natural gas prices also contribute to the decline in costs. As of July 2018, forward prices for natural gas are projected to be 7.9 percent lower for 2019 than 2018.

iv. Company-Owned Renewable Generation

Company-owned renewable generation is projected to increase by **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** in 2019. This is primarily driven by new Company-owned wind projects expected to come on-line during 2019. The projects planned to come on-line during 2019 include the following: Foxtail, Blazing Star I, Crowned Ridge and Lake Benton. These projects are planned to reach in-service dates at various times during the fall of 2019 and contribute to the increase in owned renewable generation for 2019.

v. Energy Purchases

Costs for purchases of energy increase by a net total of $1.2 million for 2019 as compared to projected costs for 2018. These purchases are comprised of long-term purchase power agreements (PPAs), community renewable programs and market purchases. There are a number of off-setting cost drivers within this category that will be discussed in the remaining subsections vi. through x.

vi. Purchased Solar Generation and Costs

Costs for purchases of solar energy are forecast to increase in 2019 as compared to 2018 by $76.8 million. These costs are comprised of purchases of solar generation from long-term purchase power contracts and purchases from the Solar*Rewards Community program. Solar generation is forecast to increase by **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** in 2019. The primary contributor to the increase in generation and costs is the assumed growth of the Solar*Rewards Community program which is forecast to increase from $76.5 million for 607 GWh of energy in 2018 to $153.4 million for 1126 GWh of energy in 2019. In 2019, the Solar*Rewards Community program is forecast to contribute 12.7 percent to total system production costs while contributing 2.2 percent to total energy produced.

vii. Purchased Wind Generation and Costs

Costs for purchases of energy from long-term wind purchase power contracts are forecast to decrease by $2.9 million in 2019 as compared to 2018. The forecast assumes a decrease in total purchases of wind energy from PPAs of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** for 2019. The decrease in purchases is primarily driven by termination of several wind PPAs in 2018 and 2019: Moraine, Moraine II, Lake Benton Power Partners II, and Viking.

viii. Purchased Natural Gas Generation and Costs

Costs for purchases of energy from natural gas PPAs are forecast to increase by $17.0 million. Generation from these PPAs is forecasted to increase by **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. The main driver for the increase in costs and generation from natural gas PPAs is the start of a new long-term PPA with the Mankato II project during 2019. Low forward prices for natural gas result in significant production from Mankato II after it comes on-line in 2019. Low natural gas prices also mitigate the cost increase caused by greater generation by decreasing the cost to generate from these facilities during 2019.

ix. Other Long-Term Energy Purchases

Costs for purchases of energy from other long-term PPAs are forecast to decrease by $31.7 million. These PPAs are primarily comprised of the Manitoba Hydro PPA and the biomass PPAs. The decrease in costs results from the termination of three biomass PPAs in 2018: Fibrominn, Laurentian, and Pine Bend; in addition to termination of the contract with Koda Energy, LLC which ends in 2019. Generation from these PPAs is forecasted to decrease **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** in 2019. Escalation in contract prices for remaining PPAs in this group partially offsets the cost decrease from the biomass PPA terminations.

x. Market Purchases and MISO Forward Prices

For 2019, forecast costs for purchases of energy from the MISO market and other market charges have declined by $58.0 million driven by lower purchase volume of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** as compared to 2018. Purchase volumes from MISO are expected to be lower in 2019 due to greater renewable generation in addition to greater purchase volumes of natural gas generation. In addition, MISO prices for 2019 are projected to decrease by 13.4 percent as compared to prices for 2018 in response to lower forward natural gas prices, further contributing to the decrease in costs forecast for MISO purchases.

C. Other Considerations for the 2019 Forecast

Certain factors may serve to affect a portion of forecast 2019 costs going forward. For example, the Minnesota jurisdictional share of NSP System wholesale sales margins will continue be credited to customers through the FCA pursuant to the Stipulation and Settlement Agreement on Asset Based Margins (Margins Settlement) in the 2005 rate case.[3] Depending on market conditions, margins from these sales will serve to reduce fuel costs as these margins are credited back to customers through the FCA. However, Asset Based sales are subject to many uncertainties, including higher than normal loads, unforeseen generating plant outages, and market price volatility, which make them prone to change.

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[3] Docket No. E002/GR-05-1428.

In addition, bill credits to Solar*Rewards Community customers will be included in the FCA as a cost to non-solar garden customers. This is increasing forecast costs for 2019 and is highly dependent on the growth of the program throughout 2018 and 2019.

Finally, there is a significant amount of uncertainty in the many variables impacting fuel and purchased energy costs that could result in materially different costs than are reflected in this filing. For example, market gas and electric prices could rise substantially because of forces or events in the broader markets; the NSP System could experience higher than normal loads resulting in increased dependence on purchases from the MISO; planned and unplanned outages could increase at low cost base load plants, resulting in higher costs for replacement energy; or some combination of all of these could materialize resulting in costs that come in higher than projected in this compliance report. Alternatively, reduced commodity prices or loads resulting from broader market events (e.g., reduced economic activity) or cooler than normal weather could result in lower costs than projected in this compliance report.

QUARTERLY FORECAST OF 12 MONTHLY FCC AND DEVIATION ANALYSIS

For this AAA reporting period, the Company has prepared and distributed four proprietary quarterly forecasts dated October 9, 2017, January 8, 2018, April 4, 2018, and July 5, 2018 to interested parties who have signed a protective agreement with the Company. These quarterly forecasts are included as Part J, Section 4 Schedule 1. Currently there are 17 customer representatives who have signed protective agreements. The Company has been providing the forecast versus actual information, and when necessary, explanation of deviation in the monthly FCC filing, pursuant to the requirements in the FCA Forecast Settlement approved by the Commission. A summary of the deviation analysis for the period July 2017 to June 2018 is included in Part J, Section 4 Schedule 2.

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Quarterly Forecast of Fuel & Purchased Energy Costs
(October 1st, 2017)

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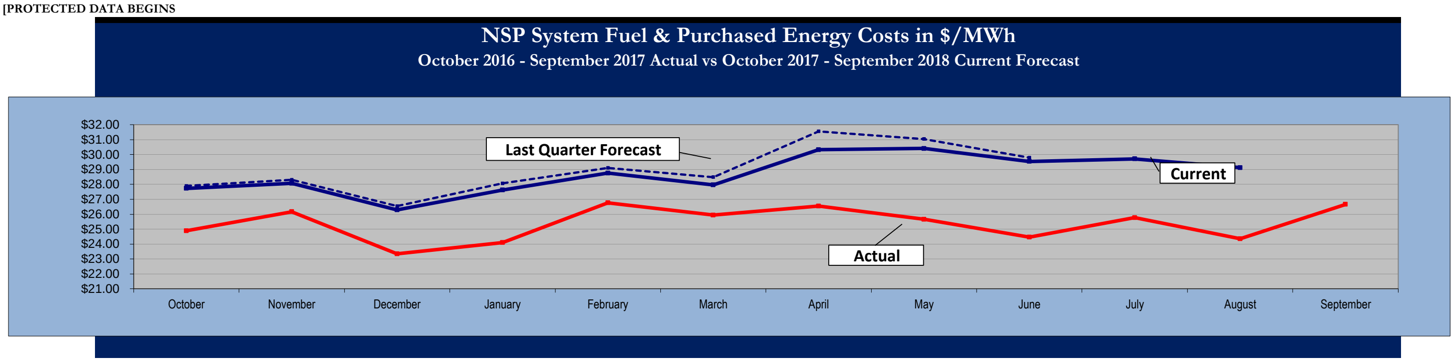

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		Quarterly Forecast			Prior Year				Deviation
		Current	Last Quarter	Change		Actual	Forecast	Actual vs Forecast	Year ago Actual vs Current Forecast
October	2017	$27.73	$27.90	-0.6%	2016	$24.89	$25.52	-2.5%	-10.2%
November	2017	$28.07	$28.30	-0.8%	2016	$26.17	$26.81	-2.4%	-6.8%
December	2017	$26.29	$26.54	-1.0%	2016	$23.35	$25.58	-8.7%	-11.2%
January	2018	$27.62	$28.07	-1.6%	2017	$24.10	$26.61	-9.4%	-12.7%
February	2018	$28.75	$29.10	-1.2%	2017	$26.76	$26.92	-0.6%	-6.9%
March	2017	$27.97	$28.49	-1.8%	2016	$25.94	$28.49	-8.9%	-7.3%
April	2018	$30.32	$31.56	-3.9%	2017	$26.54	$29.38	-9.7%	-12.5%
May	2018	$30.40	$31.04	-2.1%	2017	$25.66	$30.04	-14.6%	-15.6%
June	2018	$29.54	$29.79	-0.8%	2017	$24.46	$27.40	-10.7%	-17.2%
July	2018	$29.71			2017	$25.77	$28.28	-8.9%	-13.3%
August	2018	$29.12			2017	$24.35	$27.94	-12.8%	-16.4%
		[PROTECTED DATA BEGINS							[PROTECTED DATA BEGINS
September	2018				2017 *	$26.66	$27.28	-2.3%	
		PROTECED DATA ENDS]							PROTECTED DATA ENDS]
Average (Unweighted)		$28.68				$25.39	$27.52	-7.7%	-11.5%

* From September 2017 FCC Forecast

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Factors impacting costs in the forecast period:
- Forward market natural gas commodity prices have increased since the July 2017 quarterly filing from $2.97/MMBTU to $3.07/MMBTU which is a 3.5% increase.
- Forward market electric on-peak prices have increased since the July 2017 quarterly filing. Average On-peak prices for the period have increased by an average of 1.9% from $27.04 to $27.55/MWh.
  Average Off-peak prices increased 4.9% for the period from $17.14/MWh to $17.97/MWh.
- The cost has declined over the forecast period mainly due to changes in scheduled maintenance, forecast load and solar generation.
- The forecast assumes greater generation from solar resources including the Solar*Rewards Community program and North Star (100 MW) , Marshall (62 MW) and Aurora (100 MW) solar purchase power agreements . These purchases are higher cost than other resources and drive fuel costs up in the forecast relative to the last twelve months of actual costs.
- This forecast does not include the biomass buyouts that have been filed. If the buyouts are approved, costs for the forecast period may be lower depending on when the buyouts occur and the biomass PPAs terminate.

Other factors potentially contributing to costs in the forecast period:
- The Minnesota jurisdictional share of NSP System wholesale asset based sales margins are credited to customers through the FCA.
- Asset Based sales are subject to many uncertainties including higher than normal loads, unforeseen generating plant outages, and market price volatility, making them prone to change.

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Disclaimer
NSP's electric rates are linked to the current market prices for fuel (coal, natural gas, oil, nuclear fuel) and the cost of energy from the MISO market. Actual fuel cost charges could differ significantly from forecasted data.

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Quarterly Forecast of Fuel & Purchased Energy Costs
(January 1st, 2018)

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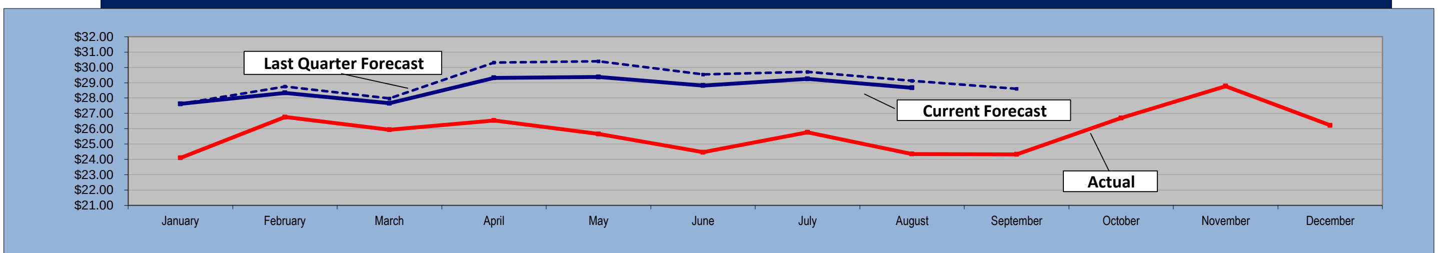
NSP System Fuel & Purchased Energy Costs in $/MWh

January 2017 - December 2017 Actual vs January 2018 - December 2018 Current Forecast



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		Quarterly Forecast				Prior Year			Deviation
		Current	Last Quarter	Change		Actual	January 2017 Forecast	Actual vs Forecast	Year ago Actual vs Current Forecast
January	2018	$27.62	$27.62	0.0%	2017	$24.10	$26.48	-9.0%	-12.7%
February	2018	$28.34	$28.75	-1.4%	2017	$26.76	$26.76	0.0%	-5.6%
March	2018	$27.66	$27.97	-1.1%	2017	$25.94	$28.45	-8.8%	-6.2%
April	2018	$29.32	$30.32	-3.3%	2017	$26.54	$31.05	-14.5%	-9.5%
May	2018	$29.37	$30.40	-3.4%	2017	$25.66	$30.62	-16.2%	-12.6%
June	2018	$28.82	$29.54	-2.4%	2017	$24.46	$27.95	-12.5%	-15.1%
July	2018	$29.25	$29.71	-1.5%	2017	$25.77	$28.85	-10.7%	-11.9%
August	2018	$28.67	$29.12	-1.5%	2017	$24.35	$27.87	-12.6%	-15.1%
		[PROTECTED DATA BEGINS		[PROTECTED DATA BEGINS					[PROTECTED DATA BEGINS
September	2018		$28.60		2017	$24.33	$27.11	-10.2%	
October	2018				2017	$26.70	$26.81	-0.4%	
November	2018				2017	$28.78	$27.42	4.9%	
December	2018				2017*	$26.22	$25.94	1.1%	
		PROTECTED DATA ENDS]		PROTECTED DATA ENDS]					PROTECTED DATA ENDS]
Average (Unweighted)		$28.46				$25.80	$27.94	-7.7%	-9.3%

* From December 2017 FCC Forecast

Forecast Assumption Highlights

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The forecasted fuel costs have declined over the 12-month forecast period, mainly due to lower forward natural gas prices and lower forecasted solar generation from the Solar*Rewards Community program. The forward markets for natural gas commodity pricing and electric prices have decreased since the October 2017 quarterly forecast, as shown in the table below:

	Oct 2017 Forecast	Jan 2018 Forecast	Increase or (Decrease)
Natural Gas Commodity Prices ($/MMBTU)	$2.93	$2.42	-17.40%
Electric On-Peak Prices ($/MWh)	$27.50	$24.60	-10.50%
Electric Off-Peak Prices ($/MWh)	$17.61	$16.31	-7.40%

Forecasted fuel costs for 2018 as compared to actual costs for 2017 on average are projected to be higher. This is driven mainly by greater forecast solar generation from the Solar*Rewards Community program for 2018.

This forecast does not include all of the biomass PPA terminations that have been filed as the Company has not received final, non-appealable orders from all jurisdictions; the Company has received verbal approval from the Minnesota Public Utilities Commission. If all the PPA termination plans are approved, costs for the forecast period may be lower depending on the timing of termination.

The Minnesota jurisdictional share of NSP System wholesale asset based sales margins are credited to customers through the FCA. Asset Based sales are subject to many uncertainties including higher than normal loads, unforeseen generating plant outages, and market price volatility, making them prone to change.

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PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Quarterly Forecast of Fuel & Purchased Energy Costs
(April 1st, 2018)

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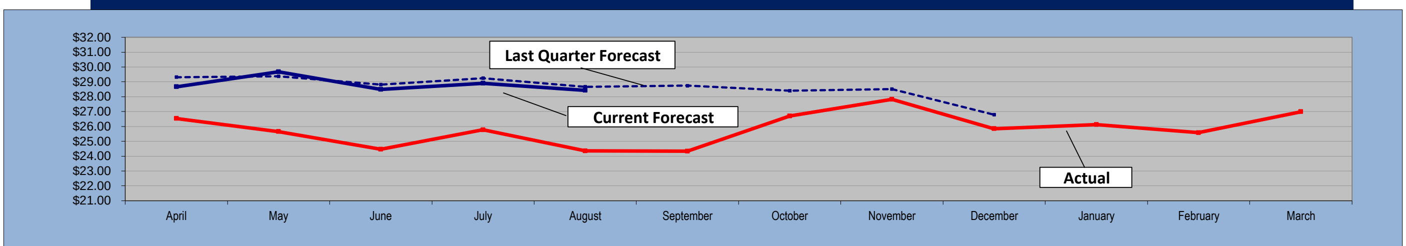
NSP System Fuel & Purchased Energy Costs in $/MWh

April 2017 - March 2018 Actual vs April 2018 - March 2019 Current Forecast



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		Quarterly Forecast			Prior Year				Deviation
		Current	Last Quarter	Change		Actual	January 2017 Forecast	Actual vs Forecast	Year ago Actual vs Current Forecast
April	2018	$28.67	$29.32	-2.2%	2017	$26.54	$28.04	-5.3%	-7.4%
May	2018	$29.68	$29.37	1.1%	2017	$25.66	$28.56	-10.1%	-13.5%
June	2018	$28.49	$28.82	-1.1%	2017	$24.46	$27.64	-11.5%	-14.1%
July	2018	$28.91	$29.25	-1.2%	2017	$25.77	$28.78	-10.4%	-10.9%
August	2018	$28.43	$28.67	-0.8%	2017	$24.35	$28.41	-14.3%	-14.4%
		[PROTECTED DATA BEGINS		[PROTECTED DATA BEGINS					[PROTECTED DATA BEGINS
September	2018		$28.74		2017	$24.33	$27.62	-11.9%	
October	2018		$28.40		2017	$26.70	$27.62	-3.3%	
November	2018		$28.51		2017	$27.82	$27.64	0.7%	
December	2018		$26.79		2017	$25.85	$26.47	-2.3%	
January	2019				2018	$26.12	$27.78	-6.0%	
February	2019				2018	$25.58	$28.65	-10.7%	
March	2019				2018*	$26.99	$28.63	-5.7%	
		PROTECTED DATA ENDS]		[ROTECTED DATA ENDS]					PROTECTED DATA ENDS]
Average (Unweighted)		$28.35				$25.85	$27.99	-7.6%	-8.8%

* From March 2018 FCC Forecast

Forecast Assumption Highlights
[PROTECTED DATA BEGINS

The forecasted fuel costs have not changed significantly since the last quarterly report due to minimal changes in commodity prices as shown in the table below. The forecast includes an updated customer load forecast which has, in general, declined from the prior forecast.

	Jan 2018 Forecast	Mar 2018 Forecast	Increase or (Decrease)
Natural Gas Commodity Prices ($/MMBTU)	$2.38	$2.36	-0.8%
Electric On-Peak Prices ($/MWh)	$24.85	$24.31	-2.2%
Electric Off-Peak Prices ($/MWh)	$16.22	$16.22	0.0%

Forecasted fuel costs for 2018 as compared to actual costs for 2017 on average are projected to be higher. This is driven mainly by greater forecast solar generation from the Solar*Rewards Community program for 2018.

This forecast does not include all of the biomass PPA terminations that have been filed as the dates of termination and closure remain uncertain at this time.

The Minnesota jurisdictional share of NSP System wholesale asset based sales margins are credited to customers through the FCA. Asset Based sales are subject to many uncertainties including higher than normal loads, unforeseen generating plant outages, and market price volatility, making them prone to change.

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Quarterly Forecast of Fuel & Purchased Energy Costs
(July 1st, 2018)

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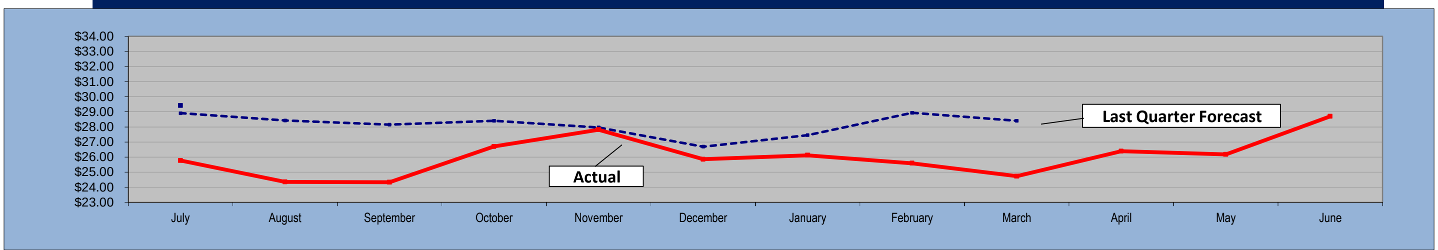
NSP System Fuel & Purchased Energy Costs in $/MWh

July 2017 - June 2018 Actual vs July 2018 - June 2019 Current Forecast



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		Quarterly Forecast				Prior Year			Deviation
		Current	Last Quarter	Change		Actual	Forecast	Actual vs Forecast	Year ago Actual vs Current Forecast
July	2018	$29.42	$28.91	1.8%	2017	$25.77	$28.71	-10.2%	-12.4%
August	2018	$28.71	$28.43	1.0%	2017	$24.35	$26.77	-9.0%	-15.2%
		[PROTECTED DATA BEGINS		[PROTECTED DATA BEGINS					[PROTECTED DATA BEGINS
September	2018		$28.15		2017	$24.33	$26.66	-8.7%	
October	2018		$28.41		2017	$26.70	$27.73	-3.7%	
November	2018		$27.97		2017	$27.82	$27.86	-0.1%	
December	2018		$26.69		2017	$25.85	$26.22	-1.4%	
January	2019		$27.46		2018	$26.12	$27.62	-5.4%	
February	2019		$28.94		2018	$25.59	$28.74	-11.0%	
March	2019		$28.41		2018	$24.73	$26.99	-8.4%	
April	2019				2018	$26.39	$28.67	-8.0%	
May	2019				2018	$26.18	$29.69	-11.8%	
June	2019				2018 *	$28.70	$28.70	0.0%	
		PROTECTED DATA ENDS]		PROTECTED DATA ENDS]					PROTECTED DATA ENDS]
Average (Unweighted)		$29.56				$26.04	$27.86	-6.5%	-11.9%

* From June 2018 FCC Forecast

Forecast Assumption Highlights

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For the forecasted period of July 2018 through June 2019, the monthly average fuel costs have increased 2.1% since the last quarterly report.
This is partially due to an increase in forecasted commodity prices as shown in the table below.
The higher costs are also driven by an increase in the forecast of solar generation from the Solar*Rewards Community program.

	Mar 2018 Forecast	Jun 2018 Forecast	Increase or (Decrease)
Natural Gas Commodity Prices ($/MMBTU)	$2.63	$2.88	9.5%
Electric On-Peak Prices ($/MWh)	$25.30	$27.34	8.1%
Electric Off-Peak Prices ($/MWh)	$17.27	$18.23	5.6%

Forecasted fuel costs for 2018 as compared to actual costs for 2017 on average are projected to be higher. This is driven mainly by greater forecast solar generation from the Solar*Rewards Community program for 2018.

This forecast does not include the impact of the biomass PPA terminations because the transactions closed after the forecast was prepared. Variances will be described once actuals are known.
The next quarterly forecast will incorporate the impact of the terminations.

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Disclaimer
NSP's electric rates are linked to the current market prices for fuel (coal, natural gas, oil, nuclear fuel) and the cost of energy from the MISO market. Actual fuel cost charges could differ significantly from forecasted data.

Northern States Power Company
Electric Operations - State of Minnesota
Deviation Analysis
Actual Costs and Projected Costs (July 2017 - June 2018)

Docket No. E999/AA-18-373
Part J, Section 4
Schedule 2

Monthly Forecast & Quarterly Forecast Deviation

		Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18
1	Monthly Forecast - Current Month	2.871¢	2.677¢	2.666¢	2.773¢	2.786¢	2.622¢	2.762¢	2.874¢	2.699¢	2.867¢	2.969¢	2.870¢
		2017 3rd Quarter (7/1/2017)			2017 4th Quarter (10/1/2017)			2018 1st Quarter (1/1/2018)			2018 2nd Quarter (4/1/2018)		
2	Quarterly Forecast - Most Recent Quarter	2.871¢	2.781¢	2.771¢	2.773¢	2.807¢	2.629¢	2.762¢	2.834¢	2.766¢	2.867¢	2.968¢	2.849¢
3	Deviation	0.000	-0.104	-0.105	0.000	-0.021	-0.007	0.000	0.040	-0.067	0.000	0.001	0.021
4	In Percent	0.0%	-3.7%	-3.8%	0.0%	-0.7%	-0.3%	0.0%	1.4%	-2.4%	0.0%	0.0%	0.7%
		2017 2nd Quarter (4/1/2017)			2017 3rd Quarter (7/1/2017)			2017 4th Quarter (10/1/2017)			2018 1st Quarter (1/1/2018)		
5	Quarterly Forecast - Previous Quarter	2.878¢	2.841¢	2.762¢	2.790¢	2.830¢	2.654¢	2.762¢	2.875¢	2.797¢	2.932¢	2.937¢	2.882¢
6	Deviation	-0.007	-0.164	-0.096	-0.017	-0.044	-0.032	0.000	-0.001	-0.098	-0.065	0.032	-0.012
7	In Percent	-0.2%	-5.8%	-3.5%	-0.6%	-1.6%	-1.2%	0.0%	0.0%	-3.5%	-2.2%	1.1%	-0.4%

Actual and Forecasted Cost Deviation

		Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18
8	Actual System Costs	2.577¢	2.435¢	2.433¢	2.670¢	2.782¢	2.585¢	2.612¢	2.559¢	2.473¢	2.639¢	2.618¢	2.389¢
9	Forecasted System Costs (From Filing 2 Months Ago)	2.871¢	2.677¢	2.666¢	2.773¢	2.786¢	2.622¢	2.762¢	2.874¢	2.699¢	2.867¢	2.969¢	2.870¢
10	Deviation	-0.294¢	-0.242¢	-0.233¢	-0.103¢	-0.004¢	-0.037¢	-0.150¢	-0.315¢	-0.226¢	-0.228¢	-0.351¢	-0.481¢
11	In Percent	-10.2%	-9.0%	-8.7%	-3.7%	-0.1%	-1.4%	-5.4%	-11.0%	-8.4%	-8.0%	-11.8%	-16.8%

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	July 2017 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 7,941,932.96	$ 8,636,781.59	$ 16,578,714.55
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 4,229,471.41	$ (328,546.48)	$ 3,900,924.93
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,595,030.67	$ (201,582.68)	$ 2,393,447.99
1	Day-Ahead Asset Energy Amount	$ 14,766,435.04	$ 8,106,652.44	$ 22,873,087.48
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (8,214.12)	$ -	$ (8,214.12)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (5,175.18)	$ -	$ (5,175.18)
4	Day-Ahead Market Administration Amount	$ 593,104.55	$ (18,067.56)	$ 575,036.99
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (12,441,178.06)	$ -	$ (12,441,178.06)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 929,220.89	$ (72,182.13)	$ 857,038.76
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,506,674.47	$ (117,038.88)	$ 1,389,635.59
5	Day-Ahead Non-Asset Energy Amount	$ (10,005,282.70)	$ (189,221.01)	$ (10,194,503.71)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 8,214.12	$ -	$ 8,214.12
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 5,175.18	$ -	$ 5,175.18
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 50,123.88	$ (3,893.64)	$ 46,230.24
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (12,345.06)	$ 10,157.50	$ (2,187.56)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (2,265,232.80)	$ 1,792,655.66	$ (472,577.14)
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 261,612.37	$ 161.63	$ 261,774.00
13 c	Real-Time Asset Energy Amount - Loss Component	$ 140,916.63	$ 117.96	$ 141,034.59
13	Real-Time Asset Energy Amount	$ (1,862,703.80)	$ 1,792,935.25	$ (69,768.55)
14	Real-Time Distribution of Losses Amount	$ (1,382,114.23)	$ -	$ (1,382,114.23)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
19	Real-Time Market Administration Amount	$ 45,595.04	$ (5,451.91)	$ 40,143.13
20	Real-Time Miscellaneous Amount	$ 71,410.10	$ 13,920.00	$ 85,330.10
21	Real-time Net inadvertent Distribution	$ 61,777.20	$ -	$ 61,777.20
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 16,493.74	$ -	$ 16,493.74
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (2,080.65)	$ 34,623.74	$ 32,543.09
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (1,518.54)	$ 9,220.59	$ 7,702.05
22	Real-Time Non-Asset Energy Amount	$ 12,894.55	$ 43,844.33	$ 56,738.88
23	Real-Time Revenue Neutrality Uplift Amount	$ 585,736.40	$ (45,500.16)	$ 540,236.24
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 294,120.50	$ (22,847.36)	$ 271,273.14
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (134,973.16)	$ 97,898.42	$ (37,074.74)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (7,409,511.47)	$ -	$ (7,409,511.47)
29	Financial Transmission Rights Market Administration Amount	$ 32,031.60	$ -	$ 32,031.60
30	Financial Transmission Rights Monthly Allocation Amount	$ (612,605.93)	$ -	$ (612,605.93)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 92,400.93	$ (3,011.97)	$ 89,388.96
34	Real -Time Schedule 24 Allocation Amount	$ (92,388.80)	$ 66,878.49	$ (25,510.31)
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 40,349.07	$ -	$ 40,349.07
37	Financial Transmission Guarantee Uplift Amount	$ (48,817.25)	$ -	$ (48,817.25)
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,620,102.73	$ -	$ 3,620,102.73
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,628,762.14)	$ 9,159.73	$ (3,619,602.41)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (127,119.86)	$ -	$ (127,119.86)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 92,725.55	$ -	$ 92,725.55
43	Real Time Price Volatility Make Whole Payment	$ (194,026.12)	$ 32,231.20	$ (161,794.92)
	TOTAL MISO CHARGES	**$ (5,151,843.38)**	**$ 9,885,683.75**	**$ 4,733,840.37**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 647,211.72**
	SCHEDULE 24 (FOR RETAIL)			**$ 63,878.65**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 4,022,750.00**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	August 2017 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 6,396,176.61	$ 7,345,033.68	$ 13,741,210.29
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,732,043.58	$ (237,861.77)	$ 2,494,181.81
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 1,963,629.32	$ (170,960.79)	$ 1,792,668.53
1	Day-Ahead Asset Energy Amount	$ 11,091,849.51	$ 6,936,211.12	$ 18,028,060.63
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (8,141.19)	$ -	$ (8,141.19)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (4,565.85)	$ -	$ (4,565.85)
4	Day-Ahead Market Administration Amount	$ 541,944.41	$ (17,366.57)	$ 524,577.84
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (11,098,231.58)	$ -	$ (11,098,231.58)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 997,499.08	$ (86,845.94)	$ 910,653.14
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,400,146.09	$ (121,901.87)	$ 1,278,244.22
5	Day-Ahead Non-Asset Energy Amount	$ (8,700,586.41)	$ (208,747.81)	$ (8,909,334.22)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 8,141.19	$ -	$ 8,141.19
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 4,565.85	$ -	$ 4,565.85
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 57,862.02	$ (5,037.68)	$ 52,824.34
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (32,854.54)	$ 12,622.58	$ (20,231.96)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,832,607.66)	$ 2,002,630.75	$ 170,023.09
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 100,999.37	$ 25.53	$ 101,024.90
13 c	Real-Time Asset Energy Amount - Loss Component	$ 81,631.30	$ 53.50	$ 81,684.80
13	Real-Time Asset Energy Amount	$ (1,649,976.99)	$ 2,002,709.78	$ 352,732.79
14	Real-Time Distribution of Losses Amount	$ (915,463.36)	$ -	$ (915,463.36)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
19	Real-Time Market Administration Amount	$ 39,130.12	$ (6,678.05)	$ 32,452.07
20	Real-Time Miscellaneous Amount	$ (52,943.90)	$ 15,840.00	$ (37,103.90)
21	Real-time Net inadvertent Distribution	$ 133,299.65	$ -	$ 133,299.65
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 18,605.36	$ -	$ 18,605.36
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (293.19)	$ 21,338.34	$ 21,045.15
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (614.55)	$ 6,951.91	$ 6,337.36
22	Real-Time Non-Asset Energy Amount	$ 17,697.62	$ 28,290.25	$ 45,987.87
23	Real-Time Revenue Neutrality Uplift Amount	$ 223,464.73	$ (19,455.66)	$ 204,009.07
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 146,960.97	$ (12,794.96)	$ 134,166.01
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (69,205.57)	$ 17,205.14	$ (52,000.43)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (5,889,555.92)	$ -	$ (5,889,555.92)
29	Financial Transmission Rights Market Administration Amount	$ 26,142.80	$ -	$ 26,142.80
30	Financial Transmission Rights Monthly Allocation Amount	$ (447,182.46)	$ -	$ (447,182.46)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 88,026.11	$ (2,742.07)	$ 85,284.04
34	Real -Time Schedule 24 Allocation Amount	$ (77,178.30)	$ 82,812.17	$ 5,633.87
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (1,120.92)	$ -	$ (1,120.92)
37	Financial Transmission Guarantee Uplift Amount	$ (391.84)	$ -	$ (391.84)
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,620,102.73	$ -	$ 3,620,102.73
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,628,762.14)	$ 17,868.65	$ (3,610,893.49)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (131,423.44)	$ -	$ (131,423.44)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 92,725.55	$ -	$ 92,725.55
43	Real Time Price Volatility Make Whole Payment	$ (112,767.09)	$ 16,884.55	$ (95,882.54)
	TOTAL MISO CHARGES	**$ (5,630,206.66)**	**$ 8,857,621.43**	**$ 3,227,414.77**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 583,172.71**
	SCHEDULE 24 (FOR RETAIL)			**$ 90,917.91**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 2,553,324.15**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	September 2017 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 9,003,652.35	$ 6,323,343.49	$ 15,326,995.84
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,543,137.57	$ (265,701.26)	$ 2,277,436.31
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,232,521.06	$ (233,248.75)	$ 1,999,272.31
1	Day-Ahead Asset Energy Amount	$ 13,779,310.98	$ 5,824,393.48	$ 19,603,704.46
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (8,474.41)	$ -	$ (8,474.41)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (7,181.35)	$ -	$ (7,181.35)
4	Day-Ahead Market Administration Amount	$ 551,951.71	$ (19,585.29)	$ 532,366.42
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (12,033,585.01)	$ -	$ (12,033,585.01)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 2,681,605.83	$ (280,168.11)	$ 2,401,437.72
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,825,144.68	$ (190,686.99)	$ 1,634,457.69
5	Day-Ahead Non-Asset Energy Amount	$ (7,526,834.50)	$ (470,855.09)	$ (7,997,689.59)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 8,474.41	$ -	$ 8,474.41
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 7,181.35	$ -	$ 7,181.35
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 115,978.79	$ (12,117.20)	$ 103,861.59
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (96,390.36)	$ 21,874.04	$ (74,516.32)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (2,868,505.92)	$ 2,946,846.14	$ 78,340.22
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 452,484.84	$ 2,758.90	$ 455,243.74
13 c	Real-Time Asset Energy Amount - Loss Component	$ 122,585.12	$ 1,020.99	$ 123,606.11
13	Real-Time Asset Energy Amount	$ (2,293,435.96)	$ 2,950,626.03	$ 657,190.07
14	Real-Time Distribution of Losses Amount	$ (1,302,537.63)	$ -	$ (1,302,537.63)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
19	Real-Time Market Administration Amount	$ 44,233.12	$ (9,228.05)	$ 35,005.07
20	Real-Time Miscellaneous Amount	$ 47,810.47	$ 14,400.00	$ 62,210.47
21	Real-time Net inadvertent Distribution	$ (61,649.28)	$ -	$ (61,649.28)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 72,020.99	$ -	$ 72,020.99
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (26,406.57)	$ 74,228.42	$ 47,821.85
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (9,772.33)	$ 17,813.53	$ 8,041.20
22	Real-Time Non-Asset Energy Amount	$ 35,842.09	$ 92,041.95	$ 127,884.04
23	Real-Time Revenue Neutrality Uplift Amount	$ 801,450.71	$ (83,733.76)	$ 717,716.95
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 365,711.53	$ (38,208.71)	$ 327,502.82
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (386,861.37)	$ 260,874.83	$ (125,986.54)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (8,383,531.61)	$ -	$ (8,383,531.61)
29	Financial Transmission Rights Market Administration Amount	$ 24,065.60	$ -	$ 24,065.60
30	Financial Transmission Rights Monthly Allocation Amount	$ (306,232.96)	$ -	$ (306,232.96)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 83,296.60	$ (3,015.72)	$ 80,280.88
34	Real -Time Schedule 24 Allocation Amount	$ (71,304.25)	$ 81,792.20	$ 10,487.95
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (56,284.32)	$ -	$ (56,284.32)
37	Financial Transmission Guarantee Uplift Amount	$ 62,630.10	$ -	$ 62,630.10
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,419,039.70	$ -	$ 3,419,039.70
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,472,296.93)	$ 17,561.86	$ (3,454,735.07)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (18,212.29)	$ -	$ (18,212.29)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 28,487.85	$ -	$ 28,487.85
43	Real Time Price Volatility Make Whole Payment	$ (307,866.23)	$ 112,066.67	$ (195,799.56)
	TOTAL MISO CHARGES	**$ (4,923,628.44)**	**$ 8,738,887.24**	**$ 3,815,258.80**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 591,437.09**
	SCHEDULE 24 (FOR RETAIL)			**$ 90,768.83**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 3,133,052.88**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	October 2017 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (610,417.01)	$ 10,575,584.27	$ 9,965,167.26
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,747,802.77	$ (454,654.86)	$ 2,293,147.91
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,114,833.22	$ (349,922.93)	$ 1,764,910.29
1	Day-Ahead Asset Energy Amount	$ 4,252,218.98	$ 9,771,006.48	$ 14,023,225.46
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (3,574.47)	$ -	$ (3,574.47)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (3,801.39)	$ -	$ (3,801.39)
4	Day-Ahead Market Administration Amount	$ 775,340.61	$ (41,571.26)	$ 733,769.35
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (8,797,500.02)	$ -	$ (8,797,500.02)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,799,301.19	$ (297,714.61)	$ 1,501,586.58
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,187,725.69	$ (196,522.57)	$ 991,203.12
5	Day-Ahead Non-Asset Energy Amount	$ (5,810,473.14)	$ (494,237.18)	$ (6,304,710.32)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 3,574.47	$ -	$ 3,574.47
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 3,801.39	$ -	$ 3,801.39
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 79,028.88	$ (13,076.22)	$ 65,952.66
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (53,286.27)	$ 18,086.26	$ (35,200.01)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (633,180.22)	$ 3,051,085.81	$ 2,417,905.59
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 75,587.16	$ 4,425.21	$ 80,012.37
13 c	Real-Time Asset Energy Amount - Loss Component	$ 33,044.01	$ 83.68	$ 33,127.69
13	Real-Time Asset Energy Amount	$ (524,549.05)	$ 3,055,594.70	$ 2,531,045.65
14	Real-Time Distribution of Losses Amount	$ (792,348.09)	$ -	$ (792,348.09)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
19	Real-Time Market Administration Amount	$ 67,059.85	$ (11,272.89)	$ 55,786.96
20	Real-Time Miscellaneous Amount	$ 102,473.41	$ 13,479.11	$ 115,952.52
21	Real-time Net inadvertent Distribution	$ (64,967.37)	$ -	$ (64,967.37)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 12,658.74	$ -	$ 12,658.74
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (26,744.69)	$ 54,322.81	$ 27,578.12
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (505.76)	$ 10,037.39	$ 9,531.63
22	Real-Time Non-Asset Energy Amount	$ (14,591.71)	$ 64,360.20	$ 49,768.49
23	Real-Time Revenue Neutrality Uplift Amount	$ 1,301,794.02	$ (215,396.46)	$ 1,086,397.56
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 242,005.39	$ (40,042.51)	$ 201,962.88
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (98,274.71)	$ 79,725.88	$ (18,548.83)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (4,426,239.40)	$ -	$ (4,426,239.40)
29	Financial Transmission Rights Market Administration Amount	$ 27,509.36	$ -	$ 27,509.36
30	Financial Transmission Rights Monthly Allocation Amount	$ (208,971.01)	$ -	$ (208,971.01)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 90,990.27	$ (7,050.81)	$ 83,939.46
34	Real -Time Schedule 24 Allocation Amount	$ (80,821.31)	$ 75,016.20	$ (5,805.11)
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (254,090.17)	$ -	$ (254,090.17)
37	Financial Transmission Guarantee Uplift Amount	$ 258,310.57	$ -	$ 258,310.57
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,419,039.70	$ -	$ 3,419,039.70
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,472,296.93)	$ 6,412.78	$ (3,465,884.15)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (18,212.29)	$ -	$ (18,212.29)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 28,487.85	$ -	$ 28,487.85
43	Real Time Price Volatility Make Whole Payment	$ (477,828.40)	$ 54,335.40	$ (423,493.00)
	TOTAL MISO CHARGES	**$ (5,652,690.96)**	**$ 12,315,369.68**	**$ 6,662,678.72**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 817,065.67**
	SCHEDULE 24 (FOR RETAIL)			**$ 78,134.35**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 5,767,478.70**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	November 2017 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (5,526,720.76)	$ 11,212,684.01	$ 5,685,963.25
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,661,246.85	$ (253,872.86)	$ 1,407,373.99
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,013,940.39	$ (460,592.39)	$ 2,553,348.00
1	Day-Ahead Asset Energy Amount	$ (851,533.52)	$ 10,498,218.76	$ 9,646,685.24
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 7,278.86	$ -	$ 7,278.86
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (705.28)	$ -	$ (705.28)
4	Day-Ahead Market Administration Amount	$ 568,782.25	$ (55,194.12)	$ 513,588.13
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (3,513,700.28)	$ -	$ (3,513,700.28)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 131,540.60	$ (20,102.12)	$ 111,438.48
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 292,799.88	$ (44,745.87)	$ 248,054.01
5	Day-Ahead Non-Asset Energy Amount	$ (3,089,359.80)	$ (64,848.00)	$ (3,154,207.80)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (7,278.86)	$ -	$ (7,278.86)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 705.28	$ -	$ 705.28
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 128,386.09	$ (19,620.05)	$ 108,766.04
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (142,633.89)	$ 48,179.67	$ (94,454.22)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (549,221.84)	$ 1,647,558.42	$ 1,098,336.58
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 70,778.42	$ (535.43)	$ 70,242.99
13 c	Real-Time Asset Energy Amount - Loss Component	$ 66,809.35	$ 0.77	$ 66,810.12
13	Real-Time Asset Energy Amount	$ (411,634.07)	$ 1,647,023.75	$ 1,235,389.68
14	Real-Time Distribution of Losses Amount	$ (783,371.78)	$ -	$ (783,371.78)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
19	Real-Time Market Administration Amount	$ 43,889.40	$ (11,006.39)	$ 32,883.01
20	Real-Time Miscellaneous Amount	$ (73,492.42)	$ 14,788.68	$ (58,703.74)
21	Real-time Net inadvertent Distribution	$ 72,996.01	$ -	$ 72,996.01
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 28,235.43	$ -	$ 28,235.43
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 3,503.68	$ 10,463.52	$ 13,967.20
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (5.03)	$ 10,084.35	$ 10,079.32
22	Real-Time Non-Asset Energy Amount	$ 31,734.08	$ 20,547.87	$ 52,281.95
23	Real-Time Revenue Neutrality Uplift Amount	$ 179,786.39	$ (27,475.08)	$ 152,311.31
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 126,340.02	$ (19,307.37)	$ 107,032.65
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (120,607.48)	$ 23,007.63	$ (97,599.85)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,186,296.03)	$ -	$ (1,186,296.03)
29	Financial Transmission Rights Market Administration Amount	$ 20,575.92	$ -	$ 20,575.92
30	Financial Transmission Rights Monthly Allocation Amount	$ (400,255.24)	$ -	$ (400,255.24)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 96,639.64	$ (6,590.14)	$ 90,049.50
34	Real -Time Schedule 24 Allocation Amount	$ (83,858.78)	$ 96,306.85	$ 12,448.07
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 319,991.92	$ -	$ 319,991.92
37	Financial Transmission Guarantee Uplift Amount	$ (349,023.92)	$ -	$ (349,023.92)
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,419,039.70	$ -	$ 3,419,039.70
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,472,296.93)	$ 5,437.03	$ (3,466,859.90)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (18,212.29)	$ -	$ (18,212.29)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 28,487.85	$ -	$ 28,487.85
43	Real Time Price Volatility Make Whole Payment	$ (47,329.87)	$ 13,956.34	$ (33,373.53)
	TOTAL MISO CHARGES	**$ (5,993,256.75)**	**$ 12,163,425.45**	**$ 6,170,168.70**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 567,047.06**
	SCHEDULE 24 (FOR RETAIL)			**$ 102,497.57**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 5,500,624.07**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	December 2017 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (11,937,882.06)	$ 15,975,375.75	$ 4,037,493.69
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,329,166.19	$ (228,050.87)	$ 1,101,115.32
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,376,194.28	$ (579,268.46)	$ 2,796,925.82
1	Day-Ahead Asset Energy Amount	$ (7,232,521.59)	$ 15,168,056.42	$ 7,935,534.83
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 5,356.06	$ -	$ 5,356.06
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 1,280.54	$ -	$ 1,280.54
4	Day-Ahead Market Administration Amount	$ 690,768.91	$ (57,120.20)	$ 633,648.71
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (3,715,572.79)	$ -	$ (3,715,572.79)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 90,717.22	$ (15,564.75)	$ 75,152.47
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 192,928.13	$ (33,101.53)	$ 159,826.60
5	Day-Ahead Non-Asset Energy Amount	$ (3,431,927.44)	$ (48,666.28)	$ (3,480,593.72)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (5,356.06)	$ -	$ (5,356.06)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (1,280.54)	$ -	$ (1,280.54)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 62,050.85	$ (10,646.34)	$ 51,404.51
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (168,861.50)	$ 11,717.95	$ (157,143.55)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 197,276.71	$ 2,047,122.14	$ 2,244,398.85
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 16,725.03	$ 0.28	$ 16,725.31
13 c	Real-Time Asset Energy Amount - Loss Component	$ 17,305.62	$ 5.38	$ 17,311.00
13	Real-Time Asset Energy Amount	$ 231,307.36	$ 2,047,127.80	$ 2,278,435.16
14	Real-Time Distribution of Losses Amount	$ (991,853.15)	$ -	$ (991,853.15)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
19	Real-Time Market Administration Amount	$ 57,091.35	$ (7,795.01)	$ 49,296.34
20	Real-Time Miscellaneous Amount	$ 72,310.23	$ 14,943.22	$ 87,253.45
21	Real-time Net inadvertent Distribution	$ 55,761.10	$ -	$ 55,761.10
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 618.34	$ -	$ 618.34
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (1.63)	$ (669.21)	$ (670.84)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (31.37)	$ (1,467.25)	$ (1,498.62)
22	Real-Time Non-Asset Energy Amount	$ 585.34	$ (2,136.46)	$ (1,551.12)
23	Real-Time Revenue Neutrality Uplift Amount	$ 1,008,080.48	$ (172,960.79)	$ 835,119.69
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ (27,868.89)	$ 4,781.59	$ (23,087.30)
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (1,081.24)	$ 775.34	$ (305.90)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (660,232.21)	$ -	$ (660,232.21)
29	Financial Transmission Rights Market Administration Amount	$ 21,107.84	$ -	$ 21,107.84
30	Financial Transmission Rights Monthly Allocation Amount	$ 141,917.90	$ -	$ 141,917.90
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 106,357.20	$ (8,810.71)	$ 97,546.49
34	Real -Time Schedule 24 Allocation Amount	$ (90,334.49)	$ 92,979.92	$ 2,645.43
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (419,228.86)	$ -	$ (419,228.86)
37	Financial Transmission Guarantee Uplift Amount	$ 419,063.21	$ -	$ 419,063.21
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,077,706.89	$ -	$ 3,077,706.89
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,090,966.42)	$ 5,660.69	$ (3,085,305.73)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (157,462.79)	$ -	$ (157,462.79)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 39,319.32	$ -	$ 39,319.32
43	Real Time Price Volatility Make Whole Payment	$ (154,244.18)	$ 16,743.67	$ (137,500.51)
	TOTAL MISO CHARGES	**$ (10,443,154.78)**	**$ 17,054,650.82**	**$ 6,611,496.04**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 704,052.89**
	SCHEDULE 24 (FOR RETAIL)			**$ 100,191.92**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 5,807,251.23**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	January 2018 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (14,015,279.47)	$ 20,699,050.09	$ 6,683,770.62
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,349,507.34	$ (234,237.16)	$ 1,115,270.18
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 4,935,912.61	$ (856,737.95)	$ 4,079,174.66
1	Day-Ahead Asset Energy Amount	$ (7,729,859.52)	$ 19,608,074.98	$ 11,878,215.46
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 20,919.82	$ -	$ 20,919.82
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 3,719.45	$ -	$ 3,719.45
4	Day-Ahead Market Administration Amount	$ 590,463.11	$ (50,319.93)	$ 540,143.18
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (5,212,659.65)	$ -	$ (5,212,659.65)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 73,151.97	$ (12,697.16)	$ 60,454.81
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 162,168.23	$ (28,147.92)	$ 134,020.31
5	Day-Ahead Non-Asset Energy Amount	$ (4,977,339.45)	$ (40,845.08)	$ (5,018,184.53)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (20,919.82)	$ -	$ (20,919.82)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (3,719.45)	$ -	$ (3,719.45)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 205,525.04	$ (35,673.46)	$ 169,851.58
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (360,075.77)	$ 16,777.81	$ (343,297.96)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 559,581.83	$ 1,656,273.29	$ 2,215,855.12
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 46,610.10	$ 3.68	$ 46,613.78
13 c	Real-Time Asset Energy Amount - Loss Component	$ 3,836.89	$ 1.36	$ 3,838.25
13	Real-Time Asset Energy Amount	$ 610,028.82	$ 1,656,278.34	$ 2,266,307.16
14	Real-Time Distribution of Losses Amount	$ (1,774,973.13)	$ -	$ (1,774,973.13)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
19	Real-Time Market Administration Amount	$ 39,261.95	$ (5,190.26)	$ 34,071.69
20	Real-Time Miscellaneous Amount	$ 262,744.35	$ 14,400.00	$ 277,144.35
21	Real-time Net inadvertent Distribution	$ 66,019.14	$ -	$ 66,019.14
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 601.46	$ -	$ 601.46
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (21.22)	$ (9,739.24)	$ (9,760.46)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (7.85)	$ 2,917.20	$ 2,909.35
22	Real-Time Non-Asset Energy Amount	$ 572.39	$ (6,822.05)	$ (6,249.66)
23	Real-Time Revenue Neutrality Uplift Amount	$ 114,566.67	$ (19,885.61)	$ 94,681.06
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 483,401.05	$ (83,905.06)	$ 399,495.99
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (638,214.90)	$ 247,677.59	$ (390,537.31)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (511,778.09)	$ -	$ (511,778.09)
29	Financial Transmission Rights Market Administration Amount	$ 17,404.08	$ -	$ 17,404.08
30	Financial Transmission Rights Monthly Allocation Amount	$ 20,641.26	$ -	$ 20,641.26
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 100,425.81	$ (8,559.65)	$ 91,866.16
34	Real -Time Schedule 24 Allocation Amount	$ (96,154.90)	$ 101,581.74	$ 5,426.84
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (61,441.36)	$ -	$ (61,441.36)
37	Financial Transmission Guarantee Uplift Amount	$ 66,631.38	$ -	$ 66,631.38
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,077,706.89	$ -	$ 3,077,706.89
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,090,966.42)	$ 40,382.56	$ (3,050,583.86)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (157,243.97)	$ -	$ (157,243.97)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 39,324.86	$ -	$ 39,324.86
43	Real Time Price Volatility Make Whole Payment	$ (368,914.39)	$ 41,198.93	$ (327,715.46)
	TOTAL MISO CHARGES	**$ (14,072,245.10)**	**$ 21,475,170.86**	**$ 7,402,925.76**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 591,618.95**
	SCHEDULE 24 (FOR RETAIL)			**$ 97,293.00**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 6,714,013.81**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	February 2018 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (5,140,151.28)	$ 8,977,223.58	$ 3,837,072.30
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 628,871.30	$ (75,881.79)	$ 552,989.51
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,766,318.85	$ (333,793.62)	$ 2,432,525.23
1	Day-Ahead Asset Energy Amount	$ (1,744,961.13)	$ 8,567,548.17	$ 6,822,587.04
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 1,815.46	$ -	$ 1,815.46
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 4,267.62	$ -	$ 4,267.62
4	Day-Ahead Market Administration Amount	$ 469,115.32	$ (25,458.44)	$ 443,656.88
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (2,938,997.15)	$ -	$ (2,938,997.15)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ (16,389.92)	$ 1,977.66	$ (14,412.26)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 91,941.98	$ (11,094.04)	$ 80,847.94
5	Day-Ahead Non-Asset Energy Amount	$ (2,863,445.09)	$ (9,116.37)	$ (2,872,561.46)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (1,815.46)	$ -	$ (1,815.46)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (4,267.62)	$ -	$ (4,267.62)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 42,953.38	$ (5,182.90)	$ 37,770.48
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (42,009.16)	$ 25,547.64	$ (16,461.52)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (908,392.51)	$ 1,723,232.26	$ 814,839.75
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 38,138.46	$ (95.58)	$ 38,042.88
13 c	Real-Time Asset Energy Amount - Loss Component	$ 6,651.33	$ (2.18)	$ 6,649.15
13	Real-Time Asset Energy Amount	$ (863,602.72)	$ 1,723,134.50	$ 859,531.78
14	Real-Time Distribution of Losses Amount	$ (1,026,169.10)	$ -	$ (1,026,169.10)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 23.00	$ -	$ 23.00
16	Real-Time Financial Bilateral Transaction Loss Amount	$ (5.34)	$ -	$ (5.34)
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (23.00)	$ -	$ (23.00)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ 5.34	$ -	$ 5.34
19	Real-Time Market Administration Amount	$ 34,394.87	$ (4,234.88)	$ 30,159.99
20	Real-Time Miscellaneous Amount	$ 83,382.84	$ 14,388.99	$ 97,771.83
21	Real-time Net inadvertent Distribution	$ 22,708.43	$ -	$ 22,708.43
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (518.41)	$ -	$ (518.41)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 792.11	$ 1,390.24	$ 2,182.35
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 18.10	$ 761.11	$ 779.21
22	Real-Time Non-Asset Energy Amount	$ 291.80	$ 2,151.35	$ 2,443.15
23	Real-Time Revenue Neutrality Uplift Amount	$ 276,123.85	$ (33,318.06)	$ 242,805.79
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ (4,041.79)	$ 487.70	$ (3,554.09)
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (25,802.49)	$ 9,699.57	$ (16,102.92)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (177,813.62)	$ -	$ (177,813.62)
29	Financial Transmission Rights Market Administration Amount	$ 25,520.16	$ -	$ 25,520.16
30	Financial Transmission Rights Monthly Allocation Amount	$ (70,652.17)	$ -	$ (70,652.17)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 81,676.67	$ (4,428.72)	$ 77,247.95
34	Real -Time Schedule 24 Allocation Amount	$ (71,173.61)	$ 96,792.99	$ 25,619.38
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (83,732.16)	$ -	$ (83,732.16)
37	Financial Transmission Guarantee Uplift Amount	$ 81,217.84	$ -	$ 81,217.84
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,077,706.89	$ -	$ 3,077,706.89
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,090,966.42)	$ 36,540.69	$ (3,054,425.73)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (157,121.31)	$ -	$ (157,121.31)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 39,319.32	$ -	$ 39,319.32
43	Real Time Price Volatility Make Whole Payment	$ (110,397.76)	$ 62,765.79	$ (47,631.97)
	TOTAL MISO CHARGES	**$ (6,097,477.16)**	**$ 10,457,318.01**	**$ 4,359,840.85**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 499,337.03**
	SCHEDULE 24 (FOR RETAIL)			**$ 102,867.33**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 3,757,636.49**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	March 2018 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (5,862,872.75)	$ 10,664,754.29	$ 4,801,881.54
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 912,715.94	$ (138,249.50)	$ 774,466.44
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,433,668.46	$ (368,628.88)	$ 2,065,039.58
1	Day-Ahead Asset Energy Amount	$ (2,516,488.35)	$ 10,157,875.90	$ 7,641,387.55
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 2,077.77	$ -	$ 2,077.77
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 1,039.78	$ -	$ 1,039.78
4	Day-Ahead Market Administration Amount	$ 731,851.55	$ (50,683.98)	$ 681,167.57
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (3,710,991.17)	$ -	$ (3,710,991.17)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 203,159.08	$ (30,772.60)	$ 172,386.48
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 268,470.28	$ (40,665.32)	$ 227,804.96
5	Day-Ahead Non-Asset Energy Amount	$ (3,239,361.81)	$ (71,437.92)	$ (3,310,799.73)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (2,077.77)	$ -	$ (2,077.77)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (1,039.78)	$ -	$ (1,039.78)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 75,683.66	$ (11,463.84)	$ 64,219.82
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (46,824.18)	$ 11,178.16	$ (35,646.02)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,592,673.73)	$ 1,561,429.19	$ (31,244.54)
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 94,480.26	$ 25.99	$ 94,506.25
13 c	Real-Time Asset Energy Amount - Loss Component	$ 65,219.04	$ 32.78	$ 65,251.82
13	Real-Time Asset Energy Amount	$ (1,432,974.43)	$ 1,561,487.96	$ 128,513.53
14	Real-Time Distribution of Losses Amount	$ (557,417.40)	$ -	$ (557,417.40)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ (7.77)	$ -	$ (7.77)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 21.32	$ -	$ 21.32
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ 7.77	$ -	$ 7.77
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (21.32)	$ -	$ (21.32)
19	Real-Time Market Administration Amount	$ 52,814.05	$ (8,141.75)	$ 44,672.30
20	Real-Time Miscellaneous Amount	$ 91,543.17	$ 14,880.00	$ 106,423.17
21	Real-time Net inadvertent Distribution	$ 92,123.93	$ -	$ 92,123.93
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 2,531.40	$ -	$ 2,531.40
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (171.58)	$ 19,665.76	$ 19,494.18
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (216.39)	$ 8,000.64	$ 7,784.25
22	Real-Time Non-Asset Energy Amount	$ 2,143.43	$ 27,666.40	$ 29,809.83
23	Real-Time Revenue Neutrality Uplift Amount	$ 596,035.10	$ (90,281.71)	$ 505,753.39
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 38,916.85	$ (5,894.75)	$ 33,022.10
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (38,372.10)	$ 12,749.74	$ (25,622.36)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (724,910.33)	$ -	$ (724,910.33)
29	Financial Transmission Rights Market Administration Amount	$ 14,893.28	$ -	$ 14,893.28
30	Financial Transmission Rights Monthly Allocation Amount	$ (81,850.95)	$ -	$ (81,850.95)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 94,053.06	$ (6,580.69)	$ 87,472.37
34	Real -Time Schedule 24 Allocation Amount	$ (85,614.43)	$ 55,553.06	$ (30,061.37)
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (78,128.20)	$ -	$ (78,128.20)
37	Financial Transmission Guarantee Uplift Amount	$ 74,688.76	$ -	$ 74,688.76
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,351,784.59	$ -	$ 3,351,784.59
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,360,340.60)	$ 41,129.71	$ (3,319,210.89)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (72,285.52)	$ -	$ (72,285.52)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 29,560.11	$ -	$ 29,560.11
43	Real Time Price Volatility Make Whole Payment	$ (132,358.39)	$ 13,688.82	$ (118,669.57)
	TOTAL MISO CHARGES	**$ (7,120,835.15)**	**$ 11,651,725.11**	**$ 4,530,889.96**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 740,733.15**
	SCHEDULE 24 (FOR RETAIL)			**$ 57,411.00**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 3,732,745.81**

		System	Intersystem	System Retail
	April 2018 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (3,360,932.31)	$ 8,062,443.77	$ 4,701,511.46
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,229,734.86	$ (276,377.61)	$ 1,953,357.25
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,126,827.19	$ (387,572.99)	$ 2,739,254.20
1	Day-Ahead Asset Energy Amount	$ 1,995,629.74	$ 7,398,493.17	$ 9,394,122.91
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 8,633.43	$ -	$ 8,633.43
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 1,086.22	$ -	$ 1,086.22
4	Day-Ahead Market Administration Amount	$ 771,172.32	$ (42,033.55)	$ 729,138.77
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (4,191,337.63)	$ -	$ (4,191,337.63)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 177,823.30	$ (22,041.36)	$ 155,781.94
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 328,203.96	$ (40,681.17)	$ 287,522.79
5	Day-Ahead Non-Asset Energy Amount	$ (3,685,310.37)	$ (62,722.53)	$ (3,748,032.90)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (8,633.43)	$ -	$ (8,633.43)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (1,086.22)	$ -	$ (1,086.22)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 132,980.08	$ (16,483.00)	$ 116,497.08
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (309,502.38)	$ 6,485.11	$ (303,017.27)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 42,654.38	$ 1,818,678.24	$ 1,861,332.62
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 149,298.77	$ (0.00)	$ 149,298.77
13 c	Real-Time Asset Energy Amount - Loss Component	$ 60,928.05	$ (0.01)	$ 60,928.04
13	Real-Time Asset Energy Amount	$ 252,881.20	$ 1,818,678.23	$ 2,071,559.43
14	Real-Time Distribution of Losses Amount	$ (767,415.68)	$ -	$ (767,415.68)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
19	Real-Time Market Administration Amount	$ 57,929.57	$ (9,725.47)	$ 48,204.10
20	Real-Time Miscellaneous Amount	$ 207,093.60	$ 14,880.00	$ 221,973.60
21	Real-time Net inadvertent Distribution	$ 76,373.38	$ -	$ 76,373.38
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 2,290.95	$ -	$ 2,290.95
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 0.03	$ 27,755.09	$ 27,755.12
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 0.07	$ 10,364.52	$ 10,364.59
22	Real-Time Non-Asset Energy Amount	$ 2,291.05	$ 38,119.61	$ 40,410.66
23	Real-Time Revenue Neutrality Uplift Amount	$ 199,041.68	$ (24,671.39)	$ 174,370.29
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 229,232.53	$ (28,413.57)	$ 200,818.96
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (137,444.24)	$ 37,147.83	$ (100,296.41)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (67,332.29)	$ -	$ (67,332.29)
29	Financial Transmission Rights Market Administration Amount	$ 32,862.32	$ -	$ 32,862.32
30	Financial Transmission Rights Monthly Allocation Amount	$ (4,206.89)	$ -	$ (4,206.89)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ (438,248.64)	$ -	$ (438,248.64)
33	Day-Ahead Schedule 24 Allocation Amount	$ 96,058.44	$ (5,258.52)	$ 90,799.92
34	Real -Time Schedule 24 Allocation Amount	$ (88,931.11)	$ 120,775.12	$ 31,844.01
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 62,379.85	$ -	$ 62,379.85
37	Financial Transmission Guarantee Uplift Amount	$ (64,723.55)	$ -	$ (64,723.55)
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,351,784.59	$ -	$ 3,351,784.59
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,360,340.59)	$ 33,326.02	$ (3,327,014.57)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (71,575.59)	$ -	$ (71,575.59)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 29,565.66	$ -	$ 29,565.66
43	Real Time Price Volatility Make Whole Payment	$ (216,371.99)	$ 23,058.51	$ (193,313.48)
	TOTAL MISO CHARGES	**$ (1,714,127.31)**	**$ 9,301,655.57**	**$ 7,587,528.26**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 810,205.19**
	SCHEDULE 24 (FOR RETAIL)			**$ 122,643.93**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 6,654,679.14**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	May 2018 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 2,614,901.39	$ 9,964,011.92	$ 12,578,913.31
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 509,014.63	$ (60,213.95)	$ 448,800.68
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,356,149.48	$ (278,720.98)	$ 2,077,428.50
1	Day-Ahead Asset Energy Amount	$ 5,480,065.50	$ 9,625,076.99	$ 15,105,142.49
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (7,051.88)	$ -	$ (7,051.88)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (4,007.79)	$ -	$ (4,007.79)
4	Day-Ahead Market Administration Amount	$ 581,519.22	$ (28,666.61)	$ 552,852.61
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (7,661,954.85)	$ -	$ (7,661,954.85)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 688,450.34	$ (81,440.31)	$ 607,010.03
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 948,699.88	$ (112,226.57)	$ 836,473.31
5	Day-Ahead Non-Asset Energy Amount	$ (6,024,804.63)	$ (193,666.88)	$ (6,218,471.51)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 7,051.88	$ -	$ 7,051.88
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 4,007.79	$ -	$ 4,007.79
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 82,136.98	$ (9,716.40)	$ 72,420.58
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (52,416.61)	$ 14,137.18	$ (38,279.43)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (5,714,535.38)	$ 1,861,919.15	$ (3,852,616.23)
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 109,304.75	$ 15.79	$ 109,320.54
13 c	Real-Time Asset Energy Amount - Loss Component	$ 146,575.92	$ 122.14	$ 146,698.06
13	Real-Time Asset Energy Amount	$ (5,458,654.71)	$ 1,862,057.08	$ (3,596,597.63)
14	Real-Time Distribution of Losses Amount	$ (910,589.02)	$ -	$ (910,589.02)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 2.35	$ -	$ 2.35
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 1.78	$ -	$ 1.78
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (2.35)	$ -	$ (2.35)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (1.78)	$ -	$ (1.78)
19	Real-Time Market Administration Amount	$ 54,043.24	$ (6,196.15)	$ 47,847.09
20	Real-Time Miscellaneous Amount	$ 65,594.78	$ 14,880.00	$ 80,474.78
21	Real-time Net inadvertent Distribution	$ 13,432.43	$ -	$ 13,432.43
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 12,557.77	$ -	$ 12,557.77
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (133.48)	$ 33,368.56	$ 33,235.08
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (1,032.49)	$ 28,423.14	$ 27,390.65
22	Real-Time Non-Asset Energy Amount	$ 11,391.80	$ 61,791.70	$ 73,183.50
23	Real-Time Revenue Neutrality Uplift Amount	$ 172,606.13	$ (20,418.46)	$ 152,187.67
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 111,692.60	$ (13,212.69)	$ 98,479.91
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (14,398.95)	$ (15,105.13)	$ (29,504.08)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,745,103.48)	$ -	$ (1,745,103.48)
29	Financial Transmission Rights Market Administration Amount	$ 14,822.88	$ -	$ 14,822.88
30	Financial Transmission Rights Monthly Allocation Amount	$ (103,422.19)	$ -	$ (103,422.19)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 105,763.28	$ (5,140.78)	$ 100,622.50
34	Real -Time Schedule 24 Allocation Amount	$ (95,334.31)	$ 95,689.44	$ 355.13
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 53,958.81	$ -	$ 53,958.81
37	Financial Transmission Guarantee Uplift Amount	$ 14,581.48	$ -	$ 14,581.48
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,351,784.59	$ -	$ 3,351,784.59
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,360,340.52)	$ 19,351.61	$ (3,340,988.91)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (71,760.16)	$ -	$ (71,760.16)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 29,565.66	$ -	$ 29,565.66
43	Real Time Price Volatility Make Whole Payment	$ (129,317.99)	$ 21,839.82	$ (107,478.17)
	TOTAL MISO CHARGES	**$ (7,823,183.19)**	**$ 11,422,700.71**	**$ 3,599,517.52**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 615,522.58**
	SCHEDULE 24 (FOR RETAIL)			**$ 100,977.63**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 2,883,017.31**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	June 2018 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (4,295,307.30)	$ 13,183,336.85	$ 8,888,029.55
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 708,282.88	$ (101,344.90)	$ 606,937.98
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,290,356.80	$ (327,716.49)	$ 1,962,640.31
1	Day-Ahead Asset Energy Amount	$ (1,296,667.62)	$ 12,754,275.46	$ 11,457,607.84
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (3,046.41)	$ -	$ (3,046.41)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (5,298.90)	$ -	$ (5,298.90)
4	Day-Ahead Market Administration Amount	$ 698,607.49	$ (43,301.51)	$ 655,305.98
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (8,175,545.00)	$ -	$ (8,175,545.00)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 752,105.21	$ (107,615.23)	$ 644,489.98
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,139,248.03	$ (163,009.70)	$ 976,238.33
5	Day-Ahead Non-Asset Energy Amount	$ (6,284,191.76)	$ (270,624.93)	$ (6,554,816.69)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 3,046.41	$ -	$ 3,046.41
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 5,298.90	$ -	$ 5,298.90
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 106,351.71	$ (15,217.37)	$ 91,134.34
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (34,357.61)	$ 25,633.38	$ (8,724.23)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (2,817,759.81)	$ 2,081,900.78	$ (735,859.03)
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 882.87	$ 41.01	$ 923.88
13 c	Real-Time Asset Energy Amount - Loss Component	$ 70,562.08	$ 89.81	$ 70,651.89
13	Real-Time Asset Energy Amount	$ (2,746,314.86)	$ 2,082,031.59	$ (664,283.27)
14	Real-Time Distribution of Losses Amount	$ (1,015,586.44)	$ -	$ (1,015,586.44)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
19	Real-Time Market Administration Amount	$ 72,958.27	$ (7,622.85)	$ 65,335.42
20	Real-Time Miscellaneous Amount	$ 191,768.95	$ 10,358.70	$ 202,127.65
21	Real-time Net inadvertent Distribution	$ (83,118.67)	$ -	$ (83,118.67)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 6,052.65	$ -	$ 6,052.65
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (286.59)	$ 2,066.57	$ 1,779.98
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (627.65)	$ 17,773.51	$ 17,145.86
22	Real-Time Non-Asset Energy Amount	$ 5,138.41	$ 19,840.07	$ 24,978.48
23	Real-Time Revenue Neutrality Uplift Amount	$ 1,724,218.20	$ (246,710.35)	$ 1,477,507.85
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 276,215.39	$ (39,522.37)	$ 236,693.02
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (19,601.94)	$ 7,559.75	$ (12,042.19)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,100,724.72)	$ -	$ (1,100,724.72)
29	Financial Transmission Rights Market Administration Amount	$ 19,888.40	$ -	$ 19,888.40
30	Financial Transmission Rights Monthly Allocation Amount	$ (58,804.62)	$ -	$ (58,804.62)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 96,251.98	$ (6,111.18)	$ 90,140.80
34	Real -Time Schedule 24 Allocation Amount	$ (82,766.29)	$ 118,852.35	$ 36,086.06
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 53,995.61	$ -	$ 53,995.61
37	Financial Transmission Guarantee Uplift Amount	$ (53,814.00)	$ -	$ (53,814.00)
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,270,304.83	$ -	$ 2,270,304.83
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,293,458.77)	$ 19,997.72	$ (2,273,461.05)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (320,148.19)	$ -	$ (320,148.19)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 41,430.89	$ -	$ 41,430.89
43	Real Time Price Volatility Make Whole Payment	$ (161,021.43)	$ 13,951.05	$ (147,070.38)
	TOTAL MISO CHARGES	**$ (9,993,446.79)**	**$ 14,423,389.51**	**$ 4,429,942.72**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 740,529.80**
	SCHEDULE 24 (FOR RETAIL)			**$ 126,226.86**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 3,563,186.06**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnestoa Retail
	July 2017 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 7,941,932.96	$ 8,636,781.59	$ 16,578,714.55	$ 12,252,728.41
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,595,030.67	$ (201,582.68)	$ 2,393,447.99	$ 1,768,910.86
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (5,175.18)	$ -	$ (5,175.18)	$ (3,824.79)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (12,441,178.06)	$ -	$ (12,441,178.06)	$ (9,194,824.81)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,506,674.47	$ (117,038.88)	$ 1,389,635.59	$ 1,027,029.41
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 5,175.18	$ -	$ 5,175.18	$ 3,824.79
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (2,265,232.80)	$ 1,792,655.66	$ (472,577.14)	$ (349,264.68)
13 c	Real-Time Asset Energy Amount - Loss Component	$ 140,916.63	$ 117.96	$ 141,034.59	$ 104,233.57
14	Real-Time Distribution of Losses Amount	$ (1,382,114.23)	$ -	$ (1,382,114.23)	$ (1,021,470.65)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 61,777.20	$ -	$ 61,777.20	$ 45,657.29
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 16,493.74	$ -	$ 16,493.74	$ 12,189.93
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (1,518.54)	$ 9,220.59	$ 7,702.05	$ 5,692.31
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 4,229,471.41	$ (328,546.48)	$ 3,900,924.93	$ 2,883,032.56
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (8,214.12)	$ -	$ (8,214.12)	$ (6,070.76)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 929,220.89	$ (72,182.13)	$ 857,038.76	$ 633,406.36
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 8,214.12	$ -	$ 8,214.12	$ 6,070.76
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 261,612.37	$ 161.63	$ 261,774.00	$ 193,467.69
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	$ (2,080.65)	$ 34,623.74	$ 32,543.09	$ 24,051.42
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (7,409,511.47)	$ -	$ (7,409,511.47)	$ (5,476,101.99)
30	Financial Transmission Rights Monthly Allocation Amount	$ (612,605.93)	$ -	$ (612,605.93)	$ (452,754.89)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 40,349.07	$ -	$ 40,349.07	$ 29,820.54
37	Financial Transmission Guarantee Uplift Amount	$ (48,817.25)	$ -	$ (48,817.25)	$ (36,079.06)
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 585,736.40	$ (45,500.16)	$ 540,236.24	$ 399,269.07
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 50,123.88	$ (3,893.64)	$ 46,230.24	$ 34,167.10
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (12,345.06)	$ 10,157.50	$ (2,187.56)	$ (1,616.75)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 294,120.50	$ (22,847.36)	$ 271,273.14	$ 200,488.17
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (134,973.16)	$ 97,898.42	$ (37,074.74)	$ (27,400.60)
43	Real Time Price Volatility Make Whole Payment	$ (194,026.12)	$ 32,231.20	$ (161,794.92)	$ (119,576.77)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 593,104.55	$ (18,067.56)	$ 575,036.99	$ 424,989.05
19	Real-Time Market Administration Amount	$ 45,595.04	$ (5,451.91)	$ 40,143.13	$ 29,668.34
29	Financial Transmission Rights Market Administration Amount	$ 32,031.60	$ -	$ 32,031.60	$ 23,673.40
33	Day-Ahead Schedule 24 Allocation Amount	$ 92,400.93	$ (3,011.97)	$ 89,388.96	$ 66,064.15
34	Real -Time Schedule 24 Allocation Amount	$ (92,388.80)	$ 66,878.49	$ (25,510.31)	$ (18,853.75)
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	$ 71,410.10	$ 13,920.00	$ 85,330.10	$ 63,064.39
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,620,102.73	$ -	$ 3,620,102.73	$ 2,675,487.02
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,628,762.14)	$ 9,159.73	$ (3,619,602.41)	$ (2,675,117.25)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (127,119.86)	$ -	$ (127,119.86)	$ (93,949.69)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 92,725.55	$ -	$ 92,725.55	$ 68,530.10
	TOTAL MISO CHARGES	**$ (5,151,843.38)**	**$ 9,885,683.75**	**$ 4,733,840.37**	**$ 3,498,610.24**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 647,211.72**	**$ 478,330.78**
	SCHEDULE 24 (FOR RETAIL)			**$ 63,878.65**	**$ 47,210.40**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 4,022,750.00**	**$ 2,973,069.06**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnestoa Retail
	August 2017 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 6,396,176.61	$ 7,345,033.68	$ 13,741,210.29	$ 10,092,337.69
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 1,963,629.32	$ (170,960.79)	$ 1,792,668.53	$ 1,316,639.20
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (4,565.85)	$ -	$ (4,565.85)	$ (3,353.42)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (11,098,231.58)	$ -	$ (11,098,231.58)	$ (8,151,181.63)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,400,146.09	$ (121,901.87)	$ 1,278,244.22	$ 938,816.31
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 4,565.85	$ -	$ 4,565.85	$ 3,353.42
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,832,607.66)	$ 2,002,630.75	$ 170,023.09	$ 124,874.77
13 c	Real-Time Asset Energy Amount - Loss Component	$ 81,631.30	$ 53.50	$ 81,684.80	$ 59,994.03
14	Real-Time Distribution of Losses Amount	$ (915,463.36)	$ -	$ (915,463.36)	$ (672,369.11)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 133,299.65	$ -	$ 133,299.65	$ 97,902.95
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 18,605.36	$ -	$ 18,605.36	$ 13,664.85
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (614.55)	$ 6,951.91	$ 6,337.36	$ 4,654.52
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,732,043.58	$ (237,861.77)	$ 2,494,181.81	$ 1,831,871.04
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (8,141.19)	$ -	$ (8,141.19)	$ (5,979.36)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 997,499.08	$ (86,845.94)	$ 910,653.14	$ 668,836.21
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 8,141.19	$ -	$ 8,141.19	$ 5,979.36
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 100,999.37	$ 25.53	$ 101,024.90	$ 74,198.51
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	$ (293.19)	$ 21,338.34	$ 21,045.15	$ 15,456.77
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (5,889,555.92)	$ -	$ (5,889,555.92)	$ (4,325,629.69)
30	Financial Transmission Rights Monthly Allocation Amount	$ (447,182.46)	$ -	$ (447,182.46)	$ (328,436.60)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (1,120.92)	$ -	$ (1,120.92)	$ (823.27)
37	Financial Transmission Guarantee Uplift Amount	$ (391.84)	$ -	$ (391.84)	$ (287.79)
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 223,464.73	$ (19,455.66)	$ 204,009.07	$ 149,836.03
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 57,862.02	$ (5,037.68)	$ 52,824.34	$ 38,797.24
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (32,854.54)	$ 12,622.58	$ (20,231.96)	$ (14,859.52)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 146,960.97	$ (12,794.96)	$ 134,166.01	$ 98,539.26
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (69,205.57)	$ 17,205.14	$ (52,000.43)	$ (38,192.12)
43	Real Time Price Volatility Make Whole Payment	$ (112,767.09)	$ 16,884.55	$ (95,882.54)	$ (70,421.67)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 541,944.41	$ (17,366.57)	$ 524,577.84	$ 385,280.23
19	Real-Time Market Administration Amount	$ 39,130.12	$ (6,678.05)	$ 32,452.07	$ 23,834.67
29	Financial Transmission Rights Market Administration Amount	$ 26,142.80	$ -	$ 26,142.80	$ 19,200.78
33	Day-Ahead Schedule 24 Allocation Amount	$ 88,026.11	$ (2,742.07)	$ 85,284.04	$ 62,637.52
34	Real -Time Schedule 24 Allocation Amount	$ (77,178.30)	$ 82,812.17	$ 5,633.87	$ 4,137.84
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	$ (52,943.90)	$ 15,840.00	$ (37,103.90)	$ (27,251.25)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,620,102.73	$ -	$ 3,620,102.73	$ 2,658,812.32
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,628,762.14)	$ 17,868.65	$ (3,610,893.49)	$ (2,652,048.52)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (131,423.44)	$ -	$ (131,423.44)	$ (96,524.96)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 92,725.55	$ -	$ 92,725.55	$ 68,102.99
	TOTAL MISO CHARGES	**$ (5,630,206.66)**	**$ 8,857,621.43**	**$ 3,227,414.77**	**$ 2,370,399.63**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 583,172.71**	**$ 428,315.69**
	SCHEDULE 24 (FOR RETAIL)			**$ 90,917.91**	**$ 66,775.36**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 2,553,324.15**	**$ 1,875,308.58**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnestoa Retail
	September 2017 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 9,003,652.35	$ 6,323,343.49	$ 15,326,995.84	$ 11,364,267.49
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,232,521.06	$ (233,248.75)	$ 1,999,272.31	$ 1,482,369.12
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (7,181.35)	$ -	$ (7,181.35)	$ (5,324.64)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (12,033,585.01)	$ -	$ (12,033,585.01)	$ (8,922,353.76)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,825,144.68	$ (190,686.99)	$ 1,634,457.69	$ 1,211,875.74
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 7,181.35	$ -	$ 7,181.35	$ 5,324.64
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (2,868,505.92)	$ 2,946,846.14	$ 78,340.22	$ 58,085.70
13 c	Real-Time Asset Energy Amount - Loss Component	$ 122,585.12	$ 1,020.99	$ 123,606.11	$ 91,648.29
14	Real-Time Distribution of Losses Amount	$ (1,302,537.63)	$ -	$ (1,302,537.63)	$ (965,772.17)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (61,649.28)	$ -	$ (61,649.28)	$ (45,710.13)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 72,020.99	$ -	$ 72,020.99	$ 53,400.28
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (9,772.33)	$ 17,813.53	$ 8,041.20	$ 5,962.19
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,543,137.57	$ (265,701.26)	$ 2,277,436.31	$ 1,688,615.02
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (8,474.41)	$ -	$ (8,474.41)	$ (6,283.39)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 2,681,605.83	$ (280,168.11)	$ 2,401,437.72	$ 1,780,556.41
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 8,474.41	$ -	$ 8,474.41	$ 6,283.39
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 452,484.84	$ 2,758.90	$ 455,243.74	$ 337,542.44
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	$ (26,406.57)	$ 74,228.42	$ 47,821.85	$ 35,457.72
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (8,383,531.61)	$ -	$ (8,383,531.61)	$ (6,216,005.85)
30	Financial Transmission Rights Monthly Allocation Amount	$ (306,232.96)	$ -	$ (306,232.96)	$ (227,057.76)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (56,284.32)	$ -	$ (56,284.32)	$ (41,732.25)
37	Financial Transmission Guarantee Uplift Amount	$ 62,630.10	$ -	$ 62,630.10	$ 46,437.36
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 801,450.71	$ (83,733.76)	$ 717,716.95	$ 532,154.35
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 115,978.79	$ (12,117.20)	$ 103,861.59	$ 77,008.62
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (96,390.36)	$ 21,874.04	$ (74,516.32)	$ (55,250.45)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 365,711.53	$ (38,208.71)	$ 327,502.82	$ 242,828.38
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (386,861.37)	$ 260,874.83	$ (125,986.54)	$ (93,413.27)
43	Real Time Price Volatility Make Whole Payment	$ (307,866.23)	$ 112,066.67	$ (195,799.56)	$ (145,176.43)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 551,951.71	$ (19,585.29)	$ 532,366.42	$ 394,725.39
19	Real-Time Market Administration Amount	$ 44,233.12	$ (9,228.05)	$ 35,005.07	$ 25,954.66
29	Financial Transmission Rights Market Administration Amount	$ 24,065.60	$ -	$ 24,065.60	$ 17,843.54
33	Day-Ahead Schedule 24 Allocation Amount	$ 83,296.60	$ (3,015.72)	$ 80,280.88	$ 59,524.61
34	Real -Time Schedule 24 Allocation Amount	$ (71,304.25)	$ 81,792.20	$ 10,487.95	$ 7,776.34
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	$ 47,810.47	$ 14,400.00	$ 62,210.47	$ 46,126.22
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,419,039.70	$ -	$ 3,419,039.70	$ 2,535,061.80
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,472,296.93)	$ 17,561.86	$ (3,454,735.07)	$ (2,561,528.29)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (18,212.29)	$ -	$ (18,212.29)	$ (13,503.58)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 28,487.85	$ -	$ 28,487.85	$ 21,122.44
	TOTAL MISO CHARGES	**$ (4,923,628.44)**	**$ 8,738,887.24**	**$ 3,815,258.80**	**$ 2,828,840.18**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 591,437.09**	**$ 438,523.59**
	SCHEDULE 24 (FOR RETAIL)			**$ 90,768.83**	**$ 67,300.94**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 3,133,052.88**	**$ 2,323,015.64**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnestoa Retail
	October 2017 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (610,417.01)	$ 10,575,584.27	$ 9,965,167.26	$ 7,232,124.07
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,114,833.22	$ (349,922.93)	$ 1,764,910.29	$ 1,280,866.63
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (3,801.39)	$ -	$ (3,801.39)	$ (2,758.82)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (8,797,500.02)	$ -	$ (8,797,500.02)	$ (6,384,700.83)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,187,725.69	$ (196,522.57)	$ 991,203.12	$ 719,356.11
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 3,801.39	$ -	$ 3,801.39	$ 2,758.82
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (633,180.22)	$ 3,051,085.81	$ 2,417,905.59	$ 1,754,771.67
13 c	Real-Time Asset Energy Amount - Loss Component	$ 33,044.01	$ 83.68	$ 33,127.69	$ 24,042.10
14	Real-Time Distribution of Losses Amount	$ (792,348.09)	$ -	$ (792,348.09)	$ (575,038.99)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (64,967.37)	$ -	$ (64,967.37)	$ (47,149.44)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 12,658.74	$ -	$ 12,658.74	$ 9,186.96
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (505.76)	$ 10,037.39	$ 9,531.63	$ 6,917.49
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,747,802.77	$ (454,654.86)	$ 2,293,147.91	$ 1,664,229.99
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (3,574.47)	$ -	$ (3,574.47)	$ (2,594.14)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,799,301.19	$ (297,714.61)	$ 1,501,586.58	$ 1,089,761.98
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 3,574.47	$ -	$ 3,574.47	$ 2,594.14
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 75,587.16	$ 4,425.21	$ 80,012.37	$ 58,068.21
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	$ (26,744.69)	$ 54,322.81	$ 27,578.12	$ 20,014.56
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (4,426,239.40)	$ -	$ (4,426,239.40)	$ (3,212,300.57)
30	Financial Transmission Rights Monthly Allocation Amount	$ (208,971.01)	$ -	$ (208,971.01)	$ (151,658.70)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (254,090.17)	$ -	$ (254,090.17)	$ (184,403.49)
37	Financial Transmission Guarantee Uplift Amount	$ 258,310.57	$ -	$ 258,310.57	$ 187,466.41
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 1,301,794.02	$ (215,396.46)	$ 1,086,397.56	$ 788,442.56
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 79,028.88	$ (13,076.22)	$ 65,952.66	$ 47,864.51
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (53,286.27)	$ 18,086.26	$ (35,200.01)	$ (25,546.07)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 242,005.39	$ (40,042.51)	$ 201,962.88	$ 146,572.61
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (98,274.71)	$ 79,725.88	$ (18,548.83)	$ (13,461.63)
43	Real Time Price Volatility Make Whole Payment	$ (477,828.40)	$ 54,335.40	$ (423,493.00)	$ (307,345.96)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 775,340.61	$ (41,571.26)	$ 733,769.35	$ 532,526.03
19	Real-Time Market Administration Amount	$ 67,059.85	$ (11,272.89)	$ 55,786.96	$ 40,486.85
29	Financial Transmission Rights Market Administration Amount	$ 27,509.36	$ -	$ 27,509.36	$ 19,964.65
33	Day-Ahead Schedule 24 Allocation Amount	$ 90,990.27	$ (7,050.81)	$ 83,939.46	$ 60,918.25
34	Real -Time Schedule 24 Allocation Amount	$ (80,821.31)	$ 75,016.20	$ (5,805.11)	$ (4,213.00)
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	$ 102,473.41	$ 13,479.11	$ 115,952.52	$ 84,151.42
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,419,039.70	$ -	$ 3,419,039.70	$ 2,481,335.10
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,472,296.93)	$ 6,412.78	$ (3,465,884.15)	$ (2,515,332.01)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (18,212.29)	$ -	$ (18,212.29)	$ (13,217.39)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 28,487.85	$ -	$ 28,487.85	$ 20,674.78
	TOTAL MISO CHARGES	**$ (5,652,690.96)**	**$ 12,315,369.68**	**$ 6,662,678.72**	**$ 4,835,374.85**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 817,065.67**	**$ 592,977.53**
	SCHEDULE 24 (FOR RETAIL)			**$ 78,134.35**	**$ 56,705.25**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 5,767,478.70**	**$ 4,185,692.06**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnestoa Retail
	November 2017 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (5,526,720.76)	$ 11,212,684.01	$ 5,685,963.25	$ 4,091,194.35
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,013,940.39	$ (460,592.39)	$ 2,553,348.00	$ 1,837,198.46
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (705.28)	$ -	$ (705.28)	$ (507.47)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (3,513,700.28)	$ -	$ (3,513,700.28)	$ (2,528,196.21)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 292,799.88	$ (44,745.87)	$ 248,054.01	$ 178,481.13
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 705.28	$ -	$ 705.28	$ 507.47
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (549,221.84)	$ 1,647,558.42	$ 1,098,336.58	$ 790,280.94
13 c	Real-Time Asset Energy Amount - Loss Component	$ 66,809.35	$ 0.77	$ 66,810.12	$ 48,071.57
14	Real-Time Distribution of Losses Amount	$ (783,371.78)	$ -	$ (783,371.78)	$ (563,655.81)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 72,996.01	$ -	$ 72,996.01	$ 52,522.48
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 28,235.43	$ -	$ 28,235.43	$ 20,316.11
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (5.03)	$ 10,084.35	$ 10,079.32	$ 7,252.33
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,661,246.85	$ (253,872.86)	$ 1,407,373.99	$ 1,012,641.18
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 7,278.86	$ -	$ 7,278.86	$ 5,237.32
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 131,540.60	$ (20,102.12)	$ 111,438.48	$ 80,182.80
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (7,278.86)	$ -	$ (7,278.86)	$ (5,237.32)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 70,778.42	$ (535.43)	$ 70,242.99	$ 50,541.60
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	$ 3,503.68	$ 10,463.52	$ 13,967.20	$ 10,049.75
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,186,296.03)	$ -	$ (1,186,296.03)	$ (853,569.99)
30	Financial Transmission Rights Monthly Allocation Amount	$ (400,255.24)	$ -	$ (400,255.24)	$ (287,993.77)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 319,991.92	$ -	$ 319,991.92	$ 230,242.28
37	Financial Transmission Guarantee Uplift Amount	$ (349,023.92)	$ -	$ (349,023.92)	$ (251,131.54)
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 179,786.39	$ (27,475.08)	$ 152,311.31	$ 109,591.84
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 128,386.09	$ (19,620.05)	$ 108,766.04	$ 78,259.92
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (142,633.89)	$ 48,179.67	$ (94,454.22)	$ (67,962.20)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 126,340.02	$ (19,307.37)	$ 107,032.65	$ 77,012.70
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (120,607.48)	$ 23,007.63	$ (97,599.85)	$ (70,225.56)
43	Real Time Price Volatility Make Whole Payment	$ (47,329.87)	$ 13,956.34	$ (33,373.53)	$ (24,013.10)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 568,782.25	$ (55,194.12)	$ 513,588.13	$ 369,539.65
19	Real-Time Market Administration Amount	$ 43,889.40	$ (11,006.39)	$ 32,883.01	$ 23,660.16
29	Financial Transmission Rights Market Administration Amount	$ 20,575.92	$ -	$ 20,575.92	$ 14,804.89
33	Day-Ahead Schedule 24 Allocation Amount	$ 96,639.64	$ (6,590.14)	$ 90,049.50	$ 64,792.89
34	Real -Time Schedule 24 Allocation Amount	$ (83,858.78)	$ 96,306.85	$ 12,448.07	$ 8,956.70
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	$ (73,492.42)	$ 14,788.68	$ (58,703.74)	$ (42,238.83)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,419,039.70	$ -	$ 3,419,039.70	$ 2,460,085.53
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,472,296.93)	$ 5,437.03	$ (3,466,859.90)	$ (2,494,493.37)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (18,212.29)	$ -	$ (18,212.29)	$ (13,104.20)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 28,487.85	$ -	$ 28,487.85	$ 20,497.73
	TOTAL MISO CHARGES	**$ (5,993,256.75)**	**$ 12,163,425.45**	**$ 6,170,168.70**	**$ 4,439,592.41**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 567,047.06**	**$ 408,004.70**
	SCHEDULE 24 (FOR RETAIL)			**$ 102,497.57**	**$ 73,749.59**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 5,500,624.07**	**$ 3,957,838.12**

		System	Intersystem	System Retail	Minnestoa Retail
	December 2017 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (11,937,882.06)	$ 15,975,375.75	$ 4,037,493.69	$ 2,887,665.53
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,376,194.28	$ (579,268.46)	$ 2,796,925.82	$ 2,000,396.01
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 1,280.54	$ -	$ 1,280.54	$ 915.86
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (3,715,572.79)	$ -	$ (3,715,572.79)	$ (2,657,423.71)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 192,928.13	$ (33,101.53)	$ 159,826.60	$ 114,309.97
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (1,280.54)	$ -	$ (1,280.54)	$ (915.86)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 197,276.71	$ 2,047,122.14	$ 2,244,398.85	$ 1,605,221.87
13 c	Real-Time Asset Energy Amount - Loss Component	$ 17,305.62	$ 5.38	$ 17,311.00	$ 12,381.04
14	Real-Time Distribution of Losses Amount	$ (991,853.15)	$ -	$ (991,853.15)	$ (709,385.67)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 55,761.10	$ -	$ 55,761.10	$ 39,881.03
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 618.34	$ -	$ 618.34	$ 442.24
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (31.37)	$ (1,467.25)	$ (1,498.62)	$ (1,071.83)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,329,166.19	$ (228,050.87)	$ 1,101,115.32	$ 787,531.32
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 5,356.06	$ -	$ 5,356.06	$ 3,830.72
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 90,717.22	$ (15,564.75)	$ 75,152.47	$ 53,749.98
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (5,356.06)	$ -	$ (5,356.06)	$ (3,830.72)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 16,725.03	$ 0.28	$ 16,725.31	$ 11,962.15
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	$ (1.63)	$ (669.21)	$ (670.84)	$ (479.79)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (660,232.21)	$ -	$ (660,232.21)	$ (472,206.26)
30	Financial Transmission Rights Monthly Allocation Amount	$ 141,917.90	$ -	$ 141,917.90	$ 101,501.44
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (419,228.86)	$ -	$ (419,228.86)	$ (299,837.68)
37	Financial Transmission Guarantee Uplift Amount	$ 419,063.21	$ -	$ 419,063.21	$ 299,719.20
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 1,008,080.48	$ (172,960.79)	$ 835,119.69	$ 597,287.95
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 62,050.85	$ (10,646.34)	$ 51,404.51	$ 36,765.15
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (168,861.50)	$ 11,717.95	$ (157,143.55)	$ (112,391.01)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ (27,868.89)	$ 4,781.59	$ (23,087.30)	$ (16,512.32)
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (1,081.24)	$ 775.34	$ (305.90)	$ (218.78)
43	Real Time Price Volatility Make Whole Payment	$ (154,244.18)	$ 16,743.67	$ (137,500.51)	$ (98,342.07)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 690,768.91	$ (57,120.20)	$ 633,648.71	$ 453,193.41
19	Real-Time Market Administration Amount	$ 57,091.35	$ (7,795.01)	$ 49,296.34	$ 35,257.35
29	Financial Transmission Rights Market Administration Amount	$ 21,107.84	$ -	$ 21,107.84	$ 15,096.59
33	Day-Ahead Schedule 24 Allocation Amount	$ 106,357.20	$ (8,810.71)	$ 97,546.49	$ 69,766.46
34	Real -Time Schedule 24 Allocation Amount	$ (90,334.49)	$ 92,979.92	$ 2,645.43	$ 1,892.04
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	$ 72,310.23	$ 14,943.22	$ 87,253.45	$ 62,404.75
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,077,706.89	$ -	$ 3,077,706.89	$ 2,201,214.11
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,090,966.42)	$ 5,660.69	$ (3,085,305.73)	$ (2,206,648.90)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (157,462.79)	$ -	$ (157,462.79)	$ (112,619.34)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 39,319.32	$ -	$ 39,319.32	$ 28,121.66
	TOTAL MISO CHARGES	**$ (10,443,154.78)**	**$ 17,054,650.82**	**$ 6,611,496.04**	**$ 4,728,623.91**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 704,052.89**	**$ 503,547.35**
	SCHEDULE 24 (FOR RETAIL)			**$ 100,191.92**	**$ 71,658.50**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 5,807,251.23**	**$ 4,153,418.05**

Northern States Power Company

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnestoa Retail
	January 2018 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (14,015,279.47)	$ 20,699,050.09	$ 6,683,770.62	$ 4,752,225.09
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 4,935,912.61	$ (856,737.95)	$ 4,079,174.66	$ 2,900,332.36
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 3,719.45	$ -	$ 3,719.45	$ 2,644.56
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (5,212,659.65)	$ -	$ (5,212,659.65)	$ (3,706,251.07)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 162,168.23	$ (28,147.92)	$ 134,020.31	$ 95,289.73
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (3,719.45)	$ -	$ (3,719.45)	$ (2,644.56)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 559,581.83	$ 1,656,273.29	$ 2,215,855.12	$ 1,575,494.27
13 c	Real-Time Asset Energy Amount - Loss Component	$ 3,836.89	$ 1.36	$ 3,838.25	$ 2,729.03
14	Real-Time Distribution of Losses Amount	$ (1,774,973.13)	$ -	$ (1,774,973.13)	$ (1,262,022.94)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 66,019.14	$ -	$ 66,019.14	$ 46,940.24
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 601.46	$ -	$ 601.46	$ 427.64
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (7.85)	$ 2,917.20	$ 2,909.35	$ 2,068.57
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,349,507.34	$ (234,237.16)	$ 1,115,270.18	$ 792,967.81
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 20,919.82	$ -	$ 20,919.82	$ 14,874.19
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 73,151.97	$ (12,697.16)	$ 60,454.81	$ 42,983.95
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (20,919.82)	$ -	$ (20,919.82)	$ (14,874.19)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 46,610.10	$ 3.68	$ 46,613.78	$ 33,142.85
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	$ (21.22)	$ (9,739.24)	$ (9,760.46)	$ (6,939.78)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (511,778.09)	$ -	$ (511,778.09)	$ (363,879.14)
30	Financial Transmission Rights Monthly Allocation Amount	$ 20,641.26	$ -	$ 20,641.26	$ 14,676.13
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (61,441.36)	$ -	$ (61,441.36)	$ (43,685.40)
37	Financial Transmission Guarantee Uplift Amount	$ 66,631.38	$ -	$ 66,631.38	$ 47,375.55
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 114,566.67	$ (19,885.61)	$ 94,681.06	$ 67,319.15
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 205,525.04	$ (35,673.46)	$ 169,851.58	$ 120,766.10
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (360,075.77)	$ 16,777.81	$ (343,297.96)	$ (244,088.15)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 483,401.05	$ (83,905.06)	$ 399,495.99	$ 284,045.49
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (638,214.90)	$ 247,677.59	$ (390,537.31)	$ (277,675.78)
43	Real Time Price Volatility Make Whole Payment	$ (368,914.39)	$ 41,198.93	$ (327,715.46)	$ (233,008.84)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 590,463.11	$ (50,319.93)	$ 540,143.18	$ 384,046.99
19	Real-Time Market Administration Amount	$ 39,261.95	$ (5,190.26)	$ 34,071.69	$ 24,225.30
29	Financial Transmission Rights Market Administration Amount	$ 17,404.08	$ -	$ 17,404.08	$ 12,374.47
33	Day-Ahead Schedule 24 Allocation Amount	$ 100,425.81	$ (8,559.65)	$ 91,866.16	$ 65,317.72
34	Real -Time Schedule 24 Allocation Amount	$ (96,154.90)	$ 101,581.74	$ 5,426.84	$ 3,858.54
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	$ 262,744.35	$ 14,400.00	$ 277,144.35	$ 197,052.29
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,077,706.89	$ -	$ 3,077,706.89	$ 2,188,279.15
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,090,966.42)	$ 40,382.56	$ (3,050,583.86)	$ (2,168,994.42)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (157,243.97)	$ -	$ (157,243.97)	$ (111,801.97)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 39,324.86	$ -	$ 39,324.86	$ 27,960.35
	TOTAL MISO CHARGES	**$ (14,072,245.10)**	**$ 21,475,170.86**	**$ 7,402,925.76**	**$ 5,263,551.30**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 591,618.95**	**$ 420,646.75**
	SCHEDULE 24 (FOR RETAIL)			**$ 97,293.00**	**$ 69,176.26**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 6,714,013.81**	**$ 4,773,728.29**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnestoa Retail
	February 2018 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (5,140,151.28)	$ 8,977,223.58	$ 3,837,072.30	$ 2,743,304.08
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,766,318.85	$ (333,793.62)	$ 2,432,525.23	$ 1,739,127.10
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 4,267.62	$ -	$ 4,267.62	$ 3,051.12
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (2,938,997.15)	$ -	$ (2,938,997.15)	$ (2,101,227.77)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 91,941.98	$ (11,094.04)	$ 80,847.94	$ 57,802.01
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (4,267.62)	$ -	$ (4,267.62)	$ (3,051.12)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (908,392.51)	$ 1,723,232.26	$ 814,839.75	$ 582,567.39
13 c	Real-Time Asset Energy Amount - Loss Component	$ 6,651.33	$ (2.18)	$ 6,649.15	$ 4,753.79
14	Real-Time Distribution of Losses Amount	$ (1,026,169.10)	$ -	$ (1,026,169.10)	$ (733,656.72)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ (5.34)	$ -	$ (5.34)	$ (3.82)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ 5.34	$ -	$ 5.34	$ 3.82
21	Real-time Net inadvertent Distribution	$ 22,708.43	$ -	$ 22,708.43	$ 16,235.33
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (518.41)	$ -	$ (518.41)	$ (370.64)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 18.10	$ 761.11	$ 779.21	$ 557.09
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 628,871.30	$ (75,881.79)	$ 552,989.51	$ 395,358.30
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 1,815.46	$ -	$ 1,815.46	$ 1,297.96
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ (16,389.92)	$ 1,977.66	$ (14,412.26)	$ (10,304.00)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (1,815.46)	$ -	$ (1,815.46)	$ (1,297.96)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 38,138.46	$ (95.58)	$ 38,042.88	$ 27,198.65
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 23.00	$ -	$ 23.00	$ 16.44
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (23.00)	$ -	$ (23.00)	$ (16.44)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 792.11	$ 1,390.24	$ 2,182.35	$ 1,560.26
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (177,813.62)	$ -	$ (177,813.62)	$ (127,127.35)
30	Financial Transmission Rights Monthly Allocation Amount	$ (70,652.17)	$ -	$ (70,652.17)	$ (50,512.57)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (83,732.16)	$ -	$ (83,732.16)	$ (59,864.07)
37	Financial Transmission Guarantee Uplift Amount	$ 81,217.84	$ -	$ 81,217.84	$ 58,066.47
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 276,123.85	$ (33,318.06)	$ 242,805.79	$ 173,593.32
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 42,953.38	$ (5,182.90)	$ 37,770.48	$ 27,003.90
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (42,009.16)	$ 25,547.64	$ (16,461.52)	$ (11,769.12)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ (4,041.79)	$ 487.70	$ (3,554.09)	$ (2,540.99)
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (25,802.49)	$ 9,699.57	$ (16,102.92)	$ (11,512.74)
43	Real Time Price Volatility Make Whole Payment	$ (110,397.76)	$ 62,765.79	$ (47,631.97)	$ (34,054.34)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 469,115.32	$ (25,458.44)	$ 443,656.88	$ 317,191.24
19	Real-Time Market Administration Amount	$ 34,394.87	$ (4,234.88)	$ 30,159.99	$ 21,562.80
29	Financial Transmission Rights Market Administration Amount	$ 25,520.16	$ -	$ 25,520.16	$ 18,245.57
33	Day-Ahead Schedule 24 Allocation Amount	$ 81,676.67	$ (4,428.72)	$ 77,247.95	$ 55,228.21
34	Real -Time Schedule 24 Allocation Amount	$ (71,173.61)	$ 96,792.99	$ 25,619.38	$ 18,316.50
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	$ 83,382.84	$ 14,388.99	$ 97,771.83	$ 69,901.70
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,077,706.89	$ -	$ 3,077,706.89	$ 2,200,397.91
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,090,966.42)	$ 36,540.69	$ (3,054,425.73)	$ (2,183,753.11)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (157,121.31)	$ -	$ (157,121.31)	$ (112,333.44)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 39,319.32	$ -	$ 39,319.32	$ 28,111.24
	TOTAL MISO CHARGES	**$ (6,097,477.16)**	**$ 10,457,318.01**	**$ 4,359,840.85**	**$ 3,117,055.99**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 499,337.03**	**$ 356,999.61**
	SCHEDULE 24 (FOR RETAIL)			**$ 102,867.33**	**$ 73,544.71**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 3,757,636.49**	**$ 2,686,511.67**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnestoa Retail
	March 2018 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (5,862,872.75)	$ 10,664,754.29	$ 4,801,881.54	$ 3,437,882.59
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,433,668.46	$ (368,628.88)	$ 2,065,039.58	$ 1,478,454.55
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 1,039.78	$ -	$ 1,039.78	$ 744.43
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (3,710,991.17)	$ -	$ (3,710,991.17)	$ (2,656,865.20)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 268,470.28	$ (40,665.32)	$ 227,804.96	$ 163,095.80
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (1,039.78)	$ -	$ (1,039.78)	$ (744.43)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,592,673.73)	$ 1,561,429.19	$ (31,244.54)	$ (22,369.37)
13 c	Real-Time Asset Energy Amount - Loss Component	$ 65,219.04	$ 32.78	$ 65,251.82	$ 46,716.71
14	Real-Time Distribution of Losses Amount	$ (557,417.40)	$ -	$ (557,417.40)	$ (399,080.14)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 21.32	$ -	$ 21.32	$ 15.26
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (21.32)	$ -	$ (21.32)	$ (15.26)
21	Real-time Net inadvertent Distribution	$ 92,123.93	$ -	$ 92,123.93	$ 65,955.66
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 2,531.40	$ -	$ 2,531.40	$ 1,812.34
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (216.39)	$ 8,000.64	$ 7,784.25	$ 5,573.09
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 912,715.94	$ (138,249.50)	$ 774,466.44	$ 554,475.29
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 2,077.77	$ -	$ 2,077.77	$ 1,487.57
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 203,159.08	$ (30,772.60)	$ 172,386.48	$ 123,419.22
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (2,077.77)	$ -	$ (2,077.77)	$ (1,487.57)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 94,480.26	$ 25.99	$ 94,506.25	$ 67,661.27
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ (7.77)	$ -	$ (7.77)	$ (5.56)
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ 7.77	$ -	$ 7.77	$ 5.56
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (171.58)	$ 19,665.76	$ 19,494.18	$ 13,956.76
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (724,910.33)	$ -	$ (724,910.33)	$ (518,995.85)
30	Financial Transmission Rights Monthly Allocation Amount	$ (81,850.95)	$ -	$ (81,850.95)	$ (58,600.77)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (78,128.20)	$ -	$ (78,128.20)	$ (55,935.49)
37	Financial Transmission Guarantee Uplift Amount	$ 74,688.76	$ -	$ 74,688.76	$ 53,473.04
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 596,035.10	$ (90,281.71)	$ 505,753.39	$ 362,091.56
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 75,683.66	$ (11,463.84)	$ 64,219.82	$ 45,977.85
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (46,824.18)	$ 11,178.16	$ (35,646.02)	$ (25,520.59)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 38,916.85	$ (5,894.75)	$ 33,022.10	$ 23,642.00
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (38,372.10)	$ 12,749.74	$ (25,622.36)	$ (18,344.20)
43	Real Time Price Volatility Make Whole Payment	$ (132,358.39)	$ 13,688.82	$ (118,669.57)	$ (84,960.87)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 731,851.55	$ (50,683.98)	$ 681,167.57	$ 487,678.45
19	Real-Time Market Administration Amount	$ 52,814.05	$ (8,141.75)	$ 44,672.30	$ 31,982.91
29	Financial Transmission Rights Market Administration Amount	$ 14,893.28	$ -	$ 14,893.28	$ 10,662.77
33	Day-Ahead Schedule 24 Allocation Amount	$ 94,053.06	$ (6,580.69)	$ 87,472.37	$ 62,625.40
34	Real -Time Schedule 24 Allocation Amount	$ (85,614.43)	$ 55,553.06	$ (30,061.37)	$ (21,522.28)
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	$ 91,543.17	$ 14,880.00	$ 106,423.17	$ 76,193.13
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,351,784.59	$ -	$ 3,351,784.59	$ 2,399,693.08
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,360,340.60)	$ 41,129.71	$ (3,319,210.89)	$ (2,376,372.10)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (72,285.52)	$ -	$ (72,285.52)	$ (51,752.45)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 29,560.11	$ -	$ 29,560.11	$ 21,163.41
	TOTAL MISO CHARGES	**$ (7,120,835.15)**	**$ 11,651,725.11**	**$ 4,530,889.96**	**$ 3,243,867.55**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 740,733.15**	**$ 530,324.12**
	SCHEDULE 24 (FOR RETAIL)			**$ 57,411.00**	**$ 41,103.11**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 3,732,745.81**	**$ 2,672,440.32**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

			System		Intersystem		System Retail		Minnestoa Retail
	April 2018 Actual								
Energy and Loss Charges									
1 a	Day-Ahead Asset Energy Amount - Energy Component	$	(3,360,932.31)	$	8,062,443.77	$	4,701,511.46	$	3,404,565.15
1 c	Day-Ahead Asset Energy Amount - Loss Component	$	3,126,827.19	$	(387,572.99)	$	2,739,254.20	$	1,983,610.90
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$	1,086.22	$	-	$	1,086.22	$	786.58
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$	(4,191,337.63)	$	-	$	(4,191,337.63)	$	(3,035,126.50)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$	328,203.96	$	(40,681.17)	$	287,522.79	$	208,207.53
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$	(1,086.22)	$	-	$	(1,086.22)	$	(786.58)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$	-	$	-	$	-	$	-
13 a	Real-Time Asset Energy Amount - Energy Component	$	42,654.38	$	1,818,678.24	$	1,861,332.62	$	1,347,870.41
13 c	Real-Time Asset Energy Amount - Loss Component	$	60,928.05	$	(0.01)	$	60,928.04	$	44,120.60
14	Real-Time Distribution of Losses Amount	$	(767,415.68)	$	-	$	(767,415.68)	$	(555,718.45)
16	Real-Time Financial Bilateral Transaction Loss Amount	$	-	$	-	$	-	$	-
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$	-	$	-	$	-	$	-
21	Real-time Net inadvertent Distribution	$	76,373.38	$	-	$	76,373.38	$	55,305.22
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$	2,290.95	$	-	$	2,290.95	$	1,658.97
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$	0.07	$	10,364.52	$	10,364.59	$	7,505.44
Congestion Related Charges									
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$	2,229,734.86	$	(276,377.61)	$	1,953,357.25	$	1,414,509.37
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$	8,633.43	$	-	$	8,633.43	$	6,251.84
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$	177,823.30	$	(22,041.36)	$	155,781.94	$	112,808.36
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$	(8,633.43)	$	-	$	(8,633.43)	$	(6,251.84)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$	-	$	-	$	-	$	-
13 b	Real-Time Asset Energy Amount - Congestion Component	$	149,298.77	$	(0.00)	$	149,298.77	$	108,113.61
15	Real-Time Financial Bilateral Transaction Congestion Amount	$	-	$	-	$	-	$	-
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$	-	$	-	$	-	$	-
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$	0.03	$	27,755.09	$	27,755.12	$	20,098.67
FTR Related Charges									
28	Financial Transmission Rights Hourly Allocation Amount	$	(67,332.29)	$	-	$	(67,332.29)	$	(48,758.19)
30	Financial Transmission Rights Monthly Allocation Amount	$	(4,206.89)	$	-	$	(4,206.89)	$	(3,046.39)
31	Financial Transmission Rights Transaction Amount	$	-	$	-	$	-	$	-
32	Financial Transmission Rights Yearly Allocation Amount	$	(438,248.64)	$	-	$	(438,248.64)	$	(317,354.55)
36	Financial Transmission Rights Full Funding Guarantee Amount	$	62,379.85	$	-	$	62,379.85	$	45,171.91
37	Financial Transmission Guarantee Uplift Amount	$	(64,723.55)	$	-	$	(64,723.55)	$	(46,869.09)
38	Financial Transmission Rights Monthly Transacton Amount	$	-	$	-	$	-	$	-
Uplift (RNU) Charges									
23	Real-Time Revenue Neutrality Uplift Amount	$	199,041.68	$	(24,671.39)	$	174,370.29	$	126,268.97
Revenue Sufficiency Guarantee (RSG) Charges									
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$	132,980.08	$	(16,483.00)	$	116,497.08	$	84,360.51
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$	(309,502.38)	$	6,485.11	$	(303,017.27)	$	(219,427.74)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$	229,232.53	$	(28,413.57)	$	200,818.96	$	145,421.58
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$	(137,444.24)	$	37,147.83	$	(100,296.41)	$	(72,628.91)
43	Real Time Price Volatility Make Whole Payment	$	(216,371.99)	$	23,058.51	$	(193,313.48)	$	(139,986.54)
Market Adminstration Charges									
4	Day-Ahead Market Administration Amount	$	771,172.32	$	(42,033.55)	$	729,138.77	$	528,000.51
19	Real-Time Market Administration Amount	$	57,929.57	$	(9,725.47)	$	48,204.10	$	34,906.65
29	Financial Transmission Rights Market Administration Amount	$	32,862.32	$	-	$	32,862.32	$	23,797.01
33	Day-Ahead Schedule 24 Allocation Amount	$	96,058.44	$	(5,258.52)	$	90,799.92	$	65,752.10
34	Real -Time Schedule 24 Allocation Amount	$	(88,931.11)	$	120,775.12	$	31,844.01	$	23,059.61
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	$	207,093.60	$	14,880.00	$	221,973.60	$	160,740.56
26	Real-Time Uninstructed Deviation Amount	$	-	$	-	$	-	$	-
Auction Revenue Rights (ARR)									
39	Auction Revenue Rights - FTR Auction Transactions	$	3,351,784.59	$	-	$	3,351,784.59	$	2,427,170.30
40	Auction Revenue Rights - Monthly ARR Revenue	$	(3,360,340.59)	$	33,326.02	$	(3,327,014.57)	$	(2,409,233.27)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$	(71,575.59)	$	-	$	(71,575.59)	$	(51,830.94)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$	29,565.66	$	-	$	29,565.66	$	21,409.76
	TOTAL MISO CHARGES	**$**	**(1,714,127.31)**	**$**	**9,301,655.57**	**$**	**7,587,528.26**	**$**	**5,494,453.11**
	SCHEDULE 16 & 17 (FOR RETAIL)					**$**	**810,205.19**	**$**	**586,704.16**
	SCHEDULE 24 (FOR RETAIL)					**$**	**122,643.93**	**$**	**88,811.71**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)					**$**	**6,654,679.14**	**$**	**4,818,937.24**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnestoa Retail
	May 2018 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 2,614,901.39	$ 9,964,011.92	$ 12,578,913.31	$ 9,199,921.41
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,356,149.48	$ (278,720.98)	$ 2,077,428.50	$ 1,519,382.35
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (4,007.79)	$ -	$ (4,007.79)	$ (2,931.20)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (7,661,954.85)	$ -	$ (7,661,954.85)	$ (5,603,773.61)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 948,699.88	$ (112,226.57)	$ 836,473.31	$ 611,776.91
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 4,007.79	$ -	$ 4,007.79	$ 2,931.20
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (5,714,535.38)	$ 1,861,919.15	$ (3,852,616.23)	$ (2,817,712.92)
13 c	Real-Time Asset Energy Amount - Loss Component	$ 146,575.92	$ 122.14	$ 146,698.06	$ 107,291.51
14	Real-Time Distribution of Losses Amount	$ (910,589.02)	$ -	$ (910,589.02)	$ (665,983.40)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 1.78	$ -	$ 1.78	$ 1.30
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (1.78)	$ -	$ (1.78)	$ (1.30)
21	Real-time Net inadvertent Distribution	$ 13,432.43	$ -	$ 13,432.43	$ 9,824.16
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 12,557.77	$ -	$ 12,557.77	$ 9,184.46
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (1,032.49)	$ 28,423.14	$ 27,390.65	$ 20,032.88
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 509,014.63	$ (60,213.95)	$ 448,800.68	$ 328,242.27
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (7,051.88)	$ -	$ (7,051.88)	$ (5,157.58)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 688,450.34	$ (81,440.31)	$ 607,010.03	$ 443,952.86
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 7,051.88	$ -	$ 7,051.88	$ 5,157.58
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 109,304.75	$ 15.79	$ 109,320.54	$ 79,954.47
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 2.35	$ -	$ 2.35	$ 1.72
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (2.35)	$ -	$ (2.35)	$ (1.72)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (133.48)	$ 33,368.56	$ 33,235.08	$ 24,307.36
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,745,103.48)	$ -	$ (1,745,103.48)	$ (1,276,327.65)
30	Financial Transmission Rights Monthly Allocation Amount	$ (103,422.19)	$ -	$ (103,422.19)	$ (75,640.56)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 53,958.81	$ -	$ 53,958.81	$ 39,464.20
37	Financial Transmission Guarantee Uplift Amount	$ 14,581.48	$ -	$ 14,581.48	$ 10,664.55
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 172,606.13	$ (20,418.46)	$ 152,187.67	$ 111,306.48
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 82,136.98	$ (9,716.40)	$ 72,420.58	$ 52,966.71
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (52,416.61)	$ 14,137.18	$ (38,279.43)	$ (27,996.67)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 111,692.60	$ (13,212.69)	$ 98,479.91	$ 72,025.89
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (14,398.95)	$ (15,105.13)	$ (29,504.08)	$ (21,578.59)
43	Real Time Price Volatility Make Whole Payment	$ (129,317.99)	$ 21,839.82	$ (107,478.17)	$ (78,607.01)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 581,519.22	$ (28,666.61)	$ 552,852.61	$ 404,343.40
19	Real-Time Market Administration Amount	$ 54,043.24	$ (6,196.15)	$ 47,847.09	$ 34,994.24
29	Financial Transmission Rights Market Administration Amount	$ 14,822.88	$ -	$ 14,822.88	$ 10,841.11
33	Day-Ahead Schedule 24 Allocation Amount	$ 105,763.28	$ (5,140.78)	$ 100,622.50	$ 73,592.93
34	Real -Time Schedule 24 Allocation Amount	$ (95,334.31)	$ 95,689.44	$ 355.13	$ 259.73
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	$ 65,594.78	$ 14,880.00	$ 80,474.78	$ 58,857.36
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,351,784.59	$ -	$ 3,351,784.59	$ 2,451,416.43
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,360,340.52)	$ 19,351.61	$ (3,340,988.91)	$ (2,443,520.73)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (71,760.16)	$ -	$ (71,760.16)	$ (52,483.69)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 29,565.66	$ -	$ 29,565.66	$ 21,623.63
	TOTAL MISO CHARGES	**$ (7,823,183.19)**	**$ 11,422,700.71**	**$ 3,599,517.52**	**$ 2,632,602.47**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 615,522.58**	**$ 450,178.74**
	SCHEDULE 24 (FOR RETAIL)			**$ 100,977.63**	**$ 73,852.66**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 2,883,017.31**	**$ 2,108,571.07**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnestoa Retail
	June 2018 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (4,295,307.30)	$ 13,183,336.85	$ 8,888,029.55	$ 6,537,128.90
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,290,356.80	$ (327,716.49)	$ 1,962,640.31	$ 1,443,518.23
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (5,298.90)	$ -	$ (5,298.90)	$ (3,897.33)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (8,175,545.00)	$ -	$ (8,175,545.00)	$ (6,013,097.86)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,139,248.03	$ (163,009.70)	$ 976,238.33	$ 718,021.45
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 5,298.90	$ -	$ 5,298.90	$ 3,897.33
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (2,817,759.81)	$ 2,081,900.78	$ (735,859.03)	$ (541,222.92)
13 c	Real-Time Asset Energy Amount - Loss Component	$ 70,562.08	$ 89.81	$ 70,651.89	$ 51,964.33
14	Real-Time Distribution of Losses Amount	$ (1,015,586.44)	$ -	$ (1,015,586.44)	$ (746,961.90)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (83,118.67)	$ -	$ (83,118.67)	$ (61,133.62)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 6,052.65	$ -	$ 6,052.65	$ 4,451.71
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (627.65)	$ 17,773.51	$ 17,145.86	$ 12,610.75
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 708,282.88	$ (101,344.90)	$ 606,937.98	$ 446,401.74
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (3,046.41)	$ -	$ (3,046.41)	$ (2,240.63)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 752,105.21	$ (107,615.23)	$ 644,489.98	$ 474,021.16
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 3,046.41	$ -	$ 3,046.41	$ 2,240.63
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 882.87	$ 41.01	$ 923.88	$ 679.51
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	$ (286.59)	$ 2,066.57	$ 1,779.98	$ 1,309.17
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,100,724.72)	$ -	$ (1,100,724.72)	$ (809,580.95)
30	Financial Transmission Rights Monthly Allocation Amount	$ (58,804.62)	$ -	$ (58,804.62)	$ (43,250.69)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 53,995.61	$ -	$ 53,995.61	$ 39,713.67
37	Financial Transmission Guarantee Uplift Amount	$ (53,814.00)	$ -	$ (53,814.00)	$ (39,580.10)
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 1,724,218.20	$ (246,710.35)	$ 1,477,507.85	$ 1,086,704.22
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 106,351.71	$ (15,217.37)	$ 91,134.34	$ 67,029.13
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (34,357.61)	$ 25,633.38	$ (8,724.23)	$ (6,416.65)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 276,215.39	$ (39,522.37)	$ 236,693.02	$ 174,087.27
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (19,601.94)	$ 7,559.75	$ (12,042.19)	$ (8,857.01)
43	Real Time Price Volatility Make Whole Payment	$ (161,021.43)	$ 13,951.05	$ (147,070.38)	$ (108,169.99)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 698,607.49	$ (43,301.51)	$ 655,305.98	$ 481,976.31
19	Real-Time Market Administration Amount	$ 72,958.27	$ (7,622.85)	$ 65,335.42	$ 48,054.08
29	Financial Transmission Rights Market Administration Amount	$ 19,888.40	$ -	$ 19,888.40	$ 14,627.88
33	Day-Ahead Schedule 24 Allocation Amount	$ 96,251.98	$ (6,111.18)	$ 90,140.80	$ 66,298.39
34	Real -Time Schedule 24 Allocation Amount	$ (82,766.29)	$ 118,852.35	$ 36,086.06	$ 26,541.23
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	$ 191,768.95	$ 10,358.70	$ 202,127.65	$ 148,664.50
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,270,304.83	$ -	$ 2,270,304.83	$ 1,669,804.90
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,293,458.77)	$ 19,997.72	$ (2,273,461.05)	$ (1,672,126.30)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (320,148.19)	$ -	$ (320,148.19)	$ (235,468.39)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 41,430.89	$ -	$ 41,430.89	$ 30,472.34
	TOTAL MISO CHARGES	**$ (9,993,446.79)**	**$ 14,423,389.51**	**$ 4,429,942.72**	**$ 3,258,214.48**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 740,529.80**	**$ 544,658.27**
	SCHEDULE 24 (FOR RETAIL)			**$ 126,226.86**	**$ 92,839.62**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 3,563,186.06**	**$ 2,620,716.60**

Northern States Power Company

Docket No. E999/AA-18-373

Part J

Section 5

Schedule 3

SUMMARY OF MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - SYSTEM

		July 17	August 17	September 17	October 17	November 17	December 17	January 18	February 18	March 18	April 18	May 18	June 18	YTD
Day Ahead & Real Time Asset & Non-Asset Energy														
1 a	Day-Ahead Asset Energy Amount - Energy Component	7,941,932.96	6,396,176.61	9,003,652.35	(610,417.01)	(5,526,720.76)	(11,937,882.06)	(14,015,279.47)	(5,140,151.28)	(5,862,872.75)	(3,360,932.31)	2,614,901.39	(4,295,307.30)	(24,792,899.63)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	(12,441,178.06)	(11,098,231.58)	(12,033,585.01)	(8,797,500.02)	(3,513,700.28)	(3,715,572.79)	(5,212,659.65)	(2,938,997.15)	(3,710,991.17)	(4,191,337.63)	(7,661,954.85)	(8,175,545.00)	(83,491,253.19)
13 a	Real-Time Asset Energy Amount - Energy Component	(2,265,232.80)	(1,832,607.66)	(2,868,505.92)	(633,180.22)	(549,221.84)	197,276.71	559,581.83	(908,392.51)	(1,592,673.73)	42,654.38	(5,714,535.38)	(2,817,759.81)	(18,382,596.95)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	16,493.74	18,605.36	72,020.99	12,658.74	28,235.43	618.34	601.46	(518.41)	2,531.40	2,290.95	12,557.77	6,052.65	172,148.42
	SUBTOTAL	(6,747,984.16)	(6,516,057.27)	(5,826,417.59)	(10,028,438.51)	(9,561,407.45)	(15,455,559.80)	(18,667,755.83)	(8,988,059.35)	(11,164,006.25)	(7,507,324.61)	(10,749,031.07)	(15,282,559.46)	(126,494,601.35)
Day Ahead & Real Time Energy Loss														
1 c	Day-Ahead Asset Energy Amount - Loss Component	2,595,030.67	1,963,629.32	2,232,521.06	2,114,833.22	3,013,940.39	3,376,194.28	4,935,912.61	2,766,318.85	2,433,668.46	3,126,827.19	2,356,149.48	2,290,356.80	33,205,382.33
3	Day-Ahead Financial Bilateral Transaction Loss Amount	(5,175.18)	(4,565.85)	(7,181.35)	(3,801.39)	(705.28)	1,280.54	3,719.45	4,267.62	1,039.78	1,086.22	(4,007.79)	(5,298.90)	(19,342.13)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	1,506,674.47	1,400,146.09	1,825,144.68	1,187,725.69	292,799.88	192,928.13	162,168.23	91,941.98	268,470.28	328,203.96	948,699.88	1,139,248.03	9,344,151.30
13 c	Real-Time Asset Energy Amount - Loss Component	140,916.63	81,631.30	122,585.12	33,044.01	66,809.35	17,305.62	3,836.89	6,651.33	65,219.04	60,928.05	146,575.92	70,562.08	816,065.34
22 c	Real-Time Non-Asset Energy Amount - Loss Component	(1,518.54)	(614.55)	(9,772.33)	(505.76)	(5.03)	(31.37)	(7.85)	18.10	(216.39)	0.07	(1,032.49)	(627.65)	(14,313.79)
14	Real-Time Distribution of Losses Amount	(1,382,114.23)	(915,463.36)	(1,302,537.63)	(792,348.09)	(783,371.78)	(991,853.15)	(1,774,973.13)	(1,026,169.10)	(557,417.40)	(767,415.68)	(910,589.02)	(1,015,586.44)	(12,219,839.01)
16	Real-Time Financial Bilateral Transaction Loss Amount	-	-	-	-	-	-	-	(5.34)	21.32	-	1.78	-	17.76
	SUBTOTAL	2,853,813.82	2,524,762.95	2,860,759.55	2,538,947.68	2,589,467.53	2,595,824.05	3,330,656.20	1,843,023.44	2,210,785.09	2,749,629.81	2,535,797.76	2,478,653.92	31,112,121.80
Virtual Energy Charges														
12	Day-Ahead Virtual Energy Amount	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Real-Time Virtual Energy Amount													-
	SUBTOTAL	-	-	-	-	-	-	-	-	-	-	-	-	-
Market Administration Charges (Schedule 16 & 17)														
4	Day-Ahead Market Administration Amount	593,104.55	541,944.41	551,951.71	775,340.61	568,782.25	690,768.91	590,463.11	469,115.32	731,851.55	771,172.32	581,519.22	698,607.49	7,564,621.45
19	Real-Time Market Administration Amount	45,595.04	39,130.12	44,233.12	67,059.85	43,889.40	57,091.35	39,261.95	34,394.87	52,814.05	57,929.57	54,043.24	72,958.27	608,400.83
29	Financial Transmission Rights Market Administration Amount	32,031.60	26,142.80	24,065.60	27,509.36	20,575.92	21,107.84	17,404.08	25,520.16	14,893.28	32,862.32	14,822.88	19,888.40	276,824.24
33	Day-Ahead Schedule 24 Allocation Amount	92,400.93	88,026.11	83,296.60	90,990.27	96,639.64	106,357.20	100,425.81	81,676.67	94,053.06	96,058.44	105,763.28	96,251.98	1,131,939.99
34	Real -Time Schedule 24 Allocation Amount	(92,388.80)	(77,178.30)	(71,304.25)	(80,821.31)	(83,858.78)	(90,334.49)	(96,154.90)	(71,173.61)	(85,614.43)	(88,931.11)	(95,334.31)	(82,766.29)	(1,015,860.58)
35	Schedule 24 Admin Allocation													-
	SUBTOTAL	670,743.32	618,065.14	632,242.78	880,078.78	646,028.43	784,990.81	651,400.05	539,533.41	807,997.51	869,091.54	660,814.31	804,939.85	8,565,925.93
Congestion Related Charges														
1 b	Day-Ahead Asset Energy Amount - Congestion Component	4,229,471.41	2,732,043.58	2,543,137.57	2,747,802.77	1,661,246.85	1,329,166.19	1,349,507.34	628,871.30	912,715.94	2,229,734.86	509,014.63	708,282.88	21,580,995.32
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	929,220.89	997,499.08	2,681,605.83	1,799,301.19	131,540.60	90,717.22	73,151.97	(16,389.92)	203,159.08	177,823.30	688,450.34	752,105.21	8,508,184.79
13 b	Real-Time Asset Energy Amount - Congestion Component	261,612.37	100,999.37	452,484.84	75,587.16	70,778.42	16,725.03	46,610.10	38,138.46	94,480.26	149,298.77	109,304.75	882.87	1,416,902.40
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	(2,080.65)	(293.19)	(26,406.57)	(26,744.69)	3,503.68	(1.63)	(21.22)	792.11	(171.58)	0.03	(133.48)	(286.59)	(51,843.78)
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	(8,214.12)	(8,141.19)	(8,474.41)	(3,574.47)	7,278.86	5,356.06	20,919.82	1,815.46	2,077.77	8,633.43	(7,051.88)	(3,046.41)	7,578.92
15	Real-Time Financial Bilateral Transaction Congestion Amount	-	-	-	-	-	-	-	23.00	(7.77)	-	2.35	-	17.58
28	Financial Transmission Rights Hourly Allocation Amount	(7,409,511.47)	(5,889,555.92)	(8,383,531.61)	(4,426,239.40)	(1,186,296.03)	(660,232.21)	(511,778.09)	(177,813.62)	(724,910.33)	(67,332.29)	(1,745,103.48)	(1,100,724.72)	(32,283,029.17)
30	Financial Transmission Rights Monthly Allocation Amount	(612,605.93)	(447,182.46)	(306,232.96)	(208,971.01)	(400,255.24)	141,917.90	20,641.26	(70,652.17)	(81,850.95)	(4,206.89)	(103,422.19)	(58,804.62)	(2,131,625.26)
32	Financial Transmission Rights Yearly Allocation Amount	-	-	-	-	-	-	-	-	-	(438,248.64)	-	-	(438,248.64)
31	Financial Transmission Rights Transaction Amount													-
36	Financial Transmission Rights Full Funding Guarantee Amount	40,349.07	(1,120.92)	(56,284.32)	(254,090.17)	319,991.92	(419,228.86)	(61,441.36)	(83,732.16)	(78,128.20)	62,379.85	53,958.81	53,995.61	(423,350.73)
37	Financial Transmission Guarantee Uplift Amount	(48,817.25)	(391.84)	62,630.10	258,310.57	(349,023.92)	419,063.21	66,631.38	81,217.84	74,688.76	(64,723.55)	14,581.48	(53,814.00)	460,352.78
38	Financial Transmission Rights Monthly Transaction Amount													-
	SUBTOTAL	(2,620,575.68)	(2,516,143.49)	(3,041,071.53)	(38,618.05)	258,765.14	923,482.91	1,004,221.20	402,270.30	402,052.98	2,053,358.87	(480,398.67)	298,590.23	(3,354,065.79)
Revenue Sufficiency Guarantee (RSG) Charges														
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	50,123.88	57,862.02	115,978.79	79,028.88	128,386.09	62,050.85	205,525.04	42,953.38	75,683.66	132,980.08	82,136.98	106,351.71	1,139,061.36
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amou	(12,345.06)	(32,854.54)	(96,390.36)	(53,286.27)	(142,633.89)	(168,861.50)	(360,075.77)	(42,009.16)	(46,824.18)	(309,502.38)	(52,416.61)	(34,357.61)	(1,351,557.33)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amour	294,120.50	146,960.97	365,711.53	242,005.39	126,340.02	(27,868.89)	483,401.05	(4,041.79)	38,916.85	229,232.53	111,692.60	276,215.39	2,282,686.15
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	(134,973.16)	(69,205.57)	(386,861.37)	(98,274.71)	(120,607.48)	(1,081.24)	(638,214.90)	(25,802.49)	(38,372.10)	(137,444.24)	(14,398.95)	(19,601.94)	(1,684,838.15)
43	Real Time Price Volatility Make Whole Payment	(194,026.12)	(112,767.09)	(307,866.23)	(477,828.40)	(47,329.87)	(154,244.18)	(368,914.39)	(110,397.76)	(132,358.39)	(216,371.99)	(129,317.99)	(161,021.43)	(2,412,443.84)
	SUBTOTAL	2,900.04	(10,004.21)	(309,427.64)	(308,355.11)	(55,845.13)	(290,004.96)	(678,278.97)	(139,297.82)	(102,954.16)	(301,106.00)	(2,303.97)	167,586.12	(2,027,091.81)
Other MISO Charges														
20	Real-Time Miscellaneous Amount	71,410.10	(52,943.90)	47,810.47	102,473.41	(73,492.42)	72,310.23	262,744.35	83,382.84	91,543.17	207,093.60	65,594.78	191,768.95	1,069,695.58
21	Real-time Net inadvertent Distribution	61,777.20	133,299.65	(61,649.28)	(64,967.37)	72,996.01	55,761.10	66,019.14	22,708.43	92,123.93	76,373.38	13,432.43	(83,118.67)	384,755.95
23	Real-Time Revenue Neutrality Uplift Amount	585,736.40	223,464.73	801,450.71	1,301,794.02	179,786.39	1,008,080.48	114,566.67	276,123.85	596,035.10	199,041.68	172,606.13	1,724,218.20	7,182,904.36
26	Real-Time Uninstructed Deviation Amount													-
	SUBTOTAL	718,923.70	303,820.48	787,611.90	1,339,300.06	179,289.98	1,136,151.81	443,330.16	382,215.12	779,702.20	482,508.66	251,633.34	1,832,868.48	8,637,355.89
Auction Revenue Rights (ARR)														-
39	Auction Revenue Rights - FTR Auction Transactions	3,620,102.73	3,620,102.73	3,419,039.70	3,419,039.70	3,419,039.70	3,077,706.89	3,077,706.89	3,077,706.89	3,351,784.59	3,351,784.59	3,351,784.59	2,270,304.83	39,056,103.83
40	Auction Revenue Rights - Monthly ARR Revenue	(3,628,762.14)	(3,628,762.14)	(3,472,296.93)	(3,472,296.93)	(3,472,296.93)	(3,090,966.42)	(3,090,966.42)	(3,090,966.42)	(3,360,340.60)	(3,360,340.59)	(3,360,340.52)	(2,293,458.77)	(39,321,794.81)
41	Auction Revenue Rights - ARR Stage 2 Distribution	(127,119.86)	(131,423.44)	(18,212.29)	(18,212.29)	(18,212.29)	(157,462.79)	(157,243.97)	(157,121.31)	(72,285.52)	(71,575.59)	(71,760.16)	(320,148.19)	(1,320,777.70)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	92,725.55	92,725.55	28,487.85	28,487.85	28,487.85	39,319.32	39,324.86	39,319.32	29,560.11	29,565.66	29,565.66	41,430.89	519,000.47
	SUBTOTAL	(43,053.72)	(47,357.30)	(42,981.67)	(42,981.67)	(42,981.67)	(131,403.00)	(131,178.64)	(131,061.52)	(51,281.42)	(50,565.93)	(50,750.43)	(301,871.24)	(1,067,468.21)
Grandfathered Charge Types														
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreement	8,214.12	8,141.19	8,474.41	3,574.47	(7,278.86)	(5,356.06)	(20,919.82)	(1,815.46)	(2,077.77)	(8,633.43)	7,051.88	3,046.41	(7,578.92)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreement	5,175.18	4,565.85	7,181.35	3,801.39	705.28	(1,280.54)	(3,719.45)	(4,267.62)	(1,039.78)	(1,086.22)	4,007.79	5,298.90	19,342.13
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements													-
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements													-
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	-	-	-	-	-	-	-	(23.00)	7.77	-	(2.35)	-	(17.58)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	-	-	-	-	-	-	-	5.34	(21.32)	-	(1.78)	-	(17.76)
	SUBTOTAL	13,389.30	12,707.04	15,655.76	7,375.86	(6,573.58)	(6,636.60)	(24,639.27)	(6,100.74)	(3,131.10)	(9,719.65)	11,055.54	8,345.31	11,727.87
	TOTAL MISO DAY 2 CHARGES	(5,151,843.38)	(5,630,206.66)	(4,923,628.44)	(5,652,690.96)	(5,993,256.75)	(10,443,154.78)	(14,072,245.10)	(6,097,477.16)	(7,120,835.15)	(1,714,127.31)	(7,823,183.19)	(9,993,446.79)	(84,616,095.67)

SUMMARY OF MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - INTERSYSTEM

	July 17	August 17	September 17	October 17	November 17	December 17	January 18	February 18	March 18	April 18	May 18	June 18	YTD
Day Ahead & Real Time Asset & Non-Asset Energy													
1 a Day-Ahead Asset Energy Amount - Energy Component	$ 8,636,781.59	$ 7,345,033.68	$ 6,323,343.49	$ 10,575,584.27	$ 11,212,684.01	$ 15,975,375.75	$ 20,699,050.09	$ 8,977,223.58	$ 10,664,754.29	$ 8,062,443.77	$ 9,964,011.92	$ 13,183,336.85	$ 131,619,623.29
5 a Day-Ahead Non-Asset Energy Amount - Energy Component													
13 a Real-Time Asset Energy Amount - Energy Component	$ 1,792,655.66	$ 2,002,630.75	$ 2,946,846.14	$ 3,051,085.81	$ 1,647,558.42	$ 2,047,122.14	$ 1,656,273.29	$ 1,723,232.26	$ 1,561,429.19	$ 1,818,678.24	$ 1,861,919.15	$ 2,081,900.78	$ 24,191,331.83
22 a Real-Time Non-Asset Energy Amount - Energy Component													
SUBTOTAL	$ 10,429,437.25	$ 9,347,664.43	$ 9,270,189.63	$ 13,626,670.08	$ 12,860,242.43	$ 18,022,497.89	$ 22,355,323.38	$ 10,700,455.84	$ 12,226,183.48	$ 9,881,122.01	$ 11,825,931.07	$ 15,265,237.63	$ 155,810,955.12
Day Ahead & Real Time Energy Loss													
1 c Day-Ahead Asset Energy Amount - Loss Component	$ (201,582.68)	$ (170,960.79)	$ (233,248.75)	$ (349,922.93)	$ (460,592.39)	$ (579,268.46)	$ (856,737.95)	$ (333,793.62)	$ (368,628.88)	$ (387,572.99)	$ (278,720.98)	$ (327,716.49)	$ (4,548,746.92)
3 Day-Ahead Financial Bilateral Transaction Loss Amount													
5 c Day-Ahead Non-Asset Energy Amount - Loss Component	$ (117,038.88)	$ (121,901.87)	$ (190,686.99)	$ (196,522.57)	$ (44,745.87)	$ (33,101.53)	$ (28,147.92)	$ (11,094.04)	$ (40,665.32)	$ (40,681.17)	$ (112,226.57)	$ (163,009.70)	$ (1,099,822.41)
13 c Real-Time Asset Energy Amount - Loss Component	$ 117.96	$ 53.50	$ 1,020.99	$ 83.68	$ 0.77	$ 5.38	$ 1.36	$ (2.18)	$ 32.78	$ (0.01)	$ 122.14	$ 89.81	$ 1,526.18
22 c Real-Time Non-Asset Energy Amount - Loss Component	$ 9,220.59	$ 6,951.91	$ 17,813.53	$ 10,037.39	$ 10,084.35	$ (1,467.25)	$ 2,917.20	$ 761.11	$ 8,000.64	$ 10,364.52	$ 28,423.14	$ 17,773.51	$ 120,880.64
14 Real-Time Distribution of Losses Amount													
16 Real-Time Financial Bilateral Transaction Loss Amount													
SUBTOTAL	$ (309,283.00)	$ (285,857.25)	$ (405,101.21)	$ (536,324.43)	$ (495,253.14)	$ (613,831.85)	$ (881,967.31)	$ (344,128.73)	$ (401,260.79)	$ (417,889.65)	$ (362,402.27)	$ (472,862.87)	$ (5,526,162.50)
Virtual Energy Charges													
12 Day-Ahead Virtual Energy Amount													
27 Real-Time Virtual Energy Amount													
SUBTOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Market Administration Charges (Schedule 16 & 17)													
4 Day-Ahead Market Administration Amount	$ (18,067.56)	$ (17,366.57)	$ (19,585.29)	$ (41,571.26)	$ (55,194.12)	$ (57,120.20)	$ (50,319.93)	$ (25,458.44)	$ (50,683.98)	$ (42,033.55)	$ (28,666.61)	$ (43,301.51)	$ (449,369.02)
19 Real-Time Market Administration Amount	$ (5,451.91)	$ (6,678.05)	$ (9,228.05)	$ (11,272.89)	$ (11,006.39)	$ (7,795.01)	$ (5,190.26)	$ (4,234.88)	$ (8,141.75)	$ (9,725.47)	$ (6,196.15)	$ (7,622.85)	$ (92,543.66)
29 Financial Transmission Rights Market Administration Amount													$ -
33 Day-Ahead Schedule 24 Allocation Amount	$ (3,011.97)	$ (2,742.07)	$ (3,015.72)	$ (7,050.81)	$ (6,590.14)	$ (8,810.71)	$ (8,559.65)	$ (4,428.72)	$ (6,580.69)	$ (5,258.52)	$ (5,140.78)	$ (6,111.18)	$ (67,300.96)
34 Real -Time Schedule 24 Allocation Amount	$ 66,878.49	$ 82,812.17	$ 81,792.20	$ 75,016.20	$ 96,306.85	$ 92,979.92	$ 101,581.74	$ 96,792.99	$ 55,553.06	$ 120,775.12	$ 95,689.44	$ 118,852.35	$ 1,085,030.53
35 Schedule 24 Admin Allocation													$ -
SUBTOTAL	$ 40,347.05	$ 56,025.48	$ 49,963.14	$ 15,121.24	$ 23,516.20	$ 19,254.00	$ 37,511.90	$ 62,670.95	$ (9,853.36)	$ 63,757.58	$ 55,685.90	$ 61,816.81	$ 475,816.89
Congestion Related Charges													
1 b Day-Ahead Asset Energy Amount - Congestion Component	$ (328,546.48)	$ (237,861.77)	$ (265,701.26)	$ (454,654.86)	$ (253,872.86)	$ (228,050.87)	$ (234,237.16)	$ (75,881.79)	$ (138,249.50)	$ (276,377.61)	$ (60,213.95)	$ (101,344.90)	$ (2,654,993.00)
5 b Day-Ahead Non-Asset Energy Amount - Congestion Component	$ (72,182.13)	$ (86,845.94)	$ (280,168.11)	$ (297,714.61)	$ (20,102.12)	$ (15,564.75)	$ (12,697.16)	$ 1,977.66	$ (30,772.60)	$ (22,041.36)	$ (81,440.31)	$ (107,615.23)	$ (1,025,166.66)
13 b Real-Time Asset Energy Amount - Congestion Component	$ 161.63	$ 25.53	$ 2,758.90	$ 4,425.21	$ (535.43)	$ 0.28	$ 3.68	$ (95.58)	$ 25.99	$ (0.00)	$ 15.79	$ 41.01	$ 6,826.99
22 b Real-Time Non-Asset Energy Amount - Congestion Component	$ 34,623.74	$ 21,338.34	$ 74,228.42	$ 54,322.81	$ 10,463.52	$ (669.21)	$ (9,739.24)	$ 1,390.24	$ 19,665.76	$ 27,755.09	$ 33,368.56	$ 2,066.57	$ 268,814.59
2 Day-Ahead Financial Bilateral Transmission Congestion Amount													
15 Real-Time Financial Bilateral Transaction Congestion Amount													
28 Financial Transmission Rights Hourly Allocation Amount													$ -
30 Financial Transmission Rights Monthly Allocation Amount													
32 Financial Transmission Rights Yearly Allocation Amount													
31 Financial Transmission Rights Transaction Amount													
36 Financial Transmission Rights Full Funding Guarantee Amount													
37 Financial Transmission Guarantee Uplift Amount													
38 Financial Transmission Rights Monthly Transaction Amount													
SUBTOTAL	$ (365,943.24)	$ (303,343.84)	$ (468,882.05)	$ (693,621.45)	$ (264,046.90)	$ (244,284.55)	$ (256,669.88)	$ (72,609.47)	$ (149,330.36)	$ (270,663.88)	$ (108,269.91)	$ (206,852.56)	$ (3,404,518.07)
Revenue Sufficiency Guarantee (RSG) Charges													
10 Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ (3,893.64)	$ (5,037.68)	$ (12,117.20)	$ (13,076.22)	$ (19,620.05)	$ (10,646.34)	$ (35,673.46)	$ (5,182.90)	$ (11,463.84)	$ (16,483.00)	$ (9,716.40)	$ (15,217.37)	$ (158,128.10)
11 Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amou	$ 10,157.50	$ 12,622.58	$ 21,874.04	$ 18,086.26	$ 48,179.67	$ 11,717.95	$ 16,777.81	$ 25,547.64	$ 11,178.16	$ 6,485.11	$ 14,137.18	$ 25,633.38	$ 222,397.28
24 Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amour	$ (22,847.36)	$ (12,794.96)	$ (38,208.71)	$ (40,042.51)	$ (19,307.37)	$ 4,781.59	$ (83,905.06)	$ 487.70	$ (5,894.75)	$ (28,413.57)	$ (13,212.69)	$ (39,522.37)	$ (298,880.08)
25 Real-Time Revenue Sufficiency Make Whole Payment Amount	$ 97,898.42	$ 17,205.14	$ 260,874.83	$ 79,725.88	$ 23,007.63	$ 775.34	$ 247,677.59	$ 9,699.57	$ 12,749.74	$ 37,147.83	$ (15,105.13)	$ 7,559.75	$ 779,216.59
43 Real Time Price Volatility Make Whole Payment	$ 32,231.20	$ 16,884.55	$ 112,066.67	$ 54,335.40	$ 13,956.34	$ 16,743.67	$ 41,198.93	$ 62,765.79	$ 13,688.82	$ 23,058.51	$ 21,839.82	$ 13,951.05	$ 422,720.75
SUBTOTAL	$ 113,546.12	$ 28,879.63	$ 344,489.63	$ 99,028.81	$ 46,216.23	$ 23,372.21	$ 186,075.81	$ 93,317.79	$ 20,258.13	$ 21,794.88	$ (2,057.22)	$ (7,595.56)	$ 967,326.44
Other MISO Charges													
20 Real-Time Miscellaneous Amount	$ 13,920.00	$ 15,840.00	$ 14,400.00	$ 13,479.11	$ 14,788.68	$ 14,943.22	$ 14,400.00	$ 14,388.99	$ 14,880.00	$ 14,880.00	$ 14,880.00	$ 10,358.70	$ 171,158.70
21 Real-time Net inadvertent Distribution													
23 Real-Time Revenue Neutrality Uplift Amount	$ (45,500.16)	$ (19,455.66)	$ (83,733.76)	$ (215,396.46)	$ (27,475.08)	$ (172,960.79)	$ (19,885.61)	$ (33,318.06)	$ (90,281.71)	$ (24,671.39)	$ (20,418.46)	$ (246,710.35)	$ (999,807.49)
26 Real-Time Uninstructed Deviation Amount													$ -
SUBTOTAL	$ (31,580.16)	$ (3,615.66)	$ (69,333.76)	$ (201,917.35)	$ (12,686.40)	$ (158,017.57)	$ (5,485.61)	$ (18,929.07)	$ (75,401.71)	$ (9,791.39)	$ (5,538.46)	$ (236,351.65)	$ (828,648.79)
Auction Revenue Rights (ARR)													
39 Auction Revenue Rights - FTR Auction Transactions													
40 Auction Revenue Rights - Monthly ARR Revenue	$ 9,159.73	$ 17,868.65	$ 17,561.86	$ 6,412.78	$ 5,437.03	$ 5,660.69	$ 40,382.56	$ 36,540.69	$ 41,129.71	$ 33,326.02	$ 19,351.61	$ 19,997.72	$ 252,829.05
41 Auction Revenue Rights - ARR Stage 2 Distribution													
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue													
SUBTOTAL	$ 9,159.73	$ 17,868.65	$ 17,561.86	$ 6,412.78	$ 5,437.03	$ 5,660.69	$ 40,382.56	$ 36,540.69	$ 41,129.71	$ 33,326.02	$ 19,351.61	$ 19,997.72	$ 252,829.05
Grandfathered Charge Types													
6 Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements													
7 Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements													
8 Day-Ahead Congestion Rebate on Option B Grandfathered Agreements													
9 Day-Ahead Losses Rebate on Option B Grandfathered Agreements													
17 Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements													
18 Real-Time Losses Rebate on Carve-Out Grandfathered Agreements													
SUBTOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL MISO DAY 2 CHARGES	$ 9,885,683.75	$ 8,857,621.43	$ 8,738,887.24	$ 12,315,369.68	$ 12,163,425.45	$ 17,054,650.82	$ 21,475,170.86	$ 10,457,318.01	$ 11,651,725.11	$ 9,301,655.57	$ 11,422,700.71	$ 14,423,389.51	$ 147,747,598.14

SUMMARY OF MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - RETAIL

	July 17	August 17	September 17	October 17	November 17	December 17	January 18	February 18	March 18	April 18	May 18	June 18	YTD
Day Ahead & Real Time Asset & Non-Asset Energy													
1 a Day-Ahead Asset Energy Amount - Energy Component	$ 16,578,714.55	$ 13,741,210.29	$ 15,326,995.84	$ 9,965,167.26	$ 5,685,963.25	$ 4,037,493.69	$ 6,683,770.62	$ 3,837,072.30	$ 4,801,881.54	$ 4,701,511.46	$ 12,578,913.31	$ 8,888,029.55	$ 106,826,723.66
5 a Day-Ahead Non-Asset Energy Amount - Energy Component	$ (12,441,178.06)	$ (11,098,231.58)	$ (12,033,585.01)	$ (8,797,500.02)	$ (3,513,700.28)	$ (3,715,572.79)	$ (5,212,659.65)	$ (2,938,997.15)	$ (3,710,991.17)	$ (4,191,337.63)	$ (7,661,954.85)	$ (8,175,545.00)	$ (83,491,253.19)
13 a Real-Time Asset Energy Amount - Energy Component	$ (472,577.14)	$ 170,023.09	$ 78,340.22	$ 2,417,905.59	$ 1,098,336.58	$ 2,244,398.85	$ 2,215,855.12	$ 814,839.75	$ (31,244.54)	$ 1,861,332.62	$ (3,852,616.23)	$ (735,859.03)	$ 5,808,734.88
22 a Real-Time Non-Asset Energy Amount - Energy Component	$ 16,493.74	$ 18,605.36	$ 72,020.99	$ 12,658.74	$ 28,235.43	$ 618.34	$ 601.46	$ (518.41)	$ 2,531.40	$ 2,290.95	$ 12,557.77	$ 6,052.65	$ 172,148.42
SUBTOTAL	$ 3,681,453.09	$ 2,831,607.16	$ 3,443,772.04	$ 3,598,231.57	$ 3,298,834.98	$ 2,566,938.09	$ 3,687,567.55	$ 1,712,396.49	$ 1,062,177.23	$ 2,373,797.40	$ 1,076,900.00	$ (17,321.83)	$ 29,316,353.77
Day Ahead & Real Time Energy Loss													
1 c Day-Ahead Asset Energy Amount - Loss Component	$ 2,393,447.99	$ 1,792,668.53	$ 1,999,272.31	$ 1,764,910.29	$ 2,553,348.00	$ 2,796,925.82	$ 4,079,174.66	$ 2,432,525.23	$ 2,065,039.58	$ 2,739,254.20	$ 2,077,428.50	$ 1,962,640.31	$ 28,656,635.41
3 Day-Ahead Financial Bilateral Transaction Loss Amount	$ (5,175.18)	$ (4,565.85)	$ (7,181.35)	$ (3,801.39)	$ (705.28)	$ 1,280.54	$ 3,719.45	$ 4,267.62	$ 1,039.78	$ 1,086.22	$ (4,007.79)	$ (5,298.90)	$ (19,342.13)
5 c Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,389,635.59	$ 1,278,244.22	$ 1,634,457.69	$ 991,203.12	$ 248,054.01	$ 159,826.60	$ 134,020.31	$ 80,847.94	$ 227,804.96	$ 287,522.79	$ 836,473.31	$ 976,238.33	$ 8,244,328.89
13 c Real-Time Asset Energy Amount - Loss Component	$ 141,034.59	$ 81,684.80	$ 123,606.11	$ 33,127.69	$ 66,810.12	$ 17,311.00	$ 3,838.25	$ 6,649.15	$ 65,251.82	$ 60,928.04	$ 146,698.06	$ 70,651.89	$ 817,591.52
22 c Real-Time Non-Asset Energy Amount - Loss Component	$ 7,702.05	$ 6,337.36	$ 8,041.20	$ 9,531.63	$ 10,079.32	$ (1,498.62)	$ 2,909.35	$ 779.21	$ 7,784.25	$ 10,364.59	$ 27,390.65	$ 17,145.86	$ 106,566.85
14 Real-Time Distribution of Losses Amount	$ (1,382,114.23)	$ (915,463.36)	$ (1,302,537.63)	$ (792,348.09)	$ (783,371.78)	$ (991,853.15)	$ (1,774,973.13)	$ (1,026,169.10)	$ (557,417.40)	$ (767,415.68)	$ (910,589.02)	$ (1,015,586.44)	$ (12,219,839.01)
16 Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5.34)	$ 21.32	$ -	$ 1.78	$ -	$ 17.76
SUBTOTAL	$ 2,544,530.82	$ 2,238,905.70	$ 2,455,658.34	$ 2,002,623.25	$ 2,094,214.39	$ 1,981,992.20	$ 2,448,688.89	$ 1,498,894.71	$ 1,809,524.30	$ 2,331,740.16	$ 2,173,395.49	$ 2,005,791.05	$ 25,585,959.30
Virtual Energy Charges													
12 Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27 Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SUBTOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Market Administration Charges (Schedule 16 & 17)													
4 Day-Ahead Market Administration Amount	$ 575,036.99	$ 524,577.84	$ 532,366.42	$ 733,769.35	$ 513,588.13	$ 633,648.71	$ 540,143.18	$ 443,656.88	$ 681,167.57	$ 729,138.77	$ 552,852.61	$ 655,305.98	$ 7,115,252.43
19 Real-Time Market Administration Amount	$ 40,143.13	$ 32,452.07	$ 35,005.07	$ 55,786.96	$ 32,883.01	$ 49,296.34	$ 34,071.69	$ 30,159.99	$ 44,672.30	$ 48,204.10	$ 47,847.09	$ 65,335.42	$ 515,857.17
29 Financial Transmission Rights Market Administration Amount	$ 32,031.60	$ 26,142.80	$ 24,065.60	$ 27,509.36	$ 20,575.92	$ 21,107.84	$ 17,404.08	$ 25,520.16	$ 14,893.28	$ 32,862.32	$ 14,822.88	$ 19,888.40	$ 276,824.24
33 Day-Ahead Schedule 24 Allocation Amount	$ 89,388.96	$ 85,284.04	$ 80,280.88	$ 83,939.46	$ 90,049.50	$ 97,546.49	$ 91,866.16	$ 77,247.95	$ 87,472.37	$ 90,799.92	$ 100,622.50	$ 90,140.80	$ 1,064,639.03
34 Real -Time Schedule 24 Allocation Amount	$ (25,510.31)	$ 5,633.87	$ 10,487.95	$ (5,805.11)	$ 12,448.07	$ 2,645.43	$ 5,426.84	$ 25,619.38	$ (30,061.37)	$ 31,844.01	$ 355.13	$ 36,086.06	$ 69,169.95
35 Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SUBTOTAL	$ 711,090.37	$ 674,090.62	$ 682,205.92	$ 895,200.02	$ 669,544.63	$ 804,244.81	$ 688,911.95	$ 602,204.36	$ 798,144.15	$ 932,849.12	$ 716,500.21	$ 866,756.66	$ 9,041,742.82
Congestion Related Charges													
1 b Day-Ahead Asset Energy Amount - Congestion Component	$ 3,900,924.93	$ 2,494,181.81	$ 2,277,436.31	$ 2,293,147.91	$ 1,407,373.99	$ 1,101,115.32	$ 1,115,270.18	$ 552,989.51	$ 774,466.44	$ 1,953,357.25	$ 448,800.68	$ 606,937.98	$ 18,926,002.32
5 b Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 857,038.76	$ 910,653.14	$ 2,401,437.72	$ 1,501,586.58	$ 111,438.48	$ 75,152.47	$ 60,454.81	$ (14,412.26)	$ 172,386.48	$ 155,781.94	$ 607,010.03	$ 644,489.98	$ 7,483,018.13
13 b Real-Time Asset Energy Amount - Congestion Component	$ 261,774.00	$ 101,024.90	$ 455,243.74	$ 80,012.37	$ 70,242.99	$ 16,725.31	$ 46,613.78	$ 38,042.88	$ 94,506.25	$ 149,298.77	$ 109,320.54	$ 923.88	$ 1,423,729.39
22 b Real-Time Non-Asset Energy Amount - Congestion Component	$ 32,543.09	$ 21,045.15	$ 47,821.85	$ 27,578.12	$ 13,967.20	$ (670.84)	$ (9,760.46)	$ 2,182.35	$ 19,494.18	$ 27,755.12	$ 33,235.08	$ 1,779.98	$ 216,970.81
2 Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (8,214.12)	$ (8,141.19)	$ (8,474.41)	$ (3,574.47)	$ 7,278.86	$ 5,356.06	$ 20,919.82	$ 1,815.46	$ 2,077.77	$ 8,633.43	$ (7,051.88)	$ (3,046.41)	$ 7,578.92
15 Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 23.00	$ (7.77)	$ -	$ 2.35	$ -	$ 17.58
28 Financial Transmission Rights Hourly Allocation Amount	$ (7,409,511.47)	$ (5,889,555.92)	$ (8,383,531.61)	$ (4,426,239.40)	$ (1,186,296.03)	$ (660,232.21)	$ (511,778.09)	$ (177,813.62)	$ (724,910.33)	$ (67,332.29)	$ (1,745,103.48)	$ (1,100,724.72)	$ (32,283,029.17)
30 Financial Transmission Rights Monthly Allocation Amount	$ (612,605.93)	$ (447,182.46)	$ (306,232.96)	$ (208,971.01)	$ (400,255.24)	$ 141,917.90	$ 20,641.26	$ (70,652.17)	$ (81,850.95)	$ (4,206.89)	$ (103,422.19)	$ (58,804.62)	$ (2,131,625.26)
32 Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (438,248.64)	$ -	$ -	$ (438,248.64)
31 Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36 Financial Transmission Rights Full Funding Guarantee Amount	$ 40,349.07	$ (1,120.92)	$ (56,284.32)	$ (254,090.17)	$ 319,991.92	$ (419,228.86)	$ (61,441.36)	$ (83,732.16)	$ (78,128.20)	$ 62,379.85	$ 53,958.81	$ 53,995.61	$ (423,350.73)
37 Financial Transmission Guarantee Uplift Amount	$ (48,817.25)	$ (391.84)	$ 62,630.10	$ 258,310.57	$ (349,023.92)	$ 419,063.21	$ 66,631.38	$ 81,217.84	$ 74,688.76	$ (64,723.55)	$ 14,581.48	$ (53,814.00)	$ 460,352.78
38 Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SUBTOTAL	$ (2,986,518.92)	$ (2,819,487.33)	$ (3,509,953.58)	$ (732,239.50)	$ (5,281.76)	$ 679,198.36	$ 747,551.32	$ 329,660.83	$ 252,722.62	$ 1,782,694.99	$ (588,668.58)	$ 91,737.67	$ (6,758,583.86)
Revenue Sufficiency Guarantee (RSG) Charges													
10 Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 46,230.24	$ 52,824.34	$ 103,861.59	$ 65,952.66	$ 108,766.04	$ 51,404.51	$ 169,851.58	$ 37,770.48	$ 64,219.82	$ 116,497.08	$ 72,420.58	$ 91,134.34	$ 980,933.26
11 Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amou	$ (2,187.56)	$ (20,231.96)	$ (74,516.32)	$ (35,200.01)	$ (94,454.22)	$ (157,143.55)	$ (343,297.96)	$ (16,461.52)	$ (35,646.02)	$ (303,017.27)	$ (38,279.43)	$ (8,724.23)	$ (1,129,160.05)
24 Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amour	$ 271,273.14	$ 134,166.01	$ 327,502.82	$ 201,962.88	$ 107,032.65	$ (23,087.30)	$ 399,495.99	$ (3,554.09)	$ 33,022.10	$ 200,818.96	$ 98,479.91	$ 236,693.02	$ 1,983,806.07
25 Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (37,074.74)	$ (52,000.43)	$ (125,986.54)	$ (18,548.83)	$ (97,599.85)	$ (305.90)	$ (390,537.31)	$ (16,102.92)	$ (25,622.36)	$ (100,296.41)	$ (29,504.08)	$ (12,042.19)	$ (905,621.56)
43 Real Time Price Volatility Make Whole Payment	$ (161,794.92)	$ (95,882.54)	$ (195,799.56)	$ (423,493.00)	$ (33,373.53)	$ (137,500.51)	$ (327,715.46)	$ (47,631.97)	$ (118,669.57)	$ (193,313.48)	$ (107,478.17)	$ (147,070.38)	$ (1,989,723.09)
SUBTOTAL	$ 116,446.16	$ 18,875.42	$ 35,061.99	$ (209,326.30)	$ (9,628.90)	$ (266,632.75)	$ (492,203.16)	$ (45,980.03)	$ (82,696.03)	$ (279,311.12)	$ (4,361.19)	$ 159,990.56	$ (1,059,765.37)
Other MISO Charges													
20 Real-Time Miscellaneous Amount	$ 85,330.10	$ (37,103.90)	$ 62,210.47	$ 115,952.52	$ (58,703.74)	$ 87,253.45	$ 277,144.35	$ 97,771.83	$ 106,423.17	$ 221,973.60	$ 80,474.78	$ 202,127.65	$ 1,240,854.28
21 Real-time Net inadvertent Distribution	$ 61,777.20	$ 133,299.65	$ (61,649.28)	$ (64,967.37)	$ 72,996.01	$ 55,761.10	$ 66,019.14	$ 22,708.43	$ 92,123.93	$ 76,373.38	$ 13,432.43	$ (83,118.67)	$ 384,755.95
23 Real-Time Revenue Neutrality Uplift Amount	$ 540,236.24	$ 204,009.07	$ 717,716.95	$ 1,086,397.56	$ 152,311.31	$ 835,119.69	$ 94,681.06	$ 242,805.79	$ 505,753.39	$ 174,370.29	$ 152,187.67	$ 1,477,507.85	$ 6,183,096.87
26 Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SUBTOTAL	$ 687,343.54	$ 300,204.82	$ 718,278.14	$ 1,137,382.71	$ 166,603.58	$ 978,134.24	$ 437,844.55	$ 363,286.05	$ 704,300.49	$ 472,717.27	$ 246,094.88	$ 1,596,516.83	$ 7,808,707.10
Auction Revenue Rights (ARR)													
39 Auction Revenue Rights - FTR Auction Transactions	$ 3,620,102.73	$ 3,620,102.73	$ 3,419,039.70	$ 3,419,039.70	$ 3,419,039.70	$ 3,077,706.89	$ 3,077,706.89	$ 3,077,706.89	$ 3,351,784.59	$ 3,351,784.59	$ 3,351,784.59	$ 2,270,304.83	$ 39,056,103.83
40 Auction Revenue Rights - Monthly ARR Revenue	$ (3,619,602.41)	$ (3,610,893.49)	$ (3,454,735.07)	$ (3,465,884.15)	$ (3,466,859.90)	$ (3,085,305.73)	$ (3,050,583.86)	$ (3,054,425.73)	$ (3,319,210.89)	$ (3,327,014.57)	$ (3,340,988.91)	$ (2,273,461.05)	$ (39,068,965.76)
41 Auction Revenue Rights - ARR Stage 2 Distribution	$ (127,119.86)	$ (131,423.44)	$ (18,212.29)	$ (18,212.29)	$ (18,212.29)	$ (157,462.79)	$ (157,243.97)	$ (157,121.31)	$ (72,285.52)	$ (71,575.59)	$ (71,760.16)	$ (320,148.19)	$ (1,320,777.70)
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 92,725.55	$ 92,725.55	$ 28,487.85	$ 28,487.85	$ 28,487.85	$ 39,319.32	$ 39,324.86	$ 39,319.32	$ 29,560.11	$ 29,565.66	$ 29,565.66	$ 41,430.89	$ 519,000.47
SUBTOTAL	$ (33,893.99)	$ (29,488.65)	$ (25,419.81)	$ (36,568.89)	$ (37,544.64)	$ (125,742.31)	$ (90,796.08)	$ (94,520.83)	$ (10,151.71)	$ (17,239.91)	$ (31,398.82)	$ (281,873.52)	$ (814,639.16)
Grandfathered Charge Types													
6 Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreement	$ 8,214.12	$ 8,141.19	$ 8,474.41	$ 3,574.47	$ (7,278.86)	$ (5,356.06)	$ (20,919.82)	$ (1,815.46)	$ (2,077.77)	$ (8,633.43)	$ 7,051.88	$ 3,046.41	$ (7,578.92)
7 Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 5,175.18	$ 4,565.85	$ 7,181.35	$ 3,801.39	$ 705.28	$ (1,280.54)	$ (3,719.45)	$ (4,267.62)	$ (1,039.78)	$ (1,086.22)	$ 4,007.79	$ 5,298.90	$ 19,342.13
8 Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9 Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17 Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (23.00)	$ 7.77	$ -	$ (2.35)	$ -	$ (17.58)
18 Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5.34	$ (21.32)	$ -	$ (1.78)	$ -	$ (17.76)
SUBTOTAL	$ 13,389.30	$ 12,707.04	$ 15,655.76	$ 7,375.86	$ (6,573.58)	$ (6,636.60)	$ (24,639.27)	$ (6,100.74)	$ (3,131.10)	$ (9,719.65)	$ 11,055.54	$ 8,345.31	$ 11,727.87
TOTAL MISO DAY 2 CHARGES	$ 4,733,840.37	$ 3,227,414.77	$ 3,815,258.80	$ 6,662,678.72	$ 6,170,168.70	$ 6,611,496.04	$ 7,402,925.76	$ 4,359,840.85	$ 4,530,889.96	$ 7,587,528.26	$ 3,599,517.52	$ 4,429,942.72	$ 63,131,502.47

SUMMARY OF DAY 2 MARKET SETTLEMENT BY CATEGORIES - MINNESOTA RETAIL (WEIGHTED BY MWH SALES)

No.	Description	July 17	August 17	September 17	October 17	November 17	December 17	January 18	February 18	March 18	April 18	May 18	June 18	YTD
	Day Ahead & Real Time Asset & Non-Asset Energy													
1 a	Day-Ahead Asset Energy Amount - Energy Component	12,252,728.41	10,092,337.69	11,364,267.49	7,232,124.07	4,091,194.35	2,887,665.53	4,752,225.09	2,743,304.08	3,437,882.59	3,404,565.15	9,199,921.41	6,537,128.90	77,995,344.76
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	(9,194,824.81)	(8,151,181.63)	(8,922,353.76)	(6,384,700.83)	(2,528,196.21)	(2,657,423.71)	(3,706,251.07)	(2,101,227.77)	(2,656,865.20)	(3,035,126.50)	(5,603,773.61)	(6,013,097.86)	(60,955,022.95)
13 a	Real-Time Asset Energy Amount - Energy Component	(349,264.68)	124,874.77	58,085.70	1,754,771.67	790,280.94	1,605,221.87	1,575,494.27	582,567.39	(22,369.37)	1,347,870.41	(2,817,712.92)	(541,222.92)	4,108,597.14
22 a	Real-Time Non-Asset Energy Amount - Energy Component	12,189.93	13,664.85	53,400.28	9,186.96	20,316.11	442.24	427.64	(370.64)	1,812.34	1,658.97	9,184.46	4,451.71	126,364.86
	SUBTOTAL	2,720,828.85	2,079,695.68	2,553,399.70	2,611,381.87	2,373,595.19	1,835,905.94	2,621,895.94	1,224,273.07	760,460.37	1,718,968.03	787,619.34	(12,740.17)	21,275,283.81
	Day Ahead & Real Time Energy Loss													
1 c	Day-Ahead Asset Energy Amount - Loss Component	1,768,910.86	1,316,639.20	1,482,369.12	1,280,866.63	1,837,198.46	2,000,396.01	2,900,332.36	1,739,127.10	1,478,454.55	1,983,610.90	1,519,382.35	1,443,518.23	20,750,805.76
3	Day-Ahead Financial Bilateral Transaction Loss Amount	(3,824.79)	(3,353.42)	(5,324.64)	(2,758.82)	(507.47)	915.86	2,644.56	3,051.12	744.43	786.58	(2,931.20)	(3,897.33)	(14,455.13)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	1,027,029.41	938,816.31	1,211,875.74	719,356.11	178,481.13	114,309.97	95,289.73	57,802.01	163,095.80	208,207.53	611,776.91	718,021.45	6,044,062.09
13 c	Real-Time Asset Energy Amount - Loss Component	104,233.57	59,994.03	91,648.29	24,042.10	48,071.57	12,381.04	2,729.03	4,753.79	46,716.71	44,120.60	107,291.51	51,964.33	597,946.57
22 c	Real-Time Non-Asset Energy Amount - Loss Component	5,692.31	4,654.52	5,962.19	6,917.49	7,252.33	(1,071.83)	2,068.57	557.09	5,573.09	7,505.44	20,032.88	12,610.75	77,754.82
14	Real-Time Distribution of Losses Amount	(1,021,470.65)	(672,369.11)	(965,772.17)	(575,038.99)	(563,655.81)	(709,385.67)	(1,262,022.94)	(733,656.72)	(399,080.14)	(555,718.45)	(665,983.40)	(746,961.90)	(8,871,115.95)
16	Real-Time Financial Bilateral Transaction Loss Amount	-	-	-	-	-	-	-	(3.82)	15.26	-	1.30	-	12.75
	SUBTOTAL	1,880,570.71	1,644,381.53	1,820,758.52	1,453,384.51	1,506,840.21	1,417,545.38	1,741,041.32	1,071,630.57	1,295,519.69	1,688,512.59	1,589,570.35	1,475,255.52	18,585,010.91
	Virtual Energy Charges													
12	Day-Ahead Virtual Energy Amount	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Real-Time Virtual Energy Amount	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTOTAL	-	-	-	-	-	-	-	-	-	-	-	-	-
	Market Administration Charges (Schedule 16 & 17)													
4	Day-Ahead Market Administration Amount	424,989.05	385,280.23	394,725.39	532,526.03	369,539.65	453,193.41	384,046.99	317,191.24	487,678.45	528,000.51	404,343.40	481,976.31	5,163,490.65
19	Real-Time Market Administration Amount	29,668.34	23,834.67	25,954.66	40,486.85	23,660.16	35,257.35	24,225.30	21,562.80	31,982.91	34,906.65	34,994.24	48,054.08	374,587.99
29	Financial Transmission Rights Market Administration Amount	23,673.40	19,200.78	17,843.54	19,964.65	14,804.89	15,096.59	12,374.47	18,245.57	10,662.77	23,797.01	10,841.11	14,627.88	201,132.66
33	Day-Ahead Schedule 24 Allocation Amount	66,064.15	62,637.52	59,524.61	60,918.25	64,792.89	69,766.46	65,317.72	55,228.21	62,625.40	65,752.10	73,592.93	66,298.39	772,518.62
34	Real -Time Schedule 24 Allocation Amount	(18,853.75)	4,137.84	7,776.34	(4,213.00)	8,956.70	1,892.04	3,858.54	18,316.50	(21,522.28)	23,059.61	259.73	26,541.23	50,209.49
35	Schedule 24 Admin Allocation	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTOTAL	525,541.18	495,091.05	505,824.54	649,682.78	481,754.29	575,205.86	489,823.01	430,544.32	571,427.23	675,515.87	524,031.41	637,497.88	6,561,939.41
	Congestion Related Charges													-
1 b	Day-Ahead Asset Energy Amount - Congestion Component	2,883,032.56	1,831,871.04	1,688,615.02	1,664,229.99	1,012,641.18	787,531.32	792,967.81	395,358.30	554,475.29	1,414,509.37	328,242.27	446,401.74	13,799,875.88
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	633,406.36	668,836.21	1,780,556.41	1,089,761.98	80,182.80	53,749.98	42,983.95	(10,304.00)	123,419.22	112,808.36	443,952.86	474,021.16	5,493,375.28
13 b	Real-Time Asset Energy Amount - Congestion Component	193,467.69	74,198.51	337,542.44	58,068.21	50,541.60	11,962.15	33,142.85	27,198.65	67,661.27	108,113.61	79,954.47	679.51	1,042,530.97
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	24,051.42	15,456.77	35,457.72	20,014.56	10,049.75	(479.79)	(6,939.78)	1,560.26	13,956.76	20,098.67	24,307.36	1,309.17	158,842.86
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	(6,070.76)	(5,979.36)	(6,283.39)	(2,594.14)	5,237.32	3,830.72	14,874.19	1,297.96	1,487.57	6,251.84	(5,157.58)	(2,240.63)	4,653.75
15	Real-Time Financial Bilateral Transaction Congestion Amount	-	-	-	-	-	-	-	16.44	(5.56)	-	1.72	-	12.60
28	Financial Transmission Rights Hourly Allocation Amount	(5,476,101.99)	(4,325,629.69)	(6,216,005.85)	(3,212,300.57)	(853,569.99)	(472,206.26)	(363,879.14)	(127,127.35)	(518,995.85)	(48,758.19)	(1,276,327.65)	(809,580.95)	(23,700,483.47)
30	Financial Transmission Rights Monthly Allocation Amount	(452,754.89)	(328,436.60)	(227,057.76)	(151,658.70)	(287,993.77)	101,501.44	14,676.13	(50,512.57)	(58,600.77)	(3,046.39)	(75,640.56)	(43,250.69)	(1,562,775.11)
32	Financial Transmission Rights Yearly Allocation Amount	-	-	-	-	-	-	-	-	-	(317,354.55)	-	-	(317,354.55)
31	Financial Transmission Rights Transaction Amount	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Financial Transmission Rights Full Funding Guarantee Amount	29,820.54	(823.27)	(41,732.25)	(184,403.49)	230,242.28	(299,837.68)	(43,685.40)	(59,864.07)	(55,935.49)	45,171.91	39,464.20	39,713.67	(301,869.04)
37	Financial Transmission Guarantee Uplift Amount	(36,079.06)	(287.79)	46,437.36	187,466.41	(251,131.54)	299,719.20	47,375.55	58,066.47	53,473.04	(46,869.09)	10,664.55	(39,580.10)	329,255.00
38	Financial Transmission Rights Monthly Transaction Amount	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTOTAL	(2,207,228.14)	(2,070,794.18)	(2,602,470.29)	(531,415.76)	(3,800.36)	485,771.09	531,516.17	235,690.09	180,935.47	1,290,925.55	(430,538.36)	67,472.88	(5,053,935.84)
	Revenue Sufficiency Guarantee (RSG) Charges													
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	34,167.10	38,797.24	77,008.62	47,864.51	78,259.92	36,765.15	120,766.10	27,003.90	45,977.85	84,360.51	52,966.71	67,029.13	710,966.74
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amou	(1,616.75)	(14,859.52)	(55,250.45)	(25,546.07)	(67,962.20)	(112,391.01)	(244,088.15)	(11,769.12)	(25,520.59)	(219,427.74)	(27,996.67)	(6,416.65)	(812,844.92)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amour	200,488.17	98,539.26	242,828.38	146,572.61	77,012.70	(16,512.32)	284,045.49	(2,540.99)	23,642.00	145,421.58	72,025.89	174,087.27	1,445,610.03
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	(27,400.60)	(38,192.12)	(93,413.27)	(13,461.63)	(70,225.56)	(218.78)	(277,675.78)	(11,512.74)	(18,344.20)	(72,628.91)	(21,578.59)	(8,857.01)	(653,509.18)
43	Real Time Price Volatility Make Whole Payment	(119,576.77)	(70,421.67)	(145,176.43)	(307,345.96)	(24,013.10)	(98,342.07)	(233,008.84)	(34,054.34)	(84,960.87)	(139,986.54)	(78,607.01)	(108,169.99)	(1,443,663.60)
	SUBTOTAL	86,061.15	13,863.20	25,996.86	(151,916.54)	(6,928.24)	(190,699.05)	(349,961.17)	(32,873.29)	(59,205.80)	(202,261.11)	(3,189.67)	117,672.75	(753,440.92)
	Other MISO Charges													
20	Real-Time Miscellaneous Amount	63,064.39	(27,251.25)	46,126.22	84,151.42	(42,238.83)	62,404.75	197,052.29	69,901.70	76,193.13	160,740.56	58,857.36	148,664.50	897,666.26
21	Real-time Net inadvertent Distribution	45,657.29	97,902.95	(45,710.13)	(47,149.44)	52,522.48	39,881.03	46,940.24	16,235.33	65,955.66	55,305.22	9,824.16	(61,133.62)	276,231.18
23	Real-Time Revenue Neutrality Uplift Amount	399,269.07	149,836.03	532,154.35	788,442.56	109,591.84	597,287.95	67,319.15	173,593.32	362,091.56	126,268.97	111,306.48	1,086,704.22	4,503,865.49
26	Real-Time Uninstructed Deviation Amount	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTOTAL	507,990.75	220,487.74	532,570.44	825,444.54	119,875.49	699,573.73	311,311.68	259,730.34	504,240.34	342,314.75	179,988.01	1,174,235.10	5,677,762.93
	Auction Revenue Rights (ARR)													
39	Auction Revenue Rights - FTR Auction Transactions	2,675,487.02	2,658,812.32	2,535,061.80	2,481,335.10	2,460,085.53	2,201,214.11	2,188,279.15	2,200,397.91	2,399,693.08	2,427,170.30	2,451,416.43	1,669,804.90	28,348,757.67
40	Auction Revenue Rights - Monthly ARR Revenue	(2,675,117.25)	(2,652,048.52)	(2,561,528.29)	(2,515,332.01)	(2,494,493.37)	(2,206,648.90)	(2,168,994.42)	(2,183,753.11)	(2,376,372.10)	(2,409,233.27)	(2,443,520.73)	(1,672,126.30)	(28,359,168.27)
41	Auction Revenue Rights - ARR Stage 2 Distribution	(93,949.69)	(96,524.96)	(13,503.58)	(13,217.39)	(13,104.20)	(112,619.34)	(111,801.97)	(112,333.44)	(51,752.45)	(51,830.94)	(52,483.69)	(235,468.39)	(958,590.05)
42	Auction Revenue Rights - Monthly infeasible ARR Revenue	68,530.10	68,102.99	21,122.44	20,674.78	20,497.73	28,121.66	27,960.35	28,111.24	21,163.41	21,409.76	21,623.63	30,472.34	377,790.44
	SUBTOTAL	(25,049.82)	(21,658.17)	(18,847.63)	(26,539.52)	(27,014.32)	(89,932.46)	(64,556.88)	(67,577.40)	(7,268.06)	(12,484.15)	(22,964.36)	(207,317.44)	(591,210.22)
	Grandfathered Charge Types													
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreement	6,070.76	5,979.36	6,283.39	2,594.14	(5,237.32)	(3,830.72)	(14,874.19)	(1,297.96)	(1,487.57)	(6,251.84)	5,157.58	2,240.63	(4,653.75)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	3,824.79	3,353.42	5,324.64	2,758.82	507.47	(915.86)	(2,644.56)	(3,051.12)	(744.43)	(786.58)	2,931.20	3,897.33	14,455.13
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	-	-	-	-	-	-	-	(16.44)	5.56	-	(1.72)	-	(12.60)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	-	-	-	-	-	-	-	3.82	(15.26)	-	(1.30)	-	(12.75)
	SUBTOTAL	9,895.55	9,332.78	11,608.03	5,352.96	(4,729.86)	(4,746.58)	(17,518.76)	(4,361.71)	(2,241.70)	(7,038.41)	8,085.76	6,137.96	9,776.03
	TOTAL MISO DAY 2 CHARGES	3,498,610.24	2,370,399.63	2,828,840.18	4,835,374.85	4,439,592.41	4,728,623.91	5,263,551.30	3,117,055.99	3,243,867.55	5,494,453.11	2,632,602.47	3,258,214.48	45,711,186.12

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT **NOTE 1**

July 2017	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	233,688	$ 7,941,932.96	505,930	$ 16,578,714.55	(272,242)	$ (8,636,781.59)		
5a Day Ahead Non Asset Energy	(349,432)	$ (12,441,178.06)	(349,432)	$ (12,441,178.06)			11,592	$ 312,474.69
13a Real Time Asset Energy	(62,713)	$ (2,265,232.80)	18,192	$ (472,577.14)	(80,905)	$ (1,792,655.66)		
22a Real Time Non Asset Energy	202	$ 16,493.74	202	$ 16,493.74				
SUBTOTAL	(178,256)	$ (6,747,984.16)	174,891	$ 3,681,453.09	(353,147)	$ (10,429,437.25)	11,592	$ 312,474.69
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,595,030.67		$ 2,393,447.99		$ 201,582.68		
5c Day Ahead Non Asset Loss		$ 1,506,674.47		$ 1,389,635.59		$ 117,038.88		
3 Day Ahead Financial Bilateral Transaction Loss		$ (5,175.18)		$ (5,175.18)		$ -		
13c Real Time Loss		$ 140,916.63		$ 141,034.59		$ (117.96)		
22c Real Time Non Asset Loss		$ (1,518.54)		$ 7,702.05		$ (9,220.59)		
14 Real Time Distribution Losses		$ (1,382,114.23)		$ (1,382,114.23)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 2,853,813.82	-	$ 2,544,530.82	-	$ 309,283.00	-	$ -
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)		$ 593,104.55		$ 575,036.99		$ 18,067.56		$ 778.96
19 Real Time Market Administration (Schedule 17)		$ 45,595.04		$ 40,143.13		$ 5,451.91		
29 Financial Transmission Rights Administration (Schedule 16)		$ 32,031.60		$ 32,031.60		$ -		$ 50.48
33 Day-Ahead Schedule 24 Allocation Amount		$ 92,400.93		$ 89,388.96		$ 3,011.97		$ 124.96
34 Real -Time Schedule 24 Allocation Amount		$ (92,388.80)		$ (25,510.31)		$ (66,878.49)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 670,743.32	-	$ 711,090.37	-	$ (40,347.05)	-	$ 954.40
Congestion & FTRs								
1b Day Ahead Congestion		$ 4,229,471.41		$ 3,900,924.93		$ 328,546.48		
5b Day Ahead Non Asset Congestion		$ 929,220.89		$ 857,038.76		$ 72,182.13		
13b Real Time Congestion		$ 261,612.37		$ 261,774.00		$ (161.63)		
22b Real Time Non Asset Congestion		$ (2,080.65)		$ 32,543.09		$ (34,623.74)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (8,214.12)		$ (8,214.12)				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (7,409,511.47)		$ (7,409,511.47)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (612,605.93)		$ (612,605.93)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ 40,349.07		$ 40,349.07				
37 Financial Transmission Guarantee Uplift Amount		$ (48,817.25)		$ (48,817.25)				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$ -				
SUBTOTAL	-	$ (2,620,575.68)	-	$ (2,986,518.92)	-	$ 365,943.24	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 50,123.88		$ 46,230.24		$ 3,893.64		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (12,345.06)		$ (2,187.56)		$ (10,157.50)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 294,120.50		$ 271,273.14		$ 22,847.36		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (134,973.16)		$ (37,074.74)		$ (97,898.42)		
43 Real Time Price Volatility Make Whole Payment		$ (194,026.12)		$ (161,794.92)		$ (32,231.20)		
SUBTOTAL	-	$ 2,900.04	-	$ 116,446.16	-	$ (113,546.12)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 71,410.10		$ 85,330.10		$ (13,920.00)		
21 Real Time Net Inadvertent Distribution		$ 61,777.20		$ 61,777.20				$ 70.63
23 Real Time Revenue Neutrality Uplift Amount		$ 585,736.40		$ 540,236.24		$ 45,500.16		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 718,923.70	-	$ 687,343.54	-	$ 31,580.16	-	$ 70.63
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 3,620,102.73		$ 3,620,102.73				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (3,628,762.14)		$ (3,619,602.41)		$ (9,159.73)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (127,119.86)		$ (127,119.86)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 92,725.55		$ 92,725.55				
SUBTOTAL	-	$ (43,053.72)	-	($33,894)	-	($9,160)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 8,214.12		$ 8,214.12				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 5,175.18		$ 5,175.18				
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	-	$ 13,389.30	-	$ 13,389.30	-	$ -	-	$ -
Total MISO Day 2 Charges	(178,256)	$ (5,151,843.38)	174,891	$ 4,733,840.37	(353,147)	$ (9,885,683.75)	11,592	$ 313,499.72

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT **NOTE 1**

August 2017	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	222,538	$ 6,396,176.61	478,973	$ 13,741,210.29	(256,435)	$ (7,345,033.68)		
5a Day Ahead Non Asset Energy	(358,202)	$ (11,098,231.58)	(358,202)	$ (11,098,231.58)			11,880	$ 277,171.50
13a Real Time Asset Energy	(60,689)	$ (1,832,607.66)	35,917	$ 170,023.09	(96,606)	$ (2,002,630.75)		
22a Real Time Non Asset Energy	686	$ 18,605.36	686	$ 18,605.36				
SUBTOTAL	(195,667)	$ (6,516,057.27)	157,374	$ 2,831,607.16	(353,041)	$ (9,347,664.43)	11,880	$ 277,171.50
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 1,963,629.32		$ 1,792,668.53		$ 170,960.79		
5c Day Ahead Non Asset Loss		$ 1,400,146.09		$ 1,278,244.22		$ 121,901.87		
3 Day Ahead Financial Bilateral Transaction Loss		$ (4,565.85)		$ (4,565.85)		$ -		
13c Real Time Loss		$ 81,631.30		$ 81,684.80		$ (53.50)		
22c Real Time Non Asset Loss		$ (614.55)		$ 6,337.36		$ (6,951.91)		
14 Real Time Distribution Losses		$ (915,463.36)		$ (915,463.36)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 2,524,762.95	-	$ 2,238,905.70	-	$ 285,857.25	-	$ -
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)		$ 541,944.41		$ 524,577.84		$ 17,366.57		$ 812.40
19 Real Time Market Administration (Schedule 17)		$ 39,130.12		$ 32,452.07		$ 6,678.05		
29 Financial Transmission Rights Administration (Schedule 16)		$ 26,142.80		$ 26,142.80		$ -		$ 763.12
33 Day-Ahead Schedule 24 Allocation Amount		$ 88,026.11		$ 85,284.04		$ 2,742.07		$ 132.32
34 Real -Time Schedule 24 Allocation Amount		$ (77,178.30)		$ 5,633.87		$ (82,812.17)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 618,065.14	-	$ 674,090.62	-	$ (56,025.48)	-	$ 1,707.84
Congestion & FTRs								
1b Day Ahead Congestion		$ 2,732,043.58		$ 2,494,181.81		$ 237,861.77		
5b Day Ahead Non Asset Congestion		$ 997,499.08		$ 910,653.14		$ 86,845.94		
13b Real Time Congestion		$ 100,999.37		$ 101,024.90		$ (25.53)		
22b Real Time Non Asset Congestion		$ (293.19)		$ 21,045.15		$ (21,338.34)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (8,141.19)		$ (8,141.19)				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (5,889,555.92)		$ (5,889,555.92)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (447,182.46)		$ (447,182.46)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (1,120.92)		$ (1,120.92)				
37 Financial Transmission Guarantee Uplift Amount		$ (391.84)		$ (391.84)				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$ -				
SUBTOTAL	-	$ (2,516,143.49)	-	$ (2,819,487.33)	-	$ 303,343.84	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 57,862.02		$ 52,824.34		$ 5,037.68		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (32,854.54)		$ (20,231.96)		$ (12,622.58)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 146,960.97		$ 134,166.01		$ 12,794.96		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (69,205.57)		$ (52,000.43)		$ (17,205.14)		
43 Real Time Price Volatility Make Whole Payment		$ (112,767.09)		$ (95,882.54)		$ (16,884.55)		
SUBTOTAL	-	$ (10,004.21)	-	$ 18,875.42	-	$ (28,879.63)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ (52,943.90)		$ (37,103.90)		$ (15,840.00)		
21 Real Time Net Inadvertent Distribution		$ 133,299.65		$ 133,299.65				$ 180.24
23 Real Time Revenue Neutrality Uplift Amount		$ 223,464.73		$ 204,009.07		$ 19,455.66		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 303,820.48	-	$ 300,204.82	-	$ 3,615.66	-	$ 180.24
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 3,620,102.73		$ 3,620,102.73				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (3,628,762.14)		$ (3,610,893.49)		$ (17,868.65)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (131,423.44)		$ (131,423.44)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 92,725.55		$ 92,725.55				
SUBTOTAL	-	$ (47,357.30)	-	($29,489)	-	($17,869)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 8,141.19		$ 8,141.19				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 4,565.85		$ 4,565.85				
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	-	$ 12,707.04	-	$ 12,707.04	-	$ -	-	$ -
Total MISO Day 2 Charges	(195,667)	$ (5,630,206.66)	157,374	$ 3,227,414.77	(353,041)	$ (8,857,621.43)	11,880	$ 279,059.58

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

Docket No. E999/AA-18-373
Part J, Section 5
Schedule 7

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT **NOTE 1**

September 2017	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	202,818	$ 9,003,652.35	471,823	$ 15,326,995.84	(269,005)	$ (6,323,343.49)		
5a Day Ahead Non Asset Energy	(340,252)	$ (12,033,585.01)	(340,252)	$ (12,033,585.01)			11,280	$ 237,102.30
13a Real Time Asset Energy	(99,130)	$ (2,868,505.92)	27,940	$ 78,340.22	(127,070)	$ (2,946,846.14)		
22a Real Time Non Asset Energy	1,108	$ 72,020.99	1,108	$ 72,020.99				
SUBTOTAL	(235,456)	$ (5,826,417.59)	160,619	$ 3,443,772.04	(396,075)	$ (9,270,189.63)	11,280	$ 237,102.30
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,232,521.06		$ 1,999,272.31		$ 233,248.75		
5c Day Ahead Non Asset Loss		$ 1,825,144.68		$ 1,634,457.69		$ 190,686.99		
3 Day Ahead Financial Bilateral Transaction Loss		$ (7,181.35)		$ (7,181.35)		$ -		
13c Real Time Loss		$ 122,585.12		$ 123,606.11		$ (1,020.99)		
22c Real Time Non Asset Loss		$ (9,772.33)		$ 8,041.20		$ (17,813.53)		
14 Real Time Distribution Losses		$ (1,302,537.63)		$ (1,302,537.63)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 2,860,759.55	-	$ 2,455,658.34	-	$ 405,101.21	-	$ -
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)		$ 551,951.71		$ 532,366.42		$ 19,585.29		$ 821.60
19 Real Time Market Administration (Schedule 17)		$ 44,233.12		$ 35,005.07		$ 9,228.05		
29 Financial Transmission Rights Administration (Schedule 16)		$ 24,065.60		$ 24,065.60		$ -		$ 236.96
33 Day-Ahead Schedule 24 Allocation Amount		$ 83,296.60		$ 80,280.88		$ 3,015.72		$ 127.20
34 Real -Time Schedule 24 Allocation Amount		$ (71,304.25)		$ 10,487.95		$ (81,792.20)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 632,242.78	-	$ 682,205.92	-	$ (49,963.14)	-	$ 1,185.76
Congestion & FTRs								
1b Day Ahead Congestion		$ 2,543,137.57		$ 2,277,436.31		$ 265,701.26		
5b Day Ahead Non Asset Congestion		$ 2,681,605.83		$ 2,401,437.72		$ 280,168.11		
13b Real Time Congestion		$ 452,484.84		$ 455,243.74		$ (2,758.90)		
22b Real Time Non Asset Congestion		$ (26,406.57)		$ 47,821.85		$ (74,228.42)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (8,474.41)		$ (8,474.41)				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (8,383,531.61)		$ (8,383,531.61)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (306,232.96)		$ (306,232.96)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (56,284.32)		$ (56,284.32)				
37 Financial Transmission Guarantee Uplift Amount		$ 62,630.10		$ 62,630.10				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$ -				
SUBTOTAL	-	$ (3,041,071.53)	-	$ (3,509,953.58)	-	$ 468,882.05	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 115,978.79		$ 103,861.59		$ 12,117.20		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (96,390.36)		$ (74,516.32)		$ (21,874.04)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 365,711.53		$ 327,502.82		$ 38,208.71		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (386,861.37)		$ (125,986.54)		$ (260,874.83)		
43 Real Time Price Volatility Make Whole Payment		$ (307,866.23)		$ (195,799.56)		$ (112,066.67)		
SUBTOTAL	-	$ (309,427.64)	-	$ 35,061.99	-	$ (344,489.63)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 47,810.47		$ 62,210.47		$ (14,400.00)		$ (16,336.27)
21 Real Time Net Inadvertent Distribution		$ (61,649.28)		$ (61,649.28)				$ (84.85)
23 Real Time Revenue Neutrality Uplift Amount		$ 801,450.71		$ 717,716.95		$ 83,733.76		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 787,611.90	-	$ 718,278.14	-	$ 69,333.76	-	$ (16,421.12)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 3,419,039.70		$ 3,419,039.70				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (3,472,296.93)		$ (3,454,735.07)		$ (17,561.86)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (18,212.29)		$ (18,212.29)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 28,487.85		$ 28,487.85				
SUBTOTAL	-	$ (42,981.67)	-	($25,420)	-	($17,562)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 8,474.41		$ 8,474.41				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 7,181.35		$ 7,181.35				
8 Day Ahead Congestion Rebate on Option B-Grandfathered		$ -		$ -				
9 Day Ahead Loss Rebate on Option B-Grandfathered		$ -		$ -				
17 Real Time Loss Rebate on Carve Out Grandfathered		$ -		$ -				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ -		$ -				
SUBTOTAL	-	$ 15,655.76	-	$ 15,655.76	-	$ -	-	$ -
Total MISO Day 2 Charges	(235,456)	$ (4,923,628.44)	160,619	$ 3,815,258.80	(396,075)	$ (8,738,887.24)	11,280	$ 221,866.94

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT **NOTE 1**

October 2017					Intersystem			
	NET INVOICE		RETAIL		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	(191,743)	$ (610,417.01)	340,992	$ 9,965,167.26	(532,735)	$ (10,575,584.27)		
5a Day Ahead Non Asset Energy	(290,179)	$ (8,797,500.02)	(290,179)	$ (8,797,500.02)			11,784	$ 253,146.99
13a Real Time Asset Energy	(19,734)	$ (633,180.22)	124,407	$ 2,417,905.59	(144,141)	$ (3,051,085.81)		
22a Real Time Non Asset Energy	254	$ 12,658.74	254	$ 12,658.74				
SUBTOTAL	(501,402)	$ (10,028,438.51)	175,474	$ 3,598,231.57	(676,876)	$ (13,626,670.08)	11,784	$ 253,146.99
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,114,833.22		$ 1,764,910.29		$ 349,922.93		
5c Day Ahead Non Asset Loss		$ 1,187,725.69		$ 991,203.12		$ 196,522.57		
3 Day Ahead Financial Bilateral Transaction Loss		$ (3,801.39)		$ (3,801.39)		$ -		
13c Real Time Loss		$ 33,044.01		$ 33,127.69		$ (83.68)		
22c Real Time Non Asset Loss		$ (505.76)		$ 9,531.63		$ (10,037.39)		
14 Real Time Distribution Losses		$ (792,348.09)		$ (792,348.09)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 2,538,947.68	-	$ 2,002,623.25	-	$ 536,324.43	-	$ -
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)		$ 775,340.61		$ 733,769.35		$ 41,571.26		$ 1,248.48
19 Real Time Market Administration (Schedule 17)		$ 67,059.85		$ 55,786.96		$ 11,272.89		
29 Financial Transmission Rights Administration (Schedule 16)		$ 27,509.36		$ 27,509.36		$ -		$ 5,166.08
33 Day-Ahead Schedule 24 Allocation Amount		$ 90,990.27		$ 83,939.46		$ 7,050.81		$ 147.20
34 Real -Time Schedule 24 Allocation Amount		$ (80,821.31)		$ (5,805.11)		$ (75,016.20)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 880,078.78	-	$ 895,200.02	-	$ (15,121.24)	-	$ 6,561.76
Congestion & FTRs								
1b Day Ahead Congestion		$ 2,747,802.77		$ 2,293,147.91		$ 454,654.86		
5b Day Ahead Non Asset Congestion		$ 1,799,301.19		$ 1,501,586.58		$ 297,714.61		
13b Real Time Congestion		$ 75,587.16		$ 80,012.37		$ (4,425.21)		
22b Real Time Non Asset Congestion		$ (26,744.69)		$ 27,578.12		$ (54,322.81)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (3,574.47)		$ (3,574.47)				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (4,426,239.40)		$ (4,426,239.40)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (208,971.01)		$ (208,971.01)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (254,090.17)		$ (254,090.17)				
37 Financial Transmission Guarantee Uplift Amount		$ 258,310.57		$ 258,310.57				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$ -				
SUBTOTAL	-	$ (38,618.05)	-	$ (732,239.50)	-	$ 693,621.45	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 79,028.88		$ 65,952.66		$ 13,076.22		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (53,286.27)		$ (35,200.01)		$ (18,086.26)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 242,005.39		$ 201,962.88		$ 40,042.51		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (98,274.71)		$ (18,548.83)		$ (79,725.88)		
43 Real Time Price Volatility Make Whole Payment		$ (477,828.40)		$ (423,493.00)		$ (54,335.40)		
SUBTOTAL	-	$ (308,355.11)	-	$ (209,326.30)	-	$ (99,028.81)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 102,473.41		$ 115,952.52		$ (13,479.11)		$ -
21 Real Time Net Inadvertent Distribution		$ (64,967.37)		$ (64,967.37)				$ (84.77)
23 Real Time Revenue Neutrality Uplift Amount		$ 1,301,794.02		$ 1,086,397.56		$ 215,396.46		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 1,339,300.06	-	$ 1,137,382.71	-	$ 201,917.35	-	$ (84.77)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 3,419,039.70		$ 3,419,039.70				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (3,472,296.93)		$ (3,465,884.15)		$ (6,412.78)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (18,212.29)		$ (18,212.29)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 28,487.85		$ 28,487.85				
SUBTOTAL	-	$ (42,981.67)	-	($36,569)	-	($6,413)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 3,574.47		$ 3,574.47				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 3,801.39		$ 3,801.39				
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	-	$ 7,375.86	-	$ 7,375.86	-	$ -	-	$ -
Total MISO Day 2 Charges	(501,402)	$ (5,652,690.96)	175,474	$ 6,662,678.72	(676,876)	$ (12,315,369.68)	11,784	$ 259,623.98

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT **NOTE 1**

November 2017	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	(353,053)	$ (5,526,720.76)	171,934	$ 5,685,963.25	(524,987)	$ (11,212,684.01)		
5a Day Ahead Non Asset Energy	(116,866)	$ (3,513,700.28)	(116,866)	$ (3,513,700.28)			11,376	$ 280,430.58
13a Real Time Asset Energy	(23,805)	$ (549,221.84)	67,888	$ 1,098,336.58	(91,693)	$ (1,647,558.42)		
22a Real Time Non Asset Energy	102	$ 28,235.43	102	$ 28,235.43				
SUBTOTAL	(493,621)	$ (9,561,407.45)	123,059	$ 3,298,834.98	(616,680)	$ (12,860,242.43)	11,376	$ 280,430.58
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 3,013,940.39		$ 2,553,348.00		$ 460,592.39		
5c Day Ahead Non Asset Loss		$ 292,799.88		$ 248,054.01		$ 44,745.87		
3 Day Ahead Financial Bilateral Transaction Loss		$ (705.28)		$ (705.28)		$ -		
13c Real Time Loss		$ 66,809.35		$ 66,810.12		$ (0.77)		
22c Real Time Non Asset Loss		$ (5.03)		$ 10,079.32		$ (10,084.35)		
14 Real Time Distribution Losses		$ (783,371.78)		$ (783,371.78)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 2,589,467.53	-	$ 2,094,214.39	-	$ 495,253.14	-	$ -
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)		$ 568,782.25		$ 513,588.13		$ 55,194.12		$ 892.32
19 Real Time Market Administration (Schedule 17)		$ 43,889.40		$ 32,883.01		$ 11,006.39		
29 Financial Transmission Rights Administration (Schedule 16)		$ 20,575.92		$ 20,575.92		$ -		$ 2,528.00
33 Day-Ahead Schedule 24 Allocation Amount		$ 96,639.64		$ 90,049.50		$ 6,590.14		$ 149.28
34 Real -Time Schedule 24 Allocation Amount		$ (83,858.78)		$ 12,448.07		$ (96,306.85)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 646,028.43	-	$ 669,544.63	-	$ (23,516.20)	-	$ 3,569.60
Congestion & FTRs								
1b Day Ahead Congestion		$ 1,661,246.85		$ 1,407,373.99		$ 253,872.86		
5b Day Ahead Non Asset Congestion		$ 131,540.60		$ 111,438.48		$ 20,102.12		
13b Real Time Congestion		$ 70,778.42		$ 70,242.99		$ 535.43		
22b Real Time Non Asset Congestion		$ 3,503.68		$ 13,967.20		$ (10,463.52)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 7,278.86		$ 7,278.86				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (1,186,296.03)		$ (1,186,296.03)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (400,255.24)		$ (400,255.24)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ 319,991.92		$ 319,991.92				
37 Financial Transmission Guarantee Uplift Amount		$ (349,023.92)		$ (349,023.92)				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$ -				
SUBTOTAL	-	$ 258,765.14	-	$ (5,281.76)	-	$ 264,046.90	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 128,386.09		$ 108,766.04		$ 19,620.05		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (142,633.89)		$ (94,454.22)		$ (48,179.67)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 126,340.02		$ 107,032.65		$ 19,307.37		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (120,607.48)		$ (97,599.85)		$ (23,007.63)		
43 Real Time Price Volatility Make Whole Payment		$ (47,329.87)		$ (33,373.53)		$ (13,956.34)		
SUBTOTAL	-	$ (55,845.13)	-	$ (9,628.90)	-	$ (46,216.23)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ (73,492.42)		$ (58,703.74)		$ (14,788.68)		
21 Real Time Net Inadvertent Distribution		$ 72,996.01		$ 72,996.01				$ 109.32
23 Real Time Revenue Neutrality Uplift Amount		$ 179,786.39		$ 152,311.31		$ 27,475.08		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 179,289.98	-	$ 166,603.58	-	$ 12,686.40	-	$ 109.32
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 3,419,039.70		$ 3,419,039.70				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (3,472,296.93)		$ (3,466,859.90)		$ (5,437.03)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (18,212.29)		$ (18,212.29)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 28,487.85		$ 28,487.85				
SUBTOTAL	-	$ (42,981.67)	-	($37,545)	-	($5,437)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (7,278.86)		$ (7,278.86)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 705.28		$ 705.28				
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	-	$ (6,573.58)	-	$ (6,573.58)	-	$ -	-	$ -
Total MISO Day 2 Charges	(493,621)	$ (5,993,256.75)	123,059	$ 6,170,168.70	(616,680)	$ (12,163,425.45)	11,376	$ 284,109.50

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT **NOTE 1**

December 2017	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	(556,370)	$ (11,937,882.06)	116,316	$ 4,037,493.69	(672,686)	$ (15,975,375.75)		
5a Day Ahead Non Asset Energy	(126,239)	$ (3,715,572.79)	(126,239)	$ (3,715,572.79)			11,592	$ 284,653.32
13a Real Time Asset Energy	2,007	$ 197,276.71	92,975	$ 2,244,398.85	(90,968)	$ (2,047,122.14)		
22a Real Time Non Asset Energy	0	$ 618.34	0	$ 618.34				
SUBTOTAL	(680,602)	$ (15,455,559.80)	83,052	$ 2,566,938.09	(763,654)	$ (18,022,497.89)	11,592	$ 284,653.32
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 3,376,194.28		$ 2,796,925.82		$ 579,268.46		
5c Day Ahead Non Asset Loss		$ 192,928.13		$ 159,826.60		$ 33,101.53		
3 Day Ahead Financial Bilateral Transaction Loss		$ 1,280.54		$ 1,280.54		$ -		
13c Real Time Loss		$ 17,305.62		$ 17,311.00		$ (5.38)		
22c Real Time Non Asset Loss		$ (31.37)		$ (1,498.62)		$ 1,467.25		
14 Real Time Distribution Losses		$ (991,853.15)		$ (991,853.15)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 2,595,824.05	-	$ 1,981,992.20	-	$ 613,831.85	-	$ -
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)		$ 690,768.91		$ 633,648.71		$ 57,120.20		$ 989.04
19 Real Time Market Administration (Schedule 17)		$ 57,091.35		$ 49,296.34		$ 7,795.01		
29 Financial Transmission Rights Administration (Schedule 16)		$ 21,107.84		$ 21,107.84		$ -		$ 3.84
33 Day-Ahead Schedule 24 Allocation Amount		$ 106,357.20		$ 97,546.49		$ 8,810.71		$ 152.08
34 Real -Time Schedule 24 Allocation Amount		$ (90,334.49)		$ 2,645.43		$ (92,979.92)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 784,990.81	-	$ 804,244.81	-	$ (19,254.00)	-	$ 1,144.96
Congestion & FTRs								
1b Day Ahead Congestion		$ 1,329,166.19		$ 1,101,115.32		$ 228,050.87		
5b Day Ahead Non Asset Congestion		$ 90,717.22		$ 75,152.47		$ 15,564.75		
13b Real Time Congestion		$ 16,725.03		$ 16,725.31		$ (0.28)		
22b Real Time Non Asset Congestion		$ (1.63)		$ (670.84)		$ 669.21		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 5,356.06		$ 5,356.06				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (660,232.21)		$ (660,232.21)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ 141,917.90		$ 141,917.90				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (419,228.86)		$ (419,228.86)				
37 Financial Transmission Guarantee Uplift Amount		$ 419,063.21		$ 419,063.21				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$ -				
SUBTOTAL	-	$ 923,482.91	-	$ 679,198.36	-	$ 244,284.55	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 62,050.85		$ 51,404.51		$ 10,646.34		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (168,861.50)		$ (157,143.55)		$ (11,717.95)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ (27,868.89)		$ (23,087.30)		$ (4,781.59)		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (1,081.24)		$ (305.90)		$ (775.34)		
43 Real Time Price Volatility Make Whole Payment		$ (154,244.18)		$ (137,500.51)		$ (16,743.67)		
SUBTOTAL	-	$ (290,004.96)	-	$ (266,632.75)	-	$ (23,372.21)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 72,310.23		$ 87,253.45		$ (14,943.22)		
21 Real Time Net Inadvertent Distribution		$ 55,761.10		$ 55,761.10				$ 74.73
23 Real Time Revenue Neutrality Uplift Amount		$ 1,008,080.48		$ 835,119.69		$ 172,960.79		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 1,136,151.81	-	$ 978,134.24	-	$ 158,017.57	-	$ 74.73
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 3,077,706.89		$ 3,077,706.89				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (3,090,966.42)		$ (3,085,305.73)		$ (5,660.69)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (157,462.79)		$ (157,462.79)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 39,319.32		$ 39,319.32				
SUBTOTAL	-	$ (131,403.00)	-	($125,742)	-	($5,661)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (5,356.06)		$ (5,356.06)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (1,280.54)		$ (1,280.54)				
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	-	$ (6,636.60)	-	$ (6,636.60)	-	$ -	-	$ -
Total MISO Day 2 Charges	(680,602)	$ (10,443,154.78)	83,052	$ 6,611,496.04	(763,654)	$ (17,054,650.82)	11,592	$ 285,873.01

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT **NOTE 1**

January 2018	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	(593,742)	$ (14,015,279.47)	119,108	$ 6,683,770.62	(712,850)	$ (20,699,050.09)		
5a Day Ahead Non Asset Energy	(120,541)	$ (5,212,659.65)	(120,541)	$ (5,212,659.65)			11,784	$ 439,594.21
13a Real Time Asset Energy	20,042	$ 559,581.83	94,619	$ 2,215,855.12	(74,577)	$ (1,656,273.29)		
22a Real Time Non Asset Energy	0	$ 601.46	0	$ 601.46				
SUBTOTAL	(694,241)	$ (18,667,755.83)	93,186	$ 3,687,567.55	(787,427)	$ (22,355,323.38)	11,784	$ 439,594.21
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 4,935,912.61		$ 4,079,174.66		$ 856,737.95		
5c Day Ahead Non Asset Loss		$ 162,168.23		$ 134,020.31		$ 28,147.92		
3 Day Ahead Financial Bilateral Transaction Loss		$ 3,719.45		$ 3,719.45		$ -		
13c Real Time Loss		$ 3,836.89		$ 3,838.25		$ (1.36)		
22c Real Time Non Asset Loss		$ (7.85)		$ 2,909.35		$ (2,917.20)		
14 Real Time Distribution Losses		$ (1,774,973.13)		$ (1,774,973.13)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 3,330,656.20	-	$ 2,448,688.89	-	$ 881,967.31	-	$ -
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)		$ 590,463.11		$ 540,143.18		$ 50,319.93		$ 832.32
19 Real Time Market Administration (Schedule 17)		$ 39,261.95		$ 34,071.69		$ 5,190.26		
29 Financial Transmission Rights Administration (Schedule 16)		$ 17,404.08		$ 17,404.08		$ -		$ 56.32
33 Day-Ahead Schedule 24 Allocation Amount		$ 100,425.81		$ 91,866.16		$ 8,559.65		$ 143.68
34 Real -Time Schedule 24 Allocation Amount		$ (96,154.90)		$ 5,426.84		$ (101,581.74)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 651,400.05	-	$ 688,911.95	-	$ (37,511.90)	-	$ 1,032.32
Congestion & FTRs								
1b Day Ahead Congestion		$ 1,349,507.34		$ 1,115,270.18		$ 234,237.16		
5b Day Ahead Non Asset Congestion		$ 73,151.97		$ 60,454.81		$ 12,697.16		
13b Real Time Congestion		$ 46,610.10		$ 46,613.78		$ (3.68)		
22b Real Time Non Asset Congestion		$ (21.22)		$ (9,760.46)		$ 9,739.24		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 20,919.82		$ 20,919.82				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (511,778.09)		$ (511,778.09)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ 20,641.26		$ 20,641.26				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (61,441.36)		$ (61,441.36)				
37 Financial Transmission Guarantee Uplift Amount		$ 66,631.38		$ 66,631.38				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$ -				
SUBTOTAL	-	$ 1,004,221.20	-	$ 747,551.32	-	$ 256,669.88	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 205,525.04		$ 169,851.58		$ 35,673.46		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (360,075.77)		$ (343,297.96)		$ (16,777.81)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 483,401.05		$ 399,495.99		$ 83,905.06		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (638,214.90)		$ (390,537.31)		$ (247,677.59)		
43 Real Time Price Volatility Make Whole Payment		$ (368,914.39)		$ (327,715.46)		$ (41,198.93)		
SUBTOTAL	-	$ (678,278.97)	-	$ (492,203.16)	-	$ (186,075.81)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 262,744.35		$ 277,144.35		$ (14,400.00)		
21 Real Time Net Inadvertent Distribution		$ 66,019.14		$ 66,019.14				$ 80.93
23 Real Time Revenue Neutrality Uplift Amount		$ 114,566.67		$ 94,681.06		$ 19,885.61		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 443,330.16	-	$ 437,844.55	-	$ 5,485.61	-	$ 80.93
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 3,077,706.89		$ 3,077,706.89				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (3,090,966.42)		$ (3,050,583.86)		$ (40,382.56)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (157,243.97)		$ (157,243.97)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 39,324.86		$ 39,324.86				
SUBTOTAL	-	$ (131,178.64)	-	($90,796)	-	($40,383)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (20,919.82)		$ (20,919.82)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (3,719.45)		$ (3,719.45)				
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	-	$ (24,639.27)	-	$ (24,639.27)	-	$ -	-	$ -
Total MISO Day 2 Charges	(694,241)	$ (14,072,245.10)	93,186	$ 7,402,925.76	(787,427)	$ (21,475,170.86)	11,784	$ 440,707.46

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT **NOTE 1**

February 2018	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	(257,007)	$ (5,140,151.28)	131,334	$ 3,837,072.30	(388,341)	$ (8,977,223.58)		
5a Day Ahead Non Asset Energy	(106,540)	$ (2,938,997.15)	(106,540)	$ (2,938,997.15)			10,656	$ 261,831.50
13a Real Time Asset Energy	(41,603)	$ (908,392.51)	24,231	$ 814,839.75	(65,834)	$ (1,723,232.26)		
22a Real Time Non Asset Energy	6	$ (518.41)	6	$ (518.41)				
SUBTOTAL	(405,145)	$ (8,988,059.35)	49,030	$ 1,712,396.49	(454,175)	$ (10,700,455.84)	10,656	$ 261,831.50
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,766,318.85		$ 2,432,525.23		$ 333,793.62		
5c Day Ahead Non Asset Loss		$ 91,941.98		$ 80,847.94		$ 11,094.04		
3 Day Ahead Financial Bilateral Transaction Loss		$ 4,267.62		$ 4,267.62		$ -		
13c Real Time Loss		$ 6,651.33		$ 6,649.15		$ 2.18		
22c Real Time Non Asset Loss		$ 18.10		$ 779.21		$ (761.11)		
14 Real Time Distribution Losses		$ (1,026,169.10)		$ (1,026,169.10)				
16 Real Time Financial Bilateral Loss		$ (5.34)		$ (5.34)				
SUBTOTAL	-	$ 1,843,023.44	-	$ 1,498,894.71	-	$ 344,128.73	-	$ -
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)		$ 469,115.32		$ 443,656.88		$ 25,458.44		$ 696.00
19 Real Time Market Administration (Schedule 17)		$ 34,394.87		$ 30,159.99		$ 4,234.88		
29 Financial Transmission Rights Administration (Schedule 16)		$ 25,520.16		$ 25,520.16		$ -		$ 83.20
33 Day-Ahead Schedule 24 Allocation Amount		$ 81,676.67		$ 77,247.95		$ 4,428.72		$ 123.20
34 Real -Time Schedule 24 Allocation Amount		$ (71,173.61)		$ 25,619.38		$ (96,792.99)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 539,533.41	-	$ 602,204.36	-	$ (62,670.95)	-	$ 902.40
Congestion & FTRs								
1b Day Ahead Congestion		$ 628,871.30		$ 552,989.51		$ 75,881.79		
5b Day Ahead Non Asset Congestion		$ (16,389.92)		$ (14,412.26)		$ (1,977.66)		
13b Real Time Congestion		$ 38,138.46		$ 38,042.88		$ 95.58		
22b Real Time Non Asset Congestion		$ 792.11		$ 2,182.35		$ (1,390.24)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 1,815.46		$ 1,815.46				
15 Real Time Financial Bilateral Congestion		$ 23.00		$ 23.00				
28 Financial Transmission Rights Hourly Allocation		$ (177,813.62)		$ (177,813.62)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (70,652.17)		$ (70,652.17)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (83,732.16)		$ (83,732.16)				
37 Financial Transmission Guarantee Uplift Amount		$ 81,217.84		$ 81,217.84				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$ -				
SUBTOTAL	-	$ 402,270.30	-	$ 329,660.83	-	$ 72,609.47	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 42,953.38		$ 37,770.48		$ 5,182.90		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (42,009.16)		$ (16,461.52)		$ (25,547.64)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ (4,041.79)		$ (3,554.09)		$ (487.70)		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (25,802.49)		$ (16,102.92)		$ (9,699.57)		
43 Real Time Price Volatility Make Whole Payment		$ (110,397.76)		$ (47,631.97)		$ (62,765.79)		
SUBTOTAL	-	$ (139,297.82)	-	$ (45,980.03)	-	$ (93,317.79)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 83,382.84		$ 97,771.83		$ (14,388.99)		
21 Real Time Net Inadvertent Distribution		$ 22,708.43		$ 22,708.43				$ 31.14
23 Real Time Revenue Neutrality Uplift Amount		$ 276,123.85		$ 242,805.79		$ 33,318.06		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 382,215.12	-	$ 363,286.05	-	$ 18,929.07	-	$ 31.14
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 3,077,706.89		$ 3,077,706.89				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (3,090,966.42)		$ (3,054,425.73)		$ (36,540.69)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (157,121.31)		$ (157,121.31)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 39,319.32		$ 39,319.32				
SUBTOTAL	-	$ (131,061.52)	-	($94,521)	-	($36,541)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (1,815.46)		$ (1,815.46)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (4,267.62)		$ (4,267.62)				
8 Day Ahead Congestion Rebate on Option B-Grandfathered		$ -		$ -				
9 Day Ahead Loss Rebate on Option B-Grandfathered		$ -		$ -				
17 Real Time Loss Rebate on Carve Out Grandfathered		$ (23.00)		$ (23.00)				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ 5.34		$ 5.34				
SUBTOTAL	-	$ (6,100.74)	-	$ (6,100.74)	-	$ -	-	$ -
Total MISO Day 2 Charges	(405,145)	$ (6,097,477.16)	49,030	$ 4,359,840.85	(454,175)	$ (10,457,318.01)	10,656	$ 262,765.04

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT **NOTE 1**

March 2018	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	(336,139)	$ (5,862,872.75)	174,781	$ 4,801,881.54	(510,920)	$ (10,664,754.29)		
5a Day Ahead Non Asset Energy	(135,153)	$ (3,710,991.17)	(135,153)	$ (3,710,991.17)			11,688	$ 263,360.55
13a Real Time Asset Energy	(63,854)	$ (1,592,673.73)	17,021	$ (31,244.54)	(80,875)	$ (1,561,429.19)		
22a Real Time Non Asset Energy	130	$ 2,531.40	130	$ 2,531.40				
SUBTOTAL	(535,016)	$ (11,164,006.25)	56,779	$ 1,062,177.23	(591,795)	$ (12,226,183.48)	11,688	$ 263,360.55
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,433,668.46		$ 2,065,039.58		$ 368,628.88		
5c Day Ahead Non Asset Loss		$ 268,470.28		$ 227,804.96		$ 40,665.32		
3 Day Ahead Financial Bilateral Transaction Loss		$ 1,039.78		$ 1,039.78		$ -		
13c Real Time Loss		$ 65,219.04		$ 65,251.82		$ (32.78)		
22c Real Time Non Asset Loss		$ (216.39)		$ 7,784.25		$ (8,000.64)		
14 Real Time Distribution Losses		$ (557,417.40)		$ (557,417.40)				
16 Real Time Financial Bilateral Loss		$ 21.32		$ 21.32				
SUBTOTAL	-	$ 2,210,785.09	-	$ 1,809,524.30	-	$ 401,260.79	-	$ -
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)		$ 731,851.55		$ 681,167.57		$ 50,683.98		$ 1,172.16
19 Real Time Market Administration (Schedule 17)		$ 52,814.05		$ 44,672.30		$ 8,141.75		
29 Financial Transmission Rights Administration (Schedule 16)		$ 14,893.28		$ 14,893.28		$ -		$ -
33 Day-Ahead Schedule 24 Allocation Amount		$ 94,053.06		$ 87,472.37		$ 6,580.69		$ 153.36
34 Real -Time Schedule 24 Allocation Amount		$ (85,614.43)		$ (30,061.37)		$ (55,553.06)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 807,997.51	-	$ 798,144.15	-	$ 9,853.36	-	$ 1,325.52
Congestion & FTRs								
1b Day Ahead Congestion		$ 912,715.94		$ 774,466.44		$ 138,249.50		
5b Day Ahead Non Asset Congestion		$ 203,159.08		$ 172,386.48		$ 30,772.60		
13b Real Time Congestion		$ 94,480.26		$ 94,506.25		$ (25.99)		
22b Real Time Non Asset Congestion		$ (171.58)		$ 19,494.18		$ (19,665.76)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 2,077.77		$ 2,077.77				
15 Real Time Financial Bilateral Congestion		$ (7.77)		$ (7.77)				
28 Financial Transmission Rights Hourly Allocation		$ (724,910.33)		$ (724,910.33)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (81,850.95)		$ (81,850.95)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (78,128.20)		$ (78,128.20)				
37 Financial Transmission Guarantee Uplift Amount		$ 74,688.76		$ 74,688.76				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$ -				
SUBTOTAL	-	$ 402,052.98	-	$ 252,722.62	-	$ 149,330.36	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 75,683.66		$ 64,219.82		$ 11,463.84		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (46,824.18)		$ (35,646.02)		$ (11,178.16)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 38,916.85		$ 33,022.10		$ 5,894.75		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (38,372.10)		$ (25,622.36)		$ (12,749.74)		
43 Real Time Price Volatility Make Whole Payment		$ (132,358.39)		$ (118,669.57)		$ (13,688.82)		
SUBTOTAL	-	$ (102,954.16)	-	$ (82,696.03)	-	$ (20,258.13)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 91,543.17		$ 106,423.17		$ (14,880.00)		$ 33.85
21 Real Time Net Inadvertent Distribution		$ 92,123.93		$ 92,123.93				$ 134.23
23 Real Time Revenue Neutrality Uplift Amount		$ 596,035.10		$ 505,753.39		$ 90,281.71		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 779,702.20	-	$ 704,300.49	-	$ 75,401.71	-	$ 168.08
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 3,351,784.59		$ 3,351,784.59				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (3,360,340.60)		$ (3,319,210.89)		$ (41,129.71)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (72,285.52)		$ (72,285.52)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 29,560.11		$ 29,560.11				
SUBTOTAL	-	$ (51,281.42)	-	($10,152)	-	($41,130)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (2,077.77)		$ (2,077.77)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (1,039.78)		$ (1,039.78)				
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		$ 7.77		$ 7.77				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ (21.32)		$ (21.32)				
SUBTOTAL	-	$ (3,131.10)	-	$ (3,131.10)	-	$ -	-	$ -
Total MISO Day 2 Charges	(535,016)	$ (7,120,835.15)	56,779	$ 4,530,889.96	(591,795)	$ (11,651,725.11)	11,688	$ 264,854.15

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT **NOTE 1**

April 2018	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	(208,013)	$ (3,360,932.31)	165,691	$ 4,701,511.46	(373,704)	$ (8,062,443.77)		
5a Day Ahead Non Asset Energy	(129,147)	$ (4,191,337.63)	(129,147)	$ (4,191,337.63)			11,472	$ 286,658.42
13a Real Time Asset Energy	(5,314)	$ 42,654.38	80,818	$ 1,861,332.62	(86,132)	$ (1,818,678.24)		
22a Real Time Non Asset Energy	(65)	$ 2,290.95	(65)	$ 2,290.95				
SUBTOTAL	(342,539)	$ (7,507,324.61)	117,297	$ 2,373,797.40	(459,836)	$ (9,881,122.01)	11,472	$ 286,658.42
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 3,126,827.19		$ 2,739,254.20		$ 387,572.99		
5c Day Ahead Non Asset Loss		$ 328,203.96		$ 287,522.79		$ 40,681.17		
3 Day Ahead Financial Bilateral Transaction Loss		$ 1,086.22		$ 1,086.22		$ -		
13c Real Time Loss		$ 60,928.05		$ 60,928.04		$ 0.01		
22c Real Time Non Asset Loss		$ 0.07		$ 10,364.59		$ (10,364.52)		
14 Real Time Distribution Losses		$ (767,415.68)		$ (767,415.68)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 2,749,629.81	-	$ 2,331,740.16	-	$ 417,889.65	-	$ -
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)		$ 771,172.32		$ 729,138.77		$ 42,033.55		$ 1,296.64
19 Real Time Market Administration (Schedule 17)		$ 57,929.57		$ 48,204.10		$ 9,725.47		
29 Financial Transmission Rights Administration (Schedule 16)		$ 32,862.32		$ 32,862.32		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 96,058.44		$ 90,799.92		$ 5,258.52		$ 161.12
34 Real -Time Schedule 24 Allocation Amount		$ (88,931.11)		$ 31,844.01		$ (120,775.12)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 869,091.54	-	$ 932,849.12	-	$ (63,757.58)	-	$ 1,457.76
Congestion & FTRs								
1b Day Ahead Congestion		$ 2,229,734.86		$ 1,953,357.25		$ 276,377.61		
5b Day Ahead Non Asset Congestion		$ 177,823.30		$ 155,781.94		$ 22,041.36		
13b Real Time Congestion		$ 149,298.77		$ 149,298.77		$ 0.00		
22b Real Time Non Asset Congestion		$ 0.03		$ 27,755.12		$ (27,755.09)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 8,633.43		$ 8,633.43				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (67,332.29)		$ (67,332.29)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (4,206.89)		$ (4,206.89)				
32 Financial Transmission Rights Yearly Allocation		$ (438,248.64)		$ (438,248.64)				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ 62,379.85		$ 62,379.85				
37 Financial Transmission Guarantee Uplift Amount		$ (64,723.55)		$ (64,723.55)				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$ -				
SUBTOTAL	-	$ 2,053,358.87	-	$ 1,782,694.99	-	$ 270,663.88	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 132,980.08		$ 116,497.08		$ 16,483.00		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (309,502.38)		$ (303,017.27)		$ (6,485.11)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 229,232.53		$ 200,818.96		$ 28,413.57		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (137,444.24)		$ (100,296.41)		$ (37,147.83)		
43 Real Time Price Volatility Make Whole Payment		$ (216,371.99)		$ (193,313.48)		$ (23,058.51)		
SUBTOTAL	-	$ (301,106.00)	-	$ (279,311.12)	-	$ (21,794.88)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 207,093.60		$ 221,973.60		$ (14,880.00)		
21 Real Time Net Inadvertent Distribution		$ 76,373.38		$ 76,373.38				$ 111.45
23 Real Time Revenue Neutrality Uplift Amount		$ 199,041.68		$ 174,370.29		$ 24,671.39		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 482,508.66	-	$ 472,717.27	-	$ 9,791.39	-	$ 111.45
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 3,351,784.59		$ 3,351,784.59				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (3,360,340.59)		$ (3,327,014.57)		$ (33,326.02)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (71,575.59)		$ (71,575.59)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 29,565.66		$ 29,565.66				
SUBTOTAL	-	$ (50,565.93)	-	($17,240)	-	($33,326)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (8,633.43)		$ (8,633.43)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (1,086.22)		$ (1,086.22)				
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	-	$ (9,719.65)	-	$ (9,719.65)	-	$ -	-	$ -
Total MISO Day 2 Charges	(342,539)	$ (1,714,127.31)	117,297	$ 7,587,528.26	(459,836)	$ (9,301,655.57)	11,472	$ 288,227.63

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT **NOTE 1**

May 2018	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	(34,757)	$ 2,614,901.39	335,248	$ 12,578,913.31	(370,005)	$ (9,964,011.92)		
5a Day Ahead Non Asset Energy	(199,972)	$ (7,661,954.85)	(199,972)	$ (7,661,954.85)			11,784	$ 320,483.99
13a Real Time Asset Energy	(225,705)	$ (5,714,535.38)	(144,100)	$ (3,852,616.23)	(81,605)	$ (1,861,919.15)		
22a Real Time Non Asset Energy	250	$ 12,557.77	250	$ 12,557.77				
SUBTOTAL	(460,183)	$ (10,749,031.07)	(8,573)	$ 1,076,900.00	(451,610)	$ (11,825,931.07)	11,784	$ 320,483.99
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,356,149.48		$ 2,077,428.50		$ 278,720.98		
5c Day Ahead Non Asset Loss		$ 948,699.88		$ 836,473.31		$ 112,226.57		
3 Day Ahead Financial Bilateral Transaction Loss		$ (4,007.79)		$ (4,007.79)		$ -		
13c Real Time Loss		$ 146,575.92		$ 146,698.06		$ (122.14)		
22c Real Time Non Asset Loss		$ (1,032.49)		$ 27,390.65		$ (28,423.14)		
14 Real Time Distribution Losses		$ (910,589.02)		$ (910,589.02)				
16 Real Time Financial Bilateral Loss		$ 1.78		$ 1.78				
SUBTOTAL	-	$ 2,535,797.76	-	$ 2,173,395.49	-	$ 362,402.27	-	$ -
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)		$ 581,519.22		$ 552,852.61		$ 28,666.61		$ 905.92
19 Real Time Market Administration (Schedule 17)		$ 54,043.24		$ 47,847.09		$ 6,196.15		
29 Financial Transmission Rights Administration (Schedule 16)		$ 14,822.88		$ 14,822.88		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 105,763.28		$ 100,622.50		$ 5,140.78		$ 165.60
34 Real -Time Schedule 24 Allocation Amount		$ (95,334.31)		$ 355.13		$ (95,689.44)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 660,814.31	-	$ 716,500.21	-	$ (55,685.90)	-	$ 1,071.52
Congestion & FTRs								
1b Day Ahead Congestion		$ 509,014.63		$ 448,800.68		$ 60,213.95		
5b Day Ahead Non Asset Congestion		$ 688,450.34		$ 607,010.03		$ 81,440.31		
13b Real Time Congestion		$ 109,304.75		$ 109,320.54		$ (15.79)		
22b Real Time Non Asset Congestion		$ (133.48)		$ 33,235.08		$ (33,368.56)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (7,051.88)		$ (7,051.88)				
15 Real Time Financial Bilateral Congestion		$ 2.35		$ 2.35				
28 Financial Transmission Rights Hourly Allocation		$ (1,745,103.48)		$ (1,745,103.48)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (103,422.19)		$ (103,422.19)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ 53,958.81		$ 53,958.81				
37 Financial Transmission Guarantee Uplift Amount		$ 14,581.48		$ 14,581.48				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$ -				
SUBTOTAL	-	$ (480,398.67)	-	$ (588,668.58)	-	$ 108,269.91	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 82,136.98		$ 72,420.58		$ 9,716.40		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (52,416.61)		$ (38,279.43)		$ (14,137.18)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 111,692.60		$ 98,479.91		$ 13,212.69		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (14,398.95)		$ (29,504.08)		$ 15,105.13		
43 Real Time Price Volatility Make Whole Payment		$ (129,317.99)		$ (107,478.17)		$ (21,839.82)		
SUBTOTAL	-	$ (2,303.97)	-	$ (4,361.19)	-	$ 2,057.22	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 65,594.78		$ 80,474.78		$ (14,880.00)		
21 Real Time Net Inadvertent Distribution		$ 13,432.43		$ 13,432.43				$ 25.00
23 Real Time Revenue Neutrality Uplift Amount		$ 172,606.13		$ 152,187.67		$ 20,418.46		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 251,633.34	-	$ 246,094.88	-	$ 5,538.46	-	$ 25.00
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 3,351,784.59		$ 3,351,784.59				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (3,360,340.52)		$ (3,340,988.91)		$ (19,351.61)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (71,760.16)		$ (71,760.16)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 29,565.66		$ 29,565.66				
SUBTOTAL	-	$ (50,750.43)	-	($31,399)	-	($19,352)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 7,051.88		$ 7,051.88				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 4,007.79		$ 4,007.79				
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		$ (2.35)		$ (2.35)				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ (1.78)		$ (1.78)				
SUBTOTAL	-	$ 11,055.54	-	$ 11,055.54	-	$ -	-	$ -
Total MISO Day 2 Charges	(460,183)	$ (7,823,183.19)	(8,573)	$ 3,599,517.52	(451,610)	$ (11,422,700.71)	11,784	$ 321,580.51

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT **NOTE 1**

June 2018	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	(255,526)	$ (4,295,307.30)	264,864	$ 8,888,029.55	(520,390)	$ (13,183,336.85)		
5a Day Ahead Non Asset Energy	(210,278)	$ (8,175,545.00)	(210,278)	$ (8,175,545.00)			11,376	$ 274,456.24
13a Real Time Asset Energy	(117,926)	$ (2,817,759.81)	(26,039)	$ (735,859.03)	(91,887)	$ (2,081,900.78)		
22a Real Time Non Asset Energy	206	$ 6,052.65	206	$ 6,052.65				
SUBTOTAL	(583,525)	$ (15,282,559.46)	28,753	$ (17,321.83)	(612,277)	$ (15,265,237.63)	11,376	$ 274,456.24
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,290,356.80		$ 1,962,640.31		$ 327,716.49		
5c Day Ahead Non Asset Loss		$ 1,139,248.03		$ 976,238.33		$ 163,009.70		
3 Day Ahead Financial Bilateral Transaction Loss		$ (5,298.90)		$ (5,298.90)		$ -		
13c Real Time Loss		$ 70,562.08		$ 70,651.89		$ (89.81)		
22c Real Time Non Asset Loss		$ (627.65)		$ 17,145.86		$ (17,773.51)		
14 Real Time Distribution Losses		$ (1,015,586.44)		$ (1,015,586.44)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 2,478,653.92	-	$ 2,005,791.05	-	$ 472,862.87	-	$ -
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)		$ 698,607.49		$ 655,305.98		$ 43,301.51		$ 973.92
19 Real Time Market Administration (Schedule 17)		$ 72,958.27		$ 65,335.42		$ 7,622.85		
29 Financial Transmission Rights Administration (Schedule 16)		$ 19,888.40		$ 19,888.40		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 96,251.98		$ 90,140.80		$ 6,111.18		$ 131.52
34 Real -Time Schedule 24 Allocation Amount		$ (82,766.29)		$ 36,086.06		$ (118,852.35)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 804,939.85	-	$ 866,756.66	-	$ (61,816.81)	-	$ 1,105.44
Congestion & FTRs								
1b Day Ahead Congestion		$ 708,282.88		$ 606,937.98		$ 101,344.90		
5b Day Ahead Non Asset Congestion		$ 752,105.21		$ 644,489.98		$ 107,615.23		
13b Real Time Congestion		$ 882.87		$ 923.88		$ (41.01)		
22b Real Time Non Asset Congestion		$ (286.59)		$ 1,779.98		$ (2,066.57)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (3,046.41)		$ (3,046.41)				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (1,100,724.72)		$ (1,100,724.72)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (58,804.62)		$ (58,804.62)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ 53,995.61		$ 53,995.61				
37 Financial Transmission Guarantee Uplift Amount		$ (53,814.00)		$ (53,814.00)				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$ -				
SUBTOTAL	-	$ 298,590.23	-	$ 91,737.67	-	$ 206,852.56	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 106,351.71		$ 91,134.34		$ 15,217.37		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (34,357.61)		$ (8,724.23)		$ (25,633.38)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 276,215.39		$ 236,693.02		$ 39,522.37		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (19,601.94)		$ (12,042.19)		$ (7,559.75)		
43 Real Time Price Volatility Make Whole Payment		$ (161,021.43)		$ (147,070.38)		$ (13,951.05)		
SUBTOTAL	-	$ 167,586.12	-	$ 159,990.56	-	$ 7,595.56	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 191,768.95		$ 202,127.65		$ (10,358.70)		
21 Real Time Net Inadvertent Distribution		$ (83,118.67)		$ (83,118.67)				$ (114.26)
23 Real Time Revenue Neutrality Uplift Amount		$ 1,724,218.20		$ 1,477,507.85		$ 246,710.35		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 1,832,868.48	-	$ 1,596,516.83	-	$ 236,351.65	-	$ (114.26)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 2,270,304.83		$ 2,270,304.83				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (2,293,458.77)		$ (2,273,461.05)		$ (19,997.72)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (320,148.19)		$ (320,148.19)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 41,430.89		$ 41,430.89				
SUBTOTAL	-	$ (301,871.24)	-	($281,874)	-	($19,998)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 3,046.41		$ 3,046.41				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 5,298.90		$ 5,298.90				
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	-	$ 8,345.31	-	$ 8,345.31	-	$ -	-	$ -
Total MISO Day 2 Charges	(583,525)	$ (9,993,446.79)	28,753	$ 4,429,942.72	(612,277)	$ (14,423,389.51)	11,376	$ 275,447.42

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT **NOTE 1**

July 2017 - June 2018	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	(2,127,308)	$ (24,792,899.63)	3,276,993	$ 106,826,723.66	(5,404,300)	$ (131,619,623.29)	-	$ -
5a Day Ahead Non Asset Energy	(2,482,801)	$ (83,491,253.19)	(2,482,801)	$ (83,491,253.19)	-	$0	138,264	$ 3,491,364.29
13a Real Time Asset Energy	(698,425)	$ (18,382,596.95)	413,868	$ 5,808,734.88	(1,112,293)	$ (24,191,331.83)	-	$ -
22a Real Time Non Asset Energy	2,879	$ 172,148.42	2,879	$ 172,148.42	-	$ -	-	$ -
SUBTOTAL	(5,305,654)	$(126,494,601.35)	1,210,939	$ 29,316,353.77	(6,516,593)	$ (155,810,955.12)	138,264	$ 3,491,364.29
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss	-	$ 33,205,382.33	-	$ 28,656,635.41	-	$ 4,548,746.92	-	$ -
5c Day Ahead Non Asset Loss	-	$ 9,344,151.30	-	$ 8,244,328.89	-	$ 1,099,822.41	-	$ -
3 Day Ahead Financial Bilateral Transaction Loss	-	$ (19,342.13)	-	$ (19,342.13)	-	$ -	-	$ -
13c Real Time Loss	-	$ 816,065.34	-	$ 817,591.52	-	$ (1,526.18)	-	$ -
22c Real Time Non Asset Loss	-	$ (14,313.79)	-	$ 106,566.85	-	$ (120,880.64)	-	$ -
14 Real Time Distribution Losses	-	$ (12,219,839.01)	-	$ (12,219,839.01)	-	$ -	-	$ -
16 Real Time Financial Bilateral Loss	-	$ 17.76	-	$ 17.76	-	$ -	-	$ -
SUBTOTAL	-	$ 31,112,121.80	-	$ 25,585,959.30	-	$ 5,526,162.50	-	$ -
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)	-	$ 7,564,621.45	-	$ 7,115,252.43	-	$ 449,369.02	-	$ 11,419.76
19 Real Time Market Administration (Schedule 17)	-	$ 608,400.83	-	$ 515,857.17	-	$ 92,543.66	-	$ -
29 Financial Transmission Rights Administration (Schedule 16)	-	$ 276,824.24	-	$ 276,824.24	-	$ -	-	$ 8,888.00
33 Day-Ahead Schedule 24 Allocation Amount	-	$ 1,131,939.99	-	$ 1,064,639.03	-	$ 67,300.96	-	$ 1,711.52
34 Real -Time Schedule 24 Allocation Amount	-	$ (1,015,860.58)	-	$ 69,169.95	-	$ (1,085,030.53)	-	$ -
35 Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 8,565,925.93	-	$ 9,041,742.82	-	$ (475,816.89)	-	$ 22,019.28
Congestion & FTRs								
1b Day Ahead Congestion	-	$ 21,580,995.32	-	$ 18,926,002.32	-	$ 2,654,993.00	-	$ -
5b Day Ahead Non Asset Congestion	-	$ 8,508,184.79	-	$ 7,483,018.13	-	$ 1,025,166.66	-	$ -
13b Real Time Congestion	-	$ 1,416,902.40	-	$ 1,423,729.39	-	$ (6,826.99)	-	$ -
22b Real Time Non Asset Congestion	-	$ (51,843.78)	-	$ 216,970.81	-	$ (268,814.59)	-	$ -
2 Day Ahead Financial Bilateral Transaction Congestion	-	$ 7,578.92	-	$ 7,578.92	-	$ -	-	$ -
15 Real Time Financial Bilateral Congestion	-	$ 17.58	-	$ 17.58	-	$ -	-	$ -
28 Financial Transmission Rights Hourly Allocation	-	$ (32,283,029.17)	-	$ (32,283,029.17)	-	$ -	-	$ -
30 Financial Transmission Rights Monthly Allocation	-	$ (2,131,625.26)	-	$ (2,131,625.26)	-	$ -	-	$ -
32 Financial Transmission Rights Yearly Allocation	-	$ (438,248.64)	-	$ (438,248.64)	-	$ -	-	$ -
31 Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36 Financial Transmission Rights Full Funding Guarantee Amount	-	$ (423,350.73)	-	$ (423,350.73)	-	$ -	-	$ -
37 Financial Transmission Guarantee Uplift Amount	-	$ 460,352.78	-	$ 460,352.78	-	$ -	-	$ -
38 Financial Transmission Rights Monthly Transacton Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ (3,354,065.79)	-	$ (6,758,583.86)	-	$ 3,404,518.07	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 1,139,061.36	-	$ 980,933.26	-	$ 158,128.10	-	$ -
11 Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (1,351,557.33)	-	$ (1,129,160.05)	-	$ (222,397.28)	-	$ -
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 2,282,686.15	-	$ 1,983,806.07	-	$ 298,880.08	-	$ -
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (1,684,838.15)	-	$ (905,621.56)	-	$ (779,216.59)	-	$ -
43 Real Time Price Volatility Make Whole Payment	-	$ (2,412,443.84)	-	$ (1,989,723.09)	-	$ (422,720.75)	-	$ -
SUBTOTAL	-	$ (2,027,091.81)	-	$ (1,059,765.37)	-	$ (967,326.44)	-	$ -
Other Charges								
20 Real Time Miscellaneous	-	$ 1,069,695.58	-	$ 1,240,854.28	$ -	$ (171,158.70)	-	$ (16,302.42)
21 Real Time Net Inadvertent Distribution	-	$ 384,755.95	-	$ 384,755.95	$ -	$ -	-	$ 533.79
23 Real Time Revenue Neutrality Uplift Amount	-	$ 7,182,904.36	-	$ 6,183,096.87	-	$ 999,807.49	-	$ -
26 Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 8,637,355.89	-	$ 7,808,707.10	-	$ 828,648.79	-	$ (15,768.63)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions	-	$ 39,056,103.83	-	$ 39,056,103.83	$ -	$ -	-	$ -
40 Auction Revenue Rights - Monthly ARR Revenue	-	$ (39,321,794.81)	-	$ (39,068,965.76)	$ -	$ (252,829.05)	-	$ -
41 Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (1,320,777.70)	-	$ (1,320,777.70)	-	$ -	-	$ -
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 519,000.47	-	$ 519,000.47	-	$ -	-	$ -
SUBTOTAL	-	$ (1,067,468.21)	-	($814,639)	-	($252,829)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (7,578.92)	-	$ (7,578.92)	-	$ -	-	$ -
7 Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ 19,342.13	-	$ 19,342.13	-	$ -	-	$ -
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	-	$ (17.58)	-	$ (17.58)	-	$ -	-	$ -
18 Real Time Congestion Rebate on Carve Out Grandfathered	-	$ (17.76)	-	$ (17.76)	-	$ -	-	$ -
SUBTOTAL	-	$ 11,727.87	-	$ 11,727.87	-	$ -	-	$ -
Total MISO Day 2 Charges	(5,305,654)	$ (84,616,095.67)	1,210,939	$ 63,131,502.47	(6,516,593)	$ (147,747,598.14)	138,264	$ 3,497,614.94

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

Total

MISO ASM MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	July 2017 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (274,704.34)		$ (274,704.34)	$ (203,024.04)
2	Day-Ahead Spinning Reserve Amount	$ (140,621.86)		$ (140,621.86)	$ (103,928.53)
3	Day-Ahead Supplemental Reserve	$ (59,809.63)		$ (59,809.63)	$ (44,203.13)
4	Real-Time Regulation Amount (See Note 1)	$ (110,336.60)	$ 236,283.45	$ 125,946.85	$ 93,082.76
5	Real-Time Spinning Reserve Amount (See Note 1)	$ (36,191.36)	$ 100,716.65	$ 64,525.29	$ 47,688.31
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 3,924.10	$ 2,423.90	$ 6,348.00	$ 4,691.58
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 17,552.40		$ 17,552.40	$ 12,972.34
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 2,717,331.77		$ 2,717,331.77	$ 2,008,281.65
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ (445,721.17)	$ (20,322.12)	$ (466,043.29)	$ (344,435.74)
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ (118,699.29)	$ (10,946.44)	$ (129,645.73)	$ (95,816.47)
9	Real Time Net Regulation Adjustment Amount	$ (30.81)	$ (226.44)	$ (257.25)	$ (190.12)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 164,163.91		$ 164,163.91	$ 121,327.61
11	Real Time Spinnng Reserve Cost Distribution	$ 184,268.01		$ 184,268.01	$ 136,185.82
12	Real Time Supplemental Reserve Cost Distribution	$ 84,066.82		$ 84,066.82	$ 62,130.75
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 132,523.83	$ (40,077.34)	$ 92,446.49	$ 68,323.86
14	Real Time Contingency Reserve Deployment Failure	$ 3,820.14	$ -	$ 3,820.14	$ 2,823.33
	TOTAL MISO ASM CHARGES	**$ 2,121,535.92**	**$ 267,851.66**	**$ 2,389,387.58**	**$ 1,765,909.96**

NOTE 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (6,388.96)		$ (6,388.96)	$ (4,721.85)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,149.01)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,870.86)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 2,130,832.63**	**$ 267,851.66**	**$ 2,398,684.29**	**$ 1,772,780.82**

MISO ASM MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	August 2017 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (261,255.41)		$ (261,255.41)	$ (191,881.05)
2	Day-Ahead Spinning Reserve Amount	$ (287,156.39)		$ (287,156.39)	$ (210,904.22)
3	Day-Ahead Supplemental Reserve	$ (35,678.29)		$ (35,678.29)	$ (26,204.19)
4	Real-Time Regulation Amount (See Note 1)	$ (20,149.82)	$ 169,129.02	$ 148,979.20	$ 109,418.92
5	Real-Time Spinning Reserve Amount (See Note 1)	$ 2,942.03	$ 166,573.70	$ 169,515.73	$ 124,502.13
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 2,133.51	$ 4,114.69	$ 6,248.20	$ 4,589.04
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 29,162.60		$ 29,162.60	$ 21,418.70
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 1,038,604.85		$ 1,038,604.85	$ 762,811.33
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ (245,088.84)	$ (8,793.38)	$ (253,882.22)	$ (186,465.75)
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ (79,848.58)	$ (7,107.12)	$ (86,955.70)	$ (63,865.28)
9	Real Time Net Regulation Adjustment Amount	$ 1,086.51	$ (2,629.18)	$ (1,542.67)	$ (1,133.03)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 134,839.26		$ 134,839.26	$ 99,033.73
11	Real Time Spinnng Reserve Cost Distribution	$ 157,052.27		$ 157,052.27	$ 115,348.25
12	Real Time Supplemental Reserve Cost Distribution	$ 29,882.96		$ 29,882.96	$ 21,947.77
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 84,691.33	$ (53,612.45)	$ 31,078.88	$ 22,826.12
14	Real Time Contingency Reserve Deployment Failure	$ 1,352.19	$ -	$ 1,352.19	$ 993.13
	TOTAL MISO ASM CHARGES	**$ 552,570.18**	**$ 267,675.28**	**$ 820,245.46**	**$ 602,435.59**

NOTE 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (6,388.96)		$ (6,388.96)	$ (4,692.42)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,135.62)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,828.04)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 561,866.89**	**$ 267,675.28**	**$ 829,542.17**	**$ 609,263.63**

MISO ASM MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	September 2017 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (366,015.71)		$ (366,015.71)	$ (271,383.93)
2	Day-Ahead Spinning Reserve Amount	$ (550,107.60)		$ (550,107.60)	$ (407,879.66)
3	Day-Ahead Supplemental Reserve	$ (51,241.64)		$ (51,241.64)	$ (37,993.34)
4	Real-Time Regulation Amount (See Note 1)	$ (102,195.92)	$ 243,834.59	$ 141,638.67	$ 105,018.61
5	Real-Time Spinning Reserve Amount (See Note 1)	$ 166,913.71	$ 197,252.57	$ 364,166.28	$ 270,012.67
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 4,596.77	$ 1,648.25	$ 6,245.02	$ 4,630.40
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 8,227.60		$ 8,227.60	$ 6,100.39
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 146,423.04		$ 146,423.04	$ 108,566.00
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ (710,471.16)	$ (47,274.59)	$ (757,745.75)	$ (561,833.87)
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ (170,500.77)	$ (12,807.42)	$ (183,308.19)	$ (135,914.65)
9	Real Time Net Regulation Adjustment Amount	$ 19,630.35	$ (10,143.00)	$ 9,487.35	$ 7,034.44
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 156,801.94		$ 156,801.94	$ 116,261.48
11	Real Time Spinnng Reserve Cost Distribution	$ 174,107.52		$ 174,107.52	$ 129,092.78
12	Real Time Supplemental Reserve Cost Distribution	$ 41,354.54		$ 41,354.54	$ 30,662.50
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 146,143.32	$ (29,360.43)	$ 116,782.89	$ 86,589.18
14	Real Time Contingency Reserve Deployment Failure	$ 911.05	$ (70.63)	$ 840.42	$ 623.13
	TOTAL MISO ASM CHARGES	**$ (1,085,422.96)**	**$ 343,079.34**	**$ (742,343.62)**	**$ (550,413.89)**

NOTE 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (6,388.96)		$ (6,388.96)	$ (4,737.12)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,155.96)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,893.09)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ (1,076,126.25)**	**$ 343,079.34**	**$ (733,046.91)**	**$ (543,520.81)**

MISO ASM MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	October 2017 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (261,287.68)		$ (261,287.68)	$ (189,627.01)
2	Day-Ahead Spinning Reserve Amount	$ (542,721.37)		$ (542,721.37)	$ (393,874.80)
3	Day-Ahead Supplemental Reserve	$ (25,670.05)		$ (25,670.05)	$ (18,629.79)
4	Real-Time Regulation Amount (See Note 1)	$ 31,956.08	$ 93,372.78	$ 125,328.86	$ 90,956.21
5	Real-Time Spinning Reserve Amount (See Note 1)	$ 281,516.03	$ 146,207.64	$ 427,723.67	$ 310,416.33
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 1,065.94	$ 2,776.16	$ 3,842.10	$ 2,788.37
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 11,337.78		$ 11,337.78	$ 8,228.28
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ (81,049.67)		$ (81,049.67)	$ (58,821.02)
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ (328,311.39)	$ (12,506.75)	$ (340,818.14)	$ (247,345.48)
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ (60,663.06)	$ (5,467.50)	$ (66,130.56)	$ (47,993.62)
9	Real Time Net Regulation Adjustment Amount	$ 8,112.00	$ (55,795.89)	$ (47,683.89)	$ (34,606.12)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 173,396.01		$ 173,396.01	$ 125,840.48
11	Real Time Spinnng Reserve Cost Distribution	$ 156,539.19		$ 156,539.19	$ 113,606.81
12	Real Time Supplemental Reserve Cost Distribution	$ 32,867.51		$ 32,867.51	$ 23,853.28
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 33,928.44	$ 22,181.15	$ 56,109.59	$ 40,720.99
14	Real Time Contingency Reserve Deployment Failure	$ 4,728.13	$ (284.08)	$ 4,444.05	$ 3,225.23
	TOTAL MISO ASM CHARGES	**$ (564,256.11)**	**$ 190,483.51**	**$ (373,772.60)**	**$ (271,261.86)**

NOTE 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (6,388.96)		$ (6,388.96)	$ (4,636.73)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,110.27)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,747.00)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ (554,959.40)**	**$ 190,483.51**	**$ (364,475.89)**	**$ (264,514.86)**

MISO ASM MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	November 2017 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (98,406.66)		$ (98,406.66)	$ (70,806.08)
2	Day-Ahead Spinning Reserve Amount	$ (354,966.39)		$ (354,966.39)	$ (255,407.29)
3	Day-Ahead Supplemental Reserve	$ (22,301.75)		$ (22,301.75)	$ (16,046.67)
4	Real-Time Regulation Amount (See Note 1)	$ (40,500.39)	$ 34,767.15	$ (5,733.24)	$ (4,125.21)
5	Real-Time Spinning Reserve Amount (See Note 1)	$ 161,028.73	$ 115,996.53	$ 277,025.26	$ 199,326.68
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 107.36	$ 1,222.43	$ 1,329.79	$ 956.82
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 602.45		$ 602.45	$ 433.48
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 835,412.57		$ 835,412.57	$ 601,100.47
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ (68,469.25)	$ (10,816.41)	$ (79,285.66)	$ (57,048.03)
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ (65,988.15)	$ (10,209.85)	$ (76,198.00)	$ (54,826.39)
9	Real Time Net Regulation Adjustment Amount	$ 1,700.23	$ 1,086.90	$ 2,787.13	$ 2,005.41
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 125,645.40		$ 125,645.40	$ 90,405.04
11	Real Time Spinnng Reserve Cost Distribution	$ 133,782.47		$ 133,782.47	$ 96,259.87
12	Real Time Supplemental Reserve Cost Distribution	$ 22,559.74		$ 22,559.74	$ 16,232.30
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 50,489.43	$ (24,191.27)	$ 26,298.16	$ 18,922.19
14	Real Time Contingency Reserve Deployment Failure	$ 515.15	$ (476.73)	$ 38.42	$ 27.64
	TOTAL MISO ASM CHARGES	**$ 681,210.94**	**$ 107,378.75**	**$ 788,589.69**	**$ 567,410.23**

NOTE 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (6,388.96)		$ (6,388.96)	$ (4,597.02)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,092.20)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,689.22)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 690,507.65**	**$ 107,378.75**	**$ 797,886.40**	**$ 574,099.45**

MISO ASM MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
December 2017 Actual					
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (64,791.18)		$ (64,791.18)	$ (46,339.45)
2	Day-Ahead Spinning Reserve Amount	$ (256,789.43)		$ (256,789.43)	$ (183,658.98)
3	Day-Ahead Supplemental Reserve	$ (25,033.47)		$ (25,033.47)	$ (17,904.25)
4	Real-Time Regulation Amount (See Note 1)	$ (27,106.75)	$ 4,145.95	$ (22,960.80)	$ (16,421.85)
5	Real-Time Spinning Reserve Amount (See Note 1)	$ 159,832.88	$ 148,251.70	$ 308,084.58	$ 220,345.91
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 2,900.17	$ 1,662.57	$ 4,562.74	$ 3,263.33
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 6,732.07		$ 6,732.07	$ 4,814.86
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 2,659,372.78		$ 2,659,372.78	$ 1,902,016.37
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ 3,900.38	$ (2,869.59)	$ 1,030.79	$ 737.24
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ 8,551.69	$ (2,969.20)	$ 5,582.49	$ 3,992.67
9	Real Time Net Regulation Adjustment Amount	$ (1,677.87)	$ 151.76	$ (1,526.11)	$ (1,091.49)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 111,239.12		$ 111,239.12	$ 79,559.60
11	Real Time Spinnng Reserve Cost Distribution	$ 75,023.88		$ 75,023.88	$ 53,658.01
12	Real Time Supplemental Reserve Cost Distribution	$ 13,804.88		$ 13,804.88	$ 9,873.42
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 45,746.06	$ (12,845.51)	$ 32,900.55	$ 23,530.88
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 2,711,705.21**	**$ 135,527.68**	**$ 2,847,232.89**	**$ 2,036,376.25**

NOTE 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (6,388.96)		$ (6,388.96)	$ (4,569.46)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,079.66)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,649.12)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 2,721,001.92**	**$ 135,527.68**	**$ 2,856,529.60**	**$ 2,043,025.38**

MISO ASM MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	January 2018 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (189,944.31)		$ (189,944.31)	$ (135,052.23)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (357,225.47)		$ (357,225.47)	$ (253,990.74)
3	Day-Ahead Supplemental Reserve	$ (113,132.59)		$ (113,132.59)	$ (80,438.36)
4	Real-Time Regulation Amount (See Note 1)	$ (62,294.47)	$ 116,648.47	$ 54,354.00	$ 38,646.22
5	Real-Time Spinning Reserve Amount	$ 99,625.51	$ 125,197.21	$ 224,822.72	$ 159,851.11
6	Real-Time Supplemental Reserve Amount.	$ 8,783.51	$ 35,774.57	$ 44,558.08	$ 31,681.22
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (4,831.83)		$ (4,831.83)	$ (3,435.48)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 5,084,795.57		$ 5,084,795.57	$ 3,615,338.48
8b	Real Time Non Excessive Energy Congestion	$ 56,110.56	$ (8,090.22)	$ 48,020.34	$ 34,142.92
8c	Real Time Non Excessive Energy Loss	$ (16,806.80)	$ (665.98)	$ (17,472.78)	$ (12,423.31)
9	Real Time Net Regulation Adjustment Amount	$ (2,074.03)	$ (3,221.82)	$ (5,295.85)	$ (3,765.40)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 189,977.89		$ 189,977.89	$ 135,076.10
11	Real Time Spinning Reserve Cost Distribution	$ 214,561.05		$ 214,561.05	$ 152,554.97
12	Real Time Supplemental Reserve Cost Distribution	$ 95,357.15		$ 95,357.15	$ 67,799.85
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 145,650.35	$ (37,298.96)	$ 108,351.39	$ 77,038.88
14	Real Time Contingency Reserve Deployment Failure	$ -	$ (4.43)	$ (4.43)	$ (3.15)
	TOTAL MISO ASM CHARGES	**$ 5,148,552.09**	**$ 228,338.84**	**$ 5,376,890.93**	**$ 3,823,021.08**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (4,653.24)		$ (4,653.24)	$ (3,308.50)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,233.95)		$ (2,233.95)	$ (1,588.36)
	Total	$ (6,887.19)		$ (6,887.19)	$ (4,896.86)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 5,155,439.28**	**$ 228,338.84**	**$ 5,383,778.12**	**$ 3,827,917.94**

MISO ASM MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	February 2018 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (88,856.64)		$ (88,856.64)	$ (63,527.81)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (195,605.49)		$ (195,605.49)	$ (139,847.60)
3	Day-Ahead Supplemental Reserve	$ (20,008.14)		$ (20,008.14)	$ (14,304.76)
4	Real-Time Regulation Amount (See Note 1)	$ (5,000.28)	$ 31,173.64	$ 26,173.36	$ 18,712.57
5	Real-Time Spinning Reserve Amount	$ 46,408.24	$ 60,387.04	$ 106,795.28	$ 76,352.99
6	Real-Time Supplemental Reserve Amount.	$ 193.73	$ (5,176.12)	$ (4,982.39)	$ (3,562.15)
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 16,213.83		$ 16,213.83	$ 11,592.03
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 2,023,572.59		$ 2,023,572.59	$ 1,446,747.55
8b	Real Time Non Excessive Energy Congestion	$ (11,521.61)	$ (4,601.92)	$ (16,123.53)	$ (11,527.47)
8c	Real Time Non Excessive Energy Loss	$ (6,307.71)	$ (802.57)	$ (7,110.28)	$ (5,083.48)
9	Real Time Net Regulation Adjustment Amount	$ 6,653.67	$ (3,111.33)	$ 3,542.34	$ 2,532.59
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 101,086.95		$ 101,086.95	$ 72,271.83
11	Real Time Spinning Reserve Cost Distribution	$ 74,806.23		$ 74,806.23	$ 53,482.50
12	Real Time Supplemental Reserve Cost Distribution	$ 4,208.80		$ 4,208.80	$ 3,009.07
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 35,577.84	$ (10,843.72)	$ 24,734.12	$ 17,683.59
14	Real Time Contingency Reserve Deployment Failure	$ 3,401.37	$ (370.23)	$ 3,031.14	$ 2,167.11
	TOTAL MISO ASM CHARGES	**$ 1,984,823.38**	**$ 66,654.79**	**$ 2,051,478.17**	**$ 1,466,698.56**

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	$ (2,470.11)		$ (2,470.11)	$ (1,766.00)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (455.23)		$ (455.23)	$ (325.47)
	Total	$ (2,925.34)		$ (2,925.34)	$ (2,091.46)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 1,987,748.72**	**$ 66,654.79**	**$ 2,054,403.51**	**$ 1,468,790.03**

MISO ASM MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	March 2018 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (76,865.89)		$ (76,865.89)	$ (55,031.74)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (283,039.62)		$ (283,039.62)	$ (202,640.77)
3	Day-Ahead Supplemental Reserve	$ (25,849.80)		$ (25,849.80)	$ (18,507.03)
4	Real-Time Regulation Amount (See Note 1)	$ (11,399.34)	$ 5,552.33	$ (5,847.01)	$ (4,186.14)
5	Real-Time Spinning Reserve Amount	$ 39,395.43	$ 145,677.49	$ 185,072.92	$ 132,502.01
6	Real-Time Supplemental Reserve Amount.	$ (14.17)	$ 5,342.05	$ 5,327.88	$ 3,814.47
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 3,596.15		$ 3,596.15	$ 2,574.65
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 1,718,635.90		$ 1,718,635.90	$ 1,230,448.61
8b	Real Time Non Excessive Energy Congestion	$ (129,832.31)	$ (14,310.97)	$ (144,143.28)	$ (103,198.64)
8c	Real Time Non Excessive Energy Loss	$ (52,819.80)	$ (9,878.76)	$ (62,698.56)	$ (44,888.71)
9	Real Time Net Regulation Adjustment Amount	$ (3,472.66)	$ 944.43	$ (2,528.23)	$ (1,810.07)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 105,213.08		$ 105,213.08	$ 75,326.77
11	Real Time Spinning Reserve Cost Distribution	$ 127,183.92		$ 127,183.92	$ 91,056.68
12	Real Time Supplemental Reserve Cost Distribution	$ 20,799.71		$ 20,799.71	$ 14,891.45
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 36,796.65	$ (8,733.92)	$ 28,062.73	$ 20,091.37
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 1,468,327.25**	**$ 124,592.65**	**$ 1,592,919.90**	**$ 1,140,442.88**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (6,388.96)		$ (6,388.96)	$ (4,574.14)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,081.79)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,655.93)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 1,477,623.96**	**$ 124,592.65**	**$ 1,602,216.61**	**$ 1,147,098.81**

MISO ASM MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	April 2018 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (239,778.55)		$ (239,778.55)	$ (173,633.88)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (270,620.13)		$ (270,620.13)	$ (195,967.59)
3	Day-Ahead Supplemental Reserve	$ (22,120.19)		$ (22,120.19)	$ (16,018.17)
4	Real-Time Regulation Amount (See Note 1)	$ (26,141.16)	$ 140,646.41	$ 114,505.25	$ 82,918.14
5	Real-Time Spinning Reserve Amount	$ 115,174.21	$ 96,313.07	$ 211,487.28	$ 153,146.97
6	Real-Time Supplemental Reserve Amount.	$ 1,789.19	$ 3,942.26	$ 5,731.45	$ 4,150.39
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 8,266.20		$ 8,266.20	$ 5,985.91
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 2,602,750.18		$ 2,602,750.18	$ 1,884,762.51
8b	Real Time Non Excessive Energy Congestion	$ (223,920.06)	$ (18,505.71)	$ (242,425.77)	$ (175,550.85)
8c	Real Time Non Excessive Energy Loss	$ (83,617.97)	$ (7,552.09)	$ (91,170.06)	$ (66,020.13)
9	Real Time Net Regulation Adjustment Amount	$ (20,835.10)	$ 7,694.64	$ (13,140.46)	$ (9,515.57)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 143,014.53		$ 143,014.53	$ 103,562.93
11	Real Time Spinning Reserve Cost Distribution	$ 160,286.03		$ 160,286.03	$ 116,069.96
12	Real Time Supplemental Reserve Cost Distribution	$ 18,913.72		$ 18,913.72	$ 13,696.23
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 96,564.49	$ (8,733.19)	$ 87,831.30	$ 63,602.39
14	Real Time Contingency Reserve Deployment Failure	$ 680.46	$ (546.38)	$ 134.08	$ 97.09
	TOTAL MISO ASM CHARGES	**$ 2,260,405.85**	**$ 213,259.01**	**$ 2,473,664.86**	**$ 1,791,286.32**

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	$ (6,388.96)		$ (6,388.96)	$ (4,626.52)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,105.63)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,732.14)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 2,269,702.56**	**$ 213,259.01**	**$ 2,482,961.57**	**$ 1,798,018.47**

MISO ASM MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	May 2018 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (358,881.36)		$ (358,881.36)	$ (262,477.39)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (309,346.81)		$ (309,346.81)	$ (226,248.98)
3	Day-Ahead Supplemental Reserve	$ (56,755.84)		$ (56,755.84)	$ (41,509.89)
4	Real-Time Regulation Amount (See Note 1)	$ 5,683.02	$ 205,647.23	$ 211,330.25	$ 154,561.98
5	Real-Time Spinning Reserve Amount	$ 166,899.18	$ 34,758.27	$ 201,657.45	$ 147,487.52
6	Real-Time Supplemental Reserve Amount.	$ 6,114.21	$ 9,730.38	$ 15,844.59	$ 11,588.36
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (6,207.79)		$ (6,207.79)	$ (4,540.23)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 3,964,719.34		$ 3,964,719.34	$ 2,899,702.50
8b	Real Time Non Excessive Energy Congestion	$ (282,078.94)	$ (12,930.22)	$ (295,009.16)	$ (215,762.76)
8c	Real Time Non Excessive Energy Loss	$ (240,273.12)	$ (17,339.22)	$ (257,612.34)	$ (188,411.60)
9	Real Time Net Regulation Adjustment Amount	$ 29,122.94	$ (8,444.07)	$ 20,678.87	$ 15,124.04
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 134,344.74		$ 134,344.74	$ 98,256.58
11	Real Time Spinning Reserve Cost Distribution	$ 130,619.57		$ 130,619.57	$ 95,532.08
12	Real Time Supplemental Reserve Cost Distribution	$ 36,404.50		$ 36,404.50	$ 26,625.40
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 129,877.91	$ (44,953.84)	$ 84,924.07	$ 62,111.47
14	Real Time Contingency Reserve Deployment Failure	$ -	$ (124.56)	$ (124.56)	$ (91.10)
	TOTAL MISO ASM CHARGES	**$ 3,350,241.55**	**$ 166,343.98**	**$ 3,516,585.53**	**$ 2,571,947.96**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (6,388.96)		$ (6,388.96)	$ (4,672.74)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,126.66)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,799.40)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 3,359,538.26**	**$ 166,343.98**	**$ 3,525,882.24**	**$ 2,578,747.36**

MISO ASM MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	June 2018 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (282,595.30)		$ (282,595.30)	$ (207,848.31)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (352,155.18)		$ (352,155.18)	$ (259,009.47)
3	Day-Ahead Supplemental Reserve	$ (48,354.82)		$ (48,354.82)	$ (35,564.88)
4	Real-Time Regulation Amount (See Note 1)	$ 7,835.65	$ 132,706.56	$ 140,542.21	$ 103,368.53
5	Real-Time Spinning Reserve Amount	$ 141,225.71	$ 136,811.73	$ 278,037.44	$ 204,496.01
6	Real-Time Supplemental Reserve Amount.	$ 5,947.05	$ 4,028.92	$ 9,975.97	$ 7,337.31
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 11,463.04		$ 11,463.04	$ 8,431.04
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 3,636,661.00		$ 3,636,661.00	$ 2,674,757.28
8b	Real Time Non Excessive Energy Congestion	$ (14,442.89)	$ (126.33)	$ (14,569.22)	$ (10,715.63)
8c	Real Time Non Excessive Energy Loss	$ (124,216.13)	$ (10,096.40)	$ (134,312.53)	$ (98,786.61)
9	Real Time Net Regulation Adjustment Amount	$ 13,567.29	$ (8,447.31)	$ 5,119.98	$ 3,765.74
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 127,986.22		$ 127,986.22	$ 94,133.62
11	Real Time Spinning Reserve Cost Distribution	$ 152,666.21		$ 152,666.21	$ 112,285.71
12	Real Time Supplemental Reserve Cost Distribution	$ 71,849.67		$ 71,849.67	$ 52,845.30
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 93,332.99	$ (21,596.18)	$ 71,736.81	$ 52,762.29
14	Real Time Contingency Reserve Deployment Failure	$ 5,353.13	$ (219.77)	$ 5,133.36	$ 3,775.58
	TOTAL MISO ASM CHARGES	**$ 3,446,123.64**	**$ 233,061.22**	**$ 3,679,184.86**	**$ 2,706,033.50**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (6,388.96)		$ (6,388.96)	$ (4,699.07)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,138.64)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,837.71)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 3,455,420.35**	**$ 233,061.22**	**$ 3,688,481.57**	**$ 2,712,871.21**

MISO ASM MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
		2018 AAA PERIOD TOTAL			
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (2,563,383.03)	$ -	$ (2,563,383.03)	$ (1,870,632.93)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (3,900,355.74)	$ -	$ (3,900,355.74)	$ (2,833,358.64)
3	Day-Ahead Supplemental Reserve	$ (505,956.21)	$ -	$ (505,956.21)	$ (367,324.47)
4	Real-Time Regulation Amount (See Note 1)	$ (359,649.98)	$ 1,413,907.58	$ 1,054,257.60	$ 771,950.73
5	Real-Time Spinning Reserve Amount	$ 1,344,770.30	$ 1,474,143.60	$ 2,818,913.90	$ 2,046,128.64
6	Real-Time Supplemental Reserve Amount.	$ 37,541.37	$ 67,490.06	$ 105,031.43	$ 75,929.13
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 102,114.50	$ -	$ 102,114.50	$ 74,575.97
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 26,347,229.92	$ -	$ 26,347,229.92	$ 19,075,711.72
8b	Real Time Non Excessive Energy Congestion	$ (2,399,846.68)	$ (161,148.20)	$ (2,560,994.88)	$ (1,879,004.08)
8c	Real Time Non Excessive Energy Loss	$ (1,011,189.69)	$ (95,842.54)	$ (1,107,032.23)	$ (810,037.59)
9	Real Time Net Regulation Adjustment Amount	$ 51,782.52	$ (82,141.31)	$ (30,358.79)	$ (21,649.60)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 1,667,709.05	$ -	$ 1,667,709.05	$ 1,211,055.78
11	Real Time Spinning Reserve Cost Distribution	$ 1,740,896.35	$ -	$ 1,740,896.35	$ 1,265,133.43
12	Real Time Supplemental Reserve Cost Distribution	$ 472,070.00	$ -	$ 472,070.00	$ 343,567.31
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 1,031,322.64	$ (270,065.66)	$ 761,256.98	$ 554,203.21
14	Real Time Contingency Reserve Deployment Failure	$ 20,761.62	$ (2,096.81)	$ 18,664.81	$ 13,637.98
	TOTAL MISO ASM CHARGES	**$ 22,075,816.94**	**$ 2,344,246.72**	**$ 24,420,063.66**	**$ 17,649,886.59**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (71,012.95)	$ -	$ (71,012.95)	$ (51,601.56)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (31,766.68)	$ -	$ (31,766.68)	$ (23,089.27)
	Total	$ (102,779.63)	$ -	$ (102,779.63)	$ (74,690.83)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 22,178,596.57**	**$ 2,344,246.72**	**$ 24,522,843.29**	**$ 17,724,577.42**

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

		July 17	August 17	September 17	3rd Qt	October 17	November 17	December 17	4th Qt	January 18	February 18	March 18	1st Qt	April 18	May 18	June 18	2nd Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount	$ (274,704.34)	$ (261,255.41)	$ (366,015.71)	$ (901,975.46)	$ (261,287.68)	$ (98,406.66)	$ (64,791.18)	$ (424,485.52)	$ (189,944.31)	$ (88,856.64)	$ (76,865.89)	$ (355,666.84)	$ (239,778.55)	$ (358,881.36)	$ (282,595.30)	$ (881,255.21)	$ (2,563,383.03)
4	Real-Time Regulation Amount	$ (110,336.60)	$ (20,149.82)	$ (102,195.92)	$ (232,682.34)	$ 31,956.08	$ (40,500.39)	$ (27,106.75)	$ (35,651.06)	$ (62,294.47)	$ (5,000.28)	$ (11,399.34)	$ (78,694.09)	$ (26,141.16)	$ 5,683.02	$ 7,835.65	$ (12,622.49)	$ (359,649.98)
10	Real Time Regulation Reserve Cost Distribution Amou	$ 164,163.91	$ 134,839.26	$ 156,801.94	$ 455,805.11	$ 173,396.01	$ 125,645.40	$ 111,239.12	$ 410,280.53	$ 189,977.89	$ 101,086.95	$ 105,213.08	$ 396,277.92	$ 143,014.53	$ 134,344.74	$ 127,986.22	$ 405,345.49	$ 1,667,709.05
	SUBTOTAL	$ (220,877.03)	$ (146,565.97)	$ (311,409.69)	$ (678,852.69)	$ (55,935.59)	$ (13,261.65)	$ 19,341.19	$ (49,856.05)	$ (62,260.89)	$ 7,230.03	$ 16,947.85	$ (38,083.01)	$ (122,905.18)	$ (218,853.60)	$ (146,773.43)	$ (488,532.21)	$ (1,255,323.96)
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount	$ (140,621.86)	$ (287,156.39)	$ (550,107.60)	$ (977,885.85)	$ (542,721.37)	$ (354,966.39)	$ (256,789.43)	$ (1,154,477.19)	$ (357,225.47)	$ (195,605.49)	$ (283,039.62)	$ (835,870.58)	$ (270,620.13)	$ (309,346.81)	$ (352,155.18)	$ (932,122.12)	$ (3,900,355.74)
5	Real-Time Spinning Reserve Amount	$ (36,191.36)	$ 2,942.03	$ 166,913.71	$ 133,664.38	$ 281,516.03	$ 161,028.73	$ 159,832.88	$ 602,377.64	$ 99,625.51	$ 46,408.24	$ 39,395.43	$ 185,429.18	$ 115,174.21	$ 166,899.18	$ 141,225.71	$ 423,299.10	$ 1,344,770.30
11	Real Time Spinnng Reserve Cost Distribution	$ 184,268.01	$ 157,052.27	$ 174,107.52	$ 515,427.80	$ 156,539.19	$ 133,782.47	$ 75,023.88	$ 365,345.54	$ 214,561.05	$ 74,806.23	$ 127,183.92	$ 416,551.20	$ 160,286.03	$ 130,619.57	$ 152,666.21	$ 443,571.81	$ 1,740,896.35
	SUBTOTAL	$ 7,454.79	$ (127,162.09)	$ (209,086.37)	$ (328,793.67)	$ (104,666.15)	$ (60,155.19)	$ (21,932.67)	$ (186,754.01)	$ (43,038.91)	$ (74,391.02)	$ (116,460.27)	$ (233,890.20)	$ 4,840.11	$ (11,828.06)	$ (58,263.26)	$ (65,251.21)	$ (814,689.09)
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve	$ (59,809.63)	$ (35,678.29)	$ (51,241.64)	$ (146,729.56)	$ (25,670.05)	$ (22,301.75)	$ (25,033.47)	$ (73,005.27)	$ (113,132.59)	$ (20,008.14)	$ (25,849.80)	$ (158,990.53)	$ (22,120.19)	$ (56,755.84)	$ (48,354.82)	$ (127,230.85)	$ (505,956.21)
6	Real-Time Supplemental Reserve Amount.	$ 3,924.10	$ 2,133.51	$ 4,596.77	$ 10,654.38	$ 1,065.94	$ 107.36	$ 2,900.17	$ 4,073.47	$ 8,783.51	$ 193.73	$ (14.17)	$ 8,963.07	$ 1,789.19	$ 6,114.21	$ 5,947.05	$ 13,850.45	$ 37,541.37
12	Real Time Supplemental Reserve Cost Distribution	$ 84,066.82	$ 29,882.96	$ 41,354.54	$ 155,304.32	$ 32,867.51	$ 22,559.74	$ 13,804.88	$ 69,232.13	$ 95,357.15	$ 4,208.80	$ 20,799.71	$ 120,365.66	$ 18,913.72	$ 36,404.50	$ 71,849.67	$ 127,167.89	$ 472,070.00
	SUBTOTAL	$ 28,181.29	$ (3,661.82)	$ (5,290.33)	$ 19,229.14	$ 8,263.40	$ 365.35	$ (8,328.42)	$ 300.33	$ (8,991.93)	$ (15,605.61)	$ (5,064.26)	$ (29,661.80)	$ (1,417.28)	$ (14,237.13)	$ 29,441.90	$ 13,787.49	$ 3,655.16
Other Charges																		
14	Real Time Contingency Reserve Deployment Failure	$ 3,820.14	$ 1,352.19	$ 911.05	$ 6,083.38	$ 4,728.13	$ 515.15	$ -	$ 5,243.28	$ -	$ 3,401.37	$ -	$ 3,401.37	$ 680.46	$ -	$ 5,353.13	$ 6,033.59	$ 20,761.62
13	Real Time Excessive/Deficient Energy Deployment	$ 132,523.83	$ 84,691.33	$ 146,143.32	$ 363,358.48	$ 33,928.44	$ 50,489.43	$ 45,746.06	$ 130,163.93	$ 145,650.35	$ 35,577.84	$ 36,796.65	$ 218,024.84	$ 96,564.49	$ 129,877.91	$ 93,332.99	$ 319,775.39	$ 1,031,322.64
9	Real Time Net Regulation Adjustment Amount	$ (30.81)	$ 1,086.51	$ 19,630.35	$ 20,686.05	$ 8,112.00	$ 1,700.23	$ (1,677.87)	$ 8,134.36	$ (2,074.03)	$ 6,653.67	$ (3,472.66)	$ 1,106.98	$ (20,835.10)	$ 29,122.94	$ 13,567.29	$ 21,855.13	$ 51,782.52
	SUBTOTAL	$ 136,313.16	$ 87,130.03	$ 166,684.72	$ 390,127.91	$ 46,768.57	$ 52,704.81	$ 44,068.19	$ 143,541.57	$ 143,576.32	$ 45,632.88	$ 33,323.99	$ 222,533.19	$ 76,409.85	$ 159,000.85	$ 112,253.41	$ 347,664.11	$ 1,103,866.78
	TOTAL MISO ASM CHARGES	$ (48,927.79)	$ (190,259.85)	$ (359,101.67)	$ (598,289.31)	$ (105,569.77)	$ (20,346.68)	$ 33,148.29	$ (92,768.16)	$ 29,284.59	$ (37,133.72)	$ (71,252.69)	$ (79,101.82)	$ (43,072.50)	$ (85,917.94)	$ (63,341.38)	$ (192,331.82)	$ (962,491.11)
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT																		
7a	Real Time Excessive Energy Amount	$ 17,552.40	$ 29,162.60	$ 8,227.60	$ 54,942.60	$ 11,337.78	$ 602.45	$ 6,732.07	$ 18,672.30	$ (4,831.83)	$ 16,213.83	$ 3,596.15	$ 14,978.15	$ 8,266.20	$ (6,207.79)	$ 11,463.04	$ 13,521.45	$ 102,114.50
7b	Real Time Excessive Energy Congestion				$ -				$ -				$ -				$ -	$ -
7c	Real Time Excessive Energy Loss				$ -				$ -				$ -				$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 2,717,331.77	$ 1,038,604.85	$ 146,423.04	$ 3,902,359.66	$ (81,049.67)	$ 835,412.57	$ 2,659,372.78	$ 3,413,735.68	$ 5,084,795.57	$ 2,023,572.59	$ 1,718,635.90	$ 8,827,004.06	$ 2,602,750.18	$ 3,964,719.34	$ 3,636,661.00	$ 10,204,130.52	$ 26,347,229.92
8b	Real Time Non Excessive Energy Congestion	$ (445,721.17)	$ (245,088.84)	$ (710,471.16)	$ (1,401,281.17)	$ (328,311.39)	$ (68,469.25)	$ 3,900.38	$ (392,880.26)	$ 56,110.56	$ (11,521.61)	$ (129,832.31)	$ (85,243.36)	$ (223,920.06)	$ (282,078.94)	$ (14,442.89)	$ (520,441.89)	$ (2,399,846.68)
8c	Real Time Non Excessive Energy Loss	$ (118,699.29)	$ (79,848.58)	$ (170,500.77)	$ (369,048.64)	$ (60,663.06)	$ (65,988.15)	$ 8,551.69	$ (118,099.52)	$ (16,806.80)	$ (6,307.71)	$ (52,819.80)	$ (75,934.31)	$ (83,617.97)	$ (240,273.12)	$ (124,216.13)	$ (448,107.22)	$ (1,011,189.69)
	SUBTOTAL	$ 2,170,463.71	$ 742,830.03	$ (726,321.29)	$ 2,186,972.45	$ (458,686.34)	$ 701,557.62	$ 2,678,556.92	$ 2,921,428.20	$ 5,119,267.50	$ 2,021,957.10	$ 1,539,579.94	$ 8,680,804.54	$ 2,303,478.35	$ 3,436,159.49	$ 3,509,465.02	$ 9,249,102.86	$ 23,038,308.05
	GRAND TOTAL MISO ASM CHARGES	$ 2,121,535.92	$ 552,570.18	$ (1,085,422.96)	$ 1,588,683.14	$ (564,256.11)	$ 681,210.94	$ 2,711,705.21	$ 2,828,660.04	$ 5,148,552.09	$ 1,984,823.38	$ 1,468,327.25	$ 8,601,702.72	$ 2,260,405.85	$ 3,350,241.55	$ 3,446,123.64	$ 9,056,771.04	$ 22,075,816.94

Northern States Power Company

Docket No. E999/AA-18-373

Part J, Section 5

Schedule 10

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

		July 17	August 17	September 17	3rd Qt	October 17	November 17	December 17	4th Qt	January 18	February 18	March 18	1st Qt	April 18	May 18	June 18	2nd Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount				$ -				$ -				$ -				$ -	$ -
4	Real-Time Regulation Amount	$ 236,283.45	$ 169,129.02	$ 243,834.59	$ 649,247.06	$ 93,372.78	$ 34,767.15	$ 4,145.95	$ 132,285.88	$ 116,648.47	$ 31,173.64	$ 5,552.33	$ 153,374.44	$ 140,646.41	$ 205,647.23	$ 132,706.56	$ 479,000.20	$ 1,413,907.58
10	Real Time Regulation Reserve Cost Distribution Amount				$ -				$ -				$ -				$ -	$ -
	SUBTOTAL	$ 236,283.45	$ 169,129.02	$ 243,834.59	$ 649,247.06	$ 93,372.78	$ 34,767.15	$ 4,145.95	$ 132,285.88	$ 116,648.47	$ 31,173.64	$ 5,552.33	$ 153,374.44	$ 140,646.41	$ 205,647.23	$ 132,706.56	$ 479,000.20	$ 1,413,907.58
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount				$ -				$ -				$ -				$ -	$ -
5	Real-Time Spinning Reserve Amount	$ 100,716.65	$ 166,573.70	$ 197,252.57	$ 464,542.92	$ 146,207.64	$ 115,996.53	$ 148,251.70	$ 410,455.87	$ 125,197.21	$ 60,387.04	$ 145,677.49	$ 331,261.74	$ 96,313.07	$ 34,758.27	$ 136,811.73	$ 267,883.07	$ 1,474,143.60
11	Real Time Spinnng Reserve Cost Distribution				$ -				$ -				$ -				$ -	$ -
	SUBTOTAL	$ 100,716.65	$ 166,573.70	$ 197,252.57	$ 464,542.92	$ 146,207.64	$ 115,996.53	$ 148,251.70	$ 410,455.87	$ 125,197.21	$ 60,387.04	$ 145,677.49	$ 331,261.74	$ 96,313.07	$ 34,758.27	$ 136,811.73	$ 267,883.07	$ 1,474,143.60
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve				$ -				$ -				$ -				$ -	$ -
6	Real-Time Supplemental Reserve Amount.	$ 2,423.90	$ 4,114.69	$ 1,648.25	$ 8,186.84	$ 2,776.16	$ 1,222.43	$ 1,662.57	$ 5,661.16	$ 35,774.57	$ (5,176.12)	$ 5,342.05	$ 35,940.50	$ 3,942.26	$ 9,730.38	$ 4,028.92	$ 17,701.56	$ 67,490.06
12	Real Time Supplemental Reserve Cost Distribution				$ -				$ -				$ -				$ -	$ -
	SUBTOTAL	$ 2,423.90	$ 4,114.69	$ 1,648.25	$ 8,186.84	$ 2,776.16	$ 1,222.43	$ 1,662.57	$ 5,661.16	$ 35,774.57	$ (5,176.12)	$ 5,342.05	$ 35,940.50	$ 3,942.26	$ 9,730.38	$ 4,028.92	$ 17,701.56	$ 67,490.06
Other Charges																		
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ (70.63)	$ (70.63)	$ (284.08)	$ (476.73)	$ -	$ (760.81)	$ (4.43)	$ (370.23)	$ -	$ (374.66)	$ (546.38)	$ (124.56)	$ (219.77)	$ (890.71)	$ (2,096.81)
13	Real Time Excessive/Deficient Energy Deployment	$ (40,077.34)	$ (53,612.45)	$ (29,360.43)	$ (123,050.22)	$ 22,181.15	$ (24,191.27)	$ (12,845.51)	$ (14,855.63)	$ (37,298.96)	$ (10,843.72)	$ (8,733.92)	$ (56,876.60)	$ (8,733.19)	$ (44,953.84)	$ (21,596.18)	$ (75,283.21)	$ (270,065.66)
9	Real Time Net Regulation Adjustment Amount	$ (226.44)	$ (2,629.18)	$ (10,143.00)	$ (12,998.62)	$ (55,795.89)	$ 1,086.90	$ 151.76	$ (54,557.23)	$ (3,221.82)	$ (3,111.33)	$ 944.43	$ (5,388.72)	$ 7,694.64	$ (8,444.07)	$ (8,447.31)	$ (9,196.74)	$ (82,141.31)
	SUBTOTAL	$ (40,303.78)	$ (56,241.63)	$ (39,574.06)	$ (136,119.47)	$ (33,898.82)	$ (23,581.10)	$ (12,693.75)	$ (70,173.67)	$ (40,525.21)	$ (14,325.28)	$ (7,789.49)	$ (62,639.98)	$ (1,584.93)	$ (53,522.47)	$ (30,263.26)	$ (85,370.66)	$ (354,303.78)
	TOTAL MISO ASM CHARGES	$ 299,120.22	$ 283,575.78	$ 403,161.35	$ 985,857.35	$ 208,457.76	$ 128,405.01	$ 141,366.47	$ 478,229.24	$ 237,095.04	$ 72,059.28	$ 148,782.38	$ 457,936.70	$ 239,316.81	$ 196,613.41	$ 243,283.95	$ 679,214.17	$ 2,601,237.46
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	$ (20,322.12)	$ (8,793.38)	$ (47,274.59)	$ (76,390.09)	$ (12,506.75)	$ (10,816.41)	$ (2,869.59)	$ (26,192.74)	$ (8,090.22)	$ (4,601.92)	$ (14,310.97)	$ (27,003.11)	$ (18,505.71)	$ (12,930.22)	$ (126.33)	$ (31,562.26)	$ (161,148.20)
8c	Real Time Non Excessive Energy Loss	$ (10,946.44)	$ (7,107.12)	$ (12,807.42)	$ (30,860.98)	$ (5,467.50)	$ (10,209.85)	$ (2,969.20)	$ (18,646.55)	$ (665.98)	$ (802.57)	$ (9,878.76)	$ (11,347.31)	$ (7,552.09)	$ (17,339.22)	$ (10,096.40)	$ (34,987.70)	$ (95,842.54)
	SUBTOTAL	$ (31,268.56)	$ (15,900.50)	$ (60,082.01)	$ (107,251.07)	$ (17,974.25)	$ (21,026.26)	$ (5,838.79)	$ (44,839.29)	$ (8,756.20)	$ (5,404.49)	$ (24,189.73)	$ (38,350.42)	$ (26,057.80)	$ (30,269.43)	$ (10,222.73)	$ (66,549.96)	$ (256,990.74)
	GRAND TOTAL MISO ASM CHARGES	$ 290,364.70	$ 194,266.94	$ 386,928.42	$ 871,560.06	$ 246,605.41	$ 179,872.92	$ 79,410.16	$ 505,888.48	$ 228,338.84	$ 66,654.79	$ 124,592.65	$ 419,586.28	$ 213,259.01	$ 166,343.98	$ 233,061.22	$ 612,664.21	$ 2,409,699.03

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

		July 17	August 17	September 17	3rd Qt	October 17	November 17	December 17	4th Qt	January 18	February 18	March 18	1st Qt	April 18	May 18	June 18	2nd Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount	$ (274,704.34)	$ (261,255.41)	$ (366,015.71)	$ (901,975.46)	$ (261,287.68)	$ (98,406.66)	$ (64,791.18)	$ (424,485.52)	$ (189,944.31)	$ (88,856.64)	$ (76,865.89)	$ (355,666.84)	$ (239,778.55)	$ (358,881.36)	$ (282,595.30)	$ (881,255.21)	$ (2,563,383.03)
4	Real-Time Regulation Amount	$ 125,946.85	$ 148,979.20	$ 141,638.67	$ 416,564.72	$ 125,328.86	$ (5,733.24)	$ (22,960.80)	$ 96,634.82	$ 54,354.00	$ 26,173.36	$ (5,847.01)	$ 74,680.35	$ 114,505.25	$ 211,330.25	$ 140,542.21	$ 466,377.71	$ 1,054,257.60
10	Real Time Regulation Reserve Cost Distribution Amou	$ 164,163.91	$ 134,839.26	$ 156,801.94	$ 455,805.11	$ 173,396.01	$ 125,645.40	$ 111,239.12	$ 410,280.53	$ 189,977.89	$ 101,086.95	$ 105,213.08	$ 396,277.92	$ 143,014.53	$ 134,344.74	$ 127,986.22	$ 405,345.49	$ 1,667,709.05
	SUBTOTAL	$ 15,406.42	$ 22,563.05	$ (67,575.10)	$ (29,605.63)	$ 37,437.19	$ 21,505.50	$ 23,487.14	$ 82,429.83	$ 54,387.58	$ 38,403.67	$ 22,500.18	$ 115,291.43	$ 17,741.23	$ (13,206.37)	$ (14,066.87)	$ (9,532.01)	$ 158,583.62
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount	$ (140,621.86)	$ (287,156.39)	$ (550,107.60)	$ (977,885.85)	$ (542,721.37)	$ (354,966.39)	$ (256,789.43)	$ (1,154,477.19)	$ (357,225.47)	$ (195,605.49)	$ (283,039.62)	$ (835,870.58)	$ (270,620.13)	$ (309,346.81)	$ (352,155.18)	$ (932,122.12)	$ (3,900,355.74)
5	Real-Time Spinning Reserve Amount	$ 64,525.29	$ 169,515.73	$ 364,166.28	$ 598,207.30	$ 427,723.67	$ 277,025.26	$ 308,084.58	$ 1,012,833.51	$ 224,822.72	$ 106,795.28	$ 185,072.92	$ 516,690.92	$ 211,487.28	$ 201,657.45	$ 278,037.44	$ 691,182.17	$ 2,818,913.90
11	Real Time Spinnng Reserve Cost Distribution	$ 184,268.01	$ 157,052.27	$ 174,107.52	$ 515,427.80	$ 156,539.19	$ 133,782.47	$ 75,023.88	$ 365,345.54	$ 214,561.05	$ 74,806.23	$ 127,183.92	$ 416,551.20	$ 160,286.03	$ 130,619.57	$ 152,666.21	$ 443,571.81	$ 1,740,896.35
	SUBTOTAL	$ 108,171.44	$ 39,411.61	$ (11,833.80)	$ 135,749.25	$ 41,541.49	$ 55,841.34	$ 126,319.03	$ 223,701.86	$ 82,158.30	$ (14,003.98)	$ 29,217.22	$ 97,371.54	$ 101,153.18	$ 22,930.21	$ 78,548.47	$ 202,631.86	$ 659,454.51
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve	$ (59,809.63)	$ (35,678.29)	$ (51,241.64)	$ (146,729.56)	$ (25,670.05)	$ (22,301.75)	$ (25,033.47)	$ (73,005.27)	$ (113,132.59)	$ (20,008.14)	$ (25,849.80)	$ (158,990.53)	$ (22,120.19)	$ (56,755.84)	$ (48,354.82)	$ (127,230.85)	$ (505,956.21)
6	Real-Time Supplemental Reserve Amount.	$ 6,348.00	$ 6,248.20	$ 6,245.02	$ 18,841.22	$ 3,842.10	$ 1,329.79	$ 4,562.74	$ 9,734.63	$ 44,558.08	$ (4,982.39)	$ 5,327.88	$ 44,903.57	$ 5,731.45	$ 15,844.59	$ 9,975.97	$ 31,552.01	$ 105,031.43
12	Real Time Supplemental Reserve Cost Distribution	$ 84,066.82	$ 29,882.96	$ 41,354.54	$ 155,304.32	$ 32,867.51	$ 22,559.74	$ 13,804.88	$ 69,232.13	$ 95,357.15	$ 4,208.80	$ 20,799.71	$ 120,365.66	$ 18,913.72	$ 36,404.50	$ 71,849.67	$ 127,167.89	$ 472,070.00
	SUBTOTAL	$ 30,605.19	$ 452.87	$ (3,642.08)	$ 27,415.98	$ 11,039.56	$ 1,587.78	$ (6,665.85)	$ 5,961.49	$ 26,782.64	$ (20,781.73)	$ 277.79	$ 6,278.70	$ 2,524.98	$ (4,506.75)	$ 33,470.82	$ 31,489.05	$ 71,145.22
Other Charges																		
13	Real Time Excessive/Deficient Energy Deployment	$ 3,820.14	$ 1,352.19	$ 840.42	$ 6,012.75	$ 4,444.05	$ 38.42	$ -	$ 4,482.47	$ (4.43)	$ 3,031.14	$ -	$ 3,026.71	$ 134.08	$ (124.56)	$ 5,133.36	$ 5,142.88	$ 18,664.81
14	Real Time Contingency Reserve Deployment Failure	$ 92,446.49	$ 31,078.88	$ 116,782.89	$ 240,308.26	$ 56,109.59	$ 26,298.16	$ 32,900.55	$ 115,308.30	$ 108,351.39	$ 24,734.12	$ 28,062.73	$ 161,148.24	$ 87,831.30	$ 84,924.07	$ 71,736.81	$ 244,492.18	$ 761,256.98
9	Real Time Net Regulation Adjustment Amount	$ (257.25)	$ (1,542.67)	$ 9,487.35	$ 7,687.43	$ (47,683.89)	$ 2,787.13	$ (1,526.11)	$ (46,422.87)	$ (5,295.85)	$ 3,542.34	$ (2,528.23)	$ (4,281.74)	$ (13,140.46)	$ 20,678.87	$ 5,119.98	$ 12,658.39	$ (30,358.79)
	SUBTOTAL	$ 96,009.38	$ 30,888.40	$ 127,110.66	$ 254,008.44	$ 12,869.75	$ 29,123.71	$ 31,374.44	$ 73,367.90	$ 103,051.11	$ 31,307.60	$ 25,534.50	$ 159,893.21	$ 74,824.92	$ 105,478.38	$ 81,990.15	$ 262,293.45	$ 749,563.00
	TOTAL MISO ASM CHARGES	$ 250,192.43	$ 93,315.93	$ 44,059.68	$ 387,568.04	$ 102,887.99	$ 108,058.33	$ 174,514.76	$ 385,461.08	$ 266,379.63	$ 34,925.56	$ 77,529.69	$ 378,834.88	$ 196,244.31	$ 110,695.47	$ 179,942.57	$ 486,882.35	$ 1,638,746.35
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT																		
7a	Real Time Excessive Energy Amount	$ 17,552.40	$ 29,162.60	$ 8,227.60	$ 54,942.60	$ 11,337.78	$ 602.45	$ 6,732.07	$ 18,672.30	$ (4,831.83)	$ 16,213.83	$ 3,596.15	$ 14,978.15	$ 8,266.20	$ (6,207.79)	$ 11,463.04	$ 13,521.45	$ 102,114.50
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 2,717,331.77	$ 1,038,604.85	$ 146,423.04	$ 3,902,359.66	$ (81,049.67)	$ 835,412.57	$ 2,659,372.78	$ 3,413,735.68	$ 5,084,795.57	$ 2,023,572.59	$ 1,718,635.90	$ 8,827,004.06	$ 2,602,750.18	$ 3,964,719.34	$ 3,636,661.00	$ 10,204,130.52	$ 26,347,229.92
8b	Real Time Non Excessive Energy Congestion	$ (466,043.29)	$ (253,882.22)	$ (757,745.75)	$ (1,477,671.26)	$ (340,818.14)	$ (79,285.66)	$ 1,030.79	$ (419,073.00)	$ 48,020.34	$ (16,123.53)	$ (144,143.28)	$ (112,246.47)	$ (242,425.77)	$ (295,009.16)	$ (14,569.22)	$ (552,004.15)	$ (2,560,994.88)
8c	Real Time Non Excessive Energy Loss	$ (129,645.73)	$ (86,955.70)	$ (183,308.19)	$ (399,909.62)	$ (66,130.56)	$ (76,198.00)	$ 5,582.49	$ (136,746.07)	$ (17,472.78)	$ (7,110.28)	$ (62,698.56)	$ (87,281.62)	$ (91,170.06)	$ (257,612.34)	$ (134,312.53)	$ (483,094.92)	$ (1,107,032.23)
	SUBTOTAL	$ 2,139,195.15	$ 726,929.53	$ (786,403.30)	$ 2,079,721.38	$ (476,660.59)	$ 680,531.36	$ 2,672,718.13	$ 2,876,588.91	$ 5,110,511.30	$ 2,016,552.61	$ 1,515,390.21	$ 8,642,454.12	$ 2,277,420.55	$ 3,405,890.06	$ 3,499,242.29	$ 9,182,552.90	$ 22,781,317.31
	GRAND TOTAL MISO ASM CHARGES	$ 2,389,387.58	$ 820,245.46	$ (742,343.62)	$ 2,467,289.42	$ (373,772.60)	$ 788,589.69	$ 2,847,232.89	$ 3,262,049.99	$ 5,376,890.93	$ 2,051,478.17	$ 1,592,919.90	$ 9,021,289.00	$ 2,473,664.86	$ 3,516,585.53	$ 3,679,184.86	$ 9,669,435.25	$ 24,420,063.66

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

		July 17	August 17	September 17	3rd Qt	October 17	November 17	December 17	4th Qt	January 18	February 18	March 18	1st Qt	April 18	May 18	June 18	2nd Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount	$ (203,024.04)	$ (191,881.05)	$ (271,383.93)	$ (666,289.03)	$ (189,627.01)	$ (70,806.08)	$ (46,339.45)	$ (306,772.55)	$ (135,052.23)	$ (63,527.81)	$ (55,031.74)	$ (253,611.78)	$ (173,633.88)	$ (262,477.39)	$ (207,848.31)	$ (643,959.58)	$ (1,870,632.93)
4	Real-Time Regulation Amount	$ 93,082.76	$ 109,418.92	$ 105,018.61	$ 307,520.29	$ 90,956.21	$ (4,125.21)	$ (16,421.85)	$ 70,409.15	$ 38,646.22	$ 18,712.57	$ (4,186.14)	$ 53,172.65	$ 82,918.14	$ 154,561.98	$ 103,368.53	$ 340,848.64	$ 771,950.73
10	Real Time Regulation Reserve Cost Distribution Amou	$ 121,327.61	$ 99,033.73	$ 116,261.48	$ 336,622.82	$ 125,840.48	$ 90,405.04	$ 79,559.60	$ 295,805.12	$ 135,076.10	$ 72,271.83	$ 75,326.77	$ 282,674.70	$ 103,562.93	$ 98,256.58	$ 94,133.62	$ 295,953.13	$ 1,211,055.78
	SUBTOTAL	$ 11,386.33	$ 16,571.61	$ (50,103.85)	$ (22,145.92)	$ 27,169.68	$ 15,473.75	$ 16,798.29	$ 59,441.72	$ 38,670.09	$ 27,456.60	$ 16,108.89	$ 82,235.58	$ 12,847.18	$ (9,658.83)	$ (10,346.16)	$ (7,157.80)	$ 112,373.58
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount	$ (103,928.53)	$ (210,904.22)	$ (407,879.66)	$ (722,712.42)	$ (393,874.80)	$ (255,407.29)	$ (183,658.98)	$ (832,941.08)	$ (253,990.74)	$ (139,847.60)	$ (202,640.77)	$ (596,479.11)	$ (195,967.59)	$ (226,248.98)	$ (259,009.47)	$ (681,226.04)	$ (2,833,358.64)
5	Real-Time Spinning Reserve Amount	$ 47,688.31	$ 124,502.13	$ 270,012.67	$ 442,203.11	$ 310,416.33	$ 199,326.68	$ 220,345.91	$ 730,088.92	$ 159,851.11	$ 76,352.99	$ 132,502.01	$ 368,706.11	$ 153,146.97	$ 147,487.52	$ 204,496.01	$ 505,130.50	$ 2,046,128.64
11	Real Time Spinnng Reserve Cost Distribution	$ 136,185.82	$ 115,348.25	$ 129,092.78	$ 380,626.85	$ 113,606.81	$ 96,259.87	$ 53,658.01	$ 263,524.69	$ 152,554.97	$ 53,482.50	$ 91,056.68	$ 297,094.15	$ 116,069.96	$ 95,532.08	$ 112,285.71	$ 323,887.75	$ 1,265,133.43
	SUBTOTAL	$ 79,945.60	$ 28,946.16	$ (8,774.22)	$ 100,117.54	$ 30,148.34	$ 40,179.26	$ 90,344.94	$ 160,672.53	$ 58,415.34	$ (10,012.11)	$ 20,917.92	$ 69,321.15	$ 73,249.34	$ 16,770.62	$ 57,772.25	$ 147,792.20	$ 477,903.42
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve	$ (44,203.13)	$ (26,204.19)	$ (37,993.34)	$ (108,400.67)	$ (18,629.79)	$ (16,046.67)	$ (17,904.25)	$ (52,580.71)	$ (80,438.36)	$ (14,304.76)	$ (18,507.03)	$ (113,250.15)	$ (16,018.17)	$ (41,509.89)	$ (35,564.88)	$ (93,092.94)	$ (367,324.47)
6	Real-Time Supplemental Reserve Amount.	$ 4,691.58	$ 4,589.04	$ 4,630.40	$ 13,911.01	$ 2,788.37	$ 956.82	$ 3,263.33	$ 7,008.51	$ 31,681.22	$ (3,562.15)	$ 3,814.47	$ 31,933.55	$ 4,150.39	$ 11,588.36	$ 7,337.31	$ 23,076.06	$ 75,929.13
12	Real Time Supplemental Reserve Cost Distribution	$ 62,130.75	$ 21,947.77	$ 30,662.50	$ 114,741.02	$ 23,853.28	$ 16,232.30	$ 9,873.42	$ 49,959.00	$ 67,799.85	$ 3,009.07	$ 14,891.45	$ 85,700.37	$ 13,696.23	$ 26,625.40	$ 52,845.30	$ 93,166.92	$ 343,567.31
	SUBTOTAL	$ 22,619.19	$ 332.61	$ (2,700.44)	$ 20,251.37	$ 8,011.85	$ 1,142.45	$ (4,767.50)	$ 4,386.80	$ 19,042.71	$ (14,857.84)	$ 198.88	$ 4,383.76	$ 1,828.45	$ (3,296.13)	$ 24,617.72	$ 23,150.04	$ 52,171.97
Other Charges																		
14	Real Time Contingency Reserve Deployment Failure	$ 2,823.33	$ 993.13	$ 623.13	$ 4,439.59	$ 3,225.23	$ 27.64	$ -	$ 3,252.87	$ (3.15)	$ 2,167.11	$ -	$ 2,163.96	$ 97.09	$ (91.10)	$ 3,775.58	$ 3,781.57	$ 13,637.98
13	Real Time Excessive/Deficient Energy Deployment	$ 68,323.86	$ 22,826.12	$ 86,589.18	$ 177,739.16	$ 40,720.99	$ 18,922.19	$ 23,530.88	$ 83,174.07	$ 77,038.88	$ 17,683.59	$ 20,091.37	$ 114,813.84	$ 63,602.39	$ 62,111.47	$ 52,762.29	$ 178,476.15	$ 554,203.21
9	Real Time Net Regulation Adjustment Amount	$ (190.12)	$ (1,133.03)	$ 7,034.44	$ 5,711.29	$ (34,606.12)	$ 2,005.41	$ (1,091.49)	$ (33,692.21)	$ (3,765.40)	$ 2,532.59	$ (1,810.07)	$ (3,042.89)	$ (9,515.57)	$ 15,124.04	$ 3,765.74	$ 9,374.21	$ (21,649.60)
	SUBTOTAL	$ 70,957.06	$ 22,686.22	$ 94,246.75	$ 187,890.03	$ 9,340.10	$ 20,955.25	$ 22,439.39	$ 52,734.73	$ 73,270.33	$ 22,383.28	$ 18,281.30	$ 113,934.90	$ 54,183.92	$ 77,144.41	$ 60,303.60	$ 191,631.93	$ 546,191.60
	TOTAL MISO ASM CHARGES	$ 184,908.18	$ 68,536.60	$ 32,668.24	$ 286,113.02	$ 74,669.97	$ 77,750.70	$ 124,815.12	$ 277,235.79	$ 189,398.47	$ 24,969.93	$ 55,506.99	$ 269,875.39	$ 142,108.88	$ 80,960.06	$ 132,347.42	$ 355,416.37	$ 1,188,640.57
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT																		
7a	Real Time Excessive Energy Amount	$ 12,972.34	$ 21,418.70	$ 6,100.39	$ 40,491.43	$ 8,228.28	$ 433.48	$ 4,814.86	$ 13,476.62	$ (3,435.48)	$ 11,592.03	$ 2,574.65	$ 10,731.20	$ 5,985.91	$ (4,540.23)	$ 8,431.04	$ 9,876.72	$ 74,575.97
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 2,008,281.65	$ 762,811.33	$ 108,566.00	$ 2,879,658.97	$ (58,821.02)	$ 601,100.47	$ 1,902,016.37	$ 2,444,295.83	$ 3,615,338.48	$ 1,446,747.55	$ 1,230,448.61	$ 6,292,534.63	$ 1,884,762.51	$ 2,899,702.50	$ 2,674,757.28	$ 7,459,222.29	$ 19,075,711.72
8b	Real Time Non Excessive Energy Congestion	$ (344,435.74)	$ (186,465.75)	$ (561,833.87)	$ (1,092,735.36)	$ (247,345.48)	$ (57,048.03)	$ 737.24	$ (303,656.27)	$ 34,142.92	$ (11,527.47)	$ (103,198.64)	$ (80,583.20)	$ (175,550.85)	$ (215,762.76)	$ (10,715.63)	$ (402,029.24)	$ (1,879,004.08)
8c	Real Time Non Excessive Energy Loss	$ (95,816.47)	$ (63,865.28)	$ (135,914.65)	$ (295,596.41)	$ (47,993.62)	$ (54,826.39)	$ 3,992.67	$ (98,827.34)	$ (12,423.31)	$ (5,083.48)	$ (44,888.71)	$ (62,395.50)	$ (66,020.13)	$ (188,411.60)	$ (98,786.61)	$ (353,218.35)	$ (810,037.59)
	SUBTOTAL	$ 1,581,001.78	$ 533,898.99	$ (583,082.13)	$ 1,531,818.64	$ (345,931.83)	$ 489,659.53	$ 1,911,561.13	$ 2,055,288.83	$ 3,633,622.61	$ 1,441,728.63	$ 1,084,935.89	$ 6,160,287.13	$ 1,649,177.44	$ 2,490,987.90	$ 2,573,686.08	$ 6,713,851.42	$ 16,461,246.02
	GRAND TOTAL MISO ASM CHARGES	$ 1,765,909.96	$ 602,435.59	$ (550,413.89)	$ 1,817,931.66	$ (271,261.86)	$ 567,410.23	$ 2,036,376.25	$ 2,332,524.62	$ 3,823,021.08	$ 1,466,698.56	$ 1,140,442.88	$ 6,430,162.53	$ 1,791,286.32	$ 2,571,947.96	$ 2,706,033.50	$ 7,069,267.78	$ 17,649,886.59

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

July 2017	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		$ (274,704.34)		$ (274,704.34)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (140,621.86)		$ (140,621.86)		$ -		
3 Day-Ahead Supplemental Reserve		$ (59,809.63)		$ (59,809.63)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (110,336.60)		$ 125,946.85		$ (236,283.45)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (36,191.36)		$ 64,525.29		$ (100,716.65)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 3,924.10		$ 6,348.00		$ (2,423.90)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(2,426)	$ 17,552.40	(2,426)	$ 17,552.40		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	68,269	$ 2,717,331.77	68,269	$ 2,717,331.77		$ -		
8b Real Time Non Excessive Energy Congestion		$ (445,721.17)		$ (466,043.29)		$ 20,322.12		
8c Real Time Non Excessive Energy Loss		$ (118,699.29)		$ (129,645.73)		$ 10,946.44		
9 Real Time Net Regulation Adjustment Amount		$ (30.81)		$ (257.25)		$ 226.44		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 164,163.91		$ 164,163.91		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 184,268.01		$ 184,268.01		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 84,066.82		$ 84,066.82		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 132,523.83		$ 92,446.49		$ 40,077.34		
14 Real Time Contingency Reserve Deployment Failure		$ 3,820.14		$ 3,820.14		$ -		
TOTAL MISO ASM CHARGES	**65,843**	**$ 2,121,535.92**	**65,843**	**$ 2,389,387.58**		**$ (267,851.66)**		**$ -**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

August 2017	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		$ (261,255.41)		$ (261,255.41)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (287,156.39)		$ (287,156.39)		$ -		
3 Day-Ahead Supplemental Reserve		$ (35,678.29)		$ (35,678.29)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (20,149.82)		$ 148,979.20		$ (169,129.02)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 2,942.03		$ 169,515.73		$ (166,573.70)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 2,133.51		$ 6,248.20		$ (4,114.69)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(2,752)	$ 29,162.60	(2,752)	$ 29,162.60		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	31,092	$ 1,038,604.85	31,092	$ 1,038,604.85		$ -		
8b Real Time Non Excessive Energy Congestion		$ (245,088.84)		$ (253,882.22)		$ 8,793.38		
8c Real Time Non Excessive Energy Loss		$ (79,848.58)		$ (86,955.70)		$ 7,107.12		
9 Real Time Net Regulation Adjustment Amount		$ 1,086.51		$ (1,542.67)		$ 2,629.18		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 134,839.26		$ 134,839.26		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 157,052.27		$ 157,052.27		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 29,882.96		$ 29,882.96		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 84,691.33		$ 31,078.88		$ 53,612.45		
14 Real Time Contingency Reserve Deployment Failure		$ 1,352.19		$ 1,352.19		$ -		
TOTAL MISO ASM CHARGES	**28,339**	**$ 552,570.18**	**28,339**	**$ 820,245.46**		**$ (267,675.28)**		**$ -**

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

September 2017	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		$ (366,015.71)		$ (366,015.71)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (550,107.60)		$ (550,107.60)		$ -		
3 Day-Ahead Supplemental Reserve		$ (51,241.64)		$ (51,241.64)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (102,195.92)		$ 141,638.67		$ (243,834.59)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 166,913.71		$ 364,166.28		$ (197,252.57)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 4,596.77		$ 6,245.02		$ (1,648.25)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,803)	$ 8,227.60	(1,803)	$ 8,227.60		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	(12,719)	$ 146,423.04	(12,719)	$ 146,423.04		$ -		
8b Real Time Non Excessive Energy Congestion		$ (710,471.16)		$ (757,745.75)		$ 47,274.59		
8c Real Time Non Excessive Energy Loss		$ (170,500.77)		$ (183,308.19)		$ 12,807.42		
9 Real Time Net Regulation Adjustment Amount		$ 19,630.35		$ 9,487.35		$ 10,143.00		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 156,801.94		$ 156,801.94		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 174,107.52		$ 174,107.52		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 41,354.54		$ 41,354.54		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 146,143.32		$ 116,782.89		$ 29,360.43		
14 Real Time Contingency Reserve Deployment Failure		$ 911.05		$ 840.42		$ 70.63		
TOTAL MISO ASM CHARGES	**(14,522)**	**$ (1,085,422.96)**	**(14,522)**	**$ (742,343.62)**		**$ (343,079.34)**		**$ -**

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

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MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

October 2017	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		$ (261,287.68)		$ (261,287.68)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (542,721.37)		$ (542,721.37)		$ -		
3 Day-Ahead Supplemental Reserve		$ (25,670.05)		$ (25,670.05)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ 31,956.08		$ 125,328.86		$ (93,372.78)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 281,516.03		$ 427,723.67		$ (146,207.64)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 1,065.94		$ 3,842.10		$ (2,776.16)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,589)	$ 11,337.78	(1,589)	$ 11,337.78		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	(8,165)	$ (81,049.67)	(8,165)	$ (81,049.67)		$ -		
8b Real Time Non Excessive Energy Congestion		$ (328,311.39)		$ (340,818.14)		$ 12,506.75		
8c Real Time Non Excessive Energy Loss		$ (60,663.06)		$ (66,130.56)		$ 5,467.50		
9 Real Time Net Regulation Adjustment Amount	102	$ 8,112.00	102	$ (47,683.89)		$ 55,795.89		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 173,396.01		$ 173,396.01		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 156,539.19		$ 156,539.19		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 32,867.51		$ 32,867.51		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 33,928.44		$ 56,109.59		$ (22,181.15)		
14 Real Time Contingency Reserve Deployment Failure		$ 4,728.13		$ 4,444.05		$ 284.08		
TOTAL MISO ASM CHARGES	**(9,652)**	**$ (564,256.11)**	**(9,652)**	**$ (373,772.60)**		**$ (190,483.51)**		**$ -**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

November 2017	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		$ (98,406.66)		$ (98,406.66)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (354,966.39)		$ (354,966.39)		$ -		
3 Day-Ahead Supplemental Reserve		$ (22,301.75)		$ (22,301.75)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (40,500.39)		$ (5,733.24)		$ (34,767.15)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 161,028.73		$ 277,025.26		$ (115,996.53)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 107.36		$ 1,329.79		$ (1,222.43)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(2,046)	$ 602.45	(2,046)	$ 602.45		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	13,791	$ 835,412.57	13,791	$ 835,412.57		$ -		
8b Real Time Non Excessive Energy Congestion		$ (68,469.25)		$ (79,285.66)		$ 10,816.41		
8c Real Time Non Excessive Energy Loss		$ (65,988.15)		$ (76,198.00)		$ 10,209.85		
9 Real Time Net Regulation Adjustment Amount	(102)	$ 1,700.23	(102)	$ 2,787.13		$ (1,086.90)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 125,645.40		$ 125,645.40		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 133,782.47		$ 133,782.47		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 22,559.74		$ 22,559.74		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 50,489.43		$ 26,298.16		$ 24,191.27		
14 Real Time Contingency Reserve Deployment Failure		$ 515.15		$ 38.42		$ 476.73		
TOTAL MISO ASM CHARGES	**11,643**	**$ 681,210.94**	**11,643**	**$ 788,589.69**		**$ (107,378.75)**		**$ -**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

December 2017	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		$ (64,791.18)		$ (64,791.18)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (256,789.43)		$ (256,789.43)		$ -		
3 Day-Ahead Supplemental Reserve		$ (25,033.47)		$ (25,033.47)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (27,106.75)		$ (22,960.80)		$ (4,145.95)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 159,832.88		$ 308,084.58		$ (148,251.70)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 2,900.17		$ 4,562.74		$ (1,662.57)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,722)	$ 6,732.07	(1,722)	$ 6,732.07		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	124,460	$ 2,659,372.78	124,460	$ 2,659,372.78		$ -		
8b Real Time Non Excessive Energy Congestion		$ 3,900.38		$ 1,030.79		$ 2,869.59		
8c Real Time Non Excessive Energy Loss		$ 8,551.69		$ 5,582.49		$ 2,969.20		
9 Real Time Net Regulation Adjustment Amount	-	$ (1,677.87)	-	$ (1,526.11)		$ (151.76)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 111,239.12		$ 111,239.12		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 75,023.88		$ 75,023.88		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 13,804.88		$ 13,804.88		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 45,746.06		$ 32,900.55		$ 12,845.51		
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**122,737**	**$ 2,711,705.21**	**122,737**	**$ 2,847,232.89**		**$ (135,527.68)**		**$ -**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

January 2018	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		$ (189,944.31)		$ (189,944.31)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (357,225.47)		$ (357,225.47)		$ -		
3 Day-Ahead Supplemental Reserve		$ (113,132.59)		$ (113,132.59)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (62,294.47)		$ 54,354.00		$ (116,648.47)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 99,625.51		$ 224,822.72		$ (125,197.21)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 8,783.51		$ 44,558.08		$ (35,774.57)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,065)	$ (4,831.83)	(1,065)	$ (4,831.83)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	117,978	$ 5,084,795.57	117,978	$ 5,084,795.57		$ -		
8b Real Time Non Excessive Energy Congestion		$ 56,110.56		$ 48,020.34		$ 8,090.22		
8c Real Time Non Excessive Energy Loss		$ (16,806.80)		$ (17,472.78)		$ 665.98		
9 Real Time Net Regulation Adjustment Amount	-	$ (2,074.03)	-	$ (5,295.85)		$ 3,221.82		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 189,977.89		$ 189,977.89		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 214,561.05		$ 214,561.05		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 95,357.15		$ 95,357.15		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 145,650.35		$ 108,351.39		$ 37,298.96		
14 Real Time Contingency Reserve Deployment Failure		$ -		$ (4.43)		$ 4.43		
TOTAL MISO ASM CHARGES	**116,913**	**$ 5,148,552.09**	**116,913**	**$ 5,376,890.93**		**$ (228,338.84)**		**$ -**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

February 2018	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		$ (88,856.64)		$ (88,856.64)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (195,605.49)		$ (195,605.49)		$ -		
3 Day-Ahead Supplemental Reserve		$ (20,008.14)		$ (20,008.14)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (5,000.28)		$ 26,173.36		$ (31,173.64)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 46,408.24		$ 106,795.28		$ (60,387.04)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 193.73		$ (4,982.39)		$ 5,176.12		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(921)	$ 16,213.83	(921)	$ 16,213.83		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	42,165	$ 2,023,572.59	42,165	$ 2,023,572.59		$ -		
8b Real Time Non Excessive Energy Congestion		$ (11,521.61)		$ (16,123.53)		$ 4,601.92		
8c Real Time Non Excessive Energy Loss		$ (6,307.71)		$ (7,110.28)		$ 802.57		
9 Real Time Net Regulation Adjustment Amount	-	$ 6,653.67	-	$ 3,542.34		$ 3,111.33		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 101,086.95		$ 101,086.95		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 74,806.23		$ 74,806.23		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 4,208.80		$ 4,208.80		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 35,577.84		$ 24,734.12		$ 10,843.72		
14 Real Time Contingency Reserve Deployment Failure		$ 3,401.37		$ 3,031.14		$ 370.23		
TOTAL MISO ASM CHARGES	**41,244**	**$ 1,984,823.38**	**41,244**	**$ 2,051,478.17**		**$ (66,654.79)**		**$ -**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

March 2018	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		$ (76,865.89)		$ (76,865.89)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (283,039.62)		$ (283,039.62)		$ -		
3 Day-Ahead Supplemental Reserve		$ (25,849.80)		$ (25,849.80)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (11,399.34)		$ (5,847.01)		$ (5,552.33)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 39,395.43		$ 185,072.92		$ (145,677.49)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (14.17)		$ 5,327.88		$ (5,342.05)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(2,591)	$ 3,596.15	(2,591)	$ 3,596.15		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	70,468	$ 1,718,635.90	70,468	$ 1,718,635.90		$ -		
8b Real Time Non Excessive Energy Congestion		$ (129,832.31)		$ (144,143.28)		$ 14,310.97		
8c Real Time Non Excessive Energy Loss		$ (52,819.80)		$ (62,698.56)		$ 9,878.76		
9 Real Time Net Regulation Adjustment Amount	-	$ (3,472.66)	-	$ (2,528.23)		$ (944.43)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 105,213.08		$ 105,213.08		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 127,183.92		$ 127,183.92		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 20,799.71		$ 20,799.71		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 36,796.65		$ 28,062.73		$ 8,733.92		
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**67,877**	**$ 1,468,327.25**	**67,877**	**$ 1,592,919.90**		**$ (124,592.65)**		**$ -**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

April 2018	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		$ (239,778.55)		$ (239,778.55)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (270,620.13)		$ (270,620.13)		$ -		
3 Day-Ahead Supplemental Reserve		$ (22,120.19)		$ (22,120.19)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (26,141.16)		$ 114,505.25		$ (140,646.41)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 115,174.21		$ 211,487.28		$ (96,313.07)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 1,789.19		$ 5,731.45		$ (3,942.26)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(3,581)	$ 8,266.20	(3,581)	$ 8,266.20		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	104,471	$ 2,602,750.18	104,471	$ 2,602,750.18		$ -		
8b Real Time Non Excessive Energy Congestion		$ (223,920.06)		$ (242,425.77)		$ 18,505.71		
8c Real Time Non Excessive Energy Loss		$ (83,617.97)		$ (91,170.06)		$ 7,552.09		
9 Real Time Net Regulation Adjustment Amount	-	$ (20,835.10)	-	$ (13,140.46)		$ (7,694.64)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 143,014.53		$ 143,014.53		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 160,286.03		$ 160,286.03		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 18,913.72		$ 18,913.72		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 96,564.49		$ 87,831.30		$ 8,733.19		
14 Real Time Contingency Reserve Deployment Failure		$ 680.46		$ 134.08		$ 546.38		
TOTAL MISO ASM CHARGES	**100,891**	**$ 2,260,405.85**	**100,891**	**$ 2,473,664.86**		**$ (213,259.01)**		**$ -**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

May 2018	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		$ (358,881.36)		$ (358,881.36)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (309,346.81)		$ (309,346.81)		$ -		
3 Day-Ahead Supplemental Reserve		$ (56,755.84)		$ (56,755.84)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ 5,683.02		$ 211,330.25		$ (205,647.23)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 166,899.18		$ 201,657.45		$ (34,758.27)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 6,114.21		$ 15,844.59		$ (9,730.38)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(681)	$ (6,207.79)	(681)	$ (6,207.79)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	60,568	$ 3,964,719.34	60,568	$ 3,964,719.34		$ -		
8b Real Time Non Excessive Energy Congestion		$ (282,078.94)		$ (295,009.16)		$ 12,930.22		
8c Real Time Non Excessive Energy Loss		$ (240,273.12)		$ (257,612.34)		$ 17,339.22		
9 Real Time Net Regulation Adjustment Amount	-	$ 29,122.94	-	$ 20,678.87		$ 8,444.07		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 134,344.74		$ 134,344.74		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 130,619.57		$ 130,619.57		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 36,404.50		$ 36,404.50		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 129,877.91		$ 84,924.07		$ 44,953.84		
14 Real Time Contingency Reserve Deployment Failure		$ -		$ (124.56)		$ 124.56		
TOTAL MISO ASM CHARGES	**59,887**	**$ 3,350,241.55**	**59,887**	**$ 3,516,585.53**		**$ (166,343.98)**		**$ -**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

June 2018	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		$ (282,595.30)		$ (282,595.30)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (352,155.18)		$ (352,155.18)		$ -		
3 Day-Ahead Supplemental Reserve		$ (48,354.82)		$ (48,354.82)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ 7,835.65		$ 140,542.21		$ (132,706.56)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 141,225.71		$ 278,037.44		$ (136,811.73)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 5,947.05		$ 9,975.97		$ (4,028.92)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,994)	$ 11,463.04	(1,994)	$ 11,463.04		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	142,808	$ 3,636,661.00	142,808	$ 3,636,661.00		$ -		
8b Real Time Non Excessive Energy Congestion		$ (14,442.89)		$ (14,569.22)		$ 126.33		
8c Real Time Non Excessive Energy Loss		$ (124,216.13)		$ (134,312.53)		$ 10,096.40		
9 Real Time Net Regulation Adjustment Amount	-	$ 13,567.29	-	$ 5,119.98		$ 8,447.31		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 127,986.22		$ 127,986.22		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 152,666.21		$ 152,666.21		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 71,849.67		$ 71,849.67		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 93,332.99		$ 71,736.81		$ 21,596.18		
14 Real Time Contingency Reserve Deployment Failure		$ 5,353.13		$ 5,133.36		$ 219.77		
TOTAL MISO ASM CHARGES	**140,813**	**$ 3,446,123.64**	**140,813**	**$ 3,679,184.86**		**$ (233,061.22)**		**$ -**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

July 2017 - June 2018	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	-	$ (2,563,383.03)	$ -	$ (2,563,383.03)	$ -	$ -	$ -	$ -
2 Day-Ahead Spinning Reserve Amount	-	$ (3,900,355.74)	$ -	$ (3,900,355.74)	$ -	$ -	$ -	$ -
3 Day-Ahead Supplemental Reserve	-	$ (505,956.21)	$ -	$ (505,956.21)	$ -	$ -	$ -	$ -
4 Real-Time Regulation Amount	-	$ (359,649.98)	$ -	$ 1,054,257.60	$ -	$ (1,413,907.58)	$ -	$ -
5 Real-Time Spinning Reserve Amount	-	$ 1,344,770.30	$ -	$ 2,818,913.90	$ -	$ (1,474,143.60)	$ -	$ -
6 Real-Time Supplemental Reserve Amount.	-	$ 37,541.37	$ -	$ 105,031.43	$ -	$ (67,490.06)	$ -	$ -
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(23,172)	$ 102,114.50	(23,172)	$ 102,114.50	$ -	$ -	$ -	$ -
7b Real Time Excessive Energy Congestion	-	$ -	-	$ -	$ -	$ -	$ -	$ -
7c Real Time Excessive Energy Loss	-	$ -	-	$ -	$ -	$ -	$ -	$ -
8a Real Time Non Excessive Energy Amount	755,185	$ 26,347,229.92	755,185	$ 26,347,229.92	$ -	$ -	$ -	$ -
8b Real Time Non Excessive Energy Congestion	-	$ (2,399,846.68)	-	$ (2,560,994.88)	$ -	$ 161,148.20	$ -	$ -
8c Real Time Non Excessive Energy Loss	-	$ (1,011,189.69)	-	$ (1,107,032.23)	$ -	$ 95,842.54	$ -	$ -
9 Real Time Net Regulation Adjustment Amount	-	$ 51,782.52	-	$ (30,358.79)	$ -	$ 82,141.31	$ -	$ -
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 1,667,709.05	-	$ 1,667,709.05	$ -	$ -	$ -	$ -
11 Real Time Spinnng Reserve Cost Distribution	-	$ 1,740,896.35	-	$ 1,740,896.35	$ -	$ -	$ -	$ -
12 Real Time Supplemental Reserve Cost Distribution	-	$ 472,070.00	-	$ 472,070.00	$ -	$ -	$ -	$ -
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 1,031,322.64	-	$ 761,256.98	$ -	$ 270,065.66	$ -	$ -
14 Real Time Contingency Reserve Deployment Failure	-	$ 20,761.62	-	$ 18,664.81	$ -	$ 2,096.81	$ -	$ -
	-	0	-	0	0	0	0	0
TOTAL MISO ASM CHARGES	**732,014**	**$ 22,075,816.94**	**732,014**	**$ 24,420,063.66**	**$ -**	**$ (2,344,246.72)**	**$ -**	**$ -**

Total

Internal Order Description	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	2018 AAA Total
NSPM MISO NSPP DA_ASSET_EN Alloc	7,641,678.27	10,575,362.19	8,535,951.98	10148264.66	8,506,782.22	18,160,285.49	20,699,050.09	8,977,223.58	10,641,248.52	8,062,443.77	9,964,011.92	13,156,192.91	71,500,170.79
NSPM MISO NSPP RT_ASSET_EN Alloc	1,789,068.86	1,812,075.88	2,423,117.66	2018914.28	2,789,312.91	3,412,197.85	1,656,273.29	1,723,232.26	1,561,429.19	1,818,678.24	1,861,919.15	2,081,900.78	10,703,432.91
NSPM MISO NSPP DA_ADMIN Alloc	(23,136.95)	(25,231.27)	(34,946.87)	-32841.29	(33,574.31)	(58,166.96)	(50,319.93)	(25,458.44)	(50,683.98)	(42,033.55)	(28,666.61)	(43,301.51)	(240,464.02)
NSPM MISO NSPP RT_ADMIN Alloc	(4,832.27)	(3,907.43)	(10,421.40)	-7357.77	(12,736.77)	(11,091.31)	(5,190.26)	(4,234.88)	(8,141.75)	(9,725.47)	(6,196.15)	(7,622.85)	(41,111.36)
NSPM MISO NSPP RT_RSG_MWP Alloc	218,481.50	64,889.95	33,234.35	8123.61	25,153.99	187,176.93	247,677.59	9,699.57	12,749.74	37,147.83	(15,105.13)	7,559.75	299,729.35
NSPM MISO NSPP RT_PV_MWP Alloc	6,073.15	29,829.05	36,784.83	43105.33	58,156.79	76,212.85	41,198.93	62,765.79	13,688.82	23,058.51	21,839.82	13,951.05	176,502.92
NSPM MISO NSPP DA_RSG_MWP Alloc	10,205.57	20,534.79	62,697.62	84007.66	80,577.19	91,550.83	16,777.81	25,547.64	11,178.16	6,485.11	14,137.18	25,633.38	99,759.28
NSPM MISO NSPP DA_SCHD_24_ALC Alloc	(3,630.43)	(4,705.10)	(5,802.96)	-6406.91	(6,404.74)	(9,988.95)	(8,559.65)	(4,428.72)	(6,580.69)	(5,258.52)	(5,140.78)	(6,111.18)	(36,079.54)
NSPM MISO NSPP RT_SCHD_24_ALC Alloc	(759.14)	(754.43)	(1,754.01)	-1464.76	(2,420.45)	(1,890.91)	(890.42)	(747.91)	(1,043.69)	(1,214.03)	(1,138.11)	(1,076.50)	(6,110.66)
NSPM MISO NSPP RT_RAA Alloc	56,150.21	56,150.61	54,339.30	-46377.24	156,867.03	56,150.61	14,400.00	14,388.99	14,880.00	14,880.00	14,880.00	10,358.70	83,787.69
NSPM MISO NSPP RT_MVP_DIST Alloc	(48,887.37)	35,607.48	15,406.22	37915.19	17,445.05	30,253.66	40,382.56	36,540.69	41,129.71	33,326.02	19,351.61	19,997.72	190,728.31
NSPM MISO NSPP ASM_REG Alloc	159,962.82	111,869.06	85,444.70	134717.46	29,242.56	67,109.78	116,648.47	31,173.64	5,552.33	140,646.41	205,647.23	132,706.56	632,374.64
NSPM MISO NSPP ASM_SPIN Alloc	189,401.90	187,943.89	366,160.10	123391.76	192,356.25	79,021.71	125,197.21	60,387.04	145,677.49	96,313.07	34,758.27	136,811.73	599,144.81
NSPM MISO NSPP ASM_SUPP Alloc	4,310.11	2,886.46	3,616.42	6147.11	(255.72)	1,649.56	35,774.57	(5,176.12)	5,342.05	3,942.26	9,730.38	4,028.92	53,642.06
NSPM MISO NSPP RT_ASM_CRDFC Alloc	408.74				408.74		(4.43)	(370.23)		(546.38)	(124.56)	(219.77)	(1,265.37)
NSPM MISO NSPP RT_ASM_EXE_DFE_DEP Alloc	(46,911.99)	(61,351.50)	(37,104.77)	-17743.96	-44283.92	(52,177.81)	(37,298.96)	(10,843.72)	(8,733.92)	(8,733.19)	(44,953.84)	(21,596.18)	(132,159.81)
NSPM MISO NSPP RT_ASM_NRGA Alloc	(9,223.81)	(6,326.83)	(4,263.27)	9577.27	270.12	(7,417.15)	(3,221.82)	(3,111.33)	944.43	7,694.64	(8,444.07)	(8,447.31)	(14,585.46)
NSPM MISO NSPP RT_SCHD_24_DIST Alloc	146,913.50	123,496.22	119,325.10	129907.38	98191.8	94,657.63	102,472.16	97,540.90	56,596.75	121,989.15	96,827.55	119,928.85	595,355.36
NSPM MISO NSPP DA_ASSET_EN	14,751,852.20	4,679,465.44	5,635,363.80	2297652.46	(7,661.18)	(8,726,387.36)	(14,015,279.47)	(5,140,151.28)	(5,862,872.75)	(3,360,932.31)	2,614,901.39	(4,295,307.30)	(30,059,641.72)
NSPM MISO NSPP DA_ASSET_EN_CG	6,693,773.94	9,162,977.08	804,947.51	-235114.55	1,041,169.43	3,445,808.29	1,349,507.34	628,871.30	912,715.94	2,229,734.86	509,014.63	708,282.88	6,338,126.95
NSPM MISO NSPP DA_ASSET_EN_LS	2,637,572.44	3,011,387.22	2,246,565.83	2199280.18	2,273,435.78	4,426,568.47	4,935,912.61	2,766,318.85	2,433,668.46	3,126,827.19	2,356,149.48	2,290,356.80	17,909,233.39
NSPM MISO NSPP DA_GFACO_RBT_CG	12,653.88	4,691.40	22,661.42	28826.73	7,389.41	13,752.42	(20,919.82)	(1,815.46)	(2,077.77)	(8,633.43)	7,051.88	3,046.41	(23,348.19)
NSPM MISO NSPP DA_FIN_LS	(4,115.25)	(1,282.04)	(4,943.79)	-5454.82	(350.42)	275.39	3,719.45	4,267.62	1,039.78	1,086.22	(4,007.79)	(5,298.90)	806.38
NSPM MISO NSPP DA_FIN_CG	(12,653.88)	(4,691.40)	(22,661.42)	-28826.73	(7,389.41)	(13,752.42)	20,919.82	1,815.46	2,077.77	8,633.43	(7,051.88)	(3,046.41)	23,348.19
NSPM MISO NSPP DA_GFACO_RBT_LS	4,115.25	1,282.04	4,943.79	5454.82	350.42	(275.39)	(3,719.45)	(4,267.62)	(1,039.78)	(1,086.22)	4,007.79	5,298.90	(806.38)
NSPM MISO NSPP DA_GFAOB_RBT_LS	-												-
NSPM MISO NSPP DA_RSG_DIST	88413.54	101546.43	140755.17	212504.71	(42,553.24)	149,113.65	205,525.04	42,953.38	75,683.66	132,980.08	82,136.98	106,351.71	645,630.85
NSPM MISO NSPP DA_RSG_MWP	-26345.38	-27314.08	-138089.08	-170329.88	(223,693.48)	(110,242.83)	(360,075.77)	(42,009.16)	(46,824.18)	(309,502.38)	(52,416.61)	(34,357.61)	(845,185.71)
NSPM MISO NSPP DA_VIRT_EN													-
NSPM MISO NSPP DA_NASSET_EN	(13,021,473.40)	(12,031,894.42)	(11,617,366.18)	-11010270.82	(6,682,039.04)	(8,738,190.78)	(5,212,659.65)	(2,938,997.15)	(3,710,991.17)	(4,191,337.63)	(7,661,954.85)	(8,175,545.00)	(31,891,485.45)
NSPM MISO NSPP DA_NASSET_EN_CG	1681442.69	1635050.27	2767318.76	2290978.4	895,301.93	1,628,179.16	73,151.97	(16,389.92)	203,159.08	177,823.30	688,450.34	752105.21	1,878,299.98
NSPM MISO NSPP DA_NASSET_EN_LS	1,802,574.91	1,494,597.03	1,685,470.12	1315206.4	690,755.74	820,238.01	162,168.23	91,941.98	268,470.28	328,203.96	948,699.88	1,139,248.03	2,938,732.36
NSPM MISO NSPP DA_ASM_REG	-203253.49	-211030.49	-210250.11	-372539.67	(218,835.36)	(260,027.78)	(189,944.31)	(88,856.64)	(76,865.89)	(239,778.55)	(358,881.36)	(282,595.30)	(1,236,922.05)
NSPM MISO NSPP DA_ASM_SPIN	(389,637.08)	(312,265.86)	(350,641.19)	-388116.87	(254,924.70)	(184,204.82)	(357,225.47)	(195,605.49)	(283,039.62)	(270,620.13)	(309,346.81)	(352,155.18)	(1,767,992.70)
NSPM MISO NSPP DA_ASM_SUPP	(128,112.49)	(104,166.58)	(79,036.23)	-74001.48	(35,474.11)	(52,166.14)	(113,132.59)	(20,008.14)	(25,849.80)	(22,120.19)	(56,755.84)	(48,354.82)	(286,221.38)
NSPM MISO NSPP RT_GFACO_RBT_CG								(23.00)	7.77	-	(2.35)		(17.58)
NSPM MISO NSPP RT_LOSS_DIST	(2,855,796.74)	(1,557,284.72)	(1,083,039.53)	-943560.52	(752,139.68)	(1,384,208.66)	(1,774,973.13)	(1,026,169.10)	(557,417.40)	(767,415.68)	(910,589.02)	(1,015,586.44)	(6,052,150.77)
NSPM MISO NSPP RT_FIN_LS								(5.34)	21.32	-	1.78		17.76
NSPM MISO NSPP RT_FIN_CG								23.00	(7.77)	-	2.35		17.58
NSPM MISO NSPP RT_GFACO_RBT_LS								5.34	(21.32)	-	(1.78)		(17.76)
NSPM MISO NSPP RT_MISC	88,512.44	152,049.08	88,603.51	112179.21	93347.4	91,346.47	317,996.70	135,469.00	146,360.50	240,661.10	93,692.33	221,832.18	1,156,011.81
NSPM MISO NSPP RT_NI_DIST	(905,844.50)	(254,345.91)	110,072.99	382324.62	166851.4	42,338.73	66,019.14	22,708.43	92,123.93	76,373.38	13,432.43	(83,118.67)	187,538.64
NSPM MISO NSPP RT_RSG_DIST1	315,992.23	372,098.76	340,232.69	154590.98	92564.14	242,110.81	483,401.05	(4,041.79)	38,916.85	229,232.53	111,692.60	276,215.39	1,135,416.63
NSPM MISO NSPP RT_RSG_MWP	-364259.72	-131572.28	-112849.1	-101807.53	-40154.78	(249,062.96)	(638,214.90)	(25,802.49)	(38,372.10)	(137,444.24)	(14,398.95)	(19,601.94)	(873,834.62)
NSPM MISO NSPP RT_RNU	1,335,881.88	1,047,875.60	(98,074.48)	661604.99	467965.97	299,374.04	114,566.67	276,123.85	596,035.10	199,041.68	172,606.13	1,724,218.20	3,082,591.63
NSPM MISO NSPP RT_PV_MWP	-225785.91	-408906.14	-270619.24	-329598.35	(500,635.71)	(300,602.11)	(368,914.39)	(110,397.76)	(132,358.39)	(216,371.99)	(129,317.99)	(161,021.43)	(1,118,381.95)
NSPM MISO NSPP RT_NASSET_EN	-87312.34	22008.37	25806.09	53572.36	-3601.38	43.68	35.84	(719.53)	2,388.13	(1,000.18)	10,121.30	5,350.90	16,176.46
NSPM MISO NSPP RT_NASSET_EN_CG	40600.7	158.2	-19688.79	-37987.58	916.82	(36.28)	(21.22)	792.11	(171.58)	0.03	(133.48)	(286.59)	179.27
NSPM MISO NSPP RT_NASSET_EN_LS	16,457.34	192.41	(6,117.29)	-15573.91	1,692.43	(7.40)	(7.85)	18.10	(216.39)	0.07	(1,032.49)	(627.65)	(1,866.21)
NSPM MISO NSPP RT_ASM_CRDFC	(408.74)			675.77	(408.74)	41.82		3,401.37		680.46		5,353.13	9,434.96
NSPM MISO NSPP RT_ASM_EXE_DFE_DEP	117,233.20	86,407.95	57,096.42	84714.53	63791.62	95,714.74	145,650.35	35,577.84	36,796.65	96,564.49	129,877.91	93,332.99	537,800.23
NSPM MISO NSPP RT_ASM_NRGA	11,738.49	17,575.14	1,756.17	-15395.62	5,821.80	8,491.08	(2,074.03)	6,653.67	(3,472.66)	(20,835.10)	29,122.94	13,567.29	22,962.11
NSPM MISO NSPP RT_ASM_REG	(86,566.96)	(31,752.22)	44,782.90	33941.33	73,530.49	87,100.06	(62,294.47)	(5,000.28)	(11,399.34)	(26,141.16)	5,683.02	7,835.65	(91,316.58)
NSPM MISO NSPP RT_ASM_REG_DIST	123,289.44	124,255.05	108,778.94	137021.63	117728.16	130,720.51	189,977.89	101,086.95	105,213.08	143,014.53	134,344.74	127,986.22	801,623.41
NSPM MISO NSPP RT_ASM_SPIN	(27,838.72)	16,612.93	(95,210.49)	15897.82	(25,356.04)	10,648.39	99,625.51	46,408.24	39,395.43	115,174.21	166,899.18	141,225.71	608,728.28
NSPM MISO NSPP RT_ASM_SPIN_DIST	238,067.59	173,598.67	127,771.51	187097.05	128175.31	123,759.66	214,561.05	74,806.23	127,183.92	160,286.03	130,619.57	152,666.21	860,123.01
NSPM MISO NSPP RT_ASM_SUPP	35,451.00	19,387.71	11,908.79	371.4	178.76	994.94	8,783.51	193.73	(14.17)	1,789.19	6,114.21	5,947.05	22,813.52
NSPM MISO NSPP RT_ASM_SUPP_DIST	167503.22	115305.55	74043.79	69961.08	46,724.18	67,034.46	95,357.15	4,208.80	20,799.71	18,913.72	36,404.50	71,849.67	247,533.55
NSPM MISO NSPP RT_ASM_EXE	(45,225.24)	(47,178.90)	173,790.85	94582.82	(10,205.87)	298,145.86	(4,831.83)	16,213.83	3,596.15	8,266.20	(6,207.79)	11,463.04	28,499.60
NSPM MISO NSPP RT_ASM_NXE	2,357,643.07	3,644,189.71	1,398,367.97	-85655.44	(1,559,001.94)	(356,627.24)	5,084,795.57	2,023,572.59	1,718,635.90	2,602,750.18	3,964,719.34	3,636,661.00	19,031,134.58
NSPM MISO NSPP RT_ASM_NXE_CG	(221,566.25)	(145,346.27)	(54,193.66)	-50253.92	(27,497.27)	(198,936.28)	56,110.56	(11,521.61)	(129,832.31)	(223,920.06)	(282,078.94)	(14,442.89)	(605,685.25)
NSPM MISO NSPP RT_ASM_NXE_LS	(7,871.36)	(91,100.46)	3,955.41	69462.82	72,002.52	5,157.77	(16,806.80)	(6,307.71)	(52,819.80)	(83,617.97)	(240,273.12)	(124,216.13)	(524,041.53)
NSPM MISO NSPP RT_ASSET_EN	213,728.78	349,451.38	(582,243.58)	-151077.15	-18938.39	431,819.46	559,581.83	(908,392.51)	(1,592,673.73)	42,654.38	(5,714,535.38)	(2,817,759.81)	(10,431,125.22)
NSPM MISO NSPP RT_ASSET_EN_CG	30,079.22	250,963.33	134,755.67	71258.6	-16456.74	41,770.07	46,610.10	38,138.46	94,480.26	149,298.77	109,304.75	882.87	438,715.21
NSPM MISO NSPP RT_ASSET_EN_LS	56,601.47	126,737.41	54,962.67	-4971.11	3,612.06	1,708.83	3,836.89	6,651.33	65,219.04	60,928.05	146,575.92	70,562.08	353,773.31
NSPM MISO NSPP RT_DRR_UPL	1.85	4,299.81	1,960.61	5410.97	1316.11	301.04	565.62	201.12	143.27	3,291.13	2,436.47	701.75	7,339.36
NSPM MISO NSPP RT_RAA	(56,150.61)	(55,715.90)	(54,774.01)	46377.24	-65962.25	(147,055.51)	(14,880.00)	(13,440.00)	(14,880.00)	(14,400.00)	(14,880.00)	(10,358.70)	(82,838.70)
NSPM MISO NSPP RT_MVP_DIST	48,919.08	(54,641.03)	(16,598.19)	-18670.35	-16320.19	(29,909.28)	(40,372.35)	(38,646.16)	(39,937.33)	(19,167.50)	(13,217.55)	(19,704.53)	(171,045.42)
NSPM MISO NSPP FTR_HR_ALC	(10,118,461.00)	(11,330,859.67)	(3,869,512.42)	-1812408.63	(1,486,846.17)	(4,664,786.32)	(511,778.09)	(177,813.62)	(724,910.33)	(67,332.29)	(1,745,103.48)	(1,100,724.72)	(4,327,662.53)
NSPM MISO NSPP FTR_MN_ALC	(144,058.98)	(373,264.68)	(362,999.48)	-268558.74	(150,032.09)	(338,255.33)	20,641.26	(70,652.17)	(81,850.95)	(4,206.89)	(103,422.19)	(58,804.62)	(298,295.56)
NSPM MISO NSPP FTR_YR_ALC	-									(438,248.64)			(438,248.64)

Internal Order Description	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	2018 AAA Total
NSPM MISO NSPP FTR_FFG	(516,778.16)	78,648.31	171,296.61	-147801.3	422,882.21	(48,608.09)	(61,441.36)	(83,732.16)	(78,128.20)	62,379.85	53,958.81	53,995.61	(52,967.45)
NSPM MISO NSPP FTR_GUL	535,488.44	(81,674.35)	(170,891.71)	149188.09	(420,266.26)	53,665.49	66,631.38	81,217.84	74,688.76	(64,723.55)	14,581.48	(53,814.00)	118,581.91
NSPM MISO NSPP FTR_ARR_FTR_TXN	2,398,660.25	2,398,660.25	2,979,882.82	2979882.82	2979882.82	2,119,952.05	3,077,706.89	3,077,706.89	3,351,784.59	3,351,784.59	3,351,784.59	2,270,304.83	18,481,072.38
NSPM MISO NSPP FTR_ARR_ARR_TXN	-2416523.31	-2416523.31	-2999227.01	-2999227.01	(2,999,227.01)	(2,124,278.57)	(3,090,966.42)	(3,090,966.42)	(3,360,340.60)	(3,360,340.59)	(3,360,340.52)	(2,293,458.77)	(18,556,413.32)
NSPM MISO NSPP FTR_ARR_INF_UPL	78,282.87	78,282.87	96,890.41	96890.41	96890.41	76,245.14	39,324.86	39,319.32	29,560.11	29,565.66	29,565.66	41,430.89	208,766.50
NSPM MISO NSPP FTR_ARR_STG2_DIST	(72,008.18)	(75,228.96)	(129,623.96)	-130003.99	-130003.99	(145,479.96)	(157,243.97)	(157,121.31)	(72,285.52)	(71,575.59)	(71,760.16)	(320,148.19)	(850,134.74)
NSPM MISO NSPP DA Native Sales (EXP)	-5646119.83	-14272295.13	-5615888.5	-3079813.65	-2560073.94	(16,089,725.18)	(7,622,881.32)	(3,384,916.10)	(4,242,079.96)	(4,349,568.74)	(5,194,828.50)	(5,346,068.95)	(30,140,343.57)
NSPM MISO NSPP RT Native Sales (EXP)	1,077,165.05	95,371.66	347,558.16	738578.22	1227189.82	(2,125,956.06)	(184,461.72)	156,593.71	161,517.57	68,238.86	1,189,727.39	1,078,352.84	2,469,968.65
NSPM MISO NSPP Battery Unit FERC Reclss	-		(3,639.48)			(3,443.90)			23,505.77			27,143.94	50,649.71
NSPM MISO NSPP RT Native Sales (EXP)	5,646,119.83	14,272,295.13	5,615,888.50	3079813.65	2,560,073.94	16,089,725.18	7,622,881.32	3,384,916.10	4,242,079.96	4,349,568.74	5,194,828.50	5,346,068.95	30,140,343.57
NSPM MISO NSPP RT Native Sales (REV)	-1077165.05	-95371.66	-347558.16	-738578.22	(1,227,189.82)	2,125,956.06	184,461.72	(156,593.71)	(161,517.57)	(68,238.86)	(1,189,727.39)	(1,078,352.84)	(2,469,968.65)
NSPM MISO NSPP DA_ADMIN	580,690.42	479,191.26	617,794.83	518878.54	517,927.85	640,080.83	590,463.11	469,115.32	731,851.55	771,172.32	581,519.22	698,607.49	3,842,729.01
NSPM MISO NSPP DA_SCHD_24_ALC	91,294.75	92,907.00	110,893.73	109274.42	95,809.57	103,086.65	100,425.81	81,676.67	94,053.06	96,058.44	105,763.28	96,251.98	574,229.24
NSPM MISO NSPP RT_ADMIN	45,672.58	36,248.32	53,940.97	42448.82	49,500.61	46,842.84	39,261.95	34,394.87	52,814.05	57,929.57	54,043.24	72,958.27	311,401.95
NSPM MISO NSPP RT_SCHD_24_ALC	7,203.46	6,991.03	9,602.36	8961.9	9,276.33	7,874.61	7,666.17	6,774.24	7,958.66	7,099.72	9,103.72	9,823.54	48,426.05
NSPM MISO NSPP RT_SCHD_24_DIST	(124,774.72)	(121,703.81)	(123,990.82)	-103063.78	(109,445.08)	(113,752.63)	(103,821.07)	(77,947.85)	(93,573.09)	(96,030.83)	(104,438.03)	(92,589.83)	(568,400.70)
NSPM MISO NSPP FTR_ADMIN	40,601.76	34,137.28	26,959.20	11575.68	29,368.48	29,508.32	17,404.08	25,520.16	14,893.28	32,862.32	14,822.88	19,888.40	125,391.12
TOTAL	14,670,444.64	12,867,855.83	9,299,438.07	7,579,659.63	6,495,828.38	9,465,049.51	14,066,674.20	6,871,474.97	6,806,231.03	10,845,372.41	7,660,392.22	9,100,515.84	55,350,660.67
Purchased Power Gen Trading													
RSG/RNU Wholesale Allocation													
Manual Adjustment - DA RSG	(7,734.67)	(10,956.92)	(19,975.92)	(30,404.60)	7,072.69	(30,097.61)	(35,673.46)	(5,182.90)	(11,463.84)	(16,483.00)	(9,716.40)	(15,217.37)	(93,736.98)
Manual Adjustment - RT RSG	(27,643.89)	(40,149.68)	(48,285.70)	(22,118.46)	(15,384.90)	(48,868.48)	(83,905.06)	487.70	(5,894.75)	(28,413.57)	(13,212.69)	(39,522.37)	(170,460.75)
Manual Adjustment - RNU	(116,866.71)	(113,066.42)	13,918.69	(94,660.65)	(77,779.66)	(60,426.68)	(19,885.61)	(33,318.06)	(90,281.71)	(24,671.39)	(20,418.46)	(246,710.35)	(435,285.59)
Total RSG/RNU	(152,245.27)	(164,173.03)	(54,342.92)	(147,183.70)	(86,091.87)	(139,392.77)	(139,464.13)	(38,013.27)	(107,640.30)	(69,567.97)	(43,347.56)	(301,450.10)	(699,483.32)
Congestion and Loss Wholesale Allocation													
Manual Adjustment - DA Congestion	(585,590.20)	(988,690.86)	(114,237.85)	33,639.55	(173,050.64)	(695,513.76)	(234,237.16)	(75,881.79)	(138,249.50)	(276,377.61)	(60,213.95)	(101,344.90)	(886,304.91)
Manual Adjustment - DA Loss	(230,742.27)	(324,930.53)	(318,831.79)	(314,667.04)	(377,863.10)	(893,473.75)	(856,737.95)	(333,793.62)	(368,628.88)	(387,572.99)	(278,720.98)	(327,716.49)	(2,553,170.91)
Manual Adjustment - DA Non-Asset Congestion	(147,097.34)	(176,422.93)	(392,736.85)	(327,786.97)	(148,806.30)	(328,637.26)	(12,697.16)	1,977.66	(30,772.60)	(22,041.36)	(81,440.31)	(107,615.23)	(252,589.00)
Manual Adjustment - DA Non-Asset Loss	(157,694.33)	(161,267.94)	(239,201.29)	(188,176.16)	(114,809.10)	(165,559.65)	(28,147.92)	(11,094.04)	(40,665.32)	(40,681.17)	(112,226.57)	(163,009.70)	(395,824.71)
Manual Adjustment - RT Non-Asset Congestion	19,383.24	15,682.95	7,691.14	7,190.19	4,570.26	40,153.98	(9,739.24)	1,390.24	19,665.76	27,755.09	33,368.56	2,066.57	74,506.97
Manual Adjustment - RT Non-Asset Loss	688.61	9,829.80	(561.35)	(9,938.55)	(11,967.39)	(1,041.06)	2,917.20	761.11	8,000.64	10,364.52	28,423.14	17,773.51	68,240.11
Manual Adjustment - ASM RT Asset EN GEN CONG	(2,631.41)	(27,079.10)	(19,124.47)	(10,195.49)	2,735.24	(8,431.01)	(8,090.22)	(4,601.92)	(14,310.97)	(18,505.71)	(12,930.22)	(126.33)	(58,565.37)
Manual Adjustment - ASM RT Asset EN GEN LOSS	(4,951.66)	(13,675.04)	(7,800.28)	711.25	(600.35)	(344.92)	(665.98)	(802.57)	(9,878.76)	(7,552.09)	(17,339.22)	(10,096.40)	(46,335.01)
Manual Adjustment - RT Asset EN Load CONG	(3,551.86)	(17.07)	2,794.23	5,435.16	(152.38)	7.32	3.68	(95.58)	25.99	(0.00)	15.79	41.01	(9.11)
Manual Adjustment - RT Asset EN Load LOSS	(1,439.73)	(20.76)	868.16	2,228.27	(281.30)	1.49	1.36	(2.18)	32.78	(0.01)	122.14	89.81	243.89
Total Congestion and Loss	(1,113,626.96)	(1,666,591.48)	(1,081,140.36)	(801,559.77)	(820,225.05)	(2,052,838.62)	(1,147,393.39)	(422,142.69)	(574,780.87)	(714,611.33)	(500,941.62)	(689,938.15)	(4,049,808.04)
Ramp Capability Amount													
Embedded in ASM - DA Regulation	(599.12)	(6,787.07)	(23,199.49)	(11,894.49)	(4,301.70)	(812.89)	(4,653.24)	(2,470.11)	(6,388.96)	(4,478.38)	(11,821.14)	(5,661.05)	(35,472.88)
Embedded in ASM - RT Regulation	(1,169.89)	(2,412.21)	(312.36)	733.71	(6,574.15)	(642.43)	(2,233.95)	(455.23)	(2,907.75)	(2,696.68)	(403.08)	(1,998.18)	(10,694.87)

Northern States Power Company
Electric Operations - State of Minnesota

Detail of MISO Day 2 Charges (New Report Format)

	July 2017	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	233,688	$14,766,435	4,305,338	$127,796,795	(3,799,408)	$ (104,393,578.71)			(272,242)	$ (8,636,781.59)				
5a	Day Ahead Non Asset Energy	(349,432)	($10,005,283)	40	$1,136	(349,472)	$ (10,006,419.03)					11,592	$312,475	-	$ -
13a	Real Time Asset Energy	(62,713)	($1,862,704)	150,055	$4,023,703	(131,863)	$ (4,093,750.76)			(80,905)	$ (1,792,655.66)				
22a	Real Time Non Asset Energy	202	$10,359	202	$10,359	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(178,256)	$ 2,908,807.07	4,455,634	$ 131,831,992.82	(4,280,743)	$ (118,493,748.50)	-	$ -	(353,147)	$ (10,429,437.25)	11,592	$ 312,474.69	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (5,175.18)		$ 285.17		$ (5,460.35)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (1,382,114.23)		$ -		$ (1,382,114.23)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,387,289.41)		$ 285.17		$ (1,387,574.58)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 593,104.55		$ 575,036.99		$ -		$ 18,067.56				$ 778.96		
19	Real Time Market Administration (Schedule 17)		$ 45,595.04		$ 40,143.13		$ -		$ 5,451.91				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 32,031.60		$ 32,031.60		$ -						$ 50.48		
33	Day-Ahead Schedule 24 Allocation Amount		$ 92,400.93		$ 89,388.96		$ -		$ 3,011.97				$ 124.96		
34	Real -Time Schedule 24 Allocation Amount		$ (92,388.80)				$ (25,510.31)				$ (66,878.49)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 670,743.32		$ 736,600.68		$ (25,510.31)		$ 26,531.44		$ (66,878.49)		$ 954.40		$ -
	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		$ (8,214.12)		$ 1,483.30		$ (9,697.42)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (7,409,511.47)		$ 395,938.53		$ (7,805,450.00)						$ 1,171.45		$ (17,309.65)
30	Financial Transmission Rights Monthly Allocation		$ (612,605.93)		$ -		$ (612,605.93)								$ (1,029.43)
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -								
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 40,349.07		$ 40,349.07								$ 372.57		
37	Financial Transmission Guarantee Uplift Amount		$ (48,817.25)				$ (48,817.25)								$ (404.58)
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ (3,617.05)
	SUBTOTAL		$ (8,038,799.70)		$ 437,770.90		$ (8,476,570.60)		$ -		$ -		$ 1,544.02		$ (22,360.71)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 50,123.88		$ 46,243.28				$ 3,880.60						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (12,345.06)		$ -		$ (2,187.56)				$ (10,157.50)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 294,120.50		$ 276,643.30		$ -		$ 17,477.20						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (134,973.16)		$ -		$ (37,074.74)				$ (97,898.42)				
43	Real Time Price Volatility Make Whole Payment		$ (194,026.12)		$ -		($161,795)				($32,231)				
	SUBTOTAL		$ 2,900.04		$ 322,886.57		$ (201,057.22)		$ 21,357.81		$ (140,287.12)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 73,946.14		$ 126,312.08		$ (38,445.94)				$ (13,920.00)				$ -
21	Real Time Net Inadvertent Distribution		$ 61,777.20		$ 98,845.40		$ (37,068.20)						$ 124.99		$ (54.36)
23	Real Time Revenue Neutrality Uplift Amount		$ 585,736.40		$ 813,468.06		$ (280,143.58)		$ 52,411.92						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 721,459.74		$ 1,038,625.54		$ (355,657.72)		$ 52,411.92		$ (13,920.00)		$ 124.99		$ (54.36)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 3,620,102.73		$ 3,647,683.29		$ (27,580.56)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (3,628,762.14)		$ 30,748.61		$ (3,650,351.02)				$ (9,159.73)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (127,119.86)		$ -		$ (127,119.86)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 92,725.55		$ 92,725.55		$ -								
	SUBTOTAL		$ (43,053.72)		$ 3,771,157.45		$ (3,805,051.44)		$ -		$ (9,159.73)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 8,214.12		$ 9,697.42		$ (1,483.30)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 5,175.18		$ 5,460.35		$ (285.17)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered														
18	Real Time Congestion Rebate on Carve Out Grandfathered														
	SUBTOTAL	-	$ 13,389.30	-	$ 15,157.77	-	$ (1,768.47)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(178,256)	$ (5,151,843.36)	4,455,634	$ 138,154,476.91	(4,280,743)	$ (132,746,938.84)	-	$ 100,301.16	(353,147)	$ (10,659,682.59)	11,592	$ 315,098.10	-	$ (22,415.07)
x	Net Congestion Amount		$ 5,418,224.04		$ 5,221,453.56				$ 196,770.48						
y	Net Loss Amount		$ 4,241,103.23		$ 3,966,166.85				$ 274,936.38						
z	Net Congestion and Loss Energy Offset		$ (9,659,327.27)		$ (9,187,620.40)				$ (471,706.87)						
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(178,256)**	$ (5,151,843.36)	4,455,634	$ 138,154,476.91	(4,280,743)	$ (132,746,938.84)	-	$ 100,301.16	(353,147)	$ (10,659,682.59)	11,592	$ 315,098.10	-	$ (22,415.07)

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

Detail of MISO Day 2 Charges (New Report Format)

August 2017		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	222,538	$11,091,850	3,820,710	$97,155,275	(3,341,737)	$ (78,718,391.60)			(256,435)	$ (7,345,033.68)				
5a	Day Ahead Non Asset Energy	(358,202)	($8,700,586)	22	$639	(358,224)	$ (8,701,225.00)					11,880	$277,172	-	$ -
13a	Real Time Asset Energy	(60,688)	($1,649,977)	59,865	$1,410,074	(23,947)	$ (1,057,420.19)			(96,606)	$ (2,002,630.75)				
22a	Real Time Non Asset Energy	687	$17,190	718	$17,964	(31)	$ (774.33)					-	$ -	-	$ -
	SUBTOTAL	(195,665)	$ 758,475.73	3,881,315	$ 98,583,951.28	(3,723,939)	$ (88,477,811.12)	-	$ -	(353,041)	$ (9,347,664.43)	11,880	$ 277,171.50	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (4,565.85)		$ 165.40		$ (4,731.25)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (915,463.36)		$ -		$ (915,463.36)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (920,029.21)		$ 165.40		$ (920,194.61)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 541,944.41		$ 524,577.84		$ -		$ 17,366.57				$ 812.40		
19	Real Time Market Administration (Schedule 17)		$ 39,130.12		$ 32,452.07		$ -		$ 6,678.05				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 26,142.80		$ 26,142.80		$ -						$ 763.12		
33	Day-Ahead Schedule 24 Allocation Amount		$ 88,026.11		$ 85,284.04		$ -		$ 2,742.07				$ 132.32		
34	Real -Time Schedule 24 Allocation Amount		$ (77,178.30)				$ 5,633.87				$ (82,812.17)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 618,065.14		$ 668,456.75		$ 5,633.87		$ 26,786.69		$ (82,812.17)		$ 1,707.84		$ -
	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		$ (8,141.19)		$ 314.26		$ (8,455.45)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (5,889,555.92)		$ 252,116.72		$ (6,141,672.64)						$ 93,398.83		$ (91,490.39)
30	Financial Transmission Rights Monthly Allocation		$ (447,182.46)		$ -		$ (447,182.46)								$ (465.64)
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -								
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (1,120.92)				$ (1,120.92)								$ (4,070.06)
37	Financial Transmission Guarantee Uplift Amount		$ (391.84)				$ (391.84)						$ 3,955.74		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ 125,873.55		$ (63,418.79)
	SUBTOTAL		$ (6,346,392.33)		$ 252,430.98		$ (6,598,823.31)		$ -		$ -		$ 223,228.12		$ (159,444.88)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 57,862.02		$ 52,824.34				$ 5,037.68						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (32,854.54)		$ -		$ (20,231.96)				$ (12,622.58)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 146,960.97		$ 134,166.01		$ -		$ 12,794.96						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (69,205.57)		$ -		$ (52,000.43)				$ (17,205.14)				
43	Real Time Price Volatility Make Whole Payment		$ (112,767.09)		$ -		($95,883)				($16,885)				
	SUBTOTAL		$ (10,004.21)		$ 186,990.35		$ (168,114.93)		$ 17,832.64		$ (46,712.27)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ (52,435.88)		$ 130,884.20		$ (167,480.08)				$ (15,840.00)				$ -
21	Real Time Net Inadvertent Distribution		$ 133,299.65		$ 168,142.99		$ (34,843.34)						$ 227.18		$ (46.94)
23	Real Time Revenue Neutrality Uplift Amount		$ 223,464.73		$ 533,281.81		$ (329,272.74)		$ 19,455.66						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 304,328.50		$ 832,309.00		$ (531,596.16)		$ 19,455.66		$ (15,840.00)		$ 227.18		$ (46.94)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 3,620,102.73		$ 3,647,683.29		$ (27,580.56)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (3,628,762.14)		$ 30,748.61		$ (3,641,642.10)				$ (17,868.65)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (131,423.44)		$ -		$ (131,423.44)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 92,725.55		$ 92,725.55		$ -								
	SUBTOTAL		$ (47,357.30)		$ 3,771,157.45		$ (3,800,646.10)		$ -		$ (17,868.65)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 8,141.19		$ 8,455.45		$ (314.26)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 4,565.85		$ 4,731.25		$ (165.40)								
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	-	$ 12,707.04	-	$ 13,186.70	-	$ (479.66)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(195,665)	$ (5,630,206.64)	3,881,315	$ 104,308,647.91	(3,723,939)	$ (100,492,032.02)	-	$ 64,074.99	(353,041)	$ (9,510,897.52)	11,880	$ 502,334.64	-	$ (159,491.82)
x	Net Congestion Amount		$ 3,830,248.84		$ 3,526,905.00				$ 303,343.84						
y	Net Loss Amount		$ 3,444,792.16		$ 3,158,934.91				$ 285,857.25						
z	Net Congestion and Loss Energy Offset		$ (7,275,041.00)		$ (6,685,839.91)				$ (589,201.09)						
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(195,665)**	$ (5,630,206.64)	3,881,315	$ 104,308,647.91	(3,723,939)	$ (100,492,032.02)	-	$ 64,074.99	(353,041)	$ (9,510,897.52)	11,880	$ 502,334.64	-	$ (159,491.82)

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

Detail of MISO Day 2 Charges (New Report Format)

	September 2017	**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	202,818	$13,779,311	3,646,285	$86,747,110	(3,174,462)	$ (66,644,455.59)			(269,005)	$ (6,323,343.49)				
5a	Day Ahead Non Asset Energy	(340,252)	($7,526,835)	97	$3,290	(340,349)	$ (7,530,124.33)					11,280	$237,102	-	$ -
13a	Real Time Asset Energy	(99,134)	($2,293,436)	35,403	$1,148,269	(7,467)	$ (494,859.30)			(127,070)	$ (2,946,846.14)				
22a	Real Time Non Asset Energy	1,108	$31,502	1,108	$31,502	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(235,460)	$ 3,990,543.04	3,682,893	$ 87,930,171.89	(3,522,278)	$ (74,669,439.22)	-	$ -	(396,075)	$ (9,270,189.63)	11,280	$ 237,102.30	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (7,181.35)		$ 137.98		$ (7,319.33)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (1,302,537.63)		$ -		$ (1,302,537.63)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,309,718.98)		$ 137.98		$ (1,309,856.96)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 551,951.71		$ 532,366.42		$ -		$ 19,585.29				$ 821.60		
19	Real Time Market Administration (Schedule 17)		$ 44,233.12		$ 35,005.07		$ -		$ 9,228.05				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 24,065.60		$ 24,065.60		$ -						$ 236.96		
33	Day-Ahead Schedule 24 Allocation Amount		$ 83,296.60		$ 80,280.88		$ -		$ 3,015.72				$ 127.20		
34	Real -Time Schedule 24 Allocation Amount		$ (71,304.25)				$ 10,487.95				$ (81,792.20)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 632,242.78		$ 671,717.97		$ 10,487.95		$ 31,829.06		$ (81,792.20)		$ 1,185.76		$ -
	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		$ (8,474.41)		$ 5,342.84		$ (13,817.25)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (8,383,531.61)		$ 834,425.43		$ (9,217,957.04)						$ 47,959.52		$ (33,434.51)
30	Financial Transmission Rights Monthly Allocation		$ (306,232.96)		$ -		$ (306,232.96)								$ (4,294.02)
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -								
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (56,284.32)				$ (56,284.32)						$ 3,320.71		
37	Financial Transmission Guarantee Uplift Amount		$ 62,630.10		$ 62,630.10										$ (3,176.20)
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ 7,469.33		$ (17,840.67)
	SUBTOTAL		$ (8,691,893.20)		$ 902,398.37		$ (9,594,291.57)		$ -		$ -		$ 58,749.56		$ (58,745.40)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 115,978.79		$ 103,861.59				$ 12,117.20						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (96,390.36)		$ -		$ (74,516.32)				$ (21,874.04)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 365,711.53		$ 327,502.82		$ -		$ 38,208.71						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (386,861.37)		$ -		$ (125,986.54)				$ (260,874.83)				
43	Real Time Price Volatility Make Whole Payment		$ (307,866.23)		$ -		($195,800)				($112,067)				
	SUBTOTAL		$ (309,427.64)		$ 431,364.41		$ (396,302.42)		$ 50,325.91		$ (394,815.54)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 52,150.05		$ 142,425.51		$ (75,875.46)				$ (14,400.00)				$ (16,336.29)
21	Real Time Net Inadvertent Distribution		$ (61,649.28)		$ 18,340.43		$ (79,989.71)						$ 20.18		$ (105.03)
23	Real Time Revenue Neutrality Uplift Amount		$ 801,450.71		$ 1,262,928.19		$ (545,211.24)		$ 83,733.76						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 791,951.48		$ 1,423,694.13		$ (701,076.41)		$ 83,733.76		$ (14,400.00)		$ 20.18		$ (16,441.32)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 3,419,039.70		$ 3,456,472.40		$ (37,432.70)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (3,472,296.93)		$ 42,634.85		$ (3,497,369.92)				$ (17,561.86)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (18,212.29)		$ -		$ (18,212.29)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 28,487.85		$ 28,487.85		$ -								
	SUBTOTAL		$ (42,981.67)		$ 3,527,595.10		$ (3,553,014.91)		$ -		$ (17,561.86)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 8,474.41		$ 13,817.25		$ (5,342.84)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 7,181.35		$ 7,319.33		$ (137.98)								
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	-	$ 15,655.76	-	$ 21,136.58	-	$ (5,480.82)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(235,460)	$ (4,923,628.43)	3,682,893	$ 94,908,216.43	(3,522,278)	$ (90,218,974.36)	-	$ 165,888.73	(396,075)	$ (9,778,759.23)	11,280	$ 297,057.80	-	$ (75,186.72)
x	Net Congestion Amount		$ 5,650,821.67		$ 5,181,939.62				$ 468,882.05						
y	Net Loss Amount		$ 4,170,478.53		$ 3,765,377.32				$ 405,101.21						
z	Net Congestion and Loss Energy Offset		$ (9,821,300.20)		$ (8,947,316.94)				$ (873,983.26)						
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(235,460)**	$ (4,923,628.43)	3,682,893	$ 94,908,216.43	(3,522,278)	$ (90,218,974.36)	-	$ 165,888.73	(396,075)	$ (9,778,759.23)	11,280	$ 297,057.80	-	$ (75,186.72)

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

Northern States Power Company
Electric Operations - State of Minnesota

Detail of MISO Day 2 Charges (New Report Format)

October 2017		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	(191,743)	$4,252,219	3,374,654	$75,313,885	(3,033,662)	$ (60,486,081.75)			(532,735)	$ (10,575,584.27)				
5a	Day Ahead Non Asset Energy	(290,179)	($5,810,473)	-	$0	(290,179)	$ (5,810,473.17)					11,784	$253,147	-	$ -
13a	Real Time Asset Energy	(19,731)	($524,549)	44,001	$1,024,218	80,409	$ 1,502,319.09			(144,141)	$ (3,051,085.81)				
22a	Real Time Non Asset Energy	254	($15,236)	254	($15,236)	-	$ (0.01)					-	$ -	-	$ -
	SUBTOTAL	(501,399)	$ (2,098,039.49)	3,418,909	$ 76,322,866.43	(3,243,432)	$ (64,794,235.84)	-	$ -	(676,876)	$ (13,626,670.08)	11,784	$ 253,146.99	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (3,801.39)		$ 232.64		$ (4,034.03)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (792,348.09)		$ -		$ (792,348.09)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (796,149.48)		$ 232.64		$ (796,382.12)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 775,340.61		$ 733,769.35		$ -		$ 41,571.26				$ 1,248.48		
19	Real Time Market Administration (Schedule 17)		$ 67,059.85		$ 55,786.96		$ -		$ 11,272.89				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 27,509.36		$ 27,509.36		$ -						$ 5,166.08		
33	Day-Ahead Schedule 24 Allocation Amount		$ 90,990.27		$ 83,939.46		$ -		$ 7,050.81				$ 147.20		
34	Real -Time Schedule 24 Allocation Amount		$ (80,821.31)				$ (5,805.11)				$ (75,016.20)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 880,078.78		$ 901,005.13		$ (5,805.11)		$ 59,894.96		$ (75,016.20)		$ 6,561.76		$ -
	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		$ (3,574.47)		$ 5,520.96		$ (9,095.43)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (4,426,239.40)		$ 1,139,384.89		$ (5,565,624.29)						$ 500,584.79		$ (308,984.67)
30	Financial Transmission Rights Monthly Allocation		$ (208,971.01)		$ -		$ (208,971.01)								$ (1,356.06)
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -								
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (254,090.17)				$ (254,090.17)								$ (19,202.81)
37	Financial Transmission Guarantee Uplift Amount		$ 258,310.57		$ 258,310.57								$ 18,589.68		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ 93,488.21		$ (237,652.19)
	SUBTOTAL		$ (4,634,564.48)		$ 1,403,216.42		$ (6,037,780.90)		$ -		$ -		$ 612,662.68		$ (567,195.73)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 79,028.88		$ 65,952.66				$ 13,076.22						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (53,286.27)		$ -		$ (35,200.01)				$ (18,086.26)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 242,005.39		$ 201,962.88		$ -		$ 40,042.51						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (98,274.71)		$ -		$ (18,548.83)				$ (79,725.88)				
43	Real Time Price Volatility Make Whole Payment		$ (477,828.40)		$ -		($423,493)				($54,335)				
	SUBTOTAL		$ (308,355.11)		$ 267,915.54		$ (477,241.84)		$ 53,118.73		$ (152,147.54)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 103,117.97		$ 136,582.35		$ (19,985.27)				$ (13,479.11)				$ -
21	Real Time Net Inadvertent Distribution		$ (64,967.37)		$ 71,375.00		$ (136,342.37)						$ 110.70		$ (195.47)
23	Real Time Revenue Neutrality Uplift Amount		$ 1,301,794.02		$ 1,143,873.71		$ (57,476.15)		$ 215,396.46						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 1,339,944.62		$ 1,351,831.06		$ (213,803.79)		$ 215,396.46		$ (13,479.11)		$ 110.70		$ (195.47)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 3,419,039.70		$ 3,456,472.40		$ (37,432.70)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (3,472,296.93)		$ 42,634.85		$ (3,508,519.00)				$ (6,412.78)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (18,212.29)		$ -		$ (18,212.29)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 28,487.85		$ 28,487.85		$ -								
	SUBTOTAL		$ (42,981.67)		$ 3,527,595.10		$ (3,564,163.99)		$ -		$ (6,412.78)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 3,574.47		$ 9,095.43		$ (5,520.96)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 3,801.39		$ 4,034.03		$ (232.64)								
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	-	$ 7,375.86	-	$ 13,129.46	-	$ (5,753.60)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(501,399)	$ (5,652,690.97)	3,418,909	$ 83,787,791.78	(3,243,432)	$ (75,895,167.19)	-	$ 328,410.15	(676,876)	$ (13,873,725.71)	11,784	$ 872,482.13	-	$ (567,391.20)
x	Net Congestion Amount		$ 4,595,946.43		$ 3,902,324.98				$ 693,621.45						
y	Net Loss Amount		$ 3,335,097.16		$ 2,798,772.73				$ 536,324.43						
z	Net Congestion and Loss Energy Offset		$ (7,931,043.59)		$ (6,701,097.70)				$ (1,229,945.89)						
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(501,399)**	$ (5,652,690.97)	3,418,909	$ 83,787,791.78	(3,243,432)	$ (75,895,167.19)	-	$ 328,410.15	(676,876)	$ (13,873,725.71)	11,784	$ 872,482.13	-	$ (567,391.20)

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

Detail of MISO Day 2 Charges (New Report Format)

	November 2017	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	(353,052)	($851,534)	3,398,161	$85,080,754	(3,226,226)	$ (74,719,603.36)			(524,987)	$ (11,212,684.01)				
5a	Day Ahead Non Asset Energy	(116,866)	($3,089,360)	21	$406	(116,887)	$ (3,089,766.07)					11,376	$280,431	-	$ -
13a	Real Time Asset Energy	(23,802)	($411,576)	47,149	$ 1,234,441.85	20,742	$ 1,541.05			(91,693)	$ (1,647,558.42)				
22a	Real Time Non Asset Energy	102	$30,325	102	$30,325	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(493,618)	$ (4,322,143.53)	3,445,433	$ 86,345,927.28	(3,322,371)	$ (77,807,828.38)	-	$ -	(616,680)	$ (12,860,242.43)	11,376	$ 280,430.58	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (705.28)		$ 1,115.47		$ (1,820.75)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (783,371.78)		$ -		$ (783,371.78)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (784,077.06)		$ 1,115.47		$ (785,192.53)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 568,782.25		$ 513,588.13		$ -		$ 55,194.12				$ 892.32		
19	Real Time Market Administration (Schedule 17)		$ 43,889.40		$ 32,883.01		$ -		$ 11,006.39				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 20,575.92		$ 20,575.92		$ -						$ 2,528.00		
33	Day-Ahead Schedule 24 Allocation Amount		$ 96,639.64		$ 90,049.50		$ -		$ 6,590.14				$ 149.28		
34	Real -Time Schedule 24 Allocation Amount		$ (83,858.78)				$ 12,448.07				$ (96,306.85)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 646,028.43		$ 657,096.56		$ 12,448.07		$ 72,790.65		$ (96,306.85)		$ 3,569.60		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ 7,278.86		$ 8,493.54		$ (1,214.68)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (1,186,296.03)		$ 918,092.29		$ (2,104,388.32)						$ 258,207.85		$ (162,357.66)
30	Financial Transmission Rights Monthly Allocation		$ (400,255.24)		$ -		$ (400,255.24)								$ (9,202.94)
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -								
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 319,991.92				$ 319,991.92								$ 4,921.46
37	Financial Transmission Guarantee Uplift Amount		$ (349,023.92)		$ (349,023.92)								$ (2,667.15)		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ 77,659.22		$ (110,538.57)
	SUBTOTAL		$ (1,608,304.41)		$ 577,561.91		$ (2,185,866.32)		$ -		$ -		$ 333,199.92		$ (277,177.71)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 128,386.09		$ 108,766.04				$ 19,620.05						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (142,633.89)		$ -		$ (94,454.22)				$ (48,179.67)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 126,340.02		$ 107,032.65		$ -		$ 19,307.37						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (120,607.48)		$ -		$ (97,599.85)				$ (23,007.63)				
43	Real Time Price Volatility Make Whole Payment		$ (47,329.87)		$ -		($33,374)				($13,956)				
	SUBTOTAL		$ (55,845.13)		$ 215,798.70		$ (225,427.60)		$ 38,927.41		$ (85,143.64)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ (72,083.63)		$ 196,629.33		$ (253,924.28)				$ (14,788.68)				$ -
21	Real Time Net Inadvertent Distribution		$ 72,996.01		$ 114,693.36		$ (41,697.35)						$ 168.01		$ (58.69)
23	Real Time Revenue Neutrality Uplift Amount		$ 179,786.39		$ 551,682.80		$ (399,371.49)		$ 27,475.08						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 180,698.77		$ 863,005.49		$ (694,993.12)		$ 27,475.08		$ (14,788.68)		$ 168.01		$ (58.69)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 3,419,039.70		$ 3,456,472.40		$ (37,432.70)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (3,472,296.93)		$ 42,634.85		$ (3,509,494.75)				$ (5,437.03)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (18,212.29)		$ -		$ (18,212.29)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 28,487.85		$ 28,487.85		$ -								
	SUBTOTAL		$ (42,981.67)		$ 3,527,595.10		$ (3,565,139.74)		$ -		$ (5,437.03)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (7,278.86)		$ 1,214.68		$ (8,493.54)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 705.28		$ 1,820.75		$ (1,115.47)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered														
18	Real Time Congestion Rebate on Carve Out Grandfathered														
	SUBTOTAL	-	$ (6,573.58)	-	$ 3,035.43	-	$ (9,609.01)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(493,618)	$ (5,993,198.18)	3,445,433	$ 92,191,135.94	(3,322,371)	$ (85,261,608.63)	-	$ 139,193.14	(616,680)	$ (13,061,918.63)	11,376	$ 617,368.11	-	$ (277,236.40)
x	Net Congestion Amount		$ 1,867,069.55		$ 1,603,022.65				$ 264,046.90						
y	Net Loss Amount		$ 3,373,544.59		$ 2,878,291.45				$ 495,253.14						
z	Net Congestion and Loss Energy Offset		$ (5,240,614.14)		$ (4,481,314.10)				$ (759,300.04)						
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(493,618)**	$ (5,993,198.18)	3,445,433	$ 92,191,135.94	(3,322,371)	$ (85,261,608.63)	-	$ 139,193.14	(616,680)	$ (13,061,918.63)	11,376	$ 617,368.11	-	$ (277,236.40)

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

Northern States Power Company
Electric Operations - State of Minnesota
Detail of MISO Day 2 Charges (New Report Format)

	December 2017	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	(556,369)	($7,232,522)	3,718,188	$97,199,615	(3,601,663)	$ (88,456,760.89)			(672,894)	$ (15,975,375.75)				
5a	Day Ahead Non Asset Energy	(126,239)	($3,431,927)	42	$874	(126,281)	$ (3,432,801.77)					11,592	$284,653	-	$ -
13a	Real Time Asset Energy	2,007	$231,307	57,806	$ 1,591,374.56	35,169	$ 687,054.93			(90,968)	$ (2,047,122.14)				
22a	Real Time Non Asset Energy	-	$4	-	$4	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(680,601)	$ (10,433,138.10)	3,776,036	$ 98,791,867.52	(3,692,775)	$ (91,202,507.73)	-	$ -	(763,862)	$ (18,022,497.89)	11,592	$ 284,653.32	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 1,280.54		$ 1,855.43		$ (574.89)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (991,853.15)		$ -		$ (991,853.15)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (990,572.61)		$ 1,855.43		$ (992,428.04)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 690,768.91		$ 633,648.71		$ -		$ 57,120.20				$ 989.04		
19	Real Time Market Administration (Schedule 17)		$ 57,091.35		$ 49,296.34		$ -		$ 7,795.01				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 21,107.84		$ 21,107.84		$ -						$ 3.84		
33	Day-Ahead Schedule 24 Allocation Amount		$ 106,357.20		$ 97,546.49		$ -		$ 8,810.71				$ 152.08		
34	Real -Time Schedule 24 Allocation Amount		$ (90,334.49)				$ 2,645.43				$ (92,979.92)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 784,990.81		$ 801,599.38		$ 2,645.43		$ 73,725.92		$ (92,979.92)		$ 1,144.96		$ -
	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		$ 5,356.06		$ 5,807.90		$ (451.84)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (660,232.21)		$ 617,691.97		$ (1,277,924.18)						$ 88.42		$ 2,329.77
30	Financial Transmission Rights Monthly Allocation		$ 141,917.90		$ -		$ 141,917.90								$ (7,673.70)
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -								
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (419,228.86)				$ (419,228.86)								$ 5,339.06
37	Financial Transmission Guarantee Uplift Amount		$ 419,063.21		$ 419,063.21								$ (5,241.45)		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (513,123.90)		$ 1,042,563.08		$ (1,555,686.98)		$ -		$ -		$ (5,153.03)		$ (4.87)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 62,050.85		$ 51,404.51				$ 10,646.34						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (168,861.50)		$ -		$ (157,143.55)				$ (11,717.95)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ (27,868.89)		$ (23,087.30)		$ -		$ (4,781.59)						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (1,081.24)		$ -		$ (305.90)				$ (775.34)				
43	Real Time Price Volatility Make Whole Payment		$ (154,244.18)		$ -		($137,501)				($16,744)				
	SUBTOTAL		$ (290,004.96)		$ 28,317.21		$ (294,949.96)		$ 5,864.75		$ (29,236.96)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 72,892.01		$ 129,834.41		$ (41,999.18)				$ (14,943.22)				$ -
21	Real Time Net Inadvertent Distribution		$ 55,761.10		$ 137,964.43		$ (82,203.33)						$ 191.90		$ (117.17)
23	Real Time Revenue Neutrality Uplift Amount		$ 1,008,080.48		$ 1,103,553.63		$ (268,433.94)		$ 172,960.79						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 1,136,733.59		$ 1,371,352.47		$ (392,636.45)		$ 172,960.79		$ (14,943.22)		$ 191.90		$ (117.17)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 3,077,706.89		$ 3,102,329.16		$ (24,622.27)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (3,090,966.42)		$ 23,598.19		$ (3,108,903.92)				$ (5,660.69)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (157,462.79)		$ -		$ (157,462.79)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 39,319.32		$ 39,319.32		$ -								
	SUBTOTAL		$ (131,403.00)		$ 3,165,246.67		$ (3,290,988.98)		$ -		$ (5,660.69)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (5,356.06)		$ 451.84		$ (5,807.90)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (1,280.54)		$ 574.89		$ (1,855.43)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered														
18	Real Time Congestion Rebate on Carve Out Grandfathered														
	SUBTOTAL	-	$ (6,636.60)	-	$ 1,026.73	-	$ (7,663.33)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(680,601)	$ (10,443,154.77)	3,776,036	$ 105,203,828.49	(3,692,775)	$ (97,734,216.04)	-	$ 252,551.46	(763,862)	$ (18,165,318.68)	11,592	$ 280,837.15	-	$ (122.04)
x	Net Congestion Amount		$ 1,436,606.81		$ 1,192,322.26				$ 244,284.55						
y	Net Loss Amount		$ 3,586,396.66		$ 2,972,564.81				$ 613,831.85						
z	Net Congestion and Loss Energy Offset		$ (5,023,003.47)		$ (4,164,887.07)				$ (858,116.40)						
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(680,601)**	$ (10,443,154.77)	3,776,036	$ 105,203,828.49	(3,692,775)	$ (97,734,216.04)	-	$ 252,551.46	(763,862)	$ (18,165,318.68)	11,592	$ 280,837.15	-	$ (122.04)

x No longer reported in 1b, 5b, 13b, 22b
y No longer reported in 1c, 5c, 13c, 22c $ 9,325,656.74
z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

Detail of MISO Day 2 Charges (New Report Format)

	January 2018	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	(593,743)	$ (7,729,859.50)	3,827,290	$ 142,115,992.61	(3,708,183)	$ (129,146,802.02)			(712,850)	$ (20,699,050.09)				
5a	Day Ahead Non Asset Energy	(120,541)	$ (4,977,339.46)	69	$ 2,310.18	(120,610)	$ (4,979,649.64)					11,784	$ 439,594.21	-	$ -
13a	Real Time Asset Energy	20,042	$ 610,028.80	90,476	$ 2,447,665.69	4,144	$ (181,363.60)			(74,577)	$ (1,656,273.29)				
22a	Real Time Non Asset Energy	-	$ 6.77	-	$ 6.77	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(694,242)	$ (12,097,163.39)	3,917,835	$ 144,565,975.25	(3,824,650)	$ (134,307,815.26)	-	$ -	(787,427)	$ (22,355,323.38)	11,784	$ 439,594.21	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 3,719.45		$ 5,076.20		$ (1,356.75)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (1,774,973.13)		$ -		$ (1,774,973.13)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,771,253.68)		$ 5,076.20		$ (1,776,329.88)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 590,463.11		$ 540,143.18		$ -		$ 50,319.93				$ 832.32		
19	Real Time Market Administration (Schedule 17)		$ 39,261.95		$ 34,071.69		$ -		$ 5,190.26				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 17,404.08		$ 17,404.08		$ -						$ 56.32		
33	Day-Ahead Schedule 24 Allocation Amount		$ 100,425.81		$ 91,866.16		$ -		$ 8,559.65				$ 143.68		
34	Real -Time Schedule 24 Allocation Amount		$ (96,154.90)		$ 101,581.74		$ (96,154.90)				$ (101,581.74)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 651,400.05		$ 785,066.85		$ (96,154.90)		$ 64,069.84		$ (101,581.74)		$ 1,032.32		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ 20,919.82		$ 26,162.08		$ (5,242.26)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (511,778.09)		$ 1,874,658.54		$ (2,386,436.63)						$ 18,700.25		$ (10,030.61)
30	Financial Transmission Rights Monthly Allocation		$ 20,641.26		$ 20,641.26										$ (1.74)
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -								
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (61,441.36)				$ (61,441.36)								$ (107.40)
37	Financial Transmission Guarantee Uplift Amount		$ 66,631.38		$ 66,631.38								$ 106.79		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ (479.00)
	SUBTOTAL		$ (465,026.99)		$ 1,988,093.26		$ (2,453,120.25)		$ -		$ -		$ 18,807.04		$ (10,618.75)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 205,525.04		$ 169,851.58				$ 35,673.46						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (360,075.77)		$ -		$ (343,297.96)				$ (16,777.81)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 483,401.05		$ 399,495.99		$ -		$ 83,905.06						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (638,214.90)		$ -		$ (390,537.31)				$ (247,677.59)				
43	Real Time Price Volatility Make Whole Payment		$ (368,914.39)		$ -		($327,715)				($41,199)				
	SUBTOTAL		$ (678,278.97)		$ 569,347.57		$ (1,061,550.73)		$ 119,578.52		$ (305,654.33)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 263,309.97		$ 398,456.39		$ (120,746.42)				$ (14,400.00)				$ -
21	Real Time Net Inadvertent Distribution		$ 66,019.14		$ 168,592.72		$ (102,573.58)						$ 213.52		$ (132.59)
23	Real Time Revenue Neutrality Uplift Amount		$ 114,566.67		$ 901,876.36		$ (807,195.30)		$ 19,885.61						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 443,895.78		$ 1,468,925.47		$ (1,030,515.30)		$ 19,885.61		$ (14,400.00)		$ 213.52		$ (132.59)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 3,077,706.89		$ 3,102,329.16		$ (24,622.27)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (3,090,966.42)		$ 23,598.19		$ (3,074,182.05)				$ (40,382.56)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (157,243.97)		$ -		$ (157,243.97)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 39,324.86		$ 39,324.86		$ -								
	SUBTOTAL		$ (131,178.64)		$ 3,165,252.21		$ (3,256,048.29)		$ -		$ (40,382.56)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (20,919.82)		$ 5,242.26		$ (26,162.08)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (3,719.45)		$ 1,356.75		$ (5,076.20)								
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	-	$ (24,639.27)	-	$ 6,599.01	-	$ (31,238.28)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(694,242)	$ (14,072,245.11)	3,917,835	$ 152,554,335.82	(3,824,650)	$ (144,012,772.89)	-	$ 203,533.97	(787,427)	$ (22,817,342.01)	11,784	$ 459,647.09	-	$ (10,751.34)
x	Net Congestion Amount		$ 1,469,248.19		$ 1,212,578.31				$ 256,669.88						
y	Net Loss Amount		$ 5,101,909.88		$ 4,219,942.57				$ 881,967.31						
z	Net Congestion and Loss Energy Offset		$ (6,571,158.07)		$ (5,432,520.88)				$ (1,138,637.19)						
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(694,242)**	$ (14,072,245.11)	3,917,835	$ 152,554,335.82	(3,824,650)	$ (144,012,772.89)	-	$ 203,533.97	(787,427)	$ (22,817,342.01)	11,784	$ 459,647.09	-	$ (10,751.34)

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

Detail of MISO Day 2 Charges (New Report Format)

	February 2018	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	(257,007)	$ (1,744,961.12)	3,400,646	$ 84,219,417.65	(3,269,312)	$ (76,987,155.19)			(388,341)	$ (8,977,223.58)				
5a	Day Ahead Non Asset Energy	(106,540)	$ (2,863,445.09)	5,195	$ 128,963.08	(111,735)	$ (2,992,408.17)					10,656	$ 261,831.50	-	$ -
13a	Real Time Asset Energy	(41,604)	$ (863,602.73)	49,310	$ 1,555,679.81	(25,080)	$ (696,050.28)			(65,834)	$ (1,723,232.26)				
22a	Real Time Non Asset Energy	6	$ 90.67	9,025	$ 256,162.86	(9,019)	$ (256,072.19)					-	$ -	-	$ -
	SUBTOTAL	(405,145)	$ (5,471,918.27)	3,464,176	$ 86,160,223.40	(3,415,146)	$ (80,931,685.83)	-	$ -	(454,175)	$ (10,700,455.84)	10,656	$ 261,831.50	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 4,267.62		$ 4,460.87		$ (193.25)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (1,026,169.10)		$ -		$ (1,026,169.10)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,021,901.48)		$ 4,460.87		$ (1,026,362.35)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 469,115.32		$ 443,656.88		$ -		$ 25,458.44				$ 696.00		
19	Real Time Market Administration (Schedule 17)		$ 34,394.87		$ 30,159.99		$ -		$ 4,234.88				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 25,520.16		$ 25,520.16		$ -						$ 83.20		
33	Day-Ahead Schedule 24 Allocation Amount		$ 81,676.67		$ 77,247.95		$ -		$ 4,428.72				$ 123.20		
34	Real -Time Schedule 24 Allocation Amount		$ (71,173.61)		$ 25,619.38						$ (96,792.99)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 539,533.41		$ 602,204.36		$ -		$ 34,122.04		$ (96,792.99)		$ 902.40		$ -
	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		$ 1,815.46		$ 5,156.83		$ (3,341.37)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (177,813.62)		$ 764,457.38		$ (942,271.00)						$ 4,491.79		$ (5,278.72)
30	Financial Transmission Rights Monthly Allocation		$ (70,652.17)		$ -		$ (70,652.17)								$ (107.84)
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -								
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (83,732.16)				$ (83,732.16)								$ (376.23)
37	Financial Transmission Guarantee Uplift Amount		$ 81,217.84		$ 81,217.84								$ 376.66		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ 2,316.00		$ -
	SUBTOTAL		$ (249,164.65)		$ 850,832.05		$ (1,099,996.70)		$ -		$ -		$ 7,184.45		$ (5,762.79)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 42,953.38		$ 37,770.48				$ 5,182.90						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (42,009.16)		$ -		$ (16,461.52)				$ (25,547.64)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ (4,041.79)				$ (3,554.09)				$ (487.70)				
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (25,802.49)		$ -		$ (16,102.92)				$ (9,699.57)				
43	Real Time Price Volatility Make Whole Payment		$ (110,397.76)		$ -		($47,632)				($62,766)				
	SUBTOTAL		$ (139,297.82)		$ 37,770.48		$ (83,750.50)		$ 5,182.90		$ (98,500.70)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 83,583.96		$ 165,658.07		$ (67,685.12)				$ (14,388.99)				$ -
21	Real Time Net Inadvertent Distribution		$ 22,708.43		$ 110,275.20		$ (87,566.77)						$ 154.24		$ (123.10)
23	Real Time Revenue Neutrality Uplift Amount		$ 276,123.85		$ 418,489.81		$ (175,684.02)		$ 33,318.06						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 382,416.24		$ 694,423.08		$ (330,935.91)		$ 33,318.06		$ (14,388.99)		$ 154.24		$ (123.10)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 3,077,706.89		$ 3,102,329.16		$ (24,622.27)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (3,090,966.42)		$ 23,598.19		$ (3,078,023.92)				$ (36,540.69)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (157,121.31)		$ -		$ (157,121.31)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 39,319.32		$ 39,322.09		$ (2.77)								
	SUBTOTAL		$ (131,061.52)		$ 3,165,249.44		$ (3,259,770.27)		$ -		$ (36,540.69)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (1,815.46)		$ 3,341.37		$ (5,156.83)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (4,267.62)		$ 193.25		$ (4,460.87)								
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	-	$ (6,083.08)	-	$ 3,534.62	-	$ (9,617.70)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(405,145)	$ (6,097,477.17)	3,464,176	$ 91,518,698.30	(3,415,146)	$ (86,742,119.26)	-	$ 72,623.00	(454,175)	$ (10,946,679.21)	10,656	$ 270,072.59	-	$ (5,885.89)
x	Net Congestion Amount		$ 651,411.95		$ 578,802.48				$ 72,609.47						
y	Net Loss Amount		$ 2,864,930.26		$ 2,520,801.53				$ 344,128.73						
z	Net Congestion and Loss Energy Offset		$ (3,516,342.21)		$ (3,099,604.02)				$ (416,738.19)						
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(405,145)**	$ (6,097,477.17)	3,464,176	$ 91,518,698.30	(3,415,146)	$ (86,742,119.26)	-	$ 72,623.00	(454,175)	$ (10,946,679.21)	10,656	$ 270,072.59	-	$ (5,885.89)

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

Detail of MISO Day 2 Charges (New Report Format)

	March 2018	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	(336,139)	$ (2,516,488.34)	3,409,547	$ 77,912,209.64	(3,234,553)	$ (69,763,943.69)			(511,133)	$ (10,664,754.29)				
5a	Day Ahead Non Asset Energy	(135,153)	$ (3,239,361.81)	78	$ 1,758.92	(135,231)	$ (3,241,120.73)					11,688	$ 263,360.55	-	$ -
13a	Real Time Asset Energy	(63,852)	$ (1,432,974.44)	36,884	$ 924,633.83	(19,861)	$ (796,179.08)			(80,875)	$ (1,561,429.19)				
22a	Real Time Non Asset Energy	130	$ 2,000.16	130	$ 2,000.16	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(535,014)	$ (7,186,824.43)	3,446,639	$ 78,840,602.55	(3,389,645)	$ (73,801,243.50)	-	$ -	(592,008)	$ (12,226,183.48)	11,688	$ 263,360.55	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 1,039.78		$ 1,580.14		$ (540.36)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (557,417.40)		$ -		$ (557,417.40)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (556,377.62)		$ 1,580.14		$ (557,957.76)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 731,851.55		$ 681,167.57		$ -		$ 50,683.98				$ 1,172.16		
19	Real Time Market Administration (Schedule 17)		$ 52,814.05		$ 44,672.30		$ -		$ 8,141.75				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 14,893.28		$ 14,893.28		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 94,053.06		$ 87,472.37		$ -		$ 6,580.69				$ 153.36		
34	Real -Time Schedule 24 Allocation Amount		$ (85,614.43)				$ (30,061.37)				$ (55,553.06)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 807,997.51		$ 828,205.52		$ (30,061.37)		$ 65,406.42		$ (55,553.06)		$ 1,325.52		$ -
	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		$ 2,077.77		$ 3,649.56		$ (1,571.79)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (724,910.33)		$ 433,088.35		$ (1,157,998.68)						$ 5.06		
30	Financial Transmission Rights Monthly Allocation		$ (81,850.95)		$ -		$ (81,850.95)								$ (223.24)
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -								
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (78,128.20)				$ (78,128.20)						$ 218.18		
37	Financial Transmission Guarantee Uplift Amount		$ 74,688.76		$ 74,688.76										$ (77.49)
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (808,122.95)		$ 511,426.67		$ (1,319,549.62)		$ -		$ -		$ 223.24		$ (300.73)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 75,683.66		$ 64,219.82				$ 11,463.84						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (46,824.18)		$ -		$ (35,646.02)				$ (11,178.16)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 38,916.85		$ 33,022.10				$ 5,894.75						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (38,372.10)		$ -		$ (25,622.36)				$ (12,749.74)				
43	Real Time Price Volatility Make Whole Payment		$ (132,358.39)		$ -		($118,670)				($13,689)				
	SUBTOTAL		$ (102,954.16)		$ 97,241.92		$ (179,937.95)		$ 17,358.59		$ (37,616.72)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 91,686.44		$ 184,002.40		$ (77,435.96)				$ (14,880.00)		$ 33.85		
21	Real Time Net Inadvertent Distribution		$ 92,123.93		$ 120,556.65		$ (28,432.72)						$ 177.33		$ (43.10)
23	Real Time Revenue Neutrality Uplift Amount		$ 596,035.10		$ 816,979.43		$ (311,226.04)		$ 90,281.71						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 779,845.47		$ 1,121,538.48		$ (417,094.72)		$ 90,281.71		$ (14,880.00)		$ 211.18		$ (43.10)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 3,351,784.59		$ 3,382,016.22		$ (30,231.63)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (3,360,340.60)		$ 30,394.72		$ (3,349,605.61)				$ (41,129.71)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (72,285.52)		$ -		$ (72,285.52)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 29,560.11		$ 29,565.65		$ (5.54)								
	SUBTOTAL		$ (51,281.42)		$ 3,441,976.59		$ (3,452,128.30)		$ -		$ (41,129.71)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (2,077.77)		$ 1,571.79		$ (3,649.56)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (1,039.78)		$ 540.36		$ (1,580.14)								
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	-	$ (3,117.55)	-	$ 2,112.15	-	$ (5,229.70)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(535,014)	$ (7,120,835.15)	3,446,639	$ 84,844,684.02	(3,389,645)	$ (79,763,202.92)	-	$ 173,046.72	(592,008)	$ (12,375,362.97)	11,688	$ 265,120.49	-	$ (343.83)
x	Net Congestion Amount		$ 1,210,183.70		$ 1,060,853.34				$ 149,330.36						
y	Net Loss Amount		$ 2,767,141.39		$ 2,365,880.60				$ 401,260.79						
z	Net Congestion and Loss Energy Offset		$ (3,977,325.09)		$ (3,426,733.95)				$ (550,591.14)						
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(535,014)**	$ (7,120,835.15)	3,446,639	$ 84,844,684.02	(3,389,645)	$ (79,763,202.92)	-	$ 173,046.72	(592,008)	$ (12,375,362.97)	11,688	$ 265,120.49	-	$ (343.83)

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

Detail of MISO Day 2 Charges (New Report Format)

April 2018		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	(208,014)	$ 1,995,629.74	3,238,954	$ 83,737,872.01	(3,073,264)	$ (73,679,798.50)			(373,704)	$ (8,062,443.77)				
5a	Day Ahead Non Asset Energy	(129,147)	$ (3,685,310.37)	49	$ 1,258.71	(129,196)	$ (3,686,569.08)					11,472	$ 286,658.42	-	$ -
13a	Real Time Asset Energy	(5,312)	$ 252,881.21	76,439	$ 2,068,004.01	4,381	$ 3,555.44			(86,132)	$ (1,818,678.24)				
22a	Real Time Non Asset Energy	(65)	$ (1,000.08)	(65)	$ (1,000.08)	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(342,538)	$ (1,437,799.50)	3,315,377	$ 85,806,134.65	(3,198,079)	$ (77,362,812.14)	-	$ -	(459,836)	$ (9,881,122.01)	11,472	$ 286,658.42	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 1,086.22		$ 1,797.51		$ (711.29)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (767,415.68)		$ -		$ (767,415.68)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (766,329.46)		$ 1,797.51		$ (768,126.97)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 771,172.32		$ 729,138.77		$ -		$ 42,033.55				$ 1,296.64		
19	Real Time Market Administration (Schedule 17)		$ 57,929.57		$ 48,204.10		$ -		$ 9,725.47				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 32,862.32		$ 32,862.32		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 96,058.44		$ 90,799.92		$ -		$ 5,258.52				$ 161.12		
34	Real -Time Schedule 24 Allocation Amount		$ (88,931.11)				$ 31,844.01				$ (120,775.12)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 869,091.54		$ 901,005.11		$ 31,844.01		$ 57,017.54		$ (120,775.12)		$ 1,457.76		$ -
	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		$ 8,633.43		$ 11,215.45		$ (2,582.02)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (67,332.29)		$ 3,556,684.43		$ (3,624,016.72)								$ (17.83)
30	Financial Transmission Rights Monthly Allocation		$ (4,206.89)		$ -		$ (4,206.89)						$ 8.06		
32	Financial Transmission Rights Yearly Allocation		$ (438,248.64)		$ -		$ (438,248.64)								$ (10,185.56)
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 62,379.85		$ 62,379.85		$ -						$ 10,195.30		
37	Financial Transmission Guarantee Uplift Amount		$ (64,723.55)		$ -		$ (64,723.55)								$ (11,896.47)
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (503,498.09)		$ 3,630,279.73		$ (4,133,777.82)		$ -		$ -		$ 10,203.36		$ (22,099.86)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 132,980.08		$ 116,497.08				$ 16,483.00						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (309,502.38)		$ -		$ (303,017.27)				$ (6,485.11)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 229,232.53		$ 200,818.96				$ 28,413.57						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (137,444.24)		$ -		$ (100,296.41)				$ (37,147.83)				
43	Real Time Price Volatility Make Whole Payment		$ (216,371.99)		$ -		($193,313.48)				$ (23,058.51)				
	SUBTOTAL		$ (301,106.00)		$ 317,316.04		$ (596,627.16)		$ 44,896.57		$ (66,691.45)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 210,384.73		$ 259,188.24		$ (33,923.51)				$ (14,880.00)		$ -		
21	Real Time Net Inadvertent Distribution		$ 76,373.38		$ 118,556.27		$ (42,182.89)						$ 171.35		$ (59.90)
23	Real Time Revenue Neutrality Uplift Amount		$ 199,041.68		$ 570,598.59		$ (396,228.30)		$ 24,671.39						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 485,799.79		$ 948,343.10		$ (472,334.70)		$ 24,671.39		$ (14,880.00)		$ 171.35		$ (59.90)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 3,351,784.59		$ 3,382,016.22		$ (30,231.63)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (3,360,340.59)		$ 30,394.76		$ (3,357,409.33)				$ (33,326.02)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (71,575.59)		$ -		$ (71,575.59)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 29,565.66		$ 29,565.66		$ -								
	SUBTOTAL		$ (50,565.93)		$ 3,441,976.64		$ (3,459,216.55)		$ -		$ (33,326.02)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (8,633.43)		$ 2,582.02		$ (11,215.45)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (1,086.22)		$ 711.29		$ (1,797.51)								
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	-	$ (9,719.65)	-	$ 3,293.31	-	$ (13,012.96)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(342,538)	$ (1,714,127.30)	3,315,377	$ 95,050,146.08	(3,198,079)	$ (86,774,064.29)	-	$ 126,585.51	(459,836)	$ (10,116,794.60)	11,472	$ 298,490.89	-	$ (22,159.76)
x	Net Congestion Amount		$ 2,556,856.96		$ 2,286,193.08				$ 270,663.88						
y	Net Loss Amount		$ 3,515,959.27		$ 3,098,069.62				$ 417,889.65						
z	Net Congestion and Loss Energy Offset		$ (6,072,816.23)		$ (5,384,262.70)				$ (688,553.53)						
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(342,538)**	$ (1,714,127.30)	3,315,377	$ 95,050,146.08	(3,198,079)	$ (86,774,064.29)	-	$ 126,585.51	(459,836)	$ (10,116,794.60)	11,472	$ 298,490.89	-	$ (22,159.76)

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

Detail of MISO Day 2 Charges (New Report Format)

May 2018		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	(34,757)	$ 5,480,065.52	3,659,973	$ 105,858,429.82	(3,324,725)	$ (90,414,352.38)			(370,005)	$ (9,964,011.92)				
5a	Day Ahead Non Asset Energy	(199,972)	$ (6,024,804.63)	50	$ 1,387.50	(200,022)	$ (6,026,192.13)					11,784	$ 320,483.99	-	$ -
13a	Real Time Asset Energy	(225,706)	$ (5,458,654.73)	50,762	$ 1,538,139.80	(194,863)	$ (5,134,875.38)			(81,605)	$ (1,861,919.15)				
22a	Real Time Non Asset Energy	250	$ 8,955.34	250	$ 8,955.34	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(460,185)	$ (5,994,438.50)	3,711,035	$ 107,406,912.46	(3,719,610)	$ (101,575,419.89)	-	$ -	(451,610)	$ (11,825,931.07)	11,784	$ 320,483.99	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (4,007.79)		$ 314.41		$ (4,322.20)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (910,589.02)		$ -		$ (910,589.02)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (914,596.81)		$ 314.41		$ (914,911.22)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 581,519.22		$ 552,852.61		$ -		$ 28,666.61				$ 905.92		
19	Real Time Market Administration (Schedule 17)		$ 54,043.24		$ 47,847.09		$ -		$ 6,196.15				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 14,822.88		$ 14,822.88		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 105,763.28		$ 100,622.50		$ -		$ 5,140.78				$ 165.60		
34	Real -Time Schedule 24 Allocation Amount		$ (95,334.31)				$ 355.13				$ (95,689.44)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 660,814.31		$ 716,145.08		$ 355.13		$ 40,003.54		$ (95,689.44)		$ 1,071.52		$ -
	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		$ (7,051.88)		$ (474.57)		$ (6,577.31)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (1,745,103.48)		$ 552,400.28		$ (2,297,503.76)								$ -
30	Financial Transmission Rights Monthly Allocation		$ (103,422.19)		$ -		$ (103,422.19)						$ -		
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -								$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 53,958.81		$ 53,958.81		$ -						$ (0.01)		
37	Financial Transmission Guarantee Uplift Amount		$ 14,581.48		$ 14,581.48		$ -								$ 0.01
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (1,787,037.26)		$ 620,466.00		$ (2,407,503.26)		$ -		$ -		$ (0.01)		$ 0.01
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 82,136.98		$ 68,924.29				$ 13,212.69						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (52,416.61)		$ -		$ (38,279.43)				$ (14,137.18)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 111,692.60		$ 133,532.42				$ (21,839.82)						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (14,398.95)		$ -		$ (29,504.08)				$ 15,105.13				
43	Real Time Price Volatility Make Whole Payment		$ (129,317.99)		$ -		($107,478.17)				$ (21,839.82)				
	SUBTOTAL		$ (2,303.97)		$ 202,456.71		$ (175,261.68)		$ (8,627.13)		$ (20,871.87)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 68,031.25		$ 121,134.57		$ (38,223.32)				$ (14,880.00)		$ -		
21	Real Time Net Inadvertent Distribution		$ 13,432.43		$ 144,138.56		$ (130,706.13)						$ 232.75		$ (207.75)
23	Real Time Revenue Neutrality Uplift Amount		$ 172,606.13		$ 787,741.23		$ (620,673.56)		$ 5,538.46						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 254,069.81		$ 1,053,014.36		$ (789,603.01)		$ 5,538.46		$ (14,880.00)		$ 232.75		$ (207.75)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 3,351,784.59		$ 3,382,016.22		$ (30,231.63)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (3,360,340.52)		$ 30,394.76		$ (3,371,383.67)				$ (19,351.61)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (71,760.16)		$ -		$ (71,760.16)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 29,565.66		$ 29,565.66		$ -								
	SUBTOTAL		$ (50,750.43)		$ 3,441,976.64		$ (3,473,375.46)		$ -		$ (19,351.61)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 7,051.88		$ 6,577.31		$ 474.57								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 4,007.79		$ 4,322.20		$ (314.41)								
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	-	$ 11,059.67	-	$ 10,899.51	-	$ 160.16	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(460,185)	$ (7,823,183.18)	3,711,035	$ 113,452,185.17	(3,719,610)	$ (109,335,559.23)	-	$ 36,914.87	(451,610)	$ (11,976,723.99)	11,784	$ 321,788.25	-	$ (207.74)
x	Net Congestion Amount		$ 1,306,636.24		$ 1,296,919.84				$ 9,716.40						
y	Net Loss Amount		$ 3,450,392.79		$ 3,450,392.79				$ -						
z	Net Congestion and Loss Energy Offset		$ (4,757,029.03)		$ (4,747,312.63)				$ (9,716.40)						
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(460,185)**	$ (7,823,183.18)	3,711,035	$ 113,452,185.17	(3,719,610)	$ (109,335,559.23)	-	$ 36,914.87	(451,610)	$ (11,976,723.99)	11,784	$ 321,788.25	-	$ (207.74)

x No longer reported in 1b, 5b, 13b, 22b

y No longer reported in 1c, 5c, 13c, 22c

z No longer used to offset the MISO billed energy amount in 1a, 5a, 13a, 22a

Detail of MISO Day 2 Charges (New Report Format)

June 2018		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	(255,527)	$ (1,296,667.60)	3,844,379	$ 100,655,687.95	(3,579,321)	$ (88,769,018.70)			(520,585)	$ (13,183,336.85)				
5a	Day Ahead Non Asset Energy	(210,278)	$ (6,284,191.76)	-	$ -	(210,278)	$ (6,284,191.76)					11,376	$ 274,456.24	-	$ -
13a	Real Time Asset Energy	(117,924)	$ (2,746,314.88)	95,968	$ 2,495,088.86	(122,005)	$ (3,159,502.96)			(91,887)	$ (2,081,900.78)				
22a	Real Time Non Asset Energy	206	$ 4,436.66	206	$ 4,436.67	-	$ (0.01)					-	$ -	-	$ -
	SUBTOTAL	(583,523)	$ (10,322,737.58)	3,940,553	$ 103,155,213.48	(3,911,604)	$ (98,212,713.43)	-	$ -	(612,472)	$ (15,265,237.63)	11,376	$ 274,456.24	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (5,298.90)		$ 106.05		$ (5,404.95)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (1,015,586.44)		$ -		$ (1,015,586.44)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,020,885.34)		$ 106.05		$ (1,020,991.39)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 698,607.49		$ 655,305.98		$ -		$ 43,301.51				$ 973.92		
19	Real Time Market Administration (Schedule 17)		$ 72,958.27		$ 65,335.42		$ -		$ 7,622.85				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 19,888.40		$ 19,888.40		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 96,251.98		$ 90,140.80		$ -		$ 6,111.18				$ 131.52		
34	Real -Time Schedule 24 Allocation Amount		$ (82,766.29)		$ 36,086.06		$ -				$ (118,852.35)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 804,939.85		$ 866,756.66		$ -		$ 57,035.54		$ (118,852.35)		$ 1,105.44		$ -
	Congestion & FTRs														
1b	Day Ahead Congestion														
5b	Day Ahead Non Asset Congestion														
13b	Real Time Congestion														
22b	Real Time Non Asset Congestion														
2	Day Ahead Financial Bilateral Transaction Congestion		$ (3,046.41)		$ 3,110.42		$ (6,156.83)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (1,100,724.72)		$ 240,740.05		$ (1,341,464.77)								$ -
30	Financial Transmission Rights Monthly Allocation		$ (58,804.62)		$ -		$ (58,804.62)						$ -		
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -								$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 53,995.61		$ 53,995.61		$ -						$ 0.01		
37	Financial Transmission Guarantee Uplift Amount		$ (53,814.00)		$ -		$ (53,814.00)								$ (12.58)
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (1,162,394.14)		$ 297,846.08		$ (1,460,240.22)		$ -		$ -		$ 0.01		$ (12.58)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 106,351.71		$ 66,829.34				$ 39,522.37						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (34,357.61)		$ -		$ (8,724.23)				$ (25,633.38)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 276,215.39		$ 290,166.44				$ (13,951.05)						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (19,601.94)		$ -		$ (12,042.19)				$ (7,559.75)				
43	Real Time Price Volatility Make Whole Payment		$ (161,021.43)		$ -		($147,070.38)				$ (13,951.05)				
	SUBTOTAL		$ 167,586.12		$ 356,995.78		$ (167,836.80)		$ 25,571.32		$ (47,144.18)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 192,470.70		$ 240,590.79		$ (37,761.39)				$ (10,358.70)		$ -		
21	Real Time Net Inadvertent Distribution		$ (83,118.67)		$ 12,907.83		$ (96,026.50)						$ 12.78		$ (127.04)
23	Real Time Revenue Neutrality Uplift Amount		$ 1,724,218.20		$ 1,954,383.29		$ (466,516.74)		$ 236,351.65						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 1,833,570.23		$ 2,207,881.91		$ (600,304.63)		$ 236,351.65		$ (10,358.70)		$ 12.78		$ (127.04)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 2,270,304.83		$ 2,279,263.02		$ (8,958.19)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (2,293,458.77)		$ 8,366.75		$ (2,281,827.80)				$ (19,997.72)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (320,148.19)		$ -		$ (320,148.19)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 41,430.89		$ 41,430.89		$ -								
	SUBTOTAL		$ (301,871.24)		$ 2,329,060.66		$ (2,610,934.18)		$ -		$ (19,997.72)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 3,046.41		$ 6,156.83		$ (3,110.42)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 5,298.90		$ 5,404.95		$ (106.05)								
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	-	$ 8,345.31	-	$ 11,561.78	-	$ (3,216.47)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(583,523)	$ (9,993,446.79)	3,940,553	$ 109,225,422.39	(3,911,604)	$ (104,076,237.12)	-	$ 318,958.52	(612,472)	$ (15,461,590.58)	11,376	$ 275,574.47	-	$ (139.62)
x	Net Congestion Amount		$ 1,460,984.37		$ 1,445,767.00				$ 15,217.37						
y	Net Loss Amount		$ 3,499,539.26		$ 3,499,539.26				$ -						
z	Net Congestion and Loss Energy Offset		$ (4,960,523.63)		$ (4,945,306.26)				$ (15,217.37)						
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(583,523)**	$ (9,993,446.79)	3,940,553	$ 109,225,422.39	(3,911,604)	$ (104,076,237.12)	-	$ 318,958.52	(612,472)	$ (15,461,590.58)	11,376	$ 275,574.47	-	$ (139.62)

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

Detail of MISO ASM Charges (New Report Format)

July 2017	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		$ (274,704.34)		$ -		$ (38,420.89)				$ (236,283.45)				
2 Day-Ahead Spinning Reserve Amount		$ (140,621.86)		$ -		$ (39,905.21)				$ (100,716.65)				
3 Day-Ahead Supplemental Reserve		$ (59,809.63)		$ -		$ (57,385.73)				$ (2,423.90)				
4 Real-Time Regulation Amount (See Note 1)		$ (110,336.60)		$ 113,636.99		$ (223,973.59)								
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (36,191.36)		$ 40,851.34		$ (77,042.70)								
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 3,924.10		$ 5,241.96		$ (1,317.86)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(2,426)	$ 17,552.40	217	$ (6,482.29)	(2,643)	$ 24,034.69								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	68,269	$ 2,152,911.29	345,724	$ 9,472,533.24	(277,454)	$ (7,319,621.95)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (30.81)		$ 26,116.72		$ (26,373.97)		$ 226.44						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 164,163.91		$ 164,163.91		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 184,268.01		$ 184,268.01		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 84,066.82		$ 84,066.82		$ -								
Penalty Charges														
13 Real Time Excessive/Deficient Energy Deployment		$ 132,523.83		$ 92,446.49		$ -		$ 40,077.34						
14 Real Time Contingency Reserve Deployment Failure		$ 3,820.14		$ 3,820.14		$ -		$ -						
MISO ASM CHARGES	65,843	$ 2,121,535.90	345,941	$ 10,180,663.33	(280,098)	$ (7,760,007.21)	-	$ 40,303.78	-	$ (339,424.00)	-	$ -	-	$ -
x Net Congestion Amount		$ (445,721.19)		$ (480,751.72)				$ 35,030.53						
y Net Loss Amount		$ (118,699.29)		$ (128,435.55)				$ 9,736.26						
z Net Congestion and Loss Energy Offset		$ 564,420.48		$ 609,187.27				$ (44,766.79)						
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	65,843	$ 2,121,535.90	345,941	$ 10,180,663.33	(280,098)	$ (7,760,007.21)	-	$ 40,303.78	-	$ (339,424.00)	-	$ -	-	$ -

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

Detail of MISO ASM Charges (New Report Format)

August 2017	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		$ (261,255.41)		$ -		$ (92,126.39)				$ (169,129.02)				
2 Day-Ahead Spinning Reserve Amount		$ (287,156.39)		$ -		$ (120,582.69)				$ (166,573.70)				
3 Day-Ahead Supplemental Reserve		$ (35,678.29)		$ -		$ (31,563.60)				$ (4,114.69)				
4 Real-Time Regulation Amount (See Note 1)		$ (20,149.82)		$ 94,392.00		$ (114,541.82)								
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 2,942.03		$ 100,969.08		$ (98,027.05)								
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 2,133.51		$ 2,736.35		$ (602.84)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(2,750)	$ 29,162.60	405	$ (3,483.52)	(3,155)	$ 32,646.12								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	31,092	$ 713,667.41	302,101	$ 6,461,025.50	(271,009)	$ (5,747,358.09)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 1,086.51		$ 17,329.76		$ (18,872.43)		$ 2,629.18						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 134,839.26		$ 134,839.26		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 157,052.27		$ 157,052.27		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 29,882.96		$ 29,882.96		$ -								
Penalty Charges														
13 Real Time Excessive/Deficient Energy Deployment		$ 84,691.33		$ 31,078.88		$ -		$ 53,612.45						
14 Real Time Contingency Reserve Deployment Failure		$ 1,352.19		$ 1,352.19		$ -		$ -						
MISO ASM CHARGES	28,342	$ 552,570.16	302,506	$ 7,027,174.73	(274,164)	$ (6,191,028.79)	-	$ 56,241.63	-	$ (339,817.41)	-	$ -	-	$ -
x Net Congestion Amount		$ (245,088.84)		$ (253,882.22)				$ 8,793.38						
y Net Loss Amount		$ (79,848.58)		$ (86,955.70)				$ 7,107.12						
z Net Congestion and Loss Energy Offset		$ 324,937.42		$ 340,837.92				$ (15,900.50)						
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	28,342	$ 552,570.16	302,506	$ 7,027,174.73	(274,164)	$ (6,191,028.79)	-	$ 56,241.63	-	$ (339,817.41)	-	$ -	-	$ -

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

Detail of MISO ASM Charges (New Report Format)

September 2017	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		$ (366,015.71)		$ -		$ (122,181.12)				$ (243,834.59)				
2 Day-Ahead Spinning Reserve Amount		$ (550,107.60)		$ -		$ (352,855.03)				$ (197,252.57)				
3 Day-Ahead Supplemental Reserve		$ (51,241.64)		$ -		$ (49,593.39)				$ (1,648.25)				
4 Real-Time Regulation Amount (See Note 1)		$ (102,195.92)		$ 173,610.44		$ (275,806.36)								
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 166,913.71		$ 266,888.77		$ (99,975.06)								
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 4,596.77		$ 5,127.39		$ (530.62)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(1,753)	$ 8,227.61	199	$ (5,941.64)	(1,952)	$ 14,169.25								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	(12,719)	$ (734,548.90)	291,892	**$ 6,203,357.77**	(304,611)	$ (6,937,906.67)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 19,630.35		$ 30,147.76		$ (20,660.41)		$ 10,143.00						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 156,801.94		$ 156,801.94		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 174,107.52		$ 174,107.52		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 41,354.54		$ 41,354.54		$ -								
Penalty Charges														
13 Real Time Excessive/Deficient Energy Deployment		$ 146,143.32		$ 116,782.89		$ -		$ 29,360.43						
14 Real Time Contingency Reserve Deployment Failure		$ 911.05		$ 840.42		$ -		$ 70.63						
MISO ASM CHARGES	(14,472)	$ (1,085,422.96)	292,091	$ 7,163,077.80	(306,563)	$ (7,845,339.41)	-	$ 39,574.06	-	$ (442,735.41)	-	$ -	-	$ -
x Net Congestion Amount		$ (710,471.16)		$ (757,745.75)				$ 47,274.59						
y Net Loss Amount		$ (170,500.77)		$ (183,308.19)				$ 12,807.42						
z Net Congestion and Loss Energy Offset		$ 880,971.93		$ 941,053.94				$ (60,082.01)						
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	(14,472)	$ (1,085,422.96)	292,091	$ 7,163,077.80	(306,563)	$ (7,845,339.41)	-	$ 39,574.06	-	$ (442,735.41)	-	$ -	-	$ -

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
Electric Operations - State of Minnesota

Detail of MISO ASM Charges (New Report Format)

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October 2017	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		$ (261,287.68)		$ -		$ (167,914.90)				$ (93,372.78)				
2 Day-Ahead Spinning Reserve Amount		$ (542,721.37)		$ -		$ (396,513.73)				$ (146,207.64)				
3 Day-Ahead Supplemental Reserve		$ (25,670.05)		$ -		$ (22,893.89)				$ (2,776.16)				
4 Real-Time Regulation Amount (See Note 1)		$ 31,956.08		$ 115,527.42		$ (83,571.34)								
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 281,516.03		$ 329,553.32		$ (48,037.29)								
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 1,065.94		$ 1,123.24		$ (57.30)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(1,641)	$ 11,337.77	284	$ (6,534.29)	(1,925)	$ 17,872.06								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	(8,166)	$ (470,024.11)	304,134	$ 6,227,416.60	(312,300)	$ (6,697,440.71)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 8,112.00		$ (37,955.20)		$ (9,728.69)		$ 55,795.89						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 173,396.01		$ 173,396.01		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 156,539.19		$ 156,539.19		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 32,867.51		$ 32,867.51		$ -								
Penalty Charges														
13 Real Time Excessive/Deficient Energy Deployment		$ 33,928.44		$ 56,109.59		$ -				$ (22,181.15)				
14 Real Time Contingency Reserve Deployment Failure		$ 4,728.13		$ 4,444.05		$ -		$ 284.08						
MISO ASM CHARGES	(9,807)	$ (564,256.11)	304,418	$ 7,052,487.44	(314,225)	$ (7,408,285.79)	-	$ 56,079.97	-	$ (264,537.73)	-	$ -	-	$ -
x Net Congestion Amount		$ (328,311.39)		$ (340,818.14)				$ 12,506.75						
y Net Loss Amount		$ (60,663.06)		$ (66,130.56)				$ 5,467.50						
z Net Congestion and Loss Energy Offset		$ 388,974.45		$ 406,948.70				$ (17,974.25)						
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	(9,807)	$ (564,256.11)	304,418	$ 7,052,487.44	(314,225)	$ (7,408,285.79)	-	$ 56,079.97	-	$ (264,537.73)	-	$ -	-	$ -

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

Detail of MISO ASM Charges (New Report Format)

November 2017	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		$ (98,406.66)		$ -		$ (63,639.51)				$ (34,767.15)				
2 Day-Ahead Spinning Reserve Amount		$ (354,966.39)		$ -		$ (238,969.86)				$ (115,996.53)				
3 Day-Ahead Supplemental Reserve		$ (22,301.75)		$ -		$ (21,079.32)				$ (1,222.43)				
4 Real-Time Regulation Amount (See Note 1)		$ (40,500.39)		$ 48,242.90		$ (88,743.29)								
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 161,028.73		$ 212,908.69		$ (51,879.96)								
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 107.36		$ 540.13		$ (432.77)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(2,045)	$ 602.45	279	$ (3,660.38)	(2,324)	$ 4,262.83								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	13,789	$ 700,955.17	271,387	$ 6,002,478.36	(257,598)	$ (5,301,523.19)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 1,700.23		$ 7,727.04		$ (4,939.91)		$ (1,086.90)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 125,645.40		$ 125,645.40		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 133,782.47		$ 133,782.47		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 22,559.74		$ 22,559.74		$ -								
Penalty Charges														
13 Real Time Excessive/Deficient Energy Deployment		$ 50,489.43		$ 26,298.16		$ -				$ 24,191.27				
14 Real Time Contingency Reserve Deployment Failure		$ 515.15		$ 38.42		$ -		$ 476.73						
MISO ASM CHARGES	11,744	$ 681,210.94	271,666	$ 6,576,560.93	(259,922)	$ (5,766,944.98)	-	$ (610.17)	-	$ (127,794.84)	-	$ -	-	$ -
x Net Congestion Amount		$ (68,469.25)		$ (79,285.66)				$ 10,816.41						
y Net Loss Amount		$ (65,988.15)		$ (76,198.00)				$ 10,209.85						
z Net Congestion and Loss Energy Offset		$ 134,457.40		$ 155,483.66				$ (21,026.26)						
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	11,744	$ 681,210.94	271,666	$ 6,576,560.93	(259,922)	$ (5,766,944.98)	-	$ (610.17)	-	$ (127,794.84)	-	$ -	-	$ -

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

Detail of MISO ASM Charges (New Report Format)

December 2017	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		$ (64,791.18)		$ -		$ (60,645.23)				$ (4,145.95)				
2 Day-Ahead Spinning Reserve Amount		$ (256,789.43)		$ -		$ (108,537.73)				$ (148,251.70)				
3 Day-Ahead Supplemental Reserve		$ (25,033.47)		$ -		$ (23,370.90)				$ (1,662.57)				
4 Real-Time Regulation Amount (See Note 1)		$ (27,106.75)		$ 37,328.75		$ (64,435.50)								
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 159,832.88		$ 212,288.22		$ (52,455.34)								
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 2,900.17		$ 3,014.85		$ (114.68)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(1,722)	$ 6,732.07	385	$ (2,639.16)	(2,107)	$ 9,371.23								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	124,459	$ 2,671,824.84	371,206	$ 7,280,750.36	(246,747)	$ (4,608,925.52)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (1,677.87)		$ (337.23)		$ (1,188.88)		$ (151.76)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 111,239.12		$ 111,239.12		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 75,023.88		$ 75,023.88		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 13,804.88		$ 13,804.88		$ -								
Penalty Charges														
13 Real Time Excessive/Deficient Energy Deployment		$ 45,746.06		$ 32,900.55		$ -				$ 12,845.51				
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -		$ -						
MISO ASM CHARGES	122,737	$ 2,711,705.20	371,591	$ 7,763,374.22	(248,854)	$ (4,910,302.55)	-	$ (151.76)	-	$ (141,214.71)	-	$ -	-	$ -
x Net Congestion Amount		$ 3,900.38		$ 1,030.79				$ 2,869.59						
y Net Loss Amount		$ 8,551.69		$ 5,582.49				$ 2,969.20						
z Net Congestion and Loss Energy Offset		$ (12,452.07)		$ (6,613.28)				$ (5,838.79)						
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	122,737	$ 2,711,705.20	371,591	$ 7,763,374.22	(248,854)	$ (4,910,302.55)	-	$ (151.76)	-	$ (141,214.71)	-	$ -	-	$ -

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

Detail of MISO ASM Charges (New Report Format)

January 2018	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		$ (189,944.31)		$ -		$ (73,295.84)				$ (116,648.47)				
2 Day-Ahead Spinning Reserve Amount		$ (357,225.47)		$ -		$ (232,028.26)				$ (125,197.21)				
3 Day-Ahead Supplemental Reserve		$ (113,132.59)		$ -		$ (77,358.02)				$ (35,774.57)				
4 Real-Time Regulation Amount (See Note 1)		$ (62,294.47)		$ 93,342.15		$ (155,636.62)								
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 99,625.51		$ 196,254.99		$ (96,629.48)								
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 8,783.51		$ 9,861.71		$ (1,078.20)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(1,065)	$ (4,831.83)	243	$ (5,594.05)	(1,308)	$ 762.22								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	117,978	$ 5,124,099.34	366,945	$ 12,991,807.63	(248,967)	$ (7,867,708.29)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (2,074.03)		$ 12,820.04		$ (18,115.89)		$ 3,221.82						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 189,977.89		$ 189,977.89		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 214,561.05		$ 214,561.05		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 95,357.15		$ 95,357.15		$ -								
Penalty Charges														
13 Real Time Excessive/Deficient Energy Deployment		$ 145,650.35		$ 108,351.39		$ -		$ 37,298.96						
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ (4.43)		$ 4.43						
MISO ASM CHARGES	116,913	$ 5,148,552.10	367,188	$ 13,906,739.95	(250,275)	$ (8,521,092.81)	-	$ 40,525.21	-	$ (277,620.25)	-	$ -	-	$ -
x Net Congestion Amount		$ 56,110.56		$ 48,020.34				$ 8,090.22						
y Net Loss Amount		$ (16,806.80)		$ (17,472.78)				$ 665.98						
z Net Congestion and Loss Energy Offset		$ (39,303.76)		$ (30,547.56)				$ (8,756.20)						
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	116,913	$ 5,148,552.10	367,188	$ 13,906,739.95	(250,275)	$ (8,521,092.81)	-	$ 40,525.21	-	$ (277,620.25)	-	$ -	-	$ -

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
Electric Operations - State of Minnesota
Detail of MISO ASM Charges (New Report Format)

February 2018	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		$ (88,856.64)		$ -		$ (57,683.00)				$ (31,173.64)				
2 Day-Ahead Spinning Reserve Amount		$ (195,605.49)		$ -		$ (135,218.45)				$ (60,387.04)				
3 Day-Ahead Supplemental Reserve		$ (20,008.14)		$ -		$ (25,184.26)				$ 5,176.12				
4 Real-Time Regulation Amount (See Note 1)		$ (5,000.28)		$ 60,072.10		$ (65,072.38)								
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 46,408.24		$ 93,846.10		$ (47,437.86)								
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 193.73		$ 1,811.51		$ (1,617.78)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(921)	$ 16,213.83	166	$ (4,190.12)	(1,087)	$ 20,403.95								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	42,166	$ 2,005,743.28	283,574	$ 8,191,077.81	(241,408)	$ (6,185,334.53)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 6,653.67		$ 5,306.42		$ (1,764.08)		$ 3,111.33						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 101,086.95		$ 101,086.95		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 74,806.23		$ 74,806.23		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 4,208.80		$ 4,208.80		$ -								
Penalty Charges														
13 Real Time Excessive/Deficient Energy Deployment		$ 35,577.84		$ 24,734.12		$ -		$ 10,843.72						
14 Real Time Contingency Reserve Deployment Failure		$ 3,401.37		$ 3,031.14		$ -		$ 370.23						
MISO ASM CHARGES	41,245	$ 1,984,823.39	283,740	$ 8,555,791.06	(242,495)	$ (6,498,908.39)	-	$ 14,325.28	-	$ (86,384.56)	-	$ -	-	$ -
x Net Congestion Amount		$ (11,521.61)		$ (16,123.53)				$ 4,601.92						
y Net Loss Amount		$ (6,307.71)		$ (7,110.28)				$ 802.57						
z Net Congestion and Loss Energy Offset		$ 17,829.32		$ 23,233.81				$ (5,404.49)						
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	41,245	$ 1,984,823.39	283,740	$ 8,555,791.06	(242,495)	$ (6,498,908.39)	-	$ 14,325.28	-	$ (86,384.56)	-	$ -	-	$ -

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
Electric Operations - State of Minnesota

Detail of MISO ASM Charges (New Report Format)

March 2018	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		$ (76,865.89)		$ -		$ (71,313.56)				$ (5,552.33)				
2 Day-Ahead Spinning Reserve Amount		$ (283,039.62)		$ -		$ (137,362.13)				$ (145,677.49)				
3 Day-Ahead Supplemental Reserve		$ (25,849.80)		$ -		$ (20,507.75)				$ (5,342.05)				
4 Real-Time Regulation Amount (See Note 1)		$ (11,399.34)		$ 25,886.99		$ (37,286.33)								
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 39,395.43		$ 94,208.12		$ (54,812.69)								
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (14.17)		$ 372.59		$ (386.76)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(2,592)	$ 3,596.15	200	$ (3,988.04)	(2,792)	$ 7,584.19								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	70,468	$ 1,535,983.79	301,577	$ 6,392,015.69	(231,109)	$ (4,856,031.90)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (3,472.66)		$ 1,220.74		$ (3,748.97)		$ (944.43)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 105,213.08		$ 105,213.08		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 127,183.92		$ 127,183.92		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 20,799.71		$ 20,799.71		$ -								
Penalty Charges														
13 Real Time Excessive/Deficient Energy Deployment		$ 36,796.65		$ 28,062.73		$ -		$ 8,733.92						
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -		$ -						
MISO ASM CHARGES	67,876	$ 1,468,327.25	301,777	$ 6,790,975.53	(233,901)	$ (5,173,865.90)	-	$ 7,789.49	-	$ (156,571.87)	-	$ -	-	$ -
x Net Congestion Amount		$ (129,832.31)		$ (144,143.28)				$ 14,310.97						
y Net Loss Amount		$ (52,819.80)		$ (62,698.56)				$ 9,878.76						
z Net Congestion and Loss Energy Offset		$ 182,652.11		$ 206,841.84				$ (24,189.73)						
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	67,876	$ 1,468,327.25	301,777	$ 6,790,975.53	(233,901)	$ (5,173,865.90)	-	$ 7,789.49	-	$ (156,571.87)	-	$ -	-	$ -

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

Detail of MISO ASM Charges (New Report Format)

April 2018	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		$ (239,778.55)		$ -		$ (99,132.14)				$ (140,646.41)				
2 Day-Ahead Spinning Reserve Amount		$ (270,620.13)		$ -		$ (174,307.06)				$ (96,313.07)				
3 Day-Ahead Supplemental Reserve		$ (22,120.19)		$ -		$ (18,177.93)				$ (3,942.26)				
4 Real-Time Regulation Amount (See Note 1)		$ (26,141.16)		$ 120,834.14		$ (146,975.30)								
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 115,174.21		$ 209,026.47		$ (93,852.26)								
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 1,789.19		$ 5,616.11		$ (3,826.92)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(3,581)	$ 8,266.20	1,212	$ (3,141.75)	(4,793)	$ 11,407.95								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	104,472	$ 2,295,212.14	361,677	$ 8,261,417.25	(257,205)	$ (5,966,205.11)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (20,835.10)		$ 17,422.00		$ (30,562.46)		$ (7,694.64)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 143,014.53		$ 143,014.53		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 160,286.03		$ 160,286.03		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 18,913.72		$ 18,913.72		$ -								
Penalty Charges														
13 Real Time Excessive/Deficient Energy Deployment		$ 96,564.49		$ 87,831.30		$ -		$ 8,733.19						
14 Real Time Contingency Reserve Deployment Failure		$ 680.46		$ 134.08		$ -		$ 546.38						
MISO ASM CHARGES	100,891	$ 2,260,405.84	362,889	$ 9,021,353.88	(261,998)	$ (6,521,631.23)	-	$ 1,584.93	-	$ (240,901.74)	-	$ -	-	$ -
x Net Congestion Amount		$ (223,920.06)		$ (242,425.77)				$ 18,505.71						
y Net Loss Amount		$ (83,617.97)		$ (91,170.06)				$ 7,552.09						
z Net Congestion and Loss Energy Offset		$ 307,538.03		$ 333,595.83				$ (26,057.80)						
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	100,891	$ 2,260,405.84	362,889	$ 9,021,353.88	(261,998)	$ (6,521,631.23)	-	$ 1,584.93	-	$ (240,901.74)	-	$ -	-	$ -

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

Detail of MISO ASM Charges (New Report Format)

May 2018	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		$ (358,881.36)		$ -		$ (153,234.13)				$ (205,647.23)				
2 Day-Ahead Spinning Reserve Amount		$ (309,346.81)		$ -		$ (274,588.54)				$ (34,758.27)				
3 Day-Ahead Supplemental Reserve		$ (56,755.84)		$ -		$ (47,025.46)				$ (9,730.38)				
4 Real-Time Regulation Amount (See Note 1)		$ 5,683.02		$ 166,983.86		$ (161,300.84)								
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 166,899.18		$ 202,851.59		$ (35,952.41)								
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 6,114.21		$ 6,795.53		$ (681.32)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(681)	$ (6,207.79)	2,937	$ (15,200.25)	(3,618)	$ 8,992.46								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	60,565	$ 3,442,367.27	331,305	$ 9,966,544.19	(270,740)	$ (6,524,176.92)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 29,122.94		$ 35,798.71		$ (15,119.84)		$ 8,444.07						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 134,344.74		$ 134,344.74		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 130,619.57		$ 130,619.57		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 36,404.50		$ 36,404.50		$ -								
Penalty Charges														
13 Real Time Excessive/Deficient Energy Deployment		$ 129,877.91		$ 84,924.07		$ -		$ 44,953.84						
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ (124.56)		$ 124.56						
MISO ASM CHARGES	59,884	$ 3,350,241.54	334,242	$ 10,750,066.51	(274,358)	$ (7,203,211.56)	-	$ 53,522.47	-	$ (250,135.88)	-	$ -	-	$ -
x Net Congestion Amount		$ (282,078.94)		$ (295,009.16)				$ 12,930.22						
y Net Loss Amount		$ (240,273.12)		$ (257,612.34)				$ 17,339.22						
z Net Congestion and Loss Energy Offset		$ 522,352.06		$ 552,621.49				$ (30,269.43)						
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	59,884	$ 3,350,241.54	334,242	$ 10,750,066.51	(274,358)	$ (7,203,211.56)	-	$ 53,522.47	-	$ (250,135.88)	-	$ -	-	$ -

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

Detail of MISO ASM Charges (New Report Format)

June 2018	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		$ (282,595.30)		$ -		$ (149,888.74)				$ (132,706.56)				
2 Day-Ahead Spinning Reserve Amount		$ (352,155.18)		$ -		$ (215,343.45)				$ (136,811.73)				
3 Day-Ahead Supplemental Reserve		$ (48,354.82)		$ -		$ (44,325.90)				$ (4,028.92)				
4 Real-Time Regulation Amount (See Note 1)		$ 7,835.65		$ 138,657.64		$ (130,821.99)								
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 141,225.71		$ 220,673.75		$ (79,448.04)								
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 5,947.05		$ 6,423.22		$ (476.17)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(1,994)	$ 11,463.04	1,106	$ (6,226.77)	(3,100.00)	$ 17,689.81								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	142,809	$ 3,498,001.98	417,635	$ 10,253,492.65	(274,826.00)	$ (6,755,490.67)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 13,567.29		$ 14,982.94		$ (9,862.96)		$ 8,447.31						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 127,986.22		$ 127,986.22		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 152,666.21		$ 152,666.21		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 71,849.67		$ 71,849.67		$ -								
Penalty Charges														
13 Real Time Excessive/Deficient Energy Deployment		$ 93,332.99		$ 71,736.81		$ -		$ 21,596.18						
14 Real Time Contingency Reserve Deployment Failure		$ 5,353.13		$ 5,133.36		$ -		$ 219.77						
MISO ASM CHARGES	140,815	$ 3,446,123.64	418,741	$ 11,057,375.70	(277,926)	$ (7,367,968.11)	-	$ 30,263.26	-	$ (273,547.21)	-	$ -	-	$ -
x Net Congestion Amount		$ (14,442.89)		$ (14,569.22)				$ 126.33						
y Net Loss Amount		$ (124,216.13)		$ (134,312.53)				$ 10,096.40						
z Net Congestion and Loss Energy Offset		$ 138,659.02		$ 148,881.75				$ (10,222.73)						
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	140,815	$ 3,446,123.64	418,741	$ 11,057,375.70	(277,926)	$ (7,367,968.11)	-	$ 30,263.26	-	$ (273,547.21)	-	$ -	-	$ -

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 ASM

A. Overall Market Performance to Date

During the 2017-2018 AAA Period, MISO continued to operate the electric system reliably and has exceeded compliance thresholds for all North American Electric Reliability Corporation (NERC) reliability standards to which they are subject.

The 2017 summer (June, July and August) temperatures averaged near-normal. The average 2017 summer load was 82.8 GW, which was 4% lower than the 2016 summer driven mainly by the mild August weather. Warmer temperatures and higher loads produced an increase in energy prices. Energy prices decreased slightly from 2016 summer, and averaged below $29.00/MWh. The 3-month average Day-Ahead LMP for summer 2017 was $28.87/MWh and the 3-month average Real-Time LMP was $28.68/MWh. Mild weather and relatively low demands contributed to the stable energy prices.

Fuel prices in summer 2017 were comparable to summers of 2015 and 2016. Natural gas prices remained below $3.00/MMBtu as they have since before the summer of 2015. Chicago Citygate and Henry Hub gas prices average $2.81/MMBtu and $2.92/MMBtu, respectively, a slight increase from summer 2016. The depressed and stable natural gas prices over the past three years are largely attributable to the increase in shale gas production. Illinois Basin coal decreased 5%, while Powder River Basin coal prices increased 30%, when compared with summer 2016.

Registered wind capacity and average summer wind generation have consistently grown in the MISO market for the summers of 2015, 2016, and 2017. The registered wind capacity for summer 2017 was 16.8 GW and Dispatchable Intermittent Resource (DIR) capacity was 14.3 GW; up from 15.9 GW and 13.4 GW, respectively for summer 2016. Following the seasonal trend, wind outputs were relatively low during summer months. Wind output averaged 3,700 MW summer of 2017, 5% higher than summer of 2016, and accounting for 5.2% of MISO's total energy.[1]

The 2018 winter (December 2017, January and February 2018) was characterized by colder temperatures across the MISO footprint, relative to the winters of 2016 and 2017. The cold weather resulted in challenging operating conditions and high load, particularly impacting the South region, which experienced a new winter peak of 32.1 GW on January 17th in HE 9. The average load for winter 2018 was 78.9 GW,

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[1]https://cdn.misoenergy.org/2017%20Summer%20Assessment%20Report103564.pdf

which was 5% higher than the average load for winter 2017. The seasonal peak load of 106.1 GW was set on January 17, 2018, and was 6% higher than winter 2017 peak. Arctic air swept through the footprint from the end of December 2017 through the first part of January 2018. As a result, the average temperature in January 2018 was 8 degrees Fahrenheit below the average in January 2017. A Cold Weather Alert was in effect from January 1 to January 6 across the footprint. The weather conditions were more challenging than the Polar Vortex of 2014 due to the duration of sustained cold weather across the footprint. However, as a result of process improvements made by MISO and its members, not only was reliability maintained but market outcomes were not as elevated as they were during the Polar Vortex. The combination of extreme cold weather and generation outages drove the Max Gen Events in the South region on January 17 and 18. Through coordination with members and neighbors, MISO reliably managed through this challenging weather event. Energy prices increased by 9% compared to winter 2017, despite lower gas prices, mainly impacted by the higher load. The average Day-Ahead and Real-Time system-wide LMPs for the 2018 winter season were $31.19/MWh and $30.23/MWh respectively, an increase of 10.7% and 7.3% respectively compared to winter 2017.

Concerning fossil fuel prices during the 2018 winter when compared to the 2017 winter, Chicago Citygate and Henry hub gas prices averaged approximately $3.11/MMBtu in winter 2018; a decrease of 3.9% compared to winter 2017. In winter 2018, Illinois Basin coal prices averaged $1.38/MMBtu, a decrease of 2.9% compared to winter 2017. Power River Basin coal prices averaged $0.69/MMBtu for winter 2018, an increase of 9.1% over the average price for winter 2017.

The share of wind as a percentage of total MISO generation was 9.9% for winter 2018, decreasing from 10.2% for winter 2017. The total wind production increased 4.8% for winter 2018 relative to winter 2017, while the capacity factor decreased from 42.6% to 42.0%. A new all-time peak wind output record of 15.0 GW was set on January 17, 2018.[2]

The MISO Independent Market Monitor, which is tasked with monitoring both the behavior of Market Participants and the operation of the market, noted in its 2017 State of the Market Report that "(s)ince their inception in 2009, jointly-optimized ancillary services markets have produced significant benefits, leading to improved flexibility and lower costs of satisfying the system's reliability needs. These markets have also facilitated more efficient energy pricing that reflects the economic trade-off between reserves and energy, particularly during shortage conditions," and that

[2] https://cdn.misoenergy.org/2017-2018%20Winter%20Assessment%20Report193529.pdf

"Monthly average clearing prices for spinning and supplemental reserves rose substantially in 2017, largely attributable to the increase in natural gas prices in the first half of the year relative to 2016 and the expansion of ELMP in May, but prices remain reasonable. The most significant increase was the average price for spinning reserves that increased 43 percent over 2016. "[3]

B. Estimated Market Benefits

1. *Benefits Calculation*

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 2017-2018 AAA reporting period, and are provided in the table below.

ASM Benefit Analysis - NSP System						
	ASM Market Run Cost (Case A)	**Self Schedule Run Cost (Case B)**	**ASM Market Savings**	**Other Market Charge Types**	**ASM Admin Fees**	**Net Savings**
Jul '17	(33,686,257)	(34,010,883)	324,626	123,795	25,433	175,398
Aug '17	(27,501,516)	(27,674,007)	172,491	81,459	23,348	67,685
Sep '17	(23,256,844)	(23,570,732)	313,888	144,169	21,712	148,007
Oct '17	(22,856,441)	(23,181,506)	325,064	52,546	30,034	242,484
Nov '17	(23,435,535)	(23,667,377)	231,842	48,445	23,312	160,086
Dec '17	(29,845,414)	(30,184,511)	339,097	52,857	30,525	255,715
Jan '18	(31,645,021)	(31,881,430)	236,409	141,031	25,534	69,843
Feb '18	(28,692,026)	(28,993,101)	301,075	31,313	19,702	250,061
Mar '18	(26,520,570)	(26,784,102)	263,532	26,244	30,549	206,739
Apr '18	(26,085,799)	(26,360,469)	274,670	101,319	30,666	142,685
May '18	(32,259,405)	(32,449,647)	190,242	136,203	23,908	30,131
Jun '18	(31,042,102)	(31,218,757)	176,655	94,069	29,877	52,710
Total	(336,826,930)	(339,976,522)	3,149,591	1,033,450	314,600	1,801,544

[3]https://www.potomaceconomics.com/wp-content/uploads/2018/07/2017-MISO-SOM_Report_6-26_Final.pdf

The Company estimates the ASM resulted in total NSP System savings of approximately $1.8 million for the 2017-18 AAA reporting period. The Minnesota jurisdictional allocation of the savings is approximately 75 percent, or $1.351 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.

2. 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 J, Section 6, Schedule 2 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 2017-2018 AAA reporting period, the net benefit for the Company was approximately $1.8 million while the amount incurred in EDEDCs was $1.0 million.[4] The $3.1 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 on a daily basis 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.

3. 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.

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[4] The $1.8 million in ASM benefits calculated by the Company for the 2017-2018 AAA period does not include all of 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.

Part J, Section 6, Schedule 3 shows NSP incurred a total of $10,176 in CRDFC during the 2017-2018 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 of whether MISO has 15 minutes to meet the standard or less than 10 minutes.

The charges were not the result of any oversight or error 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.

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.

4. 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.

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Cont Reserve Depl Failure Charge	Excessive/Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
7/1/2017	(793,932)	(802,838)	8,906	1.11%	0	2,864	436	6,021	55	608	4,998
7/2/2017	(770,302)	(776,850)	6,547	0.84%	0	6,610	601	5,981	77	606	-1,269
7/3/2017	(880,745)	(891,571)	10,826	1.21%	0	4,206	49	6,708	472	718	5,853
7/4/2017	(781,644)	(797,306)	15,662	1.96%	0	300	2	6,108	376	648	14,711
7/5/2017	(1,219,456)	(1,226,714)	7,258	0.59%	0	1,603	-486	7,771	1,157	893	5,248
7/6/2017	(1,130,414)	(1,141,588)	11,174	0.98%	0	6,181	-491	8,352	380	873	4,610
7/7/2017	(996,253)	(1,006,611)	10,358	1.03%	0	3,216	36	7,938	173	811	6,295
7/8/2017	(986,234)	(998,764)	12,530	1.25%	0	6,773	-858	7,614	149	776	5,838
7/9/2017	(926,550)	(932,821)	6,271	0.67%	0	4,644	141	7,102	657	776	710
7/10/2017	(1,101,010)	(1,110,513)	9,503	0.86%	0	1,740	-1,109	8,108	519	863	8,009
7/11/2017	(1,197,043)	(1,206,565)	9,522	0.79%	0	4,128	1,012	8,451	551	900	3,481
7/12/2017	(1,293,714)	(1,297,190)	3,476	0.27%	0	3,407	-331	8,553	512	907	-507
7/13/2017	(1,120,401)	(1,130,868)	10,467	0.93%	0	6,164	-404	7,763	703	847	3,860
7/14/2017	(975,275)	(982,688)	7,412	0.75%	0	10,903	-344	7,219	436	766	-3,913
7/15/2017	(899,142)	(913,963)	14,820	1.62%	0	1,572	-27	6,965	364	733	12,543
7/16/2017	(803,746)	(811,769)	8,023	0.99%	0	1,177	54	5,908	372	628	6,164
7/17/2017	(987,807)	(996,067)	8,261	0.83%	0	2,372	-2,802	7,440	399	784	7,907
7/18/2017	(1,171,104)	(1,182,504)	11,400	0.96%	0	2,475	2,981	8,167	1,441	961	4,984
7/19/2017	(1,378,271)	(1,385,702)	7,431	0.54%	0	3,217	991	8,515	652	917	2,306
7/20/2017	(1,792,560)	(1,843,183)	50,623	2.75%	2,423	9,753	1,409	9,516	520	1,004	36,035
7/21/2017	(1,334,924)	(1,339,858)	4,934	0.37%	851	2,858	-1,627	8,677	578	925	1,927
7/22/2017	(1,107,537)	(1,118,435)	10,898	0.97%	0	3,714	166	8,137	1,136	927	6,091
7/23/2017	(1,089,718)	(1,102,311)	12,593	1.14%	0	6,218	-645	8,081	1,027	911	6,109
7/24/2017	(1,177,323)	(1,185,873)	8,550	0.72%	0	6,027	649	8,139	505	864	1,010
7/25/2017	(1,080,945)	(1,085,529)	4,584	0.42%	0	5,624	2,724	7,868	585	845	-4,609
7/26/2017	(1,174,236)	(1,181,820)	7,584	0.64%	0	2,097	-2,486	7,913	1,521	943	7,029
7/27/2017	(1,250,900)	(1,250,711)	-189	-0.02%	0	2,498	-533	7,501	392	789	-2,944
7/28/2017	(1,058,101)	(1,064,129)	6,028	0.57%	0	842	-282	7,313	616	793	4,675
7/29/2017	(879,237)	(904,734)	25,497	2.82%	0	3,455	-1,669	7,356	101	746	22,965
7/30/2017	(903,177)	(916,207)	13,030	1.42%	0	2,157	-1,804	7,410	143	755	11,923
7/31/2017	(1,424,555)	(1,425,202)	647	0.05%	0	5,095	1,278	8,890	276	917	-6,642
8/1/2017	(1,400,046)	(1,407,261)	7,215	0.51%	0	2,498	690	9,606	694	1,030	2,996
8/2/2017	(1,179,145)	(1,180,823)	1,678	0.14%	0	1,477	561	8,984	367	935	-1,295
8/3/2017	(742,152)	(754,520)	12,368	1.64%	0	2,974	89	5,988	882	687	8,618
8/4/2017	(795,039)	(790,148)	-4,892	-0.62%	0	153	5	6,309	53	636	-5,686
8/5/2017	(799,728)	(803,523)	3,795	0.47%	0	611	-4	6,055	64	612	2,576
8/6/2017	(786,539)	(788,970)	2,430	0.31%	0	773	-16	5,953	110	606	1,067
8/7/2017	(871,861)	(873,966)	2,106	0.24%	0	2,874	308	7,576	254	783	-1,859
8/8/2017	(936,953)	(934,809)	-2,145	-0.23%	0	1,326	312	8,088	288	838	-4,620
8/9/2017	(905,862)	(909,839)	3,977	0.44%	0	3,967	-410	7,544	1,032	858	-438
8/10/2017	(836,918)	(850,833)	13,915	1.64%	0	4,846	725	7,197	330	753	7,591
8/11/2017	(908,927)	(913,034)	4,106	0.45%	0	3,149	-132	7,564	532	810	279
8/12/2017	(805,968)	(807,140)	1,172	0.15%	0	1,050	2	6,234	356	659	-539
8/13/2017	(792,945)	(795,003)	2,058	0.26%	0	774	77	5,997	1,113	711	497
8/14/2017	(985,694)	(990,214)	4,520	0.46%	0	1,558	-27	7,619	188	781	2,208
8/15/2017	(929,990)	(939,486)	9,496	1.01%	0	4,280	412	7,744	1,191	893	3,911
8/16/2017	(907,548)	(918,118)	10,570	1.15%	0	5,757	-620	7,606	1,543	915	4,518
8/17/2017	(877,559)	(893,852)	16,293	1.82%	0	6,521	231	7,094	521	762	8,779
8/18/2017	(924,601)	(932,508)	7,907	0.85%	0	995	-478	7,863	306	817	6,573
8/19/2017	(873,804)	(880,782)	6,978	0.79%	0	9,164	-333	7,366	550	792	-2,645
8/20/2017	(904,220)	(914,466)	10,245	1.12%	0	3,585	1,829	7,717	228	794	4,037
8/21/2017	(1,138,217)	(1,152,479)	14,262	1.24%	0	3,671	-380	8,782	852	963	10,008
8/22/2017	(900,062)	(912,763)	12,700	1.39%	0	5,464	-282	7,504	627	813	6,705
8/23/2017	(836,692)	(842,144)	5,452	0.65%	0	5,709	334	7,173	377	755	-1,347
8/24/2017	(813,479)	(816,780)	3,302	0.40%	0	248	-40	5,872	114	599	2,496
8/25/2017	(750,307)	(751,040)	733	0.10%	0	562	-191	5,437	212	565	-204
8/26/2017	(737,676)	(745,015)	7,339	0.99%	0	968	16	5,497	280	578	5,777
8/27/2017	(747,181)	(751,618)	4,437	0.59%	0	84	-1	5,427	112	554	3,800
8/28/2017	(787,309)	(792,510)	5,202	0.66%	0	8	0	6,419	170	659	4,535
8/29/2017	(868,259)	(871,278)	3,020	0.35%	0	1,060	202	7,138	576	771	986
8/30/2017	(926,123)	(921,955)	-4,168	-0.45%	0	1,758	162	7,392	275	767	-6,855
8/31/2017	(830,711)	(837,131)	6,421	0.77%	0	553	-2	6,203	335	654	5,215
9/1/2017	(700,532)	(701,347)	815	0.12%	0	23	-10	5,945	469	641	161

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
9/2/2017	(687,236)	(688,468)	1,232	0.18%	0	37	-20	5,812	19	583	631
9/3/2017	(679,787)	(680,314)	527	0.08%	0	283	-34	5,773	291	606	-329
9/4/2017	(664,901)	(666,935)	2,034	0.30%	0	1,219	519	5,619	381	600	-303
9/5/2017	(685,489)	(692,947)	7,458	1.08%	0	494	-21	5,439	184	562	6,424
9/6/2017	(793,387)	(793,059)	-328	-0.04%	0	433	-7	5,950	138	609	-1,363
9/7/2017	(716,459)	(721,785)	5,326	0.74%	0	1,502	-21	5,741	55	580	3,265
9/8/2017	(685,590)	(686,128)	538	0.08%	0	708	-105	5,531	244	577	-643
9/9/2017	(670,047)	(673,512)	3,465	0.51%	0	711	-279	5,418	224	564	2,469
9/10/2017	(661,129)	(663,325)	2,196	0.33%	0	898	95	5,381	317	570	634
9/11/2017	(822,559)	(819,191)	-3,368	-0.41%	0	594	527	7,753	472	822	-5,312
9/12/2017	(948,347)	(957,855)	9,508	0.99%	0	5,746	3,081	8,084	490	857	-177
9/13/2017	(937,448)	(936,304)	-1,144	-0.12%	0	6,594	2,720	8,057	619	868	-11,327
9/14/2017	(915,724)	(922,472)	6,748	0.73%	0	6,444	0	7,871	514	839	-534
9/15/2017	(719,851)	(725,486)	5,636	0.78%	0	4,010	-196	6,572	705	728	1,094
9/16/2017	(793,646)	(791,199)	-2,446	-0.31%	911	9,474	525	7,376	749	812	-14,169
9/17/2017	(707,264)	(715,143)	7,879	1.10%	0	14,100	-1,156	7,013	292	731	-5,796
9/18/2017	(798,105)	(823,099)	24,994	3.04%	0	4,022	-450	7,463	1,392	886	20,537
9/19/2017	(668,059)	(688,312)	20,253	2.94%	0	5,379	-522	6,575	1,002	758	14,639
9/20/2017	(1,012,354)	(1,052,693)	40,339	3.83%	0	24,853	16,729	7,903	1,093	900	-2,143
9/21/2017	(838,686)	(870,539)	31,853	3.66%	0	10,348	18	6,974	624	760	20,727
9/22/2017	(739,364)	(706,613)	-32,751	-4.63%	0	4,526	-897	7,108	812	792	-37,171
9/23/2017	(738,617)	(772,700)	34,082	4.41%	0	5,286	-4,727	7,148	992	814	32,709
9/24/2017	(711,561)	(722,134)	10,572	1.46%	0	1,088	722	7,108	403	751	8,011
9/25/2017	(1,039,742)	(1,093,688)	53,946	4.93%	0	5,646	1,768	7,936	1,325	926	45,606
9/26/2017	(979,190)	(1,034,349)	55,159	5.33%	0	2,559	-209	7,806	715	852	51,957
9/27/2017	(912,824)	(924,657)	11,833	1.28%	0	2,308	-932	7,275	735	801	9,656
9/28/2017	(696,265)	(705,067)	8,803	1.25%	2,910	1,021	-15	6,606	520	713	4,174
9/29/2017	(750,336)	(754,267)	3,931	0.52%	0	2,600	-215	6,982	70	705	841
9/30/2017	(582,345)	(587,144)	4,799	0.82%	0	549	5	5,087	-32	505	3,739
10/1/2017	(583,313)	(585,918)	2,605	0.44%	0	442	5	7,476	-88	739	1,419
10/2/2017	(573,093)	(591,400)	18,307	3.10%	0	850	-80	8,766	665	943	16,594
10/3/2017	(771,662)	(802,094)	30,433	3.79%	0	972	2,454	10,718	687	1,141	25,867
10/4/2017	(806,189)	(828,370)	22,181	2.68%	0	2,191	-1,005	11,156	348	1,150	19,845
10/5/2017	(785,736)	(810,832)	25,096	3.10%	0	2,218	3,384	11,319	703	1,202	18,293
10/6/2017	(769,822)	(791,065)	21,242	2.69%	0	1,952	1,543	10,738	1,323	1,206	16,541
10/7/2017	(674,838)	(695,955)	21,117	3.03%	0	390	184	8,564	1,668	1,023	19,519
10/8/2017	(799,356)	(815,907)	16,551	2.03%	0	2,556	325	9,861	586	1,045	12,626
10/9/2017	(855,890)	(892,113)	36,223	4.06%	0	5,204	1,629	10,285	711	1,100	28,290
10/10/2017	(870,502)	(885,727)	15,225	1.72%	0	1,257	-289	10,536	744	1,128	13,129
10/11/2017	(902,731)	(916,320)	13,589	1.48%	0	1,659	-167	10,738	570	1,131	10,966
10/12/2017	(775,102)	(777,535)	2,433	0.31%	0	1,790	36	9,371	1,146	1,052	-444
10/13/2017	(1,051,773)	(1,072,484)	20,711	1.93%	0	408	1,333	11,110	2,350	1,346	17,624
10/14/2017	(701,437)	(708,812)	7,374	1.04%	0	1,531	-70	7,662	352	801	5,112
10/15/2017	(616,935)	(620,996)	4,062	0.65%	0	255	-34	7,087	203	729	3,111
10/16/2017	(765,965)	(766,275)	311	0.04%	0	1,147	-20	8,203	1,051	925	-1,742
10/17/2017	(723,922)	(725,578)	1,656	0.23%	0	381	1	6,973	276	725	548
10/18/2017	(635,223)	(639,088)	3,864	0.60%	0	533	8	6,359	495	685	2,637
10/19/2017	(676,096)	(680,767)	4,671	0.69%	0	2,158	-68	7,912	829	874	1,706
10/20/2017	(604,575)	(612,837)	8,262	1.35%	0	2,108	55	7,237	605	784	5,314
10/21/2017	(601,807)	(611,708)	9,901	1.62%	0	321	-21	7,020	427	745	8,856
10/22/2017	(635,730)	(635,923)	193	0.03%	0	1,431	-4	7,235	490	773	-2,007
10/23/2017	(584,911)	(584,256)	-655	-0.11%	0	2,550	113	6,782	838	762	-4,080
10/24/2017	(547,016)	(548,392)	1,376	0.25%	0	1,911	-32	6,606	957	756	-1,259
10/25/2017	(723,978)	(728,162)	4,184	0.57%	0	1,001	-3	8,786	873	966	2,221
10/26/2017	(606,223)	(611,030)	4,806	0.79%	0	876	-42	7,258	441	770	3,202
10/27/2017	(560,342)	(566,189)	5,847	1.03%	0	1,011	1	6,673	1,092	776	4,058
10/28/2017	(839,597)	(838,837)	-761	-0.09%	0	665	-12	10,328	973	1,130	-2,543
10/29/2017	(885,821)	(896,199)	10,378	1.16%	0	1,028	19	10,826	748	1,157	8,174
10/30/2017	(792,043)	(802,265)	10,221	1.27%	0	1,317	25	9,962	1,369	1,133	7,746
10/31/2017	(1,134,813)	(1,138,475)	3,662	0.32%	0	1,326	-160	12,411	947	1,336	1,160
11/1/2017	(869,910)	(887,950)	18,041	2.03%	0	880	57	8,107	939	905	16,200
11/2/2017	(875,117)	(893,763)	18,647	2.09%	0	630	-371	8,442	616	906	17,482
11/3/2017	(791,718)	(816,021)	24,303	2.98%	0	397	-8	7,923	519	844	23,071

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
11/4/2017	(720,173)	(752,151)	31,978	4.25%	0	811	-15	7,311	670	798	30,384
11/5/2017	(671,421)	(692,963)	21,543	3.11%	0	1,046	-3	6,743	427	717	19,782
11/6/2017	(937,061)	(963,665)	26,605	2.76%	0	3,760	195	8,636	398	903	21,746
11/7/2017	(1,011,770)	(1,023,700)	11,930	1.17%	0	1,165	2,109	8,383	564	895	7,761
11/8/2017	(808,522)	(807,877)	-645	-0.08%	0	618	-156	7,620	556	818	-1,924
11/9/2017	(797,051)	(812,610)	15,559	1.91%	0	965	-23	7,701	616	832	13,785
11/10/2017	(842,610)	(858,145)	15,534	1.81%	0	1,071	-133	7,691	361	805	13,791
11/11/2017	(760,717)	(770,866)	10,149	1.32%	0	8,559	761	7,539	495	803	25
11/12/2017	(875,211)	(877,181)	1,969	0.22%	0	5,978	450	8,246	277	852	-5,311
11/13/2017	(833,464)	(837,644)	4,180	0.50%	0	2,527	-163	7,892	471	836	980
11/14/2017	(771,621)	(771,507)	-114	-0.01%	0	586	5	7,134	213	735	-1,440
11/15/2017	(509,453)	(507,605)	-1,848	-0.36%	0	335	14	5,883	411	629	-2,827
11/16/2017	(590,174)	(593,876)	3,702	0.62%	0	1,433	66	6,644	292	694	1,509
11/17/2017	(638,048)	(642,381)	4,333	0.67%	0	812	64	6,747	522	727	2,729
11/18/2017	(654,570)	(654,155)	-415	-0.06%	0	1,225	-4	5,682	815	650	-2,285
11/19/2017	(713,484)	(715,361)	1,877	0.26%	0	1,644	-8	6,298	465	676	-436
11/20/2017	(705,965)	(710,508)	4,544	0.64%	0	1,237	89	6,323	691	701	2,516
11/21/2017	(719,735)	(720,298)	564	0.08%	0	1,895	131	6,661	630	729	-2,192
11/22/2017	(926,495)	(926,774)	279	0.03%	0	1,282	-31	8,755	567	932	-1,904
11/23/2017	(865,242)	(867,216)	1,974	0.23%	0	1,286	104	7,570	608	818	-233
11/24/2017	(737,637)	(738,639)	1,003	0.14%	0	126	37	6,229	158	639	201
11/25/2017	(816,483)	(817,171)	688	0.08%	0	511	-18	7,259	171	743	-548
11/26/2017	(810,714)	(811,816)	1,101	0.14%	0	544	-47	7,210	264	747	-144
11/27/2017	(752,640)	(753,328)	688	0.09%	0	1,046	85	6,725	546	727	-1,170
11/28/2017	(786,949)	(798,446)	11,497	1.44%	0	406	30	6,974	399	737	10,324
11/29/2017	(805,849)	(807,949)	2,100	0.26%	0	1,790	-21	6,910	296	721	-390
11/30/2017	(835,734)	(835,813)	79	0.01%	0	1,037	-353	7,715	207	792	-1,397
12/1/2017	(887,543)	(906,943)	19,400	2.14%	0	3,528	51	8,275	697	897	14,924
12/2/2017	(901,151)	(917,361)	16,210	1.77%	0	866	-53	8,401	484	889	14,508
12/3/2017	(746,972)	(760,577)	13,605	1.79%	0	2,069	198	6,703	551	725	10,612
12/4/2017	(778,701)	(790,556)	11,856	1.50%	0	2,114	-63	7,259	391	765	9,040
12/5/2017	(804,796)	(818,380)	13,583	1.66%	0	1,773	9	7,519	294	781	11,020
12/6/2017	(813,925)	(820,969)	7,044	0.86%	0	3,341	-15	7,602	307	791	2,927
12/7/2017	(946,973)	(972,020)	25,047	2.58%	0	861	78	9,582	1,259	1,084	23,024
12/8/2017	(975,771)	(989,283)	13,513	1.37%	0	116	-2	8,646	385	903	12,496
12/9/2017	(885,250)	(908,289)	23,039	2.54%	0	283	-1	8,763	929	969	21,787
12/10/2017	(821,958)	(853,336)	31,378	3.68%	0	429	-3	8,044	648	869	30,084
12/11/2017	(863,189)	(867,188)	4,000	0.46%	0	562	71	8,089	545	863	2,504
12/12/2017	(979,974)	(981,793)	1,819	0.19%	0	256	6	9,573	1,224	1,080	478
12/13/2017	(881,540)	(888,171)	6,631	0.75%	0	833	-633	7,966	347	831	5,599
12/14/2017	(1,081,335)	(1,079,565)	-1,770	-0.16%	0	472	-20	9,953	287	1,024	-3,246
12/15/2017	(988,586)	(990,538)	1,953	0.20%	0	2,240	-72	9,912	868	1,078	-1,293
12/16/2017	(919,323)	(922,364)	3,041	0.33%	0	1,009	157	9,396	538	993	881
12/17/2017	(891,812)	(896,321)	4,509	0.50%	0	1,324	-11	9,156	400	956	2,240
12/18/2017	(804,520)	(808,532)	4,012	0.50%	0	963	17	7,659	403	806	2,226
12/19/2017	(899,981)	(903,831)	3,850	0.43%	0	299	10	9,073	1,005	1,008	2,533
12/20/2017	(991,438)	(1,000,480)	9,042	0.90%	0	2,695	-18	9,842	548	1,039	5,326
12/21/2017	(1,079,401)	(1,095,169)	15,768	1.44%	0	1,839	-28	10,393	989	1,138	12,818
12/22/2017	(1,060,178)	(1,060,487)	309	0.03%	0	1,353	-39	10,697	890	1,159	-2,164
12/23/2017	(936,875)	(938,976)	2,102	0.22%	0	5,180	-9	9,957	1,065	1,102	-4,172
12/24/2017	(862,974)	(863,789)	815	0.09%	0	3,882	-65	8,389	676	906	-3,909
12/25/2017	(882,146)	(883,153)	1,007	0.11%	0	2,158	30	9,391	975	1,037	-2,218
12/26/2017	(1,168,298)	(1,168,846)	548	0.05%	0	2,539	-190	11,285	1,341	1,263	-3,064
12/27/2017	(1,256,096)	(1,256,941)	845	0.07%	0	6,111	933	11,450	434	1,188	-7,388
12/28/2017	(1,286,845)	(1,286,404)	-441	-0.03%	0	2,268	-73	11,726	560	1,229	-3,865
12/29/2017	(1,188,825)	(1,197,048)	8,223	0.69%	0	914	30	10,075	656	1,073	6,207
12/30/2017	(1,184,011)	(1,275,949)	91,938	7.21%	0	127	74	9,890	756	1,065	90,672
12/31/2017	(1,075,028)	(1,081,253)	6,225	0.58%	0	82	0	10,165	-26	1,014	5,129
1/1/2018	(1,273,091)	(1,326,453)	53,362	4.02%	0	1,213	-478	8,997	328	933	51,694
1/2/2018	(1,290,399)	(1,330,504)	40,105	3.01%	0	21,761	3,048	9,468	338	981	14,315
1/3/2018	(1,094,901)	(1,078,166)	-16,735	-1.55%	0	2,719	443	8,758	188	895	-20,791
1/4/2018	(1,590,557)	(1,600,251)	9,694	0.61%	0	4,750	-1,425	9,444	1,220	1,066	5,302
1/5/2018	(1,417,056)	(1,416,251)	-805	-0.06%	0	4,454	-2,162	9,118	1,186	1,030	-4,128

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

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Cont Reserve Depl Failure Charge	Excessive/Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
1/6/2018	(1,007,061)	(1,037,840)	30,779	2.97%	0	9,444	313	7,478	451	793	20,229
1/7/2018	(871,184)	(913,042)	41,858	4.58%	0	5,729	-1,153	6,915	230	714	36,568
1/8/2018	(922,191)	(942,775)	20,584	2.18%	0	1,689	4	7,246	796	804	18,086
1/9/2018	(916,227)	(946,791)	30,564	3.23%	0	8,271	-44	7,004	632	764	21,574
1/10/2018	(776,713)	(795,923)	19,210	2.41%	0	2,280	0	5,894	243	614	16,316
1/11/2018	(866,939)	(870,932)	3,993	0.46%	0	2,758	14	6,300	247	655	566
1/12/2018	(1,011,918)	(997,074)	-14,844	-1.49%	0	1,306	7	8,097	672	877	-17,034
1/13/2018	(1,044,244)	(1,040,264)	-3,980	-0.38%	0	146	24	8,427	211	864	-5,014
1/14/2018	(1,044,699)	(1,043,244)	-1,455	-0.14%	0	4,969	-672	8,712	278	899	-6,651
1/15/2018	(973,340)	(972,567)	-773	-0.08%	0	3,244	63	8,409	257	867	-4,946
1/16/2018	(1,080,061)	(1,065,219)	-14,842	-1.39%	0	631	-7	8,507	681	919	-16,385
1/17/2018	(1,043,677)	(1,042,548)	-1,129	-0.11%	0	12,187	-740	8,790	1,575	1,037	-13,612
1/18/2018	(1,031,687)	(1,035,334)	3,647	0.35%	0	9,795	494	8,010	1,007	902	-7,543
1/19/2018	(796,641)	(803,989)	7,348	0.91%	0	4,376	15	5,901	360	626	2,331
1/20/2018	(1,008,972)	(1,012,069)	3,097	0.31%	0	2,867	23	8,253	555	881	-674
1/21/2018	(891,054)	(899,157)	8,103	0.90%	0	7,487	21	6,996	293	729	-134
1/22/2018	(772,296)	(785,629)	13,334	1.70%	0	5,617	-12	5,975	532	651	7,078
1/23/2018	(957,187)	(960,651)	3,463	0.36%	0	2,047	24	8,367	480	885	508
1/24/2018	(1,212,781)	(1,213,478)	697	0.06%	0	558	-42	9,587	518	1,010	-830
1/25/2018	(1,032,017)	(1,031,390)	-627	-0.06%	0	1,110	-110	7,325	617	794	-2,422
1/26/2018	(745,105)	(743,484)	-1,622	-0.22%	0	3,577	-36	5,290	537	583	-5,745
1/27/2018	(780,762)	(781,757)	995	0.13%	0	2,138	-11	5,524	367	589	-1,721
1/28/2018	(966,687)	(966,849)	162	0.02%	0	6,968	162	7,867	430	830	-7,797
1/29/2018	(1,190,407)	(1,190,857)	450	0.04%	0	2,245	78	9,343	446	979	-2,853
1/30/2018	(1,050,347)	(1,051,583)	1,236	0.12%	1,883	5,007	-172	8,294	802	910	-6,393
1/31/2018	(984,820)	(985,360)	539	0.05%	0	308	-173	4,214	355	457	-52
2/1/2018	(1,022,991)	(1,056,777)	33,786	3.20%	0	1,362	-4	7,151	486	764	31,665
2/2/2018	(1,215,019)	(1,256,588)	41,569	3.31%	0	449	-1	7,917	248	817	40,305
2/3/2018	(944,508)	(984,831)	40,323	4.09%	0	290	0	6,073	268	634	39,399
2/4/2018	(875,941)	(903,817)	27,876	3.08%	0	248	5	6,125	384	651	26,972
2/5/2018	(1,119,777)	(1,146,565)	26,788	2.34%	0	902	-34	7,950	547	850	25,070
2/6/2018	(1,156,697)	(1,179,780)	23,083	1.96%	0	1,021	-176	8,022	229	825	21,413
2/7/2018	(1,124,402)	(1,150,196)	25,794	2.24%	0	159	150	7,718	408	813	24,672
2/8/2018	(1,194,740)	(1,222,361)	27,621	2.26%	0	588	-418	7,982	162	814	26,636
2/9/2018	(980,549)	(998,402)	17,853	1.79%	0	111	-21	7,154	297	745	17,018
2/10/2018	(1,055,616)	(1,056,133)	517	0.05%	0	1,220	23	7,380	382	776	-1,503
2/11/2018	(904,329)	(909,185)	4,856	0.53%	0	279	-77	5,640	273	591	4,062
2/12/2018	(1,084,249)	(1,081,944)	-2,305	-0.21%	0	103	-38	7,556	295	785	-3,155
2/13/2018	(874,808)	(880,660)	5,852	0.66%	0	521	5	5,661	389	605	4,721
2/14/2018	(835,633)	(841,559)	5,926	0.70%	0	666	10	5,168	173	534	4,716
2/15/2018	(884,956)	(890,487)	5,532	0.62%	0	475	-7	5,685	555	624	4,440
2/16/2018	(1,193,543)	(1,198,939)	5,396	0.45%	0	1,368	41	5,869	232	610	3,376
2/17/2018	(832,846)	(844,610)	11,764	1.39%	0	1,844	-270	5,343	263	561	9,630
2/18/2018	(807,006)	(815,032)	8,026	0.98%	0	537	-2	5,006	204	521	6,970
2/19/2018	(856,459)	(863,588)	7,130	0.83%	0	979	521	5,513	774	629	5,001
2/20/2018	(967,190)	(968,388)	1,198	0.12%	0	1,333	-102	6,102	422	652	-686
2/21/2018	(1,915,863)	(1,916,906)	1,043	0.05%	0	5,490	5,156	8,769	694	946	-10,549
2/22/2018	(1,166,231)	(1,161,867)	-4,364	-0.38%	0	116	8	7,777	387	816	-5,305
2/23/2018	(1,075,689)	(1,073,328)	-2,361	-0.22%	0	1,134	-38	7,200	75	728	-4,185
2/24/2018	(1,058,762)	(1,058,553)	-209	-0.02%	0	928	78	7,022	179	720	-1,934
2/25/2018	(799,915)	(795,344)	-4,571	-0.57%	0	3,357	11	5,774	368	614	-8,553
2/26/2018	(836,077)	(830,900)	-5,177	-0.62%	0	874	-249	5,993	333	633	-6,435
2/27/2018	(934,633)	(934,018)	-616	-0.07%	0	185	-32	6,728	487	721	-1,491
2/28/2018	(973,598)	(972,344)	-1,254	-0.13%	0	239	-5	6,846	376	722	-2,209
3/1/2018	(923,212)	(934,200)	10,988	1.18%	0	966	24	10,410	694	1,110	8,887
3/2/2018	(905,978)	(912,426)	6,448	0.71%	0	1,487	-36	9,837	359	1,020	3,978
3/3/2018	(747,539)	(753,567)	6,027	0.80%	0	382	-6	7,255	-32	722	4,929
3/4/2018	(725,829)	(726,308)	479	0.07%	0	2	-4	7,185	-168	702	-220
3/5/2018	(766,491)	(768,192)	1,702	0.22%	0	1,483	88	7,697	640	834	-702
3/6/2018	(848,653)	(859,461)	10,808	1.26%	0	402	-8	9,499	826	1,032	9,382
3/7/2018	(951,768)	(956,991)	5,223	0.55%	0	676	32	11,053	1,228	1,228	3,286
3/8/2018	(1,106,487)	(1,114,464)	7,977	0.72%	0	2,033	346	11,952	372	1,232	4,365
3/9/2018	(973,398)	(982,795)	9,397	0.96%	0	240	-7	10,926	904	1,183	7,981

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Cont Reserve Depl Failure Charge	Excessive/Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
3/10/2018	(867,665)	(878,227)	10,562	1.20%	0	216	-34	9,811	904	1,071	9,308
3/11/2018	(808,346)	(816,424)	8,078	0.99%	0	1,652	59	9,251	237	949	5,418
3/12/2018	(861,543)	(873,952)	12,409	1.42%	0	692	32	10,137	357	1,049	10,635
3/13/2018	(1,080,037)	(1,093,921)	13,884	1.27%	0	935	37	10,732	703	1,143	11,768
3/14/2018	(830,736)	(841,818)	11,082	1.32%	0	2,155	-623	9,577	513	1,009	8,541
3/15/2018	(823,385)	(834,529)	11,144	1.34%	0	597	-197	9,386	471	986	9,758
3/16/2018	(797,543)	(799,957)	2,414	0.30%	0	1,287	-132	8,599	716	932	328
3/17/2018	(893,808)	(901,499)	7,691	0.85%	0	1,843	-155	10,500	295	1,080	4,924
3/18/2018	(913,790)	(925,432)	11,643	1.26%	0	35	-1	10,463	246	1,071	10,538
3/19/2018	(923,596)	(935,007)	11,411	1.22%	0	1,574	-66	10,670	746	1,142	8,762
3/20/2018	(940,418)	(943,013)	2,595	0.28%	0	1,892	-224	10,986	417	1,140	-213
3/21/2018	(996,530)	(1,011,180)	14,650	1.45%	0	620	-349	11,282	315	1,160	13,220
3/22/2018	(910,821)	(925,363)	14,542	1.57%	0	1,083	-332	10,244	454	1,070	12,721
3/23/2018	(767,233)	(775,574)	8,341	1.08%	0	85	2	7,409	379	779	7,476
3/24/2018	(670,497)	(676,983)	6,487	0.96%	0	2,557	116	5,949	710	666	3,148
3/25/2018	(678,357)	(681,815)	3,458	0.51%	0	1,484	93	7,617	237	785	1,096
3/26/2018	(844,181)	(848,945)	4,765	0.56%	0	1,139	-723	9,786	417	1,020	3,328
3/27/2018	(841,290)	(852,814)	11,525	1.35%	0	101	-26	9,426	333	976	10,474
3/28/2018	(806,162)	(810,810)	4,648	0.57%	0	172	-84	8,917	574	949	3,611
3/29/2018	(830,890)	(841,408)	10,518	1.25%	0	415	-1	9,281	763	1,004	9,099
3/30/2018	(814,263)	(829,906)	15,643	1.88%	0	40	0	8,410	376	879	14,725
3/31/2018	(670,127)	(677,120)	6,993	1.03%	0	182	-4	6,311	-57	625	6,189
4/1/2018	(782,117)	(810,693)	28,576	3.52%	0	509	-55	10,108	636	1,074	27,048
4/2/2018	(827,315)	(851,391)	24,076	2.83%	0	2,703	-391	10,526	584	1,111	20,653
4/3/2018	(752,140)	(784,010)	31,870	4.06%	680	2,868	27	9,291	646	994	27,301
4/4/2018	(896,009)	(902,539)	6,530	0.72%	0	5,609	-476	10,674	1,204	1,188	210
4/5/2018	(842,325)	(839,629)	-2,696	-0.32%	0	1,166	-7,670	9,982	1,128	1,111	2,697
4/6/2018	(697,701)	(697,290)	-411	-0.06%	0	539	-360	7,804	318	812	-1,402
4/7/2018	(917,462)	(916,459)	-1,003	-0.11%	0	1,936	92	10,549	715	1,126	-4,157
4/8/2018	(833,157)	(872,940)	39,783	4.56%	0	6,871	-1,127	10,185	828	1,101	32,937
4/9/2018	(1,257,156)	(1,283,375)	26,219	2.04%	0	1,431	-3,991	11,677	532	1,221	27,558
4/10/2018	(915,647)	(911,245)	-4,402	-0.48%	0	173	70	11,034	210	1,124	-5,769
4/11/2018	(808,081)	(808,795)	714	0.09%	0	2,315	12	10,495	594	1,109	-2,722
4/12/2018	(884,574)	(888,751)	4,177	0.47%	0	1,226	-85	10,719	745	1,146	1,890
4/13/2018	(659,223)	(660,151)	928	0.14%	0	1,981	-9	7,576	426	800	-1,844
4/14/2018	(706,977)	(712,266)	5,289	0.74%	0	1,901	329	8,039	1,220	926	2,133
4/15/2018	(748,072)	(748,067)	-5	0.00%	0	8,847	-192	10,178	1,313	1,149	-9,810
4/16/2018	(1,199,305)	(1,206,753)	7,448	0.62%	0	2,059	-242	11,599	547	1,215	4,416
4/17/2018	(1,453,420)	(1,445,870)	-7,550	-0.52%	0	3,857	-1,146	11,324	1,053	1,238	-11,498
4/18/2018	(1,100,182)	(1,108,282)	8,100	0.73%	0	20,873	-2,034	10,667	519	1,119	-11,858
4/19/2018	(1,419,799)	(1,431,060)	11,261	0.79%	0	7,083	-499	11,021	791	1,181	3,496
4/20/2018	(953,930)	(952,459)	-1,471	-0.15%	0	9,408	246	9,994	706	1,070	-12,196
4/21/2018	(731,453)	(734,345)	2,892	0.39%	0	3,096	-94	8,380	188	857	-967
4/22/2018	(710,567)	(713,630)	3,063	0.43%	0	2,008	1	8,843	192	904	151
4/23/2018	(929,411)	(943,827)	14,416	1.53%	0	1,887	2,078	9,896	680	1,058	9,393
4/24/2018	(765,442)	(780,774)	15,332	1.96%	0	5,367	193	9,789	841	1,063	8,709
4/25/2018	(850,170)	(863,978)	13,808	1.60%	0	6,482	295	10,292	337	1,063	5,968
4/26/2018	(683,915)	(693,406)	9,491	1.37%	0	6,237	-159	8,053	251	830	2,583
4/27/2018	(686,874)	(691,808)	4,934	0.71%	0	4,122	-361	7,774	45	782	391
4/28/2018	(745,454)	(754,712)	9,258	1.23%	0	1,563	104	8,489	340	883	6,708
4/29/2018	(639,919)	(651,773)	11,854	1.82%	0	270	66	6,955	-210	675	10,843
4/30/2018	(688,002)	(700,191)	12,189	1.74%	0	1,691	-62	7,237	133	737	9,823
5/1/2018	(835,104)	(841,081)	5,977	0.71%	0	4,234	-352	6,256	317	657	1,437
5/2/2018	(1,051,969)	(1,060,919)	8,950	0.84%	0	8,899	15,285	7,196	179	738	-15,971
5/3/2018	(1,074,518)	(1,081,791)	7,273	0.67%	0	3,531	313	7,558	493	805	2,623
5/4/2018	(898,937)	(920,479)	21,542	2.34%	0	6,485	254	6,769	414	718	14,085
5/5/2018	(777,654)	(780,704)	3,050	0.39%	0	3,287	5	6,029	193	622	-864
5/6/2018	(687,847)	(688,179)	332	0.05%	0	3,235	-221	6,287	257	654	-3,336
5/7/2018	(828,277)	(832,044)	3,767	0.45%	0	4,508	265	6,638	232	687	-1,693
5/8/2018	(762,766)	(766,363)	3,597	0.47%	0	2,583	214	5,376	733	611	189
5/9/2018	(779,339)	(787,399)	8,060	1.02%	0	3,226	306	6,042	791	683	3,845
5/10/2018	(870,160)	(889,888)	19,728	2.22%	0	2,473	1,112	6,101	370	647	15,496
5/11/2018	(672,367)	(673,241)	874	0.13%	0	2,221	214	4,683	493	518	-2,078

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
5/12/2018	(797,377)	(801,092)	3,715	0.46%	0	3,935	25	5,251	102	535	-780
5/13/2018	(1,004,336)	(1,022,268)	17,932	1.75%	0	3,769	-115	6,969	319	729	13,549
5/14/2018	(1,492,936)	(1,500,473)	7,537	0.50%	0	5,138	955	8,281	413	869	575
5/15/2018	(1,187,814)	(1,195,126)	7,312	0.61%	0	5,570	3,187	7,515	237	775	-2,220
5/16/2018	(1,237,771)	(1,243,247)	5,476	0.44%	0	3,109	695	7,531	760	829	843
5/17/2018	(1,039,129)	(1,036,013)	-3,116	-0.30%	0	2,934	112	7,285	651	794	-6,956
5/18/2018	(953,051)	(949,164)	-3,887	-0.41%	0	3,056	-106	6,934	782	772	-7,609
5/19/2018	(824,484)	(829,716)	5,232	0.63%	0	3,574	-29	6,485	414	690	998
5/20/2018	(877,415)	(880,440)	3,025	0.34%	0	5,569	521	7,116	753	787	-3,852
5/21/2018	(1,139,079)	(1,146,610)	7,531	0.66%	0	2,345	-163	8,168	552	872	4,477
5/22/2018	(1,213,262)	(1,217,613)	4,351	0.36%	0	4,469	-3,000	7,875	161	804	2,079
5/23/2018	(1,043,391)	(1,047,027)	3,636	0.35%	0	3,040	-539	7,344	112	746	389
5/24/2018	(1,006,075)	(1,005,571)	-504	-0.05%	0	2,405	-17	7,637	911	855	-3,746
5/25/2018	(1,522,254)	(1,533,905)	11,651	0.76%	0	2,799	603	8,716	478	919	7,329
5/26/2018	(1,219,170)	(1,221,295)	2,125	0.17%	0	3,101	-160	9,297	1,681	1,098	-1,914
5/27/2018	(1,281,120)	(1,283,925)	2,805	0.22%	0	1,754	565	8,295	545	884	-398
5/28/2018	(1,163,079)	(1,164,854)	1,775	0.15%	0	2,248	857	8,007	272	828	-2,158
5/29/2018	(1,375,185)	(1,377,985)	2,800	0.20%	0	1,667	-7	8,618	721	934	206
5/30/2018	(1,068,336)	(1,071,667)	3,331	0.31%	0	845	1,087	8,153	255	841	558
5/31/2018	(1,575,203)	(1,599,568)	24,365	1.52%	0	5,945	2,384	9,697	375	1,007	15,029
6/1/2018	(1,147,273)	(1,159,567)	12,294	1.06%	0	2,319	-360	9,467	373	984	9,350
6/2/2018	(767,807)	(771,556)	3,749	0.49%	0	2,216	-28	6,285	437	672	889
6/3/2018	(800,867)	(810,864)	9,997	1.23%	0	1,103	28	6,799	249	705	8,161
6/4/2018	(961,836)	(965,835)	3,999	0.41%	0	728	167	8,824	1,567	1,039	2,065
6/5/2018	(860,820)	(859,998)	-822	-0.10%	0	1,301	-110	8,792	385	918	-2,931
6/6/2018	(903,752)	(911,500)	7,748	0.85%	0	521	8	9,165	823	999	6,220
6/7/2018	(1,051,536)	(1,054,176)	2,640	0.25%	0	825	5,768	9,460	1,677	1,114	-5,067
6/8/2018	(1,061,516)	(1,064,225)	2,709	0.25%	0	3,343	110	9,222	957	1,018	-1,762
6/9/2018	(1,000,066)	(1,000,651)	585	0.06%	0	3,063	72	9,312	1,008	1,032	-3,582
6/10/2018	(699,501)	(700,872)	1,371	0.20%	0	493	-16	6,339	296	663	231
6/11/2018	(831,467)	(831,265)	-202	-0.02%	0	1,106	60	8,903	940	984	-2,352
6/12/2018	(1,042,307)	(1,057,205)	14,898	1.41%	0	2,331	560	9,719	428	1,015	10,992
6/13/2018	(1,186,522)	(1,190,697)	4,175	0.35%	0	3,881	1,338	10,579	925	1,150	-2,195
6/14/2018	(885,913)	(896,368)	10,455	1.17%	0	2,423	279	8,392	690	908	6,845
6/15/2018	(1,052,445)	(1,055,437)	2,992	0.28%	517	5,822	988	9,860	511	1,037	-5,373
6/16/2018	(943,250)	(955,644)	12,394	1.30%	0	10,262	1,030	8,902	460	936	166
6/17/2018	(1,019,639)	(1,025,673)	6,034	0.59%	0	860	11	9,260	556	982	4,181
6/18/2018	(1,374,175)	(1,403,287)	29,112	2.07%	0	2,131	-842	11,363	899	1,226	26,596
6/19/2018	(1,194,859)	(1,195,318)	459	0.04%	0	2,343	121	10,804	572	1,138	-3,143
6/20/2018	(1,110,334)	(1,112,918)	2,584	0.23%	0	8,891	951	10,155	1,435	1,159	-8,417
6/21/2018	(1,042,292)	(1,042,427)	135	0.01%	0	4,445	149	9,408	609	1,002	-5,461
6/22/2018	(1,096,311)	(1,096,315)	4	0.00%	0	1,204	-44	9,242	238	948	-2,103
6/23/2018	(946,370)	(946,975)	605	0.06%	0	3,392	675	8,214	179	839	-4,301
6/24/2018	(1,056,300)	(1,055,913)	-387	-0.04%	0	1,944	49	8,764	332	910	-3,290
6/25/2018	(855,247)	(866,125)	10,878	1.26%	0	1,893	38	8,066	896	896	8,052
6/26/2018	(1,058,618)	(1,063,741)	5,123	0.48%	0	256	487	9,065	1,226	1,029	3,351
6/27/2018	(1,212,688)	(1,215,001)	2,313	0.19%	0	2,260	6,087	9,875	343	1,022	-7,055
6/28/2018	(1,233,670)	(1,239,566)	5,896	0.48%	0	1,489	-171	10,160	525	1,068	3,510
6/29/2018	(1,305,018)	(1,320,678)	15,660	1.19%	0	2,964	-725	10,935	742	1,168	12,253
6/30/2018	(1,339,703)	(1,348,960)	9,257	0.69%	0	1,522	-460	11,304	1,854	1,316	6,879
Total	**(336,826,930)**	**(339,976,522)**	**3,149,592**	**0.92%**	**10,176**	**969,509**	**53,763**	**2,943,563**	**202,432**	**314,599**	**1,801,544**

Excessive Deficient Energy Deployment Charge by NSP Resource

LOCATION	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18
Agassiz Beach1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ALTW.MOWERCO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ALTW.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anson_G2	$ 773	$ 76	$ 957	$ 8	$ -	$ -	$ -	$ -	$ -	$ 9	$ 558	$ 26
Anson_G3	$ 879	$ 10	$ 2,112	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1	$ -
Anson_G4	$ 674	$ 298	$ 2,485	$ 8	$ -	$ -	$ -	$ -	$ -	$ 9	$ 2,863	$ 16
BayFrnt_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BayFrnt_G5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BayFrnt_G6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BigFalls_A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_dog_G2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_dog_G5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_dog_G6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,604	$ 6,949
Blk_Dog_G52	$ 36,035	$ 19,518	$ 15,801	$ 5,143	$ 32	$ -	$ -	$ -	$ -	$ -	$ 10,077	$ 6,595
Blue_Lk_G1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G7	$ 139	$ 8	$ 2	$ 251	$ -	$ -	$ -	$ 11	$ -	$ 7	$ 3,529	$ 1,282
Blue_Lk_G8	$ 68	$ 18	$ -	$ 262	$ -	$ -	$ -	$ -	$ 1,685	$ 7	$ 7,216	$ 1,023
BuffR_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BuffR_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Canon_Falls1	$ 32	$ 3	$ 7	$ -	$ 41	$ -	$ 579	$ 516	$ -	$ 16	$ 9,564	$ 502
Canon_Falls2	$ 299	$ 1	$ 1,050	$ 21	$ 1,233	$ -	$ 157	$ -	$ -	$ 18	$ 8,002	$ 1,570
CC Highbridge1	$ 11,682	$ 4,341	$ 11,313	$ 721	$ 8,381	$ 6,507	$ 16,031	$ 643	$ 949	$ 6,717	$ 4,420	$ 2,105
CC Highbridge2	$ 1,462	$ 154	$ 4,111	$ 419	$ 126	$ 7	$ 3,664	$ 18	$ 64	$ 166	$ 511	$ 14
CC Mankato	$ 17,536	$ 22,971	$ 25,402	$ 5,393	$ 11,315	$ 6,422	$ 6,072	$ 1,739	$ 232	$ 327	$ 5,632	$ 3,891
CCRiverside1	$ 6,215	$ 3,018	$ 501	$ -	$ -	$ 2,461	$ 18,824	$ 5,176	$ 1,349	$ 29,321	$ 3,808	$ 13,048
CCRiverside2	$ 12,305	$ 7,418	$ 105	$ -	$ -	$ 7,834	$ 14,926	$ 4,559	$ 4,680	$ 39,091	$ 1,186	$ 20,431
CedarFalls_A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHPFALTR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHPFALTR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CORNEL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DPC.FLAMBEAU	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Elliot_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Flambe_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_3	$ 4	$ -	$ -	$ -	$ 0	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_4	$ -	$ -	$ 7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	$ 5	$ 0	$ 42	$ -	$ 2	$ -	$ -	$ 3	$ -	$ -	$ 404	$ -
InvrHils_2	$ -	$ -	$ 20	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_3	$ 6	$ -	$ 383	$ -	$ -	$ -	$ 14	$ -	$ -	$ 0	$ 32	$ -
InvrHils_4	$ 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 540	$ -
InvrHils_5	$ 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 928	$ -
InvrHils_6	$ 344	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9	$ -
JIMFL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
King_G1	$ 2,430	$ 2,998	$ 18,366	$ 7,998	$ 8,866	$ 3,708	$ 10,794	$ 1,184	$ 2,863	$ -	$ -	$ 1,201
LSPower_1	$ 26,015	$ 2,736	$ 7,852	$ 5,787	$ 3,322	$ 2,315	$ 1,666	$ 1,338	$ 3,656	$ 5,759	$ 2,877	$ 2,643
Menomone_A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MHEB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Monticello_1	$ -	$ 22	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MORAINE2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

NSP.NOBLE.CWS1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLE.CWS2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLES_TR	$ 101	$ 78	$ 98	$ 214	$ 179	$ 157	$ 154	$ 147	$ 105	$ 122	$ 216	$ 193
NSP.NOBLES_TR2	$ 96	$ 74	$ 106	$ 176	$ 166	$ 109	$ 119	$ 151	$ 94	$ 120	$ 211	$ 166
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	$ -	$ 18	$ 38	$ -	$ -	$ -	$ -	$ -	$ 27	$ -	$ -	$ -
PR_ISLD_2	$ -	$ -	$ 22	$ 54	$ 71	$ -	$ -	$ -	$ -	$ 20	$ -	$ -
Rapidan_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Redwing_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Redwing_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIV9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIVRSD71	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIVRSD72	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIVRSD9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock Ridge_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock_County	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SHERC3	$ 4,268	$ 8,858	$ 16,110	$ 12,641	$ 6,363	$ 16,432	$ 33,445	$ 6,519	$ 10,055	$ 26,216	$ 42,892	$ 12,251
SHERCO_G1	$ 1,384	$ 1,192	$ 8,275	$ 2,315	$ 2,784	$ 4,562	$ 22,956	$ 2,651	$ -	$ -	$ 446	$ 945
SHERCO_G2	$ 729	$ 820	$ 3,648	$ 1,681	$ 2,471	$ 1,788	$ 12,532	$ 2,011	$ 2,419	$ 7,936	$ 3,870	$ 2,263
South Ridge_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St Paul Cogen	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St_Croix_7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
StCloud_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
STCRO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SWPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UofMGen1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
W_Triw_TR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WAUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
West_Pipestone	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_1	$ 17	$ 459	$ 103	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 16	$ 0
Wheaton_2	$ 214	$ 2,777	$ 3,176	$ 3	$ -	$ -	$ 12	$ -	$ -	$ -	$ 478	$ 0
Wheaton_3	$ 32	$ 243	$ 1,094	$ 10	$ -	$ -	$ 0	$ -	$ -	$ -	$ 7	$ -
Wheaton_4	$ 47	$ 217	$ 75	$ 16	$ -	$ -	$ -	$ -	$ -	$ -	$ 15	$ 0
Wheaton_5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Eastridge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Ewington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Ewngton 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Fenton 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Fenton 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Grand Meadow	$ 94	$ 93	$ 195	$ 319	$ 249	$ 183	$ 626	$ 112	$ 250	$ 218	$ 252	$ 218
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	**$ 123,890**	**$ 78,420**	**$ 123,453**	**$ 43,439**	**$ 45,600**	**$ 52,486**	**$ 142,569**	**$ 26,779**	**$ 28,428**	**$ 116,078**	**$ 112,161**	**$ 77,334**

Contigency Reserve Deployment Failure Charges by NSP Resource

LOCATION	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18
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	$ -	$ -	$ 1,391	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	$ 319	$ -	$ 422	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC Highbridge2	$ 319	$ -	$ 422	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC Mankato	$ -	$ -	$ 1,587	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCRiverside1	$ 268	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCRiverside2	$ 243	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GRE.ELKRI1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GRE.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GRE.STANTO1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HBC7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HBC8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hennipin1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Herc_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HiBridge9_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HiBridge9_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HOLCOM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 67	$ -	$ -
InvrHils_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 111	$ -	$ -
InvrHils_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 134	$ -	$ -
InvrHils_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 134	$ -	$ -
InvrHils_5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 134	$ -	$ -
InvrHils_6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 101	$ -	$ -
JIMFL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
King_G1	$ 851	$ -	$ -	$ -	$ -	$ -	$ 892	$ -	$ -	$ -	$ -	$ -
LSPower_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 517
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Contigency Reserve Deployment Failure Charges by NSP Resource

LOCATION	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SHERCO_G1	$ 637	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SHERCO_G2	$ 637	$ -	$ -	$ -	$ -	$ -	$ 991	$ -	$ -	$ -	$ -	$ -
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	**$ 3,274**	**$ -**	**$ 3,821**	**$ -**	**$ -**	**$ -**	**$ 1,883**	**$ -**	**$ -**	**$ 680**	**$ -**	**$ 517**

Annual Automatic Adjustment Report

Docket No. E999/AA-18-373

PART K

Reporting Requirements from Prior AAA Orders

2006 AAA and MISO Day 2 Ordered Reporting Requirements

On February 6, 2008, the Commission issued its 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*. In compliance with this Order, the Company is required to report the following information as part of its AAA report:

Order Item 11

Xcel Energy shall provide in future electric annual automatic adjustment filings a Wind Curtailment Summary Report Table similar to the table that Xcel is already providing in its AAA filings, but expanded to include the amount of any curtailment payments made under the following four curtailment categories:

1= Lack of firm transmission as described in Attachment C of the MISO Open Access Transmission Tariff, or any successor provision

2= Low Load

3= Transmission loading relief or MISO directive for reasons other than (1) above

4= Other, which must be explained in detail if compensation is requested

The Company has been in compliance with this reporting format since the 2006-2007 AAA Report. A Wind Curtailment Summary Report Table for January 2016 to May 2017 is included in Part H, Section 5, Schedule 1.

Order Item 12

The Commission finds that Xcel Energy has satisfied the Commission's directive in docket E002/CI-00-415 to include in its annual automatic adjustment filing a monthly comparison of generation costs allocated to retail and wholesale customers for the months of June, July and August. The Company shall continue to report this information in future annual automatic adjustment filings.

This information is reported in Part H, Section 2, Schedule 1.

Order Item 16

The Commission discontinues the requirement that all electric utilities subject to automatic adjustment filing requirements report in these annual filings "each instance where MISO directed Companies to redispatch Companies' own generation for reliability reasons, including an explanation of financial impact on rates, in any, and the reason for the redispatch, if known."

The Company discontinued reporting this item (formerly included as Part I, Section 8).

Order Item 18

All electric utilities subject to automatic adjustment filing requirements, with the exception of Dakota Electric, shall include in future annual automatic adjustment filings the actual expenses pertaining to maintenance of generation plants, with a comparison to the generation maintenance budget from the utility's most recent rate case.

The Company's compliance Maintenance Expenses of Generation Plants report is included in Part K, Section 1, Schedule 1.

Order Item 21

All electric utilities subject to automatic adjustment filing requirements, with the exception of Dakota Electric, shall provide information requested by the Department in docket E,G999/AA-07-1130 according to the spreadsheet attached to the 2007 Report pertaining to MISO Day 2 charges, one for every month in the AAA period and as a summary of MISO Day 2 charges for the entire AAA period, for a total of 13 pages in each utility's AAA filings.

The Company has included this additional MISO Day 2 Report in Part J, Section 5, Schedule 7. Amounts and MWh for the intersystem charge types are allocated based on the MISO invoice for asset based amounts, and come directly from MISO NSP Trading settlement statements for the non-asset based amounts.

			Energy Allocation Ratios		87.3278%	87.2656%
			Demand Allocation Ratios		87.3461%	87.4350%
			NSP Minnesota Company Totals		**Minnesota Jurisdictional Totals ***	
FERC Account Description		**Allocation Method**	**2016 Test Year**	**2017 Actuals**	**2016 Test Year**	**2017 Actuals**
510	Stm Maint Super&Eng	Energy	2,008,848	2,957,690	$ 1,754,283	$ 2,581,046
511	Stm Maint of Structures	Demand	2,784,311	5,369,444	$ 2,431,987	$ 4,694,774
512	Stm Maint of Boiler Plt	Energy	39,704,208	23,979,849	$ 34,672,811	$ 20,926,159
513	Stm Maint of Elec Plant	Energy	4,931,682	7,377,091	$ 4,306,730	$ 6,437,663
514	Stm Maint of Misc Stm Plt	Demand	18,325,365	11,965,103	$ 16,006,492	$ 10,461,687
528	Nuc Maint Super & Eng	Energy	6,183,520	5,229,084	$ 5,399,932	$ 4,563,192
529	Nuc Maint of Structures	Demand	9,368	419,818	$ 8,183	$ 367,068
530	Nuc Mtc of React Plt Equip	Energy	48,934,011	39,119,015	$ 42,732,995	$ 34,137,443
531	Nuc Maint of Elect Plant	Energy	13,522,861	11,596,004	$ 11,809,217	$ 10,119,323
532	Nuc Mtc of Misc Nuc Plant	Demand	25,463,010	31,371,710	$ 22,240,946	$ 27,429,855
541	Hydro Mtc Super& Eng	Energy	5,509	14,841	$ 4,811	$ 12,951
542	Hyd Maint of Structures	Demand	22,000	81,784	$ 19,216	$ 71,508
543	Hydro Mtc Resv, Dams	Demand	22,000	30,160	$ 19,216	$ 26,371
544	Hyd Maint of Elec Plant	Energy	88,144	308,887	$ 76,974	$ 269,552
545	Hyd Mt Misc Hyd Plnt Mjr	Demand	59,713	418	$ 52,157	$ 366
551	Oth Maint Super & Eng	Demand	310,346	1,141,460	$ 271,075	$ 998,035
552	Oth Maint of Structures	Demand	3,242,151	6,722,810	$ 2,831,892	$ 5,878,089
553	Oth Mtc of Gen & Ele Plant	Demand	17,225,836	10,371,752	$ 15,046,096	$ 9,068,542
554	Oth Mtc Misc Gen Plt Mjr	Demand	1,866,543	2,489,712	$ 1,630,353	$ 2,176,880
Production Maintenance Expense Totals			**$ 184,709,427**	**$ 160,546,634**	**$ 161,315,366**	**$ 140,220,503**

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

	Generation Maintenance O&M Costs
2016 Test Year	$ 184,709,427
2017 Actual	$ 160,546,634

2007 AAA Ordered Reporting Requirements

On August 31, 2009, the Commission issued its ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS AND REQUIRING ADDITIONAL FILINGS in Docket Nos. E,G999/AA-07-1130, E999/M-07-1028, E999/M-09-602 and E001/PA-05-1272. In compliance with this Order, the Company has included the following information as part of this report:

1. Annual Transmission Transformers Report

This compliance report is included in Part H, Section 4 of this report. Part H, Section 4, Schedule 1 provides status categories for each transformer (in-service standalone or in-service duplicate) as required in the Commission's Order dated August 16, 2013 in Docket No. E999/AA-11-792, Order Point No. 23a.

2. Auction Revenue Rights

Within 30 days of the 2007 AAA Order, utilities subject to automatic adjustment filing requirements were required to provide Auction Revenue Rights (ARR) data for fiscal years 2008 and 2009. On March 17, 2009, the Commission issued an interim order in Docket No. E001, E015, E002, E017/M-08-528, which authorized the Company to flow through the following 4 ARR charge types:

- ARR - FTR Auction Transactions
- Monthly ARR Revenue
- Infeasible ARR Uplift
- ARR Stage 2 Distribution

The monthly ARR by charge type data is listed in Part J, Section 5 of this report.

3. Emergency Demand Response

Currently the Company puts all of its demand response in MISO's resource adequacy construct, making the demand response available in a NERC-declared Emergency Event Alert Level Two. The Company does not offer any of its demand response economically to the market, or under Schedule 30 (Emergency demand Response) of the MISO tariff.

2008 AAA Ordered Reporting Requirements

On March 15, 2010, the Commission issued its ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS AND SETTING FURTHER REQUIREMENTS in Docket No. E999/AA-08-995. Order Point No. 12 requires the Company to report the following information as part of its AAA report:

> *All electric utilities required to file annual automatic adjustment reports shall work with their contractors to identify and develop reasonable contingency plans to mitigate against the risk of delays or lack of performance when contractors perform poorly and increase costs during plant outages. The Commission asks the OES to continue monitoring this issue and to include a report on the electric utilities' plans in its next review.*

Contractor and Supplier performance has continually improved over the last several years. Xcel Energy attributes this quality improvement to three areas of focus.

First, Xcel Energy has put into practice the use of 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 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. Scope of Work 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 the vendor/supplier, the Company utilizes a Non Conformance Reporting Process to correct deficiencies. In addition, special conditions that hold the 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.

For more information about how we have worked to manage contractor performance, see Part K, Section 4 (*2009 and 2010 AAA Ordered Reporting Requirements*) where we outline our approach to forced outages and specifically discuss our quality management program as it relates to contractors.

2009 and 2010 AAA Order Reporting Requirements

On April 6, 2012, the Commission issued its 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. In compliance with this Order, the Company has included the following information as part of this report:

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

Order Point 8 of the Commission Order states:

> *Interstate, Minnesota Power, Otter Tail, and Xcel shall report in future AAA filings any offsetting revenues or compensation recovered by the utilities as a result of contracts, investments, or expenditures paid for by their ratepayers. If any offsetting revenues and/or compensation are not credited back to a utility's ratepayers through the fuel clause, the IOUs shall clearly identify such revenues or compensation by source and amount and fully justify their action in the relevant AAA filings.*

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. See Part K, Section 4, Schedule 1 for a summary of power purchase agreement off-setting revenues.

2. Forced Outages

Order Point 22 of the Commission Order states:

> *The Commission requests Interstate, Minnesota Power, Otter Tail and Xcel to comment on sharing lessons learned regarding the handling of forced outages. The Commission also requests the companies to discuss amongst themselves whether and what kind of information sharing would be beneficial. The companies shall provide in supplemental filings to their fiscal-year 2011 AAA reports, in Docket No. E999/AA-11-792, and in future AAA reports, a simple annual identification of forced outages and a short discussion of how such outages could have been avoided or alleviated.*

Part K, Section 4, Schedule 2 provides for each forced outage, 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.

As we have stated in prior AAA reports, we have several operational improvement initiatives at work under the Generation Operating Model, including Human Performance Improvements, Quality Assurance / Quality Control and Work Management Process Improvements. We provide greater detail on each of these initiatives below.

Generation Operating Model

The Generation Operating Model Playbook outlines the principles we follow to manage, operate and maintain Xcel Energy's generating assets. It ensures alignment of resources and the standardization of the key elements in our operation to help us identify best practices, capture synergies, reduce costs and promote excellence.

The Generation Operating Model Playbook endorses the addition of an overhaul management group. This centralized group helps to plan and coordinate the major overhauls at our base and intermediate generating facilities. The ability of this group to move between plants helps ensure standardization of the best practices of the Company and promote lessons learned at other facilities. An example of a best practice is partnering with a boiler inspection contractor to thoroughly identify a prioritized work repair scope for our boilers at the beginning of each overhaul. Identifying the critical path for boiler repair generally drives overhaul duration; so the earlier the work scope can be identified during inspections, the more responsive we can be to manage them.

Another shared best practice is the use of critical path scheduling with activity trending and projection. This allows us to see where the critical path is moving during the planned outage and ensures that we are allocating resources to where they are needed most. Scheduled outage timeframes are measured by an internal metric

[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.

called Equivalent Planned Outage Factor, a measure of how close a plant adheres to their original scheduled outage time.

Human Performance

An example of a human performance improvement can be found at the Sherco plant. The Sherco team sought to engender behaviors that support safe, reliable, and predictable operation by reducing the frequency and severity of events caused by human errors in the operations department. As a result, a team created operator help guides that were incorporated into the plant's control system. Sherco Unit 1 and 2 operators and other plant personnel have access to help guides for every system and almost every piece of operating equipment. These guides cover an array of operational parameters, such as temperatures, pressures, vibrations, and environmental permit limits.

Contractor Control - Quality Assurance / Quality Control

Improvements in contractor and vendor/supplier performance continue through the implementation of the Energy Supply Quality Management Program. During this AAA reporting period, there were no events that contributed to fleet plant unplanned loss of capacity in the areas of external service and material quality, and equipment design issues directly related to poor performance by contractors and suppliers.

The 2017/2018 Quality Management program oversight efforts continue to focus on contractor/supplier performance during plant overhauls and major capital projects. A significant increase in the number of in-house plant personnel are using the quality program tools and practices to conduct oversight and monitoring of contractors and suppliers engaged in their specific projects. Plant personnel continue to identify cases where equipment or services provided by contractors did not meet specifications and requirements and document these conditions under the Non-Conformance Report (NCR) process. The NCR process has been an effective tool to correct deficiencies, prevent them from reoccurring, and also capture rework costs, recovering costs from Suppliers/Contractors.

Work Management Process Improvements

As part of the Generation Operating Model, work management process improvements are being implemented to reduce repeat failures of critical equipment by implementing standard Predictive Maintenance (PdM) and Preventive Maintenance (PM) actions prior to failure.

In 2017/2018 we continued the best practice of thermography scans and vibration monitoring during operator rounds. Prior to a planned outage, we scan critical equipment such as large motors, pumps and fans to identify any emergent repairs that may be needed to reduce the risk of unplanned derates or outages.

Improvements in reliability have also been made with the establishment of the Monitoring and Diagnostic Center in 2014. The center monitors the performance and health of our generating fleet and provides the data enabling us to make cost-effective condition-based, rather than time-based, maintenance decisions.

3. MISO Module E

Order Point 22 of the Commission Order states:

> *Interstate, Minnesota Power, Otter Tail and Xcel shall continue to provide a comparison and reconciliation of the MISO accredited value of their generators using MISO accredited UCAP values and integrated resource plan capacity ratings in future AAA filings. This comparison and reconciliation should be prepared in sufficient detail to allow the Department to understand: (a) the impacts of generation resources that are not network deliverable (i.e., not interconnected), and (b) the possible constraints of utilities' systems and the impact of those constraints.*

Part K, Section 4, Schedule 3 compares NSP's resource plan capacity assumptions with the capacity accredited by MISO through their Module E process. Schedule 3 uses the 2016-2030 Resource Plan model and the Module E accreditation for the 2017/2018 planning year. These most closely match the AAA reporting period of July 2017 to June 2018. Schedule 3 contains both the installed capacity (ICAP) and the unforced capacity (UCAP) for all capacity resources. Note that MISO uses the same ICAP value as UCAP value for intermittent resources such as run of river hydro. MISO used slightly different assumptions in accrediting wind.

All Company resources are accredited by MISO to be deliverable to NSP System load. The Company does not expect constraints on its system to impact the deliverability of these capacity resources to its loads.

4. Summary of Unusual Adjustments Over $500,000

Order Point 30 of the Commission's Order states:

> *Xcel shall 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.*

The Company began including this information in our monthly FCA reports in the report filed on April 30, 2012 for March 2012. Part K, Section 4, Schedule 4 provides a monthly breakdown of the unusual adjustments of $500,000 which were reported in the FCA filings during the current AAA reporting year.

PUBLIC DOCUMENT: NOT PUBLIC DATA HAS BEEN EXCISED

Summary of Power Purchase Agreement Off-Setting Revenues (July 1, 2017 - June 30, 2018)

Project	Docket No.	Amount Received	Date Booked	Credited to FCA (Yes/No)	Month/Year Credited to FCA	FCA Docket No.	Reason for Payment
		[PROTECTED DATA BEGINS					
Viking Group	E002/M-10-820		August 2017	Yes	October 2017	October 2017	Energy Production Credit
			October 2017	Yes	December 2017	December 2017	Energy Production Credit
			February 2018	Yes	April 2018	April 2018	Energy Production Credit
			April 2018	Yes	June 2018	June 2018	Energy Production Credit
MN Power Laurentian	E002/M-09-913		June 2018	Yes	August 2018	August 2018	Estoppel Agreement
			May 2018	Yes	July 2018	July 2018	Estoppel Agreement
			February 2018	Yes	April 2018	April 2018	Estoppel Agreement
			January 2018	Yes	March 2018	March 2018	Estoppel Agreement
		PROTECTED DATA ENDS]					

Note:
These offsetting revenues represent primarily non-recurring events for a limited number of contracts in a given month. These revenue credits are embedded in the FERC Account 555 line item in the monthly FCA calculation (Attachment 1 page 2 line 3a).

Unit Outage Information									
2018 AAA Reporting Period: July 1, 2017 - June 30, 2018									
	Updated since originally filed in monthly FCAs due to further analysis.						**[PROTECTED DATA BEGINS**		
Unit	**Outage Category**	**Primary Reason for outage**	**Outage Dates Start**	**End**	**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**
JULY 2017									
Wilmart_1	Forced	First Superheater Leaks	07/11/2017	07/14/2017	Boiler superheat tube	Boiler superheat tube leak		Seven similar failures during this reporting period.	Superheater section was replaced during the spring outage 2018.
Anson_G4	Forced	Switchyard System Protection Devices - external (OMC)	07/06/2017	07/14/2017	Line insulator	Failed Insulator on Overhead to underground structure. Also found bad terminations which didn't need immediate replacement.		No similar failures were reported during this reporting period.	Insulator was replaced. Termination replacement scheduled for October of 2018.
Blk_Dog_G52	Forced	Unit Auxiliaries Transformer	07/28/2017	07/30/2017	Station Auxiliary Transformer	Sudden Pressure Relay for transformer erroneously opened.		No similar failures were reported during this reporting period.	Replaced failed relay.
Blue_Lk_G7	Forced	Generator Voltage Control	07/20/2017	07/26/2017	VT4 Potential Transformer Failure	Internal Failure of Component causing indication failure.		No similar failures were reported during this reporting period.	Replaced voltage transformer.
French_1	Forced	Waterwall (Furnace wall)	07/13/2017	07/17/2017	Boiler water wall	It had multiple leaks from corrosion of tubes.		No similar failures were reported during this reporting period	The water wall was replaced during a planned maintenance outage in October of 2017.
French_2	Maintenance	Minor Boiler Overhaul (less Than 720 Hours)	07/20/2017	07/24/2017	Boiler	Preventative maintenance outage for periodic cleaning and inspection.		Similar events occur every 4-6 weeks.	Preventative maintenance cycle to periodically address boiler fouling, fuel delivery system and other components to aid reliable operation.
French_2	Forced	Forced Draft Fan Motors	07/26/2017	08/01/2017	Forced draft fan motor	The motor had cracked windings.		No similar failures were reported during this reporting period	Motor was rewound and placed back in service. We increased the frequency that the motor is inspected.
SHERC3	Forced	Forced Draft Fan Drives (other Than Motor)	07/18/2017	07/19/2017	32 Forced Draft Fan	Instrument tubing that was installed during the 2017 overhaul as an enhancement to provide monitoring for hydraulic positioner condition failed at the Swagelock fitting due to cycle fatigue from vibration causing an oil leak.		No similar failures were reported during this reporting period.	The hydraulic instrumentation lines were capped on this fan and 31 forced draft fan. Future design considerations will include a flexible/braided hose design.
SHERCO_G1	Forced	Air Heater (regenerative)	07/22/2017	07/23/2017	11 Air Preheater Drive Motor	Electrical Failure of the motor.		Similar event involving Unit 3, 32 Secondary Air Heater drive motor during this reporting period on 6/25/2018.	Replaced Motor. We will check magnetic coupling every overhaul for proper alignment. We will replace motor every 6 years, We will replace motor bearings in the overhaul year when the motor is not being replaced.
SHERCO_G2	Forced	First Reheater Leaks	07/26/2017	07/28/2017	Rear Reheat Assembly #107, Tube #2	Longitudinal Tube Leak due to sootblower erosion.		No similar failures were reported during this reporting period.	Sootblower lance rotated 90 degrees to change the helical pattern.
Wheaton_2	Forced	Circuit Breakers	07/01/2017	07/28/2017	Generator Breaker Stabs	Breaker stabs were leaking insulating compound		No similar failures were reported during this reporting period	Contractor (L&S Electric) rebuilt the components on all 4 GE Frame 7 units.
AUGUST 2017									
Wilmart_1	Forced	First Superheater Leaks	08/26/2017	08/29/2017	Boiler superheat tube	Boiler superheat tube leak		7 similar failures during this reporting period.	Superheater section was replaced during the spring outage 2018.
French_2	Forced	Forced Draft Fan Motors	08/01/2017	08/08/2017	Forced draft fan motor	The motor had cracked windings.		No similar failures were reported during this reporting period. This is a continuation of the event beginning 7/26/2017.	Motor was rewound and placed back in service. Increased frequency that the motor is inspected.
Redwing_2	Forced	First Superheater Leaks	08/01/2017	08/05/2017	Boiler	Superheater Tube Leak		7 similar failures during this reporting period.	Superheater section was replaced during the 2018 outage.

Unit Outage Information

2018 AAA Reporting Period: July 1, 2017 - June 30, 2018

Updated since originally filed in monthly FCAs due to further analysis.

[PROTECTED DATA BEGINS

Unit	Outage Category	Primary Reason for outage	Outage Dates Start	End	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_G1	Forced	Turbine Gland Seal System	08/12/2017	08/15/2017	11 Steam Gland Exhauster	Motor drive end shaft bearing failure.		Similar event on Unit 1 for this reporting period from 10/19/2017 to 10/23/2017.	Motor was sent to L&S for emergency repair and reinstalled. New exhauster assembly installed during the 2018 overhaul. We have adjusted inspection frequency of blower assembly to every 3 years.
SHERCO_G1	Forced	Fire protection system instrumentation and control	08/15/2017	08/16/2017	Intercept Valve Proximity Switch	Following a unit trip during startup due to loss of ignitors from a false fire protection flow switch activation, the generator output breakers did not open automatically as designed. This was due to the design of the intercept valve proximity switch linkage which showed the valves as being open.		No similar failures were reported during this reporting period.	Design using upgraded attachment brackets installed during the 2018 overhaul. Units 2 and 3 already have the upgraded design.
SEPTEMBER 2017									
SHERCO_G2	Forced	Wet Scrubber Mist Eliminators/demisters & Washdown	09/25/2017	09/30/2017	Scrubber Modules	Ash buildup on fields, spargers, and other components resulting in inefficient particulate removal and high stack opacity. Aging of equipment requires regular maintenance. Unit needs to be derated to perform cleaning functions such as flushing, high voltage cleaning, and manual nightly cleaning. Upgrades to emissions control equipment have resulted in the need for more aggressive cleaning in addition to normal equipment maintenance.		Multiple similar derates during this reporting period.	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. We are testing a chemical addititive in one of the modules that may reduce the amount of time a module has to be out of service for manual cleaning.
French_1	Maintenance	Minor Boiler Overhaul (less Than 720 Hours)	09/01/2017	09/05/2017	Boiler	Preventative maintenance outage for periodic cleaning and inspection.		Similar events occur every 4-6 weeks.	Preventative maintenance cycle to periodically address boiler fouling, fuel delivery system and other components to aid reliable operation.
French_1	Forced	In-bed reheat tubes (fbc Only)	09/11/2017	09/12/2017	Boiler	Tube failure due to erosion.		One similar event occurred during the reporting period	The tubes were flipped in March of 2018 to address this problem.
French_2	Maintenance	Minor Boiler Overhaul (less Than 720 Hours)	09/14/2017	09/18/2017	Boiler	Preventative maintenance outage for periodic cleaning and inspection.		Similar events occur every 4-6 weeks.	Preventative maintenance cycle to periodically address boiler fouling, fuel delivery system and other components to aid reliable operation.

Unit Outage Information									
2018 AAA Reporting Period: July 1, 2017 - June 30, 2018									
	Updated since originally filed in monthly FCAs due to further analysis.						[PROTECTED DATA BEGINS		
Unit	Outage Category	Primary Reason for outage	Outage Dates Start	End	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
PR_ISLD_2	Forced	Turbine Lube Oil System Valves And Piping	09/18/2017	09/20/2017	PI Unit 2 Turbine Lube Oil Piping	On Prairie Island Unit 2, an oil leak on the weld from the Turbine Main Lube Oil Pump discharge feed to the Turbine Auto Stop Oil System was discovered. Based on the leak rate continuing to increase and temporary repairs not considered to be feasible, a decision was made to reduce power and take the Turbine offline to make the repairs. The generator was taken offline and a weld repair was performed for the defective joint. The unit was then returned to 100% power. The reactor remained at power throughout the repair.		No additional failures have occurred during the reporting period	An inspection of the lube oil and seal oil piping for the Unit 2 turbine was performed. Prior to this, the Unit 1 piping was also walked down. A hand over hand inspection of all accessible portions of seal oil and lube oil piping was performed. Weld quality was examined, along with pipe stability and supports. The final weld repair for the defective weld under WO 700026968 replaced the failed weld as well as the welds neighboring the failure. No additional welds of similar poor quality were identified during the inspections. Note: This was determined to be an original construction weld from initial plant start up.
Redwing_2	Forced	First Superheater Leaks	09/01/2017	09/03/2017	Boiler	Superheater Tube Leak		7 similar failures during this reporting period	Superheater section was replaced during the 2018 outage.
Redwing_2	Forced	First Superheater Leaks	09/10/2017	09/12/2017	Boiler	Superheater Tube Leak		7 similar failures during this reporting period	Superheater section was replaced during the 2018 outage.
Redwing_2	Forced	First Superheater Leaks	09/22/2017	09/27/2017	Boiler	Superheater Tube Leak		7 similar failures during this reporting period	Superheater section was replaced during the 2018 outage.
Redwing_2	Forced	First Superheater Leaks	09/30/2017	10/01/2017	Boiler	Superheater Tube Leak		7 similar failures during this reporting period	Superheater section was replaced during the 2018 outage.
Wilmart_1	Forced	First Superheater Leaks	09/14/2017	09/17/2017	Boiler superheat tube	Boiler superheat tube leak		7 similar failures during this reporting period	Superheater section was replaced during the spring outage 2018.
OCTOBER 2017									
King_G1	Forced	Wet Coal (OMC)	10/01/2017	10/08/2017	This is not a forced outage situation. This was a derate due to wet coal.	There was no equipment failure involved.		No similar events were reported during this reporting period	During signicant rain/snow events coal loading of crushers, belts, chutes and other equipment can result in a derate that is out of operational control.
SHERCO_G1	Forced	Waterwall (Furnace Wall)	10/12/2017	10/15/2017	Waterwall tube leak between blowers C23 and C24. Also discovered a front reheat tube leak while off line, pendant #99 tube #4.	Waterwall leak was from sootblower erosion due to an inoperable rotational motor on C23. Reheat tube was a longitudinal crack due to sootblower erosion.		Similar event on Unit 2 for this reporting period on 10/12/2017 and 5/17/2018.	Replaced tubes. Checked operation of all sootblowers, aligned all wallblowers, replaced remaining thin tubes in area during 2018 overhaul. Due to the impending 2026 retirement date of the unit, reheat section tube leaks will be managed via O&M repair/replace vs a large capital investment to replace this boiler section.
SHERCO_G1	Forced	Waterwall (Furnace Wall)	10/16/2017	10/18/2017	Management decisison to conservatively keep pressure lower following tube leak repair to avoid exposing new repairs and other suspected thin tubes to full pressure until Unit 2 tube leak repair could be completed.	Tubes adjacent to tubes replaced during the last unit 1 overhaul suspected as thin. The unit was kept at a lower pressure to mitigate potential tube failure while unit 2 was offline for tube leak repair.		Similar event on Unit 2 for this reporting period on 10/12/2017 and 5/17/2018 This event is a continuation of the Unit 1 event beginning 10/12/2017.	Replaced tubes. Checked operation of all sootblowers, aligned all wallblowers, replaced remaining thin tubes in area during 2018 overhaul. Due to the impending 2026 retirement date of the unit, reheat section tube leaks will be managed via O&M repair/replace vs a large capital investment to replace this boiler section.
SHERCO_G1	Forced	Turbine Gland Seal System	10/19/2017	10/23/2017	11 Steam Gland Exhauster	Motor drive end shaft bearing failure. Unit was derated with an alternate steam exhaust path until a new motor arrived and then taken off line for repair.		Similar event on Unit 1 for this reporting period from 8/12/2017 to 8/15/2017.	Motor was sent to L&S for emergency repair and reinstalled. New exhauster assembly installed during the 2018 overhaul. Adjusted inspection frequency of blower assembly to every 3 years.

Unit Outage Information

2018 AAA Reporting Period: July 1, 2017 - June 30, 2018

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[PROTECTED DATA BEGINS

Unit	Outage Category	Primary Reason for outage	Outage Dates Start	End	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	Wet Scrubber Mist Eliminators/demisters & Washdown	10/01/2017	10/12/2017	Scrubber Modules	Ash buildup on fields, spargers, and other components resulting in inefficient particulate removal and high stack opacity. Aging of equipment requires regular maintenance. Unit needed to be derated to perform other normal cleaning functions such as flushing, high voltage cleaning, and manual nightly cleaning. Upgrades to emissions control equipment have resulted in the need for more aggressive cleaning in addition to normal equipment maintenance.		Multiple similar derates during this reporting period.	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. We are testing a chemical additive in one of the modules that may reduce the amount of time a module has to be out of service for manual cleaning.
SHERCO_G2	Forced	Waterwall (Furnace Wall)	10/12/2017	10/17/2017	Management decisison to avoid a dual unit outage by keep unit 2 available in a derate by lowering pressure until Unit 1 was restored to operation due to a tube leak repair.	Leak on offset tubes for wallblower 2A15 that could be managed with lower boiler pressure until the tube leak was repaired on unit 1.		Similar event for Unit 1 for this reporting period on 10/12/2017 and Unit 2 on 5/17/2018.	Replaced tube. We will inspect non-pressure to pressure part connections at sootblower openings during the unit 2 2019 overhaul for similar failures.
SHERCO_G2	Forced	Waterwall (Furnace Wall)	10/17/2017	10/18/2017	Waterwall tube leak near A15 soot blower.	Leak on offset tubes for wallblower 2A15. The leak propagated at the termination of the membrane to tube weld at the sootblower offset tubing.		Similar event for Unit 1 for this reporting period on 10/12/2017 and on Unit 2 5/17/2018. This event is a continuation of the Unit 2 event beginning 10/12/2017.	Replaced tube. We will inspect non-pressure to pressure part connections at sootblower openings during the unit 2 2019 overhaul for similar failures.
SHERC3	Forced	Turbine control valves	10/03/2017	10/06/2017	Turbine Control Valve #2	The valve closing spring seat was installed incorrectly within the spring can with an eye bolt still attached. Eventually the eye bolt became free and became lodged within the valve internals, preventing complete closure.		No similar failures were reported during this reporting period.	These control valves were serviced in the spring of 2017 by MD&A. The valves were removed and installed on-site during the overhaul by GE.
SHERC3	Forced	Blowdown System Piping	10/10/2017	10/11/2017	18 inch plant drain pipe	Drain pipe from the blowdown tank had become plugged due sediment buildup. This limited boiler blowdown caused a delay in water cleanup and increased plant startup time.		No similar failures were reported during this reporting period.	WOMA was used to clean out enough to prevent any more backup of water. Entire section will be completely cleaned out during 2020 overhaul. Annual cleaning maintenance plan to be put in place for cleaning of sediment traps in piping vaults.
Wilmart_1	Forced	First Superheater Leaks	10/07/2017	10/11/2017	Boiler superheat tube	Boiler superheat tube leak		7 similar failures during this reporting period.	Superheater section was replaced during the spring outage 2018.
Wilmart_1	Forced	First Superheater Leaks	10/20/2017	10/23/2017	Boiler superheat tube	Boiler superheat tube leak		7 similar failures during this reporting period.	Superheater section was replaced during the spring outage 2018.
Wilmart_1	Forced	First Superheater Leaks	10/28/2017	10/31/2017	Boiler superheat tube leak	Boiler superheat tube leak		7 similar failures during this reporting period.	Superheater section was replaced during the spring outage 2018.
Wilmart_1	Forced	First Superheater Leaks	10/31/2017	11/01/2017	Boiler superheat tube leak	Boiler superheat tube leak		7 similar failures during this reporting period.	Superheater section was replaced during the spring outage 2018.
Redwing_2	Forced	First Superheater Leaks	10/01/2017	10/03/2017	Boiler	Superheater Tube Leak		7 similar failures during this reporting period.	Superheater section was replaced during the 2018 outage.
Redwing_2	Forced	First Superheater Leaks	10/05/2017	10/07/2017	Boiler	Superheater Tube Leak		7 similar failures during this reporting period.	Superheater section was replaced during the 2018 outage.
Redwing_2	Forced	Gen. Stator Windings, Bushings, And Terminals	10/07/2017	11/01/2017	Main Generator	Generator synched out of phase due to a delayed closure of the output control breaker.		No similar failures were reported during this reporting period.	Generator output breaker was replaced and the Generator was rewound.

Unit Outage Information									
2018 AAA Reporting Period: July 1, 2017 - June 30, 2018									
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Unit	**Outage Category**	**Primary Reason for outage**	**Outage Dates Start**	**End**	**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**
French_1	Maintenance	Minor Boiler Overhaul (less Than 720 Hours)	10/20/2017	10/24/2017	Boiler	Preventative maintenance outage for periodic cleaning and inspection.		Similar events occur every 4-6 weeks.	Preventative maintenance cycle to periodically address boiler fouling, fuel delivery system and other components to aid reliable operation.
French_2	Maintenance	Minor Boiler Overhaul (less Than 720 Hours)	10/13/2017	10/16/2017	Boiler	Preventative maintenance outage for periodic cleaning and inspection.		Similar events occur every 4-6 weeks.	Preventative maintenance cycle to periodically address boiler fouling, fuel delivery system and other components to aid reliable operation.
NOVEMBER 2017									
SHERCO_G1	Forced	Flue Gas Expansion Joints	11/18/2017	11/19/2017	12 and 13 ID fan outlet expansion joints	Tears in the joints caused by flow turbulence encountered from being physically located close to the damper.		No similar failures were reported during this reporting period.	Temporary repair put in place at time of failure. Joints were replaced during the 2018 overhaul and deflector plates were added to minimize turbulence issue.
SHERCO_G1	Forced	Other Boiler Instrumentation and Control Problems	11/23/2017	11/28/2017	Distributed Controls System	Unit 1 controls replacement was completed during the 2015 overhaul. We experienced a hidden system response which caused fuel and air swings contributing to already existing opacity issues requiring conservative action.		No similar failures were reported during this reporting period.	We are working with our controls vendor to optimize tuning for boiler response.
SHERCO_G2	Forced	Other Pulverizer Problems	11/01/2017	11/05/2017	22 Coal Mill Classifier	Classifier drive belt failure.		Similar failure during this reporting period on 12/26/2017 and 6/6/2018.	Alternative design drive belt installed allowing for faster changeout, however, we are finding they only last about 9 months compared to 3 years for the original. Original style belt will be installed during next mill overhaul as it lasts longer.
SHERCO_G2	Forced	Opacity - Fossil Steam Units	11/07/2017	11/12/2017	Scrubber Modules	Ash buildup on fields, spargers, and other components resulting in inefficient particulate removal and high stack opacity. Aging of equipment requires regular maintenance. Unit needed to be derated to perform other normal cleaning functions such as flushing, high voltage cleaning, and manual nightly cleaning. Upgrades to emissions control equipment have resulted in the need for more aggressive cleaning in addition to normal equipment maintenance.		Multiple similar derates during this reporting period.	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. We are testing a chemical addititive in one of the modules that may reduce the amount of time a module has to be out of service for manual cleaning.

Unit Outage Information

2018 AAA Reporting Period: July 1, 2017 - June 30, 2018

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Unit	Outage Category	Primary Reason for outage	Outage Dates Start	End	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	Opacity - Fossil Steam Units	11/23/2017	11/27/2017	Scrubber Modules	Ash buildup on fields, spargers, and other components resulting in inefficient particulate removal and high stack opacity. Aging of equipment requires regular maintenance. Unit needed to be derated to perform other normal cleaning functions such as flushing, high voltage cleaning, and manual nightly cleaning. Upgrades to emissions control equipment have resulted in the need for more aggressive cleaning in addition to normal equipment maintenance.		Multiple similar derates during this reporting period.	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. We are testing a chemical additive in one of the modules that may reduce the amount of time a module has to be out of service for manual cleaning.
SHERC3	Forced	High Pressure Heater Tube Leaks	11/02/2017	11/15/2017		Due to single block isolation valve arrangement on these heaters, the unit had to be removed from service to facilitate repairs. This time period is the derate required with the heater out of service until unit was taken off line for repairs on 11/15/2017.		Similar event during this reporting period involving 36-1 High Pressure Heater from 6/1/2018 to 6/8/2018 and 36-2 High Pressure Heater from 6/8/2108 to 6/13/2018.	This heater is original equipment. All four high pressure feedwater heaters are nearing end of life and are scheduled to be replaced in the 2020 and 2023 overhauls. A double isolation valve arrangement will also be installed in 2020 to facilitate on line repairs.
SHERC3	Forced	High Pressure Heater Tube Leaks	11/15/2017	11/17/2017	36-2 High Pressure Feedwater Heater	Due to single block isolation valve arrangement on these heaters, the unit had to be removed from service to facilitate repairs. One failed and two missing pop-a-plugs discovered.		Similar event during this reporting period involving 36-1 High Pressure Heater from 6/1/2018 to 6/8/2018 and 36-2 High Pressure Heater from 6/8/2108 to 6/13/2018. This time period is the off line repair time following the derate which started on 11/2/2017.	The three failed plugs were replugged using welded plugs and stabilizer cables installed. 3 other tubes were plugged in the surrounding area based on inspection results. This heater is original equipment. All four high pressure feedwater heaters are nearing end of life and are scheduled to be replaced in the 2020 and 2023 overhauls. A double isolation valve arrangement will also be installed in 2020 to facilitate on line repairs.
SHERC3	Forced	Condensate/hotwell Pumps	11/19/2017	11/30/2017	31 Condensate Pump	The motor had been removed to resolve a chronic leak, upon re-install the pump failed to deliver flow. The pump shaft failed along with first stage impeller key resulting in additional damage to the pump.		No similar failures were reported during this reporting period.	Pump was rebuilt by a vendor including modifications to change the pump head. A new spare pump is being purchased from the OEM to minimize future down time.
French_2	Forced	Circulating Water Pumps	11/01/2017	11/30/2017	#2 circulating water pump	Circulating water impeller was replaced.		This was not a failure. This was a planned replacement of the impeller due to a modification made 5 years ago.	This was a planned outage to address a possible de-rate condition on unit 2 turbine generator due to normal degradation of the circulating water pump.
Redwing_2	Forced	Gen. Stator Windings, Bushings, And Terminals	11/01/2017	11/30/2017	Main Generator	Generator synched out of phase due to a delayed closure of the output control breaker		No similar failures were reported during this reporting period. This is a continuation of the event beginning 10/7/2017.	Generator output breaker replaced and the Generator was rewound.

Unit Outage Information

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[PROTECTED DATA BEGINS

Unit	Outage Category	Primary Reason for outage	Outage Dates Start	End	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
Wilmart_1	Forced	Minor Boiler Overhaul (less Than 720 Hours)	11/26/2017	11/30/2017	walking floor replacement	Walking floor at end of life.		No similar failures were reported during this reporting period.	Walking floor slates replaced during this outage and future install of distribution plate finalized to extend life of the floor. Replacement of slates scheduled for 2023.
DECEMBER 2017									
SHERC3	Forced	Condensate System	12/01/2017	12/31/2017	31 Condensate Pump	The motor had been removed to resolve a chronic leak, upon re-install the pump failed to deliver flow. The pump shaft failed along with first stage impeller key resulting in additional damage to the pump.		No similar failures were reported during this reporting period. This is a continuation of the 11/19/17 event.	Pump was rebuilt by a vendor including modifications to change the pump head. A new spare pump is being purchased from the OEM to minimize future down time.
SHERCO_G2	Forced	Boiler Fuel Supply from Bunkers to Boiler	12/26/2017	12/27/2017	26 Coal Mill Classifier	Classifier drive belt failure.		Similar failure during this reporting period on 11/1/2017 and 6/6/2018.	Alternative design drive belt installed allowing for faster changeout; however, we are finding they only last about 9 months compared to 3 years for the original. Original style belt will be installed during next mill overhaul as it lasts longer.
SHERCO_G1	Forced	Wet Scrubbers	12/29/2017	12/31/2017	Scrubber Modules	Ash buildup on fields, spargers, and other components resulting in inefficient particulate removal and high stack opacity. Aging of equipment requires regular maintenance. Unit needed to be derated to perform other normal cleaning functions such as flushing, high voltage cleaning, and manual nightly cleaning. Upgrades to emissions control equipment have resulted in the need for more aggressive cleaning in addition to normal equipment maintenance.		Multiple similar derates during this reporting period.	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. We are testing a chemical additive in one of the modules that may reduce the amount of time a module has to be out of service for manual cleaning.
Wilmart_1	Forced	Boiler Overhaul and Inspections	12/01/2017	12/03/2017	walking floor replacement	Walking floor at end of life.		No similar failures were reported during this reporting period. Continuation of the event beginning 11/26/2017.	Walking floor slates replaced during this outage and future install of distribution plate finalized to extend life of the floor. Replacement of slates scheduled for 2023.
Wilmart_2	Forced	Boiler Overhaul and Inspections	12/01/2017	12/03/2017	walking floor replacement	Walking floor at end of life.		No similar failures were reported during this reporting period.	Walking floor slates replaced during this outage and future install of distribution plate finalized to extend life of the floor. Replacement of slates scheduled for 2023.
Redwing_1	Forced	Controls\Slag and Ash Removal	12/06/2017	12/08/2017	Traveling Grate Bed	Carrier chain within traveling grate bed failed.		No similar failures were reported during this reporting period.	Repaired the chain and performed PM inspection during February 2018 major boiler outage.
King_G1	Forced	Circulating Water Systems (OMC)	12/07/2017	12/10/2017	Intake traveling screens	Frazil ice caused blockage at the intake traveling screens resulting in a loss of vacuum to the main turbine and a subsequent trip.		No similar failures were reported during this reporting period	This event is classified as Outside of Management Control (OMC) due to the atmospheric conditions required for the formation of frazil ice.

Unit Outage Information									
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Unit	Outage Category	Primary Reason for outage	Outage Dates Start	End	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 2018									
King_G1	Forced	Reheater plugged derate	01/21/2018	01/24/2018	First Reheater Slagging Or Fouling	Fouling/plugging of the Reheater section of the boiler resulted in high differential pressure.		This fouling eventually lead to a forced outage to clean the Reheater section.	The contributing factors were; extended high load operation, higher sodium content coal and higher FEGT operations. Actions taken; operational procedures are in place to ensure that an adequate load reduction and subsequent slag shed occur during extended high load operations. Fuels is restricting the amount of high sodium coal delivered.
SHERCO_G1	Forced	Unit derate to 530 MWn due to cleaning on U/L fields	01/01/2018	01/02/2018	Scrubber Modules	Ash buildup on fields, spargers, and other components resulting in inefficient particulate removal and high stack opacity. Aging of equipment requires regular maintenance. Unit needed to be derated to perform other normal cleaning functions such as flushing, high voltage cleaning, and manual nightly cleaning. Upgrades to emissions control equipment have resulted in the need for more aggressive cleaning in addition to normal equipment maintenance.		Multiple similar derates during this reporting period.	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. We are testing a chemical addititive in one of the modules that may reduce the amount of time a module has to be out of service for manual cleaning.
SHERCO_G1	Forced	Derate to HOL of 420 MW net. (7) scrubber module operation for HV cleaning and flushing.	01/06/2018	01/08/2018	Scrubber Modules	Ash buildup on fields, spargers, and other components resulting in inefficient particulate removal and high stack opacity. Aging of equipment requires regular maintenance. Unit needed to be derated to perform other normal cleaning functions such as flushing, high voltage cleaning, and manual nightly cleaning. Upgrades to emissions control equipment have resulted in the need for more aggressive cleaning in addition to normal equipment maintenance.		Multiple similar derates during this reporting period.	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. We are testing a chemical addititive in one of the modules that may reduce the amount of time a module has to be out of service for manual cleaning.

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	Outage		Outage Dates		Q1. Equipment that resulted	Q2. Description of	Q3. Change in	Q4. Failure History	Q5. Steps Taken to
Unit	Category	Primary Reason for outage	Start	End	in the forced outage	Equipment Failure	Energy Costs	During Reporting Period	Alleviate Reoccurrence
SHERCO_G1	Forced	Derate to HOL. Scrubber module HV cleaning, flushing and NOx reduction.	01/27/2018	01/29/2018	Scrubber Modules	Ash buildup on fields, spargers, and other components resulting in inefficient particulate removal and high stack opacity. Aging of equipment requires regular maintenance. Unit needed to be derated to perform other normal cleaning functions such as flushing, high voltage cleaning, and manual nightly cleaning. Upgrades to emissions control equipment have resulted in the need for more aggressive cleaning in addition to normal equipment maintenance.		Multiple similar derates during this reporting period.	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. We are testing a chemical addititive in one of the modules that may reduce the amount of time a module has to be out of service for manual cleaning.
SHERCO_G2	Forced	Derate due to 5 coal mill operation.	01/09/2018	01/13/2018	24 Coal Mill	While 23 mill was out of service for a gearbox inspection, 24 coal mill removed from service due to excessive spillage.		Similar issue to 25 coal mill during this reporting period on 3/26/2018 to 4/13/2018.	Mill floor clamp ring segment came loose and lodged under journal. The segment was replaced and bolted back into place. Bolts likely failed due to mechanical fatigue or possibly due to tramp metal going through the mill
SHERCO_G2	Forced	Derate to HOL. Scrubber module HV cleaning, flushing and NOx reduction.	01/27/2018	01/29/2018	Scrubber Modules	Ash buildup on fields, spargers, and other components resulting in inefficient particulate removal and high stack opacity. Aging of equipment requires regular maintenance. Unit needed to be derated to perform other normal cleaning functions such as flushing, high voltage cleaning, and manual nightly cleaning. Upgrades to emmissions control equipment have resulted in the need for more aggressive cleaning in addition to normal equipment maintenance.		Multiple similar derates during this reporting period.	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. We are testing a chemical addititive in one of the modules that may reduce the amount of time a module has to be out of service for manual cleaning.
SHERC3	Forced	31 Condensate Pump Issues. Pump removed from service.	01/01/2018	01/31/2018	31 Condensate Pump	The motor had been removed to resolve a chronic leak, upon re-install the pump failed to deliver flow. The pump shaft failed along with first stage impeller key resulting in additional damage to the pump.		No similar failures were reported during this reporting period. This is a continuation of the 11/19/17 event.	Pump was rebuilt by a vendor including modifactions to change the pump head. A new spare pump is being purchased from the OEM to minimize future down time.
French_1	Maintenance	U1 Boiler Cleaning and Inspection	01/26/2018	01/30/2018	Boiler	Preventative maintenance outage for periodic cleaning and inspection.		Similar events occur every 4-6 weeks.	Preventative maintenance cycle to periodically address boiler fouling, fuel delivery system and other components to aid reliable operation.
Redwing_2	Forced	Generator Rewind Needed	01/01/2018	01/31/2018	Main Generator	Generator synched out of phase due to a delayed closure of the output control breaker.		No similar failures were reported during this reporting period. This is a continuation of the event beginning 10/7/2017.	Generator output breaker replaced and the Generator was rewound.

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CCRiverside1	Forced	Hydrogen leak on U7 steam turbine generator required unit shut down and de-gas of generator for repairs	01/04/2018	01/08/2018	Unit 7 Steam Turbine Generator, NOTE: CCRiverside 1 refers to Unit 9 Combustion Turbine plus 1/2 of Unit 7 Steam Turbine. Steam turbine is common to both combustion turbines.	Following the Fall 2017 Major Steam Turbine Overhaul a hydrogen leak developed on the generator end bells. Thus, the steam turbine and generator were unavailable until repaired which also makes both combustion turbines unavailable.		No similar failures during this reporting period.	Generator end bells were inspected and re-secured , no leakage issues expereinced since.
CCRiverside2	Forced	Hydrogen leak on U7 steam turbine generator required unit shut down and de-gas of generator for repairs	01/04/2018	01/08/2018	Unit 7 Steam Turbine Generator, NOTE: CCRiverside 2 refers to Unit 10 Combustion Turbine plus 1/2 of Unit 7 Steam Turbine. Steam turbine is common to both combustion turbines.	Same event as Riverside1, above.		No similar failures during this reporting period.	Same event as Riverside1, above. Corrective actions to unit 7 address both Riverside1 and Riverside2 events.
King_G1	Forced	Unit to come offline to repair 17A HP Feedwater Heater leak	01/06/2018	01/07/2018	17A Feedwater Heater	Four previously install tube plugs were leaking		No similar failures were reported during this reporting period	The leaking plugs were replaced with welded plugs.
King_G1	Forced	Reheater plugged - offline to clean	01/24/2018	01/27/2018	First Reheater Slagging Or Fouling	First Reheater Slagging Or Fouling.		Tthe reheat section was almost completely plugged (20% open space) with an ash deposit that is tougher than usual to remove. The reheater was cleaned to approximately 60%-80% clean leaving only the upper portions fouled. It is believed this will be sufficient to operate until the spring overhaul.	The contributing factors were; extended high load operation, higher sodium content coal and higher FEGT operations. Actions taken; operational procedures are in place to ensure that an adequate load reduction and subsequent slag shed occur during extended high load operations. Fuels is restricting the amount of high sodium coal delivered.
FEBRUARY 2018									
SHERCO_G1	Forced	Circulating Water Systems	02/11/2018	02/22/2018	11 Boiler Circulating Water Pump Motor	Motor Elecrical Failure		No similar failures were reported during this reporting period.	This motor was scheduled to be replaced with a rewound motor during the overhaul but failed two weeks early. Replacement occurred during the overhaul.
SHERCO_G2	Forced	Wet Scrubbers	02/10/2018	02/12/2018	Scrubber Modules	Ash buildup on fields, spargers, and other components resulting in inefficient particulate removal and high stack opacity. Aging of equipment requires regular maintenance. Unit needed to be derated to perform other normal cleaning functions such as flushing, high voltage cleaning, and manual nightly cleaning. Upgrades to emissions control equipment have resulted in the need for more aggressive cleaning in addition to normal equipment maintenance.		Multiple similar derates during this reporting period.	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. We are testing a chemical addititive in one of the modules that may reduce the amount of time a module has to be out of service for manual cleaning.

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SHERCO_G2	Forced	Wet Scrubbers	02/24/2018	02/25/2018	Scrubber Modules	Ash buildup on fields, spargers, and other components resulting in inefficient particulate removal and high stack opacity. Aging of equipment requires regular maintenance. Unit needed to be derated to perform other normal cleaning functions such as flushing, high voltage cleaning, and manual nightly cleaning. Upgrades to emissions control equipment have resulted in the need for more aggressive cleaning in addition to normal equipment maintenance.		Multiple similar derates during this reporting period.	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. We are testing a chemical addititive in one of the modules that may reduce the amount of time a module has to be out of service for manual cleaning.
SHERC3	Forced	Condensate System	02/01/2018	02/28/2018	31 Condensate Pump	The motor had been removed to resolve a chronic leak, uponre-install the pump failed to deliver flow. The pump shaft failed along with first stage impeller key resulting in additional damage to the pump.		No similar failures were reported during this reporting period. This is a continuation of the 11/19/17 event.	Pump was rebuilt by a vendor including modifactions to change the pump head. A new spare pump is being purchased from the OEM to minimize future down time.
Wilmart_1	Forced	Slag and Ash Removal	02/11/2018	02/27/2018	C-9, DC conveyor, RDF Scalper	Main RDF fuel supply to the plant broken pans causing scalper to be unable to run.		No similar failures were reported during this reporting period.	Repaired broken pans on scalper. Scheduled for replacement in 2022
Wilmart_2	Forced	Boiler Fuel Supply to Bunker	02/19/2018	02/27/2018	RDF Scalper	Main RDF fuel supply to the plant broken pans causing scalper to be unable to run.		No similar failures were reported during this reporting period.	Repaired broken pans on scalper. Scheduled for replacement in 2022
King_G1	Forced	Boiler Tube Fireside Slagging or Fouling	02/05/2018	02/10/2018	First Reheater Slagging Or Fouling	First Reheater Slagging Or Fouling		A second cleaning outage is required to complete reheater section cleaning. The cleaning is more extensive, greater than the estimated 60% to 80% cleaning conducted during the January 24 - 27 cleaning. This cleaning enables us to operate to the planned spring outage on March 23, 2018.	The contributing factors were; extended high load operation, higher sodium content coal and higher FEGT operations. Actions taken; operational procedures are in place to ensure that an adequate load reduction and subsequent slag shed occur during extended high load operations. Fuels is restricting the amount of high sodium coal delivered.
French_1	Forced	Generator	02/06/2018	02/28/2018	Generator	The rotor windings retaining blocks were breaking causing high vibrations.		No similar failures were reported during this reporting period.	All retaining blocks on the generator rotor were replaced.
Redwing_2	Forced	Generator	02/01/2018	02/28/2018	Main Generator	Generator synched out of phase due to a delayed closure of the output control breaker.		No similar failures were reported during this reporting period. This is a continuation of the event beginning 10/7/2017.	Generator output breaker replaced and the Generator was rewound.

Unit Outage Information

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MARCH 2018									
SHERCO_G2	Forced	Boiler Air and Gas Systems	03/01/2018	03/02/2018	24 ID Fan	Broken inlet damper linkage. The threaded stud which connects the west inlet damper clevis to the damper operating mechanism had broken just where the thread met the existing weld. It was noted that there had been an existing crack evidenced by oxidation. Due to years of operation, constant motion, the stud failed. Condition based wear likely due to cycling/load follow operations.		No similar failures were reported during this reporting period.	Thourough inspection of ID fan linkages will be performed during the 2019 overhaul. Inspections were completed on the Unit 1 linkages during the 2018 overhaul.
SHERCO_G2	Forced	Boiler Fuel Supply from Bunkers to Boiler	03/12/2018	03/13/2018	22 Coal Mill	Mill and transport line fire. Damage to transport line gaskets, classifier bearings, classifier rotor, mill floor, and mill liners. Derate until 21 mill which had been out for maintenance could be restored.		No similar failures were reported during this reporting period.	Classifier was completely rebuilt, piping gaskets were replaced, and mill liners were repaired/replaced. Hot spots, which ignite mill fires, typically occur near areas of worn liners. Plant plans to continually to inspect all mills annually as a minimum.
SHERCO_G2	Forced	Boiler Fuel Supply from Bunkers to Boiler	03/19/2018	03/20/2018	21 Coal Feeder motor	Failed clutch on the motor. Loss of redundancy with 22 mill out of service following fire event.		No similar failures were reported during this reporting period.	Clutch was replaced.
SHERCO_G2	Forced	Boiler Fuel Supply from Bunkers to Boiler	03/26/2018	03/31/2018	25 Coal Mill	Bowl hub cover had come loose and pyrite skirt was badly damaged due to tramp metal going through the mill. Repairs completed while 22 Mill was unavailable due to repairs sustained during the fire event resulting in only 5 coal mills being available.		Similar to issue on 24 coal mill during this reporting period on 1/9/18 and 1/13/2018.	The bowl hub cover and the pyrite skirts were repaired. Sherco Coal Yard is taking steps to identify areas that may have tramp iron and to segregate from rest of coal pile.
SHERC3	Forced	Condensate System	03/01/2018	03/31/2018	31 Condensate Pump	The motor had been removed to resolve a chronic leak, upon re-install the pump failed to deliver flow. The pump shaft failed along with first stage impeller key resulting in additional damage to the pump.		No similar failures were reported during this reporting period. This is a continuation of the 11/19/17 event.	Pump was rebuilt by a vendor including modifactions to change the pump head. A new spare pump is being purchased from the OEM to minimize future down time.
Redwing_2	Forced	Generator	03/01/2018	03/31/2018	Main Generator	Generator synched out of phase due to a delayed closure of the output control breaker.		No similar failures were reported during this reporting period. This is a continuation of the event beginning 10/7/2017.	Generator output breaker replaced and the Generator was rewound.

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Unit	Outage Category	Primary Reason for outage	Outage Dates Start	End	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
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APRIL 2018									
SHERCO_G2	Forced	5 Mill Coal operation due to high door temps on 25 Mill	04/01/2018	04/28/2018	25 Coal Mill	Bowl hub cover had come loose and pyrite skirt was badly damaged due to tramp metal going through the mill. Repairs completed while 22 Mill was unavailable due to repairs sustained during the fire event resulting in only 5 coal mills being available. 25 mill returned on 4/13/2018 at which time 27 mill was taken out for overhaul as we anticipated it would fail prior to 22 mill return.		This is a continuation of the event starting 3/26/2018. Similar to issue on 24 coal mill during this reporting period on 1/9/18 and 1/13/2018.	The bowl hub cover and the pyrite skirts were repaired. Sherco Coal Yard is taking steps to identify areas that may have tramp iron and to segregate from rest of coal pile.
SHERC3	Forced	31 Condensate Pump Issues. Pump removed from service.	04/01/2018	04/30/2018	31 Condensate Pump	The motor had been removed to resolve a chronic leak, uponre-install the pump failed to deliver flow. The pump shaft failed along with first stage impeller key resulting in additional damage to the pump.		No similar failures were reported during this reporting period. This is a continuation of the 11/19/17 event.	Pump was rebuilt by a vendor including modifactions to change the pump head. A new spare pump is being purchased from the OEM to minimize future down time.
Anson_G4	Forced	LCI power supply	04/18/2018	04/21/2018	Power Supply	Complete Loss of functionality.		No similar failures were reported during this reporting period.	Power Supply Replaced.
Redwing_2	Forced	Generator Rewind Needed	04/01/2018	04/30/2018	Main Generator	Generator synched out of phase due to a delayed closure of the output control breaker.		No similar failures were reported during this reporting period. This is a continuation of the event beginning 10/7/2017.	Generator output breaker replaced and the Generator was rewound.
MAY 2018									
King_G1	Forced	High Pressure Turbine	05/29/2018	05/31/2018	High Pressure Turbine	Turbine over thrust event which occurred during system testing.		No similar failures were reported during this reporting period.	Complete review of logic associated with turbine trip restoration for consistency with Alstom guidance specifically as it pertains to turbine flow paths. Placed moratorium on the practice of relatching the steam turbine following a turbine trip from 3600 RPM.
CCRiverside1	Forced	Circulating Water Systems	05/25/2018	05/31/2018	#6 Circulating Water Pump	Circulating Water Pump developed high vibrations requiring the pump to be removed for inspection. With warmer river temperatures (above 50 F) condenser vacuum can not be maintained when running both Riverside units. Therefore, one CT must be held out of service.		No similar failures during this reporting period.	Condition based wear on #6 Circulating Water Pump wchich was sent off site for inspection and repair. Bearings were replaced. Going forward, each of the two circulating water pumps will be overhauled every two years during the winter months to minimize impact of pump outages.
SHERCO_G1	Forced	Boiler Fuel Supply from Bunkers to Boiler	05/18/2018	05/30/2018	12 PA Fan	Unit derate to to high vibration until troubleshooting efforts could be completed.		No similar failures were reported during this reporting period.	Rotor indications were blend-grinded, four of which required weld repair. Replaced outboard bearing. Corrected inlet vane rubbing issue, the vanes were removed and the shafts were trimmed. Tightened loose motor hold-down bolts.

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SHERCO_G1	Forced	Boiler Fuel Supply from Bunkers to Boiler	05/30/2018	05/31/2018	12 PA Fan	Unit off-line to repair fan. Completed NDE inspections of the rotor, inspections of the inlet vanes, outlet vanes, ductwork, fan inlets (pantlegs), inlet cones,etc. Discovered several indications on the rotor (likely original fabrication defects). 4 of the 12 inlet vanes on the inboard side of the fan were threaded too far into the collar allowing the inlet vane shafts to rub on the main fan shaft.		No similar failures were reported during this reporting period. This is a continuation of the derate which started on 5/18/2018.	Rotor indications were blend-grinded, four of which required weld repair. Replaced outboard bearing. Corrected inlet vane rubbing issue, the vanes were removed and the shafts were trimmed. Tightened loose motor hold-down bolts.
SHERCO_G2	Forced	Boiler Fuel Supply from Bunkers to Boiler	05/01/2018	05/31/2018	27 Coal Mill	27 coal mill taken out of service to complete needed mill overhaul while 22 coal mill was out of service for fire event repairs		No similar failures were reported during this reporting period.	This was not a failure. 27 mill was taken out for a needed overhaul while 22 was out for repairs to avoid any damage which would extend out of service time and increase cost.
SHERCO_G2	Forced	Boiler Tube Leaks	05/17/2018	05/19/2018	Waterwall leak near B23	Tube adjacent to the west offset tube for wallblower B23 brought the unit offline due to a leak. The tube leak was repaired with the through-wall repair strategy.		Similar events during this reporting period for both Units 1 and 2 on 10/12/2017.	We will inspect tubes near wall blowers for thinning and cracking during the 2019 overhaul.
SHERC3	Forced	Condensate System	05/01/2018	05/04/2018	31 Condensate Pump	The motor had been removed to resolve a chronic leak, upon re-install the pump failed to deliver flow. The pump shaft failed along with first stage impeller key resulting in additional damage to the pump.		No similar failures were reported during this reporting period. This is a continuation of the 11/19/17 event.	Pump was rebuilt by a vendor including modifications to change the pump head. A new spare pump is being purchased from the OEM to minimize future down time.
SHERC3	Forced	Boiler Fuel Supply from Bunkers to Boiler	05/04/2018	05/10/2018	310 Coal Mill	Discovered one rotating throat segment where all three bolts had failed and the lower support clip had broken off, allowing it to rub against the mill wall. They also found several other sheared rotating throat bolts that all required repair. In addition to the bolts, they found that many of the lower support clips under the rotating throat assembly had cracked welds where they attach to the extension ring.		No similar failures were reported during this reporting period.	Repaired failed rotating throat bolts, replaced lower support clips and added additional weld to strenghten the connection to the ring seat. The OEM has proposed a design modification that should mitigate these bolt and clip failures. This design modification will be installed in the next mill overhaul.
Anson_G3	Forced	Miscellaneous (Gas Turbine)	05/25/2018	05/31/2018	Turbine Vibration	High Vibration due condition based wear.		No similar failures were reported during this reporting period.	Unit held out until completion of Major Overhaul Scheduled for September 2018
CC Highbridge2	Forced	HRSG Boiler Piping System	05/09/2018	05/11/2018	U8 HRH Bypass Valve	Bypass Valve stuck due to magnetite binding between plug and guide bushing.		Similar event on June 6 2018.	Plant has ordered modified valve trim with an integral strainer and modified plug to extend valve maintenance interval without sticking.
Redwing_2	Forced	Generator	05/01/2018	05/04/2018	Main Generator	Generator synched out of phase due to a delayed closure of the output control breaker.		No similar failures were reported during this reporting period. This is a continuation of the event beginning 10/7/2017.	Generator output breaker replaced and the Generator was rewound.

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Unit	Outage Category	Primary Reason for outage	Outage Dates Start	End	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
CCRiverside1	Planned	Miscellaneous (Balance of Plant)	05/09/2018	05/24/2018	This is not a Forced Outage. Plant performed a Planned Outage during this time window.	No equipment failures.		Not applicable. Planned outage.	Not applicable. Planned outage.
CCRiverside2	Planned/Maintenance	Miscellaneous (Balance of Plant)\Circulating Water Systems	05/07/2018	05/24/2018	Planned Outage for entire plant from 5/9 - 5/24 (see line item above for Riverside1). The dates of 5/7-5/8 were a maintenance outage	Maintenance outage portion related to #6 Circulating Water pump issues (see line 112 above). Pump developed high vibration and needed to be repaired.		The #6 Circulating Water Pump is the same event as line 112. The event began prior to the Planned Outage Window and continued after the Planned Outage was complete.	Maintenance outage portion is the same event as Riverside1, see line item 112 above. Corrective actions to address both Riverside1 and Riverside2.
CCRiverside2	Forced	Miscellaneous (Gas Turbine)	05/30/2018	05/31/2018	#6 Circulating Water Pump	Continuation of previous event. Circulating Water Pump developed high vibrations requiring the pump to be removed for inspection. With warmer river temperatures (above 50 F) condenser vacuum can not be maintained when running both Riverside units. Therefore, one CT must be held out of service.		No similar failures during this reporting period. Continuation of previously reported event.	Condition based wear on #6 Circulating Water Pump wchich was sent off site for inspection and repair. Bearings were replaced. Going forward, each of the two circulating water pumps will be overhauled every two years during the winter months to minimize impact of pump outages.
JUNE 2018									
SHERCO_G1	Forced	Circulating Water Systems	06/07/2018	06/30/2018	11 Boiler Circulating Water Pump	Excessive vibration on the pump required removal from service and subsequent derate. Currently suspect a bent shaft or wear ring alignment issue.		No similar failures were reported during this reporting period.	Pump will be removed during the upcoming chemical clean outage in September 2018 and repairs made. Corrective actions will be taken once the failure mechanism is understood.
SHERCO_G2	Forced	Boiler Fuel Supply from Bunkers to Boiler	06/01/2018	06/02/2018	27 Coal Mill	27 coal mill taken out of service to complete needed mill overhaul while 22 coal mill was out of service for fire event repairs.		This is a continuation of the event beginning 4/16/2018. No similar failures were reported during this reporting period.	This was not a failure. 27 mill was taken out for a needed overhaul while 22 was out for repairs to avoid any damage which would extend out of service time and increase cost.
SHERCO_G2	Forced	Boiler Fuel Supply from Bunkers to Boiler	06/06/2018	06/07/2018	25 Coal Mill Classifier	Classifier drive belt failure.		Similar failure during this reporting period on 11/1/2017 and 12/26/2017.	Alternative design drive belt installed allowing for faster changeout, however, we are finding they only last about 9 months compared to 3 years for the original. Original style belt will be installed during next mill overhaul as it lasts longer.
SHERCO_G2	Forced	Boiler Fuel Supply from Bunkers to Boiler	06/20/2018	06/21/2018	27 Coal Mill	High Vibration. Unit was derated to perform troubleshooting on this mill.		No similar failures were reported during this reporting period.	27 mill taken out of service for internal inspection. No issues were identified that could cause high vibration.
SHERC3	Forced	Feedwater System	06/01/2018	06/05/2018	36-1 High Pressure Feedwater Heater	Due to single block isolation valve arrangement on these heaters, the unit had to be removed from service to facilitate repairs. This time period is the derate required with the heater out of service until unit was taken off line for repairs on 6/5/2018.		Similar event during this reporting period involving 36-2 High Pressure Heater from 11/2/2017 to 11/17/2017 and 36-2 High Pressure Heater from 6/8/2018 to 6/13/2018.	This heater is original equipment. All four high pressure feedwater heaters are nearing end of life and are scheduled to be replaced in the 2020 and 2023 overhauls. A double isolation valve arrangement will also be installed in 2020 to facilitate on line repairs.

Unit Outage Information									
2018 AAA Reporting Period: July 1, 2017 - June 30, 2018									
	Updated since originally filed in monthly FCAs due to further analysis.						**[PROTECTED DATA BEGINS**		
Unit	**Outage Category**	**Primary Reason for outage**	**Outage Dates Start**	**End**	**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**
SHERC3	Forced	Feedwater System	06/05/2018	06/08/2018	36-1 High Pressure Feedwater Heater	Due to single block isolation valve arrangement on these heaters, the unit had to be removed from service to facilitate repairs. One new leaking tube, one leaking welded plug and eight previously plugged tubes missing plugs discovered.		Similar event during this reporting period involving 36-2 High Pressure Heater from 11/2/2017 to 11/17/2017 and 36-2 High Pressure Heater from 6/8/2018 to 6/13/2018. This time period is the off-line repair time following the derate which started on 6/1/2018.	Leaking tube and three surrounding plugged and missing plugs replaced. Stabilizer cable installed on inlet side of leaking tube. This heater is original equipment. All four high pressure feedwater heaters are nearing end of life and are scheduled to be replaced in the 2020 and 2023 overhauls. A double isolation valve arrangement will also be installed in 2020 to facilitate on line repairs.
SHERC3	Forced	Feedwater System	06/08/2018	06/10/2018	36-2 High Pressure Feedwater Heater	Due to single block isolation valve arrangement on these heaters, the unit had to be removed from service to facilitate repairs. This time period is the derate required with the heater out of service until unit was taken off line for repairs on 6/10/2018.		Similar event during this reporting period involving 36-2 High Pressure Heater from 11/2/2017 to 11/17/2017 and 36-1 High Pressure Heater from 6/1/2018 to 6/8/2018.	This heater is original equipment. All four high pressure feedwater heaters are nearing end of life and are scheduled to be replaced in the 2020 and 2023 overhauls. A double isolation valve arrangement will also be installed in 2020 to facilitate on line repairs.
SHERC3	Forced	Feedwater System	06/10/2018	06/13/2018	36-2 High Pressure Feedwater Heater	Due to single block isolation valve arrangement on these heaters, the unit had to be removed from service to facilitate repairs. One failed welded plug and one failed pop-a-plug discovered.		Similar event during this reporting period involving 36-1 High Pressure Heater from 6/1/2018 to 6/8/2018 and 36-2 High Pressure Heater from 11/2/2017 to 11/17/2017. This time period is the off line repair time following the derate which started on 6/8/2018.	Leaking plugs welded, eight additional pitted tube plugged. This heater is original equipment. All four high pressure feedwater heaters are nearing end of life and are scheduled to be replaced in the 2020 and 2023 overhauls. A double isolation valve arrangement will also be installed in 2020 to facilitate on line repairs.
SHERC3	Forced	Boiler Air and Gas Systems	06/25/2018	06/26/2018	32 Secondary Air Heater	Motor Electrical Failure		Similar event involving Unit 1, 11 Air Heater Drive Motor during this reporting period on 7/22/2017.	Replaced Motor. Check magnetic coupling every overhaul for proper alignment. Replace motor every 6 years, Replace motor bearings in the overhaul year when motor is not being replaced.
Wilmart_2	Forced	Boiler Tube Leaks	06/23/2018	06/27/2018	Boiler superheat tube	Boiler superheat tube leak		No similar failures were reported during this reporting period.	Superheater scheduled replacement during fall outage 2018.
King_G1	Forced	Boiler Tube Leaks	06/20/2018	06/29/2018	Secondary Superheater (SSH) boiler tube	Final SSH section on the leading edge of the tube. There was moderate collateral damage to the surrounding tubes.		No similar failures were reported during this reporting period.	Damaged boiler tubes were replaced or repaired. Six sections of tube needed to be replaced and 5 pad welds on surrounding tubes.
French_2	Forced	Circulating Water Systems\Boiler Tube Leaks	06/22/2018	06/27/2018	Boiler economizer	Tube leaks.		No similar failures were reported during this reporting period.	It is scheduled for replacement in fall of 2018.

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Unit Outage Information									
2018 AAA Reporting Period: July 1, 2017 - June 30, 2018									
	Updated since originally filed in monthly FCAs due to further analysis.						[PROTECTED DATA BEGINS		
Unit	**Outage Category**	**Primary Reason for outage**	**Outage Dates Start**	**End**	**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**
CC Highbridge2	Forced	HRSG Boiler Piping System	06/06/2018	06/07/2018	U8 HRH Bypass Valve	Bypass Valve stuck due to magnetite binding between plug and guide bushing.		Similar event on May 9, 2018.	Plant has ordered modified valve trim with an integral strainer and modified plug valve to reduce frequency of sticking. Installation Fall 2018.
CC Highbridge2	Forced	Condensate System	06/08/2018	06/10/2018	U8 LP Preheater in HRSG	Tube leak at lower header due to corosion fatigue cracking.		No similar failures were reported during this reporting period.	Major NDE inspection with ultrasonic phased array testing to identify additional cracks requiring repair is planned for Fall 2018.
CC Highbridge2	Forced	HRSG Boiler Internals and Structures	06/22/2018	06/25/2018	U8 HP steam drum door	Steam leak on drum door		No similar failures were reported during this reporting period.	New style gasket installed that is designed to handle thermal cycling was installed. New 6 bolt drum doors have been ordered and will be installed in Fall 2018 outage.
CCRiverside1	Forced	Auxiliary	06/03/2018	06/05/2018	Unit 9 Hydraulic Pump fitting failure.	Hydraulic oil line fitting developed leak which required the unit to be removed from service for repair and oil clean up.		No similar failures during this reporting period.	Root cause was a failed o-ring. O-ring was replaced along with checking other fittings to ensure no other issues identified.
						PROTECTED DATA ENDS]			

The 2016-2030 Resource Plan Update modeling was based on ICAP ratings that were developed by the company's Performance Testing and Monitoring group. The Company then developed UCAP rating for use in the Strategist planning model.

	2016-2030 Resource Plan	2016-2030 Resource Plan	July, 2017	July, 2017
Network Resource	ICAP (Summer)	UCAP (Summer)	ICAP (summer) (1)	UCAP (summer) (1)
NSP.ALDRIHERC	34	23	23	0
NSP.ANSON2	109	86	98	89
NSP.ANSON3	109	78	98	78
NSP.ANSON4	168	144	148	126
NSP.BAYFRN	41	64	25	25
NSP.BIGFALL_A	4	3	6	6
NSP.CC.BLKD52	298	213	281	270
NSP.BLUEL1	50	37	40	38
NSP.BLUEL2	49	39	40	38
NSP.BLUEL3	46	38	39	37
NSP.BLUEL4	48	41	44	40
NSP.BLUE_LK7	174	154	154	141
NSP.BLUE_LK8	177	151	155	149
OTP.BRDRS1	-	-	150	38
NSP.CANFLSG1	179	157	157	156
NSP.CANFLSG2	179	155	156	150
NSP.CEDARFAL	3	2	5	5
NSP.CHEMOLSPO	262	235	243	235
NSP.CHPFAL	9	7	10	10
NSP.CORNEL	15	11	8	8
OTP.COURTENAY	-	-	200	31
OTP.FIBROMIN	55	47	39	39
NSP.FRENCH1	16	15	5	5
NSP.FRENCH2	-	-	5	5
NSP.FRENCH3	81	58	62	62
NSP.FRENCH4	81	58	59	56
NSP.GDMEADOW	101	14	100	16
NSP.GRANCT1	16	9	13	13
NSP.GRANCT2	16	11	14	14
NSP.GRANCT3	16	12	14	14
NSP.GRANCT4	16	10	13	9
NSP.HENNIPIN1	5	4	11	11
NSP.CC.HIBRDG	575	521	532	525
NSP.HOLCOM	15	11	23	23
NSP.INVRHL1	62	40	49	47
NSP.INVRHL2	62	45	48	45
NSP.INVRHL3	62	44	48	39
NSP.INVRHL4	62	40	49	44
NSP.INVRHL5	61	38	47	40
NSP.INVRHL6	61	39	49	43
NSP.JIMFL	24	18	30	30
NSP.KING1	511	520	537	497

	2016-2030 Resource Plan	2016-2030 Resource Plan	July, 2017	July, 2017
Network Resource	ICAP (Summer)	UCAP (Summer)	ICAP (summer) (1)	UCAP (summer) (1)
NSP.CC.MANKATO	357	277	310	298
NSP.MENOMOA	2	2	0	0
NSP.MNMETHANE	5	1	4	4
NSP.MNTCEL1	648	611	636	603
NSP.NOBLES	201	34	200	38
NSP.ODELL1	-	-	200	0
NSP.PVALEY	-	-	200	26
NSP.PINEBEND	12	5	4	4
NSP.PKFLSFLAM	16	11	14	0
NSP.PRISL	1,092	1,036	1049	983
NSP.RAPIDA1	5	3	2	2
NSP.REDWIN1	18	19	8	8
NSP.REDWIN2	-	-	8	8
NSP.CC.RIVRSD	487	450	460	452
NSP.SHAKOBIO1	12	12	12	12
NSP.SHERCO1	680	694	703	693
NSP.SHERCO2	682	672	710	694
NSP.SHERC3	515	487	531	521
NSP.SPGSPG1 (St. Paul Co-Gen)	25	25	23	23
NSP.STCLOUD1	9	7	7	7
NSP.STCRO	15	11	17	17
NSP.WHEATO1	56	40	47	40
NSP.WHEATO2	70	44	53	32
NSP.WHEATO3	56	43	48	41
NSP.WHEATO4	61	40	49	43
NSP.WHEATO5	70	43	0	0
NSP.WHEATO6	70	31	49	45
NSP.WILMAR1	18	17	8	8
NSP.WILMAR2	-	-	8	8
NSP.WISSOT	17	12	21	21
MHEB (375/325 MW System Purchase)	371	363	371	368
MHEB (350 MW Diversity Exchange)	350	342	350	343
MHEB (75 MW)	75	73	75	62
Laurentian Energy Authority	35	32	61	30
Solar Aggregate PPA's	108	46	164	135
Solar Community Solar Gardens	-	-	60	31
Hydro Aggregate PPA's	185	2	15	15
Wind Aggregate PPA's	1,373	181	1353	226
Total	11,547	8,858	11,650	9,080

(1) Resources and Capacity as reported in the 2017/2018 MISO GVTC

Northern States Power Company
Electric Operations - State of Minnesota
Unusual Items Over $500,000 During FCA Reporting Period *

FCA Filing Period	Item Pertaining To	Period Affected	Descriptions	Amounts	FCA Impact
Jul-17	None				
Aug-17	None				
Sep-17	None				
Oct-17	None				
Nov-17	None				
Dec-17	Coal SAP Account 5004001	October 2017	Fall Coal Survey Adjustment impacting Sherco Plant	($2,027,137)	Yes
Jan-18	Coal SAP Account 5004001	November 2017	Sherco Coal Plant erroneously reporting 31 days of coal consumption in November when there are only 30 days in the month. A correction (ie. addition back to inventory) was booked in Jan 2018.	($897,060)	Yes
Feb-18	Asset Sale to Flint Hills Resources Pine Bend, LLC	February 2018	Gain on sale of Inver Hills generating plant facilities (land and oil tanks) sharing (Docket No. E002/PA-17-529)	($1,929,053)	Yes
Mar-18	None				
Apr-18	None				
May-18	None				
Jun-18	Coal SAP Account 5004001	April 2018	Spring Coal Survey Adjustment impacting King and Sherco Plants	($1,188,596)	Yes

* Reporting requirement pursuant to Commission Order in 2008-2009 and 2009-2010 AAA (Docket Nos. E999/AA-09-961 & E999/AA-10-884) item 30:
"Xcel shall 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."

2011 AAA Ordered Reporting Requirements

On August 16, 2013, the Commission issued its ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS, REQUIRING REFUND OF CERTAIN CURTAILMENT COSTS, AND REQUIRING ADDITIONAL FILINGS in Docket No. E999/AA-11-792, the 2011 AAA report docket. In compliance with this Order, the Company has included the following information as part of this report:

1. MISO Schedule 10 Costs

Order Point 18 of the Commission Order states:

> *…The electric utilities shall provide in the initial filing of all future electric AAA reports the Minnesota jurisdictional Schedule 10 costs together with the allocation factor used and support for why the allocator is reasonable. Additionally, the electric utilities shall 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.*

Part I Section 1 provides the MISO Schedule 10 costs and allocation factors for the 2017-2018 AAA reporting period as well as for the 2016-2017 AAA reporting period for comparison. The accompanying support for why the allocation factors are reasonable, and the support for theincrease in costs, is also included in Part I, Section 1.

2. Congestion Costs

Order Point 20 of the Commission Order requests data relating congested paths, including related costs and revenues.

a. Hourly LMP Data

Subpart a) requires utilities to:

> *Provide hourly data on Day-Ahead Locational Marginal Price (LMP) basis, including energy, line losses, and congestion charges for each generation node, each load node, and Minnesota Hub for the current AAA period. The Department requests that utilities send this data to the DOC in Access file format and include a separate reference guide defining all column headers.*

Part K Section 5 Schedule 1 provides the specified information for 2017-2018 to be sent to the Department on a CD as an Access database. Two of the data fields ("MW" and "NativeMW") are Not Public data. The following fields are included on the CD:

Field	**Description**
Date_Time	Time and Hour
Location	Common Name
LMP Node	MISO Node Name
LoadAward	Load for Load Nodes, Award for Generation Nodes, and Market for MINN.HUB
Type	NAE – Non-Asset Energy, Asset Energy
MW	Total MWs awarded in Day-Ahead Markets (Positive for Loads, negative for Generators). **This field is NOT PUBLIC**.
NativeMW	MWs assigned to Native. **This field is NOT PUBLIC.**
LMP	Day-Ahead Locational Marginal Price for the Node
MCC_DayAhead	The Marginal Congestion Cost Component of the Day-Ahead LMP
MLC_DayAhead	the Marginal Loss Cost Component of the Day-Ahead LMP

b. Congestion Analysis

Subparts b) and c) require utilities to:

b. Perform the following analysis based on the above requested data:
i. Identify hours in which congestion costs are incurred between a generation node and load node (path);
ii. Sum the qualifying congestion costs by path (multiplying MW times difference in Marginal congestion costs Mcc for each path); and
iii. Identify the ten paths with the highest amount of congestion costs for current AAA period.

c. Include the ten paths identified above and the total of their congestion costs. For each path, also answer the following questions:
i. What is the Company's Financial Transmission Rights (FTRs) hedging positions and Auction Revenue Rights (ARRs) for these ten paths?
ii. Identify all FTR revenues, ARR revenues, congestion expenses, and the resulting net congestion cost or revenue for these ten paths.
iii. Based on the Company responses to a, b, and c.i. and c.ii., what cost-effective improvements could be considered to reduce the congestion amounts for the identified paths?

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	Net 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	Summer 2017	
[PROTECTED DATA BEGINS		**Peak**	**Peak Off**
			PROTECTED DATA ENDS]

Generation Node	Load Node	Fall 2017	
[PROTECTED DATA BEGINS		Peak	Peak Off
			PROTECTED DATA ENDS]

Generation Node	Load Node	Winter 2017-2018	
[PROTECTED DATA BEGINS		Peak	Peak Off
			PROTECTED DATA ENDS]

Generation Node	Load Node	Spring 2018	
[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]

3. Transmission Maintenance Expense

Order Point 22 states:

> *In future AAA filings, Xcel, Minnesota Power, Otter Tail Power, and Interstate Power and Light shall provide the information needed for the Department's Table 8 in its Report (Actual Transmission Maintenance Expense Compared to Amounts Built into Rates).*

The table below shows the actual transmission maintenance expense for 2016 and 2017 compared to the amounts built into the Company's original 2016 test year filed in Docket No. E002/GR-15-826. A Settlement was approved in this case which did not specifically quantify O&M expense levels included in base rates. The table below shows State of Minnesota jurisdictional amounts.

2016 Actual	2017 Actual	Two-Year Average	2016 Test Year As Filed	2017 Plan Year As Filed
$14,873,320	$11,547,014	$13,210,167	$14,519,959	$13,706,950

4. Transformer Reporting

Order Point 23a requires utilities to:

> *…use Xcel's reporting format for the table found in Part H, Sections 1 – 8, page 3 of 6, but with the incorporation of all transformers on a utility's system, and with status of each transformer identified as one of these four categories: in-service standalone, in-service duplicate, on-order, or storage.*

Part H, Section 4 provides a table illustrating the NSP system spare transformer inventory including whether the transformers are on-order or in storage.

Part H, Section 4, Schedule 1 provides a list of all in-service NSP system transformers over 100 kV, including whether the transformers are in either the in-service standalone or in-service duplicate categories.

Order Point 23b requires utilities to:

> *…provide information regarding policy on backup strategies for transformers*

Part K, Section 5, Schedule 2 provides a policy we submit with MISO which provides the criteria used by the Transmission Planning area when studying the performance of the NSP System.

Order Point 23c requires utilities to:

> *…provide their policy for transformer maintenance*

Part K, Section 5, Schedule 3 provides a draft policy of the maintenance program for power transformers and load tap changers on the bulk electric system.

Part K, Section 5, Schedule 1

This attachment has been submitted to the Department of Commerce separately on disk as an Access database due to its voluminous nature.

PURPOSE

This document, effective January 13th, 2017 provides the criteria to be used by the transmission planners when studying the performance of Northern States Power Company - Minnesota and Northern States Power Company - Wisconsin (jointly referred to as NSP) transmission facilities. This includes voltage, line loading, transient stability, flicker, and transmission line reclosing criteria. The document also provides guidance for acceptable forms of mitigation plans and NSP's policy for use of remedial action schemes.

APPLICABILITY AND RESPONSIBILITIES

Northern States Power Company – Minnesota and Northern States Power Company – Wisconsin

AUTHORS

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VERSION HISTORY

Effective Date	Version Number	Supersedes	Change
2/4/2013	1.0	N/A	Initial ProjectWise Document. Original document version is 1.0—ProjectWise version
3/18/2015	2.0	1.0	-Updated the nuclear plant voltage requirements -Added the criterion for Ferranti voltage rise -Added transformer loading criteria for planning -Updated damping criteria for stability analysis -Update Criteria for TPL-001-4 Standard -Update interim mitigation plans in Transmission Plans section -Replaced Special Protection Systems (SPS) with Remedial Action Schemes (RAS)
1/13/2017	3.0	2.0	-Updated bus voltage criteria Table 2

			-Changed Section 3 from Voltage Deviation to Rapid Voltage Change to better align with IEEE 1453 terminology -Removed RAS exception for sub-synchronous resonance

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1. Voltage Criteria

When performing steady state analysis, the following voltage criteria applies to NSP's buses under system intact (pre contingent) and post contingent conditions:

Table 1

Facility	Maximum voltage (p.u.) Pre Contingent	Minimum voltage (p.u.) Pre Contingent	Maximum voltage (p.u.) Post Contingent	Minimum voltage (p.u.) Post Contingent
Default for all buses > 100 kV	1.05	0.95	1.05	0.92
Default for all buses < 100 kV*	1.05	0.95	1.05	0.92
Default for all generator buses**	1.05	0.95	1.05	0.95

*For 34.5 kV and below non-generation buses, pre and post contingent voltage of 0.9PU would be acceptable.
**For all Category P0, P1, P2, P4, P5, and P7 contingencies. [1] After a Category P3 or P6 contingency, generator bus voltage would be allowed to drop to 0.92 PU.

Table 1 above presents the general voltage criteria for most of the NSP owned facilities; however specific voltage criteria exist for some of the high voltage buses, these criteria are listed below in Table 2

Table 2

Facility	Maximum (p.u.) Pre Contingent	Minimum (p.u.) Pre Contingent	Maximum (p.u.) Post Contingent	Minimum (p.u.) Post Contingent
Roseau 500 kV bus	1.10	0.95	1.10	0.92
Prairie 115 kV main bus	1.09	0.95	1.09	0.90
Prairie 115 kV capacitor bus	1.15	0.95	1.15	0.92
Sheyenne 115 kV capacitor bus	1.15	0.95	1.15	0.92
Running 230 kV capacitor bus	1.10	0.95	1.10	0.92
Roseau 230 kV capacitor bus	1.05	0.95	1.10	0.92
Chisago 500 kV bus	1.10	0.95	1.10	0.92
Forbes 500 kV bus	1.10	0.95	1.10	0.92
Bison 345 kV bus	1.05	0.95	1.10	0.92
Briggs Road 345 kV bus	1.05	0.95	1.10	0.92

In order to comply with the NUC-001 standard, for nuclear plant off-site source requirements, specific voltage criteria has to be met for Prairie Island and Monticello substation buses. The Nuclear Plant Interface Requirements (NPIR) provides the voltage requirements for the nuclear plants. Contact NSP's transmission planning group to obtain the most up to date voltage criteria for the nuclear plants.

1.1 Ferranti Voltage Rise

Voltage rise on open end of a long line, due to charging current, has to be taken into account when performing line energization studies. The maximum permissible voltage on the open end of the line is 1.05 PU unless the equipment (CCVTs, PTs and Breakers) at the open end of the line are rated to withstand higher voltage. [2]

2. Facility Loading Criteria

The ratings for facilities (transmission lines, transformers and series compensators) owned by NSP are specified in the NSP Ratings Database. The winter and summer ratings of facilities account for the thermal limit of all equipment, and relay loadability limits, as specified in NERC FAC-008-3 standards.

When planning NSP's system, for system intact condition, the current flowing through a facility should not exceed the normal rating of that facility. When studying contingency conditions, the current flowing through a facility should not exceed the emergency rating of that facility. During transmission outages, it should be assumed that the system operators, if required, would take remedial action when the current on a facility is lower than the emergency rating and greater than the normal rating. When such remedial action is not available, the normal rating of the facility should be used.

Certain facilities on NSP's system are dynamically rated, the ratings of these facilities change based on the ambient conditions, such as wind speed. When monitoring these facilities for overloads, appropriate ratings have to be chosen. The up-to-date list of dynamically rated transmission lines can be obtained from NSP's Transmission Planning or Transmission Operations Departments.

2.1 Transformer Loading Criteria for Planning Studies

When performing transmission planning studies for NSP's system the applicable transformer ratings are as follows (the percentages are based on the continuous rating of the transformer):

Table 3

Contingency	**Summer**	**Winter**
System Intact (Category P0)	100%	100%
Post Contingent (Category P1-P7)	115%	130%

The overload capability of the transformer is applicable only if there are no other limiting elements (such as bus conductor, CTs, bushings, switches or breakers) on the transformer branch. In the presence of a limiting element, the transformer branch rating would be limited by the lowest rated equipment.

3. Rapid Voltage Change Criteria

When performing planning studies for the transmission system, the following criteria applies to the NSP's system:

- The maximum voltage deviation caused by switching of any shunt device (motor load, capacitor or inductor), under system intact condition, should not exceed more than 3% at any load serving bus. [3]
- The maximum voltage deviation caused by switching of any shunt device (motor load, capacitor, or inductor), during prior outage of the largest fault current contributing element, should not exceed more than 5% at any load serving bus.

4. Voltage stability criteria

Voltage stability analysis is performed as part of load serving studies, as well as generation outlet studies, to identify the maximum transfer capability of the transmission system before a voltage collapse occurs. While performing this analysis, sufficient voltage margin has to be maintained by operating at or below Pcrit. Pcrit is determined by developing PV (Power-voltage) curves for those buses that have the largest contribution to voltage instability for any given outage. P_{limit} is calculated as the lesser of

- (0.9) * P_{crit} [where P_{crit} is defined as the maximum power transfer or system demand (nose of PV curve)] or
- The maximum power transfer or system demand which does not result in a post-contingent voltage violation as defined in Tables 1 and 2.

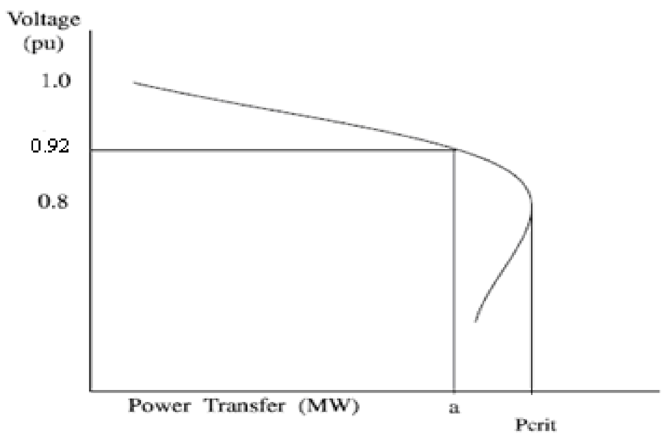

Figure 4.1

5. Steady state planning contingencies evaluated

The contingencies used for planning studies are based on the currently effective NERC TPL-001-4 standard. Refer to Table 1 of TPL-001-4 standard for the category P0 to P7 contingency events evaluated for NSP's Bulk Electric System.

For facilities not classified as Bulk Electric System, only category P0, P1, and P2.1 (opening of line section without fault) contingencies are evaluated.

6. Transient Voltage Criteria

When performing transient stability studies, after the fault is cleared, the following criteria apply to post fault voltages on NSP's buses.

Table 4

Facility	Vmax P.U	Vmin P.U
Default for all Buses	1.2	0.7
Fast Switched Capacitor buses	1.65 P.U for <5 cycles	0.7

NSP does not allow the transient voltage to dip below .7 p.u. for any amount of time.

7. Damping Criteria for Transient Stability Studies

When performing transient stability studies, the following criteria apply to generator angle oscillations:

- The generator angles should always be positively damped
- The successive peak ratio (SPPR), defined by
  SPPR=Successive swing amplitude / Previous swing amplitude
  should be less than 0.95
- The damping factor defined by
  %Damping factor = (1-SPPR)*100
  should be at least 5%

Prony analysis could be used to identify the modes. The damping factors of the modes could be calculated using the following expression:

$$\text{Damping ratio } \zeta = -\sigma / \sqrt{(\sigma^2+\omega^2)}$$

Where $\sigma \pm j\omega$ represents the mode and the frequency of the mode is given by $\omega/2\pi$.

The damping ratio, for disturbances with faults, should be at least 0.0081633. The damping ratio, for disturbances without faults, should be at least .016766.

8. Distance Relaying - Apparent Impedance Criteria

The transient apparent impedance swings on all lines can be monitored by the PSS/E model "MRELY1" against a three zone mho circle characteristics described below:

Circle A = 1.00 x line impedance
Circle B = 1.25 x line impedance
Circle C = 1.50 x line impedance

Apparent impedance transient swings into Circles A or B are considered unacceptable. Any violation of this criterion has to be investigated to ensure that additional transmission elements do not trip after the fault is cleared. Any valid violation has to be appropriately mitigated.

In addition to the generic distance relay model, specific models are included for the out of step relays on the tie lines between US and Manitoba Hydro system. When performing planning studies, it should be ensured that relay margins for the out of step relays are respected as required by the respective transmission owner. Any unintended tripping of the out of step relays is not acceptable. Any valid violation of these criteria has to be communicated with the transmission owner and should be mitigated if required.

9. Types of Disturbances Studied

The disturbances simulated for the planning studies are based on the currently effective NERC TPL-001-4 standard.

10. Sync Check Relay - Angle Separation Criteria

When reclosing a transmission line, sync check relays are used to ensure that the angle separation between the two ends of the line is not too large. This is to ensure generators, close to either end of the transmission line, do not sustain damage due to large change in power. NSP allows a maximum angle separation of 30 degrees for reclosing of a transmission line.

Under certain conditions, lines could be allowed to reclose at angle separation greater than 30 degrees. In order to allow reclosing lines, with angle separation greater than 30 degrees, switching studies have to be performed to demonstrate that the change in power at any generator does not exceed 50% of its rated power. [1]

11. Short Circuit Criteria

When planning the transmission system, the fault current design capabilities of the facilities should be respected. This includes

- Fault interrupting device capabilities
- Ground grid burn off, and Step and Touch potentials
- Structural strength of bus spans, insulators, etc.
- Personal Protection Equipment for maintenance

Any violation of facilities' capability or personal safety has to be mitigated appropriately.

12. Transmission Plans

Any valid violation of criteria, listed in sections 1 through 11, identified through planning study or assessment has to be addressed by developing an appropriate transmission plan. The plans could involve building new transmission facilities or upgrading existing transmission facilities or re-configuring existing transmission system without causing any new violations.

In addition, use of under-voltage load shedding, reverse power relays, and over current relays could be an acceptable interim mitigation plan for violations of this criteria due to single initiating events. When determining settings on relays to trigger automatic action, operational considerations should be evaluated against the Planning criteria. Settings higher or lower than the established Planning criteria may be necessary to achieve optimal system operation. Deviations from this criterion in the operational timeframe should be evaluated on a case-by-case basis.

Operating guides are used by system operators to address specific challenges that are encountered during the day to day operation of the transmission system and to meet the NERC TOP standards. For long term planning purpose, use of operating guides to meet the NERC TPL standards should be limited to address violations associated with prior outage conditions or to address violations associated with category P6 contingencies.

13. Other Studies

Additional technical studies should be performed as required to maintain system reliability and to follow good utility practice. These include studies related to voltage imbalance, harmonics, sub-synchronous resonance, small signal stability, etc.

14. NSP's policy for use of Remedial Action Schemes

It is NSPM and NSPW (jointly NSP) policy not to install, own or administer new Remedial Action Schemes (RAS), or to expand any existing RAS, to mitigate pre- or post-contingent system reliability concerns on the NSP transmission system (NSP System) or the transmission system of an interconnected neighboring utility transmission system. Reliability concerns include, but are not limited to thermal overloads, voltage violations, and system stability violations.

14.1 Retirement of existing RASs owned by NSP

For each RAS already placed in service on the NSP System, periodic reviews will be performed to ensure that the RAS is deactivated by NSP when the conditions requiring its use no longer exist, or system improvements necessary to remove the RAS are in service.

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14.2 Modification of existing RASs Owned by NSP

Modification of existing RASs would be allowed if a new transmission project requires altering the facilities associated with an existing RAS. This type of modification should be backed by a supporting technical study that demonstrates that the system reliability would not be degraded due to the modification. In addition, the required approvals from the regional reliability organization should also be obtained in accordance with NERC PRC-15 standard.

The modification of existing RASs would not be allowed for generator or load interconnections, transmission service requests or to avoid generation curtailment of existing generation resources.

14.3 New Temporary RAS

New temporary RASs could be allowed on NSP's transmission system only if the following conditions are met:

1. If the RAS is needed as a temporary measure to maintain system reliability during construction of a transmission project, such that the RAS could be retired after the completion of the project.
2. If the RAS is proposed as a short term measure to provide transmission service or allow generator or load interconnection. This would be allowed only if there is a written agreement with NSP, with a committed in-service date for the transmission facilities that would eliminate the need for the RAS.

In order to install the temporary RAS, technical studies have to be performed to demonstrate that the system reliability is not degraded. In addition, approval has to be obtained from the regional reliability organization in accordance with the NERC PRC-015 standard.

Midwest reliability Organization (MRO) reviews the effectiveness of each RAS every 5 years. NSP would not participate in this review of temporary RAS at the end of the fourth year, and will retire the temporary RAS at the end of fourth year. This could result in the generator or load losing its ability to stay interconnected to the transmission system or lose its transmission service, if the transmission facilities required for retiring the RAS are not in-service.

Temporary RASs would not be installed to avoid generation curtailment of existing or future generators that are designated "Energy Resource".

14.4 RASs Owned by Entities Other Than NSP

NSP would not support or participate in the installation of RASs by any entity on NSP's system that would require tripping or switching of NSP's transmission facilities or any generating facility interconnected to NSP's transmission system.

For a RAS owned and administered by an entity other than NSP, that does not require tripping of NSP's transmission facilities or generating facilities interconnected to NSP's transmission system, that requires installation of monitoring and communication equipment on the NSP System, NSP will cooperate with installation of such monitoring and communications equipment on the NSP System, provided the following conditions are met:

1) The entity owning and administering the RAS agrees to perform the necessary technical studies required to support the need, and the impact of the RAS on the transmission system, as required by applicable NERC standards for Special Protection Systems, and obtain the necessary approval from the applicable regional entity (e.g., the Midwest Reliability Organization)

2) The entity owning the RAS agrees to be responsible for complying with misoperation reporting requirements as required by the applicable NERC standards for RASs, and will be responsible for coordinating any corrective actions with the NSP System.

3) The entity identified as the Transmission Operator of the RAS, for the RAS owner, would be solely responsible for monitoring the status of the RAS and notifying affected entities of changes in the status of the RAS, including any degradation or potential failure to operate as expected as required by PRC-001-1 R6 and IRO-005-3a R9.

Works Cited

[1] IEEE Std C50.13 TM-2014, IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above.

[2] IEEE Std 37.012TM-2014, IEEE Guide for the Application of Capacitance Current Switching for AC High-Voltage Circuit Breakers Above 1000 V

[3] IEEE Std 1453TM-2015, IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems.

Transmission System Policy	
Xcel Energy	
Maintenance Plan for Transmission & Distribution Power Transformers and Load Tap Changers	**VERSION: 1.0**
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1.0 PURPOSE

- Define the time-condition-event based prioritization system to be utilized to predict the need for inspection and maintenance.
- Define the maintenance and diagnostic testing plans.
- Define the specific maintenance and diagnostic testing procedures for power transformers and load tap changers (LTCs).
- Document the required data to plan and schedule maintenance and diagnostic testing activities.
- Document the required data to be collected during the substation inspections, diagnostic testing, and maintenance of the power transformers and LTCs.

2.0 APPLICABILITY AND RESPONSIBILITIES

- To define a consistent and common plan and procedures for all Xcel Energy Operating Companies for the maintenance of transmission and distribution substation power transformers and LTCs.

3.0 APPROVERS

Name	Title
Dave Cenedella	Director, System Sustainability
Greg Bennett	Director, Substation CO&M
Philippa Narog	Director, Transmission Business Operations

4.0 VERSION HISTORY

Effective Date	Version Number	Supercedes	Change
11/25/2014	1.0	n/a	Initial version

TABLE OF CONTENTS

Document Structure and Governance Process

THIS SECTION IS THE SAME FOR ALL SUBSTATION MAINTENANCE PLAN/PROCEDURE DOCUMENTS

This document is part of a set of documents describing Xcel Energy's overall Substation Maintenance Plan/Procedures. These documents define the Substation Maintenance philosophy, policy, plans and procedures for all operating companies.

Substation Maintenance Plan and Procedures
For
Power Transformers and Load Tap Changers

Purpose

Background

This document has been developed to define a consistent plan and procedure for all Xcel Energy Operating Companies for the maintenance of transmission and distribution substation transformers and on-load tap changers[1] (this document uses LTC specifically for the on-load tap changer). Transformers in this procedure include power transformers, grounding banks, and include all transformers where it is possible to take an oil sample without removing the transformer from service. Proper and appropriate maintenance and diagnostic testing of transformers that may or may not have a LTC to manage voltage is essential to system reliability and operations; failure of transformers of any type is expensive, requiring extensive effort to repair and or install a new unit and may adversely affect thousands of customers and reliability statistics.

The overall plan and specific procedures establish requirements for:

- Annual or quarterly ***DGA Testing*** of oil filled transformer compartments including the main tank and the LTC compartment or compartments (i.e. independent selector switch compartments) to evaluate the condition of the asset including the transformer windings, water, dissolved gases, LTC contact condition, etc. The frequency of the DGA test is dependent upon:
    - Initial installation testing of new or rebuilt transformers
    - Voltage and size of the transformer
    - Previous DGA testing that had shown any issues in the transformer
- Annual ***Infrared Inspection*** of the transformer including the on-load LTC and no-load tap changer[2] compartments.
- Annual ***Comprehensive Oil Testing*** of samples taken from every transformer compartment including the main tank and the LTC compartment or compartments (i.e. independent selector switch compartments) to evaluate the condition of the asset through oil condition including the transformer windings, water, furans, LTC contact condition, etc.
- Periodic complete diagnostic inspection and testing of ***Ancillary Transformer Equipment*** based on the transformer cooling design and the size of the transformer.

The purpose of this plan and procedure is to:

- Define the periodic transformer diagnostic inspection plan: dissolved gas analysis, complete oil analysis, and infrared inspection.
- Define the annual on-load LTC diagnostic inspection plan: dissolved gas analysis, complete oil analysis, and infrared inspection.

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[1] On-load tap changers are capable of making adjustments to the transformer turns ratio while energized and carrying load.
[2] Transformers are often equipped with a no load tap changer that is set to the proper turns ratio (voltage ratio of high side and low side of the transformer) before the transformer is energized.

- Define the diagnostic testing plan of the peripheral (ancillary) apparatus portion of the transformer[3] based on a Maintenance number formula that ties the transformer cooling system, MVA size, overall condition and the value of the asset to the Xcel system and time since the previous ancillary diagnostic inspection to the scheduling of the work.
- Document the required data to plan, schedule and record maintenance and diagnostic testing activities.
- Document the required data to be collected during the substation inspections, DGA, diagnostic oil testing, infrared scanning and maintenance of the peripheral portions of the transformer.
- Document the storage of data for easy retrieval and reference for future inspections.

Scope

The Transmission and Distribution Transformer and LTC plan establishes the maintenance drivers and minimum required periodic visual inspection, quarterly and annual diagnostic testing, evaluation of the test results, and diagnostics of the transformer ancillary assets. No internal inspections are scheduled based on time or the Maintenance number for either the main transformer tank or the integral LTC. The goal of the plan is to monitor key diagnostic tools that predict the need for further investigations and possible repairs. This document describes the maintenance plan established to achieve this goal and the procedures used to accomplish it.

This document does not include the routine substation and equipment inspection procedures but does list the required visual inspections of the transformers.

For the purposes of this plan all oil filled substation transformers and the associated LTC within the substation fence will be included. For Xcel Energy substations, this includes looking at the two types of assets (transformers and LTC's), documenting their maintenance requirements and procedures and then defining how the two asset categories, will be inspected and diagnostically tested to minimize the required effort while maximizing the assets' life and preventing preventable failures. The following is a brief description of the two categories:

- *Power Transformer (XFMR)* - A static device consisting of a winding and two or more coupled windings, with a magnetic core for introducing mutual coupling between electric circuits. Transformers are extensively used in electric power systems to transfer power by electromagnetic induction between circuits at the same frequency, usually with changed values of voltage and current.

- *On-Load Tap Changer (LTC)* - A controlled device used to automatically or manually change the primary or secondary voltage level of a transformer while under load (effectively the turns ratio)normally up to 10% to maintain the voltage in a preset bandwidth suitable for the downstream users of the energy. There are many applications:

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[3] Peripherals include items such as temperature gauges, LTC drag hands, fans and pumps, etc.

- Transmission system where under heavy loads the voltage may sag, the LTC can be used to maintain the transmission voltage at acceptable levels.
- Distribution system to maintain the distribution substation bus voltage at acceptable levels to maintain the voltage level on individual circuits (aka feeders).
- The LTC on a smaller transformer may be used for individual feeder voltage control.
- The LTC may be used to re-direct the flow of VARs on the transmission system.
- System ties, where the voltage between electrical systems may vary and LTC's may be used to correct the voltage levels.

Equipment types included in this procedure include all transformer winding configurations; and are categorized according to the various cooling methods, oil preservation sealing system, size and voltage. LTC's have been similarly categorized according to the various technologies used to facilitate the ability to change the voltage while in service and under load and if an identifiable oil sample can be obtained to determine the LTC condition. On LTCs, where oil sampling is not possible, the Xcel Energy procedures development team has analyzed the alternatives and recommends that necessary modifications be made to the transformer to facilitate sampling. Until such changes are installed, those transformers will be removed from service to allow for LTC DGA and oil sampling to determine the LTC's condition and any need for maintenance.

Transformers: the following types of transformers are included in this plan for voltages from 4kV up to 500kV for all MVA ratings. A key factor in the maintenance and inspection of transformers, is to prevent the overheating of the insulating medium including the core and coils with load management and adequate operating cooling, fans, and if so designed oil pumps to assist natural convection. Xcel Energy's plan is based on operating transformers in the designed range of load and temperature to maximize life; a major maintenance driver is the type of designed cooling and is used here to sort the various transformer categories.

The Maintenance number formula used to schedule the complete diagnostic inspection of the transformer ancillary equipment includes an Apparatus Condition (APK) factor ranging from 1 – 5, with 5 having the least amount of ancillary cooling equipment. For transformers, the factors are based on cooling equipment regardless of arrangement. They are:

- APK = 5 is not presently used.
- APK = 4 for transformers that are self-cooled.
- APK = 3 for transformers that use fans to cool the transformer.
- APK = 2 for transformers that use both fans and oil pumps to cool the transformer.
- APK = 2 for transformers that are water cooled.
- APK = 1 is not presently used.

The cooling design for each transformer can be found on the name plate and is designated with standard letter configurations. Key to determining the APK are the IEEE designations indicating air cooling, forced air, and forced oil.

In addition the transformer Maintenance number formula uses a service constant (SK) used as a prioritizing factor in the Maintenance number formulas; the Maintenance number grows at different rates depending on how important, as expressed by the SK, each transformer is to the operation of the Xcel Energy system. Service constants are assigned and used on both the transmission and distribution transformers; the specific SK values depend on the operating voltage class of the transformer.

Service constants used in Xcel Energy's Maintenance number formulas for transformers range in value from 1 to 5, with 5 being a transformer that has the greatest consequence of failure. An asset with a service constant of 5 would be subject to ancillary diagnostics sooner than equipment with the same oil cooling methodology but with a lower service constant. For transformers, the factors are based on the MVA size of the transformers:

- SK = 5 for transformers with EHV primary voltage and larger than 200 MVA.
- SK = 4 for transformer larger than 200 MVA.
- SK = 3 for transformers 20 MVA but less than 200 MVA.
- SK = 2 for transformers 5 MVA but less than 20 MVA.
- SK = 1 is a transformer less than 5 MVA.

On-Load Tap Changers: LTCs used at Xcel Energy include units based on resistive, reactive, and vacuum switching arrangements. They are applied to power transformers that have a variable load. When a transformer's load increases the transformer impedance causes the voltage to drop. When the load decreases the voltage rises. The LTC control senses the change in voltage and adjusts/regulates the LTC to keep the voltage within acceptable limits. LTCs are mechanical devices that vary the turns-ratio of a transformer. It performs this function without opening or disconnecting the power that is flowing through the transformer. The LTC's contacts are connected to the taps of a regulating winding. The mechanical drive mechanism physically moves the position of electrical contacts to select the appropriate ratio taps of the regulating winding. Resistors or reactors are used to limit the amount of circulating current during the switching transition from tap to tap.

Differences in voltage between the tap positions cause arcing to take place as the electrical contacts connect and part. This in turn causes burning of the contacts and degradation of the insulating fluid; both can be detected in dissolved gas analysis to evaluate the LTC condition.
Vacuum bottle tap changers are not designed to cause arcing in oil, and use a Vacuum Protection system to detect issues with the vacuum interrupters.

Most Xcel Energy substation regulating transformers have a 10% tap winding with higher or lower ranges for special applications. The tap winding typically varies the transformers ratio in .625% increments for a total of 16 steps. The polarity of the tap winding can be reversed under load. This gives the transformer the ability to lower or raise the voltage ratio by 10% above or below the nominal voltage rating. Details of LTC types and operation can be found in the equipment section below.

General

Diagnostic testing, careful analysis of the results, and when required proper maintenance activities including complete diagnostic of the transformer[4] is essential to system reliability and operations. Following the plan and procedures in this document, will ensure equipment performance and system reliability, and reduce the probability of unplanned failures. To ensure the proper implementation of these guidelines, maintenance personnel shall have a thorough understanding of the apparatus in their area of responsibility; be able to perform all required DGA and oil sampling, perform diagnostic tests, adjustments, repairs, inspections, and collect and record the correct performance and evaluation data for each asset. Test reports and other information collected during the diagnostic and laboratory testing, must be accurately interpreted and correct prompt actions taken when required, based on an understanding of the implications. All employees and Xcel Energy mutually share the responsibility to develop training, work as a team to stay current on procedures and equipment, and to recognize areas requiring additional focus.

Planning and Scheduling Transformer and LTC Diagnostics and Maintenance

Xcel Energy utilizes both time and a common planning and scheduling tool across the transmission and distribution asset[5] fleet, including the transmission and distribution transformers and LTCs based on a combination of factors including time, condition of the asset, the importance of the asset to the system and events that occur, such as fault operations while the equipment is in service. This Xcel Energy methodology, called Adaptable Reliability Centered Maintenance (ARCM) utilizes traditional diagnostic testing as well as modern diagnostic techniques such as transformer and LTC dissolved gas analysis (DGA), comprehensive oil testing, infrared scanning and periodic ancillary transformer diagnostics, as well as periodic visual inspections. If there is a need to perform further tests, make repairs, or order a transformer off-line to make repairs these tools and diagnostics provide the information required to make timely decisions. The goal, to increase reliability, requires Xcel Energy to perform all diagnostic testing the right way at the right time. Both on-site diagnostics and laboratory investigations will be used to determine the condition and if there is a need for further tests or actions on the transformer and/or the LTC if present.

While DGA, oil testing and infrared is done on a periodic (time based) schedule, each transformer and LTC in the system is represented by an algorithm[6] that grows the need for the ancillary diagnostic inspection either faster or slower depending on several factors such as previous diagnostic inspections and results. The algorithm for transformers is based on the type of construction and cooling of the unit (air only, fans, forced oil, or water cooling) to determine the apparatus constant (APK), the Service Constant (SK) based on the size of the unit in MVA to determine the value to the company (reliability, cost, risk, etc.). In addition the current and previous DGA tests, complete oil testing, and infrared results will all be used to evaluate the health of a transformer and the appropriate activities to ensure continued reliable operation of the unit. The

[4] Transformers will be used generically in the general text to indicate transformers and on-line tap changers - LTCs
[5] **Asset:** An item with an independent physical and functional identity and age, within a facility (e.g. transformer, circuit breaker, pole, tower).
[6] Several algorithms are required for the complete fleet of substation assets assigned major grouping such as breakers, transformers, LTCs, etc. to generate the correct indication for maintenance activity.

Maintenance number for transformers triggers a diagnostic for the ancillary transformer equipment (temperature gauge, fans, pumps, etc.). Diagnostic testing of the transformer and LTC is as follows:

- DGA sampling and laboratory analysis: Every 12 months for all transformers and LTCs with the following exceptions:
    - Transformers operating at 345 kV or greater and larger than 200 MVA in size will have a DGA sample drawn and analyzed every 3 months unless continually monitored, then annually.
    - New transformers and repaired transformers when initially energized will have a DGA sample at 1 day, 1 week, and 1 month, unless required more often by warranty. Depending on voltage and size, the transformer will then be scheduled on either a quarterly or annual basis.
    - Transformers indicating internal issues and/or potential failures will have testing done, depending on the severity, often enough to monitor the rate of gassing and the total combustibles.

- Complete Oil Analysis by laboratory: Every 12 months for all transformers and LTCs

- Infrared Scanning and Analysis: Every 12 months for all transformers and LTCs

- Diagnostic of ancillary equipment such as gauges, pumps, fans, etc. is scheduled based on the apparatus condition and overall importance to the Xcel Energy system using the Maintenance number methodology and the formula. The formula generates a Maintenance Number (or MN_{TA}) that can be used to plan and schedule the ancillary diagnostic inspection. The formula is:

$$MN_{TA} = \left(1 + \frac{SK}{APK}\right) x \left(\frac{250xTAE}{TK}\right)$$

Definitions of the terms:

MN_{TA} is the Maintenance number indicating the need for an ancillary equipment diagnostic
SK is a service constant 1-5 where 5 is the most important asset
APK is an apparatus constant 1-5 where 5 is the best condition
TAE is the time since there was an ancillary equipment diagnostic done
TK is a time constant (unit is years). Xcel Energy's TK is initially set at 8 years

Note: The LTC is similarly tested at the same time and intervals as the transformer.

Requirements

Documentation

A comprehensive maintenance history for each transformer and LTC as installed and operating, is essential in developing an effective maintenance strategy and adapting the plan to improve reliability based on the actual field condition of the transformers. This information is also important when addressing failure trends and understanding cause and effect analysis. Consequently **all** diagnostic inspections, LTC voltage control operations, factory tests, repairs, adjustments, and failures must be clearly documented and said information securely and permanently stored in an easily retrievable and useable format. Life expectancy of transformers is greater than 75 years and records will be required for the entire service period.

In addition, a summary of the DGA, comprehensive oil tests, infrared inspections and peripheral diagnostic inspections and maintenance activities will be kept in a transformer assessment folder. The date, name of personnel, and brief description of the work performed, tests made, and counter readings shall be recorded. In addition, **all** work performed, required follow-on quantitative test results, transformer or LTC condition reports will be documented in Xcel Energy's PassPort™ Work Management System or other designated systems of record.

A comprehensive inspection, operation, diagnostic and maintenance history of each substation transformer, LTC, and peripheral equipment must be maintained. This is essential for establishing not only the "health" of the individual piece of equipment, but also other transformers in the fleet of the same model or class (sister units). This information is essential when addressing failure trends and understanding cause and effect analysis, establishing schedules, diagnostic, and maintenance requirements. It is critical to the success of the overall maintenance plan objectives to maintain the appropriate documentation and data for each piece of equipment.

Maintenance and Inspection Plans

The transformer inspection, diagnostic and maintenance plan consists of three basic inspection and diagnostic procedures. A fourth procedure, an internal inspection of the core and coils, bushing connections, LTC, etc. may be required based on the diagnostic testing of the assets, but is not specifically scheduled or planned. This procedure is not intended to establish the Substation Inspection Program and Procedures which are contained in a separate document. A brief overview of the Inspection requirements that provide data and input into the Transformer and LTC Plan and Procedures is included for completeness.

Transformer Visual Inspections:

The visual transformer inspection will be performed each time a station inspection is performed and appropriate data collected in the electronic device used for inspections and later transferred to the system of record. Included in this inspection are all external gauges such as top oil temperature, hot spot temperature, oil level, LTC drag hands, LTC counter, pressure relief indicator, etc. In addition the fans and pumps if present should be activated to insure they are operational (oil pumps flow indicator should be verified), and any oil leaks or other issues reported.

Annual DGA, Comprehensive Oil and Infrared Inspection:

Dissolved Gas Analysis (DGA): As discussed above, every transformer will have a unique sample drawn from each separate compartment for dissolved gas testing as a health index of the transformer and LTC apparatus condition.

Transformer oils perform four functions for the transformer and load tap changer. The first three are to provide insulation, provide cooling, and help extinguish arcs. In addition oil retains dissolved elements generated by:

- Oil degradation
- Moisture in the transformer paper insulation and oil
- Cellulose insulation
- Deterioration of the core and tank metals

Close observation of dissolved gases in the oil and other oil properties; provide the most valuable information about transformer health. It is important to note that while unusual, a buildup of combustible gas and failure events can occur very quickly. Through-faults, high moisture levels in a transformer, or air bubbles trapped in the windings are some of the possible causes.

The analysis of the DGA and comprehensive oil tests looks for trends by comparing information of the present laboratory results to previous DGAs from the same asset compartment (transformer or LTC), and understanding their meaning. Two specific IEEE combustible tables are used in this analysis; the total combustible gas levels and the acceptable rate of rise per day of combustible gas. The laboratory will issue consistent condition reports as to the status of the various transformers.

Xcel Energy will use DGA analysis for all substation transformers on annual or quarterly basis after being placed in service and the transformer's initial energized period where DGA samples will be taken more frequently to establish a base line and trend if any gases are forming typically after 1 day, 1 week, and 1 month. Transformers operating at 345kV or greater and 200 MVA or larger will be DGA tested quarterly, unless continually monitored, and then yearly. This is by far the most important tool for determining the health of a transformer and LTC.

After results are determined for each of the samples, the laboratory will compare the current gas levels and prior DGAs, so that trends can be recognized and rates of gas generation established. Transformers are very complex; aging, chemical actions and reactions, electric fields, magnetic fields, thermal contraction and expansion, load variations, gravity, and other forces all interact inside the tank. Externally, through-faults, voltage surges, wide ambient temperature changes, and other forces such as the earth's magnetic field and gravity affect the transformer. There are few, if any, "cut and dried" DGA interpretations; keeping accurate records of each individual transformer's operating history is paramount.

Xcel Energy will depend on the expertise of the laboratory to analyze the oil samples and rank the condition of the transformer using a pre-defined scale, indicating if there is any issue with the transformer, if a re-test is warranted, or if serious problems are found in the transformer.

DGA is also used for the LTC compartments to determine the condition of the insulating oil (gases and carbon levels), the wear on the contacts, and the remaining useful life of the LTC.

The laboratory will analyze the types of metals found in the oil samples to determine the source of the particulates and the changes in concentrations since the last testing.

Comprehensive Oil Analysis: In addition to the DGA tests, transformers and LTCs (all separate compartments) will have an annual comprehensive oil analysis, which will include:

- **Dielectric Strength of the Oil** – this test is done to see at what voltage the oil electrically breaks down which affords a good indication of the contaminants in the oil such as water and oxidation particles. The IEEE standard C57.106 sets the minimum breakdown voltages for transformer oil and the specified test methodologies. Oil not meeting the standard must be reclaimed or replaced.

- **Interfacial Tension (IFT)** - used to determine the interfacial tension between the oil sample and distilled water. As the oil ages, it is contaminated by tiny particles (oxidation products) of the oil and paper insulation. The more particles, the weaker the interfacial tension and the lower the IFT number. The IFT and acid numbers together are an excellent indication of when the oil needs to be reclaimed.

- **Acid Number** – this number (acidity) is the amount of potassium hydroxide (KOH) in milligrams (mg) that it takes to neutralize the acid in 1 gram (gm) of transformer oil. The higher the acid number, the more acid is in the oil. New transformer oils contain practically no acid.

- **Oxygen Inhibitor** - Oxygen inhibitor is a key to extending the life of transformers. The oxygen attacks the inhibitor instead of the cellulose insulation. As this occurs and the transformer ages, the inhibitor is used up and needs to be replaced. The ideal amount of inhibitor recommended by the manufacturer shall be followed but generally 0.3% by total weight of the oil (ASTM D-3487). The test is usually done at intervals of no more than 3-4 years.

- **Power Factor -** This measurement indicates the dielectric loss (leakage current) of the oil. This test may be done by the DGA laboratories or using field testing equipment such as Doble™ testing equipment or other power factor test sets. A high power factor indicates deterioration and/or contamination by-products such as water, carbon, or other conducting particles; metal soaps caused by acids (formed as mentioned above), attacking transformer metals, and products of oxidation. The DGA labs normally test the power factor at 25 °C and 100 °C. Current information indicates the in-service limit for power factor is less than 0.5% at 25 °C. If the power factor is greater than 0.5% and less than 1.0%, further investigation is required; the oil may require replacement or reclamation by some method. If the power factor is greater than 1.0% at 25 °C, the oil may cause failure of the transformer; replacement or reclaiming is required. Above 2%, the oil should be removed from service and reclaimed or replaced because equipment failure is a high probability.

- **Furans -** Furans are a family of organic compounds which are formed by degradation of paper insulation (ASTM D-5837). Overheating, oxidation, and degradation contribute to the destruction of insulation and form furanic compounds. Changes in furans between DGA tests are just as important as individual numbers. The same is true for dissolved gases. Transformers with a degree of polymerization lower than 250 should be investigated because paper insulation is being degraded. Also reexamine both the IFT and acid number. Furan testing will be done in conjunction with the ancillary diagnostic.

Infrared Inspection

The annual inspection of the power transformers and the LTC shall include a comprehensive infrared inspection to verify that there is no unusual heating of the tank and LTC as well as the connections to the bushings, etc. The inspection will include verifying the temperature of the transformer oil versus the top oil temperature gauge and also the level of the oil versus the transformer's oil level gauge.

Ancillary Diagnostic Inspection

Based on the type of transformer, specific diagnostic tests will be periodically performed based on the Maintenance number generator discussed above. At this time, the transformer will be inspected for any gauge or mechanism that can be examined safely without the transformer being de-energized.

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-18-373

PART L

TRADE SECRET JUSTIFICATION

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.

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-18-373

PART M

NOTICE OF REPORT AVAILABILITY, CERTIFICATE OF SERVICE, AND SERVICE LISTS

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie J. Sieben	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF NORTHERN STATES POWER COMPANY ANNUAL AUTOMATIC ADJUSTMENT OF CHARGES REPORT FOR ITS ELECTRIC OPERATION

NOTICE OF REPORT AVAILABILITY

DOCKET NO. E999/AA-18-373

On August 31, 2018, Northern States Power Company, doing business as Xcel Energy, filed a report with the Minnesota Public Utilities Commission for the 12 months ending June 30, 2018 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, Lynnette Sweet, 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 NOS. **E999/AA-18-373**
E999/AA-17-492
E002/GR-15-826
E002/GR-13-868

Dated this 31st day of August 2018

/s/
____
Lynnette Sweet

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