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June 19, 2015

—Via Electronic Filing—

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

RE: REPLY COMMENTS
2013-2014 ANNUAL AUTOMATIC ADJUSTMENT OF CHARGES REPORT
DOCKET NO. E999/AA-14-579

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits these Reply Comments to the Review of our Annual Automatic Adjustment of Charges (AAA) Report for 2013-2014 (FYE14) filed by the Minnesota Department of Commerce - Division of Energy Resources on May 19, 2015.

Portions of this Reply contain information marked as trade secret pursuant to Minnesota Statute § 13.37, subd. 1(b). In particular, the information designated as Trade Secret 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.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list. Please contact me at paul.lehman@xcelenergy.com or (612) 330-7529 if you have any questions regarding this filing.

Sincerely,

/s/

PAUL J LEHMAN
MANAGER, REGULATORY COMPLIANCE AND FILINGS

Enclosures
c: Service List

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STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
John Tuma	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF NORTHERN STATES POWER COMPANY, REVIEW OF 2013-2014 ANNUAL AUTOMATIC ADJUSTMENT REPORT FOR ITS ELECTRIC OPERATION

DOCKET NO. E999/AA-14-579

REPLY COMMENTS

OVERVIEW

Northern States Power Company, doing business as Xcel Energy, submits this Reply to the Minnesota Department of Commerce - Division of Energy Resources' May 19, 2015 review of our Annual Automatic Adjustment of Charges (AAA) Report for 2013-2014 (FYE14).

We appreciate the Department's review of our AAA Report. In this Reply, we respond to the Department's requests to provide additional data and explanation about certain reported MISO Day 2 and ASM expenses as well as coal delivery issues. Also provided is additional information about our response to the Department's questions on wind curtailment.

The Department recommended the Commission require the continuation of several reporting items to which we do not object. We agree with the Department's recommendations to continue the following reporting items:

- 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; and
- provide information to support MISO Schedule 10 cost increases of five percent or higher over the prior year costs, including explanation of benefits received by customers for these added costs.

As suggested in the current and prior AAA dockets, the Company proposes to work with the Department in an effort to consolidate and streamline the various additional Company-specific reporting requirements thereby making our AAA Report more concise and easier to review.

We believe this Reply is fully responsive to the Department's requests for additional information, and we respectfully request that the Commission approve our FYE14 AAA Report as supplemented by this Reply.

REPLY

A. MISO Day 2 and ASM Charges

The MISO Day 2 Market began operation on April 1, 2005, pursuant to MISO's Energy Market Tariff (TEMT). MISO's Ancillary Service Market (ASM) began operation on January 6, 2009. The Commission has determined only certain MISO costs should be recovered through utilities' FCA mechanism. In addition, the Commission established accounting procedures and several reporting requirements in monthly FCA reports and the annual AAA reports for the Department to review. Below the Company provides the additional explanation requested by the Department in its review and audit of MISO Day 2 and ASM charges in the FYE14 AAA Report.

1. #22a Real-Time Non-Asset Energy Charges

In its Review, the Department states that it understands that the year-over-year increase in the Real-Time Non Asset Energy charges is mainly attributable to increases in real-time curtailments. The Department requested that the Company provide the amount of real-time curtailments incurred in FYE13 and FYE14 and explain the reasons for any increase.

As described in response to Information Request (IR) DOC-35, Real-Time Non Asset Energy charges are offset to Day-Ahead Non Asset Energy charges. When day-ahead physical schedules are curtailed in real time, market participants are required to buy back the curtailment volume. As a result, the $1.5 million increase in Real-Time Non Asset Amount from FYE13 to FYE14 is more than offset by a credit of $33 million of Day-Ahead Non Asset Amount for the same period. See Table 1 and Table 2 below.

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Table 1: Real-Time Non Asset Energy Amount

Real-Time Non Asset Energy Amount	FYE 2014	FYE 2013	2014 vs 2013
#22a Energy Component	$1,444,147.81	-$210,271.67	$1,654,419.48
#22b Congestion Component	-$108,741.94	-$36,437.27	-$72,304.67
#22c Loss Component	-$34,246.48	$39,828.36	-$74,074.84
Total	$1,301,159.39	-$206,880.58	$1,508,039.97

Table 2: Day-Ahead Non Asset Energy Amount

Day-Ahead Non Asset Energy Amount	FYE 2014	FYE 2013	2014 vs 2013
#5a Energy Component	-$196,285,615.49	-$156,720,089.99	-$3,956,525.50
#5b Congestion Component	$22,548,166.21	$14,749,279.64	$7,798,886.57
#5c Loss Component	$12,934,546.75	$14,633,817.15	-$1,699,270.40
Total	-$160,802,902.53	-$127,336,993.20	-$33,465,909.33

In FYE13, 2.3 million MWh were scheduled in the day-ahead market; in the real-time market, 11,000 MWh of the 2.3 million MWh were curtailed. This is equivalent to 0.5 percent of physical schedules being curtailed in FYE13.

In FYE14, 2.3 million MWh were scheduled in the day-ahead market; in the real-time market, 27,000 MWh of the 2.3 million MWh were curtailed. This is equivalent to 1.2 percent of physical schedules being curtailed in FYE14, an increase of 0.7 percent. The increase is attributable to additional curtailments by MISO related to transmission constraint and maintenance during September 2013 to May 2014 period.

To clarify the Real-Time curtailment settlement process, we provide the following example. Assume 500 MWh are scheduled and sold in the Day-Ahead market to flow in hour 10 at a Day-Ahead price of $30 per MWh. The result is a credit of $15,000 settled in the Day-Ahead Non Asset Energy charge type. In the Real-Time market, the 500 MWh scheduled is curtailed to 400 MWh due to a transmission constraint. The remaining 100 MWh of the 500 MWh sold in the Day-Ahead market must be purchased at a Real-Time price of $40 per MWh. As a result, a charge of $4,000 is settled in the Real-Time Non Asset Energy account. The net result is a credit of $11,000.

Like other MISO charge types, Real-Time Non Asset Energy charges or revenues vary hour by hour according to market conditions, loading and facility availability. Therefore, the aggregated annual total could also vary from year to year.

2. #33 Day-Ahead Schedule 24 Allocation Amount

The Department understands that Day-Ahead Schedule 24 Allocation Amounts are assigned to retail and asset-based wholesale on an MWh basis, and requested that the Company confirm or clarify this understanding in Reply Comments.

The Department's understanding is correct. Day-Ahead Schedule 24 Allocation Amounts are assigned to retail and asset-based wholesale on an MWh basis. To be clear, the invoiced amount for Day-Ahead Schedule 24 is calculated by multiplying the Day-Ahead Admin Volume (in MWh) by the Schedule 24 Rate (in $/MWh). Day-Ahead Admin Volume is represented by the absolute value in MWh of all Day-Ahead scheduled generation, load, financial schedules, physical schedules, grandfathered carve-outs, and virtuals.

Wholesale amounts are calculated by multiplying the Day-Ahead Wholesale Volume (in MWh) by the Schedule 24 Rate (in $/MWh). The retail amount is equal to the invoiced amount, less charges allocated to wholesale.

3. #34 Real-Time Schedule 24 Allocation Amount

The Department requested the Company explain why Real-Time Schedule 24 Distribution charges (revenues) are only assigned to asset-based wholesale; why Real-Time Schedule 24 Distribution charges (revenues) are reclassified from asset-based wholesale to transmission revenues; and to which specific recovery mechanism we were referring in stating "…for inclusion in that recovery mechanism" in our response to IR DOC-38.2.

Schedule 24 of the MISO tariff establishes that Local Balancing Authorities (LBAs) recover certain costs incurred as a result of operating a local balancing authority area. The Company operates a local balancing authority area, and is therefore entitled to recover associated costs through Schedule 24 charges. These costs, which consist primarily of labor costs associated with personnel in NSP's transmission operations center, are separately recorded in a sub-account of Uniform System of Accounts No. 561.2, Load Dispatch-Monitor and Operate the Transmission System, and submitted annually to MISO for recovery.

Under the MISO tariff, in order to fund payments to LBA operators, Schedule 24 charges are assessed to all MISO Market Participants based on related activity volumes in the Day-Ahead and Real-Time Energy and Operating Reserve Markets, and are therefore settled as an energy-based cost within market settlements. For simplicity, and in order for MISO to clearly remain revenue-neutral on Schedule 24, distributions to LBA operators are also settled through market settlements. However, as this distribution represents the utility's recovery of transmission expense, it is recorded as transmission revenue. Assignment of Real-Time Schedule 24 Distribution charges (revenues) to asset-based wholesale is a representation of this market settlement item not being assigned to retail. These amounts are immediately reclassified out of the asset-based account and into a transmission account, which represents flow through the Transmission Cost Recovery (TCR) Rider.

In our response to IR DOC-38.2, the comment "[Schedule 24 distributions] are reclassified to Transmission Revenue for inclusion in that recovery mechanism" refers to the fact that Schedule 24 distributions do not flow through the fuel clause. Rather, similar to other transmission revenues, other than RECB-related revenues which flow through the TCR rider, Schedule 24 distributions are a component of base rates.

4. #20 Real-Time Miscellaneous Charges

The Department recommended that the Commission require the Company to return to customers FYE14 MVP ARR revenues in our next TCR Rider filing. These revenues are not distributed to owners of the MISO MVP projects, but rather to customers paying the charges related to those projects. Xcel Energy is both an owner and a customer, and we receive these credits as an offset to the expense we pay for MISO MVP projects. For that reason, the credits are booked as an offset to MISO Schedule 26A expense.

Our current process is to offset Schedule 26/26A RECB expenses with the MVP ARR revenue credits in our annual TCR Rider Petitions, filed on a calendar year basis. Xcel Energy did not receive any MVP ARR revenues prior to June 2014. The June 2014 MVP ARR revenues, and subsequent months beyond the FYE14 AAA reporting period, were included in the TCR Rider which was verbally approved by the Commission on May 21, 2015 in Docket No. E002/M-14-852; the final Order is pending. Table 3 below shows the actual MVP ARR offset from June 2014 through April 2015. These values were used in the calculations to be included in our forthcoming compliance filing in the recently approved TCR docket.

Table 3: MVP ARR Offsets in TCR Rider

June 2014	$32,597.09
July 2014	$33,840.59
August 2014	$36,163.70
September 2014	$29,332.67
October 2014	$29,213.68
November 2014	$29,687.34
December 2014	$52,210.57
Total 2014	**$243,045.64**
January 2015	$95,051.51
February 2015	$70,005.00
March 2015	$69,381.57
April 2015	$47,609.77
Total 2015	**$282,047.85**

5. ASM Excessive Deficient Energy Deployment Charges (EDEDC)

The Department recommended that the Company provide a plan to mitigate future EDEDC penalty charges given the significant increase in these costs in FYE14. The Company stated in our FYE14 AAA Report our reasons for offering our generating resources into the MISO ASM and that a certain level of EDEDC is unavoidable given the current design of the ASM EDEDC charges. Consistent with the discussion cited in Department's Review, we are already mitigating EDEDC charges to the best of our ability through our current procedure. The procedure calls for the system dispatcher to monitor in real time the generation unit performance to MISO setpoints to ensure that plants are keeping up with offered ramp rates. To help ensure the costs are minimized to the full extent possible, 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. A certain level of EDEDC is unavoidable – and we continue to manage it reasonably and prudently – in light of the overwhelming benefits associated with high unit flexibility that more than offset these charges.

6. #4 ASM Real-Time Regulation Amount

The Department requested an explanation of the method or methods used to allocate Day-Ahead Regulation Amount (#1), Real-Time Regulation Amount (#4), and Real-Time Regulation Reserve Cost Distribution Amount (#10) between retail and asset-based wholesale in the Company's journal entry.

The Day-Ahead Regulation Amount and Real-Time Regulation Amount total revenues of negative $3,058,186.51 represent generator sales of regulation services to the market. On an hourly basis, Xcel Energy compares the regulation requirement for load to the amount of regulation sold to the market on a volumetric basis. When the amount sold is greater than the load requirement for a given hour, the excess is considered a sale to a third party and therefore allocated to asset-based wholesale. Of the negative $3,058,186.51 revenue total, $1,540,406.81 represents sales to third parties, therefore revenues of negative $1,540,406.81 are assigned to asset-based wholesale and revenues of negative $1,517,779.70 are assigned to retail.

The Real-Time Regulation Reserve Cost Distribution Amount of $1,603,877.12 represents the cost to procure regulation services from the market to serve load, therefore 100 percent of this cost is assigned to retail.

Table 4: ASM Real-Time Regulation Amount

	Net Invoice (System)	Retail	Asset-Based Wholesale
Day-Ahead Regulation Amount	-$3,391,900.34	-$3,391,900.34	- -
Real-Time Regulation Amount	$333,713.83	$1,874,120.64	-1,540,406.81
Subtotal	-$3,058,186.51	-$1,517,779.70	-$1,540,406.81
Real-Time Regulation Reserve Cost Distribution	$1,603,877.12	$1,603,877.12	- -
Regulation Total	**-$1,454,309.39**	**$86,097.42**	**-$1,540,406.81**

7. #5 ASM Real-Time Spinning Reserve amount

The Department requested that the Company provide an explanation of the method or methods used to allocate Day-Ahead Spinning Reserve Amount (#2), Real-Time Spinning Reserve amount (#5), and Real-Time Spinning Reserve Cost Distribution Allocation (#11) charge types between retail and asset-based wholesale in the Company's journal entry.

The Day-Ahead Spinning Reserve Amount and Real-Time Spinning Reserve Amount total revenues of negative $2,268,891.93 represent generator sales of spinning reserve services to the market. On an hourly basis Xcel Energy compares the spinning reserve requirement for load to the amount of spinning reserve sold to the market on a volumetric basis. When the amount sold is greater than the load requirement for a given hour, the excess is considered a sale to a third party and allocated to asset-based. Of the negative $2,268,891.93 revenue total, $1,018,038.46 represents sales to third parties, therefore revenues of negative $1,018,038.46 are assigned to asset-based and revenues of negative $1,250,853.47 are assigned to retail.

The Real-Time Spinning Reserve Cost Distribution Amount of $2,152,865.11 represents the cost to procure spinning reserve services from the market to serve load, therefore 100 percent of this cost is assigned to retail.

Table 5: ASM Real-Time Spinning Reserve Amount

	Net Invoice (System)	**Retail**	**Asset-Based Wholesale**
Day-Ahead Spinning Reserve Amount	-$1,726,218.24	-$1,726,218.24	- -
Real-Time Spinning Reserve Amount	-$542,673.69	$475,364.77	-$1,018,038.46
Subtotal	-$2,268,891.93	-$1,250,853.47	-$1,018,038.46
Real-Time Spinning Reserve Cost Distribution	$2,152,865.11	$2,152,865.11	- -
Spinning Reserve Total	**-$116,026.82**	**$902,011.64**	**-$1,018,038.46**

B. Coal Deliveries

1. Rail Transportation Costs

The Department requested the Company to explain whether it is possible to negotiate terms and conditions in its rail transportation contracts that would **[TRADE SECRET BEGINS**

TRADE SECRET ENDS]

Recently, the railroads have been reluctant to provide any type of service commitments in their new transportation contracts. As legacy agreements expire, the service commitments language is removed. The railroads rely on "commercially reasonable" or "good faith efforts" as standard language rather than a specific service commitment declaration. **[TRADE SECRET BEGINS**

TRADE SECRET ENDS]

2. Terms of Rail Contracts

The Department requested the Company to explain whether and how the terms and conditions of its rail contracts in the future can be strengthened in any other way to avoid the issues discussed in the Department Review.

When the current rail contracts expire, NSP will endeavor to negotiate terms that are at least as favorable as the current agreements. Outside of negotiating certain terms into our agreements that prevent fuel shortages, Senator Franken has put forth legislation that will require the Secretary of Energy to investigate fuel shortages, convene meetings with the Federal Energy Regulatory Commission, Surface Transportation Board and Regional Reliability Coordinators, and submit recommendations for actions that would help alleviate the fuel supply emergency. NSP believes that working with the railroads, governmental and regulatory agencies, and negotiating agreements that include a form of service commitment will mitigate the severity of future delivery problems.

C. Wind Curtailment

The Department's Review noted that they will more fully assess our wind curtailment reporting when they submit Response Comments to allow additional time to review our response to an information request on wind curtailment (DOC-33). We believe the curtailment costs experienced during the FYE14 AAA period were prudently incurred expenses and look forward to the Department's assessment of the information provided. The Company acknowledges that it is our responsibility to justify the prudence of our actions, in this case as it pertains to wind curtailment, and we apologize for the extra time taken to provide a complete response. We offer some additional context to explain why information needed to answer the questions asked is not always readily available.

In the last several years, in addition to curtailments called for by MISO operations, a handful of major events have caused increased curtailment, either through the event itself or recovery from the event, including tornados, ice storms, and CapX2020 regional construction. In each of our FYE12, FYE13, and FYE14 AAA Reports, we identified the occurrence of wind curtailment and also explained the primary underlying reasons for the resulting increases in curtailment costs. While we could identify the general impact of outages, in reality, during the course of a single month, numerous individual transmission line outages occur in a given area for varying durations and will effect and impact deliverability from multiple wind generation facilities.

In IR DOC-33, the Department asked for detailed information, explanation, and analysis about *each and all* curtailment events for which the Company made payments in FYE14. Based on our understanding of the question, we began querying our systems for the detailed information needed, and proceeded to plan an approach for analyzing the resulting large volume of data to respond to the various questions for each instance of curtailment and realized more time than the normal response time of 10 days would be necessary. We considered the possibility of misunderstanding the information specifically being requested for the Department's analysis and contacted the Department for clarification and to request a time extension.

With the curtailment reason coding system in place, significant weather events and major transmission construction would likely be code "4" events, and we already incorporate explanation of code 4 curtailments into our documentation. However, code "3" events are called by MISO. We must respond and follow MISO direction to reduce output as applicable, and do not have detailed documentation for why MISO called for the curtailment—only that MISO directed curtailment; further analysis of why MISO directed a curtailment takes time to collect. We certainly want to provide the information the Department needs for its analysis, even though there was a time delay in providing our response. It is important to note that data of this nature, while available for query and further analysis, is not readily available on a timely basis and that any lag in supplying the data does not indicate whether the curtailments were prudent and does not indicate operational deficiencies.

We believe that our curtailment costs are accurate and the curtailments incurred were prudent. To clarify the extensive internal approval process conducted before any curtailment payment is issued to an individual counterparty, we explain below how each wind vendor's claim for curtailment payments is reviewed, analyzed and confirmed.

Prior to payment of curtailment invoices received from contract counterparties, Xcel Energy's Commercial Operations personnel work with the relevant counterparty to obtain agreement on the date of the curtailment, the duration of the curtailment, the volume of energy curtailed, and pricing of the curtailment. As part of the process, Commercial Operations personnel determine the reason for the curtailment and whether the curtailment is non-compensable or compensable. The Company pays the counterparty only for curtailment energy net of any non-compensable curtailments by analyzing the curtailment energy using the best-available data and methods to determine an accurate representation of the amount of energy curtailed. The quantity of energy that would have been produced by the facility but for the curtailment is determined as if the generation had not been curtailed. Unit availability, wind speed, and the power curve, among other factors, are used to calculate the volume of curtailed energy. This data is all well-documented, but because each month can involve thousands of individual curtailments, all of the associated information cannot be compiled into a report quickly, and thus the delay in providing the response to the Department's question.

We believe the process to review curtailments described above support our prudent efforts to scrutinize and minimize curtailment costs, and look forward to reviewing the Department's curtailment analysis.

CONCLUSION

Xcel Energy appreciates this opportunity to submit its Reply to the Department's Review. Through this Reply, we have worked to provide additional information as requested by the Department.

We respectfully request that the Commission accept and approve Xcel Energy's FYE14 Electric AAA Report as supplemented by this Reply.

Dated: June 19, 2015

Northern States Power Company

CERTIFICATE OF SERVICE

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

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

xx electronic filing

DOCKET NO. E999/AA-14-579

Dated this 19th day of June 2015

/s/

____

SaGonna Thompson

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