MINNESOTA DEPARTMENT OF COMMERCE

85 7TH PLACE EAST, SUITE 500
SAINT PAUL, MINNESOTA 55101-2198
MN.GOV/COMMERCE
651.539.1500 FAX: 651.539.1547
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August 26, 2015 **PUBLIC DOCUMENT**

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **PUBLIC Response Comments** of the Division of Energy Resources of the Minnesota Department of Commerce (DOC or the Department) to Electric Utilities' Reply Comments
Docket No. E999/AA-14-579

Dear Mr. Wolf:

Attached please find the Department's *Response Comments* to the Minnesota Large Industrial Group's (MLIG) *Reply Comments* and the electric utilities' *Reply Comments.* The Department requests that the Commission receive these *Response Comments*, which are intended to help complete the record in this matter. Specifically, the Department responds to the *Reply Comments* of the following parties:

- MLIG, reply comments filed on June 19, 2015;
- Minnesota Power, reply comments filed on June 18, 2015
- Interstate Electric, reply comments filed on June 19, 2015;
- Otter Tail Power Company, reply comments filed on June 19, 2015; and
- Xcel Electric, reply comments filed on June 19, 2015.

Based on the review of each of these parties' *Reply Comments*, the Department's *Response Comments* contain revised recommendations to the original recommendations included in the Department's *Review of the 2013-2014 (FYE14) Annual Automatic Adjustment Reports for Electric Utilities* filed on May 19, 2015 (Report).

The Department recommends that the Minnesota Public Utilities Commission (Commission) adopt the Department's revised recommendations, as discussed in greater detail herein and listed at the end of this document. The Department is available to answer any questions that the Commission may have.

Sincerely,

/s/ NANCY A. CAMPBELL
Financial Analyst

/s/ SAMIR OUANES
Rates Analyst

NAC/SO/lt
Attachment

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BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

PUBLIC REPLY COMMENTS OF THE MINNESOTA DEPARTMENT OF COMMERCE DIVISION OF ENERGY RESOURCES

DOCKET NO. E999/AA-14-579

I. BACKGROUND

On May 19, 2015, the Division of Energy Resources of the Minnesota Department of Commerce (DOC or the Department) filed its *Review (Report) of the 2013-2014 (FYE14) Annual Automatic Adjustment Reports (AAA Reports)* with the Minnesota Public Utilities Commission (Commission) in the present docket. The Report pertains only to rate-regulated electric utilities. In its Report, the Department requested that the electric utilities address specific concerns in *Reply Comments*. The following are the electric utilities that filed reply comments on June 18 and 19, 2015:

- Interstate Electric (IPL);
- Minnesota Power (MP);
- Otter Tail Power Company (OTP); and
- Northern States Power, d/b/a Xcel Electric (Xcel).

In addition, the Minnesota Large Industrial Group (MLIG) filed *Reply Comments on June 19, 2015.* Below, the Department responds to each set of *Reply Comments* and provides the Department's recommendations based on our review.

II. DEPARTMENT ANALYSIS – WIND CURTAILMENT REPORT

A. BACKGROUND

As discussed further in the Report, the Department concluded that Xcel Electric had not shown that it was reasonable to charge its ratepayers for the material increase in curtailment payments during FYE14.

The Department's review of Xcel Electric's wind curtailment data showed that curtailment costs increased substantially, to 8.59 percent of the total cost of wind in FYE14:

> Most of the curtailment payments (about 99 percent of a total of about $15.6 million) are related to [Midcontinent Independent System Operator] MISO directives (curtailment reason code 3). However, in light of the substantial increase in curtailment payments, the Department requested Xcel Electric through discovery to identify and fully describe the events that resulted in the FYE14 curtailment payments, explain whether Xcel could have been more proactive in alleviating the occurrence and/or consequences of each such events and whether Xcel could have used a lower cost option to address the specific need for curtailment as a result of each such events.

The Department discusses below Xcel Electric's response.[1]

B. DEPARTMENT'S REVIEW OF XCEL ELECTRIC'S RESPONSE

According to Xcel Electric, the following three categories of events are responsible for the FYE14 wind curtailments:

1) Transmission Events which include:

    - Storm related repair on Buffalo Ridge – Pipestone – Split Rock 115 kV lines and unplanned substation maintenance on Buffalo Ridge Substation Transformers TR1 and TR2 (Buffalo Ridge Events)
    - Unplanned substation maintenance on Chanarambie Substation Transformers TR 1 and TR 2 (Chanarambie Events)
    - Storm Related Repair on Split Rock-Nobles-Lakefield Junction 345 kV Lines (345 kV Storm Repair Events)

2) Dispatchable Intermittent Resource (DIR) Economic, Congestion & Negative locational marginal price (LMP) Related Curtailments (DIR Curtailment Events)

3) Manual Economic, Congestion & Negative LMP Related Curtailments (Manual Curtailment Events)

In response to the Department's discovery asking Xcel Electric to identify and describe any and all preventive steps it could have taken to either eliminate or alleviate the need to curtail wind facilities, Xcel Electric stated:[2]

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[1] Xcel Electric's response consists of its May 8, 2015 response to the Department's April 10, 2015 information request No. 33 and its June 19, 2015 Reply Comments.

[2] Source: Xcel's response to the Department's information request No. 33.

> There are limited means of managing generation through situations where generation levels exceed transmission capability and economic conditions warrant less production.
> Xcel Energy could not have taken other actions to either eliminate or alleviate the need to curtail wind facilities.

In response to the Department's discovery asking Xcel Electric to identify, for each of the events responsible for the need to curtail wind facilities during FYE15, the wind facilities that could have been curtailed in place of those that were curtailed, Xcel Electric stated:[3]

> There are no other wind projects that could substitute for the curtailment that occurred with each of the categories of events.
>
> *1. Transmission Events*
>
> *a) Buffalo Ridge Events*

Xcel Electric provided the following explanation regarding the Buffalo Ridge Events:[4]

> In July 2011, a tornado struck the Buffalo Ridge area in southwestern Minnesota damaging multiple feeder lines from the Buffalo Ridge substation and the surrounding 115 kV transmission lines. Feeder line and transmission repair/replacement work had been completed on damaged segments prior to this AAA period. The 115 kV lines from the Buffalo Ridge and Split Rock 115 kV substations into the Pipestone substation are double circuited, sharing towers for five spans. All segments of these lines, except for these five spans, were rebuilt in the storm recovery work in 2011 and 2012.
>
> In addition to benefiting wind generation outlet, these lines also provide transmission service benefits to support the Sioux Falls area. To gain the benefits of the higher line ratings made possible by the previously reconstructed facilities, these five double circuit spans also needed to be rebuilt. Structures were ordered early in 2013 and construction work began in July continuing through September, causing reduced transmission outlet capability because of the Buffalo Ridge-Pipestone-Split Rock 115 kV line being out of service for construction.
>
> Wind projects directly impacted by this transmission work are the Lake Benton I and Lake Benton II and Wind Power Partners 1993 wind projects. Only Lake Benton II has partial outlet through another area substation, Chanarambie, thus there were no other options to receive full amounts of wind energy from

[3] Source: Xcel's response to the Department's information request No. 33.
[4] Source: Xcel's response to the Department's information request No. 33.

> these facilities during this construction outage. Together, these 3 wind facilities are nominally rated at approximately 225 MW.
> …
>
> Unplanned maintenance work on two 115-34.5 kV transformers in the Buffalo Ridge substation became necessary when inspection and monitoring work performed during summer 2013 revealed early indications of impending failure of bushings (insulators within a transformer). Without attention, damaged bushings would eventually force the transformer out of service, which could have potentially resulted in catastrophic transformer failure. At this location and due to long lead times for replacement equipment, such damage would cause significant disruption to wind generation outlet for the three connected facilities: Lake Benton I, Lake Benton II and Wind Power Partners 1993.
>
> Both transformers at the Buffalo Ridge substation were found to have the same conditions occurring. Replacement equipment was ordered and work began as soon as materials were received, taking each transformer out of service for maintenance one at a time to minimize curtailments produced because of reduced capability of the substation during the repair work. Outage work occurred late October 2013 continuing through late November.
> …
> During FYE14 the Company experienced **[TRADE SECRET HAS BEEN EXCISED]** of curtailment related to the Buffalo Ridge Events as shown in Attachment B.
>
> In order to maintain reliability of the transmission system for the Buffalo Ridge Events, the Operating Guides require generation connected at the Buffalo Ridge substation be limited to a specified level. Therefore, we are only able to use wind generators that are connected to the Buffalo Ridge substation to manage this transmission event.

Given that Xcel Electric had to curtail generation connected at the Buffalo Ridge substation to maintain reliability of the transmission system for the Buffalo Ridge Events and that "there are no other wind projects that could substitute for the curtailment that occurred," the Department will not pursue further the issue of the FYE14 wind curtailments resulting from the Buffalo Ridge events.

b) Chanarambie Events

Xcel Electric provided the following explanation regarding the Chanarambie Events:[5]

> Following inspection results at Buffalo Ridge substation, the Chanarambie substation was also examined and found to have similar testing results on the low-side transformer bushings.
>
> Replacement equipment was also ordered for this substation and work was initiated after completion of Buffalo Ridge substation repair. Wind energy facilities impacted by outages at the Chanarambie substation include: Moraine I, Moraine II and Ridgewind. As was done at Buffalo Ridge, each of the two 115-34.5 kV transformers at Chanarambie was removed from service for repair one at a time to minimize the wind curtailment that would occur by limiting the capability of the substation while the maintenance was being done.
>
> The Company controls the wind generation at the affected substations with Operating Guides which assign generation limits to the wind projects impacted by certain transmission events such as those that occurred during 2013 and 2014. This wind generation is controlled through DIR and manual curtailment.
>
> …
>
> During FYE14 the Company experienced [TRADE SECRET HAS BEEN EXCISED] of curtailment related to the Chanarambie Events as shown in Attachment B.
>
> In order to maintain reliability of the transmission system for the Chanarambie Events, the Operating Guides require generation connected at the Chanarambie substation be limited to a specified level. Therefore, we are only able to use wind generators that are connected to the Chanarambie substation to manage this transmission event.

Given that Xcel Electric had to curtail generation connected at the Chanarambie substation to maintain reliability of the transmission system for the Chanarambie Events and that "there are no other wind projects that could substitute for the curtailment that occurred," the Department will not pursue further the issue of the FYE14 wind curtailments resulting from the Chanarambie events.

c) 345 kV Storm Repair Events

Xcel Electric provided the following explanation regarding the 345 kV Storm Repair Events:[6]

[5] Source: Xcel's response to the Department's information request No. 33.
[6] Source: Xcel's response to the Department's information request No. 33.

One of the key high-voltage transmission lines providing electric service support as well as wind generation outlet is located across the southern portion of Minnesota from the Buffalo Ridge area towards southeastern part of the state. This line is relatively new, having been completed in 2008. Since 2012, winter icing and wind conditions have periodically created physical movement along the conductor, or transmission line, known as “galloping.” Our engineering areas have been

investigating use of anti-galloping devices and different conductors or conductor configurations and in addition to the damage repair described below, are in the process of implementing solutions to reduce the potential for conductor galloping. In a preventative effort, we have been working with the Electric Power Research Institute (EPRI) in designing anti-galloping mitigation plans. Additional transmission outages planned in 2014 and 2015 are to install devices and spacer equipment to prevent the conductors from contacting each other during movement in high winds, and to reconductor especially sensitive area along the transmission line where geographic orientation of the line and prevailing winds combine unfavorably.

In early April 2013, a winter storm produced wide-spread snow and icing conditions from the Sioux Falls area to the east, across southern Minnesota. Combination of ice weight and wind created extreme conductor galloping and caused severe damage, bringing down and/or weakening equipment, conductors and ground wires all along the Split Rock-Nobles-Lakefield Junction 345 kV line. Temporary repair was completed as quickly as possible and the line was placed back in service in mid-May 2013. Detailed ground inspection and engineering followed to determine the materials and plans needed for permanent line repair.

Once materials were available in September 2013, construction work was performed on each of the damaged line segments, where the lines were taken out of service for significant periods of time beginning in mid-September 2013 through February 2014, with further work continuing in 2014. When outages are occurring along this 345 kV line the amount of available wind generation outlet becomes reduced and wind facilities will experience curtailments as needed to remain in compliance with transmission limitations. Wind generation facilities impacted by outages of the Split Rock-Nobles-Lakefield Junction 345 kV line include: Lake Benton II, Chanarambie Power Partners, Ridgewind, Moraine I, Moraine II, Fenton and Zepher, all of which in total are nominally rated at over 500 MW.

> During FYE14 the Company experienced **[TRADE SECRET HAS BEEN EXCISED]** of curtailment related to the 345 kV Storm Repair Events as shown in Attachment B.
>
> In order to maintain reliability of the transmission system for the 345 kV Storm Repair Events, the Operating Guides require generation connected at the Chanarambie, Fenton and Nobles County substations be limited to a specified level. Therefore, we are only able to use wind generators that are connected to the Chanarambie, Fenton and Nobles County substations to manage this transmission event. As shown in Attachment C, to manage this event, we curtailed generation at Chanarambie Power Partners, Moraine I, Lake Benton II, Moraine II, Ridgewind (RPP in spreadsheet), Fenton and Zephyr.

Given that Xcel Electric had to curtail generation connected to the Chanarambie, Fenton and Nobles County substations to maintain reliability of the transmission system for the 345 kV Storm Repair Events and that "there are no other wind projects that could substitute for the curtailment that occurred," the Department will not pursue further the issue of the FYE14 wind curtailments resulting from the 345 kV Storm Repair events.

2. DIR Economic, Congestion and Negative LMP Related Curtailments

Xcel Electric provided the following discussion regarding economic curtailments:[7]

> MISO manages generation resources using Locational Marginal Prices (LMP) to determine when curtailment is the most economic option to alleviate constraints or minimum generation events. The LMP represents the value of energy produced at a specific location in the market. When the LMP drops below the marginal cost of production for any resource, it is more economical to back the resource down to avoid incurring the cost to produce that energy and instead purchase that energy from MISO at the lower market price.
>
> As described above, the LMP represents the marginal value of energy at any location within MISO. It is the price paid to a generator for every MWh produced, and the price paid by a load for every MWh consumed. LMPs can vary at each generator or load node in the MISO footprint because of transmission losses and congestion. When the LMP is positive, a generator is paid that price by MISO for its output while a load will pay that price to MISO for its demand. When the LMP is negative, the opposite is true, i.e. a generator will pay MISO that price for each

[7] Source: Xcel's response to the Department's information request No. 33.

additional MWh produced and a load will be paid for each additional MWh consumed.

NSP has Power Purchase Agreements (PPA) with both dispatchable and non dispatchable ("intermittent') wind generation resources. Intermittent resources are price takers in the market meaning that MISO accommodates any actual power produced by the resource through re-dispatch of other thermal resources. In other words, MISO does not calculate a set-point for non-dispatchable intermittent resources to operate and curtailment requires a manual process accomplished through a phone call to the farm itself. The wind farm operator controls the facility locally based on instructions from the NSP system dispatcher. Manual curtailment is imprecise and can lead to either too much or too little wind being curtailed in response to negative LMP prices. If too much wind is curtailed, LMP prices may rebound to well above zero. If not enough wind is curtailed, LMPs will remain significantly negative signaling even more curtailment is necessary.

MISO does send set points to dispatchable intermittent generation (including wind generation) that possess Automatic Generator Control ("AGC") which are registered as DIR using an automated set-point communicated through the Company's Energy Management System (EMS). With this functionality in place, MISO is able to accurately determine the appropriate amount of energy to curtail to relieve the capacity or transmission constraints that create negative LMPs. The Company offers DIRs such as Zypher and Morraine II into the MISO market at or above a certain price just like traditional thermal resources. When the LMP drops below the wind farm's offer price, MISO sends a setpoint to the farm to dispatch down automatically by exactly the amount necessary to relieve the constraint. The improved precision with which dispatchable resources can be curtailed on AGC helps reduce the magnitude of negative pricing events and the volume of energy curtailed from the associated wind farms.
…
During FYE14 the Company experienced **[TRADE SECRET HAS BEEN EXCISED]** of curtailment that was due to LMPs below the wind farm offer price, resulting in AGC signals from MISO to reduce output.

The wind projects that were curtailment are registered with MISO as DIR and are required to comply with the MISO cost signals. Failure to comply would result in Revenue Sufficiency Guarantee, "failure to follow," and potentially other penalties.

Given that Xcel Electric "must respond and follow MISO direction to reduce output as applicable," the Department will not pursue further the issue of the FYE14 wind curtailments resulting from the DIR Economic, Congestion and Negative LMP Related Curtailments.[8]

3. Manual Economic, Congestion and Negative LMP Related Curtailments

Xcel Electric provided the following discussion of the Manual Curtailment Events:[9]

> Unlike DIR wind farms, non-DIR wind farms require recognition of trends and action by an NSP system dispatcher. MISO broadcasts real time LMPs every five minutes. Action taken or not taken by an NSP operator impacts future 5 minute intervals LMPs. In this Information Request, the DOC sought to gather information concerning whether it would have been more economical to have curtailed other wind farms or to have taken action at other generation resources in lieu of curtailments at the selected resources. As noted above, the economic decision to curtail a wind farm is specifically affected by whether or not a wind farm qualifies for federal Production Tax Credits. As a result, the comparison of the real-time dispatch price for the wind farm with the relevant LMP determines if it is economic to curtail the wind farm or accept the generation.
>
> Concerning the economic result of curtailments, at times, the average hourly real time LMP at the wind farm may be above the curtailment price threshold when the curtailment occurred, which can be due to 1) an LMP rebounded much stronger than expected when the NSP system dispatcher initiated the curtailment; or 2) the curtailment occurred only during the part of the hour when 5 minute LMPs were below the curtailment threshold.
>
> During FYE14 the Company experienced **[TRADE SECRET HAS BEEN EXCISED]** of curtailment that was the result of manual actions related to economics.
>
> …
>
> 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 $992,723.46. See Attachment D.

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[8] Source: Xcel Electric's June 19, 2015 reply comments at 11.

[9] Source: Xcel's response to the Department's information request No. 33.

> To perform this analysis NSP started with estimated hourly averaged curtailment volumes and hourly averaged LMP values for all non-DIR wind farms. NSP then manually subtracted the curtailment volumes for hours that were specifically identified as Transmission Curtailments. 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 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. The financial impact of any PTC [Production Tax Credits] credit owed to a wind farm due to the curtailments was added to the economic analysis of the settlement impact.

Given that "the curtailments produced customer economic value by reducing costs by $992,723.46," the Department will not pursue further the issue of the FYE14 wind curtailments resulting from the Manual Economic, Congestion and Negative LMP Related Curtailments.

The Department's review of Attachment D indicates that the cost reduction would have been larger if Xcel Electric curtailed only the facilities that do not receive Production Tax Credits.

Therefore, the Department recommends that the Commission require Xcel Electric to discuss in a supplement of its FYE15 AAA report whether and why it is still reasonable to curtail wind facilities that are receiving Production Tax Credits, in response to Manual Curtailment Events.

Based on the record to date, the Department recommends approval of Xcel Electric's FYE14 wind report.

III. FUEL CLAUSE ISSUES: RESPONSE TO MLIG

In its June 19, 2015 reply comments, MLIG called attention to the discussions in other recent AAA dockets and among stakeholders regarding reforming the fuel clause adjustment mechanism (the "FCA"):

> The Department provided some context for these discussions in Attachment E16 of the DOC Report, including referencing key points from its December 31, 2014 response comments in Docket No. E999/AA-12-757, in which it proposed an incentive FCA and summarized the difficulties with the current operation of the current FCA. In response to the Department's proposal for an incentive FCA in December, various parties, including MLIG, submitted additional reply comments in February. The Commission has not yet taken action on these recommendations and comments.

> More than $1.3 billion was recovered by the Utilities in fuel costs during fiscal year 2014. Given the enormous amount of money that flows through the FCA, it is of enormous importance to ratepayers for utilities to have effective incentives to control these costs and for regulators to have the ability to effectively review them. As MLIG, the Department and others have argued in previous discussions, the current FCA does not provide utilities such incentives. And further, it practically puts the burden of proof on regulators and ratepayers to demonstrate when costs are not just and reasonable. Although the Department has made recommendations for ways to improve the type of information it receives to assist in its review of costs, better information will not improve the underlying problem, which is that utilities do not have "skin in the game" with respect to costs recoverable via the FCA.
>
> These issues have been developed in more detail in the previous AAA proceedings, but MLIG believes that it is important to raise them again here because they underlie every AAA proceeding. The Department and other parties have raised serious concerns about the current FCA that need to be addressed. Ratepayers cannot be confident that costs recovered through the FCA are just and reasonable when regulators are not confident in their ability to effectively review those costs. These issues are well-developed in the 12-757 docket and are ready for Commission action to move the process along. For these reasons, MLIG urges the Commission to establish a process and a timeline for implementing FCA reform.

The Department agrees with MLIG that the underlying problem, with respect to costs being recovered via the FCA, is that utilities do not have a "skin in the game." As discussed further in the "Background Information on Fuel Clause Issues from Recent Dockets" in Attachment E16 of our May 19, 2015 Report in the instant docket, the Department is still recommending the use of a fuel recovery mechanism designed to give utilities the same incentive to minimize FCA costs as utilities currently have to minimize costs recovered in base rate that do no change between rate cases.[10] When rates are fixed between rate cases, the utility receives a clear incentive to reduce these costs between rate cases.

Pages 8-16 of the Department's comments in E999/AA-12-757 discussed the background of the FCA, included information from the National Regulatory Research Institute's (NRRI) report called "*The Two Sides of Cost Trackers: Why Regulators Must Consider Both*" (Ken Costello, October 27, 2009)[11] and suggested options for the Commission to consider regarding reform of the FCA, along with advantages and disadvantages of the various

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[10] See Attachment E16 of the Department's May 19, 2015 report in Docket No. E999/AA-14-579, available at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={58985132-8599-4031-A311-EA7D9016DAB5}&documentTitle=20155-110569-02

[11] Available at http://mn.gov/puc/documents/pdf_files/012415.pdf

options. For ease of reference, those comments are at https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={1BCA9F40-4ACC-43E8-A01F-71BDF6BED367}&documentTitle=201412-105847-01 and attached to these comments. The Department's overall recommendation in the December 31, 2014 comments was:

> As next steps, the Department recommends that the Commission consider asking parties to file comments on these options, bringing parties together to talk about these options, or both, whichever option would allow the issues to be developed in a manner acceptable to the Commission.

On February 11 and 12, 2015, utilities, MLIG and OAG-RUD provided reply comments.

MLIG raised a concern that the Department's recommendations in the previous AAA docket (13-599) "for ways to improve the type of information it receives to assist in its review of [FCA] costs" would not improve the underlying problem. The Department agrees and stresses that the additional reporting requirements it recommended in its December 31, 2014 response comments in 13-599 and/or any information required by the Commission to help the Commission make a determination on the reasonableness of the utilities' FCA rates were only meant to be a second-best solution until a new FCA recovery mechanism is approved by the Commission.

As a result, the Department is also looking forward to the Commission's guidance in this matter.

IV. RAIL DELIVERY ISSUES

A. OTTER TAIL

In its May 19, 2015 Report, the Department recommended that Otter Tail explain in reply comments why it opts to transport coal under tariff, rather than under long-term contract, and explain specifically what coal conservation measures it took during calendar year 2013 and the specific costs to ratepayers associated with those measures.

1. Shipping Coal Under Contract vs. Tariff

In its Reply Comments, Otter Tail stated that the fact that it transports coal under tariff, rather than long-term contract **[TRADE SECRET HAS BEEN EXCISED].**

In its Report, the Department noted that Otter Tail has implemented coal conservation measures five times in the last eight years, and asked Otter Tail to explain whether transporting under contract, rather than tariff, would help alleviate some of these delivery issues. Relatedly, the Department also asked Otter Tail to discuss in Reply Comments options under either tariffs or contracts for railroads to pay for a portion of the costs of replacement power due to unacceptable service. In Reply Comments, **[TRADE SECRET HAS BEEN EXCISED].** Additionally, Otter Tail stated that it is not aware of a contract or tariff provision that would require railroads to pay for a portion of the costs of replacement power due to unacceptable service.

The Department notes that coal transportation contracts can, and often do, include clauses related to minimum service standards, and provide for financial compensation if those service standards are not met. While not specifically tied to the cost of replacement power, any compensation received by the utility could and should be used to offset the cost of replacement power charged to ratepayers. [TRADE SECRET HAS BEEN EXCISED]. Additionally, transporting under tariff preserves Otter Tail's ability to pursue rate relief with the STB.

The Department concludes that Otter Tail's coal transportation policies are reasonable. However, the Department recommends that the Commission require Otter Tail to report in future AAA filings any coal conservation measures taken in response to coal delivery issues during the relevant reporting period, along with a discussion of OTP's efforts to minimize coal, coal delivery and any replacement power costs if needed to address issues with coal supplies for OTP.

2. Coal Conservation Measures

In its Report, the Department noted that Otter Tail provided a detailed discussion of the coal conservation methods it undertook from June 19, 2014 through the end of 2014, but did not describe the measures it took during calendar year 2013 other than to say they were "similar" to the actions taken during 2014. Thus, in its Report, the Department requested that Otter Tail explain specifically the coal conservation methods it undertook during calendar year 2013. The Department also requested that Otter Tail provide an estimate of the costs to ratepayers associated with the coal conservation measures it undertook during 2013.

In its Reply Comments, Otter Tail provided specific descriptions of the actions it took intermittently during November and December 2013. During off-peak hours, Otter Tail's share of Big Stone Plant's production capability between maximum and minimum output was offered in to the MISO market at an artificially high price, which was intended to be slightly higher than the market clearing price, and thus caused Big Stone not to be dispatched. Otter Tail estimated that the incremental cost of these measures taken during FYE14 was $218,000 on a total system basis (*i.e.*, non-jurisdictionalized).

The Department concludes that, given the coal delivery issues experienced at Big Stone Plant, Otter Tail's coal conservation measures during FYE14 were reasonable. The Department recommends that the Commission accept Otter Tail's reporting with respect to fuel costs associated with coal shortages.

B. XCEL

In its Report, the Department noted that [TRADE SECRET HAS BEEN EXCISED].

The Department requested that Xcel explain in reply comments whether the terms and conditions of its rail contracts could be negotiated in the future in a way [TRADE SECRET HAS BEEN EXCISED] or strengthened in any other way to avoid the issue described above.

In its Reply Comments, Xcel stated that recently, railroads have been reluctant to include any type of service commitments in their new transportation contracts, and that as existing agreements expire, the railroads are replacing the service commitment language with standard language requiring the railroad to use “commercially reasonable” or “good faith efforts” to provide satisfactory service. With respect to the possibility of **[TRADE SECRET HAS BEEN EXCISED].**

With respect to other ways the contracts can be strengthened to avoid the issue described above, Xcel stated that when its current rail contracts expire it will endeavor to negotiate terms that are at least as favorable as the current agreements. Additionally, the Company stated that it 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 problems. The Company noted that Minnesota Senator Al Franken has put forth legislation that will require the Secretary of Energy to investigate fuel shortages and also work with other parties to develop recommendations for actions that will help alleviate the fuel supply emergency.

After review, the Department concludes that Xcel’s responses are reasonable, and recommends that the Commission accept Xcel’s reporting with respect to fuel costs associated with coal shortages.

C. MINNESOTA POWER

In its Report, which was filed on May 19, 2015, the Department noted that MP did not provide complete responses to the Department’s March 18, 2015 information requests until May 7, 2015, when MP provided responses totaling approximately 800 pages of documents. The Department did not have time to complete its analysis for inclusion in its Report, and stated that it would provide its analysis in response comments. The Department’s analysis follows.

1. General Background

During FYE14, Minnesota Power had three plants fueled solely by coal: Boswell Energy Center (Boswell), Laskin Energy Center (Laskin), and, and Taconite Harbor Energy Center (Tac Harbor).[12] MP also has two plants that consume a mixture of coal and biomass: Hibbard Renewable Energy Center (Hibbard) and Rapids Energy Center (Rapids).

MP forecasts its coal needs by forecasting expected generation using a production cost model called RTSim. MP stated that the main assumptions used in the generation model are planned outages, estimates of unplanned outages, customer demand, forecasted market prices, and estimated coal costs. MP then converts the output of RTSim (forecasted generation at its coal plants) to estimate its coal needs.[13]

In its response to DOC IR 21, MP provided the following coal procurement guidelines:

[12] Laskin has been converted from coal to natural gas, and received its last shipment of coal on Feb. 12, 2015. MP response to DOC IR 21. Please note that all MP responses to discovery related to this section are provided in Attachment 2.

[13] MP response to DOC IR 21.

- One year out: target is 90-100 percent of total estimated deliveries;
- Two years out: target is 60 percent of total estimated deliveries;
- Three years out: target is 30 percent of total estimated deliveries;
- Later years: 10 percent of total estimated deliveries.

However, MP stated that it uses a flexible approach to coal procurement that allows it to purchase more coal when market conditions are favorable, and less coal when conditions are not favorable. MP stated that this flexibility allows performance of test burns from time to time, which are designed to expand the number of suppliers from which MP can purchase coal.

[TRADE SECRET HAS BEEN EXCISED]

As described in MP's response to DOC IR 22, part b, [TRADE SECRET HAS BEEN EXCISED]

2. Rail Delivery Issues

In its response to DOC IR 26 part a, MP provided lengthy descriptions of the rail delivery issues experienced at its plants which the Department will not repeat here in full. In summary, MP experienced numerous delays in coal deliveries resulting from congestion on BNSF's rail lines caused by high volumes and track closures for maintenance, crew and locomotive shortages, and various weather events throughout BNSF's system.

MP stated that at Boswell, rail delivery issues began in mid-2013, and between June 25, 2013 and mid-October, Boswell's coal inventory decreased from 26 days' burn (slightly below MP's target inventory of 30 days) to 10 days' burn. Boswell's coal inventory was largely unchanged by the end of November 2013. In December, BNSF decreased the number of cars per train serving Boswell from 115 to 108, and crew shortages, high volumes, extreme temperatures and snow, and a derailment on BNSF's system increased delays, and by January 2, 2014, Boswell's coal inventory fell to five days' burn.

Rail service to Boswell improved slightly between January and March 2014, and planned outages during April and May allowed inventory levels to improve to 34 days' burn. However, rail delivery issues caused by high volumes and bad weather began again in June, and by September 1, 2014, Boswell's inventory fell to 10 days' burn. Beginning in October 2014, Boswell's inventory began to increase steadily as rail service improved, reaching 46 days' burn by the end of 2014, and continued to increase through the end of February.

MP stated that the delivery issues that affected Boswell affected Tac Harbor as well. MP also stated it diverted trains destined for Tac Harbor to Boswell in order to keep Boswell, MP's lowest cost unit, running. MP attempted to supplement Tac Harbor's coal supply with deliveries from an alternative source, but was only able to secure one train. Tac Harbor's coal stockpile hit its FYE14 low point of 23 days' burn on June 4, 2014.

MP stated that Laskin was the least affected of the three energy centers due to the fact that only one train set was needed to meet Laskin's coal needs. Laskin's coal inventory fell to 24 days' burn in December 2013, its lowest point.

[TRADE SECRET HAS BEEN EXCISED].

3. Reasonableness of MP's Actions

a) Ex-Ante Actions

As noted above, MP attempts to maintain coal inventories equal to **[TRADE SECRET HAS BEEN EXCISED]** These inventories help protect ratepayers from negative impacts associated with rail delivery issues.

As noted in MP's response to DOC IR 21, prior to the start of each calendar year, MP must nominate the number of tons of coal it wants delivered by BNSF during the upcoming calendar year. **[TRADE SECRET HAS BEEN EXCISED].**

Table 1:
MP's Requested and Actual Coal Deliveries

Description	Line/formula	2011	2012	2013	2014
[TRADE SECRET DATA HAS BEEN EXCISED					

[TRADE SECRET DATA HAS BEEN EXCISED].

[TRADE SECRET DATA HAS BEEN EXCISED]. As shown in the attachment to MP's response to DOC IR 23, BNSF did not consent to MP disclosing a copy of its rail transportation contract. Because MP did not provide a copy of its contract with BNSF, the Department was unable to refer to the contract for guidance on this issue. Thus, the Department cannot conclude that MP fully met its burden of proof to show that the rates MP charged to its ratepayers were reasonable.

In its response to DOC IR 25, part a, MP stated **[TRADE SECRET DATA HAS BEEN EXCISED]**.

In its response to DOC IR 21, part c, MP stated that if less coal is consumed at a plant than anticipated, MP would allow coal inventory to build until a later date in order to avoid paying liquidated damages to the railroad for not shipping its nominated amount (implying that the nominated amount referenced above puts a binding obligation on both the railroad and MP). However, MP stated that that there are two exceptions to this obligation: if the physical area of the coal stockpile cannot safely hold the additional tons of coal, or if there is a catastrophic event that significantly affects coal burn, then MP would use the force majeure provision of its contracts to excuse MP of its contractual performance. MP's ability to use a force majeure provision of the its rail contracts to avoid paying damages on canceled deliveries when coal stockpiles reach maximum levels limits risk to MP associated with over-estimating its coal needs when determining the nominated amount of deliveries for an upcoming year.

[TRADE SECRET DATA HAS BEEN EXCISED].

In DOC IR 45, the Department asked [TRADE SECRET DATA HAS BEEN EXCISED] In its response, MP stated that during 2013, its thermal generation was greater than it anticipated when determining its Declared Tonnage in October 2012. This difference was a result of wholesale power prices increasing by 27 percent from 2012 to 2013, which MP did not anticipate. MP stated that the higher wholesale power prices resulted from high natural gas prices, generation outages across the MISO footprint, transmission outages, and weather.

Similarly, during early 2014, historically cold weather resulted in higher than expected wholesale power prices, which led to higher than expected generation at MP's coal plants. [TRADE SECRET DATA HAS BEEN EXCISED].

In summary, the Department concludes that MP took reasonable actions to forecast its coal needs and ensure adequate coal supply during FYE14, but its [TRADE SECRET DATA HAS BEEN EXCISED].

b) Ex-Post Actions

[TRADE SECRET DATA HAS BEEN EXCISED].

After review, the Department concludes that MP's actions during FYE14 in response to its coal delivery issues (*i.e.*, given that the delivery problems occurred) were reasonable. However, for the reason identified above, the Department cannot confirm that the rates MP charged to its ratepayers were reasonable during this period.

As noted above, MP also implemented coal conservation measures after FYE14 ended (on June 30, 2014). The Department will analyze those actions in greater detail in the next AAA proceeding.

V. DEPARTMENT ANALYSIS – REVIEW OF MISO DAY 1 AND DAY 2 CHARGES & MODULE E – GENERATION DELIVERABILITY RESULTS, AND ASM

A. DOC'S RESPONSE TO XCEL ELECTRIC'S REPLY COMMENTS

1. MISO Day 2

In the Department's Report, we asked Xcel Electric to respond to the following issues regarding MISO Day 2 in reply comments:

- The Department understood that Xcel Electric's year-over-year increase in Real-Time Non Asset Energy charges was mainly attributable to increases in real-time curtailments. Thus, the Department recommended that the Company provide in its reply comments the amount of real-time curtailments incurred in FYE13 and FYE14 and explain the reasons for any increase.

- The Department understood that Xcel Electric's Day-Ahead Schedule 24 Allocation Amounts were assigned to retail and asset-based wholesale on a MWh basis. The Department recommended that Xcel Electric confirm our understanding in reply comments.

- The Department recommended that Xcel Electric explain why no Real-Time Schedule 24 Distribution charges (revenues) were assigned to ratepayers (instead assigning all revenues to the asset-based wholesale sector, which is equivalent to keeping the revenues for shareholders). In addition, the Department recommended that Xcel Electric explain why Real-Time Schedule 24 Distribution charges (revenues) are reclassified from asset-based wholesale to transmission revenues. Finally, the Department recommended that Xcel Electric explain which specific recovery mechanism it was referring to when it stated "…for inclusion in that recovery mechanism."

- The Department recommended that the Company return its FYE14 Multi-Value Project Auction Revenue Rights (MVP ARRs) revenues in its next transmission cost recovery (TCR) Rider.

- The Department recommended that the Commission not accept Xcel Electric's MISO Day 2 reporting until the Company had provided the required information in its reply comments.

a) #22a Real-Time Non Asset Energy

In our initial comments, the Department noted that the Real-Time Non Asset Energy charges (revenues) assigned to retail had increased from ($210,272) in FYE13 to $1,444,148 in FYE14. Based on Xcel Electric's response to DOC Information Request No. 35, the Department understood that the year-over-year increase in the Real-Time Non Asset Energy charges was attributable to increases in real-time curtailments. As a result, the Department recommended that the Company provide in its reply comments the amount of real-time curtailments incurred in FYE13 and FYE14 and explain the reasons for any increase.

Beginning on page 2 of its Reply Comments, Xcel stated that:

> 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 2 and Table 3 below.

Table 2: 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	$1,654,419.4
#22b Congestion Component	-$108,741.94	-$36,437.27	-$72,304.67
#22c Loss Component	-$34,246.48	$39,828.3	-$74,074.84
Total	$1,301,159.39	-$206,880.58	$1,508,039.9

Table 3: Day-Ahead Non Asset Energy Amount

Day-Ahead Non Asset Energy Amount	FYE 2014	FYE 2013	2014 vs 2013
#5a Energy Component	-	-	-
#5b Congestion	$22,548,166.	$14,749,279.	$7,798,886.5
#5c Loss Component	$12,934,546.	$14,633,817.	-
Total	-	-	-

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.

Based on our review of Xcel Electric's reply comments, the Department concludes that Xcel has reasonably explained the increase in real-time curtailments. In addition, the Department agrees that the year-over-year increase in the Real-Time Non Asset Energy charges (due to curtailments) is more than offset by corresponding increases in Day-Ahead Non Asset Energy Amount for the same period. Thus, the Department concludes that Xcel's Real-Time Non Asset Energy charges (revenues) for FYE14 appear to be reasonable.

b) #33 Day-Ahead Schedule 24 Allocation Amount

In our initial comments, based on Xcel Electric's response to DOC Information Request No. 38-1, the Department understood that Day-Ahead Schedule 24 Allocation Amount charges were assigned to retail and asset-based wholesale on a MWh basis. As a result, the Department recommended that Xcel Electric confirm our understanding in reply comments.

Xcel Electric stated on page 4 of their Reply Comments that the Department's understanding was correct. The Department appreciates Xcel 's confirmation and concludes that the Company's Day-Ahead Schedule 24 Allocation Amount charges (revenues) for FYE14 appear to be reasonable.

c) #34 Real-Time Schedule 24 Allocation and Real-Time Schedule 24 Distribution

In its response to DOC Information Request No. 38-2, Xcel Electric stated that the Real-Time Schedule 24 Allocation line item was net of two different charge types – Real-Time Schedule 24 Allocation and Real-Time Schedule 24 Distribution. Xcel stated that Real-Time Schedule 24 Allocation charges were assigned to retail and asset-based wholesale on a MWh basis. In contrast, Xcel stated that Real-Time Schedule 24 Distribution charges (revenues) were only assigned to asset-based wholesale where they were then reclassified to transmission revenues.

In our initial comments, the Department recommended that Xcel Electric explain why no Real-Time Schedule 24 Distribution charges (revenues) were assigned to retail ratepayers. In addition, the Department recommended that Xcel Electric fully explain why Real-Time Schedule 24 Distribution charges (revenues) were reclassified from asset-based wholesale to transmission revenues. Finally, the Department recommended that Xcel Electric explain which specific recovery mechanism it was referring to when it stated "…for inclusion in that recovery mechanism."

Xcel Electric stated on page 24 of its Reply Comments that:

> 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.

Based on the above, the Department understands that Real-Time Schedule 24 Allocation revenues are meant to reimburse Xcel Electric for operating balancing activities in its control area. The reason these revenues are reclassified to base rates is because the underlying O&M expense for these activities are in base rates. Likewise, Real-Time Schedule 24 distribution expenses do not flow through the FCA, but are removed and treated as revenue credits in base rates.

Based on our review, the Department concludes that Xcel's Real-Time Schedule 24 Allocation and Real-Time Schedule 24 Distribution charges (revenues) appear reasonable for FYE14. However, for clarification purposes, the Department recommends that Xcel discontinue netting these two charge types and report them as separate line items in future AAA filings.

d) Multi-Value Project Auction Revenue Rights (MVP ARRs)

In our initial comments, the Department recommended that the Company return its FYE14 Multi-Value Project Auction Revenue Rights (MVP ARRs) revenues in its next TCR Rider.

Beginning on page 5 of its Reply Comments, Xcel stated that:

> 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 4: 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

Based on the above, the Department concludes that Xcel's plan to pass back its MVP ARR revenues to customers in its TCR Rider compliance filing in Docket No. E002/M-14-852 appears reasonable.

e) MISO Day 2 Summary

Based on all of the above, the Department recommends that the Commission accept Xcel Electric's MISO Day 2 reporting for FYE14.

2. ASM

In the Department's Report, we asked Xcel Electric to respond to the following issues regarding ASM in reply comments:

- Given the significant increase in Excessive Deficient Energy Deployment Charges (EDEDC) charges in FYE14, the Department recommended that the Company continue to work to mitigate these costs in the future.
- The Department recommended that Xcel Electric fully explain in reply comments the method or methods used to allocate Day-Ahead Regulation Amount, Real-Time Regulation Amount, and Real-Time Regulation Reserve Cost Distribution Amount between retail and asset-based wholesale in its journal entry.
- The Department recommended that Xcel Electric fully explain in reply comments the method or methods used to allocate Day-Ahead Spinning Reserve Amount, Real-Time Spinning Reserve Amount, and Real-Time Spinning Reserve Cost Distribution Amount between retail and asset-based wholesale in its journal entry.
- The Department recommended that the Commission not accept Xcel Electric's ASM reporting until the Company had provided the required information in its reply comments.

The Department discusses Xcel Electric's responses to the Department's above issues and the Department's recommendations as a result of our additional review below.

a) Excessive Deficient Energy Deployment Charges (EDEDC)

Regarding EDEDC, Xcel stated that:

> 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.

The Department appreciates Xcel's explanation and agrees that the benefits attributable to EDEDC far exceed the costs. The Department cannot confirm that Xcel is "already mitigating EDEDC charges to the best of [its] ability through [its] current procedure." As noted in Attachment 1, " From a regulatory perspective, one difficulty is the inability to know what choices the utility should have made, but did not make, in managing operations, assessing resources, engaging in MISO activities or other areas that would have reduced costs for ratepayers." The Department will continue to monitor these costs in future AAA fillings.

b) Day-Ahead Regulation Amount, Real-Time Regulation Amount, and Real-Time Regulation Reserve Cost Distribution Amount

In our initial comments, the Department noted that the net invoice amounts for Day-Ahead Regulation Amount, Real-Time Regulation Amount, and Real-Time Regulation Reserve Cost Distribution Amount charges totaled ($1,454,309.39) in FYE14, of which retail was assigned costs of $86,097.42 and asset-based wholesale (essentially, shareholders) was assigned revenues of ($1,540,406.81). As a result, the Department recommended that Xcel Electric fully explain in reply comments the method or methods used to allocate these three charges between retail and asset-based wholesale in its journal entry.

Xcel stated in its Reply Comments that:

> 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 5: 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

Based on our review, the Department concludes that Xcel Electric's allocation of Day-Ahead Regulation Amount, Real-Time Regulation Amount, and Real-Time Regulation Reserve Cost Distribution Amount costs and revenues appear to be reasonable at this time. Moreover, the Department's concern with Xcel Electric's allocation of these costs and revenues is somewhat mitigated by the fact that Xcel Electric's asset-based margins are returned to ratepayers through the FCA (as opposed to a fixed amount in base rates). The Department notes that reasonable cost allocation between retail customers and the wholesale sector is still necessary, but less of a concern regarding overall impact to retail customers due to the flow-through method of asset-based margins.

The Department notes the lack of transparency given that Xcel Electric aggregates two of the three charge types before allocating a portion to asset-based wholesale (-$1,540,406.81) in a single journal entry under Real-Time Regulation Amount. For transparency purposes, the Department recommends that in future AAA filings Xcel allocate the asset-based wholesale portion of these two charge types separately under each charge type.

c) Day-Ahead Spinning Reserve Amount, Real Time Spinning Reserve amount, and Real Time Spinning Reserve Cost Distribution

In our initial comments, the Department noted that the net invoice amounts for Day-Ahead Spinning Reserve Amount, Real-Time Spinning Reserve amount, and Real-Time Spinning Reserve Cost Distribution totaled ($116,026.82) in FYE14, of which retail was assigned costs of $902,011.64 and asset-based wholesale was assigned revenues of ($1,018,038.46). As a result, the Department recommended that Xcel Electric fully explain in reply comments the method or methods used to allocate these three charges between retail and asset-based wholesale in its journal entry.

Xcel stated in its Reply Comments that:

> 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 6: 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**

Similar to Xcel Electric's allocation of regulation amounts, the Department concludes that Xcel Electric's allocation of Day-Ahead Spinning Reserve Amount, Real Time Spinning Reserve Amount, and Real Time Spinning Reserve Cost Distribution costs and revenues appear to be reasonable at this time. Likewise, the Department's concern with Xcel Electric's allocation of these costs and revenues is somewhat mitigated by the fact that Xcel Electric's asset-based margins are returned to ratepayers through the FCA (as opposed to a fixed amount in base rates). Again, the Department notes that reasonable cost allocation between retail customers and the wholesale sector is still necessary, but less of a concern regarding overall impact to retail customers due to the flow-through method of asset-based margins.

The Department notes the lack of transparency given that Xcel Electric aggregates two of the three charge types before allocating a portion to asset-based wholesale (-$1,018,038.46) in a single journal entry under Real-Time Spinning Reserve. For transparency purposes, the Department recommends that in future AAA filings Xcel allocate the asset-based wholesale portion of these two charge types separately under each charge type.

d) ASM Summary

Based on all of the above, the Department recommends that the Commission accept Xcel Electric's ASM reporting for FYE14 with the caveat that it cannot be confirmed that Xcel is "already mitigating EDEDC charges to the best of [its] ability through [its] current procedure."

B. DOC'S RESPONSE TO MP'S REPLY COMMENTS

In its Report, the Department noted that MP's Day-Ahead Asset Energy Charges in September 2013 and May 2014 were $8.7 million and $8.9 million, respectively; higher than in any other month since at least July 2010, and asked MP to explain in reply comments the reasons for the charges.

In its Reply Comments, MP stated that the high charges incurred during September 2013 were the result of scheduled outages. Boswell Units 3 and 4 had, respectively, five and seven day outages for boiler maintenance. In addition, Square Butte Young #2 had a 24 day outage for turbine maintenance.

MP also stated that the high day-ahead charges incurred in May 2014 resulted from a scheduled 13 day outage for a major boiler overhaul, and a five day forced outage at Boswell Unit 3 for a boiler tube leak.

The Department concludes that MP's explanations are reasonable, and recommends that the Commission accept MP's MISO Day 2 reporting for FYE14.

C. DOC'S RESPONSE TO OTP'S REPLY COMMENTS

1. MISO Day 2

After analyzing OTP's initial filing the Department requested that OTP explain why the Company incurred such large increases in Congestion and FTR costs and revenues in the July 2013 to June 2014 period as compared to the previous year. The Company stated that both of these increases were due to shifting its Big Stone and Coyote power plants from MISO Option B to Option A, resulting in OTP no longer receiving a congestion rebate, but instead receiving Auction Revenue Rights (ARRs) for these facilities. Under Option B OTP would receive congestion revenues for adequately predicting its energy usage, while under option A the Company instead receives ARRs for these facilities. Thus costs and revenues increased for Congestion and FTRs/ARRs, with revenues increasing by a larger amount, resulting in lower net costs assigned to customers.

In our May 19, 2015 Comments, the Department requested that OTP explain in its reply comments why ratepayers are better off under Option A compared to Option B, and to document that all ARRs are being returned to ratepayers.

On June 19, 2015, OTP provided reply comments addressing these questions. OTP noted that several plants were being switched from Option B to Option A due to increasing difficulties in forecasting day ahead cleared MW volumes. Under Option B in cases where OTP scheduled energy in excess of actual energy cleared by the units in the Day Ahead Market congestions revenues would be lost. In contrast Option A essentially is the equivalent of holding an FTR between the generating unit and the load zone, resulting in congestion revenues being granted to the Company. OTP states that Option A is a better congestion hedge for its customers at this time, and the Company notes that the grandfathered transmission rights allow OTP to choose between different congestion hedging instruments on an annual basis. OTP documents the Company's reasons for the transition from Option B to Option A on page 8 of its Trade Secret reply comments. Finally

OTP confirmed that all ARRs are being returned to ratepayers and that these revenues are included in the amounts reported annually within the Retail section of OTP's Detail of MISO Day 2 Charges (FYE 2014 AAA Attachment K) schedules.

The Department concludes that OTP has adequately answered the questions and recommends that the Commission Accept OTP's MISO Day 2 reporting. The Department requests that OTP provide in future AAA filings information and narrative to explain why the selected Option for FTRs and ARRs is better for rate payers than the alternative.

2. Recommendations

The Department recommends that the Commission accept OTP's MISO Day 2 reporting. The Department requests that OTP provide in future AAA filings information and narrative to explain why the selected Option for FTRs and ARRs is better for ratepayers than the alternative.

D. DOC'S RESPONSE TO INTERSTATE ELECTRIC'S REPLY COMMENTS

1. MISO Day 2

a) General Dispatch

In its May 19, 2015 Comments, the Department requested clarification beyond that provided in information request responses as to why IPL's generation was not dispatched in the MISO market despite highly elevated locational marginal prices (LMPs) as a result of the polar vortex of 2013-2014.

The Department noted that IPL's Day 2 net costs to retail customers had sharply increased in FYE14 to more than double that experienced in FYE13, and issued an information request to the Company for more details on the increased costs.[14] The Company responded that a combination of factors including higher relative fuel costs and lower relative generator efficiencies at IPL generators, large quantities of wind generation in the area, and resulting transmission congestion combined to cause increased amount of Day Ahead (DA) Asset Energy costs due to its generators not clearing. The increase in the DA Asset Energy costs was the main driver behind the total increase in Day 2 costs for IPL in FYE14.

Additionally the Marginal Energy Component (MEC) of the LMP was increased greatly in FYE14 as a result of the frigid temperatures associated with the polar vortex in early 2014. Finally, the significant gap between cleared generation and IPL's load resulted from planned baseload generator outages, and increased localized congestion from high wind months in FYE14.

The Department requested that the Company explain in reply comments why, even with the highly elevated LMPs, IPL's generation was not dispatched in the MISO market.

In its discussion of the dispatch of its generation resources during the period of elevated LMP's during the polar vortex, the Company indicated in Reply Comments that it typically offers its low cost coal generation to MISO at cost into the DA market, and that if available, they were offered at the daily maximum capacity to MISO. The Department understands

[14] MN DOC Information Request No. 30 Issue April 6, 2016, response received April 16, 2015

that although they were offered, those offers may not have been accepted as part of MISO's economic dispatch protocol. The Company additionally stated that all real-time commit decisions are based on reliability only and not economics. The Department agrees with the statement that commit decisions that put units in the dispatch stack for MISO are reliability based, but the dispatch of those units once in the stack – or whether that unit runs or not – is based on the economics of the generator.

The Company further provided explanation of the dynamics between the nodal LMP at the ALTW.ALTW load zone and the traded Ventura natural gas price as a means to demonstrate why some generators may not be dispatched by MISO even during times of high LMPs. The Companies' gas generators are priced off Ventura trading hub, which during the polar vortex, was the highest price. The implied heat rate of the plant is the nodal LMP divided by the $/MMBTU at the Ventura hub, and due to the high gas prices, that figure was lower than the actual heat rate of the generators. When the implied heat rate falls below the actual generator heat rate, it's uneconomical for that generator to operate because the market won't pay the generator enough to cover the high cost of the natural gas priced as it was. Thus, the generators were not asked to run by MISO primarily as a result of high gas prices at the Ventura hub.

Additionally, the Company made note of a few outages in its natural gas generation fleet during the polar vortex due to weak local gas pressures during periods with high customer draw. Ultimately, the high Ventura hub prices were the most influential factor in the IPL's generation failing to be dispatched despite high LMP periods. IPL abided by its required MISO tariff guidelines during the polar vortex and offered all of its generating units.

b) Polar Vortex Effects

As noted in the previous section, the increased occurrence of significantly colder temperatures than normally experienced during the polar vortex caused an increase in the MEC of the LMP, and since IPL experienced a larger discrepancy than historically seen between its cleared generation and its load, the Company bore more DA Asset Energy costs in FYE14 through purchases from MISO which drove up the total Day 2 costs for the Company in FYE14.

The Department requested that the Company explain in its reply comments the effect of the polar vortex on its Day-Ahead purchases in FYE14.

The Company stated that the effects of the polar vortex in January of 2014 for example, produced a large increase in load and a concurrent increase in load expense to $73 million as compared to the original load expense forecast of $46 million. Load was only 3 percent higher than forecasted, and only contributed $1 million to the $27 million increase, the bulk of which was the increase in prices with an average price of $49/MWh compared to the forecast price of $32/MWh, which contributed $26 million to the load expense variance from the forecast.

Additionally, load was driven up as a result of extremely cold temperatures, and load expense was $121 million, which was more than 50 percent higher than forecast. Again, most of this was from higher energy prices and the remainder by increased load demand. Overall the effects of the polar vortex on the Company's Day-Ahead purchases was significant, and caused market prices to become high and volatile multiple times during the winter of 2013-2014, precisely in the months of January, February, and March 2014.

c) MISO Day 2 Summary

The Department believes Interstate Electric has done a reasonable job explaining and clarifying the issues raised by the Department in its May 19, 2015 comments regarding its

Day 2 costs and the effects of the 2013-2014 polar vortex on its Day-Ahead purchases in 2014. The Department recommends that the Commission accept the Company's filing with respect to the MISO Day 2 charges.

2. MISO Ancillary Services Market

a) Excessive/Deficient Energy Deployment Charge (EDEDC)

In its May 19, 2015 Comments, the Department noted the continual increase of the ASM EDEDC, and issued an information request the Company to determine steps IPL was taking to reduce the EDEDC penalties.[15] The Company responded that it had evaluated its generation fleet and each unit's ability to respond, and made changes to its regulation offers for certain units as a result of that evaluation.[16] The Department agreed with the necessity to reduce EDEDC penalties and noted that it was not clear why IPL did not take action sooner given that it had been experiencing higher EDEDC penalties in recent years.

The Department requested that the Company explain in reply comments why its ratepayers should pay for the high level of EDEDC penalty costs charged to IPL during this reporting period.

The Company explained in its reply comments that the increases encountered in EDEDC penalties following the December 2012 implementation of the new system by MISO have not caused customers' bills to increase. IPL stated that no change to net costs for receiving regulation has been experienced by ratepayers because of the offset created by a corresponding decrease in the Regulation Distribution charge.

IPL stated that the EDEDC penalties should be included in the fuel cost recovery and that the Company has acted prudently by identifying and curtailing offers from those plants that are not suitable to offer regulations. Additionally, the Company stated that it continues to monitor the continued offering of units to provide regulation, even when those units may not be able to meet MISO's set point instructions and would therefore have to return some regulation mileage to MISO.

b) ASM Summary

While the Department may not agree with all of IPL's statements regarding recovering EDEDC penalties, because there was a corresponding decrease in the Regulation Distribution charge, Interstate Electric appears to have done a reasonable job explaining and clarifying the issues raised by the Department in its May 19, 2015 comments regarding

[15] MN DOC Information Request No. 31 Issue April 6, 2016, response received April 16, 2015
[16] The Department's May 19, 2015 Comments Docket No. E999/14-579, pg. 66

why the EDEDC should be included as a prudently incurred cost in fuel cost recovery, at least in regard to IPL. The Department recommends that the Commission accept the Company's filing with respect to Ancillary Services Market.

VI. DOC'S RESPONSE TO OTTER TAIL POWER'S REPLY COMMENTS ON CHARTS FOR INFORMATIONAL PURPOSES

Section IX Charts for Informational Purposes and the Department's Attachment E11 provided various aspects of fuel charges and the effects on customers' bills. OTP showed the highest average monthly residential bill of $94.52 among the IOUs.

The Department appreciates OTP's clarification and additional information in its reply comments dated June 19, 2015 on reasons why the Company incurred higher average monthly residential charges. OTP's explanation stated as follows:

> OTP residential customers have a much higher level of usage during the winter months compared to other utilities, a characteristic driven in large part, by the nature of Otter Tail's service territory.
>
> Otter Tail serves approximately 48,000 Minnesota residential customers who live in and around 149 communities in northwest and west central Minnesota. The majority of Otter Tail served communities do not have natural gas service, so alternative means for home heating used during the winter, including a higher percentage of customer using some form of electric heat. Otter Tail is a winter peaking utility due in large part to weather sensitive loads.
>
> While the Department notes that Otter Tail has the highest average monthly bill ($94.52/month), naturally, a higher amount of usage (weather driven) is going to yield a higher bill amount. The average bill is not higher due to higher than normal fuel related costs. In fact, **<u>Otter Tail's combined Energy +FCA rate, as noted by the Department in their second paragraph (8.16 c/kWh) is actually the second lowest rate among the utilities.</u>** Otter Tail believes that the per kWh rate comparisons provided by the Department provide a much more "apples to apples" comparison as opposed to comparing total average bill amounts. Otter Tail appreciates the opportunity to highlight some of its unique operational differences within its service territory and hopes the information provided is helpful and beneficial to the Commission.

The Department notes that the charts that were prepared in Section IX of the Report are for informational purposes only. The Department recognizes that each utilities operates in different situations, thus the Department appreciates the additional information provided by OTP in its reply comments.

VII. DEPARTMENT RECOMMENDATIONS – COMPLIANCE FILINGS

This section includes all of the Department's recommendations, either in the May 19, 2015 *Report* or in these *Response Comments*.

- The Department recommends that the Commission approve Xcel Electric's compliance filing on the high level cost allocation test between retail customers and the wholesale sector for June, July and August 2014. The Department recommends that the Commission continue to require Xcel Electric to report this generation cost allocation data in future AAA filings.

- The Department recommends that the Commission accept Xcel Electric's Natural Gas Financial Instruments compliance filing in the FYE14 docket. The Department will review Xcel Electric's continued compliance with this requirement in the FYE15 AAA report.

- The Department recommends that the Commission accept Xcel Electric's FYE14 wind curtailment report.

- The Department recommends that the Commission require Xcel Electric to discuss in a supplemental of its FYE15 AAA report whether and why it is still reasonable to curtail wind facilities that are receiving Production Tax Credits, in response to Manual Curtailment Events.

- The Department recommends that the Commission accept Xcel Electric's compliance filing regarding Xcel Electric's Nuclear Fuel Sinking Fund. The Department will continue to monitor Xcel Electric's Nuclear Fuel Sinking Fund in future AAA filings.

- The Department recommends that the Commission accept Otter Tail Power's Enbridge Energy compliance filing in this docket. The Department recommends that Otter Tail Power no longer be required to report this information.

- The Department concludes that Xcel Electric complied with the January 29, 2009 Order in Docket No. E002/M-08-1098, requiring Xcel Electric to report in future AAA filings any revenue from any source as a result of the Renewable Energy Purchase Agreement with Koda Energy, and to itemize any such revenue by source and amount.

- The Department concludes that Xcel Electric complied with the August 26, 2010 Order in Docket No. E002/M-10-486, requiring Xcel Electric to offset its recovery of costs by any revenues Xcel Electric receives from any and all sources as a result of Xcel Energy's purchase power agreement with Diamond K Dairy, and to report and itemize any such revenues by source and amount in its annual automatic adjustment reports.

- The Department concludes that the IOUs complied with the April 6, 2012 Order in Docket No. E999/AA-10-884 (Ordering Point 8), requiring the IOUs to 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.

- The Department recommends that the Commission accept the IOUs' compliance filings regarding their actual expenses pertaining to maintenance of generation plants, with a comparison to the generation maintenance budget from the IOUs' most recent rate cases.

- The Department recommends that the Commission accept the IOUs' compliance filings regarding their plant outages' contingency plans.

- The Department recommends that the Commission accept the IOUs' compliance filings regarding sharing lessons learned about forced outages. However, the Department continues to conclude that utilities should do more to develop joint systems to share information about outages, similar to the mechanisms developed by the nuclear generation owners. The Department looks forward to discussing the general issue of consumer protection and various ways to accomplish that goal when the Commission considers the comments in Dockets E999/AA-12-757 and E999/AA-13-599.

- The Department concludes that Xcel Electric complied with the April 30, 2010 Order in Docket No. E002/M-10-161, requiring Xcel Electric to report on any curtailment from WM Renewable Energy, including the reasons for any curtailments and amounts paid, in its monthly fuel clause adjustment filings.

- The Department concludes that Minnesota Power is in compliance with the Commission's March 11, 2011 Order in Docket No. E015/M-10-961.

- The Department recommends that the Commission accept Interstate Electric's compliance with the October 2, 2009 Order in Docket No. E-001/M-09-455.

- The Department agrees with OTP that the reporting requirement discussed under Section III.O of the Report need not continue.

VIII. DEPARTMENT RECOMMENDATIONS – FUEL CLAUSE ISSUES

The Department continues to recommend that the Commission consider options to improve incentives for utilities to reduce costs that flow through the fuel clause rider, through use of a fuel recovery mechanism designed to give utilities the same incentive to minimize FCA costs as utilities currently have to minimize costs recovered in base rate that do no change between rate cases.

The Department agrees with MLIG's concern that the Department's recommendations in the previous AAA docket (13-599) "for ways to improve the type of information it receives to assist in its review of [FCA] costs will not improve the underlying problem, which is that utilities do not have 'skin in the game' with respect to costs recoverable via the FCA." For ease of reference, an overview of the underlying problem with the design of the FCA mechanism, as discussed in the 2012 AAA docket (12-757), is provided in Attachment 1 to

these *Response Comments*. The Department stresses that the additional reporting requirements it recommended in its December 31, 2014 response comments in 13-599 and/or any information required by the Commission to help the Commission make a determination on the reasonableness of the utilities' FCA rates were only meant to be a second-best solution to modify the FCA mechanism and is intended to be used only until a new FCA recovery mechanism is approved by the Commission.
As a result, the Department is also looking forward to the Commission's guidance in this matter.

IX. DEPARTMENT RECOMMENDATIONS – RAIL DELIVERY ISSUES

A. XCEL ELECTRIC

The Department recommends that the Commission accept Xcel's reporting with respect to fuel costs associated with coal shortages during FYE14.

B. MINNESOTA POWER

As described above, while Minnesota Power's coal procurement policies and actions taken in response to coal shortages during 2013 appear to be reasonable, because MP **[TRADE SECRET DATA HAS BEEN EXCISED]**. Therefore, the Department is unable to make a recommendation to the Commission regarding MP's reporting with respect to fuel costs associated with coal shortages during FYE14. That is, the Department cannot conclude that MP fully met its burden of proof to show that the rates MP charged to its ratepayers were reasonable.

C. OTTER TAIL POWER

The Department recommends that the Commission accept Otter Tail's reporting with respect to fuel costs associated with coal shortages during FYE14. However, the Department recommends that the Commission require Otter Tail to report in future AAA filings any coal conservation measures taken in response to coal delivery issues during the relevant reporting period, along with a discussion of OTP's efforts to minimize coal, coal delivery and any replacement power costs if needed to address issues with coal supplies for OTP.

D. INTERSTATE ELECTRIC

The Department recommends that the Commission accept Xcel's reporting with respect to fuel costs associated with coal shortages during FYE14.

X. DEPARTMENT RECOMMENDATIONS – MISO DAY 1

- Overall, the Department concludes that the Companies' responses complied generally with all of the AAA MISO Day 1 compliance reporting requirements. The Department expects utilities to continue to work hard to mitigate costs or the effects of changes by MISO or FERC that could negatively impact Minnesota retail customers. Utilities are required to continue to show benefits of MISO Day 1 in the context of their rate cases before receiving cost recovery of Schedule 10 costs.

- The Department recommends that the Commission continue to require 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 Department recommends that the Commission continue to require utilities to 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. This additional information would expedite the Department's review of MISO Day 1 costs in future electric AAA filings.

XI. DEPARTMENT RECOMMENDATIONS – MISO DAY 2

A. XCEL ELECTRIC

- The Department concludes that Xcel Electric's Real-Time Non Asset Energy charges appear reasonable for FYE14.

- The Department concludes that Xcel's Day-Ahead Schedule 24 Allocation Amount charges (revenues) appear reasonable for FYE14.

- The Department concludes that Xcel's Real-Time Schedule 24 Allocation and Real-Time Schedule 24 Distribution charges (revenues) appear reasonable for FYE14. However, for clarification purposes, the Department recommends that Xcel discontinue netting these two charge types and report them as separate line items in future AAA filings.

- The Department concludes that Xcel's plan to pass back its MVP ARR revenues to customers in its TCR Rider compliance filing in Docket No. E002/M-14-852 appears reasonable.

- Based on all of the above, the Department recommends that the Commission accept Xcel Electric's MISO Day 2 reporting for FYE14.

B. MINNESOTA POWER

- The Department recommends that the Commission accept MP's MISO Day 2 reporting for FYE14.

C. OTTER TAIL POWER

The Department recommends that the Commission accept OTP's MISO Day 2 reporting. The Department requests that OTP provide in future AAA filings information and narrative to explain why the selected Option for FTRs and ARRs is better for rate payers than the alternative.

D. INTERSTATE ELECTRIC

- The Department recommends that the Commission accept Interstate Electric's MISO Day 2 reporting.

XII. DEPARTMENT RECOMMENDATIONS – ANCILLARY SERVICES MARKET

A. XCEL ELECTRIC

- The Department concludes that Xcel Electric has reasonably explained its increase in EDEDC penalty costs for FYE14.

- The Department concludes that Xcel Electric's allocation of Day-Ahead Regulation Amount, Real-Time Regulation Amount, and Real-Time Regulation Reserve Cost Distribution Amount costs and revenues appear to be reasonable at this time. For transparency purposes, the Department recommends that in future AAA filings Xcel allocate the asset-based wholesale portion of Day-Ahead Regulation Amount and Real-Time Regulation Amount separately under each charge type.

- The Department concludes that Xcel Electric's allocation of Day-Ahead Spinning Reserve Amount, Real Time Spinning Reserve Amount, and Real Time Spinning Reserve Cost Distribution costs and revenues appear to be reasonable at this time. For transparency purposes, the Department recommends that in future AAA filings Xcel allocate the asset-based wholesale portion of Day-Ahead Spinning Reserve Amount and Real Time Spinning Reserve Amount separately under each charge type.

- Based on all of the above, the Department recommends that the Commission accept Xcel Electric's ASM reporting for FYE14.

B. MINNESOTA POWER

- The Department recommends that the Commission accept MP's ASM reporting.

C. OTTER TAIL POWER

- The Department recommends that the Commission accept Otter Tail Power's ASM reporting.

D. INTERSTATE ELECTRIC

- The Department recommends that the Commission accept Interstate Electric's ASM reporting.

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Attachment 1: Discussion from pages 8-16 of the Department's 12/31/2014 Reply Comments in E999/AA-12-757

III. FCA MECHANISM

A. OVERVIEW OF THE FCA: ADVANTAGES AND DISADVANTAGES

While the history of the FCA is extensive, this discussion focuses primarily on the current structure and operation of the FCA. Overall, the FCA has several advantages:

1. The FCA was intended to allow utilities to address fuel price volatility without filing frequent, expensive rate cases.

2. The FCA addressed costs that were presumed to be beyond the utility's control.

3. The FCA was intended to reduce a utility's business risk and thereby improve the utility's credit ratings.

4. At the time the FCA was first established, the Federal Energy Regulatory Commission (FERC) regulated power costs. Now, the "Day 2" energy market of the Midcontinent Independent System Operator (MISO) is a source of replacement power costs.

5. The FCA provided a way to pass savings to ratepayers if the actual cost of fuel dipped below the base cost included in rates.

However, the FCA also has drawbacks. A report and teleseminar by the National Regulatory Research Institute (NRRI) explained that utilities will treat costs recovered through trackers differently that costs recovered in base rates. "The Two Sides of Cost Trackers: Why Regulators Must Consider Both" (Ken Costello, October 27, 2009)[17] stated:

> When mechanisms for cost recovery differ across functional areas, perverse incentives can arise that would make it profitable for the utility not to pursue cost-minimizing activities. The result is higher rates to utility customers.
> (1) A utility with an FAC might postpone maintenance of a power plant even when such maintenance would cost less than the savings in fuel costs (i.e., when beneficial to consumers but not to the utility).
> (2) The utility could not immediately (or ever) recover additional maintenance costs, while it could pass the higher fuel costs through the FAC.

This report explained reasons for this different treatment of costs by utilities, first by noting that "[a]n important incentive for cost control by regulated utilities is the threat of cost

[17] Found at: http://mn.gov/puc/documents/pdf_files/012415.pdf

disallowance from retrospective review." Second, the Report noted that, while "[r]egulators have long recognized the importance of retrospective reviews in motivating a utility to avoid cost disallowances from grossly subpar performance," "[t]o the extent that cost trackers dilute the frequency and quality of these reviews, further erosion of incentives for cost control occurs." This dilution occurs because:

> Rational utility management, as a general rule, would exert minimal effort in controlling costs if it has no effect on the utility's profits.
>
> a. This condition occurs when a utility is able to pass through (with little or no regulatory scrutiny) higher costs to customers with minimal consequences for sales.
> b. Cost containment constitutes a real cost to management. Without any expected benefits, management would exert minimum effort on cost containment.

Minimizing costs recovered in base rates increases a utility's annual profits between rate cases. By contrast, minimizing costs recovered in the FCA has no effect on the utility's profits. Thus, "rational utility management" will focus the greatest efforts on minimizing non-FCA costs. The bias toward higher FCA costs in place of non-FCA costs is not limited to O&M costs; utilities also have little incentive to improve heat rates of generation plants when they can save those costs and incur more FCA costs. In addition, as the NRRI report notes,

> Cost trackers, in the long run, can bias a utility's technological and investment decisions.
>
> (1) A utility recovering fuel costs through an FAC, for example, might want to adopt fuel-intensive generation technologies even if they are more expensive from a lifecycle perspective.
> (2) The result, again, is higher rates to utility customers.

It is critical to design incentive mechanisms to ensure that all utilities consider all costs of providing energy as utilities add resources and respond to growth in demand for power.

B. DIFFICULTIES IN CURRENT OPERATION OF THE FCA

Current operation of the FCA mechanism is problematic for ratepayers and regulators; this discussion highlights a few of the recent concerns.

In the FYE11 docket (Docket No. E999/AA-11-792), the Department conducted an extensive audit of utilities' forced (unexpected) outages, assessing the extent to which utilities took reasonable steps to avoid such outages or minimize costs of replacement power (which are charged to ratepayers through the FCA. This audit focused on the limited question of whether the utilities had shown it to be reasonable to charge ratepayers for all of the replacement power costs during a subset of unplanned (forced) outages. The audit did not question or assess the issue of recovery of replacement power costs during planned (unforced) outages, not did it address recover of replacement power during all unplanned outages.

As discussed further in the Department's December 12, 2012 Response Comments (DOC Response Comments) in the 11-792 Docket, it took several rounds of discovery and lengthy time periods for utility responses even before the Department received information sufficient to identify potential issues and assess whether the utilities had shown it to be reasonable for ratepayers to pay for replacement power costs for a subset of forced outages, limited to the most questionable forced outages, for which utilities provided little to no justification for charging ratepayers for all of the replacement power costs.

Utility resistance even in providing the necessary information, let alone being required to show that the costs recovered through the FCA are reasonable, raises the concern that the identified issues may only be the tip of the iceberg. In addition, IOUs' responses to the issues raised by the Department in the 11-792 Docket indicated that the IOUs did not treat energy costs as part of their total cost of doing business, *i.e.*, energy costs are not treated as internalized costs. As noted above, the NRRI report indicates that utilities will treat costs recovered through trackers differently that costs recovered in base rates.

To demonstrate the IOUs' resistance to being held accountable for meeting their burden of proof for their own mistakes, the Department notes two examples from the 11-792 Docket. There, the Department made several recommendations regarding recovery of replacement power costs during the forced outages, including recommendations related to the following two simple examples.

First, following extensive discovery from the Department, Xcel acknowledged that, as a result of human error, a wrench fell into the buss duct work during maintenance of a power plant generator, and that, as a result, the King plant was off-line for about 30 hours in January 2011. In response to the Department's recommended disallowance of the corresponding increase in energy costs to ratepayers, Xcel stated that "[t]he [Department] Response Comments have not demonstrated that the Company's actions were not prudent under the circumstances. As such, the replacement energy costs meet the just and reasonable standard for FCR cost recovery." DOC Response Comments at 22-27. The Department notes that it is the utility's burden of proof to show that the costs it charges to its ratepayers are just and reasonable.

Second, following extensive discovery from the Department, MP's November 9, 2012 response still did not explain why MP's ratepayers should pay for the full amount of the increased energy costs passed through the FCA during FYE11, as a result of the use by a vendor of "replacement O-rings made of materials incompatible with the fluids used in the hydraulic system." MP described the difficulties related with finding reliable vendors and holding them accountable for mistakes. However, it does not appear that MP had a reasonable system or any system in place in place to prevent or alleviate the vendor's error. The only option discussed by MP to prevent or alleviate the error would be to have an engineer watch the entire rebuild process (5 weeks). MP did not explain why it raised no red flag to address the change in the color of the viton O-rings. In any case, given the additional cost incurred by MP's ratepayers ($507,715) for this error, the additional cost of an engineer watching the entire rebuild process for five weeks would have been justified.

The fact that MP did not adequately supervise the contractor for five weeks, which lead to over a half million in costs for replacement power, is an example of how a utility seeks to minimize costs recovered in base rates without giving reasonable attention to minimizing FCA costs. These facts were particularly concerning because, in response to an earlier discovery in that proceeding regarding contractors' delays and/or lack of performance during FYE11, MP stated that "[d]uring this period, there were no delays or lack of performance by contractors affecting outages." As became clear after extensive discover by the Department, MP should have at least noted the incompatible O-ring error in response to the Department's discovery.

Despite the extensive effort by the Department and time for utility responses and development of the record, on August 16, 2013, the Commission concluded that the "record in this docket does not contain detail sufficient for the Commission to resolve disputes of fact necessary to finally determine the prudence of the utilities' plant operation and maintenance."[18]

This proceeding highlighted some of the flaws in the current operation of the FCA, including:

- the extensive time and resources needed to assess the reasonableness of rates the utility already charged,
- difficulty in assessing whether utility management has reasonably minimized FCA costs,
- difficulty by utilities to explain why unplanned outages occurred, how utilities minimized costs,
- inherent difficulties the Commission faces in attempting to address such issues after-the-fact, particularly when utilities argue that the burden of proof regarding the statutory requirement concerning reasonable rates shifts from utilities to regulators.

Because the current design and operation of the FCA makes it difficult to conclude that utilities are minimizing FCA costs and making decisions in a holistic sense, the Department discusses ways to improve ratemaking for fuel costs. The Department, other consumer advocates and utilities met and subsequently exchanged ideas, as discussed below.

C. INCENTIVE FCA

All rates have incentives built into them. As the NRRI report notes, even "regulatory lag" is an incentive rate – an important one:

> (1) "Regulatory lag" refers to the time gap between when a utility undergoes a change in cost or sales levels and when the utility can reflect these changes in new rates.

[18] Source: Commission's Order in Docket No. E999/AA-11-792.

(2) Economic theory predicts that the longer the regulatory lag, the more incentive a utility has to control its costs; when a utility incurs costs, the longer it has to wait to recover those costs, the lower its earnings are in the interim. The utility consequently, would have an incentive to minimize costs.
(3) Regulators rely on regulatory lag as an important tool for motivating utilities to act efficiently.

As discussed above, the two different recovery mechanisms for IOUs – automatic adjustments and fixed recovery in rates – provide different incentives for utilities to minimize costs in practice. A well-designed incentive mechanism would encourage IOUs to minimize overall costs of providing energy, including costs that are currently passed through the FCA. To do so, such a mechanism should ensure that IOUs internalize their *total* cost of doing business, including their fuel and replacement power costs during outages. Under such an incentive mechanism, IOUs would have the appropriate incentives to keep these costs as low as possible because it would be in their own best interest to do so.

Discussions about incentives also have a long history, as evidenced by the extensive comments filed in Docket No. E999/AA-03-802 (which were suspended when the MISO Day 2 energy market was expected to begin operations). In that proceeding, the consensus appeared to be that the FCA had advantages, but consumer advocates held that utilities needed to be given better incentives to minimize FCA costs, whereas utilities wanted little if any change to the operation of the FCA. The parties are in essentially the same circumstance today.

The Department and interested parties, including the Minnesota Chamber of Commerce, Xcel Large Industrial Customers (XLI), Office of the Attorney General-Antitrust and Utilities Division (OAG-AUD), Commission Staff and the IOUs, exchanged ideas for how to resolve the issues. While there was some movement by utilities toward a modification to the FCA, and some ideas advanced by consumer advocates to improve the operation of the FCA, the issues certainly are not resolved. The Department provides a number of options for changes to the FCA for the Commission and other parties to consider. Going forward, the Commission should decide whether to bring the parties together for more discussions, request comments, or both.

These issues continue to be important to address since it affects utilities' resource choices. For example, it is important to ensure that utilities are appropriately balancing the total effects on their customers of 1) relying heavily on the MISO energy market even when prices are expected to be high with 2) acquiring long-tern, lower cost energy resources (e.g. a purchased power agreement or generation capacity).

1. Overall Goal of Reforming the FCA

To help ensure that utilities are efficient, ratemaking in regulation should provide a reasonable substitute for prices in a competitive market by requiring the regulated firm to consider and internalize all costs of providing service, including its energy costs. While the current regulatory construct worked when electric energy costs were fairly low and stable, and when there was excess generation capacity, the mechanism is not working under current circumstances, especially when utilities argue, in effect, that the burden of proof is on the Commission to disallow costs rather than the burden of proof being on the utility to show that their costs are reasonable. Such arguments turn ratemaking on its head and ignore the fact that the IOUs have the specific knowledge regarding their day-to-day operations; the Commission cannot be expected to micro-manage the utilities' operations.

At the same time, it is important to ensure that utilities have a reasonable opportunity to recover their costs of providing service. To the extent that the utility does not control FCA costs (e.g. higher energy costs due to a declining supply of generation in the MISO region), and has appropriately managed the risk of incurring those high energy costs, then such energy costs should be considered a reasonable cost of doing business. However, if utilities are not adequately managing the risk of higher energy costs, then it is legitimate to ask whether ratepayers should pay for all of those higher costs. From a regulatory perspective, one difficulty is the inability to know what choices the utility should have made, but did not make, in managing operations, assessing resources, engaging in MISO activities or other areas that would have reduced costs for ratepayers.

As a result, the Department recommended that a more decentralized mechanism be used for IOUs to recover energy costs. This mechanism should be designed to ensure that energy costs are internalized by IOUs in the same manner that IOUs internalize capital costs (between rate cases) and thus would have an incentive to consider all costs as utilities make decisions. Various options for doing so include the following.

a. Rolling-average FCA

This mechanism would set the level of energy costs a utility can recover over a given future period on the basis of a rolling average of previous actual energy costs ($/kWh) and let the IOUs manage their business within that parameter. Rates should be set on a monthly basis, to reflect actual monthly variations in fuel costs.

Advantages of this approach include ease of implementation, ability to reflect recent costs, advanced notification to consumers about costs, and heightened utility scrutiny to FCA costs. Disadvantages include the question of whether previous actual costs were reasonable and questions about whether recent costs adequately predict future costs.

b. Fuel costs set in a rate case

Recovery of energy costs could be fixed in a rate case, with no adjustment between rate cases, based on analysis in the rate case. Again, rates should be set on a monthly basis, so that rates would provide better price signals to customers to reduce energy use during peak periods.

Advantages of this approach include more certainty that rates charged to ratepayers have been reviewed prior to implementation, advanced notification to consumers about costs, and giving IOUs clear incentives in between rate cases to minimize their total cost of doing business. A disadvantage involves questions about whether setting recovery of fuel costs in a rate case would give utilities an adequate opportunity to recover costs of providing electric service. Similarly, ratepayers may not benefit from unexpected decreases in energy costs.

c. Fuel costs set in a rate case with index adjustments

Another option to improve setting recovery in base rates is to allow the level of recovery of fuel costs to change each year after the rate case, based on an index of energy costs, such as a factor based on a percent changes in prices in the MISO energy market.

Advantages of this approach include more certainty that rates charged to ratepayers have been reviewed prior to implementation, advanced notification to consumers about costs, giving IOUs clear incentives in between rate cases to minimize their total cost of doing business, and ensuring that fuel cost recovery reflects current trends in energy costs. A disadvantage is that the mechanism may not be able to reflect large, unexpected changes in costs on a utility's system due to significant outages.

d. Fuel costs set in a rate case with band adjustments

Yet another option to improve setting recovery in base rates, which could be used in conjunction with the approaches above, is that, subsequent to the rate case, utilities could not recover fuel cost variations if they lie within a certain "tolerable range," or band of variation defined in the utility's most recent rate case. However, if a utility's fuel costs swing outside of the tolerable range, then any cost reductions would go immediately to ratepayers whereas utilities could defer any cost increases during a special proceeding where utilities would justify why the materially higher costs should be charged to ratepayers.

Advantages of this approach include more certainty that rates charged to ratepayers have been reviewed prior to implementation, advanced notification to consumers about costs, giving IOUs clear incentives in between rate cases to minimize their total cost of doing business, ensuring that fuel cost recovery reflects current trends in energy costs, allowing ratepayers to benefit from materially lower costs and giving utilities an opportunity to explain why ratepayers should pay for materially higher costs. The Department is not able to identify any major disadvantage to this approach.

2. Advantages and Disadvantages of Improved FCA Incentives

The overall advantages and disadvantages of these incentives are as follows. First, advantages are:

- Would give IOUs clear incentives in between rate cases to minimize their total cost of doing business, using their specific knowledge of their day-to-day operations. Thus, it extends the incentives to minimize capital costs to energy costs.
- Would treat capital and fuel costs similarly, thus giving utilities the incentive to minimize *total costs.*
- Would provide ratepayers with more advanced notification about the rates they will be paying in the near future.

- Over the long run, this approach should lead to lower overall costs compared to the current regulatory mechanism.
- Would alleviate the need for discussing whether the Commission has the burden of proof to disallow costs or whether the burden of proof is on the IOUs to show that their costs are reasonable.
- Would not require the Commission to address, after the fact, whether the rates that were charged to ratepayers were reasonable.

Disadvantages are:

- Decreases in energy costs may not be completely passed to ratepayers between rate cases.
- Utilities may file more frequent rate cases; however, the utility would need to consider how their total cost has changed before doing so.

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Public Response Comments

Docket No. E999/AA-14-579

Dated this 26th day of August 2015

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_14-579_AA-14-579
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_14-579_AA-14-579
Marie	Doyle	marie.doyle@centerpointenergy.com	CenterPoint Energy	800 LaSalle Avenue P O Box 59038 Minneapolis, MN 554590038	Electronic Service	No	OFF_SL_14-579_AA-14-579
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_14-579_AA-14-579
Bruce	Gerhardson	bgerhardson@otpco.com	Otter Tail Power Company	PO Box 496 215 S Cascade St Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_14-579_AA-14-579
Michael	Greiveldinger	michaelgreiveldinger@alliantenergy.com	Interstate Power and Light Company	4902 N. Biltmore Lane Madison, WI 53718	Electronic Service	No	OFF_SL_14-579_AA-14-579
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_14-579_AA-14-579
Amber	Lee	ASLee@minnesotaenergyresources.com	Minnesota Energy Resources Corporation	2665 145th St W Rosemount, MN 55068	Electronic Service	No	OFF_SL_14-579_AA-14-579
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_14-579_AA-14-579
Leann	Oehlerking Boes	lboes@mnpower.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	OFF_SL_14-579_AA-14-579
Randy	Olson	rolson@dakotaelectric.com	Dakota Electric Association	4300 220th Street W. Farmington, MN 55024-9583	Electronic Service	No	OFF_SL_14-579_AA-14-579

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
SaGonna	Thompson	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_14-579_AA-14-579
Stuart	Tommerdahl	stommerdahl@otpco.com	Otter Tail Power Company	215 S Cascade St PO Box 496 Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_14-579_AA-14-579
Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company	200 First St SE Cedar Rapids, IA 52401	Electronic Service	No	OFF_SL_14-579_AA-14-579
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_14-579_AA-14-579