MINNESOTA DEPARTMENT OF COMMERCE

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December 31, 2014

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **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-12-757

Dear Dr. Haar:

Attached please find the *Response Comments* to the electric utilities' *Reply Comments.* Specifically, the Department responds to the *Reply Comments* of the following electric utilities:

- Interstate Electric, reply comments filed on September 20, 2013;
- Minnesota Power, reply comments filed on September 12, 2013 and September 23, 2013;
- Otter Tail Power Company, reply comments filed on September 20, 2013; and
- Xcel Electric, reply comments filed on August 26, 2013.

This proceeding was effectively suspended due to discussions of incentives for fuel-clause recovery and due to the significant drain on regulatory resources from numerous concurrent, contested proceedings, all involving material issues. Based on the review of each of these utilities' *Reply Comments*, the DOC's *Response Comments* contain revised recommendations to the original recommendations included in the DOC's *Review of the 2011-2012 (FYE12) Annual Automatic Adjustment Reports for Electric Utilities* filed on June 5, 2013 (Report). The DOC recommends that the Minnesota Public Utilities Commission (Commission) adopt the DOC's revised recommendations, as discussed in greater detail herein. The DOC 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

RESPONSE COMMENTS OF THE MINNESOTA DEPARTMENT OF COMMERCE DIVISION OF ENERGY RESOURCES

DOCKET NO. E999/AA-12-757

I. BACKGROUND

On June 5, 2013, the Division of Energy Resources of the Minnesota Department of Commerce (DOC or the Department) filed its *Review (Report) of the 2011-2012 (FYE12) Annual Automatic Adjustment Reports (Reports)* with the Minnesota Public Utilities Commission (Commission) in the present docket. The Report pertains only to regulated electric utilities. In its Report, the DOC requested that the electric utilities address specific concerns in *Reply Comments*. The following are the electric utilities that filed reply comments and the date of their reply comments:

- Interstate Electric, reply comments filed on September 20, 2013;
- Minnesota Power, reply comments filed on September 12, 2013 and September 23, 2013;
- Otter Tail Power Company, reply comments filed on September 20, 2013; and
- Xcel Electric, reply comments filed on August 26, 2013.

Below, the DOC provides our response to each of the electric utilities' *Reply Comments* and the DOC's recommendations based on our review.

II. DEPARTMENT ANALYSIS – COMPLIANCE ISSUES

The Department requested Xcel Electric to provide the following information in reply comments regarding the recovery of the $540,526 in wind curtailment payments made under the "Other" category during FYE12:

- A chronological description of each and all events that led to the wind curtailments and corresponding curtailment payments made under the "other" category during FYE12.

- For each such event, the curtailment payments made and a complete description of the steps taken by Xcel Electric before and after the event to alleviate the need for such curtailments and curtailment payments.
- For each such event, Xcel Electric's complete justification for why Xcel Electric's ratepayers should bear the full cost of these curtailment payments.

The Department requested that IPL Electric, Xcel Electric and OTP provide updated information on generation operation and maintenance costs being recovered from ratepayers in the most recent rate cases, and the utilities' 2012 actual generation operation and maintenance (O&M) costs.

The Department requested Xcel Electric to provide the short discussion of how such outages could have been avoided or alleviated as required by the April 6, 2012 Order in Docket Nos. E999/AA-09-961 and E999/AA-10-884.

The Department recommended that MP provide in reply comments either: 1) a revised Table 1 (calculation of the additional replacement energy costs resulting from a forced outage) with no changes in energy costs where MP initially calculated negative changes in energy costs as a result of forced outages, or 2) full justification for such calculations (why it is reasonable to expect a reduction in energy costs as a result of forced outages).

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

A. XCEL'S WIND CURTAILMENT REPORT

1. Background

As discussed further in the Report (pp. 7-8), the Department recommended that the Commission accept Xcel Electric's FYE12 wind curtailment report (Wind Report), with the exception of the curtailment payments made under the "other" category.

The Department noted that the Wind Report did not include a detailed explanation for the curtailment payments made under the "Other" category. The only information provided was the amount of MWhs curtailed and the amount of curtailment payments ($878 in October 2011 and $92,095 in March 2012) under the "Other" category for FYE12. In addition, the total amount of curtailment payments made under the "Other" category during FYE12 increased substantially to $540,526 according to Xcel Electric's April 30, 2013 FCA filing in Docket No. E002/AA-13-331.

Therefore, the Department requested Xcel Electric to provide in reply comments additional information in support of the recovery of the $540,526 in wind curtailment payments made under the "Other" category during FYE12.

- A chronological description of each and all events that led to the wind curtailments and corresponding curtailment payments made under the "other" category during FYE12.
- For each such event, the curtailment payments made and a complete description of the steps taken by Xcel Electric before and after the event to alleviate the need for such curtailments and curtailment payments.
- For each such event, Xcel Electric's complete justification for why Xcel Electric's ratepayers should bear the full cost of these curtailment payments.

2. *Department's Review of Xcel Electric's Response*

In response to the data "discrepancy" issue discussed above, Xcel Electric stated in its August 26, 2013 Reply Comments at 3:[1]

> The Department noted that the wind curtailment payments made under the "Reason Code 4 – Other" category in FYE12 were reported as $540,526 in the Company's April 30, 2013 monthly Fuel Clause Adjustment (FCA) filing whereas when the AAA report was filed on August 31, 2012, wind curtailment payments made under the Other category for the same time period were reported to be $92,973.
>
> We clarify that there is frequently a lag of up to several months between a curtailment incident and when an invoice for that incident is received, reviewed, and if the claim is found eligible for payment, approved and paid. We then update our curtailment summary reports to record a payment in the month of the incident rather than the month in which the payment was made. We have found this recording method to be more helpful for tracking purposes, but to improve the clarity of our reporting in the future, we will make particular note of curtailment values that may be subject to change because they are under review.
>
> At the time we made the FYE12 AAA filing we had information supporting curtailment payments through May 2012. The payments we made in FYE12 for "Reason Code 4 – Other" curtailments increased because we received invoices related to the FYE12 reporting period after we made our filing. After investigating these invoices, we paid them. This resulted in the approximately $440,000 increase in the "Reason Code 4 – Other" curtailment payments.

[1] Note: While Xcel Electric listed these figures as trade secret, the Company showed the figures as public in its August 31, 2012 initial filing.

The Department concludes that Xcel Electric's explanation is reasonable and appreciates Xcel Electric's commitment to identify in future filings the curtailment data that may be subject to change.

In response to the missing information regarding curtailment payments made under the "Other" category discussed above, Xcel Electric stated in its August 26, 2013 Reply Comments at 4:

> Given the circumstances surrounding these curtailments, we deemed these events unique enough to be separately identified as "Reason Code 4 – Other" rather than as being due to lack of available transfer capacity (ATC), which would also have been applicable. We recognize that we are required to provide an explanation of each instance of "Reason Code 4 – Other." We apologize for not providing this required information with our initial filing and are revisiting our internal reporting procedures to ensure process improvements are made going forward.

The Department appreciates Xcel Electric's commitment to revisit its internal reporting procedures to ensure that the required information is provided in Xcel Electric's initial AAA filings going forward.

The Department finally notes that Xcel Electric provided the requested additional information in support of the wind curtailments and corresponding curtailment payments made under the "other" category during FYE12.[2]

According to Xcel Electric, three wind generation projects (Lake Benton I, Lake Benton II, and Fenton) recorded "Reason Code 4 – Other" curtailment events during FYE12. These curtailments would have been related to:

- Low voltage conditions at Lake Benton I and Lake Benton II, and
- A transmission conductor "galloping" event at Fenton.[3]

3. *Low Voltage Conditions at Lake Benton I and Lake Benton II*

According to Xcel Electric, the turbine generators used in the Lake Benton projects have limited ability to regulate voltage, contrary to modern wind turbines which have built-in voltage regulators. To address this issue, capacitor banks were installed along the length of the Buffalo Ridge area feeder lines. Without the capacitors, the feeders can experience unacceptable voltage levels which will result in tripping the wind turbine generators off-line.

[2] See Xcel Electric's Reply Comments at 4-11.
[3] Conductor gallop is the high-amplitude, low-frequency oscillation of overhead power lines due to wind. The movement of the wires occurs most commonly in the vertical plane, although horizontal or rotational motion is also possible.

In response to increasing capacitor repair and maintenance needs, Xcel Electric engaged an engineering consultant in 2010 to assist in the evaluation of the wind generation feeder lines and the capacitor banks. As a result of the consultant's February 2011 report, Xcel Electric undertook a Capacitor Replacement Project.

Xcel Electric stated that "[w]hile work was in progress, a tornado hit the area in July 2011, damaging multiple feeder lines and the surrounding 115 kV transmission lines."

Given that "[a]ctions to improve performance of the equipment designed to support area voltage at an acceptable level for the wind turbines were underway but implementation was delayed by the unforeseeable July 2011 storm producing local damage," the Department will not pursue further the issue of wind curtailments that occurred at Lake Benton I and II between October 2011 and April 2012.

4. Transmission Conductor "Galloping" Event at Fenton

According to Xcel Electric, "[t]he [March 2012] curtailment event at Fenton … was a combination of weather and a previously planned construction outage…" High wind generation, combined with the unavailability of the Nobles County-Split Rock and the Lakefield Junction-Nobles County 345 kV lines, resulted in declining voltages in the area. The system operators had to open two Fenton breakers to reduce and remove generation from the network in order to maintain system stability, which resulted in the curtailed generation.

Xcel Electric stated that "[g]iven the weather-related nature of the damage which was not within the Company's control, we believe this situation could not have been avoided and is similar to other system limitations which occur periodically, causing the need to reduce energy production when the generator might have otherwise been producing energy."

As a result, the Department will not pursue further the issue of wind curtailments that occurred at Fenton on March 2012.

B. MAINTENANCE EXPENSES OF GENERATION PLANTS

1. Background

As discussed in the Report, the Department noted that only MP and Xcel Electric spendt more on O&M costs than they are charging to their customers in rates.

Table: Comparison of Generation O&M costs[4]

	Test Year	Rate Case	Historical 2009-11 Average	Difference from Rate Case	% Difference
IPL	2009	$3,779,345	$3,260,868	($518,477)	(14%)
MP	2010	$33,619,194	$40,007,657	$6,388,463	19%
Xcel Electric	2011	$157,432,572	$166,463,341	$9,030,769	6%
OTP	2009	$13,192,047	$11,727,090	($1,464,957)	(11%)

Because Interstate Electric, Xcel Electric and OTP have all had more recent rate cases than the years shown in the table above, the Department requested that Interstate Electric, Xcel Electric and OTP provide in their reply comments updated information on generation O&M costs being recovered in the most recent rate cases, and utilities' actual 2012 generation O&M costs.

2. *Department Review of IOUs' Response*

The Department's review of the IOUs' reply comments indicated that Xcel Electric was still spending more on generation O&M costs in 2012 than they are charging to their customers in rates. However, it appears that Interstate Electric and OTP both continued to spend less in 2012 on generation O&M costs than they charged to their customers in rates.

Interstate Electric under-spent its 2009 test year generation O&M costs of $3,779,345 by a 2010-2012 annual average of $388,515, or an average actual amount of 10 percent less than what IPL is charging in rates. OTP under-spent its 2009 test year generation O&M costs of $13,142,720 by a 2010-2012 annual average of $1,835,124, or an average actual amount 14 percent less than what OTP is charging in rates. Since Xcel has had ongoing rate cases during these years, it has not been possible to compare the test year levels to O&M spending in a year between rate cases.

It is troubling that both OTP and IPL under-spent O&M costs since the level of O&M on facilities and forced outages of facilities is linked; without adequate O&M, higher forced outages are more likely to occur. Unfortunately, as discussed in the FCA incentive section below, current ratemaking structures encourage utilities to minimize O&M costs but provide little to no incentive to minimize replacement power costs. Until a reasonable FCA incentive is in place, the Department expects to continue to monitor the IOUs' actual expenses pertaining to maintenance of generation plants, with a comparison to the generation maintenance budget from the IOUs' most recent rate cases in future AAA filings. However, the Department believes a well-designed FCA incentive would be more appropriate response to address this issue.

[4] Attachment E5 of the Report provides an annual breakdown of the IOUs' maintenance expenses of generation plants between 2005 and 2011. The Department revised OTP's 2009 test year and actual 2011 data following OTP's response to the Department's information request number 12 in Docket No. E999/AA-13-757.

C. SHARING LESSONS LEARNED REGARDING FORCED OUTAGES

In its April 6, 2012 Order in Docket Nos. E999/AA-09-961 and E999/AA-10-884, the Commission required the IOUs to provide in future AAA reports, a simple annual identification of forced outages and a short discussion of how such outages could have been avoided or alleviated.

1. Sharing Lessons Learned

In this 12-757 docket, MP, IPL and OTP provided the required information in their initial AAA reports. The Department requested Xcel Electric to provide in reply comments discussion of how each of the identified forced outages could have been avoided or alleviated.

Xcel Electric provided the required information in its August 26, 2013 reply comments at 12-17.

The Department's premise is that sharing this information among the IOUs can provide, in addition to participation to other industry forums, a simple and reasonable way to avoid costly mistakes, including human errors.

The Department expects the IOUs to be aware of causes of forced outages before they request recovery of replacement energy costs. The IOUs are also expected to identify and implement in-time solutions from the lessons learned from their participation to industry forums and other IOUs' forced outages. The Department discusses this issue further in its concurrent comments in Docket E999/AA-13-599.

2. Changes in Energy Costs Due to a Forced Outage

Regarding the changes in energy costs due to each outage, the Department agreed with Xcel Electric that there is no change in energy costs due to a forced outage when "generation from the power plant would have not have [sic] been utilized at the time of the outage because its economic dispatch costs were more than the cost of other Company generation or the MISO market price."[5] However, utilities would need to document that the costs of replacement power were less than the costs of operating the facility on outage.

The Department noted that it is not appropriate for replacement power costs to be negative, as MP showed for some of its outages, since the plant would not have been used to produce electricity if were more expensive than the cost of power in the MISO market. Therefore, the Department recommended that MP provide in reply comments either a revised Table 1 with no changes in energy costs where MP initially calculated negative changes in energy costs as a result of forced outages, or fully justify such calculations (why it is reasonable to expect a reduction in energy costs as a result of forced outages).

In its reply comments, MP justified calculating negative changes in energy costs as a result of forced outages as follows:

[5] Xcel Electric's August 31, 2012 report in Docket No. E999/AA-12-757 at 261 of 302.

> Minnesota Power disagrees with the statement above "it is not appropriate for replacement power costs to be negative." Minnesota Power calculates the Outage MWh replaced by purchases on an hourly basis. The Outage MWh Replaced by Purchases is calculated by taking the *lesser of* either the purchases made to serve FAC load or the unit's budgeted maximum output. Market pricing can significantly fluctuate from hour to hour. In one hour it might be economical to run the unit while in the next hour it may not be. Some generating units cannot be shut down or started without significant lead time and may have minimum levels they need to run at. Minnesota Power calculates the Purchased Outage Costs by multiplying the Hourly Outage MWh Replaced by Purchases times the Hourly Average Purchase Cost then sums up each hour to get the Total Purchased Outage Costs. The Average Purchase Cost is calculated by dividing the sum of the total Purchased Outage Costs by the total Outage MWh Replaced by Purchases. This is then compared to the unit's average cost for the month. When the unit's average cost is higher than the calculated average cost of the replaced energy a benefit might be shown. See the example of this calculation for one day as shown in Exhibit A.

The Department agrees with MP that there may be some cases, such as when generating units cannot be shut down or started without significant lead time, when a forced outage may result in a reduction in energy costs. The Department notes however that it will still be MP's burden of proof to support such calculations when needed as a result of an audit of its forced outages.

As discussed further in Section III below, the Department recommends an alternative ratemaking approach to holding utilities accountable for replacement power costs. This approach is also intended to encourage utilities to consider all costs in providing service, including replacement power costs, in short-term and long-term planning.

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)[6] 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 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,

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

c. 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."[7]

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.
> (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

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

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 recovery 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.

IV. 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

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

- The Department noted that Day Ahead and Real Time Energy costs were about $8.6 higher reflecting a 6.3 percent increase in FYE12 of $146.1 million compared to FYE11 of $137.5 million. As a result, the Department asked Xcel Electric to explain in its reply comments the reason for this increase in Day Ahead and Real Time Energy costs for FYE12.
- The Department noted that Real Time Revenue Neutrality Uplift costs were about $4.7 million higher, reflecting a 77.0 percent increase in FYE12 costs of $10.9 million compared to FYE 11 of $6.1 million. As a result, the Department asked Xcel Electric to in its reply comments the reasons for this increase in Real Time Revenue Neutrality Uplift costs for FYE12.
- The Department recommended that Xcel Electric explain, in reply comments, whether any of the Company's MISO Day 2 cost allocation methods have changed during the 2011-2012 reporting period. If so, the Department recommended that Xcel Electric explain, in reply comments, the nature of these changes and the effect these changes have had on the charges assigned to various customer categories in the 2011-2012 AAA Report.
- The Department recommended that the Commission not accept Xcel Electric's MISO Day 2 reporting until the Company provided the required information in its reply comments.
- The Department recommended that Xcel Electric provide a brief narrative on how the ASM is doing at the MISO level and at the Company level consistent with their report in FYE11 AAA, in their reply comments for FYE12 and in future AAA filings, as required by the Commission's August 23, 2010 ASM Order, specifically ordering paragraph 10.
- Since the net amount for the two charges (Excessive/Deficient Energy Deployment Charges and Contingency Reserve Deployment Failure Charges) are up slightly and Xcel Electric has not explained the causes for these charges as required by the Commission's August 23, 2010 ASM Order, specifically ordering paragraph 11, the DOC recommended that the Commission not accept Xcel Electric's ASM reporting until the Company 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.

1. *Day Ahead and Real Time Energy Costs*

As noted above, Xcel Electric's Day Ahead and Real Time Energy costs were about $8.6 higher, a 6.3 percent increase in FYE12 of $146.1 million compared to FYE11 of $137.5 million. As a result, the Department asked Xcel Electric to explain in its reply comments the reason for this increase in Day Ahead and Real Time Energy costs for FYE12.

Xcel Electric stated on page 17 of its August 26, 2013 reply comments that the increase in costs coincided with a 5.8 percent increase in energy amounts (5,266,289 MWh to 5,570,119 MWh) with the dollars per MWh cost for the two periods being $26.10/MWh in TYE11 and $26.22/MWh in FYE12.

Xcel Electric noted the primary driver for the increase in per MWh costs as the result of the decrease in Day Ahead Non-Energy credit. The credit is associated with bilateral contracts with counterparties. The Company noted that for these contracts they pay for the energy to the counterparty based on of the power purchase agreement and the energy is delivered to the Company through the MISO market, where the Company receives a credit for the energy delivered. The Company noted that the biggest driver in decreased credits is due to a change in the market price. Because the marginal energy component of LMP decreased, the associated payment decreased. The Company indicated another change between FYE11 and FYE12 was the expiration of the 40 MW purchase from Cyprus Sliver Bay.

Based on this additional information provided by Xcel Electric in its reply comments, the DOC concludes that Xcel Electric's Day Ahead and Real Time Energy amounts for FYE12 are reasonable.

2. *Real Time Revenue Neutrality Costs*

In its Report, the Department noted that Real Time Revenue Neutrality Uplift costs were about $4.7 million or 77.0 percent higher in FYE12 ($10.9 million) compared to FYE 11 ($6.1 million). In response to the Department's request that Xcel Electric explain in reply comments the reasons for this increase in Real Time Revenue Neutrality Uplift costs for FYE12, Xcel Electric provided the following response on pages 17 and 18 of its reply comments:

> Our Real Time Revenue Neutrality Uplift (RNU) costs were $10.9 million in FYE12 compared to $6.1 million in FYE11. Many components make up this cost, and the change in cost has multiple drivers. As MISO is required to be revenue neutral, this charge type is used to account for any revenue inadequacy and allocates those costs to load. At times, as RNU goes up, other costs might go down, or vice versa. For instance, market to market settlements with PJM go through RNU. When PJM pays

MISO through this charge type, there is an offsetting cost of redispatch that is paid by MISO load. This payment may decrease, but the costs will also decrease. NSP, along with other stakeholders, pushes MISO for continual improvement and monitoring of some of the drivers of this charge. As noted below the MISO Independent Market Monitor (IMM), also monitors this charge, and makes operational recommendations to mitigate excursions.

NSP has also supported one of the short-term incentive goals for MISO management to be linked to market efficiency, which is in turn linked to RNU. The main driver for the cost change was the real time congestion sub-component.

On a MISO footprint-wide basis, this sub-component changed from a $17.3 million credit to a $15.5 million charge. The many drivers of real time congestion costs cannot be controlled by the Company. The overall driver for the change in costs is the difference between MISO's real time actions and models compared to MISO's day ahead models and expected flows. MISO's discontinuation of relaxing internal constraints contributed to the real time congestion. This change resulted in real time prices reaching the marginal value limit for constraints that bound in real time, but were not modeled or did not bind in the day ahead model. The Company mitigated the exposure to real time price volatility by purchasing its expected load in the day ahead market and by working with MISO to decrease the marginal value limits of lower voltage constraints, thus decreasing this charge.

In addition, there was significant real time congestion in March 2012. The MISO IMM attributed the significant increase to "congestion out of the West and in Michigan. External constraints were substantial in March, including TLRs [Transmission Loading Relief] called by IESO [Independent Electricity System Operator] for outages affecting the Ontario interface and two SPP constraints." The MISO IMM recommended that the re-dispatch MISO performs for external constraints should be monitored because it is not efficient and can generate significant costs. After the IMM made its recommendation, the March 2012 level of costs ($96 million) has not since been reached. For additional information, please see the IMM Monthly Market Metrics Report for March 2012 which can be found at the following address:

> https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/BOD/Markets%20Committee/2012/20120418/20120418%20Markets%20Committee%20of%20the%20BOD%20Item%2003%20IMM%20Report.pdf.

Based on this additional information provided by Xcel Electric in its reply comments, the DOC concludes that Xcel Electric's Real Time Revenue Neutrality costs for FYE12 are reasonable.

3. MISO Day 2 Allocation and MISO Day 2 Report

In its report, the Department recommended that Xcel Electric explain in reply comments whether any of the Company's MISO Day 2 cost allocation methods changed during the 2011-2012 reporting period. If so, the Department recommended that Xcel Electric explain the nature of these changes and the effect these changes had on the charges assigned to various customer categories in the 2011-2012 AAA Report.

Xcel Electric explain on pages 18 and 19 of its reply comments that its allocations methods of MISO Day 2 charges across the Company's retail asset based wholesale/intersystem and non-asset based wholesale/intersystem did not changed during the FYE12 AAA reporting period.

As a result of this response confirming the Company has not changed its MISO Day 2 allocations and the two above responses on Day Ahead and Real Time Energy and Real Time Revenue Neutrality, the Department recommends the Commission accept Xcel Electric's MISO Day 2 report for FYE12.

4. ASM Reporting

The Department requested in its Report that Xcel Electric address the following two Department recommendations related to ASM:

- The Department recommended that Xcel Electric provide a brief narrative on how the ASM is doing at the MISO level and at the Company level consistent with their report in FYE11 AAA, in their reply comments for FYE12 and in future AAA filings, as required by the Commission's August 23, 2010 ASM Order, specifically ordering paragraph 10.
- Since the net amount for the two charges (Excessive/Deficient Energy Deployment Charges and Contingency Reserve Deployment Failure Charges) are up slightly and Xcel Electric has not explained the causes for these charges as required by the Commission's August 23, 2010 ASM Order, specifically ordering paragraph 11, the DOC recommended the Commission not accept Xcel Electric's ASM reporting at this time until the Company has provided the required information in its reply comments.

Xcel Electric provided the following response on page 19 of its reply comments to address the two ASM recommendations of the Department:

> During the 2011-2012 AAA reporting period, MISO continued to operate the electric system reliably and has exceeded compliance thresholds for all North American Electric Reliability Corporation (NERC) reliability standards to which they are subject. The MISO IMM, which is tasked with monitoring both behavior of the Market Participants and the operation of the market, noted in its 2011 State of the Market Report that the "ASM markets continue to perform as expected with no significant issues in 2011. Since their inception in 2009, jointly-optimized ancillary service markets have produced significant benefits, leading to improved flexibility and lower costs of satisfying the systems reliability needs."
>
> The Market Monitor also noted an overall six to 10 percent decrease in regulation prices when compared to 2010 due primarily to a reduction in spinning reserve shortages and a reduction in opportunity costs of providing reserves. Reduction in spinning reserve was coincident with the departure of FirstEnergy, which had the most non-conforming load that can change abruptly and cause transitory shortages.
>
> Opportunity costs decreased in 2011 as energy prices fell due to lower natural gas prices. The slight increase in contingency reserve deployment charges was due to an issue with a power purchase generator, LS Power, which has since been remedied. The slight decrease of excessive deficient deployment charges between FYE11 and FYE12 can be attributed to several factors. Variance analysis indicates that the decrease is partially due to Sherco Unit 2 and the Wheaton plant operating less, and so having less opportunity to incur these charges.
>
> We confirm we will provide this information in future AAA filings, as required by the Commission's August 23, 2010 ASM Order.

Based on this additional information provided by the Company in its reply comments regarding the two ASM concerns of the Department, the Department recommends that the Commission accept Xcel Electric's ASM report.

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

1. Real Time Congestion Charges in May, 2012

On page 35 of our June 5, 2013 Report, the Department noted that MP's Real Time congestion charges for the month of May, 2012 totaled negative $451,362, but did not fall below negative $200,000 in any other month. The Department requested that Minnesota Power explain in reply comments the conditions that led to this large credit.

In its September 20, 2013 Reply Comments, MP explained that the high level of negative real time congestion charges in May 2012 was driven by larger-than-normal differentials between LMPs at the west and east nodes of MP's high voltage direct current (HVDC) line. MP stated that during May, 2012, it was able to increase energy flows across the HVDC line to take advantage of the increased price spreads.

The Department understands that congestion charges and credits result from LMP differentials between injection nodes and withdrawal nodes, but is still curious as to the causes of the LMP differentials between the west and east nodes of MP's HVDC line. However, because the causes of these price differentials are likely outside of MP's control, the Department concludes that MP's explanation is reasonable, and appreciates MP's efforts to minimize congestion charges.

2. Real Time Miscellaneous Charges in May, 2012

On page 35 of our June 5, 2013 Report, the Department noted that MP's Real Time Miscellaneous Charges for the month of May, 2012 totaled negative $506,004, but did not exceed $20,000 in absolute terms in any other month. The Department requested that MP describe in reply comments the nature of this charge in May, 2012, and provide any documentation it has received from MISO regarding the charge.

In its September 20, 2013 Reply Comments, MP explained that it received an Excess Congestion Fund refund from MISO in May, 2012 of $494,518.81, which was included in its reports in the Miscellaneous Charge type. The Department concludes that this explanation is reasonable.

3. Offer Parameters for Boswell 4

On page 45 of our June 5, 2013 Report, the Department noted that MP changed its offer parameters at Boswell Unit 4 to clear more energy, leaving less of that unit's capacity available to be used for regulation service. The Department requested that MP describe the reasons for this change in more detail in reply comments.

In its Reply Comments, MP clarified that it changed its offer parameters for Boswell Unit 4 such that the unit was not made available to provide regulation service during on-peak hours during the last two months of 2012. MP stated that its decision to try to clear more energy from Boswell Unit 4 was based on comparing the customer benefit created by energy sales from Boswell Unit 4 to the customer benefit created from sales of regulation services. MP stated that during the period July, 2010 through October, 2011, the average on-peak day-ahead LMP was $32.85 per MWh, and the average cost of Boswell Unit 4 was $15.31 per MWh. MP stated that the net benefit of energy cleared at Boswell Unit 4 was the difference between those two figures, or $17.54 per MWh. MP stated that over the same period, the net benefit created by the provision of regulation services was equal to the regulation clearing price of $13.61 per MWh, or $3.93 per MWh less than the benefit of energy cleared.

It is not clear to the Department from MP's explanation how ratepayers benefit from restricting Boswell Unit 4 from providing regulation service during on-peak hours. The question of whether it makes economic sense to clear energy or regulation services from Boswell Unit 4 would seem to rest on the ultimate use of the energy that would be produced. If that energy is needed to serve MP's own load, and the only alternative source of energy is the spot market, then MP's analysis is reasonable, as the benefit to ratepayers of producing energy at Boswell Unit 4 would be the cost of producing energy at Boswell Unit 4 versus the cost of sourcing that energy from the market. MP's analysis demonstrates that this benefit averages $17.54 per MWh during on-peak hours, while the benefit to ratepayers of providing regulations services is only $13.61 per MWh. However, if the energy that would be produced at Boswell 4 is not used to serve MP's load (*i.e.*, MP sells it to the market to earn an asset-based margin), ratepayers would not see any benefit, as MP's asset-based margins are fixed in its base rates and are not shared with ratepayers in the fuel clause. Thus, MP's ratepayers would be better off if MP used Boswell 4 to provide regulation service because the revenues from the provision of service would be shared through the fuel clause.

The Department notes, however, that even if MP were to offer Boswell Unit 4 to the market to provide both energy and regulation services, the Department would expect that it would be selected to provide energy, not regulation, due to the fact that it is a coal plant, and is therefore operationally inflexible relative to a gas plant, which can be ramped up and down more quickly. Further, MP stated in its Reply Comments that it restricted Boswell Unit 4 from providing regulation services in only two months of FYE12. Therefore, the Department would expect that the impact from this restriction is minimal. The Department will continue to monitor Boswell Unit 4's offer parameters in the future.

4. Difference between ASM Charges Reported in Attachments 9 and 10-A

On page 45 of our June 5, 2013 Report, the Department noted that the ASM charge amounts reported in Attachment 10-A of MP's FYE12 AAA Filing do not exactly match the ASM charge amounts reported in Attachment 9, and requested that Minnesota Power explain the difference between the two Attachments in reply comments.

In its Reply Comments, MP stated that Attachment 9 reports MISO charges in the month in which the charges were recorded in MP's General Ledger. Attachment 10-A summarizes ASM charges by the month to which they pertain. MP occasionally receives a charge or credit in one month that is an adjustment related to a transaction in a prior month. Attachment 9 reflects such charges or credits in the month in which it is received, whereas

Attachment 10-A reflects such charges or credits in the month during which the original transaction took place. This timing difference accounts for the differences between Attachment 9 and 10-A.

The Department concludes that this explanation is reasonable.

5. Recommendation

Based on its review of the information provided in MP's Reply Comments, the Department recommends that the Commission accept MP's MISO Day 2 reporting.

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

In our June 5, 2013 Comments, the Department asked OTP to explain the following in reply comments:

1) why the total 2011-2012 MISO Day 2 charges assigned to retail increased from $16.1 million in 2010-2011 to $28.0 million in 2011-2012;

2) why the Company incurred such large Day Ahead Energy Losses (DA FBT Loss Amt) in August, 2011;

3) why the Company incurred such large Day Ahead Congestion (DA FBT Congestion Amt) costs in June, 2012;

4) whether the Company's allocation methods changed during the 2011-2012 reporting period and, if so, the effect these changes had on the charges assigned to various customer categories in OTP's 2011-2012 AAA Report; and

5) ASM

OTP's reply to each of these issues is discussed in more detail below along with the DOC's response.

1) Total MISO Day 2 Charges

In their September 20, 2013 reply comments, OTP stated that:

> There are two primary drivers for the increased MISO Day 2 charges between AAA reporting periods. They include different treatment on bilateral purchase transactions and generator outages.
>
> First, OTP purchased 50MW of on-peak power for the two AAA reporting periods. However, the purchase for ten months of the

2010-2011 AAA reporting period was made with a counterparty using a financial schedule through the MISO market. When a purchase is made using a financial schedule, OTP pays the counterparty for the full purchase price of the energy and subsequently schedules the energy through the MISO. In turn, OTP receives revenue in the MISO settlement for the energy—offsetting OTP's MISO charges. The energy purchase in the 2011-2012 AAA reporting period was scheduled as a Contract for Differences ("CFD"). When a purchase is made as a CFD, the two counterparties settle the difference between the full purchase price and the Locational Marginal Price ("LMP") between themselves. Therefore, no offsetting revenue is received from the MISO. The MISO financial schedule revenue for the 2010-2011 reporting period is 50MW purchase x 10 months x 16 hours/day x 20 days/month x $32.76/MWh = $5.25M.

Second, the difference between the MISO Day 2 charges also is the result of differences in OTP's scheduled outages during the two periods. OTP had limited outages during 2010-2011 (therefore the Day 2 charges are comparatively low). By contrast, OTP had three major scheduled plant outages during the 2011-2012 AAA reporting period (therefore increasing the Day 2 charges over the preceding period). Big Stone was offline from 9/15/2011 thru 12/5/2011 and 6/5/2012 thru 6/16/2012. Coyote was offline from 3/30/2012 thru 5/14/2012. Using average LMP values during these periods to estimate the impact, the lost MISO revenue relating to these three scheduled outages includes:

Start	Stop	Days	Unit	Lost MW*	Hours	Average LMP	Estimated Lost Revenue
9/15/2011	12/5/2011	81	Big Stone	189	1944	$20.87	$7,667,972
3/30/2012	5/14/2012	45	Coyote	103	1080	$17.52	$1,948,925
6/5/2012	6/16/2012	11	Big Stone	189	264	$25.61	$1,277,837
						Total	$10,894,733

* Estimate of expected clearing between on and off-peak periods. Max output (Big Stone: 256MW; Coyote 140MW)

Assumes full output during on-peak and minimum output during off-peak.

The Department reviewed OTP's reply comments and agrees that the Company's treatment of bilateral purchases and scheduled outages account for the increase in total MISO Day 2 charges between AAA reporting periods. As a result, the Department concludes that OTP's total MISO Day charges for the 2011-2012 AAA reporting period appear reasonable.

2) Day Ahead Energy Losses

OTP stated in their reply comments that:

> As background, the DA FBT Loss Amt reflects the amount of financial energy losses paid by OTP to the MISO for moving energy from Big Stone and Coyote to OTP's retail load. The charge per MWh for losses is determined by the LMP market (the difference in the Marginal Loss Component of the LMP between the generator and the load). The volume (MWh) is determined by the market clearing results for OTP's generators. In addition, OTP receives a refund of the excess loss collection on these schedules through the DA GFAOB RBT LS (resulting in a 50% reduction in loss costs for these two units).
>
> During the reporting month of August 2011, the average LMP losses between Big Stone and OTP load were the second highest for the reporting year for Big Stone; slightly over 40% more than the reporting year average. Average losses between Coyote and OTP load during the same time period were nearly 30% more than the reporting year average; the largest cost for Coyote for the reporting year. In addition, generation was the highest at these two stations during the month of August 2011. These two factors, the cost of losses and the amount of generation, were the direct causes of the higher costs.

Based on our review, the Department concludes that OTP has reasonably explained its large increase in Day Ahead Energy Losses for August 2011.

3) Day Ahead Congestion Costs

OTP stated in their reply comments that:

> As background, the DA FBT Congestion Amt reflects the amount of financial congestion paid by OTP to MISO for moving energy from Big Stone and Coyote generating stations to OTP's retail load. The charge per MWh for losses is determined by the LMP market (the difference in the Marginal Congestion Component of the LMP between the generator and the load). The volume (MWh) is determined by the market clearing results for OTP's generators. OTP receives a full refund of these charges through the DA GFAOB RBT CG charge type—therefore, this charge type has no impact on retail customer costs.
> For the accounting month of June 2012, the monthly average congestion between Big Stone and OTP load was $0.96 more than the AAA reporting year average. The congestion between

> Coyote and OTP load during these same time references was nearly $1.30 more. This increase in congestion, determined by the MISO market, is the direct cause of the higher costs in June 2012 compared to other months in the 2011-2012 AAA reporting period.

The Department concludes that OTP reasonably explained its large increase in Day Ahead Congestion Costs for June 2012. Moreover, the Department agrees that OTP receives a full refund for these costs through another MISO charge type. As a result, these charges do not impact retail customer costs.

4) Changes in Allocation Methods

OTP stated on page 5 of their reply comments that they made no changes made to their allocation methods during the 2011-2012 AAA reporting period. The Department appreciates OTP's clarification.

5) ASM Net Benefits

In our initial comments, the DOC noted that OTP's ASM net benefits decreased significantly from $230,559 in 2010-2011 to $32,764 in 2011-2012. As a result, the DOC recommended that OTP explain this decrease in their reply comments.

OTP stated on page 5 of their reply comments that:

> There are two primary drivers for the reduction in net ASM benefits between the AAA reporting periods: a significant reduction in ASM prices and generator outages.
>
> As background, ASM net benefits are comprised of revenues received from MISO for selling the three market-based ancillary services (regulation, spinning reserve, and supplemental reserve) netted against the cost charged to OTP for its share of ancillary service costs in the MISO footprint. OTP offers all three ancillary services from eligible units along with energy. MISO's market simultaneously co-optimizes the selection of energy and ancillary services for each unit—maximizing each generator's revenue. Therefore, clearing fewer ancillary services is not necessarily a concern as it likely means that additional energy revenue was received.
>
> The ancillary service clearing prices for 2011-2012 dropped significantly relative to 2010-2011. Average regulation prices fell by 25%, spinning reserve by 28%, and supplemental reserve by 18%. As ASM prices fell, OTP's units were less likely to clear, and when they did clear, generated less ASM revenue.

> Also, as described above, OTP had three major scheduled plant outages during the 2011-2012 AAA reporting period, but OTP did not have any major outages during 2010-2011. Big Stone was offline from 9/15/2011 thru 12/5/2011 and 6/5/2012 thru 6/16/2012. Coyote was offline from 3/30/2012 thru 5/14/2012. Reduced unit availability for these major stations directly reduced the amount of ASM revenue over the period.

Based on the above, the Department concludes that OTP reasonably explained its decrease in ASM net benefits. As a result, the Department recommends that the Commission accept OTP's ASM reporting.

V. DEPARTMENT RECOMMENDATIONS – COMPLIANCE FILINGS

- The Department recommends that the Commission approve Xcel Electric's compliance filing on the high level cost allocation test between retail and wholesale customers for June, July and August 2012. The Department recommends that the Commission continue to require Xcel Electric to report this generation cost allocation in future AAA filings.

- The Department recommends that the Commission accept Xcel Electric's Natural Gas Financial Instruments compliance filing in the FYE12 docket. The Department will review Xcel Electric's continued compliance with this requirement in the FYE13 AAA report.

- The Department recommends that the Commission accept Xcel Electric's FYE12 wind curtailment report.

- 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 will continue to monitor this compliance filing in future AAA reports.

- 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 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.

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

VI. DEPARTMENT RECOMMENDATIONS – FCA MECHANISM

The Department identified several options for reforming the FCA, as discussed above.

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.

VII. DEPARTMENT RECOMMENDATIONS – MISO DAY 1

- Overall the Department concludes that the Companies' responses have 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 require utilities to continue 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.

VIII. DEPARTMENT RECOMMENDATIONS – MISO DAY 2

A. XCEL ELECTRIC

- Based on this additional information provided by Xcel Electric in its reply comments, the DOC concludes that Xcel Electric's Day Ahead and Real Time Energy amounts for FYE12 are reasonable.
- Based on this additional information provided by Xcel Electric in its reply comments, the DOC concludes that Xcel Electric's Real Time Revenue Neutrality costs for FYE12 are reasonable.
- As a result of the Company's response confirming the Company has not changed its MISO Day 2 allocations and the two above responses on Day Ahead and Real Time Energy and Real Time Revenue Neutrality, the Department recommends that the Commission accept Xcel Electric's MISO Day 2 report for FYE12.

B. MINNESOTA POWER

- Based on the information provided by MP in its Reply Comments, the Department recommends that the Commission accept MP's MISO Day 2 reporting for FYE12.

C. OTTER TAIL POWER

- Based on our review, the Department concludes that Otter Tail Power's allocation of costs between Retail and Wholesale customers is reasonable for the FYE12 reporting period and therefore the Department recommends that the Commission accept Otter Tail Power's MISO Day 2 reporting.

D. INTERSTATE ELECTRIC

- Based on a limited review, Interstate Electric's allocation of costs between Retail and Wholesale customers appears to be reasonable for the FYE12 reporting period and therefore the Department recommends that the Commission accept Interstate Electric's MISO Day 2 reporting.

IX. DEPARTMENT RECOMMENDATIONS – ANCILLARY SERVICES MARKET

- Based on this additional information provided by the Company in its reply comments regarding the two ASM concerns of the Department, the Department recommends that the Commission accept Xcel Electric's ASM report.

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

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

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

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Attachment 1

Summary of the Department's Investigation of IOUs' FYE11 Forced Outages
Docket No. E999/AA-11-792

Background information is available at pp. 4-61 of the Department's December 12, 2012 Response Comments in Docket No. E999/AA-11-792, available at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7b29D584DF-51F7-4DC3-A2D2-38777542C303%7d&documentTitle=201212-81728-01

Safety Relief Valve (SRV) leak at Monticello

- Xcel's Minnesota ratepayers were charged $334,100 in increased energy costs as a result of a forced four-day outage in June 2011 to replace the SRV at the Monticello plant. The SRV prevents the primary system piping from being over-pressurized.

- Between 1984 and 1993, there were three instances similar to the 2011 occurrence where elevated tailpipe temperatures were present following testing of the valve during startup that required SRV replacement.

- In 2004, the American Society of Mechanical Engineers code was revised to no longer require SRVs to be opened and closed at reduced or normal system pressure following maintenance.

- As a result, Xcel asked the Nuclear Regulatory Commission in February 2012 to allow Xcel to manually activate the SRVs during plant startup.

- Xcel provided no analysis to support its decision to wait until its "normal industry update" to adopt "the new method for testing SRVs at that time." The only justification provided was that "it is not common within the industry to request approval for alternative forms of testing from the NRC, especially when our normal industry update was soon approaching and we planned on adopting the new method for testing SRVs at that time."

Coal bunker explosion at Black Dog

- Xcel's Minnesota ratepayers were charged $326,300 in increased energy costs as a result of a forced outage resulting from a coal bunker explosion during Fall 2010 due to the buildup of carbon monoxide at the Black Dog plant.

- Three similar instances occurred at the King plant in 2007, 2008 and 2009. The preventive steps developed in response to these forced outages were only applied to the King plant.

- Xcel waited until 2010 to assess all coal-plant handling processes for risk relative to CO explosions. According to Xcel, there have been no CO explosion events at plants on the NSP-Minnesota system since then.

- Xcel provided no analysis to support its conclusion that "the actions we took at King were not seen as necessary, or prudent, to apply across the system absent a clear need to do so."

Use of Incompatible O-rings by a Contractor at Boswell

- MP's ratepayers were charged $507,715 in increased energy costs as a result of a forced outage in January 2011 resulting from replacement o-rings made of materials incompatible with the fluids used in the hydraulic system at the Boswell Energy Center.

- MP informed the vendor that all o-rings and seals were to be replaced and that viton was the only acceptable material.

- According to MP, viton o-rings were a different color so it was easy to tell one material from another. However, now they can be any color. To alleviate the potential confusion, MP purchased a tester to determine the material of o-rings.

- No red flags appear to have been raised to take into account the change in the color of the o-rings. Even if such a red flag was raised, MP provided no analysis to justify why it has not purchased a tester sooner.

- According to MP, there was no reason to add to the cost of the rebuild by having an engineer watch the entire rebuild process (5 weeks). However, MP provided no analysis to support its conclusion that "this cost could not be justified."

Incorrect Assembly of Water Pump Suction Valves by a Contractor at Boswell

- MP's ratepayers were charged $161,187 in increased energy costs as a result of a forced outage during Fall 2010 resulting from the incorrect assembly of water pump suction valves at the Boswell Energy Center.
- As a result of similar issues with other pumps repaired by vendors, MP will increase inspection work both onsite and at the vendor's facility.
- MP provided no analysis to support the action chosen: no action.

Employee error at King, Sutherland and Prairie Creek

- Xcel's Minnesota ratepayers were charged $61,300 in increased energy costs as a result of a forced outage resulting from an allen wrench that fell in the bus duct work due to an employee error.
- As a result, a work order was created to cover the buss duct opening. All material going in and out of the exciter will be signed in and out.
- Xcel also created a Plant Management Directive outlining sensitive areas where sign-in and sign-out of equipment is required. However, Xcel still has not clarified whether and when similar measures were taken at all plants on Xcel's system.

- IPL's Minnesota ratepayers were charged $55,656 in increased energy costs as a result of a forced outage resulting from an oil pump failure due to an employee error.
- The pump failed when a valve was left in the closed position, reducing oil flow to the turbine bearings.
- According to IPL, the development of an organization to operate at a zero failure level would require more staff and higher levels of training, and testing than customers may be willing to support. However, IPL provided no analysis showing that the costs of the training system IPL put in place after the error were higher than the $1,012,357 in replacement power cost that were charged to all ratepayers as a result of the outage.

- IPL's Minnesota ratepayers were charged $8,460 in increased energy costs as a result of a forced outage resulting from a primary air fan fire due to an employee error.
- According to IPL, the coal pulverizing mill should have been immediately shut down when the mill became plugged.

- Xcel and IPL have not shown that they had a reasonable system in place prior to these incidents.

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
Response Comments

Docket No. **E999/AA-12-757**

Dated this 31st day of December 2014

/s/Sharon Ferguson

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