MINNESOTA DEPARTMENT OF COMMERCE

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December 30, 2016 **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-15-611

Dear Mr. Wolf:

Attached please find the Department's *Response Comments* to 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:

- Minnesota Power, reply comments filed on August 10, 2016;
- Xcel Electric reply comments filed on August 11, 2016;
- Otter Tail Power Company, reply comments filed on August 11, 2016; and
- Xcel Electric, reply comments filed on September 6, 2016.

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 2014-2015 (FYE15) Annual Automatic Adjustment Reports for Electric Utilities* filed on June 15 and 16, 2016 (Part I of the Report) and August 25, 2016 (Part II of the Report).

The Department recommends that the Minnesota Public Utilities Commission (Commission) adopt the Department's revised recommendations, as discussed in greater detail herein and summarized 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-15-611

I. BACKGROUND

On June 15 and 16, 2016, the Division of Energy Resources of the Minnesota Department of Commerce (DOC or the Department) filed its *Review (Part I of the Report) of the 2014-2015 (FYE15) Annual Automatic Adjustment Reports (AAA Reports)* with the Minnesota Public Utilities Commission (Commission) in the present docket.

On August 25, 2016, the Department filed its Review (Part II of the Report) of the 2014-2015 (FYE15) AAA Reports with the Commission.

Part I and Part II of the Report (Report) pertain 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:

- Minnesota Power, reply comments filed on August 10, 2016;
- Xcel Electric reply comments filed on August 11, 2016 and September 6, 2016; and
- Otter Tail Power Company (OTP), reply comments filed on August 11, 2016 and September 6, 2016.

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 2014-2015 (FYE15) Annual Automatic Adjustment Reports for Electric Utilities* filed on June 15 and 16, 2016 (Part I of the Report) and August 25, 2016 (Part II of the 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.

II. DEPARTMENT ANALYSIS – FILING REQUIREMENTS (AUDIT REPORTS)

A. BACKGROUND

In its June 15, 2016 Part I Report, the Department reviewed each auditor's report filed and noted the following.

First, the audit performed for Dakota Electric Association (DEA) provided the most comprehensive assessment of the accuracy of the rates DEA charged to its member/ratepayers. Assuming that the fuel clause adjustment (FCA) continues to operate as it currently does, the Department recommends that the Commission consider requiring other utilities to conduct such comprehensive audits, which involved:

- comparing the documentation supporting payments and invoices received from the energy supplies,
- comparing the base costs of power approved by the Commission to the bases used by the utility,
- recalculating the billing adjustment charge (credit) per kWh charged customers for purchased power for the entire applicable period by class of customer,
- comparing the accounting records for the revenues billed to customers for energy delivered for the relevant period to the total sales of electric energy,
- on a test basis, examining individual billings in each customer class by recalculating the automatic adjustment of charges and credits and tracing to the individual customers' subsidiary records to ensure that the calculated credit or charge was correctly recorded,
- examination of any corrections to FCA charges or other billing errors,
- reconciliation of total revenue and cost of power in the utility's general ledger,
- recalculation of any true-up, and tracing the related revenue and expense amounts to the utility's accounting records.

Second, the Department noted that Xcel and Otter Tail Power's audit reports provided a helpful list of dockets in which the Commission made decisions regarding the respective FCAs of these utilities. The Department recommended that the Commission consider requiring all utilities to list all of the dockets in which the Commission has granted any variances to utilities' FCAs (such as true-up provisions, allowing costs of purchased power adjustments to flow through the FCA, allowing MISO costs and revenues to be included in the FCA, etc.)

B. DEPARTMENT ANALYSIS

In its August 11, 2016 reply comments at 2-3, OTP indicated that "the depth and breadth of work necessary to render an opinion is more comprehensive (and more costly) than a review with a scope limited to an agreed-upon set of procedures:"

> While DEA's independent accountant specifically identified certain testing procedures applied during the accountant's

> review of DEA, it appears the review was limited to those agreed upon procedures only, and as the report indicates, did not go to the level necessary to render an opinion. In contrast, D&T's independent examination of Otter Tail follows American Institute of Certified Public Accountants (AICPA) standards and deploys examination and testing procedures sufficient to render an opinion that the Energy Adjustment Factors have been compiled in compliance with the criteria established by the Commission through rules and orders. It is Otter Tail's understanding that the depth and breadth of work necessary to render an opinion is more comprehensive (and more costly) than a review with a scope limited to an agreed-upon set of procedures. If a comparable set of agreed-upon review procedures (as opposed to an examination opinion) would be acceptable to the Commission, Otter Tail would be receptive to that approach as an alternative to satisfy Rule 7825.2820 compliance in a more cost effective manner.

In its August 10, 2016 reply comments at 2-3, MP stated that it "will work with their external auditors to include applicable items above that are not currently covered in the audit of the AAA filings." MP also stated that it "will work with their external auditors compile a list of dockets in which the Commission has granted any variances to the Company's FCA, including allowing MISO costs and revenues to flow through the FCA."

While the depth and breadth of work necessary to render an opinion may be more comprehensive than a review with a scope limited to an agreed-upon set of procedures, the Department recommends that the Commission strongly consider requiring MP, Xcel Electric and OTP to include applicable items above that are not currently covered in the audits of the utilities' AAA filings.

In addition, the Department continues to recommend that the Commission require all utilities to list all of the dockets in which the Commission has granted any variances to utilities' FCAs (such as true-up provisions, allowing costs of purchased power adjustments to flow through the FCA, allowing MISO costs and revenues to be included in the FCA, etc.)

III. DEPARTMENT ANALYSIS – FILING REQUIREMENTS (MP'S AUDITOR'S EXCEPTIONS)

A. BACKGROUND

According to MP's FYE15 report, MP's auditor noted several exceptions where the difference between the "average monthly cost of fuel consumed per ton" and the "average monthly cost of fuel purchased by ton" was greater than 5 percent. MP's auditors stated that MP's management indicated that the differences were due either to "inventory quantity adjustments following physical inventory accounts" or to "recent declines in the cost of inventory purchases" for the tested months of October 2014 and April 2015.

In its June 15, 2016 Part I Report, the Department recommended that MP provide a narrative in reply comments explaining and discussing this issue with enough detail to allow the Commission to make a determination regarding the reasonableness of the corresponding energy costs that were charged to MP's ratepayers.

B. DEPARTMENT ANALYSIS

In MP's August 10, 2016 reply comments, the Company stated that it "would agree that the cost of fuel consumed should be equal or relatively close to the cost of fuel purchased if the Company had no beginning fuel inventory, no inventory adjustments due to the results of physical inventory and all fuel was received at the beginning of the month prior to consumptions."

MP identified the noted exceptions and provided supporting data showing that the cost of fuel consumed falls between the beginning average cost and the cost of purchases during the month for each of these exceptions.

The Department concludes that MP's reply comments provided helpful information and as a result will not pursue this issue further.

IV. DEPARTMENT ANALYSIS – PLANT OUTAGES CONTINGENCY PLANS AND LESSONS LEARNED

A. BACKGROUND

In its June 15, 2016 Part I Report, the Department summarized its review of these two issues in part as follows:

> In its FYE07 AAA report, the Department requested suggestions from the utilities regarding improving outage-related contracts to better protect ratepayers. In response, the utilities appeared to jointly state that "while we attempt to include contract terms or performance bonds to indemnify us for delays or lack of performance, requiring a contractor to indemnify us for replacement energy cost is cost prohibitive." (MP's September 29, 2009 reply comments at 9). However, utilities did not provide evidence to support that position, nor did they suggest other methods to protect ratepayers from paying for high replacement power costs during forced (unforeseen) outages.
>
> …
>
> As the utilities generally have not advanced this discussion, the Department suggests an industry standard the Commission may wish to consider to ensure that the rates utilities charge to ratepayers through the permissive FCA are reasonable.

Hold utilities at least partially if not fully responsible for incremental costs of replacement power due to forced outages caused by improper work by contractors: The Nuclear Regulatory Commission holds utilities with licenses to operate nuclear generation facilities responsible for all events that occur at such facilities, whether due to work performed by a contractor or a direct employee of a utility. The Minnesota Commission may wish to use a similar standard regarding work done by contractors at non-nuclear facilities, including responsibility for incremental costs of replacement power due to forced outages caused by improper work on generation facilities. For example, since utilities have maintained that it is not feasible to hold contractors accountable for their work, utilities should not rely on contractors to supervise themselves; instead, utilities should supervise contractors directly. The Department discusses this issue further under the "Lessons Learned" section immediately below.

…

The goal is for utilities to share information about lessons learned during outages and develop best practices to minimize occurrences of forced outages, thus minimizing the cost of replacement power for which ratepayers may be charged. In addition, as indicated in our September 16, 2014 and December 31, 2014 Reports in Docket No. E999/AA-13-599, the Department continues to believe that utilities could reduce the costs that ratepayers pay for longer-than-expected plant outages by holding contractors more accountable for errors and delays, and by exploring reasonable insurance options.

…

The Department notes that industry standards exist for ways to minimize forced outages. A December 2009 report by the Electric Power Research Institute (EPRI), "Field Guide: Boiler Tube Failure" described the importance of inspecting boiler tubes: …

Because the EPRI report identifies industry standards that utilities should already be following, the Department recommends that the Commission consider **holding utilities financially responsible for replacement power costs due to any failure to exclude foreign material in work in generation facilities.**

Enforcement of this standard and the standard above of holding utilities accountable for contractor errors may be difficult to enforce. However, assuming that the FCA continues to function as it currently does, as a start the Commission may choose, for example, to require utilities to file the lengths (duration) and

> purposes of planned outages for the previous five years, along with the lengths and purposes for expected future outages for upcoming two years. Before being allowed recovery of the costs of any outages that are longer than expected, utilities at a minimum would need to explain sufficiently what caused the extensive delay and why it is reasonable to require ratepayers to pay for the incremental costs of replacement power.

B. DEPARTMENT ANALYSIS

In response to the Department's recommendation to hold utilities at least partially if not fully responsible for incremental costs of replacement power due to forced outages caused by improper work by contractors, MP's August 10, 2016 reply comments stated in part:

> Minnesota Power provides strong scopes of work in our capital projects and maintenance activities through collaboration and pre-job planning. The work of contractors falls into two categories: work that takes place in the generating facilities and work that takes place at the contractor's facility. We audit contractor work with an assigned MP Representative, typically an engineer or superintendent that is ultimately responsible for the work. We hold to the terms of our agreements, but also negotiate any change orders based changing conditions and inspections. Warranties and make good premises are common in the negotiated terms and conditions.
>
> <u>Work at Generating Facilities</u>
> For work that takes place at the generating facility, the MP Representative is responsible for development of the work scope and budget, ensuring that the execution of the work is in line with what was expected, and coordinating QA/QC efforts. The most common work performed by contractors that has a potential to impact production are boiler repairs and turbine repairs. In both cases, an MP Representative is assigned to directly supervise the contractor. Contractor supervision is complicated from a liability perspective. The MP Representative has to be careful about becoming so involved that it eliminates liability on the part of the contractor to perform quality work in a safe manner. There have been cases where a worker injury has left the company liable as they were doing work as assigned by a company employee.
>
> <u>Work at Contractors' Facility</u>
> For work that takes place off-site at the contractor's facility, the process is slightly different. The MP Representative writes a scope of work that defines deliverables from the contractor. There are often hold points in the scope to allow the MP

> Representative to observe the work in process. For example: A typical pump overhaul scope has a hold point following the initial disassembly and inspection. The MP Representative can then go inspect the pump, request bids from additional venders, or allow the repair to proceed. There is a second hold point after the contractor performs the repairs prior to final assembly. This hold point allows the MP Representative to verify all the repairs were completed, review dimensions, and/or QA/QC information the contractor assembles. The final hold point is at final balance and final assembly of the pump. Inspection prior to final assembly is probably the most critical. Once the pump is reassembled, it is difficult to determine if proper procedures were followed.
>
> These processes have been successful for Minnesota Power. In the past several years, there has not been loss of production or delay in return from a planned outage due to poor contractor performance.

The Department notes the following. First, MP has stated previously that it is "unrealistic"[1] to hold contractors accountable for higher replacement power costs even when such costs are caused by unacceptable work by the contractor. Thus, unless the Company has changed its position, the scope of MP's reference to "make good premises" in agreements with contractors appears to exclude making ratepayers whole for higher replacement power costs, even when caused by the contractor's incorrect work.

Second, while the processes described above by MP to alleviate loss of production due to poor contractor performance appear to be reasonable, including the assignment of an "MP Representative to directly supervise the contractor," MP's choices as to when these processes will be used are unclear, given the Company's language above as to liability due to involvement by utility personnel and given that these processes were not implemented in at least two cases during FYE11 as discussed further in the Department's December 12, 2012 extensive review of the utilities' forced outages in Docket No. E999/AA-11-792.[2]

For ease of reference from that case, the Department notes that, in one instance, MP's ratepayers were charged an additional $161,187 in increased energy costs in FYE11 as a result of an "incorrect assembly of water pump suction valves" by a contractor, despite the

[1] See, for example, the December 15, 2009 Second Response Comments of the Department, at pages 6-7 in Docket No. E999/AA-08-995 and the December 12, 2012 comments of the Department, pages 51-56, in Docket E999/AA-11-792. In the latter comments, Minnesota Power stated that "it was found that [the] rebuild procedure used by the outside contractors was incorrect" for Boswell 3, but that "[a]dding replacement power costs as a term of the contract is unrealistic and is a risk no vendor would agree to."

[2] MP's related section is provided as Attachment 1 to these comments. The Department's full review is available online at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=viewDocument&documentId={29D584DF-51F7-4DC3-A2D2-38777542C303}&documentTitle=201212-81728-01&userType=public

fact that MP decided not to provide "any specific close monitoring" on the basis that "[t]heir [contractor] performance had been exceptional."[3]

In another instance, MP's ratepayers were charged an additional $507,715 in increased energy costs in FYE11 as a result of the installation by a contractor of "replacement o-rings made of materials incompatible with the fluids used in the hydraulic system," despite the fact that MP did not have any system in place to prevent or alleviate the contractor's error.[4] 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.

Thus, as to the specific information above, MP should explain to the Commission whether the Company is now holding contractors accountable for replacement power costs, whether MP's supervision processes would now excuse a contractor from supervision given past performances and whether MP's processes would be able to identify whether a contractor used incorrect parts or rebuild procedures.

MP is not alone in this issue; Otter Tail Power and Xcel have also stated that it is not feasible to hold contractors accountable for their poor performance. For example, OTP stated:

> This event has certainly heightened OTP's and the Big Stone Plant Owners' awareness of the importance of prudent risk management for power plant operations. OTP and the Big Stone Plant Owners will continue to pursue contractual provisions, where necessary enforce contract terms so as to disincentivize non-performance and poor performance by contractors. As has been discussed in various other matters recently before the Commission, however, contractors often have limitations on the contractual exposures they can accept. It has been OTP's experience, for example, that contractors often require waivers of consequential damages and other liability limitations. Because these exposures often cannot be transferred to contractors through contract terms, OTP and the Big Stone Owners have considered whether other risk mitigation strategies, such as the purchase of outage insurance, might be available to cover these risks. Unfortunately, insurance products to cover these large exposures don't appear to be commercially feasible.[5]

The utilities made these statements but did not provide evidence as support. Nonetheless, in response to these concerns, the Department suggested making contractors accountable even for a portion of the replacement power costs; however, the utilities have not shown that they have done so.

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[3] Source: Attachment 1 at 28-31 of 33.
[4] Source: Attachment 1 at 9-16 of 33.
[5] August 20, 2009 Review by the Department in Docket No. E999/AA-08-995, page 29.

As a result, if the Commission chooses to allow the FCA to continue in its current form, the Commission should consider, on a going-forward basis, holding the utilities at least partially if not fully responsible for incremental costs of replacement power due to forced outages caused by improper work by utility personnel or contractors until an improved regulatory process is put in place to ensure that utilities internalize their energy costs (treat energy costs as part of their cost of doing business) as the current regulatory process does for the utilities' capital costs. Currently only the level of capital cost recovery is fixed between rate cases, providing a clear incentive to utilities to reduce these costs between rate cases.

The Department notes that no utilities addressed directly the Department's recommendation to hold utilities financially responsible for replacement power costs due to any failure to exclude foreign material in work in generation facilities. MP's recommendation that the Commission and the Department participate in an outage occurrence does not change the fact that:

1) the utilities have the specific knowledge not only of their operations but also about choices that are available to utilities to minimize short-term and long-term costs, while neither the Department nor the Commission have such knowledge, and
2) the Commission and the Department cannot and should not be in the business of micro-managing utilities' operations. Instead, just as utilities have appropriate incentives to minimize non-fuel costs between rate cases, utilities should be given reasonable incentives to minimize fuel costs.

V. DEPARTMENT ANALYSIS – XCEL ELECTRIC NON COMPLIANCE WITH NRC'S CODE OF FEDERAL REGULATIONS

A. BACKGROUND

In its Report, the Department recommended that the Commission require Xcel to refund most if not all of the incremental costs of replacement power due to the FYE15 forced outages at Xcel's nuclear power plants that were caused by Xcel's non-compliance with the requirements of the United States Nuclear Regulatory Commission's Code of Federal Regulations (NRC Code).[6]

The Department identified these incremental costs as being **[TRADE SECRET DATA HAS BEEN EXCISED]** for Prairie Island Unit 1 and **[TRADE SECRET DATA HAS BEEN EXCISED]** for Prairie Island Unit 2.[7]

The **[TRADE SECRET DATA HAS BEEN EXCISED]** figure did not appear to include the costs of replacement power for the additional three days as Unit 2 ascended fully.[8] Thus, the Department recommended that Xcel provide the costs of replacement power for the

[6] Source: DOC's June 25, 2016 Report-Part 1 at 24-28.
[7] Source: DOC's June 25, 2016 Report-Part 1 at 25 and 27.
[8] Source: *Id.* at 27.

additional three days. In addition, the Department requested that Xcel indicate in its reply comments whether, and if so why, the data indicated above continues to be trade secret at this time.

B. DEPARTMENT ANALYSIS

In response to the Department's recommendations, Xcel Electric stated that:[9]

> As discussed below, we believe the replacement power costs associated with all five outages are properly recoverable as just and reasonable costs of operating a nuclear generating plant. Additionally, two of the outages identified by the Department—the third reactor coolant pump outage [April 7-May 9, 2015] and the heater drain tank outage [March 5-6, 2015]—do not relate to an NRC inspection finding and, therefore, would not qualify for disallowance under the Department's policy recommendation. Finally, while the NRC did issue an inspection finding with respect to the instrument air valve solenoid outage, the NRC did not find that the regulatory violation actually caused the outage. We therefore believe that only two of the outages identified actually fit within the policy position set out in the Department's Comments.

Following our review of Xcel Electric's August 11, 2016 reply comments, the Department concurs in part with Xcel Electric. The Department's calculation of the incremental costs of replacement power due to FYE15 forced outages at Prairie Island 1 that were caused by Xcel's non-compliance with the requirements of the NRC Code inadvertently included the additional costs related to the March 5-6, 2015 forced outage at Prairie Island I.

As a result of excluding the costs of replacement power for March 5-6 at Prairie Island I the amount reduces slightly, to **[TRADE SECRET DATA HAS BEEN EXCISED]** for Prairie Island Unit 1 and maintains the amount at **[TRADE SECRET DATA HAS BEEN EXCISED]** for Prairie Island Unit 2. The Department provides the following table summarizing the Department's corrected identification of the incremental costs of replacement power due to the FYE15 forced outages at Xcel Electric's nuclear power plants that were caused by Xcel's non-compliance with the requirements of the NRC Code.

The four forced outages identified by the Department (three at Prairie Island I and one at Prairie Island II) are as follows:[10]

[9] Source: Xcel Electric's August 11, 2016 reply comments at 3.
[10] Source: Unit Outage Information, Part K, Section 4, Schedule 2 of Xcel's FYE15 AAA report in Docket No. E999/AA-15-611.

Unit	Outage Date	Equipment that Resulted in the Forced Outage	Incremental Costs
Outage 1. Prairie Island I	12/10/2014-12/27/2014	Reactor Coolant Pump Seal (RCP)	**[TRADE SECRET DATA**
Outage 2.a. Prairie Island I	1/26/2015-1/31/2015	Reactor Coolant Pump Seal	**HAS BEEN EXCISED]**
Outage 2.b. Prairie Island I	2/1/2015-2/12/2015	Reactor Coolant Pump Seal	
Outage 3.a. Prairie Island I	4/7/2015-4/30/2015	Reactor Coolant Pump Seal	
Outage 3.b. Prairie Island I	5/1/2015-5/9/2015	Reactor Coolant Pump Seal	
Total Prairie Island I		Reactor Coolant Pump Seal	
Outage 4. Prairie Island II	3/5/2015-3/25/2015	Air Isolation Control Valve	

The Department notes that Xcel Electric continues to maintain that their estimated cost of replacement power should be treated as Trade Secret data.[11]

1. Outages 1-3: Reactor Coolant Pump Seal at Prairie Island I

Xcel Electric's reply comments did not address the issue raised by the Department regarding the three outages related to the reactor coolant pump seal (RCP seal) at Prairie Island I. As summarized below, the NRC's May 6, 2015 Prairie Island Report explained on page 15 that these outages were caused by Xcel Electric's failure to follow NRC's requirements:[12]

> A self-revealing finding of very low safety significance and an NCV of TS 5.4.1 was identified on December 19, 2014, due to the licensee's failure to follow Procedure FP–MA–FME–01, "Foreign Material Exclusion and Control." Specifically, workers failed to implement and adhere to the FME [foreign material exclusion] control requirements for a Level 1 foreign material exclusion area (FMEA) when replacing the #12 RCP seal and its associated piping during Refueling Outage 1R29. <u>The failure to implement and adhere to the FME control requirements resulted in introducing foreign material into the #12 RCP seal. This caused RCP seal degradation in December 2014 and January 2015 and led to two subsequent Unit 1 reactor shutdowns.</u>
> (underlined emphasis added)

[11] Source: Xcel Electric's August 11, 2016 reply comments at 12.
[12] Source: NRC's May 6, 2015 *Prairie Island Nuclear Generating Plant, Units 1 and 2 NRC Integrated Inspection Report and Exercise of Enforcement Discretion* at 15 and 19. The full report is available at: https://adamswebsearch2.nrc.gov/webSearch2/view?AccessionNumber=ML15127A218

Instead, Xcel Electric argued that "the replacement power costs associated with these outages are just, reasonable, and recoverable."[13]

Xcel Electric appears to support this argument as follows.

Xcel Electric states that "[d]ifficult and novel engineering problems—like the development of new equipment to comply with new, post- Fukushima requirements—frequently involve a certain amount of trial and error."[14] While the Department may not disagree with this general statement, this statement is irrelevant to the issue raised by the Department. The May 6, 2015 NRC Integrated Inspection Report clearly stated that the three RCP-related outages were caused by Xcel's failure to implement and adhere to the FME control requirements. In addition, the NRC report indicated that Xcel Electric did not even follow its own procedures as discussed further below:[15]

> Enforcement: TS 5.4.1 states that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Section 9 of Regulatory Guide 1.33, Revision 2, Appendix A, February 1978, requires procedures for performing maintenance. Specifically, Regulatory Guide 1.33, Section 9, requires that maintenance that can affect the performance of safety-related equipment be properly pre-planned and performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstance. Procedure FP-MA-FME-01, "Foreign Material Exclusion and Control," was the procedure used by the licensee to ensure that foreign material was not introduced into safety-related systems or components during the performance of maintenance on equipment.
>
> Section 5.1.1 of Procedure FP-MA-FME-01 stated that a Level 1 FMEA (highest level) was required to be established when a loss of FME integrity could result in personnel injury, nuclear fuel failure, reduced safety system or station availability, or an outage extension or significant cost for recovery. Step 5.1.1.4 stated that a Level 1 FMEA was required when performing intrusive work on SSCs that provide a direct path to the reactor vessel such as the RCS at Prairie Island. Lastly, Section 5.2 stated that a formal FME control plan was required for large projects with FME Level 1 activities.
>
> Contrary to the above, between October 7 and December 19, 2014, the licensee failed to properly establish a Level 1 FMEA

[13] Source: Xcel Electric's August 11, 2016 reply comments at 9.
[14] Source: Xcel Electric's August 11, 2016 reply comments at 9.
[15] Source: NRC's May 6, 2015 Integrated Inspection Report at 19-20.

> during RCP seal replacement activities even though the RCP seal replacement work was performed on portions of the RCS that provided a direct path to the reactor vessel and a loss of FME integrity could have resulted in nuclear fuel failure, reduced safety system or station availability, or an outage extension or significant cost for recovery. In addition, a formal FME control plan was not developed even though the RCP seal replacement activity determined to be a large project with FME Level 1 activities. Because this violation was of very low safety significance and was entered into the licensee's CAP as CAP 1459098, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000282/2015001–02: Failure to Follow Foreign Material Exclusion Procedure during Reactor Coolant Pump Seal Replacement)**. Corrective actions for this issue included replacing the RCP seal, flushing the seal piping and establishing a process to review work document quality to ensure that appropriate programmatic requirements were included.
> (underlined emphasis added)

Xcel Electric also stated that:

> At the same time, we believe it is reasonable to experience a certain number of unplanned outages due to the safety standards of both the NRC and nuclear industry … Finally, given the safety-first priority of the NRC, we believe it is reasonable to expect that some of our nuclear plant outages will relate to NRC findings like those identified by the Department—all of which were classified by the NRC as having "very low safety significance."

While the Department may not disagree with this general statement, this statement is irrelevant to the issue raised by the Department. The issue here is that the outages at hand occurred as a result of Xcel Electric failing to follow its own procedures and/or NRC's requirements, not that it is not "reasonable to expect that some of our nuclear plant outages will relate to NRC findings… all of which were classified by the NRC as having "very low safety significance." The Commission does not regulate safety issues at nuclear plants, but does regulate utilities' rates.

Finally, the Department notes that Xcel Electric confirmed that the third RCP outage was a continuation of the first two RCP outages:[16]

> Following this extensive series of flushes, Seal 12-4 was installed on February 5, 2015. Again, it began to degrade soon after startup, but the degradation rate was slower than both of the

[16] Source: Xcel Electric's August 11, 2016 reply comments at 8.

> previous seal failures. The degradation resulted in the final RCP-related outage on April 7, 2015 [Outage 3 that lasted until May 9, 2015]. While the degradation was again due to foreign material found in the seal, the debris was present in "orders of magnitude lower quantities" than the previous outages due to the aggressive flushes that had been performed.

Given the clear finding by the NRC that Xcel failed to follow its own and/or NRC's procedures, the Department continues to recommend that the Commission require Xcel Electric to refund most if not all of the incremental costs of replacement power of **[TRADE SECRET DATA HAS BEEN EXCISED]**. These replacement power costs were due to forced outages at Xcel's Prairie Island Unit I that were caused by Xcel's non-compliance with the requirements of the NRC's Code of Federal Regulations.

2. Outage 4: Solenoid Valve at Prairie Island II

Xcel Electric's reply comments did not address the issue raised by the Department regarding the outage at Prairie Island II resulting from the failure of an air isolation control valve. As summarized below, the NRC's May 6, 2015 Prairie Island Report explained that this outage was the result of the failure of a solenoid valve (SV-33283) which should have been replaced earlier but was not, in violation of NRC's requirements:[17]

> 1. <u>Unit 2 Shutdown Due to Loss of Instrument Air to Containment Building</u>
>
> a. <u>Inspection Scope</u>
>
> On March 5, 2015 at 1:38 a.m., Unit 2 experienced a loss of instrument air to containment when the reactor building instrument air isolation control valve (CV–31742) unexpectedly failed closed.
>
> …
>
> b. <u>Findings</u>
>
> <u>Introduction</u>: A self-revealing finding of very low safety-significance (Green) and an NCV of 10 CFR 50.49 was identified on March 5, 2015, for the failure to keep EQ files current and the failure to replace or refurbish EQ electrical equipment at the end of its designated life. Specifically, the licensee had identified numerous EQ file errors in May 2014. These file errors resulted in the EQ designated life for multiple safety-related solenoid valves being non-conservative. Correction of the file errors should have resulted in the replacement of ten solenoid valves on a near-term basis. However, none of the solenoid valves has been replaced prior to the event on March 5, 2015.

[17] Source: NRC's May 6, 2015 *Prairie Island Nuclear Generating Plant, Units 1 and 2 NRC Integrated Inspection Report and Exercise of Enforcement Discretion* at 26-28. The full report is available at: https://adamswebsearch2.nrc.gov/webSearch2/view?AccessionNumber=ML15127A218

…
The licensee also determined that CV–31742 had failed closed due to the failure of its solenoid valve (SV–33283).
…
During the inspectors' review of the corrective action program database, the inspectors identified CAP 1431268 which was written on May 19, 2014. This CAP documented multiple deficiencies found during a review of the EQ program. The CAP contained the following information:

"The qualification calculations of ASCO solenoid valves contained several errors. For a specific model number, the incorrect test report was applied. Also, a non-conservative value for the temperature rise was used, resulting in a longer life than actually exists. This will require near-term replacement of approximately 10 valves ahead of schedule."

The inspectors discussed the information provided above with engineering personnel to determine if SV–33283 was one of the ten specific ASCO solenoid valves referred to in CAP 1431268. Engineering personnel informed the inspectors that SV–33283 was one of the ten valves needing replacement. The inspectors were also informed that due to the deficiencies identified in CAP 1431268 the EQ designated life was reduced from 17.3 years to 4.96 years. The inspectors performed an additional review of CAP 1431268 and held discussions with engineering and work management personnel to determine what actions had been taken to correct the EQ files and replace the ten valves referred to in the CAP. The inspectors found that little to no action had been taken to correct either condition. Specifically, a work order was written to replace a different solenoid valve during the fall 2014 Unit 1 refueling outage; the inspectors found that this valve replacement had not occurred. In addition, no other work orders had been written for the remaining nine valves until March 6, 2015, due to the licensee's belief that the issues identified in CAP 1431268 were programmatic in nature and had no impact on plant equipment. The licensee replaced eight of the nine valves during the outage that followed the loss of air event. These valves had been installed for at least 13 years. The remaining valves were scheduled for replacement in April 2015. The inspectors also found that the licensee had assigned an action to initiate a process to reconstitute the EQ files and other EQ program documentation. Although this action was originally scheduled for completion on June 23, 2014, it had been extended twice and was not yet complete. The failure to replace or refurbish the solenoid valves at the end of their designated life

> and to correct the EQ file deficiencies violated the requirements of 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants."
> (underlined emphasis added)

Instead of addressing this issue, Xcel Electric argued that "the NRC did not conclude that the violation was the cause of the component [solenoid valve] failure and the resulting forced outage."[18]

Xcel's argument sidesteps NRC's findings as to Xcel's actions and lack or actions regarding the solenoids. The NRC found that Xcel's "qualification calculations of ASCO solenoid valves contained several errors" including use of an incorrect test report and "a non-conservative value for the temperature rise" which overstated the expected lives of the solenoids. Moreover, the NRC concluded as stated above that the forced outage was the result of the solenoid valve failure. In addition, the NRC report clearly shows that Xcel Electric knew since May 2014 that ten valves needed to be replaced, including the solenoid valve that failed, after it identified that the designated lives of these valves were only 4.96 years instead of 17 years. Despite the fact that the valves have been installed for at least 13 years, "no action was taken to replace or refurbish the specific ASCO solenoid valves or justify the valves had additional life through the performance of ongoing qualification activities."[19]

Thus, the Department continues to recommend that the Commission require Xcel Electric to refund most if not all of the incremental costs of replacement power **[TRADE SECRET DATA HAS BEEN EXCISED]** due to forced outages at Xcel's Prairie Island Unit II that were caused by Xcel's non-compliance with the requirements of the NRC's Code of Federal Regulations.

VI. DEPARTMENT ANALYSIS – EFFECTS OF MISO DAY 1 ON MINNESOTA RATEPAYERS

A. BACKGROUND

In its June 15, 2016 Part I Report, the Department summarized its review of the electric utilities' MISO Day 1 costs as follows:

- 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.

[18] Source: Xcel Electric's August 11, 2016 reply comments at 10.
[19] Source: NRC's May 6, 2015 *Prairie Island Nuclear Generating Plant, Units 1 and 2 NRC Integrated Inspection Report and Exercise of Enforcement Discretion* at 28. The full report is available at: https://adamswebsearch2.nrc.gov/webSearch2/view?AccessionNumber=ML15127A218

- 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.

B. DEPARTMENT ANALYSIS

In MP's August 10, 2016 reply comments, the Company stated that:

> The Company respectfully disagrees with this recommendation. As the Department noted in their comments, "these costs are not charged through the FCA, rather, they are charged through base rates".
>
> Since MISO Schedule 10 costs are not included in the FCA, but are scrutinized during a general rate case and are included in base rates, review of these costs represents time spent by the Department staff that could be used to review other relevant costs.

The Department notes that the Department's review of MISO Day 1 costs in the electric AAA filings stems from a Commission Order, April 26, 2002 in Docket No. E015/PA-01-539, which required in part (Ordering point 2.C.3) that MP report as part of its AAA filings the Schedule 10 administrative charges paid to the MISO under the MISO tariff.

If MP wishes to change an Order requirement, the Department suggests that MP file and support such a request, to allow for development of a meaningful record in front of the Commission.

VII. DEPARTMENT ANALYSIS – MUNICIPAL MARGINS FOR XCEL

A. BACKGROUND

In its August 25, 2016 Part II Report, the Department noted in its review of Xcel Electric's asset based margins and ancillary services margins for December 2014, that the Cost of Goods Sold included costs related to the Municipal Time of Day Rate. As a result, the Department requested that Xcel Electric provide additional information in reply comments regarding the revenues for the Municipal Time of Day (TOD) Rate and why Xcel Electric does not directly assign these costs and revenues to relevant customers rather than including them in the asset based margins returned to ratepayers.

B. XCEL ELECTRIC'S REPLY COMMENTS

In Xcel Electric's September 6, 2016 reply comments the Company stated that the Municipal TOD Rate is a partial requirements obligation to a limited number (4) of municipal customers, totaling approximately 217,725 MWh in the 2014-2015 AAA reporting period. According to the Company, Municipal TOD energy sales are priced at NSPM's hourly incremental energy cost, which Xcel stated ensures that those sales are made at no risk to retail customers. Further, the Company collects a scheduling fee for these sales that may vary on a per MWh basis or may be set on a flat monthly basis. The Company noted that these fees are returned to retail customers as generation margins through the fuel clause adjustment (FCA). The Company provided further detail regarding the 2014-2015 partial requirement municipal customer revenues and costs in Attachment A to their reply comments.

Xcel Electric also stated in its September 6, 2016 reply comments that since the revenue and costs associated with these partial requirements sales are variable and not easily forecasted, the Company included these sales in asset based margins to ensure that retail customers receive a more accurate benefit, with no associated risk.

C. DOC'S REVIEW AND RECOMMENDATION

The additional information provided by Xcel was helpful.[20] Also, by email the Department confirmed that the Municipal TOD revenues (both scheduling fees and energy revenues) are included in the "Non-MISO Asset Based Revenue" amount of $1,319,293 as shown on page 42 of Department's August 25, 2016 AAA comments.

Based on our review, the Department concludes that Xcel Electric's responses are reasonable, and that asset based margins, ancillary service margins and Municipal TOD Rate margins appear to be appropriately calculated and returned to ratepayers via the fuel clause adjustment.

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[20] In addition to Xcel's discussion about risks to retail customers, the Department notes that there is no risk for Xcel Electric by passing back these Municipal TOD Rate margins through the FCA.

VIII. DEPARTMENT RECOMMENDATIONS – AUDIT REPORTS

The Department recommends that the Commission consider requiring all utilities to list all of the dockets in which the Commission has granted any variances to utilities' FCAs (such as true-up provisions, allowing costs of purchased power adjustments to flow through the FCA, allowing MISO costs and revenues to be included in the FCA, etc.).

IX. 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 2015. 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 FYE15 docket. The Department will review Xcel Electric's continued compliance with this requirement in the FYE16 AAA report.

- The Department recommends that the Commission accept Xcel Electric's FYE15 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 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 provides further recommendations below regarding recovery of replacement power costs.

- 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.

X. DEPARTMENT RECOMMENDATIONS – PLANT OUTAGES CONTINGENCY PLANS AND LESSONS LEARNED

The Department recommends two possible industry standards for the Commission to consider putting in place, if the FCA regulations continue to operate as they currently do, namely:

- Hold utilities at least partially if not fully responsible for incremental costs of replacement power due to forced outages caused by improper work by contractors, and
- Hold utilities financially responsible for replacement power costs due to any failure to exclude foreign material in work in generation facilities.

XI. DEPARTMENT RECOMMENDATIONS – XCEL ELECTRIC NON COMPLIANCE WITH NRC'S CODE OF FEDERAL REGULATIONS

The Department continues to recommend that the Commission require Xcel Electric to refund most if not all of the incremental costs of replacement power **[TRADE SECRET DATA HAS BEEN EXCISED]** due to forced outages at Xcel's Prairie Island Unit I that were caused by Xcel's non-compliance with the requirements of the NRC's Code of Federal Regulations.

The Department continues to recommend that the Commission require Xcel Electric to refund most if not all of the incremental costs of replacement power **[TRADE SECRET DATA HAS BEEN EXCISED]** due to the forced outage at Xcel's Prairie Island Unit II that was caused by Xcel's non-compliance with the requirements of the NRC's Code of Federal Regulations.

XII. DEPARTMENT RECOMMENDATIONS – MISO DAY 1

As a result of the Department's review of the effects of the MISO Day 1 on Minnesota Ratepayers, the Department recommends the following:

- 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 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.

XIII. DEPARTMENT RECOMMENDATIONS – MISO DAY 2

As a result of the Department's review of the effects of the MISO Day 2 market, including Asset Based Margins, on Minnesota ratepayers, the Department recommends that the Commission accept:

- Xcel Electric's MISO Day 2 reporting, including the costs related to the Municipal Time of Day Rate,

- MP's MISO Day 2 reporting,

- OTP's MISO Day 2 reporting, and

- IPL's MISO Day 2 reporting.

XIV. DEPARTMENT RECOMMENDATIONS – ANCILLARY SERVICES MARKET

As a result of the Department's review of the effects of the Ancillary Services Market (ASM) on Minnesota ratepayers, the Department recommends that the Commission accept the ASM reporting by all of the IOUs.

DOC Attachment 1

division of energy resources
Minnesota Department of Commerce

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December 12, 2012

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' Response Comments**
Docket No. E999/AA-11-792

Dear Dr. Haar:

Attached please find the Department's *Response Comments* to the electric utilities' November 9, 2012 *Response Comments.* Specifically, the Department responds to the following electric utilities:

- Interstate Electric, reply comments filed on July 18, 2012 and response comments filed on November 9, 2012;
- Minnesota Power, reply comments filed on July 19, 2012 and response comments filed on November 9, 2012;
- Otter Tail Power Company, reply comments filed on July 17, 2012 and response comments filed on November 9, 2012; and
- Xcel Electric, reply comments filed on July 11, 2012, supplemental reply comments filed on August 17, 2012 and response comments filed on November 9, 2012.

Based on the record in this proceeding, the main issues from the Department's September 26, 2012 Reply Comments that remain to be resolved are related to the discussion of the effects on ratepayers of forced outages at utilities' generation facilities and the cost of wind curtailment payments. The Department's *Response Comments* contain revised recommendations to the recommendations included in the Department's September 26, 2012 Reply Comments. The Department recommends that the Minnesota Public Utilities Commission (Commission) adopt the DOC's revised recommendations, as discussed in greater detail herein. The Department is available to answer any questions that the Commission may have.

Sincerely,

/s/ SAMIR OUANES
Rates Analyst

SO/ja
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-11-792

I. BACKGROUND

As discussed further in the Department's June 1, 2012 Review of the 2010-2011 (FYE11) Annual Automatic Adjustment Reports for regulated electric utilities in Minnesota (Report), the Department reviewed the Investor Owned Utilities' (IOUs) FYE11 forced outages to examine whether the utilities took prudent action to attempt to prevent and to address the unexpected outages.

On February 8, 2012 the Department requested the IOUs to identify and fully explain in understandable terms all involved equipment and equipment failures that resulted in forced outages, to identify all such equipment failures after June 2006, and to describe all steps taken to alleviate any reoccurrence of such failures.

Following phone calls and/or emails with the IOUs, the Department clarified that this discovery was designed to help the IOUs make their case that the replacement energy costs due to the forced outages were prudently incurred.[1]

OTP responded to the Department's February 8, 2012 initial discovery on February 21, 2012, Interstate Electric on February 29, 2012, Xcel Electric on April 10, 2012 and MP on April 16, 2012.

[1] See for example the February 28, 2012 email exchange with MP under Attachment 1 of these comments.

Interstate Electric's and Xcel Electric's responses provided the level of information that allowed for reasonable understanding of the specific primary reasons for the forced outages.[2] As a result, the Department was able to follow-up with further discovery on specific issues to allow Interstate Electric and Xcel Electric to make their cases that the replacement energy costs due to specific forced outages were prudently incurred.[3]

On April 20, 2012, Interstate Electric provided its response to the Department's April 5, 2012 follow-up discovery.

On June 1, 2012, the Department filed the Report. The Department's initial review and recommendations of Interstate Electric's FYE11 forced outages are summarized in the Report. Xcel's May 21, 2012 response to the Department's April 12, 2012 follow-up discovery regarding forced outages was not received in time to be reviewed and discussed in the Report. The Department did not follow up with further discovery with OTP due to OTP's relatively limited amount of forced outages as discussed in the Report. However, the Department put OTP on notice that it should be prepared in future AAA reports to provide upon request a more specific description of the equipment failures that resulted in forced outages (see as an example Interstate Electric's response to similar discovery).

Due to the length of time MP took in responding to the Department's information requests, the Department was not able to issue specific follow-up questions, as it did with Xcel Electric and Interstate Electric, to provide MP with an opportunity to make its case that the replacement energy costs due to the forced outages were prudently incurred. In addition, MP's response to the Department's February 8, 2012 discovery, received on April 16, 2012, did not provide a level of information allowing for a reasonable understanding of the specific primary reasons for the forced outages, as Interstate Electric was able to do on February 29, 2012. As a result, the Department explained in the Report that it may be able to review the prudency of MP's replacement energy costs due to the forced outages that occurred in FYE11 if MP provides the level of detail provided by Interstate Electric (see Interstate Electric's response to the Department's information request Nos. 52-57, and follow-up response to the Department's information request Nos. 127-132 discussed in the Report).

On June 11, 2012, the Commission issued a Notice of Extended Reply Comment Period.

On July 11, 2012, the Department filed Supplemental Comments. The Department provided its review of Xcel Electric's response to the Department's follow-up discovery and recommendations on issues related to Xcel Electric's FYE11 forced outages. The Department clarified that our analysis is based on the premise that the prudency of these costs is associated with the IOUs' ability to:

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[2] See Attachments E16 and E17 of the Report.

[3] See pp. 21-32 and Attachment E18 of the Report.

1) learn from past "failures," e.g., have in place a system that keeps a meaningful and tractable record of (a) past forced outages, (b) the source of these outages (incidents), and (c) the steps taken to prevent and/or alleviate a reoccurrence of these incidents, and

2) justify the specific preventive steps taken, even if no steps were taken, based on a reasonable ex-ante analysis that identifies all reasonable options available, including industry-available best practices.

On July 11, 2012, Xcel Electric filed its Reply Comments.

On July 17, 2012, OTP filed its Reply Comments.

On July 18, 2012, Interstate Electric filed its Reply Comments.

In its July 19, 2012 Reply Comments, MP provided a revised response to the Department's February 8, 2012 discovery. As a result the Department followed up with further discovery on August 3, 2012 on specific issues to allow MP another opportunity to make its case that the replacement energy costs due to specific forced outages were prudently incurred.

On August 9, 2012, the Commission issued a Second Notice of Extended Reply Comments.

On August 17, 2012, Xcel Electric filed its Supplemental Reply Comments.

On September 26, 2012, the Department filed as requested by the Commission its Reply Comments in response to all Reply Comments.

On October 30, 2012, the Commission issued a Notice of Extended Response Comment Period to submit responses to the Department's September 26, 2012 Reply Comments.

On November 9, 2012, Interstate Electric, OTP, MP and Xcel Electric filed their Response Comments.

As requested by the Commission, the Department provides below its analysis and recommendations on outstanding issues related to the IOUs' FYE11 forced outages and an unresolved wind curtailment issue based on the record in this proceeding.

II. DEPARTMENT ANALYSIS – BURDEN OF PROOF

The IOUs bear the burden of showing that their proposed rates are reasonable. Minn. Stat. §216B.16, subd. 4 (2010). Minnesota law requires that every rate established by the Commission must be just and reasonable, and that *any doubt* is to be resolved in favor of the consumer:

> Every rate made, demanded or received by a public utility … shall be just and reasonable. … Any doubt as to reasonableness should be resolved in favor of the consumer.
> Minn. Stat. §216B.03 (2010).

The Minnesota Supreme Court found that the burden is on the utility to prove the facts required to sustain its burden by a fair preponderance of the evidence. *In re Northern States Power Co.*, 416 N.W.2d 719, 722 (Minn. 1987). The Supreme Court described the Commission's role in determining just and reasonable rates in a rate proceeding:

> [I]n the exercise of the statutorily imposed duty to determine whether the inclusion of the item generating the claimed cost is appropriate, or whether the ratepayers or the shareholders should sustain the burden generated by the claimed cost, the MPUC acts in both a quasi-judicial and a partially legislative capacity. To state it differently, in evaluating the case, the accent is more on the inferences and conclusions to be drawn from the basic facts (i.e., the amount of the claimed costs) rather than on the reliability of the facts themselves. Thus, by merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of demonstrating it is just and reasonable that the ratepayers bear the costs of those expenses.
> *Id.* at 722-23.

III. DEPARTMENT ANALYSIS – FORCED OUTAGES

When there is an unexpected (forced) outage at a utility's generation facility, the utility typically must purchase power to replace the lost energy production. The Department provides brief overall observations regarding forced outages of utilities' generation facilities, followed by the Department's review of the IOUs' response to the Department's discovery and recommendations on issues related to the IOUs' forced outages during the July 2010-June 2011 (FYE11) period.

III.1 Review of Forced Outages

In Minnesota, IOUs' energy costs, including replacement power costs during generation outages and congestion costs when transmission facilities are constrained, are automatically recovered through the fuel clause adjustment (FCA), while costs to invest in and operate and maintain energy facilities are typically recovered through fixed base rates. These two different recovery mechanisms – automatic adjustments versus fixed recovery in rates – provide different incentives for utilities to minimize costs.

Specifically, utilities have an incentive to minimize costs with fixed recovery, such as operation and maintenance (O&M) costs for energy facilities, to maximize profit for shareholders between rate cases. By contrast, utilities have little incentive to minimize costs that are passed automatically through the FCA to ratepayers since there is no short-term benefit to shareholders in doing so.

In other words, if the choice is between (a) minimizing O&M costs and incurring higher replacement power costs or (b) minimizing replacement power costs by incurring higher O&M costs, the incentive is for utilities to choose option (a).

When generation units are relatively new, the differences in incentives likely have no material effect. However, as generation units age, utilities are likely to face more choices between increasing spending on O&M costs in the near term to reduce the likelihood of forced outages or delaying O&M spending to keep within budgets for such spending and thus taking a greater risk that there may be forced outages. Given these differences in incentives for recovery of costs of maintaining generation facilities and costs of replacement power when generation facilities fail unexpectedly, the Department examined the reasons for forced (unplanned) outages to provide more balance in the recovery of replacement power costs due to such failures.

As discussed below, utilities' reasons for forced outages spanned a wide range. The information is helpful as a foundation regarding maintenance of the facilities and for assessing whether the utility is acting in a balanced manner to minimize all costs for ratepayers, particularly the costs that affect FCA rates, which are allowed to change between rate cases.

Overall, the Department's review of the IOUs' FYE11 forced outages highlighted a fundamental issue: the IOUs appear to act as if their ratepayers, not the IOUs' management and/or shareholders, should be held accountable for the costs of forced outages even when the costs are the result of a utility's employee errors or outside vendors' mistakes.

The Department provides its analysis and recommendations on these issues below.

III.2. Department's Review and Recommendations Related to IPL's FYE11 Forced Outages

System-wide, Interstate Electric's ratepayers incurred about $11,184,000 (3.23 percent of total energy costs) in additional costs due to forced outages in FYE11, as a result of replacement energy costs being higher than the units' incremental costs. The Department notes that these costs would have been substantially higher if not for the relatively low cost ($/MWh) of replacement energy during FYE11 compared to previous years.

The Department's initial review of Interstate Electric's February 29, 2012 response to the Department's February 8, 2012 discovery identified issues related to forced outages including

2. Lessons Learned from Monticello

The Department also requested the Company provide the lessons learned from both the Monticello feedwater pump event and the partial loss of the process computer. In general, operating events at Xcel Energy's nuclear plants are thoroughly investigated as part of its corrective action program. For the feedwater pump event, we completed an ACE and then took the following actions to address the apparent cause:

- Replace the reactor feedwater pumps during the next refueling outage which will include new seals;
- Added cautionary statements in the Condensate and Feed water pump startup procedure to ensure idle reactor feedwater pump seals are monitored closely with the condensate feedwater system in operation, and to test lube oil on idle reactor feedwater pump prior to starting if water is found in seal emergency drain housing; and
- Updated the lesson plan on the feedwater system to include the operating experience learned, stressing the importance of inspecting seal emergency drain housing weep holes for leakage. With regard to the plant process computer, this was installed at Monticello in 1984 and this module had not previously failed. The AM96 module was replaced and tested and upgrades to the plant process computer are currently under review.

III.4. Department's Review and Recommendations Related to Minnesota Power's FYE11 Forced Outages

System-wide, MP's ratepayers incurred about $8,535,000 (4.02 percent of total energy costs) in additional costs due to forced outages in FYE11, as a result of replacement energy costs being higher than the affected units' incremental costs. The Department notes that these costs would have been substantially higher if not for the relatively low cost ($/MWh) of replacement energy during FYE11 compared to previous years.

The Department's initial review of MP's July 19, 2012 response to the Department's February 8, 2012 discovery identified issues related to forced outages including the following: incompatible o-rings, failed card in input/output (I/O) cabinet, incorrect pump rebuild procedure, and failed insulators.[21]

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[21] Source: MP's July 19, 2012 Reply Comments.

As a result, the Department followed up with discovery regarding each of these issues to assess the prudency of the related additional energy costs that MP passed on to its ratepayers through the FCA during FYE11.

The Department reviewed MP's August 29, 2012 response to the Department's August 3, 2012 follow-up discovery. As with other utilities, for clarity of the record in this matter and to provide for a better informed Commission decision-making process, the Department requested MP to provide a narrative fully describing in a chronological order and explaining in understandable terms the actions and events that gave rise to the need for the replacement energy. The Department appreciates the information that MP provided; however, despite several time extensions for MP's responses to discovery, some of the information provided was still incomplete as it did not fully explain how the unplanned failures in MP's facilities occurred, why the failures occurred and whether and how the failures could have been avoided or alleviated, in some of the cases discussed below.

The Department's initial review and recommendations of MP's FYE11 forced outages are summarized in the Department's September 26, 2012 Reply Comments.

On November 9, 2012, MP filed its Response Comments.

Based on the information in the record at this time, the Department provides below its review and recommendations regarding five issues that are/were still outstanding: incompatible o-rings, failed card in input/output (I/O) cabinet, incorrect pump rebuild procedure, failed insulators, and incorrect assembly of water pump suction valves.

III.4.1. Incompatible O-rings

The Department's initial review and recommendations[22]

MP's July 19, 2012 response to the Department's February 8, 2012 Information Request No. 62 identified "incompatible o-rings" as the equipment(s) which failure resulted in an unplanned outage of Boswell Energy Center 4 in January 2011. According to MP, "[h]ydraulic cylinders which control the turbine governor valves were repaired by an outside repair facility in 2010. The failure mechanism was replacement o-rings made of materials incompatible with the fluids used in the hydraulic system."

MP's August 29, 2012 response to the Department's August 3, 2012 follow-up discovery stated in part:[23]

[22] Source: Department's September 26, 2012 Reply Comments at 29-32.
[23] Source: Attachment RC-2 of the Department's September 26, 2012 Reply Comments.

Boswell 4 turbine control is Electronic Hydraulic Control (EHC). The system uses a high pressure fluid (phosphate ester at 1800 psi) to operate the valves to control the turbine. The EHC system is common to the main turbine and the boiler feed pump turbines. There are a total of 18 actuators on the system. The actuators are typically refurbished on about a 12-year interval unless there is an indication of problems. Each actuator has an associated control block that directs the fluid in the cylinder to open or close the valve. Between the actuator and the control block there are roughly a dozen o-rings and Teflon seals. This results in over 200 for the entire system.

Phosphate ester fluid is used as the motive [hydraulic] fluid because it will not sustain combustion and is the only fluid approved by GE, Siemens and Factory Mutual Insurance. The downside of the fluid is that it requires the use of viton o-rings. The standard buna o-rings will break down when exposed to the fluid.

In the fall of 2010, Boswell 4 had an extended planned outage to install new high efficiency turbine rotors. Due to the time available, the actuators were removed for refurbishment. In the past we had used a vender in North Carolina that did good work but had late delivery. We then tried a vender in Colorado that had good delivery but quality control issues. So this time, we used a Minnesota vender that we have used to supply other components in the system. We informed the vender that all o-rings and seals were to be replaced and that viton was the only acceptable material. Having done similar work for us they fully understood the request.

The cylinders were received and reinstalled in October 2010 on schedule. A short time after startup we had a small leak on one of the valves. Due to the location of the leak, the leak could be isolated and inspected. The o-ring was found pinched but did not look deteriorated. We assumed that it was an assembly issue and that the materials used were correct.

Roughly a month later we had another leak. Being a small drip, we continued to operate the unit. While continuing the run, additional leaks showed up. Consistent with our efforts to avoid unplanned outages, when the unit was down for another reason all of the leaks were repaired. It was at this time that we noted that some of the o-rings showed signs of deterioration. Since, historically it had not been necessary for us to stock every seal and

> o-ring in the system, we were not able to do a complete change out of all the seals during the outage. Based on the o-ring damage and some o-ring incompatibility, the only prudent action was to assume all of the seals were wrong and a full set was ordered and installed in January 2011.
>
> The situation was discussed with the vender who assured us that we must have been mistaken about the incorrect o-rings. After encountering a similar issue in May 2012 on a subcomponent in the system, we can no longer trust the supplier to supply the correct material consistently. Historically, 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, we purchased a tester to determine the material of o-rings. We are also looking at a fourth vender in Michigan that may be able to provide quick turn around and a higher degree of confidence that all parts, including o-rings, meet our specifications.
> …
> No other outages or derates for issues (Incompatible O-Rings in EHC System) of this nature were identified across the thermal fleet between July 2006 and June 2011.
> …
> Minnesota Power has not performed any separate analysis regarding whether replacement energy costs in fiscal year 2011 were prudently incurred.
> …

MP's response is helpful in explaining what went wrong and the steps MP took to address the issues. However, what is not clear is why MP's ratepayers should be responsible for the replacement power costs. The following questions remain as to steps MP should have taken to protect its ratepayers:

- What steps did MP take as a result of previous "quality control issues" with vendors to eliminate or, at least, alleviate the reoccurrence of these "quality control issues?"

- Did MP have any performance provision in the contract with the errant vendor to protect its shareholders and its ratepayers from any additional costs in case the vendor fails to perform?
    - If so, what was the provision and how did MP pursue that provision? Were any amounts recovered by MP?
    - If not, why didn't MP have such a provision in a contract pertaining to such a valuable resource?

- Given that MP has already faced “quality control issues” with another vendor in the past, how did MP select the “Minnesota vendor” who installed the “incompatible o-rings?” How did MP ascertain the “reliability” of this vendor?

- Given that MP was fully aware that “viton was the only acceptable material” for the replacement o-rings, did MP have a representative at the repair facility to ensure that only the required material was used?

Because it does not appear that MP’s replacement energy costs for this outage were prudently incurred, the Department concludes that MP did not demonstrate that the actions and events that gave rise to the need for the forced outage resulting from the use of incompatible o-rings by an outside repair vendor were reasonable.

While MP did not identify the additional energy costs (difference between the replacement energy cost and the unit’s incremental cost) imposed on its system during FYE11 as a result of the use of incompatible o-rings in its August 29, 2012 response to the Department’s August 3, 2012 follow-up discovery, Table 1 of MP’s July 19, 2012 Reply Comments indicates that MP’s ratepayers were charged an additional $507,715 during FYE11 as a result of the use of incompatible o-rings on MP’s system.

Therefore, the Department recommends that the Commission require MP to refund $507,715 to its ratepayers through an appropriate adjustment of MP’s monthly FCAs following the date of the Commission’s Order in this matter.

<u>The Department’s current review and recommendations</u>

In its November 9, 2012 response comments, MP added the following information to the record:

> *What steps did MP take as a result of previous “quality control issues” with vendors to eliminate or, at least, alleviate the reoccurrence of these “quality control issues?”*
>
> Vendors which have not performed work as expected are normally not used for future work. Minnesota Power works with several repair facilities to obtain the best value for the customer within the time constraints of planned outages. With a limited number of vendors providing these services, our choice of vendor facility is based on our past experience with the vendor, feedback from other utilities and other information that may be available from sources such as trade organizations. During our outage planning process, vendors are selected to provide anticipated services, however, due to workload already scheduled at those repair facilities, the number of vendors available to perform the work can be limited. It is important to understand that most utilities have outages in the same

"shoulder month" windows when energy demand is low. This sometimes limits our choice of vendors. Based on our knowledge and experience with the quality of services provided by the vendor, we determine our level of involvement (specifications, custom procedures, site visits to repair facility, etc).

In the past 30 years, Minnesota Power has used three different vendors to perform cylinder/control block rebuilds. The first contractor was located in the State of Virginia. They did excellent work. While there was no re-work involved with work performed by this contractor, the repair cycle including transportation to and from the repair facility had a negative effect on outage duration. We would use this vendor in the future if they can meet the timing needs for the repairs.

The second vendor is located in Colorado. We did not specifically choose this vendor as they were a subcontractor to a vendor we used to perform system tune-up and oil flush. All of their repairs were done on time: however, we did have two rod seal leaks. With those leaks, we again found the difficulty in working with a vendor from out of state to obtain the needed parts. We do not plan to use this vendor in the future.

The vendor we used this time was from Minnesota. We have been purchasing new products from them for over 10 years based on pricing and service. The new products have performed as designed. This was the first time we have used them for repair/refurbishment. The problems associated with this outage revolved around three issues:

1. O-rings that were pinched during assembly at the repair shop,
2. Some non-viton o-rings,
3. Leaks where the pipefitters installing the fittings failed to use new Teflon backup rings on all assemblies (not vendor related).

Since the previous new equipment supplied had performed without problems or non-compatible materials, Minnesota Power did not deem it necessary to perform a visit to the repair shop. Since the repairs took place over a 5 week period, it is unknown when exactly we would need to be there. The vendor did supply all of the necessary parts and labor to correct the issues at their expense as per the contract. Minnesota Power has informed the vendor that future use of their services will not take place unless we have assurances that the quality issues have been resolved.

We used an industry group to locate another vendor in Michigan. They appear to be a reputable company that many other utilities use. We will use them on a few non-critical items to evaluate their quality.

• *Did MP have any performance provision in the contract with the errant vendor to protect its shareholders and its ratepayers from any additional costs in case the vendor fails to perform?*

· *If so, what was the provision and how did MP pursue that provision? Were any amounts recovered by MP?*

· *If not, why didn't MP have such a provision in a contract pertaining to such a valuable resource?*

As noted above, the vendor did supply labor and material to resolve the problems they were responsible for. That is the limit of their contractual responsibilities.

Minnesota Power typically has various legal protections in our contracts. Purchase orders also have terms and conditions which help protect Minnesota Power and our stakeholders. As in this case, experience has shown that the potential recovery of costs associated with any claim (damages) is usually limited to the costs of the actual services performed by the vendor with the typical remedy being the cost of the repair or something less. Adding replacement power costs as a term of the contract is unrealistic and is a risk that no vendor would agree to. Our experience has been that if a vendor is held responsible for ALL costs (including replacement power) of a subsequent outage associated with a repair, no vendor would be willing to work on our equipment.

Nobody agrees to consequential damages if they have any assets. That language precludes the use of reputable companies. With the potential high cost of replacement power, the consequential damages for a $1000 repair could bankrupt a company.

• *Given that MP has already faced "quality control issues" with another vendor in the past, how did MP select the "Minnesota vendor" who installed the "incompatible o-rings?"*

The incompatible o-ring issue was specific to this particular rebuild and has not been an issue which has resulted in other unplanned outages. As noted above, the only other vendor where we had an issue, other than the time to get the repair/rebuild

> completed, was the vendor in Colorado which was subcontracted by another vendor. As noted above, the Minnesota vendor selected to perform this overhaul was chosen based on the new product we have purchased from them over the past 10 years as well as their local presence and technical support.
>
> • *How did MP ascertain the "reliability" of this vendor?*
>
> As noted above, the Minnesota vendor selected to perform this overhaul was chosen based on the type of product we have purchased from them over the past 10 years and their ability to meet our schedule as well as their local presence and technical support. This vendor was used by a number of other utilities, and we were not aware of any other complaints.
>
> • *Given that MP was fully aware that "viton was the only acceptable material" for the replacement o-rings, did MP have a representative at the repair facility to ensure that only the required material was used?*
>
> The specifications for all components used in the rebuild are known to the vendor. As this was a reputable vendor with much experience, there was no reason to add to the cost of the rebuild by having an engineer watch the entire rebuild process (5 weeks). While 20/20 hindsight is almost always perfect, this cost could not be justified for every rebuild or repair.

MP's November 9, 2012 narrative described the difficulties related to 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). Given the high cost of replacement power ($507,715), MP's argument that the additional cost of an engineer watching the entire rebuilt process could not be justified is not supported by the record.

It is difficult to accept that reputable companies would not be able to obtain liability insurance to stand behind their work on generation facilities. Even taking this assertion as a fact, it does not seem likely that utilities have no contractual remedies or recourse to hold companies that work on generation facilities accountable for their work.

In any case, MP's November 9, 2012 response still has not explained 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 "replacement o-rings made of materials incompatible with the fluids used in the hydraulic system."

Thus, the Department continues to recommend that the Commission require MP to refund $507,715 through an appropriate adjustment to MP's monthly FCAs following the date of the Commission's Order in this matter.

III.4.2. Failed Card in I/O Cabinet

The Department's initial review and recommendations[24]

MP's July 19, 2012 response to the Department's February 8, 2012 Information Request No. 62 identifies an "I/O card" as the equipment(s) which failure resulted in an unplanned outage of Young 2 in January 2011. According to MP, "[c]ard in I/O cabinet failed resulting in loss of control to hotwell, feed water system and turbine steam seal system."

MP's August 29, 2012 response to the Department's August 3, 2012 follow-up discovery stated in part:[25]

> Input/Output (I/O) cabinets contain multiple electronic circuit boards (cards) which are the interfaces between the DCS (computer that is used to control the boiler and/or other systems) and the field devices (flow sensors, level sensors, temperature sensors, etc). The cards control communications between the field devices and the DCS. The cards may be configured to control or monitor a specific device or may control or monitor many devices. I/O cabinets usually have multiple cards and the cards are not necessarily interchangeable. While each facility usually maintains an inventory of some of the more common cards, due to the specialized nature of some cards and the very infrequent failure of a card, it is not practical to have all types of cards in inventory.
>
> As with any complex electronic device the primary failure time is in the first few hours or days of operation – commonly referred to as infant mortality. Once an electronic device moves beyond this infant mortality window, failures tend to be very limited with devices typically being replaced only when they are obsolete or no longer supported by the manufacturer. In certain specific instances electronic devices can have a design flaw causing premature failure. Usually these design flaws result in a notice to users by the manufacturers similar to a recall notice for automobile defects.

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[24] Source: Department's September 26, 2012 Reply Comments at 32-33.

[25] Source: Attachment RC-3 of the Department's September 26, 2012 Reply Comments.

> The failure of this card could be best classified as a random failure. As with most failures of this type, in the absence of a specific defect reported by the manufacturer or industry users, and no realistic way to perform tests which would indicate a pending failure, card failures cannot be predicted. It should be noted that card failures can be difficult to diagnose which can lead to additional outage time.
> …
> Minnesota Power has not performed any separate analysis regarding whether replacement energy costs in fiscal year 2011 were prudently incurred.

According to MP's response to discovery, the only other similar incidents across MP's thermal fleet occurred at Boswell 2 (July 2006 and November 2009) and at Taconite Harbor (September 2007). MP's response above raises the following unanswered questions:

- Given that MP's thermal fleet faced similar card failures in 2006, 2007 and 2009, what were the lessons learned in 2007 or 2009?

- How did MP use these lessons learned in the selection of the manufacturer(s) and specific models of these cards? What criteria were used for the selection of the manufacturer(s) and specific models of the cards that failed during FYE11 to eliminate or, at least, alleviate the reoccurrence of card failures? Did they include a reliability criterion?

- Did MP use industry-wide forums or other sources of information to assess the respective reliability of these cards?

- What is the reliability history of the card that failed as well as similar cards? When was the failed card installed?

- How long did it take before MP was able to receive a replacement for the failed card? Would it have been more cost-effective to have a replacement card in inventory?

Because MP did not provide any analysis as to whether replacement energy costs in fiscal year 2011 were prudently incurred, and given the questions above, the Department concluded in our September 26 comments that MP did not demonstrate that the actions and events that gave rise to the need for the forced outage resulting from a failed card in I/O cabinet were reasonable.

Therefore, the Department recommended that the Commission require MP to refund to its ratepayers $377,746 for the replacement energy costs resulting from a failed card in I/O via an adjustment of MP's monthly FCAs following the date of the Commission's Order in this matter. Table 1 of MP's July 19, 2012 Reply Comments shows that MP's ratepayers were charged an additional $377,746 during FYE11 as a result of "failed card in I/O cabinet" on MP's system.

The Department's current review and recommendations

In its November 9, 2012 response comments, MP added the following information to the record:

> • *Given that MP's thermal fleet faced similar card failures in 2006, 2007 and 2009, what were the lessons learned in 2007 or 2009?*
>
> In the IR associated with this unplanned outage and several other IRs, Minnesota Power listed all known failures or problems with similar equipment which caused an unplanned outage. While there were failures or problems with similar equipment which resulted in an unplanned outage, they weren't necessarily identical. In this case, the cards in other years at other facilities were not failures of the **identical** card and occurred in a variety of unrelated systems for a variety of reasons. At any facility there are literally hundreds, sometimes thousands of "cards" in service in various devices and/or sub-systems. As mentioned in the associated IR (IR-146), due to the typical random nature of card failures, in the absence of a known failure history or vendor/industry alert it is difficult to predict a card failure and also difficult to determine which "cards" should be held in inventory.
>
> A lesson learned in this specific event is that "cards" can and do fail unexpectedly. As mentioned above, with most card failures the failure mode is totally random. They cannot be predicted or tested for. There is no applicable PM. In some applications redundancy has been designed into the control system, however this is not typical based on the industry history of failures and costs involved. In the absence of a known failure history, no vendor or industry alert and no other reason to expect a sudden card failure, there wasn't any way to predict this card failure.
>
> • *How did MP use these lessons learned in the selection of the manufacturer(s) and specific models of these cards? What criteria were used for the selection of the manufacturer(s) and specific models of the cards that failed during FYE11 to eliminate or, at least, alleviate the reoccurrence of card failures? Did they include a reliability criterion?*
>
> In this specific case, the lessons learned did not indicate any specific problem with the system, the card design or the manufacturer. Systems and devices are selected based on a variety of criteria related to the function (intended purpose), performance

history (reliability), vendor or manufacturer reputation, industry acceptance, units/systems installed and other appropriate criteria. Depending on the system, cards with specific functions can be included as “options”. In those cases you order the function rather than specifying the exact card, you get a card that provides that function. Since cards are components of a more complex device or sub-system, they are not and usually cannot be specified or evaluated as individual components – the system or device is evaluated in total.

• *Did MP use industry-wide forums or other sources of information to assess the respective reliability of these cards?*

Minnesota Power participates in a number of industry forums, associations, service organizations and other groups which provide information on reliability of equipment and systems common to our industry. These forums, associations and organizations provide information and discussion opportunities on all aspects of our industry well beyond the reliability of specific equipment or vendors.

While the failure of this card resulted in an outage with an impact to customers, unless there were multiple failures of the same card used in the same application, the level of concern for most groups would not rise to the alert level. Where there are multiple failures at multiple facilities an industry alert may be issued and this would likely be a discussion item at one or more of the industry group meetings.

Minnesota Power had not heard about any specific card failure issues at any industry gatherings. Discussions have occurred regarding whole systems or devices that have problems.

• *What is the reliability history of the card that failed as well as similar cards? When was the failed card installed?*

As mentioned in IR-146, this is the first known failure of this specific card in this specific application. Card failures are usually random. No specific problem has been previously identified with this specific card. As mentioned in IR-146, diagnosing a card failure can be the critical path in determining the length of repair. In this case a back-up system was in place, but due to the nature of the card failure, the automatic transfer did not occur.

> • *How long did it take before MP was able to receive a replacement for the failed card?*
>
> Once it was determined what the problem was (card failure), a replacement card from a back-up system was installed. The duration of the outage was not determined by the length of time needed to get a replacement card installed. The critical path for the outage was the time required to refill the boiler drum. When the card failed, the level of the water in the drum dropped below the OEM recommended acceptable restart level. To avoid a catastrophic drum failure, the drum needed to cool before it could be refilled. While the card problem initiated the outage, the drum level determined the duration of the outage.
>
> • *Would it have been more cost-effective to have a replacement card in inventory?*
>
> In this specific case a replacement card was available in a back-up system; however with the random nature of most card failures it is unrealistic to inventory a replacement for every card that is in service at a facility. Parts inventories are typically based on OEM recommendations and the mean time between failures (MTBF) if such a history is available. When a large number of a single card is used at any facility, backup card(s) may be inventoried.

The Department appreciates the additional information above. According to MP's discussion, the card at issue would not have had a known failure history, and its failure cannot be predicted or tested for. This situation appears to preclude any kind of quality control of such cards to prevent or alleviate their failure. In addition, a replacement card was available in a back-up system for this card.

As a result, the Department concludes that the actions and events that gave rise to the need for the forced outage at Young 2 as a result of a failed card in I/O cabinet were reasonable and prudently incurred. Therefore, the Department withdraws its previous recommendation that the Commission require MP to credit back the incremental replacement power costs ($377,746) to its ratepayers.

III.4.3. Incorrect Pump Rebuild Procedure

The Department's initial review and recommendations[26]

MP's July 19, 2012 response to the Department's February 8, 2012 Information Request No. 64 identifies a "Main Boiler Feed Pump" as the equipment(s) which failure resulted in an unplanned outage of Boswell Energy Center 3 in March 2011. According to MP, "[t]he unit was taken offline a number of times to correct a vibration problem and avoid a major outage for a rebuild. Ultimately the pump was taken out of service and it was found that rebuild procedure used by the outside contractor was incorrect for this pump."

MP's August 29, 2012 response to the Department's August 3, 2012 follow-up discovery stated in part:[27]

> The boiler feed pumps (BFP) on Boswell 3 and 4 are turbine driven 6 stage pumps that operate at over 5000 RPM. They have a discharge pressure of about 3000 psi. They are typically overhauled every 8-10 years. The overhauls are based on condition vibration more so than hydraulic performance. For that reason, all of the pumps have continuous vibration monitoring from Bently-Nevada (a global leader in this technology) to track over time any changes as well as to protect the asset in case of an upset.
>
> Minnesota Power has used 3 different venders for BFP overhauls for competitive bid purposes. We have had vibration issues with all three venders where the pump is not operating in a precise state as determined by API standards. It does not mean that reliability is in danger or that it does not function correctly, it is just not operating as precise as you would like.
>
> The pump on Boswell 3 had been installed and operating with some vibration. The routine inspections look at the bearings and seals for any problems, which was done without finding a problem. We have had some success in balancing out vibration by adding weights to the coupling. The coupling is used because there is no other access point to add balance weights. After several attempts to balance the coupling it was determined that balancing would not work on this pump. All of these attempts were made in low power demand times to avoid the lengthy outage which would be required to rebuild the pump.

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26 Source: Department's September 26, 2012 Reply Comments at 34-36.

27 Source: Attachment RC-4 of the Department's September 26, 2012 Reply Comments.

> Plans were made to remove the pump and turbine in March 2011 to resolve the problem before summer demand. The turbine rotor was removed, inspected and high speed balanced to remove it as a potential cause. The pump was disassembled with a member of the Minnesota Power reliability group inspecting every component as they were removed. That person then went with the pump to the contracted repair facility to follow the remainder of the disassembly.
>
> The root cause of the vibration was that as the pumps have been rebuilt over the years, the repair facilities have removed small amounts of material on the machined mating surfaces. Although they are typically only .005-.010" at a time, after a number of rebuilds we had slowly worked our way out of specification. The result of this learning was to write a repair specification for these pumps that is more comprehensive than what had been used previously. We also learned the value of having a Minnesota Power representative at the repair facility to audit their data while the pump was disassembled. The March 2011 rebuild resulted in a very good operating pump.
> …
> Minnesota Power has not performed any separate analysis regarding whether replacement energy costs in fiscal year 2011 were prudently incurred.

The Department indicated in its September 26 comments that, if the incident above were an isolated event, the Department would likely agree that the costs of the replacement power should be recovered from ratepayers. However, according to MP's response to discovery, several other similar failures across MP's thermal fleet occurred between July 2006 and June 2011 at Boswell 3 and Boswell 4, and at Taconite Harbor 1 (December 2008). Thus, the following questions remained unanswered:

- Given that MP's thermal fleet faced several other similar failures between July 2006 and June 2011, why did MP wait until the "March 2011 rebuild" to "write a repair specification for these pumps that is more comprehensive than what had been used previously?"

- Did MP use industry-wide forums or other sources of information available to attempt to resolve this issue?

- Given that MP's thermal fleet has already faced several other similar failures between July 2006 and June 2011, how did MP select the "outside contractor" where the contractors' work on the pump was "not operating in a precise state as determined by API standards"? How did MP ascertain the reliability of the contractor?

- Given that MP's thermal fleet has already faced several other similar failures between July 2006 and June 2011, did MP have language in its contract with the "outside contractor" to protect its shareholders and its ratepayers from any additional costs in case the contractor failed to perform? If so, were any amounts recovered by MP under the contract?

Because similar outages occurred at MP's other generation plants, the Department concluded that MP did not demonstrate that the actions and events that gave rise to the need for the forced outage resulting from an outside contractor using an incorrect pump rebuild procedure were reasonable.

Therefore, the Department recommended that the Commission require MP to refund to its ratepayers $646,830 (6-day unplanned outage at Boswell 3 in March 2011), through an appropriate adjustment of MP's monthly FCAs following the date of the Commission's Order in this matter, for the replacement energy costs resulting from an incorrect pump rebuild procedure used by an outside contractor on MP's system.

<u>The Department's current review and recommendations</u>

In its November 9, 2012 response comments, MP added the following information to the record:

> • *Given that MP's thermal fleet faced several other similar failures between July 2006 and June 2011, why did MP wait until the "March 2011 rebuild" to "write a repair specification for these pumps that is more comprehensive than what had been used previously?"*
>
> In the IR associated with this unplanned outage and several other IRs, Minnesota Power listed all known failures or problems with similar equipment which caused an unplanned outage. While there were failures or problems with similar equipment which resulted in an unplanned outage, the particular pump associated with this unplanned outage is specific to Boswell-3 and Boswell-4 (a total of three (3) pumps which are significantly different from other pumps in the fleet) and the root cause of the failure was unique. Once the root cause was determined, as stated in Minnesota Power's response to IR-148, the repair specification was updated for these pumps and is more comprehensive than what had been used previously addressing the recent finding.
>
> It is important to distinguish between failure and choice to repair. Among the three pumps of this type unique to Boswell 3 and 4, we have had pump failures. Prior to this issue, the failures have been

caused by coupling failures and check valve failures. These were outside of the pump assembly.

A more typical situation is having a pump running off specification. The critical items monitored are pump discharge pressure and flow, vibration and balance drum leak off. As the pump performance and/or vibration trend off desired conditions, the planning process to replace the pump begins. A typical removal and installation of a pump takes about a week. If there isn't any outage windows of that length scheduled, we have typically looked for ways to safely extend the operation to the next available outage window. On this particular pump, the performance was still adequate, but the vibration was higher than desired for a 5200 RPM application. Several attempts were made to add balance weights to the pump coupling to lower the vibration. Those attempts failed and the pump was scheduled for disassembly.

The exact problem noted with this particular pump was unlike previous problems. For that reason, as well as the operational problems it had been causing, particular attention was placed on the disassembly and inspection. Members of the Minnesota Power Reliability Group followed all of the disassembly in the field as well as the shop disassembly and reassembly. During the process, the most notable observance was that when typical pump rebuilds are performed, a machining cleanup is performed resulting in a change of .005-.010" in a dimension. The first time or second or third times this is done there are no notable changes in performance. These pumps have been rebuilt 6 or more times. At that point, the culmination of the tolerances is exceeded. From now on our specification will include welding, stress relief and machining to return the components to the precise original dimension.

• *Did MP use industry-wide forums or other sources of information available to attempt to resolve this issue?*

Minnesota Power participates in a number of industry forums, associations, service organizations and other groups which provide information on reliability of equipment and systems common to our industry. These forums, associations and organizations provide information and discussion opportunities on all aspects of our industry well beyond the reliability of specific equipment or vendors.

While the failure of this pump resulted in an outage with an impact to customers, pump repair/rebuilds are common maintenance activities in our industry. Unless there were multiple failures of the same pump used in the same application, or catastrophic failures, the level of concern for most groups would not rise to the alert level.

This is a very common pump in the utility industry. As noted above, failures are rare. Mean times between overhauls vary considerably. Industry average is 7-10 years between rebuilds. Some plants overhaul every 3 years "just to be sure". Failure mode analysis would suggest that doing that is a higher risk. To take a well running, well performing pump apart opens us up for infant mortality failure.

Our mean time between overhauls is closer to 5-7 years versus the 7-10 year industry average. Based on this pump, we have reviewed the way we decide on rebuilds, how the rebuild has performed including specifications as well as what is monitored and trended.

• *Given that MP's thermal fleet has already faced several other similar failures between July 2006 and June 2011, how did MP select the "outside contractor" where the contractors' work on the pump was "not operating in a precise state as determined by API standards"? How did MP ascertain the reliability of the contractor?*

As stated previously, in the IR associated with this unplanned outage and several other IRs, Minnesota Power listed all known failures or problems with similar equipment which caused an unplanned outage. While there were failures or problems with similar equipment which resulted in an unplanned outage the root cause of the failure was unique. Minnesota Power selects contractors based on a variety of criteria including our past experience with the contractor, feedback from other utilities and other information that may be available from sources such as trade organizations. Based on our experience, this contractor was capable of providing the services required and has done good work in the past. This specific issue as described only became apparent with the latest overhaul.

> Lessons learned are that we need to review the way we decide on when a rebuild is needed, establish repair specifications incorporating what we learned with this failure and put in place a program to evaluate how the rebuilt pump has performed including specifications as well as what is monitored and trended.
>
> • *Given that MP's thermal fleet has already faced several other similar failures between July 2006 and June 2011, did MP have language in its contract with the "outside contractor" to protect its shareholders and its ratepayers from any additional costs in case the contractor failed to perform? If so, were any amounts recovered by MP under the contract?*
>
> As stated in the response III.4.1 above, Minnesota Power typically has various legal protections in our contracts. Purchase orders also have terms and conditions which help protect Minnesota Power and our stakeholders. As in this case, experience has shown that the potential recovery of costs associated with any claim (damages) is usually limited to the costs of the actual services performed by the vendor with the typical remedy being the cost of the repair or something less.
>
> Adding replacement power costs as a term of the contract is unrealistic and is a risk that no vendor would agree to. Our experience has been that if a vendor is held responsible for ALL costs (including replacement power) of a subsequent outage associated with a repair, no vendor would be willing to work on our equipment.
>
> Nobody agrees to consequential damages if they have any assets. That language precludes the use of reputable companies. With the potential high cost of replacement power, the consequential damages for a $1000 repair could bankrupt a company.

MP's response above indicates that the Company took appropriate steps to address this issue on a going-forward basis. Further, there were no other such outages or derates of MP's facilities for a similar reason. Moreover, it is unlikely that MP could have taken steps to address this issue sooner than occurred in this instance. Thus, the Department concludes that MP has addressed this issue at this time.

Therefore, the Department withdraws its previous recommendation that the Commission require MP to credit back the incremental replacement power costs ($646,830) to its ratepayers.

III.4.4. Failed Insulators

The Department's initial review and recommendations[28]

MP's July 19, 2012 response to the Department's February 8, 2012 Information Request No. 65 appears to identify "insulators" as the equipment(s) which failure resulted in a 7-day unplanned outage of Boswell Energy Center 4 in June 2011. According to MP, "[i]nsulators for main conductors leading from the generator to the station transformer failed causing the conductor to ground to conduit. The conductor is supported in the middle of the metal conduit by the insulators."

MP's August 29, 2012 response to the Department's August 3, 2012 follow-up discovery stated in part:[29]

> In October 2010, MP hired GE (the OEM designer/manufacturer) to inspect the iso-phase bus. This is the enclosed duct between the generator and main transformer with limited access. The inspection was performed with a boroscope due to the limited access. While there had not been any problems with the system, as part of our ongoing preventative maintenance efforts, the inspection was performed. No problems were noted by GE that would affect reliability.
>
> The construction of the buss has the electrical conductor supported every 6 feet or so by insulators attached to the top of the duct /housing. The failure occurred at the connection between the insulator and the outer housing. When the first insulator failed, that increased the loading on adjacent insulators which ultimately led to the conductor contacting or arcing to the duct which resulted in a unit trip.
>
> As the OEM, GE was consulted and repairs were made to reconnect the insulators. It was also learned at this time that the "hanging conductor" design was not the most reliable and GE had a different design (retrofit) that supports the conductor off the bottom of the duct (supported rather than hung in the duct). It surprised us that they did not bring this up in 2010 when doing the visual inspection. To avoid the risk of a similar failure in the future, the retrofit was made during the planned outage in the spring of 2012. The updated design should prevent a reoccurrence according to GE.

[28] Source: Department's September 26, 2012 Reply Comments at 36-37.
[29] Source: Attachment RC-5 of the Department's September 26, 2012 Reply Comments.

> …
> No other outages or derates for issues (Failed Iso-Bus Insulators) of this nature were identified across the thermal fleet between July 2006 and June 2011.
> …
> Minnesota Power has not performed any separate analysis regarding whether replacement energy costs in fiscal year 2011 were prudently incurred.

As indicated in our September 26 comments, the Department concluded that MP's response indicates that the Company took appropriate steps to address this issue on a going-forward basis. Further, there were no other such outages or derates of MP's facilities for a similar reason. Moreover, it is unlikely that MP could have taken steps to address this issue sooner than occurred in this instance. Thus, the Department concludes that MP has addressed this issue at this time. MP should examine whether other changes are needed in similar facilities.

III.4.5. Incorrect Assembly of Water Pump Suction Valves

The Department's initial review and recommendations[30]

In its August 29, 2012 response to the Department's August 3, 2012 follow-up discovery, the Department noted a fifth issue that resulted in a 3-day forced outage at Boswell 4 on November 2010 due to a boiler circulating water pumps trip.

MP provided the following description of the actions and events that led to this forced outage: [31]

> 4A, 4B, 4C, 4D boiler circ pumps caused a boiler trip due to incorrect assembly of the water pump suction valves by the vendor. All four pumps had been reconditioned by the vendor during the major outage. The lantern ring was incorrectly assembled which required the lantern rings to be replaced along with the packing.
>
> See Attachment-2 for a list of outages and derates for similar boiler circulating pump failures that were reported across the thermal fleet during this reporting period.
>
> Based on similar issues with other pumps repaired by vendors, increased inspection work will be done both onsite and at the vendor's facility. Part of any vendor rebuild requires that the vendors has [sic] a copy of the most current drawing.

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[30] Source: Department's September 26, 2012 Reply Comments at 37-38.
[31] Source: Attachment RC-6 of the Department's September 26, 2012 Reply Comments.

MP's response indicates that several MP facilities faced similar outages. Because it does not appear that MP held the vendor adequately accountable for the work, the Department concluded that MP did not demonstrate that the actions and events that gave rise to the need for the forced outages resulting from the incorrect assembly of water pump suction valves by a vendor were reasonable.

Therefore, the Department recommended that the Commission require MP to refund the amount of $161,187 ($75,656 + $85,531) to its ratepayers through an appropriate adjustment of MP's monthly FCAs following the date of the Commission's Order in this matter.

The Department's current review and recommendations

In its November 9, 2012 response comments, MP added the following information to the record:

> As stated previously in the IR associated with this unplanned outage and several other IRs, Minnesota Power listed all known failures or problems with similar equipment which caused an unplanned outage. While there were failures or problems with similar equipment which resulted in an unplanned outage the root cause of the failure was unique.
>
> The Boswell-4 October 2010 unplanned outage related to the assembly of the BCP suction valves was a unique event. The suction valves on the four Boswell-3 BCPs are the only valves of that type in the entire Minnesota Power fleet and were the original 1970 era valves. The outage was initiated by a trip of the 4B BCP due to pump differential. During the investigation, packing on one of the valves was found to be leaking. Considering the age of the equipment and this observation, the decision was made to repack the valves to minimize the risk of a future unplanned outage. Due to the uniqueness of these valves and the difficulty of obtaining parts, a vendor experienced in these types of repairs was chosen to perform the work on site. The repairs required the unit to be cooled and drained which added to the length of the outage. Following the repair, it was discovered that one of the valves had been assembled incorrectly. Considering that only one of the repacked valves had an issue, it was determined that the vendor had the correct specification and drawings and the "failure" was the result of an assembly error.
>
> We have used this particular contractor for many different jobs over the past 7-10 years. This is the first time we are aware that they made this type of mistake. They have done valve disassembly, machining, and assembly many times. Their

> performance had been exceptional so there wasn't any indication they required any specific close monitoring. Based on this single occurrence on a single valve, our process and our choice of contractor would not change beyond addressing this specific event and reminding the contractor of this specific issue before having them provide future services.
>
> Regarding any potential claims, as stated in response III.4.1 above, Minnesota Power typically has various legal protections in all of our contracts. Purchase orders also have terms and conditions which help protect Minnesota Power and our stakeholders. Experience has shown that as well written as some of these provisions may be, the potential recovery of costs associated with any claim (damages) is usually limited to the costs of the actual services performed by the vendor. The typical remedy is the cost of the repair or something less. Adding replacement power costs as a term of the contract is unrealistic and is a risk that no vendor would agree to. Our experience has been that if a vendor is held responsible for ALL costs (including replacement power) of a subsequent outage associated with a repair, no vendor would be willing to work on our equipment.

As shown above, in its August 29, 2012 response to discovery form the Department, MP stated:

> Based on similar issues with other pumps repaired by vendors, increased inspection work will be done both onsite and at the vendor's facility. Part of any vendor rebuild requires that the vendors has [sic] a copy of the most current drawing.

Despite these previous quality control issues, MP's November 9, 2012 response comments do not show that MP had a reasonable system or any system in place in place to prevent or alleviate this particular vendor's error. MP did not discuss any option to prevent or alleviate this assembly error, besides alluding to "specific close monitoring." The record does not show whether MP analyzed or even considered at least the option of specific monitoring of the assembly of the water pump section valves.

In any case, MP's November 9, 2012 response still has not explained 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 incorrect assembly of water pump suction valves, instead of the utility's shareholders and/or the utility's management (employees with the decision rights and specific knowledge regarding energy costs).

Thus, the Department continues to recommend that the Commission require MP to refund $161,187 through an appropriate adjustment to MP's monthly FCAs following the date of the Commission's Order in this matter.[32]

IV. DEPARTMENT ANALYSIS – SHARING LESSONS LEARNED REGARDING FORCED OUTAGES

The Department's review and recommendations[33]

1. Background

In its April 6, 2012 Order in Docket Nos. E99/AA-09-961 and E999/AA-10-884, the Commission requested Interstate Electric, Minnesota Power, Otter Tail and Xcel Electric to comment on sharing lessons learned regarding the handling of forced outages. The Commission also requested the IOUs to discuss among themselves what kind of information sharing would be beneficial. The IOUs were required to provide in supplemental filings to their fiscal-year 2011 AAA reports, in Docket No. E-999/AA-11-792, and in future AAA reports, a simple annual identification of forced outages and a short discussion of how such outages could have been avoided or alleviated.

On February 8, 2012, the Department requested the IOUs to provide preliminary comments on sharing the lessons learned regarding forced outages and, as part of the response, to include the type of data, format and level of explanation needed to help each utility avoid or alleviate the impact of forced outages.[34]

The Department appreciated the wealth of sources information sharing provided by Xcel Electric and Interstate Electric that may benefit all IOUs and noted that the IOUs are apparently using several forums to benefit from lessons learned regarding outages.

Based on our review of the IOUs' responses to discovery requesting the IOUs to identify and fully explain in understandable terms all equipment and equipment failures that resulted in forced outages, to identify all such equipment failures after June 2006, and to describe all steps taken to alleviate any reoccurrence of such failures, the Department concluded that there is a useful role for information sharing among the IOUs regarding lessons learned about forced outages, including the specific actions utilities described in this proceeding for minimizing risks of human error, CO explosions and other events.[35]

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32 The Department notes that MP did not object in its November 9, 2012 Response Comments to the Department's calculation of the increased energy costs resulting from the forced outage due to the incorrect assembly of water pump suction valves.

33 Source: Department's September 26, 2012 Reply Comments at 42-43.

34 IOUs' responses are provided under Attachment E20 of the Report.

35 See forced outages discussion in Section III of the Report.

However, it appears that, despite the availability of many relevant sources of information regarding plant operations discussed above, a utility had still to discover on its own during FYE11 that a new emission control equipment, Selective Catalytic Reduction (SCR), which reduces nitrogen oxide emissions, could cause an outage as a result of the screens above the SCR getting plugged with fly-ash. The utility developed “air-rake style cleaning tools for online cleaning of the SCR” to alleviate a reoccurrence of this issue. Another utility had also to discover on its own that a build-up of carbon monoxide in a coal bunker can result in an explosion. The utility added carbon monoxide monitors to alleviate a reoccurrence of this issue.

The Department’s premise was that sharing this information among the IOUs can provide, in addition to participation to other industry forums, a simple and cheap way to avoid costly mistakes, including human errors. Therefore, the Department requested the IOUs to discuss and propose in reply comments a mechanism for some level of information sharing that would help the IOUs alleviate the reoccurrence of similar forced outages.

2. Department Review of IOUs’ Response

The Department’s review of the IOUs’ reply comments indicates that the IOUs disagree with the Department’s premise that some level of information sharing among the IOUs can provide, in addition to participation in other industry forums, a simple and cheap way to avoid costly mistakes, including forced outages resulting from human errors.

OTP’s response summarizes the position of all four IOUs regarding the Department’s proposal:[36]

> DOC Request: The Department requests the IOUs to discuss and propose in reply comments a mechanism for some level of information sharing that would help the IOUs alleviate the reoccurrence of similar forced outages.
>
> As noted in comments filed by OTP and the other utilities during discovery, information sharing with regard to plant operations is common, and takes place in a number of ways including: direct communications between utilities; participation in industry forums; attendance at technical workshops and conferences; communications with equipment suppliers; and through industry publications and whitepapers.
>
> While a formal information sharing program among the Minnesota IOUs may provide some benefit, OTP believes that maintaining active participation in industry groups to share information with a larger number of utilities and plant operators is a more efficient

[36] OTP’s July 17, 2012 Reply Comments at 2.

> approach to sharing and gathering information specific to each utility's unique generation portfolio.

The Department notes the IOUs' position that the utilities have all of the necessary venues for sharing forced outage information. As a result, the Department notes that in the future the IOUs will be expected to be aware of causes of forced outages before they request recovery of replacement energy costs and will be expected to identify and implement in-time solutions from the lessons learned from another IOU's forced outages.

V. DEPARTMENT ANALYSIS – XCEL ELECTRIC'S WIND CURTAILMENTS

The Department's initial review and recommendations[37]

Background

As discussed further in the Report (pp. 11-14), the Department requested Xcel Electric to explain why it had not shifted curtailments from the wind farms still receiving the production tax credits (PTC) to those for which the PTC has ended (Lake Benton I and/or Lake Benton II) to reduce total curtailment payments for FYE11.

Xcel Electric's response to discovery from the Department identified two reasons why it had not adjusted its curtailments to reduce curtailment payments.[38] One reason was due to situations where it would not be technically possible for either Lake Benton I or Lake Benton II to address the need for curtailment. The other reason was due to the rotational system Xcel Electric uses to curtail wind generation from the Buffalo Ridge area.

Xcel Electric's response related to the use of a rotational system stated in part that:

> 2. The Company has identified 2,297 MW hours during FY2011 where the Lake Benton II Wind Golf project could have been curtailed instead of the Chanarambie Power Partners, Moraine Wind or Fenton Wind Projects. It should be clarified that the 2,297 MW hours represent the amount of curtailment that could have been reduced on the Fenton, Moraine and Chanarambie Power Partners projects combined.
>
> 3. Please note that because the Lake Benton I and/or the non-Golf Lake Benton II projects could not have reduced the FYE2011 Fenton Wind curtailments, this response addresses only why curtailment at the 41.25 MW Lake Benton II Wind "Golf" project

[37] Source: Department's September 26, 2012 Reply Comments at 38-41.

[38] Source: Attachment E9 of the Report.

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-15-611

Dated this 30th day of December 2016

/s/Sharon Ferguson

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