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Minnesota Public Utilities Commission

Staff Briefing Papers

Meeting Date: **April 12 & 14, 2016 .... Agenda Item # ___**

Companies: All Commission-Regulated Electric Utilities

Docket Nos. E-999/CI-03-802
In the Matter of an Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments

E-999/AA-12-757
In the Matter of the Review of the 2011-2012 Annual Automatic Adjustment Reports for All Electric Utilities

E-999/AA-13-599
In the Matter of the Review of the 2012-2013 Annual Automatic Adjustment Reports for All Electric Utilities

E-999/AA-14-579
In the Matter of the Review of the 2013-2014 Annual Automatic Adjustment Reports for All Electric Utilities

Issues:

1. Should the Commission accept the electric utilities' annual automatic adjustment (AAA) reports for fiscal-years 2012, 2013, and 2014?

2. Should the Commission accept the Minnesota Department of Commerce's uncontested comments, conclusions and recommendations for fiscal-years 2012, 2013, and 2014?

3. Should the Commission defer taking action on Xcel's recovery of replacement powers costs during the unplanned, forced outage of Sherco Unit 3?

4. How should the Commission address requests for recovery of replacement power costs charged through the FCA during unplanned, forced outages?
    a. Reporting Requirements
    b. Sharing Lessons Learned
    c. Contractor Accountability for Replacement Power Costs & Supplier Warranties

5. Should the Commission require investor-owned electric utilities (IOUs) to obtain Business Interruption Insurance (BII)?

6. Should the Commission disallow fifty percent (or $37,085) of the difference between OTP's May 2013 Revenue Sufficiency Guaranty (RSG) charges and the average RSG monthly charges for this time period?

7. Were Minnesota Power's rail transportation costs for fiscal-year 2014 reasonable?

8. Should the electric IOUs' fuel clause adjustment mechanisms be reformed, and if so, how, and what are the next steps?

9. Should the Commission close its investigation into the appropriateness of continuing to permit electric energy cost adjustments, Docket No. E-999/CI-03-802?

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Relevant Documents

Investigation into Electric Energy Cost Adjustments - Docket No. E-999/CI-03-802

PUC – Order Approving Proposal, Requiring Compliance Filing, And Opening Investigation into the Continuing Usefulness of Fuel Clause Adjustments for Electric Utilities .... Jun. 4, 2003
PUC Staff – Briefing Papers .... Nov. 6, 2003
PUC – Order Determining Scope and Setting Procedural Framework .... Dec. 19, 2003

<u>Comments</u>
Xcel .... Feb. 20, 2004
MP .... Feb. 19, 2004
OTP .... Feb. 20, 2004
IPL .... Feb. 16, 2004
DEA .... Feb. 19, 2004

<u>Reply Comments</u>
MP .... Apr. 1, 2004
MP Supplemental (TS) .... Jun. 11, 2004
IPL .... Apr. 2, 2004
DOC (TS) .... Apr. 5, 2004
DOC – Addendum and Revised Pages to Reply Comments (TS) .... Apr. 16, 2004

<u>Notice for Comments</u>
PUC .... Mar. 30, 2007

Comments

Xcel .... Apr. 30, 2007
MP.. Apr. 30, 2007
OTP .... Apr. 30, 2007
IPL - Part 1 & 2.. Apr. 30, 2007
DEA .... Apr. 30, 2007
OAG – Comment & Part 2, Exhibit E .... Apr. 30, 2007
DOC .... Apr. 30, 2007

Reply Comments

Xcel .... May 15, 2007
MP .... May 15, 2007
OTP... May 15, 2007
IPL .... May 15, 2007
DOC .... May 15, 2007
Minnesota Chamber of Commerce .... July 19, 2007

Notice for Comments

PUC .... Aug. 16, 2007

Comments

Xcel... Sep. 28, 2007
MP .... Sep. 28, 2007
IPL... Sep. 28, 2007
DEA .... Sep. 19, 2007
OAG (resubmittal of Apr. 30, 2007 comments) .... Sep. 28, 2007
DOC... Sep. 28, 2007

Reply Comments

OTP .... Oct. 30, 2007
DOC .... Oct. 30, 2007
Minnesota Chamber of Commerce .... Oct. 30, 2007

Performance-based Gas Purchasing Plans – Docket No. G-008/CI-98-1219

PUC - Report on Performance-based Gas Purchasing Plans,
pursuant to Minn. Stat. § 216B.167, subd. 7 (1995) .... Feb. 3, 1999

2012 Electric Annual Automatic Adjustment Reports - Docket No. E-999/AA-12-757

Annual Review

Department of Commerce (DOC)
Report (TS) .... Jun. 5, 2013
Attachments E1 through E12 ....Jun. 5, 2013

Reply Comments

Xcel (TS)... Aug. 26, 2013
Interstate Power .... Sep. 20, 2013

Minnesota Power (TS) .... Sep. 20, 2013
Otter Tail Power (TS) .... Sep. 20, 2013
Office of Attorney General (also filed in #11-792) .... Sep. 20, 2013
Minnesota Chamber of Commerce .... Sep. 20, 2013
Minnesota Large Industrial Group (also filed in #11-792) .... Sep. 20, 2013
MP – Letter (also filed in #11-792 & 03-802) .... Sep. 12, 2013
IPL – Letter (also filed in #11-792) .... Sep. 16, 2013

Procedural Comments
PUC Staff Briefing Papers (also filed in #11-792) .... Oct. 24, 2013
DOC – Letter .... Nov. 1, 2013

Response Comments & Comments
DOC (TS) .... Dec. 31, 2014
MLIG .... Dec. 31, 2014
OAG (also filed in #13-599) .... Dec. 31, 2014
Otter Tail .... Dec. 31, 2014

Additional Reply Comments
MLIG .... Feb. 11, 2015
OAG (TS) (also filed in #13-599) .... Feb. 11, 2015
Otter Tail .... Feb. 11, 2015
Xcel Energy .... Feb. 11, 2015
Minnesota Power .... Feb. 11, 2015

2013 Electric Annual Automatic Adjustment Reports - Docket No. E-999/AA-13-599

Annual Review
DOC - Annual Review & Report (TS) .... Sep. 16, 2014

Comments
OAG – Comments (TS) .... Sep. 26, 2014
Attachments A, B & C (TS) .... Sep. 26, 2014

Reply Comments
Xcel - (TS) .... Nov. 10, 2014
Interstate Power .... Nov. 10, 2014
Minnesota Power .... Nov. 10, 2014
Otter Tail Power (TS) .... Nov. 10, 2014

Response Comments
DOC .... Dec. 31, 2014
OAG (also filed in #12-757) .... Dec. 31, 2014
Otter Tail .... Dec. 31, 2014

Additional Reply Comments
Otter Tail .... Feb. 11, 2015

Interstate .... Feb. 11, 2015
MP .... Feb. 11, 2015
Xcel .... Feb. 11, 2015
OAG (TS) (also filed in #12-757).. Feb. 11, 2015

2014 Electric Annual Automatic Adjustment Reports - Docket No. E-999/AA-14-579

Annual Review
DOC - Annual Review & Report (TS) .... May 19, 2015

Reply Comments
Xcel (TS).. Jun. 19, 2015
Minnesota Power (TS) .... Jun. 18, 2015
Otter Tail Power (TS) .... Jun. 19, 2015
Interstate Power .... Jun. 19, 2015
Minnesota Large Industrial Group .... Jun. 19, 2015

Response Comments
DOC - Response Comments & Attachment 1 (TS) .... Aug. 26, 2015
Attachment 2, Part 1 of 9 (TS).. Aug. 26, 2015
Attachment 2, Part 2 of 9 (TS).. Aug. 26, 2015
Attachment 2, Part 3 of 9 (TS).. Aug. 26, 2015
Attachment 2, Part 4 of 9 (TS).. Aug. 26, 2015
Attachment 2, Part 5 of 9 (TS).. Aug. 26, 2015
Attachment 2, Part 6 of 9 (TS).. Aug. 26, 2015
Attachment 2, Part 7 of 9 (TS).. Aug. 26, 2015
Attachment 2, Part 8 of 9 (TS).. Aug. 26, 2015
Attachment 2, Part 9 of 9 (TS).. Aug. 26, 2015

Response to Reply Comments
Minnesota Power (TS) .... Oct. 2, 2015

Reply Comments
DOC (TS).. Dec. 14, 2015
DOC .... Feb. 24, 2016

The attached materials are workpapers of the Commission Staff. They are intended for use by the Public Utilities Commission and are based upon information already in the record unless otherwise noted.

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April 5, 2016

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Statement of the Issues

- Should the Commission accept the electric utilities' annual automatic adjustment (AAA) reports for fiscal-years 2012, 2013, and 2014?

- Should the Commission accept the Minnesota Department of Commerce's uncontested comments, conclusions and recommendations for fiscal-years 2012, 2013, and 2014?

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    - Reporting Requirements
    - Sharing Lessons Learned
    - Contractor Accountability for Replacement Power Costs & Supplier Warranties

- Should the Commission require investor-owned electric utilities (IOUs) to obtain Business Interruption Insurance (BIS)?

- Should the Commission disallow fifty percent (or $37,085) of the difference between OTP's May 2013 Revenue Sufficiency Guaranty (RSG) charges and the average RSG monthly charges for this time period?

- Were Minnesota Power's rail transportation costs for fiscal-year 2014 reasonable?

- Should the electric IOUs' fuel clause adjustment mechanisms be reformed, and if so, how, and what are the next steps?

- Should the Commission close its investigation into the appropriateness of continuing to permit electric energy cost adjustments, Docket No. E-999/CI-03-802?

Background

The Commission conducts an annual review of the electric utilities' automatic adjustment of charges for the previous twelve-month period (i.e. the fiscal-year from July 1 through June 30).[1] This review occurs after the utilities file annual automatic adjustment (AAA) of charges reports on September 1 of each year, and, after the Minnesota Department of Commerce-Division of Energy Resources (Department) submits its analysis of the AAA reports.

[1] Minn. Rules, part 7825.2850. Annual Commission Meeting. The Commission shall annually conduct a separate meeting to review the automatic adjustment of charges reported herein.

The utilities' AAA reports are prepared in accordance with the Commission's automatic adjustment of charges rules, i.e. Minn. Rules, parts 7825.2390 through 7825.2920. The AAA reports also contain compliance information required by Commission orders in previous AAA dockets and other Commission proceedings. (For example, compliance information required by the orders in the proceedings that authorized transfer of control of utility transmission assets to MISO,[2] and the orders authorizing the pass-through of MISO ancillary service market (ASM) costs and revenue through the fuel clause adjustment mechanisms.)[3]

Annual Automatic Adjustment Reports

On or about September 1st of 2012, 2013, and 2014, all of the Commission-regulated electric utilities except Northwestern Wisconsin Electric Company[4] submitted Annual Automatic Adjustment (AAA) reports covering the twelve-month periods from July 1, 2011 through June 30, 2012 (i.e. fiscal-year 2012), July 1, 2012 through June 30, 2013 (i.e. fiscal-year 2013), and July 1, 2013 through June 30, 2014 (i.e. fiscal-year 2014), in these dockets.[5]

The following electric utilities submitted AAA reports:

- Dakota Electric Association (DEA)
- Interstate Power and Light Company, an Alliant Energy Company (Interstate)
- Minnesota Power (MP)
- Northern States Power Company, a Minnesota corporation d/b/a Xcel Energy and wholly owned subsidiary of Xcel Energy Inc. (Xcel)
- Otter Tail Power Company (Otter Tail)

Department Review of the Fiscal-Year 2012, 2013, and 2014 AAA Reports

On June 5, 2013, the Department submitted its Review of fiscal-year 2012 Annual Automatic Adjustment Reports for Electric Utilities (Review or Report), in Docket No. E-999/AA-12-757. On September 16, 2014, the Department submitted its Review of fiscal-year 2013 Annual Automatic Adjustment Reports for Electric Utilities (Review or Report), in Docket No. E-999/AA-13-599. On May 19, 2015, the Department submitted its Review of fiscal-year 2014 Annual Automatic Adjustment Reports for Electric Utilities (Review or Report), in Docket No. E-999/AA-14-579.

The Department's Reviews cover all of the electric utilities' AAA reports, AAA-related compliance filings, and other reports requested by the Commission in various orders.

On pp. 3-4 of the Department's 2012 Review, p. 3 of the 2013 Review, and on pp. 2-3 of the

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[2] Docket Nos. E-002/M-00-257, E-001/PA-01-1505, E-015/PA-01-539, and E-017/PA-01-1391
[3] Docket No. E-001,015,002,017/M-08-528
[4] On December 18, 2001, the Commission granted Northwestern Wisconsin Electric Company (NWEC) a variance from the annual reporting requirements in the automatic adjustment rules. This variance has no expiration date. (Docket No. G,E-999/AA-00-1027)
[5] Copies of the electric utilities' fiscal-year 2012, 2013, and 2014 annual automatic adjustment reports are available through the "eDockets" system at (https://www.edockets.state.mn.us/EFiling/search.jsp)

2014 Review, the Department summarized the electric utilities' fuel cost projections for the next five years on a $ per MWh basis and as a year-to-year percentage change in cost. The electric utilities' reported a wide range of fuel costs and annual percentage changes because each of the utilities' generation fleet, mix of PPAs, and other factors differ from utility-to-utility. (The utilities designated this information as non-public data.)

In each year's Review, the Department provides a summary comparison for each utility of the total actual costs of fuel purchased during the year (including purchased power costs) to the fuel costs recovered through automatic adjustments.[6]

Summary of Automatic Fuel Adjustments - Fiscal Year 2012 (Adapted from Table 4, DOC, June 5, 2013 Review, p. 22)				
Utility	Fuel Cost Recovered ($)	Fuel Cost ($)	Over-Recovery/ (Under-Recovery) ($)	Over-Recovery/ (Under-Recovery) (%)
DEA	$ 139,947,225	$ 137,938,728	$ 2,008,497	1.46%
IPL	$ 16,073,383	$ 17,125,241	($ 1,051,857)	(6.14%)
MP	$ 168,317,955	$ 172,309,289	($ 3,991,334)	(2.32%)
OTP	$ 45,472,638	$ 46,635,031	($ 1,162,393)	(2.49%)
Xcel	$ 820,658,807	$ 835,081,488	($ 14,422,681)	(1.73%)
Total	$ 1,190,470,008	$ 1,209,089,777	($ 18,619,769)	(1.54%)

Summary of Automatic Fuel Adjustments - Fiscal Year 2013 (Adapted from Table 2, DOC, September 16, 2014 Review, p. 24)				
Utility	Fuel Cost Recovered ($)	Fuel Cost ($)	Over-Recovery/ (Under-Recovery) ($)	Over-Recovery/ (Under-Recovery) (%)
DEA	$ 141,371,168	$ 140,557,100	$ 814,068	0.58%
IPL	$ 18,203,624	$ 17,624,531	$ 579,094	3.29%
MP	$ 187,342,761	$ 186,736,616	$ 606,145	0.32%
OTP	$ 50,482,963	$ 50,027,392	$ 455,570	0.91%
Xcel	$ 894,345,964	$ 883,488,131	$ 10,857,833[7]	1.23%
Total	$ 1,291,746,480	$ 1,278,433,770	$ 13,312,710	1.04%

[6] DEA's total includes capacity in addition to fuel. Xcel Electric's data is highlighted in the calculations below because the Company was granted a variance to charge FCA rates based on Xcel's forecast of fuel costs in the upcoming month, rather than the two-month average cost per kWh required by Minnesota Rules, and the Company adjusts its rates to refund or recover previous over- and under-recoveries of its energy costs through a monthly (2 lag-month) true-up.
[7] Does not include Saver's Switch true-up adjustment.

Summary of Automatic Fuel Adjustments - Fiscal Year 2014 (Adapted from Table 2, DOC, May 19, 2015 Review, p. 30)				
Utility	Fuel Cost Recovered ($)	Fuel Cost ($)	Over-Recovery/ (Under-Recovery) ($)	Over-Recovery/ (Under-Recovery) (%)
DEA	$ 147,088,516	$ 149,582,605	($ 2,494,089)	(1.67%)
IPL	$ 19,229,800	$ 19,912,643	($ 682,843)	(3.43%)
MP	$ 193,435,652	$ 195,704,305	($ 2,268,653)	(1.16%)
OTP	$ 53,873,959	$ 55,705,064	($ 1,831,105)	(3.29%)
Xcel	$ 941,003,558	$ 926,441,508	$ 14,165,747[8]	1.57%
Total	$ 1,354,631,485	$ 1,347,346,125	$ 7,285,360	0.54%

The main focus of the Department's Reviews for fiscal-years 2012, 2013 and 2014 (as it has been in recent years) is the pass-through and allocation of Midwest Independent Transmission System Operator (MISO) costs and revenues in the utilities' fuel clause adjustment mechanisms. Throughout its Reviews, the Department focused on each IOU's efforts to minimize energy and transmission costs for Minnesota retail consumers. Please see pp. 25-47 of the Department's FY-2012 Review, pp. 27-52 of the Department's FY-2013 Review, and pp. 33-66 of the Department's FY-2014 Review for the Department's discussion of the effects of the MISO Day 1 and 2 markets on Minnesota ratepayers and for a discussion of the MISO ancillary services market (ASM).

In Attachment E11 of the FY2012 Review ad Attachment E15 of the FY2014 Review, the Department provided a comparison of each utility's average residential customer's electric bill for the most recent calendar year.

Throughout its Review, the Department's analysis was comprehensive and thorough. The Department's initial recommendation is at the end of its Review. In subsequent filings, the Department revised its recommendations. The attachments to these briefing papers contains a summary of the Department's uncontested recommendations for each fiscal year.

Several issues remain in contention in these dockets. The main issue is whether the fuel clause adjustment mechanism still serves a useful purpose and should continue or whether the Commission should look at alternatives. This question has been the subject of discussion and investigation off-and-on for over fifteen years and there continues to be significant disagreement. Absent reform of the fuel clause mechanism, the Department has made several recommendations for addressing and monitoring the cost of replacement purchased power during unplanned (forced) outages.

Parties' Comments

The parties to each year's annual review of the automatic adjustment of charges for the recovery of fuel and purchased power costs have participated in several rounds of comments each year. The additional information and explanations provided in these additional rounds of comments

[8] Does not include Saver's Switch true-up adjustment.

has further developed the record and has addressed most of the issues and concerns raised by the Department.

PUC Staff Comment

Except for the issues discussed or noted in the briefing papers, all of the utilities appear to have accepted and agreed to the Department's non-contested recommendations. Staff has compiled a list of these recommendations from the Department for each year. The three lists of recommendations do not include the supporting or qualifying comments or the conclusions that were in the Department's various recommendations. (Please see the Attachments A, B & C to the decision alternatives at the end of the briefing papers.)

The Commission could generally accept the Department's comments and conclusions, and specifically order these three lists of decision points. Alternatively, the Commission could accept the Department's comments, conclusions, and recommendations without including them in its order[s]. Staff does not believe there is any substantive difference between these alternatives, however, the list of uncontested decision alternatives in the attachment may provide a clearer record of what the Commission is requiring parties to do in the future.

Staff also believes a catch-all request for the Department to continue its monitoring and review of relevant issues in its next annual review of the AAA reports, and related compliance filings, would be appropriate.

Sherco Unit 3 – Extended Plant Outage

On November 19, 2011, a catastrophic event at Xcel's Sherco 3 generating unit prevented the unit from producing power until repair was completed and the unit was released for MISO operations on October 28, 2013. During this period, it was necessary for Xcel to replace the power no longer supplied by Sherco 3 either through dispatch of Xcel's other generating plants or through purchases of replacement power through the MISO market.

The Department recommended in its Review of the FY-2012 AAA reports, in Docket No. E-999/AA-12-757, that the Commission preserve the determination of cost recovery related to the replacement power costs related to the Sherco Unit 3 extended plant outage until the next AAA filings were made for FY-2013 (in docket #13-599). Xcel agreed with this recommendation.

Department of Commerce

(DOC 2013 AAA Review – Docket #13-599, September 16, 2014, pp. 18-24, the following has been copied, excerpted or adapted, mostly verbatim, from the Department's Review)

The Sherco Unit 3 (Sherco 3) extended plant outage began on November 19, 2011. Sherco 3 was not released for MISO dispatch until October 28, 2013, nearly two year later. Xcel's FCA (fuel clause adjustment) filings identified continued outages at Sherco 3 between November 15 and December 30, 2013 as being most problematic. As a result, a significant level of replacement power costs were charged to ratepayers via Xcel's FCA for the period of November 2011 to October 2013.

This issue was discussed extensively in Xcel's 2013 rate case, in docket #13-868. In that rate case, the issue of replacement power costs was identified as an issue that should be addressed in this proceeding, in docket #13-599.

The Department analyzed the prudency of Sherco 3 outage-related additional fuel costs based on an assessment of whether Xcel's actions caused the Event and whether Xcel had (or should have had) knowledge about the potential for such an event and learned from past similar "failures" by taking specific preventive steps.

On October 21, 2013, Xcel filed a Root Cause Analysis Report. On November 15, 2013 the joint owners and insurers of Sherco 3 filed a joint complaint against General Electric to recover costs associated with this Event, and on January 27, 2014 they amended the complaint.

Based on the record to date (as of September 16, 2014), the Department concluded that the Event was likely caused by the original design of the finger pinned blade attachments, not by abnormal operating conditions or maintenance practices. The Department also concluded that GE had specialized knowledge about the risks of SCC-related failure associated with the finger dovetail in the LP turbine but failed to share this information with Xcel and SMMPA.

The Department noted that additional facts may develop during this legal process through either briefs or discovery that are not available to date, and suggested that the Commission may want to retain the right to revisit this issue if additional facts develop that contradict the record to date.

The Department also reminded the Commission that it has the authority to make refunds and changes in allocations between retail and wholesale customers in the AAA filing.

OAG

(OAG, Comments, Docket #13-599, September 26, 2014, pp. pp. 1-10, the following has been copied, excerpted or adapted, mostly verbatim, from the OAG's Comments)

The OAG believes the Commission should continue to defer taking action or approving Xcel Energy's replacement power costs related to Sherco 3 because:

- Xcel has taken the position that third-parties are liable for those costs due to the circumstances of the Sherco 3 failure and is engaged in ongoing litigation regarding resolution of those issues and, at the appropriate time, the Commission may order modification of Xcel's automatic adjustment of charges as necessary to balance and protect ratepayer interests.

OAG does not believe the Commission has all of the necessary information at this time to make an equitable and informed decision as to the amount of and responsibility for Xcel's replacement power costs that resulted from the Sherco 3 event.

The Commission should notify Xcel of its reservation of this issue for future investigation (and, if appropriate, action), and require that Xcel continue to provide information necessary to thoroughly analyze this issue.

Additionally, the Commission may wish to consider the question of whether the annual AAA review docket is the only context in which it wants to receive updates on this issue, or if a separate docket to monitor developments in the litigation with General Electric and the other defendants is now appropriate in order to protect ratepayer interests.

In its June 2013 report regarding Xcel's 2012 AAA filing (in docket #12-757), the Department recommended "that the Commission preserve the determination of cost recovery related to the replacement power costs related to the Sherco Unit 3 extended plant outage until…full information about the cause of the extended plant outage is available and is able to be reviewed by the Department and other interested parties." The OAG supports this recommendation and takes the position that subsequent events have only served to make it even more clear that "full information about the cause of the extended plant outage" is not yet available and the Commission is not in a position to make a determination on the appropriateness of these costs.

As to the issue of causation, the Department relied solely on Xcel's Root Cause Analysis Report and accepted Xcel's consultant's conclusions as "the record to date," without further fact-finding or expert analysis. Similarly, as to the issue of foreseeability, the Department also appears to base its conclusion solely on Xcel Energy's Root Cause Analysis report and the allegations in Xcel's lawsuit against the turbine manufacturer.

OAG believes the Commission should defer action until more information is available regarding the resolution of these legal claims, which directly affect ratepayer interests. The Department's prudency review is premature and based on an inadequate record to support its conclusions. The record currently available does not support conclusions regarding liability for those replacement power costs. Alternatively, if the Commission does not want to wait for resolution of the litigation of these questions, it could commence its own investigation and process to answer those questions. In either event, the Commission does not have the necessary information at this time.

- The method of calculation and total amount of the replacement costs are disputed.

The OAG does not believe that full information about the cause of the extended plant outage is available and the Commission is not in a position to make a determination on the appropriateness of the replacement power costs. The DOC's conclusions regarding causation and foreseeability of the failure are premature and based on analysis of inadequate information.

For these reasons, the OAG believes the Commission should (1) continue to defer approval of the replacement power costs until more information is available regarding the resolution of the legal claims, and (2) clarify that it may act in the future to remedy any inequities for ratepayers.

Alternatively, if the Commission does not want to wait for resolution of the litigation of these questions, it could commence its own investigation and process to answer those questions. In either event, the Commission does not have the necessary information at this time.

Xcel Reply

(Xcel, Reply Comments, Docket #13-599, November 10, 2014, pp. pp. 16-18, the following has been copied, excerpted or adapted, mostly verbatim, from Xcel's Reply Comments)

The OAG's comments of September 26, 2014 request the Commission defer or delay action or approval of Sherco 3 replacement power costs because of incomplete information, referencing a hearing scheduled for June 2015 in the GE litigation case. According to the OAG, the Commission should know the full outcome of the GE lawsuit before taking action in the AAA docket. At a case management conference on October 2, 2014, the GE litigation trial date has now been revised to September 2016. Holding the entire AAA docket open for approximately 2 years or more pending this one issue seems too long.

The intent of the fuel clause adjustment mechanism is for timely recovery of eligible costs, all subject to subsequent Commission review and approval. We fully understand and accept the Commission's authority for this review and approval. The plant has been returned to service and the full amount of replacement power cost for the event is known and details of its calculation are available and have been submitted for review. We disagree any deferral or delay is warranted because not enough information is available or information is incomplete.

Contrary to the OAG's suggestion, it is not necessary to direct the Company to provide continuous information for review—we have been and will continue to provide information relating to the Sherco 3 event and insurance recovery in the rate case and AAA dockets on a regular basis. We do not believe additional reporting requirements are needed at this time and will update the Commission as developments occur.

The OAG has raised an issue about the difference in calculation methodologies between the AAA and the GE litigation. It is important to recognize the calculation methodology used for the AAA is consistent with how the cost of replacement power has been calculated for all other plant outage situations. The distinction is for the AAA we compare to the market using the LMP at the NSP load node whereas for the litigation, the whole portfolio is considered as a hedge against losses at the Sherco node. A full description of the differences along with the calculation results was provided to the OAG in our response to IR No. OAG-001 in this docket. The response and a subsequent updated response are included here [in Xcel's November 10, 2014 reply comments, in docket #13-599) as Attachment I.

The OAG has additionally recommended consideration of opening a separate docket in which to monitor the GE litigation. We do not believe further procedural steps such as a docket to monitor another docket is necessary.

The Department noted in its Review that "during the legal process, additional facts may be developed through either briefs or discovery that are not available to date," and recommended that "the Commission may want to retain the right to revisit this issue if additional facts developed during the legal process contradict the record to date." The Commission has available the information necessary to review and make a determination on the prudency of replacement power costs for the Sherco 3 Event and can do so at this time, but we agree with the Department that it may be necessary to reconsider the issue if additional information emerges through the litigation procedure. To the extent there are further future developments leading to the specific award of our claim for replacement power costs in the GE litigation, the Commission can authorize such amounts can be dealt with at that time.

[T]he Commission has the information needed to take action on review of the Sherco 3 replacement power costs and can adopt the Department's recommendations and need not defer or delay action as suggested by the OAG.

DOC Response

(DOC, Response Comments, Docket #13-599, December 31, 2014, pp. 11-13, the following has been copied, excerpted or adapted, mostly verbatim, from the Department's Response Comments)

The Department agrees with Xcel Electric that it is not necessary to open a separate docket to monitor the litigation. Xcel Electric has committed to provide information relating to the Sherco 3 event and insurance recovery in the rate case and AAA dockets on a regular basis. Important information would include scheduling, findings about negligence, etc. Opening a separate Commission investigation would certainly be less efficient than the development of the record through the state district court action and likely would not benefit from the extensive information expected to be filed in that proceeding.

Finally, the Department notes that Xcel Electric agreed with the Department that "it may be necessary to reconsider the issue if additional information emerges through the litigation procedure."

Xcel Electric acknowledged that "to the extent there are further future developments leading to the specific award of our claim for replacement power costs in the GE litigation, the Commission can authorize such amounts can be dealt with [sic] at that time." The Commission could explicitly reserve the right to do so if it wishes.

The Department continues to recommend that the Commission find that the prudence of costs related to Sherco 3 outage between November 2011 and December 2013, as identified in the Department's September 16, 2014 Report, in Docket No. E999/AA-13-599, remains subject to review by the Commission.

OAG

(OAG, Comments, Docket #13-599, December 30, 2014, pp. 7-8, the following has been copied, mostly verbatim, from the OAG's Comments)

The OAG has previously made specific recommendations as to why the Commission should continue to defer action on or approval of Xcel Energy's replacement power costs incurred after the catastrophic failure at Sherco 3. As explained in the OAG's Comments, Xcel Energy has taken the position in filings in Minnesota state court that third-parties are liable for the replacement power costs, which could make it appropriate in the future for the Commission to order modification of Xcel's automatic adjustment charges to balance and protect ratepayer interests. The OAG does not agree with the DOC's conclusions regarding causation and foreseeability of the failure, which are based on premature analysis of inadequate information.

In addition, the method of calculation and total amount of Xcel Energy's replacement power costs are disputed. For these reasons, approval of the costs should continue to be deferred and the Commission should clarify that it may act in the future to remedy any inequities for ratepayers.

Xcel

(Xcel, Additional Reply Comments, Docket #13-599, February 11, 2015, p. 7, the following has been copied, mostly verbatim, from Xcel's Additional Reply Comments)

The Department continues to recommend that the Commission find the prudence of costs related to the Sherco 3 outage remain subject to review by the Commission if additional facts develop during the legal process that contradict the record to date. As we stated in our November 10th Reply Comments, the Commission has the information necessary to review and can make a determination on the prudency of replacement power costs at this time. We agree that it may be necessary to reconsider the issue if additional information emerges through the litigation and appreciate the Department's support that no additional action related to Sherco 3 outage costs is necessary at this time.

The OAG, however, continues to recommend that the Commission defer action on the issue of replacement power costs related to Sherco 3 while the Company's claims for those costs against third-parties are adjudicated or, alternatively, to commence its own investigation and process. Further procedural steps are not necessary. The Company is on record as fully understanding and accepting the Commission's authority for full review and approval of the Sherco costs, but we continue to disagree that any deferral or delay is warranted. If there are further developments in the context of the litigation, the Commission can authorize that such amounts can be dealt with at that time.

Xcel supports the Commission adopting the Department's recommendations regarding the Sherco 3 outage event and replacement power costs and does not agree with the OAG for deferral or action or initiation of a separate Commission investigation.

OAG

(OAG, Reply Comments, Docket #13-599, February 11, 2015, p. 18, the following has been copied from the OAG's Reply Comments)

For the reasons stated in the OAG's previous comments, the OAG recommended that the Commission defer any decision on the recovery of Sherco 3 energy replacement cost until there is a sufficient record to determine if recovery is appropriate.

PUC Staff Comment

Staff recommends the Commission ask Xcel for an updated timeline for the litigation in complaint proceeding involving General Electric. It is staff's understanding that this matter is scheduled to go to trial later this year (in 2016).

Staff also recommends the Commission ask for clarification of the parties' positions on Xcel's proposed calculation of the cost of replacement power as presented in Xcel's November 10, 2014 reply comments and the amounts identified in the Department's September 16, 2014 Report.

Regardless of the answers to these two questions and because of the significant amount of replacement power cost incurred, the Commission may want to either defer this issue completely until Xcel's complaint against GE is resolved or take no action.

Staff does not believe an investigation into whether any of the parties to this docket are effectively participating in the litigation against GE would be a productive use of time.

Decision Alternatives

1. Find that the replacement power costs related to the Sherco 3 outage between November 2011 and December 2013 were prudently incurred by Xcel. Accept Xcel's commitment to provide information relating to the Sherco 3 event and insurance recovery as additional information emerges through litigation. And Xcel's acknowledgement that if there are further developments in the context of the litigation, the Commission can authorize that such amounts can be dealt with at that time. (Xcel)

2. Find that the prudence of costs related to Sherco 3 outage between November 2011 and December 2013, as identified in the Department's September 16, 2014 Report in Docket No. E999/AA-13-599, remain subject to review by the Commission if additional facts developed during the General Electric legal process contradict the record to date. (DOC)

3. Defer any decision on the recovery of Sherco 3 energy replacement costs until there is a sufficient record to determine if recovery is appropriate and clarify that the Commission may act in the future to remedy any inequities for ratepayers. (OAG)

4. Open an investigation to review the cause and foreseeability of the Sherco 3 outage and the prudency of the replacement power costs Xcel incurred during the Sherco 3 outage. (OAG alternative)

5. Take no action.

Replacement Power Costs Charged to Ratepayers During Unplanned (Forced) Outages

Background

(DOC – Response Comments, Docket No. E-999/AA-13-599, December 31, 2014, pp. 1-9, the following has been copied, excerpted or adapted, mostly verbatim, from the Department's Response Comments)

At the outset, it is important to note that the discussion below does not address replacement power costs or utility practices regarding planned (unforced) outages that are generally within expectations. As discussed in the Department's comments and recommendations in Docket No. E999/AA-12-757 (12-757), due to discussions over the years between the Department and utilities, these and other issues have largely been resolved reasonably.

Instead, this discussion is about replacement power costs that are charged to ratepayers through the FCA during: unplanned (forced) outages. Specifically, in its April 6, 2012 Order in Docket Nos. E999/AA-09-961 and E999/AA-10-884 (2012 Order), the Commission required the investor-owned utilities (IOUs) to provide in future AAA reports, a simple annual identification of forced outages and a short discussion of how such outages could have been avoided or alleviated.

While the Department concluded that the IOUs complied with the 2012 Order in their initial FYE13 AAA reports, the Department requested that utilities provide the following additional information in reply comments to identify solutions to outage-related issues:

- How Minnesota and other utilities can share best practices across utilities in a timely manner (e.g., videos as Xcel describes, electronic bulletins of best practices) to ensure that as many generation plants as possible maximize the days of operation and minimize the number of unexpected, or forced outages.
- Utilities should discuss any electronic databases that have been developed to share best practices in plant maintenance and repair.
- Utilities should discuss their efforts to obtain Business Interruption Insurance due to any factor that causes an unplanned outage or longer than-expected planned outages.
- If utilities have not obtained Business Interruption Insurance, they should provide a full explanation as to why not.
- Utilities should discuss any revisions of language in contracts with contractors working on plants to increase the contractor's accountability in minimizing the length of the outage and ensuring that the plant runs smoothly.
- Utilities should discuss any efforts to recoup replacement power costs from contractors that worked on plants that subsequently had outages, or any other source of reimbursement for replacement power costs.
- If utilities did not pursue any reimbursement for replacement power costs, utilities should provide a full explanation as to why not.

- Utilities should provide the dates and duration of their scheduled and forced outages by plant since 2001.
- Utilities should discuss the general factors utilities consider in scheduling planned outages.

The IOUs provided the requested information in their November 10, 2014 reply comments.

As explained in the Report, the rationale for these questions is not for utilities to release confidential information. Instead, the goal is for utilities to share information about best practices to allow more generators to avoid forced outages so that, when forced outages occur for one utility, there will be more supplies of electricity from other suppliers, thereby reducing the cost of replacement power for the utility with the forced outage.

The Department's FYE11 investigation of forced outages for the IOUs highlighted the lack of incentive by the IOUs to minimize energy costs.[9] The Department concluded that the IOUs appear to act as if their ratepayers, not the IOUs' management and/or shareholders, should be held accountable for all of the costs of forced outages even when the outages are the result of a utility's employee errors or outside vendors' mistakes. The Department's investigation also highlighted the inherent difficulties the Commission faces in attempting to address such issues after-the-fact, particularly when utilities argue that the burden of proof regarding the statutory requirement concerning reasonable rates shifts from utilities to regulators.

As discussed further in the Department's reply comments to be filed by December 31, 2014 in Docket 12-757, the Department recommends an alternative ratemaking approach to encourage utilities to consider all costs in providing service, including replacement power costs, in short-term and long-term planning.

The current design of the FCA in Minnesota allows utilities to recover fuel costs in a different way than costs recovered in base rates. IOUs' energy costs, including replacement power costs during generation outages and congestion costs when transmission facilities are constrained, are automatically recovered from ratepayers through the FCA, while costs to invest in and operate and maintain energy facilities are typically recovered through fixed base rates that do not change between rate cases. These two different recovery mechanisms – automatic adjustments and fixed recovery in rates – provide different incentives for utilities to minimize costs in practice.

Utilities have acknowledged that base-rate recovery provides a stronger incentive to minimize costs than FCA recovery. For example, as Otter Tail Power stated in a recent petition before the Commission:

> …treating replacement energy costs differently [recovered through the FCA] from the allowance costs [recovered in base rates] would serve as a disincentive to purchase allowances even when doing so would be less costly than curtailing plant operations and purchasing replacement energy. [10]

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[9] Department's December 12, 2012 Response Comments in Docket No. E999/AA-11-792.
[10] Docket No. E-017/M-14-649, petition at 15.

A well-designed incentive mechanism would encourage IOUs to minimize overall costs of providing energy, including costs that are currently passed through the FCA. To do so, such a mechanism should ensure that IOUs internalize their total cost of doing business, including their fuel and replacement power costs during outages. Under such an incentive mechanism, IOUs would have the appropriate incentives to keep these costs as low as possible because it would be in their own best interest to do so. The Department proposes such an incentive in its 12-757 comments.

However, because such a mechanism is not yet in place, and because the incentive to minimize total costs is not as strong when costs are automatically recovered from ratepayers, the Department concludes that the IOUs must show that they are meeting their burden of proof to show that rates they are charging are reasonable. For example, utilities should be aware of causes of forced outages before they request recovery of replacement energy costs. Further, utilities may be able to reduce the costs that ratepayers pay for longer-than-expected plant outages by holding their employees and contractors more accountable for errors and delays, and through insurance options.

Forced Outage Reporting Requirements for Utilities Seeking to Recover Replacement Power Costs

Department of Commerce

(DOC, Response Comments, Docket No. E-999/AA-13-599, December 31, 2014, pp. 9 and 25, the following has been copied from the Department's Response Comments)

At least until the FCA incentive is changed, the Department recommends that the Commission require the following for IOUs:

Utilities seeking to recover replacement power costs due to a forced outage must provide;

a. Information showing the causes of forced outages;
b. Efforts the utility took to prevent the forced outage;
c. Efforts the utility took to minimize the length of the forced outage;
d. Efforts the utility took to protect ratepayers from having to pay for the costs of the forced outage;
e. Efforts the utility took to recover replacement power costs from all potential sources; and
f. The amount by which the replacement power costs exceed the power costs the utility would otherwise have charged ratepayers.

Xcel

(Xcel, Additional Reply Comments, Docket #13-599, February 11, 2015, pp. 2-3, the following has been copied, excerpted or adapted, mostly verbatim, from Xcel's Additional Reply Comments)

Understandably, power plant forced outages are the subject of much review—both by utilities who want to resolve the issue as quickly as possible to restore normal operation and by regulators who want to be sure the utility is acting prudently in the maintenance, operation and management of power plants. The Department continues to be dissatisfied with the information utilities are providing in the fuel clause annual reports regarding efforts to manage costs and reduce occurrences of forced outages. We are willing to provide the information that the Department believes is useful and necessary in order to fully evaluate utilities' forced outage costs; however, we believe it would be helpful if these reporting requirements could be streamlined and clarified.

Since 2012, utilities have been providing an increased level of information about forced outage costs in annual fuel clause reports.[11] The Department requested in its June 5, 2013 Review of Utilities' FYE12 AAA Reports (Docket No. E999/AA-12-757), that utilities present the following details for each forced outage using Minnesota Power's Attachment A outage report as a model:

- a description of the equipment that resulted in the forced outage;
- a description of the equipment failure;
- the change in energy costs resulting from the outage;
- the failure history during the reporting period; and
- the steps taken to alleviate reoccurrence of the outage.

The Company provided these details for FYE12 in its August 26, 2013 Reply Comments and has continued to provide these details in our initial AAA Reports for both FYE13 and FYE14.

However, the Department has now recommended in its recent Response Comments that utilities seeking to recover replacement power costs due to a forced outage must provide:

a. Information showing the causes of forced outages;
b. Efforts the utility took to prevent the forced outage;
c. Efforts the utility took to minimize the length of the forced outage;
d. Efforts the utility took to protect ratepayers from having to pay for the costs of the forced outage;
e. Efforts the utility took to recover replacement power costs from all potential sources; and
f. The amount by which the replacement power costs exceed the power costs the utility would otherwise have charged ratepayers.

These newly suggested reporting requirements appear to overlap with reporting requirements already in place. If current reporting requirements are not providing the Department with the

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[11] Order Point 22 of the Commission's April 6, 2012 ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS AND REQUIRING ADDITIONAL FILINGS in Docket Nos. E999/AA-09-961 and E999/AA-10-884, the FYE09 and FYE10 AAA report dockets, states, in part:

> The companies shall provide in supplemental filings to their fiscal-year 2011 AAA reports, in Docket No. E999/AA-11-792, and in future AAA reports, a simple annual identification of forced outages and a short discussion of how such outages could have been avoided or alleviated.

information needed, the Company suggests parties work to clarify the existing report format instead of simply adding yet more reporting requirements. Past reporting requirements and newly suggested reporting requirements should be considered together and clarified to form a new, concise outage report that provides clear information needed by the Department to evaluate outages.

In clarifying the outage report information we would also request to clarify reporting frequency. Xcel Energy provides a brief outage report containing high level outage information in its monthly FCA filings, but provides the expanded detail in its annual AAA reports. The Department's recommendation does not specify whether the reporting requirements should be added to monthly or annual reports. We would recommend an annual report may be more useful in order to have a wider perspective for outages that often cross over into the next month.

Given that this is an issue important to all utilities, we would suggest that the IOUs work together with the Department to assess possible formatting for future outage reporting.

Minnesota Power

(MP, Additional Reply Comments, Docket #13-599, February 11, 2015, pp. 2-3, the following has been copied, excerpted or adapted, mostly verbatim, from MP's Additional Reply Comments)

Minnesota Power provided the following comments on the Department's proposed reporting requirements

Items "a" (information showing the causes of forced outages), and "f" (the amount by which the replacement power costs exceed the power costs the utility would otherwise have charged ratepayers):

> Minnesota Power currently includes information related to items "a" and "f" in its AAA filings.

Item "b" (efforts the utility took to prevent the forced outage):

> Minnesota Power inherently take action to minimize the financial impact of replacement energy costs for our customers. Minnesota Power would be able to provide the above information for forced outages.

Item "c" (efforts the utility took to minimize the length of the forced outage):

> Minnesota Power will continue to takes a variety of actions to minimize the financial impact of replacement energy costs for our customers, as we have described in great detail in past AAA dockets. Minnesota Power's Energy Supply Department works closely with the Generation Operations and Transmission groups in an effort to minimize customer costs. Energy Supply is constantly monitoring current and forward energy markets to ensure least cost supply for all Minnesota Power ratepayers. Upon notification of a generation event that

may lead to a forced outage, Energy Supply evaluates the market to determine the best time to take the unit offline to minimize customer costs. Market drivers that are evaluated include:

- Weather
- Load
- Generation Outages (planned and existing, at both MP and other utilities/marketers).
- Transmission Outages/Constraints
- Wind Forecasts
- MISO Imports and Exports

Upon the market evaluation, Energy Supply develops price forecasts to determine the expected market costs to ratepayers for multiple scenarios. The market costs of the scenarios are then weighed against plant personnel safety, environmental compliance, resource availability and potential risk of equipment damage due to delaying the forced outage. Following this evaluation, the optimal time to take the outage is determined.

Minnesota Power will continue to be able to provide the above information for forced outages.

Item "d" (efforts the utility took to protect ratepayers from having to pay for the costs of the forced outage):

Minnesota Power will continue contractual negotiation as well as post-event warranty claims in effort to ensure that responsible parties (such as vendors, contractors, etc.) pay costs that cause fuel clause impacts on customers.

Item "e" (efforts the utility took to recover replacement power costs from all potential sources):

One of Energy Supply's objectives is to provide least cost supply to Minnesota Power customers.

During a forced outage this is done by ensuring that all potential sources of replacement power have been evaluated. Sources of replacement power include:

- Additional generation that can be dispatched from other Minnesota Power Generators
- Additional generation that can be dispatched from generators owned by Minnesota Power Customers
- Demand side management
- Dual Fuel
- Critical Peak Period declaration
- Demand Response
- Price Recall
- Bilateral purchases from neighboring utilities or power marketers

- Physical purchases from neighboring ISO's
- MISO market purchases

The need for replacement power during forced outages varies depending on the size of the generator that was forced offline and MP system load during the expected outage period. Upon acting on the afore mentioned sources of replacement power, the Energy Supply group constantly monitors the overall energy position of Minnesota Power to determine the amount of replacement power that needs to be procured in order to assure least cost supply for Minnesota Power Ratepayers.

Otter Tail Power

(OTP, Additional Reply Comments, Docket #13-599, February 11, 2015, p. 4, the following has been copied or excerpted, mostly verbatim, from OTP's Additional Reply Comments)

The information outlined by the Department is generally in-line with information typically requested when a forced outage is analyzed by the Department. Otter Tail notes that depending on the nature of the forced outage; the associated analysis and determination of outage causes; and the outcomes from applicable mitigation efforts (insurance, warranties, etc.) an extended period of time may pass before all information is available. Otter Tail understands that this information provides transparency associated with the efforts utilities must often go through to respond and resolve the various issues associated with forced outages as quickly and prudently as possible. Otter Tail is not opposed to providing responses to the questions above but requests clarification as to how the Department would like this information provided (e.g. AAA filings or other filings).

Interstate Power & Light

(IPL, Additional Reply Comments, Docket #13-599, February 11, 2015, pp. 102, the following has been copied or excerpted, mostly verbatim, from IPL's Additional Reply Comments)

IPL currently provides the information in a, b, c, and f in the monthly Fuel Cost Adjustment filings and the Annual Automatic Adjustment filing and will continue to do so. IPL strives to protect the ratepayer from unnecessary costs in every outage decision. To describe the efforts taken on behalf of the ratepayer for specific outages will require additional documentation, but can be provided going forward, if required.

PUC Staff Comment

Staff believes the Department's proposal to require an initial report of information on forced outages that are likely to result in requests for recovery of replacement power costs is reasonable. Staff believes this could be helpful in establishing a baseline of data about forced outages and could provide a useful way to screen events to determine which events should be looked at more closely. Staff also appreciates Xcel's comment that it would be administratively easier to comply with the Department's requests for information and to manage the information that is collected and provided to the Department if the information requested does not change from one year to the next.

Decision Alternatives

1. Require utilities seeking to recover replacement power costs due to a forced outage to provide the following:

    a. Information showing the causes of forced outages;
    b. Efforts the utility took to prevent the forced outage;
    c. Efforts the utility took to minimize the length of the forced outage;
    d. Efforts the utility took to protect ratepayers from having to pay for the costs of the forced outage;
    e. Efforts the utility took to recover replacement power costs from all potential sources; and
    f. The amount by which the replacement power costs exceed the power costs the utility would otherwise have charged ratepayers.

2. Require the utilities to provide the information in 1(a) through 1(f) in their

    a. September 1st annual automatic adjustment (AAA) of charges reports,
    b. Monthly fuel clause adjustment (FCA) reports,
    c. Some other filing or combination of filings to-be-determined.

3. Request that the Department, Xcel, Minnesota Power and Otter Tail Power work together to develop and clarify future outage reporting requirements. Request a report from the Department, Xcel, Minnesota Power and Otter Tail Power within 90 days of the Commission's meeting and a plan for implementing the new reporting requirements in the AAA reports for fiscal-year 2016 that are due September 1, 2016. The report should include the information that is to be provided and the frequency and format of the reports.

Sharing Lessons Learned

Department of Commerce

(DOC, Response Comments, December 31, 2014, pp. 1-9, and 25, #13-599, the following has been copied, excerpted, or adapted from the Department's Response Comments)

In response to the Department's request for information on managing generator outages, utilities provided several responses. OTP stated that the IOUs held several conference calls to share information about how they gather information and stay abreast of issues around plant operations and maintenance. MP stated that they are members of the Fossil Operations and Maintenance Information Service (FOMIS), which provides members with access to an electronic user group forum where questions can be submitted for other utilities to answer, along with a searchable database to retrieve previous questions asked by other users and any responses.

The Department appreciates the IOUs' willingness to identify and share the sources of information they use.[12] Voluntary participation in forums, associations and conferences may be helpful; however, what is really needed is a system such as that used for nuclear power plants, as discussed in Xcel's comments (at 8-9):

> On the nuclear side, the Nuclear Organization at Xcel Energy has an extensive Operating Experience program that results in the sharing of operating experiences between nuclear power plants in the United States and around the world. Sharing of operating experience is required by the Nuclear Regulatory Commission and facilitated by Xcel Energy's membership in the Institute of Nuclear Power Operations (INPO) and the United Services Alliance (USA) peer groups.
>
> The creation of the nuclear industry's Operating Experience Program stems from the Three Mile Island accident and a recommendation by the Kemeny Commission for nuclear power plants to establish a means to systematically gather, review, and analyze operating experience at all nuclear power plants. In response, the US nuclear utilities industry established the INPO. The initial operating experience program was called the Significant Event Evaluation and Information Network (SEE-IN) Program. It was developed jointly by INPO and the Nuclear Safety Analysis Center at the Electric Power Research Institute (EPRI) in early 1980. The program objective was to provide a systematic means of sharing operating experience information among nuclear power plants.
>
> Following the reactor accident at Chernobyl Nuclear Power Plant in April 1986, utilities operating nuclear power plants worldwide formed the World Association of Nuclear Operators (WANO). The INPO Operating Experience Program interfaces with the WANO Operating Experience Program to ensure that INPO members benefit from international experience and to share U.S. nuclear industry experiences internationally.
>
> The objective of the Nuclear Operating Experience Program is to improve operating nuclear power plant safety and reliability by allowing each plant to learn from the operating experience of the world community of nuclear plants.

These important efforts to improve the reliability and safety of nuclear plants were not voluntary programs; instead, as Xcel stated, "Sharing of operating experience is required by the Nuclear Regulatory Commission." While Xcel does "not believe that any additional centralized systems are necessary for sharing best practices," the Department concludes that utilities have not shown why fossil-fueled generation facilities would not benefit from a mandatory centralized information system about outages and preventative efforts. There should be greater assurance that utilities are taking all reasonable steps to keep their plants operating safely and reliably. As fossil fuel plants continue to age, such a resource will become even more valuable.

For example, if the FOMIS program that MP described is at the same high standard as INPO, membership in such an organization, particularly if it is made up of owners of generation

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[12] See OTP's list of forums for information sharing, Attachment 1 of OTP's Reply Comments.

facilities similar to those in Minnesota, may be valuable. In any case, any utility requesting recovery of replacement power costs due to forced outages should be required to show that it has pursued all reasonable options both to avoid the forced outage and to minimize replacement power costs.

The Department does not agree with IPL that "it is difficult to convey sufficient information in a printed report that would aid other utilities in reducing forced outages." As discussed further under the Department's forced outages-related recommendations in Docket No. E999/AA-11-792, a big step forward to alleviate, for example, a reoccurrence of MP's January 2011 forced outage at Boswell Energy Center 4, which resulted in an additional cost to MP's ratepayers of more than half a million dollars through the FCA, would include:

- a short description of the source of the forced outage (see Attachment E5 of the Department's Report),
- the identification of the vendor that provided the "incompatible o-rings," and
- quality management improvements such as oversight of contractors, including raising and following-up on red flags when replacement parts that need to be made of a specific material cannot be identified based on their color anymore.[13]

Again, Xcel Electric identified an important source for lessons learned specific to the nuclear industry, which describes the attributes of the program as follows:[14]

- The organization avoids complacency and cultivates a continuous learning. The attitude that "it can't happen here" is not allowed.
- Individuals are well informed of the underlying lessons learned from significant industry and station events, and are committed to not repeating these mistakes.

At least until there is a change in the FCA design, the Department recommends that the Commission require any IOU requesting recovery of replacement power costs due to forced outages to show that it has pursued all reasonable options both to avoid the forced outage and to minimize replacement power costs. At a minimum, Minnesota IOUs should develop a robust, searchable database applicable to non-nuclear facilities that shares the attributes of the SEE-IN program and provides for a systematic gathering, review, and analysis of operating experience at (Minnesota) IOUs-owned non-nuclear facilities. This database should help the IOUs identify and implement in-time solutions from the lessons learned from their own forced outages and other IOUs' forced outages and from their participation in industry forums.

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[13] Background information is available at pp. 40-45 of the Department's December 12, 2012 Response Comments in Docket No. E999/AA-11-792, available at:
https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={29D584DF-51F7-4DC3-A2D2-38777542C303}&documentTitle=201212-81728-01
and summary in Attachment E5 of the Department's Report, available at:
https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={8F4704DF-FF11-4E08-9DC4-4DA65EBD8FAD}&documentTitle=20149-103105-02
[14] Source: http://www.nrc.gov/public-involve/conference-symposia/ric/past/2005/slides/04-f2-gard.pdf

Until a well-designed incentive mechanism is approved by the Commission, this searchable database would give utilities a basis to show the Commission, after-the fact, that their actions regarding plant operation and maintenance issues were prudent, a requirement necessary to meet the statutory requirement that rates charged by IOUs are reasonable.

The Department also recommends that the Commission accept the IOUs' compliance filings regarding sharing lessons learned about forced outages.

Xcel

(Xcel, Additional Reply Comments, Docket #13-599, February 11, 2015, pp. 3-5, the following has been copied, mostly verbatim, from Xcel's Additional Reply Comments)

The Department continues to support the development of a searchable database applicable to non-nuclear facilities that shares the attributes of the Significant Event Evaluation and Information Network (SEE-IN) Program for nuclear facilities which Xcel Energy described in our original Reply Comments. The stated purpose would be so that utilities can share best practices across utilities in a timely manner to ensure that as many generation plants as possible maximize the days of operation and minimize the number of forced outages.

However, the development of a new database system for non-nuclear facilities is not necessary for several reasons. First, the SEE-IN Program the Department cites as a model is effective for sharing information amongst nuclear facilities because there is a centralized organization to maintain such a system, the Institute of Nuclear Power Operations (INPO). There is no such centralized organization to create and maintain this type of a database for Minnesota utilities. Creating a new database system to force comparison among power plants that may not have similar technology and design provides no concrete benefit to minimize the number of forced outages that can't be achieved through the other ways utilities already share information. Each utility has its own internal systems and networks for tracking and sharing information across our own and similar plants. Unless a new database system seamlessly interacts with systems already in place, the maintenance of an additional tracking system is unduly burdensome, potentially costly, and duplicative of activity already occurring within the industry.

Second, we believe the dialog and periodic visits between the Minnesota investor-owned utilities which are already occurring are the best and most effective ways to exchange information without adding additional costs. As we described in our original Reply in this docket,

> We have conducted on-going networking with Great River Energies (GRE) regarding best practices with burning RDF as it relates to the Elk River RDF station. In 2012, Xcel Energy personnel toured the plant and discussed best practices. Xcel Energy personnel also visited GRE's Coal Creek station in 2008 to learn more about non-destructive techniques for sizing thermal fatigue cracking in water walls. We have plans to reconnect with this plant's staff during the 2015 Energy conference to conduct best practice boiler benchmarking.
>
> We have also networked with plant personnel at Minnesota Power (MP). We visited their Tac Harbor station and Boswell station regarding their Pratt Whitney Shock Wave cleaning

> system in 2006. In 2010 and 2011, we visited their Boswell station twice regarding their combustion optimization work. Furthermore, engineers from MP visited Xcel Energy's Sherco plant in 2009-2010 to benchmark best practices. MP engineers also participated in our Company-wide Xcel Energy Boiler conference in Denver in July 2013, and they presented a power point on their combustion optimization work. This month we have plans to visit Boswell station again to discuss best boiler combustion practices.
>
> In addition, we met with Otter Tail Power (OTP) staff at the July 2014 Boiler conference regarding best cyclone boiler practices. Also this year, we met with OTP consultants regarding details of the company's 2015 outage work at the Big Stone plant. Last month we conducted a site visit scheduled at Big Stone to discuss best boiler outage/reliability/combustion practices.
>
> The Company takes advantage of many opportunities to network with our neighboring Minnesota utilities where appropriate, and we also network at a national level among utilities with similar fleets when that approach makes more sense. We believe that we utilize these opportunities where available.

Lastly, we believe we are already effectively maximizing the days of operation and minimizing the number of forced outages at all of our plants. As a result of our thorough generation maintenance program, our power plants have been well-managed and maintained, and they provide adequate service for our customers. However, despite our proactive maintenance efforts, outages will occur in mechanical, electronic and electrical equipment and are not completely avoidable.

If the Commission believes such a database is needed to share information in addition to the many ways we have already described, an existing system such as FOMIS would be a preferable way to systematically exchange information as it has already been developed and is being maintained by an outside organization.

Minnesota Power

(MP, Additional Reply Comments, Docket #13-599, February 11, 2015, pp. 3-4, the following has been copied, mostly verbatim, from MP's Additional Reply Comments)

Minnesota Power's understanding of the key attributes of a SEE-IN type program include dedicated departments/resources on a full time basis to administer the program, common equipment and nomenclature and a procedure intense operation (all common of a Nuclear Regulated industry). It would be possible to implement such a program among Minnesota IOU's; however it would be very difficult, and of limited value, given the differences in generating unit characteristics. A more in-depth analysis should be performed to determine the prudency of implementation of such a program.

Minnesota Power is a paying member for FOMIS (Fossil Operations & Maintenance Information Service), EPRI and EEI among others. These forums provide Minnesota Power a mechanism to learn from other utilities along with the additional ability to access emergency spare parts to prevent forced outages at our plants.

Otter Tail Power
(OTP, Additional Reply Comments, Docket #13-599, February 11, 2015, pp. 4-5, the following has been copied, mostly verbatim, from OTP's Additional Reply Comments)

In Reply Comments filed on November 10, 2014, Otter Tail provided a table of information[15] that was jointly developed by the utilities, that summarized numerous conferences; trade organizations and industry memberships; consultants, vendors and contractors; and publications which the utilities have found to be the most informative and beneficial forums to share their information given their unique generation portfolios. The table showed both those forums that all utilities utilized, as well as those that were unique to each utility. As Otter Tail has noted in the past, vendor and technology specific forums often provide the most relevant and targeted information sharing.

In addition to the information shared within that table, Otter Tail benefits extensively from information provided by its insurance providers, who act as a conduit of information acquired from their clients that operate similar facilities. The insurance providers also work closely with Otter Tail in conducting risk assessments and collaborating on various plant maintenance planning efforts, as part of each facility's on-going loss prevention program.

While the SEE-IN program, a nationally developed program, may serve the nuclear industry quite well due to the breadth of participation across the entire industry, Otter Tail questions the benefit of developing a specific database related to just Minnesota utilities that each have their own unique and diverse mix of generation resources.

Interstate Power & Light
(IPL, Additional Reply Comments, Docket #13-599, February 11, 2015, p. 3, the following has been copied, mostly verbatim, from IPL's Additional Reply Comments)

IPL does not own a nuclear generation facility and is not familiar with the current SEE-IN program. The Company is not capable of independently developing a comparable database that can be searched and shared with other utilities. However, if such a database were to be made available through a broader effort among Minnesota IOUs, then IPL would contribute information to the extent required and without risking confidentiality.

Additionally, as IPL noted in its November 10, 2014, Reply Comments, IPL is currently an active member of several user groups that focus on improving the reliability of key plant equipment, such as turbines, generators and boilers. Through these forums, IPL is able to share best practices on topics such as boiler reliability, turbine and generator reliability and maintenance, and predictive and preventive maintenance strategies.

[15] Otter Tail Reply Comments filed 11/10/2014, Attachment 1.

PUC Staff Comment

Staff appreciates the Department's interest in having better information but also recognizes that the Department's proposal for the development of a high-quality and useful Minnesota-specific database is very ambitious. Staff believes Xcel's suggestion to look to an existing organization or system would be preferable than starting an entirely new system from scratch.

Decision Alternatives

1. Require the IOUs to develop a searchable database applicable to non-nuclear facilities that shares the attributes of the SEE-IN program and provides for a systematic gathering, review, and analysis of operating experience at (Minnesota) IOUs-owned non-nuclear facilities.

2. Require the IOUs to develop a way to share information, using an existing system such as FOMIS that has already been developed and is maintained by an outside organization, that includes a searchable database applicable to non-nuclear facilities and provides for a systematic gathering, review, and analysis of operating experience at (Minnesota) IOUs-owned non-nuclear facilities.

3. Take no action

Contractor Accountability for Replacement Power Costs & Supplier Warranties

Department of Commerce

(DOC, 2013 AAA Review – Docket #13-599, September 16, 2014, p. 23, the following has been copied, excerpted or adapted, mostly verbatim, from the Department's Review)

The Department notes that the legal process regarding Sherco 3 is likely to take several years to complete. In the meantime, ... the utilities were also asked to respond to the following questions:

- Utilities should discuss any revisions of language in contracts with contractors working on plants to increase the contractor's accountability in minimizing the length of the outage and ensuring that the plant runs smoothly.
- Utilities should discuss any efforts to recoup replacement power costs from contractors that worked on plants that subsequently had outages or any other source of reimbursement for replacement power costs.
- If utilities did not pursue any reimbursement for replacement power costs, utilities should provide a full explanation as to why not.

Xcel Energy

(Xcel, Reply Comments, Docket #13-599, November 10, 2014, pp. 9-15, the following has been copied, excerpted or adapted, mostly verbatim, from Xcel's Reply Comments)

Contractor Accountability

The Department requested that utilities discuss in Reply Comments any revisions of language in contracts with contractors working on plants to increase the contractor's accountability in minimizing the length of the outage and ensuring that the plant runs smoothly.

With respect to specific contract language, the Company's General Conditions for Major Supply Agreement (General Conditions Agreement 9386) contain industry accepted clauses regarding damages and indemnity, which provide standard contractual protections for the Company (and indirectly ratepayers). The selected provisions are provided as Attachment C.

Xcel Energy has put into practice the use of quality assurance and quality control protocols for major supply, maintenance and repair services, and construction service contracts. These protocols contain specific quality requirements and company expectations that legally bind contractors as well as suppliers to specific performance criteria outlined in the Company Special Conditions for Quality Management Attachment 2.0, included as Attachment D. These Special Conditions for Quality Management are introduced to the supplier/contractor during the contract bid evaluation process stages to ensure the supplier/contractor understands their obligations to achieve full quality compliance. These quality contract requirements are also integrated into the Company's initiative for the development of Master Service Agreements with our suppliers and contractors for repetitive and frequently used services.

The Company's Special Conditions for Quality Management Attachment 2.0 have been in place and exercised over the past two years. It has shown very positive results in the Company's ability to capture rework costs and identify and document opportunities to address avoided costs that are the supplier/contractor's responsibility.

We have also closely managed our contracts to ensure the best relationship with the contractors to receive the highest quality of service. We reported on our efforts to ensure a high level of contractor performance in Part K, Section 3 of our most recent AAA Report in Docket No. E999/AA-14-579 (FYE14) as follows:

> Contractor and Supplier performance has improved over the last couple of years. Xcel Energy attributes this quality improvement to three areas of focus.
>
> First, Xcel Energy has put in to practice the use of a quality assurance and control protocol for the majority of our contracts. This proactive approach is designed to draw attention to the required quality steps Xcel Energy expects each contractor to follow.
>
> Second, Xcel Energy has awarded several alliance-like agreements with companies that consistently exceed others in technology; quality and contract management (including

> following the Scope of Work). As Xcel Energy increases the percentage of spend with these select companies, the possibility of contractor service or supplier product failure decreases.
>
> Third, Xcel Energy has invested time and resources in developing a better scope of work. Scope of work is measured by completion of the total work scope defined in the bid Technical Specification that is part of the Purchase Order and/or contract. By writing scopes of work with greater level of details and expectations, Xcel Energy gets a better quality project in the end.
>
> In the event problems arise with services, equipment, and/or materials provided by the vendor/supplier, the remedy is found in the Terms and Conditions of the Purchase Order and/or contract. Remedies for problems that adversely affect generating plant performance (such as de-rates or unplanned outages) include the direct costs of re-work, including labor and/or materials, depending on the nature of the problem.
>
> The Company strives to always contract for generation plant repair and maintenance services with parties who have a history of performing work safely, reliably, and in a timely manner. Therefore, we will continue to identify and work with these types of contractor issues on a going forward basis.

Furthermore, we provided specific examples of improvements in 2013 and 2014 in Part K, Section 4 of our FYE14 AAA Report:

> Improvements in contractor and vendor/supplier performance continue through the implementation of the Energy Supply Quality Management Program. In the last half of 2013, we experienced a significant decrease in the number and types of events that contributed to fleet plant unplanned loss of capacity in the areas of external service and material quality, and equipment design issues directly related to poor performance by contractors and suppliers.
>
> We have focused the 2014 QA/QC program oversight efforts on contractor/supplier performance during plant overhauls. Comprehensive overhaul quality plans are developed for each plant overhaul which includes aggressive oversight for supplier repairs of plant equipment as well as independent inspection of the contractors performing the plant equipment/component installation activities. The results of contractor/supplier performance for plant overhauls in the NSP region for the first half of 2014 have improved. Plant overhaul schedules were met, with plant startups commencing on or before the scheduled startup/return to service dates. Post overhaul equipment failures and rework has been significantly reduced, and in most cases eliminated. The Minnesota region Unplanned Outage Rate performance metric as a key performance indicator (KPI) is projecting top quartile performance of our industry peers.

The NSPM Nuclear function uses procurement management practices for contracts and contractors similar to Fossil plants, as described above, to the extent industry regulatory requirements allow.

Replacement Power Costs

The Department requested that utilities discuss in Reply Comments any efforts to recoup replacement power costs from contractors that worked on plants that subsequently had outages or any other source of reimbursement for replacement power costs. The Department also requested we provide a full explanation as to why utilities did not pursue any reimbursement for replacement power costs if they had not.

As discussed above, we believe contractor performance has generally seen improvements over the past several years, and therefore there have not been many events for which replacement power costs could be recouped from contractors who had worked on our plants. We discussed one such example, however, in our response to Information Request (IR) No. DOC-002 submitted in Docket No. E999/AA-12-757 (FYE12 AAA).

> We identified one instance where contractor performance resulted in increased costs during this AAA reporting period. The Allen S. King Unit 1 experienced an extension of a planned outage from June 3-7, 2012 due to an issue with Gas Recirculation Fan Seals. The planned outage was scheduled for the period May 5 to June 3, 2012, and was extended a few additional days.
>
> During the King plant Major Boiler Overhaul outage, it was discovered that a vendor did not perform adequate quality control when fabricating the gas recirculation fan seal plates. The fabrication discrepancy was identified by the vendor's field installation advisor (as part of original contract) near the end of the outage since installing the seal plates is one of the last activities to occur prior to completion. The vendor's field advisor informed the Company that the seal plate was fabricated with a 9 inch outside diameter instead of an 8 inch outside diameter and that the plate would need to be replaced. The outage extension was the time it took to build and install the correctly sized seal plates.
>
> We have calculated the net replacement energy cost for the additional days of the planned King outage to be approximately $645,000. Net Replacement Cost is based on estimated average replacement cost less unit incremental cost. The cost impact reflected the cost of the identified outage event, which may or may not be consequences of the identified contractor's performance related issue.
>
> The replacement energy cost is an NSP System number before allocation to NSPW via the Interchange Agreement and the allocation to other retail jurisdictions.
>
> When we derive outage costs we calculate replacement energy costs and net that against estimated production costs and do not distinguish what could have been delivered to native load or Asset Based sales. If the King unit had been online during the four day extension period, it is difficult to say for certain whether dispatch from the unit would have occurred; we would expect King generation would have added to the overall supply and potentially reduced LMP prices, which may or may not have resulted in unit dispatch. There were some asset based sales during the extended outage period, which implies the NSP System had

> unused generation, and having King in service would have added to that available generation, possibly increasing the volume of sales. We agreed to [*****XCEL - TRADE SECRET BEGINS*** ***XCEL - TRADE SECRET ENDS*****] deduction from the final costs due to the vendor for the project as settlement of the performance and quality issues experienced during installation of the gas recirculating fan assembly. The deduction was reflected as an offset to the capital cost of the project, benefitting customers through a reduction in plant in service.
>
> Generally the indemnity or penalty payments from contractors related to plant maintenance projects are credited back to the applicable O&M or capital expense of the project and are outside of fuel and energy accounting.

In the same IR response, we also discuss the specific issue of nuclear contractor work:

> While extended nuclear outage durations are most often caused by unanticipated issues discovered during the outage and requiring attention, and not by contractor performance, the Company seeks to mitigate the risk of unnecessary outage delays caused by nuclear plant contractors via the following mechanisms:
>
> - All major contracts include a performance bonus and scorecard which allow significant dollar reductions for poor performance. Components of the scorecard are usually safety, schedule adherence, and radiological based.
> - If a contractor performs poorly, dollar adjustments are made accordingly. Reductions could range from 10% to 20% of their otherwise billable amount. Should a performance issue result that in a fair settlement, or else future work would most likely be awarded to a competitor.
> - All contractor performance is recorded daily and quantified during the daily outage cost tracking meetings with actions to the Supply Chain contract coordinator to initiate charge backs against contractor billings when appropriate.

The Company believes it has made reasonable efforts to recoup replacement power costs from contractors when appropriate to the situation, and we continually monitor contractor performance in order to ensure the highest level of quality and value.

Minnesota Power

(MP, Reply Comments, Docket #13-599, November 10, 2014, pp. 3-5, the following has been copied, excerpted or adapted, mostly verbatim, from MP’s Reply Comments)

Minnesota Power engages in rigorous and disciplined contract negotiation and contractor management activities. With regard to contractor selection, Minnesota Power is often limited by the number of qualified contractors who have the expertise and knowledge needed to provide equipment and services for our plants. In contract negotiations, Minnesota Power balances operational considerations and risk transfer and mitigation measures to reach a commercially reasonable agreement. Primary among our operational considerations are clear and thorough contract specifications, warranty provisions, performance guarantees (as appropriate) and active project management provisions (such as subcontractor and change management control). With regard to work conducted during planned outages, Minnesota Power is careful to include a realistic schedule for all work conducted during planned outages. Minnesota Power's schedules include critical milestone dates and an active project management role for Minnesota Power to mitigate the risk of scheduled work prolonging an outage. Minnesota Power may also include liquidated damages in these contracts to ensure that contractors are on schedule and paying attention to the milestones. In our industry, major contractors are able to require limitation of liability provisions that may impact Minnesota Power's ability to hold a contractor accountable for all losses that could be caused by that contractor. In Minnesota Power's experience, many contractors will refuse to provide equipment or services if they cannot also limit their potential liability and financial exposure in the contract. In situations where a contract would allow for recovery of replacement power costs and a contractor would be responsible for those costs, Minnesota Power would actively pursue recovery from the contractor. Minnesota Power does not specifically include a contract provision that requires a contractor to pay replacement power costs; however, contract remedies would allow for recovery of those costs if Minnesota Power could prove that the contractor caused the loss and there was nothing in the contract to limit or waive that recovery.

Otter Tail

(OTP, Reply Comments, Docket #13-599, November 10, 2014, pp. 4-5, the following has been copied or excerpted, mostly verbatim, from OTP's Reply Comments)

With regards to contract language or recouping replacement power costs from contractors, it is Otter Tail's experience that most sophisticated vendors will not agree to a project with the prospect of unlimited exposure to indirect damages (e.g., replacement power costs). On the other hand, contractors are usually able to insure against direct damages (e.g., physical injuries/death or property damage). Most sophisticated vendors will insist on language that forecloses recovery for indirect damages and also imposes a cap or limitation of liability. Otter Tail frequently includes liquidated damages clauses in its contracts to incent timely performance of work. For very large projects, Otter Tail requires payment and performance bonding as an additional level of protection.

Interstate Power & Light

(IPL, Reply Comments, Docket #13-599, November 10, 2014, pp. 6-7, the following has been copied or excerpted, mostly verbatim, from IPL's Reply Comments)

IPL seeks strong project controls within its contracts, including seeking to place the contractor in a position to meet or exceed outage schedules. IPL seeks these terms to place risk on the contractor for schedule and scope compliance. IPL seeks such terms so as to limit the Company's and, in turn, its customers' risk for extended outages. These rigorous project control provisions accompanied by liquidated damage provisions place the contractor in a position to meet or exceed their schedule and scope obligation. While there is a potential cost increase for this, it mitigates the risk for the owner in lieu of consequential damages for schedule and scope adherence.

It is IPL's experience that construction contractors do not agree to include replacement power costs as a remedy for a project of any size. However, for large capital construction contracts, IPL transfers the risk of achieving a schedule milestone to a contractor. If the contractor fails to achieve that milestone then a liquidated damage is assessed against the contractor for each day of delay up to a cap which is often a percentage of the overall contract price.

Department of Commerce

(DOC, Response Comments, December 31, 2014, pp. 1-9, and 25, Docket #13-599, the following has been copied or excerpted, mostly verbatim, from the Department's Response Comments)

Contractor Accountability

The IOUs appear to agree with IPL's statement that "construction contractors do not agree to include replacement power costs as a remedy for a project of any size." OTP stated:

> …it is Otter Tail's experience that most sophisticated vendors will not set agree [sic] to a project with the prospect of unlimited exposure to indirect damages (e.g., replacement power costs). On the other hand, contractors are usually able to insure against direct damages (e.g., physical injuries/death or property damage). Most sophisticated vendors will insist on language that forecloses recovery for indirect damages and also imposes a cap or limitation of liability.

However, Xcel Electric stated that in the past two years, it has used a "Quality Management" program with contractors, which uses approaches such as: (1) identifying and working with parties that have a history of performing work safely, reliably, and in a timely manner; (2) investing time and resources in developing a better scope of work; and (3) specifically identifying the required oversight for supplier repairs of plant equipment as well as independent inspection of the contractors performing the plant equipment/component installation activities.

Xcel's program, identified in more detail in Attachment D of its November 10 comments, appears to be a reasonable start to holding contractors more accountable for replacement power costs. If the FCA incentive is not changed, the Department recommends that the Commission require all utilities to adopt such a program, to the extent those practices are not already in place.

Supplier Warranties

In addition, the Department recommends that the Commission require Xcel and other utilities to add language to the "Supplier Warranties" section of their contracts to indicate that contractors may be liable for a limited amount of replacement power costs, such as a stated dollar amount per day, for any defect with respect to contractor work that caused a material delay in an outage.

For example, Xcel could consider language such as the following:

> Upon receipt of notice from Company of any failure to comply with the terms of the Agreement including these General Conditions, without limitation, any defect with respect to the Work, either prior to or during the term of the Warranty Period, Supplier shall without additional compensation re-perform, repair or replace such defective Work within a reasonable time acceptable to Company and reimburse Company for Company's reasonable costs and expenses resulting from Company's cure of defective Work, (the cost of removal and reinstallation are not reimbursable by Contractor unless mutually agreed to on the Purchase Order/Work Order or if installation is part of Contractor's initial scope of Work) including any transportation costs incurred by Company, a portion of replacement power costs not otherwise secured by the Company, subject to the limitations and exclusions in Sections 30.2 and 30.3 below. If Supplier fails to timely re-perform, repair or replace any such defective Work, Company may cause such defective Work to be replaced by another and the reasonable expense thereof shall be the responsibility of Supplier.

Such a provision would apply if the contractor did not perform satisfactorily, which was the concern the Department raised regarding Boswell 4 (the o-rings). By limiting the potential for contractor liability for replacement power costs only to when a contractor fails to comply with the contract, and limiting the amount of replacement power costs to a specific amount or formula, this provision should be acceptable to contractors. Nonetheless, this provision would place the responsibility for the higher replacement power costs on the entity that caused the higher costs and would reduce the amount of replacement power costs charged to ratepayers.

At least until the FCA incentive is changed, the Department recommends that the Commission require the following for IOUs:

- Utilities should adopt Xcel's program, identified in more detail in Attachment D of Xcel's November 10 comments, to hold contractors more accountable for replacement power costs, to the extent those practices are not already in place.

- Xcel and other utilities should add language to the "Supplier Warranties" section of the contracts as discussed above to indicate that contractors may be liable for a limited amount of replacement power costs.

Xcel

(Xcel, Additional Reply Comments, Docket #13-599, February 11, 2015, pp. 5-6, the following has been copied or excerpted, mostly verbatim, from Xcel's Additional Reply Comments)

The Department recommends that utilities should add language to the "Supplier Warranties" section of contracts with outside plant maintenance vendors to indicate that contractors may be liable for a limited amount of replacement power costs. Specifically, the Department believes that "By limiting the potential for contractor liability for replacement power costs only to when a contractor fails to comply with the contract, and limiting the amount of replacement power costs to a specific amount or formula, this provision should be acceptable to contractors." However, the Company's General Conditions for Major Supply Agreement (General Conditions

Agreement 9386) already contain widely used and industry-accepted clauses regarding damages and indemnity, which provide standard contractual protections for the Company (and indirectly ratepayers).

We disagree with the Department's suggestion to require additional contract language as it would impede our ability to individually negotiate contracts and could inflate contractor costs if such clauses are added. We have worked hard to make improvements in our vendor contracting practices, as described in our original Reply and as held up as a model by the Department in its Response, and we do hold contractors more accountable than in the past. However, we must still be able to arrange and manage outside vendor contracts using our extensive utility business experience with this type of work. We are concerned that we would not be successful in contracting with high quality vendors if we are required to add language to our contracts specifically placing liability for replacement power costs on the vendors. We believe it is likely that many reputable vendors would not be willing to take on such risk.

We believe that all utilities are working hard to maintain their plants in the most cost efficient ways possible. Xcel Energy in particular has seen contractor performance generally improve over the past several years, and we have made reasonable efforts to recoup replacement power costs from contractors when appropriate to the situation.

We continually monitor contractor performance in order to ensure the highest level of quality and value. Maintaining quality relationships with our vendors and monitoring their performance as described in our original Reply are the best ways to ensure high quality contractor performance. We do not agree that additional contract restrictions are the best solution to keeping our plants running cost-effectively for our customers.

Minnesota Power

(MP, Reply Comments, Docket #13-599, February 11, 2015, pp. 5-9, , the following has been copied or excerpted, mostly verbatim, from MP's Reply Comments)

<u>Contractor Accountability</u>
While MP has not adopted a centralized approach to a formal quality management plan as illustrated by the Xcel program cited by the Department, operational divisions within MP have implemented standard practices which are designed to achieve a similar result.

The MP Engineering Services group utilizes a standard Project Procedures Manual. In developing project specifications and engaging contractors, quality management is a primary focus and concern. In addition, certain areas of operations require adoption of specific quality standards, such as the Dam Safety QCIP program; State Building Code compliance for structural engineering; and FERC requirements for hydro generation facilities. The MP Generation Reliability group has developed standard scope of work documents for complex, operation critical activities, such as the overhaul of a boiler feed pump.

Contracting with suppliers who have rigorous quality standards is a priority for MP. Many of MP's alliance partners have ISO 9001 Quality Management Systems Certification.

In addition, quality management considerations are incorporated into MP's contracting processes. MP engineers and project managers develop clear and thorough contract specifications and scopes of work. The commercial terms included in MP's contracts contain warranty rights and active project management provisions.

MP does not anticipate any impediment to adopting a centralized, standard approach to contractor quality management as long as that approach contains the flexibility needed to manage individual projects.

Supplier Warranties

MP uses two standard form agreements that are relevant to this discussion: (1) purchase order terms and conditions; and (2) major supply agreement conditions of contract. The standard warranty provisions in MP's contracts provide for the recovery of replacement power costs to the extent that such costs are caused by a supplier default, but note that sophisticated vendors will negotiate these provisions out of their contracts because the scope of risk is too great for them to bear in performing the work.

The warranty provisions of these agreements provide:

> Purchase Order Terms and Conditions:
> Seller warrants that: (a) all the goods, work and services furnished under this Purchase Order shall be produced and furnished in compliance with all applicable federal, state and local laws, rules, orders and regulations; (b) all goods supplied will be: (i) of good quality and in accordance with the standards of Seller's industry (including the North American Electric Reliability Corporation); (ii) new unless otherwise required or permitted by this Purchase Order; (iii) of the kind, make, and quality specified in this Purchase Order; (iv) free from errors, omissions, faults and defects in design, workmanship, and materials; and (v) in full conformity with this Purchase Order and performing as required by this Purchase Order; and (c) all services provided by Seller will be: (i) performed in a professional, prudent and workmanlike manner that is free from defects, errors and omissions and with the highest degree of skill and care that is utilized by nationally-recognized professionals in the same field under the same or similar circumstances; (ii) strictly in accordance with this Purchase Order and all applicable laws, and (iii) performed in accordance with all applicable engineering, environmental, construction, safety, and electrical generation codes and standards, as such codes and standards exist on the date of delivery of the goods and/or performance of the work. If Seller, after notice, fails to proceed promptly to remedy any failure to comply with any of the warranties set forth herein, Purchaser may remedy such failure of deficiency or have such failure or deficiency remedied by a third party, and Seller will be liable for all costs and expenses so incurred. Compliance with or conformance to a quality assurance, quality control or similar program will not relieve Seller of its warranty obligations hereunder. In addition to its warranty obligations set forth herein, Seller will be fully responsible to Purchaser for the cost of repair or replacement of property of Purchaser that is damaged as a result of goods or services provided by Seller that are faulty or defective, or

otherwise fail to conform to the warranties provided herein. Unless otherwise specified herein, Seller shall obtain all permits necessary for performance under this Purchase Order.

Further, the purchase order terms and conditions contain a broad indemnification clause (including first party indemnity) that provides, in pertinent part: "Seller shall, at its own cost and expense, completely indemnify, defend, and hold Purchaser, its officers, agents and representatives ("Indemnitees") harmless from and against all claims for personal injury, property damage, wrongful death or other damages, losses, and expenses, including attorneys' fees ("Claims"), arising out of, or resulting from, defective goods or the performance of work or services for Purchaser."

Major Supply Agreement Conditions of Contract:
Supplier warrants that all Work, including without limitation, the Goods, will conform to the kind, quality and capability designated or described by the Agreement. Supplier shall perform the Work with due care, skill and diligence, in accordance with Applicable Law and applicable professional standards, industry procedures (including NERC CIP) and construction practices. Unless a greater period of time is specified in the Agreement, Supplier shall warrant the Work and all Goods, including parts, equipment, materials and labor furnished under the Agreement to be as specified herein and free from defects in (i) title (including any liens, encumbrances or other third party interests) at all times after passage to Company, and (ii) Design, material and workmanship for the longer period of (A) twelve (12) months after Final Acceptance or the period of any manufacturer's warranty, or (B) with respect to warranty work performed by Supplier, for an additional period of one (1) year following such warranty work. Any and all manufacturer warranties shall be and hereby are transferred to Company pursuant to the provisions and operation of the Agreement. After delivery of conforming Goods to the Site, Company shall store, maintain and install the Goods consistent with Supplier's written instructions or, in the absence of such instructions, in accordance with prudent industry practices.

Upon receipt of notice from Company of any failure to comply with the terms of the Agreement including these General Conditions, including without limitation any defect with respect to the Work, either prior to or after Final Acceptance, Supplier shall without additional compensation correct any such defects within a time acceptable to Company and reimburse Company for any resulting costs, expenses or damages suffered by Company, including but not limited to costs of removal, reinstallation, re-procurement and any other third party costs, damages and losses incurred by Company. If Supplier fails to timely replace any such defective Work, Company may cause such defective Work to be replaced by another and all expenses thereof shall be the responsibility of Supplier. Company shall be entitled to deduct such expense and any resulting damages from amounts otherwise due to Supplier.

As provided above, the warranty rights of these agreements provide the ability to recover replacement power costs from a supplier when the supplier's performance falls short of that required by the warranty.

The Department recommended that utilities consider including a specific statement in their warranty language that addresses replacement power costs. Specifically, MP has been asked to add: "…a portion of replacement power costs not otherwise secured by the Company."

Such language would be unnecessarily limiting. As provided above, MP's standard language is quite inclusive and would include a claim for replacement power costs. Expressly providing recovery for "a portion of replacement power costs not otherwise secured by the Company" introduces ambiguous language that may not be enforceable. If the agreement is not clear on what "a portion" means, there would likely be no recovery unless the language was found ambiguous. If it were deemed ambiguous, then the burden would be on the parties to demonstrate what they understood "a portion" would mean. If MP is willing to agree to less than all (i.e., "a portion"), in order to enforce such a provision, the parties would likely need to reach agreement on a specific percentage of replacement power costs. From a negotiation standpoint, if MP will accept a portion of replacement power costs, why wouldn't MP also accept a portion of property damage costs?

In addition, the phrase "not otherwise secured by the Company" creates a difficult standard and burden for the utility. MP does not believe that a supplier would agree to such language without understanding how MP would "otherwise secure" replacement power costs and to what extent MP can and will do so. Contracting parties weigh risk exposure in their agreements and decisions to undertake work, and the risk presented by the proposed language in indeterminable.

Adding the recommended language may also have an unintended negative impact on the contractual remedies available to MP. Pursuant to a maxim of contract construction - expressiounius est exclusio alterius (meaning, the failure to include something in a laundry list may exclude it) – such an addition may have the consequence of foreclosing other types of remedies that are not specifically stated. While MP's standard language may mention a particular remedy, it carefully preserves all or any costs and expenses and includes an illustrative item only when industry practice has identified that type of damage to be the subject of misunderstanding or frequent negotiation.

The Commission should be aware that overall Minnesota Power engages in rigorous and disciplined contract negotiation and contractor management activities. With regard to contractor selection, Minnesota Power is often limited by the number of qualified contractors who have the expertise and knowledge needed to provide equipment and services for our plants.

In contract negotiations, Minnesota Power balances operational considerations and risk transfer and mitigation measures to reach a commercially reasonable agreement. Primary among our operational considerations are clear and thorough contract specifications, warranty provisions, performance guarantees (as appropriate) and active project management provisions (such as subcontractor and change management control).

With regard to work conducted during planned outages, Minnesota Power is careful to include a realistic schedule for all work conducted during planned outages. Minnesota Power's schedules include critical milestone dates and an active project management role for Minnesota Power to mitigate the risk of scheduled work prolonging an outage. Minnesota Power may also include liquidated damages in these contracts to ensure that contractors are on schedule and paying attention to the milestones.

In our industry, major contractors are able to require limitation of liability provisions that may impact Minnesota Power's ability to hold a contractor accountable for all losses that could be caused by that contractor. In Minnesota Power's experience, many contractors will refuse to provide equipment or services if they cannot also limit their potential liability and financial exposure in the contract. Minnesota Power does not specifically include a contract provision that requires a contractor to pay replacement power costs; however, the specific clause is not necessary because contract remedies would allow for recovery of those costs if Minnesota Power could prove that the contractor caused the loss and there was nothing in the contract to limit or waive that recovery. In situations where a contract would allow for recovery of replacement power costs and a contractor would be responsible for those costs, Minnesota Power would actively pursue recovery from the contractor.

Otter Tail Power

(OTP, Additional Reply Comments, Docket #13-599, February 11, 2015, pp. 5-9, the following has been copied or excerpted, mostly verbatim, from OTP's Additional Reply Comments)

<u>Contractor Accountability</u>
Otter Tail has processes and procedures in place to select its vendors and contractors, and subsequently manage their work. Procurement and contracting processes assist in hiring the appropriate contractor and putting contractual terms in place that appropriately protect Otter Tail.

Project management processes and procedures assist in proper project quality-assurance and in holding contractors accountable. Otter Tail believes its current program serves Otter Tail's needs very well and requests that the Commission not require Otter Tail to adopt Xcel's program. A summary of Otter Tail's processes and procedures specifically related to Procurement, Contracting and Quality Assurance are listed below.

> <u>Procurement and Contracting</u>
> Standardized contracts are used as much as possible, with formal legal review required of all contracts over $250,000. Otter Tail believes that the use of competition in the supplier selection process helps Otter Tail achieve reasonable pricing and contractual terms.
>
> Otter Tail strives to have appropriate contractual assurances in place for each transaction by using standardized base contracts as much as possible for the purposes of warding off supplier dilution of the terms during the bid and negotiation process. A required step in Otter Tail's contracting process is the development of a Contract Risk Assessment ("CRA"). The CRA is a worksheet listing the main risks in the particular transaction(s) the contractor is hired for, what sections of the contract the risk is covered, and a narrative describing how each particular risk is addressed in the contract. The CRA allows for an appropriate contract to be developed as the transaction is negotiated with the supplier. The CRA documentation

enhances the risk assessment of a project and is a useful tool in the discussions between Subject Matter Experts ("SME"), Sourcing personnel, Legal, and Insurance in developing risk mitigation strategies. The CRA helps ensure the SME is aware of the risk associated with the work being done by the contractor; the risk is addressed in the contract; and assists the SME in holding the contractor responsible.

Depending on the nature of the project, additional financial assurances are also sought when needed. These assurances can include retainage, liquidated damage clauses, performance guarantees, letters of credit, bonds, etc. For instance, Retainage - the withholding of a portion of each invoice during a large construction project - is an excellent way to ensure performance.[16] The leverage that retainage provides helps ensure Otter Tail's work remains priority, which is especially critical if there is an issue on a particular project. In the end, this a key strategy that help's Otter Tail hold contractors accountable.

The contract approval process ensures he contract is reviewed at the appropriate levels up the organizational structure. The CRA is included with the contract as the contract moves through various levels of organizational approvals, to ensure the risks are flagged up for each reader to analyze and understand.

For major procurements on large construction projects, Otter Tail will often hold pre-Request For Proposal and pre-contract execution meetings between the SME, Project Management, Sourcing, Legal and Insurance personnel. These meetings allow for robust discussion regarding the project risks and ultimately help to more efficiently acquire the best vendor and execute the best contract possible.

<u>Quality Assurance ("QA") Quality Control ("QC")/ Project Management</u>
Each SME is responsible for quality of the work of the contractor. The size and nature of the project will often dictate what resources are used to ensure quality work is completed. On large projects, Otter Tail uses a separate QA SME and a QA firm. For the smaller construction projects, Otter Tail uses the SME and possibly an outside firm. Formal QAQC programs are developed for the larger projects. These plans are vetted heavily by Otter Tail's engineering staff, outside QA firms, and Sr. Engineering Management.

The scope of Project Management ("PM") required depends on the size and complexity of the project / transaction. Otter Tail's larger projects require that a Risk Register is completed by the Project Manager. The Risk Register is a worksheet or table listing the risks associated with the respective project as a whole. These are items that, if they occur, may cause the project to be delayed, cost more than expected, or to be postponed altogether. Each risk is analyzed and an estimated cost as well approximate probability of occurring is listed. The Risk Register assists Project Management in proactively managing the project and increasing the quality of work performed by all involved, including contractors. If needed, items

[16] Not only does the supplier suffer cost of capital expenses for amounts withheld during a long period of time, but (more importantly) the outstanding amounts affect the supplier's Days Sales Outstanding financial metrics. Any nonperformance of work will be more evident to not only supplier's operations groups, but also their financial and executive groups.

identified in the Risk Register are incorporated into the contractual terms of the supplier. There are other requirements, all of which assist in the project being well run and the respective contractors held accountable.

Given the size and nature of Otter Tail's business and the types of projects Otter Tail is involved in, the sourcing strategies and resources outlined above help Otter Tail to prudently scale and deploy resources as needed to effectively manage contractor performance and achieve desired performance outcomes. While Otter Tail's program may not be identical to that of Xcel's, Otter Tail believes its sourcing and contracting program achieves similar protections and outcomes as Xcel's program does for them.

Supplier Warranties

As summarized in Otter Tail's response above, Otter Tail uses numerous strategies and tools to enhance contractor performance. However, as Otter Tail previously stated in Comments submitted earlier in this docket, obtaining a warranty from a vendor for purposes of covering the costs of replacement power, as suggested by the Department, is generally not possible with most vendors without incurrence of significant cost relative to the amount of warranty coverage.

Otter Tail also would have a concern if the Commission were to require such a term without also indicating what amount of cost would be reasonable to add to a procurement contract to get this additional warranty. It should also be noted that the negotiation of terms and conditions for many procurement contracts can be complex and require the weighing of numerous terms including price, warranty, and other terms.

Interstate Power & Light

(IPL, Additional Reply Comments, Docket #13-599, February 11, 2015, pp. 3-7, the following has been copied or excerpted, mostly verbatim, from IPL's Additional Reply Comments)

Contractor Accountability

IPL seeks strong project controls within its contracts, including seeking to place the contractor in a position to meet or exceed outage schedules. IPL seeks these terms to place risk on the contractor for schedule and scope compliance. IPL seeks such terms so as to limit the Company's and, in turn, its customers' risk for extended outages. These rigorous project control provisions accompanied by liquidated damage provisions place the contractor in a position to meet or exceed their schedule and scope obligation. While there is a potential cost increase for this, it mitigates the risk for the owner in lieu of consequential damages for schedule and scope adherence.

Supplier Warranties

It is IPL's experience that construction contractors do not typically agree to include replacement power costs as a remedy for a project of any size.

However, for large capital construction contracts, such as the installation of a selective catalytic reduction technology at a generating unit, IPL seeks to transfer the risk of achieving a schedule milestone to a contractor. If the contractor fails to achieve that milestone then a liquidated damage is assessed against the contractor for each day of delay up to a cap, which is often a percentage of the overall contract price.

Additionally, mandating specific language in a contract regarding liability for replacement cost could dissuade reputable contractors from bidding on the project, and could ultimately lead to higher construction costs.

PUC Staff Comment

Minnesota Power indicated that it does not anticipate any impediment to adopting a centralized, standard approach to contractor quality management as long as that approach contains the flexibility needed to manage individual projects. Otter Tail, however, objected to the Department's recommendation because it believes its system for managing projects does not need to be supplemented or replaced. It is staff's impression that Otter Tail believes its current procedures for managing large construction projects are working and do not need to be modified. Staff assumes that MP and OTP will both consider the Department's recommendation to be friendly advice to conduct an internal evaluation of current procedures to ensure that best practices are adopted and followed.

All three utilities objected to adopting the Department's recommended supplier warranty language in their standard contracts. For the most part, these objections are based on the assumption that contractors would not be interested in working for the utilities if they had to warranty their work. The utilities also objected because the Department's proposed contract terms are outside industry norms.

Decision Alternatives

Contractor Accountability

1. Require Minnesota Power and Otter Tail Power to adopt Xcel's Quality Management program, identified in more detail in Attachment D of Xcel's November 10 comments, to hold contractors more accountable for replacement power costs, to the extent those practices are not already in place.

2. Take no action

Supplier Warranties

1. Require Xcel, Minnesota Power and Otter Tail Power to add language to the "Supplier Warranties" section of the contracts as discussed above to indicate that contractors may be liable for a limited amount of replacement power costs. [DOC]

2. Take no action

Business Interruption Insurance (BII)

Department of Commerce

(DOC, 2013 AAA Review – Docket #13-599, September 16, 2014, p. 23, the following has been copied, excerpted or adapted, mostly verbatim, from the Department's Review)

The Department notes that the legal process regarding Sherco 3 is likely to take several years to complete. In the meantime, this example raises an important question about the role that Business Interruption Insurance could play. Such insurance is defined as:

> **Business interruption insurance** (also known as **business income insurance**) covers the loss of income that a business suffers after a disaster while its facility is either closed because of the disaster or in the process of being rebuilt after it. A property insurance policy only covers the physical damage to the business, while the additional coverage allotted by the business interruption policy covers the profits that would have been earned. This extra policy provision is applicable to all types of businesses, as it is designed to put a business in the same financial position it would have been in if no loss had occurred.[17]

The Department requested that utilities discuss in reply comments whether they have obtained such insurance and, if not, why not. More specifically, the utilities were asked to respond to the following questions:

- Utilities should discuss their efforts to obtain Business Interruption Insurance due to any factor that causes an unplanned outage or longer than expected planned outage.
- If utilities have not obtained Business Interruption Insurance, they should provide a full explanation as to why not.

Xcel Energy

(Xcel, Reply Comments, #13-599, November 10, 2014, pp. 9-15, the following has been copied, excerpted or adapted, mostly verbatim, from Xcel's Reply Comments)

Xcel Energy carries business interruption insurance for our two nuclear plants, Prairie Island and Monticello, but not for any of our other plants. In our pending electric rate case, Docket No. E002/GR-13-868, we discussed why we believe business interruption insurance makes sense for our nuclear fleet but also why it is cost prohibitive for our non-nuclear fleet. The Direct Testimony of Company witness Mr. Michael Anderson states on pages 44-45:

> We carry business interruption insurance for our nuclear fleet for several reasons. As I have explained, all of our Insurance Program seeks to identify risks and insure them at a reasonable price. With respect to business interruption insurance, our nuclear fleet presents a different risk profile than our non-nuclear generation fleet and we obtain very cost-effective pricing for this product.

[17] Source: http://en.wikipedia.org/wiki/Business_interruption_insurance

> First, the marginal cost of energy from our nuclear plants is extremely low. Because of this, any replacement costs of energy are likely to be higher than the energy produced by our nuclear plants. This supports insuring against replacement energy costs for our nuclear sites but not for our non-nuclear fleet.
>
> Second, given the complexity of our nuclear operations, a forced outage of a nuclear plant is likely to last significantly longer than a normal forced outage of our non-nuclear fleet. I note that our nuclear business interruption insurance does not start providing coverage until an outage lasts at least 12 weeks.
>
> Third, our nuclear business interruption insurance is very cost-effective. [*****XCEL TRADE SECRET BEGINS*****
>
> *****XCEL TRADE SECRET ENDS*****] for our non-nuclear fleet.

As Mr. Anderson testifies, the nuclear business interruption insurance does not start providing coverage until the outage has lasted at least 12 weeks. Since we began reporting outages in our Fuel Cost Adjustment filings and corresponding AAA filings in 2007, only three non-nuclear outages have reached that 12 week threshold. For one of these outages, the 2011 outage event at Sherco 3, we have the ability to seek restitution through litigation because of faulty equipment. Assuming our litigation is successful, business interruption insurance coverage was not necessary to recoup those replacement power costs and in fact, **[*** XCEL TRADE SECRET BEGINS*****
***** XCEL TRADE SECRET ENDS*****]. Similarly, a longer outage at Key City was due to aging plant infrastructure, and while it may be possible this could be considered a covered event with properly maintained equipment, the cost of such insurance for our non-nuclear fleet is cost prohibitive and even if arranged, it would likely not be feasible to include peaking plants in a BII program.

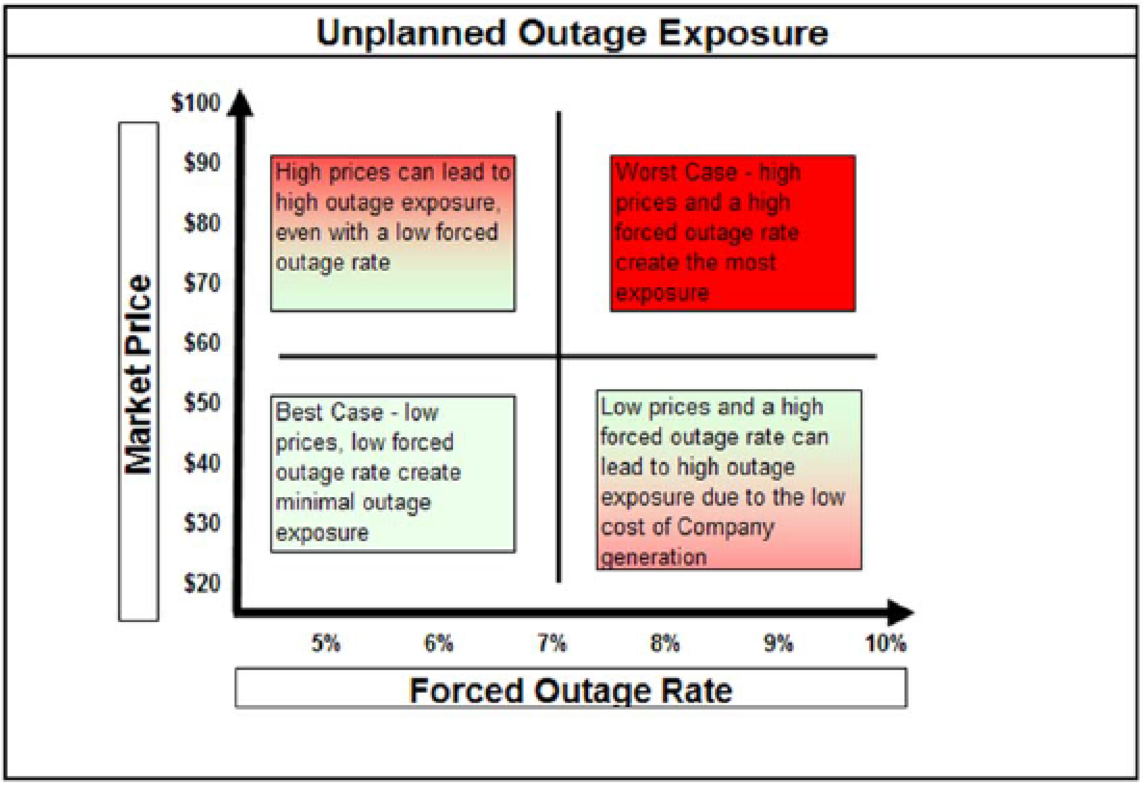
In summary, we do not believe that business interruption insurance for our non-nuclear fleet is cost effective or in the best interest of our customers.

Minnesota Power

(MP, Reply Comments, #13-599, November 10, 2014, pp. 3-5, the following has been copied, excerpted or adapted, mostly verbatim, from MP's Reply Comments)

Minnesota Power (MP) reviews all insurance coverage, including the potential to purchase business interruption insurance, on an annual basis as part of policy renewals. Minnesota Power currently has business interruption coverage for our Bison wind assets and the DC Line converter stations. This coverage was initiated to protect the low cost energy and related production tax credits for MP's customers. Minnesota Power performed a detailed risk assessment and determined that damage to the DC line converter stations, whether caused by a natural event such as a fire or by catastrophic equipment failure, would take significant time (potentially two to three years) to repair due to the unique/customized nature of the equipment and the lead time required to order and manufacture replacement equipment. An extended outage could create significant exposure, even with other mitigation (e.g. spare parts inventory help, using alternative AC transmission system, etc.), so the business interruption coverage was purchased to mitigate this low probability, but potentially high impact exposure.

MP has not purchased business interruption insurance for our thermal generation or hydro generation assets. The decision to not purchase coverage for thermal generation assets was based on reviewing market conditions, the company's expected energy position, and available business interruption coverage terms (premium, strike price, and deductible). The risk assessment methodology for unplanned outage exposure is summarized in the graphic below:



Market prices have remained relatively low and have shown reduced price volatility over the last 5 years. In addition, as thermal generation variable costs have increased over time, the difference between these costs and the wholesale power market costs have decreased. This difference is important when evaluating business interruption coverage because claims are based on these specific parameters. Minnesota Power performed scenario analysis, comparing both expected and stressed forced outage rates and market prices to different business interruption coverage options. Based on this analysis we found that Minnesota Power would not receive a net payout (insurance claims – deductible-premium) under most scenarios, unless we had an extremely high forced outage rate (e.g. over 15%) or average replacement energy purchase prices exceeded an extremely high level (e.g. $100/MWH+). Based on the low probability of an extremely high forced outage rate or extremely high wholesale market prices, we decided to not initiate coverage on MP's thermal generation assets.

We recently completed an extensive review of our hydro generation coverage, including the potential to add business interruption insurance. Our current property insurance carrier (FM Global) was not willing (past or present) to provide business interruption coverage for our hydro generation assets. Our brokers were able to identify one carrier that would provide coverage, but the premium was approximately three times higher than what Minnesota Power currently pays. Minnesota Power compared the potential cost of this coverage to a current unit-by-unit risk assessment and determined that we would not purchase coverage at this time. The major driver of this decision was the recent repairs completed to meet a higher FERC standard, reducing the probability of another significant event at MP's largest hydro facility.

Otter Tail

(OTP, Reply Comments, #13-599, November 10, 2014, p. 4, the following has been copied, excerpted or adapted, mostly verbatim, from OTP's Reply Comments)

During Otter Tail's 2014 property insurance renewal process, Otter Tail investigated business interruption insurance with its insurance carrier. Otter Tail requested a quote for this type of coverage. The minimum deductible for such coverage was not tied to a dollar value, but was instead tied to the length of time of the business interruption. In this particular case, the time element was 60 days. In other words, the coverage for business interruption would not start until after the forced outage or outage extension went beyond 60 days.

Based on past experience with the durations of forced outages, Otter Tail determined that the cost of the additional premium for such coverage outweighed the benefit of adding that coverage. Otter Tail will likely revisit this or similar types of coverage again in future renewals.

IPL

(IPL, Reply Comments, #13-599, November 10, 2014, pp. 6-7, the following has been copied, excerpted or adapted, mostly verbatim, from IPL's Reply Comments)

IPL annually reviews the state of the market for Business Interruption Insurance with the Company's insurance broker. The market does not support economical rates for the coverage based on IPL's exposures.

It is more economical for IPL to utilize the other resources within the Company's fleet, or purchase power in the market, than to pay the premiums that the market dictates. IPL understands that market conditions have also led other utilities to the same conclusion.

Department of Commerce

(DOC, Response Comments, #13-599, December 31, 2014, pp. 6-9, the following has been copied, excerpted or adapted, mostly verbatim, from the Department's Response Comments)

Utilities responded to the request for information about business interruption Insurance largely by stating that it would not be a viable option; however, none of the utilities provided any quotes from insurance companies for the costs of business interruption insurance for fossil-fueled generation facilities.

According to OTP,

> Otter Tail requested a quote for this type of coverage. The minimum deductible for such coverage was not tied to a dollar value, but was instead tied to the length of time of the business interruption. In this particular case, the time element was 60 days. In other words, the coverage for business interruption would not start until after the forced outage or outage extension went beyond 60 days.

OTP concluded that "the cost of the additional premium for such coverage outweighed the benefit of adding that coverage." However, OTP did not provide the results of the quote or the cost of the premium.

MP has business interruption coverage, but only for its Bison wind assets and the DC line converter stations. MP purchased the coverage to "protect the low cost energy and related production tax credits for MP's customers." MP explained that it did not purchase business interruption insurance for its thermal or hydro generation assets based on "market conditions, the company's expected energy position, and available business interruption coverage terms." MP's assessment led the Company to conclude that it would not be cost effective to obtain such insurance. However, MP did not provide any data to support that claim.

Xcel Electric was the only utility that provided a cost estimate for the business interruption insurance; however, this estimate was Xcel's figure and was not supported by quotes from any insurance company. Xcel Electric also stated that it does "not believe that business interruption insurance for our non-nuclear fleet is cost effective or in the best interest of our customers." By contrast, Xcel Electric stated that it carries nuclear business interruption insurance because it is "very cost-effective," even though "the nuclear business interruption insurance does not start providing coverage until the outage has lasted at least 12 weeks."

Given the lack of support by utilities for their statements, the Department discussed this issue with Minnesota Insurance Regulators, who noted that, if utilities can pass all costs of replacement power through the FCA to ratepayers, the risk of high replacement power costs would be transferred to ratepayers, leaving little or no risk to insure for utilities. Even if, say, a utility bought business interruption insurance on behalf of its customers and charged ratepayers for those costs in the FCA, the mechanism would be flawed because the party that would bear the risk (ratepayers) would not be the party that could manage the risk (utilities) by abiding by inspection and repair guidelines, hold contractors accountable for their missteps, etc.:

> We can find ways to cover this exposure/risk, you can also utilize a Boiler & Machinery product and/or Business Interruption policy. The difficulty is that the Utilities have no "skin in the game", i.e., the regulation change needs to come first,

> the insurance industry could then respond. At this point, there is no incentive to the utility to purchase the coverage.

Of course, ratepayers could not ensure that utilities followed all of those practices to minimize the risk of an unplanned outage; thus, the risk/responsibility structure would be flawed.

Office of Attorney General

(OAG, Comments, December 30, 2014, #13-599, pp. 8-11, the following has been copied, excerpted or adapted, mostly verbatim, from the OAG's Comments)

It is important to ensure that ratepayers are receiving utility service at a reasonable rate. As Xcel Energy's experience with the long-term loss of Sherco 3 has shown, interruption in normal utility production can have significant financial consequences on fuel costs and charges for replacement power. Business interruption insurance ("BII") may have the potential to insulate ratepayers and utilities from excessive risk related to plant outages. In the context of automatic recovery of fuel costs, all Minnesota utilities essentially have a form of BII under the current system: either an insurance company has issued a policy for such insurance, or the ratepayers provide full coverage, with no deductible (and without even collecting a premium). The Commission should examine the equity of putting the ratepayers in the position of providing this coverage free of charge, and alternatives for shifting that risk off of ratepayers.

BII insures against lost cash flows for outages caused by severe weather, terrorism, fire, explosions, and other events that cause an outage to occur at a utility's generation facility. The DOC requested information from each utility regarding its efforts to obtain and use BII, and a full explanation as to why the utility has not obtained BII.[18] Each utility filed comments that briefly explained each company's experience with BII. The utilities' responses to these questions were not satisfactory, especially in explaining why they have generally not obtained BII. This subject is not simple and answering these questions demands a certain amount of specificity and analysis; most utilities did not provide sufficient information to fully analyze this issue.

In general, most utilities stated that they found that BII was too expensive.[19] On the other hand, Xcel Energy has BII for its nuclear operations[20] and Minnesota Power has BII for its Bison Wind assets.[21] The fact that some utilities have found BII affordable and appropriate for some types of generation assets, while other utilities have found it unaffordable for other assets, demonstrates that simply stating that coverage is "too expensive" is not a sufficient answer to the question. Assuming Xcel Energy and Minnesota Power acted prudently in obtaining their coverage, this information demonstrates that for certain types of generation (e.g., base load and low fuel cost generators), and under certain circumstances, BII is appropriate and affordable.

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[18] Department of Commerce Report at 15 (September 16, 2014).
[19] Of the four utilities that responded to the Department's request to provide information on their efforts to obtain business interruption insurance, none concluded that it was viable as a generalized solution. Xcel and Minnesota Power have BII for their nuclear and select wind assets, respectively. IPL and Otter Tail Power claimed that they do not have any form of BII and have concluded that it was not in their respective interest to acquire it.
[20] Xcel Energy Reply Comments at 9 (November 10, 2014).
[21] Minnesota Power Reply Comments at 3 (November 10, 2014).

Utilities that found BII (other than pass-through of fuel costs to ratepayers) to be too expensive must provide sufficient explanation as to how they reached that conclusion. One company stated that an interruption of 60 days had never occurred previously in its system, so it did not find it financially feasible to purchase BII.[22] However, this is not an appropriate application of probability theory – the probability of an event occurring at a given generation facility is not zero or reduced because such an event has not occurred in the past. By claiming that BII is too expensive, utilities are implicitly claiming that they have estimated the probability of the event occurring and the costs associated with each event. No such analysis was provided, and such an answer is far too simplistic for this complicated issue. Additionally, taking the utilities' claims at face value, if insurance companies have provided quotes for coverage that multiple utilities have deemed too expensive to accept, it could be that there is some type of risk that the insurance companies do not want to underwrite. The Commission should examine this risk and all options available to mitigate it because, under the current system, the ratepayers will bear that risk in the absence of any other arrangement.[23]

Deregulated electric generators have more of an incentive to purchase BII because they are not able to shift risk onto ratepayers through the regulatory structure. BII is common in the burgeoning solar generation market even though insurance premiums can make up to 25% of a solar system's annual operating expense.[24] For this reason, the OAG would like a much more rigorous explanation as to why utilities are not purchasing BII, especially on those facilities that would logically benefit most from it.

The OAG has requested additional analysis from each of the electric utilities[25] in order to explore this issue further. The OAG recommends that in reply comments each utility should submit a more detailed response to the initial questions posed by the DOC, and which responds to the following:

1. Given that Xcel Energy and Minnesota Power obtained BII for some generation facilities, there must exist some cost threshold or breakeven point for BII that depends on variables. More simply said, there is a price at which BII becomes affordable given the characteristics of a generation facility. Each utility should discuss this threshold and the variables considered to influence this threshold. The response should include quantification of the threshold and variables whenever possible.

    a. This response should include discussion of quotes from insurance companies, and an estimate of an "affordable" BII premium for a generation facility that uses cost-benefit principles, among other things.

[22] Otter Tail Power Reply Comments at 4 (November 10, 2014).
[23] There may be disincentives influencing the utilities' willingness to purchase BII. First, the utilities likely consider themselves to have been adequately protected by using ratepayers as their insurance against unanticipated costs of this type. Second, utilities and their shareholders would bear the risk that an insurance company might not pay their claims if they were found to be negligent or otherwise culpable.
[24] National Renewable Energy Laboratory, Insuring Solar Photovoltaics: Challenges and Possible Solutions, at iv (Feb. 2010).
[25] Excluding Dakota Electric Association.

b. This response should include discussion of all underwriting criteria that are used by the insurance brokers that were contacted by each utility.

c. This response should include an explanation as to why additional brokers were not contacted if the primary insurance broker for the utility did not offer BII, or it was deemed too expensive.

2. If a utility finds that BII is still too expensive once a more comprehensive analysis has been completed, it should discuss the characteristics that are causing the premiums and deductibles to be too high and how it plans to better insulate ratepayers from these risks without BII.[26]

3. The utilities should discuss the possibility of using other risk management instruments to control for price increases in the event of an outage. For example, what are the opportunities for the utilities to use call-put option collars, forward contracts, or other techniques and instruments to control for replacement power costs?

Xcel Energy

(Xcel, Additional Reply Comments, #13-599, February 11, 2015, p. 6, the following has been copied from Xcel's Additional Reply Comments)

The Department discussed the issue of Business Interruption Insurance (BII) in its Response Comments and acknowledged that Xcel Energy provided a BII cost estimate in our Reply, but noted the estimate was not supported by quotes from any insurance company. Attachment A to these Reply Comments is our response to Information Request No. OAG-6 in this docket which provides the supporting term sheet for our estimate. As we stated in the discovery response, a firm bid for business interruption insurance is only issued if there is a commitment to purchase the insurance. To date we have not found this type of insurance to be practical or cost effective, so we have not made such a commitment and solicited firm bidding prices.

As stated in our response to OAG-6, we periodically solicit these term sheets to assess whether BII is cost-effective and therefore in the best interest of our customers. At this time, BII is not cost-effective, and we believe continuing to obtain information through term sheets is the right approach to gain knowledge of current conditions and to protect our customers from unnecessary costs.

Minnesota Power

(MP, Reply Comments, Docket #13-599, February 11, 2015)

Minnesota Power did not provide additional comments on business interruption insurance.

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[26] Some risk will remain due to the expense of decreasing risk. The objective is to ensure that utilities are not shifting risk that would be cost effective to avoid and that the utility is identifying all relevant information.

Otter Tail Power

(OTP, Additional Reply Comments, Docket #13-599, February 11, 2015, pp. 5-9, the following has been copied or excerpted, mostly verbatim, from OTP's Additional Reply Comments)

Both the Department and the OAG have advanced the idea that the utilities should be exploring further, the use of business interruption insurance for purposes of covering replacement power costs associated with forced outages.

Otter Tail has worked with its insurance provider to understand the Business Interruption ("BI") products available. Coverages are generally specific to each location, based on each location's unique factors. In addition Otter Tail found that BI insurance, if available for a location, can be purchased in a range of coverages for a range of perils or exposures. The lowest cost coverage typically insures the differential cost between power generated at the location and power purchased on the open market with coverage for limited perils or exposures (for example equipment breakdown only, natural hazards, contingent BI for offsite assets such as transformers or power lines owned by others, etc…). The highest cost coverage insures 100 percent of the financial impact had the asset not been impaired and would cover the broadest range of perils and exposures.

For its evaluation, Otter Tail has relied on insurance industry rate ranges, as provided by the insurer, for business interruption insurance. Costs range from $0.55 to $1.20 per $100 of limit purchased with a minimum 60 day deductible. The range in pricing is due to varying levels and types of business interruption insurance available and location-specific factors that would be considered in underwriting (as described above). Based upon these premium levels and Otter Tail's historic performance experience, it was determined that purchasing such insurance would not be a reasonable value. Our insurer notes that less than 5 percent of regulated utilities purchase business interruption insurance.

Otter Tail also notes that the OAG made the following statement in their December 31, 2014 Comments, claiming that Otter Tail had previously stated it had never had an interruption longer than 60 days:

> Utilities that found BII (other than pass-through of fuel costs to ratepayers) to be too expensive must provide sufficient explanation as to how they reached that conclusion. One company stated that an interruption of 60 days had never occurred previously in its system, so it did not find it financially feasible to purchase BII.

What Otter Tail <u>actually stated</u> in its Reply Comments submitted on November 10, 2014 was:

> During Otter Tail's 2014 property insurance renewal process, Otter Tail investigated business interruption insurance with its insurance carrier. Otter Tail requested a quote for this type of coverage. The minimum deductible for such coverage was not tied to a dollar value, but was instead tied to the length of time of the business interruption. In this particular case, the time element was 60 days. In other words, the coverage for business

> interruption would not start until after the forced outage or outage extension went beyond 60 days.
>
> Based on past experience with the durations of forced outages, Otter Tail determined that the cost of the additional premium for such coverage outweighed the benefit of adding that coverage. Otter Tail will likely revisit this or similar types of coverage again in future renewals.

While Otter Tail has historically had very few forced outages that exceeded 60 days, <u>Otter Tail wants to be clear that Otter Tail did not claim that it has never had a forced outage longer than 60 days</u>, as the OAG Comments suggest.

Otter Tail's risk management process associated with plant maintenance and operations includes two primary components. The initial focus is on minimizing the probability of equipment breakdown by implementing maintenance programs focused on engineering out losses before they occur. The second focus is to minimize the financial consequences of losses that do occur. Otter Tail's insurance program is instrumental throughout the risk management process. In addition to providing insurance on physical assets, Otter Tail's insurer provides loss preventions services including site evaluations, risk quality benchmarking, client training and impairment management. Otter Tail attributes its historically low frequency and duration of outages to its loss prevention activity.

Otter Tail knows the probability of a loss exceeding 60 days is something greater than zero however Otter Tail believes the expense required to maintain the loss prevention component of its risk management program is a better use of funds than the purchase of insurance to finance the consequence of losses that its history indicates have a low probability of occurring.

Interstate Power & Light

(IPL, Additional Reply Comments, Docket #13-599, February 11, 2015, pp. 3-7, the following has been copied, excerpted or adapted, mostly verbatim, from IPL's Additional Reply Comments)

In response to the OAG's questions, IPL indicated that it does not have specific analysis of premium and price to insure IPL's risk for generation interruptions. Based on utility benchmarking data, IPL makes a general inquiry with its broker and does not provide specific underwriting criterion. Generating mixes, risk profiles and financial structures differ throughout utility peers. Availability of BII or Replacement Power/Unplanned Outage insurance can vary by fuel type (for example, IPL understands that nuclear coverage is more readily available), loss history and the particular turbine generators to be covered. The property insurance broker has market knowledge as to the availability of coverage, including limits, terms, retentions and price based on our profile. After a general inquiry with insurers, the broker is able to determine that the markets appetite for this risk has not developed to a point where coverage with meaningful limits, retentions and price available and specific inquiry relative to our risk would not be fruitful.

The Midcontinent Independent System Operator, Inc. (MISO) provides its members the flexibility to rely on the market for short-term and longer-term energy needs. In the case of a short-term (less than one month) forced outage, a utility is able to continue purchasing its load from MISO and simply loses any financial hedge value that may have been provided by the generator suffering the outage, while having the ability to procure short-term energy purchases in the bilateral market to attempt to replace the hedge. For outages expected to last more than one month, utilities can enter into limited duration bilateral power purchase agreements that provide hedging benefit into the future.

Due to the size, stability and nature of the MISO energy market, the loss of any individual generator would likely have only a minimal impact on the energy price for the market overall, including the pricing for forward purchases at the major trading hubs. However, there could still be local congestion-driven cost impacts that result from outages that result in financial impact, but for which no marketing company would be willing to become exposed.

Historically, IPL's hedging activities typically included the use of financial and derivative instruments to increase price stability. IPL had previously requested variances to the fuel clause adjustment (FCA) rules, as financial hedging was not specifically covered by the FCA rules, but has since expressed its intent to discontinue future requests for a variance. Should sufficient interest be expressed, IPL would participate in a future rulemaking addressing the ability of Minnesota electric public utilities to recover the costs of financial hedging through the FCA rules.

Office of Attorney General

(OAG, Reply Comments, Docket #13-599, February 11, 2015, pp. 2-8, the following has been copied or excerpted, mostly verbatim, from OAG's Reply Comments)

In its February 11, 2015 reply comments, at pages 1 through 2, the OAG agreed with the Department's conclusion that the utilities did not provide sufficient analysis to support their claims that BII is cost prohibitive, but did not agree that BII would only be beneficial to ratepayers when it is accompanied by a fuel clause adjustment incentive mechanism. The OAG stated that BII would function better with a fuel clause incentive mechanism. However, even without a fuel clause incentive mechanism, BII would provide benefits to ratepayers. The OAG stated that "The Commission should order utilities to conduct further analysis on the costs and benefits of BII for ratepayers" that presumably incorporates, at a minimum, the recommendations in the OAG's previous comments.

- The Utilities Provided Contradictory And Misleading Information About BII

Multiple utilities provided Reply Comments in those dockets and additional information has been produced to the OAG by the utilities on the subject of BII. In general, the information provided by most utilities has been sparse and lacked detailed analysis. At best, the information is incomplete and insufficient to determine whether BII is affordable. In analyzing the comments and responses to information requests that have been provided, the OAG found that the utilities provided contradictory and possibly misleading information. It appears that most utilities have not fully analyzed the costs and benefits of BII to ratepayers. Those utilities with incomplete analyses should be ordered by the Commission to conduct further analysis to ensure that ratepayers are paying reasonable rates, and not taking on unreasonable risks, for the service they are receiving.

In Xcel's November 10, 2014 Trade Secret Reply Comments, the company estimated that insuring its non-nuclear fleet would cost **[***XCEL TRADE SECRET BEGINS*** ***XCEL TRADE SECRET ENDS***]**. However, in its response to OAG Information Request 6, Xcel noted that "(t)he above-noted cost estimate includes our 20 largest units across the entire Xcel Energy service territory, not just generators in the NSP System. The cost share for NSPM would likely be at the lower end of the noted range."[27] This was not explained in its comments filed with the Commission. Moreover, Xcel did not provide any documentation to support the original claimed cost. When the OAG sought additional information regarding the basis for Xcel's estimate of NSPM costs, it revealed that the company calculated the figures based on a verbal estimate from its broker.[28] Xcel estimated that NSPM's portion of the costs would be in the range of **[***XCEL TRADE SECRET BEGINS***

XCEL TRADE SECRET ENDS]**.

Xcel's claimed costs for BII are questionable. For comparison purposes, the OAG calculated each of the responding utility's cost according to both premium cost per $100 of coverage and by premium cost per megawatt. Xcel estimated BII to cost [***XCEL TRADE SECRET BEGINS*** ***XCEL TRADE SECRET ENDS***].[29] By comparison, Otter Tail Power ("OTP") received a verbal quote[30] from its insurer of $0.55 to $1.20 per $100 of coverage for BII.[31] Minnesota Power ("MP") pays [***MP TRADE SECRET BEGINS*** [***MP TRADE SECRET ENDS***[32] for BII that is currently in place. MP's cost is the only cost that was actually provided by an insurance company in writing, while OTP and Xcel relied on verbal quotes. Xcel's estimate is **[*** XCEL TRADE SECRET BEGINS***

XCEL TRADE SECRET ENDS].[33]

The utilities have also not taken the steps necessary to sufficiently evaluate BII. The OAG has attached two excerpts from the Market Power Review and an article from Power Engineering International that discuss the communication process and informational exchange that can be

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[27] See Xcel's response to OAG Information Request 6, attached as Exhibit A.
[28] See Xcel's response to OAG Information Request 21, attached as Exhibit B.
[29] See Xcel's response to OAG Information Request 6, attached as Exhibit A.
[30] See OTP's response to OAG Information Request 10, attached as Exhibit C.
[31] OTP did not provide enough information to make the dollars per megawatt calculation. For OTP's estimate, see its response to OAG Information Request 9, attached as Exhibit D.
[32] See MP's response to OAG Information Request 13 and 14, attached as Exhibit E
[33] While the OAG recognizes that comparing the different estimated BII cost information that has been provided from different utilities is not a direct comparison, it is the best comparison possible with the information provided by the utilities.

followed to procure an accurate quote for BII.[34] These articles describe basic steps that utilities should take in evaluating BII. For example, a common first step would be for the utility's broker to send an engineer to meet station managers and carry out a risk assessment to compile a risk report.[35] It is not clear utilities have completed this initial step or any of the subsequent recommended steps as outlined in these articles. Moreover, a key conclusion that the Power Engineering International article comes to is that if a company is quoted a high premium, the company is either not providing enough information or it has a risk management problem that is being identified by the insurer.

Utilities have also provided contradictory information regarding the different types of BII, the restrictions that insurance companies may or may not apply to BII policies, and how these factors could impact affordability. OTP included the following summary on the different types of BII coverage:

> Otter Tail found that the coverage is specific to each location, based on each location's unique factors. In addition Otter Tail found that BII, if available for a location, can be purchased in a range of coverages [sic] for a range of perils or exposures. The lowest cost coverage typically insures the differential cost between power generated at the location and power purchased on the open market with coverage for limited perils or exposures (for example equipment breakdown only, natural hazards, contingent BII for offsite assets such as transformers or power lines owned by others, etc…). The highest cost coverage insures 100 percent of the financial benefit that would have passed to the insured had the asset not been impaired and would cover the broadest range of perils and exposures.[36]

On the other hand, Xcel noted that BII "would not be available for purchase for a single plant, but would need to be purchased for a group of plants."[37] Xcel did not indicate whether a minimum number of generation facilities would be required in order to obtain a BII policy, nor did it substantiate the claim that BII cannot be purchased for fewer plants than Xcel's estimate included with information provided directly from an insurer or broker. For its part, MP insured fewer plants than Xcel stated it could, but [***MP **TRADE SECRET BEGINS*****]
[***MP **TRADE SECRET ENDS*****].[38] Each utility has provided limited analysis of differing types of BII and, except for MP, has not provided sufficient analysis to demonstrate whether the differing types of BII are prudent. OTP's, IPL's, and Xcel's methodologies do not rely on quotes from direct insurers[39] or any detailed analysis of the affordability of BII. Failure to consider this basic information is unreasonable.

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[34] Power Market Review (Summer 2010). Global Markets International. Found at: http://www.willis.com/Documents/Publications/Industries/Renewables/PowerMarketReview.pdf (attached as Exhibit F) and Power Engineering International, Power and insurance – an effective partnership (2011). Found at: http://www.powerengineeringint.com/articles/print/volume-19 /issue-5/features/power-and-insurance-an-effectivepartnership. html (attached as Exhibit G).
[35] Power Engineering International (2011).
[36] See OTP's response to OAG Information Request 11, attached as Exhibit H.
[37] See Xcel's response to OAG Information Request 6, attached as Exhibit A
[38] See MP's response to OAG Information Request 13 and 14, attached as Exhibit E.
[39] Xcel and OTP used verbal quotes from brokers to make calculations. The complexity of BII, including the numerous options available and types of generation, make verbal quotes a questionable method to receive accurate

- The Utilities Failure to Purchase BII is Influenced by the Lack of Incentive to Minimize Fuel Costs

Evidence suggests that regulated utilities are failing to minimize fuel costs to the detriment of ratepayers. A recent report found that deregulated coal generation plants pay 12% less for coal than do regulated plants, primarily because regulated generators pass through costs directly to ratepayers and have no incentive to "shop around" for lower coal prices.[40] The same report found that regulated utilities choose to spend more money on coal scrubber technology to comply with regulation, instead of simply substituting cheaper low-sulfur coal to accomplish the same result, in order to make additional returns on their capital improvements.[41] Each of these findings support the claim that regulated utilities do not minimize their fuel costs without having an incentive to do so.

The fact that regulated utilities do not have an incentive to minimize their fuel costs could impact whether or not they consider BII to be a profit-maximizing business decision. Since both fuel and replacement fuel costs are passed directly through to ratepayers, utilities' interest in obtaining BII is lower than it would be if utilities internalized some fuel cost risk. Evidence suggests that regulated utilities do not consider BII to be necessary for their businesses. In OTP's response to OAG Information Request 10, the company stated that its "insurer notes that less than five percent of regulated utilities purchase business interruption insurance."[42] Given that regulated utilities do not have an incentive to minimize fuel and replacement fuel costs, this statement should not be a surprise. It should also not be surprising that unregulated electricity generators commonly purchase BII because those generators retain the risk of replacement fuel costs associated with forced outages.[43] Given that regulated utilities do not minimize fuel costs and that unregulated electricity generators purchase BII due to the risk of replacement power costs, it is likely that regulated utilities are not purchasing BII because they have no incentive to minimize the costs BII would insure against.

For this reason, the DOC indicated that the effectiveness of BII will be greatly compromised unless utilities have an incentive to minimize fuel and replacement fuel costs. Specifically, the DOC stated "(e)ven if, say, a utility bought business interruption insurance on behalf of its customers and charged ratepayers for those costs in the FCA, the mechanism would be flawed

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and complete information. While such a quote may have been an acceptable bases to provide an initial response to the Commission, a more thorough analysis and a more transparent methodology are required so that the Commission can control for variables affecting cost and protection for ratepayers.

40 NBER, When Does Regulation Distort Costs? Lessons From Fuel Procurement in U.S. Electricity Generation. Cicala (2014).

41 Id.

42 See OTP's response to OAG Information Request 10, attached as Exhibit C.

43 See Law360 Underwriting the Wind, December 20, 2010, and NREL, Insuring Solar Photovoltaics: Challenges and Possible Solutions (2010) for information on BII for wind and solar. Exelon Generation is an example of a firm that insures its solar and wind generation facilities. See Part I, Item 1 at 15, February 21, 2013 of 10-K report. See Power Engineering International article for a discussion of BII in the (mostly unregulated) electric generation sector in other countries, attached as Exhibit F.

because the party that would bear the risk (ratepayers) would not be the party that could manage the risk (utilities) by abiding by inspection and repair guidelines, hold contractors accountable for their missteps, etc. . . .” For this reason, the DOC suggests that a mechanism to incent utilities to reduce their fuel costs must come before the utility obtains BII.

BII would be more beneficial if a FCA incentive mechanism were in place, but BII could be a prudent cost without such a mechanism. First, BII could require the utility to prove that an interruption, such as a forced outage, was not caused by its negligence. Second, BII is often a policy that guards against catastrophic incidents. A FCA incentive mechanism would ensure that utilities are minimizing their costs under normal conditions, but stops far short of insuring that catastrophic events do not occur and provides no protection for ratepayers if such an event were to occur. Regardless, the FCA incentive mechanism and BII complement one another and it is clear that ratepayers would be less likely to pay inflated fuel costs with a FCA incentive mechanism. It is also clear that utilities need to conduct further analysis on the costs and benefits of BII. The Commission should require additional analysis of BII by the utilities and implement beneficial ratepayer protections.

PUC Staff Comment

The Department appears to be of the opinion that until there is a regulation change so that utilities have some “skin in the game”, the risk/responsibility structure would be flawed. Thus, it appears that the Department thinks the regulation change, such as their proposal with respect to the FCA mechanism, should come first.

The OAG, on the other hand, has recommended that the Commission order the utilities, or at least Xcel, OTP and IPL, to conduct a meaningful analysis on whether BII is in the interest of ratepayers. The OAG recommends that this analysis incorporate, at a minimum, the recommendations made in its December 30, 2014 comments.

The utilities appear to feel that they are taking enough of a look at BII at a high level, and that based on the current market, have in most instances decided not to purchase BII for the bulk of their facilities.

The Commission should decide whether it wishes to require further analysis of BII. If further analysis is required, the commission should decide:

- which utilities should file further analysis;
- if that further analysis should follow the OAG’s recommendations, or whether it wishes to set different, or no, parameters on the further analysis; and
- where and when it would like to see such further analysis (e.g., in a compliance filing in this docket; in the utilities’ next AAA reports, which would be filed September 1, 2016).

A cost/risk/potential benefit analysis of BII for various facilities, or groups of facilities, might be helpful for the Commission to determine if BII and the risk to ratepayers have been seriously considered by each utility. Since IPL no longer has retail operations in Minnesota, staff suggests that the Commission may wish to consider having Xcel, MP, and OTP provide such an analysis, with quotes from insurers, in their September 2016 AAA reports. For example, staff found helpful in understanding the analysis that was done by MP, MP's explanation that it performed a scenario analysis upon which it determined that MP "would not receive a net payout (insurance claims – deductible-premium) under most scenarios, unless [MP] had an extremely high forced outage rate (e.g. over 15%) or average replacement energy purchase prices exceeded an extremely high level (e.g. $100/MWH+)."

The Commission could require the electric utilities to provide sufficient explanation in the 2016 AAA reports as to how they reached the conclusion to:

- Purchase BII for those facilities for which they purchased it, including an evaluation of the risk posed by an interruption, and the cost and terms of the policy; and

- Not purchase BII for those facilities for which they did not purchase it, including an evaluation of the risk posed by an interruption, the potential costs of an interruption, insurer quotes for the cost of BII for those facilities along with details of the considered terms such as deductible and/or length of outage before coverage kicks in.

Decision Alternatives

1. Take no further action at this time. [The Department did not recommend any further action on BII.] OR

2. Require Xcel, OTP, and IPL [or some other configuration of utilities] to conduct a meaningful analysis on whether BII is in the interest of ratepayers that incorporates, at a minimum, the following: [OAG Recommendation]

    a. Given that Xcel Energy and Minnesota Power obtained BII for some generation facilities, there must exist some cost threshold or breakeven point for BII that depends on variables. More simply said, there is a price at which BII becomes affordable given the characteristics of a generation facility. Each utility should discuss this threshold and the variables considered to influence this threshold. The response should include quantification of the threshold and variables whenever possible.

        i. This response should include discussion of quotes from insurance companies, and an estimate of an "affordable" BII premium for a generation facility that uses cost-benefit principles, among other things.

        ii. This response should include discussion of all underwriting criteria that are used by the insurance brokers that were contacted by each utility.

iii. This response should include an explanation as to why additional brokers were not contacted if the primary insurance broker for the utility did not offer BII, or it was deemed too expensive.

b. If a utility finds that BII is still too expensive once a more comprehensive analysis has been completed, it should discuss the characteristics that are causing the premiums and deductibles to be too high and how it plans to better insulate ratepayers from these risks without BII.[44]

c. The utilities should discuss the possibility of using other risk management instruments to control for price increases in the event of an outage. For example, what are the opportunities for the utilities to use call-put option collars, forward contracts, or other techniques and instruments to control for replacement power costs?

OR

3. Require Xcel, Minnesota Power, and Otter Tail Power to provide sufficient explanation in the 2016 AAA reports as how they reached the conclusion to: [Staff provided alternative.]

    a. Purchase BII for those facilities for which they purchased it, including an evaluation of the risk of an interruption, and the cost and terms of the policy; and

    b. Not purchase BII for those facilities for which they did not purchase it, including an evaluation of the risk of an interruption, the potential costs of an interruption, insurer quotes for the cost of BII for those facilities along with details of the considered terms such as deductible and/or length of outage before coverage kicks in.

[44] Some risk will remain due to the expense of decreasing risk. The objective is to ensure that utilities are not shifting risk that would be cost effective to avoid and that the utility is identifying all relevant information.

Otter Tail Power's RSG and Make Whole Payments Costs

Department of Commerce

(DOC, 2013 AAA Review – Docket #13-599, September 16, 2014, pp. 39-40)

In its review of Otter Tail Power's (OTP's) MISO Day 2 charges, one of the items the Department noted was that OTP's Revenue Sufficiency Guaranty (RSG) and Make Whole Payments costs totaled $251,163.27 in May 2013. This amount was significantly higher than the costs OTP charged to other months during the 2012-2013 AAA reporting period. The Department recommended that OTP explain, in reply comments, why it incurred such large RSG and Make Whole Payments costs in May 2013 and why these costs are appropriately assigned to retail customers. (The Department recommended that the Commission accept all other aspects of OTP's MISO Day 2 reporting.)

Otter Tail Power

(OTP, Reply Comments, Docket #13-599, November 10, 2014, p. 12, the following has been copied or adapted, mostly verbatim, from OTP's Reply Comments)

The increase in RSG and Make Whole Payments for the month of May 2013 was primarily driven by a then recently installed automated real-time load forecasting software program. This software program reforecast Otter Tail load after the Day Ahead (DA) forecast was submitted, yet prior to actual Real Time values. Submitting updated forecast information prior to the real time allowed for potential netting (reducing) of deviations from the DA schedule, which in turn would reduce RSG charges.

For a portion of the May 2013 month, Otter Tail discovered the load data transfer between Otter Tail and MISO was increasing the deviations. This resulted in increased RSG charges for a few days. Otter Tail immediately ceased use of the program when settlement statements revealed higher RSG charges. Otter Tail was unable to determine the cause of the data transfer issue with MISO. At present, Otter Tail is not utilizing the above described reforecasting software.

RSG charges are a MISO expense which the company incurs in order to serve retail load. OTP believes it is appropriate to assign these charges to retail customers.

Department of Commerce

(DOC, Response Comments, Docket #13-599, December 31, 2014, pp. 23 & 26, the following has been copied or adapted, mostly verbatim, from the Department's Response Comments)

The Department reviewed OTP's reply comments and concludes that, while OTP explained the source of the significantly higher RSG charges, OTP did not adequately explain why rate payers should be held solely responsible for the increased RSG and Make Whole Payments caused by the software issue. Nor is it clear to the Department how much testing OTP did of what was a new tool, prior to using it.

The Department appreciates that OTP stopped using the defective software, but does not believe OTP has provided a reasonable explanation for why all of the costs of the defective software used in May 2013 should be assigned to ratepayers. OTP's statement that "RSG charges are a MISO expense which the company incurs in order to serve our retail load" does not address this question.

Thus, the Department recommends that the Commission disallow at least 50 percent of the difference between the May 2013 RSG level and the average RSG monthly charges for this period or require OTP to identify (and explain) the portion of that amount that is due to the software issue.

The Department concludes that OTP adequately answered all of the Department's other questions in regards to MISO Day 2 Costs, but concludes that it is not reasonable to charge all of the incrementally higher charge accrued in the month of May 2013 for RSG and Make Whole payments to retail customers. Thus the Department recommends that the Commission disallow at least 50 percent of the difference between the May 2013 RSG level and the average RSG monthly charges for this period or require OTP to identify (and explain) the portion of that amount that is due to the software issue.

Otter Tail Power

(OTP, Additional Reply Comments, February 11, 2015, pp. 2-3, the following has been copied or adapted, mostly verbatim, from OTP's Additional Reply Comments)

Otter Tail deployed a software program in 2013 that would reforecast Otter Tail load after the initial Day Ahead ("DA") forecast was submitted to MISO. This update to RT forecasts prior to the incurrence of actual RT values, was done for the purposes of providing a more current forecast prior to RT, to allow for potential netting (reducing) of deviations from the values initially submitted in the DA schedule, which in turn would reduce RSG charges.

As noted in Otter Tail's November 10, 2014 Reply Comments, a data transfer error resulted in an increase in the deviations between forecast loads and actual loads and consequently an increase in RT RSG charges to Otter Tail. The Department has recommended that the Commission dis-allow at least 50 percent of the difference between the May 2013 RSG level and the average RSG monthly charges for this period or require Otter Tail to identify (and explain) the portion of the amount that is due to the software issue.

Otter Tail worked with its programmers to review the data that was transmitted from its forecasting software through its MISO data interface vendor, OATI, and ultimately to MISO, to confirm the exact days where the issue occurred and develop an estimate of the impact. Otter Tail has identified a mid-afternoon forecast submission that from May 7 to May 16, 2013, was transmitting zeros as the updated RT load forecast.

Otter Tail's initial analysis shows that the total RSG charges for those ten days (inclusive of all settlement statements: S7, S14, S55 and S105 for the affected days) was $176,770.37 (system basis), or $17,677.04 per day. The daily average RSG charge for all other days that month was

$3,298.68. The incremental increase in RSG charges (over average) for those ten affected days was $14,378.36 per day ($17,677.04 – $3,298.68 = $14,378.36), or a total of $143,783.56 of increased RSG charges (system basis). Minnesota's share (51.6 percent) of those RSG charges is approximately $74,170. The Department has suggested a disallowance of 50 percent of the excess charges or approximately $37,085.

The development and deployment of this software was the result of an initiative to reduce costs to our customers by providing more up to date forecasts based on more current information. The merit and intent of the initiative were sound. The initial phase of implementation, which began in March of 2013 worked well for nearly two months. A modification for submitting updated DA forecasts in May (another attempt to reduce costs), is what triggered this particular issue. This aspect of the program was stopped when the issue was identified through settlement statements.

The development and deployment of technology enhancements and innovations such as these comes with certain inherent risks. Even with the costs identified by the Department that were associated with the temporary software problem, this was a reasonable effort by Otter Tail with the sole intent of reducing costs for customers over the longer term. While Otter Tail appreciates the Department's recommended compromise regarding disallowance at half of the identified costs, even this recommended disallowance could have a chilling effect that would stifle interest in innovations such as these.

PUC Staff Comment

Otter Tail attributes this error to a modification that was to a software program that had been successfully deployed for approximately two months prior to the modification. It took ten days to discover the error. Otter Tail does not describe how the new program modification that caused the error was tested before it was introduced into the software program. The Commission may want to consider whether this was prudent.

Otter Tail also described the intent of deploying this new software as being solely for the purpose of reducing costs for customers over the long term. However, Otter Tail does not describe how that will happen or provide any quantification of the expected short or long term savings that might occur or how those savings could be measured or realized by ratepayers. The Commission might find some of that information useful for putting the Department's recommended disallowance of $37,058 into context and for assessing whether this amount is material with respect to Otter Tail's assertion that a disallowance would chill any future efforts to innovate.

Decision Alternatives

1. Accept Otter Tail Power's identification of and explanation for the higher RSG and make whole payments in May 2013. [OTP, DOC]

2. Allow OTP to recover the cost of all of its RSG charges for May 2013. [OTP]

3. Disallow 50 percent of the difference between the actual amount of RSG charges and the average amount of RSG monthly charges for this period in May 2013 as calculated by OTP, i.e. $37,058. (DOC]

4. Disallow 100 percent of the difference between the actual amount of RSG charges and the average amount of RSG monthly charges for this period in May 2013 as calculated by OTP, i.e. $74,170.

Rail Delivery Issues & MP's Rail Transportation Costs

References:
DOC, 2014 Annual Review, Docket #14-579, May 19, 2015, pp. 21-30
Xcel, Reply Comments, Docket #14-579, May 19, 2015, pp. 8-9
OTP, Reply Comments, Docket #14-579, May 19, 2015, pp. 2-7
DOC, Response Comments, Docket #14-579, August 26, 2015, pp. 12-21 and 37-38
MP, Reply Comments, Docket #14-579, October 2, 2015, pp. 1-2
DOC, Reply Comments, Docket #s 14-579 & 15-875, December 14, 2015, pp. 3-4
DOC, Reply Comments, Docket #s 14-579 & 15-875, February 24, 2016, pp. 4-5

(The following discussion is copied, excerpted or adapted, mostly verbatim, from the parties' comments.)

Xcel Energy

With respect to Xcel, the Department stated that

> ... the Department concludes that Xcel's responses are reasonable, and recommends that the Commission accept Xcel's reporting with respect to fuel costs associated with coal shortages.[45]

This Department's recommendation appears as item #17 in Attachment C to the decision alternatives.

Otter Tail

In its August 26, 2015 response comments, the Department stated that with respect to Otter Tail Power:

> Shipping Coal Under Contract vs. Tariff. ... the Department recommends that the Commission require Otter Tail to report in future AAA filings any coal conservation measures taken in response to coal delivery issues during the relevant reporting period, along with a discussion of OTP's efforts to minimize coal, coal delivery and any replacement power costs if needed to address issues with coal supplies for OTP.[46]

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[45] DOC, Response Comments, Docket #14-579, August 26, 2015, p. 15
[46] DOC, Response Comments, Docket #14-579, August 26, 2015, p. 13

> Coal Conservation Measures. The Department concludes that, given the coal delivery issues experienced at Big Stone Plant, Otter Tail's coal conservation measures during FYE14 were reasonable. The Department recommends that the Commission accept Otter Tail's reporting with respect to fuel costs associated with coal shortages.[47]

This Department's recommendation appears as item #18 in Attachment C to the decision alternatives.

Interstate Power & Light

With respect to IPL, the Department stated

> The Department concludes, ex-ante, that IPL's actions with respect to its coal inventories were reasonable. The Department also concluded, ex-post, that IPL's actions were reasonable. According to the Department, IPL limited production during periods with low LMPs. IPL estimated that the total incremental cost of its coal conservation measures were approximately $0.5 million on a total-company basis.[48]

This Department's recommendation appears as item #19 in Attachment C to the decision alternatives.

Minnesota Power

<u>Department of Commerce</u>
On pp. 17-21 of the Department's August 26, 2015 Response Comments, in Docket # 14-579, the Department explained its analysis of MP's handling of rail delivery issues. According to the Department

> **[***MP TRADE SECRET DATA BEGINS***]**
>
> **[***MP TRADE SECRET DATA ENDS***].**
>
> Reasonableness of MP's Actions
>
> - Ex-Ante Actions
>
> As noted above, MP attempts to maintain coal inventories equal to **[***MP TRADE SECRET DATA BEGINS***]**

[47] DOC, Response Comments, Docket #14-579, August 26, 2015, p. 14
[48] DOC, 2014 Annual Review, Docket #14-579, May 19, 2015, p. 27

[*MP TRADE SECRET DATA ENDS***]** These inventories help protect ratepayers from negative impacts associated with rail delivery issues.

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

[*MP TRADE SECRET DATA ENDS***]**.

MP's Requested and Actual Coal Deliveries

Description	Line/Formula	2011	2012	2013	2014
[*MP Trade Secret Begins ***]**					
					[*MP Trade Secret Data Ends***]**

[* MP TRADE SECRET DATA BEGINS***]**

[*MP TRADE SECRET DATA ENDS***].**

[*MP TRADE SECRET DATA BEGINS***]**

[*MP TRADE SECRET DATA ENDS***].** As shown in the attachment to MP's response to DOC IR 23, BNSF did not consent to MP disclosing a copy of its rail transportation contract. Because MP did not provide a copy of its contract with BNSF, the Department was unable to refer to the contract for guidance on this issue. Thus, the

Department cannot conclude that MP fully met its burden of proof to show that the rates MP charged to its ratepayers were reasonable.

In its response to DOC IR 25, part a, MP stated **[***MP TRADE SECRET DATA BEGINS***]**

[*MP TRADE SECRET DATA ENDS***]**.

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

[*****MP TRADE SECRET DATA BEGINS]**

[*MP TRADE SECRET DATA ENDS**].

In DOC IR 45, the Department asked **[***MP TRADE SECRET DATA BEGINS**]

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

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

[*MP TRADE SECRET DATA ENDS***].**

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

[*MP TRADE SECRET DATA ENDS***].**

- Ex-Post Actions

[*MP TRADE SECRET DATA BEGINS***]**

[*MP TRADE SECRET DATA ENDS***].**

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

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

Department Recommendation
As described above, while Minnesota Power's coal procurement policies and actions taken in response to coal shortages during 2013 appear to be reasonable, because MP **[***MP TRADE SECRET DATA BEGINS***]**

[*MP TRADE SECRET DATA ENDS***]**. Therefore, the Department is unable to make a recommendation to the Commission regarding MP's reporting with respect to fuel costs associated with coal shortages during FYE14. That is, the Department cannot conclude that MP fully met its burden of proof to show that the rates MP charged to its ratepayers were reasonable.[49]

[49] DOC, Response Comments, Docket #14-579, August 26, 2015, pp. 37-38

Minnesota Power

(MP, Reply Comments, October 2, 2015, Docket #14-579, pp. 1-2, the following has been copied, mostly verbatim, from MP's Reply Comments)

> As noted at pages 15 through 17 of the Department Comments, upon receipt of the Department Information Requests, Minnesota Power requested permission from the BNSF railroad to disclose the terms of Minnesota Power's negotiated rail contract. This specific contract has been in effect since 2002, and this is the first time the Department has requested to review a copy. (This is also the first time Minnesota Power is aware of the Department requesting a copy of any of its rail contracts).
>
> Minnesota Power did not have sole authority to provide or file a copy of the BNSF contract, and as shown in the attached Information Request response, the BNSF denied Minnesota Power's request to file a copy of the rail contract. However, the BNSF did consent to an in-camera review of that contract by the Department upon its request. Minnesota Power therefore made all arrangements possible to make the contract available to the Department.
>
> The Department indicated in its Comments that it cannot conclude that Minnesota Power fully met its burden of proof to show that the rates MP charged ratepayers for rail transportation were reasonable – ostensibly due to the Department not being provided the contract by Minnesota Power. Minnesota Power's rail transportation costs were reasonable even before the delivery issues arose -- and they remain reasonable today due to the steps Minnesota Power has taken both by negotiating an agreement beneficial to ratepayers and by the actions Minnesota Power has taken to address BNSF delivery issues. Over 800 pages in response to the Department's Information Requests are simply further evidence that Minnesota Power was a leader in addressing coal rail delivery issues in the 2013–2014 time period.
>
> Minnesota Power's rail transportation costs should not be subject to question simply because the Department did not take the steps necessary to review the BNSF contract.

Department of Commerce

(DOC, Reply Comments, Docket #s 14-579 & 15-875, February 24, 2016, pp. 4-5, the following has been copied or excerpted, mostly verbatim, from the DOC's Reply Comments)

On pp. 4-5 in its reply comments, in docket #s 14-579 & 15-875, the Department explained why it was unable to conclude that the amount MP proposed was reasonable. According to the Department

- Did MP provide in reply comments a narrative and documentation showing that the amount received in the negotiated settlement is reasonable or, at a minimum, documentation identifying the amount received and when it was received?

No. Instead, the Company stated that:[50]

> A separate settlement agreement does not exist related to the negotiated settlement. The negotiated settlement was part of the newly negotiated contract with the coal transportation provider. Through the contract negotiation process, Minnesota Power attempted to recoup 100% of the impact to its customers. At the beginning of the negotiation process the coal transportation provider countered with no payment at all. Through months of negotiations, the parties settled on the final amount of **[TRADE SECRET DATA EXCISED].**
>
> As noted in Minnesota Power's response to IR 23, Attachment 1 in Docket AA-14-579 and related Reply Comments to the same docket, due to the confidential nature of the contract, the coal transportation provider did not consent to Minnesota Power disclosing for filing a copy of the contract to the Department. However, the coal transportation provided [sic] did consent to an in-camera review of that contract by the Department upon its request. The coal transportation provider has reiterated its consent to an in-camera review upon the Department's request.

The Department notes that the FYE14 AAA proceeding (14-579) to which MP refers, on page 16 of in its August 26, 2015 Reply Comments, the Department stated:

> Because MP did not provide a copy of its contract with BNSF, the Department was unable to refer to the contract for guidance on this issue. Thus, the Department cannot conclude that MP fully met its burden of proof to show that the rates MP charged to its ratepayers were reasonable.

That is, the Department could not conclude in that proceeding that MP met its burden of proof to show that the rates charged to its ratepayers during the July 2013-June 2014 period of the FYE14 AAA were reasonable, in part because of MP's unwillingness to provide a complete copy of its rail transportation contract. Further, in MP's October 2, 2015 Reply Comments, MP offered to provide only an in-camera review of a redacted copy of the Agreement.[51]

The issue of the reasonableness of the rates that MP charged to its ratepayers during the July 2013 through June 2014 time period is not at issue in the instant docket; that matter is in the FYE14 AAA docket. While the Department cannot verify that the amount of the refund is the amount that MP asserts, it is important to refund as soon as possible MP's customers their share of the full settlement amount of the **[TRADE SECRET DATA HAS BEEN EXCISED]** that MP claims it received from the coal transportation provider. Thus, the Department takes Minnesota Power at its word that the asserted amount of the refund is correct.

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[50] Source: MP Reply Comments at 1-2.

[51] MP's October 2, 2015 Reply Comments in the FYE14 AAA docket stated on page 1 of 2 of MP's response to DOC Information Request 23 "BNSF will consent to an in camera review by a representative of the Minnesota Department of Commerce **of a redacted version** of the Agreement provided by BNSF at an office of your choosing in Minneapolis or St. Paul." [Emphasis added]

- Did MP provide a narrative in reply comments fully discussing and quantifying any and all potential trade-offs that may have been needed to obtain the settlement payment, including but not limited to possibly (or potentially) less favorable terms for **[Trade Secret Data Has Been Excised]**?

No. MP simply referenced an attachment in another docket, the FYE15 AAA docket (15- 611):[52]

> In regards to the Department's inquiry as to "potential tradeoffs that were needed to obtain the settlement payment, including but not limited to possibly (or potentially) less favorable terms for the agreement, Minnesota Power references Docket AA-15-611 Attachment No. 1 – Fuel and Energy Source Procurement, under the Minnesota Power's Coal & Transportation Procurement Strategy section.

The Department notes that the above-referenced attachment does not include the requested narrative. Nonetheless, as noted above, since the goal is for the refund to be provided to MP's ratepayers as soon as possible, the Department does not pursue this issue at this time.

PUC Staff Comment

MP responded to the Department's statement that it cannot conclude that MP fully met its burden of proof to show that the rates MP charged ratepayers for rail transportation were reasonable. In the recommendations section of its Response Comments, the Department stated that it "is unable to make a recommendation to the Commission regarding MP's reporting with respect to fuel costs associated with coal shortages during FYE 14. That is, the Department cannot conclude that MP fully met its burden of proof to show that the rates MP charged to its ratepayers were reasonable."

MP responded that MP's rail transportation costs were reasonable even before the delivery issues arose – and they remain reasonable today due to the steps MP has taken both by negotiating an agreement beneficial to ratepayers and by the actions MP has taken to address BNSF delivery issues. MP's rail transportation costs should not be subject to question simply because the Department did not take the steps necessary to review the BNSF contract.

MP's proposed credit to wholesale, large power and retail customers, in Docket # 15-875, was on the agenda for the Commission's April 7, 2016 meeting. Staff's understanding is that MP and the Department were in agreement about most aspects of the proposed credit in that docket and left the dispute over access to records and the verification of the appropriateness of the amount of the proposed credit to this docket (#14-579).

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[52] Source: MP Reply Comments at 2.

Decision Alternatives

1. Find that Minnesota Power's coal procurement policies and actions taken in response to coal shortages during 2013 appear to be reasonable, however, because MP **[***MP TRADE SECRET DATA BEGINS***]**

   [*MP TRADE SECRET DATA ENDS***]**. Find that that MP has not fully met its burden of proof to show that the rates MP charged to its ratepayers were reasonable.[53]

2. Find that Minnesota Power's coal procurement policies and actions taken in response to coal shortages during 2013 were reasonable and the rates MP charged ratepayers for rail transportation were also reasonable.

3. Take no action.

[53] DOC, Response Comments, Docket #14-579, August 26, 2015, pp. 37-38

Reform of the Fuel Clause Adjustment (FCA) Mechanism

Department of Commerce – 2012 Annual Review

(DOC, Docket #12-757, pp. 16-22, June 5, 2013, copied almost verbatim except footnotes omitted)

Background
During Xcel's [2012] rate case [in Docket No. E-002/GR-12-961], the Antitrust and Utilities Division of the Minnesota Office of the Attorney General (OAG) proposed to fix the level of recovery of energy costs on a calendar year basis at Xcel's proposed base cost of energy with a 3 percent cap. OAG's proposal was based on the following observations. First, a significant amount of fuel and purchased power costs are expected to be recovered by Xcel during the test year, $825 million. Second, the fuel and purchased power costs are automatically passed through to customers through an automatic adjustment on customer's bills through the FCA each month. Third, there are no incentives for Xcel to control these costs except for the potential that costs may be disallowed after-the-fact as a result of the annual automatic adjustment review that is conducted after the end of the year for all IOUs. Fourth and finally, there is no internal incentive structure in place for Xcel to provide the oversight to control this cost on behalf of ratepayers.

DOC Analysis
The OAG raised important concerns regarding the current energy recovery mechanism that warrant Commission attention, not only for Xcel, but for all electric utilities. As indicated in the Department's April 5, 2004 Reply Comments[54], the FCA was originally designed to allow the utility to recover, outside of rate cases, costs that were largely outside of the control of the utility. The FCA also provided a way to pass savings to ratepayers if the actual cost of fuel dipped below the base cost included in rates. At the time that FCAs were originally put in place (perhaps thirty or more years ago), there were few purchases of wholesale electric energy, and such rates were federally regulated, which provided another level of oversight for such costs included in automatic adjustments. Further, at that time, costs for electric energy purchased was low and fairly consistent with the cost of generating electricity on the utility's own system.

However, even at that time, there were drawbacks of the FCA, as noted in the Department's April 5, 2004 comments noted above:

> At the outset, an important disadvantage of the FCA appeared to be its potential to distort incentives by treating fuel costs differently than other costs. Distortion of incentives could occur in the following ways:
>
> - By easing the recovery of fuel costs, the FCA could encourage utilities to use fuel more intensively. In other words, the FCA could skew input selection in favor of fuel and against other inputs.

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[54] In the Matter of the Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments, Docket No. E-999/CI-03-802

- By allowing utilities to pass fuel cost increases to [ratepayers], the FCA would weaken utilities' incentives to aggressively manage fuel costs. Specifically, the FCA could reduce utilities incentives to:
  (i) Select less volatile fuel sources over more volatile fuel sources when installing new plants;
  (ii) Switch existing plants to less volatile fuel sources; and
  (iii) Invest time and resources into negotiating lower prices for fuels currently in use.

These disadvantages need to be considered in light of current circumstances, including the need to add more generation resources, the development of the MISO energy market, environmental regulations, and the effects of factors such as the following on the costs for fuel, replacement energy, and electricity procured through PPAs that is recovered through the fuel clause:

- the utility's ability to use tools such as demand response and energy efficiency (including interruptible programs) to manage costs,
- the extent to which the utility plans for and obtains sufficient reliable resources to meet the needs of its retail customers and the extent to which the utility either plans to rely on the MISO spot market or fails to implement plans to obtain sufficient resources,
- the extent to which the utilities plans for the availability and deliverability of natural gas and other replacement resources as the Environmental Protection Agency's (EPA) Mercury and Air Toxics Standard (MATS) and other rules are implemented; and
- the extent to which utilities have sufficiently maintained their generation resources, to minimize the effects of unplanned outages.

While utilities are not in complete control of energy costs, utilities' choices have far more influence on FCA costs than has been the case previously. The Department's comments in the FYE11 AAA proceeding (in Docket No. E-999/AA-11-792) and in utilities' resource plans, among others, point out ways that utilities' choices affect or could affect FCA costs. Further, it is expected that FCA costs will become far more volatile in the near future than in the past, as the MISO region as a whole responds or fails to respond to the MATS rule, aging infrastructure, and growth in demand as the economy recovers. Ratepayers should not be paying for a utility's failure to plan for and manage these developments.

It is critical to design incentive mechanisms to ensure that all utilities consider all costs of providing energy as utilities add resources and respond to growth in demand for power. The following provides more background and the Department's recommendation on an incentive method for the fuel adjustment clause.

As noted above, the current design of the FCA in Minnesota allows utilities to recover fuel costs in a different way than costs recovered in base rates. IOUs' energy costs, including replacement power costs during generation outages and congestion costs when transmission facilities are constrained are automatically recovered through the 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 and fixed recovery in rates – provide different incentives for utilities to minimize costs in practice.

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, IOUs have little incentive to minimize costs that are passed automatically through the FCA (and other riders) to ratepayers since there is no short-term benefit to shareholders in doing so. In fact, there are higher costs involved in minimizing fuel costs, such as aggressively pursuing lower cost contracts for fuel, pursuing extensive preventive maintenance of plants, replacing aging or ineffective resources. There may also be lower revenues through pursuing demand-side management resources. Further, by utilities relying extensively on the MISO market for energy, retail ratepayers are at risk for higher costs during scarcity pricing periods.

A well-designed incentive mechanism would encourage IOUs to minimize overall costs of providing energy, including costs that are currently passed through the FCA. To do so, such a mechanism should ensure that IOUs internalize their total cost of doing business, including their fuel and replacement power costs during outages. Under such an incentive mechanism, IOUs would have the appropriate incentives to keep these costs as low as possible because it would be in their own best interest to do so.

The Department's recent investigation of the IOUs' forced outages, along with Xcel's wind curtailments in Docket No. E-999/AA-11-792 (AAA 11-792 Docket) highlighted the IOUs' lack of incentive to minimize energy costs and the difficulty of assessing the IOUs' claimed prudency of such costs. 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 outages are the result of a utility's employee errors or outside vendors' mistakes. As discussed further in the Department's December 12, 2012 Response Comments (DOC Response Comments) in the AAA 11-792 Docket, it took several rounds of discovery for the Department to receive information sufficient to identify potential issues and then assess the prudency of the costs even of a limited subset of potential issues. This resistance in providing the necessary information raises the concern that the identified issues may only be the tip of the iceberg. In addition, IOUs' responses to the issues raised by the Department in the AAA 11-792 Docket indicates that the IOUs do not treat energy costs as part of their total cost of doing business, i.e., energy costs are not treated as internalized costs.

The Department provides the following three simple examples from the DOC Response Comments in the AAA 11-792 Docket: the first two relate to forced outages and the third to wind curtailment payments. These examples demonstrate the IOUs' resistance to being held accountable for meeting their burden of proof for their own mistakes.

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

Second, following extensive discovery from the Department, MP's November 9, 2012 response still did not explain why MP's ratepayers should pay for the full amount of the increased energy costs passed through the FCA during FYE11, as a result of the use by a vendor of "replacement o-rings made of materials incompatible with the fluids used in the hydraulic system." MP described the difficulties related with finding reliable vendors and holding them accountable for mistakes. However, it does not appear that MP had a reasonable system or any system in place 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). Certainly there are other options. However, given the additional cost incurred by MP's ratepayers ($507,715) for this error, the additional cost of an engineer watching the entire rebuild process for five weeks would have been justified. The fact that MP defended its decision not to have an engineer watch the entire process for five weeks due to the cost of the engineer, and ignoring over a half million in costs for replacement power, shows that MP did not consider it to be reasonable to balance the costs of an engineer's five weeks of time against the costs of replacement power. This example indicates that MP has an adequate incentive to minimize costs of an engineer's time, but does not have an adequate incentive to minimize replacement power costs. The Department notes that in response to an earlier discovery in that proceeding regarding contractors' delays and/or lack of performance during FYE11, MP stated that "[d]uring this period, there were no delays or lack of performance by contractors affecting outages." Clearly, the incompatible o-ring error should have been noted by MP in response to the Department's discovery.

Third, following extensive discovery from the Department, Xcel acknowledged its error in not placing the Lake Benton II wind project at the top of the curtailment list. This error resulted in increased energy costs that were passed through to ratepayers in the FCA. In response to the Department's recommended disallowance of the corresponding increase in energy costs to ratepayers, Xcel stated that "the wind curtailment costs are not unreasonable and should be recoverable."

The Department notes that in all such cases, the utility failed to take steps to ensure that ratepayers would not bear the costs of the utility's errors. These examples indicate that the IOUs could have minimized costs further if they had appropriate incentives to do so.

As noted above and in numerous comments by the Department in utilities' resource plans, it will be important for utilities to have enough generation to meet their load given the upcoming EPA changes expected to significantly affect coal plants within the U.S., including the MISO footprint, effective 2015-2016. While the results will not be known until the MATS and other rules take effect, it has been estimated that 12.6 GW of coal plants in the MISO market may be at risk for retirement. The Department has included a MISO summary on EPA impacts with links to MISO analysis and on-going work below. The effects of this and potentially other rules, along with aging resources and the continuing economic recovery in Minnesota and the MISO region will likely put upward pressure on energy prices in the MISO market and put ratepayers at risk for significantly higher costs in the near future. As a result, under the current ratemaking structure, ratepayers of utilities that are relying on the MISO market excessively, rather than having sufficient generation to meet their load will likely see a significant increase in their bills as those energy costs are simply passed on to ratepayers with no risk or responsibility for untimely planning incurred by the utilities.

> <u>MISO Summary on EPA Impacts</u>:
> MISO completed its EPA Impact Analysis in 2012 and works to further evaluate compliance risks and facilitate optimal solutions. MISO is now conducting multi-faceted analyses. ...
>
> Through these consolidated analyses, MISO aims to inform state regulators and generation owners about potential risks and suggest strategies, including potential Tariff changes, to best comply with the regulations.
>
> <u>Coal & Natural Gas Concerns</u>
> Initial MISO analyses indicates approximately 86 percent of the coal fleet will require action to comply with the regulations. The 2011 EPA Impact Analysis found that some generators will retire while others will be retrofitted with additional environmental controls.
>
> Whether due to EPA related coal retirements or lower natural gas prices, MISO anticipates increased utilization of natural gas fueled generation resulting in changes to the system's generation configuration and concerns about the ability of the current pipeline infrastructure's ability to deliver enough gas.

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

The Department recommends that a more decentralized mechanism be used for IOUs to recover energy costs. This mechanism should be designed to ensure that energy costs are internalized by IOUs in the same manner that IOUs internalize capital costs (between rate cases) and thus would have an incentive to consider all costs as utilities make decisions. One such mechanism would be to set the level of energy costs a utility can recover over a given future period on the basis of a rolling average of previous actual energy costs ($/kWh) and let the IOUs manage their business the best they can. Over the long run, this approach should lead to lower energy costs and would include the effects of changes in the market over time. The issue here is whether regulators and IOUs are willing to take the risk of temporary excess benefits or costs.

DOC Proposal

While the Department is open to any reasonable proposal by other parties, the Department recommends that, rather than allowing utilities to recover all changes in energy costs on a month-to-month basis, recovery of energy costs should be fixed in a rate case, with no adjustment between rate cases, at the IOU's average energy costs ($/kWh) over the previous three years before a rate case is filed.

While this approach could set the recovery of energy costs at a single rate throughout the year, it would be more appropriate to set the energy rates for each month of the year based on average costs for that month in the past three years, so that rates could provide better price signals to customers to reduce energy use during peak periods. This approach would give the IOUs clear incentives in between rate cases to minimize their total cost of doing business. That is, not only would utilities have an incentive to minimize capital and other costs recovered in base rates, but they would also have the same incentive to minimize energy costs.

The period for the calculation of this average should not be too short, to alleviate gaming of the system, nor too long, to take into account changes in the output mix of the IOUs. This balance is why the Department recommends a three-year period for calculating the average monthly costs. As more recent years are added to the calculation proposed above in subsequent rate cases, the new three-year average would better reflect the costs of a firm that is minimizing its total cost of doing business. To ensure uniform treatment across all IOUs, the Department recommends that this new recovery mechanism be implemented at the earliest of each IOU's next rate case filing or July 1, 2014, which is the beginning of the next fiscal year (after the 2013-14 fiscal year) for annual automatic adjustments. The Department anticipates that the IOUs would continue to file monthly FCA filings and the annual automatic adjustment (AAA) reports for at least the near future, to assess how this approach is working in practice or to review any issues the Commission decides should be monitored under this approach.

In setting the fixed fuel cost rate, the Department prefers the use of a total comprehensive rate, i.e., all energy costs less offsetting asset-based and non-asset based margins when applicable.

However, the Department does not object to the use of a partial rate, i.e., all energy costs without offsetting asset-based and non-asset-based margins. Given the different recovery mechanisms currently in place across IOUs and within IOUs, the Department is following up with discovery to collect the data that would be used for such proposals. This data will be filed and discussed in reply comments by the Department.

Reply Comments – August & September 2013

Xcel Energy

(Xcel, Reply Comments, August 26, 2013, pp. 22-26, Docket #12-757, copied almost verbatim except footnotes omitted)

We appreciate the Department's interest in exploring improvements to the FCA mechanism. Given the significant amount of dollars for fuel and purchased energy costs flowing through the fuel clause mechanisms of each utility, it is appropriate to periodically review whether utilities are taking suitable actions to minimize these costs that are automatically passed on to the ratepayers.

There have been multiple previous efforts at examining the notion of whether utilities are motivated to keep costs low and whether a change to the FCA mechanism may be appropriate. Ideas and concepts were discussed in the generic fuel clause docket of 2003 and again revisited after our rate cases in 2008 and 2010, but ultimately no change resulted. During this proceeding, we intend to work with the Department to develop a proposal supportive of effective incentive principles, as described further below.

By design, the FCA permits utilities to recover costs largely out of our control, outside of a rate case. Customers are billed their share of volumes and cost of fuel, dollar for dollar; they do not pay any more for these items than the utility incurs to produce and/or procure the energy on their behalf. Fuel clause mechanisms provide significant benefit to utilities, regulators and ratepayers by creating a method for recovery of certain volatile costs. The utility is kept whole with that portion of its costs; ratepayers pay their share of costs according to how much electricity they use; and regulators are able to focus review on these limited types of costs on a regular basis, rather than during a rate case where all costs are reviewed.

Under NSP's current FCA calculation method, fuel price volatility is reflected on customers' bills relatively close to when the cost is incurred. Thus, customers are provided fuel price points fairly close to their electric usage and have a reasonable opportunity to adjust their electric usage with the incentive of reducing their next bill, if they choose. Similarly, any potential FCA mechanism should provide utilities the opportunity to earn an incentive for their actions associated with activities that are under their control.

We believe an effective fuel clause incentive:

- Rewards desired actions and outcomes
- Leads to measurable results
- Provides transparency and predictability
- Limits risk to customers and stakeholders
- Aligns compatibly with current business climate
- Avoids producing unintended results
- Evolves, subject to evaluation.

Incentives should motivate action with outcomes that are good for all stakeholders. However, attention to safe, reliable, and reasonably-priced service should be kept in balance and not be inadvertently skewed towards reducing cost without regard for other factors. The outcome of an incentive should not create 'winners' and 'losers' based on conditions utilities cannot influence. As illustrated further below, we do not believe the Department's proposal will achieve their intended outcome of incenting utilities to take action to minimize energy costs on behalf of ratepayers. Rather, the proposal produces volatile and random results which would be quite disruptive, potentially changing the risk and reward relationship we now have.

The general effect of the Department's proposal is to normalize FCA recovery using monthly patterns derived from averages of the prior three year period, setting and fixing this level during a rate case with no adjustment between rate cases. While this may set a limitation of monthly FCA costs, it would be largely based on costs the Company does not control, such as the price of fuel, and not recognize new events or changed circumstances, diluting the impact of those events and circumstances until three or more years had passed. The random nature of weather impacts and fuel prices alone could blot out any offsetting cost reductions the utility could potentially make. Price swings are driven by events we have no control over, thus there is no meaningful incentive to manage costs under the Department's proposal.

Consider the MERP project for example; coal use was retired at the High Bridge and Riverside plants by the end of 2008, however, under the Department's proposal, it would not be until 2012 when the FCA would recognize the use of natural gas at these facilities. Prices for natural gas and the MISO market dropped sharply in 2009 but ratepayers would not have benefitted from the lower prices until several years later since the FCA level would be based on out of date information. Another example is the addition of power purchases to fulfill Minnesota's renewable energy policy such as the power purchase agreements with Fibrominn and Laurentian, or other long-term contracts such as with Manitoba Hydo. These transactions were entered into for the benefit of ratepayers and Minnesota state policy, and contractually contain annual price escalation; yet actual cost recovery would not be possible under the Department's proposal because of the use of an averaging methodology, not lack of cost management diligence on our part.

To illustrate the random effect, we applied the 3-year averaging proposal to our most recent 5-year period of FCA data, identified the major factors influencing price during the timeframe, and examined the overall effect on the Company's total cost of doing business. In our back-cast of the Department's proposal, for the five year period 2008-2012, we would have under-recovered fuel and purchased power cost by nearly $100 million. Using information reported in our annual Minnesota Jurisdictional Reports, we modified the Company's total revenue by the amount of change to FCA recovery and recalculated the earned return. The resulting impact on earned ROE to an individual year during this timeframe ranges between negative 241 basis points to positive 126 basis points as shown in the Table 3 below.

Table 3: Impact of Department's Proposal

	Change to FCA Recovery ($M)	Actual ROE Weather Normalized (%)	Realized W/N ROE Under DOC FCA Incentive Proposal (%)	Difference (%)
2008	+ $94.5	10.19	7.78	- 2.41
2009	+ $54.4	10.18	11.44	+ 1.26
2010	+ $32.8	8.78	9.48	+ 0.70
2011	- $26.5	9.08	8.56	- 0.52
2012	- $63.1	8.20	7.05	- 1.15
Period Total	- $96.9			

We investigated the primary drivers influencing our FCA during this same period and generally found these cost drivers could be grouped into the following three categories: (1) commodity fuel and transportation cost, (2) resource supply mix, and (3) state policy.

Table 4 provides the main factors impacting Xcel's FCA during 2008-2014. (This is a copy of the updated versions of this table that Xcel provided in its Feb. 11, 2015 reply comments.)

Table 4-Updated: Main Factors Impacting FCA from 2008-2014

2008	2009	2010	2011	2012	2013	2014
Additional Biomass purchases (Fibrominn & Laurentian)	Additional biomass purchases (Fibrominn, Laurentian and Rahr Malting)	Additional biomass purchases (Fibrominn, Laurentian and Rahr Malting)				
Additional wind purchases (Fenton, MinnDakota, CBED)	Additional wind purchases (Fenton, MinnDakota, CBED)	Additional wind purchases (Fenton, MinnDakota, CBED)	Additional wind purchases - CBED (generally higher prices)	Additional wind purchases - CBED & Prairie Rose (generally higher prices)	Additional wind purchases - CBED & Prairie Rose (generally higher prices)	Additional wind purchases - CBED & Prairie Rose (generally higher prices)
	Grand Meadow wind online	Grand Meadow and Nobles wind online	Grand Meadow and Nobles wind online	Grand Meadow and Nobles wind online	Grand Meadow and Nobles wind online	
Higher coal prices due to increased transport cost (diesel surcharge)	Higher coal prices due to increased transport cost (diesel surcharge)	Higher coal and rail prices	Higher coal and rail prices	Higher coal and rail prices	Higher wind curtailment costs	Higher wind curtailment costs
Higher nuclear fuel prices	Higher nuclear fuel prices	Higher nuclear fuel prices	Higher nuclear fuel prices	Higher nuclear fuel prices	Higher coal and rail prices	Increased rail transport cost and

Table 4-Updated: Main Factors Impacting FCA from 2008-2014

2008	2009	2010	2011	2012	2013	2014
						diesel surcharge at King and Black Dog
Higher natural gas prices					Higher nuclear fuel prices	
High Bridge and Riverside retired from coal use in 2007 and 2008.	High Bridge and Riverside retired from coal use in 2007 and 2008.	High Bridge and Riverside retired from coal use in 2007 and 2008.				Higher natural gas prices in Q1 2014 due to extreme cold
Lower cost MISO Market purchases as operations become smoother	Lower natural gas and MISO market prices	Lower natural gas and MISO market prices	Lower natural gas and MISO market prices	Lower natural gas and MISO market prices	Higher MISO costs (mainly congestion)	Higher MISO costs (mainly congestion)
		More planned coal maintenance	More planned coal maintenance		More planned coal maintenance	
		One nuclear refueling outage (2 nuclear refueling other yrs in period)	More planned nuclear maintenance	More planned nuclear maintenance	More planned nuclear maintenance	One nuclear Refueling outage (vs. 2 in other yrs) and less planned maintenance
			Sherco 3 forced outage near year-end	Sherco 3 forced outage	Sherco 3 forced outage	Sherco 3 in service
						Mild summer weather; lower load

In summary, other than the forced outage impact of Sherco 3 experienced in 2012 and 2013, the major events influencing the FCA were related to fuel prices, supply mix and state policy for Xcel Energy during this past five year period.

While gas prices have been fairly low, we also calculated the effect of a change in gas price to put context around gas price sensitivity. Using our current projection of gas burn amounts, if gas prices rise by $1 or $2 per MMBtu, the associated incremental projected 2013 fuel cost increase would be $72 million - $143 million. Also, with the annual contract escalation in long-term power purchase agreements, using a three year average essentially means recovery will always be roughly two years out of sync with the actual PPA price for any given year. Based on our contracts in place for the 2012-2014 period, this translates to under recovery of approximately $10-11 million per year of costs for electricity resources used to serve our customers.

There would have been little to no opportunity for a utility to drive down fuel and purchase power costs in a material way to overcome the cost drivers shown in Table 4. The 3-year averaging proposal is simply not the right fit for motivating cost reduction. We recommend instead design of an incentive that provides meaningful motivation through reward or penalty for actions we can take to control costs and does not disrupt the current risk/reward relationship.

We do agree with and understand the Department's desire to ensure utilities are appropriately motivated to minimize costs for ratepayers, particularly with regards to generation plant performance and availability and want to participate constructively in developing such an approach. Respectfully, we request the Commission not take action to adopt the Department's FCA incentive proposal. Rather, we intend to work with the Department during this AAA proceeding to develop an incentive with the above discussed goals and principals in mind and propose an alternative option for Commission consideration.

Minnesota Power

(MP, Reply Comments, Docket #12-757, September 20, 2013, pp. 3-13, copied almost verbatim except footnotes omitted)

First and foremost, it should be made clear that the utilities have done nothing wrong with their current management of the fuel clause process. The Department has concerns with the current fuel clause operation – [with] which it has every right to raise issues of concern. But any changes to the fuel clause could have far reaching impacts that the Commission should carefully consider. In this case, the Department's recommendation to freeze fuel clause cost recovery at a three-year historic average would be catastrophic and would greatly skew the balance of just and reasonable rates. Just and reasonable rates are a key component of the regulatory compact – a concept that protects both the ratepayer and the utility.

The Department's recommendation guarantees Minnesota Power will significantly under recover its fuel and purchase energy costs. The following tables utilize information from Attachment 4 to Minnesota Power's FYE12 and FYE13 AAA – which Attachments are included as Exhibits B and C respectively to these Reply Comments – and demonstrate Minnesota Power's expected fuel and purchase energy costs. Attachment 4 of Minnesota Power's FYE12 and FYE13 AAA clearly shows our projected FCA costs and how they are expected to rise from 2013-2018:

*****MP TRADE SECRET DATA BEGINS*****

*****MP TRADE SECRET DATA ENDS*****

These projected cost increases are not the anticipated outcome of poor planning or imprudency; they are due to increasing costs beyond the direct control of Minnesota Power, including increased fuel and transportation costs, market prices, load additions, and bridging purchase costs that have increased FCA costs but have delayed generation-related capital investment costs. For example, our use of bridging purchases provides the overall least cost to our customers even though they do increase FCA costs

Using the Department's proposal, a frozen fuel clause will result in an under recovery of fuel costs that annual rate cases will not fix. The following charts illustrate Minnesota Power's annual fuel and purchased energy costs as measured against the Department's proposal for cost recovery: Because Minnesota Power's projected FCA in the FYE13 AAA were lower than the FYE12 AAA, the FYE13 values were utilized to help ensure the impact of the proposed change was not over stated.

*****MP TRADE SECRET DATA BEGINS*****

*****MP TRADE SECRET DATA ENDS*****

The chart above shows very significant under recovery in 2016, 2017 and 2018 which the Department should have recognized and should have understood that their proposal would be unworkable for Minnesota Power. Remarkably, the Department had in its possession Minnesota Power's five-year fuel clause projection as exhibited by Attachment 4 to Minnesota Power's FYE12 AAA. It is clear that the Department's recommendation not only ignored the information contained in the Attachment 4, it also did not take into consideration the changing nature of each utility's generation portfolio: the nature of commodity price fluctuations and changing fuel transportation costs; the impact of renewable energy mandates; or changing emission regulations and enforcement actions when it developed its proposal. It is not clear whether the Department even reviewed this information when it considered its fuel clause proposal.

The Department's attempt at wholesale changes to the current fuel clause operation has resulted in a proposal that would severely and inexplicably penalize Minnesota Power and is simply not acceptable even as a starting point in a discussion of alternatives. While Minnesota Power does not share the Department's opinion that a change to the fuel clause is necessary, appropriate or will automatically benefit customers, any change must consider the utility's five-year fuel clause projection and must assure complete and timely recovery of a utility's fuel costs recovery. Minnesota Power does not believe the Department's proposal meets these criteria.

The Department continues to emphasize that the utilities do not have an incentive to lower fuel clause costs. To the contrary, Minnesota Power has such an incentive: our globally-competitive large power customers require the lowest energy prices available in order to compete in the world market – otherwise they face idled or shuttered operations. The reduced energy sales that would result would directly and immediately affect Minnesota Power's annual revenue and severely impact the company financially. These customers provide 60% of our revenue and the FCA accounts for approximately 40% of their monthly energy bill. These customers materially affect the company in many ways and we take all of their costs and all other customer costs into consideration as we procure energy supply and manage generation availability, so for the Department to suggest we simply pass these costs through with no regard is not merely misguided but also not true.

Minnesota Power has some of the lowest all-in rates in the country and has always had to be especially mindful of rate impacts in resource decisions. It is ironic that Minnesota Power's low energy cost makes it a target for outage cost examination in part due to the marked difference between its generation supply cost and replacement energy costs purchased in the wholesale market – and that is true even in the depressed wholesale market prices we see today. Minnesota Power understands the concerns of the Department regarding increased energy costs and the impacts of increasing fuel and purchased energy costs have on our customers. Minnesota Power believes it does a good job in controlling FCA costs and does not believe change in the FCA is required to ensure least cost supply because providing the all-in lowest cost alternative is already a strong and well established process at Minnesota Power. The financial impact of fuel clause operations on ratepayers is indirect but always prevalent – so much so that Minnesota Power annually budgets its anticipated fuel clause costs and reviews those costs with its large power customers so they are aware of their cost impacts. Minnesota Power implemented this close working relationship with its customer base long before the Commission ever became interested in these issues related to fuel clause operation. These annual updates became the model for updating the Department of Commerce monthly fuel clause projections that we use today.

The Department's recommendation of changing the basis of fuel and purchase energy recovery would fundamentally change the business model that Minnesota Power is currently working under and has used to make long-term supply decisions. Resource decisions need to be made by considering all aspect of costs, including capital investment, fuel cost and deliverability. Minnesota Power has worked hard to minimize all energy and capacity costs through a robust Integrated Resource Plan, as well as competitive fuel, rail and purchase power contracts over the last twenty and thirty years. Energy procurement and commodity costs are increasing. The favorable long-term fuel and transportation agreements negotiated in the past (whose benefits have already been passed on to ratepayers) are expiring, being replaced by shorter-term fuel contracts that contain cost escalators. In addition, Minnesota Power's Energy Forward Strategy (as reflected in our Integrated Resource Plan) could be impacted by changes to the fuel adjustment process. Specifically, as Minnesota Power moves toward less carbon-intensive generating resources as required by the State's renewable energy standards as well as federal generator emission regulations, we introduce more variability to fuel costs. For example, the additions of the Bison wind assets have led to lower fuel costs when the wind is blowing but require dispatchable or intermediate resources when the wind generation is not available. This energy can come in the form of low priced MISO market purchases or through the addition of natural gas generation. Either element adds additional fuel cost variability when compared to the Company's current baseload coal resources. If the fuel adjustment were to be fixed or capped at a certain level, it may change the Company's operating philosophy or future resource additions.

The Department's proposal in effect penalizes for the perception that the utilities are not doing enough to control these costs and simply use the FCA as a pass through with no regard to customer costs. However, the proposed changes would result in greater energy supply costs to ratepayers – not less. A changed fuel clause would require Minnesota Power to manage long-term fuel costs by purchasing all energy in advance. As Minnesota Power has described in the CI-03-802 Docket, the current combination of a long-term and short-term energy purchase approach has worked best in Minnesota Power's experience and has benefited customers by protecting them from over-exposure to market energy prices. Minnesota Power would also explore the need to obtain financial products (hedging or outage insurance products) in order to manage increased risk exposure. The premium cost of those products would be the subject of cost reimbursement – a cost currently not a component of Minnesota Power's fuel clause costs, but a required product necessary to manage the shift in risk. Any material change to the fuel clause operation that included an outright shift in risk to the utility would likely cause a ratings agency downgrade that would severely impact Minnesota Power's credit rating. A downgrade would significantly impact Minnesota Power's cost of capital and have long-term financial impacts on customers and strategy. The increased risk factors would arguably require a higher ROE in future rate cases – which shows that the Department's drastic proposal would likely end up shifting costs rather than eliminating them.

The following table models similar information provided by Xcel Energy in its comments to the Department's proposal:

Impact on Minnesota Power due to Department's 3 year averaging proposal [footnote omitted]				
Calendar Year	Change to FCA Recovery ($M)	Actual ROE (%)	ROE Under DOC FCA Incentive Proposal (%)	Difference (%)
2008	-$3.2	10.46	10.06	-0.40
2009	+$12.9	5.29	6.55	+1.26
2010	+$3.4	9.49	9.82	+0.33
2011	-$11.3	8.84	7.85	-0.99
2012	-$5.6	7.46	7.05	-0.41
2008-2012 (Total)	-$3.8			
	*****MP TRADE SECRET DATA BEGINS*****			

Impact on Minnesota Power due to Department's 3 year averaging proposal [footnote omitted]				
Calendar Year	Change to FCA Recovery ($M)	Actual ROE (%)	ROE Under DOC FCA Incentive Proposal (%)	Difference (%)

*****MP TRADE SECRET DATA ENDS*****

The impact of the 3 year averaging proposal on the 2008-2012 time frame would have been an additional under recovery by Minnesota Power of $3.8 million. The projected impact of the 3 year averaging proposal on the 2013- 2018 time frame is an under recovery of *****MP TRADE SECRET DATA BEGINS***** *****MP TRADE SECRET DATA ENDS***** million.

Minnesota Power obviously disagrees with the Department's analysis and recommendation regarding a frozen fuel clause. However, we wholeheartedly agree with the Department's overall recommendation that a separate stakeholder discussion of these issues is greatly needed. The Commission should convene a meeting with all interested parties to discuss the benefits, difficulties, expectations and other matters pertaining to the operation of utilities fuel clause adjustment process. Minnesota Power understands that the Commission has expressed a desire to have some utility "skin in the game" in its discussion of forced outages. Minnesota Power hopes that the Commission will revive the CI-03-802 Docket to explore ways to ensure that replacement energy costs due to forced outages are prudent. Taking this discussion out of the context of reviewing each company's annual AAA filing, and instead making it an overall commission investigation or workgroup process would be the most beneficial way to address the wide array of issues at play if the entire fuel adjustment clause mechanism is reviewed. Most importantly, such a discussion can occur outside of a Commission agenda item requiring an immediate decision, and would allow more time for information gathering, inquiry and reflection.

Finally, on an overall policy basis, Minnesota Power is not in favor of locking-in any component of energy rates with the intent of "providing better price signals to customers…". We fail to see how fixing any component of the energy rate facilitates true price signals. True costs must be the starting point for allowing customers to shape their energy usage behavior – artificially fixing any component skews the starting point.

Otter Tail Power

(OTP, Reply Comments, Docket #12-757, September 20, 2013, pp. 6-10, copied almost verbatim except footnotes omitted)

OTP understands that the Department's alternative proposal begins from the premise that utilities do not have adequate focus on plant operations, which can affect fuel and purchased power costs. OTP believes that its Key Performance Indicator mechanism (described below) and its plant performance statistics will show that it currently operates with focus on these issues and that focus has been successful. Because OTP agrees with Xcel Energy's Comments that the Department's proposal would have several unintended negative consequences for its operations and for ratepayers, OTP does not believe such an approach should be pursued. Also, because OTP believes that its current KPI mechanism has successfully focused its employees and operations on plant performance, OTP requests that this KPI mechanism be viewed as a reasonable alternative to the Department's proposal, at least for OTP.

As noted, the Department's Comments and its proposal begin from a premise that utilities have not focused their attention on plant performance, but we believe that the historical record does not bear this out for OTP. Instead, the principles under which OTP has been operating for many years demonstrate OTP's commitment to doing all that it can to keep energy costs as low as possible for its customers through efforts to incentivize and maximize our own generation facility performance.

Our total fuel costs are comprised of the costs incurred to generate electricity from our low cost plants, as well as the costs incurred through purchases of energy from other sources. Management of fuel and purchased power costs is a significant area of focus for the entire company at OTP. So much so, that it is an integral part of OTP's Mission Statement which begins with the following statement:

> "Our mission is to <u>produce</u> and deliver <u>electricity as reliably, economically, and environmentally responsibly as possible</u> …"

And OTP's focus on these issues does not stop there. OTP management has developed mechanisms to motivate employees to fulfill its mission, including its KPI mechanisms, which are described in greater detail later in these Comments. These mechanisms have been successful and resulted in higher plant performance and lower fuel and purchased power costs for OTP ratepayers.

- Comparison to Industry Average Plant Availability – GADS Data

From a fuel cost perspective, the most effective way for OTP to minimize fuel cost impact to its customers is to keep the generating plants operating and producing the low cost energy they were designed to produce.

When measuring the performance of OTP's conventional generating facilities against aggregate industry performance, OTP consistently meets or exceeds industry average performance as compared to similar plants (Type and size). The North American Electric Reliability Corporation ("NERC") collects and reports through the Generating Availability Data System ("GADS"), operating performance information for conventional generating units. The following tables show both yearly plant availability levels compared to industry average for similar sized plants as well as comparisons based on a 5 year rolling average plant availability measure. The 5 year rolling average measure helps to incorporate extended maintenance outages into the comparison to industry averages which would also have extended planned maintenance outages embedded into those averages.

Otter Tail Power
Yearly Plant Availability Compared to GADS Avg
2003 - 2012

	Big Stone 475 MW	Coyote 427 MW	Coal 400 - 599 MW GADS Avg			Hoot Lake #2 60 MW	Hoot Lake #3 84 MW	Coal 1 - 99 MW GADS Avg
2003	87.55	79.4	83.61		2003	98.3	98.8	85.7
2004	92.28	91.5	84.96		2004	91.8	69.5	86.18
2005	77.73	89.21	83.36		2005	98.9	97.7	85.2
2006	82.17	81.23	84.52		2006	96.3	87.5	86.9
2007	64.2	86.26	82.42		2007	97.6	98.4	82.48
2008	92.45	87.6	83.98		2008	56.8	95.8	82.37
2009	91.56	72.5	82.04		2009	92.1	72.0	84.06
2010	92.95	87.8	n/a[1]		2010	95.51	97.3	n/a[1]
2011	74.3	89	82.67		2011	97.78	98.3	83.89
2012	91.27	69.7	81.39		2012	96.01	97.6	84.05

(green) = major outage year
(yellow) = equivalent aviailability for Big Stone Plant was negatively affected by derates during 2006 caused by a DOE-sponsored environmental emissions demonstration project. That equipment was subsequently removed.

1. 2010 single year GADS values were not available in the on-line database.

Otter Tail Power
5 Year Average Plant Availability Compared to GADS Avg
2003 - 2012

5-Year averages	Big Stone	Coyote	Coal 400 - 599 MW GADS Avg		5-Year averages	Hoot Lake #2	Hoot Lake #3	Coal 1 - 99 MW GADS Avg
2003 -07	81.62	83.36	83.51		2003 -07	88.34	90.28	85.67
2004-08	84.67	83.08	82.88		2004-08	87.66	90.19	85.45
2005-09	83.09	84.63	82.72		2005-09	87.96	92.35	86.37
2006-10	88.51	81.32	82.23		2006-10	87.64	92.19	85.4
2007-11	87.52	79.75	81.97		2007-11	95.35	91.29	84.64
2008-12	86.17	82.17	81.86		2008-12	96.43	97.72	84.08

For many years, OTP management has established an annual company-wide Key Performance Indicator ("KPI") on Equivalent Plant Availability. It is one of five company-wide KPIs[55] that

[55] In addition to Plant Equivalent Availability, OTP establishes company-wide KPIs for Reliability, Customer Satisfaction, Safety, and Operation and Maintenance Expenses.

are measured as part of OTP's company-wide annual Key Performance Award ("KPA") employee incentive plan.[56]

OTP President Charles MacFarlane provided the following explanation of Equivalent Availability in OTP's 2007 general rate case, Docket E-017/GR-07-1178:

> Equivalent availability represents the portion of time that a generating unit is available to operate, including consideration of the lost capacity effects of partial equipment deratings when the unit was available but at less than full capacity. Performing well on the equivalent availability measure is important because OTP has invested in very low-cost generating plants that typically produce energy well below market prices. Therefore, we can reduce our overall energy costs by making sure we get every megawatt hour out of those plants that is reasonably possible. **By far, our performance and equivalent availability has more impact on OTP's fuel and purchased power costs than does any other factor over which we have any reasonable control**. That's why we have chosen to use it as one of our primary KPIs.[57]

In addition to the five company-wide KPIs established annually, each department within OTP also establishes their own KPIs which support the overall company-wide KPIs.

Fuel costs are also a separate KPI within the generation department and each plant establishes a plant-specific equivalent availability KPI. OTP management establishes the overall Equivalent Plant Availability goal, taking into account, plant maintenance schedules that are applicable to the generating fleet. Meeting or exceeding the Equivalent Plant Availability goal triggers that KPI's incentive payment to all employees who are eligible to participate in the KPA plan. The goals for plant availability are aggressive goals, not easy to meet, conveying the importance of, and high expectation for, keeping the plants operating.

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[56] The KPA program is eligible to all non-executive management employees except for those who are party to a collective bargaining agreement.
[57] EX. 7 MacFarlane, C. Rebuttal at10 in Docket E-017/GR-07-1178 (emphasis added)

The following table summarizes the annual goals from 2007 through 2013 and the actual performance against those goals:

Equivalent Plant Availability KPI			
Year	Goal	Actual	Incentive % Payout
2007	>= 86.0%	78.62%	0%
2008	>=89.7%	87.99%	0%
2009	>=88.1%	83.61%	0%
2010	>=90.5%	92.34%	1%
2011	>=85.7%	84.04%	0%
2012	>=87.5%	86.50%	0%
2013	>=88.9%		

As noted earlier, the goals vary from year to year. In years where an extended planned outage is scheduled, the targeted availability goal for the generation fleet is adjusted accordingly. In all instances, the annual goal for Equivalent Plant Availability exceeds industry averages for plant availability as reported by NERC.

As discussed earlier, OTP's plants have exceeded the performance of comparable plants in the industry. These KPI mechanisms have been an important motivator for our employees in achieving these high levels of performance. Because these are the objectives sought by the Department, OTP believes that its KPI mechanism should be considered a reasonable alternative to the Department's proposal, at least for OTP.

- Big Stone and Coyote are Jointly Owned Plants

One additional factor to note for OTP's plant operations is that its two largest plants are jointly-owned units. OTP is operator for both the Big Stone and Coyote Generating stations, but OTP is only a partial owner of these facilities. The other owners of these facilities rely on OTP for day-to-day operations and to maintain the plants in a manner which maximizes the plant's availability to generate low cost electricity. An operating committee of representatives from each of the plant's owners determines annual maintenance schedules and plant capital and O&M budgets. This joint-operations approach to plant ownership provides OTP ratepayers with significant benefit in that they get the benefit of larger economies of scale and an additional level of oversight by the other owners, who have a similar interest in keeping plant availability high. It also shows, however, that as a practical matter OTP is not unilaterally able to change plant operations and budgets. Therefore, if the Commission does desire to consider a change to the FCA or any other mechanism with the intention of changing plant operations and/or budgets, it should note that OTP does not have the ability to make such changes unilaterally and that any mechanism should not put OTP in the position where it cannot be responsive to the other owners of the plants.

In summary, OTP believes that its current KPI mechanism should be affirmed as an appropriate alternative to the Department's proposal to change the FCA. The historical performance of OTP's plants demonstrates that this mechanism has worked well for OTP and its ratepayers.

Interstate Power
(IPL, Reply Comments, Docket #12-757, September 20, 2013, pp. 3-5, copied almost verbatim except footnotes omitted)

The Department's FCA proposal, as described on page 2 of these reply comments, for all intents and purposes eliminates the monthly FCA as implemented in today's regulatory environment. The Department believes its proposal would give investor-owned utilities clear incentives between rate cases to minimize their total cost of doing business.

IPL believes the FCA mechanism continues to be a valid mechanism for reflecting the costs of fuel and purchased power on a dollar-for-dollar basis. As IPL stated in the Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments (Docket No. E999/CI-03-802), the purpose and rationale behind the FCA is based in the general understanding that fuel and purchased power costs have unique attributes which necessitate recovery of cost changes between general rate cases. Fuel and purchased power costs are subject to wide price fluctuations due to weather, production, and other supply and demand factors which are generally out of the control of individual utilities. The monthly FCA more closely matches current market prices of energy with customer usage to send better pricing signals. Fuel and purchased power costs also make up a large portion of a utility's expenses and lack of full recovery would pose an extreme hardship on a utility.

IPL notes that as a result of being able to recover price fluctuations in fuel or purchased power, the FCA reduces the need to file frequent general rate case filings to recover or reconcile volatile fuel and purchased power costs. The FCA eliminates the time, resources, and regulatory lag of frequent general rate cases that burden both the utilities, and the regulatory agencies.

Moreover, an important issue affecting utility credit ratings is the regulatory mechanism for recovery of fuel and purchased power costs and its impact on the level of utility business risk. As noted by such credit rating agencies as Moody's, the ability to recover prudently incurred costs in a timely manner is perhaps the single most important credit consideration for regulated utilities as the lack of timely recovery of such costs has caused financial stress for utilities on several occasions. The FCA's function as a mechanism to allow timely cost recovery helps the utility match revenue with costs. This in turn helps keep the utility's business risk low, a factor which contributes to a good credit rating.

The current FCA has served Minnesota utilities and ratepayers well. The monthly FCA has captured the price signals of a volatile and ever-changing marketplace while allowing a utility to recover one of its major operating expenses. IPL supports the current FCA approach and believes that any changes would be a detriment to Minnesota utilities and ratepayers alike. However, IPL also is available to participate in future discussions related to these issues.

Minnesota Chamber of Commerce
(MCC, Comments, Docket #12-757, September 20, 2013, pp. 1-6, copied largely verbatim except footnotes omitted)

Over the past several years the Chamber has had growing concern with fuel management, the changing fuel mix and power purchase practices that utilities have put in practice. Even for traditional fuels, Minnesota's utilities have changed the length of their purchases to much shorter contracts. These changes have, in part, led to the Chamber's intervention in resource planning and other dockets to comment on the concern over reduced stability in Minnesota's rates and loss of competitiveness, both in the short term and long term.

The Chamber is commenting in this proceeding to provide policy related feedback to the DOC's proposal to fix fuel and purchased power costs in base rates. The DOC has recommended such an approach in order to incentivize utilities to manage and minimize these costs in the same manner as other costs that are fixed in base rates. As the discussion below indicates, the Chamber supports DOC's recommendations to fix fuel and purchased power costs in base rates and provides additional guidance regarding this proposal and discusses our continued concern over long-term pricing that this proposal will not address.

Introduction
The current Fuel Cost Adjustment ("FCA") mechanism allows utilities' fuel and purchased power costs to be automatically passed through to ratepayers. The Department of Commerce ("DOC") conducts an after-the-fact review of these costs after the end of the year for all utilities. It is very difficult to verify after-the-fact whether the costs were prudently incurred given the long regulatory lag between the time that the costs are actually incurred, DOC's review and the Commission's determination. Thus, under the current mechanism, it is very difficult to protect ratepayers' interest. Furthermore, given the automatic pass through nature, there is no incentive for utilities to minimize fuel costs. For example, replacement costs associated with forced outages are automatically passed through the FCA rider, regardless of whether it is appropriate for ratepayers to incur these costs. Unlike treatment of fuel, utilities are motivated to minimize costs such as fixed O&M costs included in base rates between rate cases to maximize shareholder profits. This inconsistent treatment creates the potential for an inappropriate trade off where the utility could incur higher replacement power costs (passed on to ratepayers) at the expense of minimizing its O&M costs (benefiting the utility). Therefore, the Chamber believes that the current mechanism is inefficient and lacks the incentive for minimizing fuel costs.

Further, the Chamber agrees with the DOC's concern that under the current paradigm, the burden of proof falls on regulators or intervenors to prove that certain costs should be disallowed instead of the utilities having to prove that these costs are reasonable.

DOC's Proposal
The DOC's proposal consists of the following elements to address the foregoing concerns regarding fuel and purchased power costs:

- Recovery of energy costs are fixed in a rate case, with no adjustment between rate cases.

- The fixed rate would be based on the utilities' average energy costs ($/kWh) over the previous three years before a rate case is filed. Monthly energy rates would be set based on average costs for that month in the past three years.

- Utilities would need to submit rate case petitions in order to change these rates and the FCA Rider would be eliminated.

- The new recovery mechanism would be implemented at the earliest of each utility's next rate case filing or July 1, 2014, which is the beginning of the next fiscal year (after the 2013-14 fiscal year) for annual automatic adjustments.

- While the DOC indicated a preference to net out wholesale margins, it stated that it did not object to the use of a fixed rate without wholesale margin offsets.

Chamber's Comments

Response to the Department's Proposed Approach

The Chamber shares the DOC's concerns and supports the approach to fix fuel and purchased power costs in base rates. These costs often represent 40% or more of a business customer's bill depending on load factor. Under the current mechanism, the risk associated with poorly managed fuel or purchased power acquisitions as well as risks on forced outages for utility owned and operated generation is passed on to the ratepayers. Thus, it is crucial that utilities are made more accountable for managing these costs. Utilizing the DOC's approach of fixing fuel costs in base rates is one way to shift this risk burden appropriately to the utilities.

The Chamber recommends the following changes in order to build on DOC's proposal:

- Similar to treatment of other costs, these costs should be adjusted for known and measurable changes in rate cases. The known and measurable changes aspect will assist in addressing utilities' concerns regarding forward looking costs.

- Outliers such as costs associated with forced outages should be removed in calculating the monthly energy costs.

- There should be proper accounting of wholesale margins.

The Chamber welcomes the opportunity to work with the DOC and other interested parties to further discuss this approach. The implementation of DOC's proposed approach combined with the Chamber's recommendations are an effective way of providing utilities the same motivation needed to minimize fuel costs as other costs such as fixed O&M included in base rates. Further, it also results in the same yardstick for prudency review as other costs fixed in base rates.[58] For all of the reasons discussed above, the Chamber believes that this approach is worthy of further discussion.

Long Term Fuel Management Issues

Under the current mechanism, there is inadequate incentive to manage short term or long term fuel costs. The DOC's recommended approach along with the Chamber's changes will encourage short term fuel cost management and will not inhibit long term fuel management. Due to a utility's ability to account for known and measurable changes while fixing fuel costs in base rates, a utility will have the opportunity to reduce risks and enter into contracts that provide price stability. The Chamber has consistently commented in IRP proceedings, on the need for risk management for fuel purchases, including but not limited to concern on future natural gas pricing.

The Chamber believes that, in addition to the DOC's proposal to fix [cost recovery for] fuel in base rates, utilities [should be required to] file fuel risk management plans in the years that utilities do not file integrated resource plans.

Of concern to the Chamber, many utilities are considering expanded natural gas fired generation resources for long term electric supply needs of ratepayers. Natural gas has historically been much more volatile than other fuels, so it is important that risk management plans be put in place in order to protect customers from price volatility. The objective of the risk management plan would be to include a diversified strategy that incorporates a combination of storage, short term and long term procurement. Currently, the Chamber believes there is a deterrent to utilities entering long-term fuel agreements that may be in the best interest of ratepayers, because utilities have a reluctance to enter into a contract if there is a chance that prices are more favorable in the future. It could cause intervenors to argue that a contract was a poor decision that ratepayers should not pay for. This is currently a disincentive to long-term planning. The approach could be to have the risk management plan approved by the Commission so that utilities are not inhibited from implementing these longer-term strategies. The Chamber welcomes discussions with others regarding this approach and encourages the Commission to also consider providing guidance to the utilities regarding long term fuel management as described herein.

Conclusions

The Chamber supports the DOC's recommendation to fix fuel costs in base rates. Further, the following changes to DOC's proposal should be incorporated:

- Similar to treatment of other costs, these costs should be adjusted for known and measurable changes in rate cases.

[58] At the hearing in AAA 11-792 docket, the Commission identified the difficulty in rendering decisions to disallow fuel and purchased power costs on the basis that the standard of the prudence review was not defined. By fixing fuel costs in base rates, the Commission's concern regarding a lack of a clear definition of a "prudence standard" for fuel and purchased power is resolved.

- Outliers such as costs associated with forced outages should be removed in calculating the monthly energy costs.

- There should be proper accounting of wholesale margins.

The DOC's recommended approach along with the Chamber's enhancements will encourage short term fuel cost management and not inhibit long term fuel management due to the ability to account for known and measurable changes while fixing fuel costs in base rates.

The Chamber also proposes development of a fuel risk management plan and welcomes comments from others regarding this approach in reply comments.

Minnesota Large Industrial Group

(MLIG, Reply Comments, Docket #12-757, September 30, 2013, pp. 1-8, copied largely verbatim except footnotes omitted)

- Overview

Under Minnesota law, the Commission may permit utilities to file for approval of the automatic adjustment of rates for energy and emission control costs. Specifically, Minnesota law states:

> the Commission may permit a public utility to file rate schedules containing provisions for the automatic adjustment of charges for public utility service in direct relation to changes in:
>
> (1) federally regulated wholesale rates for energy delivered through interstate facilities;
> (2) direct costs for natural gas delivered;
> (3) costs for fuel used in generation of electricity or the manufacture of gas; or
> (4) prudent costs incurred by a public utility for sorbents, reagents, or chemicals used to control emissions from an electric generation facility, provided that these costs are not recovered elsewhere in rates. The utility must track and report annually the volumes and costs of sorbents, reagents, or chemicals using separate accounts by generating plants.[59]

Commission rules spell out the purpose of the fuel adjustment clause and govern application of this statutory provision. The purpose of the rules is "to enable regulated gas and electric utilities to adjust rates to reflect changes in the cost of energy delivered to customers from those costs authorized by the Commission in the utility's most recent general rate case."[60]

The purpose is not, however, to provide actual recovery for fuel and purchased energy costs. To be sure, the calculation for any adjustment precludes recovery of actual costs via the defined period of recovery. The rules state that "The adjustment per kWh is the sum of the current period cost of energy purchased and cost of fuel consumed per kWh less the base electric cost per

[59] Minn. Stat. § 216B.16 subd. 7.
[60] Minn. R. 7825.2390.

kWh."[61] The term "current period" is defined as "the most recent two-month moving average used by electric utilities in computing an automatic adjustment of charges."[62] Also, "The amount of the billing period adjustment to charges must be determined by extending kilowatthour sales in the billing period by an adjustment per kWh."[63] Given these definitions, the current method of calculation does not entitle the Utilities to recover actual fuel and purchased energy costs.

But not all of the Utilities use the backward looking calculation contemplated by applicable rules. In 2000, NSP petitioned for and obtained a variance from the rules governing automatic adjustment for fuel costs.[64] Claiming that customers would receive better price signals with a forward looking fuel clause, Xcel requested the following (i) a revision allowing for the monthly FCA to be based on a one-month ahead forecast of sales and energy costs; (ii) a revision allowing for a monthly FCA true-up factor to be included in monthly FCA filing; and (iii) a revision allowing the monthly FCA to be prorated based on the number of days in each billing cycle.[65] With a slight modification, the Commission approved NSP's request on June 27, 2000.[66] NSP is the only electric utility in Minnesota using the forward looking method.

In its 2008 rate case, Minnesota Power proposed to modify its fuel adjustment clause method consistent with NSP's method described above. Minnesota power proposed a new methodology that projected fuel costs and MWh for the current billing month with a true-up against actual costs occurring two months after the billing month.[67] A number of parties objected, including the Large Power Intervenors.[68] These objections were largely focused on Minnesota Power's claimed impacts of the proposed change. Minnesota Power asserted that there would be roughly $3.1 million in stranded costs associated with a change to a forward looking fuel adjustment clause and an $18.6 million charge associated with the update to the base cost of fuel.[69] Ultimately, these issues were resolved via settlement, whereby Minnesota Power withdrew the requests for a forward looking fuel clause and update to the base cost of fuel.[70]

Regardless of whether the FCA is forward or backward looking, the Utilities' (including NSP) cost recovery is not precise.[71] More importantly, utilities have no incentive to control fuel and

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[61] Minn. R. 7825.2600 subp. 2.
[62] Minn. R. 7825.2400 subp. 13.
[63] Minn. R. 7825.2600 subp. 1.
[64] In the Matter of the Petition of Northern States Power Company to Amend the Terms of Its Electric Fuel Clause Adjustment, Docket No. E-002/M-00-420, NSP Petition (April 4, 2000).
[65] Id. at 7-8.
[66] In the Matter of the Petition of Northern States Power Company to Amend the Terms of Its Electric Fuel Clause Adjustment, Docket No. E-002/M-00-420, ORDER (June 24, 2000).
[67] See In re Minnesota Power, Docket No. E-015/GR-08-415, Direct Testimony of Pete Seeling, pg. 16.
[68] See In re Minnesota Power, Docket No. E-015/GR-08-415, Direct Testimony of James T. Selecky.
[69] See In re Minnesota Power, Docket No. E-015/GR-08-415, Direct Testimony of Pete Seeling, pg. 16, pg. 19-20. A similar issue existed with respect to NSP's transition, but that issue was resolved via agreement between the Department and NSP, wherein NSP netted the transition costs against a refund due customers. In the Matter of the Petition of Northern States Power Company to Amend the Terms of Its Electric Fuel Clause Adjustment, Docket No. E-002/M-00-420, ORDER (November 1, 2000).
[70] In re Minnesota Power, Docket No. E-015/GR-08-415, Stipulation and Settlement Agreement, Ex. 107 (November 18, 2008).
[71] See The Department's Review, pg. 22, Table 4.

purchased energy costs. Despite the utilities' efforts, purchased energy for what are arguably unreasonable forced outages will be built into the FCA for a specific time period. And the Commission appears hesitant, even where there is evidence that a portion of the utility's fuel and purchased energy costs are unjust and unreasonable, to require a refund of that portion of fuel and purchased energy costs. Given these shortcomings, the proposal in the Department's Review is a good starting point for discussion of this critical issue.

- The Overarching Concerns Raised by the Department Must be Addressed in a Timely Manner

In 2012, the Utilities recovered over $1.2 billion in their respective FCAs.[72] These significant figures, combined with the perverse incentive of FCA cost recovery, changes in the MISO energy market, PPA structure, and costs due to utilities' mistakes, have lead the Department to the conclusion that a change is necessary. MLIG agrees. The Department states:

> While the Department is open to any reasonable proposal by other parties, the Department recommends that, rather than allowing utilities to recover all changes in energy costs on a month-to-month basis, recovery of energy costs should be fixed in a rate case, with no adjustment between rate cases, at the IOU's average energy costs ($/kWh) over the previous three years before a rate case is filed. While this approach could set the recovery of energy costs at a single rate throughout the year, it would be more appropriate to set the energy rates for each month of the year based on average costs for that month in the past three years, so that rates could provide better price signals to customers to reduce energy during peak periods. This approach would give the IOUs clear incentives in between rate cases to minimize their total cost of doing business. That is, not only would utilities have an incentive to minimize capital and other costs recovered in base rates, but they would also have the same incentive to minimize energy costs.[73]

A likely complaint of the Utilities to this concept, and one raised in NSP's Reply Comment, is that the Department's proposal is arbitrary and could lead to under-collection. The same could be said about the current methodologies employed by NSP and the other Utilities. But MLIG is sensitive to any revision to the FCA that would lead to a greater likelihood of under-recovery than the present methodology. MLIG agrees with the sentiment in NSP's Reply Comment that any revision to the FCA "should not create 'winners' and 'losers' based on conditions utilities cannot influence."[74] MLIG does not, however, believe that the list of principles in NSP's Reply Comment adequately addresses concerns from the ratepayers' perspective.[75] NSP's list of principles fails to include reference to a penalty for undesired actions and outcomes. More importantly, NSP's list does not include reference to the Utilities' burden of proving rates are just and reasonable.

[72] The Department's Review, pg. 22-24.
[73] Id. at 21.
[74] NSP Reply Comment, pg. 23.
[75] Id.

- The Commission Should Consider Fixing All or a Portion of the Utilities' Fuel and Purchased Energy Costs During a Rate Proceeding

As the Commission is well aware, "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."[76] Utilities bear the burden of demonstrating rate proposals are just and reasonable.[77] The Minnesota Supreme Court has expanded upon this burden and stated "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."[78] But it appears that, with respect to fuel and purchased energy costs, the charges imposed by the Utilities are assumed by the Commission to be just and reasonable unless demonstrated to the contrary by clear and convincing evidence. With respect to the 2010-2011 AAA docket, the Commission found:

> The Department investigated in great detail forced plant outages experienced by the electric utilities, and concluded that several unplanned outages experienced by Xcel, Minnesota Power, and Interstate were the product of inadequate or improper operating or maintenance practices and therefore unreasonable. Certain other outages, in the Department's view, were the result of preventable employee error.[79]

Despite the Department's detailed and extensive effort, the Commission ultimately determined that the docket did not contain "detail sufficient for the Commission to resolve disputes of fact necessary to finally determine the prudence of the utilities' plant operation and maintenance."[80]

It is difficult to understand what additional information could have been produced in the Department's analysis. Furthermore, it is hard to reconcile the Commission's decision with the statutory directive to resolve doubts in favor of the ratepayer. MLIG sincerely hopes the Commission understands these frustrations from the ratepayer's perspective.

But rather than debate prior decisions, MLIG believes effort should focus on designing a revised FCA mechanism to generally address concerns from the ratepayers' perspective. MLIG agrees with the intent of the Department's proposal - the Utilities should have some "skin in the game" on fuel and purchased energy costs. Nonetheless, slight modifications to the Department's proposal may be necessary to assuage the Utilities' objections. One potential modification would be to allow continued adjustments for fuel costs while fixing the level of purchased energy costs. Another potential modification would be for parties to discuss and agree upon an appropriate method (other than a three-year historical average) of arriving at representative fuel and/or purchased energy costs for the rate case test year. In any case, the parties could also clarify that

[76] MINN. STAT. § 216B.03.
[77] MINN. STAT. § 216B.16, subd. 4 ("The burden of proof to show that the rate change is just and reasonable shall be upon the public utility seeking the change.").
[78] In re Northern States Power Co., 416 N.W.2d 719, 722-23 (Minn. 1987).
[79] In the Matter of the Review of the 2010-2011 Annual Automatic Adjustment Reports for All Electric Utilities, Docket No. E-999/AA-11-792, Order Acting On Electric Utilities' Annual Reports, Requiring Refund Of Certain Curtailment Costs, And Requiring Additional Filings, pg. 4 (August 16, 2013) (emphasis added).
[80] Id. at 5.

if, for some reason, an unplanned and extended outage at a generating facility occurs and the utility purchases much more energy from the market than planned, then the Utilities would be free to submit a filing seeking recovery. MLIG emphasizes that the purpose of fixing all or a portion of FCA costs in a rate case should be to force the Utilities to justify as reasonable any costs in excess of the fixed amount, and not to force the Utilities into a position of constant under-collection. Ratepayers should not bear the burden of questioning recovery of fuel and purchased energy costs in order to demand a refund for certain unreasonable costs after those costs have been recovered. The current method, which places this precise burden on ratepayers, needs to be revisited.

Office of the Attorney General (OAG)

(OAG, Reply Comments, Docket #12-757, September 20, 2013, pp. 1-7, copied largely verbatim except footnotes omitted)

While the OAG agrees with the DOC's overall assessment that the current automatic recovery mechanism for fuel and purchased power costs fail to provide the proper incentive to control these significant costs, it disagrees that the best method to fix the current problem is to eliminate the FCA. Moreover, the OAG is concerned that convening additional meetings, as suggested by the DOC,[81] will not provide progress toward a resolution. Accordingly, the OAG continues to recommend that the Commission adopt the FCA incentive mechanism, described below, that it has recommended in past rate cases. In the alternatives, the OAG recommends the Commission solicit specific proposals for an FCA incentive mechanism from parties for comments.

1. The Current FCA Model Has Been Questioned for Years.

For ten years, the Commission and parties have discussed the appropriateness of utilities' current FCA. Despite these discussions on whether the FCA continues to be appropriate, Minnesota utilities still pass through actual costs of fuel and purchased power costs and adjust their recovery monthly. The Commission has discretion to allow fuel and purchased power cost recovery automatically and may discontinue or modify an automatic adjustment provision for an individual utility.[82] Because many of the reasons for adopting the FCA no longer apply, the Commission should modify the FCA to conform with current conditions.

As the DOC explained: "the FCA was originally designed to allow the utility to recover, outside of rate cases, costs that were largely outside the control of the utility."[83] Moreover, "[t]he FCA also provided a way to pass savings to ratepayers if the actual cost of fuel dipped below the base cost included in rates."[84] Based on concerns that utilities' automatic recovery of fuel and purchased power may not be in the best interests of ratepayers, however, the Commission opened

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[81]The DOC made its suggestion to conduct an additional meeting on utilities' FCAs in Docket No. E-999/ AA-11-792. Accordingly, these comments apply equally to that docket. past rate cases. In the alternative, the OAG recommends the Commission solicit specific proposals for an FCA incentive mechanism from parties for comment.
[82] Minn. Rule 7825.2920, subp. 3.
[83] Comments of DOC IN THE MATTER OF THE REVIEW OF THE 2011-2012 ANNUAL AUTOMATIC ADJUSTMENT REPORTS, Dkt. No. E999-AA-12-757 (June 5, 2013) at 16.
[84] Id.

an investigation on June 4, 2003, to investigate the propriety of continuing the automatic adjustment of charges by utilities.[85] In opening the investigation, the Commission stated:

> Investigation Opened
> Finally, as noted above, the Commission concurs with the Department that this is an appropriate time to open a proceeding to explore the usefulness of the fuel clause adjustment as a regulatory tool. The Commission also concurs with Xcel that this proceeding should be industry-wide, not company-specific.
>
> While the advantages of permitting fuel clause adjustments are widely understood and have come to be taken for granted, their disadvantages have not been carefully examined since their initial adoption.
>
> Furthermore, since that time, the kinds of costs recovered through the fuel clause have significantly changed. Purchased power costs and the costs associated with the practice of "hedging," for example, are very different from the straightforward fuel costs the fuel clause was originally designed to recover. As the Department notes in its comments, these new costs may pose different issues in terms of risk management, price signals, and oversight and accountability.

The Commission's investigation has never concluded and the question of whether the FCA is an appropriate tool for cost recovery remains today. As explained by the Chamber of Commerce, in its comments dated October 30, 2007, automatic cost recovery fails to provide incentives for a utility to manage its costs:

> To us, however, ensuring proper management of FCAs by the utility might mean giving utilities appropriate incentives to optimize maintenance of existing resources, plan for outages, hedge fuel purchases, and respond to external factors (e.g, weather, unplanned outages) without a guarantee that customers will foot the bill under any circumstance.[86]

Since October 2007, no party has made a filing in the Commission's docket that began in 2003. Throughout that docket, however, the parties conducted extensive meetings to address the various ancillary issues surrounding an incentive mechanism to control fuel and purchase power costs. Despite the numerous meetings that have been held over the years, utilities continue to collect their fuel and purchased power costs through the FCA.

2. Adopting an Incentive Mechanism is Appropriate at this Time Due to Utilities' Expanded Influence over their Fuel Costs.

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[85] IN THE MATTER OF THE COMMISSION'S INVESTIGATION INTO THE APPROPRIATENESS OF CONTINUING TO PERMIT ELECTRIC COST ADJUSTMENTS, Dkt. No. E999/CI-03-802 (June 4, 2003) at 5.
[86] Chamber Comments - October 30, 2007 in the 03-802 Docket. The OAG notes that the Commission would still maintain authority to review the specific methods used by utilities to control fuel costs.

As explained by the DOC, the conditions that existed when the FCA was first implemented have changed, rendering an incentive mechanism for the FCA even more important than it was previously. As noted above, when initially implemented, the FCA was seen as having an equal potential to benefit both utilities and ratepayers. Because fuel costs were considered to be outside the control of utilities, the FCA protected utilities from unavoidable increasing costs. On the other hand, ratepayers benefitted from an immediate reduction to their bills when fuel costs declined. Even with the potential to balance both the interests of utilities and ratepayers, parties recognized the many drawbacks of automatic pass-through of fuel costs and the potential to distort market incentives.[87] Despite these drawbacks, the FCA was adopted as the method to balance utility and ratepayer interests.

Any balance that may have existed in the potential benefits to ratepayers and utilities when the FCA was adopted no longer exists. As noted by the DOC, "[w]hile utilities are not in complete control of energy costs, utilities' choices have far more influence on FCA costs than has been the case previously."[88] Ratepayers, however, continue to have no control over their utilities' fuel costs. It is unfair, therefore, for ratepayers to bear an equal risk for changes in fuel costs for which utilities have considerable influence. Instead, the Commission should incentivize utilities to manage their fuel costs for all parties' benefit.

3. Parties Should Provide Specific Proposals to Amend the FCA.

While the OAG agrees with the DOC's statement that many nuances exist in the FCA,[89] it is not convinced that convening a workgroup or conducting further meetings will spur meaningful progress to resolve these nuances. As noted above, the parties have conducted various meetings and discussions for ten years. The issue has spanned six different dockets - three rate cases in which the OAG recommended an incentive mechanism, two Annual Automatic Adjustment proceedings, and the initial investigation initiated by the Commission.

Until the DOC's recent proposal to eliminate the FCA, no party had provided a specific alternative to the OAG's proposed FCA incentive mechanism. The lack of progress to-date means that utilities continue to recover their costs of fuel without any incentive to mitigate these costs. Additional open-ended discussion, without specific proposals or directives, will likely lead to further delays.

For its part, the OAG continues to recommend the proposal it made in each of NSP's 2008, 2010, and 2012 rate cases. While the OAG understands the administrative benefits of eliminating the FCA altogether-as suggested by the DOC-it is not convinced that eliminating the FCA is the optimal solution in light of utilities' greater control of their fuel costs. In other words, since utilities have greater control of fuel costs, they have the ability to minimize their risks for

[87] See Comments of DOC IN THE MATTER OF THE REVIEW OF THE 2011-2012 ANNUAL AUTOMATIC ADJUSTMENT REPORTS, Dkt. No. E999-AA-12-757 (June 5, 2013) at 16-17.
[88] Id. at 17.
[89] See Comments of the DOC IN THE MATTER OF THE REVIEW OF THE 2010-2011 ANNUAL AUTOMATIC ADJUSTMENT REPORTS FOR ALL UTILITIES, Dkt.No. E999/AA-l 1-792 (Sept. 5, 2013) at 2.

changes to these costs. The DOC proposal, however, places an equal risk on ratepayers for decreases in fuel costs as it does on utilities for increases in fuel costs.

The OAG proposal would cap utilities' cost recovery for fuel and purchased power and thereby provide an incentive to utilities to control their fuel and purchased power costs. The OAG's proposed cap is generous, at three percent above the authorized base cost in a utility's rate case. Accordingly, utilities would be able to recover three percent more than that approved in their base rates without filing a new rate case.

This proposal recognizes the increased control that utilities have over their overall fuel costs and retains the principle that utilities should not receive a windfall simply because the cost of fuel declined. Therefore, the Commission should adopt the OAG's proposal.

If the Commission believes that additional discussion on the FCA incentive is warranted, then the OAG urges the Commission to establish deadlines for any party that supports an incentive mechanism to submit a proposal and to provide substantive comments on other proposals. Certainly, if parties want to meet informally to help develop an incentive mechanism proposal, the OAG has no objection. However, the OAG requests that the Commission not establish a formal workgroup or conduct additional Commission meetings, as these processes will likely lead to further delays.

<u>OAG's Recommendations</u>
For the reasons set forth above, the OAG does not support eliminating or freezing the FCA as recommended by DOC in Docket 12-757, nor does it support further meetings as recommended by DOC in Docket 11-792. Past meetings have not produced viable consideration of any incentive mechanism, including the proposal offered by the OAG. Accordingly, the OAG recommends adopting its proposed three percent cap on fuel costs above a utility's base cost.

In the alternative, the OAG recommends that the Commission: (1) establish principles for the design of an incentive mechanism to control costs; and (2) solicit additional rounds of comments to consider the OAG's proposed incentive mechanism, or alternatively allow other parties to recommend a different incentive mechanism which would be subject to critique by other parties.

The OAG has recommended and continues to recommend the following principles for an incentive mechanism:

- that the incentive mechanism be simple to administer and not require extensive analysis and debate about whether the utility has justified full recovery of its fuel and purchased power costs each year; and

- that the incentive mechanism does not incorporate the potential that the utility profit from reduced costs that should be passed on to ratepayers.

The OAG appreciates that there is agreement that the FCA fails to provide proper incentives to control fuel and purchased power costs as indicated by the DOC and the Chamber of Commerce.

However, the OAG cannot support the DOC's proposal because it could result in higher costs to ratepayers despite increased control of these costs by utilities. Also, as more renewable resources such as wind and solar, with no fuel costs, are included in the generation resource mix, it is possible that fuel and purchased power costs will decline. Thus, the OAG does not support elimination of the FCA but instead encourages the Commission to establish an incentive mechanism so that utilities will internalize the need to control fuel and purchased power costs.

Reply Comments – December 31, 2014

Department of Commerce

(DOC, Response Comments, Docket #12-757, December 31, 2014, pp. 8-16, and 28, copied largely verbatim except footnotes omitted)

Overview of the FCA: Advantages and Disadvantages

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

1. The FCA was intended to allow utilities to address fuel price volatility without filing frequent, expensive rate cases.
2. The FCA addressed costs that were presumed to be beyond the utility's control.
3. The FCA was intended to reduce a utility's business risk and thereby improve the utility's credit ratings.
4. At the time the FCA was first established, the Federal Energy Regulatory Commission (FERC) regulated power costs. Now, the "Day 2" energy market of the Midcontinent Independent System Operator (MISO) is a source of replacement power costs.
5. The FCA provided a way to pass savings to ratepayers if the actual cost of fuel dipped below the base cost included in rates.

However, the FCA also has drawbacks. A report and teleseminar by the National Regulatory Research Institute (NRRI) explained that utilities will treat costs recovered through trackers differently that costs recovered in base rates. "The Two Sides of Cost Trackers: Why Regulators Must Consider Both" (Ken Costello, October 27, 2009)[90] stated:

> When mechanisms for cost recovery differ across functional areas, perverse incentives can arise that would make it profitable for the utility not to pursue cost-minimizing activities. The result is higher rates to utility customers.

- A utility with an FAC might postpone maintenance of a power plant even when such maintenance would cost less than the savings in fuel costs (i.e., when beneficial to consumers but not to the utility).
- The utility could not immediately (or ever) recover additional maintenance costs, while it could pass the higher fuel costs through the FAC.

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[90] Found at: http://mn.gov/puc/documents/pdf_files/012415.pdf Docket No. E-999/AA-12-757

This [NRRI] report explained reasons for this different treatment of costs by utilities, first by noting that "[a]n important incentive for cost control by regulated utilities is the threat of cost disallowance from retrospective review." Second, the Report noted that, while "[r]egulators have long recognized the importance of retrospective reviews in motivating a utility to avoid cost disallowances from grossly subpar performance," "[t]o the extent that cost trackers dilute the frequency and quality of these reviews, further erosion of incentives for cost control occurs." This dilution occurs because:

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

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

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

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

<u>Difficulties in Current Operation of the FCA</u>
Current operation of the FCA mechanism is problematic for ratepayers and regulators; this discussion highlights a few of the recent concerns.

In the FYE11 docket (Docket No. E999/AA-11-792), the Department conducted an extensive audit of utilities' forced (unexpected) outages, assessing the extent to which utilities took reasonable steps to avoid such outages or minimize costs of replacement power (which are charged to ratepayers through the FCA. This audit focused on the limited question of whether the utilities had shown it to be reasonable to charge ratepayers for all of the replacement power costs during a subset of unplanned (forced) outages. The audit did not question or assess the issue of recovery of replacement power costs during planned (unforced) outages, nor did it address recovery of replacement power costs during all unplanned outages.

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

Utility resistance even in providing the necessary information, let alone being required to show that the costs recovered through the FCA are reasonable, raises the concern that the Docket No. E999/AA-12-757 identified issues may only be the tip of the iceberg. In addition, IOUs' responses to the issues raised by the Department in the 11-792 Docket indicated that the IOUs did not treat energy costs as part of their total cost of doing business, i.e., energy costs are not treated as internalized costs. As noted above, the NRRI report indicates that utilities will treat costs recovered through trackers differently that costs recovered in base rates.

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Despite the extensive effort by the Department and time for utility responses and development of the record, on August 16, 2013, the Commission concluded that the "record in this docket does not contain detail sufficient for the Commission to resolve disputes of fact necessary to finally determine the prudence of the utilities' plant operation and maintenance."[91]

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

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

Because the current design and operation of the FCA makes it difficult to conclude that utilities are minimizing FCA costs and making decisions in a holistic sense, the Department discusses

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

ways to improve ratemaking for fuel costs. The Department, other consumer advocates and utilities met (in late 2013 and early 2014) and subsequently exchanged ideas, as discussed below.

Incentive FCA

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

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

(2) Economic theory predicts that the longer the regulatory lag, the more incentive a utility has to control its costs; when a utility incurs costs, the longer it has to wait to recover those costs, the lower its earnings are in the interim. The utility consequently, would have an incentive to minimize costs.

(3) Regulators rely on regulatory lag as an important tool for motivating utilities to act efficiently.

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

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

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

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

Overall Goal of Reforming the FCA

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

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

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

a. Rolling-average FCA

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

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

b. Fuel costs set in a rate case

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

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

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

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

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

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

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

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

Advantages and Disadvantages of Improved FCA Incentives

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

- Would give IOUs clear incentives in between rate cases to minimize their total cost of doing business, using their specific knowledge of their day-to-day operations. Thus, it extends the incentives to minimize capital costs to energy costs.
- Would treat capital and fuel costs similarly, thus giving utilities the incentive to minimize total costs.
- Would provide ratepayers with more advanced notification about the rates they will be paying in the near future.
- Over the long run, this approach should lead to lower overall costs compared to the current regulatory mechanism.
- Would alleviate the need for discussing whether the Commission has the burden of proof to disallow costs or whether the burden of proof is on the IOUs to show that their costs are reasonable.
- Would not require the Commission to address, after the fact, whether the rates that were charged to ratepayers were reasonable.

Disadvantages are:

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

<u>Department Recommendation</u>

The Department has identified several options for reforming the FCA, as discussed above. As next steps, the Department recommends that the Commission consider asking parties to file comments on these options, bringing parties together to talk about these options, or both, whichever option would allow the issues to be developed in a manner acceptable to the Commission.

Minnesota Large Industrial Group

(MLIG, Comments, Docket #12-757, December 31, 2014, pp. 1-8, copied, excerpted, or adapted, largely verbatim except footnotes omitted)

The Minnesota Large Industrial Group ("MLIG") has previously commented in this docket about the importance of reforming electric utilities' fuel clause adjustment mechanisms and appreciates the Minnesota Department of Commerce's efforts to facilitate stakeholder discussions about this topic last winter (in early 2014). As part of that stakeholder process, MLIG submitted the enclosed comment letter [dated February 14, 2014] to the Department, which includes our analysis of the proposals made by various stakeholders and MLIG's recommendations.

MLIG looks forward to renewing the discussion in this docket and moving toward implementation of modifications to fuel clause adjustment mechanisms.

February 14, 2014 MLIG Letter:
The Department has requested comments on four proposals offered by (1) Northern States Power Company d/b/a Xcel Energy ("Xcel"), the (2) Minnesota Chamber of Commerce (the "Chamber"), (3) the Office of the Attorney General - Antitrust and Utilities Division ("OAG") and (4) the Department itself. Each of these proposals addresses different aspects of the current FCA and therefore potentially offers a range of advantages and disadvantages. Below we provide MLIG's evaluation of the pros and cons of each proposal and a recommendation.

Overview of FCA Proposals
In general, each of the proposals to update or replace the FCA include methodologies to set a benchmark for the amount of recovery of fuel and purchased energy costs and approaches to determine actual recovery of fuel and purchased energy costs relative to the benchmark.

- Summary of Recommended Benchmarks. Three of the four proposals recommend setting fuel costs in base rates (Department, Chamber, and the OAG). In setting that base rate, the Department recommends using a historic average of fuel and purchased energy costs, while the Chamber recommends incorporating certain forward-looking factors such as market indices. The OAG does not elaborate on how fuel and purchased energy costs should be calculated for inclusion in base rates. Xcel recommends using a historic performance measure (the Equivalent Availability Factor or Equivalent Unplanned Outage Rate) to set a benchmark for future performance.

- Summary of Recommended Recovery Mechanisms. Each of the proposals provides a mechanism for cost recovery relative to the benchmark. The Department recommends that there be no adjustments to recovery amounts between rate cases. The Chamber recommends that there be no adjustment to recovery amounts so long as actual costs fall within a 2% band above or below the base level. The OAG recommends implementing a cap on fuel and purchased energy cost recovery at 3% above the base level. Xcel recommends a set dollar amount of over- or under- recovery based on its performance relative to a generating unit availability metric.

As described further below, there are pros and cons to each of these proposals, but there may also be some common ground.

Evaluation of FCA Proposals

- Statutory Background. Minnesota law permits the automatic adjustment of rates for energy and emission control costs. Specifically, Minnesota law states:

> the Commission may permit a public utility to file rate schedules containing provisions for the automatic adjustment of charges for public utility service in direct relation to changes in:

(1) federally regulated wholesale rates for energy delivered through interstate facilities;
(2) direct costs for natural gas delivered;
(3) costs for fuel used in generation of electricity or the manufacture of gas; or
(4) prudent costs incurred by a public utility for sorbents, reagents, or chemicals used to control emissions from an electric generation facility, provided that these costs are not recovered elsewhere in rates. The utility must track and report annually the volumes and costs of sorbents, reagents, or chemicals using separate accounts by generating plants.[92]

Commission rules spell out the purpose of the fuel adjustment clause and govern application of this statutory provision. The purpose of the rules are "to enable regulated gas and electric utilities to adjust rates to reflect changes in the cost of energy delivered to customers from those costs authorized by the commission in the utility's most recent general rate case."[93] The rules state that "The adjustment per kWh is the sum of the current period cost of energy purchased and cost of fuel consumed per kWh less the base electric cost per kWh."[94] The term "current period" is defined as "the most recent two-month moving average used by electric utilities in computing an automatic adjustment of charges."[95] Also, "The amount of the billing period adjustment to charges must be determined by extending kilowatt-hour sales in the billing period by an adjustment per kWh."[96] Given the method of calculation, utilities are not entitled to recover actual fuel and related variable costs. Instead, the method provides a means for utilities to recover certain fuel and related variable costs, which should approach actual costs over time (though there may be over-collection and under-collection). Further, the statutory language states that the Commission "may permit" automatic adjustments, which implies appropriate limitations can be set. One such limitation that must govern recovery is that rates remain just and reasonable, with any doubt resolved in favor of the consumer.[97]

- Evaluation Criteria. Based upon the regulatory framework and policy goals of the FCA, MLIG weighed the following questions in evaluating the pros and cons of the proposals:

(1) Does the proposal provide an incentive for utilities to manage fuel and purchased energy costs?
(2) Does the proposal appropriately allocate the burden of proof for cost recovery?
(3) Can the proposal be implemented with reasonable administrative efficiency?

- Evaluation of Proposals.

[92] Minn. Stat. § 216B.16 subd. 7.
[93] MINN. R. 7825.2390.
[94] MINN. R. 7825.2600 subp. 2.
[95] MINN. R. 7825.2400 subp. 13.
[96] MINN. R. 7825.2600 subp. 1. Certain utilities have obtained variances from the rules and employ variations on this mechanism.
[97] MINN. STAT. § 216B.03.

Department Proposal

1. Benchmark for Recovery Amounts. The Department proposes to fix recovery of fuel and purchased energy costs in a rate case at a utility's average energy costs over the previous three years. While the Department's proposal may have the advantage of being administratively efficient, using a historical average may result in chronic under- or over-recovery of costs if long-term trends outside of a utility's control cause fuel costs to consistently rise or fall.

2. Methodology for Cost Recovery. The Department's proposal would not provide for any adjustment to recovery amounts between rates cases. As a result, utilities would have an incentive to keep their fuel and purchased energy costs at or below the level set in the rate case.

However, as noted above, the historic-looking methodology for setting the rate may result in substantial over- or under-recovery.

Chamber Proposal

1. Benchmark for Recovery Amounts. The Chamber proposes a methodology based on Wisconsin's policy that uses existing contracts, historic averages of outage rates, and market indices to set base rates for fuel and purchased energy costs recovery. The Chamber's methodology for rate setting is more complex than the Department's methodology, but the inclusion of forward-looking components may result in rates that better reflect actual costs. The Chamber also references procedures used in Wisconsin whereby utilities make annual filings to set their base costs. However, an annual process may be burdensome and unnecessary if base costs are established in a rate case.

2. Methodology for Cost Recovery. The Chamber proposes to establish a 2% "deadband" around the recovery amount set in the rate case for which there would be no adjustment to recovery relative to actual costs. Like the Department's proposal, this mechanism may provide an incentive for utilities to keep costs at the fixed level or up to 2% below it. Accordingly, and as with the Department's proposal, ratepayers would be insulated from some of the normal fluctuation in fuel and purchased energy costs. While the plus or minus 2% deadband proposed by the Chamber appears reasonable, it may not be beneficial to establish a fixed deadband. Uncertainty regarding costs may vary over time and among utilities, which may make variations on the range of a deadband appropriate.

The Chamber's proposal does not go into detail regarding what should happen if actual costs deviate more than 2% in either direction. Presumably, ratepayers would receive a refund if actual costs were more than 2% below the set amount. If actual costs are more than 2% higher, MLIG assumes the burden would be on the utility to request additional recovery. MLIG would welcome additional discussion on this issue.

OAG Proposal

1. Benchmark for Recovery Amounts. Like the Department, the OAG recommends setting base costs in a rate case, but does not elaborate on how fuel and purchased energy costs should be calculated for inclusion in base rates.

2. Methodology for Cost Recovery. The OAG proposes that automatic recovery of fuel costs continue as under the current FCA, but that cost recovery be capped at 3% above the amount set in a rate case. The advantage of a cap rather than a deadband is that it avoids the possibility of a windfall for the utility if fuel prices decline, while maintaining the benefit of placing the burden on the utility to justify recovery of costs above a certain threshold. It also allows for automatic adjustments to continue so long as they are within a set range above base rates. Furthermore, this mechanism allows automatic adjustment to continue for any amount below base rates, which would provide ratepayers the full benefit of any savings. Finally, although a 3% cap does not appear unreasonable, it may be better to set the cap on a case-by-case basis in a rate case in order to account for varying levels of uncertainty and risk over time and across utilities.

Xcel Proposal

1. Xcel proposes to establish incentives and penalties based on the Equivalent Availability Factor ("EAF") of selected generation units or, alternatively based on a combination of the EAF and the Equivalent Unplanned Outage Rate ("EUOR"). Xcel's proposal focuses on providing an incentive to control costs associated with unplanned outages and purchased energy. While Xcel's proposal appears to address one of MLIG's primary areas of concern—unplanned outages—it would not resolve issues related to fuel price spikes. Further, Xcel's proposal to measure its performance solely against its own past performance, does not seem adequate. Incorporating a MISO or industry-wide metric would provide a more objective measure of performance. Finally, further discussion is needed regarding other details of Xcel's proposal, including:

    a. Whether it is appropriate to exclude nuclear facilities.
    b. Whether, to the extent EAF or EUOR is used as a benchmark, it would be based on a rolling average of recent years. A rolling average would ensure that improvements over time would gradually become a higher standard of performance.
    c. Further explanation and analysis of the proposed metrics. The historical EAF and historical EUOR charts provided with Xcel's proposal indicate that they would yield substantially different results, despite being seemingly related metrics.

2. Methodology for Cost Recovery. Xcel proposes that cost recovery would continue as normal under the FCA, but that an incentive (in the form of a set dollar amount of over- or under-recovery) based on the company's performance against its historic EAF (or a combination of EAF and EUOR). While Xcel's proposal includes the clearest incentive/disincentive mechanism, it ultimately may not be beneficial to ratepayers to use over-recovery as an incentive. In MLIG's view, the primary goal for updating the FCA is not to create winners or losers, but to establish appropriate presumptions of reasonableness that align the motivations of all parties to control costs.

<u>MLIG Recommendations</u>
The current FCA is outdated for a variety of reasons that have been discussed at length by stakeholders. In recent years, the types of costs that are recovered through the FCA have expanded greatly, which has created an enormous and inappropriate burden on regulators and ratepayers to review the reasonableness of those costs. With all fuel and purchased energy costs automatically passed through under a statutory formula and without an effective means of review, the current system does not encourage utilities to control costs or ensure that rates remain just and reasonable.

Based on our review of the four proposals and analysis of the FCA's policy framework, MLIG believes that a "cap" approach best meets the goals of providing an incentive to control costs, appropriately allocating the burden to establish reasonableness for costs, and reducing administrative burdens. In particular, MLIG recommends that base costs for fuel and purchased energy be established in a rate case (incorporating appropriate forecasting factors) and that an appropriate cap on automatic adjustments be set in the same rate case. Below the cap, adjustments would continue as under the current FCA. Above the cap, the burden would be on the utility to seek recovery through a rate case or request deferred accounting. This system would best address the three questions MLIG posed above.

A. Does the proposal provide an incentive for utilities to manage fuel and purchased energy costs? Yes. As noted above, MLIG does not believe the goal of establishing an incentive to control costs is to pit utilities and ratepayers against each other. Rather, the purpose is (or at least should be) to ensure that the parties' interests are aligned to control fuel and purchased energy costs. MLIG believes that utilities are most capable of managing day-to-day fuel and purchased energy costs and that the primary concern is events that cause significant spikes in costs. Establishing a cap allows utilities to continue to manage day-to-day costs, while establishing an incentive to prevent cost spikes.

B. Does the proposal appropriately allocate the burden of proof for cost recovery? Yes. MLIG believes that an appropriate cap can be reasonably established in the context of a rate case. Costs above the cap would require the utility to request cost recovery and to justify those costs. This is a burden MLIG believes is appropriately placed on the utility. And the cap would ensure that resources deployed to review the reasonableness of fuel costs would be best utilized focusing on the events with the largest impact on ratepayers.

C. Can the proposal be implemented with reasonable administrative efficiency? Yes. The cap would arguably establish a presumption that costs below the cap level are reasonable, which would reduce the burden on the Department and ratepayers to scrutinize such costs. Ultimately, however, it would still be the utility's burden to establish that rates are just and reasonable and parties would be free to raise questions when appropriate.[98] This shifting of presumptions regarding reasonableness should reduce the burden on the Department in auditing costs passed through the FCA.

Office of Attorney General

(OAG, Comments, Docket #s 12-757 & 13-599, December 30, 2014, pp. 1–7, copied largely verbatim)

Annual automatic adjustments are permitted under Minnesota Statutes section 216B.16, subdivision 7, which allows for monthly adjustments for utilities to recover their fuel and purchased power costs ("energy costs") incurred to generate electricity.[99] The energy cost adjustment for each billing period is computed in accordance with Minnesota Rules parts 7825.2390 to 7825.2920. Each utility must submit an annual report detailing its energy costs for the period from July 1 to June 30 each year.[100] Each utility must also submit an independent auditor's report evaluating the accounting for automatic adjustments for the reporting period.[101]

The Minnesota Department of Commerce ("DOC") thereafter provides its evaluation of energy cost adjustments for each utility, and the Commission considers each utility's report. The annual evaluation of automatic adjustments has grown to be a significant task for a number of reasons.

First, the types of costs that are permitted recovery as energy costs has expanded to include such items as Midwest Independent System Operator ("MISO") costs, asset based and non-asset based margins, purchased wind contract and curtailment costs, and other items for which the Commission has granted specific authority for recovery.

Second, the scope and type of generation costs has expanded to include costs related to renewable energy resources such as wind and solar. More recently, new legislation has also expanded utilities' obligations to purchase distributed solar energy from customers or their designated provider of solar power.

Third, the annual evaluation processes have been complicated by recent events, including the catastrophic failure of Sherco 3, because of extended plant outages. Unplanned outages typically result in the utility incurring additional costs to generate electricity from more expensive sources of generation.

[98] See MINN. STAT. §§ 216B.03, 216B.16, subd. 4; 216B.17, and 216B.21.
[99] See Minn. Stat. § 216B.16, subd. 7 (2014) (specifying the types of costs allowed for monthly adjustments). The Commission has the authority to permit the use of automatic adjustments for energy cost; alternatively, the Commission may deny this recovery method.
[100] See Minn. Rule 7825.2810.
[101] See Minn. Rule 7825.2820.

Stakeholders and the Commission have raised questions about the current automatic energy cost recovery mechanism. The current system requires a lengthy process to explore whether the energy costs were reasonable and necessary, and whether they justify recovery from ratepayers. The current mechanism also fails to adequately incentivize utilities to minimize fuel costs.

- The Commission Should Consider Implementing a FCA Incentive Mechanism to Manage Fuel Costs.

Modifications to the FCA mechanism in Minnesota should attempt to address the need to manage this substantial category of costs. Rather than an automatic recovery mechanism, an incentive mechanism, which has the potential for financial impacts on the utility, will help focus management's attention on the need to manage its costs for the mutual benefit of the utility and ratepayers. Parties have raised concerns with the FCA mechanism dating back more than 10 years.[102] These concerns have been addressed in various dockets, including rate cases and annual evaluation dockets. OAG witness Mr. John Lindell first proposed a FCA incentive mechanism to address these concerns in Xcel's 2009 rate case and again in Xcel's 2011 and 2013 rate cases.[103]

Other parties have also identified the need for a FCA incentive mechanism and offered or discussed various incentive proposals.[104] There are various ways to provide some level of financial incentive for electric utilities in Minnesota to manage their energy costs on behalf of their ratepayers, and the Commission should further consider the matter.

The OAG's previous proposals for a FCA incentive mechanism were structured to incentivize utilities to manage their costs for energy. Currently, under a direct cost recovery model, there are no financial incentives to control energy costs because the costs are automatically recovered from ratepayers each month. While utilities may argue that they have incentive to control their energy costs based on potential disallowance (whether recommended by DOC or other parties), the bottom line is that the utilities have not been denied recovery for these costs. A FCA incentive mechanism should be structured to accomplish the goal of providing a financial incentive for the utilities to manage their energy costs.[105] The incentive mechanism should be easy to administer and should comply with Minnesota law.

Mr. Lindell's proposal in Xcel's last rate case was to establish a 3% cap above the base cost of energy, as established in the rate case.[106] If the utility's cost per megawatt hour for the year exceeded the 3% cap, it would not be able to recover the amount above the cap. Under this proposal, utilities would have incentive to manage their costs throughout the year because any

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[102] Docket No. E999/CI-03-802.
[103] See Lindell testimony in Docket Nos. E002/GR-08-1065, E002/GR-10-971 and E002/GR-12-961.
[104] See, e.g. DOC's June 5, 2013 Comments in Docket No. E999/AA-12-757.
[105] The proposal recognized that the goal of such a mechanism should not simply be to minimize energy costs because such an approach could cause unintended consequences where a utility's other costs of providing service increase as a result of focusing solely on minimizing energy costs. The mechanism should not create a high probability of cost disallowance. The goal is to provide a utility with the incentive to manage its energy costs in conjunction with other costs to provide service, not to disallow legitimate and well-managed energy costs.
[106] In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service Minnesota, Docket No. E002/GR-12-961, Lindell Direct at 12-18 (February 28, 2013).

excess costs above the cap in the beginning of the year could potentially be offset by keeping costs below the cap during the remainder of the year. Similarly, if a utility were to manage its costs and keep the cost per megawatt hour below the cap at the beginning of the year, it would still have incentive to manage its costs during the remainder of the year to limit its exposure to unforeseen high costs later in the year. The OAG also offered an alternative to this proposal in response to any concern that the utility was exposed to excessive cost disallowance.[107] The alternative proposal would establish a 2% cap with a limit on total disallowance equal to the amount of Conservation Improvement Program ("CIP") bonus[108] that the utility earned during the year.

The proposal previously offered by the OAG would be authorized by existing Minnesota law. Because the FCA is a discretionary tool that allows the automatic pass through of energy costs, establishing a cap in conjunction with the FCA would be similar to not allowing any automatic pass-through of energy costs. Absent the FCA, a fixed level of energy costs would be used for recovery and operate as both a cap and a floor for cost recovery. Therefore, the proposal would not violate existing statutes or rules governing energy cost recovery. The Commission will need to proceed with caution if any proposed incentive mechanism contains both a cap and a floor that would allow a utility to profit by reducing costs below the base cost of energy. Minnesota law provides only limited opportunities for utilities to earn above their authorized rate of return.[109] In addition to carefully considering the policy of any such mechanism, the Commission would also need to ensure that Minnesota law allows a utility to profit from reducing its energy costs.

Other states use different fuel cost incentive mechanisms. In Wisconsin, for example, adjustments for the actual cost of energy are prohibited in a range around the base cost of fuel as established in a Commission proceeding.[110] Wisconsin's band is 2% above and below the base cost of fuel, which is established annually. If actual costs for fuel exceed the base cost plus 2%, the utility is permitted to defer those costs for future recovery (subject to objections from other parties who may oppose cost recovery in excess of the 2% band). Similarly, if actual costs for fuel are more than 2% below the base cost, the utility defers the difference for a future adjustment, resulting in a rebate to ratepayers. This band mechanism provides incentive to manage the cost of fuel and also limits the exposure for the utility and its ratepayers from excessive fluctuations in the cost of fuel. Any time the actual costs for fuel exceed or fall below the base cost of fuel plus the allowable variation, a Commission proceeding is necessary to establish the amount to rebate or surcharge ratepayers.

Washington uses a FCA mechanism that is specific to each utility. Washington utility Avista, for example, uses a FCA mechanism with a so-called "dead band," with no sharing within the dead band. There is sharing of the costs or savings when energy costs fall outside of an allowable

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[107] Id.
[108] CIP bonuses are authorized by statute and allow the utility to earn above its authorized rate of return as an incentive to implement effective conservation programs.
[109] The CIP bonus, for example, is authorized by statute. See Minn. Stat. §216B.16, Subd. 6c (2014).
[110] See Wisconsin Public Service Administrative Code Ch. 116.

range.[111] This FCA mechanism, also known as an Energy Recovery Mechanism, is intended to stabilize earnings and cash flow for the utility, offers the potential for rebates to customers, and also reduces financing costs for customers. The mechanism establishes a dead band where no adjustments for cost recovery are made. Based on the OAG's calculations, the dead band appears to be in the range of 2% to 3%, which is $6 million above or below the base cost of energy for Avista. When costs or savings exceed the dead band range, the utility and ratepayers share the additional costs or savings, which are deferred and applied to rates only when the total deferral reaches a trigger amount. The shared cost or savings occur in different ratios depending on the magnitude of the variance. For 2012 the Washington Utilities and Transportation Commission approved the sharing of the 2012 savings of $14.7 million with Avista retaining the first $6 million plus 25% of the next $4 million or $1.5 million plus 10% of the savings above $10 million or approximately $470,000.[112] Avista retained approximately $8 million of the total $14.7 million of savings and ratepayers received credit for $6.7 million.

Utilities criticize incentive mechanisms for a number of reasons; primarily, utilities have argued that they have little control over the costs paid for fuel.[113] That should not stop the Commission from protecting ratepayer interests. Energy costs can be managed and minimized, and they are subject to some degree of control. The utility must be given some incentive to act prudently in incurring these costs, however. The Commission should consider implementing a FCA mechanism that provides sufficient incentive to Minnesota utilities to control these costs to the maximum extent possible.

Reply Comments - February 11, 2015

Xcel Energy

(Xcel, Reply Comments, Docket #12-757, February 11, 2015, pp. 3-7, copied largely verbatim)

In addition to the Department's prior suggestion to set the FCA based on historic data, the Department offered three other alternatives for reforming the fuel clause and incenting utilities. Each of these ideas, however, involves things over which utilities have no control.

By design, the FCA permits utilities to recover costs largely out of our control, outside of a rate case. Customers are billed their share of volumes and cost of fuel, dollar for dollar; they do not pay any more for these items than the utility incurs to produce and/or procure the energy on their behalf. Fuel clause mechanisms provide significant benefit to utilities, regulators and ratepayers by creating a method for recovery of certain volatile costs. The utility is kept whole with that portion of its costs; ratepayers pay their share of costs according to how much electricity they use; and regulators are able to focus review on these limited types of costs on a regular basis, rather than during a rate case where all costs are reviewed.

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[111] 14 See In the Matter of Avista Energy Recovery Mechanism Annual Filing to Review Deferrals for Calendar Year 2012, ORDER AUTHORIZING ENERGY RECOVERY MECHANISM DEFERRALS FOR CALENDAR YEAR 2012, Docket UE-130438, Order 01 (July 11, 2013).
[112] Id.
[113] See, e.g. Rebuttal Testimony of Xcel witness Allan Krug, Docket No. E002/GR-12-961 at 22.

We continue to have concerns and reservation about supporting alternate FCA methods that will clearly reduce and limit any opportunity we might have to recover FCA type costs with no ability to improve our outcomes through our own actions.

In our August 2013 Reply Comments, we thoroughly described our concerns about the Department's suggestion to set forward-looking fuel clause recovery based on an average of past actual experience. The proposal to use an historic rolling average approach produces volatile and random results. Included in our Reply was a backcast analysis applying the suggested 3-year average to recent historic data as well as a summary of the primary drivers influencing our FCA during these years. With the passage of time, we have updated the table with 2013 results. This information was provided to the OAG in response to an information request and is included here as Attachment A.[114] As can be seen in the updated results, we would have under-recovered approximately $100 million in 2013 using the Department's historic rolling average approach.

Table 3-Updated: Impact of Department's Proposal

	Change to FCA Recovery ($M)	Actual ROE Weather Normalized (%)	Realized W/N ROE Under DOC FCA Incentive Proposal (%)	Difference (%)
2008	+$94.5	10.19	7.78	-2.41
2009	+$54.4	10.18	11.44[115]	+1.26
2010	+$32.8	8.78	9.48	+0.70
2011	-$26.5	9.08	8.56	-0.52
2012	-$63.1	8.20	7.05	-1.15
2013	-$112.1	8.22	6.32	-1.90

The primary drivers influencing our FCA during this same period can be grouped into the following three general cost categories: (1) commodity fuel and transportation cost, (2) resource supply mix, and (3) state policy. (Please see pp. 13-15 of the briefing papers for the updated version of Xcel's table four.) Other than the forced outage impact of Sherco 3 experienced in 2012 and 2013, the major events influencing the FCA were related to fuel prices, supply mix and state policy for Xcel Energy during this past seven year period.

With respect to the other alternatives identified by the Department, we see similar issues and would be happy to participate in further discussion if that is the direction the Commission provides. A repeated concern and criticism the Department has in AAA proceedings is around plant outages. We are working hard to keep our plants operating at top performance and believe the other utilities are as well. For the record, we note that we also proposed during stakeholder meetings and communications an incentive mechanism which revolved around something utilities have more control over—plant operations. We thought our proposal was a good start and may have been of interest to at least one other utility, but it did not appeal to other stakeholders.

[114] For ease of filing, Attachment A to this Reply includes only the text portions of our response to Information Request No. OAG-2.
[115] In Table 3 as originally filed, we reported this ROE to be 11.44. Upon subsequent analysis, we discovered that this ROE should be 11.46. The correction is reflected here and in the response to Information Request No. OAG-2.

We are willing to continue to participate in discussions that include consideration of incentives, but feel there is no inherent flaw in the fuel clause as it now exists. However, we would agree it could be beneficial to look for ways to streamline or simplify reporting to aid review.

Minnesota Power

(MP, Reply Comments, Docket #12-757, February 11, 2015, pp. 1-7, copied largely verbatim)

The Department has been focused on creating an incentive FCA since the closure of the 11-792 Docket. In discussing its goal of reforming the FCA, the Department appropriately cites that the utility should have a reasonable opportunity to recover their costs of providing service. While current ratemaking structures encourage utilities to minimize O&M costs and provide little to no incentive to minimize replacement power costs, utilities still have an inherent obligation and incentive to minimize customer cost overall – an FCA incentive is not a prerequisite to the utilities fulfilling this obligation.

While alternatives to an incentive FCA were not on the table for discussion in the Department-led review in the aftermath of the 11-792 Docket, it was a good opportunity for the stakeholders to gather to discuss the FCA. As noted by the Department, various alternatives were considered but the issues were certainly not resolved in the stakeholder meetings. It is clear that there are many complex and nuanced issues involved – often with many differing perspectives and opinions.

The Department recommends an alternative ratemaking approach holding utilities accountable for replacement power costs. The Department does not define what "accountability" means or how it would be applied. In any event, the Department believes this would encourage utilities to consider all costs of providing service, including replacement power costs, short-term and long-term planning. However, Minnesota Power already considers replacement power costs in both short-term and long-term planning, and also considers replacement power costs if the unit is operating in such a fashion that a forced outage should be taken in the near-term in order to protect the asset on a long-term basis. This least-cost planning approach was explained in detail in Docket No. E-999/CI/03-802.

The Department could be more proactive in their review of outage data and costs by spending more time with the monthly filings. It appears through a review of utility regulatory costs that this is now occurring, and Minnesota Power welcomes a more "real-time" review of the fuel clause on a monthly basis (as we have advocated previously). A more timely review would enable the utilities to provide more current responses without having to try to recover information from months or years ago. Also, in the event that costs were deemed imprudent, this would provide for more timely return of funds to the ratepayers who paid for these costs.

Minnesota Power believes that taking this discussion out of the context of reviewing each company's annual AAA filing – and instead making it an overall Commission investigation or workgroup process – would be the most beneficial way to address the wide array of issues at play if the entire fuel adjustment clause mechanism is reviewed. That is one reason why Minnesota Power reminded the Commission of the open Investigation in Docket E999/CI-03-

802 during the recent deliberations of the 11-792 Docket. Opening a dialogue would allow the Commission to shape the scope of inquiry and provide direction to the parties as to the information the Commission will need in its decision making process, and allow more time for information gathering, inquiry and reflection.

At present, the perceived "problems" and how to address them are a moving target. For example, the Department's comments in the 11-792 Docket focused on forced outage costs and whether some replacement energy costs were prudently incurred, with the disallowance of certain costs as the proposed resolution. However, the Department comments in the AA-12-757 Docket abandoned the forced outage cost inquiry completely and instead substitutes a menu of options for consideration – options that have not been fully vetted by all stakeholders. Obviously the Department is continuing to seek a replacement of the current fuel clause mechanism and appears intent on advocating to do so until the current system is changed, despite the Commission's clear rejection of the Department's advocacy in the Order in 11-792. The Department recommends various options to the current fuel clause mechanism, including a rolling average FCA, fuel costs set in a rate case, fuel costs set in a rate case with index adjustments, and fuel costs set in a rate case with band adjustments. After listing numerous "advantages" to these recommendations, the Department identifies two potential disadvantages, with one being that reduced costs [may not be completely passed to ratepayers between rate cases, and the other that utilities may file more frequent rate cases; however, utilities would need to consider how their total cost have changed before doing so.]

But any changes to the fuel clause could have far reaching impacts that the Commission should carefully consider. The Department's recommendations of an incentive fuel clause did not take into consideration the changing nature of each utility's generation portfolio; the nature of commodity price fluctuations and changing fuel transportation costs; the impact of renewable energy mandates; or changing emission regulations and enforcement actions. The Department's comment regarding utilities being accountable for replacement power costs would presumably shift these costs from ratepayers to the utility for the provision of electric service to utility customers. This would be a significant change in the rate-making equation, and without an overall, holistic approach to resource planning and generation supplied decision-making a targeted modification to the FCA that shifts replacement power costs from ratepayers to utilities would be problematic. Until the Commission initiates an overall review of the fuel clause, the fuel clause's role in overall utility service (including resource planning), the operation of the MISO market, the impact of transportation costs and fuel costs on both the wholesale and commodity level, these recommendations have no context and no value. These impacts need to be explored and understood in the context of the entire fuel clause operation and application before the Commission can even determine if there is in fact a "problem" that must then be addressed in a balanced way.

The Department's recommendations do not take into consideration the changing nature of each utility's generation portfolio: the nature of commodity price fluctuations and changing fuel transportation costs; the impact of renewable energy mandates; or changing emission regulations and enforcement actions. Any change must consider the utility's five-year fuel clause projection and must assure complete and timely recovery of a utility's fuel costs recovery. Minnesota

Power projects total fuel and purchase energy costs (FPE) to increase from 2015-2018. The projected cost increases are not the anticipated outcome of poor planning or imprudency; they are due to increasing costs beyond the direct control of Minnesota Power, including increased fuel and transportation costs, market prices, load additions, and bridging purchase costs that have increased FCA costs but have delayed generation-related capital investment costs. For example, our use of bridging purchases provides the overall least cost to our customers even though they do increase FCA costs.

Further, the Department's recommendation also does not take into consideration two of the most significant issues that have faced Minnesota Power in recent years regarding fuel clause impacting events: the loss of the Thompson Hydro system for almost 2 years due to a significant weather event, and the effect that the BNSF Railway Co. has had in shifting its coal delivery schedule and choking fuel necessary for generation supply. Without a discussion of these two significant events, it is unclear how an "improved FCA incentive" mechanism could even adequately address fuel clause operation.

The Department continues to emphasize that the utilities do not have an incentive to lower fuel clause costs. The Department cites a National Regulatory Research Institute paper that is filled with suppositions but is short on specific facts or examples, and is not focused on Minnesota. Most remarkably is the sentence that states "By contrast, minimizing costs recovered in the FCA has no effect on utilities profits." As Minnesota Power has stated repeatedly, if the Company does not manage its fuel clause costs to minimize the impact of the FCA on its energy prices, then its customer base is not profitable and the customers themselves are exposed to temporary or permanent shutdown, severely impacting Minnesota Power's other ratepayers and our overall business interests as a whole. As a result, the FCA is one of the areas of Minnesota Power's greatest focal points for reducing minimizing and managing customer costs: our globally-competitive large power customers require the lowest energy prices available in order to compete in the world market – otherwise they face idled or shuttered operations. The reduced energy sales that would result would directly and immediately affect Minnesota Power's annual revenue and severely impact the company financially. These customers provide 60% of our revenue and the FCA accounts for approximately 40% of their monthly energy bill. These customers materially affect the company in many ways and we take all of their costs and all other customer costs into consideration as we procure energy supply and manage generation availability, so for the Department to suggest we simply pass these costs through with no regard is not merely misguided but also not true.

Minnesota Power has the 4th lowest rates in the country and has always had to be especially mindful of rate impacts in resource decisions. It is ironic that Minnesota Power's low energy cost makes it a target for outage cost examination in part due to the marked difference between its generation supply cost and replacement energy costs purchased in the wholesale market – and that is true even in the depressed wholesale market prices we see today. Minnesota Power understands the concerns of the Department regarding increased energy costs and the impacts of increasing fuel and purchased energy costs have on our customers. Minnesota Power believes it does a good job in controlling FCA costs and does not believe change in the FCA is required to ensure least cost supply because providing the all-in lowest cost alternative is already a strong and well established process at Minnesota Power. The financial impact of fuel clause operations on ratepayers is indirect but always prevalent – so much so that Minnesota Power annually budgets its anticipated fuel clause costs and reviews those costs with its large power customers so they are aware of their cost impacts. Minnesota Power implemented this close working relationship with its customer base long before the Commission ever became interested in these issues related to fuel clause operation. These annual updates became the model for updating the Department of Commerce monthly fuel clause projections that we use today.

The Department's recommendation of changing the basis of fuel and purchase energy recovery could fundamentally change the business model that Minnesota Power is currently working under and has used to make long-term supply decisions. Resource decisions need to be made by considering all aspect of costs, including capital investment, fuel cost and deliverability. Minnesota Power has worked hard to minimize all energy and capacity costs through a robust Integrated Resource Plan, as well as competitive fuel, rail and purchase power contracts over the last twenty and thirty years. Energy procurement and commodity costs are increasing. The favorable long-term fuel and transportation agreements negotiated in the past (whose benefits have already been passed on to ratepayers) are expiring, being replaced by shorter-term fuel contracts that contain cost escalators.

In addition, Minnesota Power's Energy Forward Strategy (as reflected in our Integrated Resource Plan) could be impacted by changes to the fuel adjustment process. Specifically, as Minnesota Power moves toward less carbon-intensive generating resources as required by the State's renewable energy standards as well as federal generator emission regulations, we introduce more variability to fuel costs. For example, the additions of the Bison wind assets have led to lower fuel costs when the wind is blowing but require dispatchable or intermediate resources when the wind generation is not available. This energy can come in the form of low priced MISO market purchases or through the addition of natural gas generation. Either element adds additional fuel cost variability when compared to the Company's current baseload coal resources. If the fuel adjustment were to be fixed or capped at a certain level, it may change the Company's operating philosophy or future resource additions.

In describing difficulties in the current operation of the fuel adjustment class, the Department has again cited the fact that it took several rounds of discovery lengthy time periods for utility responses in the 11–7 92 docket. The Department cited this is utility resistance to inquiry and difficulty by the utilities to show the cost to recover to the fuel clause are reasonable. As for the difficulties the Department believes they have encountered during the review of the AAA filings, not all of these difficulties are utility-created. The Department explicitly noted the rounds of discovery needed to review reasons for forced outages. We disagree with the contention that the utilities were being difficult and uncooperative; the initial information requests were vague and confusing; requested information not normally kept for long periods of time; was requested in a format that was not compatible with our reports created at the time. In fact, the Department's level of inquiry was unprecedented, and was requesting information that utilities had not previously been required to assemble and provide the Department. Further, difficulty interpreting Department financial analysts' request by the engineering staff on site at the various generators lead to additional rounds of discussions in order to clarify the exact nature of information the

Department was requesting. The Commission rejected the Department's recommendations in that Docket because the Department was attempting to apply standards after the fact, and holding the utilities to those standards that it created through its inquiry process. It is disingenuous for the Department to now claim that the difficulties it faced in undertaking that inquiry should now be used as a basis to attribute reluctance to regulatory review by the utilities.

Finally, in providing its overview of the FCA mechanism, the Department is in error in stating that the FERC formerly regulated purchased power costs but now does not with the advent of the MISO energy market. In fact, prior to the creation of MISO (first as a transmission management entity and then later as an energy market manager), the cost of replacement energy was not regulated any differently and was in fact much less transparent than it is today. The advent of the MISO market has increased transmission reliability and has allowed a more open and transparent energy market so that regulators utilities and customers can monitor energy prices. Prior to MISO, utilities could manipulate the availability of transmission, and could use that transmission market power to drive up market energy prices. The resulting energy market replacement costs were not as visible as they are today, even though the resulting prices impacted utility customers in the same exact way as they do today.

Otter Tail Power

(OTP, Reply Comments, Docket #12-757, February 11, 2015, pp. 2-3, copied largely verbatim)

A predominate issue within this Docket has centered on whether or not the current fuel clause mechanism should be changed to some other type of recovery mechanism. Otter Tail believes the current FCA mechanism works well within the context for which it was designed and in conjunction with operational goals Otter Tail has already employed to foster an environment which strives for low cost energy for our customers. Otter Tail has noted in prior Comments[116] submitted in this docket, that it believes plant performance and plant availability are important to keeping energy costs low for its customers.

The Department provided a brief outline of four alternative fuel clause mechanism structures in their December 31, 2014 Comments. Likewise, the OAG and MLIG also offered comments suggesting that alternative fuel clause mechanisms should be explored.

While there may be numerous alternatives that could be considered, one option which was shared with the Department and between stakeholders a year ago was an option for a mechanism which considered incorporating the use of a Plant Equivalent Availability metric for determining incentives tied to fuel cost recovery. Otter Tail continues to believe that plant availability is the key driver which influences fuel costs the most, and therefor believes that a mechanism that focuses on plant availability would most closely align with the operational goals and objectives[117] already in place at Otter Tail.

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[116] Otter Tail Reply Comments submitted September 13, 2013 and Additional Comments submitted December 31, 2014.

[117] In Reply Comments submitted 9-20-2013, pages 6-10 , Otter Tail outlines numerous aspects of its operations, (Company Mission Statement, Key Performance Indicators, Generating Availability Data System ("GADS") data

As noted earlier, Otter Tail believes the current fuel clause mechanism continues to serve the purpose and intent for which it was originally established. However, should the Commission desire to further evaluate changes to the fuel clause mechanism, Otter Tail recommends that further evaluation be addressed in a separate docket instead of within this or any other AAA report docket.

Minnesota Large Industrial Group
(MLIG, Reply Comments, #12-757, February 11, 2015, pp. 1-2, copied largely verbatim)

The Minnesota Large Industrial Group ("MLIG") continues to appreciate the Minnesota Department of Commerce's efforts to facilitate stakeholder discussions on reforming the fuel clause adjustment ("FCA") mechanism.

<u>FCA Options</u>
In its comments filed December 31, 2014, the Department identified four options for reforming the FCA: (1) rolling-average FCA, (2) fuel costs set in a rate case, (3) fuel costs set in a rate case with index adjustments, and (4) fuel costs set in a rate case with band adjustments. MLIG generally agrees with the Department's analysis of the difficulties presented by the current FCA mechanism as well as the advantages and disadvantages of the four incentive-based alternatives. While MLIG remains open to further discussions of any of the options presented by the Department, it has previously recommended a variation on option (4) that should also be considered. Specifically, in the letter attached to MLIG's December 31, 2014 comments, MLIG recommended a cap approach that would set a fuel and purchased energy cost recovery level in a rate case, require automatic adjustments for costs below that level, and cap automatic adjustments for costs above that level (e.g. at +3%). This approach would provide a clear incentive for utilities to manage fuel and purchased energy costs to avoid reaching the cap, would appropriately allocate the burden of proof to utilities for setting cost recovery levels and requesting recovery amounts above the cap, and would ease the administrative burden on regulators and ratepayers by presuming that costs under the cap are reasonable. And, unlike most of the other options identified by the Department, this cap approach would also insure that ratepayers receive the benefit from any decrease in costs between rate cases.[118]

<u>Next Steps</u>
In its December 31, 2014 comments, the Department recommended that the Commission request that parties file comments on these options or convene parties to further discuss these options, or both. As noted in MLIG's December 31, 2014 comments, MLIG and other parties participated in discussions of FCA reform in late 2013 and early 2014. These discussions included an in person meeting as well as an exchange of FCA reform proposals and comments on those proposals. Through this stakeholder process, previous comments filed in this docket, and comments filed

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performance, accountability to other joint plant owners) that help demonstrate a culture focused on keeping our plants operating at a high level and our customer's energy costs low.

[118] See the attachment to MLIG's December 31, 2014 comments for a more detailed explanation of this option. This option also is similar to the proposal made by the Office of the Attorney General–Residential Utilities and Anti-trust Division ("OAG"), which was most recently described in the OAG's December 30, 2014 comments in this docket.

during this current comment period, there is extensive information about FCA reform options in the record and the positions of various parties' on those options.

If helpful to the Commission, MLIG would be supportive of the Commission requesting further comments on FCA reform options as framed in the Department's December 31, 2014, comments. However, given the volume of information already developed on these issues, a long time period should not be necessary for parties to file and respond to such comments. Similarly, MLIG would be supportive of a Commission-organized meeting of the parties to further discuss FCA reform options. But again, a long-lead period for such a meeting should not be necessary since parties have had ample time to develop their ideas and positions. However the Commission chooses to proceed, MLIG urges the Commission to establish a timeline for a decision on FCA reform within the next six months.

MLIG continues to believe that the FCA is long-overdue for reform. Utilities recover an enormous amount of money through their respective FCAs and it is nearly impossible for ratepayers and regulators to effectively review these costs. Thus, MLIG urges the Commission to establish a firm timeline for moving these discussions to a conclusion and implementing incentive-based FCA reform.

Office of Attorney General

(OAG, Reply Comments, Docket #12-757, February 11, 2015, pp. 8-18, copied largely verbatim)

- A FCA Incentive Mechanism Is Needed To Ensure Ratepayers Are Charged Reasonable Rates.

The changes in electricity markets and regulation since the FCA was first implemented have exacerbated the perverse economic incentives within the FCA. The FCA incentivizes utilities to substitute capital for increased fuel efficiency, choose suboptimal fuel mixes across the generating fleet, and skew short- and long-term planning. The lack of incentive to minimize fuel costs has created a scenario in which each utility's poor performance is likely increasing fuel costs for Minnesota ratepayers. At a recent energy forum Xcel Energy's CEO, Mr. Ben Fowke, stated that "incentives do work."[119] Given the utilities' recent interest in performance based regulation ("PBR"), the Commission should implement a FCA incentive mechanism to ensure that Minnesota ratepayers are receiving reasonable rates and utilities are incented to improve performance.

- Utilities Control Multiple Factors That Directly Influence Fuel Costs.

Utilities control multiple factors that directly influence fuel costs over the short- and long-run. Regulators should not be forced to micro-manage each and every decision that impacts fuel costs, nor can regulators possibly review or have knowledge about even a small portion of all these decisions. Since the factors that impact fuel costs are partially controlled by the utilities'

[119] Center for Energy and Environment's 35th Anniversary Policy Forum. Video available on CEE's website.

performance, utilities need to be provided with an incentive to minimize fuel costs to provide reasonable rates.

Xcel's August 26, 2013 comments in Docket No. 12-757, included a table that listed the main factors impacting the FCA from 2008 to 2012. Xcel updated this list of factors to include 2013 to 2014 in its response to an information request.[120] The list of factors that occurred at least once between 2008 to 2014 can be simplified as follows:

1. Higher natural gas, coal and nuclear fuel prices,
2. Additional purchased power agreements ("PPAs") and general purchases for biomass and wind,
3. Increased company owned wind,
4. Higher rail prices to transport coal,
5. Retired coal generation,
6. MISO market price and related expenses, and
7. Planned and forced outages.

Other than nuclear costs, which are unique to Xcel, each of the above factors can influence fuel costs for any electric utility in Minnesota. Whether each factor is controlled or influenced by the utility helps to inform whether or not an FCA incentive mechanism is prudent. Therefore, the OAG analyzed the utilities' control over the above factors. The OAG's analysis demonstrates that utilities have significant control over many of these factors.

First, as referenced above, a recent National Bureau of Economic Research study found that deregulated coal generators paid 12% less for coal than coal generators under cost-of-service regulation.[121] The study, however, found that the same sample considered in the coal analysis did not pay a different amount for natural gas purchases. The discrepancy between the findings regarding natural gas and coal costs was primarily attributed to information asymmetry—natural gas prices are settled in a transparent open market, while coal contracts are primarily confidential bilateral contracts.[122] The study indicates that regulated utilities have poor performance with respect to confidential bilateral fuel contract negotiation. Moreover, regulators cannot police and readily compare the confidential bilateral contracts in the same way that they can review natural gas costs, which provides the regulated utility less incentive to minimize the fuel costs for coal.

This finding indicates that ratepayers could save significantly, perhaps tens of millions of dollars, if the incentive was given to Minnesota utilities to lower their coal costs through better negotiation and procurement strategies.[123]

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[120] See Xcel's response to OAG Information Request #2 attached as Exhibit I. Xcel's original table is included within its response, which details costs by year.
[121] Utilities make a comparison of average coal costs in AAA filings. Comparing simple averages does not provide enough information to determine if coal costs are prudent because they do not take into account the numerous variables that impact coal costs for each utility such as location, type of coal, quantity purchased, transportation costs, among many other things.
[122] NBER (2014) at 3.
[123] See tonnage purchased and average prices paid by each Minnesota utility in Docket No. 13-599.

Second, utilities also have some control over the cost that company-owned wind and wind curtailments cause within their system. As the DOC pointed out in a previous AAA filing, Xcel has increased the cost of wind curtailments by not curtailing the cheapest wind resources first, which increased the fuel costs over the short-run for ratepayers.[124] Utilities also have control of the planning and integration of these facilities, which contributes to the costs of curtailments and operation within MISO (such as congestion costs) that flow through the FCA.

Third, like wind curtailments, utilities have control over planned outages, and the DOC has pointed out multiple cases where utilities have had some control over forced outages.[125] For example, utilities have caused outages due to their employee's own human error and poor oversight of their vendors.[126] These mistakes were obviously under the control of and caused by the utility, but utilities still attempted to pass through these costs to ratepayers. Utilities do not have proper incentive to minimize the time or frequency of these outages because they do not pay any replacement fuel costs.

Fourth, utilities have some control over MISO related costs that flow through the FCA, which have increased dramatically over the last decade. There are many costs associated with MISO (such as NSP's "proprietary resource trading methods") that are far too complex, making it difficult to determine whether or not they are reasonable. On the other hand, there are costs within MISO that are clearly partially under the control of utilities, such as congestion costs. For example, annual revenue rights are allocated each year as a hedge for congestion costs, which means a better hedging strategy will lower congestion costs, all else constant. This demonstrates some costs are too complex for regulators to effectively manage because of information asymmetry. For these costs to be minimized, the Commission should rely on a FCA incentive mechanism.

Fifth, the fuel costs related to coal transportation are similar to the issues posed by coal contract negotiation. Coal transportation costs are partially dictated by the utilities' ability to negotiate the lowest reasonable price. However, the utilities have no incentive to obtain the lowest price because the cost flows through the FCA. Utilities also do not have an incentive to achieve the most beneficial terms within the contract. Since utilities do not pay for replacement fuel costs, they are not significantly impacted financially by whether their generation plants run or not. Additionally, utilities have no reason to hold rail companies accountable for causing replacement power costs because utilities do not pay these costs. Utilities are likely paying too much for poor service from their rail providers, while ratepayers pick up the tab for the transportation and the replacement power costs due to low supplies of coal.

As discussed above, natural gas is procured in a relatively transparent market. However, natural gas hedging can impact the risk associated with prices. When addressing the FCA incentive mechanism in Xcel's 2012 electric rate case, a company witness, Mr. Allen Krug, stated "that an incentive mechanism would likely cause increases in hedging costs that the Company would

[124] See the DOC's comments filed June 1, 2012 at 14.
[125] See the DOC's comments filed June 1, 2012.
[126] Id.

have to incur to protect against fuel and purchased power cost volatility."[127] The fact that Xcel would increase hedging costs if it were to have an incentive to minimize its costs demonstrates that Xcel is willing to expose ratepayers to a higher level of risk than its stockholders with respect to fuel and purchased power cost volatility. Xcel and other utilities expose ratepayers to too much risk with regard to fuel and purchased power costs.

- A FCA Incentive Mechanism Is A Performance Based Regulation That Would Help Deliver Reasonable Fuel Costs.

The above analysis demonstrates that, based on both economic theory and the results of empirical studies, utilities have significant control over numerous factors that influence fuel costs. Since utilities have some control over fuel costs, they should internalize some of the risk associated with fuel costs in order to minimize costs. A FCA incentive mechanism would not only minimize fuel costs but would also reward utilities for improved performance. Most FCA incentive mechanisms are therefore a form of PBR, which has been requested by multiple Minnesota utilities. The OAG and DOC have suggested that these same utilities implement a FCA incentive mechanism that is similar, if not the same, to other metrics that could be developed under PBR for over a decade, without success.

The OAG is concerned that utilities may only want to pursue PBR when utilities are virtually assured of benefitting from the mechanism implemented. Structuring PBRs this way will not provide an effective or equitable mechanism. PBR requires that utilities take on more risk than traditional regulation in order to be eligible for larger rewards. If utilities are only willing to adopt PBR mechanisms that are designed with asymmetric information, the benefits for ratepayers will be eliminated or minimized.

- Hindsight Analysis of Possible FCA Incentive Mechanisms Demonstrate Reasonable Outcomes for Utilities and Ratepayers.

The OAG conducted hindsight analysis on two types of FCA incentive mechanisms to determine whether either would produce reasonable results. The OAG's analysis demonstrates both methods would provide outcomes that are better than the current model. The first analysis was conducted on a FCA incentive mechanism that sets fuel costs within a rate case with a band adjustment of 2%. This "band mechanism" would set the base cost of fuel in a rate case with a tolerance band of 2% and be trued-up annually when necessary. This would allow utilities to benefit from their improved performance up to 2% by lowering fuel prices and would punish utilities for poor performance up to 2% for higher fuel prices. Any costs above 2% would be deferred and addressed in a special proceeding where utilities would have to demonstrate why these costs were necessary and, therefore, should be recovered from ratepayers. Any costs that fall below 2% would go back to ratepayers. The second analysis was conducted on a FCA incentive mechanism that shares a percentage of the costs and benefits associated with increasing and decreasing fuel costs. This "sharing mechanism" would provide a 10 percent/90 percent sharing of costs and benefits between the utilities and ratepayers, respectively. These

[127] See Krug Rebuttal at 22 in Docket No. 12-961.

mechanisms were selected to demonstrate that there are reasonable FCA incentive mechanisms that can minimize fuel costs, and because both of these mechanisms have been implemented in other states.[128] These two mechanisms are not presented as the only possibilities, as the DOC provided additional options in previous comments (and noted that mechanisms can be combined).[129] The following analyses demonstrate that each of the FCA incentive mechanisms have benefits and detriments associated with them, but both provide outcomes superior to having no FCA incentive mechanism.

The OAG's analysis for each FCA incentive mechanism was conducted using similar methodologies, by incorporating data provided by Xcel[130] and data on the base cost of energy set in Xcel's previous rate cases. Each analysis uses the base cost of energy for Xcel's system and compares it to the actual cost of fuel within Xcel's system to determine whether there would have been an over- or under-collection. The two mechanisms differ by the way in which the over or under collection is dealt with, as explained above.

Table 1, below, summarizes how the band mechanism would have worked over the 2011 to 2014 time period.[131]

Table 1 - Band Mechanism

(1)	(2)	(3)	(4)	(5)
Year	% Over/Under Collected	\$ within Tolerance Band	\$ Over (Under) Band	Total
2011	2.40%	$16,626,703	$3,331,643	$19,958,347
2012	-0.89%	($7,493,441)	$0	($7,493,441)
2013	-8.79%	($18,423,077)	($62,531,428)	($80,954,505)
2014	-0.16%	($1,329,348)	$0	($1,329,348)
Total		($10,619,162)		

Table 1, above, displays the percentage that was over or under collected in column 2, how much of the over or under collection was within the 2% tolerance band in column 3, how much was outside of the band that would be deferred by the utility or returned to ratepayers in column 4, and the total over or under collection that occurred in the given year in column 5.

The results in Table 1 demonstrate that Xcel would have been outside of the 2% tolerance band in two out of the last four years, and would have under-collected fuel costs slightly for two years. Total under-collection over the four year period would have been approximately $10 million, or 0.31% of total fuel costs. The band mechanism results also demonstrate that the company and consumers are protected by providing consumers with benefits some years and protecting the

[128] FCA incentive mechanisms have been implemented in Washington, Idaho, Oregon, Missouri, and Wisconsin.
[129] The OAG has not addressed the possible need for statutory or rule changes to implement such mechanisms.
[130] See Xcel's response to OAG Information Request 2, attached as Exhibit I.
[131] The OAG chose to use the 2011 to 2014 time period because in Xcel's 2008 rate case the base cost of energy was increased by approximately 50%, a historically unprecedented increase. This increase was over 25% greater than the actual cost of fuel experienced by Xcel in 2009 and 2010. The OAG considers these years outliers due to the uncharacteristically unreliable estimate that was used as the base cost of fuel for those years.

utility from large market disruptions that can lead to significant under-collections. One drawback to the band mechanism is that ratepayers would not immediately receive benefits from a utility's improved performance. Rather, ratepayers' benefits would accrue overtime as utilities hold costs below what they would be otherwise.

The band mechanism may require regulators to affirmatively reset the base cost of energy on a regular basis to ensure the band is providing a strong incentive if the actual cost of energy is consistently under the base cost of energy and utilities avoid rate cases.

In contrast to the band mechanism, the sharing mechanism would provide benefits for ratepayers immediately. Table 2, below, displays the results of a 10 percent/90 percent sharing mechanism.

Table 2 – Sharing Mechanism

(1)	(2)	(3)	(4)	(5)
Year	% Over/Under Collected	10% Sharing w/Utility	90% Sharing w/Consumer	Total
2011	2.40%	$1,995,835	$17,962,512	$19,958,347
2012	-0.89%	($749,344)	($6,744,097)	($7,493,441)
2013	-8.79%	($8,095,451)	($72,859,055)	($80,954,505)
2014	-0.16%	($132,935)	($1,196,413)	($1,329,348)
Total		($6,981,895)		

Table 2, above, displays similar information to Table 1 except for columns 3 and 4, which summarize the sharing of over- or under-collection. Xcel would have under-collected by approximately $7 million, or 0.2% of total actual fuel costs, over the last four years.

Table 2 demonstrates that ratepayers and utilities would share in the costs and benefits every year. The sharing mechanism, under most circumstances, would not provide as strong of an incentive to the utility as the band mechanism since the utility would share in the costs and benefits with ratepayers. For example, in 2011, Xcel would have been able to retain over $16 million due to the lower cost of fuel under the band mechanism but less than $2 million under the sharing mechanism; ratepayers would have received a greater benefit under the sharing mechanism. The sharing mechanism also does not acknowledge that utilities may not have control over large fluctuations in energy prices, such as a 10% swing in fuel costs within one year.

The OAG's analyses of the band and sharing mechanisms results in a variation of fuel cost recovery of between 0.2% to 0.3% for Xcel over a four year period. These analyses demonstrate that a there is more than one option to ensure that utilities have incentive to control factors that influence the price of energy. The Commission should consider implementing a FCA incentive mechanism that protects ratepayers from paying avoidable, higher energy costs.

The OAG recommends that the Commission consider implementing one of the FCA incentive mechanisms in order to protect ratepayers.

Comments - Docket E-999/AA-14-579

Minnesota Large Industrial Group

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

> The Department provided some context for these discussions in Attachment E16 of the DOC Report, including referencing key points from its December 31, 2014 response comments in Docket No. E999/AA-12-757, in which it proposed an incentive FCA and summarized the difficulties with the current operation of the current FCA. In response to the Department's proposal for an incentive FCA in December, various parties, including MLIG, submitted additional reply comments in February. The Commission has not yet taken action on these recommendations and comments.
>
> More than $1.3 billion was recovered by the Utilities in fuel costs during fiscal year 2014. Given the enormous amount of money that flows through the FCA, it is of enormous importance to ratepayers for utilities to have effective incentives to control these costs and for regulators to have the ability to effectively review them. As MLIG, the Department and others have argued in previous discussions, the current FCA does not provide utilities such incentives. And further, it practically puts the burden of proof on regulators and ratepayers to demonstrate when costs are not just and reasonable. Although the Department has made recommendations for ways to improve the type of information it receives to assist in its review of costs, better information will not improve the underlying problem, which is that utilities do not have "skin in the game" with respect to costs recoverable via the FCA.
>
> These issues have been developed in more detail in the previous AAA proceedings, but MLIG believes that it is important to raise them again here because they underlie every AAA proceeding. The Department and other parties have raised serious concerns about the current FCA that need to be addressed. Ratepayers cannot be confident that costs recovered through the FCA are just and reasonable when regulators are not confident in their ability to effectively review those costs. These issues are well-developed in the 12-757 docket and are ready for Commission action to move the process along. For these reasons, MLIG urges the Commission to establish a process and a timeline for implementing FCA reform.

Department of Commerce

(DOC, Response Comments, Docket #14-579, August 26, 2015, pp. 11-12 & 37, the following has been copied, mostly verbatim, from the Department's Response Comments)

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

Pages 8-16 of the Department's comments in E999/AA-12-757 discussed the background of the FCA, included information from the National Regulatory Research Institute's (NRRI) report called "The Two Sides of Cost Trackers: Why Regulators Must Consider Both" (Ken Costello, October 27, 2009) and suggested options for the Commission to consider regarding reform of the FCA, along with advantages and disadvantages of the various options. For ease of reference, those comments are at https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={1BCA9F40-4ACC-43E8-A01F-71BDF6BED367}&documentTitle=201412-105847-01 and attached to these comments. The Department's overall recommendation in the December 31, 2014 comments was:

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

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

The Department agrees with MLIG's concern that the Department's recommendations in the previous AAA docket (13-599) "for ways to improve the type of information it receives to assist in its review of [FCA] costs will not improve the underlying problem, which is that utilities do not have 'skin in the game' with respect to costs recoverable via the FCA." For ease of reference, an overview of the underlying problem with the design of the FCA mechanism, as discussed in the 2012 AAA docket (12-757), is provided in Attachment 1 to these Response Comments. The Department stresses that the additional reporting requirements it recommended in its December 31, 2014 response comments in 13-599 and/or any information required by the Commission to help the Commission make a determination on the reasonableness of the utilities' FCA rates were only meant to be a second-best solution to modify the FCA mechanism and is intended to be used only until a new FCA recovery mechanism is approved by the Commission.

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

PUC Staff Comment

The main question the Commission needs to decide is whether there is a problem with the way the three electric IOUs are allowed to recover their energy costs on a pass-through basis. This includes all fuel, purchased power, and most, if not all, non-administrative MISO-related costs.

The FCA mechanisms have been used for many years. The FCAs are authorized under statute (Minn. Stat. § 216B.16, subd. 7)[132] and Commission rules (Minn. Rules, parts 7825.2390 through 7825.2920).[133] The FCA mechanisms and Commission rules are fairly robust in that they have accommodated a number of cost recovery challenges that include the use of Purchased Power Agreements (for a variety of purposes including contracts with Manitoba Hydro and contracts with renewable and other alternative energy suppliers), the transition to MISO, and the acquisition of replacement power during unplanned, forced plant outages.

However, the Energy Cost Adjustment statute does not require the Commission to authorize the use of the FCA. Staff does not believe there would be a legal impediment or a need to change the statute, if the Commission would like to change or modify the way IOU's recover fuel and purchased power costs. Nevertheless, staff believes that developing a record for changing the way fuel and purchased costs are recovered would be the least problematic in a rate case because the IOUs establish new base costs of energy in rate cases anyway. However, parties would need to be clear about whether any variances would be needed to the Automatic Adjustment of Charges rules and explain very clearly and in detail, how best to effectuate the transition to a different method of recovering fuel and purchased power costs. Because the current FCA mechanism is essentially a utility privilege rather than a right or entitlement under the statute, the Commission might also want to consider whether there are conditions related to the frequency of rate cases that should be incorporated into each utility's FCA mechanism if the base energy (fuel and purchased power) rates are fixed in a rate case.[134] This would be a precaution against long-term, over-earning if the base energy rates are inadvertently set too high.

Staff does not believe Minnesota law currently provides for electric utilities to have performance-based, i.e. non-cost-based, fuel and purchased power cost recovery. For example, Minn. Law currently does not explicitly allow the Commission to authorize cost recovery for any amounts above the amount of actual fuel and purchased power costs based simply on a showing of better performance relative to a benchmark or test-year normal amount of cost. (This is not true, however, for gas utilities. The Commission's 1999 report to the Legislature on performance-based gas purchasing plans, pursuant to Minn. Stat. § 216B.167, subd. 7, is included in the relevant documents for this meeting if the Commission is interested in reviewing CenterPoint Energy's gas PBR pilot program from the 1990s.)

[132] Rate Change, Procedure, Hearing – Energy Cost Adjustment
[133] PUC, Utilities, Financial, Regulatory Matters – Automatic Adjustment of Charges
[134] For example, at the federal level, the Federal Energy Regulatory Commission (FERC) required interstate pipelines to file rate cases every three years when the interstate pipelines were selling natural gas and using a PGA-like cost recovery mechanism to recover their costs. This requirement ended when the regulation of interstate pipelines was restructured and the pipelines were taken out of the merchant business.

Staff will not try to summarize the parties' arguments but will attempt to summarize each parties' position as of their most recent comments in these dockets.

Department of Commerce

"The Department identified four potential alternatives that could be used to reform the FCA."

- Rolling-average FCA

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

- Fuel costs set in a rate case

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

- Fuel costs set in a rate case with index adjustments

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

- Fuel costs set in a rate case with band adjustments

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

"The Department recommends that the Commission consider asking parties to file comments on these options, bringing parties together to talk about these options, or both, whichever option would allow the issues to be developed in a manner acceptable to the Commission. The Department is also looking forward to the Commission's guidance in this matter."

Office of the Attorney General (OAG)

"The Commission should consider implementing a FCA mechanism that provides sufficient incentive to Minnesota utilities to control these costs to the maximum extent possible." "The OAG's proposal in Xcel's 2012 rate case was to establish a 3% cap above the base cost of energy, as established in the rate case. If the utility's cost per megawatt hour for the year exceeded the 3% cap, it would not be able to recover the amount above the cap. Under this proposal, utilities would have incentive to manage their costs throughout the year because any excess costs above the cap in the beginning of the year could potentially be offset by keeping costs below the cap during the remainder of the year. Similarly, if a utility were to manage its costs and keep the cost per megawatt hour below the cap at the beginning of the year, it would still have incentive to manage its costs during the remainder of the year to limit its exposure to unforeseen high costs later in the year. The OAG also offered an alternative to this proposal in response to any concern that the utility was exposed to excessive cost disallowance. The alternative proposal would establish a 2% cap with a limit on total disallowance equal to the amount of Conservation Improvement Program ("CIP") bonus that the utility earned during the year."

Minnesota Large Industrial Group (MLIG)
"MLIG urges the Commission to establish a process and a timeline for implementing FCA reform." "MLIG believes that a "cap" approach best meets the goals of providing an incentive to control costs, appropriately allocating the burden to establish reasonableness for costs, and reducing administrative burdens. In particular, MLIG recommends that base costs for fuel and purchased energy be established in a rate case (incorporating appropriate forecasting factors) and that an appropriate cap on automatic adjustments be set in the same rate case. Below the cap, adjustments would continue as under the current FCA. Above the cap, the burden would be on the utility to seek recovery through a rate case or request deferred accounting."

Minnesota Chamber of Commerce
"The Chamber supports the Department's recommendation to fix fuel costs in base rates. Further, the following changes to DOC's proposal should be incorporated:

- Similar to treatment of other costs, these costs should be adjusted for known and measurable changes in rate cases.
- Outliers such as costs associated with forced outages should be removed in calculating the monthly energy costs.
- There should be proper accounting of wholesale margins.

The Chamber believes the Department's recommended approach along with the Chamber's enhancements will encourage short term fuel cost management and not inhibit long term fuel management due to the ability to account for known and measurable changes while fixing fuel costs in base rates. The Chamber also proposes development of a fuel risk management plan and welcomes comments from others regarding this approach in reply comments."

Xcel Energy
"Xcel continues to have concerns and reservations about alternative FCA methods that will clearly reduce and limit any opportunity Xcel might have to recover FCA type costs with no ability to improve Xcel's outcomes through Xcel's own actions."

"With respect to the alternatives identified by the Department, Xcel believes the results would most likely be volatile and random. Xcel is willing to continue to participate in discussions that include consideration of incentives, but feel there is no inherent flaw in the fuel clause as it now exists. However, Xcel would agree it could be beneficial to look for ways to streamline or simplify reporting to aid review."

"Xcel notes that a repeated concern and criticism the Department has in AAA proceedings is around plant outages. We are working hard to keep our plants operating at top performance and believe the other utilities are as well. For the record, we note that we also proposed during stakeholder meetings and communications an incentive mechanism which revolved around something utilities have more control over—plant operations. We thought our proposal was a good start and may have been of interest to at least one other utility, but it did not appeal to other stakeholders."

Minnesota Power

"Minnesota Power believes the perceived "problems" with the FCA and how to address them are a moving target." "Minnesota Power believes that taking this discussion out of the context of reviewing each company's annual AAA filing – and instead making it an overall Commission investigation or workgroup process – would be the most beneficial way to address the wide array of issues at play if the entire fuel adjustment clause mechanism is reviewed. That is one reason why Minnesota Power reminded the Commission of the open Investigation in Docket E999/CI-03- 802 during the recent deliberations of the 11-792 Docket. Opening a dialogue would allow the Commission to shape the scope of inquiry and provide direction to the parties as to the information the Commission will need in its decision making process, and allow more time for information gathering, inquiry and reflection."

Otter Tail Power

"Otter Tail believes the current FCA mechanism works well within the context for which it was designed and in conjunction with operational goals Otter Tail has already employed to foster an environment which strives for low cost energy for its customers. However, should the Commission desire to further evaluate changes to the fuel clause mechanism, Otter Tail recommends that further evaluation be addressed in a separate docket instead of within this or any other AAA report docket. While there may be numerous alternatives that could be considered, one option would be for a mechanism which incorporates the use of a Plant Equivalent Availability metric for determining incentives tied to fuel cost recovery. Otter Tail believes plant availability is the key driver which influences fuel costs the most, and believes that a mechanism that focuses on plant availability would most closely align with the operational goals and objectives already in place at Otter Tail."

Staff also notes that Xcel, OAG and MLIG briefly discussed establishing principles for the design of an incentive mechanism for controlling energy costs. Xcel's suggested principles are slightly different from OAG's and MLIG's and provide a comparison between the utility and the ratepayer perspective on cost recovery.

Xcel recommended principles that suggest that any revisions to the FCA mechanism should

- Provide rewards for desired actions and outcomes
- Lead to measurable results
- Provide transparency and predictability
- Limit risk to customers and stakeholders
- Align compatibly with current business climate
- Avoids producing unintended results

- Evolve, subject to evaluation.

OAG recommended principles that include

- The incentive mechanism should be simple to administer and not require extensive analysis and debate about whether the utility has justified full recovery of its fuel and purchased power costs each year; and
- The incentive mechanism should not incorporate the potential that the utility profit from reduced costs that should be passed on to ratepayers

MLIG recommended principles that include

- A penalty for undesired actions and outcomes, and
- A reference to the Utilities' burden of proving rates are just and reasonable.

Because several proposals for alternative cost-recovery mechanisms have been proposed staff does not believe it is necessary to spend a lot of time evaluating design principles in the abstract. Nevertheless, staff believes these principles may be helpful in informing the analysis of alternative proposals in these AAA dockets.

Staff believes the following decision alternatives capture the range of alternatives available to the Commission. As stated earlier, staff believes the threshold question for the Commission to decide is whether it believes there is a problem, and if so, how to proceed.

If the decision is to proceed, the Commission may want to consider whether there is any benefit to further discussion of potential alternatives on a theoretical level or whether it would be appropriate to start looking at actual proposals that could be implemented. If the decision is to require the submission of actual proposals that could be implemented, staff notes that Xcel and Otter Tail have rate cases pending that will be decided in approximately one year's time. Both of these cases have been referred to the Office of Administrative Hearings for contested case proceedings. However, staff believes the FCA reform issue could potentially be added to the Xcel and Otter Tail cases by requiring Xcel and Otter Tail to provide FCA reform proposals in supplemental pre-filed direct testimony for intervenors in their respective rate cases to evaluate and comment on in their testimony. If this is an alternative the Commission would like to explore, the Commission may want provide notice in those two dockets to parties and the ALJ, and possibly suggest an extension of the intervention deadline and evidentiary hearing schedule to ensure that a record is developed in this issue in time for the ALJ to issue their reports and recommendations.

Staff does not believe it is necessary for the Commission to make a decision on April 14 on the specific mechanisms recommended by the Department, the OAG, MLIG or the Chamber. Staff believes it would probably be best to leave those decisions until after there are actual proposals (with records) in front of the Commission. Nevertheless, if the Commission requires the electric IOUs to submit proposals for revised FCAs, the Commission may want to indicate generally the kind of features and/or provisions that it would like to see in those proposals.

Decision Alternatives

Next Steps

1. Require all three IOUs (Xcel, MP, and OTP) to file proposals for pilot programs to change or modify their tariffs for their Fuel Clause Adjustment (FCA) riders used for the recovery of energy (fuel and purchased power) costs, or

2. Request additional written comments or schedule another meeting on whether there are potential (and realistic) alternatives for FCA reform and other topics related to the discussion at the Commission's meetings on April 12 & 14. Request these written comments or schedule another meeting in the

    a. 12-757 docket,
    b. a new Commission investigation (CI) docket,
    c. the existing 03-802 Commission investigation docket, [135] or

3. Authorize Xcel to work with the Department to develop an alternative option for Commission consideration, or [Xcel]

4. Affirm OTP's belief that its current KPI mechanism is an appropriate alternative to the Department's proposal to change the FCA, or [OTP]

5. Take no action and close the CI-03-802 Commission investigation docket,[136] or

6. An alternative next step determined by the Commission

If one or more of the IOUs are required to propose a revised mechanism for recovering energy (fuel and purchased power) costs, when should proposals be submitted?

7. At the earliest of each IOU's next rate case <u>or</u> in a petition submitted no later than January 1, 2017 for implementation on July 1, 2017 (at the beginning of the 2017-2018 fiscal year for annual automatic adjustments), whichever comes first, or

8. In each IOU's next rate case (incorporating appropriate test-year forecasting factors), or

9. In individual utility-specific petitions submitted no later than January 1, 2017 for implementation on July 1, 2017 (at the beginning of the 2017-2018 fiscal year for annual automatic adjustments), or

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[135] Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments, Docket No. E-999/CI-03-802
[136] Ibid.

10. For Xcel (in Docket No. E-002/GR-15-826) and Otter Tail (in Docket No. E-017/GR-15-1033), in their pending rate cases, in supplemental direct testimony, within 60 days of the Commission's April 14, 2016 meeting, and

11. For MP, in its next rate case or in a petition submitted no later than January 1, 2017 for implementation on July 1, 2017, whichever comes first, or

12. An alternative schedule determined by the Commission.

If pilot program proposals for revised, alternative mechanisms for recovering energy (fuel and purchased power) costs are required, the Commission may want to direct the IOUs to include in their proposals, one or more of the following features or provisions:

13. Annual or monthly energy cost rates

    a. A single rate throughout the year at the IOU's average energy costs ($/kWh) over the previous three years, or

    b. A different energy rate for each month of the year based on the IOU's average costs for that month over the past three years, [DOC]

    c. Some other alternative (other than a three-year historical average) that is representative of fuel and/or purchased energy costs for the rate case test year [MLIG]

14. Inclusion of fuel and/or purchased power costs

    a. Allow continued adjustments for fuel costs while fixing the level of purchased energy costs. (MLIG)

15. Asset-based and non-asset based margins

    a. A total comprehensive rate, i.e., all energy costs less offsetting asset-based and non-asset based margins when applicable, [OAG] or

    b. A partial rate, i.e., all energy costs without offsetting asset-based and non-asset-based margins, [OAG] or

    c. Proper accounting for wholesale margins. [MCC]

16. Known and measurable changes and replacement power costs

    a. Costs should be adjusted for known and measurable changes in rate cases. [MCC]

b. Outliers such as costs associated with forced outages should be removed in calculating the monthly energy costs. [MCC]

c. Clarify that if, for some reason, an unplanned and extended outage at a generating facility occurs and the utility purchases much more energy from the market than planned, then the Utilities would be free to submit a filing seeking recovery. [MLIG]

17. Caps and Deadbands

    a. Set the fixed fuel cost rate with a cap on utilities' cost recovery for fuel and purchased power costs at three percent above the authorized base cost in a utility's rate case. (OAG)

    b. Establish an appropriate cap on automatic adjustments. Below the cap, adjustments would continue as under the current FCA. Above the cap, the burden would be on the utility to seek recovery through a rate case or request deferred accounting. (MLIG)

18. Ongoing monitoring of fuel and purchased power costs during FCA reform pilot programs

    a. Require the IOUs to continue submitting monthly FCA filings and the annual automatic adjustment (AAA) reports to assess how this approach is working. [DOC]